TROPOSPHERE LEGAL

September 17, 2024

Ms. Lisa Felice
Michigan Public Service Commission
7109 W. Saginaw Hwy.
Lansing, MI 48909

Via E-File

RE: MPSC Case No. U-21534

Dear Ms. Felice:

Attached please find the enclosed documents for filing:

- Official Exhibits and Exhibit Lists of Michigan Environmental Council, Natural Resources Defense Council, Sierra Club, and Citizens Utility Board of Michigan;
- Proof of Service;
- Please note MEC-1 through MEC-22 were pre-filed for AG, MEC, and NRDC. Also note MEC-121C is a confidential exhibit and will be filed under seal.

Sincerely,

Digitally signed by Tracy Jane Andrews
DN: cn=Tracy Jane Andrews, o=Troposphere Legal, PLC, email=tjandrews@tropospherelegal.com, c=US
Date: 2024.09.17 14:09:07 -04'00'

Tracy Jane Andrews
tjandrews@tropospherelegal.com

CC: Parties to Case No. U-21534

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of **DTE ELECTRIC COMPANY** for authority to increase its rates, amend its rate schedules and rules governing the distribution and supply of electric energy, and for miscellaneous accounting authority.	Case No. U-21534

EXHIBIT LIST OF
MICHIGAN ENVIRONMENTAL COUNCIL

Exh #	Description
MEC-1	Curriculum Vitae of Paul J. Alvarez
MEC-2	MNSCDE-2.5 with Atts -22 Monthly Rate Benchmarking, April 2024 & -25 Spring 2023 Annual
MEC-3	MNSCDE-15.25c-h
MEC-4	U-20162, DTE Tree Trim Annual Report, March 2024
MEC-5	MNSCDE-8.5c (S1) with Atts 2022, 2023, and 2024 Budget Appropriations
MEC-6	MNSCDE-8.16di
MEC-7	MNSCDE-7.2h
MEC-8	MNSCDE-7.4a-d
MEC-9	MNSCDE-7.3a-f
MEC-10	Curriculum Vitae of Dennis Stephens
MEC-11	AG-MN Strategic Capital Disallowance Table
MEC-12	DS Equp Fail Analysis
MEC-13	U-21297 AGDE-4.103b with Att 01 PTMM and 4.8kV Hardening Metrics
MEC-14	MNSCDE-3.8c and -8.9c
MEC-15	MNSCDE-3.15ci - cii, also -3.23d, and -3.1a-c with excerpt from -3.1-01 Outages 2017-2023 (Dec. 2023 Outages)
MEC-16	MNSCDE-3.26a-b with Att -01 Subtransmission Interruptions
MEC-17	MNSCDE-1.8a with Att GPM
MEC-18	MNSCDE-5.4a-c
MEC-19	MNSCDE-8.5a with Att -01 Project Alternatives
MEC-20	MNSCDE-8.5c(S1)-04 4.8kV CC Almond Relief and Circuit Conversion (Midas)

MEC-21	MNSCDE-8.5c(S1) with Atts -47, -48, and -49
MEC-22	MNSCDE-8.18d
MEC-23	*Reserved*
MEC-24	IRM Investment Plan for 2025
MEC-25	MNSCDE-18.2a with Atts -01 through -08
MEC-26	MNSCDE-18.2b with Atts -01 through -20
MEC-27	MNSCDE-18.5a-c
MEC-28	*Reserved*
MEC-29	MNSCDE-17.16b
MEC-30	MNSCDE-17.24
MEC-31	MNSCDE-18.7
MEC-32	MNSCDE-18.10
MEC-33	MNSCDE-19.37a-d
MEC-34	MNSCDE-15.20c
MEC-35	MNSCDE-17.19 and -3.1a with excerpt from Att -01
MEC-36	Excerpt from U-21297 – 3 TR 392 Top 50 List
MEC-37	U-21297 Ex MNSC-89
MEC-38	Case No. U-12270 DTE 2023 Reliability Report
MEC-39	MNSCDE-17.18
MEC-40	MNSCDE-17.20
MEC-41	MNSCDE-18.27
MEC-42	MNSCDE-18.28 and -18.30
MEC-43	MNSCDE-18.29
MEC-44	MNSCDE-18.31
MEC-45	MNSCDE-18.32
MEC-46	MNSCDE-18.33c
MEC-47	MNSCDE-18-33d, e
MEC-48	MNSCDE-18.33g, h
MEC-49	MNSCDE-18.34
MEC-50	MNSCDE-18.35 and -15.41a
MEC-51	MNSCDE-18.36
MEC-52	MNSCDE-18.41
MEC-53	MNSCDE-18.42
MEC-54	MNSCDE-18.43 and -18.44
MEC-55	MNSCDE-19.12a, b

MEC-56	MNSCDE-19.16 and -19.17
MEC-57	MNSCDE-19.19
MEC-58	MNSDCD-19.35 and -19.36
MEC-59	Dec 2016 Smart Grid Report
MEC-60	Smart Grid Distribution Automation
MEC-61	MNSCDE-18.17
MEC-62	MNSCDE-18.20a, b, c
MEC-63	MNSCDE-18.21
MEC-64	MNSCDE-18.23 with Att -01
MEC-65	MNSCDE-18.24 with Att -01
MEC-66	MNSCDE-18.25
MEC-67	MNSCDE-12.9 with Att -01
MEC-68	MNSCDE-15.47h with Att -01
MEC-69	MNSCDE-20.12, -12.13, and -12.14
MEC-70	Annual TT Reports
MEC-71	WP AJK U-21534 GPM Model (working excel)
MEC-72	WP AJK U-21534 Reliability Model (working excel)
MEC-73	MNSCDE-19.28
MEC-74	MNSCDE-19.29, -19.30, -19.33, and -19.34
MEC-75	U-20162 Excerpt from Bruzzano Direct
MEC-76	*Reserved*
MEC-77	MNSCDE-19.2a-f
MEC-78	MNSCDE-17.1 and -13.11
MEC-79	MNSCDE-17.2 with Att -01
MEC-80	MNSCDE-17.4 and -15.34e with Att -01
MEC-81	MNSCDE-17.5a
MEC-82	MNSCDE-17.6
MEC-83	MNSCDE-19.5a-b
MEC-84	MNSCDE-19.6
MEC-85	MNSCDE-17.8
MEC-86	MNSCDE-17.9
MEC-87	*Reserved*
MEC-88	MNSCDE-17.10
MEC-89	*Reserved*
MEC-90	Ex A-12, Schedule B5.4 from U-21297

MEC-91	*Reserved*
MEC-92	U-21297 MNSCDE-2.11 supp with Att -01
MEC-93	*Reserved*
MEC-94	*Reserved*
MEC-95	*Reserved*
MEC-96	*Reserved*
MEC-97	U-21297 MNSCDE-3.8d, -3.9c, -3.16c, -3.23b, and -3.24b
MEC-98	U-21297 MNSCDE-3.13a-b
MEC-99	*Reserved*
MEC-100	*Reserved*
MEC-101	*Reserved*
MEC-102	*Reserved*
MEC-103	U-21297 STDE-6.4a-b
MEC-104	USDA Bulletin 1724D-101A
MEC-105	*Reserved*
MEC-106	MNSCDE-17.7
MEC-107	U-21534 MNSCDE-8.5c(S1) - narrative response (4 pages)
MEC-108	U-21534 MNSCDE-8.5c(S1)-33 CODI Islandview Substation - Phase 1
MEC-109	U-21534 MNSCDE-8.5c(S1)-34 CODI Islandview Substation - Phase 2
MEC-110	U-21534 MNSCDE-8.5c(S1)-35 CODI Islandview Substation - Phase 2
MEC-111	U-21534 MNSCDE-15.33a-b + 8.12a
MEC-112	U-21297 Ex A-23 Schedule M5 pp 1-5, 294-297 (Almont aka Midas)
MEC-113	U-21297 Ex A-23 Schedule M5 pp 250-253 (Islandview)
MEC-114	U-20836 Ex A-23 Schedule M5 Revised pp 1-4, 220-223 (Almont aka Midas)
MEC-115	U-20836 Ex A-12 Schedule B5.4 [p10 line 56 is Almont/Midas]
MEC-116	U-20836 Ex A-23 Schedule M5 Revised pp 172-175 (Islandview) - optional?
MEC-117	U-20561 Ex A-12 Schedule B5.4
MEC-118	U-20561 Ex A-23 Revised Schedule M5 pp 1-2, 70-71 (Almont), 68-69 (Islandview)
MEC-119	U-21297 Direct Testimony, Rebuttal Testimony and Cross Examination of Deol
MEC-120	MNSCDE-17.5c
MEC-121C	Attachment NDA CEII U-21534 MNSCDE-17.5a 4.8kV Circuits
MEC-122	MNSCDE-20.3 with Att -01
MEC-123	MNSCDE-20.4 with Att -01
MEC-124	MNSCDE-20.5 with Atts -01 and -02

MEC-125	MNSCDE-19.1a-c
MEC-126	MNSCDE-20.16
MEC-127	Staff Responses to MNSC 1a-d
MEC-128	AAA Meeting Presentation, dated April 18, 2023
MEC-129	Commission Orders Relating to EAAC, 2021-2022

TROPOSPHERE LEGAL, PLLC
Counsel for MEC, NRDC, SC, and CUB

Date: September 17, 2024

By: Digitally signed by Tracy Jane Andrews
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Curriculum Vitae -- Paul J. Alvarez MM, NPDP

Wired Group, PO Box 620756, Littleton, CO 80162. palvarez@wiredgroup.net 303-997-0317

Profile

After 15 years in Fortune 500 product development and product management, including P&L responsibility, Mr. Alvarez entered the utility industry by way of demand-side management rate and program development, marketing, and impact measurement for Xcel Energy in 2001. He has since designed renewable portfolio standard compliance and distributed generation rates and incentive programs. These experiences led to unique projects involving the measurement of grid modernization costs and benefits (energy, capacity, operating savings, revenue capture, reliability, environmental, and customer experience), which revealed conflicts between ratemaking and benefit maximization. Since 2012 Mr. Alvarez has led the Wired Group, a boutique consultancy serving consumer, business, and environmental advocates, and regulators in matters of distribution planning, investment, and performance measurement.

Appearances and Research Projects in Regulatory Proceedings

Evaluate Public Service Oklahoma Application for Rate Increase & Changes in Cost Recovery for Some Expense Types. Testimony on behalf of Commission Staff in PUD 2023-000086. July 29, 2024.

Evaluate DTE Energy's Request for Rate Increase, and to Extend and Expand Rider IRM. Testimony on behalf of a group of environmental and consumer advocates in Michigan PSC U-21534. July 26, 2024.

Determine If Customer Interest Is Served by Smart Meter Stipulation. Testimony before the Ohio PUC on behalf of the Office of Consumer Counsel. Ohio PUC 22-0704-EL-UNC. June 11, 2024.

Evaluate Commonwealth Edison Company's Refiled Grid Plan. Panel Testimony with Dennis Stephens on behalf of the Attorney General in Illinois Commerce Commission Case No. 22-0486. May 23, 2024.

Evaluate Ameren Illinois Company's Refiled Grid Plan. Panel Testimony with Dennis Stephens on behalf of the Attorney General in Illinois Commerce Commission Case No. 22-0487. May 13, 2024.

Evaluate Oklahoma Gas & Electric's historical spending. Testimony on behalf of Oklahoma Corporation Commission Staff in PUD-2023-000087. April 26, 2024.

Evaluate National Grid's historical spending and multi-year rate plan. Panel testimony with Dennis Stephens on behalf of the Attorney General in Massachusetts DPU Case 23-150. March 29, 2024.

Evaluate Pepco's Second Multi-Year Rate Plan. Panel testimony with Dennis Stephens on behalf of the Office of People's Counsel in Maryland PSC Case No. 9702. December 15, 2023.

Evaluate First Energy's Application to Continue Grid Mod I Program Spending in Grid Mod II. Testimony on behalf of the Ohio Consumers' Counsel in Ohio PUC Case No. 22-0704. October 23, 2023

Evaluate BGE's Second Multi-Year Rate Plan (Electric Distribution Components 2024-2027) and Electric Distribution Spending 2021-2022. Panel testimony with Dennis Stephens on behalf of the Office of People's Counsel in Maryland PSC Case No. 9692. June 20, 2023.

Evaluate DTE Energy's Request for Strategic Capital Plan Cost Recovery and Infrastructure Recovery Mechanism Rider on behalf of the Attorney General and a group of environmental and consumer advocates in Michigan PSC U-21297. June 13, 2023.

Evaluate Commonwealth Edison's Multi-year Grid Plan. Panel testimony with Dennis Stephens on behalf of the Attorney General in Illinois Commerce Commission 22-0486. May 22, 2023.

Evaluate Ameren Illinois Corporation's Multi-year Grid Plan. Panel testimony with Dennis Stephens on behalf of the Attorney General in Illinois Commerce Commission 22-0487. May 11, 2023.

Evaluate Public Service Oklahoma's $450 million Grid Enhancement and Resilience Plan and Request for Rider Cost Recovery from a Policy Perspective. Testimony on behalf of the Attorney General in PUD-2022-000093. March 7, 2023.

Evaluate Duke Energy's Peak-time Rebate Pilot Results. Testimony on behalf of the Attorney General in 2022-00251. November 9, 2022.

Evaluate Georgia Power's Transmission & Distribution Spending Proposals. Panel testimony with Dennis Stephens on behalf of Public Interest Advocacy Staff. Georgia PSC 44280. October 20, 2022.

Evaluate Pacific Gas & Electric's 2023-2026 Multi-year Rate Plan. Panel testimony with Dennis Stephens on behalf of AARP. California PUC A.21-06-021. June 10, 2022.

Evaluate the Distribution Business Components of Georgia Power Company's Integrated Resource Plan. Panel testimony with Dennis Stephens on behalf of Public Interest Advocacy Staff. Georgia PSC 44160. May 6, 2022.

Evaluate Policy Issues and Precedents Associated with Oklahoma Gas & Electric Company's Grid Modernization Factor. Testimony on behalf of the Office of Attorney General in PUD 2021000164. April 27, 2022.

Evaluate Grid Modernization and Advanced Metering Proposals by Massachusetts Utilities. Panel testimonies with Dennis Stephens on behalf of the Office of Attorney General in D.P.U. 21-80, 21-81, and 21-82. January 19, 2022.

Evaluate Dominion's Grid Transformation Plan. Testimony on behalf of Appalachian Voices/Southern Environmental Law Center. Virginia SCC PUR-2021-00127. September 13, 2021.

Investigate Avista Utilities' Electric Distribution and Wildfire Spending, Plans, and Processes. Panel testimony with Dennis Stephens on behalf of Public Counsel. WUTC 200900. April 29, 2021.

Evaluate Kentucky Utilities/Louisville Gas & Electric's CPCN to Install Advanced Meters. Testimony on behalf of the Attorney General. Kentucky PSC 2020-00349/00350. March 5, 2021.

Examine Potomac Electric Power Company's Electric Distribution Spending and Plan. Panel testimony with Dennis Stephens on behalf of the Office of People's Counsel. MD PSC 9655. March 3, 2021.

Determine If Customer Interest Is Served by Smart Meter Stipulation. Testimony before the Ohio PUC on behalf of the Office of Consumer Counsel. Ohio PUC 18-1875-EL-GRD. December 17, 2020.

Critique Public Service Electric & Gas Company's Smart Meter Deployment Plan. Testimony before the New Jersey Board of Public Utilities on behalf of the Division of Rate Counsel. NJ BPU EO18101115. Aug. 31, 2020.

Examine Oklahoma Gas and Electric's $800 million Grid Enhancement Plan. Testimony before the Oklahoma Corporations Commission on behalf of AARP. PUD 202000021. August 25, 2020.

Examine Baltimore Gas and Electric's 2021-2023 Grid Investment and Operations Plan. Panel testimony before the Maryland Public Service Commission with Dennis Stephens on behalf of the Office of People's Counsel. MDPSC 9645. August 14, 2020.

Critique of Duke Energy Carolinas/Duke Energy Progress $2.3 billion Grid Improvement Plan. Testimony before the North Carolina Utilities Commission on behalf of a coalition of consumer and environmental advocates. NCUC E-7, Sub 1214 February 18, 2020, and E-2, Sub 1219 March 25, 2020.

Critique of Investment in Traditional Meters (Equipped with AMR). Testimony before the New Hampshire Public Utilities Commission recommending rejection of cost recovery. DE 19-057. December 20, 2019.

Critique of Smart Meter Benefits Claimed by Puget Sound Energy. Testimony before the Washington Utility and Telecom Commission recommending rejection of cost recovery pending demonstration of benefits in excess of costs. UE-190529 and UG-190530. November 22, 2019.

Critique of Smart Meter Benefits Claimed by Rockland Electric Company. Testimony before the New Jersey Board of Public Utilities on behalf of the Division of Consumer Advocate recommending rejection of cost recovery pending demonstration of benefits in excess of costs. ER19050552. October 11, 2019.

Critique of Grid Improvement Plan Proposed by Indianapolis Power and Light. Testimony before the Indiana Utility Regulatory Commission recommending reductions in the size of the plan ($1.2 billion) based on benefit-cost analyses of plan components. Cause 45264. October 7, 2019.

Investigation into Distribution Planning Processes. Comments to the Michigan Public Service Commission recommending a transparent, stakeholder-engaged distribution planning process. U-20147. September 11, 2019.

Investigation into Grid Modernization. Comments to the New Hampshire Public Utilities Commission recommending a transparent, stakeholder-engaged distribution planning process. IR 15-296. September 6, 2019.

Arguments to Reduce and Re-prioritize Grid Modernization Investments Proposed by Pacific Gas & Electric. Testimony before the California Public Utilities Commission. A.18-12-009. July 26, 2019.

Evaluation of Xcel Energy's Request for an Advance Determination of Prudence Regarding Natural Gas Generation Plant Purchase. Testimony before the North Dakota Public Service Commission. PU-18-403. May 28, 2019.

Critique of Smart Meter Replacement Program Implied by Proposed Duke Energy Ohio Global Settlement Agreement. Testimony before the Public Utilities Commission of Ohio on behalf of the Office of Consumer Counsel. Numerous cases including 17-0032-EL-AIR. June 25, 2018.

Support for Considering Duke Energy Grid Modernization Investments in a Distinct Proceeding. Testimony before the North Carolina Utilities Commission on behalf of the Environmental Defense Fund. E-2 Sub 1142, October 18, 2017 and E-7 Sub 1146, January 19, 2018.

Evaluate Southern California Edison's Request to Invest $2.3 Billion in its Grid to Accommodate Distributed Energy Resources. Testimony before the California Public Utilities Commission on behalf of The Utility Reform Network. A16-09-001. May 2, 2017.

Evaluate Kentucky Utilities/Louisville Gas & Electric Smart Meter Deployment Plan. Testimony before the Kentucky Public Service Commission on behalf of the Kentucky Attorney General in 2016-00370/2016-00371. March 3, 2017. Also in 2018-00005 May 18, 2018

Evaluate National Grid's Massachusetts Smart Meter Deployment Plan. Testimony before the Massachusetts Department of Public Utilities on behalf of the Massachusetts Attorney General in 15-120. March 10, 2017. Also Unitil in 15-121 and Eversource in 15-122/123, March 10, 2017

Evaluate Pacific Gas & Electric's Request to Invest $100 Million in Its Grid to Accommodate Distributed Energy Resources. Testimony before the California Public Utilities Commission on behalf of The Utility Reform Network, A15-09-001. April 29, 2016

Arguments to Consider Duke Energy's Smart Meter CPCN in the Context of a Rate Case. Testimony before the Kentucky Public Service Commission on behalf of the Attorney General in 2016-00152. July 18, 2016.

Evaluate Westar Energy's Proposal To Mandate a Rate Specific to Distributed Generation-Owning Customers. Testimony before the Kansas Corporation Commission on Behalf of the Environmental Defense Fund, case 15-WSEE-115-RTS. July 9, 2015.

Regulatory Reform Proposal to Base a Significant Portion of Utility Compensation on Performance in the Public Interest. Testimony before the Maryland PSC on behalf of the Coalition for Utility Reform, case 9361. December 8, 2014.

Duke Energy Ohio Smart Grid Audit and Assessment. Primary research and report prepared for the Public Utilities Commission of Ohio case 10-2326-GE. June 30, 2011.

SmartGridCity™ Demonstration Project Evaluation Summary. Primary research and report prepared for Xcel Energy. Colorado Public Utilities Commission case 11A-1001E. October 21, 2011.

Books

Smart Grid Hype & Reality: A Systems Approach to Maximizing Customer Return on Utility Investment. Second edition. ISBN 978-0-615-88795-1. Wired Group Publishing. 360 pages. 2018.

Noteworthy Publications

Alternative Ratemaking in the US: A Prerequisite for Grid Modernization, or an Unwarranted Shift of Risk to Customers? With Kenneth Costello, Sean Ericson and Dennis Stephens. Electricity Journal. Volume 35 (October, 2022).

Utility Regulation Through Legislation: A Cautionary Tale for Legislators, Regulators, Stakeholders, and Utilities. With Sean Ericson and Dennis Stephens. Electricity Journal. Volume 34 (August, 2021).

Florida Storm Protection Plans: A Bonanza for Utilities, a Bust for Consumers and the State. Whitepaper co-authored with Dennis Stephens for AARP-Florida. October 5, 2020.

Challenging Utility Grid Modernization Proposals. With Sean Ericson and Dennis Stephens. Public Utilities Fortnightly. Part 1, August, 2020, pages 59-62; Part 2 September, 2020.

The Rush to Modernize: An Editorial on Distribution Planning and Performance Measurement. With Sean Ericson and Dennis Stephens. Public Utilities Fortnightly. July 8, 2019. Pages 116+

Modernizing the Grid in the Public Interest: Getting a Smarter Grid at the Least Cost for South Carolina Customers. Whitepaper co-authored with Dennis Stephens for GridLab. January 31, 2019

Modernizing the Grid in the Public Interest: A Guide for Virginia Stakeholders. Whitepaper co-authored with Dennis Stephens for GridLab. October 5, 2018.

Measuring Distribution Performance? Benchmarking Warrants Your Attention. With Sean Ericson. Electricity Journal. Volume 31 (April, 2018), pages 1-6.

Busting Myths: Investor-Owned Utility Performance Can be Credibly Benchmarked. With Joel Leonard. Electricity Journal. Volume 30 (October, 2017), pages 45-48.

Price Cap Electric Ratemaking: Does it Merit Consideration? With Bill Steele. Electricity Journal. Volume 30, (October, 2017), pages 1-7.

Integrated Distribution Planning: An Idea Whose Time has Come. Public Utilities Fortnightly. November, 2014; also International Confederation of Energy Regulators Chronicle, 3rd Ed, March, 2015

Smart Grid Economic and Environmental Benefits: A Review and Synthesis of Research on Smart Grid Benefits and Costs. Secondary research report prepared for the Smart Grid Consumer Collaborative. October 8, 2013. Companion piece: Smart Grid Technical and Economic Concepts for Consumers.

Is This the Future? Simple Methods for Smart Grid Regulation. Smart Grid News. October 2, 2014.

A Better Way to Recover Smart Grid Costs. Smart Grid News. September 3, 2014.

Why Should We Switch to Performance-based Compensation? Smart Grid News. August 15, 2014.

The True Cost of Smart Grid Capabilities. Intelligent Utility. June 30, 2014.

Maximizing Customer Benefits: Performance Measurement and Action Steps for Smart Grid Investments. Public Utilities Fortnightly. January, 2012.

Buying Into Solar: Rewards, Challenges, and Options for Rate-Based Investments. Public Utilities Fortnightly. December, 2009.

Notable Presentations

NASUCA Annual Meeting. *Alternative Ratemaking: Unintended Consequences and Recommendations for Consumer Advocates.* Charlotte, NC. November 7, 2023.

NASUCA Electricity Committee Meeting. *Alternative Ratemaking and Grid Modernization: Considerations for Consumer Advocates.* With Dennis Stephens and Ken Costello. December 7, 2022.

NASUCA Annual Meeting. *Reinventing Distribution Planning in New Hampshire.* With D. Maurice Kreis, Executive Director, Office of Consumer Advocate. San Antonio, TX. November 19, 2019.

National Council on Electricity Policy Annual Meeting. Trainer on the economics of distribution grid interoperability and standard compliance; Presentation on communication network economics. Austin, TX. Sept 10-12, 2019.

NASUCA Annual Meeting. *Grid Modernization: Basic Technical Challenges Advocates Should Assert.* Orlando, FL. November 13, 2018.

Illinois Commerce Commission, NextGrid Working Group 7. *Using Peer Comparisons in Distributor Performance Evaluation.* Workshop 3 Presentation. Chicago, IL. July 30, 2018.

NARUC Committee on Electricity. *Using Peer Comparisons in Distributor Performance Evaluation.* Smart Money in Grid Modernization Panel Presentation. Scottsdale, AZ. July 16, 2018.

Public Utilities Commission of Ohio, Power Forward Proceeding Phase 2. *Getting a Smart Grid for FREE.* Columbus, Ohio. July 26, 2017.

NASUCA Mid-Year Meeting. *Using Performance Benchmarking to Gain Leverage in an "Infrastructure Oriented" Environment.* Denver, CO. June 6, 2017.

NARUC Committee on Energy Resources and the Environment. *How big data can lead to better decisions for utilities, customers, and regulators***.** Washington DC. February 15, 2016.

National Conference of Regulatory Attorneys 2014 Annual Meeting. *Smart Grid Hype & Reality.* Columbus, Ohio. June 16, 2014.

NASUCA 2013 Annual Conference. *A Review and Synthesis of Research on Smart Grid Benefits and Costs.* Orlando, FL. November 18, 2013.

NARUC Subcommittee on Energy Resources and the Environment. *The Distributed Generation (R)Evolution.* Orlando, FL. November 17, 2013.

IEEE Power and Energy Society, ISGT 2013. *Distribution Performance Measures that Drive Customer Benefits.* Washington DC. February 26, 2013.

Great Lakes Smart Grid Symposium. *What Smart Grid Deployment Evaluations are Telling Us*. Chicago. September 26, 2012.

Mid-Atlantic Distributed Resource Initiative. *Smart Grid Deployment Evaluations: Findings and Implications for Regulators and Utilities.* Philadelphia. April 20, 2012

DistribuTECH 2012. *Lessons Learned: Utility and Regulator Perspectives.* Panel Moderator. January 25.

DistribuTECH 2012. *Optimizing the Value of Smart Grid Investments.* Half-day course. January 23.

NARUC Subcommittee on Electricity. *Maximizing Smart Grid Customer Benefits: Measurement and Other Implications for Investor-Owned Utilities and Regulators*. St. Louis, MO. November 13, 2011.

Canadian Electric Institute 2013 Annual Distribution Conference. *The (Smart Grid) Story So Far: Costs, Benefits, Risks, Best Practices, and Missed Opportunities.* Toronto, Canada. January 23, 2011.

Teaching

Post-graduate Adjunct Professor. University of Colorado, Global Energy Management Program. Course: Renewable Energy Commercialization -- Electric Technologies, Markets, and Policy.

Guest Lecturer. Michigan State University, Institute for Public Utilities. Courses: Performance Measurement of Distribution Utility Businesses; Introduction to Grid Modernization.

Education

Master's Degree in Management, 1991, Kellogg School of Management, Northwestern University. Concentrations: Finance, Accounting, Information Systems, and International Business.

Bachelor's Degree in Business Administration, 1984, Kelley School of Business, Indiana University. Concentrations: Finance, Marketing.

Certifications

New Product Development Professional. Product Development and Management Association. 2007.

MPSC Case No: U-21534

Requester: MNSC

Question No.: MNSCDE-2.5

Respondent: A. Willis

Page: 1 of 1

Question: 5. Produce all analyses prepared by or for DTE Electric within the past three years that compare its present or proposed rates to other electric distribution companies or electric utilities, including all workpapers and source documents. (By way of example and not by way of limitation, see attachments provided with discovery response AGDE-1.13 in Case No. U-20836.)

Answer: DTE Electric objects for the reason that the request is unduly burdensome, overly broad, and incapable of answer in its present form since the Company cannot be certain that it is aware of "all" such materials described by the requestor. Subject to and without waiving its objection, the Company would answer as follows:

Please refer to the attached documents

Attachment:
U-21534 MNSCDE-2.5-01 Monthly Rate Benchmarking - 2022 07_July vFinal.pdf
U-21534 MNSCDE-2.5-02 Monthly Rate Benchmarking - 2022 08_August vFinal.pdf
U-21534 MNSCDE-2.5-03 Monthly Rate Benchmarking - 2022 09_September vFinal.pdf
U-21534 MNSCDE-2.5-04 Monthly Rate Benchmarking - 2022 10_October vFinal.pdf
U-21534 MNSCDE-2.5-05 Monthly Rate Benchmarking - 2022 11_November vFinal.pdf
U-21534 MNSCDE-2.5-06 Monthly Rate Benchmarking - 2022 12_December vFinal.pdf
U-21534 MNSCDE-2.5-07 Monthly Rate Benchmarking - 2023 01_January vFinal.pdf
U-21534 MNSCDE-2.5-08 Monthly Rate Benchmarking - 2023 02_February vFinal.pdf
U-21534 MNSCDE-2.5-09 Monthly Rate Benchmarking - 2023 03_March vFinal.pdf
U-21534 MNSCDE-2.5-10 Monthly Rate Benchmarking - 2023 04_April vFinal.pdf
U-21534 MNSCDE-2.5-11 Monthly Rate Benchmarking - 2023 05_May vFinal.pdf
U-21534 MNSCDE-2.5-12 Monthly Rate Benchmarking - 2023 06_June vFinal.pdf
U-21534 MNSCDE-2.5-13 Monthly Rate Benchmarking - 2023 07_July vFinal.pdf
U-21534 MNSCDE-2.5-14 Monthly Rate Benchmarking - 2023 08_August vFinal.pdf
U-21534 MNSCDE-2.5-15 Monthly Rate Benchmarking - 2023 09_September vFinal.pdf
U-21534 MNSCDE-2.5-16 Monthly Rate Benchmarking - 2023 10_October vFinal.pdf
U-21534 MNSCDE-2.5-17 Monthly Rate Benchmarking - 2023 11_November vFinal.pdf
U-21534 MNSCDE-2.5-18 Monthly Rate Benchmarking - 2023 12_December vFinal.pdf
U-21534 MNSCDE-2.5-19 Monthly Rate Benchmarking - 2024 1_January vFinal.pdf
U-21534 MNSCDE-2.5-20 Monthly Rate Benchmarking - 2024 2_February vFinal.pdf
U-21534 MNSCDE-2.5-21 Monthly Rate Benchmarking - 2024 3_March vFinal.pdf
U-21534 MNSCDE-2.5-22 Monthly Rate Benchmarking - 2024_4 April vFinal.pdf
U-21534 MNSCDE-2.5-23 Spring 2024 Annual.pdf
U-21534 MNSCDE-2.5-24 Spring 2022 Annual.pdf
U-21534 MNSCDE-2.5-25 Spring 2023 Annual.pdf
U-21534 MNSCDE-2.5-26 2020 Baseline - EIA Rate Benchmarking Data Monthly Analysis_2023 December.xlsx
U-21534 MNSCDE-2.5-27 2021 Baseline - EIA Rate Benchmarking Data Monthly Analysis_2024 January.xlsx



Monthly Electric Rate Benchmarking

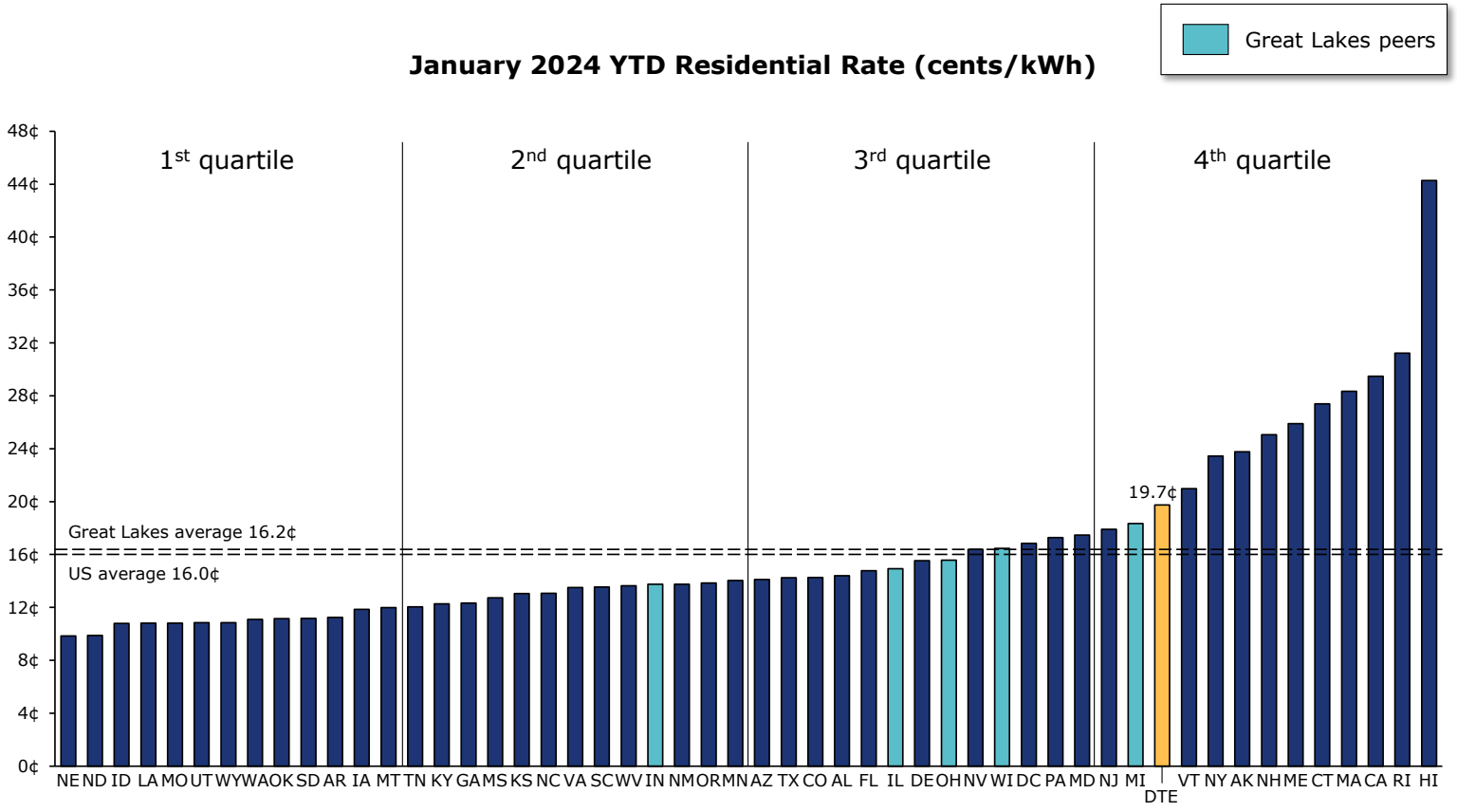
April 12, 2024

Agenda

- Electric Rate Benchmarking (EIA data through January 2024)

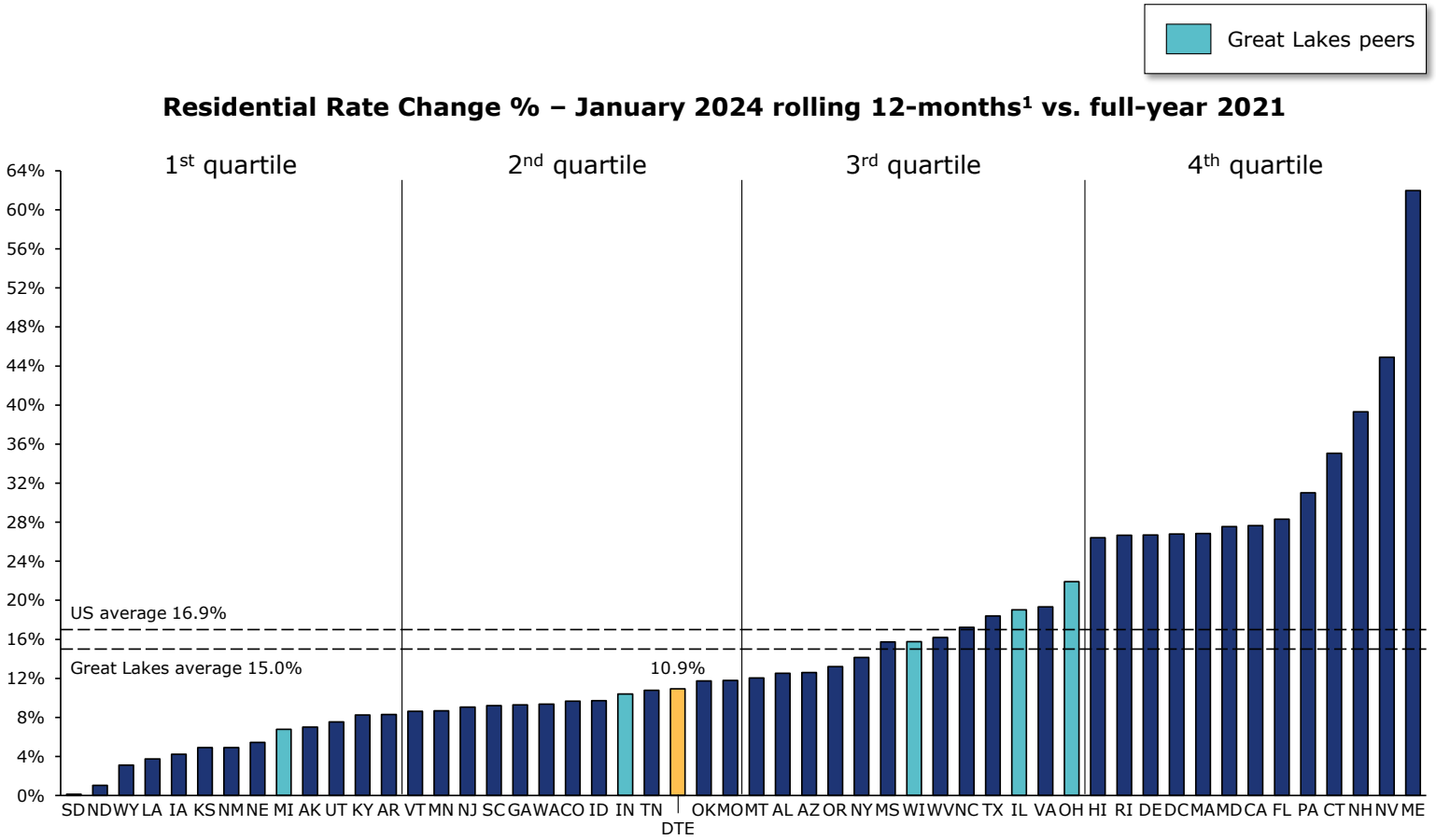
- National Electric Rate Case Approvals

While DTE's residential rates are above the national average…



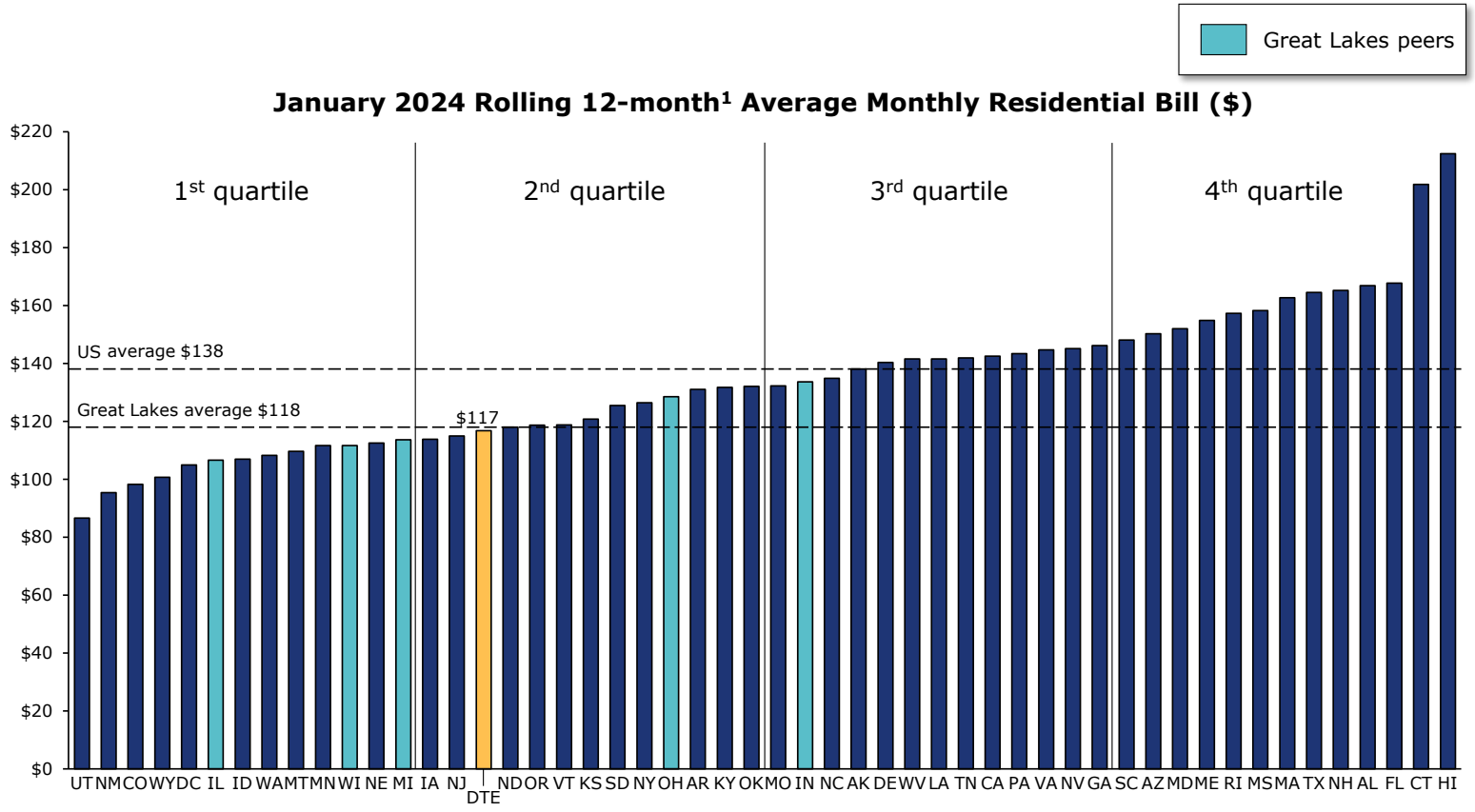
Source: EIA form 861M

… DTE's rates have been increasing at a slower pace than most other states since 2021



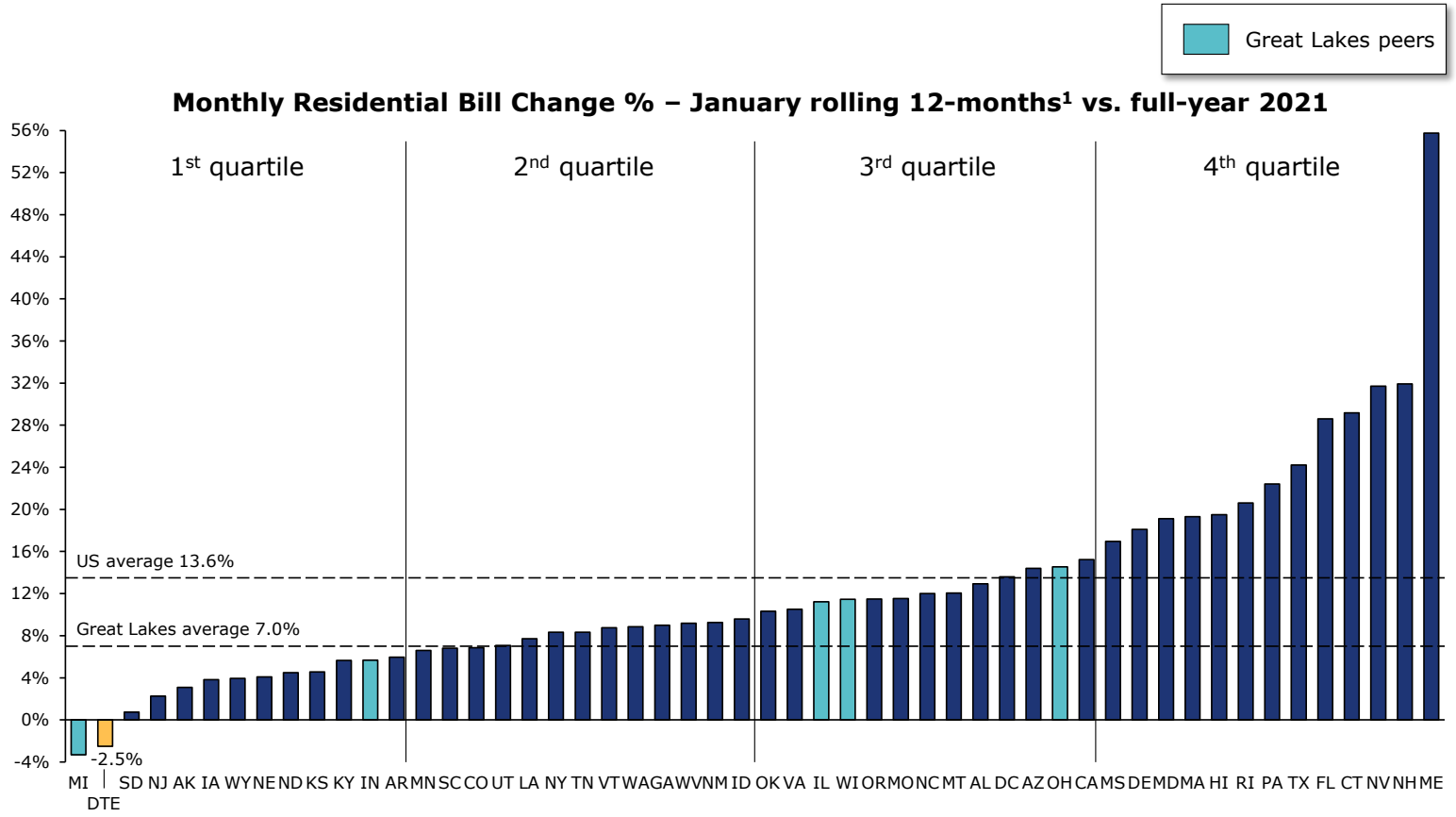
Source: EIA form 861M
1. The 12-month average is the average residential rate from February 2023 to January 2024

DTE's residential bills remain in the 2nd quartile and below the Great Lakes average



Source: EIA form 861M
1. The 12-month average is the average monthly residential bill from February 2023 to January 2024

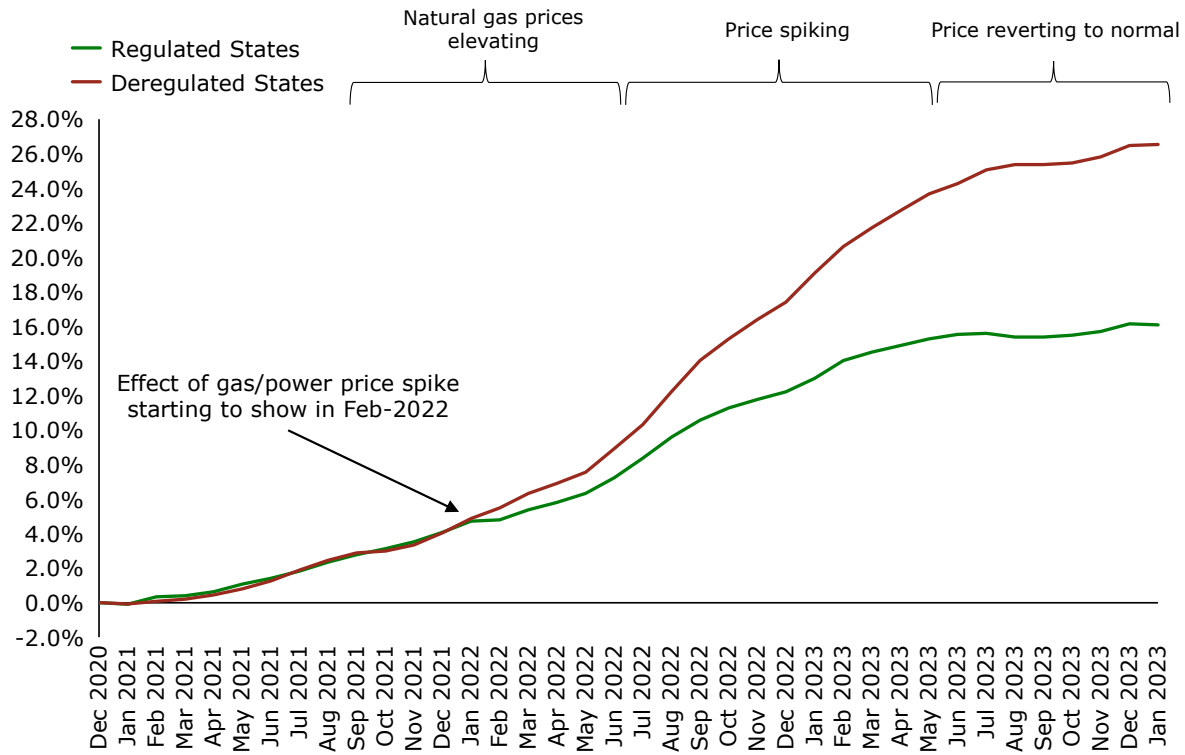
DTE's residential bill has decreased since 2021 and is first quartile in the nation



Source: EIA form 861M
1. The 12-month average is the average monthly residential bill from February 2023 to January 2024

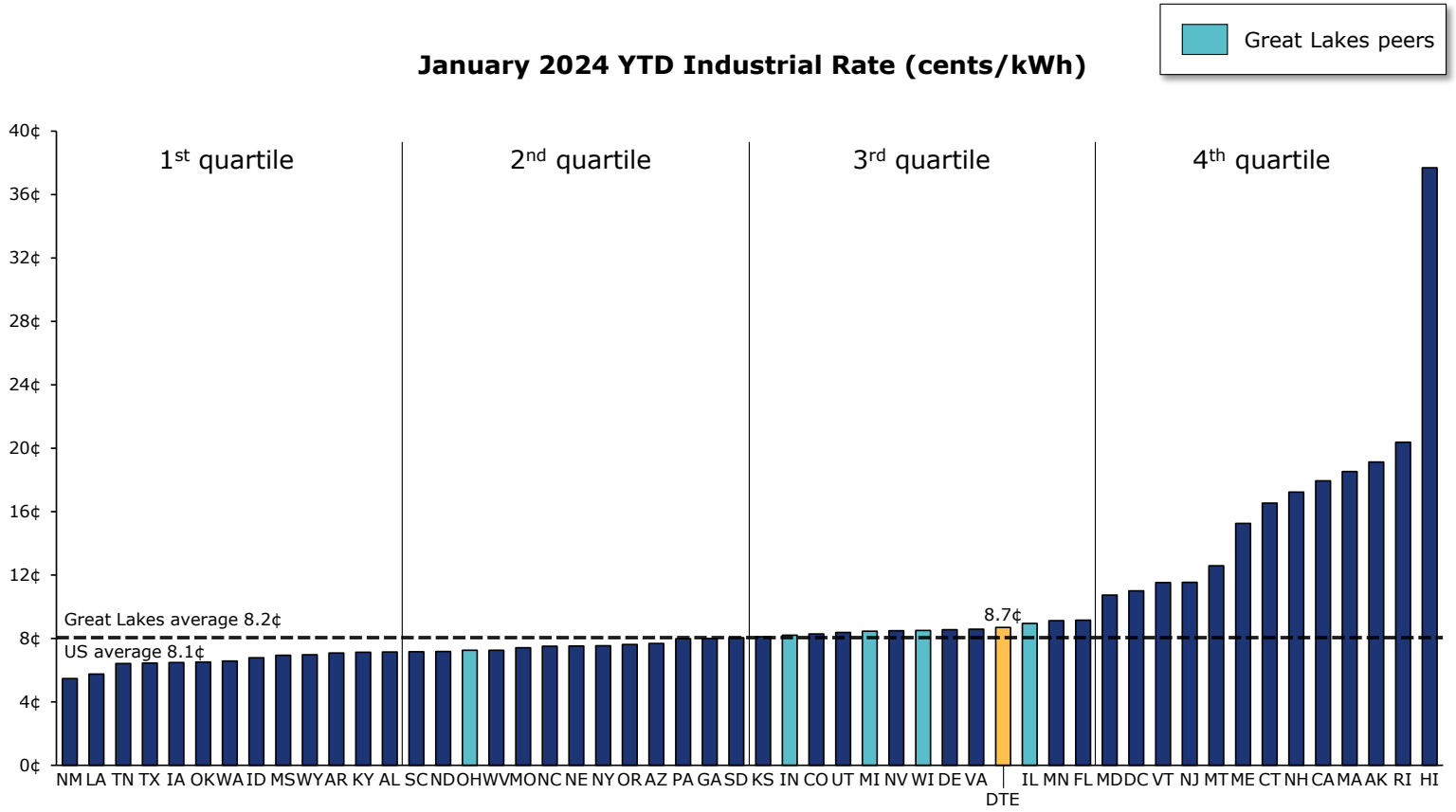
Rate increases in deregulated states have remained elevated from regulated states, despite gas prices reverting to normal

Residential Electric Rate Change %
Rolling 12 months[1] vs. full-year 2020



Source: EIA form 861M and 861
1. Rolling 12 Months is the average residential rate from the preceding 12 months

DTE's average industrial rates are ranked 3rd quartile and above the national and Great Lakes averages



DTE

Source: EIA form 861M

Agenda

- Electric Rate Benchmarking (EIA data through January 2024)

- National Electric Rate Case Approvals

1. Bureau of Labor Statistics

Approved Electric Rate Cases since 2021 through April 12, 2024 – Regulated States[1] (1 of 2)

Utility	State	Auth. Date	Years Since Last Rate Case	Requested Increase ($M)	Auth. Increase ($M)	Requested ROE	Auth. ROE	Increase as % of Revenue[2]
PacifiCorp	WA	03/19/24	3.3	$41	$34	ROE Not Made Public		0.7%
Arizona Public Service Co.	AZ	03/05/24	2.3	$690	$492[3]	10.25%	9.55%	12.9%
Consumers Energy	MI	03/01/24	1.1	$169	$92	10.25%	9.90%	1.9%
Public Service Co. of NM	NM	01/03/24	6.0	$64	$15	10.25%	9.26%	1.5%
Idaho Power Co.	ID	12/28/23	12.0[4]	$111	$55	10.40%	9.60%	3.9%
Nevada Power	NV	12/26/23	3.0	$93	$37	10.26%	9.52%	1.5%
Portland General	OR	12/18/23	1.7	$391	$386	9.80%	9.50%	18.0%
Entergy Arkansas	AR	12/04/23	1.0	$89	$88	ROE Not Made Public		4.3%
DTE Electric	MI	12/01/23	1.0	$583	$368	10.25%	9.90%	6.5%
Appalachian Power Co.	VA	11/30/23	3.0	$213	$127	ROE Not Made Public		4.3%
Northern States Power	WI	11/09/23	2.0	$40	$1	10.25%	9.80%	0.0%
Wisconsin Power & Light	WI	11/09/23	2.0	$182	$111	10.00%	9.80%	8.7%
Public Service Co. of OK	OK	11/03/23	1.8	$294	$131	10.40%	9.30%	7.4%
Public Service Co. of CO	CO	09/06/23	1.5	$303	$45	10.25%	9.30%	1.3%
NIPSCO	IN	08/02/23	3.7	$279	$262	10.40%	9.80%	15.1%
Union Electric	MO	06/14/23	1.5	$239	$140	ROE Not Made Public		4.5%
Oklahoma Gas & Electric	AR	03/02/23	1.0	$10	$10	ROE Not Made Public		0.3%

Source: S&P Capital IQ Pro

1. Peer set includes utilities with more than 500,000 customers or companies within the Great Lakes peer set
2. Based on electric utility revenue from 2022 and gathered from S&P Capital IQ Pro
3. Large rate increase driven by increase to authorized ROE (8.90% in last rate case) and approval of $1.5 billion increase to rate base
4. Riders were available to recover investments for the past 12 years prior to this rate case

Approved Electric Rate Cases since 2021 through April 12, 2024 – Regulated States[1] (2 of 2)

Utility	State	Auth. Date	Years Since Last Rate Case	Requested Increase ($M)	Auth. Increase ($M)	Requested ROE	Auth. ROE	Increase as % of Revenue[2]
Southwestern Electric Power	LA	02/17/23	10.0[5]	$95	$27	10.35%	9.50%	1.4%
Wisconsin Electric Power	WI	12/29/22	1.4	$258	$281	10.00%	9.80%	9.0%
Wisconsin Public Service Co.	WI	12/22/22	3.1	$73	$113	10.00%	9.80%	9.7%
Puget Sound	WA	12/22/22	2.5	$347	$223	9.90%	9.40%	8.9%
Evergy Metro	MO	11/21/22	4.1	$48	$25	ROE Not Made Public		1.5%
Indiana Michigan Power	IN	02/23/22	2.0	$107	($95)[4]	10.00%	9.70%	(4.6%)
Dominion Energy SC	SC	07/21/21	8.6	$178	$62	10.25%	9.50%	2.1%
Kentucky Utilities	KY	06/30/21	2.2	$170	$106	10.00%	9.43%	5.4%

Source: S&P Capital IQ Pro
1. Peer set includes utilities with more than 500,000 customers or companies within the Great Lakes peer set
2. Based on electric utility revenue from 2022 and gathered from S&P Capital IQ Pro
3. Georgia Power approved rate case to be recovered over three years
4. Rate reduction in IMP's Indiana rate case reflects the removal of $141 million of annual lease payment attributable to the December 2022 lease termination for unit 2 of the Rockport plant and a lower cost of capital structure (9.7% vs. 10% ROE)

Approved Electric Rate Cases since 2021 through April 12, 2024 – Deregulated States[1]

Utility	State	Auth. Date	Years Since Last Rate Case	Requested Increase ($M)	Auth. Increase ($M)	Requested ROE	Auth. ROE	Increase as % of Revenue[2]
Jersey Central Power & Light	NJ	02/14/24	3.3	$192	$85	10.40%	9.60%	4.4%
NSTAR Electric	MA	12/26/23	1.1	$105	$105	ROE Not Made Public		3.5%
San Diego Gas & Electric	CA	12/22/23	1.0	$44	$44	10.65%	10.65%	1.1%
Southern California Edison	CA	12/22/23	1.0	$201	$201	10.75%	10.75%	1.3%
Pacific Gas and Electric	CA	12/22/23	1.0	$158	$158	10.70%	10.70%	1.0%
Atlantic City Electric	NJ	11/17/23	2.3	$92	$45	10.50%	9.60%	3.8%
Massachusetts Electric	MA	09/28/23	1.0	$67	$67	ROE Not Made Public		2.5%
Central Maine Power	ME	06/06/23	3.3	$90	$67	10.20%	9.35%	8.3%
Oncor Electric	TX	03/09/23	5.4	$251	$101	10.30%	9.70%	2.2%
Duke Energy Ohio	OH	12/14/22	4.0	$55	$23	10.30%	9.50%	2.0%
Dayton Power & Light	OH	12/14/22	4.2	$121	$76	10.50%	10.00%	10.3%
Duquesne Light	PA	12/16/21	3.0	$115	$74	ROE Not Made Public		6.9%
PECO Energy	PA	11/18/21	2.9	$246	$168	ROE Not Made Public		6.4%
Ohio Power	OH	11/17/21	9.9	$402	$295	10.15%	9.70%	8.8%

Source: S&P Capital IQ Pro
1. Peer set includes utilities with more than 500,000 customers or companies within the Great Lakes peer set
2. Based on bundled electric utility revenue and bundled electric sales from 2022; gathered from S&P Capital IQ Pro

Approved Multi-Year Electric Rate Cases since 2021 through April 12, 2024 – All States[1]

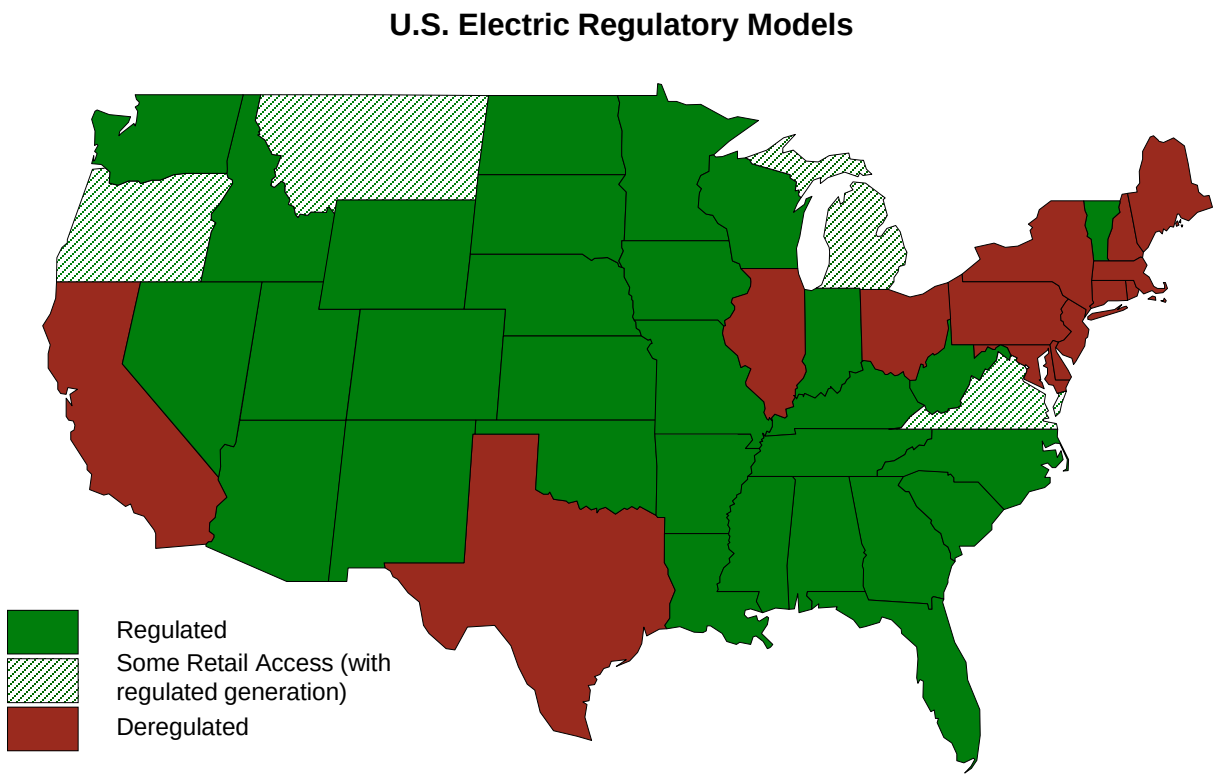
Utility	State	Auth. Date	Years Since Last Rate Case	Requested Increase ($M)	Auth. Increase ($M)	Requested ROE	Auth. ROE	Years to Recover Increase
Duke Energy Carolinas	NC	12/15/23	2.7	$833	$769	10.40%	10.10%	3
Baltimore Gas & Electric	MD	12/14/23	3.0	$314	$179	10.40%	9.50%	3
Commonwealth Edison	IL	12/14/23	1.1	$1,487	$506	10.65%	8.91%	4
Ameren Illinois	IL	12/14/23	1.0	$465	$142[2]	10.50%	8.72%	4
NY State Electric & Gas	NY	10/12/23	2.9	$274	$137	10.20%	9.20%	3
Duke Energy Progress	NC	08/18/23	2.3	$227	$148	10.40%	9.80%	3
ConEd of NY	NY	07/20/23	3.5	$1,038	$442	10.00%	9.25%	3
Georgia Power	GA	12/20/22	1.1	$1,004	$996	11.00%	10.50%	3
Delmarva Power & Light	MD	12/14/22	0.8	$37	$29	10.25%	9.60%	3
Niagara Mohawk Power	NY	01/20/22	3.8	$103	$49	9.50%	9.00%	3
Florida Power & Light	FL	10/26/21	4.9	$1,680	$1,252	11.50%	10.60%	2[3]
Tampa Electric Company	FL	10/21/21	4.0	$423	$302	10.75%	9.95%	3
Potomac Electric Power	MD	06/28/21	1.9	$104	$52[3]	10.20%	9.55%	3
Duke Energy Florida	FL	05/04/21	3.5	$195	$195	9.85%	9.85%	3

Source: S&P Capital IQ Pro

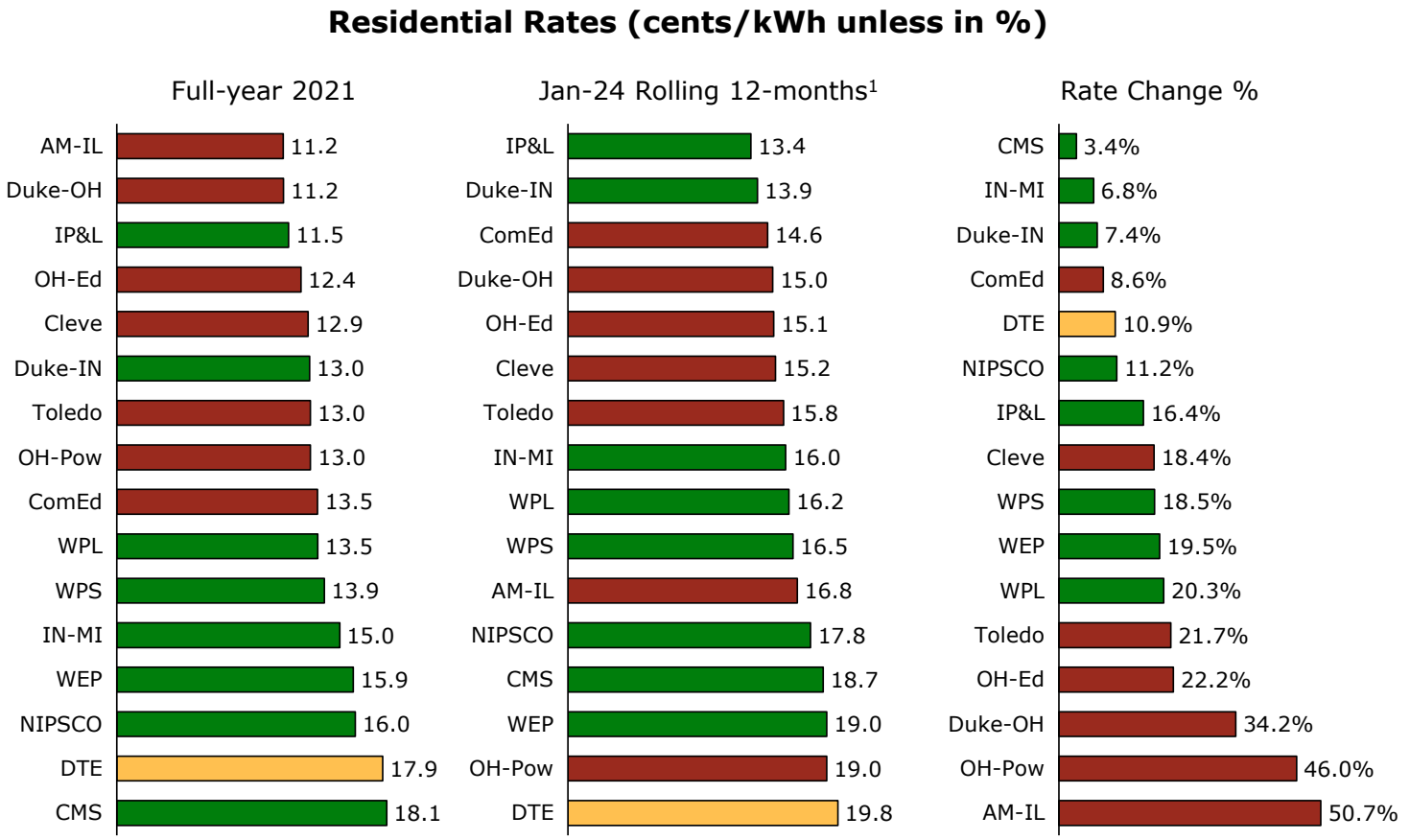
1. Peer set includes utilities with more than 500,000 customers or companies within the Great Lakes peer set (both regulated and deregulated states included on this page)
2. Ameren Illinois originally was granted a $58M rate increase but amendatory order increased this to $142M (this $142M increase has had a request for rehearing placed by Ameren Illinois that is still pending)
3. Florida Power and Light can recover full authorized increase in 2 years, but has a stay-out clause for 3 years (until 2025)

Appendix

We benchmark state-level data (EIA) with a three-month lag by regulatory models. We track national rate case and multi-year plan approval results

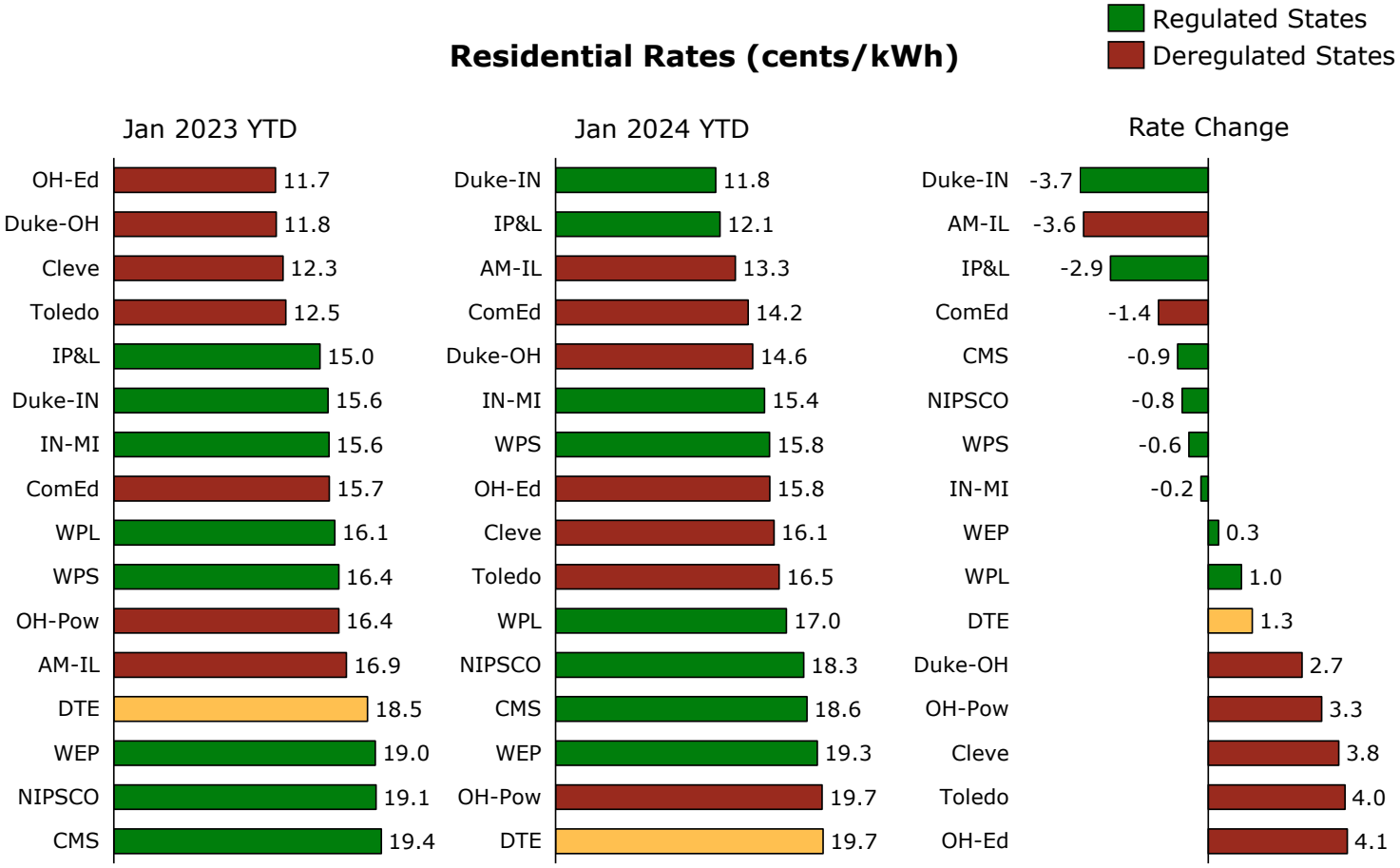


Great Lakes peer utilities 2021 to January 2024 rate increase



Source: EIA Form 861M, fully bundled rates
1. The 12-month average is the average residential rate from February 2023 to January 2024

Great Lakes peer utilities year to date rate increase (January 2023 YTD to January 2024 YTD)



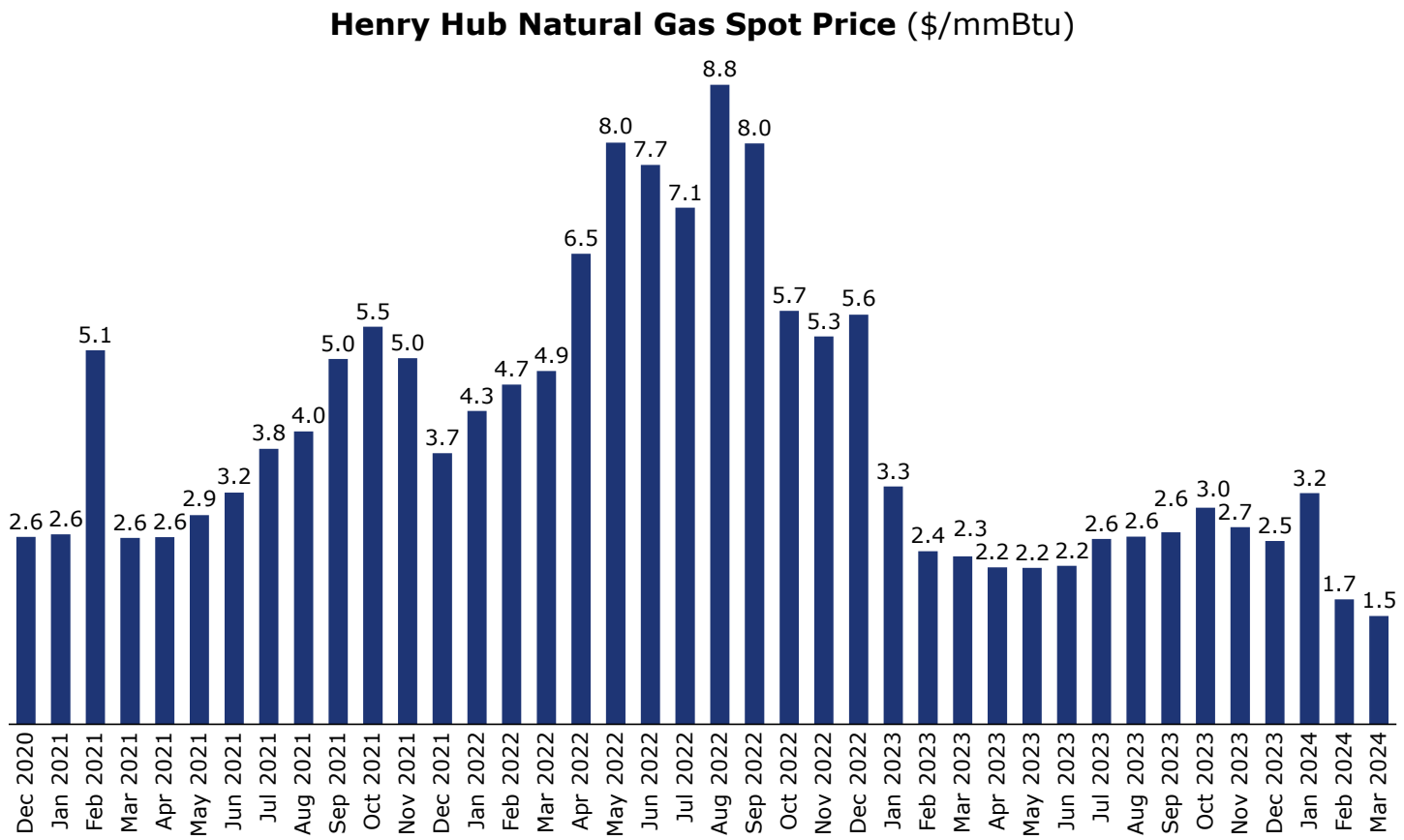
Source: EIA Form 861M, fully bundled rates

The rate case benchmarking peer set includes utilities with more than 500,000 customers or are part of DTE's Great Lakes peer group

Regulated		Deregulated	
AES Indiana*	MidAmerican Energy*	Ameren Illinois	NY State Electric & Gas
Alabama Power	Nevada Power	Atlantic City Electric	Niagara Mohawk Power
Appalachian Power	Northern IN Pub. Serv.	Baltimore Gas & Electric	NSTAR Electric
Arizona Public Service	Northern States Power	CenterPoint Houston*	Ohio Edison
Consumers Energy	Oklahoma Gas & Electric	Central Maine Power	Ohio Power
Dominion Energy SC	PacifiCorp	Cleveland Electric*	Oncor Electric
DTE Electric	Portland General Electric	Commonwealth Edison	Pacific Gas & Electric
Duke Energy Carolinas	Pub. Serv. of CO	Con. Edison of NY	PECO Energy
Duke Energy Florida	Pub. Serv. of NH*	CT Light & Power*	Pennsylvania Electric*
Duke Energy Indiana*	Pub. Serv. of NM	Dayton Power & Light	Potomac Electric
Duke Energy Progress	Pub. Serv. of OK	Delmarva Power & Light	PPL Electric*
Entergy Arkansas	Puget Sound	Duke Energy Ohio	Pub. Serv. Electric & Gas*
Entergy Louisiana*	Southwestern Electric	Duquesne Light	San Diego Gas & Electric
Evergy Metro	Tampa Electric	Jersey Central P&L	Southern CA Edison
Florida Power & Light	Union Electric	Massachusetts Electric	Toledo Edison*
Georgia Power	Wisconsin Electric Power	Metropolitan Edison*	West Penn Power*
Idaho Power	Wisconsin Power & Light		
Indiana Michigan Power	Wisconsin Pub. Serv.		
Kentucky Utilities			

*Utility has not had an electric rate case approved since 2021 (as of April 12, 2024)

Natural gas prices have been volatile since 2020



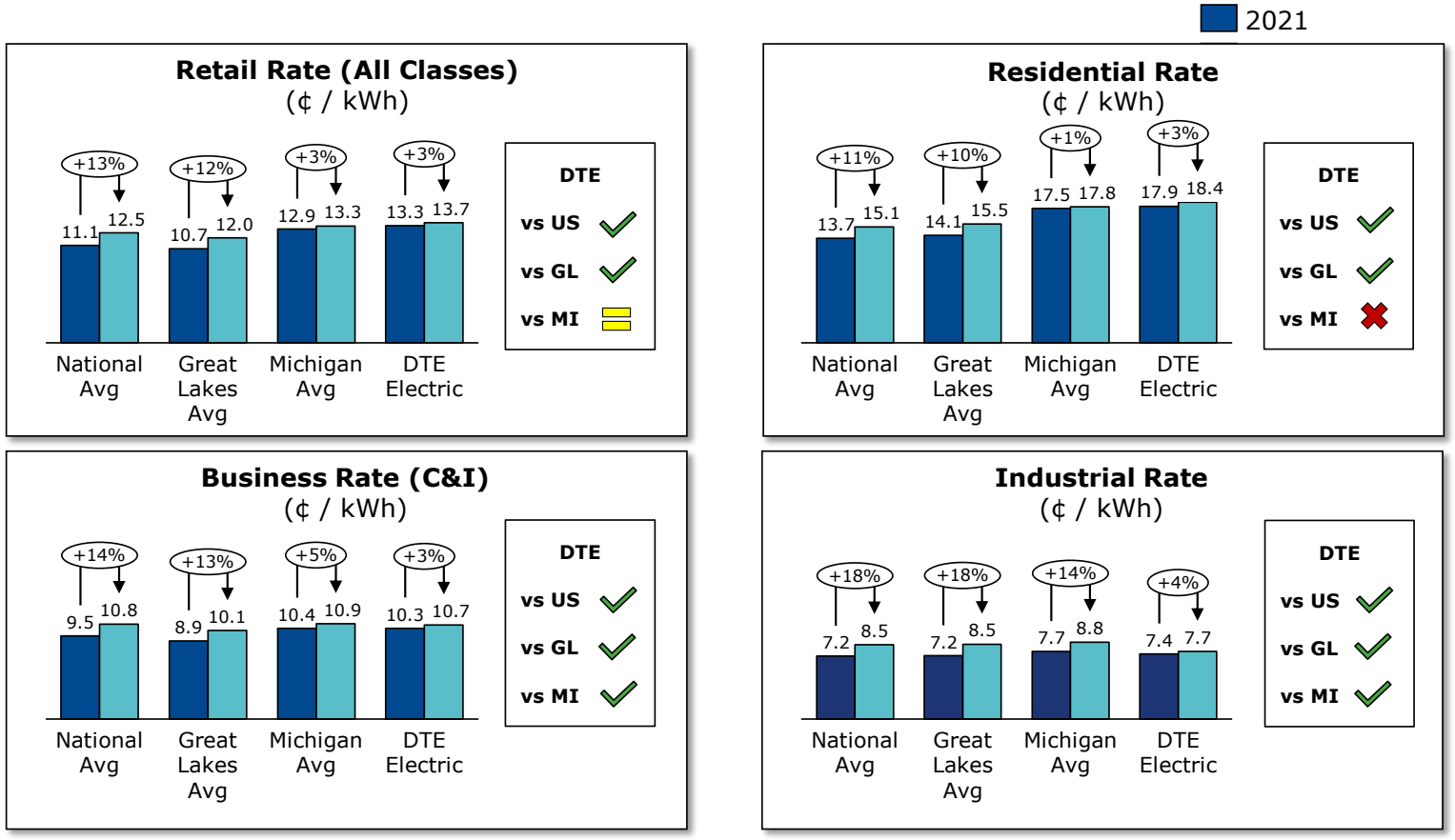
DTE Source: EIA Natural Gas Data



Annual Rate Benchmarking

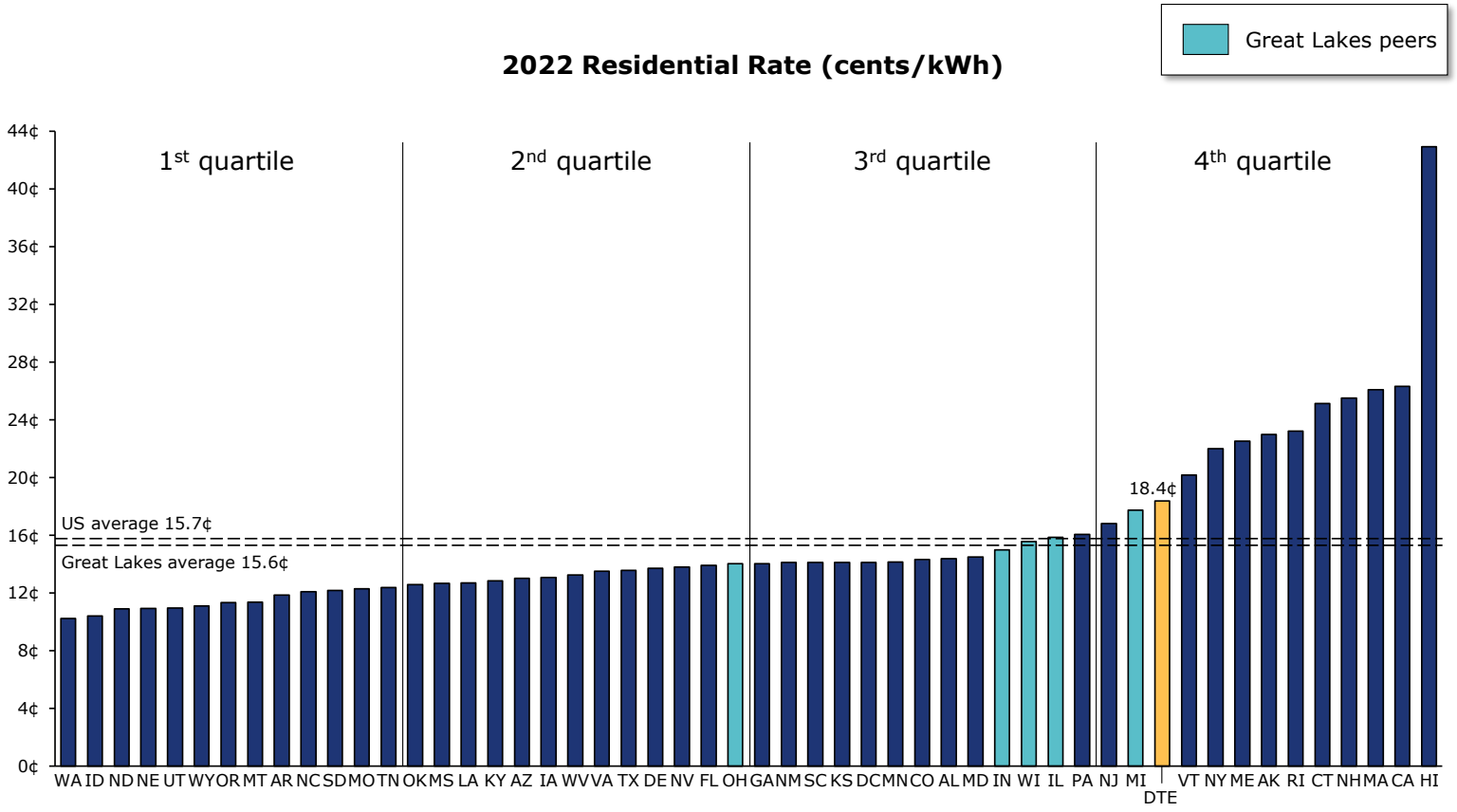
April 18, 2023

From 2021 to 2022, DTE's electric rates grew at a slower pace than its Great Lakes and national peers across all rate classes



Source: EIA form 861 and 861M

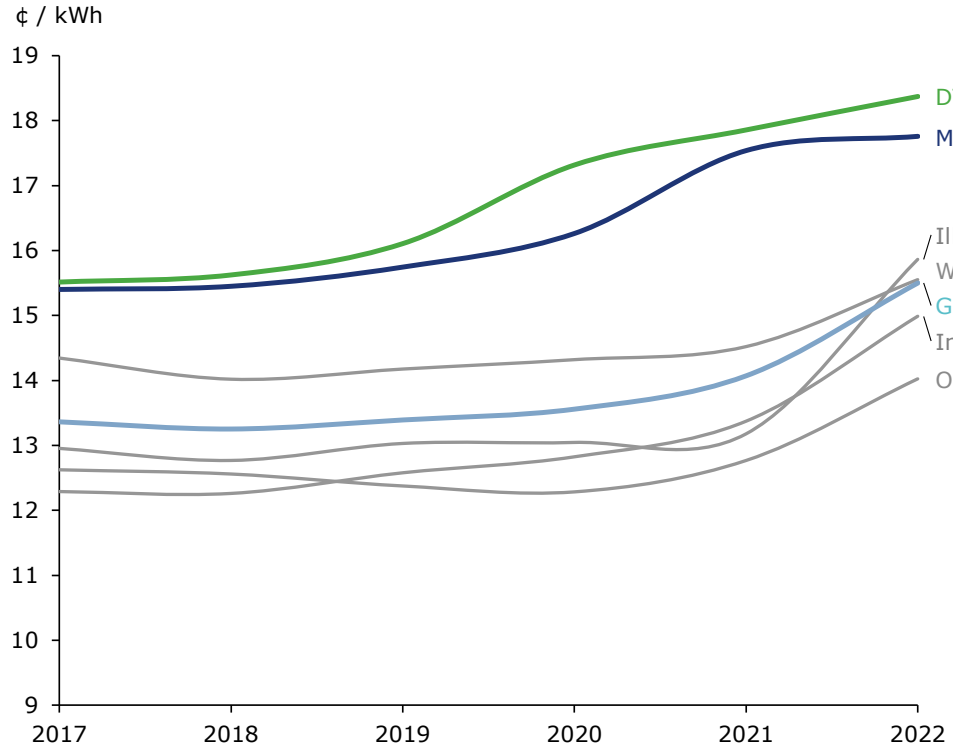
While DTE's residential rates are above the national average…



DTE

Source: EIA form 861M

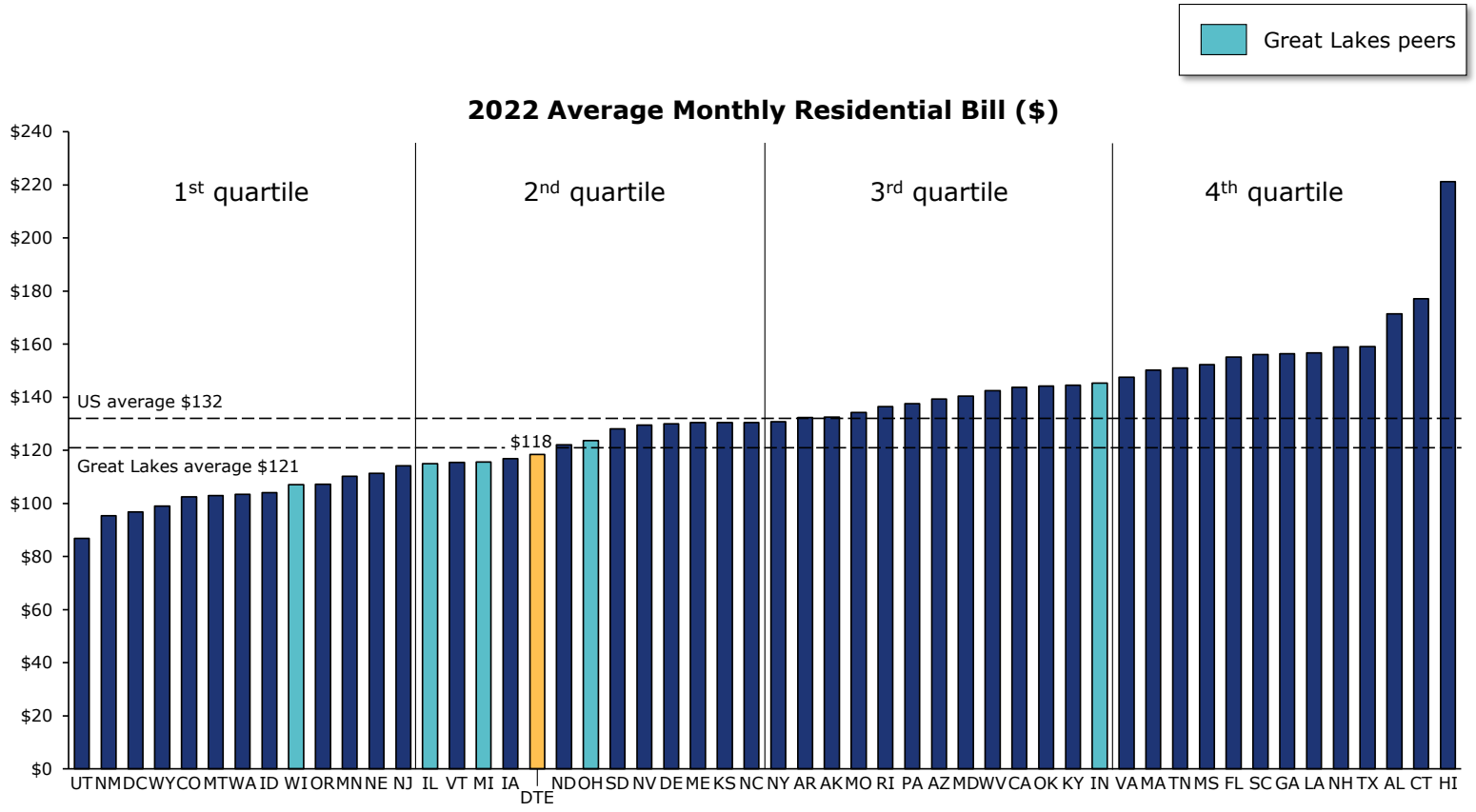
DTE and Michigan had the lowest one-year growth rates and are below the Great Lakes average for five-year growth rates



	Average annual growth		
	1-year	3-year	5-year
DTE	**2.9%**	**4.5%**	**2.9%**
Michigan	**1.2%**	**4.1%**	**2.9%**
Illinois	20.4%	6.8%	4.1%
Wisconsin	7.1%	3.1%	1.6%
Great Lakes avg.	**10.2%**	**5.0%**	**3.0%**
Indiana	12.1%	6.0%	4.0%
Ohio	9.8%	4.2%	2.1%

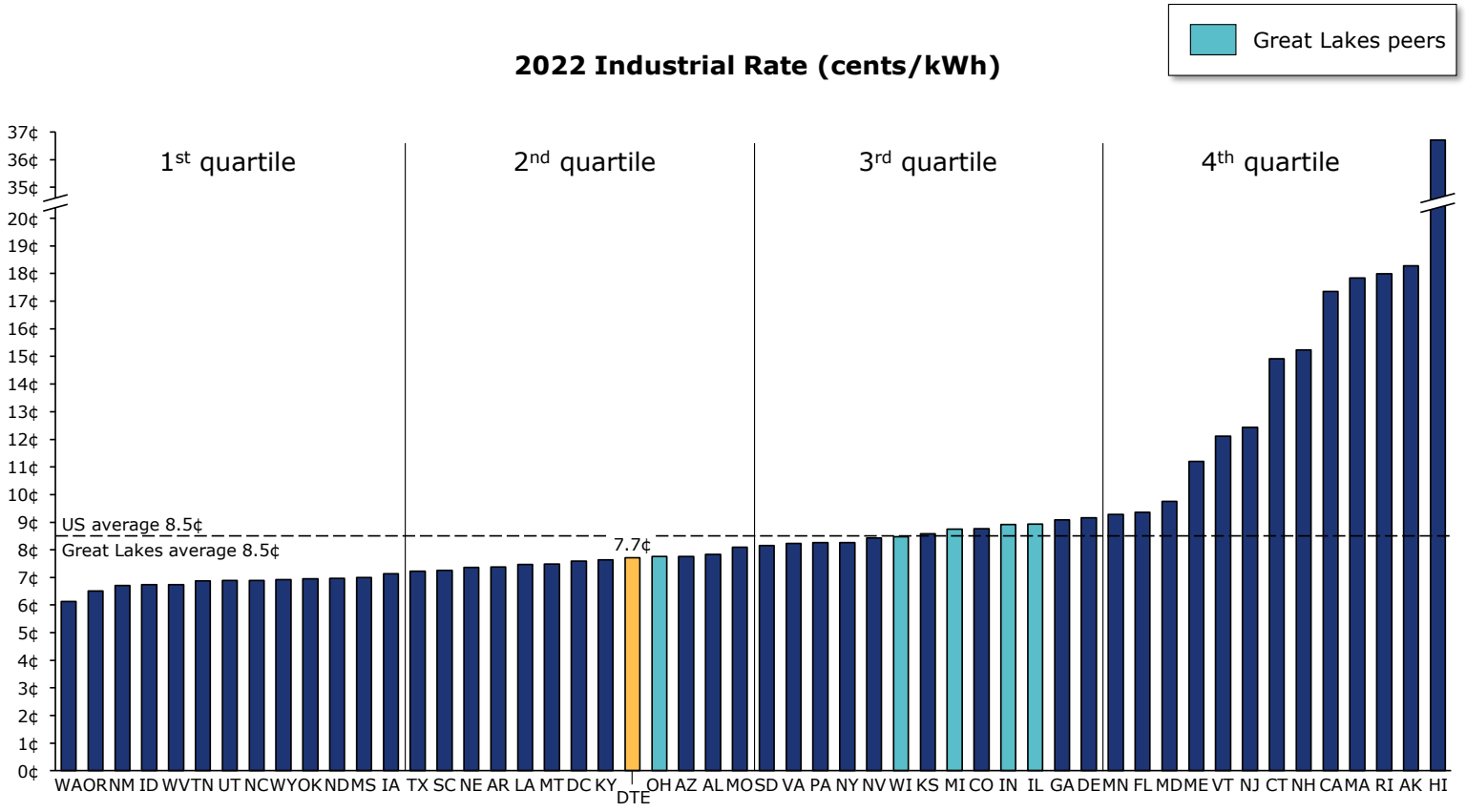
Source: EIA form 861M and 861

Residential bills remain in the 2nd quartile



Source: EIA form 861M
1. The 2022 average is the average monthly residential bill from January 2022 to December 2022

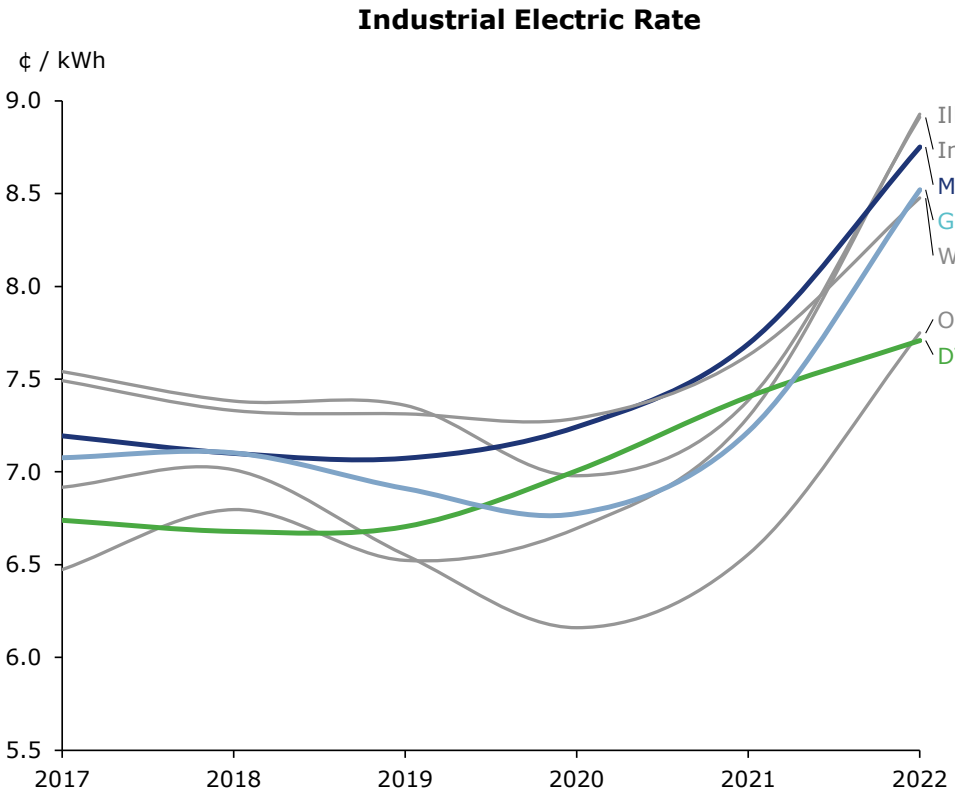
DTE industrial rates were below the national and Great Lakes averages



DTE

Source: EIA form 861M

DTE had by far the lowest year-over-year growth in Industrial rates and is now lower than any of the states in the region



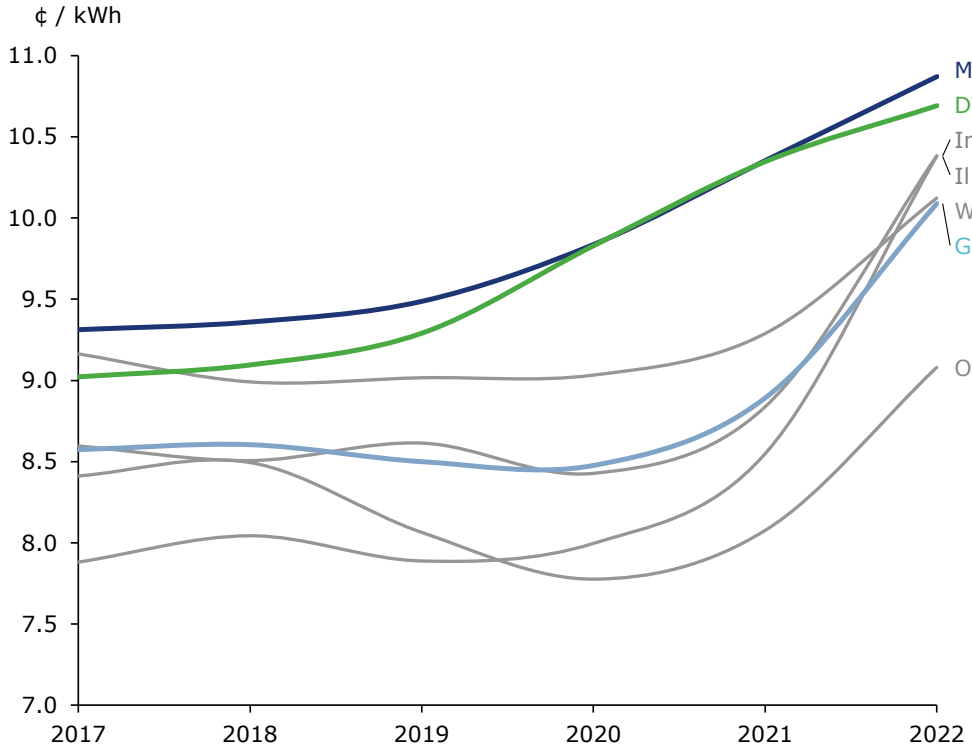
	Average annual growth		
	1-year	3-year	5-year
Illinois	22.4%	11.0%	6.6%
Indiana	20.7%	6.6%	3.4%
Michigan	**13.8%**	**7.4%**	**4.0%**
Great Lakes avg.	**18.1%**	**7.2%**	**3.8%**
Wisconsin	11.1%	5.0%	2.5%
Ohio	18.2%	5.8%	2.3%
DTE	**4.1%**	**4.8%**	**2.7%**

DTE

Source: EIA form 861M and 861

DTE total business rate changes compare unfavorably to the regional average over one-, three-, and five-year periods

Total Business (C&I) Electric Rate

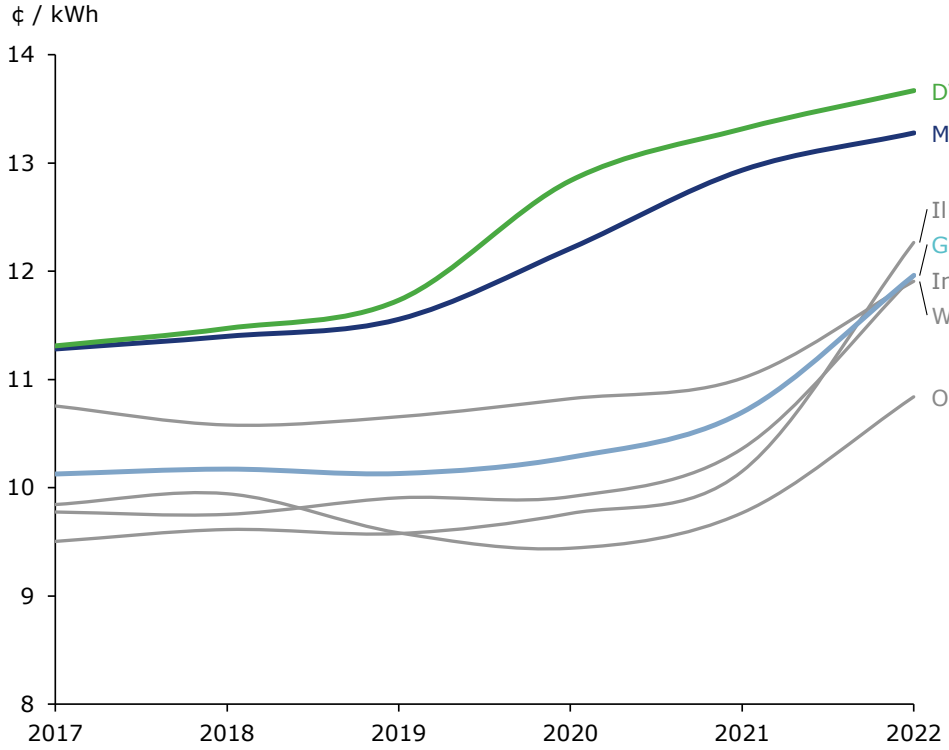


	Average annual growth		
	1-year	3-year	5-year
Michigan	**5.0%**	**4.6%**	**3.1%**
DTE	**3.3%**	**4.8%**	**3.5%**
Indiana	17.5%	6.4%	3.9%
Illinois	21.5%	9.6%	5.7%
Wisconsin	9.0%	3.9%	2.0%
Great Lakes avg.	**13.5%**	**5.9%**	**3.3%**
Ohio	12.4%	4.0%	1.5%

Source: EIA form 861M and 861

The changes in DTE Electric retail rates compare favorably to our regional average over one- and three-year periods

Total Retail Electric Rate (All Classes)

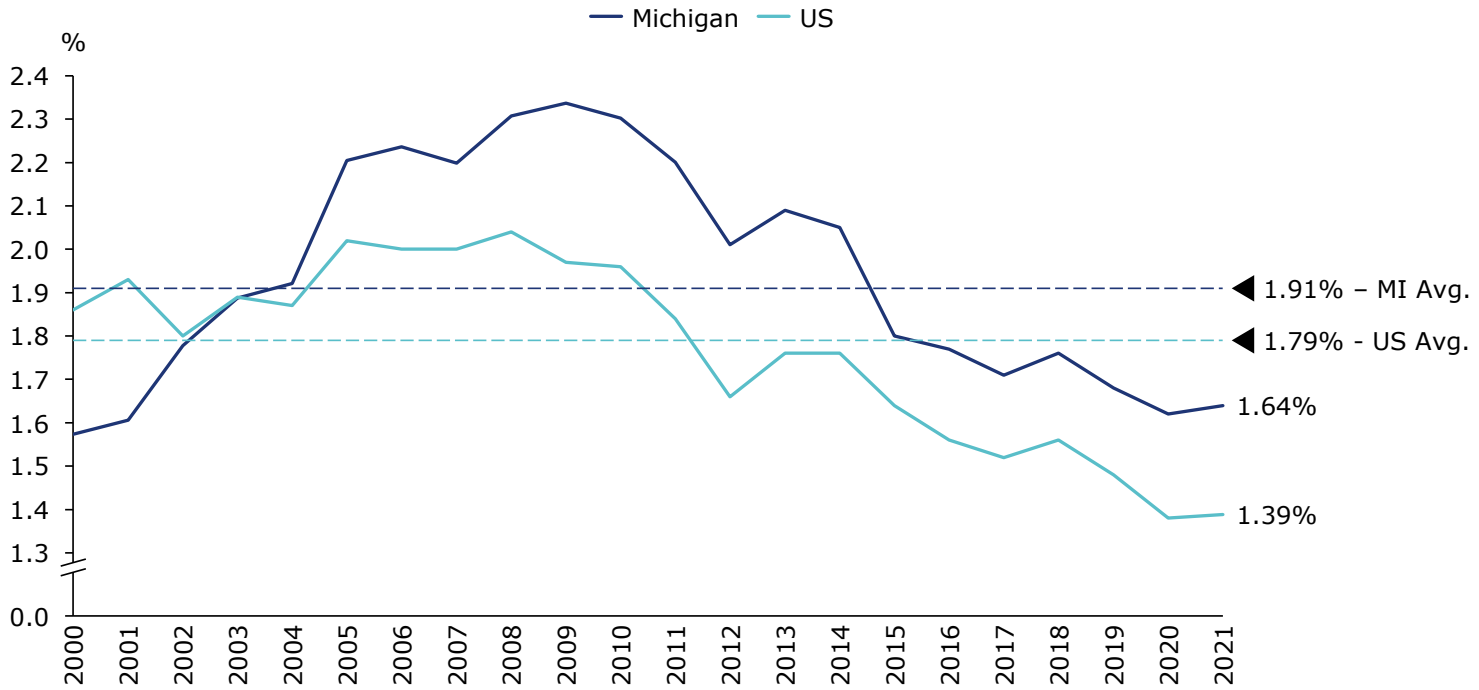


	Average annual growth		
	1-year	3-year	5-year
DTE	**2.7%**	**5.2%**	**3.9%**
Michigan	**2.7%**	**4.7%**	**3.3%**
Illinois	20.9%	8.6%	5.2%
Great Lakes avg.	**11.8%**	**5.7%**	**3.4%**
Indiana	15.4%	6.5%	4.1%
Wisconsin	8.1%	3.8%	2.1%
Ohio	11.0%	4.2%	1.9%

Source: EIA form 861M and 861

The share of disposable income for residential electric and gas utility expense in Michigan has been trending lower over the past decade

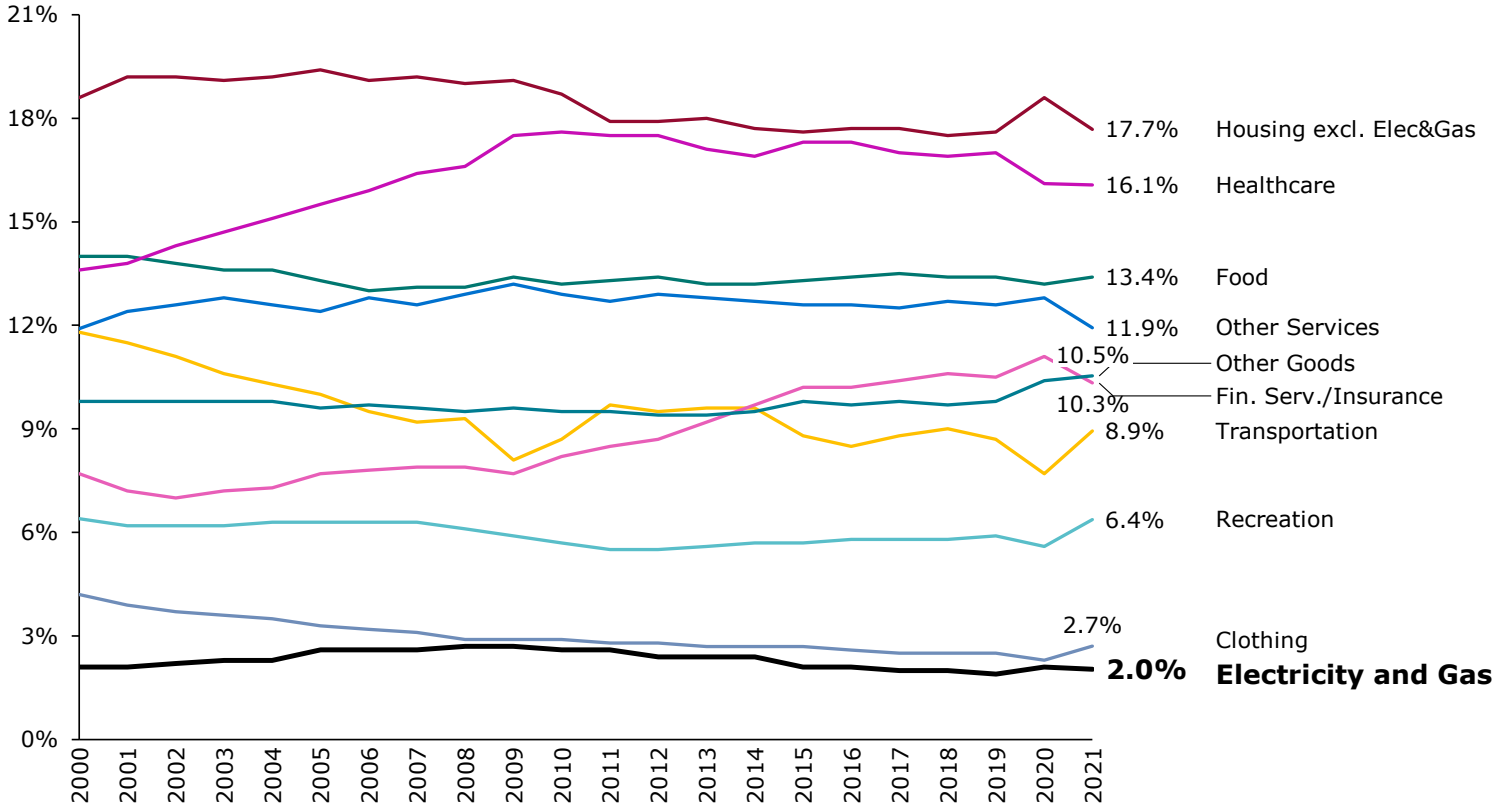
Electric and Gas utility expenditure as a percent of disposable income



Source: BEA Table 2.1. and EIA, BEA SAINC1 Personal Income Summary: Personal Income, Population, Per Capita Personal Income

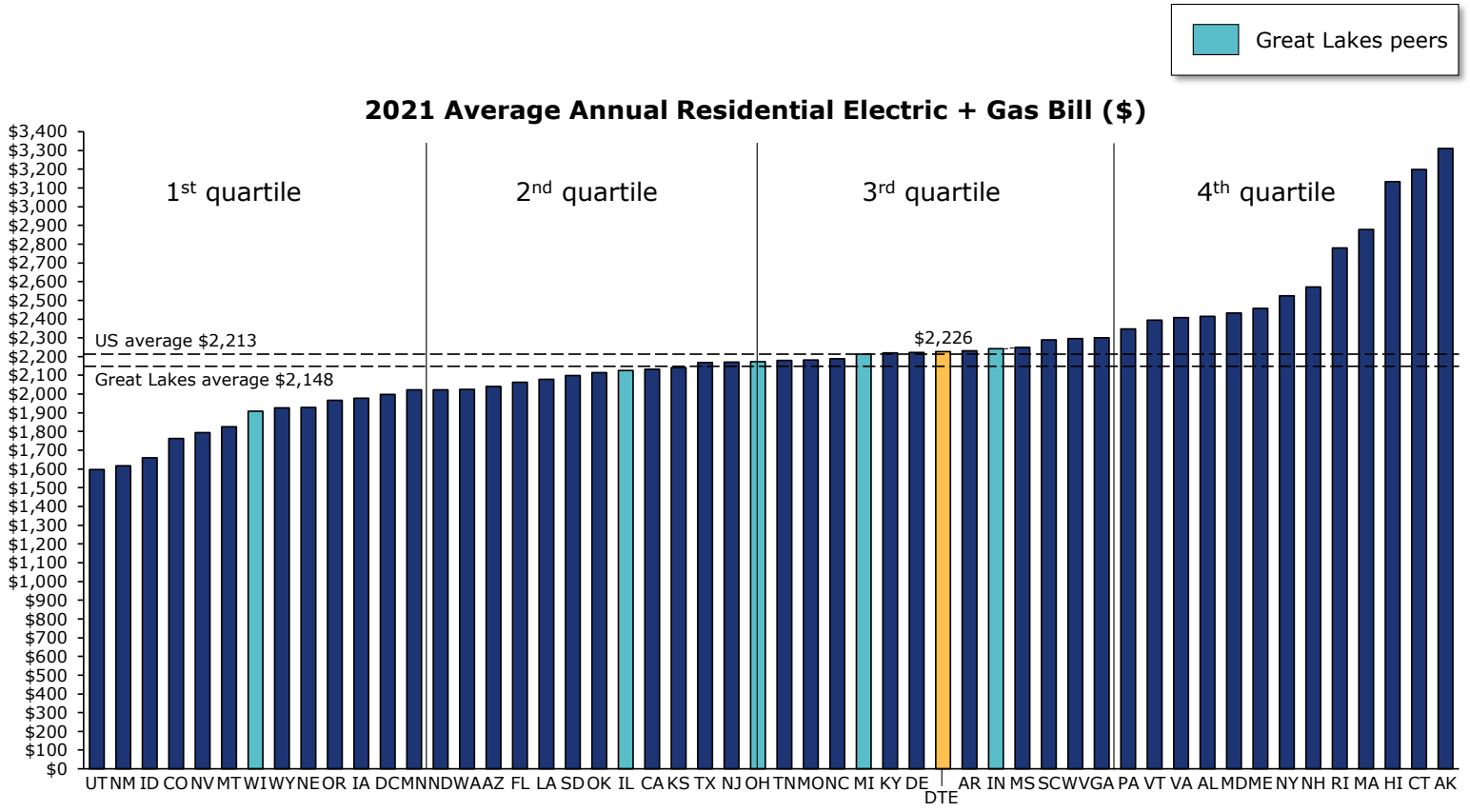
The share of spend on residential electric and gas utility bills in Michigan has also remained small relative to other typical categories of household spend

Michigan percentage of personal consumption expenditures over time



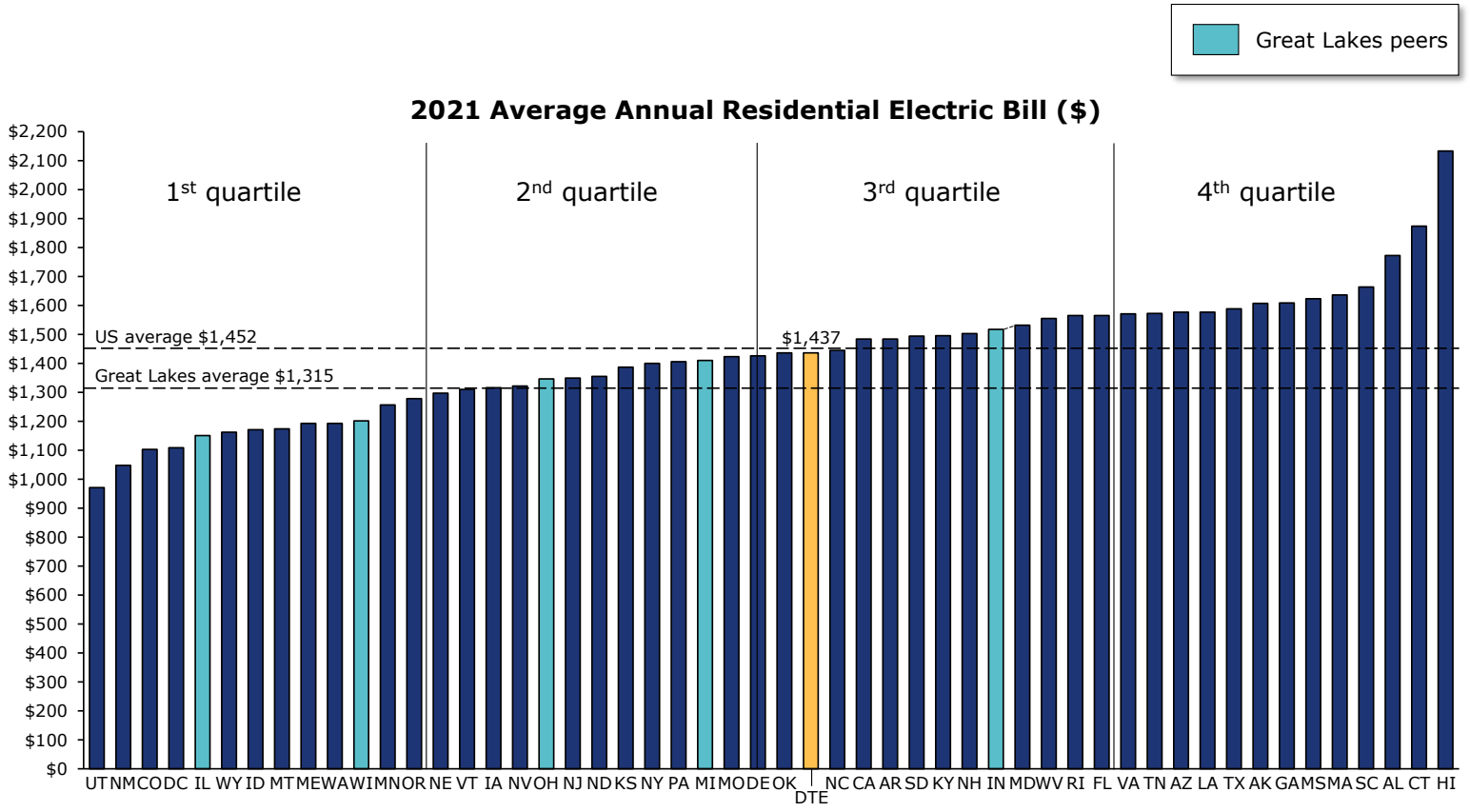
Source: BEA SAEXP1 Total personal consumption expenditures (PCE) by state (Michigan), EIA for Electric and Gas

Full Year 2021 Combined Electric and Gas Bills



Source: EIA form 861 and 176

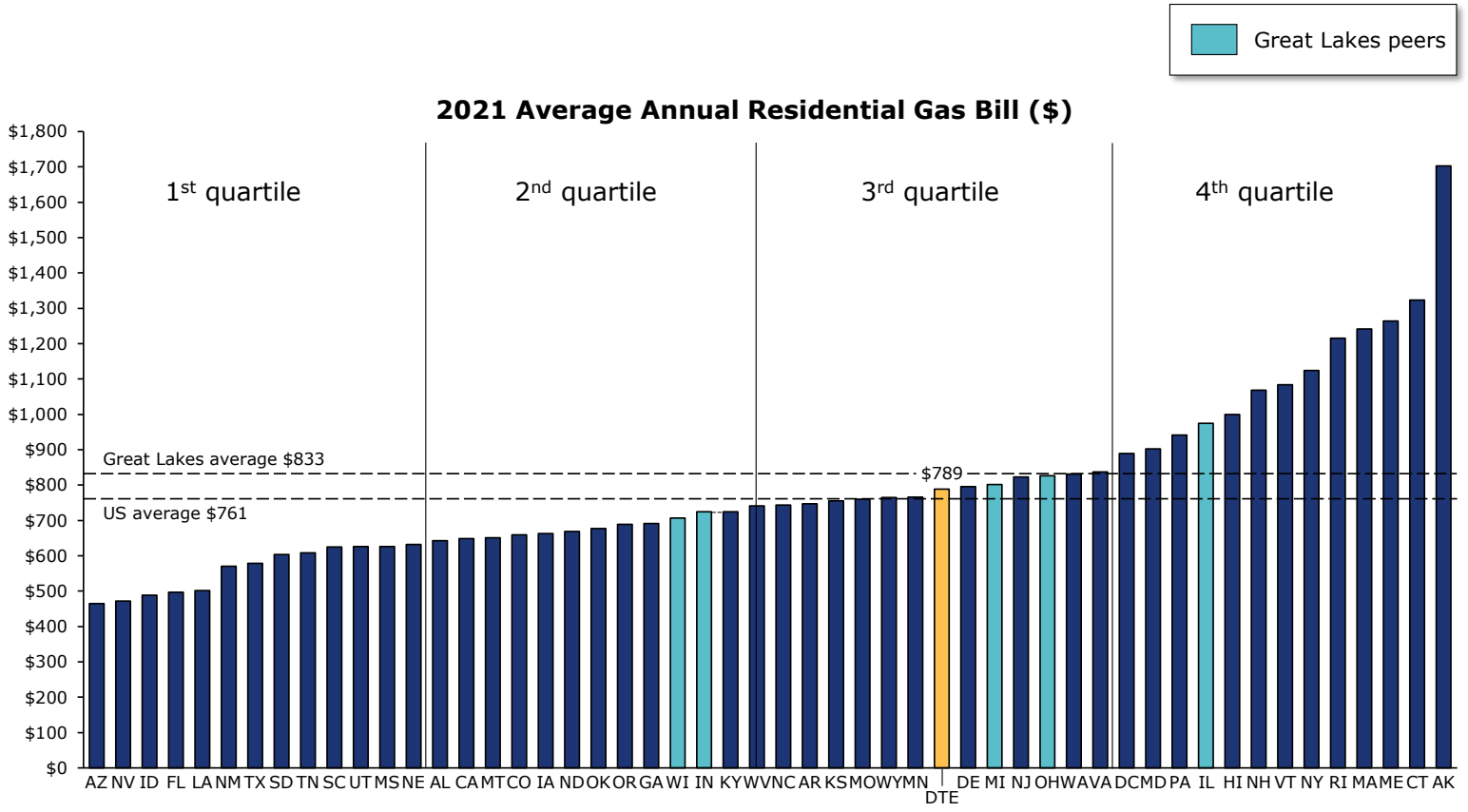
Full Year 2021 Electric Bills



DTE

Source: EIA form 861

Full Year 2021 Gas Bills



DTE

Source: EIA form 176

MPSC Case No: U-21534

Requester: MNSC

Question No.: MNSCDE-15.25c

Respondent: M. Elliott Andahazy

Page: 1 of 1

Question: 25. Refer to the Company's response to MNSC 8.1.f(i), which indicates that circuits with vegetation management were eliminated from the control group used to compare circuits on which 4.8kV hardening was completed to secure estimates of reliability improvement benefits.

c. Refer to the response to sub-part (b). For each program/analysis provided, confirm that vegetation management circuits were removed from the control group. If this cannot be confirmed, please explain.

Answer: The Company confirms that tree trim circuits were removed from the control group for the 4.8kV Hardening Program effectiveness analysis**.**

The control group for the Tree Trim analysis includes circuits that have not been trimmed to the Enhanced Tree Trimming Program (ETTP) specification.

Attachment: N/A

MPSC Case No: U-21534

Requester: MNSC

Question No.: MNSCDE-15.25d

Respondent: M. Elliott Andahazy

Page: 1 of 1

Question: 25. Refer to the Company's response to MNSC 8.1.f(i), which indicates that circuits with vegetation management were eliminated from the control group used to compare circuits on which 4.8kV hardening was completed to secure estimates of reliability improvement benefits.

d. For each of the following programs, identify whether tree trimming is completed as part of the program work (or not): 4.8kV Hardening; 4.8kV circuit conversion; PTMM; and distribution automation.

Answer: For all the programs referenced, tree trimming is completed as part of the program. Trimming under these programs is executed to provide the Company safe and efficient access to complete the work – the scope and extent of trimming varies by program and project.

Attachment: N/A

MPSC Case No: U-21534

Requester: MNSC

Question No.: MNSCDE-15.25e

Respondent: M. Elliott Andahazy

Page: 1 of 1

Question: 25. Refer to the Company's response to MNSC 8.1.f(i), which indicates that circuits with vegetation management were eliminated from the control group used to compare circuits on which 4.8kV hardening was completed to secure estimates of reliability improvement benefits.

e. Refer to the response to subpart (d). For each program in which tree trimming is completed as part of program work, confirm that tree trimming is capitalized as part of overall project costs and depreciated over the same time frame as the expected useful life of the project. If not confirmed, please explain.

Answer: Tree trimming is associated with all programs referenced and is capitalized as part of the overall project investments and depreciated at the same rate as the capitalized assets.

Attachment: N/A

MPSC Case No: U-21534

Requester: MNSC

Question No.: MNSCDE-15.25f

Respondent: T. Uzenski

Page: 1 of 1

Question: 25. Refer to the Company's response to MNSC 8.1.f(i), which indicates that circuits with vegetation management were eliminated from the control group used to compare circuits on which 4.8kV hardening was completed to secure estimates of reliability improvement benefits.

f. Please provide the expected useful life used to depreciate each program's capital spending: Tree trimming if capitalized; 4.8kv Hardening; 4.8kV circuit conversion; PTMM; and distribution automation.

Answer: To forecast projected depreciation expense for rate case purposes, a depreciation rate of 4.11% is applied to distribution capital that is projected to be in-service.

Attachment: None.

MPSC Case No: U-21534

Requester: MNSC

Question No.: MNSCDE-15.25g

Respondent: R. Steudle

Page: 1 of 1

Question: 25. Refer to the Company's response to MNSC 8.1.f(i), which indicates that circuits with vegetation management were eliminated from the control group used to compare circuits on which 4.8kV hardening was completed to secure estimates of reliability improvement benefits.

g. For 2022, estimate the dollar amount of program capital spending associated with tree trimming for each program: 4.8kv Hardening; 4.8kV circuit conversion; PTMM; and distribution automation. Provide workpapers used to complete each estimate, including data employed and identifying sources of data employed.

Answer: See the below table, there was no tree trim associated with distribution automation in 2022:

Program	2022 Investment	Methodology for Estimate
4.8 Hardening	$34.6	Direct charged to project
4.8 Conversions	$0.4	Direct charged to project
PTMM	$8.8	Journal Entry (Logic Attached) and Direct charges
Distribution Automation	$0.0	Direct charged to project

Attachment: U-21534 MNSC 15.25g-h PTMM Journal Entry Logic

MPSC Case No: U-21534

Requester: MNSC

Question No.: MNSCDE-15.25h

Respondent: R. Steudle

Page: 1 of 1

Question: 25. Refer to the Company's response to MNSC 8.1.f(i), which indicates that circuits with vegetation management were eliminated from the control group used to compare circuits on which 4.8kV hardening was completed to secure estimates of reliability improvement benefits.

h. For 2023, estimate the dollar amount of program capital spending associated with tree trimming for each program: 4.8kv Hardening; 4.8kV circuit conversion; PTMM; and distribution automation. Provide workpapers used to complete each estimate, including data employed and identifying sources of data employed.

Answer:

Program	2023 Investment ($M)	Methodology for Estimate
4.8 Hardening	$18.40	Direct charged to project
4.8 Conversions	$2.10	Direct charged to project
PTMM	$9.30	Journal Entry (Logic Attached) and Direct charges
Distribution Automation	$0.17	Direct charged to project

Attachment: U-21534 MNSC 15.25g-h PTMM Journal Entry Logic

Illustrative Data

PTMM Budget	$	60,000,000
PTMM Miles		1300
Tree Trim Budget (Line Clearance Only)	$	100,000,000
Tree Trim Miles		5000
Coincidence Factor (B6/B3)		26%
Capitalization Factor		18.89%
Journal Entry (B5*B8*B10)	$	4,911,400

The journal entry related to tree trimming and the PTMM program is based on the annual miles that undergo PTMM and the annual miles trimmed. *Annual budgets and miles are illustrative*

DTE Electric Company
One Energy Plaza, 1635 WCB
Detroit, MI 48226-1279



Andrea E. Hayden
(313) 235-9449
andrea.hayden@dteenergy.com

March 1, 2024

Ms. Lisa Felice
Executive Secretary
Michigan Public Service Commission
7109 West Saginaw Highway
Lansing, Michigan 48917

Re: In the matter of the Application of DTE Electric Company for authority to increase its rates, amend its rate schedules and rules governing the distribution and supply of electric energy, and for miscellaneous accounting authority.
MPSC Case No. U-20162

Dear Ms. Felice:

Pursuant to the Commission's final Order in MPSC Case No. U-20162, please find attached DTE Electric Company's March 1, 2024 Tree Trim Annual Report. If you have any questions, please feel free to contact me.

Very truly yours,

Andrea E. Hayden

Digitally signed by Andrea E. Hayden
Date: 2024.03.01 09:18:18 -05'00'

Andrea E. Hayden

AEH/cdm
Encl.

March 1, 2024 Tree Trim Annual Report

In Case U-20162, on May 2, 2019, the Commission directed DTE Electric (DTEE) to file an annual report to detail the progress of the Surge program and Enhanced Tree Trim Program (ETTP) performance. From the U-20162 Order:

> Thus, the annual report shall also break out all activity, costs, and miles trimmed under any and all tree trimming programs (including hardening) in the city of Detroit, to provide information on the progress made in the city of Detroit with each program. The reporting shall include measurable data for the efforts, including miles completed by service center, performance of ETTP circuits compared to non-ETTP circuits, the costs of the efforts, number of employees directly involved in the efforts, tree-related outage reductions, SAIDI reductions, and whether the funding for the efforts is a capital expense or O&M cost. Further, the report shall track ETTP circuit performance, comparing average outages for the three years prior to the enhanced trimming with outages in the years after the trimming has been performed. The first report is due in this docket March 1, 2020, and an annual report is due on March 1 of each year thereafter.

Per Case U-20162 order and Case U-20561 order, this report covers the requested information. The report is split into six sections:

1) Miles Completed to ETTP Standard – Annual ETTP maintenance miles are reported by Service Center over the 2015-2023 time period. City of Detroit miles are broken out separately.
2) O&M and Capital Spend on Tree Trimming Activities – Annual tree trim spend are reported by Service Center over the 2016-2023 time period. City of Detroit spend is broken out separately. Costs from 2015 are not included because the ETTP specification makes up a relatively small portion of the overall tree trim spend in that year.
3) ETTP Circuit Performance – ETTP circuit performance comparing average outage events, customer interruptions, outage minutes, and wire downs before and after ETTP work. The performance will cover ETTP circuits trimmed in 2015 through 2022 with reliability data that ranges from 2012 to 2023. Performance of ETTP circuits trimmed in 2023 will be measured starting in 2024.
4) Spot Tree Trimming – Description of spot-trimming work done on the 10 worst performing circuits.
5) Tree Trim Workforce – A 2023 summary of the tree trim workforce is broken down by DTEE employees and contractors.

6) Incremental Funding for Tree Trim Program – Description of the additional work completed in 2023 from the increased funding from Case No. U-21128, in which the Company committed an incremental $90M to the tree trim program.

Section 1 – Miles Completed to ETTP Standard

Since the inception of the ETTP standard, the Company has trimmed 38,550 miles. 5,299 ETTP miles were trimmed in 2023 as part of the Surge program. Below, **Table 1** breaks out ETTP miles trimmed by distribution and subtransmission, **Table 2** details miles trimmed by service center and year. **Table 3** shows total miles trimmed to ETTP, which may include second and third cycle ETTP trimming. It has a breakdown of only unique miles trimmed to ETTP, which does not count the second or third cycle of ETTP trimming. It also shows miles in backlog (off-cycle), average density and work location by service center. Previous filings from the Company also included manual/climbing trimming data by service center, which was from a onetime study performed by a third-party consultant. The Company does not collect climbing data for each circuit trimmed, however, backlot work is strongly correlated with manual/climbing trimming. **Table 4** shows ETTP miles trimmed in the City of Detroit, and **Table 5** covers miles trimmed as part of the 4.8kV Hardening Program.

Table 1 – ETTP Miles Trimmed by Circuit Type

Circuit Type	2015	2016	2017	2018	2019	2020	2021	2022	2023	Total	% of System
Distribution[1]	257	2,270	2,733	3,128	3,181	4,583	5,021	5,991	4,566	31,730	81%
Subtransmission[2]	188	1,030	868	540	1,006	1,006	726	723	733	6,820	100%
Total Miles	**445**	**3,300**	**3,601**	**3,668**	**4,187**	**5,589**	**5,747**	**6,714**	**5,299**	**38,550**	**83%[3]**

[1] Some of these distribution miles are on their second cycle of ETTP trimming and show up in the numbers more than once.
[2] Some of these subtransmission miles are on their second or third cycle of ETTP trimming and show up in the numbers more than once.
[3] Numerator only includes unique miles – it only counts the miles once even if the miles are on their second or third cycle of ETTP trimming.

Table 2 – ETTP Miles Trimmed by Service Center

Service Center	2015	2016	2017	2018	2019	2020	2021	2022	2023	Total
ANN	5	143	566	309	246	537	285	585	423	3,099
CAN	40	60	62	271	307	335	360	375	244	2,054
HWL	192	272	445	262	264	603	659	719	320	3,736
LAP	13	341	390	423	378	653	584	555	616	3,953
MAR	70	351	419	432	303	334	395	776	781	3,861
MTC	23	250	259	115	321	430	274	335	79	2,086
NAE	42	693	470	533	557	463	826	793	605	4,982
NPT	5	159	263	342	254	536	561	196	437	2,753
PON	6	426	230	237	424	567	618	551	443	3,502
RFD	24	219	112	381	670	444	300	922	466	3,538
SBY	8	111	102	207	129	114	181	377	453	1,682
WWS	17	275	283	156	334	573	704	531	433	3,306
Total Miles	**445**	**3,300**	**3,601**	**3,668**	**4,187**	**5,589**	**5,747**	**6,714**	**5,299**	**38,550**

Table 3 – ETTP Miles Trimmed, Miles of Backlog, Average Tree Density and Mix of Work by Service Center

Service Center	Cumulative Miles Trimmed ETTP[4]	Total System Miles		For the 2023 Plan Only			
		Unique Miles Trimmed to ETTP[5]	Remaining Miles of Backlog to ETTP[6]	2023 Unique Miles Trimmed to ETTP[5]	Total 2023 Miles Trimmed	Avg. Tree Density[7] (trees/mile)	Work Location[7] (% Backlot)
ANN	3,099	2,090	146	184	423	575	73%
CAN	2,054	1,387	40	1	244	408	93%
HWL	3,736	2,404	25	38	320	301	74%
LAP	3,953	2,645	24	115	616	276	65%
MAR	3,861	2,449	534	370	781	201	61%
MTC	2,086	1,365	1,206	0	79	108	80%
NAE	4,982	2,887	895	140	605	157	84%
NPT	2,753	1,943	10	46	437	125	75%
PON	3,502	2,614	238	294	443	476	68%
RFD	3,538	2,994	423	226	466	315	84%
SBY	1,682	1,239	71	260	453	286	60%
WWS	3,306	2,343	1,006	95	433	290	82%
Total Miles	**38,551**	**26,359**	**4,615**	**1,768**	**5,299**	**290**	**73%**

[4] Includes second or third cycle ETTP trim.
[5] Does not include second or third cycle ETTP trim.
[6] Remaining miles in backlog after 2023 trimming.
[7] Density and work location are calculated based on task points identified by the planners during planning – includes brush.

Table 4 – ETTP Miles Trimmed in the City of Detroit by Service Center

Service Center	2015	2016	2017	2018	2019	2020	2021	2022	2023	Total	% of City
CAN	40	42	60	234	293	291	326	246	240	**1,772**	**-**
MTC	-	-	6	-	-	6	-	**-**	5	**17**	**-**
RFD	5	87	27	251	464	90	129	259	192	**1,504**	**-**
Total Detroit Miles[8]	**45**	**129**	**93**	**485**	**757**	**387**	**455**	**505**	**438**	**3,293**	**97%[9]**

Table 5 – ETTP Miles Trimmed as Part of the 4.8kV Hardening Program[10]

Service Center	2015	2016	2017	2018	2019	2020	2021	2022	2023	Total
CAN	-	-	-	20	0	106	198	199	143	**666**
RFD	-	-	-	127	158	161	129	325	100	**1,000**
Total 4.8kV Miles	**-**	**-**	**-**	**147**	**158**	**267**	**327**	**524**	**243**	**1,666**

Section 2 – O&M and Capital Spend on Tree Trimming Activities

The Company spent $169,669,666 in O&M for its tree trim program in 2023 as detailed in **Table 6**; years 2016 through 2022 are also included for reference. **Table 6** groups costs into five categories:

1) Line Clearance Maintenance – Comprises costs needed for maintenance activities such as contractor labor and equipment, general foreman cost, per diems, and overtime premiums.
2) Trouble – Spend on non-storm unplanned reactive tree trim work related to outage or non-outage problems on the electric system.
3) Tree Trim Program/Other – Includes customer request work, auditing, software maintenance, the herbicide program, training, safety, and other cost miscellaneous costs associated with Tree Trim.
4) DTE Staff Cost – DTE staff costs related to the tree trim program.
5) COVID Expenses – Includes costs associated with the additional safety measures that were taken due to the COVID-19 Pandemic.

[8] Some of these miles are on their second cycle of ETTP trimming and show up in the number more than once.
[9] Numerator only includes unique miles trimmed to ETTP, therefore does not double count miles on second- cycle or beyond.
[10] Program began in 2018 and miles in Table 5 are a subset of miles in Tables 1-3.

Table 6 – Annual O&M Tree Trim Spend by Category[11]

O&M Spend	2016	2017	2018	2019	2020	2021	2022	2023
Line Clearance Maintenance	$59,155,543	$69,344,451	$71,757,936	$116,748,952	$151,021,453	$140,202,546	$209,270,442	$149,227,403
Trouble	$10,738,172	$11,395,011	$12,966,909	$16,556,969	$12,237,821	$10,667,520	$12,682,979	$9,535,799
Tree Trim Program/Other	$2,771,660	$1,812,622	$2,500,756	$10,229,182	$6,839,979	$15,670,339	$13,013,567	$6,483,393
DTE Staff Cost	$1,496,789	$1,704,325	$1,883,630	$2,667,190	$3,722,732	$4,372,897	$4,603,174	$4,423,070
COVID-19[12]					$1,340,624	$746,118		
O&M Total	**$74,162,165**	**$84,256,409**	**$89,109,232**	**$146,202,293**	**$175,162,609**	**$171,659,420**	**$239,570,162**	**$169,669,666**

Table 7 further breaks down the "Line Clearance Maintenance" costs in **Table 6** by service center.

Table 7 – Annual Maintenance Tree Trim Spend by Service Center (O&M Only)

Service Center	2016	2017	2018	2019	2020	2021	2022	2023
ANN	$4,081,462	$12,103,989	$9,489,387	$6,699,698	$18,811,275	$11,077,345	$19,663,782	$17,458,180
CAN	$3,312,191	$1,200,014	$8,851,085	$18,827,931	$11,253,759	$6,701,520	$14,189,914	$4,913,541
HWL	$4,838,162	$12,561,698	$6,269,100	$6,523,040	$19,744,784	$23,573,175	$20,366,427	$10,942,721
LAP	$5,145,835	$5,820,146	$4,385,310	$5,306,986	$12,866,142	$8,215,356	$6,297,393	$9,272,157
MAR	$3,679,637	$4,450,068	$5,021,951	$2,757,355	$5,087,650	$3,444,947	$8,968,144	$11,316,545
MTC	$3,868,638	$4,093,991	$1,961,451	$3,770,923	$9,913,687	$3,727,800	$4,874,212	$2,258,725
NAE	$3,100,279	$2,242,086	$2,615,529	$3,137,335	$5,336,176	$3,858,290	$5,567,071	$4,196,993
NPT	$1,990,418	$4,844,204	$5,288,021	$3,400,257	$9,634,726	$12,826,082	$6,520,390	$11,730,643
PON	$12,293,540	$8,619,875	$8,167,988	$24,883,843	$27,768,967	$29,346,468	$31,445,874	$19,290,761
RFD	$5,929,162	$3,762,082	$11,025,927	$28,999,125	$12,309,855	$6,816,756	$42,187,521	$27,138,327
SBY	$3,351,803	$3,078,400	$4,338,480	$2,656,440	$3,982,452	$2,863,698	$15,143,984	$13,380,970
WWS	$7,564,417	$6,567,898	$4,343,707	$9,786,018	$14,311,980	$27,751,110	$34,045,729	$17,327,840
Total	**$59,155,544**	**$69,344,451**	**$71,757,936**	**$116,748,951**	**$151,021,453**	**$140,202,546**	**$209,270,442**	**$149,227,403**

[11] Table does not include any spot trimming expenses from other programs because they are not part of the tree trim maintenance costs. This table does not include tree trimming cost related to storm, those costs are charged outside the tree trim budget.
[12] These expenses were mainly for the one-person per vehicle policy, and PPE for DTEE employees and contractors.

Table 8 details the 4.8kV Hardening capital spend in 2018-2023.

Table 8 – Annual 4.8kV Hardening Tree Trim Capital Spend by Service Center

Service Center	2018	2019	2020	2021	2022	2023
CAN	$ 2,136,156	-	$5,878,864	$11,757,474	$10,675,606	$7,819,132
RFD	$ 7,858,107	$ 10,081,771	$12,025,855	$10,274,963	$25,313,553	$10,955,464
Total	**$ 9,994,263**	**$ 10,081,771**	**$17,904,719**	**$22,032,437**	**$35,989,159**	**$18,774,596**

Table 9 highlights the $25,903,156 tree trim spend in the City of Detroit for the year 2023, which includes $16,148,871 of Capital spend. City spend in 2016 through 2023 is included for reference.

Table 9 – Annual Detroit O&M and 4.8kV Hardening Capital Tree Trim Spend

	2018	2019	2020	2021	2022	2023
Detroit - O&M	$14,071,122	$40,513,330	$7,333,594	$3,875,167	$8,468,206	$9,754,285
Detroit – 4.8kV Hardening Capital	$9,326,363	$10,081,771	$11,888,408	$21,408,206	$28,865,840	$16,148,871
Detroit Total	**$23,397,485**	**$50,595,101**	**$19,222,002**	**$25,283,373**	**$37,334,046**	**$25,903,156**

Section 3 – ETTP Circuit Performance

Methodology Used to Calculate ETTP Performance

The methodology used to calculate ETTP Performance for all distribution circuits uses the average of three years of pre-trim ETTP tree-related outage events and compares it to each year post-trimming. All post-trim year results of the same year were then summed to increase the sample size (as an example, all post-trim year 1 results are included collectively as a sum). The difference between the before trimming performance and the post trimming performance was used to create the "% Change in Outage Event Reduction for ETTP circuits". To create a control group for comparison, the same methodology was used for the remainder of circuits not trimmed ETTP[13] (Non-ETTP circuits), which are identified as "% Change in Outage Event Reduction for Non-ETTP circuits". To account for natural weather variation, the performance of the control group is subtracted from the ETTP circuit performance to provide an accurate representation of the true impact of the ETTP. This is the same methodology outlined in Case U-20561, U-20836, and U-21297.

[13] This group consists of circuits that have not been trimmed to the ETTP specification and are considered off-cycle.

Table 10 – Methodology for ETTP Performance Analysis

2012	2103	2014	2015	2016	2017	2018	2019	# of ETTP Circuits
			Three Year Average Pre-ETTP Performace			Year of Trim	Post Trim Year 1	321
		Three Year Average Pre-ETTP Performace			Year of Trim	Post Trim Year 1	Post Trim Year 2	128
	Three Year Average Pre-ETTP Performace			Year of Trim	Post Trim Year 1	Post Trim Year 2	Post Trim Year 3	171
Three Year Average Pre-ETTP Performace			Year of Trim	Post Trim Year 1	Post Trim Year 2	Post Trim Year 3	Post Trim Year 4	20

Table 11 – Methodology for Control Group Non-ETTP Performance Analysis

2012	2103	2014	2015	2016	2017	2018	2019	# of ETTP Circuits
			Three Year Average Pre-Non-ETTP Performace			Year of Trim	Post Trim Year 1	N/A
		Three Year Average Pre-Non-ETTP Performace			Year of Trim	Post Trim Year 1	Post Trim Year 2	N/A
	Three Year Average Pre-Non-ETTP Performace			Year of Trim	Post Trim Year 1	Post Trim Year 2	Post Trim Year 3	N/A
Three Year Average Pre-Non-ETTP Performace			Year of Trim	Post Trim Year 1	Post Trim Year 2	Post Trim Year 3	Post Trim Year 4	N/A

The control group of non-ETTP circuits and the ETTP circuits are compared against each other to account for non-tree trim related variations. This methodology normalizes reliability performance from variations that occur year-to-year, such as weather and storms. This approach provides a more accurate measure of the ETTP effectiveness since we are comparing circuits over the course of years.

ETTP Outage Event Performance

The actual difference of outage events on ETTP circuits compared to the balance of the system not trimmed ETTP is 54.0% in post-trim year 1, 36.8% in the second year, 43.8% in the third year,

and 11.1% in the fourth year. The actual reduction for Years 1-4 post ETTP trim is depicted in **Table 12**.

Table 12 – ETTP Tree-Related Outage Event Difference Compared to Non ETTP Circuits

	Number of Dist. Circuits ETTP Trimmed	% Change in Outage Event Reduction for ETTP circuits	% Change in Outage Event Reduction for Non-ETTP circuits	**Difference in % Change in Event Reduction ETTP vs Non-ETTP circuits**	U-20162 Surge Model Projected Reduction
1 Year Post Trim	2,063	-22.0%	32.0%	**-54.0%**	-57.0%
2 Years Post Trim	1,442	-12.8%	49.6%	**-36.8%**	-57.0%
3 Years Post Trim	974	9.94%	53.7%	**-43.8%**	-50.0%
4 Years Post Trim	491	58.1%	69.2%	**-11.1%**	-37.0%

ETTP Customer Interruptions Performance

Using the same methodology discussed above, the Company has determined that actual customer interruptions on ETTP circuits vs. Non-ETTP circuits show a 57.9% difference in Year 1, 59.3% difference in Year 2, 48.6% difference in Year 3, and 40.7% difference in Year 4. These results are shown in Table 13.

Table 13 – ETTP Tree-Related Customer Interruption Difference Compared to Non ETTP Circuits

	Number of Dist. Circuits ETTP Trimmed	% Change in Outage Interruption Reduction for ETTP circuits	% Change in Outage Interruption Reduction for Non-ETTP circuits	**Difference in % Change in Event Reduction ETTP vs Non-ETTP circuits**	U-20162 Surge Model Projected Reduction
1 Year Post Trim	2,063	-38.8%	19.1%	**-57.9%**	-57.0%
2 Years Post Trim	1,442	-28.0%	31.2%	**-59.3%**	-57.0%
3 Years Post Trim	974	-24.1%	24.6%	**-48.6%**	-50.0%
4 Years Post Trim	491	-14.3%	26.4%	**-40.7%**	-37.0%

ETTP Customer Outage Minute Performance

Customer minutes of interruption, shown in **Table 14**, also shows significant improvements from the ETTP program. Actual minutes of customer interruption on ETTP circuits vs. Non-ETTP circuits show a 32.4% difference in Year 1, 8.1% difference in Year 2, -22.4% difference in Year 3, and -6.4% difference in Year

Table 14 – ETTP Tree-Related Customer Outage Minutes of Interruption Difference Compared to Non ETTP Circuits

	Number of Dist. Circuits ETTP Trimmed	% Change in Outage Minutes Reduction for ETTP circuits	% Change in Outage Minutes Reduction for Non-ETTP circuits	**Difference in % Change in Event Reduction ETTP vs Non-ETTP circuits**	U-20162 Surge Model Projected Reduction
1 Year Post Trim	2,063	-27.0%	5.3%	**-32.4%**	-57.0%
2 Years Post Trim	1,442	16.4%	24.5%	**-8.1%**	-57.0%
3 Years Post Trim	974	10.5%	-11.9%	**22.4%**	-50.0%
4 Years Post Trim	491	1.3%	-5.2%	**6.4%**	-37.0%

Table 15 shows the 2023 outage minutes avoided due to ETTP trimming and the impact to overall system SAIDI, which reflects a net reduction of 226 SAIDI minutes. If only ETTP circuits are considered, the SAIDI reduction is 313 minutes.

Table 15 – 2023 ETTP Outage Minute Reduction and SAIDI Impact

	ETTP Outage Minutes
3 Years Before Trim Avg. Outage Minutes	603,540,803
2023 Outage Minutes	900,537,209
Minutes Saved	-296,996,406
Minutes Avoided – Non ETTP System Deterioration	947,747,698
Total Minute Reduction	650,751,293
ETTP Overall System SAIDI Minute Reduction	**300**

SAIDI Minute Reduction for ETTP Circuits ONLY	**390**

ETTP Wire-Down Performance

Using the same methodology discussed above, the Company has determined that actual wire-down events for ETTP circuits vs. Non-ETTP circuits show a 55.4% difference in Year 1, 56.8% difference in Year 2, 39.8% difference in Year 3, and 15.3% difference in Year 4. These results are shown in **Table 16**.

Table 16 – Post-ETTP Wire-Down Difference Compared to Non-ETTP Circuits

	Number of Dist. Circuits ETTP Trimmed	% Change Wire-Down Events for ETTP circuits	% Change for Wire-Down Events for Non-ETTP circuits	**Difference in % Change in Wire-Down Events ETTP vs. Non-ETTP circuits**
1 Year Post Trim	2,063	-65.5%	-10.1%	**-55.4%**
2 Years Post Trim	1,442	-64.8%	-8.0%	**-56.8%**
3 Years Post Trim	974	-58.3%	-18.5%	**-39.8%**
4 Years Post Trim	491	-52.7%	-37.4%	**-15.3%**

Section 4 – Spot Trimming on Worst Performing Circuits

DTE Electric provides an annual power quality investigation report which contains data on all primary customer power quality investigations conducted in the past year for end-use customers, derived from their power quality meters, and the outcome of each investigation. This report contains the DTE Electric January 1, 2023 through December 31, 2023 results and identifies a list of 10 worst performing circuits based on SAIFI outages compared to the rest of the system (based on all cause codes, not just tree related events). Table 17 lists these circuits and the spot trimming that took place in 2023, or planned maintenance trimming.

Table 17 – Tree Trimming on 2023 Ten Worst Performing Circuits

Circuit	sysSAIFI[14]	sysSAIFI ex MED[15]	Spot Trimming		Last Maintenance Trimming Year
			Performed in 2023?	Number of Poles Trimmed	
MOTT9789	0.01031	0.00451	No		2020
NIXON8932	0.00905	0.00339	No		2023
CROWN9832	0.00853	0.00581	Yes	4	2022
GODSN8134	0.00792	0.00390	Yes	110	2018
PERU9432	0.00765	0.00508	No		2022
KENSL9858	0.00719	0.00436	No		2022
STATE8137	0.00657	0.00308	No		2014
DUBLN8195	0.00617	0.00093	Yes	12	2020
CODY9537	0.00606	0.00187	Yes	125	2015
DUBLN8205	0.00595	0.00126	Yes	21	2020

Section 5 – Tree Trim Workforce

The internal employees directly involved in Tree Trimming are detailed in **Table 18**. In 2023, the average number for contractors on property were 1,282. Contractor headcount fluctuation over the course of 2023 is seen in **Chart 1**.

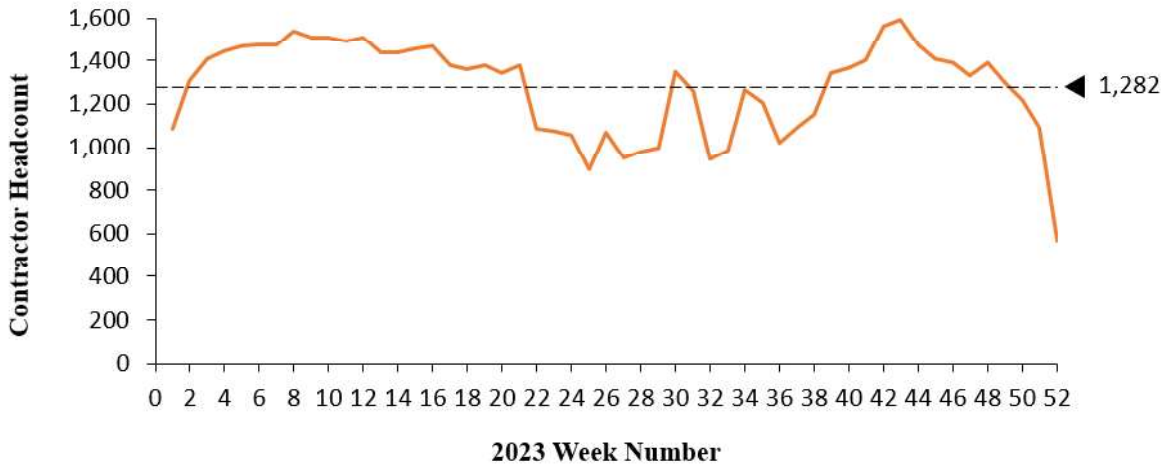
Table 18 – 2023 DTE and Contractor Tree Trim Headcount

Facilitator – Arborists	13
Supervision	8
Regional Foresters	5
Strategy and Planning	9
Internal Employees involved with ETTP	**35**

2023 Average # of Contractors	**1,282**

[14] sysSAFI is the number of customer interruptions on a specific circuit divided by the number of system customer interruptions.
[15] MED stands for Major Event Days.

Chart 1 – 2023 Contract Tree Trim Headcount by Week



The 2023 average local journeymen trimmers were 641, and the number of local apprentices were 229. Outsourced journeymen trimmers averaged 412 for 2023. It is typical for the workforce numbers to fluctuate over the year, especially in the late fall when many outsource trimmers return to their home states for the holidays. The outsource trimmers then slowly return through the first quarter of the year based on the Company's capacity needs.

The Company is participating in three programs in an effort to increase the number of local trimmers. The three programs are the Parnall Correctional Facility Vocational Village Training Program, the City of Detroit Tree Trim Academy, and the IBEW Local 17 Traditional Boot Camp. Below is an update on each of the programs:

1. Parnall Correctional Facility The Parnall Tree Trimming program is designed to provide returning citizens the skills needed to start as an apprentice tree trimmer. DTE has partnered with the Michigan Department of Corrections to provide qualified instructors and the required training support within the prison facility before participants are released. The company has paired 30 graduates with jobs.

2. Tree Trim Academy – The Company has partnered with the City of Detroit, IBEW Local 17, and its tree-trimming contractors to develop and implement a pre-woodsman training pilot program to satisfy the demand for qualified tree trimmers. The pilot tree trimming academy is located within the City of Detroit and facilitates training that is aimed at preparing local resident candidates to work as woodsmen. Once candidates complete the pre-woodsman program, graduates enter the nine-day boot camp that was previously designed in partnership with the Company, IBEW Local 17, and the Company's tree-trimming contractors.

To date the tree trimming academy has trained and graduated 202 individuals. Graduates leave the program with sought after climbing experience, a Class B CDL, and a federally required pesticide Applicator certification.

3. Traditional Boot Camp – IBEW continues to hold regular scheduled boot camp training for apprentices. Current camps are conducted at their training facility in Wales, MI.

Section 6 – Incremental Funding for Tree Trim Program

On August 31, 2021, the Company proposed additional funding for the Tree Trim program in Case No. U-21128. Per the application, the Company would invest incremental funding into the Tree Trim Surge during the remainder of 2021 through 2023, beyond the authorized regulatory asset amounts, and would not seek recovery of the additional expenditures. This has the effect of advancing the Company's tree trimming efforts while avoiding future customer expense for those investments, thus providing an affordability benefit to customers. The Company's application was approved on November 4th, 2021, and the Company committed to $90 million of incremental funding for the Tree Trimming program.

In 2022, the Company spent $85.8 million of the incremental $90 million investment. The annual maintenance plan was developed based on the total budget, including the incremental $85.8 million. The Company did not distinguish specific circuits trimmed as part of the base budget compared to the incremental funding. However, the Company can calculate the incremental work the additional funding enabled us to complete. The additional $85.8 million allowed the Company to complete an extra 1,700 off-cycle miles in 2022 and lead the system to be 79% on-cycle at year end. These miles were focused in poor reliability areas and trimming was completed prior to the 2022 storm season.

In 2023, the remaining $4.2 million of the incremental funding was spent to support the Company's spot trimming program to address high-risk areas that were not on the 2023 maintenance plan. The spot trimming program and circuit impact are reviewed in Section 4.

MPSC Case No: U-21534

Requester: MNSC

Question No.: MNSCDE-8.5c

Respondent: J. Kryscynski

Page: 1 of 1

Question: 5. Refer to Mr. Kryscynski's testimony at page 56, which states "The engineering team evaluates alternatives to meet the system needs and selects the best project or program to move forward. If necessary, a BCA takes place as part of the engineering process to select the best option. The solution which is selected to move forward is scored in the GPM for prioritization." Refer also to NDA U-21534 MNSCDE-1.8a GPM CONFIDENTIAL, which provides GPM scores for 138 different projects in tab "GPM Results".

c. Provide the approved capital project authorizations on every one of these 138 projects with an expected total capital cost exceeding $10 million. Include all supporting documentation presented to management with each capital project authorization.

Answer: DTE Electric objects to providing the capital project authorizations and supporting documentation for the reason that the request is unduly burdensome and overly broad. Subject to this objection, and without waiving this objection, DTE Electric would answer as follows:

The approved capital project authorizations to the extent they are available will be provided in a supplemental response as soon as the information can be collected.

Attachment: None.

Co-respondent: Legal

MPSC Case No: U-21534

Requester: MNSC

Question No.: MNSCDE-8.5c (S1)

Respondent: J. Kryscynski

Page: 1 of 4

Question: 5. Refer to Mr. Kryscynski's testimony at page 56, which states "The engineering team evaluates alternatives to meet the system needs and selects the best project or program to move forward. If necessary, a BCA takes place as part of the engineering process to select the best option. The solution which is selected to move forward is scored in the GPM for prioritization." Refer also to NDA U-21534 MNSCDE-1.8a GPM CONFIDENTIAL, which provides GPM scores for 138 different projects in tab "GPM Results".

c. Provide the approved capital project authorizations on every one of these 138 projects with an expected total capital cost exceeding $10 million. Include all supporting documentation presented to management with each capital project authorization.

Answer: Duplicative capital authorizations were requested in MNSCDE-8.5c, MNSCDE-8.6, MNSCDE-8.9d, MNSCDE-8.14a, MNSCDE-8.15a, MNSCDE-8.16a, MNSCDE-8.17a, MNSCDE-8.18a, MNSCDE-8.19a, MNSCDE-8.20a, MNSCDE-8.21a, MNSCDE-8.22b, MNSCDE-9.3b, MNSCDE-12.2j, MNSCDE-12.11, and MNSCDE-12.12. To the extent available, the requested authorizations are attached.

The Distribution Grid Plans (DGP), filed with the Commission, include a 5-year investment plan which constitutes the initial capital investment plan that is reviewed and approved by management. For the 2023 DGP which includes the 5-year investments for capital projects and programs, please see Exhibit A-23 Schedule M8.

The DGP 5-year investment plan is a key input to the annual management review. For 2023 capital investments, the 2021 DGP was the supportive grid planning reference. For 2024 to 2027 investments, the 2023 DGP is the grid planning reference. Below is an example from section 11 of the 2023 DGP, showing planned future investments that were reviewed by management.

MPSC Case No: U-21534

Requester: MNSC

Question No.: MNSCDE-8.5c (S1)

Respondent: J. Kryscynski

Page: 2 of 4

Programs	$ Millions					
	2024	2025	2026	2027	2028	5-Year Total
Infrastructure Resilience & Hardening						
Pole and Pole Top Maintenance and Modernization	$121	$121	$151	$192	$188	$773

The Company considers this annual management review, which includes the President of DTE Electric and which subsequently leads to the request contained in the rate case, to be the authorization for projects under $10 million and for programs that are composed of many individual projects that are below that threshold (e.g. PTMM, 4.8kV Hardening).

Supporting this discovery request, in addition to the 2023 DGP and the rate case budget submitted in Exhibit A-12, Schedule B5.4, the Company is providing two types of capital project authorizations, depending on whether they are authorizations for projects above $10MM, such as a converison, or for programs, such as PTMM.

First, in addition to the management reviews and approvals as noted, individual projects greater than $10 million require specific management approval and must be authorized by a Capital Appropriations Request Form (CARF). Approved CARFs for projects associated with projects in tab “GPM Results” have been collected and attached. Some large projects in the engineering and design phase may not have yet reached the threshold to require a CARF.

Second, capital programs (e.g., PTMM) and projects smaller than $10MM that are authorized during the annual management review process receive futher confirmed immediatley prior to the year in which they are to be executed. The relavant forms for 2022, 2023, and 2024 are attached.

Attachment: U-21534 MNSCDE-8.5c(S1)-01 2022 Budget Appropriation
U-21534 MNSCDE-8.5c(S1)-02 2023 Budget Appropriation

MPSC Case No: U-21534

Requester: MNSC

Question No.: MNSCDE-8.5c (S1)

Respondent: J. Kryscynski

Page: 3 of 4

U-21534 MNSCDE-8.5c(S1)-03 2024 Budget Appropriation
U-21534 MNSCDE-8.5c(S1)-04 4.8 kV CC Almont Relief and Circuit Conversion (Midas)
U-21534 MNSCDE-8.5c(S1)-05 4.8 kV CC Ariel Substation and Circuit Conversion
U-21534 MNSCDE-8.5c(S1)-06 4.8 kV CC Buckler Circuit Conversion
U-21534 MNSCDE-8.5c(S1)-07 4.8 kV CC Cortland - Oakman - Linwood Consolidation
U-21534 MNSCDE-8.5c(S1)-08 4.8 kV CC Cortland - Oakman - Linwood Consolidation

U-21534 MNSCDE-8.5c(S1)-09 4.8 kV CC GRFIN & WMSTN Conversions
U-21534 MNSCDE-8.5c(S1)-10 4.8 kV CC Hilton Substation and Circuit Conversion
U-21534 MNSCDE-8.5c(S1)-11 4.8 kV CC I-94 Substation and Circuit Conversion (Promenade) - Below Grade
U-21534 MNSCDE-8.5c(S1)-12 4.8 kV CC Pinegrove Substation Relocation and Conversion
U-21534 MNSCDE-8.5c(S1)-13 4.8 kV CC Pinegrove Substation Relocation and Conversion
U-21534 MNSCDE-8.5c(S1)-14 4.8 kV CC Zenon Substation and Circuit Conversion
U-21534 MNSCDE-8.5c(S1)-15 4.8 kV CC Zenon Substation and Circuit Conversion
U-21534 MNSCDE-8.5c(S1)-16 8.3 kV CC Pontiac Overhead Conversion
U-21534 MNSCDE-8.5c(S1)-17 ADMS DMS-OMS
U-21534 MNSCDE-8.5c(S1)-18 ADMS DMS-OMS
U-21534 MNSCDE-8.5c(S1)-19 Ann Arbor System Improvements
U-21534 MNSCDE-8.5c(S1)-20 Ann Arbor System Improvements
U-21534 MNSCDE-8.5c(S1)-21 Buffalo-Charles OH to UG pilot
U-21534 MNSCDE-8.5c(S1)-22 CODI Alfred Substation Expansion
U-21534 MNSCDE-8.5c(S1)-23 CODI CATO Substation Expansion
U-21534 MNSCDE-8.5c(S1)-24 CODI Charlotte Network Upgrade
U-21534 MNSCDE-8.5c(S1)-25 CODI Charlotte Network Upgrade
U-21534 MNSCDE-8.5c(S1)-26 CODI Corktown Substation

MPSC Case No: U-21534

Requester: MNSC

Question No.: MNSCDE-8.5c (S1)

Respondent: J. Kryscynski

Page: 4 of 4

U-21534 MNSCDE-8.5c(S1)-27 CODI Garfield Network Upgrade
U-21534 MNSCDE-8.5c(S1)-28 CODI Garfield Network Upgrade
U-21534 MNSCDE-8.5c(S1)-29 CODI Garfield Radial (Midtown Circuits)
U-21534 MNSCDE-8.5c(S1)-30 CODI Garfield Radial (Midtown Circuits)
U-21534 MNSCDE-8.5c(S1)-31 CODI Howard Conversion
U-21534 MNSCDE-8.5c(S1)-32 CODI Howard Conversion
U-21534 MNSCDE-8.5c(S1)-33 CODI Islandview Substation - Phase 1
U-21534 MNSCDE-8.5c(S1)-34 CODI Islandview Substation - Phase 2
U-21534 MNSCDE-8.5c(S1)-35 CODI Islandview Substation - Phase 2
U-21534 MNSCDE-8.5c(S1)-36 CODI Kent-Gibson Conversion - Phase 1
U-21534 MNSCDE-8.5c(S1)-37 CODI Kent-Gibson Conversion - Phase 1
U-21534 MNSCDE-8.5c(S1)-38 CODI Midtown Substation Expansion
U-21534 MNSCDE-8.5c(S1)-39 Station Upgrade Northeast (Relay Replacement)
U-21534 MNSCDE-8.5c(S1)-40 Station Upgrade Warren (Relay Replacement)
U-21534 MNSCDE-8.5c(S1)-41 Substation Risk Apache
U-21534 MNSCDE-8.5c(S1)-42 Substation Risk Apache
U-21534 MNSCDE-8.5c(S1)-43 Substation Risk Chestnut
U-21534 MNSCDE-8.5c(S1)-44 Substation Risk Chestnut
U-21534 MNSCDE-8.5c(S1)-45 Substation Risk McGraw
U-21534 MNSCDE-8.5c(S1)-46 Subtransmission Redesign & Rebuild Boyne
U-21534 MNSCDE-8.5c(S1)-47 Subtransmission Redesign & Rebuild Tie 4105 Phase 1
U-21534 MNSCDE-8.5c(S1)-48 Subtransmission Redesign & Rebuild Tie 4105 Phase 3
U-21534 MNSCDE-8.5c(S1)-49 Subtransmission Redesign & Rebuild Tie 4105 Phase 3
U-21534 MNSCDE-8.5c(S1)-50 Subtransmission Redesign & Rebuild Tie 810
U-21534 MNSCDE-8.5c(S1)-51 Subtransmission Redesign & Rebuild Tie 810
U-21534 MNSCDE-8.5c(S1)-52 Subtransmission Redesign & Rebuild Trunk 2308
U-21534 MNSCDE-8.5c(S1)-53 Subtransmission Redesign & Rebuild Trunk 4911
U-21534 MNSCDE-8.5c(S1)-54 System Loading Richmond-Armada
U-21534 MNSCDE-8.5c(S1)-55 System Loading Richmond-Armada
U-21534 MNSCDE-8.5c(S1)-56 Clerical Corrections

Distribution Operations Budget Appropriation Sign Off

DO Managed 2022 Capital Budget

10/28/2021

Emergent Replacements	*371,753,014*
Customer Attachments	*136,566,464*
Equipment, Relocation & Other	*115,303,129*
Infrastructure Redesign	*215,018,042*
Infrastructure Resilience & Hardening	*320,615,975*
Technology Enhancement	*74,971,134*
	$ 1,234,227,757

Brian VanJaarsveld /s/ — 11/01/2021

Manager - Budget/ forecast & Reporting (DO) — **MM/DD/YY**

Controller - DTE Electric — **MM/DD/YY**

President & COO - DTE Electric — **MM/DD/YY**

		Project Type	**2022**
	ERUC- Trouble		
1	ERUC Trouble Emergent OH (Outage)	Blanket	106,680,976
2	ERUC Trouble Emergent UG (Outage)	Blanket	18,140,794
3	ERUC Trouble OH TRSD's	Blanket	1,675,246
4	ERUC Trouble UG TRSD's	Blanket	13,699,096
5	ERUC Trouble Reactive OH (Follow-up)	Blanket	15,223,917
6	ERUC Trouble Reactive UG (Follow-up)	Blanket	8,322,561
7	ERUC Trouble Environmental	Blanket	1,061,418
8	**Total ERUC- Trouble**		**$ 164,804,009**
	ERUC- Storm		
9	Storm	Blanket	110,517,880
10	Storm - SO Follow Up	Blanket	45,708,635
11	Capital Completions & Removals	Blanket	6,377,566
12	**Total EURC - Storm**		**$ 162,604,081**
	Substation Improvements - Failures		
13	Z Budget Failures Major Equipment	Blanket	11,243,071
14	Z Budget Failures Minor Equipment	Blanket	17,034,138
15	Z Budget Failures Trfs/Regs	Blanket	11,314,258
16	Z Budget Non-Electrical	Blanket	4,467,192
17	Z Budget- Minor System/ Circuits	Blanket	286,264
18	**Total ERUC - Storm_subs**		**$ 44,344,923**
19	***Total Trouble/ Storm/ Substn CM***		**$ 371,753,014**
	Customer Attachments		
20	New Business & Load Growth Projects	* See note below	26,785,342
21	Customer Connections	Blanket	90,629,206
22	Small Load Growth Blanket	Blanket	19,151,915
23	**Total Customer Attachments**		**$ 136,566,464**
	Equipment, Relocation & Other		
24	Cuts & Restores	Blanket	7,303,635
25	Electric System (Transformers, Regulators & Meters)	Blanket	40,659,564
26	General Plant, Tools & Equipment and Miscellaneous	Blanket	8,494,415
27	NRUC, Improvement Blankets	Blanket & individual project less than $10M	30,494,953
28	Small Relocation Blanket	Blanket	15,853,361
29	Relocation Project	Individual projects, each less than $10M	8,624,200
30	Other	Individual projects, each less than $10M	3,873,000
31	**Total Equipment, Relocation & Other**		**$ 115,303,129**
	Infrastructure Redesign		
32	4.8kV CC	Individual projects, each less than $10M	64,311,674
33	8.3kV CC	Individual projects, each less than $10M	4,208,593
34	CODI	*See note below	63,853,269
35	Strategic and Service Undergrounding Pilot	Individual projects, each less than $10M	20,283,129
36	Subtransmission Redesign & Rebuild	Individual projects, each less than $10M	51,786,409
37	System Loading	Individual projects, each less than $10M	10,574,968
38	**Total Infrastructure Redesign**		**$ 215,018,042**
	Infrastructure Resilience & Hardening		
39	4.8 kV Hardening	Individual projects, each less than $10M	117,640,176
40	4.8 kV Relay Improvement (Delta Ground Detection Program)	Individual projects, each less than $10M	3,075,000
41	40kV Subtrans APTS Switch Rep Program	Individual projects, each less than $10M	5,300,000
42	Breaker Replacement Program	Individual projects, each less than $10M	15,437,575
43	Cable Replacement Program	Individual projects, each less than $10M	35,127,811
44	Disconnect and Switcher Replacement	Individual projects, each less than $10M	3,525,000
45	Frequent Outage Program (CEMI) including Circuit Renewal	Blanket	6,038,996
46	Highway Crossings	Individual projects, each less than $10M	3,000,000
47	Mobile Fleet Program	Individual projects, each less than $10M	4,480,000
48	Pole and Pole Top Hardware (PTM)	Blanket	58,912,241
49	Pontiac Vaults	Individual projects, each less than $10M	615,487
50	PTD Replacement	Individual projects, each less than $10M	1,425,000
51	Rapid Response - Frequent Outage Program (CEMI)	Individual projects, each less than $10M	40,000,000
52	Regulator Replacement	Individual projects, each less than $10M	425,000
53	Substation Risk	Individual projects, each less than $10M	11,023,057
54	Substation Upgrade	Individual projects, each less than $10M	8,563,521
55	URD Replacement Program	Individual projects, each less than $10M	6,027,111
56	**Total Infrastructure Resilience & Hardening**		**$ 320,615,975**
	Technology Enhancement		
57	Asset Management	Individual projects, each less than $10M	1,300,000
58	CVR/VVO	Individual projects, each less than $10M	7,000,000
59	DER Control	Individual projects, each less than $10M	2,830,000
60	Distribution Automation	Individual projects, each less than $10M	4,062,340
61	Distribution Planning Process Capabilities	Individual projects, each less than $10M	9,967,813
62	Grid Automation Telecommunications	Individual projects, each less than $10M	14,800,000
63	Mobil Technology	Individual projects, each less than $10M	450,000
64	Modernize Grid Management	Individual projects, each less than $10M	11,321,850
65	Operational Technology	Individual projects, each less than $10M	2,000,000
66	Pilot	Individual projects, each less than $10M	10,399,707
67	Sensing	Individual projects, each less than $10M	5,616,350
68	Substation Cybersecurity	Individual projects, each less than $10M	2,300,000
69	Work Management	Individual projects, each less than $10M	2,923,074
70	**Total Technology Enhancement**		**$ 74,971,134**
71	**TOTAL DO INVESTMENT PLAN**		**$ 1,234,227,757**

Sign Off covers all items that do not need FC-20 approval.
* Any individual project over $10M will still need to go through the FC-20 process.

Hope L Allen

From: Case R Lancaster
Sent: Monday, November 15, 2021 12:13 PM
To: Brian R VanJaarsveld
Subject: FW: 2022 DO Capital Budget CARF

FYI

From: Trevor F Lauer <trevor.lauer@dteenergy.com>
Sent: Monday, November 15, 2021 12:12 PM
To: Case R Lancaster <case.lancaster@dteenergy.com>
Cc: Karen Vucinaj <karen.vucinaj@dteenergy.com>
Subject: Re: 2022 DO Capital Budget CARF

Approved

Trevor F Lauer
DTE Energy
(313) 605 7275 (M)
(313) 235 8104 (O)

He/Him/His

From: Case R Lancaster <case.lancaster@dteenergy.com>
Sent: Monday, November 15, 2021 11:55:36 AM
To: Trevor F Lauer <trevor.lauer@dteenergy.com>
Cc: Karen Vucinaj <karen.vucinaj@dteenergy.com>
Subject: FW: 2022 DO Capital Budget CARF

Trevor – please let me know if you approve this CARF for DO capital budget for 2022. An email approval will suffice. Please let me know if you have any questions or concerns.

Case

From: Case R Lancaster
Sent: Wednesday, November 3, 2021 3:00 PM
To: Trevor F Lauer <Trevor.Lauer@dteenergy.com>
Cc: Karen Vucinaj <Karen.Vucinaj@dteenergy.com>; Brian R VanJaarsveld <Brian.VanJaarsveld@dteenergy.com>
Subject: 2022 DO Capital Budget CARF

Trevor,

Attached is the 2022 DO Capital CARF for your review and signature. We ask for approval now to be able to set up the required work orders. Note that this capital request ties to the 2022 capital targets and the capital to be filed in the upcoming rate case. Please let me know if you have any questions.

Pleas sign and return, or reply all with your approval

Case

Case Lancaster

DTE Electric Controller
DTE Energy
o: 313-235-3973
m: 248-930-4189

Distribution Operations Budget Appropriation Sign Off

2023 DO Managed Capital Budget

11/3/2022

Emergent Replacements	*445,860,040*
Customer Attachments	*163,609,886*
Equipment, Relocation & Other	*80,548,719*
Infrastructure Resilience and Hardening	*338,286,399*
Infrastructure Redesign and Modernization	*360,928,925*
Technology and Automation	*135,076,616*
	$ 1,524,310,585

Brian VanJaarsveld — 11/09/22

Manager - Budget/ forecast & Reporting (DO) — **MM/DD/YY**

Case Lancaster — 11/14/2022

Controller - DTE Electric — **MM/DD/YY**

President & COO - DTE Electric — **MM/DD/YY**

			Project Type	2023
	ERUC- Trouble			
1	ERUC Trouble Emergent OH (Outage)		Blanket	104,361,322
2	ERUC Trouble Emergent UG (Outage)		Blanket	6,836,763
3	ERUC Trouble OH TRSD's		Blanket	7,741,553
4	ERUC Trouble UG TRSD's		Blanket	41,701,482
5	ERUC Trouble Reactive OH (Follow-up)		Blanket	3,418,774
6	ERUC Trouble Reactive UG (Follow-up)		Blanket	4,407,553
7	ERUC Trouble Environmental		Blanket	1,885,820
8	Other (Trk 7130A-B, LCSTR Cable)			17,502
9	**Total ERUC- Trouble**			**$ 170,370,769**
	ERUC- Storm			
10	Storm		Blanket	176,045,416
11	Storm - SO Follow Up		Blanket	51,829,775
12	Capital Completions & Removals		Blanket	6,098,651
13	**Total EURC - Storm**			**$ 233,973,841**
	Substation Improvements - Failures			
14	Z Budget Failures Major Equipment		Blanket	15,092,952
15	Z Budget Failures Minor Equipment		Blanket	10,059,476
16	Z Budget Failures Trfs/Regs		Blanket	519,883
17	Z Budget Non-Electrical		Blanket	3,659,647
18	Z Budget- Minor System/ Circuits		Blanket	12,183,472
19	**Total ERUC - Storm_subs**			**$ 41,515,430**
20	***Total Trouble/ Storm/ Substn CM***			**$ 445,860,040**
	Customer Attachments			
21	New Business & Load Growth Projects		* See note below	48,081,037
22	Customer Connections		Blanket	92,369,731
23	Small Load Growth Blanket		Blanket	23,159,117
24	**Total Customer Attachments**			**$ 163,609,886**
	Equipment, Relocation & Other			
25	Cuts & Restores		Blanket	7,366,867
26	Electric System (Transformers, Regulators & Meters)		Blanket	29,289,041
27	General Plant, Tools & Equipment and Miscellaneous		Blanket	6,621,701
28	NRUC, Improvement Blankets		Blanket & individual project less than $10M	6,096,109
29	Small Relocation Blanket		Blanket	7,503,191
30	Relocation Project		Individual projects, each less than $10M	17,754,259
31	Other		Individual projects, each less than $10M	5,917,550
32	**Total Equipment, Relocation & Other**			**$ 80,548,719**
	Infrastructure Resilience and Hardening			
33	4.8 kV and 8.3 kV CC		Individual projects, each less than $10M	102,702,743
34	CODI		Individual projects, each less than $10M	108,965,195
35	Strategic Undergrounding Pilot		Individual projects, each less than $10M	1,000,000
36	Subtransmission Redesign & Rebuild		Individual projects, each less than $10M	109,959,433
37	System Loading		Individual projects, each less than $10M	15,659,028
38	**Total Infrastructure Resilience and Hardening**			**$ 338,286,399**
	Infrastructure Redesign and Modernization			
39	4.8 kV Hardening		Individual projects, each less than $10M	60,000,000
40	40kV Subtrans APTS Switch Rep Program		Individual projects, each less than $10M	6,324,700
41	Batteries and Chargers Replacement Program		Individual projects, each less than $10M	2,500,000
42	Breaker Replacement Program		Individual projects, each less than $10M	14,375,000
43	Cable Replacement Program		Individual projects, each less than $10M	24,870,445
44	Disconnect and Switcher Replacement		Individual projects, each less than $10M	4,900,000
45	Frequent Outage		Blanket	50,655,976
46	Mobile Fleet Program		Individual projects, each less than $10M	5,305,000
47	Pole and Pole Top Hardware (PTM)		Blanket	127,021,571
48	Pontiac Vaults		Individual projects, each less than $10M	57,725
49	PTD Replacement		Individual projects, each less than $10M	1,611,488
50	Regulator Replacement		Individual projects, each less than $10M	894,439
51	Substation Risk		Individual projects, each less than $10M	47,826,498
52	Substation Upgrade		Individual projects, each less than $10M	6,586,083
53	URD Replacement Program		Individual projects, each less than $10M	8,000,000
54	**Total Infrastructure Redesign and Modernization**			**$ 360,928,925**
	Technology and Automation			
55	4.8 kV Relay Improvement (Delta Ground Detection Program)		Individual projects, each less than $10M	17,500,000
56	ADAMS		Individual projects, each less than $10M	10,258,000
57	Asset Management - Roadmap		Individual projects, each less than $10M	1,725,000
58	DER Control		Individual projects, each less than $10M	4,930,000
59	Distribution Automation		Individual projects, each less than $10M	7,000,000
60	Distribution Planning Process Capabilities - Roadmap		Individual projects, each less than $10M	12,646,563
61	Grid Automation Telecommunications		Individual projects, each less than $10M	19,100,000
62	Mobile Technology - Roadmap		Individual projects, each less than $10M	4,575,000
63	Modernize Grid Management - Roadmap		Individual projects, each less than $10M	6,763,210
64	Pilot		Individual projects, each less than $10M	10,335,897
65	Substation Cybersecurity Pilot		Individual projects, each less than $10M	1,700,000
66	SOC Modernization		Individual projects, each less than $10M	27,100,000
67	Tree Trim Risk Prioritization Model		Individual projects, each less than $10M	1,440,000
68	Work Management & Scheduling - Roadmap		Individual projects, each less than $10M	10,002,946
69	**Total Technology and Automation**			**$ 135,076,616**
70	**TOTAL DO INVESTMENT PLAN**			**$ 1,524,310,585**

Sign Off covers all items that do not need FC-20 approval.

* Any individual project over $10M will still need to go through the FC-20 process.

Hope L Allen

From: Trevor F Lauer
Sent: Wednesday, November 16, 2022 7:47 AM
To: Case R Lancaster; Karen Vucinaj
Cc: Brian R VanJaarsveld; Michael L Wood
Subject: Re: DO Capital Budget for Trevor's signature

approved

Trevor F Lauer
DTE Energy
(313) 605 7275 (M)
(313) 235 8104 (O)

He/Him/His

From: Case R Lancaster <case.lancaster@dteenergy.com>
Sent: Tuesday, November 15, 2022 9:48:59 AM
To: Karen Vucinaj <karen.vucinaj@dteenergy.com>
Cc: Brian R VanJaarsveld <brian.vanjaarsveld@dteenergy.com>; Trevor F Lauer <trevor.lauer@dteenergy.com>; Michael L Wood <michael.l.wood@dteenergy.com>
Subject: DO Capital Budget for Trevor's signature

Karen,

Can you please have Trevor sign the attached document for 2023 DO Capital budget. Contact me, Brian VanJaarsveld or Mike Wood with any questions or concerns.

Case

Case Lancaster
DTE Energy
O: 313.235.3973
M: 248.930.4189

Distribution Operations Budget Appropriation Sign Off
2024 DO Managed Capital Budget

10/24/2023

Emergent Replacements	*423,420,001*
Customer Attachments	*199,514,249*
Equipment, Relocation & Other	*82,235,239*
Infrastructure Redesign and Modernization	*359,882,229*
Infrastructure Resilience and Hardening	*380,893,092*
Technology and Automation	*169,297,305*
	$ 1,615,242,115

Brian VanJaarsveld 10/24/23

Manager - Budget/ forecast & Reporting (DO) — **MM/DD/YY**

Case Lancaster 10/31/2023

Controller - DTE Electric — **MM/DD/YY**

10/31/23

President & COO - DTE Electric — **MM/DD/YY**

		Project Type	2024
	ERUC- Trouble		
1	ERUC Trouble Emergent OH (Outage)	Blanket	105,537,289
2	ERUC Trouble Emergent UG (Outage)	Blanket	6,925,736
3	ERUC Trouble OH TRSD's	Blanket	7,842,301
4	ERUC Trouble UG TRSD's	Blanket	42,244,180
5	ERUC Trouble Reactive OH (Follow-up)	Blanket	3,463,265
6	ERUC Trouble Reactive UG (Follow-up)	Blanket	4,464,912
7	ERUC Trouble Environmental	Blanket	1,910,361
8	Other (Trk 7130A-B, LCSTR Cable)		18,745
9	**Total ERUC- Trouble**		**$ 172,406,790**
	ERUC- Storm		
10	Storm	Blanket	157,906,531
11	Storm - SO Follow Up	Blanket	44,571,823
12	Capital Completions & Removals	Blanket	5,244,630
13	**Total EURC - Storm**		**$ 207,722,984**
	Substation Improvements - Failures		
14	Z Budget Failures Major Equipment	Blanket	12,704,319
15	Z Budget Failures Minor Equipment	Blanket	15,738,180
16	Z Budget Failures Trfs/Regs	Blanket	10,489,522
17	Z Budget Non-Electrical	Blanket	3,816,098
18	Z Budget- Minor System/ Circuits	Blanket	542,108
19	**Total ERUC - Storm_subs**		**$ 43,290,226**
20	***Total Trouble/ Storm/ Substn CM***		**$ 423,420,001**
	Customer Attachments		
21	New Business & Load Growth Projects	* See note below	71,127,673
22	Customer Connections	Blanket	104,320,760
23	Small Load Growth Blanket	Blanket	19,365,816
24	TEP (transportation electrification)		4,700,000
25	**Total Customer Attachments**		**$ 199,514,249**
	Equipment, Relocation & Other		
26	Cuts & Restores	Blanket	8,320,011
27	Electric System (Transformers, Regulators & Meters)	Blanket	22,462,260
28	General Plant, Tools & Equipment and Miscellaneous	Blanket	7,909,141
29	NRUC, Improvement Blankets	Blanket & individual project less than $10M	15,977,655
30	Small Relocation Blanket	Blanket	8,961,298
31	Relocation Project	Individual projects, each less than $10M	12,678,704
32	Other	Individual projects, each less than $10M	5,926,171
33	**Total Equipment, Relocation & Other**		**$ 82,235,239**
	Infrastructure Redesign and Modernization		
34	Subtransmission Redesign & Rebuild		100,287,058
35	CODI		99,842,781
36	4.8kV CC/ 8.3kV CC		98,440,779
37	System Loading		46,667,772
38	Strategic Undergrounding Pilot		14,643,840
39	**Total Infrastructure Resilience and Hardening**		**$ 359,882,229**
	Infrastructure Resilience and Hardening		
40	4.8 kV Hardening		80,000,000
41	Pole and Pole Top Hardware		121,000,000
42	Frequent Outage		48,049,745
43	40 kV Automatic Pole Top Switch		4,995,000
44	Substation Risk		50,798,110
45	Station Upgrades		5,314,241
46	Breaker Replacement		14,278,548
47	Disconnect and Switcher Replacement		4,900,000
48	Cable Replacement Program		21,391,919
49	URD Replacement Program		15,041,398
50	Mobile Fleet Program		5,000,000
51	SCADA Pole Top Device Replacement		1,808,034
52	Substation Regulator Replacement		816,097
53	Steel Pole Highway Crossings		5,000,000
54	Batteries and Chargers Replacement		2,500,000
55	**Total Infrastructure Redesign and Modernization**		**$ 380,893,092**
	Technology and Automation		
56	Grid Automation		111,397,305
57	Grid Management		26,300,000
58	Distribution Planning		12,000,000
59	Work Management		10,000,000
60	Asset Management		1,400,000
61	Mobile Technology		8,200,000
62	**Total Technology and Automation**		**$ 169,297,305**
63	**TOTAL DO INVESTMENT PLAN**		**$ 1,615,242,115**

Sign Off covers all items that do not need FC-20 approval.
* Any individual project over $10M will still need to go through the FC-20 process.

MPSC Case No: U-21534

Requester: MNSC

Question No.: MNSCDE-8.16di

Respondent: J. Kryscynski

Page: 1 of 4

Question: 16. Refer to Exhibit A-12, Schedule B5.4, page 13, and to line 13, the PTMM program. Refer also to Exhibit A-33, Schedule X1, line 7, and to the PPTM budgets proposed for the IRM in 2026 and 2027.

d. Refer to the responses to subparts (a) and (b) above. Explain how the PTMM program budget was established for each of the following years, and provide a list of circuits and capital dollars budgeted for each project each year:

i. 2023

Answer: The Company develops the long-term vision for the grid and 5-year investment plans for distribution programs and projects using the process described in the 2021 and 2023 Distribution Grid Plans (DGP). The DGP investments address aging infrastructure, improvements to reliability, resiliency, and safety, and current and projected future capacity constraints. Investments are prioritized using the GPM as well as other considerations, as discussed in Witness Kryscynski's testimony.

The 5-year investment plan is a key reference when developing the annual distribution budgets. The annual budget planning process includes the 5-year DGP plan, updated information on grid needs including reliability data, and regulatory feedback obtained through rate cases. For 2023 investments, the 2021 DGP is the supportive grid planning reference.

The capital investment associated with PTMM for 2023 where the Company is seeking recovery through the current case can be found in Exhibit A-12, Schedule B5.4, page 13, line 13, column c. No investment associated with the PTMM Program has been authorized for IRM treatment in 2023.

PTMM Circuits Completed in 2023:

- ALGON0307
- ARNLD1653
- ARNLD2730
- AUBRN8866
- BEMIS9871
- BIDLE1677

Co-Respondent(s): N. Foley, M. Elliott Andahazy

MPSC Case No: U-21534

Requester: MNSC

Question No.: MNSCDE-8.16di

Respondent: J. Kryscynski

Page: 2 of 4

- BISHP1755
- BREWR9229
- BRITN0332
- BRITN0333
- BURTN0386
- BVRLY0357
- BVRLY1579
- BVRLY1865
- CALMT0344
- CHIPW0346
- CHIPW0348
- COLFX9873
- COMLK9538
- DRAKE8969
- ELGIN1433
- FINLY1550
- FLTRK0303
- FOWLR0302
- FRLDG8042
- GARCY0580
- GARCY1604
- GAY 1747
- GAY 1762
- GRENA9813
- HINES9378
- HINES9459
- HOWEL0980
- HOWEL0981
- HOWEL2931
- HOWEL2933
- HOWEL2934
- IDA 0311
- JEFSN9338
- JEFSN9409

Co-Respondent(s): N. Foley, M. Elliott Andahazy

MPSC Case No: U-21534

Requester: MNSC

Question No.: MNSCDE-8.16di

Respondent: J. Kryscynski

Page: 3 of 4

- KELOG9864
- KENEY0486
- KENEY2697
- KERN 8898
- KOPNK9437
- KOPNK9463
- LIBER1056
- LYNCH2260
- MALTA8469
- MALTA8543
- MEDNA8692
- MTMRA0302
- NINMI0252
- NINMI0560
- NINMI0825
- NINMI0860
- ORION9071
- PHENX9833
- PINGV2607
- PROSP0305
- PROSP0306
- PROTR2601
- PTAUS0312
- QTNRD0326
- QUAIL0311
- RAISN0305
- RAISN0306
- REMER8796
- ROCHR1814
- ROCHR1838
- RUSH 8089
- SHERW0321
- SHERW0322
- STEPH8669

Co-Respondent(s): N. Foley, M. Elliott Andahazy

MPSC Case No: U-21534

Requester: MNSC

Question No.: MNSCDE-8.16di

Respondent: J. Kryscynski

Page: 4 of 4

- SYRAC1901
- SYRAC1903
- TAMRK9096
- TFANY8024
- TFANY8038
- TFANY8038
- TIE 4708
- TIE 9205
- TINKN8933
- TRK 3536
- TRK 7115
- TRK 7756
- UTICA2558
- UTICA2583
- VENOY9383
- WCHTR1618
- WCHTR1937
- WCHTR2687

Attachment: *N/A*

Co-Respondent(s): N. Foley, M. Elliott Andahazy

MPSC Case No: U-21534

Requester: MNSC

Question No.: MNSCDE-7.2h

Respondent: S. Hartwick

Page: 1 of 1

Question: 2. Refer to Exhibit A-23, Schedule M7 (S. Hartwick) at page 48, which states, regarding Distribution Automation, "The planned Distribution Automation work for 2024 is expected to address ground detection and isolation for 63 circuits at 18 substations that is part of the IRM, and an additional 32 circuits at 11 substations. It is also expected to reduce SAIDI on impacted circuits by 45%, reducing system SAIDI by 9 minutes, based on the circuit level benefits modeling discussed earlier. The planned work for 2025 is expected to address ground detection and isolation for 281 circuits at 73 substations and is expected to reduce SAIDI on impacted circuits by 47% reducing system SAIDI by 45 minutes."

h. Describe any assurances the Company is willing to provide that system SAIDI will fall 54 minutes in 2026 from the baseline provided in response to subpart (g) above as a result of distribution automation installed in 2024 and 2025. Provide the amount of cost recovery the Company is willing to place at risk for failing to deliver 54 minutes' reduction from system SAIDI in 2026. If the Company is not willing to place any amount of cost recovery at risk based on the results of its distribution automation spending, please explain why not.

Answer: DTE Electric objects for the reason that the information requested is not relevant, nor is it reasonably calculated to lead to the discovery of relevant evidence. The Company's revenue requirement in this case is determined based upon the capital investments projected to go into service by the end of the test year. Therefore, assurances and recovery reductions based upon performance beyond the test year are not relevant to this proceeding. The Company also objects as it is unclear what is meant by "place at risk". Without waiving these objections, but subject to them, the Company responds as follows:

The Company has confidence that the investments will yield reliability improvements, however the Company can't predict the specific outcome in a specific year based on the impacts of weather or storm.

Attachment: None

Co-respondent: J. Kryscynski, Legal

MPSC Case No: U-21534

Requester: MNSC

Question No.: MNSCDE-7.4a

Respondent: S. Hartwick

Page: 1 of 1

Question: 4. Refer to Ms. Hartwick's Direct Testimony regarding Grid Automation Telecommunications generally, pages SMH 21-48, and specifically to the proposal to continue deploying fiber to substations through 2028, and to the statement "In 2026 and through the end of the program, fiber routes will be run through a cost benefit analysis to determine the appropriate future technology to be used that will support the telecommunications needs of all other DTEE investments and programs."

a. Provide a count of substations the Company operates today. Of these, provide counts of i) substations served by Company-owned fiber; ii) substations served by leased fiber; and iii) substations served by microwave or other wireless communications.

Answer: Refer to Table 1 in Witness Kryscynski's direct testimony for the total number of substations.

Request	Number of Substations
i) substations served by Company-owned fiber	17
ii) substations served by leased fiber	6
iii) substations served by microwave or other wireless communications	589

Additionally, 181 number of substations have Company owned fiber up to the substation premise as part of the fiber program.

Attachment: None

Co-respondent: J. Kryscynski

MPSC Case No: U-21534

Requester: MNSC

Question No.: MNSCDE-7.4b

Respondent: S. Hartwick

Page: 1 of 1

Question: 4. Refer to Ms. Hartwick's Direct Testimony regarding Grid Automation Telecommunications generally, pages SMH 21-48, and specifically to the proposal to continue deploying fiber to substations through 2028, and to the statement "In 2026 and through the end of the program, fiber routes will be run through a cost benefit analysis to determine the appropriate future technology to be used that will support the telecommunications needs of all other DTEE investments and programs."

b. Provide a list of substations to which the Company plans to extend fiber from January 1, 2024 through December 31, 2028. Provide the capital cost estimate for each deployment.

Answer: DTE Electric objects to the request for the reason that the request seeks confidential and proprietary, commercially sensitive and/or customer sensitive personal information that the disclosure of which will result in harm to the company or its customers. Subject to this objection and without waiver thereof, the Company would answer as follows:

The Company estimated investments for 2024 and 2025 are provided in the attachment. The investment timing for specific stations may change based on permitting, constructability and coordination with other DTE, utility, municipality, county, or state construction. Deployments in 2026 and beyond are outside of the instant case.

Attachment: NDA_U-21534 MNSCDE-7.4b 2024-2025 Fiber Deployment.xlsx

Co-respondent: Legal

MPSC Case No: U-21534

Requester: MNSC

Question No.: MNSCDE-7.4c

Respondent: S. Hartwick

Page: 1 of 1

Question: 4. Refer to Ms. Hartwick's Direct Testimony regarding Grid Automation Telecommunications generally, pages SMH 21-48, and specifically to the proposal to continue deploying fiber to substations through 2028, and to the statement "In 2026 and through the end of the program, fiber routes will be run through a cost benefit analysis to determine the appropriate future technology to be used that will support the telecommunications needs of all other DTEE investments and programs."

c. Provide the template or model of the cost benefit analysis tool to be used to determine the appropriate future technologies to deploy, including all identified inputs and assumptions. If the tool is already in use, please provide the results of all analyses for fiber deployments installed since 2020, including all data used, sources of data and caluculations, and all fiber deployments currently planned. If the tool is not already in use, please explain why not, and provide and example of how the cost benefit analysis will be applied including examples of input data, the sources of the data, and all calculations, workpapers and spreadsheets.

Answer: The cost benefit analysis tool does not currently exist.

The fiber deployments through 2025 are focused on completing the critical rings for the fiber backhaul network that connects the key infrastructure sites such as substations and other critical facilities to the various data centers. These investments are critical for enabling secure and reliable communications that directly support improved resiliency and improved speed of restoration. See questions 43-46 of Witness Hartwick's testimony discuss how fiber deployment was evaluated for the critical rings for the fiber backhaul network.

Beyond 2025, DTE Electric will need to continue to expand the telecommunications network investments to the next tier of locations that are prioritized from a resiliency perspective. The company is currently developing the cost benefit analysis tool for determining fiber deployments beyond 2025, but it is not yet completed.

Attachment: None

MPSC Case No: U-21534

Requester: MNSC

Question No.: MNSCDE-7.4d

Respondent: S. Hartwick

Page: 1 of 1

Question: 4. Refer to Ms. Hartwick's Direct Testimony regarding Grid Automation Telecommunications generally, pages SMH 21-48, and specifically to the proposal to continue deploying fiber to substations through 2028, and to the statement "In 2026 and through the end of the program, fiber routes will be run through a cost benefit analysis to determine the appropriate future technology to be used that will support the telecommunications needs of all other DTEE investments and programs."

d. Explain how the Company has identified the fiber deployments which are likely to deliver benefits in excess of costs to date.

Answer: Not all benefits are definable on a strict cost basis. See A42 of Witness Hartwick's testimony for customer benefits.

Attachment: None

MPSC Case No: U-21534

Requester: MNSC

Question No.: MNSCDE-7.3a

Respondent: S. Hartwick

Page: 1 of 1

Question: 3. Refer to Ms. Hartwick's Direct Testimony regarding Grid Automation Telecommunications generally, SMH pages 21-48, and to the DTE Electric Distribution Grid Plan, page 140, diagrams 10.1.5.1 (current technology landscape) and 10.1.5.2 (future technology landscape) (Exhibit A-23 Schedule M8, page 141 of 274). Provide a complete description of the Grid Automation Telecommunications plan the Company proposes to deploy to move from the current to the future technology landscape, including but not limited to:

a. An estimated timeline for the plan through completion (as depicted in the future technology landscape diagram);

Answer: The future technology landscape diagram 10.1.5.2 in Exhibit A-23 Schedule M8, page 141 of 274 is an overview. However, a simplified layered structure of the Grid Telecommunication Network is presented in Figure 2 of Witness Hartwick's testimony. As described in testimony, the Fiber Backhaul network will be the singular focus of Grid Automation Telecommunications investment through 2025. Fiber installations will continue through 2028. The advanced mesh is beyond the scope of the current case but will utilize the fiber backbone built with this investment to connect the last mile network.

Attachment: None

MPSC Case No: U-21534

Requester: MNSC

Question No.: MNSCDE-7.3b

Respondent: S. Hartwick

Page: 1 of 1

Question: 3. Refer to Ms. Hartwick's Direct Testimony regarding Grid Automation Telecommunications generally, SMH pages 21-48, and to the DTE Electric Distribution Grid Plan, page 140, diagrams 10.1.5.1 (current technology landscape) and 10.1.5.2 (future technology landscape) (Exhibit A-23 Schedule M8, page 141 of 274). Provide a complete description of the Grid Automation Telecommunications plan the Company proposes to deploy to move from the current to the future technology landscape, including but not limited to:

b. The most significant (by cost) components of the plan;

Answer: The most significant component of the plan is the installation of fiber between locations followed by the electronics and routers needed to utilize the fiber.

Attachment: None

MPSC Case No: U-21534

Requester: MNSC

Question No.: MNSCDE-7.3c

Respondent: S. Hartwick

Page: 1 of 1

Question: 3. Refer to Ms. Hartwick's Direct Testimony regarding Grid Automation Telecommunications generally, SMH pages 21-48, and to the DTE Electric Distribution Grid Plan, page 140, diagrams 10.1.5.1 (current technology landscape) and 10.1.5.2 (future technology landscape) (Exhibit A-23 Schedule M8, page 141 of 274). Provide a complete description of the Grid Automation Telecommunications plan the Company proposes to deploy to move from the current to the future technology landscape, including but not limited to:

c. The estimated capital cost of the plan by year, by component through completion;

Answer: Please see Exhibit A-12, Schedule B5.4, page 17, line 6 for the capital investment by year and Exhibit A-23, Schedule M7, page 77 for a breakdown by material, labor and other. The Company does not have the breakdown by component.

Attachment: None

MPSC Case No: U-21534

Requester: MNSC

Question No.: MNSCDE-7.3d

Respondent: S. Hartwick

Page: 1 of 1

Question: 3. Refer to Ms. Hartwick's Direct Testimony regarding Grid Automation Telecommunications generally, SMH pages 21-48, and to the DTE Electric Distribution Grid Plan, page 140, diagrams 10.1.5.1 (current technology landscape) and 10.1.5.2 (future technology landscape) (Exhibit A-23 Schedule M8, page 141 of 274). Provide a complete description of the Grid Automation Telecommunications plan the Company proposes to deploy to move from the current to the future technology landscape, including but not limited to:

d. Any benefit-cost analysis the Company has completed on the plan;

Answer: Secure and reliable telecommunications are foundational for distribution automation. Without this base capability, the modern infrastructure of the grid would be unable to function at its full capability and provide benefits to customers including integrating new technology such as distributed generation and storage. The Company has not completed a benefit-cost analysis for the Grid Automation Telecommunications program; however, a qualitative analysis for the fiber backhaul component of the plan is presented in Figure 3, 4, and 5 of Witness Hartwick's testimony.

Attachment: None

MPSC Case No: U-21534

Requester: MNSC

Question No.: MNSCDE-7.3e

Respondent: S. Hartwick

Page: 1 of 1

Question: 3. Refer to Ms. Hartwick's Direct Testimony regarding Grid Automation Telecommunications generally, SMH pages 21-48, and to the DTE Electric Distribution Grid Plan, page 140, diagrams 10.1.5.1 (current technology landscape) and 10.1.5.2 (future technology landscape) (Exhibit A-23 Schedule M8, page 141 of 274). Provide a complete description of the Grid Automation Telecommunications plan the Company proposes to deploy to move from the current to the future technology landscape, including but not limited to:

e. All approved capital expenditure requests approved for the plan so far; and

Answer: Please refer to the Exhibit A-12, Schedule B.5.4, page 17, line 6. Grid Automation Telecommunications disallowances from U-21297 have been provided in STDE3.4.

Attachment: None

MPSC Case No: U-21534

Requester: MNSC

Question No.: MNSCDE-7.3f

Respondent: S. Hartwick

Page: 1 of 1

Question: 3. Refer to Ms. Hartwick's Direct Testimony regarding Grid Automation Telecommunications generally, SMH pages 21-48, and to the DTE Electric Distribution Grid Plan, page 140, diagrams 10.1.5.1 (current technology landscape) and 10.1.5.2 (future technology landscape) (Exhibit A-23 Schedule M8, page 141 of 274). Provide a complete description of the Grid Automation Telecommunications plan the Company proposes to deploy to move from the current to the future technology landscape, including but not limited to:

f. A description of the portions of the plan completed through December 31, 2023 and the capital spent on each portion through that date.

Answer: Fiber deployments completed in 2022 and 2023 are discussed in Q47 of Witness Hartwick's direct testimony. Yearly capital investments are detailed in Exhibit A-12, Schedule B.5.4, page 17, line 6.

Attachment: None

Curriculum Vitae – Dennis Stephens

DS Consulting, 1153 Bergen Pkwy, Evergreen CO 80439 dstephens@wiredgroup.net 303.434.0957

Profile

Mr. Stephens has over 40 years' experience in electric and gas distribution grid planning, design, operations management, and asset management, and the innovative use of technology to assist with these functions. He spent his entire career at Xcel Energy and its subsidiary Public Service Company of Colorado, a distribution utility serving 1.5 million electric customers and 1.4 million gas customers. After a series of electrical and gas engineering and management roles of increasing responsibility, Mr. Stephens retired as the Director of Innovation and Smart Grid Investments for all of Xcel Energy's electric and gas distribution businesses in 2011. He now works for the Wired Group and its clients on a part-time basis.

Career History (all positions with Public Service Company of Colorado or its parent, Xcel Energy)

1976 -- Planning Engineer. Performed electric distribution system planning for Southeast Denver, Boulder, Front Range and Cheyenne divisions, including system protection, voltage support and distribution system design.

1983 – Senior Engineer, Electric Distribution Planning. Provided direction and guidance for junior engineers. Led special projects relating to electric distribution system reliability and design. Promoted to Supervisor of Electric Distribution Planning with a staff of 12 electrical engineers with responsibility for capacity and reliability planning.

1988 -- Manager of Operations, Colorado Front Range Division. Responsible for all electric and gas distribution operations, including a high-pressure gas system (engineering, operations, and construction).

1994 -- Manager of Operations & Maintenance Engineering, Southeast Denver. Managed the design of gas and electric distribution system replacements.

1997 -- Manager, Distribution Reliability Assessment, Xcel Energy South (CO, WY, TX, OK). Led an engineering team focused on electric distribution grid reliability and capacity.

1998 -- Director of Electric and Gas Operations, Southwest Denver Division. Responsible for all aspects of electric and gas engineering, operations, and construction in the Southwest Denver Division.

1999 -- Director of Operations, City and County of Denver Division. Responsible for all aspects of electric and gas engineering, operations, and construction for Division, including downtown Denver. Promoted to Director, New Construction of electric and gas systems for the entire metro area.

2001 -- Director Electric Distribution Asset Strategy, Xcel Energy. Developed and implemented asset management strategies for all electric distribution assets in Xcel Energy's 8-state service area.

2005 -- Director of Utility Innovations and Smart Grid Investments. Led Xcel Energy's Utility Innovations department, developing and implementing new technologies and business processes in multiple electric and gas distribution functional areas. Advanced the concept of an Intelligent Network at Xcel Energy, and led several aspects of the SmartGridCity® demonstration project in Boulder, Colorado. Department secured a national Edison Award for Innovation in 2006. Retired in 2011.

2016 – Senior Technical Consultant, Wired Group.

Noteworthy Projects

Smart Grid Solutions Development, 2010. Worked with several large solution providers to develop and implement technical distribution grid solutions and innovations, including IBM, ABB, and Siemens**.**

DER Integration Strategy and Roadmap Development, 2009. Established DER integration strategy and road-maps for Xcel Energy, including technology and capability roadmap for high DER penetration geographies in Boulder, Colorado.

SmartGridCity™ Project Development, 2008. Developed the technical foundations for the SmartGridCity project in Boulder, Colorado (46,000 customers).

Distribution Automation Design, 2007. Worked with ABB Corporation to design software to identify and locate failures in underground cable. The ABB Smart Analyzer™ was programmed with three traps to capture detailed information using Oscillography/Digital Fault Records (O/DFR).

Utility Innovations Program Development, 2006. Led the development of Xcel Energy's Utility Innovations program, for which Mr. Stephens' team receive a national Edison Award.

Distribution Asset Optimization Process, 2005. Taking advantage of SPL's Centricity Outage Management Program and Itron's Real Time Performance Management system (RTPM), developed a Distribution Asset Optimization process by mining AMI meter data and asset utilization information in the development of an enhanced asset loading forecasting process. The process took advantage of the systems' abilities to forecast sudden changes in usage patterns to take proactive mediation of equipment overloading.

Distribution Asset Optimization Software Development, 2004. Worked with Itron on the development of a Distribution Asset Optimization software program.

Fixed AMI Communications Network Development, 2003. Worked with Itron to pilot one of the first applications of a fixed wireless radio network to collect data from customer meters.

Electric Asset Management Strategy Development, 2002. Developed Xcel Energy's Electric Distribution Asset Management Strategy

Automated Switching System Deployment, 2001. Worked with S&C Electric Corporation to deploy its Intelliteam™ devices on Xcel Energy's distribution grid to reduce the number of customers impacted by an outage by isolate faults through automated switching routines.

High Pressure Gas Pipe Replacement Program, 1988. Initiated and managed the renewal and replacement of 26 miles of high pressure gas pipe, over a 5 year period, reducing the likelihood of seam failures as outlined in an "Alert Notice" issued by the Department of Transportation's Office of Pipeline

Safety. Project roles included community engagement, government and regulator relations (PUC, DOT, EPA), and contractor management. Project completed 1 year ahead of schedule and 14% under budget.

Regulatory Appearances

Evaluate the Application of Public Service of Oklahoma for a Rate Increase and Changes in Cost Recovery Practices for Some Expenses. Testimony on behalf of Commission Staff in PUD 2023-000086. July 29, 2024.

Evaluate DTE Energy's Request for Rate Increase, and to Extend and Expand Rider IRM. Testimony on behalf of a group of environmental and consumer advocates in Michigan PSC U-21534. July 26, 2024.

Evaluate Commonwealth Edison Company's Refiled Grid Plan. Panel Testimony with Paul J. Alvarez on behalf of the Attorney General in Illinois Commerce Commission Case No. 22-0486. May 23, 2024.

Evaluate Ameren Illinois Company's Refiled Grid Plan. Panel Testimony with Paul J. Alvarez on behalf of the Attorney General in Illinois Commerce Commission Case No. 22-0487. May 13, 2024.

Evaluate Oklahoma Gas & Electric Company's historical spending. Testimony on behalf of the Oklahoma Corporation Commission Staff in PUD 2023-000087. April 26, 2024.

Evaluate National Grid's historical spending and multi-year rate plan. Panel testimony with Paul J. Alvarez on behalf of the Attorney General in Massachusetts DPU Case 23-150. March 29, 2024.

Evaluate Pepco's Second Multi-year Rate Plan. Panel testimony with Paul J. Alvarez on behalf of the Office of People's Counsel in Maryland PSC Case No. 9702. December 15, 2023.

Evaluate BGE's Second Multi-Year Rate Plan (Electric Distribution Components 2024-2027) and Electric Distribution Spending 2021-2022. Panel testimony with Paul J. Alvarez on behalf of the Office of People's Counsel in Maryland PSC Case No. 9692. June 20, 2023.

Evaluate DTE Energy's Request for Strategic Capital Plan Cost Recovery and Infrastructure Recovery Mechanism Rider on behalf of the Attorney General and a group of environmental and consumer advocates in Michigan PSC U-21297. June 13, 2023.

Evaluate Commonwealth Edison's Multi-year Grid Plan. Panel testimony with Paul Alvarez on behalf of the Attorney General in Illinois Commerce Commission 22-0486. May 22, 2023.

Evaluate Ameren Illinois Corporation's Multi-year Grid Plan. Panel testimony with Paul Alvarez on behalf of the Attorney General in Illinois Commerce Commission 22-0487. May 11, 2023.

Evaluate the Technical Justifications for Public Service Oklahoma's $450 million Grid Enhancement and Resilience Plan. Testimony on behalf of the Attorney General in PUD-2022-000093. March 7, 2023.

Evaluate Georgia Power's Transmission and Distribution Spending Proposals. Panel testimony with Paul Alvarez on behalf of Public Interest Advocacy Staff. Georgia PSC 44280. October 20, 2022.

Evaluate Pacific Gas & Electric's 2023-2026 Multi-year Rate Plan. Panel testimony with Paul Alvarez on behalf of AARP. California PUC A.21-06-021. June 10, 2022.

Evaluate the Distribution Business Components of Georgia Power Company's Integrated Resource Plan. Panel testimony with Paul J. Alvarez on behalf of Public Interest Advocacy Staff. Georgia PSC 44160. May 6, 2022.

Evaluate Oklahoma Gas & Electric Company Grid Modernization Spending and Plans. Testimony on behalf of the Office of Attorney General in PUD 202100164. April 27, 2022.

Evaluate Grid Modernization and Advanced Metering Proposals by Massachusetts Utilities. Panel testimonies with Paul J. Alvarez on behalf of the Office of Attorney General in D.P.U. 21-80, 21-81, and 21-82. January 19, 2022.

Dominion Grid Modernization Plan Review. Testimony on behalf of Appalachian Voices/Southern Environmental Law Center. PUR-2021-00127. September 13, 2021.

Avista Utilities' Electric Distribution and Wildfire Spending, Plans, and Processes. Panel testimony with Paul J. Alvarez on behalf of Public Counsel. WUTC 200900, 200901, and 200894. April 29, 2021.

Pepco's 2021-2023 Grid Investment and Plan. Panel testimony with Paul J. Alvarez on behalf of the Maryland Office of People's Counsel. MDPSC 9655. March 3, 2021

Baltimore Gas & Electric Company's 2021-2023 Grid Investment and Operations Plan. Panel testimony with Paul J. Alvarez on behalf of the Maryland Office of People's Counsel. MD PSC 9645. Aug 14, 2020.

Review of Maryland Utilities' 2019 Annual Performance Reports. Comments of the Office of People's Counsel. MD PSC 9353. June 8, 2020

Duke Energy Carolinas/Duke Energy Progress $2.3 billion Grid Improvement Plan. Testimony before the North Carolina Utilities Commission critiquing Duke Energy's Plan on behalf of a group of environmental and consumer advocates. NCUC E-7, Sub 1214 Feb 18, 2020 & E-2, Sub 1219 Mar 25, 2020.

Indianapolis Power and Light's proposed $1.2 billion Grid Improvement Plan. Testimony before the Indiana Utility Regulatory Commission on behalf of the City of Indianapolis critiquing Indianapolis Power and Light's proposed $1.2 billion Grid Improvement Plan. Cause 45264. October 7, 2019.

Investigation into Distribution Planning Processes. Comments to the Michigan Public Service Commission recommending a transparent, stakeholder-engaged distribution planning process. U-20147. September 11, 2019.

New Hampshire Public Utilities Commission Distribution Planning/Grid Modernization Proceeding. Comments in IR 15-296 describing a transparent, stakeholder-engaged distribution planning process.

Pacific Gas and Electric 2019 General Rate Case. Testimony in A.18-12-009 on behalf of TURN related to $270 million in proposed "Integrated Grid Platform" investments.

Southern California Edison 2017 General Rate Case. Testimony in A.16-09-001 on behalf of TURN related to $2.3 billion in proposed grid modernization investments.

Pacific Gas and Electric 2016 General Rate Case. Testimony in A.15-09-001 on behalf of related to $100 million in proposed grid modernization investments.

Notable Publications and Presentations

Alternative Ratemaking in the US: A Prerequisite for Grid Modernization, or an Unwarranted Shift of Risk to Customers? With Paul Alvarez, Kenneth Costello, and Sean Ericson. Electricity Journal. Volume 35 (October 2022).

Utility Regulation Through Legislation: A Cautionary Tale for Legislators, Regulators, Stakeholders, and Utilities. With Paul Alvarez and Sean Ericson. Electricity Journal. Volume 34 (August 2021).

Florida Storm Protection Plans: A Bonanza for Utilities, A Bust for Consumers and the State. Whitepaper co-authored with Paul J. Alvarez for AARP-Florida. October 5, 2020.

Challenging Utility Grid Modernization Proposals. With Sean Ericson and Dennis Stephens. Public Utilities Fortnightly. Part 1, August, 2020, pages 59-62; Part 2 to be published September, 2020.

The Rush to Modernize: An Editorial on Distribution Planning and Performance Measurement. With Paul Alvarez & Sean Ericson. Accepted for publication by Public Utilities Fortnightly. Anticipated publication June, 2019.

Modernizing the Grid in the Public Interest: Getting a Smarter Grid at the Least Cost for South Carolina Customers. Whitepaper co-authored with Paul Alvarez for GridLab. January 31, 2019

Modernizing the Grid in the Public Interest: A Guide for Virginia Stakeholders. Whitepaper co-authored with Paul Alvarez for GridLab. October 5, 2018.

DistribuTECH 2010, Tampa, Florida. "Realizing the Benefits of DER, DG and DR in the Context of Smart Grid"

OSI 2008 User's Conference, Denver, Colorado; DistribuTECH 2007, San Diego, California. "Smart Grid City: A blueprint for a connected, intelligent grid community"

ABB 2007 World Conference, Jacksonville, Florida. "Use of Distribution Automation Systems to identify Underground Cable Failure"

North American T&D Conference 2005, Toronto, Canada; Itron 2005 User Conference, Boca Raton, Florida. "Xcel Energy Utility Innovations and Distribution Asset Optimization"

DistribuTECH 2005, San Diego, California. "How Advanced Metering Technology is Driving Innovation at Xcel Energy"

Education

Bachelor of Science Degree in Electrical Engineering, 1975, University of Missouri at Rolla.

Awards

Led Xcel Energy team that received a National Edison Award for Utility Innovations, 2006.

AG-MN 2024 / 2025 Test Year Reductions	($ in millions)	Reduction in 2024	Reduction in 2025 Test Year
4.8kV Hardening			
DTE Requested '24/ '25 Test Year		80.000	125.000
AG-MN Recommended Adjustment		(73.333)	(81.800)
AG-MN Recommended '24 / '25 Test Year Spend		6.667	43.200
Pole and Poletop Maintenance and Modernization			
DTE Requested '25		n/a	121.000
AG-MN Recommended Adjustment		n/a	(57.550)
AG-MN Recommended '25 Test Year Spend		n/a	63.450
Distribution Automation			
DTE Requested '25		n/a	125.625
AG-MN Recommended Adjustment		n/a	(101.176)
AG-MN Recommended '25 Test Year Spend		n/a	24.449
Strategic & Service Line OH to UG Pilots			
DTE Requested '24/ '25 Test Year		15.644	16.019
AG-MN Recommended Adjustment		(15.644)	(16.019)
AG-MN Recommended '24 / '25 Test Year Spend		0.000	0.000
Grid Automation Telecommunications			
DTE Requested '24/ '25 Test Year		16.900	15.000
AG-MN Recommended Adjustment		(16.900)	(15.000)
AG-MN Recommended '24 / '25 Test Year Spend		0.000	0.000
Subtransmission Redesign and Rebuild Disallowances			
Tie 4105 Phase 3 (projected to be in service in 2024)		(19.274)	0.000
Tie 4105 Phase 4 (projected to be in service in 2025)		0.000	(2.808)
Trunk 3509 (Projected to be in service 2024)		(6.062)	0.000
Total Subtransmission Redesign and Rebuild Disallowance		(25.336)	(2.808)

2024 /2025 Test Year Reduction Summary	**2024**	**2025**
4.8kV Hardening	(73.333)	(81.800)
Pole and Poletop Maintenance & Modernization	n/a	(57.550)
Distribution Automation	n/a	(101.176)
Strategic & Service Line OH to UG Pilots	(15.644)	(16.019)
Grid Automation Telecommunications	(16.900)	(15.000)
Subtransmission Redesign and Rebuild	(25.336)	(2.808)
TOTALS	**(131.213)**	**(274.353)**

Strategic Capital Programs AG-MN Disallowance Summary	**2024**	**2025**	
Infrastructure Resilience and Hardening			
4.8kV Hardening	(73.333)	(81.800)	Ex A-12 B5.4 p13 Infrastructure Resilience and Hardening line 12, col (d), (g)
Pole and Poletop Maintenance & Modernization	n/a	(57.550)	Ex A-12 B5.4 p13 Infrastructure Resilience and Hardening line 13, col (d), (g)
TOTAL Infrastructure Resilience and Hardening Disallowances	**(73.333)**	**(139.350)**	**Ex A-12 B5.4 p1 line 19 col (d), f)**
Infrastructure Redesign and Modernization			
Strategic & Service Line OH to UG Pilots	(15.644)	(16.019)	Ex A-12 B5.4 p15 Infrastructure Redesign & Modernization line 64, col (d), (g))
Subtransmission Redesign and Rebuild	(25.336)	(2.808)	Ex A-12 B5.4 p16 Infrastructure Redesign & Modernization line 114, col (d), (g))
TOTAL Infrastructure Redesign & Modernization Disallowances	**(40.980)**	**(18.827)**	**Ex A-12 B5.4 p1 line 20 col (d), f)**
Technology and Automation			
Distribution Automation	n/a	(101.176)	Ex A-12 B5.4 p17 Technology & Automation line 2, col (d), (g))
Grid Automation Telecommunications	(16.900)	(15.000)	Ex A-12 B5.4 p17 Technology & Automation line 6, col (d), (g))
TOTAL Technology and Automation Disallowances	**(16.900)**	**(116.176)**	**Ex A-12 B5.4 p1 line 21 col (d), f)**
TOTAL Strategic Capital Programs Disallowances	(131.213)	(274.353)	**Ex A-12 B5.4 p1 line 22 col (d), f)**

Job Number	Outage Time	Restore Time	Duration	egio	Circuit	stomers Affec	vice Ext	Extent	Cause Code	DS Device	DS Cause	Material Affected	Storm Number
NW23032100506	3/20/2023 18:00	3/21/2023 13:56	181	NW	Circuit508	2270	RECLO	)evice (ii	Equipment Failure	NA	NA	null	null
NE23031001474	3/10/2023 18:09	3/10/2023 22:55	266	NE	Circuit1208	174	RECLO	)evice (ii	Equipment Failure	PTTM	PTMM FAILURE	null	null
NE23020701129	2/7/2023 14:37	2/8/2023 5:10	871	NE	Circuit1210	2271	RECLO	)evice (ii	Equipment Failure	WIRE DOWN	3RD PARTY DAMAGE	null	null
SW23042300837	4/23/2023 22:08	4/24/2023 9:30	681	SW	Circuit2423	510	FUSE	)evice (ii	Equipment Failure	NA	NA	null	null
SW23042400888	4/24/2023 15:11	4/24/2023 10:36	23	SW	Circuit2423	608	OHCKT	rcuit Lev	Equipment Failure	NA	NA	null	null
NE23042900055	4/29/2023 2:35	4/29/2023 17:20	878	NE	Circuit1217	124	FUSE	)evice (ii	Equipment Failure	NA	NA	null	null
SE23022100530	2/21/2023 11:35	2/21/2023 21:41	606	SE	Circuit2442	112	FUSE	)evice (ii	Equipment Failure	PTTM	PTMM FAILURE	null	null
SE23022709812	2/23/2023 7:53	2/28/2023 21:35	1508	SE	Circuit2442	981	OHCKT	rcuit Lev	Equipment Failure	NA	NA	CABLE	2023003
NW23032500911	3/24/2023 12:34	3/25/2023 21:35	462	NW	Circuit1587	2290	OHCKT	rcuit Lev	Equipment Failure	NA	NA	null	null
NW23050100692	5/1/2023 12:19	5/1/2023 19:39	439	NW	Circuit1587	126	CP	)evice (i	Equipment Failure	NA	NA	null	null
NW23041201488	4/12/2023 19:07	4/13/2023 5:24	432	NW	Circuit2450	153	RECLO	)evice (ii	Equipment Failure	NA	NA	null	null
NW23041201299	4/12/2023 19:05	4/12/2023 22:08	182	NW	Circuit1470	1089	OHCKT	rcuit Lev	Equipment Failure	RECLOSER	EQUIP FAILURE	null	null
NW23030319097	3/3/2023 20:46	3/4/2023 16:47	1196	NW	Circuit1469	211	RECLO	)evice (ii	Equipment Failure	NA	NA	null	2023003
SE23031700047	3/17/2023 1:35	3/17/2023 16:08	873	SE	Circuit1590	211	CP	)evice (i	Equipment Failure	WIRE DOWN	NA	null	null
SE23050401499	5/4/2023 17:40	5/4/2023 22:20	240	SE	Circuit1593	1141	RECLO	)evice (ii	Equipment Failure	JUMPER OPEN	VEGETATION DAMAGE	null	null
SE23020901596	2/9/2023 17:34	2/9/2023 20:21	165	SE	Circuit1598	332	RECLO	)evice (ii	Equipment Failure	WIRE DOWN	NA	null	null
SE23042400216	4/24/2023 1:55	4/24/2023 5:49	203	SE	Circuit1600	136	G TRAN	e Transf	Equipment Failure	OK ON ARRIVAL	NA	null	null
SE23042400213	4/24/2023 1:55	4/24/2023 5:49	203	SE	Circuit1600	141	H TRAN	e Transf	Equipment Failure	OK ON ARRIVAL	NA	null	null
NW23022000803	2/20/2023 11:10	2/20/2023 16:47	137	NW	Circuit2485	2030	OHCKT	rcuit Lev	Equipment Failure	WIRE DOWN	NA	null	null
NW23042401589	4/24/2023 13:32	4/24/2023 18:23	230	NW	Circuit2485	124	FUSE	)evice (ii	Equipment Failure	NA	NA	null	null
NW23042401753	4/24/2023 15:56	4/24/2023 17:56	117	NW	Circuit2486	716	OHCKT	rcuit Lev	Equipment Failure	PTMM	PTMM FAILURE	null	null
NW23042401750	4/24/2023 15:56	4/24/2023 16:32	33	NW	Circuit2486	787	OHCKT	rcuit Lev	Equipment Failure	NA	NA	null	null
NW23042801989	4/28/2023 17:30	4/30/2023 17:25	2766	NW	Circuit2489	341	FUSE	)evice (ii	Equipment Failure	WIRE DOWN	NA	null	null
NW23032000254	3/20/2023 8:26	3/20/2023 10:03	94	NW	Circuit2490	111	UGCKT	rcuit Lev	Equipment Failure	POLE BROKEN	NA	null	null
SE23020902008	2/9/2023 19:33	2/10/2023 2:18	347	SE	Circuit1617	835	OHCKT	rcuit Lev	Equipment Failure	POLE	NA	null	null
SE23031600395	3/16/2023 10:18	3/16/2023 17:21	416	SE	Circuit1617	474	FUSE	)evice (ii	Equipment Failure	NA	NA	null	null
SE23020901993	2/9/2023 20:26	2/10/2023 2:18	351	SE	Circuit1618	722	OHCKT	transmis	Equipment Failure	POLE BROKEN	NA	null	null
SW23021701519	2/17/2023 7:21	2/17/2023 10:54	57	SW	Circuit719	1781	null	)evice (ii	Equipment Failure	NA	NA	null	null
SW23041001058	4/10/2023 13:19	4/10/2023 20:17	417	SW	Circuit719	174	FUSE	)evice (ii	Equipment Failure	NA	NA	null	null
SW23041300202	4/13/2023 9:08	4/13/2023 11:16	125	SW	Circuit719	173	FUSE	)evice (ii	Equipment Failure	NA	CAUSE NOT FOUND	null	null
SW23050401233	5/4/2023 15:24	5/4/2023 19:54	266	SW	Circuit719	172	FUSE	)evice (ii	Equipment Failure	NA	NA	null	null
SW23052601208	5/26/2023 14:37	5/26/2023 16:37	119	SW	Circuit719	172	FUSE	)evice (ii	Equipment Failure	PTMM	PTMM FAILURE	null	null
SW23030301309	3/3/2023 12:53	3/5/2023 14:45	2972	SW	Circuit720	519	RECLO	)evice (ii	Equipment Failure	NA	NA	null	2023003
NE23030309961	3/3/2023 18:11	3/4/2023 16:03	1299	NE	Circuit1220	134	FUSE	)evice (ii	Equipment Failure	NA	NA	null	2023003
NE23032000516	3/20/2023 8:29	3/21/2023 7:17	1298	NE	Circuit1220	1878	OHCKT	rcuit Lev	Equipment Failure	NA	NA	null	null
NE23033001412	3/30/2023 16:30	3/30/2023 16:46	14	NE	Circuit1220	1879	OHCKT	rcuit Lev	Equipment Failure	SWITCH	EQUIP FAILURE	null	null
NW23042300932	4/24/2023 0:09	4/24/2023 8:04	467	NW	Circuit1949	1163	OHCKT	rcuit Lev	Equipment Failure	NA	NA	null	null
NW23042300950	4/24/2023 0:09	4/24/2023 8:03	444	NW	Circuit1951	2100	OHCKT	rcuit Lev	Equipment Failure	NA	NA	null	null
NW23060501473	6/5/2023 15:23	6/5/2023 22:27	421	NW	Circuit1951	101	CP	)evice (i	Equipment Failure	NA	NA	null	null
NE23050800171	5/8/2023 8:22	5/8/2023 11:23	177	NE	Circuit2503	217	FUSE	)evice (ii	Equipment Failure	NA	NA	null	null
NE23050800206	5/8/2023 8:35	5/8/2023 14:15	338	NE	Circuit2503	358	FUSE	)evice (ii	Equipment Failure	NA	NA	null	null
NW23031000729	3/10/2023 11:41	3/10/2023 17:42	340	NW	Circuit2505	446	RECLO	)evice (ii	Equipment Failure	NA	NA	CONDUCTOR	null
SE23030309797	3/3/2023 18:11	3/4/2023 22:07	1664	SE	Circuit813	234	FUSE	)evice (i	Equipment Failure	WIRE DOWN	NA	null	2023003
SE23030301881	3/3/2023 15:54	3/4/2023 19:15	1640	SE	Circuit817	330	RECLO	)evice (ii	Equipment Failure	NA	NA	null	2023003
NW23040500804	4/5/2023 10:10	4/5/2023 16:46	389	NW	Circuit2514	809	OHCKT	rcuit Lev	Equipment Failure	NA	NA	null	null
SW23032700047	3/27/2023 1:17	3/27/2023 3:34	106	SW	Circuit2408	2949	RECLO	)evice (ii	Equipment Failure	NA	NA	null	2023004
NE23051801145	5/18/2023 15:16	5/18/2023 17:18	82	NE	Circuit1228	3090	OHCKT	rcuit Lev	Equipment Failure	NA	NA	null	null
NE23032101398	3/21/2023 13:48	3/21/2023 14:18	13	NE	Circuit2524	2148	OHCKT	rcuit Lev	Equipment Failure	NA	NA	null	null
NE23032900072	3/29/2023 7:07	3/29/2023 15:57	500	NE	Circuit2524	2150	OHCKT	rcuit Lev	Equipment Failure	NA	NA	null	null
SW23022101423	2/21/2023 23:08	2/22/2023 3:55	266	SW	Circuit2017	156	FUSE	)evice (ii	Equipment Failure	NA	NA	null	null
NE23053000208	5/30/2023 3:43	5/30/2023 8:05	183	NE	Circuit2529	1940	OHCKT	rcuit Lev	Equipment Failure	NA	NA	null	null
NE23020900365	2/9/2023 9:22	2/9/2023 11:58	156	NE	Circuit2532	175	RECLO	)evice (ii	Equipment Failure	JUMPER OPEN	NA	null	null
SE23022226400	2/22/2023 22:56	2/26/2023 13:12	5175	SE	Circuit345	737	OHCKT	rcuit Lev	Equipment Failure	SERVICE BROKEN	VEGETATION DAMAGE	null	2023003
SW23061200345	6/12/2023 2:18	6/12/2023 8:04	310	SW	Circuit1385	680	FUSE	)evice (ii	Equipment Failure	PTMM	PTMM FAILURE	null	null
SW23021702358	2/17/2023 11:17	2/17/2023 20:18	346	SW	Circuit2024	3114	CP	)evice (ii	Equipment Failure	SUBSTATION EQUIP	NA	null	null
SW23042900262	4/29/2023 6:35	4/29/2023 21:34	897	SW	Circuit2027	953	RECLO	)evice (ii	Equipment Failure	WIRE DOWN	NA	null	null

SW23042900995	4/29/2023 6:35	4/29/2023 23:07	604	SW	Circuit2027	469	PTS Device (ii	Equipment Failure	WIRE DOWN	NA	null	null
NE23021800272	2/18/2023 10:52	2/18/2023 16:32	337	NE	Circuit1231	810	OHCKT rcuit Lev	Equipment Failure	PTMM	PTMM FAILURE	null	null
NW23030309870	3/3/2023 18:13	3/6/2023 8:55	3752	NW	Circuit2554	2259	OHCKT rcuit Lev	Equipment Failure	NA	NA	null	2023003
SE23033101982	3/31/2023 22:24	3/31/2023 23:18	50	SE	Circuit1622	706	OHCKT rcuit Lev	Equipment Failure	NA	NA	null	null
SE23033102041	3/31/2023 22:44	4/1/2023 3:28	280	SE	Circuit1623	483	OHCKT rcuit Lev	Equipment Failure	WIRE DOWN	NA	null	null
SE23040100383	4/1/2023 0:51	4/1/2023 3:38	26	SE	Circuit1623	482	OHCKT rcuit Lev	Equipment Failure	WIRE DOWN	NA	null	null
SE23040100413	4/1/2023 3:10	4/1/2023 3:49	8	SE	Circuit1623	482	OHCKT rcuit Lev	Equipment Failure			null	null
SE23033102074	3/31/2023 22:25	3/31/2023 23:11	16	SE	Circuit1624	553	RECLO Device (ii	Equipment Failure	NA	NA	null	null
SE23032500398	3/25/2023 10:47	3/25/2023 20:21	543	SE	Circuit1626	659	OHCKT rcuit Lev	Equipment Failure			null	2023004
SE23033102075	3/31/2023 22:24	3/31/2023 23:10	14	SE	Circuit1626	659	OHCKT rcuit Lev	Equipment Failure			null	null
SW23060801153	6/8/2023 10:26	6/8/2023 13:43	94	SW	Circuit2029	2866	OHCKT rcuit Lev	Equipment Failure	NA	NA	null	null
NW23051501069	5/15/2023 13:05	5/15/2023 16:32	205	NW	Circuit1480	203	OHDS Device (ii	Equipment Failure	NA	NA	null	null
NW23032202021	3/22/2023 23:45	3/23/2023 8:23	514	NW	Circuit1481	1758	OHDS Device (ii	Equipment Failure			null	null
NW23032300091	3/22/2023 23:46	3/23/2023 6:46	233	NW	Circuit1481	1813	FUSE Device (ii	Equipment Failure			null	null
NW23032100226	3/21/2023 9:07	3/21/2023 13:31	261	NW	Circuit1482	190	G TRANe Transf	Equipment Failure			null	null
NW23032300113	3/22/2023 23:55	3/23/2023 8:25	317	NW	Circuit1483	122	RECLO Device (ii	Equipment Failure			null	null
NW23032300404	3/23/2023 7:06	3/23/2023 19:01	601	NW	Circuit1483	476	RECLO Device (ii	Equipment Failure			null	null
SE23021000055	2/10/2023 1:14	2/10/2023 1:47	16	SE	Circuit2559	641	OHCKT rcuit Lev	Equipment Failure	NA	NA	null	null
SE23021000088	2/10/2023 2:05	2/10/2023 5:25	196	SE	Circuit2559	641	OHCKT rcuit Lev	Equipment Failure	NA	NA	null	null
SE23051601918	5/16/2023 19:23	5/17/2023 5:47	618	SE	Circuit2559	327	RECLO Device (ii	Equipment Failure	WIRE DOWN	NA	null	null
NE23031701374	3/17/2023 8:31	3/17/2023 15:31	418	NE	Circuit2562	889	RECLO Device (ii	Equipment Failure			null	null

SE23060101927

JOB_NUMBER	CREATEDAT	NOTES
SE23060101927	2023-06-01 18:50:14	lost appx 50A of load on all 3 phases
SE23060101927	2023-06-02 04:08:46	1745- Joseph D Clark: Work complete to change out 2 transformers, circuit not normal open loop exists btw 168-6 and 168-7, trouble report written for reconductor after trans fire burned up cable in 168-6.
SE23060101927	2023-06-02 04:08:46	MapNumber:DET 2-26FeederNumber:PF A168Reconductor:YJacketedCable:NCableCart:NLiveFront:NIsolatedBetweenLow:A168-6IsolatedBetweenHigh:A168-7Crew:1745

MPSC Case No: U-21297

Requester: AG

Question No.: AGDE-4.103b

Respondent: M. Elliott Andahazy

Page: 1 of 1

Question: Refer to Exhibit A-12, Schedule B5.4.8. Please:

b. Provide in Excel the number of units, miles, activities, number of projects, and other data or metrics supporting the actual expenditures for each year 2017 to 2022 and forecasted for 2022, 2023, 2024, and the projected test year.

Answer: See attachment U-21297 AGDE-4.103b-01 PTMM and 4.8kV Hardening Metrics.

Attachment: *U-21297 AGDE-4.103b-01 PTMM and 4.8kV Hardening Metrics*

U-21297 AGDE-4.103b-01 PTMM and 4.8kV Hardening Metrics 2017-2022

Program	Metric	2017	2018	2019	2020	2021	2022
Pole and Pole Top Maintenance and Modernization (PTMM)	Miiles Modernized	786	2,019	1,027	1,496	1,541	1,562
Pole and Pole Top Maintenance and Modernization (PTMM)	Poles Replaced	2,700	3,165	1,333	1,431	1,016	4,537
Pole and Pole Top Maintenance and Modernization (PTMM)	Poles Reinforced	N/A*	2,050	2,717	27	109	1,116
Pole and Pole Top Maintenance and Modernization (PTMM)	Pole Inspections	63,230	84,005	58,080	7,400	45,400	87,000
4.8kV Hardening	Miles Hardened	-	105	128	209	202	475
4.8kV Hardening	Miles of Arc Wire Removed	-	53	54	120	71	224

*The Company did not track this metric in 2017

MPSC Case No: U-21534

Requester: MNSC

Question No.: MNSCDE-3.8c

Respondent: M. Elliott Andahazy

Page: 1 of 1

Question: Refer to Exhibit A-23 Schedule M13, the 1898 & Co, benefit-cost analysis for 'Pole and Pole Top Maintenance and Modernization' and 'Overhead to Underground conversion Pilots'.

c. Provide an example of the documentation that is provided to management that approves spending on these types of projects, including the information from the 1898 models that justify the project spending. If there is just a single capital request for the entire PTMM program, please provide that approved capital request and all supporting documentation.

Answer: DTE Electric Company objects to this request for the reason that the request is overly broad, seeks excessive detail, is unduly burdensome, is overly vague, and is otherwise not reasonably calculated to lead to the discovery of relevant evidence. Subject to this objection, and without waiving this objection, DTE Electric would answer as follows:

The Company does not maintain the information in the form requested.

PTMM: Capital requests for the PTMM program are approved at the program level.

Overhead to Underground Pilots: Capital requests for Overhead to Underground conversions Pilots will be approved on a project-by-project basis.

Attachment: *N/A*

MPSC Case No: U-21534

Requester: MNSC

Question No.: MNSCDE-8.9c

Respondent: M. Elliott Andahazy

Page: 1 of 1

Question: 9. Refer to the Company's response to MNSCDE-3.15(b)(i), which states "The Company has not purchased or installed wood crossarms, porcelain cutouts, or porcelain insulators since it changed its standards in the second half of 2019 and does not have recent average prices for these items that account for inflation experienced from 2019-2024."

c. The PTMM program appears to involve a new, more frequent inspection standard. Please provide any benefit-cost analyses, pilot study, results, or other materials on which the decision to modify the previous inspection standard for the new PTMM program was based.

Answer: The Company's PTMM program is not currently on a new, more frequent inspection cycle as described in my testimony on page MEA-49.

The Company's aspiration is to achieve a 10-year pole inspection cycle and a 5-year pole-top inspection cycle. Benchmarking results are shared in my direct testimony on pages MEA-32 through MEA-34.

Attachment: *N/A*

MPSC Case No: U-21534

Requester: MNSC

Question No.: MNSCDE-3.15ci

Respondent: M. Elliott Andahazy

Page: 1 of 1

Question: Refer to Case No. U-21297 and to the Company's discovery response to MNSCDE-7.32a, and to Witness Elliott Andahazy's testimony in Case No. U-21297, at MEA-24:14, which states: "The enhanced specification calls for modernizing equipment, which includes replacement of damaged wood crossarms with fiberglass crossarms, porcelain cutouts with polymer cutouts,

c. For each type of equipment listed in response to subpart (a) above please provide (or estimate):

i. The number of outages caused by failure of that type of equipment for each of the past five years (include any workpapers and list all data sources); and

Answer: The Company does not have the data as requested. The Company has provided all outages on its system by cause code from 2018-2023 in response to MNSCDE-3.1.

Attachment: *N/A*

MPSC Case No: U-21534

Requester: MNSC

Question No.: MNSCDE-3.15cii

Respondent: M. Elliott Andahazy

Page: 1 of 1

Question: Refer to Case No. U-21297 and to the Company's discovery response to MNSCDE-7.32a, and to Witness Elliott Andahazy's testimony in Case No. U-21297, at MEA-24:14, which states: "The enhanced specification calls for modernizing equipment, which includes replacement of damaged wood crossarms with fiberglass crossarms, porcelain cutouts with polymer cutouts, and porcelain insulators with polymer clamp-top insulators (Table 6)."

c. For each type of equipment listed in response to subpart (a) above please provide (or estimate):

ii. The estimated average customers interrupted (CI) and Customer Minutes Interrupted (CMI) per event (include any workpapers and list all data sources).

Answer: The Company does not have the data as requested. The Company has provided all outages on its system by cause code from 2018-2023 in response to MNSCDE-3.1.

Attachment: *N/A*

MPSC Case No: U-21534

Requester: MNSC

Question No.: MNSCDE-3.23d

Respondent: M. Elliott Andahazy

Page: 1 of 1

Question: Refer to Exhibit A-23 Schedule M13, page 17 of 26, regarding 4.4.1 Equipment Failure Reactive Costs, which states “When assets fail before being proactively replaced, it creates an urgency to minimize the impact on the customer.”

d. Provide the estimated average Customer Interrupted (CI) and Customer Minutes Interrupted (CMI) that results in instances in which pole top equipment failures result in an interruption. Please explain the basis for the estimate, and include any workpapers or assumptions.

Answer: The Company does not have the data as requested but has provided all outages on its system from 2017-2023 by cause code in response to MNSCDE-3.1 and has provided the BCA models in their entirety in response to MNSCDE-3.24.

Attachment: *N/A*

MPSC Case No: U-21534

Requester: MNSC

Question No.: MNSCDE-3.1a

Respondent: S. Deol

Page: 1 of 1

Question: 1. Refer to Case No. U-21297, the Company's discovery responses attachment labeled "U-21297 MNSCDE-2.3", and the supplemental attachment labeled "U-21297 MNSCDE-2.3 outages w Field Notes" which provided a spreadsheet of outages with a separate tab which provided the "Field Notes":

a. Please provide, in the same format as provided above, the outages for the years 2017 through 2023. Please provide the field notes on the same sheet as the interruptions such that the field notes line up with the associated interruptions.

Answer: The Company objects for the reason that the request is unduly burdensome, overly broad, oppressive and calculated to cause unreasonable expense to DTE Electric and its customers as there are well over a million field notes associated with this request. The Company also objects because the information requested is not relevant, nor is it reasonably calculated to lead to the discovery of relevant evidence, because the information requested may be subject to attorney/client privileged and/or because the information requested may contain customer information that is prohibited from disclosure by law. Without waiving these objections, but subject to them, based upon currently available information the Company responds as follows:

See attachment U-21534 MNSCDE-3.1-01 Outages 2017-2023

Attachment: U-21534 MNSCDE-3.1-01 Outages 2017-2023

Co-respondent: Legal

MPSC Case No: U-21534

Requester: MNSC

Question No.: MNSCDE-3.1b

Respondent: S. Deol

Page: 1 of 1

Question: 1. Refer to Case No. U-21297, the Company's discovery responses attachment labeled "U-21297 MNSCDE-2.3", and the supplemental attachment labeled "U-21297 MNSCDE-2.3 outages w Field Notes" which provided a spreadsheet of outages with a separate tab which provided the "Field Notes":

b. Also provide an additional column to the spread sheet that shows the type of equipment that failed causing the outage for all interruptions that have a "caused code" of "Equipment Failure"

Answer: The Company objects for the reason that the request is unduly burdensome, overly broad, oppressive and calculated to cause unreasonable expense to DTE Electric and its customers. The Company also objects because the information requested is not relevant, nor is it reasonably calculated to lead to the discovery of relevant evidence. Without waiving these objections, but subject to them, based upon currently available information the Company responds as follows:

The Company has cause codes that identify outages due to equipment failure. The system lacks an independent field to capture the specific equipment that failed. To fulfill this request, a team member would need to read the chronology of each outage which may or may not identify the specific equipment involved and which would take, on average, 0.5-1 hour per outage. There are nearly 99,000 outages resulting in an estimated total time ranging from 50,000 to 100,000 hours.

Attachment: None.

Co-respondent: Legal

MPSC Case No: U-21534

Requester: MNSC

Question No.: MNSCDE-3.1c

Respondent: S. Deol

Page: 1 of 1

Question: 1. Refer to Case No. U-21297, the Company's discovery responses attachment labeled "U-21297 MNSCDE-2.3", and the supplemental attachment labeled "U-21297 MNSCDE-2.3 outages w Field Notes" which provided a spreadsheet of outages with a separate tab which provided the "Field Notes":

c. Also refer to refer to Case No. U-21534, Exhibit A-23 Schedule M13, starting at Page 17 of 26 which states, regarding Non-equipment Outage Reactive Cost, "In addition to asset failures causing outages, there are other causes for customer outages. The model uses the historical OMS data to estimate outages caused by Animals, Tree/Wind, Weather (lightning and ice), and other causes." Please add the necessary columns and show these additional causes to the spreadsheet provided in response to subparts (a) and (b) above.

Answer: The Company objects for the reason that the request is unduly burdensome, overly broad, oppressive and calculated to cause unreasonable expense to DTE Electric and its customers. The Company also objects because the information requested is not relevant, nor is it reasonably calculated to lead to the discovery of relevant evidence. Without waiving these objections, but subject to them, based upon currently available information the Company responds as follows:

See MNSCDE-3.1a.

Attachment: None.

Co-respondent: Legal

NE23113000971	REESE0302	2023	2023-11-30 16:17:14	2023-12-01 02:41:26	1	624.2	EQUIPMENT FAILURE	Non-storm
SW23113000733	POPLR9885	2023	2023-11-30 16:40:36	2023-11-30 17:04:46	1	24.17	NO ISSUES FOUND	Non-storm
NE23113000924	SLATR2652	2023	2023-11-30 17:42:56	2023-11-30 17:50:55	1	7.98	WIND	Non-storm
SE23113000780	OUTDR1304	2023	2023-11-30 18:28:41	2023-11-30 19:58:30	16	1433.25	TREEIROW	Non-storm
SE23113001210	OUTDR1304	2023	2023-11-30 18:28:42	2023-11-30 19:58:17	1	89.58	CUSTOMER EQUIPMENT	Non-storm
NE23113001119	FAWN8755	2023	2023-11-30 20:03:51	2023-11-30 22:47:22	220	35922.82	ANIMAL	Non-storm
NE23113001161	FAWN8755	2023	2023-11-30 20:03:53	2023-11-30 22:47:12	1	163.32	NO ISSUES FOUND	Non-storm
NE23113001198	FAWN8755	2023	2023-11-30 20:03:57	2023-11-30 22:46:20	1	162.38	NO ISSUES FOUND	Non-storm
SE23113001188	NRLND9018	2023	2023-11-30 20:29:38	2023-11-30 22:17:04	15	1604.17	EQUIPMENT FAILURE	Non-storm
NW23113001195	LOMRD8503	2023	2023-11-30 21:01:35	2023-12-01 04:07:02	24	10180.03	EQUIPMENT FAILURE	Non-storm
SE23113000713	WSEND1038	2023	2023-11-30 21:24:21	2023-11-30 21:43:35	1	19.23	EQUIPMENT FAILURE	Non-storm
SE23113000851	EMPIR2232	2023	2023-11-30 22:27:32	2023-11-30 22:50:59	1	23.45	EQUIPMENT FAILURE	Non-storm
NE23113001193	BISHP1755	2023	2023-11-30 22:53:14	2023-12-01 00:09:16	8	606.91	TROUBLE INTENTIONAL	Non-storm
NE23113001220	BISHP1755	2023	2023-11-30 22:53:19	2023-12-01 00:09:15	10	758.52	TROUBLE INTENTIONAL	Non-storm
NE23113001223	BISHP1755	2023	2023-11-30 22:53:22	2023-12-01 00:09:12	2	151.68	TROUBLE INTENTIONAL	Non-storm
NW23120100017	CONRD8130	2023	2023-12-01 02:58:09	2023-12-01 09:51:14	1	413.08	EQUIPMENT FAILURE	Non-storm
SW23120100016	WAYNE9366	2023	2023-12-01 03:07:06	2023-12-01 08:52:22	61	20705.09	ANIMAL	Non-storm
SW23120100754	WAYNE9366	2023	2023-12-01 03:07:24	2023-12-01 08:52:20	1	344.93	NO ISSUES FOUND	Non-storm
SW23120100077	DUBLN8195	2023	2023-12-01 03:53:29	2023-12-01 12:26:32	1	513.05	TREEIROW	Non-storm
SE23113000868	BVRLY1865	2023	2023-12-01 06:38:04	2023-12-01 07:10:48	1	32.73	EQUIPMENT FAILURE	Non-storm
SW23120100040	POPLR9885	2023	2023-12-01 06:48:13	2023-12-01 08:06:24	14	1093.46	TREEIROW	Non-storm
NE23120100050	MELRO1455	2023	2023-12-01 06:56:51	2023-12-01 09:51:39	1	174.8	TREEIROW	Non-storm
SW23120100575	SALEM9926	2023	2023-12-01 07:16:15	2023-12-01 11:40:00	17	2971.48	TREEIROW	Non-storm
SW23120100064	SALEM9900	2023	2023-12-01 07:16:16	2023-12-01 11:39:59	25	3317.98	TREEIROW	Non-storm
SW23120100065	SALEM9926	2023	2023-12-01 07:16:16	2023-12-01 11:40:09	56	14765.55	EQUIPMENT FAILURE	Non-storm
SW23120100060	SALEM9900	2023	2023-12-01 07:16:17	2023-12-01 11:40:00	21	1504.85	TREEIROW	Non-storm
SW23120100576	SALEM9926	2023	2023-12-01 07:16:25	2023-12-01 11:40:07	1	263.7	NO ISSUES FOUND	Non-storm
SE23120100105	GRPTE2053	2023	2023-12-01 07:45:39	2023-12-01 19:48:05	21	15167.28	TROUBLE INTENTIONAL	Non-storm
SW23120100100	DREXL9036	2023	2023-12-01 07:46:29	2023-12-01 14:19:56	26	4792.41	EQUIPMENT FAILURE	Non-storm
SW23120100628	DREXL9036	2023	2023-12-01 07:46:39	2023-12-01 14:29:23	1	402.73	NO ISSUES FOUND	Non-storm
SE23112800200	DIX2058	2023	2023-12-01 08:57:24	2023-12-01 09:07:04	1	9.67	EQUIPMENT FAILURE	Non-storm
SE23120100441	HLTRD9758	2023	2023-12-01 09:06:18	2023-12-01 12:23:45	1	197.45	TREEBROW	Non-storm
SE23120100153	GDRIV0493	2023	2023-12-01 09:17:29	2023-12-01 14:59:02	22	4630.91	EQUIPMENT FAILURE	Non-storm
SE23120100812	GDRIV0493	2023	2023-12-01 09:17:29	2023-12-01 14:50:21	1	332.87	WIND	Non-storm
SW23120100484	GRILE0333	2023	2023-12-01 09:37:47	2023-12-01 09:52:42	1	14.92	NO ISSUES FOUND	Non-storm
SW23120100164	GRILE2840	2023	2023-12-01 09:37:49	2023-12-01 09:53:03	4938	74531.17	NO CAUSE	Non-storm
SE23120100216	MCGRW1111	2023	2023-12-01 09:43:34	2023-12-01 10:40:08	1	56.57	PLANNED INTENTIONAL	Non-storm
NE23120100115	CHIPW0348	2023	2023-12-01 09:44:09	2023-12-01 09:52:58	1	8.82	EQUIPMENT FAILURE	Non-storm
SW23120100142	HASKL1624	2023	2023-12-01 10:26:40	2023-12-01 10:40:53	1	14.22	EQUIPMENT FAILURE	Non-storm
NW23120100469	BLMFD9121	2023	2023-12-01 10:27:35	2023-12-01 12:47:18	4	558.75	TREEIROW	Non-storm
NW23120100489	BLMFD8888	2023	2023-12-01 10:27:36	2023-12-01 12:47:18	1	139.7	TREEIROW	Non-storm
NW23120100486	BLMFD9121	2023	2023-12-01 10:27:37	2023-12-01 12:47:17	1	139.67	TREEIROW	Non-storm
NE23120100709	SAXON8046	2023	2023-12-01 10:29:44	2023-12-01 17:50:02	1	440.3	EQUIPMENT FAILURE	Non-storm
SE23113000886	ANNCH1373	2023	2023-12-01 10:44:24	2023-12-01 20:13:33	1	569.15	EQUIPMENT FAILURE	Non-storm
SW23120100499	PROSP0306	2023	2023-12-01 10:50:42	2023-12-01 13:46:07	230	31246.97	TREEIROW	Non-storm
NW23120100133	BLMFD9121	2023	2023-12-01 10:58:08	2023-12-01 14:39:50	1	221.7	TREEBROW	Non-storm
SE23120100210	SYRAC1851	2023	2023-12-01 11:15:49	2023-12-01 11:33:21	13	224.49	EQUIPMENT FAILURE	Non-storm
NE23120100565	BOYNE8739	2023	2023-12-01 11:17:01	2023-12-01 13:42:58	1	145.95	EQUIPMENT FAILURE	Non-storm
NE23120100581	NBALT8434	2023	2023-12-01 11:17:03	2023-12-01 13:42:58	1	145.92	NO ISSUES FOUND	Non-storm
NE23120100601	BOYNE8739	2023	2023-12-01 11:17:06	2023-12-01 13:44:02	1	146.93	EQUIPMENT FAILURE	Non-storm
SE23120100589	CRTIS2104	2023	2023-12-01 11:31:52	2023-12-01 12:35:47	1	1503.92	TREEBROW	Non-storm
SW23120100762	PROSP0305	2023	2023-12-01 11:33:01	2023-12-01 13:46:15	6	773.58	EQUIPMENT FAILURE	Non-storm
SE23120100590	COOLG0060	2023	2023-12-01 11:43:11	2023-12-02 03:00:09	4	3666.59	NO CAUSE	Non-storm
SE23120100460	SHADK1119	2023	2023-12-01 11:49:36	2023-12-01 12:07:07	2	34.64	EQUIPMENT FAILURE	Non-storm
NE23113000340	STEPH8688	2023	2023-12-01 11:52:16	2023-12-01 13:07:41	4	301.64	EQUIPMENT FAILURE	Non-storm
SE23113000963	SYRAC2000	2023	2023-12-01 11:58:01	2023-12-01 12:15:07	1	17.1	EQUIPMENT FAILURE	Non-storm
NE23120100705	YATES0311	2023	2023-12-01 12:01:27	2023-12-01 17:43:36	1	342.15	EQUIPMENT FAILURE	Non-storm
NE23120101018	NHAVN0311	2023	2023-12-01 12:02:20	2023-12-01 20:05:59	1	483.65	EQUIPMENT FAILURE	Non-storm
SE23120100620	TIRMN1255	2023	2023-12-01 12:16:23	2023-12-01 13:53:09	10	964.58	TREEIROW	Non-storm
SE23120100630	TIRMN1255	2023	2023-12-01 12:16:23	2023-12-01 13:52:51	1	96.47	EQUIPMENT FAILURE	Non-storm
SE23120100622	TIRMN1255	2023	2023-12-01 12:16:24	2023-12-01 13:53:09	13	1253.92	TREEIROW	Non-storm
SE23120100749	TIRMN1255	2023	2023-12-01 12:16:39	2023-12-01 13:53:07	1	96.47	PLANNED INTENTIONAL	Non-storm
NW23120100780	WHTLK0307	2023	2023-12-01 12:18:12	2023-12-01 19:49:32	1	451.33	TREEBROW	Non-storm
NW23120100645	HURST9842	2023	2023-12-01 12:26:49	2023-12-01 17:19:55	2	515.61	EQUIPMENT FAILURE	Non-storm
SW23120100641	SUMTR9498	2023	2023-12-01 12:41:08	2023-12-01 18:26:22	96	23751.29	EQUIPMENT FAILURE	Non-storm
SW23120100003	RSVLT0021	2023	2023-12-01 12:45:11	2023-12-01 12:52:55	1	7.73	NO ISSUES FOUND	Non-storm
NW23120100776	WATFD8854	2023	2023-12-01 13:25:37	2023-12-01 14:27:58	10	621.34	EQUIPMENT FAILURE	Non-storm
SE23120100649	WAYBN2092	2023	2023-12-01 13:46:34	2023-12-01 14:56:25	1	43.2	EQUIPMENT FAILURE	Non-storm
SE23120100818	CHTNT8293	2023	2023-12-01 14:09:31	2023-12-01 18:26:00	105	26900.86	EQUIPMENT FAILURE	Non-storm
SW23120100825	SPRUC9874	2023	2023-12-01 14:11:38	2023-12-01 16:41:58	2	300.54	EQUIPMENT FAILURE	Non-storm
SW23120100829	SPRUC9874	2023	2023-12-01 14:11:40	2023-12-01 16:41:56	1	150.27	EQUIPMENT FAILURE	Non-storm
SE23113001093	REDFD2120	2023	2023-12-01 14:24:35	2023-12-01 14:41:15	1	16.67	EQUIPMENT FAILURE	Non-storm
NW23120100847	WATFD8967	2023	2023-12-01 14:33:23	2023-12-01 15:16:44	2	86.2	TROUBLE INTENTIONAL	Non-storm
NW23120100855	SENCA8934	2023	2023-12-01 14:44:45	2023-12-01 19:52:18	29	8907.79	EQUIPMENT FAILURE	Non-storm
SE23113000041	BERKY1957	2023	2023-12-01 14:44:51	2023-12-01 14:49:56	1	5.08	EQUIPMENT FAILURE	Non-storm
SE23120100902	KORTE2034	2023	2023-12-01 15:33:10	2023-12-01 18:14:59	1	144.73	EQUIPMENT FAILURE	Non-storm
NE23120100446	ELGMI1535	2023	2023-12-01 15:46:45	2023-12-01 16:03:42	1	16.95	METER / BLOCKS	Non-storm
SW23120100916	MACON8049	2023	2023-12-01 16:07:16	2023-12-01 20:16:52	44	10954.19	EQUIPMENT FAILURE	Non-storm
SW23120100971	TFANY8038	2023	2023-12-01 16:53:21	2023-12-02 18:09:57	5	7582.61	ANIMAL	Non-storm
NE23120100860	VICTR8699	2023	2023-12-01 17:21:08	2023-12-01 18:25:50	1	64.7	EQUIPMENT FAILURE	Non-storm
NE23120101007	PRKRD8779	2023	2023-12-01 17:21:54	2023-12-01 18:56:18	4	377.14	NO ISSUES FOUND	Non-storm
NE23120101016	PRKRD8779	2023	2023-12-01 17:21:54	2023-12-01 18:56:10	1	94.27	NO ISSUES FOUND	Non-storm
NE23120100986	PRKRD8779	2023	2023-12-01 17:21:58	2023-12-01 18:56:26	174	16330.93	EQUIPMENT FAILURE	Non-storm
NE23120101026	PRKRD8779	2023	2023-12-01 17:21:59	2023-12-01 18:56:16	1	94.28	NO ISSUES FOUND	Non-storm
NE23120101052	PRKRD8779	2023	2023-12-01 17:21:59	2023-12-01 18:56:16	1	94.28	NO ISSUES FOUND	Non-storm
NE23120101044	PRKRD8779	2023	2023-12-01 17:22:01	2023-12-01 18:56:18	1	94.28	NO ISSUES FOUND	Non-storm
NE23120101032	PRKRD8779	2023	2023-12-01 17:22:03	2023-12-01 18:56:20	1	94.28	NO ISSUES FOUND	Non-storm
NE23120100998	PRKRD8779	2023	2023-12-01 17:22:12	2023-12-01 18:56:30	2	188.56	NO ISSUES FOUND	Non-storm
SE23113001112	TIRMN2093	2023	2023-12-01 17:37:42	2023-12-01 17:42:47	1	5.08	EQUIPMENT FAILURE	Non-storm
NE23120200129	WABSH8797	2023	2023-12-01 18:59:57	2023-12-02 17:25:12	1	1345.25	EQUIPMENT FAILURE	Non-storm
SW23120100784	ELGIN1830	2023	2023-12-01 19:08:56	2023-12-02 00:42:54	23	2058.02	TREEIROW	Non-storm
NW23120100118	QTNRD0322	2023	2023-12-01 19:14:12	2023-12-01 19:48:48	1	34.6	EQUIPMENT FAILURE	Non-storm
SE23120101094	REDFD1363	2023	2023-12-01 19:20:48	2023-12-02 00:08:46	1	302.19	EQUIPMENT FAILURE	Non-storm
NE23120100966	VICTR8721	2023	2023-12-01 19:34:11	2023-12-02 10:42:44	1	908.55	EQUIPMENT FAILURE	Non-storm
SW23120100815	ELGIN1830	2023	2023-12-01 19:45:01	2023-12-01 20:42:52	363	20753.53	TROUBLE INTENTIONAL	Non-storm
SE23120101108	FOX2676	2023	2023-12-01 21:08:30	2023-12-02 12:51:09	24	22609.2	TREEBROW	Non-storm
SW23120101103	SPRUC9874	2023	2023-12-01 21:38:27	2023-12-02 01:42:50	66	15549.75	EQUIPMENT FAILURE	Non-storm
SW23120101146	ROMLS9464	2023	2023-12-01 21:53:38	2023-12-03 01:30:10	1	790.35	TREEIROW	Non-storm
NE23120200053	ALMOT0304	2023	2023-12-01 22:36:41	2023-12-02 09:11:06	1	634.42	EQUIPMENT FAILURE	Non-storm
SE23120200133	ESTLD1303	2023	2023-12-01 23:01:11	2023-12-02 09:38:48	1	637.62	TREEBROW	Non-storm
SW23120200183	MAURD9387	2023	2023-12-01 23:28:23	2023-12-02 14:05:45	624	198759.28	EQUIPMENT FAILURE	Non-storm
NE23120101152	ERIN2410	2023	2023-12-01 23:47:46	2023-12-02 03:44:05	455	104071.03	EQUIPMENT FAILURE	Non-storm
NE23120200097	ERIN2410	2023	2023-12-01 23:48:41	2023-12-02 03:44:09	4	940.87	CUSTOMER EQUIPMENT	Non-storm
NE23120200405	ERIN2410	2023	2023-12-01 23:48:59	2023-12-02 03:44:12	1	235.22	CUSTOMER EQUIPMENT	Non-storm
NW23120200012	STKBR9888	2023	2023-12-02 00:28:34	2023-12-02 12:59:54	7	5257.2	PUBLIC INTERFERENCE	Non-storm
NW23120200022	STKBR9888	2023	2023-12-02 00:28:34	2023-12-02 13:00:02	51	38301.67	PUBLIC INTERFERENCE	Non-storm
SW23120200136	MAURD9387	2023	2023-12-02 01:30:26	2023-12-02 14:05:43	481	99533.46	EQUIPMENT FAILURE	Non-storm
SW23120200041	KOPNK9407	2023	2023-12-02 01:51:22	2023-12-02 08:41:13	10	2208.66	NO ISSUES FOUND	Non-storm
SW23120200043	KOPNK9407	2023	2023-12-02 01:51:26	2023-12-02 08:41:14	26	6625.48	EQUIPMENT FAILURE	Non-storm
SW23120200045	WAYNE9435	2023	2023-12-02 01:51:29	2023-12-02 03:26:28	1	94.98	NO ISSUES FOUND	Non-storm
SW23120200050	KOPNK9407	2023	2023-12-02 01:51:31	2023-12-02 08:41:13	1	409.7	NO ISSUES FOUND	Non-storm
SW23120200432	MAURD9387	2023	2023-12-02 02:36:10	2023-12-02 12:52:21	1	121.43	EQUIPMENT FAILURE	Non-storm
SW23120200108	WAYNE9413	2023	2023-12-02 04:28:33	2023-12-02 12:17:43	1	469.17	EQUIPMENT FAILURE	Non-storm
SW23120100634	HINES9423	2023	2023-12-02 04:44:44	2023-12-02 10:26:50	7	1201.92	EQUIPMENT FAILURE	Non-storm
SW23120200241	DAYTN8105	2023	2023-12-02 04:51:58	2023-12-02 17:53:05	1	781.12	EQUIPMENT FAILURE	Non-storm
NE23120200192	SAVOY8714	2023	2023-12-02 04:53:25	2023-12-02 13:44:20	1	530.92	EQUIPMENT FAILURE	Non-storm
SW23120200427	OREGN9785	2023	2023-12-02 05:17:20	2023-12-02 16:31:03	1	673.72	EQUIPMENT FAILURE	Non-storm
SW23120200088	BREST9350	2023	2023-12-02 05:50:05	2023-12-02 06:57:04	13	868.52	ANIMAL	Non-storm
SW23120100431	TAYLR8292	2023	2023-12-02 06:41:22	2023-12-02 07:07:05	1	25.72	EQUIPMENT FAILURE	Non-storm
NW23120200104	STRFD9093	2023	2023-12-02 07:14:20	2023-12-02 10:14:47	29	5529.66	EQUIPMENT FAILURE	Non-storm
NW23120200147	WOLFH8838	2023	2023-12-02 07:42:51	2023-12-02 09:57:31	1	134.67	ANIMAL	Non-storm
NW23120200172	WOLFH8838	2023	2023-12-02 07:43:12	2023-12-02 09:58:51	1	135.65	ANIMAL	Non-storm
NW23120101186	NIXON8926	2023	2023-12-02 07:45:27	2023-12-02 10:06:02	1	140.58	METER / BLOCKS	Non-storm
SE23120200132	SOFLD9088	2023	2023-12-02 08:01:00	2023-12-02 11:45:58	343	59399.17	EQUIPMENT FAILURE	Non-storm
SW23120200155	MOTT9783	2023	2023-12-02 08:26:22	2023-12-02 09:44:34	21	1636.4	ANIMAL	Non-storm
NE23120200156	OTSGO8762	2023	2023-12-02 08:32:10	2023-12-02 09:05:18	1	33.13	PLANNED INTENTIONAL	Non-storm
NW23120200336	MALTA8543	2023	2023-12-02 08:35:34	2023-12-02 17:47:23	4	1685.08	ANIMAL	Non-storm
NW23120200170	WOLFH8822	2023	2023-12-02 08:45:36	2023-12-02 14:03:47	1	318.18	ANIMAL	Non-storm
SE23120200168	GNSTN1319	2023	2023-12-02 08:55:16	2023-12-02 10:50:00	2	94.04	PLANNED INTENTIONAL	Non-storm
SE23120200180	PULFD2111	2023	2023-12-02 09:09:34	2023-12-02 10:18:28	1	68.9	PLANNED INTENTIONAL	Non-storm
SE23120200179	LAUDR1272	2023	2023-12-02 09:13:49	2023-12-02 11:13:47	8	804.41	PLANNED INTENTIONAL	Non-storm
NW23120200199	SPKNE8842	2023	2023-12-02 09:15:46	2023-12-02 09:20:47	1	5.02	PLANNED INTENTIONAL	Non-storm
NE23120200195	OTSGO8762	2023	2023-12-02 09:20:43	2023-12-02 09:39:48	1	19.08	PLANNED INTENTIONAL	Non-storm
SE23120200191	LAUDR1272	2023	2023-12-02 09:27:26	2023-12-02 10:30:14	1	62.8	PLANNED INTENTIONAL	Non-storm
NE23120200213	PINGV0325	2023	2023-12-02 09:31:25	2023-12-02 11:11:44	1	100.32	PLANNED INTENTIONAL	Non-storm
SW23120200204	WICK9346	2023	2023-12-02 09:33:30	2023-12-02 09:43:59	13	134.17	PLANNED INTENTIONAL	Non-storm
SE23120101028	DENVR1462	2023	2023-12-02 09:36:57	2023-12-02 10:32:52	1	55.92	WIND	Non-storm
SW23120200211	PERU9440	2023	2023-12-02 09:38:05	2023-12-02 10:26:35	1	48.5	PLANNED INTENTIONAL	Non-storm
SE23120100946	GENSE2176	2023	2023-12-02 09:38:09	2023-12-02 10:09:46	1	31.62	TREEIROW	Non-storm
SE23120200229	BVRLY0356	2023	2023-12-02 09:48:10	2023-12-02 10:04:30	10	160.53	PLANNED INTENTIONAL	Non-storm
SE23113000342	TURNR1147	2023	2023-12-02 09:49:47	2023-12-02 11:22:26	1	92.65	EQUIPMENT FAILURE	Non-storm
NE23120200221	OTSGO8762	2023	2023-12-02 09:50:35	2023-12-02 10:00:56	1	10.35	PLANNED INTENTIONAL	Non-storm
SE23120200231	WHITR2750	2023	2023-12-02 09:51:28	2023-12-02 10:22:49	21	657.49	PLANNED INTENTIONAL	Non-storm
SE23120200177	WEBST1932	2023	2023-12-02 09:52:00	2023-12-02 10:43:44	1	51.73	PLANNED INTENTIONAL	Non-storm
NW23120200240	STKWL4010	2023	2023-12-02 09:59:54	2023-12-02 12:38:05	12	1896.44	PLANNED INTENTIONAL	Non-storm
NW23120200252	SPKNE8842	2023	2023-12-02 10:11:18	2023-12-02 10:36:40	1	25.37	PLANNED INTENTIONAL	Non-storm
NW23120200247	SPKNE8842	2023	2023-12-02 10:11:29	2023-12-02 10:35:56	1	24.45	PLANNED INTENTIONAL	Non-storm
NW23120200249	SPKNE8842	2023	2023-12-02 10:12:00	2023-12-02 10:50:55	2	77.66	PLANNED INTENTIONAL	Non-storm
NW23120200254	MILFD9247	2023	2023-12-02 10:17:34	2023-12-02 11:06:38	1	49.07	TREEBROW	Non-storm
SW23120200079	OREGN9785	2023	2023-12-02 10:17:38	2023-12-02 10:28:26	1	10.8	EQUIPMENT FAILURE	Non-storm
NE23120200255	MILFD9246	2023	2023-12-02 10:17:42	2023-12-02 11:07:19	7	344.5	TREEBROW	Non-storm
NE23120200280	RICHM2415	2023	2023-12-02 10:24:20	2023-12-02 12:08:16	3	133.23	PLANNED INTENTIONAL	Non-storm
SE23120100027	CHAND1213	2023	2023-12-02 10:40:17	2023-12-02 11:48:22	2	135.75	EQUIPMENT FAILURE	Non-storm
SE23120200281	LAUDR1272	2023	2023-12-02 10:46:57	2023-12-02 11:48:16	1	61.32	EQUIPMENT FAILURE	Non-storm
NW23120200288	GODSN8134	2023	2023-12-02 10:51:42	2023-12-02 13:36:42	2	329.48	ANIMAL	Non-storm
SE23120200256	CHAND1213	2023	2023-12-02 10:51:58	2023-12-02 10:57:01	2	10.08	EQUIPMENT FAILURE	Non-storm
SW23120200275	PERU9440	2023	2023-12-02 10:51:58	2023-12-02 12:03:00	4	283.74	PLANNED INTENTIONAL	Non-storm
NE23120200271	RICHM2415	2023	2023-12-02 10:59:43	2023-12-02 11:40:45	1	41.03	PLANNED INTENTIONAL	Non-storm
SE23120200278	GNSTN1319	2023	2023-12-02 11:01:50	2023-12-02 12:08:43	1	66.88	PLANNED INTENTIONAL	Non-storm
NW23120200292	SPKNE8842	2023	2023-12-02 11:02:42	2023-12-02 11:59:39	2	104.8	PLANNED INTENTIONAL	Non-storm
NE23120200291	RICHM2415	2023	2023-12-02 11:04:57	2023-12-02 11:26:36	1	21.65	PLANNED INTENTIONAL	Non-storm
NE23120200298	BREWR8840	2023	2023-12-02 11:06:50	2023-12-02 11:13:28	1	6.63	PLANNED INTENTIONAL	Non-storm

NE23120200303	OTSGO8762	2023	2023-12-02 11:15:10	2023-12-02 11:59:45	1	44.58	PLANNED INTENTIONAL	Non-storm
NW23120200300	WALTN2669	2023	2023-12-02 11:19:47	2023-12-02 12:00:10	1	40.38	PLANNED INTENTIONAL	Non-storm
NW23120200328	STERL8442	2023	2023-12-02 11:19:55	2023-12-02 12:29:15	2	138.26	NO ISSUES FOUND	Non-storm
SE23120200312	BVRLY0356	2023	2023-12-02 11:26:01	2023-12-02 12:27:30	6	367.81	PLANNED INTENTIONAL	Non-storm
NE23120200283	RICHM2415	2023	2023-12-02 11:29:09	2023-12-02 12:45:03	1	75.9	PLANNED INTENTIONAL	Non-storm
SE23120200321	SAVAN1086	2023	2023-12-02 11:31:19	2023-12-02 12:01:46	1	30.45	PLANNED INTENTIONAL	Non-storm
NW23120200327	SPKNE8842	2023	2023-12-02 11:40:10	2023-12-02 12:12:24	4	128.24	PLANNED INTENTIONAL	Non-storm
SE23120200322	WEBST1932	2023	2023-12-02 11:42:51	2023-12-02 12:24:14	1	41.38	PLANNED INTENTIONAL	Non-storm
NE23120200330	BREWR8840	2023	2023-12-02 11:51:42	2023-12-02 12:09:38	1	17.93	PLANNED INTENTIONAL	Non-storm
NW23120200355	SPKNE8842	2023	2023-12-02 12:11:41	2023-12-02 12:46:04	1	34.38	PLANNED INTENTIONAL	Non-storm
NW23120200352	SPKNE8842	2023	2023-12-02 12:11:44	2023-12-02 12:46:07	1	34.38	PLANNED INTENTIONAL	Non-storm
SE23120100933	FRMNT1593	2023	2023-12-02 12:22:29	2023-12-02 12:52:16	2	32.58	TREEBROW	Non-storm
SW23120200433	MALRD9387	2023	2023-12-02 12:25:34	2023-12-02 14:05:43	42	4198.04	EQUIPMENT FAILURE	Non-storm
SW23120200410	MALRD9387	2023	2023-12-02 12:25:43	2023-12-02 14:04:45	1	99.03	NO CAUSE	Non-storm
SW23120200417	GARCY1615	2023	2023-12-02 12:25:44	2023-12-02 14:05:43	1	99.98	NO ISSUES FOUND	Non-storm
SE23120200441	LYNCH2227	2023	2023-12-02 12:34:20	2023-12-02 12:42:53	1	8.55	CUSTOMER EQUIPMENT	Non-storm
SW23120200372	WICK9346	2023	2023-12-02 12:36:47	2023-12-02 12:49:07	1	12.33	EQUIPMENT FAILURE	Non-storm
SW23120200369	WICK9346	2023	2023-12-02 12:36:48	2023-12-02 12:49:08	1	12.33	PLANNED INTENTIONAL	Non-storm
NE23120200377	BREWR8840	2023	2023-12-02 13:00:55	2023-12-02 13:19:06	1	18.18	PLANNED INTENTIONAL	Non-storm
SE23120200025	KENEY2697	2023	2023-12-02 13:05:39	2023-12-02 13:19:41	1	14.03	TREEBROW	Non-storm
SE23120200302	BLTMR8340	2023	2023-12-02 13:09:22	2023-12-02 13:20:11	1	10.82	TREEBROW	Non-storm
SE23120200420	WEBST1932	2023	2023-12-02 13:42:22	2023-12-02 15:15:39	17	1580.55	PLANNED INTENTIONAL	Non-storm
NW23120200411	COLFX8186	2023	2023-12-02 13:44:26	2023-12-02 14:42:49	1	58.38	PLANNED INTENTIONAL	Non-storm
SE23120200418	STLUS1136	2023	2023-12-02 13:51:39	2023-12-02 14:44:59	1	53.33	PLANNED INTENTIONAL	Non-storm
NE23120200402	STRFD9150	2023	2023-12-02 13:58:13	2023-12-02 14:12:59	1	14.77	EQUIPMENT FAILURE	Non-storm
SE23120200178	GRANT1598	2023	2023-12-02 14:05:01	2023-12-02 14:21:56	1	16.92	TREEBROW	Non-storm
NW23120200439	STKWL4010	2023	2023-12-02 14:08:43	2023-12-02 15:50:13	1	101.5	PLANNED INTENTIONAL	Non-storm
SE23120100610	LYNCH2227	2023	2023-12-02 14:16:50	2023-12-02 15:32:27	1	26.97	EQUIPMENT FAILURE	Non-storm
SE23120200264	MANDY0308	2023	2023-12-02 14:23:58	2023-12-02 15:05:36	1	41.63	EQUIPMENT FAILURE	Non-storm
NW23120200440	SPKNE8842	2023	2023-12-02 14:24:11	2023-12-02 16:42:22	2	238.75	PLANNED INTENTIONAL	Non-storm
NE23120200446	RICHM2415	2023	2023-12-02 14:24:34	2023-12-02 14:36:54	1	12.33	PLANNED INTENTIONAL	Non-storm
NW23120200461	SPKNE8842	2023	2023-12-02 14:24:56	2023-12-02 15:07:06	1	42.17	PLANNED INTENTIONAL	Non-storm
NW23120200452	SPKNE8842	2023	2023-12-02 14:31:02	2023-12-02 15:11:25	12	480.76	PLANNED INTENTIONAL	Non-storm
NW23120200557	STKWL4010	2023	2023-12-02 14:41:00	2023-12-02 15:50:17	1	69.28	EQUIPMENT FAILURE	Non-storm
NW23120200459	CODY9542	2023	2023-12-02 14:54:47	2023-12-02 16:29:05	1	45.58	EQUIPMENT FAILURE	Non-storm
NE23120200516	ROBIN9309	2023	2023-12-02 15:16:39	2023-12-02 19:05:33	1	228.9	ANIMAL	Non-storm
SE23120200482	COOLG1402	2023	2023-12-02 15:17:54	2023-12-02 15:57:41	4	158.28	PLANNED INTENTIONAL	Non-storm
SW23120100154	ARGO0319	2023	2023-12-02 15:49:46	2023-12-02 16:07:28	1	17.7	EQUIPMENT FAILURE	Non-storm
SW23120200496	MACON8049	2023	2023-12-02 15:49:49	2023-12-02 16:34:36	24	1066.07	EQUIPMENT FAILURE	Non-storm
SE23120200424	EMPIR2232	2023	2023-12-02 15:50:27	2023-12-02 16:02:28	1	12.02	TREEBROW	Non-storm
SE23120200500	SIXMI1251	2023	2023-12-02 15:56:05	2023-12-02 17:23:42	9	786.78	TROUBLE INTENTIONAL	Non-storm
NW23120200553	SENCA8934	2023	2023-12-02 17:52:06	2023-12-02 22:23:29	68	16620.64	EQUIPMENT FAILURE	Non-storm
NW23120300643	HILL2590	2023	2023-12-02 21:26:02	2023-12-03 21:11:53	1	1425.85	EQUIPMENT FAILURE	Non-storm
SW23120400821	WILSN8101	2023	2023-12-03 01:04:49	2023-12-05 08:06:17	2	91	EQUIPMENT FAILURE	Non-storm
SW23120300016	PITTS0381	2023	2023-12-03 02:00:38	2023-12-03 05:50:04	34	7520.35	EQUIPMENT FAILURE	Non-storm
SW23120300018	CROWN9803	2023	2023-12-03 02:00:41	2023-12-03 05:50:03	1	229.37	EQUIPMENT FAILURE	Non-storm
SW23120300043	WAYNE9421	2023	2023-12-03 06:41:22	2023-12-03 08:12:34	233	21203.54	EQUIPMENT FAILURE	Non-storm
NW23120300060	PAGE8828	2023	2023-12-03 07:10:54	2023-12-03 09:56:03	2	330.04	EQUIPMENT FAILURE	Non-storm
SE23120200598	GNSTN1226	2023	2023-12-03 07:40:06	2023-12-03 07:46:53	1	6.78	EQUIPMENT FAILURE	Non-storm
NW23120200618	WALTN0324	2023	2023-12-03 07:57:04	2023-12-03 08:02:06	1	5.03	TREEROW	Non-storm
WSHTN0343	WSHTN0343	2023	2023-12-03 08:17:03	2023-12-03 10:57:33	31	4973.65	EQUIPMENT FAILURE	Non-storm
NW23120300092	WSHTN0343	2023	2023-12-03 08:17:04	2023-12-03 10:57:32	2	320.9	EQUIPMENT FAILURE	Non-storm
NW23120300084	WSHTN0343	2023	2023-12-03 08:17:05	2023-12-03 10:57:32	8	1283.5	EQUIPMENT FAILURE	Non-storm
NW23120300001	FLINT9784	2023	2023-12-03 08:24:52	2023-12-03 08:42:01	1	17.15	EQUIPMENT FAILURE	Non-storm
SE23120200594	DENVR1462	2023	2023-12-03 08:49:29	2023-12-03 09:13:26	1	23.95	NO ISSUES FOUND	Non-storm
SW23120300185	CROWN9803	2023	2023-12-03 09:59:24	2023-12-03 12:01:04	1	121.67	ANIMAL	Non-storm
NW23120300170	KENSL9858	2023	2023-12-03 10:08:47	2023-12-03 13:08:02	10	1792.14	EQUIPMENT FAILURE	Non-storm
NE23120200591	ROSVL1756	2023	2023-12-03 10:10:15	2023-12-03 10:36:51	1	26.6	EQUIPMENT FAILURE	Non-storm
SE23120300177	CHTNT8839	2023	2023-12-03 10:23:48	2023-12-03 11:14:00	1	50.2	NO ISSUES FOUND	Non-storm
SE23120300174	CHTNT8839	2023	2023-12-03 10:23:51	2023-12-03 11:14:09	13	652.47	ANIMAL	Non-storm
SW23120300176	LIMA9892	2023	2023-12-03 10:27:28	2023-12-03 11:32:43	18	1167.12	EQUIPMENT FAILURE	Non-storm
SW23120300193	PDMNT9881	2023	2023-12-03 10:54:28	2023-12-03 11:21:45	9	243.27	PLANNED INTENTIONAL	Non-storm
SW23120300192	PERU9432	2023	2023-12-03 10:55:14	2023-12-03 14:24:18	55	7617.6	EQUIPMENT FAILURE	Non-storm
NW23120300210	TINKN8884	2023	2023-12-03 11:11:43	2023-12-03 13:24:54	23	3059.55	EQUIPMENT FAILURE	Non-storm
SW23120300058	PERU9440	2023	2023-12-03 11:22:23	2023-12-03 11:28:49	1	6.43	NO ISSUES FOUND	Non-storm
SW23120300444	PERU9441	2023	2023-12-03 11:29:43	2023-12-03 17:04:39	1	334.93	NO ISSUES FOUND	Non-storm
SE23120300241	ECORS2103	2023	2023-12-03 11:51:47	2023-12-04 08:41:11	1	1249.4	EQUIPMENT FAILURE	Non-storm
NW23120300312	DISCO8403	2023	2023-12-03 11:59:41	2023-12-03 12:13:09	1	13.47	CUSTOMER EQUIPMENT	Non-storm
NE23120300246	ARMAD8550	2023	2023-12-03 12:10:44	2023-12-03 14:16:09	80	10061.47	EQUIPMENT FAILURE	Non-storm
SW23120300277	BCKLR9941	2023	2023-12-03 12:22:43	2023-12-03 13:16:09	1	53.43	EQUIPMENT FAILURE	Non-storm
NE23120300285	STEPH8415	2023	2023-12-03 12:37:29	2023-12-04 11:46:06	1	1388.62	TREEBROW	Non-storm
NW23120300612	WALTN0324	2023	2023-12-03 13:19:09	2023-12-04 12:36:39	1	1397.5	EQUIPMENT FAILURE	Non-storm
NW23120300309	ORION9080	2023	2023-12-03 13:34:58	2023-12-03 18:03:18	5	1153.92	EQUIPMENT FAILURE	Non-storm
SE23120300640	GRPTE1355	2023	2023-12-03 13:59:29	2023-12-03 17:43:41	1	224.2	NO ISSUES FOUND	Non-storm
SW23120100978	PERU9432	2023	2023-12-03 14:09:42	2023-12-03 14:24:25	2173	31396.37	EQUIPMENT FAILURE	Non-storm
SW23120300408	DRAKE8969	2023	2023-12-03 14:10:57	2023-12-03 16:25:20	9	1208.89	EQUIPMENT FAILURE	Non-storm
SW23120300416	DAYTN8105	2023	2023-12-03 14:17:13	2023-12-04 06:09:50	42	39955.04	EQUIPMENT FAILURE	Non-storm
SE23120300637	TIRMN1541	2023	2023-12-03 14:19:06	2023-12-04 12:50:17	1	1351.18	TREEBROW	Non-storm
SE23120300465	SYRAC2017	2023	2023-12-03 14:27:04	2023-12-04 09:43:19	1	1156.25	TREEROW	Non-storm
NW23120300423	ORION9071	2023	2023-12-03 14:27:50	2023-12-03 20:57:05	1	389.25	EQUIPMENT FAILURE	Non-storm
NW23120300429	ORION9071	2023	2023-12-03 14:27:50	2023-12-03 20:58:01	2	779.54	ANIMAL	Non-storm
NW23120300432	ORION9071	2023	2023-12-03 14:28:04	2023-12-03 20:57:20	1	389.27	TREEBROW	Non-storm
NE23120300431	HUNTC8761	2023	2023-12-03 14:29:37	2023-12-03 16:45:01	2	270.72	EQUIPMENT FAILURE	Non-storm
NW23120300428	PAGE8828	2023	2023-12-03 14:31:28	2023-12-03 15:13:46	1	42.3	EQUIPMENT FAILURE	Non-storm
NW23120300459	PAGE8828	2023	2023-12-03 14:31:28	2023-12-03 15:13:46	1	42.3	EQUIPMENT FAILURE	Non-storm
SE23120300445	CHTNT9034	2023	2023-12-03 14:42:28	2023-12-03 20:33:08	24	8412.24	ICE	Non-storm
SE23120400007	CHTNT9034	2023	2023-12-03 14:42:35	2023-12-03 20:33:04	1	350.48	NO ISSUES FOUND	Non-storm
SE23120300436	HAZPK1208	2023	2023-12-03 14:46:47	2023-12-04 18:11:19	1	1644.53	TREEBROW	Non-storm
SE23120300461	REDFD1363	2023	2023-12-03 15:01:40	2023-12-03 17:11:56	23	2993.01	EQUIPMENT FAILURE	Non-storm
SE23120300491	HAWTH1289	2023	2023-12-03 15:25:04	2023-12-04 14:49:47	1	1404.72	EQUIPMENT FAILURE	Non-storm
SW23120300482	MALRD9387	2023	2023-12-03 15:31:03	2023-12-03 19:45:16	229	26309.77	EQUIPMENT FAILURE	Non-storm
SW23120300583	HASKL1627	2023	2023-12-03 15:34:50	2023-12-04 11:00:23	1	1165.55	NO ISSUES FOUND	Non-storm
SE23120300495	HAYES1047	2023	2023-12-03 15:46:12	2023-12-03 20:16:14	217	58527.53	EQUIPMENT FAILURE	Non-storm
NW23120300294	WMSTN8021	2023	2023-12-03 15:55:00	2023-12-03 16:43:49	168	8321.42	EQUIPMENT FAILURE	Non-storm
SW23120300582	BLCRK8011	2023	2023-12-03 16:01:41	2023-12-03 16:52:52	5	254.14	NO ISSUES FOUND	Non-storm
SE23120300589	BENSN8496	2023	2023-12-03 16:08:23	2023-12-03 17:00:09	1	51.77	EQUIPMENT FAILURE	Non-storm
NW23120300599	NIXON8932	2023	2023-12-03 16:36:12	2023-12-04 07:32:04	2	1790.99	TREEBROW	Non-storm
NE23120300322	PTHUR2301	2023	2023-12-03 16:57:41	2023-12-03 17:18:04	1	20.38	TREEROW	Non-storm
SE23120300466	GLEND2212	2023	2023-12-03 17:29:46	2023-12-03 18:00:14	16	490.56	TREEROW	Non-storm
SE23120300609	GLEND2212	2023	2023-12-03 17:29:51	2023-12-03 18:00:13	1	30.37	NO ISSUES FOUND	Non-storm
NW23120400238	WMSTN8021	2023	2023-12-03 17:42:33	2023-12-04 09:34:40	1	150.19	EQUIPMENT FAILURE	Non-storm
SW23120300595	YPSIL0317	2023	2023-12-03 18:36:27	2023-12-03 18:54:42	1	18.25	ANIMAL	Non-storm
NE23120300682	MACMB8521	2023	2023-12-03 19:47:12	2023-12-03 21:18:52	124	11330.8	EQUIPMENT FAILURE	Non-storm
NE23120400012	MACMB8521	2023	2023-12-03 19:47:13	2023-12-04 06:21:47	82	36792.46	EQUIPMENT FAILURE	Non-storm
SW23120300644	GLBRT9373	2023	2023-12-03 21:15:46	2023-12-03 21:22:47	23	159.17	EQUIPMENT FAILURE	Non-storm
NW23120300727	PAGE8828	2023	2023-12-03 21:21:31	2023-12-04 00:14:47	1	11.84	EQUIPMENT FAILURE	Non-storm
NW23120400031	WATFD0314	2023	2023-12-03 22:24:02	2023-12-04 03:59:07	759	23368.8	TREEROW	Non-storm
NW23120400033	WATFD0314	2023	2023-12-03 22:24:02	2023-12-04 03:59:04	1	335.03	NO ISSUES FOUND	Non-storm
NW23120400034	WATFD0314	2023	2023-12-03 22:24:05	2023-12-04 03:59:06	1	335.02	EQUIPMENT FAILURE	Non-storm
NE23120400104	COTAG8743	2023	2023-12-03 23:09:44	2023-12-04 17:00:01	1	1070.28	PUBLIC INTERFERENCE	Non-storm
NW23120400015	CLYDE8910	2023	2023-12-03 23:36:32	2023-12-04 12:28:32	1	772	NO ISSUES FOUND	Non-storm
NW23120300796	CLYDE8910	2023	2023-12-03 23:36:36	2023-12-04 12:28:40	10	7718.04	EQUIPMENT FAILURE	Non-storm
NW23120400099	CLYDE8910	2023	2023-12-03 23:36:36	2023-12-04 12:26:32	2	1539.85	NO ISSUES FOUND	Non-storm
SE23120300701	KORTE1511	2023	2023-12-04 00:11:23	2023-12-04 11:00:58	1	649.58	EQUIPMENT FAILURE	Non-storm
SE23120300579	GRANT1598	2023	2023-12-04 02:44:56	2023-12-04 02:57:47	1	12.85	NO ISSUES FOUND	Non-storm
SW23120400453	FISHR8188	2023	2023-12-04 03:46:01	2023-12-04 15:46:37	1	720.6	ANIMAL	Non-storm
NW23120400067	CLYDE8910	2023	2023-12-04 04:47:16	2023-12-04 11:22:29	2	696.63	NO ISSUES FOUND	Non-storm
SW23120400073	WICK9457	2023	2023-12-04 05:02:19	2023-12-04 09:48:44	12	3433.5	EQUIPMENT FAILURE	Non-storm
SW23120300797	SHERW0321	2023	2023-12-04 05:56:30	2023-12-04 11:07:36	7	1061.47	NO ISSUES FOUND	Non-storm
SE23120300211	CHAND1026	2023	2023-12-04 07:09:58	2023-12-04 07:25:26	1	15.47	PUBLIC INTERFERENCE	Non-storm
SW23120300714	MOTTB124	2023	2023-12-04 07:19:37	2023-12-04 07:28:36	1	8.98	EQUIPMENT FAILURE	Non-storm
SW23120300625	NANKN2828	2023	2023-12-04 07:20:21	2023-12-04 07:45:16	1	24.92	EQUIPMENT FAILURE	Non-storm
SE23120300639	PATON8920	2023	2023-12-04 07:32:13	2023-12-04 09:18:50	1	106.62	ANIMAL	Non-storm
NE23120400610	BRUCE8953	2023	2023-12-04 07:43:28	2023-12-04 17:14:55	1	571.45	ANIMAL	Non-storm
SE23120400153	JUPTR8390	2023	2023-12-04 08:26:17	2023-12-04 09:38:18	7	502.27	ANIMAL	Non-storm
NE23120400163	OMEGA8444	2023	2023-12-04 08:30:58	2023-12-04 10:04:18	2	186.38	ANIMAL	Non-storm
NE23120400169	TCOLA8766	2023	2023-12-04 08:41:55	2023-12-04 09:38:00	1	56.08	PLANNED INTENTIONAL	Non-storm
NE23120400172	ATLAN8790	2023	2023-12-04 08:43:05	2023-12-04 10:44:06	14	1781.43	PUBLIC INTERFERENCE	Non-storm
SW23120300665	VENOY9426	2023	2023-12-04 08:48:38	2023-12-04 09:22:22	1	18.66	EQUIPMENT FAILURE	Non-storm
SE23120400173	WAYBN2164	2023	2023-12-04 08:54:25	2023-12-04 09:32:11	2	75.54	PLANNED INTENTIONAL	Non-storm
SW23120400181	EMRCK2926	2023	2023-12-04 09:06:00	2023-12-04 13:24:18	3	773.93	PLANNED INTENTIONAL	Non-storm
NE23120400193	OTSGO8762	2023	2023-12-04 09:07:28	2023-12-04 09:48:48	1	41.33	PLANNED INTENTIONAL	Non-storm
NW23120400277	SPKNE8842	2023	2023-12-04 09:15:59	2023-12-04 09:27:56	1	11.95	PLANNED INTENTIONAL	Non-storm
SE23120400201	CORTL0476	2023	2023-12-04 09:18:35	2023-12-04 09:50:54	1	32.32	PLANNED INTENTIONAL	Non-storm
NE23120400224	HOSTN8746	2023	2023-12-04 09:25:57	2023-12-04 12:45:01	2	398.08	TREEROW	Non-storm
SW23120400220	ORION8966	2023	2023-12-04 09:26:55	2023-12-04 17:52:06	5	2524.09	ANIMAL	Non-storm
SW23120400212	ROMLS9464	2023	2023-12-04 09:28:57	2023-12-04 11:04:02	2	33.68	PLANNED INTENTIONAL	Non-storm
NW23120400226	GRAYL8540	2023	2023-12-04 09:31:35	2023-12-04 12:10:17	5	793.19	TROUBLE INTENTIONAL	Non-storm
SE23120300686	APPOL2076	2023	2023-12-04 09:35:06	2023-12-04 09:46:35	1	11.48	EQUIPMENT FAILURE	Non-storm
SE23120400213	GLEND1417	2023	2023-12-04 09:35:46	2023-12-04 11:30:05	1	114.32	PLANNED INTENTIONAL	Non-storm
SE23120400242	null	2023	2023-12-04 09:38:48	2023-12-04 11:09:42	1	90.9	PLANNED INTENTIONAL	Non-storm
SW23120400243	GAY1926	2023	2023-12-04 09:46:52	2023-12-04 10:30:27	16	694.42	TROUBLE INTENTIONAL	Non-storm
NE23120400244	OTSGO8762	2023	2023-12-04 10:00:24	2023-12-04 10:16:02	1	15.63	PLANNED INTENTIONAL	Non-storm
SW23120400273	SHERW0321	2023	2023-12-04 10:04:28	2023-12-04 11:07:36	3	189.32	TROUBLE INTENTIONAL	Non-storm
SW23120400290	SHERW0321	2023	2023-12-04 10:04:28	2023-12-04 11:07:35	1	63.12	TROUBLE INTENTIONAL	Non-storm
SW23120400288	SHERW0321	2023	2023-12-04 10:04:29	2023-12-04 11:07:35	1	63.1	TROUBLE INTENTIONAL	Non-storm
SE23120400253	PULFD0419	2023	2023-12-04 10:04:57	2023-12-04 10:12:36	1	7.65	PLANNED INTENTIONAL	Non-storm
NW23120400269	DISCO8104	2023	2023-12-04 10:06:11	2023-12-04 12:26:37	8	1122.72	EQUIPMENT FAILURE	Non-storm
SW23120400246	WICK9346	2023	2023-12-04 10:06:11	2023-12-04 10:34:56	2	57.52	PLANNED INTENTIONAL	Non-storm
NW23120400275	SPKNE8842	2023	2023-12-04 10:11:27	2023-12-04 10:21:46	2	20.65	PLANNED INTENTIONAL	Non-storm
SE23120400270	LAUDR1272	2023	2023-12-04 10:14:58	2023-12-04 10:45:41	2	56.17	PLANNED INTENTIONAL	Non-storm
NW23120400265	SPKNE8842	2023	2023-12-04 10:15:35	2023-12-04 10:39:38	9	214.65	PLANNED INTENTIONAL	Non-storm
NE23120400245	TCOLA8766	2023	2023-12-04 10:20:17	2023-12-04 11:59:09	2	177.02	PLANNED INTENTIONAL	Non-storm
NW23120400293	SLYON0301	2023	2023-12-04 10:24:07	2023-12-04 11:55:18	26	2157.78	TROUBLE INTENTIONAL	Non-storm
SW23120400287	WICK9346	2023	2023-12-04 10:25:05	2023-12-04 11:05:12	10	400.27	PLANNED INTENTIONAL	Non-storm
NE23120400296	VERNR1489	2023	2023-12-04 10:28:45	2023-12-04 11:07:14	247	9444.04	EQUIPMENT FAILURE	Non-storm
NE23120400292	SAVOY8711	2023	2023-12-04 10:30:01	2023-12-04 11:37:03	1	67.03	PLANNED INTENTIONAL	Non-storm
NE23120400305	OTSGO8762	2023	2023-12-04 10:30:30	2023-12-04 10:46:09	1	15.65	PLANNED INTENTIONAL	Non-storm
NW23120400308	COLFX8186	2023	2023-12-04 10:34:45	2023-12-04 11:31:21	1	56.6	PLANNED INTENTIONAL	Non-storm
SW23120400310	ROMLS9464	2023	2023-12-04 10:41:55	2023-12-04 11:00:36	23	426.89	PLANNED INTENTIONAL	Non-storm
SW23120400237	PERU9440	2023	2023-12-04 10:42:54	2023-12-04 11:42:29	5	296.61	PLANNED INTENTIONAL	Non-storm
NW23120400323	BVRLY0356	2023	2023-12-04 10:46:43	2023-12-04 11:05:13	1	18.5	PLANNED INTENTIONAL	Non-storm

NW23120400336	REDRN8555	2023	2023-12-04 10:48:15	2023-12-04 17:40:23	12	4945.46	ANIMAL	Non-storm
SW23120400285	ROMLS9464	2023	2023-12-04 10:48:23	2023-12-04 11:14:46	1	26.38	PLANNED INTENTIONAL	Non-storm
NE23120400329	OTSGO8762	2023	2023-12-04 10:51:55	2023-12-04 10:57:20	1	5.42	PLANNED INTENTIONAL	Non-storm
SW23120400337	SHELD8185	2023	2023-12-04 10:51:55	2023-12-04 12:53:13	1	121.3	PUBLIC INTERFERENCE	Non-storm
NW23120400211	COLFX8186	2023	2023-12-04 10:53:15	2023-12-04 11:26:10	1	32.92	PLANNED INTENTIONAL	Non-storm
SW23120400332	PROSP0305	2023	2023-12-04 10:59:46	2023-12-04 12:23:31	1	83.75	PLANNED INTENTIONAL	Non-storm
SW23120400333	PERU9440	2023	2023-12-04 11:00:07	2023-12-04 12:14:51	5	372.71	PLANNED INTENTIONAL	Non-storm
SW23120400359	PERU9440	2023	2023-12-04 11:00:19	2023-12-04 12:14:51	1	74.53	PLANNED INTENTIONAL	Non-storm
SE23120400346	COOLG1402	2023	2023-12-04 11:00:46	2023-12-04 11:36:14	1	35.47	PLANNED INTENTIONAL	Non-storm
SW23120400567	BEMIS9802	2023	2023-12-04 11:03:24	2023-12-04 14:40:30	1	217.1	ANIMAL	Non-storm
NE23120400367	SAVOY8711	2023	2023-12-04 11:07:46	2023-12-04 12:26:34	2	153.23	PLANNED INTENTIONAL	Non-storm
NE23120400365	OTSGO8762	2023	2023-12-04 11:23:05	2023-12-04 11:30:12	1	7.12	PLANNED INTENTIONAL	Non-storm
SW23120400388	RGENT0357	2023	2023-12-04 11:25:29	2023-12-04 13:01:34	1	96.08	PLANNED INTENTIONAL	Non-storm
NW23120400279	LNGLK9110	2023	2023-12-04 11:35:00	2023-12-04 13:43:36	4	514.28	PLANNED INTENTIONAL	Non-storm
NE23120400387	TCOLA8766	2023	2023-12-04 11:37:12	2023-12-04 13:58:41	5	707.13	PLANNED INTENTIONAL	Non-storm
NE23120400392	TCOLA8766	2023	2023-12-04 11:37:15	2023-12-04 13:58:41	1	141.43	EQUIPMENT FAILURE	Non-storm
NE23120400393	BREWR8840	2023	2023-12-04 11:40:44	2023-12-04 12:16:30	1	35.77	PLANNED INTENTIONAL	Non-storm
NW23120400457	COLFX8186	2023	2023-12-04 11:53:08	2023-12-04 13:00:33	1	67.42	PLANNED INTENTIONAL	Non-storm
NW23120400138	WLNUT9013	2023	2023-12-04 11:57:45	2023-12-04 12:13:29	1	15.73	EQUIPMENT FAILURE	Non-storm
SE23120400412	WDSID2757	2023	2023-12-04 11:57:52	2023-12-04 13:17:40	1	79.8	PLANNED INTENTIONAL	Non-storm
SW23120400369	ROMLS9464	2023	2023-12-04 12:00:32	2023-12-04 12:14:56	1	14.4	PLANNED INTENTIONAL	Non-storm
SE23120400423	CORTL0476	2023	2023-12-04 12:06:17	2023-12-04 12:20:59	2	29.42	PLANNED INTENTIONAL	Non-storm
SE23120400425	WHITR2750	2023	2023-12-04 12:07:53	2023-12-04 12:38:12	2	60.62	PLANNED INTENTIONAL	Non-storm
NW23120400458	HURST9853	2023	2023-12-04 12:13:48	2023-12-04 13:15:43	1	61.92	ANIMAL	Non-storm
NE23120400465	BUNRT8110	2023	2023-12-04 12:22:04	2023-12-04 13:44:32	37	3045.2	EQUIPMENT FAILURE	Non-storm
SW23120400443	PROSP0305	2023	2023-12-04 12:27:45	2023-12-04 14:53:54	1	146.15	PLANNED INTENTIONAL	Non-storm
SW23120400474	ROMLS9464	2023	2023-12-04 12:35:53	2023-12-04 12:46:08	7	71.61	PLANNED INTENTIONAL	Non-storm
SE23120400557	LINCN2694	2023	2023-12-04 12:36:05	2023-12-04 14:19:03	69	3903.31	EQUIPMENT FAILURE	Non-storm
SE23120400489	SIXMI2173	2023	2023-12-04 12:49:24	2023-12-04 14:19:55	175	11297.83	TREEROW	Non-storm
NE23120400553	GRAYL8540	2023	2023-12-04 12:49:38	2023-12-05 09:37:09	1	1247.52	EQUIPMENT FAILURE	Non-storm
SW23120400472	PERU9440	2023	2023-12-04 12:50:12	2023-12-04 13:52:29	1	62.28	PLANNED INTENTIONAL	Non-storm
NE23120400485	LAKPT2616	2023	2023-12-04 12:50:43	2023-12-04 13:24:47	1	34.07	PLANNED INTENTIONAL	Non-storm
NE23120400477	RICHM2415	2023	2023-12-04 12:54:49	2023-12-04 14:23:35	1	88.77	PLANNED INTENTIONAL	Non-storm
NE23120400527	LIBER1820	2023	2023-12-04 13:05:50	2023-12-04 20:05:17	22	9220.87	EQUIPMENT FAILURE	Non-storm
NE23120400526	LIBER1820	2023	2023-12-04 13:05:56	2023-12-04 20:05:15	18	7595.28	EQUIPMENT FAILURE	Non-storm
NE23120400531	LIBER1820	2023	2023-12-04 13:05:56	2023-12-04 20:05:15	4	1676.54	EQUIPMENT FAILURE	Non-storm
NE23120400528	LIBER1820	2023	2023-12-04 13:06:00	2023-12-04 20:05:08	1	419.13	EQUIPMENT FAILURE	Non-storm
NE23120400374	DERBY2635	2023	2023-12-04 13:09:05	2023-12-04 13:21:28	1	12.38	NO ISSUES FOUND	Non-storm
NW23120400568	COLFX8186	2023	2023-12-04 13:09:34	2023-12-04 15:11:53	1	111.65	PLANNED INTENTIONAL	Non-storm
SE23120200448	SHADK1119	2023	2023-12-04 13:15:12	2023-12-04 13:31:52	1	16.67	TREEBROW	Non-storm
SW23120400524	BLCRK8011	2023	2023-12-04 13:17:40	2023-12-04 14:42:35	2	169.55	PLANNED INTENTIONAL	Non-storm
NE23120400548	OTSGO8762	2023	2023-12-04 13:27:12	2023-12-04 14:10:25	1	43.22	PLANNED INTENTIONAL	Non-storm
SW23120400551	PERU9440	2023	2023-12-04 13:37:27	2023-12-04 14:01:39	5	120.83	PLANNED INTENTIONAL	Non-storm
NW23120400566	CAMDN8282	2023	2023-12-04 13:53:33	2023-12-04 14:30:51	1	37.3	PLANNED INTENTIONAL	Non-storm
NE23120400596	FAWN8794	2023	2023-12-04 14:05:22	2023-12-04 15:23:51	34	2664.16	EQUIPMENT FAILURE	Non-storm
SE23120400575	MLVDL2114	2023	2023-12-04 14:17:36	2023-12-04 16:23:07	2	217.62	PLANNED INTENTIONAL	Non-storm
SE23120400632	GLEND1513	2023	2023-12-04 14:33:30	2023-12-04 15:03:54	1	30.4	PLANNED INTENTIONAL	Non-storm
NW23120400640	SPKNE8842	2023	2023-12-04 14:40:05	2023-12-04 14:55:32	15	228.61	NO ISSUES FOUND	Non-storm
SW23120400624	PERU9440	2023	2023-12-04 15:06:54	2023-12-04 15:12:34	6	33.88	PLANNED INTENTIONAL	Non-storm
SE23120400658	COOLG1402	2023	2023-12-04 15:11:09	2023-12-04 16:11:26	10	599.96	PLANNED INTENTIONAL	Non-storm
NW23120300647	PAGE8828	2023	2023-12-04 15:41:48	2023-12-04 16:06:46	1	24.97	NO ISSUES FOUND	Non-storm
NW23120300772	PAGE8828	2023	2023-12-04 15:41:49	2023-12-04 16:06:47	1	24.97	EQUIPMENT FAILURE	Non-storm
SE23120500080	HAWTH1841	2023	2023-12-04 16:14:03	2023-12-04 16:44:36	1	30.55	TREEBROW	Non-storm
NE23120400642	BEACH8673	2023	2023-12-04 16:18:31	2023-12-04 21:32:26	77	5902.5	PUBLIC INTERFERENCE	Non-storm
NW23120500169	WALTN0324	2023	2023-12-04 17:09:46	2023-12-05 12:22:33	1	1152.78	EQUIPMENT FAILURE	Non-storm
SE23120400143	ESTLD2241	2023	2023-12-04 17:47:41	2023-12-04 17:53:10	1	5.48	NO ISSUES FOUND	Non-storm
SE23120400697	GDRIV1115	2023	2023-12-04 18:02:14	2023-12-04 18:20:04	22	387.16	TREEROW	Non-storm
NW23120400148	LARDO8973	2023	2023-12-04 18:29:37	2023-12-04 18:41:54	1	12.28	EQUIPMENT FAILURE	Non-storm
SE23120400794	SOFLD9094	2023	2023-12-04 19:11:42	2023-12-05 08:38:22	1	126.03	EQUIPMENT FAILURE	Non-storm
SE23120400864	EMPIR2221	2023	2023-12-04 19:45:24	2023-12-04 20:50:16	1	64.87	NO ISSUES FOUND	Non-storm
SE23120300121	WEBST1812	2023	2023-12-04 19:58:40	2023-12-04 20:20:52	1	22.2	TREEBROW	Non-storm
SE23120400897	DCATR1271	2023	2023-12-04 20:34:36	2023-12-05 12:14:33	1	939.95	EQUIPMENT FAILURE	Non-storm
SE23120400830	BRAZL8827	2023	2023-12-04 21:26:03	2023-12-04 21:44:42	1	18.65	EQUIPMENT FAILURE	Non-storm
SE23120400530	HAYES2084	2023	2023-12-04 22:19:17	2023-12-04 22:36:22	1	17.08	EQUIPMENT FAILURE	Non-storm
SE23120500235	STLUS0230	2023	2023-12-05 00:25:41	2023-12-05 14:27:07	1	841.43	PUBLIC INTERFERENCE	Non-storm
SW23120500020	SPRUC9874	2023	2023-12-05 02:56:28	2023-12-05 08:25:01	36	8046.59	EQUIPMENT FAILURE	Non-storm
SW23120500075	BNSTN9355	2023	2023-12-05 07:26:32	2023-12-05 10:44:54	1	198.37	EQUIPMENT FAILURE	Non-storm
NE23120500089	CASVL8819	2023	2023-12-05 08:07:44	2023-12-05 09:36:41	16	1421.74	ANIMAL	Non-storm
NW23120500104	PONTC8875	2023	2023-12-05 08:25:06	2023-12-05 09:53:04	12	1052.04	ANIMAL	Non-storm
SE23120400390	VERNR1503	2023	2023-12-05 09:24:55	2023-12-05 09:40:33	1	15.63	EQUIPMENT FAILURE	Non-storm
SE23120400798	TURNR2165	2023	2023-12-05 09:25:28	2023-12-05 09:35:38	1	10.17	EQUIPMENT FAILURE	Non-storm
NE23120500176	OTSGO8762	2023	2023-12-05 09:32:27	2023-12-05 09:46:58	1	14.52	PLANNED INTENTIONAL	Non-storm
SW23120500175	ROMLS9464	2023	2023-12-05 09:34:12	2023-12-05 09:46:24	7	84.87	PLANNED INTENTIONAL	Non-storm
SE23120500187	PULFD2155	2023	2023-12-05 09:51:19	2023-12-05 11:19:01	12	523.68	PLANNED INTENTIONAL	Non-storm
SW23120500199	ROMLS9464	2023	2023-12-05 09:57:27	2023-12-05 10:24:32	2	54.04	PLANNED INTENTIONAL	Non-storm
SW23120500615	MAURD9393	2023	2023-12-05 10:01:11	2023-12-05 19:38:21	1	577.17	CUSTOMER EQUIPMENT	Non-storm
NE23120500044	MARLT8281	2023	2023-12-05 10:01:46	2023-12-05 11:20:03	1	40.66	ANIMAL	Non-storm
SE23120400559	BALFR2162	2023	2023-12-05 10:06:38	2023-12-05 10:32:48	2	46.2	TREEBROW	Non-storm
NE23120500221	ALGON8748	2023	2023-12-05 10:08:58	2023-12-05 17:05:20	2	832.36	ANIMAL	Non-storm
SW23120500245	PITTS0383	2023	2023-12-05 10:12:42	2023-12-05 10:49:49	1	37.12	PLANNED INTENTIONAL	Non-storm
SE23120500224	PULFD2224	2023	2023-12-05 10:14:17	2023-12-05 12:31:59	39	4195.19	PLANNED INTENTIONAL	Non-storm
NW23120500239	WLNUT9029	2023	2023-12-05 10:23:16	2023-12-06 02:02:23	1	939.12	PUBLIC INTERFERENCE	Non-storm
NW23120500236	WLNUT9029	2023	2023-12-05 10:23:30	2023-12-05 20:17:44	3	1782.47	PUBLIC INTERFERENCE	Non-storm
SW23120500205	ROMLS9464	2023	2023-12-05 10:24:12	2023-12-05 10:33:28	19	171.42	PLANNED INTENTIONAL	Non-storm
SE23120500242	MLVDL2114	2023	2023-12-05 10:35:39	2023-12-05 12:06:15	6	484.57	PLANNED INTENTIONAL	Non-storm
SW23120500233	ROMLS9464	2023	2023-12-05 10:36:07	2023-12-05 10:42:43	3	19.74	PLANNED INTENTIONAL	Non-storm
NW23120500238	CATLI9136	2023	2023-12-05 10:40:38	2023-12-05 11:20:46	1	40.13	PLANNED INTENTIONAL	Non-storm
SE23120500260	PULFD2155	2023	2023-12-05 10:51:29	2023-12-05 11:13:02	1	21.55	PLANNED INTENTIONAL	Non-storm
SW23120500283	PROSP0305	2023	2023-12-05 11:14:34	2023-12-05 13:13:19	4	474.66	PLANNED INTENTIONAL	Non-storm
SE23120500234	MCGRW1167	2023	2023-12-05 11:24:20	2023-12-05 17:20:54	612	29146.58	PUBLIC INTERFERENCE	Non-storm
SE23120500461	TURNR1144	2023	2023-12-05 11:26:21	2023-12-05 14:15:50	1	169.48	EQUIPMENT FAILURE	Non-storm
SE23120500156	PULFD2111	2023	2023-12-05 11:37:01	2023-12-05 12:18:59	1	41.97	PLANNED INTENTIONAL	Non-storm
SE23120500068	GLEND2198	2023	2023-12-05 11:40:02	2023-12-05 12:59:42	1	79.67	EQUIPMENT FAILURE	Non-storm
SE23120500361	GNSTN1319	2023	2023-12-05 11:40:40	2023-12-05 12:38:26	1	57.77	PLANNED INTENTIONAL	Non-storm
SE23120500363	STOPL1078	2023	2023-12-05 11:41:37	2023-12-05 13:24:34	1	102.95	PLANNED INTENTIONAL	Non-storm
SE23120500368	LAMBT1456	2023	2023-12-05 11:49:21	2023-12-05 12:57:58	7	478.44	PLANNED INTENTIONAL	Non-storm
SE23120500413	LAMBT1456	2023	2023-12-05 11:49:22	2023-12-05 12:57:42	1	68.33	PLANNED INTENTIONAL	Non-storm
SE23120500387	LAMBT1456	2023	2023-12-05 11:49:27	2023-12-05 12:57:46	1	68.32	PLANNED INTENTIONAL	Non-storm
NE23120500410	CASVL8805	2023	2023-12-05 11:54:29	2023-12-05 12:37:16	1	42.78	NO ISSUES FOUND	Non-storm
NW23120500379	HURST9853	2023	2023-12-05 11:56:13	2023-12-05 12:19:57	1	23.73	PLANNED INTENTIONAL	Non-storm
NE23120500408	LEXTN8770	2023	2023-12-05 12:11:19	2023-12-05 13:37:10	1	85.85	PLANNED INTENTIONAL	Non-storm
NE23120500426	APLGT0312	2023	2023-12-05 12:35:12	2023-12-05 14:36:05	1	120.88	PLANNED INTENTIONAL	Non-storm
SW23120500433	WSTLD8002	2023	2023-12-05 12:39:48	2023-12-05 13:53:25	16	1177.23	ANIMAL	Non-storm
SE23120500636	MCGRW1167	2023	2023-12-05 12:40:51	2023-12-05 20:46:54	1	486.05	EQUIPMENT FAILURE	Non-storm
SE23120500593	MCGRW1167	2023	2023-12-05 12:47:33	2023-12-05 20:52:30	4	565.12	EQUIPMENT FAILURE	Non-storm
NE23120500628	JEWEL9191	2023	2023-12-05 12:58:38	2023-12-06 16:51:26	1	232.8	EQUIPMENT FAILURE	Non-storm
NE23120500453	CAPAC8013	2023	2023-12-05 12:59:57	2023-12-05 17:14:47	1	254.83	ANIMAL	Non-storm
NE23120500455	FAWN8794	2023	2023-12-05 13:02:09	2023-12-05 15:01:34	1	119.42	PLANNED INTENTIONAL	Non-storm
NW23120500493	TINKN8850	2023	2023-12-05 13:22:18	2023-12-05 13:49:32	12	304.39	EQUIPMENT FAILURE	Non-storm
NW23120500501	WCHTR1937	2023	2023-12-05 13:22:20	2023-12-05 13:49:25	1	27.08	NO ISSUES FOUND	Non-storm
SW23120500537	PITTS0383	2023	2023-12-05 14:11:47	2023-12-05 15:23:51	5	357.78	EQUIPMENT FAILURE	Non-storm
SE23120500219	SAVAN1086	2023	2023-12-05 14:12:06	2023-12-05 14:37:43	1	25.62	METER / BLOCKS	Non-storm
SE23120500419	SYRAC2000	2023	2023-12-05 14:24:35	2023-12-05 14:30:20	1	5.75	EQUIPMENT FAILURE	Non-storm
SE23120500127	VILLA1553	2023	2023-12-05 14:33:41	2023-12-05 14:51:42	1	18.02	TREEBROW	Non-storm
SE23120500576	WAGNR1374	2023	2023-12-05 14:41:56	2023-12-05 19:06:32	5	1269.69	EQUIPMENT FAILURE	Non-storm
SE23120500671	WDSID2757	2023	2023-12-05 15:27:03	2023-12-05 22:03:42	1	396.65	TREEROW	Non-storm
SE23120500710	EVRGN1062	2023	2023-12-05 16:31:11	2023-12-06 06:48:42	1	592.33	EQUIPMENT FAILURE	Non-storm
NW23120500660	TAMRK9067	2023	2023-12-05 17:01:00	2023-12-05 17:16:00	1	15	EQUIPMENT FAILURE	Non-storm
NW23120500614	MANDY0307	2023	2023-12-05 17:24:02	2023-12-05 18:02:14	1	38.2	TREEBROW	Non-storm
SE23120500823	EVRGN1257	2023	2023-12-05 17:27:58	2023-12-05 20:18:58	1	155.45	NO ISSUES FOUND	Non-storm
SE23120500755	GNSTN1295	2023	2023-12-05 17:29:50	2023-12-06 02:23:11	5	2665.79	NO ISSUES FOUND	Non-storm
SE23120500760	GNSTN1295	2023	2023-12-05 17:29:55	2023-12-06 02:23:01	3	1597.64	EQUIPMENT FAILURE	Non-storm
SE23120500753	GNSTN1295	2023	2023-12-05 17:30:00	2023-12-06 02:23:12	5	2664.94	EQUIPMENT FAILURE	Non-storm
SE23120500820	GNSTN1295	2023	2023-12-05 17:30:01	2023-12-06 02:23:12	1	533.18	EQUIPMENT FAILURE	Non-storm
SE23120500777	LAMBT1468	2023	2023-12-05 17:40:59	2023-12-05 19:41:33	480	57738.44	PUBLIC INTERFERENCE	Non-storm
SE23120500806	LAMBT1468	2023	2023-12-05 17:41:05	2023-12-05 19:41:29	1	120.4	PUBLIC INTERFERENCE	Non-storm
SE23120500685	HAYES1484	2023	2023-12-05 17:49:19	2023-12-05 19:19:31	1	15.19	WIND	Non-storm
SE23120500688	ALNPK1833	2023	2023-12-05 18:51:10	2023-12-05 19:06:44	1	15.57	EQUIPMENT FAILURE	Non-storm
SW23120500431	OREGN9785	2023	2023-12-05 19:52:15	2023-12-05 22:10:16	18	2479.15	EQUIPMENT FAILURE	Non-storm
NW23120500840	WRNSI2668	2023	2023-12-05 20:06:15	2023-12-05 22:56:38	1	26.79	CUSTOMER EQUIPMENT	Non-storm
NE23120600087	HOSTN8746	2023	2023-12-06 01:39:46	2023-12-06 01:43:46	1	604	EQUIPMENT FAILURE	Non-storm
SE23120500847	MCGRW1167	2023	2023-12-06 03:47:49	2023-12-06 03:53:30	1	5.68	EQUIPMENT FAILURE	Non-storm
SE23120600284	HAYES2084	2023	2023-12-06 03:55:16	2023-12-06 05:07:04	1	71.8	WIND	Non-storm
SE23120600016	HAYES2084	2023	2023-12-06 03:55:17	2023-12-06 05:07:18	805	57782.09	EQUIPMENT FAILURE	Non-storm
SE23120600046	HAYES1141	2023	2023-12-06 03:55:17	2023-12-06 05:07:13	306	21951.07	EQUIPMENT FAILURE	Non-storm
SE23120500872	MEYRS1656	2023	2023-12-06 04:25:08	2023-12-06 04:45:02	1	19.9	EQUIPMENT FAILURE	Non-storm
SE23120600015	CONAT1269	2023	2023-12-06 07:42:39	2023-12-06 07:52:26	1	9.78	EQUIPMENT FAILURE	Non-storm
SW23120600106	STATE8126	2023	2023-12-06 08:09:31	2023-12-06 09:20:10	5	352.25	ANIMAL	Non-storm
SW23120600126	BNSTN9355	2023	2023-12-06 08:15:52	2023-12-06 09:29:23	47	3452.43	ANIMAL	Non-storm
NW23120600133	SLOAN8524	2023	2023-12-06 08:38:58	2023-12-06 09:26:14	4	188.72	ANIMAL	Non-storm
SE23120600112	PULFD2111	2023	2023-12-06 08:47:40	2023-12-06 12:48:40	17	2943.72	PLANNED INTENTIONAL	Non-storm
NW23120600142	BVRLY0356	2023	2023-12-06 08:54:18	2023-12-06 09:52:40	3	174.88	PLANNED INTENTIONAL	Non-storm
SE23120600169	LAMBT1456	2023	2023-12-06 09:08:32	2023-12-06 09:41:43	2	66.2	NO ISSUES FOUND	Non-storm
SE23120600150	LAUDR1272	2023	2023-12-06 09:09:16	2023-12-06 09:56:14	1	46.97	PLANNED INTENTIONAL	Non-storm
NE23120600098	BOYNE8566	2023	2023-12-06 09:09:36	2023-12-06 09:18:13	1	8.62	EQUIPMENT FAILURE	Non-storm
SE23120600211	LAUDR1272	2023	2023-12-06 09:19:05	2023-12-06 09:56:47	1	37.7	PLANNED INTENTIONAL	Non-storm
NW23120600170	HURST9853	2023	2023-12-06 09:21:31	2023-12-06 09:34:32	1	13.02	PLANNED INTENTIONAL	Non-storm
SE23120600180	PULFD2155	2023	2023-12-06 09:23:00	2023-12-06 10:06:56	6	241.73	PLANNED INTENTIONAL	Non-storm
SW23120600174	SALIN9788	2023	2023-12-06 09:23:22	2023-12-06 09:29:52	1	6.5	PLANNED INTENTIONAL	Non-storm
SE23120600173	LAUDR1272	2023	2023-12-06 09:25:48	2023-12-06 10:32:01	1	66.22	PLANNED INTENTIONAL	Non-storm
NW23120600187	SPKNE8842	2023	2023-12-06 09:32:05	2023-12-06 09:41:14	1	9.15	PLANNED INTENTIONAL	Non-storm
SW23120600175	ROMLS9464	2023	2023-12-06 09:34:00	2023-12-06 09:46:43	1	12.72	PLANNED INTENTIONAL	Non-storm
SW23120600204	GARCY1601	2023	2023-12-06 09:53:18	2023-12-06 10:05:28	1	12.17	PLANNED INTENTIONAL	Non-storm
NE23120600216	BUNRT8110	2023	2023-12-06 09:54:42	2023-12-06 12:44:46	45	7646.7	TREEBROW	Non-storm
NE23120600206	EMMET0301	2023	2023-12-06 09:55:01	2023-12-06 11:36:04	2	202.1	PLANNED INTENTIONAL	Non-storm
SW23120600217	SALIN9788	2023	2023-12-06 10:00:47	2023-12-06 10:13:29	1	12.7	PLANNED INTENTIONAL	Non-storm
SE23120600200	EIGMI1507	2023	2023-12-06 10:01:29	2023-12-06 11:04:54	1	63.42	PLANNED INTENTIONAL	Non-storm
SW23120600225	RGENT0357	2023	2023-12-06 10:01:47	2023-12-06 12:46:59	1	165.2	PLANNED INTENTIONAL	Non-storm
NW23120600227	SENCA8940	2023	2023-12-06 10:01:53	2023-12-06 10:57:21	258	14004.56	PUBLIC INTERFERENCE	Non-storm
NW23120600248	SPKNE8982	2023	2023-12-06 10:02:02	2023-12-06 10:55:58	1	53.93	NO ISSUES FOUND	Non-storm
NW23120600195	HURST9853	2023	2023-12-06 10:02:03	2023-12-06 10:13:16	1	11.22	PLANNED INTENTIONAL	Non-storm
NE23120600241	JEWEL8457	2023	2023-12-06 10:03:29	2023-12-06 11:03:35	45	2690.67	ANIMAL	Non-storm

NW23120600233	HURST9853	2023	2023-12-06 10:09:29	2023-12-06 10:28:47	1	19.3	PLANNED INTENTIONAL	Non-storm
SE23120600280	GDRIV1184	2023	2023-12-06 10:10:26	2023-12-06 10:49:03	1	38.62	PLANNED INTENTIONAL	Non-storm
SW23120600230	ROMLS9464	2023	2023-12-06 10:11:06	2023-12-06 10:20:15	3	27.41	PLANNED INTENTIONAL	Non-storm
SE23120600282	NRLND1567	2023	2023-12-06 10:22:15	2023-12-06 13:38:33	31	2531.44	TROUBLE INTENTIONAL	Non-storm
NW23120600283	LILY9120	2023	2023-12-06 10:23:49	2023-12-06 13:08:14	4	655.53	NO ISSUES FOUND	Non-storm
SW23120600287	ROMLS9464	2023	2023-12-06 10:32:29	2023-12-06 10:39:59	3	22.18	PLANNED INTENTIONAL	Non-storm
SE23120600305	INDIN1406	2023	2023-12-06 10:34:26	2023-12-06 12:54:36	12	1679.94	TROUBLE INTENTIONAL	Non-storm
SW23120600272	BLCRK8011	2023	2023-12-06 10:44:44	2023-12-06 11:25:25	2	79.95	PLANNED INTENTIONAL	Non-storm
SE23120600319	SYRAC1813	2023	2023-12-06 10:50:47	2023-12-06 11:57:31	26	1728.92	TROUBLE INTENTIONAL	Non-storm
NW23120600324	CAMDN8282	2023	2023-12-06 10:51:47	2023-12-06 11:42:24	2	98.42	EQUIPMENT FAILURE	Non-storm
NW23120600316	HURST9853	2023	2023-12-06 10:55:08	2023-12-06 11:02:09	1	7.02	PLANNED INTENTIONAL	Non-storm
NW23120600308	SPKNE8842	2023	2023-12-06 10:55:22	2023-12-06 11:18:41	1	23.32	PLANNED INTENTIONAL	Non-storm
NE23120600321	HARPR2463	2023	2023-12-06 10:55:26	2023-12-06 11:42:49	8	377.52	PLANNED INTENTIONAL	Non-storm
SW23120600299	ROMLS9464	2023	2023-12-06 11:07:32	2023-12-06 11:32:13	3	73.8	PLANNED INTENTIONAL	Non-storm
NW23120600331	HURST9853	2023	2023-12-06 11:08:05	2023-12-06 11:21:50	1	13.75	PLANNED INTENTIONAL	Non-storm
SW23120600336	SALIN9788	2023	2023-12-06 11:10:39	2023-12-06 11:22:18	3	34.86	PLANNED INTENTIONAL	Non-storm
NW23120600342	ADAMS9131	2023	2023-12-06 11:13:51	2023-12-06 12:29:19	2	150.51	PLANNED INTENTIONAL	Non-storm
SE23120600345	LAMBT1456	2023	2023-12-06 11:21:41	2023-12-06 12:08:43	1	47.03	PLANNED INTENTIONAL	Non-storm
NE23120600351	OTSGO8762	2023	2023-12-06 11:23:18	2023-12-06 11:35:00	1	11.7	PLANNED INTENTIONAL	Non-storm
SE23120600301	ANGLA8862	2023	2023-12-06 11:24:33	2023-12-06 16:53:48	4	1316.76	PLANNED INTENTIONAL	Non-storm
NW23120600365	WDUOW9064	2023	2023-12-06 11:27:02	2023-12-06 12:32:37	1	65.58	PLANNED INTENTIONAL	Non-storm
SE23120600381	GNSTN1319	2023	2023-12-06 11:28:01	2023-12-06 12:49:44	1	81.72	PLANNED INTENTIONAL	Non-storm
SW23120600326	ROMLS9464	2023	2023-12-06 11:32:08	2023-12-06 11:49:15	23	389.47	PLANNED INTENTIONAL	Non-storm
NW23120600371	HURST9853	2023	2023-12-06 11:32:34	2023-12-06 11:40:13	1	7.65	PLANNED INTENTIONAL	Non-storm
SE23120600377	ANGLA8862	2023	2023-12-06 11:36:55	2023-12-06 18:45:49	11	4717.98	PLANNED INTENTIONAL	Non-storm
NW23120600392	STERL8442	2023	2023-12-06 11:38:23	2023-12-06 12:08:12	1	29.82	PLANNED INTENTIONAL	Non-storm
SE23120600397	LAUDR1554	2023	2023-12-06 11:48:16	2023-12-06 12:42:11	1	53.92	PLANNED INTENTIONAL	Non-storm
SE23120600387	MLVDL2105	2023	2023-12-06 11:51:24	2023-12-06 13:38:57	1	107.55	PLANNED INTENTIONAL	Non-storm
SE23120600384	LINCN0356	2023	2023-12-06 11:52:11	2023-12-06 13:01:29	1	69.3	PLANNED INTENTIONAL	Non-storm
NW23120600379	HURST9853	2023	2023-12-06 11:55:09	2023-12-06 12:09:04	1	13.92	PLANNED INTENTIONAL	Non-storm
SW23120600383	SALIN9788	2023	2023-12-06 12:04:40	2023-12-06 12:14:42	1	10.03	PLANNED INTENTIONAL	Non-storm
SE23120300648	GLEND2025	2023	2023-12-06 12:08:06	2023-12-06 12:18:00	1	9.9	EQUIPMENT FAILURE	Non-storm
NE23120600401	RICHM2415	2023	2023-12-06 12:09:48	2023-12-06 13:42:42	1	92.9	PLANNED INTENTIONAL	Non-storm
NW23120600406	JEWEL9194	2023	2023-12-06 12:10:13	2023-12-06 14:07:46	2	234.85	ANIMAL	Non-storm
SE23120600433	WAREN8374	2023	2023-12-06 12:12:51	2023-12-06 13:39:39	18	1558.36	ANIMAL	Non-storm
SW23120600409	CROWN9832	2023	2023-12-06 12:14:14	2023-12-06 13:09:16	1035	56772.74	PUBLIC INTERFERENCE	Non-storm
SW23120600455	CROWN9832	2023	2023-12-06 12:14:16	2023-12-06 13:09:14	38	2072.26	PUBLIC INTERFERENCE	Non-storm
SW23120600611	CROWN9832	2023	2023-12-06 12:14:21	2023-12-06 13:09:13	1	54.87	EQUIPMENT FAILURE	Non-storm
NW23120600446	HURST9853	2023	2023-12-06 12:17:24	2023-12-06 13:10:46	1	53.37	PLANNED INTENTIONAL	Non-storm
SE23120600469	GLEND2025	2023	2023-12-06 12:24:51	2023-12-06 14:08:50	1	103.98	PLANNED INTENTIONAL	Non-storm
SE23120600327	EVRGN1062	2023	2023-12-06 12:44:32	2023-12-06 18:53:44	11	2689.37	PUBLIC INTERFERENCE	Non-storm
SE23120600486	EVRGN1062	2023	2023-12-06 12:50:15	2023-12-06 16:48:00	18	1983.78	PUBLIC INTERFERENCE	Non-storm
NE23120600482	LIBER1056	2023	2023-12-06 12:50:51	2023-12-06 13:19:06	1	28.25	PLANNED INTENTIONAL	Non-storm
NW23120600586	WMSTN9857	2023	2023-12-06 12:52:02	2023-12-06 17:23:34	1	271.53	ANIMAL	Non-storm
SE23120600640	EVRGN1062	2023	2023-12-06 12:58:05	2023-12-06 16:24:44	1	120.64	PUBLIC INTERFERENCE	Non-storm
SW23120600495	ROMLS9464	2023	2023-12-06 13:09:26	2023-12-06 13:17:28	2	16.06	PLANNED INTENTIONAL	Non-storm
SW23120600508	BLCRK9330	2023	2023-12-06 13:14:30	2023-12-06 13:21:58	1	7.47	PLANNED INTENTIONAL	Non-storm
SW23120600527	FRONT0063	2023	2023-12-06 13:19:51	2023-12-06 14:22:21	18	1115.18	NO CAUSE	Non-storm
SW23120600526	FRONT0360	2023	2023-12-06 13:19:55	2023-12-06 19:38:25	2	756.96	EQUIPMENT FAILURE	Non-storm
SE23120700182	EVRGN1062	2023	2023-12-06 13:20:50	2023-12-07 10:44:39	1	1283.82	EQUIPMENT FAILURE	Non-storm
SW23120600505	PERU9440	2023	2023-12-06 13:22:57	2023-12-06 13:49:34	3	79.54	PLANNED INTENTIONAL	Non-storm
NW23120600564	BRONC8593	2023	2023-12-06 13:24:40	2023-12-06 14:23:57	1	59.28	EQUIPMENT FAILURE	Non-storm
NE23120600530	TCOLA8766	2023	2023-12-06 13:28:03	2023-12-06 13:48:53	1	20.83	PLANNED INTENTIONAL	Non-storm
SE23120600524	SRGNT9129	2023	2023-12-06 13:30:34	2023-12-06 14:30:55	1	60.35	PLANNED INTENTIONAL	Non-storm
NW23120600536	HURST9853	2023	2023-12-06 13:32:11	2023-12-06 13:56:25	2	48.43	PLANNED INTENTIONAL	Non-storm
NW23120600541	HURST9853	2023	2023-12-06 13:36:11	2023-12-06 13:50:55	1	14.73	PLANNED INTENTIONAL	Non-storm
SE23120600560	VENIC1412	2023	2023-12-06 13:54:55	2023-12-06 14:13:36	1	18.68	PLANNED INTENTIONAL	Non-storm
SE23120600410	GDRIV1182	2023	2023-12-06 14:02:39	2023-12-06 14:35:17	1	32.63	EQUIPMENT FAILURE	Non-storm
SW23120600567	EMRCK2925	2023	2023-12-06 14:14:22	2023-12-06 14:55:38	1	41.27	PLANNED INTENTIONAL	Non-storm
SE23120600583	ALFRD8165	2023	2023-12-06 14:18:23	2023-12-06 14:55:19	97	3565.22	EQUIPMENT FAILURE	Non-storm
NW23120600597	SPKNE8842	2023	2023-12-06 14:35:52	2023-12-06 16:00:32	6	507.43	PLANNED INTENTIONAL	Non-storm
NW23120600603	CARTR9115	2023	2023-12-06 14:44:45	2023-12-06 17:49:59	9	1664.57	EQUIPMENT FAILURE	Non-storm
NW23120600604	CARTR9115	2023	2023-12-06 14:44:45	2023-12-06 17:50:42	3	555.78	NO ISSUES FOUND	Non-storm
NW23120600613	SPKNE8842	2023	2023-12-06 14:54:01	2023-12-06 15:13:40	11	213.91	PLANNED INTENTIONAL	Non-storm
SE23120600489	EVRGN1062	2023	2023-12-06 14:59:55	2023-12-06 16:47:56	7	754.58	PUBLIC INTERFERENCE	Non-storm
SE23120600492	EVRGN1062	2023	2023-12-06 14:59:56	2023-12-06 16:47:47	4	431.22	PUBLIC INTERFERENCE	Non-storm
SW23120700029	FISHR8188	2023	2023-12-06 15:03:14	2023-12-07 07:49:04	1	1005.83	ANIMAL	Non-storm
NW23120600629	CAMDN8282	2023	2023-12-06 15:16:09	2023-12-06 16:03:12	1	47.05	PLANNED INTENTIONAL	Non-storm
SE23120600720	SAVAN1116	2023	2023-12-06 16:20:21	2023-12-07 09:54:05	2	1186.33	METER / BLOCKS	Non-storm
NW23120600399	NIXON8926	2023	2023-12-06 17:04:58	2023-12-06 17:21:52	1	16.9	TREEBROW	Non-storm
NW23120600750	SPKNE8842	2023	2023-12-06 17:09:11	2023-12-06 17:23:38	8	114.68	TROUBLE INTENTIONAL	Non-storm
NW23120600353	SPKNE8842	2023	2023-12-06 17:09:13	2023-12-06 17:23:45	6	86.02	EQUIPMENT FAILURE	Non-storm
SW23120600739	FREDM9808	2023	2023-12-06 17:12:06	2023-12-06 18:37:27	77	6567.13	EQUIPMENT FAILURE	Non-storm
SW23120600764	TAMRK9096	2023	2023-12-06 17:34:20	2023-12-06 17:59:50	1	25.5	NO ISSUES FOUND	Non-storm
NW23120600785	GENOA8217	2023	2023-12-06 18:35:06	2023-12-07 11:23:23	1	1008.28	EQUIPMENT FAILURE	Non-storm
SW23120600784	TAMRK9096	2023	2023-12-06 18:49:43	2023-12-06 19:46:00	7	388.65	NO ISSUES FOUND	Non-storm
SE23120600791	TIRMN1102	2023	2023-12-06 20:16:13	2023-12-06 20:47:30	1	31.28	EQUIPMENT FAILURE	Non-storm
SE23120600828	SAVAN1087	2023	2023-12-06 21:35:07	2023-12-07 11:07:10	1	812.05	TREEBROW	Non-storm
SE23120700114	SAVAN1340	2023	2023-12-06 22:25:15	2023-12-07 11:07:52	1	762.62	TREEIROW	Non-storm
SE23120600619	FRMNT1171	2023	2023-12-06 22:27:42	2023-12-06 23:09:11	12	504.49	THEFT	Non-storm
SE23120600839	FRMNT1171	2023	2023-12-06 22:27:42	2023-12-06 23:09:10	2	82.95	EQUIPMENT FAILURE	Non-storm
NW23120600598	IVNHO2679	2023	2023-12-06 22:47:16	2023-12-06 22:55:48	1	8.53	EQUIPMENT FAILURE	Non-storm
SW23120700021	ACME9499	2023	2023-12-07 01:34:51	2023-12-07 03:34:33	1	119.7	NO ISSUES FOUND	Non-storm
SW23120700011	ACME9499	2023	2023-12-07 01:34:52	2023-12-07 03:34:44	481	57562.57	EQUIPMENT FAILURE	Non-storm
SW23120700016	OKRDG9673	2023	2023-12-07 01:34:52	2023-12-07 03:34:33	1	119.68	NO ISSUES FOUND	Non-storm
SW23120700019	ACME9499	2023	2023-12-07 01:34:52	2023-12-07 03:34:43	11	1316.5	EQUIPMENT FAILURE	Non-storm
SE23120600787	GARY2115	2023	2023-12-07 03:27:35	2023-12-07 03:35:20	1	7.75	EQUIPMENT FAILURE	Non-storm
SE23120600801	GLEND2025	2023	2023-12-07 05:28:32	2023-12-07 05:34:28	1	5.93	EQUIPMENT FAILURE	Non-storm
SW23120700436	BLCRK8011	2023	2023-12-07 07:55:56	2023-12-07 17:21:51	10	5658.78	EQUIPMENT FAILURE	Non-storm
SW23120700056	BLCRK8011	2023	2023-12-07 07:55:57	2023-12-07 17:21:50	25	4133.02	ANIMAL	Non-storm
SW23120700664	BLCRK8011	2023	2023-12-07 07:55:58	2023-12-07 17:21:51	2	1131.76	NO ISSUES FOUND	Non-storm
NE23120600815	VERNR2043	2023	2023-12-07 08:02:13	2023-12-07 09:46:14	1	104.02	TREEBROW	Non-storm
SE23120700071	GNSTN0444	2023	2023-12-07 08:37:22	2023-12-07 09:25:38	2	96.3	PLANNED INTENTIONAL	Non-storm
SE23120600800	ATLAS1730	2023	2023-12-07 08:43:00	2023-12-07 09:01:07	1	18.12	EQUIPMENT FAILURE	Non-storm
NW23120700037	STERL8435	2023	2023-12-07 08:48:21	2023-12-07 09:26:32	1	38.18	PUBLIC INTERFERENCE	Non-storm
NE23120700093	LIBER1056	2023	2023-12-07 08:54:56	2023-12-07 09:33:48	2	74.92	PLANNED INTENTIONAL	Non-storm
NW23120700094	WLNUT9007	2023	2023-12-07 08:56:26	2023-12-07 11:55:14	6	1069.2	ANIMAL	Non-storm
NW23120700105	STRFD9093	2023	2023-12-07 08:57:51	2023-12-08 01:25:16	1	987.42	ANIMAL	Non-storm
NE23120700072	OTSGO8762	2023	2023-12-07 09:02:08	2023-12-07 09:44:37	1	42.48	PLANNED INTENTIONAL	Non-storm
SE23120700068	CONAT2235	2023	2023-12-07 09:12:49	2023-12-07 09:24:34	1	11.75	EQUIPMENT FAILURE	Non-storm
SE23120700036	SIXMI1216	2023	2023-12-07 09:18:18	2023-12-07 10:06:03	31	1479.31	EQUIPMENT FAILURE	Non-storm
NE23120700123	NINMI2492	2023	2023-12-07 09:26:06	2023-12-07 09:47:11	12	250.9	PLANNED INTENTIONAL	Non-storm
NE23120700097	PINGV0325	2023	2023-12-07 09:29:49	2023-12-07 10:59:52	2	180.02	PLANNED INTENTIONAL	Non-storm
NE23120700137	RICHM2415	2023	2023-12-07 09:34:03	2023-12-07 10:19:41	1	45.63	PLANNED INTENTIONAL	Non-storm
NW23120700145	BRONC8593	2023	2023-12-07 09:35:23	2023-12-07 10:37:57	1	62.57	NO ISSUES FOUND	Non-storm
NW23120700607	CULVR2789	2023	2023-12-07 09:40:14	2023-12-07 09:50:08	1	9.9	NO ISSUES FOUND	Non-storm
SW23120700046	HASKL1627	2023	2023-12-07 09:43:03	2023-12-07 10:11:50	1	28.78	EQUIPMENT FAILURE	Non-storm
SE23120700193	KORTE1245	2023	2023-12-07 09:46:07	2023-12-07 10:30:14	1	44.12	NO ISSUES FOUND	Non-storm
NW23120700146	HURST9853	2023	2023-12-07 09:50:21	2023-12-07 09:59:41	1	9.33	PLANNED INTENTIONAL	Non-storm
NE23120700162	OAKWD8984	2023	2023-12-07 09:50:47	2023-12-07 10:40:12	2	98.65	ANIMAL	Non-storm
SW23120700151	ROMLS9464	2023	2023-12-07 09:54:51	2023-12-07 10:53:58	1	59.12	PLANNED INTENTIONAL	Non-storm
SE23120700168	LAUDR1272	2023	2023-12-07 10:00:46	2023-12-07 11:14:54	1	74.13	PLANNED INTENTIONAL	Non-storm
NW23120700171	SPKNE8842	2023	2023-12-07 10:04:36	2023-12-07 11:06:26	5	308.67	PLANNED INTENTIONAL	Non-storm
SW23120700403	SALIN9788	2023	2023-12-07 10:05:03	2023-12-07 12:47:05	6	102.39	PLANNED INTENTIONAL	Non-storm
SE23120700163	LAUDR1272	2023	2023-12-07 10:05:53	2023-12-07 11:11:37	1	65.73	PLANNED INTENTIONAL	Non-storm
NW23120700192	CRWFD8312	2023	2023-12-07 10:15:19	2023-12-07 13:06:02	1	170.72	EQUIPMENT FAILURE	Non-storm
NW23120700235	APACE9017	2023	2023-12-07 10:15:32	2023-12-07 13:05:16	1	169.73	EQUIPMENT FAILURE	Non-storm
SW23120700302	DRAKE8936	2023	2023-12-07 10:18:05	2023-12-07 19:25:10	1	547.08	PLANNED INTENTIONAL	Non-storm
SW23120700198	FRMTN8873	2023	2023-12-07 10:22:39	2023-12-07 16:15:13	105	36992.88	EQUIPMENT FAILURE	Non-storm
NW23120700138	HURST9853	2023	2023-12-07 10:25:22	2023-12-07 11:07:25	1	42.05	PLANNED INTENTIONAL	Non-storm
SW23120700223	SENCA8908	2023	2023-12-07 10:27:57	2023-12-07 11:14:15	7	323.28	NO ISSUES FOUND	Non-storm
SE23120700205	LAMBT1456	2023	2023-12-07 10:29:39	2023-12-07 10:53:18	1	23.65	PLANNED INTENTIONAL	Non-storm
NW23120700213	HURST9853	2023	2023-12-07 10:37:37	2023-12-07 11:08:46	1	31.15	PLANNED INTENTIONAL	Non-storm
NE23120700228	OTSGO8762	2023	2023-12-07 10:39:43	2023-12-07 10:47:55	1	8.2	PLANNED INTENTIONAL	Non-storm
SE23120700107	STLUS1595	2023	2023-12-07 10:39:44	2023-12-07 11:09:13	1	29.48	EQUIPMENT FAILURE	Non-storm
SW23120700255	WOLFH8838	2023	2023-12-07 10:51:58	2023-12-08 01:48:13	4	3584.13	TREEIROW	Non-storm
SW23120700252	SWANC9445	2023	2023-12-07 10:52:18	2023-12-07 11:15:32	51	1208.01	PLANNED INTENTIONAL	Non-storm
NW23120700245	HURST9853	2023	2023-12-07 10:55:22	2023-12-07 11:12:01	1	16.65	PLANNED INTENTIONAL	Non-storm
NW23120700202	CAMDN8282	2023	2023-12-07 10:56:03	2023-12-07 13:19:26	1	143.38	PLANNED INTENTIONAL	Non-storm
SW23120700247	ROMLS9464	2023	2023-12-07 10:58:24	2023-12-07 11:04:10	3	17.22	PLANNED INTENTIONAL	Non-storm
SE23120700259	MAURD9375	2023	2023-12-07 10:59:12	2023-12-07 11:40:44	1	41.53	PLANNED INTENTIONAL	Non-storm
SE23120700271	GNSTN1319	2023	2023-12-07 11:04:18	2023-12-07 13:40:12	1	155.9	PLANNED INTENTIONAL	Non-storm
SE23120700331	MLVDL2105	2023	2023-12-07 11:12:14	2023-12-07 12:59:03	2	213.58	PLANNED INTENTIONAL	Non-storm
SE23120700344	MLVDL2105	2023	2023-12-07 11:13:01	2023-12-07 11:35:54	1	22.88	PLANNED INTENTIONAL	Non-storm
NE23120700386	GOLFB697	2023	2023-12-07 11:13:26	2023-12-07 14:08:03	27	4705.49	ANIMAL	Non-storm
NE23120700295	GOLFB697	2023	2023-12-07 11:13:27	2023-12-07 14:08:27	99	17287.56	EQUIPMENT FAILURE	Non-storm
SE23120700276	LINCN0356	2023	2023-12-07 11:16:20	2023-12-07 12:11:12	2	89.05	PLANNED INTENTIONAL	Non-storm
SE23120700345	GNSTN1319	2023	2023-12-07 11:19:39	2023-12-07 12:26:19	12	433.05	PLANNED INTENTIONAL	Non-storm
NE23120700268	RICHM2415	2023	2023-12-07 11:32:19	2023-12-07 12:47:32	1	75.22	PLANNED INTENTIONAL	Non-storm
NE23120700370	LIBER1056	2023	2023-12-07 11:38:15	2023-12-07 12:32:17	2	98.9	PLANNED INTENTIONAL	Non-storm
SE23120700368	DCATR1271	2023	2023-12-07 11:38:15	2023-12-07 11:52:07	1	13.87	PLANNED INTENTIONAL	Non-storm
SW23120700394	JEFSN9404	2023	2023-12-07 11:39:21	2023-12-07 13:14:57	4	382.06	EQUIPMENT FAILURE	Non-storm
NW23120700415	SPKNE8842	2023	2023-12-07 11:41:09	2023-12-07 12:12:17	3	93.22	PLANNED INTENTIONAL	Non-storm
NW23120700398	SPKNE8842	2023	2023-12-07 11:41:15	2023-12-07 12:12:09	1	30.9	PLANNED INTENTIONAL	Non-storm
SW23120700369	HURST9853	2023	2023-12-07 11:43:28	2023-12-07 11:59:03	1	15.58	PLANNED INTENTIONAL	Non-storm
NE23120700414	OTIS8505	2023	2023-12-07 11:47:27	2023-12-07 12:47:16	25	1488.27	PLANNED INTENTIONAL	Non-storm
NE23120700391	APLGT0312	2023	2023-12-07 11:48:07	2023-12-07 13:12:27	1	84.33	PLANNED INTENTIONAL	Non-storm
SW23120700393	ROMLS9464	2023	2023-12-07 11:51:55	2023-12-07 12:05:02	1	13.12	PLANNED INTENTIONAL	Non-storm
SE23120700527	GNSTN1319	2023	2023-12-07 11:56:09	2023-12-07 12:25:09	1	29	PLANNED INTENTIONAL	Non-storm
NW23120700412	HURST9853	2023	2023-12-07 11:57:49	2023-12-07 12:34:39	1	36.83	PLANNED INTENTIONAL	Non-storm
SW23120700427	HAMBG9912	2023	2023-12-07 11:58:23	2023-12-07 15:39:08	1	220.75	ANIMAL	Non-storm
NW23120700480	KENSL9858	2023	2023-12-07 12:02:57	2023-12-07 15:03:41	1	180.73	EQUIPMENT FAILURE	Non-storm
NW23120700437	KENSL9858	2023	2023-12-07 12:03:10	2023-12-07 15:03:57	2	361.46	EQUIPMENT FAILURE	Non-storm
SW23120700156	PERU9440	2023	2023-12-07 12:04:43	2023-12-07 16:25:29	1	260.77	PLANNED INTENTIONAL	Non-storm
NW23120700424	HURST9853	2023	2023-12-07 12:08:04	2023-12-07 12:31:12	1	23.13	PLANNED INTENTIONAL	Non-storm
NW23120700448	TAMRK9067	2023	2023-12-07 12:12:24	2023-12-07 14:28:14	1	135.83	EQUIPMENT FAILURE	Non-storm
NW23120700430	WHTLK0307	2023	2023-12-07 12:14:26	2023-12-07 12:37:34	1	23.13	PLANNED INTENTIONAL	Non-storm
SE23120700433	MLVDL2105	2023	2023-12-07 12:15:26	2023-12-07 13:03:19	8	380.44	PLANNED INTENTIONAL	Non-storm
NE23120700359	PINGV0325	2023	2023-12-07 12:18:59	2023-12-07 12:32:32	1	13.55	PLANNED INTENTIONAL	Non-storm
NE23120700454	RUSH8089	2023	2023-12-07 12:20:05	2023-12-07 13:52:58	1	92.88	ANIMAL	Non-storm
SW23120700450	HEMLK1986	2023	2023-12-07 12:22:32	2023-12-07 12:43:03	34	695.06	PLANNED INTENTIONAL	Non-storm
NW23120700439	HURST9853	2023	2023-12-07 12:23:42	2023-12-07 12:35:26	1	11.73	PLANNED INTENTIONAL	Non-storm

SW23120700464	PROSP0306	2023	2023-12-07 12:29:27	2023-12-07 15:05:21	6	932.96	EQUIPMENT FAILURE	Non-storm
SE23120700646	GRPTE1355	2023	2023-12-07 12:32:20	2023-12-08 11:31:49	1	1379.48	EQUIPMENT FAILURE	Non-storm
NW23120700452	HURST9853	2023	2023-12-07 12:33:35	2023-12-07 12:43:59	1	10.4	PLANNED INTENTIONAL	Non-storm
NE23120700455	TCOLA8766	2023	2023-12-07 12:36:18	2023-12-07 12:44:41	1	8.38	PLANNED INTENTIONAL	Non-storm
SW23120700477	CALLA9923	2023	2023-12-07 12:42:41	2023-12-07 15:05:38	1	142.95	EQUIPMENT FAILURE	Non-storm
NW23120700457	HURST9853	2023	2023-12-07 12:43:06	2023-12-07 13:23:56	1	40.83	PLANNED INTENTIONAL	Non-storm
NW23120700471	BARTL4032	2023	2023-12-07 12:55:54	2023-12-07 13:52:41	19	1076.77	PLANNED INTENTIONAL	Non-storm
SE23120700498	MLVDL2105	2023	2023-12-07 13:07:21	2023-12-07 13:55:19	11	524.95	PLANNED INTENTIONAL	Non-storm
SE23120700482	SRGNT9129	2023	2023-12-07 13:11:21	2023-12-07 13:41:23	1	30.03	PLANNED INTENTIONAL	Non-storm
SE23120700406	DALY0562	2023	2023-12-07 13:11:45	2023-12-07 13:40:18	1	28.55	EQUIPMENT FAILURE	Non-storm
NW23120700563	BREWR9229	2023	2023-12-07 13:24:51	2023-12-07 17:26:16	1	241.42	ANIMAL	Non-storm
NW23120700509	HURST9853	2023	2023-12-07 13:35:01	2023-12-07 13:47:32	1	12.52	PLANNED INTENTIONAL	Non-storm
SW23120700514	PERU9440	2023	2023-12-07 13:37:24	2023-12-07 14:51:54	8	594.48	EQUIPMENT FAILURE	Non-storm
NE23120700489	OTSGO8762	2023	2023-12-07 13:37:46	2023-12-07 14:10:39	1	32.88	PLANNED INTENTIONAL	Non-storm
NW23120700516	CLKSN9009	2023	2023-12-07 13:39:10	2023-12-07 16:03:39	17	2441.37	EQUIPMENT FAILURE	Non-storm
SW23120700521	TAHOE9510	2023	2023-12-07 13:43:16	2023-12-07 15:06:39	43	3579.09	ANIMAL	Non-storm
NE23120800262	SAVOY8714	2023	2023-12-07 13:44:05	2023-12-08 11:48:22	22	5152.57	ANIMAL	Non-storm
NW23120700533	HURST9853	2023	2023-12-07 13:59:58	2023-12-07 14:23:09	2	46.34	PLANNED INTENTIONAL	Non-storm
SE23120700541	GLEND2025	2023	2023-12-07 14:05:18	2023-12-07 14:47:56	1	42.63	PLANNED INTENTIONAL	Non-storm
SW23120700539	GLBRT9381	2023	2023-12-07 14:07:19	2023-12-07 14:13:37	1	6.3	PLANNED INTENTIONAL	Non-storm
NW23120700699	CODY9542	2023	2023-12-07 14:10:12	2023-12-07 19:21:40	1	311.47	NO ISSUES FOUND	Non-storm
SW23120700556	GLBRT9373	2023	2023-12-07 14:15:46	2023-12-07 15:31:42	22	1659.46	PLANNED INTENTIONAL	Non-storm
NW23120700554	HURST9853	2023	2023-12-07 14:20:20	2023-12-07 15:04:09	1	43.82	PLANNED INTENTIONAL	Non-storm
NW23120700567	EUCLD9065	2023	2023-12-07 14:22:47	2023-12-07 16:53:11	24	3590.46	EQUIPMENT FAILURE	Non-storm
SW23120700548	PERU9440	2023	2023-12-07 14:25:07	2023-12-07 15:26:34	5	307.12	PLANNED INTENTIONAL	Non-storm
NW23120700566	STKWL4010	2023	2023-12-07 14:28:01	2023-12-07 15:36:41	5	340.47	PLANNED INTENTIONAL	Non-storm
NE23120700575	MTCLM0306	2023	2023-12-07 14:36:44	2023-12-07 16:18:19	33	3350.33	ANIMAL	Non-storm
SE23120700545	SRGNT9129	2023	2023-12-07 14:36:51	2023-12-07 15:18:36	1	41.75	PLANNED INTENTIONAL	Non-storm
SW23120700591	DAVIS9073	2023	2023-12-07 14:49:45	2023-12-08 03:18:17	3	2245.18	ANIMAL	Non-storm
SE23120700588	GDRIV2220	2023	2023-12-07 15:03:40	2023-12-07 16:24:53	2	155.85	PLANNED INTENTIONAL	Non-storm
NW23120700600	SPKNE8842	2023	2023-12-07 15:05:08	2023-12-07 15:32:48	5	137.9	PLANNED INTENTIONAL	Non-storm
NW23120700626	CRWFD8312	2023	2023-12-07 15:50:22	2023-12-07 21:40:44	4	1401.46	EQUIPMENT FAILURE	Non-storm
SE23120700278	EVRGN1925	2023	2023-12-07 16:05:56	2023-12-07 16:16:30	1	10.57	EQUIPMENT FAILURE	Non-storm
NE23120700677	REDRN8555	2023	2023-12-07 16:57:26	2023-12-07 17:36:07	14	539.16	EQUIPMENT FAILURE	Non-storm
NW23120700678	NIXON8932	2023	2023-12-07 16:57:52	2023-12-07 18:40:05	10	1019.8	EQUIPMENT FAILURE	Non-storm
NW23120700681	NIXON9141	2023	2023-12-07 17:07:53	2023-12-07 19:19:12	687	90521.08	PUBLIC INTERFERENCE	Non-storm
NW23120700796	NIXON9141	2023	2023-12-07 17:07:56	2023-12-07 19:18:19	1	130.38	PUBLIC INTERFERENCE	Non-storm
NW23120700799	NIXON9141	2023	2023-12-07 17:08:03	2023-12-07 19:18:26	1	130.38	NO ISSUES FOUND	Non-storm
NW23120700709	COMLK9524	2023	2023-12-07 17:15:12	2023-12-07 18:47:27	11	1012.83	EQUIPMENT FAILURE	Non-storm
SW23120700715	MACON8049	2023	2023-12-07 17:26:15	2023-12-07 20:33:18	69	12707.54	PUBLIC INTERFERENCE	Non-storm
SW23120700791	MACON8049	2023	2023-12-07 17:56:54	2023-12-07 20:33:22	25	2947.23	PUBLIC INTERFERENCE	Non-storm
SE23120800498	REDFD1285	2023	2023-12-07 18:29:06	2023-12-08 22:30:34	1	1681.47	EQUIPMENT FAILURE	Non-storm
NW23120700801	EUCLD9084	2023	2023-12-07 19:49:09	2023-12-07 22:42:04	31	5348.3	EQUIPMENT FAILURE	Non-storm
NW23120700804	EUCLD9084	2023	2023-12-07 19:49:10	2023-12-07 22:41:07	1	171.95	NO ISSUES FOUND	Non-storm
SE23120700841	TIRMN1196	2023	2023-12-07 21:51:45	2023-12-08 02:47:09	1	295.4	EQUIPMENT FAILURE	Non-storm
SW23120700868	OMAHA8233	2023	2023-12-07 23:33:23	2023-12-08 04:04:08	51	13806.85	EQUIPMENT FAILURE	Non-storm
NE23120800032	SULVN2644	2023	2023-12-08 00:15:17	2023-12-08 09:16:55	1	541.63	TREEROW	Non-storm
NE23120800045	SULVN2644	2023	2023-12-08 00:15:21	2023-12-08 09:16:59	1	541.63	TREEROW	Non-storm
NE23120800027	SULVN2644	2023	2023-12-08 00:15:23	2023-12-08 09:17:01	1	541.63	TREEROW	Non-storm
NE23120800031	SULVN2644	2023	2023-12-08 00:15:26	2023-12-08 09:17:03	1	541.62	TREEROW	Non-storm
NE23120800006	SULVN2644	2023	2023-12-08 00:26:27	2023-12-08 08:32:18	1	525.43	TREEROW	Non-storm
NE23120800007	SULVN2644	2023	2023-12-08 00:26:27	2023-12-08 08:32:18	1	525.43	TREEROW	Non-storm
SW23120800016	MOTT9789	2023	2023-12-08 02:13:20	2023-12-08 11:37:39	64	16608.55	EQUIPMENT FAILURE	Non-storm
NE23120800127	CHEST8504	2023	2023-12-08 05:22:13	2023-12-08 16:31:42	2	1338.7	EQUIPMENT FAILURE	Non-storm
NE23120800041	MILTN8801	2023	2023-12-08 05:37:00	2023-12-08 12:58:54	1	394.6	EQUIPMENT FAILURE	Non-storm
SE23120800062	BLTMR8340	2023	2023-12-08 07:37:38	2023-12-08 12:37:54	1	900.27	EQUIPMENT FAILURE	Non-storm
SW23120800067	DEWEY8085	2023	2023-12-08 08:13:10	2023-12-08 10:03:49	12	1325.54	EQUIPMENT FAILURE	Non-storm
NE23120800069	NINMI2492	2023	2023-12-08 08:25:48	2023-12-08 09:46:04	1	80.27	PLANNED INTENTIONAL	Non-storm
NW23120800265	JEWEL8686	2023	2023-12-08 08:29:44	2023-12-08 12:49:17	1	259.55	ANIMAL	Non-storm
SE23120800079	LAUDR1272	2023	2023-12-08 08:32:15	2023-12-08 10:41:13	1	128.97	PLANNED INTENTIONAL	Non-storm
NW23120800107	BRONC8544	2023	2023-12-08 08:38:14	2023-12-08 09:42:19	7	446.91	EQUIPMENT FAILURE	Non-storm
NW23120800088	BRONC8544	2023	2023-12-08 08:38:15	2023-12-08 09:42:04	1	63.82	ANIMAL	Non-storm
NE23120800450	MTMRA8035	2023	2023-12-08 08:38:52	2023-12-08 16:46:50	1	487.97	ANIMAL	Non-storm
NW23120800082	HURST9853	2023	2023-12-08 08:38:52	2023-12-08 08:55:04	1	16.2	PLANNED INTENTIONAL	Non-storm
NW23120800104	STKWL4010	2023	2023-12-08 08:51:33	2023-12-08 10:50:30	1	118.95	PLANNED INTENTIONAL	Non-storm
SE23120800102	ARNLD1695	2023	2023-12-08 09:01:47	2023-12-08 10:08:15	1	66.47	PLANNED INTENTIONAL	Non-storm
NW23120800121	ORION9080	2023	2023-12-08 09:02:13	2023-12-08 10:13:29	10	704.99	EQUIPMENT FAILURE	Non-storm
NE23120800109	TCOLA8766	2023	2023-12-08 09:02:15	2023-12-08 09:25:05	1	22.83	PLANNED INTENTIONAL	Non-storm
NW23120800152	ORION9080	2023	2023-12-08 09:02:18	2023-12-08 10:12:37	1	70.32	NO ISSUES FOUND	Non-storm
NW23120800106	HURST9853	2023	2023-12-08 09:03:32	2023-12-08 09:47:15	2	87.42	PLANNED INTENTIONAL	Non-storm
SE23120800111	GDRIV2220	2023	2023-12-08 09:11:12	2023-12-08 09:59:47	1	48.58	PLANNED INTENTIONAL	Non-storm
NW23120800131	SPKNE8842	2023	2023-12-08 09:11:28	2023-12-08 09:29:46	1	18.3	PLANNED INTENTIONAL	Non-storm
SE23120800035	STLUS1233	2023	2023-12-08 09:16:28	2023-12-08 10:35:29	2	30.71	TREEBROW	Non-storm
NW23120800133	HURST9853	2023	2023-12-08 09:20:07	2023-12-08 09:37:40	1	17.55	PLANNED INTENTIONAL	Non-storm
NE23120800135	GOLFB531	2023	2023-12-08 09:20:47	2023-12-08 10:08:04	49	2309.88	ANIMAL	Non-storm
NE23120800138	RICHM2415	2023	2023-12-08 09:25:14	2023-12-08 11:21:39	1	116.42	PLANNED INTENTIONAL	Non-storm
NE23120800146	MACMB8521	2023	2023-12-08 09:29:18	2023-12-08 16:04:25	2	790.22	ANIMAL	Non-storm
SE23120800449	WAYBN2092	2023	2023-12-08 09:30:15	2023-12-08 15:47:00	1	376.75	EQUIPMENT FAILURE	Non-storm
NE23120800141	PINGV0325	2023	2023-12-08 09:32:57	2023-12-08 10:45:28	1	72.52	PLANNED INTENTIONAL	Non-storm
SE23120800140	LAUDR1272	2023	2023-12-08 09:40:50	2023-12-08 12:15:51	26	4025.73	PLANNED INTENTIONAL	Non-storm
NW23120800154	STKWL4010	2023	2023-12-08 09:43:07	2023-12-08 10:18:53	1	35.77	PLANNED INTENTIONAL	Non-storm
SE23120800180	MLVDL2105	2023	2023-12-08 09:46:22	2023-12-08 10:35:37	9	442.49	PLANNED INTENTIONAL	Non-storm
SW23120800168	ROMLS9464	2023	2023-12-08 09:48:21	2023-12-08 10:44:29	38	2122.62	PLANNED INTENTIONAL	Non-storm
NW23120800160	CAMDN8276	2023	2023-12-08 09:49:31	2023-12-08 10:46:44	1	57.22	PLANNED INTENTIONAL	Non-storm
NW23120800162	STKWL4010	2023	2023-12-08 09:49:31	2023-12-08 10:43:48	1	54.28	PLANNED INTENTIONAL	Non-storm
NW23120800171	SPKNE8842	2023	2023-12-08 09:57:58	2023-12-08 10:24:10	1	26.2	TROUBLE INTENTIONAL	Non-storm
SE23120800178	GNSTN0444	2023	2023-12-08 10:00:10	2023-12-08 11:48:54	6	632.41	PLANNED INTENTIONAL	Non-storm
SW23120800184	PHENX9804	2023	2023-12-08 10:00:41	2023-12-08 12:36:05	38	5900.45	PUBLIC INTERFERENCE	Non-storm
SE23120800137	MLVDL2105	2023	2023-12-08 10:06:01	2023-12-08 11:27:47	1	81.77	PLANNED INTENTIONAL	Non-storm
NW23120800183	HURST9853	2023	2023-12-08 10:10:28	2023-12-08 10:20:50	1	10.37	PLANNED INTENTIONAL	Non-storm
SE23120800191	GDRIV1297	2023	2023-12-08 10:13:30	2023-12-08 10:53:28	1	39.97	PLANNED INTENTIONAL	Non-storm
NW23120800209	DISCO8562	2023	2023-12-08 10:14:42	2023-12-08 10:51:59	20	741.14	ANIMAL	Non-storm
NE23120800207	OTSGO8762	2023	2023-12-08 10:16:22	2023-12-08 11:37:40	2	162.55	PLANNED INTENTIONAL	Non-storm
SE23120800216	GNSTN1319	2023	2023-12-08 10:21:51	2023-12-08 14:14:34	10	2324.45	PLANNED INTENTIONAL	Non-storm
SE23120800260	GNSTN1319	2023	2023-12-08 10:21:55	2023-12-08 14:14:21	1	232.43	PLANNED INTENTIONAL	Non-storm
SE23120800220	GNSTN1319	2023	2023-12-08 10:24:09	2023-12-08 10:52:40	1	28.52	PLANNED INTENTIONAL	Non-storm
NW23120800278	CHILS9877	2023	2023-12-08 10:29:17	2023-12-08 17:59:37	1	450.33	ANIMAL	Non-storm
NW23120800214	HURST9853	2023	2023-12-08 10:32:34	2023-12-08 11:38:02	1	65.47	PLANNED INTENTIONAL	Non-storm
SE23120800272	WAYBN1178	2023	2023-12-08 10:35:02	2023-12-08 11:11:28	1	36.43	PLANNED INTENTIONAL	Non-storm
SW23120800245	AKRON8964	2023	2023-12-08 10:41:09	2023-12-08 12:51:14	40	5180.83	ANIMAL	Non-storm
SW23120800390	AKRON8964	2023	2023-12-08 10:41:18	2023-12-08 12:51:07	1	129.82	NO ISSUES FOUND	Non-storm
SW23120800271	AKRON8964	2023	2023-12-08 10:41:30	2023-12-08 12:50:24	1	128.9	NO ISSUES FOUND	Non-storm
SE23120800244	GNSTN1319	2023	2023-12-08 10:44:30	2023-12-08 11:39:11	1	54.68	PLANNED INTENTIONAL	Non-storm
NE23120800259	VICTR8717	2023	2023-12-08 10:46:01	2023-12-08 12:25:28	30	2979.01	ANIMAL	Non-storm
NE23120800285	VICTR8717	2023	2023-12-08 10:46:06	2023-12-08 12:25:24	1	99.3	NO ISSUES FOUND	Non-storm
NW23120800263	APACE9041	2023	2023-12-08 10:51:39	2023-12-08 11:01:45	1	10.1	PLANNED INTENTIONAL	Non-storm
NW23120800273	HURST9853	2023	2023-12-08 11:04:23	2023-12-08 11:34:23	1	30	PLANNED INTENTIONAL	Non-storm
NW23120800288	SPKNE8842	2023	2023-12-08 11:05:23	2023-12-08 12:11:38	2	132.12	PLANNED INTENTIONAL	Non-storm
NW23120800246	SPKNE8842	2023	2023-12-08 11:05:29	2023-12-08 12:11:40	4	264.22	PLANNED INTENTIONAL	Non-storm
NW23120800282	EUCLD9065	2023	2023-12-08 11:07:16	2023-12-08 12:17:20	10	698.55	TREEBROW	Non-storm
NW23120800296	JORDN8396	2023	2023-12-08 11:12:07	2023-12-08 11:43:09	29	876.75	TROUBLE INTENTIONAL	Non-storm
NW23120800303	FLINT9797	2023	2023-12-08 11:15:45	2023-12-08 14:43:49	49	10186.18	ANIMAL	Non-storm
NW23120800338	FLINT9797	2023	2023-12-08 11:15:45	2023-12-08 14:43:38	1	207.88	ANIMAL	Non-storm
SE23120800300	REDFD1118	2023	2023-12-08 11:17:43	2023-12-08 12:02:05	1	44.37	PLANNED INTENTIONAL	Non-storm
SE23120800295	PULFD2111	2023	2023-12-08 11:18:12	2023-12-08 12:46:25	1	88.22	PLANNED INTENTIONAL	Non-storm
NW23120800319	ALPNE8919	2023	2023-12-08 11:19:54	2023-12-08 13:01:52	8	814.42	TREEROW	Non-storm
NW23120800627	ALPNE8919	2023	2023-12-08 11:20:04	2023-12-08 13:01:51	1	101.78	EQUIPMENT FAILURE	Non-storm
SE23120800317	VERNR1592	2023	2023-12-08 11:21:07	2023-12-08 12:07:18	1	46.18	PLANNED INTENTIONAL	Non-storm
NE23120800298	PINGV0325	2023	2023-12-08 11:23:34	2023-12-08 12:43:15	1	79.68	PLANNED INTENTIONAL	Non-storm
SW23120800307	SAUIN9788	2023	2023-12-08 11:29:50	2023-12-08 11:40:26	1	10.6	PLANNED INTENTIONAL	Non-storm
NW23120800344	CLKSN8860	2023	2023-12-08 11:33:03	2023-12-08 12:18:10	1	645.12	EQUIPMENT FAILURE	Non-storm
NW23120800316	HURST9853	2023	2023-12-08 11:36:26	2023-12-08 11:58:34	2	44.27	PLANNED INTENTIONAL	Non-storm
SE23120800315	SRGNT9129	2023	2023-12-08 11:37:51	2023-12-08 13:14:11	1	96.33	PLANNED INTENTIONAL	Non-storm
SE23120800328	SRGNT9129	2023	2023-12-08 11:50:26	2023-12-08 12:52:28	4	212.61	PLANNED INTENTIONAL	Non-storm
SE23120800345	MLVDL2105	2023	2023-12-08 11:56:35	2023-12-08 13:18:27	16	1307.66	PLANNED INTENTIONAL	Non-storm
NE23120800347	FRASR1720	2023	2023-12-08 11:57:02	2023-12-08 12:24:47	17	469.75	PLANNED INTENTIONAL	Non-storm
SW23120800361	PERU9440	2023	2023-12-08 11:57:24	2023-12-08 13:24:35	23	810.49	PLANNED INTENTIONAL	Non-storm
SW23120800348	DUBLN8205	2023	2023-12-08 11:57:25	2023-12-08 13:41:27	47	4875.35	EQUIPMENT FAILURE	Non-storm
NW23120800337	HURST9853	2023	2023-12-08 12:00:41	2023-12-08 12:15:10	1	14.48	PLANNED INTENTIONAL	Non-storm
NE23120800343	APLGT0312	2023	2023-12-08 12:01:01	2023-12-08 14:06:40	1	125.65	PLANNED INTENTIONAL	Non-storm
SE23120800314	ANGLA9060	2023	2023-12-08 12:05:04	2023-12-08 13:05:30	1	60.43	PLANNED INTENTIONAL	Non-storm
NE23120800364	OTTER0302	2023	2023-12-08 12:11:09	2023-12-08 13:12:00	74	4481.5	PLANNED INTENTIONAL	Non-storm
SW23120800376	BNSTN9700	2023	2023-12-08 12:14:42	2023-12-08 14:17:44	7	859.25	EQUIPMENT FAILURE	Non-storm
SW23120800377	BNSTN9700	2023	2023-12-08 12:14:48	2023-12-08 14:41:42	10	1368.6	EQUIPMENT FAILURE	Non-storm
SW23120800384	BNSTN9700	2023	2023-12-08 12:14:49	2023-12-08 13:40:52	7	600.93	EQUIPMENT FAILURE	Non-storm
NW23120800366	SLKRK9828	2023	2023-12-08 12:15:30	2023-12-08 12:32:54	10	172.66	PLANNED INTENTIONAL	Non-storm
NW23120800374	HURST9853	2023	2023-12-08 12:19:25	2023-12-08 12:32:03	1	12.63	PLANNED INTENTIONAL	Non-storm
NW23120800395	WLNUT9007	2023	2023-12-08 12:21:56	2023-12-08 13:15:32	6	320.93	TROUBLE INTENTIONAL	Non-storm
NW23120800398	WLNUT9007	2023	2023-12-08 12:22:01	2023-12-08 13:16:27	7	376.32	TROUBLE INTENTIONAL	Non-storm
SE23120800381	LAUDR1272	2023	2023-12-08 12:26:47	2023-12-08 13:25:39	1	58.87	PLANNED INTENTIONAL	Non-storm
SE23120800388	ECORS2091	2023	2023-12-08 12:29:54	2023-12-08 13:08:17	1	38.38	PLANNED INTENTIONAL	Non-storm
NW23120800224	ARIEL9893	2023	2023-12-08 12:30:11	2023-12-08 13:36:40	27	1785.25	EQUIPMENT FAILURE	Non-storm
NW23120800389	HURST9853	2023	2023-12-08 12:30:36	2023-12-08 12:46:04	2	30.86	PLANNED INTENTIONAL	Non-storm
NE23120800397	LAKSD1894	2023	2023-12-08 12:32:51	2023-12-08 13:13:22	1	40.52	PLANNED INTENTIONAL	Non-storm
NE23120800362	PRKRD8779	2023	2023-12-08 12:36:07	2023-12-08 12:52:33	1	16.43	PLANNED INTENTIONAL	Non-storm
SE23120800335	PINGV0325	2023	2023-12-08 12:36:20	2023-12-08 13:40:10	1	63.83	PLANNED INTENTIONAL	Non-storm
NE23120800408	APLGT0312	2023	2023-12-08 12:45:52	2023-12-08 13:27:34	1	41.7	PLANNED INTENTIONAL	Non-storm
SE23120800402	PULFD0419	2023	2023-12-08 13:00:13	2023-12-08 14:22:13	1	82	PLANNED INTENTIONAL	Non-storm
NW23120800438	CATLI9136	2023	2023-12-08 13:04:57	2023-12-08 14:46:05	2	200.86	EQUIPMENT FAILURE	Non-storm
SE23120800279	TIRMN1541	2023	2023-12-08 13:08:05	2023-12-08 14:19:24	1	71.32	TREEBROW	Non-storm
SE23120800475	PULFD2155	2023	2023-12-08 13:14:17	2023-12-08 14:40:08	12	1025.14	PLANNED INTENTIONAL	Non-storm
SE23120800434	PULFD2155	2023	2023-12-08 13:14:25	2023-12-08 14:40:06	2	171.34	PLANNED INTENTIONAL	Non-storm
NW23120800437	HURST9853	2023	2023-12-08 13:15:00	2023-12-08 15:00:45	1	105.75	PLANNED INTENTIONAL	Non-storm
SE23120800461	MLVDL2105	2023	2023-12-08 13:19:06	2023-12-08 14:07:26	1	48.33	PLANNED INTENTIONAL	Non-storm
NW23120800426	HURST9853	2023	2023-12-08 13:22:29	2023-12-08 13:49:21	1	26.87	PLANNED INTENTIONAL	Non-storm
NW23120800439	HURST9853	2023	2023-12-08 13:24:09	2023-12-08 13:47:39	1	23.5	PLANNED INTENTIONAL	Non-storm
NE23120800436	PRKRD8779	2023	2023-12-08 13:32:17	2023-12-08 14:07:58	1	35.68	PLANNED INTENTIONAL	Non-storm
SW23120800416	GLBRT9373	2023	2023-12-08 13:34:43	2023-12-08 15:02:49	1	88.1	PLANNED INTENTIONAL	Non-storm
SE23120800453	GNSTN1319	2023	2023-12-08 13:41:00	2023-12-08 14:32:18	1	51.3	PLANNED INTENTIONAL	Non-storm
SE23120800457	MLVDL2105	2023	2023-12-08 13:53:31	2023-12-08 14:12:55	1	19.4	PLANNED INTENTIONAL	Non-storm
SE23120800467	LAUDR1554	2023	2023-12-08 14:09:25	2023-12-08 14:57:26	2	79.18	PLANNED INTENTIONAL	Non-storm
NW23120800488	AKRON9000	2023	2023-12-08 14:11:47	2023-12-08 14:52:52	15	614.81	PLANNED INTENTIONAL	Non-storm

NW23120800484	HURST9853	2023	2023-12-08 14:17:46	2023-12-08 14:22:56	1	5.17	PLANNED INTENTIONAL	Non-storm
NW23120800509	HURST9853	2023	2023-12-08 14:50:31	2023-12-08 15:11:27	1	20.93	PLANNED INTENTIONAL	Non-storm
SE23120800526	DIX2022	2023	2023-12-08 15:00:34	2023-12-08 15:57:13	11	620.91	PLANNED INTENTIONAL	Non-storm
NE23120800608	PINGV0324	2023	2023-12-08 16:52:25	2023-12-08 17:14:09	10	214.64	EQUIPMENT FAILURE	Non-storm
SE23120800626	ALFRD8254	2023	2023-12-08 17:24:58	2023-12-08 17:37:14	1	12.27	EQUIPMENT FAILURE	Non-storm
SE23120800153	STOPL2231	2023	2023-12-08 17:29:45	2023-12-08 19:27:20	1	117.58	EQUIPMENT FAILURE	Non-storm
NW23120800483	SPKNE8842	2023	2023-12-08 17:41:53	2023-12-08 18:28:37	1	46.73	EQUIPMENT FAILURE	Non-storm
SE23120800653	MIDTN8351	2023	2023-12-08 18:19:51	2023-12-08 19:46:10	1	86.32	NO ISSUES FOUND	Non-storm
NE23120800630	STCLR0303	2023	2023-12-08 20:25:30	2023-12-09 00:02:49	1	217.32	EQUIPMENT FAILURE	Non-storm
SE23120800494	SCOTN1069	2023	2023-12-08 20:30:35	2023-12-08 20:58:54	1	28.32	EQUIPMENT FAILURE	Non-storm
NW23120800695	CLKSN8009	2023	2023-12-08 21:18:52	2023-12-09 01:16:06	47	2508.57	TROUBLE INTENTIONAL	Non-storm
NE23120800651	MELRO1466	2023	2023-12-08 21:29:55	2023-12-08 21:51:30	1	21.58	EQUIPMENT FAILURE	Non-storm
SE23120900073	VERNR1503	2023	2023-12-08 23:46:29	2023-12-09 14:49:34	1	903.08	EQUIPMENT FAILURE	Non-storm
NE23120900078	BERND2613	2023	2023-12-09 05:44:40	2023-12-09 12:48:23	1	423.72	EQUIPMENT FAILURE	Non-storm
SW23120900592	TAHOE9511	2023	2023-12-09 05:49:48	2023-12-09 18:10:36	20	7600.84	NO ISSUES FOUND	Non-storm
SE23120900405	APPOL1142	2023	2023-12-09 06:52:25	2023-12-09 14:24:42	1	452.28	TREEBROW	Non-storm
NE23120900059	ELBA0302	2023	2023-12-09 07:47:20	2023-12-09 10:58:17	1	190.95	EQUIPMENT FAILURE	Non-storm
NW23120800702	BIHAM1930	2023	2023-12-09 08:08:14	2023-12-09 08:17:46	1	9.53	EQUIPMENT FAILURE	Non-storm
SW23120900068	BLCRK8011	2023	2023-12-09 08:15:13	2023-12-09 10:47:34	28	4259.76	EQUIPMENT FAILURE	Non-storm
SW23120900194	SORLD8912	2023	2023-12-09 08:22:29	2023-12-09 15:21:00	1	203.75	METER / BLOCKS	Non-storm
NW23120900088	CLKSN8860	2023	2023-12-09 08:42:22	2023-12-09 11:28:55	1	166.55	ANIMAL	Non-storm
SW23120900080	PERU9441	2023	2023-12-09 08:44:16	2023-12-09 08:49:36	6	30.75	PLANNED INTENTIONAL	Non-storm
NW23120900074	DUDLY1675	2023	2023-12-09 08:50:14	2023-12-09 09:45:26	1	55.2	PLANNED INTENTIONAL	Non-storm
NW23120900089	LOMRD8600	2023	2023-12-09 08:54:49	2023-12-09 09:03:43	1	8.9	EQUIPMENT FAILURE	Non-storm
SE23120900175	WEBST1932	2023	2023-12-09 08:57:47	2023-12-09 09:58:50	1	61.05	NO ISSUES FOUND	Non-storm
NW23120900102	SPKNE8842	2023	2023-12-09 08:59:40	2023-12-09 09:48:21	11	532.23	EQUIPMENT FAILURE	Non-storm
NW23120900116	SPKNE8842	2023	2023-12-09 08:59:44	2023-12-09 09:48:21	2	96.94	EQUIPMENT FAILURE	Non-storm
NE23120900100	PINGV0325	2023	2023-12-09 09:02:58	2023-12-09 09:44:11	1	41.22	PLANNED INTENTIONAL	Non-storm
NE23120900170	SAVOY8714	2023	2023-12-09 09:10:27	2023-12-09 10:06:11	10	556.32	ANIMAL	Non-storm
NE23120900174	SAVOY8714	2023	2023-12-09 09:10:33	2023-12-09 10:06:11	1	55.63	ANIMAL	Non-storm
SE23120900164	GNSTN0444	2023	2023-12-09 09:14:17	2023-12-09 10:51:43	2	194.88	PLANNED INTENTIONAL	Non-storm
SE23120900169	PULFD0419	2023	2023-12-09 09:15:20	2023-12-09 11:39:21	1	144.02	PLANNED INTENTIONAL	Non-storm
SW23120900105	OMAHA8240	2023	2023-12-09 09:19:27	2023-12-09 11:11:59	1	112.53	PLANNED INTENTIONAL	Non-storm
SW23120900177	OMAHA8240	2023	2023-12-09 09:19:42	2023-12-09 11:12:14	1	112.53	NO ISSUES FOUND	Non-storm
NW23120900191	WLNUT9013	2023	2023-12-09 09:27:23	2023-12-09 12:14:31	3	501.08	EQUIPMENT FAILURE	Non-storm
NW23120900180	HAMBG9099	2023	2023-12-09 09:31:43	2023-12-09 11:08:27	18	846.12	ANIMAL	Non-storm
SE23120900204	MLVDL2105	2023	2023-12-09 09:39:59	2023-12-09 09:46:19	1	6.33	PLANNED INTENTIONAL	Non-storm
SE23120900200	PULFD2111	2023	2023-12-09 09:45:24	2023-12-09 12:06:25	1	141.02	PLANNED INTENTIONAL	Non-storm
NW23120900201	HURST9853	2023	2023-12-09 09:45:45	2023-12-09 10:02:11	6	98.4	WIND	Non-storm
NE23120900213	RICHM8420	2023	2023-12-09 09:46:02	2023-12-09 10:10:10	1	24.13	PLANNED INTENTIONAL	Non-storm
SE23120900218	PULFD0419	2023	2023-12-09 09:50:03	2023-12-09 10:06:36	1	16.55	PLANNED INTENTIONAL	Non-storm
SE23120900197	LAUDR1272	2023	2023-12-09 09:51:03	2023-12-09 14:31:58	10	945.22	PLANNED INTENTIONAL	Non-storm
NW23120900206	SPKNE8842	2023	2023-12-09 09:53:03	2023-12-09 10:42:56	6	298.63	PLANNED INTENTIONAL	Non-storm
NW23120900220	SPKNE8842	2023	2023-12-09 09:53:07	2023-12-09 10:42:57	2	99.54	PLANNED INTENTIONAL	Non-storm
SW23120900238	OMAHA8233	2023	2023-12-09 09:54:42	2023-12-09 12:06:39	54	7085.93	EQUIPMENT FAILURE	Non-storm
SE23120900207	CHAND1021	2023	2023-12-09 09:56:19	2023-12-09 10:58:45	1	62.43	PLANNED INTENTIONAL	Non-storm
SE23120900162	GNSTN1319	2023	2023-12-09 09:58:23	2023-12-09 10:54:01	1	55.63	PLANNED INTENTIONAL	Non-storm
SE23120900221	OAKPK1707	2023	2023-12-09 09:58:25	2023-12-09 10:31:21	1	32.93	NO ISSUES FOUND	Non-storm
SW23120900217	PETER9345	2023	2023-12-09 10:00:14	2023-12-09 14:24:10	29	7640.67	EQUIPMENT FAILURE	Non-storm
NW23120900240	STKWL4010	2023	2023-12-09 10:03:08	2023-12-09 12:38:19	1	155.18	PLANNED INTENTIONAL	Non-storm
NW23120900234	SPKNE8842	2023	2023-12-09 10:06:56	2023-12-09 10:45:33	9	345.78	PLANNED INTENTIONAL	Non-storm
NE23120900229	APLGT0312	2023	2023-12-09 10:10:44	2023-12-09 10:49:17	1	38.55	PLANNED INTENTIONAL	Non-storm
SW23120900246	JEFSN9409	2023	2023-12-09 10:13:25	2023-12-09 12:00:52	538	44877.48	EQUIPMENT FAILURE	Non-storm
NW23121000229	CLKSN8897	2023	2023-12-09 10:14:19	2023-12-10 13:34:41	1	1640.37	EQUIPMENT FAILURE	Non-storm
SE23120900235	SAVAN1086	2023	2023-12-09 10:21:20	2023-12-09 12:31:52	2	179.23	PLANNED INTENTIONAL	Non-storm
SW23120900278	YPSIL0314	2023	2023-12-09 10:21:52	2023-12-09 11:49:48	57	4995.75	PUBLIC INTERFERENCE	Non-storm
NW23120900245	HURST9853	2023	2023-12-09 10:23:02	2023-12-09 10:45:11	3	66.24	PLANNED INTENTIONAL	Non-storm
SE23120900233	GNSTN1319	2023	2023-12-09 10:28:04	2023-12-09 10:44:26	1	16.37	PLANNED INTENTIONAL	Non-storm
NE23120900298	ALGON8073	2023	2023-12-09 10:34:41	2023-12-09 11:01:41	6	161.47	NO CAUSE	Non-storm
NE23120900343	CAPAC8013	2023	2023-12-09 10:43:03	2023-12-09 12:36:35	1	113.53	ANIMAL	Non-storm
SE23120900319	MLVDL2105	2023	2023-12-09 10:43:36	2023-12-09 11:23:06	1	39.5	PLANNED INTENTIONAL	Non-storm
SE23120900301	ALNPK1833	2023	2023-12-09 10:44:13	2023-12-09 11:52:54	1	68.68	PLANNED INTENTIONAL	Non-storm
NW23120900781	HURST9853	2023	2023-12-09 10:44:31	2023-12-10 08:30:36	1	1306.08	EQUIPMENT FAILURE	Non-storm
SW23120900325	PERU9440	2023	2023-12-09 11:04:01	2023-12-09 12:06:53	6	374.42	PLANNED INTENTIONAL	Non-storm
SE23120900303	SRGNT9129	2023	2023-12-09 11:05:12	2023-12-09 11:25:43	1	20.52	PLANNED INTENTIONAL	Non-storm
SE23120900302	GDNRV2199	2023	2023-12-09 11:09:11	2023-12-09 13:11:08	1	121.95	PLANNED INTENTIONAL	Non-storm
SW23120900329	GLBRT9381	2023	2023-12-09 11:20:34	2023-12-09 11:29:28	1	8.9	PLANNED INTENTIONAL	Non-storm
NW23120900347	STKBR9888	2023	2023-12-09 11:21:08	2023-12-09 14:46:10	58	10263.3	TREEBROW	Non-storm
SE23120900340	REDFD1064	2023	2023-12-09 11:25:40	2023-12-09 12:48:54	1	25.93	EQUIPMENT FAILURE	Non-storm
SE23120900390	LAUDR1272	2023	2023-12-09 11:31:19	2023-12-09 14:27:27	1	176.13	PLANNED INTENTIONAL	Non-storm
SE23120900369	EIGMI1512	2023	2023-12-09 11:40:14	2023-12-09 12:27:53	2	92.1	PLANNED INTENTIONAL	Non-storm
SE23120900060	GRPTE2053	2023	2023-12-09 11:41:07	2023-12-09 12:02:10	1	21.05	TREEROW	Non-storm
SE23120900035	WEBST1932	2023	2023-12-09 11:48:58	2023-12-09 12:52:19	1	63.35	EQUIPMENT FAILURE	Non-storm
SE23120900375	LAUDR1272	2023	2023-12-09 11:55:11	2023-12-09 12:40:09	1	44.97	PLANNED INTENTIONAL	Non-storm
SE23120900365	PULFD0419	2023	2023-12-09 11:57:32	2023-12-09 13:56:12	1	118.67	PLANNED INTENTIONAL	Non-storm
NW23120900387	CLYDE9079	2023	2023-12-09 12:01:13	2023-12-09 14:22:27	1	141.23	EQUIPMENT FAILURE	Non-storm
SE23120900368	DCATR1271	2023	2023-12-09 12:03:55	2023-12-09 12:54:13	2	83.85	PLANNED INTENTIONAL	Non-storm
SE23120900382	GNSTN1319	2023	2023-12-09 12:09:07	2023-12-09 12:40:28	1	31.35	PLANNED INTENTIONAL	Non-storm
NW23120900386	ALPNE8921	2023	2023-12-09 12:13:57	2023-12-09 12:20:49	1	6.87	PLANNED INTENTIONAL	Non-storm
SW23120900320	EMRCK2929	2023	2023-12-09 12:17:59	2023-12-09 13:54:38	1	96.65	EQUIPMENT FAILURE	Non-storm
SE23120900401	GNSTN0444	2023	2023-12-09 12:21:35	2023-12-09 12:59:22	1	37.78	PLANNED INTENTIONAL	Non-storm
NW23120900414	BOND8058	2023	2023-12-09 12:31:20	2023-12-09 15:07:07	25	3887.04	TREEBROW	Non-storm
SW23120900413	ROMLS9464	2023	2023-12-09 12:37:36	2023-12-09 13:49:37	1	72.02	PLANNED INTENTIONAL	Non-storm
SW23120900407	PERU9441	2023	2023-12-09 12:37:49	2023-12-09 13:10:16	1	32.45	PLANNED INTENTIONAL	Non-storm
SE23120900428	EIGMI1512	2023	2023-12-09 12:44:24	2023-12-09 14:08:26	1	84.03	PLANNED INTENTIONAL	Non-storm
NE23120900393	LIBER1056	2023	2023-12-09 12:49:17	2023-12-09 14:36:26	1	88.94	EQUIPMENT FAILURE	Non-storm
NW23120900444	SPKNE8842	2023	2023-12-09 12:54:36	2023-12-09 13:36:19	1	41.72	PLANNED INTENTIONAL	Non-storm
NW23120900472	SPKNE8842	2023	2023-12-09 12:54:38	2023-12-09 13:37:18	1	42.67	EQUIPMENT FAILURE	Non-storm
NW23120900453	PAGE9495	2023	2023-12-09 13:00:33	2023-12-09 15:25:07	37	5342.97	TREEBROW	Non-storm
NE23120900466	OTSGO8762	2023	2023-12-09 13:06:17	2023-12-09 13:42:59	1	36.7	PLANNED INTENTIONAL	Non-storm
NE23120900473	ELBA0302	2023	2023-12-09 13:08:13	2023-12-09 20:45:53	13	5946.55	EQUIPMENT FAILURE	Non-storm
SE23120900330	GENSE1091	2023	2023-12-09 13:13:17	2023-12-09 13:41:13	1	27.93	EQUIPMENT FAILURE	Non-storm
NW23120900478	CAMDN8284	2023	2023-12-09 13:13:19	2023-12-09 16:31:02	8	1580.02	EQUIPMENT FAILURE	Non-storm
NW23120900474	SPKNE8842	2023	2023-12-09 13:15:51	2023-12-09 13:44:22	2	57.02	EQUIPMENT FAILURE	Non-storm
NE23120900746	QUAIL0312	2023	2023-12-09 13:30:04	2023-12-09 18:29:37	1	299.55	EQUIPMENT FAILURE	Non-storm
SE23120900492	EIGMI2079	2023	2023-12-09 13:33:07	2023-12-09 13:44:50	1	11.72	PLANNED INTENTIONAL	Non-storm
SE23120900394	FRMNT2096	2023	2023-12-09 13:37:14	2023-12-09 14:14:05	1	36.85	EQUIPMENT FAILURE	Non-storm
NE23120900366	UNVIL0301	2023	2023-12-09 13:40:01	2023-12-09 14:55:32	156	12993.23	EQUIPMENT FAILURE	Non-storm
SW23120900567	SHERW0322	2023	2023-12-09 14:07:56	2023-12-09 14:55:18	191	8860.38	EQUIPMENT FAILURE	Non-storm
SW23120900589	SHERW0322	2023	2023-12-09 14:08:34	2023-12-09 14:54:31	1	45.95	NO ISSUES FOUND	Non-storm
SW23120900588	SHERW0322	2023	2023-12-09 14:08:43	2023-12-09 14:54:40	1	45.95	NO ISSUES FOUND	Non-storm
SW23120900544	MOTT8124	2023	2023-12-09 14:13:01	2023-12-09 15:51:54	263	5075.53	EQUIPMENT FAILURE	Non-storm
SW23120900553	OTTWA9540	2023	2023-12-09 14:15:21	2023-12-09 18:05:10	4	918.8	TREEIROW	Non-storm
NE23120900560	BADAX0312	2023	2023-12-09 14:15:24	2023-12-09 21:53:19	1	457.92	TREEBROW	Non-storm
NW23120900604	OASIS9008	2023	2023-12-09 14:27:38	2023-12-10 11:34:11	1	1266.55	TREEIROW	Non-storm
SW23120900573	SPKNE8842	2023	2023-12-09 14:29:25	2023-12-09 14:35:45	1	6.33	EQUIPMENT FAILURE	Non-storm
NE23120900576	BRAY8780	2023	2023-12-09 14:32:31	2023-12-09 17:16:02	1	163.52	EQUIPMENT FAILURE	Non-storm
SE23120900586	MLVDL2259	2023	2023-12-09 14:33:08	2023-12-09 17:16:05	1	162.95	TREEBROW	Non-storm
SE23120900493	DENVR2222	2023	2023-12-09 14:52:48	2023-12-09 15:22:53	1	30.08	TREEIROW	Non-storm
SW23120900646	TAHOE9510	2023	2023-12-09 15:00:58	2023-12-09 17:01:05	1	120.12	TREEIROW	Non-storm
NW23121000349	GRFIN9883	2023	2023-12-09 15:02:27	2023-12-10 19:43:15	1	1720.8	EQUIPMENT FAILURE	Non-storm
SE23120900851	HAWTH1841	2023	2023-12-09 15:28:04	2023-12-10 10:14:37	1	1126.55	TREEBROW	Non-storm
SE23120900619	TIRMN2093	2023	2023-12-09 15:30:37	2023-12-09 18:09:16	14	2216.12	TREEIROW	Non-storm
SE23120900622	TIRMN2093	2023	2023-12-09 15:30:47	2023-12-09 18:09:08	1	158.35	EQUIPMENT FAILURE	Non-storm
NE23120900629	BUNRT8110	2023	2023-12-09 15:42:09	2023-12-09 17:23:05	14	1410.86	EQUIPMENT FAILURE	Non-storm
NE23120900685	BUNRT8110	2023	2023-12-09 15:42:13	2023-12-09 17:23:09	6	604.66	EQUIPMENT FAILURE	Non-storm
NE23120900628	BUNRT8110	2023	2023-12-09 15:42:14	2023-12-09 17:23:05	17	1713.18	EQUIPMENT FAILURE	Non-storm
NW23120900631	DISCO8104	2023	2023-12-09 15:44:32	2023-12-09 17:56:54	1277	82041	LIGHTNING	Non-storm
NW23120900637	DISCO8104	2023	2023-12-09 15:44:33	2023-12-09 17:56:55	520	42667.43	NO ISSUES FOUND	Non-storm
NW23120900697	BRONC8593	2023	2023-12-09 17:33:48	2023-12-09 17:55:56	1	22.13	EQUIPMENT FAILURE	Non-storm
NW23120900773	WMSTN9857	2023	2023-12-09 17:59:02	2023-12-09 18:21:59	21	478.24	TREEBROW	Non-storm
NW23120900771	WMSTN9857	2023	2023-12-09 17:59:10	2023-12-09 18:21:56	1	22.77	TREEBROW	Non-storm
SE23120900585	EVRGN1892	2023	2023-12-09 18:06:13	2023-12-09 18:35:05	4	115.34	EQUIPMENT FAILURE	Non-storm
SE23120900599	EVRGN1892	2023	2023-12-09 18:06:14	2023-12-09 18:35:10	3	86.49	EQUIPMENT FAILURE	Non-storm
SW23120900808	OTTWA9540	2023	2023-12-09 18:39:27	2023-12-10 16:34:01	38	46434.6	NO ISSUES FOUND	Non-storm
NW23120900787	RAPST4017	2023	2023-12-09 18:42:37	2023-12-09 19:30:54	19	902.46	NO ISSUES FOUND	Non-storm
NW23120900826	WSHTN0344	2023	2023-12-09 21:50:49	2023-12-09 22:21:42	1	30.88	EQUIPMENT FAILURE	Non-storm
NW23120900831	WSHTN0344	2023	2023-12-09 21:50:50	2023-12-09 22:21:42	1	30.87	EQUIPMENT FAILURE	Non-storm
NW23120900816	STERL8061	2023	2023-12-09 21:51:56	2023-12-09 22:51:09	1	59.22	EQUIPMENT FAILURE	Non-storm
SE23120900852	REDFD1064	2023	2023-12-09 22:32:54	2023-12-10 11:11:39	1	758.75	TREEBROW	Non-storm
NW23121000132	WSHTN0344	2023	2023-12-09 22:58:19	2023-12-10 08:17:11	1	48.46	EQUIPMENT FAILURE	Non-storm
NW23120900860	KELOG8121	2023	2023-12-09 23:26:23	2023-12-10 01:13:26	21	2245.99	TREEBROW	Non-storm
NW23121000172	KELOG8121	2023	2023-12-09 23:26:36	2023-12-10 13:42:05	1	855.48	TREEIROW	Non-storm
SE23121000004	ANGLA9112	2023	2023-12-10 00:01:49	2023-12-10 02:34:31	45	5997.47	EQUIPMENT FAILURE	Non-storm
NW23121000019	CALMT0344	2023	2023-12-10 03:25:47	2023-12-10 03:58:29	11	350.59	EQUIPMENT FAILURE	Non-storm
SW23121000043	OMAHA8240	2023	2023-12-10 05:52:22	2023-12-11 17:46:08	1	2153.77	TREEBROW	Non-storm
NW23121000403	CATLI9128	2023	2023-12-10 07:38:50	2023-12-11 11:49:35	1	1690.75	EQUIPMENT FAILURE	Non-storm
NE23121000051	OXFRD8074	2023	2023-12-10 07:41:01	2023-12-10 10:19:08	29	4564.13	TREEBROW	Non-storm
SW23121000237	WILSN8101	2023	2023-12-10 08:06:47	2023-12-10 12:33:49	1	267.03	ANIMAL	Non-storm
SW23121000062	DRAKE8936	2023	2023-12-10 08:07:52	2023-12-10 08:59:36	23	1183.9	EQUIPMENT FAILURE	Non-storm
SW23121000064	DRAKE8969	2023	2023-12-10 08:08:05	2023-12-10 08:59:36	1	51.52	NO ISSUES FOUND	Non-storm
SW23121000068	STATE8137	2023	2023-12-10 08:40:21	2023-12-10 10:57:36	1969	185699.49	EQUIPMENT FAILURE	Non-storm
SW23121000245	STATE8137	2023	2023-12-10 08:40:21	2023-12-10 12:02:38	1	202.28	NO ISSUES FOUND	Non-storm
SW23121000227	STATE8137	2023	2023-12-10 08:40:22	2023-12-10 10:57:27	237	22060.64	NO ISSUES FOUND	Non-storm
SW23121000225	STATE8137	2023	2023-12-10 08:40:23	2023-12-10 10:57:26	1	137.05	NO ISSUES FOUND	Non-storm
SW23121000224	STATE8137	2023	2023-12-10 08:40:34	2023-12-10 10:57:37	1	137.05	NO ISSUES FOUND	Non-storm
SW23121000067	SNSET9016	2023	2023-12-10 08:51:11	2023-12-10 13:25:33	4	1094.92	PLANNED INTENTIONAL	Non-storm
NW23121100103	BISMK8458	2023	2023-12-10 08:55:58	2023-12-11 17:28:03	1	1952.08	ANIMAL	Non-storm
NE23121000060	VICTR8721	2023	2023-12-10 09:09:14	2023-12-10 11:13:28	1	124.23	EQUIPMENT FAILURE	Non-storm
NW23121000137	JASON8511	2023	2023-12-10 09:33:19	2023-12-10 11:21:46	5	540.73	ANIMAL	Non-storm
SW23121000158	DEWEY8085	2023	2023-12-10 09:43:25	2023-12-10 10:39:25	10	514.7	ANIMAL	Non-storm
NW23121000211	SENCA8934	2023	2023-12-10 09:44:07	2023-12-10 13:12:58	1	208.85	ANIMAL	Non-storm
SW23121000249	STATE8137	2023	2023-12-10 09:45:55	2023-12-10 10:57:25	1	71.5	NO ISSUES FOUND	Non-storm
SW23121000228	STATE8137	2023	2023-12-10 09:46:07	2023-12-10 10:57:37	1	71.5	NO ISSUES FOUND	Non-storm
SW23121000145	STATE9809	2023	2023-12-10 09:46:34	2023-12-10 09:57:06	622	6388.31	EQUIPMENT FAILURE	Non-storm
SW23120900193	FRMTN8880	2023	2023-12-10 09:52:19	2023-12-10 10:11:29	12	221.61	EQUIPMENT FAILURE	Non-storm
NW23121000174	GODSN8134	2023	2023-12-10 10:00:33	2023-12-10 12:48:36	13	2051.32	PLANNED INTENTIONAL	Non-storm
NW23120900813	HURST9853	2023	2023-12-10 10:05:30	2023-12-10 10:22:32	4	48.38	EQUIPMENT FAILURE	Non-storm
NE23121000196	STRFD9093	2023	2023-12-10 10:12:35	2023-12-10 10:43:12	1	30.62	PLANNED INTENTIONAL	Non-storm
NE23121000493	VICTR8721	2023	2023-12-10 10:29:44	2023-12-10 21:43:29	1	152.83	EQUIPMENT FAILURE	Non-storm
SW23121000243	INKST0315	2023	2023-12-10 10:47:21	2023-12-10 12:12:59	1	85.63	EQUIPMENT FAILURE	Non-storm
SW23121100065	BLCRK9344	2023	2023-12-10 10:54:05	2023-12-11 09:43:48	1	1369.72	ANIMAL	Non-storm

SW23121000233	BLCRK9330	2023	2023-12-10 10:58:10	2023-12-10 11:58:58	3	181.48	ANIMAL	Non-storm
SW23121000241	BLCRK9330	2023	2023-12-10 10:58:15	2023-12-10 11:58:57	2	120.7	ANIMAL	Non-storm
SE23121000307	COOLG1263	2023	2023-12-10 11:46:29	2023-12-10 16:23:55	1	279.2	EQUIPMENT FAILURE	Non-storm
SW23121000387	NVILL9336	2023	2023-12-10 12:13:20	2023-12-10 17:37:05	1	323.75	ANIMAL	Non-storm
SW23121000271	NVILL9336	2023	2023-12-10 12:13:22	2023-12-10 17:37:07	2	647.48	EQUIPMENT FAILURE	Non-storm
NE23121000308	MACMB8409	2023	2023-12-10 13:08:15	2023-12-10 14:08:29	1	60.23	ANIMAL	Non-storm
NE23121000297	MACMB8409	2023	2023-12-10 13:08:16	2023-12-10 14:08:29	2	120.44	ANIMAL	Non-storm
NW23121000300	KENSL9844	2023	2023-12-10 13:10:21	2023-12-10 16:05:29	1	175.13	ANIMAL	Non-storm
SE23121000246	CRTIS1343	2023	2023-12-10 13:18:07	2023-12-10 13:26:07	1	8	EQUIPMENT FAILURE	Non-storm
SW23121000318	BNSTN9700	2023	2023-12-10 13:57:21	2023-12-11 00:30:23	9	5695.1	EQUIPMENT FAILURE	Non-storm
SW23121000322	BNSTN9700	2023	2023-12-10 13:57:21	2023-12-11 00:30:15	7	4429.52	EQUIPMENT FAILURE	Non-storm
SW23121000320	BNSTN9700	2023	2023-12-10 13:57:22	2023-12-10 16:27:31	8	1200.22	EQUIPMENT FAILURE	Non-storm
SW23121000324	BNSTN9700	2023	2023-12-10 13:57:23	2023-12-11 00:30:20	10	6327.92	EQUIPMENT FAILURE	Non-storm
SW23121000325	BNSTN9700	2023	2023-12-10 13:57:24	2023-12-10 16:35:06	6	945.5	EQUIPMENT FAILURE	Non-storm
NW23121000339	PAGEB828	2023	2023-12-10 14:26:19	2023-12-10 16:33:57	1	127.63	EQUIPMENT FAILURE	Non-storm
NW23121000346	BRONC8677	2023	2023-12-10 14:54:01	2023-12-10 17:20:33	1	146.53	EQUIPMENT FAILURE	Non-storm
NW23121000378	TEGER9122	2023	2023-12-10 16:43:47	2023-12-10 17:02:37	47	878.63	EQUIPMENT FAILURE	Non-storm
NW23121000377	TEGER9122	2023	2023-12-10 16:43:48	2023-12-10 17:28:43	33	732.38	EQUIPMENT FAILURE	Non-storm
NW23121000418	CODY9537	2023	2023-12-10 19:42:38	2023-12-10 22:00:44	751	43944.2	EQUIPMENT FAILURE	Non-storm
SE23121000390	HIKRY1591	2023	2023-12-10 20:10:58	2023-12-10 20:17:57	1	6.98	NO ISSUES FOUND	Non-storm
SE23121000491	SAVAN1116	2023	2023-12-10 20:26:13	2023-12-11 01:21:32	8	440.54	EQUIPMENT FAILURE	Non-storm
SE23121000564	PULFD2155	2023	2023-12-10 21:00:45	2023-12-11 01:53:41	1	292.93	EQUIPMENT FAILURE	Non-storm
NW23121000514	SALEM9900	2023	2023-12-10 21:29:03	2023-12-10 21:58:57	13	379.75	EQUIPMENT FAILURE	Non-storm
NW23121000521	SALEM9900	2023	2023-12-10 21:29:34	2023-12-10 21:58:42	11	331.6	EQUIPMENT FAILURE	Non-storm
NE23121000411	BERND2613	2023	2023-12-11 02:28:26	2023-12-11 03:01:47	1	33.35	EQUIPMENT FAILURE	Non-storm
SW23121100013	COLNS9851	2023	2023-12-11 05:53:09	2023-12-11 09:21:14	1	208.08	EQUIPMENT FAILURE	Non-storm
SE23121000479	GRANT2195	2023	2023-12-11 07:26:09	2023-12-11 07:31:27	1	5.3	EQUIPMENT FAILURE	Non-storm
SE23121100031	ECORS1956	2023	2023-12-11 08:01:34	2023-12-11 08:33:08	1	31.57	TREEBROW	Non-storm
SW23121100062	GAY1747	2023	2023-12-11 08:24:57	2023-12-11 09:23:41	1	24.42	TREEROW	Non-storm
NW23121100102	HURST9853	2023	2023-12-11 08:46:28	2023-12-11 08:56:50	1	10.37	PLANNED INTENTIONAL	Non-storm
NW23121100139	GRFIN9799	2023	2023-12-11 08:49:48	2023-12-11 09:07:27	1	17.65	PLANNED INTENTIONAL	Non-storm
SE23121100311	JUPTR8336	2023	2023-12-11 09:01:34	2023-12-11 13:53:11	1	291.62	PLANNED INTENTIONAL	Non-storm
SE23121100141	MLVDL2105	2023	2023-12-11 09:03:18	2023-12-11 10:15:49	1	72.52	PLANNED INTENTIONAL	Non-storm
SE23121100143	PULFD2111	2023	2023-12-11 09:09:07	2023-12-11 10:32:41	1	83.57	PLANNED INTENTIONAL	Non-storm
NW23121100146	GRFIN9799	2023	2023-12-11 09:11:05	2023-12-11 09:30:09	1	19.07	PLANNED INTENTIONAL	Non-storm
SW23121100157	PIONR9793	2023	2023-12-11 09:16:20	2023-12-11 11:15:54	1	119.57	ANIMAL	Non-storm
NW23121100169	HURST9853	2023	2023-12-11 09:29:05	2023-12-11 09:43:31	1	14.43	PLANNED INTENTIONAL	Non-storm
NE23121100168	APLGT0312	2023	2023-12-11 09:31:46	2023-12-11 10:44:07	1	72.35	PLANNED INTENTIONAL	Non-storm
NW23121100186	CARTR8878	2023	2023-12-11 09:41:47	2023-12-11 11:34:46	63	7106.71	EQUIPMENT FAILURE	Non-storm
NW23121100187	CARTR8878	2023	2023-12-11 09:41:48	2023-12-11 11:34:45	83	9364.06	ANIMAL	Non-storm
NE23121100178	OTSGO8762	2023	2023-12-11 09:45:17	2023-12-11 10:28:13	1	42.93	PLANNED INTENTIONAL	Non-storm
NW23121100175	ALPNE8921	2023	2023-12-11 09:47:38	2023-12-11 11:03:34	2	58.69	PLANNED INTENTIONAL	Non-storm
SE23121100094	MLVDL2008	2023	2023-12-11 09:48:11	2023-12-11 10:10:17	1	22.1	EQUIPMENT FAILURE	Non-storm
SW23121100194	PROSP0305	2023	2023-12-11 09:53:41	2023-12-11 11:03:20	1	69.65	PLANNED INTENTIONAL	Non-storm
NW23121100209	HAMLN8849	2023	2023-12-11 09:58:16	2023-12-11 17:39:47	1	461.52	NO ISSUES FOUND	Non-storm
NW23121100195	HURST9853	2023	2023-12-11 09:58:27	2023-12-11 10:42:23	1	43.93	PLANNED INTENTIONAL	Non-storm
NW23121100213	HURST9853	2023	2023-12-11 09:58:27	2023-12-11 10:42:23	1	43.93	PLANNED INTENTIONAL	Non-storm
NE23121100206	CASVL8819	2023	2023-12-11 10:00:17	2023-12-11 11:47:24	1	107.12	PLANNED INTENTIONAL	Non-storm
NW23121100252	SPKNE8842	2023	2023-12-11 10:16:14	2023-12-11 11:05:26	10	490.18	EQUIPMENT FAILURE	Non-storm
SW23121100303	BLCRK8011	2023	2023-12-11 10:16:56	2023-12-11 13:32:07	1	195.18	TROUBLE INTENTIONAL	Non-storm
SE23121100254	JUPTR8365	2023	2023-12-11 10:21:18	2023-12-11 15:29:52	52	5262.83	EQUIPMENT FAILURE	Non-storm
SW23121100246	BLCRK9330	2023	2023-12-11 10:24:03	2023-12-11 13:07:47	6	813.47	PLANNED INTENTIONAL	Non-storm
NW23121100269	HURST9853	2023	2023-12-11 10:36:17	2023-12-11 10:41:44	1	5.45	PLANNED INTENTIONAL	Non-storm
NW23121100274	GODSN8134	2023	2023-12-11 10:45:21	2023-12-11 14:37:55	9	1565.41	EQUIPMENT FAILURE	Non-storm
SW23121100276	DAYTN8105	2023	2023-12-11 10:53:41	2023-12-11 12:11:42	3	232.6	PLANNED INTENTIONAL	Non-storm
SE23121100295	MLVDL2105	2023	2023-12-11 11:02:54	2023-12-11 13:53:06	14	1028.32	PLANNED INTENTIONAL	Non-storm
SW23121100305	SPRUC9827	2023	2023-12-11 11:03:27	2023-12-11 13:28:55	1	145.47	EQUIPMENT FAILURE	Non-storm
SE23121100323	MLVDL2105	2023	2023-12-11 11:06:48	2023-12-11 11:47:40	1	40.87	PLANNED INTENTIONAL	Non-storm
NW23121100277	ALPNE8921	2023	2023-12-11 11:10:18	2023-12-11 11:21:42	1	11.4	PLANNED INTENTIONAL	Non-storm
SE23121100349	GNSTN1295	2023	2023-12-11 11:16:47	2023-12-11 12:17:09	1	60.37	PLANNED INTENTIONAL	Non-storm
SE23121100321	LAUDR1272	2023	2023-12-11 11:18:17	2023-12-11 12:04:11	1	45.9	PLANNED INTENTIONAL	Non-storm
SW23121100325	PERU9440	2023	2023-12-11 11:44:01	2023-12-11 12:46:21	5	311.25	PLANNED INTENTIONAL	Non-storm
SE23121100339	GNSTN1319	2023	2023-12-11 11:49:45	2023-12-11 12:27:11	1	37.43	PLANNED INTENTIONAL	Non-storm
SE23121100354	EIGMI1512	2023	2023-12-11 11:55:57	2023-12-11 12:36:08	1	40.18	PLANNED INTENTIONAL	Non-storm
NE23121100318	OTSGO8762	2023	2023-12-11 12:02:18	2023-12-11 12:09:13	1	6.92	PLANNED INTENTIONAL	Non-storm
SW23121100350	GLBRT9373	2023	2023-12-11 12:09:53	2023-12-11 12:59:40	1	49.78	PLANNED INTENTIONAL	Non-storm
NE23121100308	IMLAY0302	2023	2023-12-11 12:16:59	2023-12-11 12:38:13	1	21.23	CUSTOMER EQUIPMENT	Non-storm
NW23121100381	ALPNE8921	2023	2023-12-11 12:18:09	2023-12-11 12:43:21	1	25.2	PLANNED INTENTIONAL	Non-storm
SE23121100423	PULFD0419	2023	2023-12-11 12:24:21	2023-12-11 13:09:30	1	45.15	PLANNED INTENTIONAL	Non-storm
SE23121100686	DERBN2055	2023	2023-12-11 12:32:40	2023-12-11 16:32:48	1	240.13	EQUIPMENT FAILURE	Non-storm
SE23121100416	DERBN2055	2023	2023-12-11 12:32:42	2023-12-11 16:33:07	61	14648.17	TREEBROW	Non-storm
NW23121100438	CLKSN8860	2023	2023-12-11 12:38:36	2023-12-11 13:54:50	1	76.23	ANIMAL	Non-storm
SE23121100374	GNSTN1319	2023	2023-12-11 12:38:57	2023-12-11 13:04:55	1	25.97	PLANNED INTENTIONAL	Non-storm
SW23121100408	HEMLK1952	2023	2023-12-11 12:52:16	2023-12-11 13:50:40	1	58.4	PLANNED INTENTIONAL	Non-storm
SE23121100580	SHADK1093	2023	2023-12-11 12:55:13	2023-12-11 21:34:21	1	519.13	TREEBROW	Non-storm
NW23121100454	CAMDN8282	2023	2023-12-11 12:52:07	2023-12-11 12:59:47	1	130.67	NO ISSUES FOUND	Non-storm
NW23121100516	CAMDN8282	2023	2023-12-11 13:02:13	2023-12-11 15:11:58	2	259.48	EQUIPMENT FAILURE	Non-storm
SE23121100575	SHADK1093	2023	2023-12-11 13:05:36	2023-12-11 15:18:26	1	132.83	PUBLIC INTERFERENCE	Non-storm
SE23121100619	SHADK1093	2023	2023-12-11 13:05:38	2023-12-11 15:18:28	1	132.83	TREEBROW	Non-storm
NW23121100457	SPKNE8842	2023	2023-12-11 13:07:35	2023-12-11 14:20:53	6	437.82	PLANNED INTENTIONAL	Non-storm
SW23121100331	GAY1759	2023	2023-12-11 13:14:05	2023-12-11 14:05:52	1	37.97	TREEIROW	Non-storm
NE23121100482	OTSGO8762	2023	2023-12-11 13:36:10	2023-12-11 14:33:29	1	57.32	PLANNED INTENTIONAL	Non-storm
SE23121100589	TIRMN1196	2023	2023-12-11 13:36:55	2023-12-11 14:07:34	1	30.65	TREEIROW	Non-storm
NW23121100235	CAMDN8276	2023	2023-12-11 13:47:22	2023-12-11 13:56:47	1	9.42	EQUIPMENT FAILURE	Non-storm
NW23121100505	ALPNE8916	2023	2023-12-11 13:50:34	2023-12-11 14:39:43	3	146.08	PLANNED INTENTIONAL	Non-storm
NW23121100549	ALPNE8916	2023	2023-12-11 13:50:34	2023-12-11 14:38:57	3	145.12	TREEBROW	Non-storm
NE23121100526	BENSN8496	2023	2023-12-11 13:52:59	2023-12-11 14:12:27	7	135.43	TROUBLE INTENTIONAL	Non-storm
NE23121100532	BENSN8496	2023	2023-12-11 13:53:07	2023-12-11 14:12:28	1	19.35	TROUBLE INTENTIONAL	Non-storm
SE23121100528	MLVDL2105	2023	2023-12-11 14:02:04	2023-12-11 14:32:49	1	30.75	PLANNED INTENTIONAL	Non-storm
SW23120900467	PERU9432	2023	2023-12-11 14:03:21	2023-12-11 14:22:18	1	18.95	TREEBROW	Non-storm
SE23121100552	LAUDR1554	2023	2023-12-11 14:18:49	2023-12-11 15:16:52	1	58.05	PLANNED INTENTIONAL	Non-storm
SE23121100597	GDRIV2220	2023	2023-12-11 14:29:31	2023-12-11 15:49:36	1	80.08	EQUIPMENT FAILURE	Non-storm
SE23121100608	GDRIV1297	2023	2023-12-11 14:56:42	2023-12-11 15:26:03	1	29.35	PLANNED INTENTIONAL	Non-storm
NW23121100628	SENCA8908	2023	2023-12-11 15:21:26	2023-12-11 20:34:50	8	1042.58	PLANNED INTENTIONAL	Non-storm
NW23121100627	HURST9853	2023	2023-12-11 15:21:32	2023-12-11 15:43:20	1	21.8	NO ISSUES FOUND	Non-storm
NW23121100685	HURST9853	2023	2023-12-11 16:24:18	2023-12-11 16:52:34	15	423.45	TROUBLE INTENTIONAL	Non-storm
NE23121100690	ALMOT0303	2023	2023-12-11 17:29:09	2023-12-11 17:39:33	1	10.4	EQUIPMENT FAILURE	Non-storm
NE23121100680	TCOMA8311	2023	2023-12-11 17:44:09	2023-12-11 21:53:25	4	955.82	EQUIPMENT FAILURE	Non-storm
SW23121100866	OKRDG9614	2023	2023-12-11 18:11:58	2023-12-12 15:15:02	1	1263.07	EQUIPMENT FAILURE	Non-storm
NW23121100641	DOVER9032	2023	2023-12-11 18:20:40	2023-12-11 18:50:35	1	29.92	EQUIPMENT FAILURE	Non-storm
NW23121100753	DUDLY8114	2023	2023-12-11 18:21:17	2023-12-11 21:02:54	1737	280089.68	EQUIPMENT FAILURE	Non-storm
SE23121100651	APPOL1327	2023	2023-12-11 19:36:58	2023-12-11 20:12:21	1	35.38	TREEIROW	Non-storm
SE23121100868	SHADK1093	2023	2023-12-11 20:00:51	2023-12-11 21:19:42	1	78.85	PUBLIC INTERFERENCE	Non-storm
SE23121100857	SAVAN1087	2023	2023-12-11 20:00:57	2023-12-12 11:03:27	2	1804.78	NO ISSUES FOUND	Non-storm
SE23121200086	SAVAN1087	2023	2023-12-11 20:01:04	2023-12-12 11:03:28	1	902.4	NO ISSUES FOUND	Non-storm
WSHTN9343	WSHTN9343	2023	2023-12-11 21:07:49	2023-12-11 21:25:17	5	87.08	EQUIPMENT FAILURE	Non-storm
SE23121100829	ALNPK2085	2023	2023-12-11 21:09:03	2023-12-12 09:34:07	1	745.07	EQUIPMENT FAILURE	Non-storm
NW23121200127	BALDW8945	2023	2023-12-12 01:03:16	2023-12-12 11:11:37	1	608.35	EQUIPMENT FAILURE	Non-storm
NE23121200020	PRKRD8760	2023	2023-12-12 02:39:28	2023-12-12 10:32:06	1	472.63	EQUIPMENT FAILURE	Non-storm
NE23121200025	HARPR2575	2023	2023-12-12 03:15:30	2023-12-12 12:51:21	6	158.02	TREEIROW	Non-storm
SE23121100547	HIKRY8192	2023	2023-12-12 06:11:42	2023-12-12 06:20:45	1	9.05	NO ISSUES FOUND	Non-storm
SW23121200058	HAMBG9968	2023	2023-12-12 07:21:21	2023-12-12 09:09:34	1	108.22	NO ISSUES FOUND	Non-storm
SE23121200051	LAMBT1456	2023	2023-12-12 07:26:14	2023-12-12 08:32:38	1	66.4	PLANNED INTENTIONAL	Non-storm
SE23121200759	STLUS1099	2023	2023-12-12 08:03:56	2023-12-12 20:59:42	1	775.77	EQUIPMENT FAILURE	Non-storm
NW23121200106	GRFIN9799	2023	2023-12-12 08:43:06	2023-12-12 08:52:44	1	9.63	PLANNED INTENTIONAL	Non-storm
NW23121200096	HURST9853	2023	2023-12-12 08:43:19	2023-12-12 08:59:32	1	16.22	PLANNED INTENTIONAL	Non-storm
NW23121200112	SENCA8997	2023	2023-12-12 08:45:50	2023-12-12 09:55:09	108	7458.4	EQUIPMENT FAILURE	Non-storm
NW23121200714	GRFIN9799	2023	2023-12-12 08:50:56	2023-12-12 17:37:46	1	526.83	NO ISSUES FOUND	Non-storm
NW23121200122	GRFIN9799	2023	2023-12-12 08:51:06	2023-12-12 10:13:26	1	82.33	PLANNED INTENTIONAL	Non-storm
NW23121200138	ROBIN9309	2023	2023-12-12 08:52:24	2023-12-12 10:39:34	16	1706.98	NO ISSUES FOUND	Non-storm
SE23121200125	null	2023	2023-12-12 08:53:50	2023-12-12 20:50:15	1	716.42	PLANNED INTENTIONAL	Non-storm
NW23121200133	GRFIN9799	2023	2023-12-12 08:56:26	2023-12-12 09:29:25	1	32.98	PLANNED INTENTIONAL	Non-storm
SE23121100732	FRMNT1593	2023	2023-12-12 09:01:33	2023-12-12 09:07:14	1	5.68	EQUIPMENT FAILURE	Non-storm
NW23121200131	ALPNE8921	2023	2023-12-12 09:05:42	2023-12-12 09:51:57	1	46.25	PLANNED INTENTIONAL	Non-storm
NW23121200547	HAMLN8931	2023	2023-12-12 09:07:53	2023-12-12 14:33:05	1	325.2	NO ISSUES FOUND	Non-storm
SE23121100587	MLVDL2259	2023	2023-12-12 09:22:16	2023-12-12 09:49:08	1	26.87	METER / BLOCKS	Non-storm
NW23121200165	GRFIN9799	2023	2023-12-12 09:23:12	2023-12-12 09:38:57	1	15.75	PLANNED INTENTIONAL	Non-storm
NW23121200159	HURST9853	2023	2023-12-12 09:23:29	2023-12-12 09:37:35	1	14.1	PLANNED INTENTIONAL	Non-storm
SE23121200204	SYRAC2017	2023	2023-12-12 09:27:52	2023-12-12 10:12:30	1	44.63	EQUIPMENT FAILURE	Non-storm
NW23121200183	HURST9853	2023	2023-12-12 09:32:05	2023-12-12 09:38:50	1	6.75	PLANNED INTENTIONAL	Non-storm
SW23121100723	HARV1743	2023	2023-12-12 09:32:13	2023-12-12 09:49:32	1	17.32	CUSTOMER EQUIPMENT	Non-storm
SE23121200217	GNSTN1319	2023	2023-12-12 09:35:40	2023-12-12 09:58:05	1	22.42	PLANNED INTENTIONAL	Non-storm
NW23121200181	HURST9853	2023	2023-12-12 09:37:44	2023-12-12 09:55:56	1	18.2	PLANNED INTENTIONAL	Non-storm
SE23121100726	HAWTH1261	2023	2023-12-12 09:39:00	2023-12-12 09:48:36	1	9.6	NO ISSUES FOUND	Non-storm
NW23121200158	GRFIN9799	2023	2023-12-12 09:39:29	2023-12-12 09:49:45	1	10.27	PLANNED INTENTIONAL	Non-storm
SE23121200194	GDRIV2199	2023	2023-12-12 09:39:57	2023-12-12 11:00:42	1	80.75	NO ISSUES FOUND	Non-storm
SE23121200248	GDRIV2199	2023	2023-12-12 09:39:59	2023-12-12 11:00:42	1	80.72	NO ISSUES FOUND	Non-storm
SE23121200200	GDRIV2199	2023	2023-12-12 09:42:04	2023-12-12 11:10:27	18	1587.88	PLANNED INTENTIONAL	Non-storm
SE23121200196	PULFD2224	2023	2023-12-12 09:44:07	2023-12-12 11:30:46	1	106.65	PLANNED INTENTIONAL	Non-storm
SE23121200213	SYRAC1851	2023	2023-12-12 09:46:00	2023-12-12 10:55:31	1	69.52	PLANNED INTENTIONAL	Non-storm
SE23121200219	SYRAC1851	2023	2023-12-12 09:46:02	2023-12-12 10:55:39	2	138.98	NO ISSUES FOUND	Non-storm
SE23121200211	PULFD2111	2023	2023-12-12 09:47:42	2023-12-12 11:10:47	1	83.08	PLANNED INTENTIONAL	Non-storm
SE23121200206	MAUME8241	2023	2023-12-12 09:48:34	2023-12-12 10:22:18	1	33.73	PLANNED INTENTIONAL	Non-storm
NW23121200203	HURST9853	2023	2023-12-12 09:49:09	2023-12-12 10:18:17	1	29.13	PLANNED INTENTIONAL	Non-storm
NW23121200215	HURST9853	2023	2023-12-12 09:54:50	2023-12-12 10:03:51	1	9.02	PLANNED INTENTIONAL	Non-storm
SE23121200207	GLEND2025	2023	2023-12-12 09:54:53	2023-12-12 11:15:03	1	80.17	PLANNED INTENTIONAL	Non-storm
NW23121200162	PAGE9495	2023	2023-12-12 09:57:46	2023-12-12 10:29:35	1	31.82	EQUIPMENT FAILURE	Non-storm
NW23121200222	SPKNE8842	2023	2023-12-12 10:00:35	2023-12-12 11:08:47	2	135.7	PLANNED INTENTIONAL	Non-storm
NW23121200229	SPKNE8842	2023	2023-12-12 10:00:41	2023-12-12 11:08:59	1	68.3	PLANNED INTENTIONAL	Non-storm
NW23121200230	SPKNE8842	2023	2023-12-12 10:01:17	2023-12-12 11:10:18	11	755.41	PLANNED INTENTIONAL	Non-storm
NW23121200228	SPKNE8842	2023	2023-12-12 10:01:33	2023-12-12 11:10:28	1	68.92	PLANNED INTENTIONAL	Non-storm
SW23121200311	DREXL8957	2023	2023-12-12 10:11:28	2023-12-12 12:23:50	1	132.37	ANIMAL	Non-storm
SW23121200100	OMAHA8233	2023	2023-12-12 10:17:33	2023-12-13 14:14:08	1	1676.58	EQUIPMENT FAILURE	Non-storm
SW23121200247	FRLDG8042	2023	2023-12-12 10:18:07	2023-12-12 10:30:02	1	11.92	PLANNED INTENTIONAL	Non-storm
NW23121200277	MALTA8481	2023	2023-12-12 10:21:58	2023-12-12 10:39:17	14	239.84	NO ISSUES FOUND	Non-storm
NW23121200234	KERNB902	2023	2023-12-12 10:23:36	2023-12-12 11:12:54	22	314.15	PLANNED INTENTIONAL	Non-storm
SE23121200237	GNSTN1319	2023	2023-12-12 10:23:53	2023-12-12 10:55:04	1	31.18	PLANNED INTENTIONAL	Non-storm
NW23121200256	SPKNE8842	2023	2023-12-12 10:26:37	2023-12-12 11:10:01	13	561.2	PLANNED INTENTIONAL	Non-storm
SE23121200253	PULFD0419	2023	2023-12-12 10:29:31	2023-12-12 11:04:10	1	34.65	PLANNED INTENTIONAL	Non-storm
NE23121200284	BADAX8787	2023	2023-12-12 10:31:01	2023-12-12 13:06:33	9	1399.5	TROUBLE INTENTIONAL	Non-storm
NE23121200296	OTSGO8762	2023	2023-12-12 10:33:44	2023-12-12 10:58:17	1	24.55	PLANNED INTENTIONAL	Non-storm
NW23121200259	ALPNE8921	2023	2023-12-12 10:37:06	2023-12-12 11:25:29	5	241.32	PLANNED INTENTIONAL	Non-storm

SE23121200275	LAMBT1485	2023	2023-12-12 10:41:53	2023-12-12 11:10:42	7	201.62	PLANNED INTENTIONAL	Non-storm
SW23121200427	PERU9441	2023	2023-12-12 10:44:09	2023-12-12 12:52:39	1	53.41	PLANNED INTENTIONAL	Non-storm
SE23121200433	TURNR1148	2023	2023-12-12 10:48:44	2023-12-12 15:28:54	1	280.17	EQUIPMENT FAILURE	Non-storm
SE23121200292	PULFD2111	2023	2023-12-12 10:48:48	2023-12-12 12:32:12	2	206.08	PLANNED INTENTIONAL	Non-storm
NW23121200304	HURST9853	2023	2023-12-12 10:53:09	2023-12-12 11:03:54	1	10.75	PLANNED INTENTIONAL	Non-storm
SW23121200378	BLCRK8011	2023	2023-12-12 10:57:27	2023-12-12 13:49:11	2	336.07	EQUIPMENT FAILURE	Non-storm
SE23121200327	LAMBT1485	2023	2023-12-12 11:03:44	2023-12-12 12:15:25	1	71.68	PLANNED INTENTIONAL	Non-storm
SE23121100418	FLANE1840	2023	2023-12-12 11:06:38	2023-12-12 11:28:46	1	22.13	TREEBROW	Non-storm
NW23121200316	BREWR8840	2023	2023-12-12 11:11:08	2023-12-12 11:27:09	1	16.02	PLANNED INTENTIONAL	Non-storm
SE23121200339	PULFD0419	2023	2023-12-12 11:17:37	2023-12-12 11:32:43	1	15.1	PLANNED INTENTIONAL	Non-storm
SE23121200348	WAREN8362	2023	2023-12-12 11:22:06	2023-12-12 19:57:31	34	15555.43	TREEIROW	Non-storm
SE23121200364	WAREN8362	2023	2023-12-12 11:22:51	2023-12-12 19:57:33	1	514.7	TREEIROW	Non-storm
SW23121200361	HEMLK1952	2023	2023-12-12 11:24:23	2023-12-12 12:13:32	4	195.89	PLANNED INTENTIONAL	Non-storm
SW23121200341	HEMLK1952	2023	2023-12-12 11:24:26	2023-12-12 12:13:24	1	48.97	PLANNED INTENTIONAL	Non-storm
NW23121200347	ORION8966	2023	2023-12-12 11:27:45	2023-12-12 12:05:27	1	37.7	PLANNED INTENTIONAL	Non-storm
SW23121200355	LILY9120	2023	2023-12-12 11:30:03	2023-12-12 15:29:22	9	1277.29	NO ISSUES FOUND	Non-storm
NW23121200350	CAMDN8282	2023	2023-12-12 11:35:07	2023-12-12 12:41:06	1	65.98	PLANNED INTENTIONAL	Non-storm
NW23121200432	CAMDN8282	2023	2023-12-12 11:35:11	2023-12-12 12:42:04	1	66.88	PLANNED INTENTIONAL	Non-storm
NW23121200300	MALTA8543	2023	2023-12-12 11:35:49	2023-12-12 12:07:25	1	31.6	EQUIPMENT FAILURE	Non-storm
SE23121200367	GNSTN1319	2023	2023-12-12 11:41:36	2023-12-12 12:05:44	1	24.13	PLANNED INTENTIONAL	Non-storm
SW23121200388	BCKLR9936	2023	2023-12-12 11:42:46	2023-12-12 12:38:13	1	55.45	ANIMAL	Non-storm
SW23121200751	TAHOE9510	2023	2023-12-12 11:47:38	2023-12-12 20:11:59	3	1512.58	TREEIROW	Non-storm
SE23121100631	GENSE2138	2023	2023-12-12 12:01:03	2023-12-12 12:25:46	2	13.32	EQUIPMENT FAILURE	Non-storm
NW23121200407	KERNB902	2023	2023-12-12 12:02:20	2023-12-12 12:09:57	1	7.62	PLANNED INTENTIONAL	Non-storm
SE23121200346	LAUDR1272	2023	2023-12-12 12:02:39	2023-12-12 12:55:32	1	52.88	PLANNED INTENTIONAL	Non-storm
NW23121200422	SPKNE8842	2023	2023-12-12 12:05:30	2023-12-12 12:53:18	12	572.73	PLANNED INTENTIONAL	Non-storm
SE23121200305	PULFD0420	2023	2023-12-12 12:06:38	2023-12-12 12:52:57	1	46.32	PLANNED INTENTIONAL	Non-storm
SE23121100475	SAVAN1279	2023	2023-12-12 12:09:29	2023-12-12 12:39:17	1	29.8	TREEBROW	Non-storm
SE23121200529	DERBN2292	2023	2023-12-12 12:16:55	2023-12-12 13:55:01	1	98.1	EQUIPMENT FAILURE	Non-storm
NE23121200431	BECK8466	2023	2023-12-12 12:18:21	2023-12-12 14:30:03	4	502.46	ANIMAL	Non-storm
SW23121200436	GLBRT9373	2023	2023-12-12 12:29:52	2023-12-12 15:20:26	36	4459.08	PLANNED INTENTIONAL	Non-storm
SE23121200443	SRGNT9129	2023	2023-12-12 12:35:31	2023-12-12 13:52:46	8	458.56	PLANNED INTENTIONAL	Non-storm
SE23121200452	LAUDR1272	2023	2023-12-12 12:37:59	2023-12-12 15:26:27	1	168.47	PLANNED INTENTIONAL	Non-storm
SW23121200457	FLRDA8178	2023	2023-12-12 12:38:38	2023-12-12 18:12:49	29	9689.54	EQUIPMENT FAILURE	Non-storm
SW23121200461	FLRDA8178	2023	2023-12-12 12:38:40	2023-12-12 18:12:49	53	15520.13	NO ISSUES FOUND	Non-storm
SW23121200512	LIMA9896	2023	2023-12-12 12:44:32	2023-12-12 14:39:48	1	115.27	EQUIPMENT FAILURE	Non-storm
SE23121200455	GNSTN1319	2023	2023-12-12 12:44:49	2023-12-12 14:05:28	2	159.14	PLANNED INTENTIONAL	Non-storm
SW23121200444	NVILL9461	2023	2023-12-12 12:45:37	2023-12-12 13:03:59	1	18.37	PLANNED INTENTIONAL	Non-storm
SW23121200144	PERU9441	2023	2023-12-12 12:46:09	2023-12-12 13:06:11	1	20.03	EQUIPMENT FAILURE	Non-storm
NW23121200487	WOLFH8838	2023	2023-12-12 12:46:56	2023-12-12 20:47:54	1	480.97	ANIMAL	Non-storm
NW23121200471	WOLFH8838	2023	2023-12-12 12:46:57	2023-12-12 20:47:56	1	480.98	ANIMAL	Non-storm
SE23121200474	STLUS1099	2023	2023-12-12 12:48:22	2023-12-12 14:02:06	18	1325.65	PUBLIC INTERFERENCE	Non-storm
SE23121200540	STLUS1099	2023	2023-12-12 12:48:38	2023-12-12 14:13:36	1	84.97	PUBLIC INTERFERENCE	Non-storm
NW23121200290	TAMRK9031	2023	2023-12-12 12:49:54	2023-12-12 13:40:42	1	50.8	EQUIPMENT FAILURE	Non-storm
SW23121200484	STATE8137	2023	2023-12-12 12:51:14	2023-12-12 15:47:52	10	1762.45	EQUIPMENT FAILURE	Non-storm
SE23121200680	EIGMI1518	2023	2023-12-12 12:52:19	2023-12-12 17:13:20	1	199.08	EQUIPMENT FAILURE	Non-storm
NW23121200488	CLKSN8897	2023	2023-12-12 12:55:41	2023-12-12 13:54:39	190	11051.21	ANIMAL	Non-storm
NW23121200518	CLKSN9113	2023	2023-12-12 12:55:44	2023-12-12 13:53:48	2	116.08	ANIMAL	Non-storm
NE23121200466	SAVOY8711	2023	2023-12-12 12:58:19	2023-12-12 14:09:19	1	71	PLANNED INTENTIONAL	Non-storm
SW23121200623	GLBRT9373	2023	2023-12-12 12:58:44	2023-12-12 15:20:11	1	141.45	NO ISSUES FOUND	Non-storm
NW23121200492	GRFIN9799	2023	2023-12-12 13:00:30	2023-12-12 13:13:23	1	18.88	PLANNED INTENTIONAL	Non-storm
SE23121200473	MAUME8241	2023	2023-12-12 13:03:11	2023-12-12 13:59:47	1	56.6	PLANNED INTENTIONAL	Non-storm
NW23121200523	LOCDL8861	2023	2023-12-12 13:05:39	2023-12-12 16:58:37	2	465.72	ANIMAL	Non-storm
SE23121200515	MLVDL1516	2023	2023-12-12 13:11:46	2023-12-12 14:13:09	1	61.38	PLANNED INTENTIONAL	Non-storm
SW23121200519	ROMLS9464	2023	2023-12-12 13:15:48	2023-12-12 16:04:11	22	3699.24	PLANNED INTENTIONAL	Non-storm
SW23121200661	ROMLS9464	2023	2023-12-12 13:15:48	2023-12-12 16:03:57	2	336.26	EQUIPMENT FAILURE	Non-storm
SE23121200525	MLVDL2105	2023	2023-12-12 13:21:50	2023-12-12 14:15:32	1	53.7	PLANNED INTENTIONAL	Non-storm
SW23121200359	ZEBRA9474	2023	2023-12-12 13:23:15	2023-12-12 13:35:21	1	12.1	NO ISSUES FOUND	Non-storm
NW23121200602	MALTA8481	2023	2023-12-12 13:28:06	2023-12-12 15:25:50	37	734.09	EQUIPMENT FAILURE	Non-storm
NW23121200560	SPKNE8842	2023	2023-12-12 13:41:06	2023-12-12 14:10:41	1	29.58	PLANNED INTENTIONAL	Non-storm
SE23121200543	GDRIV2199	2023	2023-12-12 13:41:08	2023-12-12 14:14:19	1	33.18	PLANNED INTENTIONAL	Non-storm
SE23121200541	JUPTR8352	2023	2023-12-12 13:41:15	2023-12-12 14:18:10	1	36.92	PLANNED INTENTIONAL	Non-storm
SE23121200539	ECORS1382	2023	2023-12-12 13:44:59	2023-12-12 14:54:50	1	69.85	PLANNED INTENTIONAL	Non-storm
SE23121200535	ECORS1382	2023	2023-12-12 13:57:57	2023-12-12 15:27:00	1	89.05	PLANNED INTENTIONAL	Non-storm
NW23121200582	KERNB902	2023	2023-12-12 14:07:27	2023-12-12 14:36:50	18	525.49	PLANNED INTENTIONAL	Non-storm
SE23121200566	GLEND2025	2023	2023-12-12 14:12:45	2023-12-12 15:09:55	1	57.17	PLANNED INTENTIONAL	Non-storm
SE23121200587	GLEND2025	2023	2023-12-12 14:12:56	2023-12-12 15:15:36	1	62.67	EQUIPMENT FAILURE	Non-storm
SE23121200542	ECORS1382	2023	2023-12-12 14:14:13	2023-12-12 14:38:21	1	24.13	PLANNED INTENTIONAL	Non-storm
NE23121200774	OTSGO8762	2023	2023-12-12 14:28:02	2023-12-12 19:31:17	1	303.25	EQUIPMENT FAILURE	Non-storm
NW23121200607	SPKNE8842	2023	2023-12-12 14:37:48	2023-12-12 15:02:27	10	246	PLANNED INTENTIONAL	Non-storm
SE23121200588	GRANT1494	2023	2023-12-12 14:49:16	2023-12-12 15:36:32	1	47.27	PLANNED INTENTIONAL	Non-storm
NE23121200683	JEWEL8686	2023	2023-12-12 15:06:58	2023-12-12 17:28:05	1	141.12	EQUIPMENT FAILURE	Non-storm
SE23121200638	GDRIV2220	2023	2023-12-12 15:13:08	2023-12-12 15:47:48	1	34.67	PLANNED INTENTIONAL	Non-storm
SE23121200619	GDRIV2199	2023	2023-12-12 15:47:55	2023-12-12 16:26:25	1	38.5	PLANNED INTENTIONAL	Non-storm
SE23121200744	EVRGN1062	2023	2023-12-12 17:00:55	2023-12-13 02:41:43	1	580.8	EQUIPMENT FAILURE	Non-storm
NW23121200703	BLMFD8882	2023	2023-12-12 17:12:52	2023-12-12 17:33:56	1	21.07	EQUIPMENT FAILURE	Non-storm
NE23121200781	YATES0312	2023	2023-12-12 19:07:19	2023-12-12 19:53:23	54	2394.94	EQUIPMENT FAILURE	Non-storm
NW23121200702	WIXOM8905	2023	2023-12-12 20:22:27	2023-12-12 21:18:19	2	76.14	EQUIPMENT FAILURE	Non-storm
SW23121200820	HAGER9436	2023	2023-12-12 21:30:41	2023-12-13 01:58:40	1	267.98	EQUIPMENT FAILURE	Non-storm
SE23121200449	ANNCH1373	2023	2023-12-12 21:32:14	2023-12-12 21:39:35	1	7.35	CUSTOMER EQUIPMENT	Non-storm
SE23121200394	EVRGN2166	2023	2023-12-12 21:40:50	2023-12-12 22:16:30	1	35.67	NO ISSUES FOUND	Non-storm
SE23121200370	EVRGN2166	2023	2023-12-12 21:41:25	2023-12-12 22:15:31	1	34.1	NO ISSUES FOUND	Non-storm
NW23121200827	MILFD9248	2023	2023-12-12 22:11:26	2023-12-13 00:57:27	72	11222.3	EQUIPMENT FAILURE	Non-storm
NW23121200830	MILFD9248	2023	2023-12-12 22:11:29	2023-12-13 00:12:23	4	483.1	EQUIPMENT FAILURE	Non-storm
NW23121300017	CLYDE8910	2023	2023-12-13 02:23:08	2023-12-13 07:15:51	1	292.72	EQUIPMENT FAILURE	Non-storm
NW23121300052	HURST9842	2023	2023-12-13 03:47:29	2023-12-13 06:21:57	794	91010.14	NO ISSUES FOUND	Non-storm
NW23121300037	WOLFH8838	2023	2023-12-13 04:41:50	2023-12-13 06:21:50	2	199.86	EQUIPMENT FAILURE	Non-storm
NW23121300151	KELOG8121	2023	2023-12-13 04:41:50	2023-12-13 06:21:51	4	398.76	EQUIPMENT FAILURE	Non-storm
NW23121300174	HURST9842	2023	2023-12-13 04:41:53	2023-12-13 06:21:49	1	99.93	NO ISSUES FOUND	Non-storm
NW23121300205	HURST9842	2023	2023-12-13 04:41:54	2023-12-13 06:20:49	1	98.92	EQUIPMENT FAILURE	Non-storm
NW23121300154	KELOG8121	2023	2023-12-13 04:41:55	2023-12-13 06:21:55	4	399.78	EQUIPMENT FAILURE	Non-storm
NW23121300105	HURST9842	2023	2023-12-13 04:41:57	2023-12-13 06:20:57	1	99	NO ISSUES FOUND	Non-storm
NW23121300113	HURST9842	2023	2023-12-13 04:41:57	2023-12-13 05:53:53	1	71.93	NO ISSUES FOUND	Non-storm
NW23121300166	QTNRD0322	2023	2023-12-13 05:34:21	2023-12-13 13:13:24	1	459.05	EQUIPMENT FAILURE	Non-storm
NW23121300172	QTNRD1409	2023	2023-12-13 05:34:26	2023-12-13 13:13:27	1	459.02	EQUIPMENT FAILURE	Non-storm
SW23121300181	DIMND9875	2023	2023-12-13 06:14:03	2023-12-13 10:58:04	1	129.93	EQUIPMENT FAILURE	Non-storm
NW23121300183	MADRD9933	2023	2023-12-13 06:32:42	2023-12-13 19:19:12	1	766.5	EQUIPMENT FAILURE	Non-storm
SE23121200796	HIKRY1597	2023	2023-12-13 08:09:21	2023-12-13 08:18:45	1	9.4	EQUIPMENT FAILURE	Non-storm
SE23121400081	APPOL1270	2023	2023-12-13 08:12:18	2023-12-14 11:36:42	1	1644.4	METER / BLOCKS	Non-storm
SE23121300207	GNSTN0444	2023	2023-12-13 08:31:00	2023-12-13 10:00:12	1	89.2	PLANNED INTENTIONAL	Non-storm
SE23121200780	MOUND1453	2023	2023-12-13 08:38:39	2023-12-13 08:46:42	1	8.05	EQUIPMENT FAILURE	Non-storm
NW23121300255	MADRD9862	2023	2023-12-13 08:54:35	2023-12-13 12:33:55	1	219.33	ANIMAL	Non-storm
SE23121300259	GDRIV2199	2023	2023-12-13 08:59:20	2023-12-13 12:38:09	8	689.06	PLANNED INTENTIONAL	Non-storm
NE23121300319	PRKRD8779	2023	2023-12-13 09:05:28	2023-12-13 09:28:07	1	22.65	NO ISSUES FOUND	Non-storm
SE23121300241	PULFD2224	2023	2023-12-13 09:08:58	2023-12-13 12:32:38	1	203.67	PLANNED INTENTIONAL	Non-storm
NW23121300253	HURST9853	2023	2023-12-13 09:10:31	2023-12-13 09:26:26	1	15.92	PLANNED INTENTIONAL	Non-storm
SE23121300603	GDRIV2199	2023	2023-12-13 09:17:07	2023-12-13 12:26:19	2	144.01	PLANNED INTENTIONAL	Non-storm
SE23121300272	GDRIV2199	2023	2023-12-13 09:24:42	2023-12-13 09:35:54	1	11.2	PLANNED INTENTIONAL	Non-storm
SE23121300268	PULFD2111	2023	2023-12-13 09:29:49	2023-12-13 12:09:48	7	892.46	PLANNED INTENTIONAL	Non-storm
NW23121300284	MALTA8481	2023	2023-12-13 09:29:51	2023-12-13 09:44:28	11	160.37	PLANNED INTENTIONAL	Non-storm
NE23121300288	OTSGO8762	2023	2023-12-13 09:35:23	2023-12-13 10:00:17	1	24.9	PLANNED INTENTIONAL	Non-storm
SW23121300301	BLCRK8011	2023	2023-12-13 09:37:52	2023-12-13 17:13:21	8	3643.52	ANIMAL	Non-storm
SE23121300303	PULFD2111	2023	2023-12-13 09:39:30	2023-12-13 10:59:24	2	159.8	PLANNED INTENTIONAL	Non-storm
SE23121300310	GNSTN1319	2023	2023-12-13 09:40:44	2023-12-13 10:30:40	1	49.93	PLANNED INTENTIONAL	Non-storm
SE23121300316	LAMBT1485	2023	2023-12-13 09:41:08	2023-12-13 10:35:25	8	432.34	PLANNED INTENTIONAL	Non-storm
SE23121300351	LAMBT1485	2023	2023-12-13 09:41:09	2023-12-13 10:35:12	1	54.05	PLANNED INTENTIONAL	Non-storm
NW23121300298	BARTL4032	2023	2023-12-13 09:43:25	2023-12-13 11:27:21	12	1247.89	PLANNED INTENTIONAL	Non-storm
NW23121300335	BARTL4032	2023	2023-12-13 09:43:27	2023-12-13 11:27:22	1	103.92	PLANNED INTENTIONAL	Non-storm
SE23121300325	PULFD2111	2023	2023-12-13 09:49:00	2023-12-13 11:50:03	2	241.92	PLANNED INTENTIONAL	Non-storm
NE23121300332	HOSTN8746	2023	2023-12-13 09:50:24	2023-12-13 10:50:26	2	120	PLANNED INTENTIONAL	Non-storm
SW23121300343	CHILS9845	2023	2023-12-13 09:52:05	2023-12-13 10:26:44	1	34.65	EQUIPMENT FAILURE	Non-storm
SE23121300542	LAUDR1272	2023	2023-12-13 09:55:25	2023-12-13 11:09:18	1	73.88	NO CAUSE	Non-storm
NW23121300352	ORION9080	2023	2023-12-13 09:57:16	2023-12-13 11:28:17	46	4150.8	WIND	Non-storm
NW23121300356	CLKSN8860	2023	2023-12-13 09:58:09	2023-12-13 13:08:07	3	569.67	ANIMAL	Non-storm
SE23121300292	LAUDR1272	2023	2023-12-13 10:03:46	2023-12-13 11:12:09	1	68.38	PLANNED INTENTIONAL	Non-storm
SE23121300359	PULFD2155	2023	2023-12-13 10:12:27	2023-12-13 11:00:29	1	48.03	PLANNED INTENTIONAL	Non-storm
SE23121300366	LAUDR1272	2023	2023-12-13 10:13:01	2023-12-13 11:38:23	2	161.75	PLANNED INTENTIONAL	Non-storm
NE23121300194	MAYVL0303	2023	2023-12-13 10:17:41	2023-12-13 11:45:49	1	88.13	EQUIPMENT FAILURE	Non-storm
SW23121300380	HEMLK1952	2023	2023-12-13 10:20:12	2023-12-13 13:31:41	8	1531.14	PLANNED INTENTIONAL	Non-storm
SW23121300724	DRAKE9066	2023	2023-12-13 10:23:05	2023-12-13 15:20:47	2428	390902.15	PUBLIC INTERFERENCE	Non-storm
SW23121300867	DRAKE9066	2023	2023-12-13 10:23:05	2023-12-13 19:22:50	1	539.75	PUBLIC INTERFERENCE	Non-storm
SW23121300919	DRAKE9066	2023	2023-12-13 10:23:05	2023-12-13 19:22:26	1	539.35	NO ISSUES FOUND	Non-storm
SE23121300361	PULFD2155	2023	2023-12-13 10:23:53	2023-12-13 10:56:55	1	33.03	PLANNED INTENTIONAL	Non-storm
SW23121300390	PAUL0350	2023	2023-12-13 10:24:02	2023-12-13 10:42:13	643	11211.86	TROUBLE INTENTIONAL	Non-storm
NW23121300377	SPKNE8842	2023	2023-12-13 10:24:43	2023-12-13 10:49:34	3	73.45	PLANNED INTENTIONAL	Non-storm
SW23121300647	PAUL0350	2023	2023-12-13 10:24:52	2023-12-13 10:41:33	1	16.68	CUSTOMER EQUIPMENT	Non-storm
SW23121300435	ZEBRA9476	2023	2023-12-13 10:24:53	2023-12-13 18:52:05	1	507.2	CUSTOMER EQUIPMENT	Non-storm
SW23121300436	ZEBRA9476	2023	2023-12-13 10:24:55	2023-12-13 18:52:06	1	507.18	ANIMAL	Non-storm
NE23121300372	BREWR8840	2023	2023-12-13 10:25:36	2023-12-13 10:39:23	1	13.78	PLANNED INTENTIONAL	Non-storm
SE23121300419	PULFD0419	2023	2023-12-13 10:27:22	2023-12-13 11:53:49	1	86.45	PLANNED INTENTIONAL	Non-storm
NW23121300428	HURST9853	2023	2023-12-13 10:33:33	2023-12-13 10:49:41	1	16.13	PLANNED INTENTIONAL	Non-storm
NW23121200564	BRUCE8953	2023	2023-12-13 10:35:01	2023-12-13 11:53:22	3	197.55	EQUIPMENT FAILURE	Non-storm
SE23121300449	LAUDR1554	2023	2023-12-13 10:35:55	2023-12-13 12:32:52	2	230.43	PLANNED INTENTIONAL	Non-storm
NW23121300468	KEEGO0312	2023	2023-12-13 10:36:29	2023-12-13 15:26:03	3	868.02	PLANNED INTENTIONAL	Non-storm
SE23121300370	SRGNT9129	2023	2023-12-13 10:36:48	2023-12-13 11:54:56	1	78.13	PLANNED INTENTIONAL	Non-storm
NW23121300465	OSPRY8683	2023	2023-12-13 10:37:28	2023-12-13 12:23:42	5	528.63	EQUIPMENT FAILURE	Non-storm
SE23121300375	GDRIV1297	2023	2023-12-13 10:39:23	2023-12-13 11:25:11	1	45.8	PLANNED INTENTIONAL	Non-storm
SW23121300758	PETER9417	2023	2023-12-13 10:40:17	2023-12-13 17:27:28	1	368.37	EQUIPMENT FAILURE	Non-storm
SE23121300481	PULFD2111	2023	2023-12-13 10:52:52	2023-12-13 12:21:47	5	442.53	PLANNED INTENTIONAL	Non-storm
SE23121300572	PULFD2111	2023	2023-12-13 10:52:53	2023-12-13 12:20:50	1	87.95	PLANNED INTENTIONAL	Non-storm
SE23121300505	GNSTN1319	2023	2023-12-13 10:54:22	2023-12-13 11:56:18	1	61.93	PLANNED INTENTIONAL	Non-storm
NE23121300509	OMEGA8444	2023	2023-12-13 11:03:57	2023-12-13 16:58:04	2	707.94	ANIMAL	Non-storm
SE23121300515	SRGNT8250	2023	2023-12-13 11:05:26	2023-12-13 11:34:20	1	28.9	PLANNED INTENTIONAL	Non-storm
SW23121300504	HEMLK1952	2023	2023-12-13 11:06:06	2023-12-13 14:19:33	6	1061.96	PLANNED INTENTIONAL	Non-storm
SW23121300551	HEMLK1952	2023	2023-12-13 11:06:14	2023-12-13 13:55:05	1	168.85	PLANNED INTENTIONAL	Non-storm
SW23121300541	HEMLK1952	2023	2023-12-13 11:06:17	2023-12-13 13:55:07	1	168.83	PLANNED INTENTIONAL	Non-storm
SE23121300511	NAVAR2066	2023	2023-12-13 11:08:27	2023-12-13 11:25:10	85	1403.94	PLANNED INTENTIONAL	Non-storm
SE23121300777	COOLG2204	2023	2023-12-13 11:09:02	2023-12-13 17:47:06	1	398.07	TREEIROW	Non-storm
NW23121300517	HURST9853	2023	2023-12-13 11:13:12	2023-12-13 11:20:00	1	6.8	PLANNED INTENTIONAL	Non-storm
NW23121300500	KERNB902	2023	2023-12-13 11:13:25	2023-12-13 11:33:01	13	252.42	PLANNED INTENTIONAL	Non-storm
SE23121300624	null	2023	2023-12-13 11:18:33	2023-12-13 15:02:07	1	223.57	PLANNED INTENTIONAL	Non-storm
NE23121300549	CENTR0348	2023	2023-12-13 11:27:32	2023-12-13 14:05:39	11	1736.7	EQUIPMENT FAILURE	Non-storm

NE23121300548	MTCLM0306	2023	2023-12-13 11:28:20	2023-12-13 12:45:02	33	2529.01	ANIMAL	Non-storm
NE23121300552	APLGT0312	2023	2023-12-13 11:39:26	2023-12-13 11:56:03	1	16.62	PLANNED INTENTIONAL	Non-storm
NW23121300557	HURST9853	2023	2023-12-13 11:41:27	2023-12-13 11:50:05	1	8.63	PLANNED INTENTIONAL	Non-storm
NW23121300578	DAVIS8835	2023	2023-12-13 11:42:59	2023-12-13 16:59:11	27	8536.11	EQUIPMENT FAILURE	Non-storm
NW23121300748	DAVIS8835	2023	2023-12-13 11:42:59	2023-12-13 16:59:05	1	316.1	NO ISSUES FOUND	Non-storm
NW23121300581	DAVIS8835	2023	2023-12-13 11:43:00	2023-12-13 16:59:04	2	632.14	NO ISSUES FOUND	Non-storm
SW23121300570	GLBRT9373	2023	2023-12-13 11:45:54	2023-12-13 12:25:42	1	39.8	PLANNED INTENTIONAL	Non-storm
SW23121300575	SALIN9788	2023	2023-12-13 11:47:16	2023-12-13 13:01:21	9	666.21	PLANNED INTENTIONAL	Non-storm
SE23121300563	GDRIV1050	2023	2023-12-13 11:54:18	2023-12-13 12:38:06	1	43.8	PLANNED INTENTIONAL	Non-storm
SE23121300630	WEBST1812	2023	2023-12-13 11:56:16	2023-12-13 14:00:21	1	124.08	PLANNED INTENTIONAL	Non-storm
SE23121300601	LAMBT1485	2023	2023-12-13 12:02:52	2023-12-13 12:44:37	5	208.6	PLANNED INTENTIONAL	Non-storm
NE23121300605	APLGT0312	2023	2023-12-13 12:05:04	2023-12-13 13:16:02	1	70.97	PLANNED INTENTIONAL	Non-storm
SW23121300618	GLBRT9373	2023	2023-12-13 12:15:03	2023-12-13 12:59:20	23	1010.77	PLANNED INTENTIONAL	Non-storm
NE23121300857	JACOB8698	2023	2023-12-13 12:36:20	2023-12-14 08:43:29	1	1207.15	ANIMAL	Non-storm
SE23121300645	LAUDR1272	2023	2023-12-13 12:42:34	2023-12-13 13:20:48	1	38.23	PLANNED INTENTIONAL	Non-storm
NW23121300657	CAMDN8284	2023	2023-12-13 12:46:50	2023-12-13 15:26:21	10	1592.36	WIND	Non-storm
NW23121300670	CAMDN8284	2023	2023-12-13 12:46:50	2023-12-13 15:26:32	9	1434.13	NO ISSUES FOUND	Non-storm
NE23121300666	STEPH8522	2023	2023-12-13 12:46:51	2023-12-13 13:41:20	1	54.48	EQUIPMENT FAILURE	Non-storm
SE23121300652	GNSTN1319	2023	2023-12-13 12:47:37	2023-12-13 13:12:25	1	24.8	PLANNED INTENTIONAL	Non-storm
NE23121300606	PINGV0328	2023	2023-12-13 12:56:46	2023-12-13 13:19:13	7	126.33	EQUIPMENT FAILURE	Non-storm
SE23121300660	EIGMI1512	2023	2023-12-13 13:03:26	2023-12-13 13:21:46	1	18.33	PLANNED INTENTIONAL	Non-storm
SE23121300681	LAUDR1272	2023	2023-12-13 13:16:54	2023-12-13 13:46:24	1	29.5	PLANNED INTENTIONAL	Non-storm
NW23121300688	HURST9853	2023	2023-12-13 13:27:51	2023-12-13 13:49:53	1	22.03	PLANNED INTENTIONAL	Non-storm
SE23121300691	LAUDR1272	2023	2023-12-13 13:32:16	2023-12-13 14:20:00	1	47.73	PLANNED INTENTIONAL	Non-storm
SE23121300702	PULFD2155	2023	2023-12-13 13:40:45	2023-12-13 13:49:52	1	9.12	PLANNED INTENTIONAL	Non-storm
NW23121300757	SPKNE8842	2023	2023-12-13 13:42:14	2023-12-13 14:52:22	1	70.13	TREEIROW	Non-storm
SE23121300632	STOPL1078	2023	2023-12-13 13:56:18	2023-12-13 14:22:42	1	17.66	EQUIPMENT FAILURE	Non-storm
SE23121300750	EIGMI1507	2023	2023-12-13 14:04:28	2023-12-13 17:22:13	10	1605.26	PLANNED INTENTIONAL	Non-storm
SE23121300694	SRGNT9129	2023	2023-12-13 14:07:05	2023-12-13 15:10:16	1	63.18	PLANNED INTENTIONAL	Non-storm
NW23121300751	ROBIN9309	2023	2023-12-13 14:21:11	2023-12-13 18:07:13	1	226.03	ANIMAL	Non-storm
NE23121300770	OTSGO8762	2023	2023-12-13 14:54:03	2023-12-13 15:09:41	1	15.63	PLANNED INTENTIONAL	Non-storm
NE23121300791	OTIS8615	2023	2023-12-13 15:05:02	2023-12-13 17:13:40	34	4364.34	ANIMAL	Non-storm
SE23121300785	LAUDR1554	2023	2023-12-13 15:08:46	2023-12-13 15:43:05	1	34.32	PLANNED INTENTIONAL	Non-storm
SE23121300781	GDRIV2220	2023	2023-12-13 15:16:14	2023-12-13 15:43:38	1	27.4	PLANNED INTENTIONAL	Non-storm
NE23121300936	KILGR8772	2023	2023-12-13 17:27:05	2023-12-14 04:13:52	1	646.78	EQUIPMENT FAILURE	Non-storm
SE23121300910	FOX1657	2023	2023-12-13 17:33:54	2023-12-13 18:32:23	2	116.66	TROUBLE INTENTIONAL	Non-storm
NW23121300453	MILFD9246	2023	2023-12-13 17:48:09	2023-12-13 18:31:13	1	43.07	EQUIPMENT FAILURE	Non-storm
SE23121300940	MCGRW1167	2023	2023-12-13 18:41:57	2023-12-13 21:37:56	2	351.56	EQUIPMENT FAILURE	Non-storm
SW23121300621	GAY1926	2023	2023-12-13 18:55:11	2023-12-13 19:59:49	14	935.07	EQUIPMENT FAILURE	Non-storm
SW23121300944	GAY1926	2023	2023-12-13 18:55:19	2023-12-13 19:59:48	1	64.48	EQUIPMENT FAILURE	Non-storm
SW23121300945	GAY1926	2023	2023-12-13 18:55:19	2023-12-13 19:59:47	2	128.95	EQUIPMENT FAILURE	Non-storm
SE23121300961	TIRMN1368	2023	2023-12-13 19:21:30	2023-12-14 02:27:22	1	425.87	PUBLIC INTERFERENCE	Non-storm
NW23121400020	ORION9071	2023	2023-12-13 19:48:14	2023-12-14 08:39:00	1	843.33	EQUIPMENT FAILURE	Non-storm
SW23121300969	GAY1773	2023	2023-12-13 21:04:53	2023-12-14 01:05:07	21	5042.71	EQUIPMENT FAILURE	Non-storm
SW23121300720	HOMER9357	2023	2023-12-13 23:59:56	2023-12-14 00:17:10	1	17.23	CUSTOMER EQUIPMENT	Non-storm
NW23121400003	WDLOW9064	2023	2023-12-14 00:05:47	2023-12-14 02:23:25	1	137.63	EQUIPMENT FAILURE	Non-storm
SW23121400099	WAYNE9401	2023	2023-12-14 00:12:37	2023-12-14 09:27:02	1	554.42	NO ISSUES FOUND	Non-storm
NW23121400068	MADRD9862	2023	2023-12-14 06:16:16	2023-12-14 07:56:19	1	100.05	EQUIPMENT FAILURE	Non-storm
NE23121400057	PRKRD8779	2023	2023-12-14 06:39:00	2023-12-14 10:02:47	1	76.9	EQUIPMENT FAILURE	Non-storm
NE23121400061	BREWR8840	2023	2023-12-14 07:14:37	2023-12-14 09:51:37	2	313.22	EQUIPMENT FAILURE	Non-storm
NW23121500082	TEGER9122	2023	2023-12-14 07:44:42	2023-12-15 12:35:56	1	1731.23	EQUIPMENT FAILURE	Non-storm
NW23121400066	TEGER9122	2023	2023-12-14 07:44:50	2023-12-15 12:34:11	1	1729.35	EQUIPMENT FAILURE	Non-storm
NW23121400191	KELOG8121	2023	2023-12-14 08:23:03	2023-12-14 11:18:13	1	175.17	ANIMAL	Non-storm
NW23121400083	STERL8628	2023	2023-12-14 08:26:49	2023-12-14 09:10:24	61	2651.62	ANIMAL	Non-storm
NW23121400090	STERL8628	2023	2023-12-14 08:26:51	2023-12-14 09:10:19	1	43.47	ANIMAL	Non-storm
NW23121400089	STERL8628	2023	2023-12-14 08:26:53	2023-12-14 09:10:21	1	43.47	ANIMAL	Non-storm
NW23121400087	STERL8628	2023	2023-12-14 08:26:54	2023-12-14 09:10:22	1	43.47	ANIMAL	Non-storm
SW23121400103	SEVLE9367	2023	2023-12-14 08:52:00	2023-12-14 09:45:34	1	53.57	PLANNED INTENTIONAL	Non-storm
NE23121400106	HARPR2515	2023	2023-12-14 08:57:10	2023-12-14 10:54:16	46	5374.53	ANIMAL	Non-storm
NW23121400465	WOLFH8838	2023	2023-12-14 09:04:51	2023-12-14 16:00:14	3	1245.45	EQUIPMENT FAILURE	Non-storm
NW23121400124	BLMFD8888	2023	2023-12-14 09:07:18	2023-12-14 10:46:51	103	10165.66	ANIMAL	Non-storm
SE23121400118	LAMBT1524	2023	2023-12-14 09:09:12	2023-12-14 09:55:16	4	184	PLANNED INTENTIONAL	Non-storm
NW23121400115	HURST9853	2023	2023-12-14 09:09:26	2023-12-14 09:34:55	1	25.48	PLANNED INTENTIONAL	Non-storm
NE23121400227	BREWR8840	2023	2023-12-14 09:10:39	2023-12-14 17:43:42	2	1022.63	ANIMAL	Non-storm
NW23121400127	ARIEL9893	2023	2023-12-14 09:10:49	2023-12-14 10:39:14	25	2204.84	ANIMAL	Non-storm
SE23121400111	PULFD2155	2023	2023-12-14 09:11:36	2023-12-14 11:25:08	1	133.53	PLANNED INTENTIONAL	Non-storm
NE23121400105	BREWR8840	2023	2023-12-14 09:13:49	2023-12-14 09:25:31	1	11.7	PLANNED INTENTIONAL	Non-storm
NW23121400132	HURST9853	2023	2023-12-14 09:16:14	2023-12-14 09:26:05	1	9.85	PLANNED INTENTIONAL	Non-storm
NE23121400620	MTMRA8035	2023	2023-12-14 09:17:15	2023-12-15 03:03:08	1	1065.88	EQUIPMENT FAILURE	Non-storm
NW23121400141	CARTR9115	2023	2023-12-14 09:18:38	2023-12-14 10:53:26	81	7663.84	ANIMAL	Non-storm
NW23121400145	SPKNE8842	2023	2023-12-14 09:22:29	2023-12-14 11:20:52	1	118.38	PLANNED INTENTIONAL	Non-storm
NW23121400205	HURST9853	2023	2023-12-14 09:23:58	2023-12-14 09:38:20	1	14.37	PLANNED INTENTIONAL	Non-storm
SE23121400154	LAMBT1524	2023	2023-12-14 09:25:14	2023-12-14 09:38:36	1	13.37	NO ISSUES FOUND	Non-storm
NW23121400139	SPKNE8842	2023	2023-12-14 09:26:09	2023-12-14 09:32:07	1	5.97	PLANNED INTENTIONAL	Non-storm
NW23121400157	SPKNE8842	2023	2023-12-14 09:32:34	2023-12-14 10:18:33	7	321.42	PLANNED INTENTIONAL	Non-storm
NW23121400171	SPKNE8842	2023	2023-12-14 09:32:36	2023-12-14 10:18:31	2	91.84	ANIMAL	Non-storm
NE23121400173	RICHM8420	2023	2023-12-14 09:33:06	2023-12-14 10:08:50	1	35.73	PLANNED INTENTIONAL	Non-storm
NW23121400166	GENOA8217	2023	2023-12-14 09:33:29	2023-12-14 12:21:12	6	1005.66	ANIMAL	Non-storm
NE23121400319	REMER8807	2023	2023-12-14 09:35:02	2023-12-14 13:28:22	1	233.33	EQUIPMENT FAILURE	Non-storm
NW23121400167	HURST9853	2023	2023-12-14 09:41:33	2023-12-14 09:47:10	1	5.62	PLANNED INTENTIONAL	Non-storm
SE23121400151	LAUDR1554	2023	2023-12-14 09:47:02	2023-12-14 10:39:53	2	97.9	PLANNED INTENTIONAL	Non-storm
NW23121400188	BISMK8439	2023	2023-12-14 09:51:27	2023-12-14 11:32:39	52	5253.33	ANIMAL	Non-storm
NW23121400184	HURST9853	2023	2023-12-14 09:57:07	2023-12-14 10:09:19	1	12.2	PLANNED INTENTIONAL	Non-storm
SE23121400186	PULFD2111	2023	2023-12-14 09:57:10	2023-12-14 13:15:20	1	198.17	PLANNED INTENTIONAL	Non-storm
SW23121400221	ARGO0323	2023	2023-12-14 09:59:04	2023-12-14 13:46:24	1	227.33	EQUIPMENT FAILURE	Non-storm
NE23121400172	BREWR8840	2023	2023-12-14 10:00:32	2023-12-14 10:26:45	1	26.22	PLANNED INTENTIONAL	Non-storm
NW23121400195	WLNUT9029	2023	2023-12-14 10:01:55	2023-12-14 10:56:31	4	217.68	PLANNED INTENTIONAL	Non-storm
NE23121300905	MACMB8283	2023	2023-12-14 10:02:56	2023-12-14 13:37:43	1	214.78	METER / BLOCKS	Non-storm
SE23121400371	GNSTN1319	2023	2023-12-14 10:04:35	2023-12-14 12:28:17	1	143.7	PLANNED INTENTIONAL	Non-storm
SE23121400297	GNSTN1319	2023	2023-12-14 10:04:37	2023-12-14 12:28:19	1	143.7	PLANNED INTENTIONAL	Non-storm
NW23121400212	WOLFH8838	2023	2023-12-14 10:05:58	2023-12-14 10:38:14	24	774	TROUBLE INTENTIONAL	Non-storm
SE23121400183	GDRIV1297	2023	2023-12-14 10:06:55	2023-12-14 12:44:07	2	109.53	PLANNED INTENTIONAL	Non-storm
SE23121400199	PULFD2111	2023	2023-12-14 10:07:03	2023-12-14 11:30:02	1	82.98	PLANNED INTENTIONAL	Non-storm
NW23121400211	WDLOW9064	2023	2023-12-14 10:08:43	2023-12-14 11:58:10	1	109.45	ANIMAL	Non-storm
NW23121400313	WDLOW9064	2023	2023-12-14 10:08:50	2023-12-14 11:58:19	1	109.48	EQUIPMENT FAILURE	Non-storm
SW23121400200	GLBRT9373	2023	2023-12-14 10:12:58	2023-12-14 13:51:02	13	2634.21	PLANNED INTENTIONAL	Non-storm
SE23121400196	PULFD2111	2023	2023-12-14 10:15:28	2023-12-14 12:03:55	1	108.45	PLANNED INTENTIONAL	Non-storm
SE23121400225	LAUDR1554	2023	2023-12-14 10:15:30	2023-12-14 15:05:29	24	2887.96	PLANNED INTENTIONAL	Non-storm
SE23121400232	LAUDR1554	2023	2023-12-14 10:15:30	2023-12-14 12:05:32	37	4083.98	PLANNED INTENTIONAL	Non-storm
NW23121400193	ALPNE8921	2023	2023-12-14 10:17:08	2023-12-14 10:40:49	1	23.68	PLANNED INTENTIONAL	Non-storm
SW23121300535	YOST9403	2023	2023-12-14 10:21:47	2023-12-14 10:47:41	1	25.9	EQUIPMENT FAILURE	Non-storm
SW23121400208	SEVLE9367	2023	2023-12-14 10:22:28	2023-12-14 10:57:21	5	173.25	PLANNED INTENTIONAL	Non-storm
SE23121400283	PULFD2111	2023	2023-12-14 10:22:58	2023-12-14 12:42:34	5	517.21	PLANNED INTENTIONAL	Non-storm
SE23121400231	GNSTN1319	2023	2023-12-14 10:23:48	2023-12-14 11:08:36	1	44.8	PLANNED INTENTIONAL	Non-storm
NE23121400234	RICHM2415	2023	2023-12-14 10:26:38	2023-12-14 11:10:52	6	75.8	PLANNED INTENTIONAL	Non-storm
SE23121400233	PULFD2155	2023	2023-12-14 10:26:49	2023-12-14 12:03:26	2	192.53	PLANNED INTENTIONAL	Non-storm
SW23121400069	PERU9444	2023	2023-12-14 10:29:24	2023-12-14 11:06:35	1	37.18	METER / BLOCKS	Non-storm
NW23121400239	ALPNE8921	2023	2023-12-14 10:30:45	2023-12-14 11:36:34	1	65.82	PLANNED INTENTIONAL	Non-storm
SE23121400259	SAVAN1086	2023	2023-12-14 10:30:59	2023-12-14 12:29:21	4	322.53	PLANNED INTENTIONAL	Non-storm
SE23121400243	GNSTN1319	2023	2023-12-14 10:33:33	2023-12-14 11:21:29	1	47.93	PLANNED INTENTIONAL	Non-storm
SW23121300690	FRMTN1703	2023	2023-12-14 10:37:09	2023-12-14 10:49:40	1	12.52	EQUIPMENT FAILURE	Non-storm
NW23121400257	HURST9853	2023	2023-12-14 10:45:53	2023-12-14 11:04:49	2	37.84	PLANNED INTENTIONAL	Non-storm
NW23121300484	CHTNT8857	2023	2023-12-14 10:46:42	2023-12-14 11:28:17	1	41.58	EQUIPMENT FAILURE	Non-storm
NW23121400270	ALPNE8921	2023	2023-12-14 10:48:09	2023-12-14 11:22:15	1	34.1	PLANNED INTENTIONAL	Non-storm
SE23121400246	EIGMI1507	2023	2023-12-14 10:49:10	2023-12-14 12:08:14	1	79.07	PLANNED INTENTIONAL	Non-storm
SW23121400267	CULVR0316	2023	2023-12-14 10:49:13	2023-12-14 11:11:59	1	22.77	PLANNED INTENTIONAL	Non-storm
SE23121400280	GDRIV2199	2023	2023-12-14 10:50:49	2023-12-14 12:08:41	1	77.87	PLANNED INTENTIONAL	Non-storm
SE23121400258	LAMBT1485	2023	2023-12-14 10:54:15	2023-12-14 11:47:40	1	53.42	PLANNED INTENTIONAL	Non-storm
NW23121400288	MALTA8481	2023	2023-12-14 10:54:16	2023-12-14 11:20:26	12	297.84	PLANNED INTENTIONAL	Non-storm
SE23121400266	LAMBT1524	2023	2023-12-14 10:56:32	2023-12-14 11:31:22	1	34.83	PLANNED INTENTIONAL	Non-storm
SE23121400300	LAMBT1485	2023	2023-12-14 10:57:57	2023-12-14 11:09:22	22	246.29	PLANNED INTENTIONAL	Non-storm
SW23121500104	GRILE2841	2023	2023-12-14 10:59:15	2023-12-14 11:22:53	1	23.63	EQUIPMENT FAILURE	Non-storm
SW23121400289	HEMLK1952	2023	2023-12-14 11:01:07	2023-12-14 13:15:07	2	267.88	PLANNED INTENTIONAL	Non-storm
NW23121400304	CODY9542	2023	2023-12-14 11:01:49	2023-12-14 16:35:38	1	333.82	ANIMAL	Non-storm
SW23121400305	PROSP0305	2023	2023-12-14 11:08:25	2023-12-14 11:24:27	1	16.03	PLANNED INTENTIONAL	Non-storm
SE23121400311	LAMBT1524	2023	2023-12-14 11:12:42	2023-12-14 11:50:40	1	37.97	PLANNED INTENTIONAL	Non-storm
NW23121400299	ALPNE8921	2023	2023-12-14 11:12:49	2023-12-14 12:11:53	8	142.53	PLANNED INTENTIONAL	Non-storm
NE23121400293	BREWR8840	2023	2023-12-14 11:13:28	2023-12-14 11:33:58	1	20.5	PLANNED INTENTIONAL	Non-storm
NW23121400308	HURST9853	2023	2023-12-14 11:13:34	2023-12-14 11:23:06	1	9.53	PLANNED INTENTIONAL	Non-storm
NE23121400336	STEPH8415	2023	2023-12-14 11:19:33	2023-12-14 12:39:31	2	156.85	PLANNED INTENTIONAL	Non-storm
NW23121400310	HURST9853	2023	2023-12-14 11:19:37	2023-12-14 11:50:29	1	30.87	PLANNED INTENTIONAL	Non-storm
NE23121400314	RICHM8420	2023	2023-12-14 11:25:26	2023-12-14 12:16:54	1	51.47	PLANNED INTENTIONAL	Non-storm
SE23121400326	LAMBT1485	2023	2023-12-14 11:26:45	2023-12-14 12:00:31	1	33.77	PLANNED INTENTIONAL	Non-storm
NE23121400029	HARPR2402	2023	2023-12-14 11:30:50	2023-12-14 11:44:14	1	13.4	EQUIPMENT FAILURE	Non-storm
SW23121400334	PTSAN0302	2023	2023-12-14 11:37:19	2023-12-14 15:19:11	1	221.87	PLANNED INTENTIONAL	Non-storm
NE23121400330	PINGV0325	2023	2023-12-14 11:39:03	2023-12-14 12:54:08	1	75.08	PLANNED INTENTIONAL	Non-storm
NW23121400339	HURST9853	2023	2023-12-14 11:39:30	2023-12-14 11:47:31	1	8.02	PLANNED INTENTIONAL	Non-storm
NW23121400327	SLKRK9828	2023	2023-12-14 11:39:45	2023-12-14 13:10:04	12	1081.66	PLANNED INTENTIONAL	Non-storm
NW23121400363	JSLYN9140	2023	2023-12-14 11:41:10	2023-12-14 12:01:40	5	101.86	PLANNED INTENTIONAL	Non-storm
SW23121400337	PERU9441	2023	2023-12-14 11:45:42	2023-12-14 12:28:02	1	42.33	PLANNED INTENTIONAL	Non-storm
SE23121400354	EIGMI1512	2023	2023-12-14 11:51:03	2023-12-14 12:50:47	1	59.73	PLANNED INTENTIONAL	Non-storm
NE23121400366	MENLO8806	2023	2023-12-14 11:51:22	2023-12-14 12:01:41	1	10.32	PLANNED INTENTIONAL	Non-storm
SE23121400356	SRGNT9129	2023	2023-12-14 11:52:18	2023-12-14 13:06:48	9	668.68	PLANNED INTENTIONAL	Non-storm
NE23121400358	MALTA9600	2023	2023-12-14 11:53:41	2023-12-14 13:51:02	36	4215.7	ANIMAL	Non-storm
NW23121400386	PINCK9878	2023	2023-12-14 11:58:52	2023-12-14 16:16:22	1	257.5	METER / BLOCKS	Non-storm
NE23121400377	RICHM2415	2023	2023-12-14 12:05:04	2023-12-14 12:30:52	2	36.2	PLANNED INTENTIONAL	Non-storm
NE23121400376	RICHM2415	2023	2023-12-14 12:06:02	2023-12-14 12:14:30	1	8.47	PLANNED INTENTIONAL	Non-storm
SE23121400381	GDRIV2199	2023	2023-12-14 12:06:13	2023-12-14 12:51:39	1	45.43	PLANNED INTENTIONAL	Non-storm
SE23121400411	GDRIV2199	2023	2023-12-14 12:06:16	2023-12-14 12:51:41	1	45.42	PLANNED INTENTIONAL	Non-storm
NE23121400374	PINGV0325	2023	2023-12-14 12:07:11	2023-12-14 13:45:07	2	139.82	PLANNED INTENTIONAL	Non-storm
SW23121400360	BREWR8840	2023	2023-12-14 12:08:19	2023-12-14 12:46:13	1	37.9	PLANNED INTENTIONAL	Non-storm
SE23121400391	PULFD0419	2023	2023-12-14 12:17:31	2023-12-14 12:49:22	1	31.85	PLANNED INTENTIONAL	Non-storm
NW23121400384	HURST9853	2023	2023-12-14 12:17:50	2023-12-14 12:52:55	1	35.08	PLANNED INTENTIONAL	Non-storm
NE23121400415	APLGT0312	2023	2023-12-14 12:18:33	2023-12-14 12:37:10	1	18.62	PLANNED INTENTIONAL	Non-storm
SE23121400389	PULFD0419	2023	2023-12-14 12:19:16	2023-12-14 12:50:06	1	30.83	PLANNED INTENTIONAL	Non-storm
NW23121400388	HURST9853	2023	2023-12-14 12:20:55	2023-12-14 12:26:04	1	5.15	PLANNED INTENTIONAL	Non-storm
NW23121400527	MALTA8102	2023	2023-12-14 12:21:25	2023-12-14 17:49:51	1	328.43	ANIMAL	Non-storm
NW23121400425	SPKNE8842	2023	2023-12-14 12:40:33	2023-12-14 13:35:52	6	331.16	ANIMAL	Non-storm
NE23121400287	PTHUR2315	2023	2023-12-14 12:43:18	2023-12-14 12:48:21	1	5.05	EQUIPMENT FAILURE	Non-storm
NW23121400416	HURST9853	2023	2023-12-14 12:43:51	2023-12-14 12:54:27	2	20.45	PLANNED INTENTIONAL	Non-storm
SW23121400426	HEMLK1910	2023	2023-12-14 12:51:49	2023-12-14 13:31:26	13	512.91	PLANNED INTENTIONAL	Non-storm
NW23121400437	ALPNE8921	2023	2023-12-14 13:08:43	2023-12-14 13:26:14	1	17.52	PLANNED INTENTIONAL	Non-storm

NW23121400442	ALPNE8921	2023	2023-12-14 13:26:56	2023-12-14 13:47:25	2	40.08	PLANNED INTENTIONAL	Non-storm
NW23121400452	JASON8454	2023	2023-12-14 13:27:52	2023-12-14 14:24:00	3	168.06	ANIMAL	Non-storm
SW23121400449	HEMLK1910	2023	2023-12-14 13:31:40	2023-12-14 13:52:50	3	62.44	PLANNED INTENTIONAL	Non-storm
NW23121400461	SPKNE8842	2023	2023-12-14 13:31:56	2023-12-14 14:12:28	1	40.53	PLANNED INTENTIONAL	Non-storm
NW23121400464	ALPNE8921	2023	2023-12-14 13:55:07	2023-12-14 14:13:26	1	18.32	PLANNED INTENTIONAL	Non-storm
NW23121400492	SPKNE8842	2023	2023-12-14 14:10:27	2023-12-14 14:38:36	22	613.01	PLANNED INTENTIONAL	Non-storm
NW23121400501	MALTA8481	2023	2023-12-14 14:13:21	2023-12-14 14:42:46	16	468.66	EQUIPMENT FAILURE	Non-storm
NW23121400338	STKWL4002	2023	2023-12-14 14:19:01	2023-12-14 14:28:29	1	9.47	METER / BLOCKS	Non-storm
SE23121400512	KORTE1511	2023	2023-12-14 14:27:24	2023-12-14 15:29:41	6	308.85	PLANNED INTENTIONAL	Non-storm
NW23121400517	SPKNE8842	2023	2023-12-14 14:33:53	2023-12-14 15:53:44	6	475.12	NO ISSUES FOUND	Non-storm
NW23121400515	ALPNE8921	2023	2023-12-14 14:34:08	2023-12-14 14:52:35	7	124.81	TROUBLE INTENTIONAL	Non-storm
NW23121400531	SPKNE8842	2023	2023-12-14 14:52:34	2023-12-14 15:25:33	6	197.53	PLANNED INTENTIONAL	Non-storm
NE23121400079	ERIN2422	2023	2023-12-14 14:56:32	2023-12-14 15:05:23	1	8.85	EQUIPMENT FAILURE	Non-storm
NE23121400537	OPAL8572	2023	2023-12-14 15:03:32	2023-12-14 15:44:08	1	40.6	PLANNED INTENTIONAL	Non-storm
NW23121400545	MALTA8481	2023	2023-12-14 15:12:38	2023-12-14 15:27:46	2	29.96	NO ISSUES FOUND	Non-storm
NE23121400554	COTAGE743	2023	2023-12-14 15:31:41	2023-12-14 19:44:52	1	57.03	EQUIPMENT FAILURE	Non-storm
NW23121400574	MALTA8481	2023	2023-12-14 15:56:21	2023-12-14 16:06:42	11	112.5	NO ISSUES FOUND	Non-storm
SW23121400580	WAYNE9366	2023	2023-12-14 17:13:47	2023-12-15 12:45:52	1	1172.08	EQUIPMENT FAILURE	Non-storm
NW23121400638	HURST9853	2023	2023-12-14 17:25:55	2023-12-14 17:42:00	1	16.08	NO ISSUES FOUND	Non-storm
SE23121400640	SOFLD9088	2023	2023-12-14 17:30:30	2023-12-14 17:46:49	157	2450.77	PLANNED INTENTIONAL	Non-storm
SE23121400641	SOFLD9088	2023	2023-12-14 17:31:08	2023-12-14 17:46:50	185	2862.19	PLANNED INTENTIONAL	Non-storm
SW23121400667	BLCRK9332	2023	2023-12-14 17:43:23	2023-12-14 18:08:21	7	174.14	TROUBLE INTENTIONAL	Non-storm
NW23121400679	CLKSN9009	2023	2023-12-14 18:22:29	2023-12-14 20:05:18	3	308.42	TROUBLE INTENTIONAL	Non-storm
NE23121400433	SHAW0312	2023	2023-12-14 18:58:19	2023-12-14 19:22:22	1	24.05	EQUIPMENT FAILURE	Non-storm
NE23121400720	RICHV0301	2023	2023-12-14 19:43:14	2023-12-15 00:34:51	1	291.62	EQUIPMENT FAILURE	Non-storm
SE23121400637	FRSB2117	2023	2023-12-14 21:05:35	2023-12-14 21:13:37	1	8.03	EQUIPMENT FAILURE	Non-storm
SE23121400688	STLUS1136	2023	2023-12-14 22:51:52	2023-12-14 22:58:34	1	6.7	EQUIPMENT FAILURE	Non-storm
SE23121500010	PURTN1246	2023	2023-12-15 00:10:05	2023-12-15 03:18:11	1	188.1	TREEBROW	Non-storm
SE23121400714	GRANT1306	2023	2023-12-15 01:00:42	2023-12-15 01:10:35	1	9.88	EQUIPMENT FAILURE	Non-storm
NE23121500004	BREWR8840	2023	2023-12-15 01:58:45	2023-12-15 02:07:49	1	9.07	EQUIPMENT FAILURE	Non-storm
SE23121500019	PURTN1246	2023	2023-12-15 02:15:08	2023-12-15 03:18:16	12	754.09	TREEBROW	Non-storm
SE23121500030	STLUS1394	2023	2023-12-15 03:29:21	2023-12-15 05:11:49	375	35311.29	PUBLIC INTERFERENCE	Non-storm
SE23121500040	STLUS1394	2023	2023-12-15 03:29:37	2023-12-15 05:09:25	1	99.8	WIND	Non-storm
SE23121500064	STLUS0230	2023	2023-12-15 03:29:38	2023-12-15 05:09:32	19	1895.53	PUBLIC INTERFERENCE	Non-storm
SE23121500072	STLUS1394	2023	2023-12-15 03:29:39	2023-12-15 05:09:27	1	99.8	PUBLIC INTERFERENCE	Non-storm
SE23121500024	STLUS1394	2023	2023-12-15 03:29:40	2023-12-15 05:09:26	1	99.77	PUBLIC INTERFERENCE	Non-storm
SE23121500066	STLUS1394	2023	2023-12-15 03:33:11	2023-12-15 03:56:10	4	91.8	PUBLIC INTERFERENCE	Non-storm
SE23121500021	STLUS1394	2023	2023-12-15 03:39:06	2023-12-15 05:03:36	1	36.38	PUBLIC INTERFERENCE	Non-storm
NE23121500150	BADAX8787	2023	2023-12-15 05:07:09	2023-12-15 09:28:09	1	261	ANIMAL	Non-storm
SW23121500076	MACON8049	2023	2023-12-15 05:41:48	2023-12-15 06:32:26	1	50.63	EQUIPMENT FAILURE	Non-storm
NW23121500111	WALLK1655	2023	2023-12-15 07:53:38	2023-12-15 07:59:15	808	4387.75	PLANNED INTENTIONAL	Non-storm
NW23121500138	WALLK1655	2023	2023-12-15 07:53:46	2023-12-15 08:00:02	1	6.27	NO ISSUES FOUND	Non-storm
NW23121500165	LNGLK8169	2023	2023-12-15 08:25:21	2023-12-15 10:32:03	7	881.68	TREEROW	Non-storm
NW23121500172	LARDO8973	2023	2023-12-15 08:32:13	2023-12-15 08:52:12	10	198.21	EQUIPMENT FAILURE	Non-storm
NE23121500199	ADAMS9131	2023	2023-12-15 08:37:55	2023-12-15 13:50:28	3	937.65	ANIMAL	Non-storm
SW23121500177	WAYNE9446	2023	2023-12-15 08:38:38	2023-12-15 09:22:54	43	1889.29	ANIMAL	Non-storm
SW23121500181	PERU9441	2023	2023-12-15 08:47:04	2023-12-15 11:08:02	9	1226.76	PLANNED INTENTIONAL	Non-storm
SW23121500557	PERU9441	2023	2023-12-15 08:47:09	2023-12-15 11:48:03	1	180.9	PLANNED INTENTIONAL	Non-storm
SE23121500201	LAMBT1485	2023	2023-12-15 08:59:18	2023-12-15 09:22:52	6	141.26	TREEROW	Non-storm
NE23121500187	PINGV0325	2023	2023-12-15 09:00:29	2023-12-15 09:15:37	1	15.13	PLANNED INTENTIONAL	Non-storm
SE23121500191	PULFD2224	2023	2023-12-15 09:03:15	2023-12-15 11:43:03	1	159.8	PLANNED INTENTIONAL	Non-storm
NE23121500556	LNDIS8132	2023	2023-12-15 09:11:39	2023-12-15 12:08:08	181	30247.96	ANIMAL	Non-storm
NE23121500209	LNDIS8132	2023	2023-12-15 09:11:40	2023-12-15 10:24:59	1738	127868.33	ANIMAL	Non-storm
SE23121500262	LAMBT1524	2023	2023-12-15 09:14:32	2023-12-15 09:52:51	1	38.32	PLANNED INTENTIONAL	Non-storm
NW23121500278	ALPNE8921	2023	2023-12-15 09:15:53	2023-12-15 09:38:47	9	200.22	NO ISSUES FOUND	Non-storm
NE23121500194	OTSGO8762	2023	2023-12-15 09:16:09	2023-12-15 09:52:17	71	2555.96	PLANNED INTENTIONAL	Non-storm
SW23121500283	YPSIL0318	2023	2023-12-15 09:19:33	2023-12-15 09:30:43	2	21.94	EQUIPMENT FAILURE	Non-storm
SE23121500284	GDRIV2199	2023	2023-12-15 09:29:16	2023-12-15 10:13:33	1	44.28	PLANNED INTENTIONAL	Non-storm
NE23121500233	ALGON8748	2023	2023-12-15 09:29:36	2023-12-15 11:16:08	4	423.22	PLANNED INTENTIONAL	Non-storm
SE23121500360	PULFD2155	2023	2023-12-15 09:35:48	2023-12-15 10:25:09	1	49.35	PLANNED INTENTIONAL	Non-storm
NW23121500800	COLFK8186	2023	2023-12-15 09:39:04	2023-12-15 16:24:40	3	1216.57	ANIMAL	Non-storm
SE23121500404	PERU9444	2023	2023-12-15 09:39:23	2023-12-15 10:22:22	1	42.98	PUBLIC INTERFERENCE	Non-storm
SE23121500370	LAMBT1524	2023	2023-12-15 09:43:03	2023-12-15 09:59:15	1	16.2	PLANNED INTENTIONAL	Non-storm
SE23121500413	GNSTN0444	2023	2023-12-15 09:45:15	2023-12-15 14:48:53	1	303.63	PLANNED INTENTIONAL	Non-storm
NW23121500988	HURST9853	2023	2023-12-15 09:46:58	2023-12-15 19:09:30	1	562.53	EQUIPMENT FAILURE	Non-storm
SE23121500381	GDRIV2199	2023	2023-12-15 09:52:07	2023-12-15 10:21:48	1	29.68	PLANNED INTENTIONAL	Non-storm
NW23121500393	LILY9120	2023	2023-12-15 09:52:12	2023-12-15 13:49:53	1	237.68	NO ISSUES FOUND	Non-storm
SW23121500406	TRNTY9331	2023	2023-12-15 09:56:27	2023-12-15 11:53:42	2	234.35	EQUIPMENT FAILURE	Non-storm
SW23121500388	SALIN9840	2023	2023-12-15 09:56:28	2023-12-15 11:51:42	1378	158810.34	ANIMAL	Non-storm
SW23121500742	SALIN9788	2023	2023-12-15 09:56:28	2023-12-15 12:41:57	1	165.48	EQUIPMENT FAILURE	Non-storm
SW23121500390	SALIN9788	2023	2023-12-15 09:56:29	2023-12-15 12:42:31	2349	357052.09	ANIMAL	Non-storm
SW23121500463	FLMNG9434	2023	2023-12-15 09:56:32	2023-12-15 11:53:42	1	117.17	EQUIPMENT FAILURE	Non-storm
SW23121500843	SALIN9788	2023	2023-12-15 09:56:32	2023-12-15 12:42:01	1	165.48	NO ISSUES FOUND	Non-storm
SW23121500435	FULER0379	2023	2023-12-15 09:56:38	2023-12-15 11:53:48	1	117.17	NO ISSUES FOUND	Non-storm
SE23121500391	PULFD0419	2023	2023-12-15 09:59:09	2023-12-15 11:20:51	1	81.7	PLANNED INTENTIONAL	Non-storm
NW23121500431	DOVER8204	2023	2023-12-15 10:05:19	2023-12-15 11:10:38	1	65.32	PLANNED INTENTIONAL	Non-storm
SE23121500364	PULFD0419	2023	2023-12-15 10:05:31	2023-12-15 12:12:08	1	126.62	PLANNED INTENTIONAL	Non-storm
NW23121500446	STKWL4010	2023	2023-12-15 10:06:01	2023-12-15 11:27:49	14	1071.23	PLANNED INTENTIONAL	Non-storm
NW23121500270	CAMDN8282	2023	2023-12-15 10:08:50	2023-12-15 11:53:23	26	2716.62	PLANNED INTENTIONAL	Non-storm
NW23121500447	CAMDN8282	2023	2023-12-15 10:08:57	2023-12-15 11:53:23	1	104.43	PLANNED INTENTIONAL	Non-storm
SE23121500445	GNSTN1319	2023	2023-12-15 10:14:59	2023-12-15 11:46:00	1	31.02	PLANNED INTENTIONAL	Non-storm
SW23121500425	SEVLE9367	2023	2023-12-15 10:17:21	2023-12-15 11:05:16	4	190.66	PLANNED INTENTIONAL	Non-storm
NW23121500452	HURST9853	2023	2023-12-15 10:20:43	2023-12-15 11:06:48	1	46.08	PLANNED INTENTIONAL	Non-storm
SW23121500934	SHELD8185	2023	2023-12-15 10:22:00	2023-12-15 21:38:03	1	676.05	EQUIPMENT FAILURE	Non-storm
NW23121500517	DUDLY8906	2023	2023-12-15 10:24:43	2023-12-15 11:52:41	1	87.97	PUBLIC INTERFERENCE	Non-storm
NW23121500484	HANCK8136	2023	2023-12-15 10:24:58	2023-12-15 11:55:05	27	1916.78	PUBLIC INTERFERENCE	Non-storm
NW23121500520	HANCK8136	2023	2023-12-15 10:25:08	2023-12-15 11:29:07	1	63.98	NO ISSUES FOUND	Non-storm
SE23121500464	LAMBT1485	2023	2023-12-15 10:25:28	2023-12-15 10:42:50	6	103.39	PLANNED INTENTIONAL	Non-storm
NW23121500509	PROUD9475	2023	2023-12-15 10:29:47	2023-12-15 12:32:29	3	366.55	ANIMAL	Non-storm
NW23121500494	PROUD9475	2023	2023-12-15 10:29:55	2023-12-15 12:31:46	1	121.85	ANIMAL	Non-storm
SW23121500481	HEMLK1910	2023	2023-12-15 10:33:01	2023-12-15 11:21:27	8	387.12	PLANNED INTENTIONAL	Non-storm
SE23121500527	PULFD0419	2023	2023-12-15 10:35:23	2023-12-15 11:20:47	1	45.4	PLANNED INTENTIONAL	Non-storm
NW23121500525	DAVIS8202	2023	2023-12-15 10:37:52	2023-12-15 12:02:51	3	254.63	ANIMAL	Non-storm
SE23121500530	GNSTN1295	2023	2023-12-15 10:42:48	2023-12-15 11:32:31	1	49.72	PLANNED INTENTIONAL	Non-storm
SE23121500532	GNSTN1319	2023	2023-12-15 10:46:49	2023-12-15 11:12:13	1	25.4	PLANNED INTENTIONAL	Non-storm
NW23121500333	ALPNE8921	2023	2023-12-15 10:52:16	2023-12-15 11:54:47	8	280.68	PLANNED INTENTIONAL	Non-storm
NW23121500543	SPKNE9056	2023	2023-12-15 10:54:46	2023-12-15 12:31:51	42	4070.04	ANIMAL	Non-storm
NW23121500587	SPKNE9056	2023	2023-12-15 10:54:54	2023-12-15 12:31:48	1	96.9	ANIMAL	Non-storm
NE23121500562	OTIS8181	2023	2023-12-15 11:00:56	2023-12-15 13:13:50	12	1591.16	ANIMAL	Non-storm
NE23121500877	SUTTN0383	2023	2023-12-15 11:06:27	2023-12-15 16:43:13	1	336.77	PUBLIC INTERFERENCE	Non-storm
SW23121500627	GLBRT9373	2023	2023-12-15 11:06:34	2023-12-15 13:09:35	2	210.6	TROUBLE INTENTIONAL	Non-storm
NW23121500616	ALPNE8921	2023	2023-12-15 11:07:05	2023-12-15 11:40:32	1	33.45	PLANNED INTENTIONAL	Non-storm
NE23121500567	RICHM2496	2023	2023-12-15 11:08:21	2023-12-15 13:09:49	7	626.67	PLANNED INTENTIONAL	Non-storm
NW23121500901	HURST9853	2023	2023-12-15 11:14:54	2023-12-15 17:45:03	1	390.15	EQUIPMENT FAILURE	Non-storm
NW23121500596	DUDLY8906	2023	2023-12-15 11:16:09	2023-12-15 11:52:27	1	36.3	PUBLIC INTERFERENCE	Non-storm
NW23121500589	DUDLY8906	2023	2023-12-15 11:16:10	2023-12-15 11:52:04	1	35.9	PUBLIC INTERFERENCE	Non-storm
NW23121500597	DUDLY8906	2023	2023-12-15 11:16:11	2023-12-15 11:52:06	2	71.85	PUBLIC INTERFERENCE	Non-storm
NW23121500592	DUDLY8906	2023	2023-12-15 11:16:12	2023-12-15 11:52:29	1	36.28	PUBLIC INTERFERENCE	Non-storm
NW23121500613	WOLFH8822	2023	2023-12-15 11:16:36	2023-12-15 13:07:03	1	110.45	PLANNED INTENTIONAL	Non-storm
NW23121500577	STERL8628	2023	2023-12-15 11:17:37	2023-12-15 12:22:41	181	11708.59	TREEBROW	Non-storm
NW23121500566	HURST9853	2023	2023-12-15 11:21:19	2023-12-15 13:12:12	1	110.88	PLANNED INTENTIONAL	Non-storm
SW23121500595	HEMLK1952	2023	2023-12-15 11:32:37	2023-12-15 12:01:42	7	195.18	PLANNED INTENTIONAL	Non-storm
NE23121500621	MEDNA8412	2023	2023-12-15 11:38:02	2023-12-15 12:27:06	1	49.07	PLANNED INTENTIONAL	Non-storm
NE23121500568	PINGV0325	2023	2023-12-15 11:50:45	2023-12-15 12:20:06	1	29.35	PLANNED INTENTIONAL	Non-storm
SE23121500585	VILLA1555	2023	2023-12-15 11:53:25	2023-12-15 12:08:14	1	14.82	NO CAUSE	Non-storm
NE23121500207	CAPAC8013	2023	2023-12-15 11:55:29	2023-12-15 12:52:52	1	57.38	EQUIPMENT FAILURE	Non-storm
SE23121500652	GDRIV1297	2023	2023-12-15 11:58:35	2023-12-15 12:59:25	2	121.55	PLANNED INTENTIONAL	Non-storm
SE23121500689	SRGNT9129	2023	2023-12-15 12:08:09	2023-12-15 13:09:46	1	61.62	PLANNED INTENTIONAL	Non-storm
NW23121500729	STRFD9093	2023	2023-12-15 12:09:04	2023-12-15 22:58:56	1	649.87	ANIMAL	Non-storm
NW23121500588	STERL8628	2023	2023-12-15 12:10:02	2023-12-15 14:39:46	32	4671.9	PUBLIC INTERFERENCE	Non-storm
NE23121500674	PINGV0325	2023	2023-12-15 12:17:00	2023-12-15 12:59:16	2	84.45	PLANNED INTENTIONAL	Non-storm
NE23121500614	PINGV0325	2023	2023-12-15 12:19:45	2023-12-15 13:36:22	1	76.62	PLANNED INTENTIONAL	Non-storm
SW23121500669	HEMLK1910	2023	2023-12-15 12:20:11	2023-12-15 13:05:17	5	225.17	PLANNED INTENTIONAL	Non-storm
NW23121500688	HURST9853	2023	2023-12-15 12:21:06	2023-12-15 12:33:47	1	12.68	PLANNED INTENTIONAL	Non-storm
NW23121500700	HURST9853	2023	2023-12-15 12:38:21	2023-12-15 12:54:42	1	16.35	PLANNED INTENTIONAL	Non-storm
SW23121500711	HINES9394	2023	2023-12-15 12:39:44	2023-12-15 12:49:49	2	20	EQUIPMENT FAILURE	Non-storm
SW23121500541	BURTN0381	2023	2023-12-15 12:40:33	2023-12-15 14:18:07	1	97.57	PLANNED INTENTIONAL	Non-storm
NE23121500793	PTSAN0301	2023	2023-12-15 12:50:10	2023-12-15 17:31:45	1	281.58	EQUIPMENT FAILURE	Non-storm
SE23121500790	PULFD2155	2023	2023-12-15 13:00:42	2023-12-15 14:03:38	1	62.93	NO ISSUES FOUND	Non-storm
SW23121400633	ELM9365	2023	2023-12-15 13:03:38	2023-12-15 13:34:35	1	30.95	EQUIPMENT FAILURE	Non-storm
NE23121500732	BEACH8601	2023	2023-12-15 13:13:22	2023-12-15 14:47:34	479	45036.92	EQUIPMENT FAILURE	Non-storm
NE23121501042	BEACH8601	2023	2023-12-15 13:13:28	2023-12-15 14:47:29	1	94.02	CUSTOMER EQUIPMENT	Non-storm
SW23121500687	SEVLE9367	2023	2023-12-15 13:15:00	2023-12-15 13:59:20	1	44.33	PLANNED INTENTIONAL	Non-storm
SW23121500745	SEVLE9367	2023	2023-12-15 13:15:14	2023-12-15 14:07:07	8	372.08	PLANNED INTENTIONAL	Non-storm
NW23121500743	SPKNE8842	2023	2023-12-15 13:20:56	2023-12-15 15:14:39	2	199.97	PLANNED INTENTIONAL	Non-storm
NW23121500721	ALPNE8921	2023	2023-12-15 13:21:28	2023-12-15 13:44:02	1	22.57	PLANNED INTENTIONAL	Non-storm
SE23121500772	LAUDR1554	2023	2023-12-15 13:29:22	2023-12-15 14:50:29	1	81.12	PLANNED INTENTIONAL	Non-storm
NW23121500749	HURST9853	2023	2023-12-15 13:31:21	2023-12-15 13:57:04	1	25.72	PLANNED INTENTIONAL	Non-storm
SE23121500761	SAVAN1086	2023	2023-12-15 13:33:58	2023-12-15 14:55:56	1	81.97	PLANNED INTENTIONAL	Non-storm
NW23121500775	SPKNE8842	2023	2023-12-15 13:34:58	2023-12-15 14:01:05	1	26.12	PLANNED INTENTIONAL	Non-storm
SE23121500780	GDRIV2199	2023	2023-12-15 13:39:17	2023-12-15 14:01:39	1	22.37	PLANNED INTENTIONAL	Non-storm
SE23121500658	ANGLA9060	2023	2023-12-15 13:39:20	2023-12-15 14:19:52	1	40.53	EQUIPMENT FAILURE	Non-storm
SW23121500821	PERU9441	2023	2023-12-15 13:52:57	2023-12-15 20:16:36	1	383.65	EQUIPMENT FAILURE	Non-storm
NE23121500798	SHORS1908	2023	2023-12-15 13:54:55	2023-12-15 17:14:38	1	199.72	EQUIPMENT FAILURE	Non-storm
NW23121500795	SPKNE8842	2023	2023-12-15 13:58:08	2023-12-15 15:15:55	15	1162.43	PLANNED INTENTIONAL	Non-storm
SW23121500812	GLBRT9381	2023	2023-12-15 14:00:01	2023-12-15 14:43:02	4	172.02	EQUIPMENT FAILURE	Non-storm
SE23121500693	GRANT1494	2023	2023-12-15 14:03:51	2023-12-17 05:49:28	1	1928.38	CUSTOMER EQUIPMENT	Non-storm
SW23121500796	PERU9440	2023	2023-12-15 14:04:33	2023-12-15 14:11:08	1	6.58	PLANNED INTENTIONAL	Non-storm
NE23121500805	PINGV0325	2023	2023-12-15 14:11:16	2023-12-15 14:25:44	1	14.47	PLANNED INTENTIONAL	Non-storm
NE23121500862	BRAZL8402	2023	2023-12-15 14:37:41	2023-12-15 20:44:22	2	733.35	NO ISSUES FOUND	Non-storm
NE23121501040	BRAZL8402	2023	2023-12-15 14:37:42	2023-12-15 20:44:22	1	366.67	EQUIPMENT FAILURE	Non-storm
SE23121500874	DALY1738	2023	2023-12-15 14:58:26	2023-12-15 17:02:52	1	124.43	NO ISSUES FOUND	Non-storm
NE23121500462	TCOMA8311	2023	2023-12-15 15:05:51	2023-12-15 16:53:05	1	107.23	EQUIPMENT FAILURE	Non-storm
NW23121500865	KELOG8121	2023	2023-12-15 15:07:04	2023-12-15 15:18:10	1	11.1	PLANNED INTENTIONAL	Non-storm
NW23121500911	EUCLD9084	2023	2023-12-15 15:43:01	2023-12-15 17:01:41	3	234.7	ANIMAL	Non-storm
NW23121501002	COLFX9880	2023	2023-12-15 16:16:49	2023-12-15 19:20:01	1	183.2	TREEBROW	Non-storm
NW23121500940	MADRD9933	2023	2023-12-15 16:24:30	2023-12-15 18:39:19	1	134.82	TREEBROW	Non-storm
NW23121500929	PAGE9495	2023	2023-12-15 16:36:34	2023-12-15 20:45:15	2	497.02	TREEROW	Non-storm
NW23121501001	PAGE9495	2023	2023-12-15 16:36:40	2023-12-15 20:45:24	5	1242.56	NO ISSUES FOUND	Non-storm
NW23121500941	PAGE9495	2023	2023-12-15 16:36:41	2023-12-15 20:45:12	1	248.52	NO ISSUES FOUND	Non-storm
NW23121500928	PAGE9495	2023	2023-12-15 16:36:44	2023-12-15 20:45:16	2	497.04	NO ISSUES FOUND	Non-storm
NW23121500994	PAGE9495	2023	2023-12-15 16:36:45	2023-12-15 20:45:16	1	248.52	NO ISSUES FOUND	Non-storm

NW23121500943	PAGE9495	2023	2023-12-15 16:36:53	2023-12-15 20:44:27	1	247.57	NO ISSUES FOUND	Non-storm
NW23121500976	PAGE9495	2023	2023-12-15 16:36:53	2023-12-15 20:45:24	1	248.52	NO ISSUES FOUND	Non-storm
NW23121500939	CLKSN8897	2023	2023-12-15 16:46:55	2023-12-15 19:12:58	6	876.1	EQUIPMENT FAILURE	Non-storm
SE23121500944	LAMBT1456	2023	2023-12-15 16:49:00	2023-12-15 19:42:25	17	1476.87	EQUIPMENT FAILURE	Non-storm
SW23121400734	PERU9440	2023	2023-12-15 17:14:17	2023-12-15 17:53:39	14	547.78	EQUIPMENT FAILURE	Non-storm
NE23121500953	ATKCA0302	2023	2023-12-15 17:50:28	2023-12-15 17:58:29	1	8.02	EQUIPMENT FAILURE	Non-storm
SW23121500560	FISHR8188	2023	2023-12-15 18:40:14	2023-12-15 18:56:40	1	16.43	EQUIPMENT FAILURE	Non-storm
SE23121501047	DENVR1341	2023	2023-12-15 19:32:29	2023-12-16 07:46:27	5	3565.01	WIND	Non-storm
SE23121500983	CRTIS1159	2023	2023-12-15 19:53:00	2023-12-15 20:16:50	1	23.83	EQUIPMENT FAILURE	Non-storm
SW23121501054	POPLR9885	2023	2023-12-15 19:58:57	2023-12-15 21:03:24	1	64.45	EQUIPMENT FAILURE	Non-storm
SE23121501056	STLUS1394	2023	2023-12-15 20:29:54	2023-12-16 01:27:38	16	4760.85	WIND	Non-storm
SE23121501060	STLUS2075	2023	2023-12-15 20:29:57	2023-12-16 01:27:39	3	892.62	WIND	Non-storm
SE23121501066	STLUS1394	2023	2023-12-15 20:30:00	2023-12-16 01:27:34	1	297.57	WIND	Non-storm
NE23121501072	PINGV0325	2023	2023-12-15 21:23:35	2023-12-15 21:34:37	1	11.03	EQUIPMENT FAILURE	Non-storm
NW23121600044	ALPNE8919	2023	2023-12-16 08:07:22	2023-12-16 10:18:56	9	1182.6	TREEROW	Non-storm
NW23121600064	ALPNE9724	2023	2023-12-16 08:07:24	2023-12-16 10:18:49	1	131.42	ANIMAL	Non-storm
NW23121600047	WLNUT9029	2023	2023-12-16 08:47:31	2023-12-16 14:20:07	1	332.6	EQUIPMENT FAILURE	Non-storm
NW23121600041	WLNUT9029	2023	2023-12-16 08:47:33	2023-12-16 14:20:08	1	332.58	EQUIPMENT FAILURE	Non-storm
SE23121501098	KORTE1245	2023	2023-12-16 08:50:02	2023-12-16 09:32:24	1	42.37	EQUIPMENT FAILURE	Non-storm
SW23121600040	WLVRN8266	2023	2023-12-16 08:52:08	2023-12-16 10:12:41	59	4743.74	ANIMAL	Non-storm
SE23121600063	LAMBT1485	2023	2023-12-16 09:02:29	2023-12-16 09:53:30	3	152.54	PLANNED INTENTIONAL	Non-storm
NW23121600497	WOLFH8838	2023	2023-12-16 09:07:25	2023-12-17 09:36:42	1	1469.28	TREEROW	Non-storm
SE23121600046	PULFD2224	2023	2023-12-16 09:09:33	2023-12-16 11:59:54	9	1530.2	PLANNED INTENTIONAL	Non-storm
SE23121600061	PULFD2224	2023	2023-12-16 09:09:35	2023-12-16 11:59:29	17	776.94	PLANNED INTENTIONAL	Non-storm
SE23121600059	PULFD0419	2023	2023-12-16 09:09:50	2023-12-16 11:22:42	7	537.58	PLANNED INTENTIONAL	Non-storm
NE23121600057	PINGV0325	2023	2023-12-16 09:11:09	2023-12-16 09:30:27	1	19.3	PLANNED INTENTIONAL	Non-storm
SE23121600039	SRGNT9129	2023	2023-12-16 09:12:34	2023-12-16 11:10:43	2	236.28	PLANNED INTENTIONAL	Non-storm
NW23121600067	SPKNE8842	2023	2023-12-16 09:12:50	2023-12-16 10:53:50	1	101	EQUIPMENT FAILURE	Non-storm
SE23121600060	INKST0318	2023	2023-12-16 09:15:20	2023-12-16 09:48:53	1	33.55	TREEROW	Non-storm
NE23121500895	CENTR1769	2023	2023-12-16 09:16:50	2023-12-16 09:22:00	1	5.17	EQUIPMENT FAILURE	Non-storm
SW23121600200	YOST8144	2023	2023-12-16 09:19:43	2023-12-16 12:03:00	1	163.28	EQUIPMENT LOADING	Non-storm
NW23121600069	WSHTN0344	2023	2023-12-16 09:21:04	2023-12-16 12:26:44	45	8129.95	EQUIPMENT FAILURE	Non-storm
SE23121600049	PULFD0419	2023	2023-12-16 09:31:34	2023-12-16 10:07:27	1	35.88	PLANNED INTENTIONAL	Non-storm
SE23121600083	PULFD0419	2023	2023-12-16 09:31:42	2023-12-16 11:23:26	1	111.73	PLANNED INTENTIONAL	Non-storm
SE23121501092	SIXMI2173	2023	2023-12-16 09:35:34	2023-12-16 09:44:39	1	9.08	EQUIPMENT FAILURE	Non-storm
SE23121600081	GLEND1513	2023	2023-12-16 09:36:17	2023-12-16 11:08:46	1	92.48	PLANNED INTENTIONAL	Non-storm
SE23121600112	GLEND1513	2023	2023-12-16 09:36:18	2023-12-16 11:08:47	1	92.48	EQUIPMENT FAILURE	Non-storm
NE23121600082	CYPRS8754	2023	2023-12-16 09:39:18	2023-12-16 10:47:53	1	68.58	PLANNED INTENTIONAL	Non-storm
NE23121600124	MEDNA8477	2023	2023-12-16 09:39:56	2023-12-16 16:36:44	1	416.8	EQUIPMENT FAILURE	Non-storm
SW23121600078	HEMLK1910	2023	2023-12-16 09:40:20	2023-12-16 10:26:51	1	46.52	PLANNED INTENTIONAL	Non-storm
SW23121600387	DUVAL9644	2023	2023-12-16 09:44:15	2023-12-16 14:41:48	1	297.55	NO ISSUES FOUND	Non-storm
NE23121600086	EIGMI1231	2023	2023-12-16 09:50:55	2023-12-16 10:55:36	1	64.68	PLANNED INTENTIONAL	Non-storm
SW23121600087	PERU9440	2023	2023-12-16 09:51:13	2023-12-16 10:02:53	1	11.67	PLANNED INTENTIONAL	Non-storm
SE23121600113	LAMBT1485	2023	2023-12-16 09:58:28	2023-12-16 10:13:59	1	15.52	PLANNED INTENTIONAL	Non-storm
SE23121600096	LAMBT1485	2023	2023-12-16 09:58:51	2023-12-16 10:14:22	1	15.52	PLANNED INTENTIONAL	Non-storm
NE23121600126	PINGV0325	2023	2023-12-16 09:59:09	2023-12-16 10:22:43	1	23.57	PLANNED INTENTIONAL	Non-storm
SE23121600261	WSEND1038	2023	2023-12-16 09:59:41	2023-12-16 13:27:02	19	3936.29	NO ISSUES FOUND	Non-storm
SE23121600205	WSEND1038	2023	2023-12-16 09:59:42	2023-12-16 13:27:10	15	3108.36	NO ISSUES FOUND	Non-storm
SE23121600203	WSEND1038	2023	2023-12-16 09:59:44	2023-12-16 13:26:58	2	414.45	NO ISSUES FOUND	Non-storm
SE23121600199	WSEND1038	2023	2023-12-16 09:59:45	2023-12-16 13:26:58	1	207.22	NO ISSUES FOUND	Non-storm
SE23121600128	WSEND1038	2023	2023-12-16 09:59:46	2023-12-16 13:27:02	179	36945.94	EQUIPMENT FAILURE	Non-storm
SE23121600189	WSEND1038	2023	2023-12-16 09:59:59	2023-12-16 13:25:52	4	823	NO ISSUES FOUND	Non-storm
SE23121600238	WSEND1038	2023	2023-12-16 10:00:06	2023-12-16 13:25:50	1	205.73	NO ISSUES FOUND	Non-storm
SE23121600110	BVRLY1865	2023	2023-12-16 10:00:23	2023-12-16 10:57:39	13	743.3	TREEBROW	Non-storm
NW23121600173	STERL8628	2023	2023-12-16 10:01:26	2023-12-16 11:14:20	1	72.9	ANIMAL	Non-storm
SE23121600090	HAWTH1289	2023	2023-12-16 10:07:34	2023-12-16 11:28:32	2	158.53	PLANNED INTENTIONAL	Non-storm
NW23121600121	WIXOM8239	2023	2023-12-16 10:07:37	2023-12-16 12:58:21	7	1193.02	NO ISSUES FOUND	Non-storm
NW23121600122	WIXOM8239	2023	2023-12-16 10:07:37	2023-12-16 12:58:52	61	10397.68	EQUIPMENT FAILURE	Non-storm
SE23121600129	WSEND1038	2023	2023-12-16 10:11:03	2023-12-16 10:42:10	382	11851.93	PLANNED INTENTIONAL	Non-storm
NW23121600130	HURST9853	2023	2023-12-16 10:12:11	2023-12-16 10:24:30	1	12.32	NO ISSUES FOUND	Non-storm
SW23121600095	BURTN0381	2023	2023-12-16 10:14:13	2023-12-16 11:34:49	5	402.79	PLANNED INTENTIONAL	Non-storm
SE23121600089	EIGMI1507	2023	2023-12-16 10:15:37	2023-12-16 11:21:11	1	65.57	PLANNED INTENTIONAL	Non-storm
SW23121600111	HEMLK1910	2023	2023-12-16 10:17:01	2023-12-16 11:54:36	12	1167.81	PLANNED INTENTIONAL	Non-storm
SE23121600159	JUPTR8328	2023	2023-12-16 10:17:18	2023-12-16 12:01:54	15	1564.68	PLANNED INTENTIONAL	Non-storm
SW23121600163	PERU9440	2023	2023-12-16 10:21:55	2023-12-16 10:32:33	1	10.63	PLANNED INTENTIONAL	Non-storm
NW23121600179	WATFD8967	2023	2023-12-16 10:22:15	2023-12-16 11:44:50	2	165.14	NO ISSUES FOUND	Non-storm
NW23121600193	WATFD8967	2023	2023-12-16 10:22:17	2023-12-16 11:44:52	2	165.14	CUSTOMER EQUIPMENT	Non-storm
NW23121600161	CAMDN8282	2023	2023-12-16 10:25:02	2023-12-16 11:56:48	22	2015.86	PLANNED INTENTIONAL	Non-storm
SW23121600158	HEMLK1910	2023	2023-12-16 10:25:47	2023-12-16 11:15:01	2	98.3	PLANNED INTENTIONAL	Non-storm
NE23121600180	STEPH8707	2023	2023-12-16 10:36:45	2023-12-16 11:48:00	16	1136	EQUIPMENT FAILURE	Non-storm
NE23121600195	STEPH8707	2023	2023-12-16 10:36:55	2023-12-16 11:47:57	2	142.02	EQUIPMENT FAILURE	Non-storm
NW23121600175	COLFX8186	2023	2023-12-16 10:42:24	2023-12-16 13:14:40	1	152.27	PLANNED INTENTIONAL	Non-storm
NW23121600182	SPKNE8842	2023	2023-12-16 10:48:19	2023-12-16 12:57:06	4	513.25	PLANNED INTENTIONAL	Non-storm
SE23121500873	GRPTE2073	2023	2023-12-16 10:55:34	2023-12-16 14:20:19	1	204.75	TREEROW	Non-storm
SE23121600191	GDRIV2220	2023	2023-12-16 10:55:41	2023-12-16 12:37:08	1	101.45	PLANNED INTENTIONAL	Non-storm
SE23121600166	GNSTN1319	2023	2023-12-16 10:58:10	2023-12-16 12:23:22	1	85.2	PLANNED INTENTIONAL	Non-storm
NE23121500792	OTIS8615	2023	2023-12-16 10:59:35	2023-12-16 11:07:15	1	7.67	EQUIPMENT FAILURE	Non-storm
SW23121600213	DEWEY8085	2023	2023-12-16 11:10:01	2023-12-16 11:50:19	1	40.3	ANIMAL	Non-storm
NE23121600230	GLOBE8034	2023	2023-12-16 11:13:09	2023-12-16 11:57:02	1	43.88	EQUIPMENT FAILURE	Non-storm
SE23121600217	GDRIV2220	2023	2023-12-16 11:14:39	2023-12-16 11:20:17	2	10.84	PLANNED INTENTIONAL	Non-storm
NE23121600058	ALGON8073	2023	2023-12-16 11:20:31	2023-12-16 17:01:02	1	144.45	EQUIPMENT FAILURE	Non-storm
NW23121600215	ARNLD2731	2023	2023-12-16 11:20:49	2023-12-16 14:55:59	65	13979.71	PLANNED INTENTIONAL	Non-storm
NW23121600242	APACE8996	2023	2023-12-16 11:20:54	2023-12-16 14:55:54	1	215	NO ISSUES FOUND	Non-storm
NW23121600417	ARNLD2731	2023	2023-12-16 11:20:55	2023-12-16 14:55:53	1	214.97	PLANNED INTENTIONAL	Non-storm
NW23121600251	GRAYL8540	2023	2023-12-16 11:39:21	2023-12-16 16:32:12	1	292.85	ANIMAL	Non-storm
SW23121600240	HEMLK1910	2023	2023-12-16 11:50:49	2023-12-16 12:52:32	17	1044.19	PLANNED INTENTIONAL	Non-storm
SW23121600247	SEVLE9367	2023	2023-12-16 11:57:39	2023-12-16 12:33:11	12	424.38	PLANNED INTENTIONAL	Non-storm
NE23121600244	CYPRS8754	2023	2023-12-16 11:58:20	2023-12-16 13:37:21	2	198.05	PLANNED INTENTIONAL	Non-storm
SW23121600249	HEMLK1910	2023	2023-12-16 12:05:23	2023-12-16 12:12:35	5	35.67	PLANNED INTENTIONAL	Non-storm
SE23121600245	LAMBT1485	2023	2023-12-16 12:08:20	2023-12-16 12:32:47	3	72.97	PLANNED INTENTIONAL	Non-storm
NW23121600266	STKWL4010	2023	2023-12-16 12:10:01	2023-12-16 12:59:05	1	49.07	PLANNED INTENTIONAL	Non-storm
SE23121600256	MAUME8241	2023	2023-12-16 12:17:08	2023-12-16 12:32:48	1	15.67	PLANNED INTENTIONAL	Non-storm
SW23121400639	SYRAC2063	2023	2023-12-16 12:19:13	2023-12-16 12:31:39	1	12.43	EQUIPMENT FAILURE	Non-storm
SE23121600300	MEYRS1702	2023	2023-12-16 12:23:56	2023-12-16 12:34:59	1	11.05	TREEBROW	Non-storm
SE23121600265	PULFD2155	2023	2023-12-16 12:26:48	2023-12-16 13:49:19	1	82.52	PLANNED INTENTIONAL	Non-storm
NW23121600262	SPKNE8842	2023	2023-12-16 12:28:50	2023-12-16 12:52:42	5	118.81	PLANNED INTENTIONAL	Non-storm
SE23121600297	SYRAC1813	2023	2023-12-16 12:30:34	2023-12-16 13:05:48	1	35.23	TROUBLE INTENTIONAL	Non-storm
SE23121600269	MLVDL2105	2023	2023-12-16 12:30:37	2023-12-16 12:52:21	1	21.73	PLANNED INTENTIONAL	Non-storm
SW23121600268	HEMLK1952	2023	2023-12-16 12:31:08	2023-12-16 13:56:56	6	512.87	PLANNED INTENTIONAL	Non-storm
NW23121600272	SPKNE8842	2023	2023-12-16 12:32:57	2023-12-16 12:57:02	7	168.48	PLANNED INTENTIONAL	Non-storm
NE23121600276	PRKRD8757	2023	2023-12-16 12:33:57	2023-12-16 15:12:48	8	1268.62	EQUIPMENT FAILURE	Non-storm
NW23121600279	PROUD9475	2023	2023-12-16 12:38:54	2023-12-16 13:42:57	51	3255.5	EQUIPMENT FAILURE	Non-storm
NW23121600284	PROUD9475	2023	2023-12-16 12:38:54	2023-12-16 13:43:35	40	2555.31	EQUIPMENT FAILURE	Non-storm
NW23121600299	PROUD9475	2023	2023-12-16 12:38:54	2023-12-16 13:42:38	1	63.73	NO ISSUES FOUND	Non-storm
NE23121600220	CAPAC8756	2023	2023-12-16 12:49:33	2023-12-16 14:01:35	1	67.63	EQUIPMENT FAILURE	Non-storm
SE23121600301	SORLD9082	2023	2023-12-16 12:52:57	2023-12-16 13:00:44	615	4397.55	NO CAUSE	Non-storm
SW23121600339	SOFLD9082	2023	2023-12-16 12:53:02	2023-12-16 12:59:45	1	6.72	NO ISSUES FOUND	Non-storm
SW23121600335	SOFLD9082	2023	2023-12-16 12:53:03	2023-12-16 13:00:42	1	7.65	NO ISSUES FOUND	Non-storm
SE23121600311	ALNPK1284	2023	2023-12-16 12:57:00	2023-12-16 13:37:46	12	486.05	TROUBLE INTENTIONAL	Non-storm
SE23121600318	ALNPK1284	2023	2023-12-16 12:57:02	2023-12-16 13:37:49	11	445.54	PLANNED INTENTIONAL	Non-storm
SW23121600307	PERU9440	2023	2023-12-16 13:00:32	2023-12-16 13:59:47	1	59.25	PLANNED INTENTIONAL	Non-storm
SW23121600321	YPSIL0318	2023	2023-12-16 13:00:50	2023-12-16 13:15:57	2	29.98	EQUIPMENT FAILURE	Non-storm
NW23121600190	MALTA8423	2023	2023-12-16 13:01:56	2023-12-16 13:28:46	1	26.83	TREEROW	Non-storm
SE23121600323	GLEND2212	2023	2023-12-16 13:08:42	2023-12-16 13:58:21	2	91.9	PLANNED INTENTIONAL	Non-storm
SE23121600362	PURTN1246	2023	2023-12-16 13:14:53	2023-12-16 14:58:56	1	104.05	PUBLIC INTERFERENCE	Non-storm
NW23121600346	SPKNE8842	2023	2023-12-16 13:19:13	2023-12-16 13:47:52	1	28.65	PLANNED INTENTIONAL	Non-storm
SE23121600347	GLEND1013	2023	2023-12-16 13:31:24	2023-12-16 14:39:35	5	275.61	PLANNED INTENTIONAL	Non-storm
NW23121600348	ALPNE8921	2023	2023-12-16 13:32:28	2023-12-16 15:58:44	1	146.27	PLANNED INTENTIONAL	Non-storm
SE23121600394	GDRIV2220	2023	2023-12-16 13:46:31	2023-12-16 14:57:25	1	70.9	NO ISSUES FOUND	Non-storm
SE23121600354	LAUDR1554	2023	2023-12-16 13:47:06	2023-12-16 15:28:13	8	409.84	PLANNED INTENTIONAL	Non-storm
SW23121600360	PERU9444	2023	2023-12-16 14:02:42	2023-12-16 14:27:40	1	24.97	PLANNED INTENTIONAL	Non-storm
SW23121600338	PERU9440	2023	2023-12-16 14:02:47	2023-12-16 14:27:44	1	24.95	PLANNED INTENTIONAL	Non-storm
NW23121600377	CLKSN8860	2023	2023-12-16 14:07:02	2023-12-16 15:55:44	39	4216.72	ANIMAL	Non-storm
NW23121600374	CLKSN8860	2023	2023-12-16 14:07:14	2023-12-16 15:54:54	1	107.67	ANIMAL	Non-storm
SW23121600393	GRFIN9883	2023	2023-12-16 14:33:48	2023-12-16 16:11:09	5	485.91	TREEBROW	Non-storm
SW23121600389	GRFIN9883	2023	2023-12-16 14:33:57	2023-12-16 16:11:09	1	97.2	TREEBROW	Non-storm
SW23121600390	GLBRT9373	2023	2023-12-16 14:45:41	2023-12-16 15:25:31	1	39.83	PLANNED INTENTIONAL	Non-storm
SE23121600363	EIGMI1507	2023	2023-12-16 14:52:59	2023-12-16 15:39:06	1	46.12	PLANNED INTENTIONAL	Non-storm
NW23121600398	ALPNE8921	2023	2023-12-16 14:59:32	2023-12-16 15:49:44	1	50.2	PLANNED INTENTIONAL	Non-storm
SW23121600264	SIDNY9431	2023	2023-12-16 16:02:16	2023-12-16 16:09:14	1	6.97	METER / BLOCKS	Non-storm
SE23121600414	ZENON2192	2023	2023-12-16 16:33:22	2023-12-17 09:15:53	1	1002.52	PUBLIC INTERFERENCE	Non-storm
SW23121600198	GAY1762	2023	2023-12-16 16:36:22	2023-12-16 16:51:37	1	15.25	EQUIPMENT FAILURE	Non-storm
NW23121600446	CONRD8130	2023	2023-12-16 16:50:30	2023-12-16 19:01:50	1	131.33	EQUIPMENT FAILURE	Non-storm
SW23121600419	SPRUC9827	2023	2023-12-16 16:51:40	2023-12-16 17:07:25	1	15.75	EQUIPMENT FAILURE	Non-storm
SW23121600459	CRWFD9076	2023	2023-12-16 16:58:55	2023-12-16 19:13:16	1	134.35	EQUIPMENT FAILURE	Non-storm
NE23121600448	NUMY2433	2023	2023-12-16 19:19:54	2023-12-16 19:26:20	1	6.43	EQUIPMENT FAILURE	Non-storm
NW23121600482	ALPNE8916	2023	2023-12-16 19:22:51	2023-12-16 19:40:54	465	7988.65	TROUBLE INTENTIONAL	Non-storm
SE23121600468	ANNCH1520	2023	2023-12-16 19:44:17	2023-12-16 19:59:34	27	404.97	EQUIPMENT FAILURE	Non-storm
SE23121600471	ANNCH1520	2023	2023-12-16 19:44:21	2023-12-16 20:48:38	13	281.62	EQUIPMENT FAILURE	Non-storm
SE23121700310	ANNCH1361	2023	2023-12-16 22:19:58	2023-12-18 06:48:13	1	1948.25	PUBLIC INTERFERENCE	Non-storm
NW23121700039	MILFD9245	2023	2023-12-17 03:41:52	2023-12-17 09:33:04	2	701.33	EQUIPMENT FAILURE	Non-storm
SW23121700029	TAHOE9511	2023	2023-12-17 05:12:49	2023-12-17 09:40:21	21	5601.44	EQUIPMENT FAILURE	Non-storm
NW23121700038	STKBR9888	2023	2023-12-17 06:58:33	2023-12-17 09:49:42	1	171.15	EQUIPMENT FAILURE	Non-storm
NE23121700157	NUNLY2433	2023	2023-12-17 07:20:18	2023-12-17 13:21:39	1	361.35	TREEBROW	Non-storm
NW23121700042	BRONC8593	2023	2023-12-17 07:52:16	2023-12-17 09:23:16	50	4455.82	EQUIPMENT FAILURE	Non-storm
NW23121700050	BRONC8593	2023	2023-12-17 07:52:21	2023-12-17 09:19:32	1	87.18	EQUIPMENT FAILURE	Non-storm
NE23121700047	WABSH8797	2023	2023-12-17 08:07:35	2023-12-17 09:32:13	5	422.71	ANIMAL	Non-storm
SE23121700048	SYRAC1813	2023	2023-12-17 08:22:32	2023-12-17 10:29:15	1	126.72	TREEBROW	Non-storm
SW23121700057	HAGER9449	2023	2023-12-17 08:48:58	2023-12-17 11:17:43	26	3920.83	EQUIPMENT FAILURE	Non-storm
SW23121700088	HAGER9425	2023	2023-12-17 08:49:01	2023-12-17 11:17:44	1	148.72	EQUIPMENT FAILURE	Non-storm
SW23121700066	BENSN8418	2023	2023-12-17 09:11:26	2023-12-17 12:00:04	21	3537.53	EQUIPMENT FAILURE	Non-storm
SW23121700063	WSTLD9494	2023	2023-12-17 09:11:33	2023-12-17 10:30:52	134	10599.03	TREEROW	Non-storm
NE23121700073	ALGON8073	2023	2023-12-17 09:26:12	2023-12-17 09:31:58	1	5.77	PLANNED INTENTIONAL	Non-storm
NE23121700051	BNGHM0301	2023	2023-12-17 09:29:16	2023-12-17 12:48:20	562	111797.35	PLANNED INTENTIONAL	Non-storm
NE23121700052	BNGHM0302	2023	2023-12-17 09:29:20	2023-12-17 12:48:52	167	33267.04	PLANNED INTENTIONAL	Non-storm
NE23121700080	GAGTN0302	2023	2023-12-17 09:29:24	2023-12-17 12:48:49	2	398.58	EQUIPMENT FAILURE	Non-storm
NW23121700090	HURST9853	2023	2023-12-17 09:40:45	2023-12-17 10:15:23	1	34.63	EQUIPMENT FAILURE	Non-storm
NE23121700083	CASSC0311	2023	2023-12-17 09:42:16	2023-12-17 10:11:59	41	1212.03	EQUIPMENT FAILURE	Non-storm
NE23121700097	ALGON8073	2023	2023-12-17 10:19:20	2023-12-17 10:25:05	1	5.75	PLANNED INTENTIONAL	Non-storm
NE23121700132	ALMOT0304	2023	2023-12-17 10:22:49	2023-12-17 12:18:18	7	807.26	EQUIPMENT FAILURE	Non-storm
NE23121700116	ALMOT0304	2023	2023-12-17 10:22:53	2023-12-17 12:18:12	1	115.32	NO ISSUES FOUND	Non-storm
NE23121700118	ALMOT0304	2023	2023-12-17 10:22:53	2023-12-17 12:17:16	1	114.38	NO ISSUES FOUND	Non-storm

SW23121700101	BLCRK8011	2023	2023-12-17 10:34:49	2023-12-17 11:20:50	1	46.02	PLANNED INTENTIONAL	Non-storm
SW23121700149	MOTT8124	2023	2023-12-17 11:12:02	2023-12-17 12:24:13	52	4222.65	TREEROW	Non-storm
NW23121700147	HURST9853	2023	2023-12-17 11:22:59	2023-12-17 11:31:02	90	977.98	PLANNED INTENTIONAL	Non-storm
SE23121700142	SRGNT8247	2023	2023-12-17 11:34:57	2023-12-17 11:57:21	1	22.4	TREEROW	Non-storm
SE23121700081	GRPTE1375	2023	2023-12-17 11:38:47	2023-12-17 12:01:24	1	22.62	TREEROW	Non-storm
NW23121700289	TAMRK9063	2023	2023-12-17 11:48:02	2023-12-17 17:08:57	1	320.92	NO ISSUES FOUND	Non-storm
NW23121700188	TAMRK9063	2023	2023-12-17 11:48:04	2023-12-17 17:08:50	1	320.77	EQUIPMENT FAILURE	Non-storm
SW23121700095	FLAG1680	2023	2023-12-17 11:54:31	2023-12-17 19:57:42	1	483.18	TREEROW	Non-storm
SW23121700133	DIMND9866	2023	2023-12-17 11:59:54	2023-12-17 12:08:43	1	8.82	EQUIPMENT FAILURE	Non-storm
SW23121700190	OMAHA8240	2023	2023-12-17 12:47:58	2023-12-17 14:24:47	9	870.06	EQUIPMENT FAILURE	Non-storm
SE23121700301	GDRIV2074	2023	2023-12-17 12:56:18	2023-12-17 16:52:07	21	4940.62	TREEROW	Non-storm
SE23121700227	GDRIV2074	2023	2023-12-17 12:56:22	2023-12-17 16:51:22	1	235	TREEROW	Non-storm
SE23121700212	GDRIV2074	2023	2023-12-17 12:56:23	2023-12-17 16:51:26	26	6109.08	TREEROW	Non-storm
SE23121700209	DENVR1462	2023	2023-12-17 13:29:32	2023-12-17 16:48:53	1	199.35	EQUIPMENT FAILURE	Non-storm
NW23121700363	NOLAN9839	2023	2023-12-17 13:49:35	2023-12-18 08:40:07	1	1130.53	EQUIPMENT FAILURE	Non-storm
SE23121700231	FRMNT1593	2023	2023-12-17 13:49:40	2023-12-17 18:15:36	1	265.93	TREEROW	Non-storm
SE23121700175	DCATR1271	2023	2023-12-17 14:00:41	2023-12-17 14:29:44	1	29.05	EQUIPMENT FAILURE	Non-storm
SE23121700225	TIRMN1541	2023	2023-12-17 14:14:39	2023-12-17 14:28:28	24	327.49	EQUIPMENT FAILURE	Non-storm
SE23121700265	LCSTR8844	2023	2023-12-17 15:43:25	2023-12-17 17:06:30	37	3031.42	EQUIPMENT FAILURE	Non-storm
SE23121700268	LCSTR8844	2023	2023-12-17 15:43:29	2023-12-17 17:06:17	1	82.8	EQUIPMENT FAILURE	Non-storm
NE23121700239	ROSVL2416	2023	2023-12-17 15:47:16	2023-12-17 16:00:24	1	13.13	TREEROW	Non-storm
SW23121700173	INKST2027	2023	2023-12-17 16:13:00	2023-12-17 16:41:36	1	28.6	EQUIPMENT FAILURE	Non-storm
NE23121700287	CHEST8417	2023	2023-12-17 16:19:07	2023-12-17 17:31:59	30	2182.58	WIND	Non-storm
SW23121700049	ELM9365	2023	2023-12-17 16:36:31	2023-12-17 16:54:06	1	17.58	TREEBROW	Non-storm
SE23121700262	CONAT1446	2023	2023-12-17 16:41:19	2023-12-18 03:50:09	1	668.83	TREEROW	Non-storm
NE23121700308	FAWN8755	2023	2023-12-17 17:17:14	2023-12-17 19:05:22	3	323.92	EQUIPMENT FAILURE	Non-storm
SE23121700321	COOLG1209	2023	2023-12-17 18:03:10	2023-12-17 19:41:01	2	195.7	EQUIPMENT FAILURE	Non-storm
NE23121700332	BRAY8780	2023	2023-12-17 18:52:49	2023-12-17 21:06:27	1	133.63	ANIMAL	Non-storm
SW23121800008	ROMLS9464	2023	2023-12-17 19:00:10	2023-12-17 19:34:50	4	120.45	EQUIPMENT FAILURE	Non-storm
NE23121700337	MENLO8768	2023	2023-12-17 19:23:49	2023-12-17 21:25:38	61	8982.65	EQUIPMENT FAILURE	Non-storm
NE23121700353	CHEST8430	2023	2023-12-17 19:57:59	2023-12-18 02:32:01	10	3935.68	PLANNED INTENTIONAL	Non-storm
NW23121700377	CESNA9805	2023	2023-12-17 21:02:11	2023-12-18 02:34:07	20	6636.26	PLANNED INTENTIONAL	Non-storm
NW23121700386	CESNA9805	2023	2023-12-17 21:02:12	2023-12-18 02:34:07	17	5640.78	PLANNED INTENTIONAL	Non-storm
NE23121700405	AGSTA8424	2023	2023-12-17 23:33:56	2023-12-18 08:33:31	60	32355.18	EQUIPMENT FAILURE	Non-storm
SE23121800053	AGSTA8424	2023	2023-12-17 23:33:57	2023-12-18 08:33:12	1	539.25	EQUIPMENT FAILURE	Non-storm
NE23121800005	CYPRS8812	2023	2023-12-17 23:55:39	2023-12-18 09:39:20	1	583.68	EQUIPMENT FAILURE	Non-storm
NE23121800056	BRAY8780	2023	2023-12-18 06:29:44	2023-12-18 11:47:22	1	317.63	EQUIPMENT FAILURE	Non-storm
NE23121801236	CASVL8805	2023	2023-12-18 07:22:16	2023-12-19 14:19:56	1	1857.67	TREEROW	Non-storm
SW23121800052	HINES9423	2023	2023-12-18 07:48:14	2023-12-18 10:53:19	10	1491.49	ANIMAL	Non-storm
SW23121800100	HOOVR0366	2023	2023-12-18 08:28:06	2023-12-18 10:09:15	1	101.15	TREEBROW	Non-storm
NE23121800363	QUNCY0331	2023	2023-12-18 09:08:56	2023-12-18 11:32:59	1	144.05	EQUIPMENT FAILURE	Non-storm
NE23121800119	YATES0311	2023	2023-12-18 09:08:57	2023-12-18 11:34:15	1808	262187.65	EQUIPMENT FAILURE	Non-storm
NE23121800362	SDF052629	2023	2023-12-18 09:08:57	2023-12-18 11:33:59	1	145.03	NO ISSUES FOUND	Non-storm
NE23121800130	SAXON8046	2023	2023-12-18 09:08:59	2023-12-18 11:34:19	334	48431	EQUIPMENT FAILURE	Non-storm
SE23121800380	QUNCY0331	2023	2023-12-18 09:09:01	2023-12-18 11:34:05	1	145.07	EQUIPMENT FAILURE	Non-storm
NE23121800137	YATES0311	2023	2023-12-18 09:09:03	2023-12-18 11:33:11	1	144.13	EQUIPMENT FAILURE	Non-storm
NE23121800206	LEXTN8770	2023	2023-12-18 09:09:06	2023-12-18 11:34:14	8	1160.56	NO ISSUES FOUND	Non-storm
NE23121800164	SAXON8046	2023	2023-12-18 09:09:08	2023-12-18 11:34:09	1	145.02	EQUIPMENT FAILURE	Non-storm
SW23121800358	DUBLN8205	2023	2023-12-18 09:14:40	2023-12-18 13:12:28	6	1425.02	ANIMAL	Non-storm
NW23121800328	MALTA8543	2023	2023-12-18 09:16:50	2023-12-18 09:58:26	30	1237.6	ANIMAL	Non-storm
SW23121900318	SHELD8185	2023	2023-12-18 09:21:48	2023-12-19 17:07:09	1	1905.35	EQUIPMENT FAILURE	Non-storm
NE23121801155	MENLO8789	2023	2023-12-18 09:33:22	2023-12-19 02:03:57	2	1981.15	TREEROW	Non-storm
NE23121800391	GOLF8697	2023	2023-12-18 09:36:10	2023-12-18 10:24:29	50	2405.42	ANIMAL	Non-storm
NE23121800419	GOLF8697	2023	2023-12-18 09:36:11	2023-12-18 10:24:21	2	96.22	ANIMAL	Non-storm
SE23121800435	GOLF8697	2023	2023-12-18 09:36:22	2023-12-18 10:24:28	1	48.1	ANIMAL	Non-storm
SE23121800401	GOLF8697	2023	2023-12-18 09:36:23	2023-12-18 10:24:29	1	48.1	ANIMAL	Non-storm
SE23121800037	LINCN0349	2023	2023-12-18 10:23:43	2023-12-18 10:57:19	1	33.6	TREEBROW	Non-storm
SW23121800444	PROSP0305	2023	2023-12-18 10:27:00	2023-12-18 10:55:05	1	28.08	PLANNED INTENTIONAL	Non-storm
SE23121800101	ROTUN8356	2023	2023-12-18 10:54:22	2023-12-18 12:49:06	20	2164.9	TREEROW	Non-storm
NW23121800499	HURST9853	2023	2023-12-18 11:24:09	2023-12-18 11:40:55	20	334.84	CUSTOMER EQUIPMENT	Non-storm
NW23121800502	HURST9853	2023	2023-12-18 11:24:09	2023-12-18 11:40:55	25	417.61	EQUIPMENT FAILURE	Non-storm
NW23121800545	MILFD9245	2023	2023-12-18 11:44:48	2023-12-18 14:21:13	16	1717.75	EQUIPMENT FAILURE	Non-storm
NW23121800555	MILFD9245	2023	2023-12-18 11:44:56	2023-12-18 13:20:49	1	95.88	EQUIPMENT FAILURE	Non-storm
NW23121800552	BARTL4011	2023	2023-12-18 11:45:19	2023-12-18 13:34:45	1	109.43	NO ISSUES FOUND	Non-storm
SE23121801235	SIXMI1237	2023	2023-12-18 11:45:52	2023-12-19 02:37:50	1	891.97	TREEBROW	Non-storm
SE23121800897	GENSE2147	2023	2023-12-18 11:57:41	2023-12-18 14:00:46	1	1563.08	TREEBROW	Non-storm
SE23121800572	BROKS8092	2023	2023-12-18 12:02:04	2023-12-18 13:02:23	9	534.27	EQUIPMENT FAILURE	Non-storm
NW23121800586	TAMRK9096	2023	2023-12-18 12:12:42	2023-12-18 13:01:32	1	48.83	EQUIPMENT FAILURE	Non-storm
SW23121800592	HAGER9522	2023	2023-12-18 12:17:27	2023-12-19 01:06:20	1	768.88	EQUIPMENT FAILURE	Non-storm
SW23121800585	HAGER9522	2023	2023-12-18 12:17:29	2023-12-19 01:06:30	2	1537.78	CUSTOMER EQUIPMENT	Non-storm
SE23121700233	CHARL0015	2023	2023-12-18 12:21:21	2023-12-18 13:03:11	2	83.58	EQUIPMENT FAILURE	Non-storm
NW23121800609	WHTLK8009	2023	2023-12-18 12:43:40	2023-12-18 13:54:50	29	2039.2	EQUIPMENT FAILURE	Non-storm
NW23121800614	WMSTN8033	2023	2023-12-18 12:44:25	2023-12-18 15:57:32	22	4241.87	TREEBROW	Non-storm
NW23121800627	WMSTN8033	2023	2023-12-18 12:44:29	2023-12-18 15:57:24	1	192.92	TREEBROW	Non-storm
NW23121801093	WDLOW9064	2023	2023-12-18 13:20:01	2023-12-18 22:06:46	1	526.75	TREEROW	Non-storm
SE23121800535	EMPIR1224	2023	2023-12-18 13:25:24	2023-12-18 14:43:12	1	32.35	EQUIPMENT FAILURE	Non-storm
SW23121800564	MOTT9789	2023	2023-12-18 13:37:37	2023-12-18 14:00:17	1	22.67	EQUIPMENT FAILURE	Non-storm
SW23121800579	HOOVR0366	2023	2023-12-18 13:51:18	2023-12-18 14:08:16	1	16.97	EQUIPMENT FAILURE	Non-storm
SE23120700335	CHIGO2081	2023	2023-12-18 13:53:19	2023-12-18 18:34:46	1	281.45	EQUIPMENT FAILURE	Non-storm
SW23121800702	BNSTN9389	2023	2023-12-18 13:55:05	2023-12-18 18:12:06	73	18752.31	EQUIPMENT FAILURE	Non-storm
SW23121800708	BNSTN9389	2023	2023-12-18 13:55:11	2023-12-18 18:12:05	1	256.9	EQUIPMENT FAILURE	Non-storm
SW23121800887	BNSTN9389	2023	2023-12-18 13:55:11	2023-12-18 18:12:04	1	256.88	NO ISSUES FOUND	Non-storm
SE23121800718	ECORS1345	2023	2023-12-18 13:59:14	2023-12-18 15:20:51	54	4042.25	WIND	Non-storm
SE23121800753	HLTRD9705	2023	2023-12-18 14:01:53	2023-12-18 15:16:09	1	74.27	PUBLIC INTERFERENCE	Non-storm
SW23121800725	DREXL8957	2023	2023-12-18 14:03:02	2023-12-18 15:43:29	9	895.13	PUBLIC INTERFERENCE	Non-storm
NW23121800724	CHILS9845	2023	2023-12-18 14:04:10	2023-12-18 16:40:33	34	5309.84	CUSTOMER EQUIPMENT	Non-storm
NW23121800741	JEWEL8686	2023	2023-12-18 14:06:35	2023-12-18 17:52:58	46	10404.7	TREEBROW	Non-storm
NE23121800759	YALE2633	2023	2023-12-18 14:18:32	2023-12-18 23:09:48	1	531.27	EQUIPMENT FAILURE	Non-storm
SE23121800804	WHITR2716	2023	2023-12-18 14:22:22	2023-12-19 15:05:15	1	1482.88	TREEROW	Non-storm
SW23121800792	POPLR9885	2023	2023-12-18 14:25:47	2023-12-18 15:35:08	1	69.35	EQUIPMENT FAILURE	Non-storm
NW23121900057	LOCDL8909	2023	2023-12-18 14:26:32	2023-12-19 03:20:58	50	38676.99	EQUIPMENT FAILURE	Non-storm
NW23121801001	LOCDL8909	2023	2023-12-18 14:26:35	2023-12-18 17:50:10	521	79831.21	EQUIPMENT FAILURE	Non-storm
NW23121801142	LOCDL8909	2023	2023-12-18 14:34:03	2023-12-19 13:17:10	2	1630.38	EQUIPMENT FAILURE	Non-storm
SE23121801018	BROKS8153	2023	2023-12-18 14:35:23	2023-12-19 10:55:53	1	1220.5	TREEROW	Non-storm
SE23121800795	HAYES1140	2023	2023-12-18 14:38:13	2023-12-18 15:48:10	60	4178.07	TREEBROW	Non-storm
SE23121800681	WEBST1809	2023	2023-12-18 14:39:35	2023-12-18 15:00:42	1	21.12	EQUIPMENT FAILURE	Non-storm
NW23121800814	WLNUT9013	2023	2023-12-18 14:40:53	2023-12-18 19:20:28	194	50289.12	TREEROW	Non-storm
SE23121700364	LAMBT2078	2023	2023-12-18 14:41:32	2023-12-18 15:06:18	1	24.77	EQUIPMENT FAILURE	Non-storm
NW23121800831	PINCK9878	2023	2023-12-18 14:48:27	2023-12-18 16:29:30	28	2827.96	TREEBROW	Non-storm
NE23121800825	OPALB572	2023	2023-12-18 14:51:12	2023-12-18 15:12:41	1	21.48	PLANNED INTENTIONAL	Non-storm
SW23121800851	BLTMR1488	2023	2023-12-18 14:55:25	2023-12-18 20:00:36	16	4880.92	TREEBROW	Non-storm
SW23121800858	HEMLK1958	2023	2023-12-18 15:04:07	2023-12-18 15:52:27	18	861.98	EQUIPMENT FAILURE	Non-storm
SW23121800869	FRMTN1712	2023	2023-12-18 15:05:13	2023-12-18 19:23:58	8	2067.39	EQUIPMENT FAILURE	Non-storm
NW23121800872	SLKRK9772	2023	2023-12-18 15:12:30	2023-12-18 17:37:16	97	14037.68	EQUIPMENT FAILURE	Non-storm
SE23121800883	MCGRW1048	2023	2023-12-18 15:31:40	2023-12-18 20:50:33	1	318.88	TREEBROW	Non-storm
NE23121800945	PTHUR2301	2023	2023-12-18 15:45:31	2023-12-18 17:10:14	1	84.72	EQUIPMENT FAILURE	Non-storm
SW23121800944	AIRPT9521	2023	2023-12-18 15:53:32	2023-12-19 09:11:18	5	5187.31	EQUIPMENT FAILURE	Non-storm
SW23121800934	AIRPT9521	2023	2023-12-18 15:53:33	2023-12-19 09:11:15	2	2074.92	CUSTOMER EQUIPMENT	Non-storm
SW23121801011	AIRPT9521	2023	2023-12-18 15:53:34	2023-12-19 09:11:04	2	2074.9	CUSTOMER EQUIPMENT	Non-storm
SW23121801096	AIRPT9521	2023	2023-12-18 15:53:44	2023-12-19 09:11:12	1	1037.47	EQUIPMENT LOADING	Non-storm
SW23121801046	AIRPT9521	2023	2023-12-18 15:53:51	2023-12-19 09:11:19	1	1037.47	CUSTOMER EQUIPMENT	Non-storm
SW23121800941	OKRDG9673	2023	2023-12-18 15:58:42	2023-12-18 19:12:17	72	13049.04	PUBLIC INTERFERENCE	Non-storm
SW23121800948	OKRDG9673	2023	2023-12-18 15:58:43	2023-12-18 19:09:17	3	550.65	PUBLIC INTERFERENCE	Non-storm
SW23121801032	OKRDG9673	2023	2023-12-18 15:58:43	2023-12-18 19:12:15	1	193.53	NO ISSUES FOUND	Non-storm
SE23121801045	COOLG2080	2023	2023-12-18 16:06:02	2023-12-18 17:50:33	1	104.52	NO ISSUES FOUND	Non-storm
SW23121801041	CARLT1562	2023	2023-12-18 16:18:42	2023-12-18 21:00:42	27	7607.65	TREEROW	Non-storm
NE23121801106	BADAX8787	2023	2023-12-18 16:26:28	2023-12-19 13:20:05	1	1253.62	EQUIPMENT FAILURE	Non-storm
NE23121900181	BADAX8787	2023	2023-12-18 16:26:29	2023-12-19 13:20:08	2	2507.28	WIND	Non-storm
NE23121801089	BADAX8787	2023	2023-12-18 16:26:34	2023-12-19 13:20:08	1	1253.57	WIND	Non-storm
NE23121801063	BISHP2405	2023	2023-12-18 16:28:22	2023-12-18 17:28:50	42	2537.48	ANIMAL	Non-storm
SE23121801090	BISHP2405	2023	2023-12-18 16:28:32	2023-12-18 17:28:59	1	60.45	NO ISSUES FOUND	Non-storm
NW23121801131	FLINT9797	2023	2023-12-18 16:34:59	2023-12-19 00:09:50	1	454.85	TREEROW	Non-storm
SE23121700285	BALFR2097	2023	2023-12-18 16:43:59	2023-12-18 16:54:15	1	10.27	EQUIPMENT FAILURE	Non-storm
NW23121801095	STRFD9093	2023	2023-12-18 16:57:44	2023-12-18 22:13:16	2	630.95	TREEBROW	Non-storm
NE23121801104	CASVL8805	2023	2023-12-18 17:01:20	2023-12-18 23:14:06	10	3726.72	TREEBROW	Non-storm
NE23121801146	CASVL8805	2023	2023-12-18 17:05:33	2023-12-19 01:49:14	1	283.68	EQUIPMENT FAILURE	Non-storm
SE23121801200	OAKPK1564	2023	2023-12-18 17:45:39	2023-12-19 00:58:33	1	432.9	EQUIPMENT FAILURE	Non-storm
NW23121801166	WOLFH8838	2023	2023-12-18 17:53:55	2023-12-19 00:25:11	1	391.27	TREEBROW	Non-storm
NW23121801163	WOLFH8838	2023	2023-12-18 17:53:56	2023-12-19 00:26:06	1	392.17	TREEBROW	Non-storm
NW23121801170	WOLFH8838	2023	2023-12-18 17:53:57	2023-12-19 00:25:14	1	391.28	TREEBROW	Non-storm
NW23121801174	WOLFH8838	2023	2023-12-18 17:53:57	2023-12-19 00:26:08	1	392.18	TREEBROW	Non-storm
NW23121801160	WOLFH8838	2023	2023-12-18 17:54:00	2023-12-19 00:25:16	1	391.27	TREEBROW	Non-storm
NW23121801158	WOLFH8838	2023	2023-12-18 17:54:02	2023-12-19 00:25:17	1	391.25	TREEBROW	Non-storm
SW23121801151	FRMTN1712	2023	2023-12-18 18:08:13	2023-12-18 19:23:48	9	678.03	EQUIPMENT FAILURE	Non-storm
SW23121900161	WLVRN8248	2023	2023-12-18 18:22:04	2023-12-19 10:34:37	1	972.55	EQUIPMENT FAILURE	Non-storm
SE23121801199	FOX1648	2023	2023-12-18 18:24:28	2023-12-18 20:32:56	14	1797.05	TREEBROW	Non-storm
NE23121801183	ALGON8073	2023	2023-12-18 18:28:11	2023-12-18 21:46:43	519	83196.81	TROUBLE INTENTIONAL	Non-storm
SE23121801255	EVRGN1783	2023	2023-12-18 19:17:37	2023-12-19 13:48:53	1	1111.27	TREEBROW	Non-storm
NE23121801251	NEAST8437	2023	2023-12-18 19:25:14	2023-12-19 00:22:58	19	5199.2	TREEROW	Non-storm
NE23121801269	NEFFO314	2023	2023-12-18 19:50:16	2023-12-19 02:49:57	118	37468.19	WIND	Non-storm
SE23121800891	BALFR2038	2023	2023-12-18 20:02:44	2023-12-19 00:20:57	1	18.22	EQUIPMENT FAILURE	Non-storm
NE23121801328	LAKPT2624	2023	2023-12-18 21:04:29	2023-12-19 07:54:38	1	650.15	TREEROW	Non-storm
NE23121801407	PTHOP0302	2023	2023-12-18 21:35:34	2023-12-19 14:56:59	10	10412.72	TREEBROW	Non-storm
NE23121801368	NRBRN8808	2023	2023-12-18 21:36:17	2023-12-19 13:00:10	58	49694.61	TREEBROW	Non-storm
SE23121801187	LCSTR9092	2023	2023-12-18 22:01:26	2023-12-19 00:29:56	431	65538.57	EQUIPMENT FAILURE	Non-storm
NE23121801447	STEPH8522	2023	2023-12-18 22:52:45	2023-12-19 02:49:57	1	837.2	EQUIPMENT FAILURE	Non-storm
SE23121801444	VERNR1592	2023	2023-12-18 23:00:31	2023-12-19 11:26:36	19	14007.84	TREEROW	Non-storm
SW23121801047	BLTMR1488	2023	2023-12-18 23:02:00	2023-12-19 06:40:15	1	458.25	EQUIPMENT FAILURE	Non-storm
SE23121801454	VILLA2161	2023	2023-12-18 23:05:55	2023-12-19 01:00:42	1	114.78	TREEBROW	Non-storm
NE23121900059	QUAIL0311	2023	2023-12-18 23:20:00	2023-12-20 10:59:21	1	2139.35	EQUIPMENT FAILURE	Non-storm
SW23121801467	CODY9542	2023	2023-12-18 23:41:21	2023-12-19 02:40:54	1	179.55	TREEROW	Non-storm
NW23121900014	CODY9542	2023	2023-12-18 23:41:22	2023-12-19 02:40:55	1	179.55	NO ISSUES FOUND	Non-storm
SE23121900420	CRTIS2104	2023	2023-12-19 00:05:11	2023-12-19 14:27:00	1	861.82	TREEBROW	Non-storm
SE23121900220	BROKS8153	2023	2023-12-19 00:17:07	2023-12-19 10:56:06	6	1506.06	PLANNED INTENTIONAL	Non-storm
NW23122000050	BRITN0333	2023	2023-12-19 01:48:33	2023-12-20 13:25:22	1	2136.82	EQUIPMENT FAILURE	Non-storm
SE23121900076	DIX1498	2023	2023-12-19 03:20:00	2023-12-19 10:34:35	2	869.16	EQUIPMENT FAILURE	Non-storm
SE23121900143	SCOTN1068	2023	2023-12-19 04:29:13	2023-12-19 10:21:31	1	352.3	PUBLIC INTERFERENCE	Non-storm
SW23121900155	WIXOM8905	2023	2023-12-19 07:13:20	2023-12-19 13:30:14	1	376.9	EQUIPMENT FAILURE	Non-storm
NW23121900112	WOLFH8838	2023	2023-12-19 07:17:34	2023-12-19 15:08:43	1	471.15	EQUIPMENT FAILURE	Non-storm
SW23121900324	PERU9441	2023	2023-12-19 09:01:02	2023-12-19 11:28:54	7	944.26	PLANNED INTENTIONAL	Non-storm
NW23121900176	AUBRN8864	2023	2023-12-19 09:05:08	2023-12-19 09:33:22	1	28.23	NO ISSUES FOUND	Non-storm
SW23121900171	FLMNG9434	2023	2023-12-19 09:06:35	2023-12-19 12:40:26	1	213.85	EQUIPMENT FAILURE	Non-storm

NW23121900175	KELOG8121	2023	2023-12-19 09:17:45	2023-12-19 10:23:01	22	1431.67	NO ISSUES FOUND	Non-storm
SW23121900180	YOST9371	2023	2023-12-19 09:18:38	2023-12-19 10:50:45	22	2021.31	PLANNED INTENTIONAL	Non-storm
NE23121900198	BEACH8601	2023	2023-12-19 09:25:34	2023-12-19 09:37:19	1	11.75	CUSTOMER EQUIPMENT	Non-storm
NW23121900189	HURST9853	2023	2023-12-19 09:27:04	2023-12-19 09:35:56	1	8.87	PLANNED INTENTIONAL	Non-storm
NW23121900195	HURST9853	2023	2023-12-19 09:36:13	2023-12-19 11:21:18	1	105.08	PLANNED INTENTIONAL	Non-storm
SW23121801066	GAY2829	2023	2023-12-19 09:49:38	2023-12-19 09:58:03	1	8.42	EQUIPMENT FAILURE	Non-storm
NE23121900631	CASVL8819	2023	2023-12-19 09:50:59	2023-12-19 23:32:21	3	2450.03	EQUIPMENT FAILURE	Non-storm
SE23121900213	MLVDL2105	2023	2023-12-19 09:55:15	2023-12-19 12:19:01	1	143.77	PLANNED INTENTIONAL	Non-storm
SE23121900211	VILLA0636	2023	2023-12-19 09:58:11	2023-12-19 10:21:51	1	23.67	PLANNED INTENTIONAL	Non-storm
SE23121900274	BROKS8153	2023	2023-12-19 09:59:03	2023-12-19 10:56:10	1	57.12	CUSTOMER EQUIPMENT	Non-storm
NE23121900223	PRKRD8779	2023	2023-12-19 10:01:54	2023-12-19 11:36:09	78	7393.1	PLANNED INTENTIONAL	Non-storm
NE23121900236	DERBY2635	2023	2023-12-19 10:03:37	2023-12-20 01:09:21	1	905.73	NO ISSUES FOUND	Non-storm
NE23121900208	JACOB8698	2023	2023-12-19 10:07:52	2023-12-19 10:15:44	1	7.87	PLANNED INTENTIONAL	Non-storm
SE23121900228	SAVAN1221	2023	2023-12-19 10:08:33	2023-12-19 11:47:38	1	99.08	PLANNED INTENTIONAL	Non-storm
NE23121900259	LNDIS8164	2023	2023-12-19 10:29:32	2023-12-19 11:08:22	8	309.54	PLANNED INTENTIONAL	Non-storm
SE23121900262	SIXMI1216	2023	2023-12-19 10:32:04	2023-12-19 11:29:59	270	15198.63	TROUBLE INTENTIONAL	Non-storm
SE23121900282	SIXMI1216	2023	2023-12-19 10:32:21	2023-12-19 11:30:04	1	57.72	TROUBLE INTENTIONAL	Non-storm
SE23121801062	PINGR0403	2023	2023-12-19 10:38:50	2023-12-19 11:18:12	1	39.37	CUSTOMER EQUIPMENT	Non-storm
SE23121900301	GDRIV2220	2023	2023-12-19 10:47:45	2023-12-19 13:47:53	10	1798.38	PLANNED INTENTIONAL	Non-storm
SE23121900279	GDRIV2220	2023	2023-12-19 10:47:46	2023-12-19 13:47:50	14	2546.79	PLANNED INTENTIONAL	Non-storm
NE23121900298	LOMRD8600	2023	2023-12-19 10:49:39	2023-12-19 16:48:06	6	2148.24	EQUIPMENT FAILURE	Non-storm
SW23121900243	PERU9440	2023	2023-12-19 10:52:44	2023-12-19 11:06:54	1	14.17	PLANNED INTENTIONAL	Non-storm
NE23121900275	JACOB8698	2023	2023-12-19 10:52:56	2023-12-19 11:01:47	1	8.85	PLANNED INTENTIONAL	Non-storm
SW23121900303	NBURG8075	2023	2023-12-19 10:58:56	2023-12-19 12:00:17	58	3533.47	NO ISSUES FOUND	Non-storm
SE23121900313	GNSTN1319	2023	2023-12-19 11:04:14	2023-12-19 12:16:54	1	72.67	PLANNED INTENTIONAL	Non-storm
NE23121900316	FRASR2437	2023	2023-12-19 11:04:43	2023-12-19 11:12:18	1	7.58	NO ISSUES FOUND	Non-storm
NE23121900353	JACOB8698	2023	2023-12-19 11:09:44	2023-12-19 11:18:36	1	8.87	PLANNED INTENTIONAL	Non-storm
SW23121900296	TAYLR9483	2023	2023-12-19 11:15:46	2023-12-19 11:39:02	8	184.2	PLANNED INTENTIONAL	Non-storm
SW23121900333	HEMLK1967	2023	2023-12-19 11:16:27	2023-12-19 13:05:49	12	688.43	EQUIPMENT FAILURE	Non-storm
NE23121900336	BENSN8720	2023	2023-12-19 11:21:28	2023-12-19 12:12:14	12	608.35	EQUIPMENT FAILURE	Non-storm
SE23121900337	VERNR1490	2023	2023-12-19 11:30:11	2023-12-19 13:49:20	1	139.15	PLANNED INTENTIONAL	Non-storm
SE23121900377	GDRIV2199	2023	2023-12-19 11:36:03	2023-12-19 13:49:00	1	132.95	PLANNED INTENTIONAL	Non-storm
SE23121900375	MLVDL2105	2023	2023-12-19 11:41:50	2023-12-19 13:50:04	1	128.23	PLANNED INTENTIONAL	Non-storm
NW23121900354	WOLFH8822	2023	2023-12-19 11:47:14	2023-12-19 12:06:00	1	18.77	PLANNED INTENTIONAL	Non-storm
SE23121900347	GDRIV2220	2023	2023-12-19 12:05:29	2023-12-19 12:36:21	1	30.87	PLANNED INTENTIONAL	Non-storm
SW23121900390	GLBRT9373	2023	2023-12-19 12:08:35	2023-12-19 12:31:05	19	422.83	EQUIPMENT FAILURE	Non-storm
NE23121900424	NUNLY1936	2023	2023-12-19 12:12:36	2023-12-19 15:04:11	1	171.58	NO ISSUES FOUND	Non-storm
NW23121900349	CULVR0315	2023	2023-12-19 12:16:20	2023-12-19 12:55:52	1	39.53	PLANNED INTENTIONAL	Non-storm
SE23121900339	VENIC2205	2023	2023-12-19 12:22:29	2023-12-19 12:37:26	1	14.95	TREEROW	Non-storm
SE23121900447	EVRGN1783	2023	2023-12-19 12:27:09	2023-12-19 13:09:54	2	85.49	EQUIPMENT FAILURE	Non-storm
NW23121900367	CAMDN8282	2023	2023-12-19 12:30:06	2023-12-19 13:38:17	1	68.18	PLANNED INTENTIONAL	Non-storm
SE23121900426	LAUDR1554	2023	2023-12-19 12:42:50	2023-12-19 13:19:28	1	36.63	PLANNED INTENTIONAL	Non-storm
NW23121900479	WOLFH8838	2023	2023-12-19 12:49:20	2023-12-19 18:24:03	15	5016.55	EQUIPMENT FAILURE	Non-storm
NW23121900637	WOLFH8838	2023	2023-12-19 12:49:20	2023-12-19 18:23:57	1	334.62	EQUIPMENT FAILURE	Non-storm
NW23121900449	SPKNE8842	2023	2023-12-19 12:49:45	2023-12-19 14:03:02	4	293.06	PLANNED INTENTIONAL	Non-storm
NW23121900451	NIXON8926	2023	2023-12-19 12:59:55	2023-12-19 13:25:35	1	25.67	PLANNED INTENTIONAL	Non-storm
NE23122000127	CASVL8819	2023	2023-12-19 13:08:54	2023-12-20 13:31:54	1	1463	ANIMAL	Non-storm
NW23122000105	WHMLK8099	2023	2023-12-19 13:15:58	2023-12-20 11:13:41	1	1317.72	EQUIPMENT FAILURE	Non-storm
SE23121900483	FRISB1275	2023	2023-12-19 13:20:18	2023-12-19 14:02:22	1	42.07	EQUIPMENT FAILURE	Non-storm
NW23121900478	GENOA8217	2023	2023-12-19 13:20:20	2023-12-19 17:08:47	1	228.45	ANIMAL	Non-storm
SW23121900465	GLBRT9373	2023	2023-12-19 13:20:47	2023-12-19 13:51:47	1	31	PLANNED INTENTIONAL	Non-storm
SE23121900476	GNSTN1295	2023	2023-12-19 13:21:52	2023-12-19 13:54:20	1	32.47	PLANNED INTENTIONAL	Non-storm
NW23121900473	COLFX8186	2023	2023-12-19 13:26:52	2023-12-19 16:16:58	2	340.1	PLANNED INTENTIONAL	Non-storm
SW23121900493	GLBRT9381	2023	2023-12-19 13:37:55	2023-12-19 14:25:16	2	94.2	PLANNED INTENTIONAL	Non-storm
SW23121900197	FRMTN8880	2023	2023-12-19 13:41:27	2023-12-19 14:11:39	2	52.53	EQUIPMENT FAILURE	Non-storm
SE23121900522	PULFD2155	2023	2023-12-19 13:42:56	2023-12-19 15:13:17	1	90.35	PLANNED INTENTIONAL	Non-storm
NW23121900486	SPKNE8842	2023	2023-12-19 13:48:28	2023-12-19 14:54:00	1	65.53	PLANNED INTENTIONAL	Non-storm
SE23121900087	BLTMR1454	2023	2023-12-19 14:00:45	2023-12-19 14:16:50	1	16.08	TREEBROW	Non-storm
NE23121900511	LNDIS8132	2023	2023-12-19 14:01:29	2023-12-19 14:15:33	1	14.07	NO ISSUES FOUND	Non-storm
NE23121900525	LNDIS8164	2023	2023-12-19 14:01:50	2023-12-19 14:17:02	25	374.24	NO ISSUES FOUND	Non-storm
NE23121900512	LNDIS8164	2023	2023-12-19 14:01:56	2023-12-19 14:17:02	14	210.1	NO ISSUES FOUND	Non-storm
SE23121900526	TWEMI1938	2023	2023-12-19 14:01:58	2023-12-19 14:16:02	1	14.07	NO ISSUES FOUND	Non-storm
NE23121900513	LNDIS8164	2023	2023-12-19 14:02:00	2023-12-19 14:17:01	1	15.02	NO ISSUES FOUND	Non-storm
NW23121900503	COLFX8186	2023	2023-12-19 14:06:26	2023-12-19 14:30:45	1	24.32	PLANNED INTENTIONAL	Non-storm
NE23121900734	CAPAC8013	2023	2023-12-19 14:19:34	2023-12-19 23:41:36	1	594.92	EQUIPMENT FAILURE	Non-storm
SW23121900497	PERU9440	2023	2023-12-19 14:22:02	2023-12-19 15:01:13	1	39.18	PLANNED INTENTIONAL	Non-storm
SE23121800484	GENSE2147	2023	2023-12-19 14:25:22	2023-12-19 14:35:21	1	9.98	EQUIPMENT FAILURE	Non-storm
SE23121900627	GDRIV2220	2023	2023-12-19 14:53:18	2023-12-19 15:41:18	1	48	PLANNED INTENTIONAL	Non-storm
NW23121900618	SPKNE8842	2023	2023-12-19 14:56:02	2023-12-19 15:20:48	5	122.25	PLANNED INTENTIONAL	Non-storm
NE23121900346	BADAX0311	2023	2023-12-19 16:26:10	2023-12-19 17:19:42	1	53.53	EQUIPMENT FAILURE	Non-storm
SE23121900701	GDRIV1297	2023	2023-12-19 16:39:56	2023-12-19 20:31:29	32	6193.31	EQUIPMENT FAILURE	Non-storm
NE23121900529	BERND2645	2023	2023-12-19 16:42:22	2023-12-19 17:12:23	1	21.15	EQUIPMENT FAILURE	Non-storm
SE23121900806	GDRIV1182	2023	2023-12-19 17:50:33	2023-12-19 20:31:26	1	160.88	NO ISSUES FOUND	Non-storm
SE23121801353	ECORS2103	2023	2023-12-19 18:00:47	2023-12-19 18:06:39	1	5.87	NO ISSUES FOUND	Non-storm
NW23121900789	WLNUT9013	2023	2023-12-19 18:18:35	2023-12-19 18:47:30	149	5766.57	TROUBLE INTENTIONAL	Non-storm
NW23121900779	WIXOM9532	2023	2023-12-19 18:22:07	2023-12-19 19:50:15	7	490.16	EQUIPMENT FAILURE	Non-storm
SW23121900816	SALIN9867	2023	2023-12-19 19:55:45	2023-12-20 04:53:54	55	14546.31	EQUIPMENT FAILURE	Non-storm
SW23122000004	SALIN9867	2023	2023-12-19 19:55:50	2023-12-20 04:53:03	1	537.22	EQUIPMENT FAILURE	Non-storm
NW23121900830	COMLK9525	2023	2023-12-19 20:29:24	2023-12-20 11:56:50	34	12858.66	TROUBLE INTENTIONAL	Non-storm
SE23122000155	VENIC1437	2023	2023-12-19 21:14:30	2023-12-20 07:01:17	1	28.48	EQUIPMENT FAILURE	Non-storm
SE23121900850	PURTN1246	2023	2023-12-19 21:17:35	2023-12-20 08:49:01	1	691.43	TREEBROW	Non-storm
NW23121900752	HANCK8142	2023	2023-12-19 21:19:47	2023-12-20 02:30:26	2	595.27	EQUIPMENT FAILURE	Non-storm
SE23121900797	LAUDR1272	2023	2023-12-19 21:55:30	2023-12-19 22:10:11	1	14.68	EQUIPMENT FAILURE	Non-storm
SE23121900739	MEYRS1896	2023	2023-12-19 21:57:46	2023-12-19 22:16:05	1	18.32	CUSTOMER EQUIPMENT	Non-storm
SE23121801449	ALNPK2090	2023	2023-12-19 22:01:37	2023-12-19 22:20:29	1	18.87	EQUIPMENT FAILURE	Non-storm
SE23121900064	GENSE2176	2023	2023-12-19 22:21:06	2023-12-19 22:26:59	1	5.88	NO ISSUES FOUND	Non-storm
SE23121900879	ECORS1157	2023	2023-12-19 22:39:36	2023-12-20 09:41:28	1	661.87	EQUIPMENT FAILURE	Non-storm
SW23121900861	OMAHA8215	2023	2023-12-19 22:52:40	2023-12-20 02:01:06	59	11105.15	EQUIPMENT FAILURE	Non-storm
NW23121900870	BRONC8677	2023	2023-12-19 23:23:37	2023-12-20 01:50:00	152	11882.35	EQUIPMENT FAILURE	Non-storm
SE23121900883	CRTIS1159	2023	2023-12-20 03:00:53	2023-12-20 03:07:07	1	6.23	EQUIPMENT FAILURE	Non-storm
NW23122000099	STRFD9093	2023	2023-12-20 08:21:38	2023-12-20 13:10:06	1	288.47	ANIMAL	Non-storm
NE23122000070	TLBOT8051	2023	2023-12-20 08:23:54	2023-12-20 10:30:40	1	126.77	PUBLIC INTERFERENCE	Non-storm
NE23122000100	TLBOT8051	2023	2023-12-20 08:23:57	2023-12-20 10:30:44	1	126.78	PUBLIC INTERFERENCE	Non-storm
NE23122000065	TLBOT8051	2023	2023-12-20 08:24:03	2023-12-20 10:30:53	2	253.55	PUBLIC INTERFERENCE	Non-storm
SE23122000077	LAMBT1524	2023	2023-12-20 08:46:32	2023-12-20 09:27:53	1	41.35	PLANNED INTENTIONAL	Non-storm
NE23122000823	CAPAC8013	2023	2023-12-20 08:57:58	2023-12-20 18:50:33	1	592.58	EQUIPMENT FAILURE	Non-storm
NW23122000115	null	2023	2023-12-20 09:06:32	2023-12-20 10:20:42	13	958.78	LIGHTNING	Non-storm
SE23122000104	LAUDR1272	2023	2023-12-20 09:18:06	2023-12-20 11:30:17	9	1188	PLANNED INTENTIONAL	Non-storm
NW23122000108	ALPNE8921	2023	2023-12-20 09:19:58	2023-12-20 09:44:53	2	49.55	PLANNED INTENTIONAL	Non-storm
NW23122000140	ORION8966	2023	2023-12-20 09:28:18	2023-12-20 14:22:37	1	294.32	ANIMAL	Non-storm
SW23122000136	HASKL1788	2023	2023-12-20 09:42:09	2023-12-20 10:24:23	11	269.07	TROUBLE INTENTIONAL	Non-storm
SW23122000141	HASKL1788	2023	2023-12-20 09:42:26	2023-12-20 10:00:21	2	35.82	TROUBLE INTENTIONAL	Non-storm
SE23122000073	ROTUN8329	2023	2023-12-20 09:47:57	2023-12-20 10:23:43	1	18.77	CUSTOMER EQUIPMENT	Non-storm
NE23122000142	JACOB8698	2023	2023-12-20 09:48:27	2023-12-20 09:57:07	1	8.67	PLANNED INTENTIONAL	Non-storm
NE23122000078	GOLFB730	2023	2023-12-20 09:57:02	2023-12-20 10:19:24	1	22.37	METER / BLOCKS	Non-storm
SE23122000090	BAUFR1212	2023	2023-12-20 09:59:58	2023-12-20 10:10:28	1	10.5	CUSTOMER EQUIPMENT	Non-storm
NW23122000153	HURST9853	2023	2023-12-20 10:00:10	2023-12-20 12:24:12	1	144.03	PLANNED INTENTIONAL	Non-storm
NW23122000151	COLFX8186	2023	2023-12-20 10:03:03	2023-12-20 11:38:53	1	95.83	PLANNED INTENTIONAL	Non-storm
NE23122000168	CAPAC8756	2023	2023-12-20 10:08:13	2023-12-20 10:52:04	6	260.18	TREEROW	Non-storm
NE23122000200	CAPAC8756	2023	2023-12-20 10:08:24	2023-12-20 10:51:57	1	43.55	NO ISSUES FOUND	Non-storm
SE23122000167	MEDNA8692	2023	2023-12-20 10:09:15	2023-12-20 12:00:40	16	1780.13	ANIMAL	Non-storm
SE23122000180	PULFD2155	2023	2023-12-20 10:16:29	2023-12-20 11:24:23	1	67.9	PLANNED INTENTIONAL	Non-storm
SE23122000173	KENT0046	2023	2023-12-20 10:17:15	2023-12-20 13:00:02	14	2145.66	PLANNED INTENTIONAL	Non-storm
SE23122000355	KENT0046	2023	2023-12-20 10:17:18	2023-12-20 12:59:52	1	162.57	PLANNED INTENTIONAL	Non-storm
SE23122000178	KENT0046	2023	2023-12-20 10:17:19	2023-12-20 12:59:53	1	162.57	PLANNED INTENTIONAL	Non-storm
SE23122000182	KENT0046	2023	2023-12-20 10:17:21	2023-12-20 12:59:55	1	162.57	PLANNED INTENTIONAL	Non-storm
SE23122000195	KENT0046	2023	2023-12-20 10:17:21	2023-12-20 12:59:55	1	162.57	PLANNED INTENTIONAL	Non-storm
SE23122000202	KENT0046	2023	2023-12-20 10:17:25	2023-12-20 12:59:59	1	162.57	PLANNED INTENTIONAL	Non-storm
SE23122000076	LAUDR1272	2023	2023-12-20 10:21:21	2023-12-20 10:59:50	1	38.48	EQUIPMENT FAILURE	Non-storm
NW23122000211	ALPNE8921	2023	2023-12-20 10:31:15	2023-12-20 10:48:09	11	233.52	EQUIPMENT FAILURE	Non-storm
SE23122000205	DIK1498	2023	2023-12-20 10:31:36	2023-12-20 11:34:13	1	62.62	TROUBLE INTENTIONAL	Non-storm
NW23122000228	DISCO8562	2023	2023-12-20 10:37:10	2023-12-20 12:07:30	11	991.85	EQUIPMENT FAILURE	Non-storm
NW23122000215	DISCO8562	2023	2023-12-20 10:37:15	2023-12-20 12:12:29	48	3876.88	EQUIPMENT FAILURE	Non-storm
NE23122000214	JACOB8698	2023	2023-12-20 10:38:05	2023-12-20 10:45:50	1	7.75	PLANNED INTENTIONAL	Non-storm
NW23122000318	ALPNE8921	2023	2023-12-20 10:40:55	2023-12-20 11:54:35	1	73.67	PLANNED INTENTIONAL	Non-storm
NW23122000249	SPKNE8842	2023	2023-12-20 10:45:02	2023-12-20 11:33:07	1	48.08	PLANNED INTENTIONAL	Non-storm
SE23122000233	APPOL1318	2023	2023-12-20 10:46:00	2023-12-20 12:52:24	16	2021.49	TROUBLE INTENTIONAL	Non-storm
NE23122000208	LNDIS8164	2023	2023-12-20 10:46:33	2023-12-20 11:19:12	1	32.65	PLANNED INTENTIONAL	Non-storm
NE23122000235	BECK8727	2023	2023-12-20 10:51:11	2023-12-20 13:15:04	17	2443.27	ANIMAL	Non-storm
NW23122000714	GODSN8986	2023	2023-12-20 10:53:46	2023-12-20 17:44:01	1	410.25	ANIMAL	Non-storm
SW23122000248	INKST0315	2023	2023-12-20 11:08:32	2023-12-20 12:22:29	6	442.62	PLANNED INTENTIONAL	Non-storm
SE23122000287	GDRIV2199	2023	2023-12-20 11:19:36	2023-12-20 13:27:00	27	3437.1	PLANNED INTENTIONAL	Non-storm
SE23122000320	LINCN2694	2023	2023-12-20 11:23:40	2023-12-20 12:13:31	1	49.85	PLANNED INTENTIONAL	Non-storm
SE23122000279	WAGNR2113	2023	2023-12-20 11:33:23	2023-12-20 12:38:24	1	65.02	TROUBLE INTENTIONAL	Non-storm
NW23122000273	ALPNE8921	2023	2023-12-20 11:34:43	2023-12-20 11:42:52	2	15.95	PLANNED INTENTIONAL	Non-storm
SW23122000278	GLBRT9373	2023	2023-12-20 11:36:37	2023-12-20 14:07:36	46	6850.21	PLANNED INTENTIONAL	Non-storm
SW23122000296	PHENX9833	2023	2023-12-20 11:43:38	2023-12-20 14:08:24	103	11313.03	ANIMAL	Non-storm
SW23122000301	PRICE2923	2023	2023-12-20 11:43:42	2023-12-20 14:08:25	5	722.75	EQUIPMENT FAILURE	Non-storm
SW23122000515	PHENX9833	2023	2023-12-20 11:43:50	2023-12-20 14:08:23	1	144.55	ANIMAL	Non-storm
SE23122100143	PULFD2224	2023	2023-12-20 11:47:06	2023-12-21 11:44:24	14	3598.47	PLANNED INTENTIONAL	Non-storm
NE23122000305	JACOB8698	2023	2023-12-20 11:54:24	2023-12-20 12:04:47	1	10.38	PLANNED INTENTIONAL	Non-storm
SE23122000333	LAUDR1272	2023	2023-12-20 11:55:15	2023-12-20 12:21:08	1	25.88	PLANNED INTENTIONAL	Non-storm
NW23122000467	CAMDN8282	2023	2023-12-20 12:03:55	2023-12-20 14:02:18	1	118.38	EQUIPMENT FAILURE	Non-storm
SE23122000346	LAUDR1554	2023	2023-12-20 12:06:09	2023-12-20 13:07:39	1	61.5	PLANNED INTENTIONAL	Non-storm
SW23122000176	HOOVR0365	2023	2023-12-20 12:08:54	2023-12-20 19:45:22	1	456.47	EQUIPMENT FAILURE	Non-storm
NW23122000342	HURST9853	2023	2023-12-20 12:17:36	2023-12-20 14:34:57	1	137.35	PLANNED INTENTIONAL	Non-storm
NE23122000353	OMEGA8444	2023	2023-12-20 12:22:36	2023-12-20 18:01:00	2	676.54	ANIMAL	Non-storm
NW23122000357	CRWFD9076	2023	2023-12-20 12:26:27	2023-12-20 14:09:33	9	926.58	ANIMAL	Non-storm
NE23122000376	JACOB8698	2023	2023-12-20 12:36:01	2023-12-20 12:43:29	1	7.47	PLANNED INTENTIONAL	Non-storm
NE23121900325	BRAZL8495	2023	2023-12-20 12:39:45	2023-12-20 12:56:09	1	16.4	TREEROW	Non-storm
SW23122000484	HOMER9360	2023	2023-12-20 12:41:54	2023-12-20 15:52:10	1	190.27	EQUIPMENT LOADING	Non-storm
SW23122000599	GLBRT8106	2023	2023-12-20 12:41:54	2023-12-20 15:52:09	1	190.25	NO ISSUES FOUND	Non-storm
SW23122000374	FRLDG8042	2023	2023-12-20 12:41:55	2023-12-20 15:52:23	1569	298542.3	EQUIPMENT FAILURE	Non-storm
NE23122000371	WORTH0301	2023	2023-12-20 12:46:27	2023-12-20 14:05:15	2	156.05	PLANNED INTENTIONAL	Non-storm
NE23122000485	MENLO8815	2023	2023-12-20 12:59:47	2023-12-20 15:17:49	74	10113.35	EQUIPMENT FAILURE	Non-storm
NW23122000548	WRNS1869	2023	2023-12-20 13:20:33	2023-12-20 13:28:29	1	7.93	EQUIPMENT FAILURE	Non-storm
SW23122000538	PERU9440	2023	2023-12-20 13:35:27	2023-12-20 15:47:04	6	257.59	PLANNED INTENTIONAL	Non-storm
NW23122000546	ALPNE8921	2023	2023-12-20 13:40:57	2023-12-20 13:50:55	1	9.97	PLANNED INTENTIONAL	Non-storm
NW23122000553	SPKNE8842	2023	2023-12-20 13:48:45	2023-12-20 14:39:26	12	606.91	PLANNED INTENTIONAL	Non-storm
NW23122000563	WOLFH8822	2023	2023-12-20 13:53:51	2023-12-20 15:05:33	1	71.7	PLANNED INTENTIONAL	Non-storm
SE23122000571	MLVDL2105	2023	2023-12-20 13:54:23	2023-12-20 14:47:09	2	105.54	PLANNED INTENTIONAL	Non-storm
NE23122000594	NINMI2474	2023	2023-12-20 13:56:11	2023-12-20 14:28:44	1	32.55	PLANNED INTENTIONAL	Non-storm

SW23122000580	PIONR9787	2023	2023-12-20 14:06:21	2023-12-20 16:05:34	3	357.64	ANIMAL	Non-storm
NW23122000561	ALPNE8921	2023	2023-12-20 14:07:05	2023-12-20 14:31:29	1	24.4	PLANNED INTENTIONAL	Non-storm
NE23122000828	ROBIN9309	2023	2023-12-20 14:10:24	2023-12-20 20:28:36	2	756.4	EQUIPMENT FAILURE	Non-storm
NW23122000044	HURST9826	2023	2023-12-20 14:15:07	2023-12-20 14:25:26	1	10.32	EQUIPMENT FAILURE	Non-storm
SW23122000602	PERU9440	2023	2023-12-20 14:40:43	2023-12-20 15:37:46	1	57.05	PLANNED INTENTIONAL	Non-storm
NW23122000633	MILFD9245	2023	2023-12-20 15:06:24	2023-12-20 17:39:53	1	153.48	ANIMAL	Non-storm
NW23122000596	ALPNE8921	2023	2023-12-20 15:14:34	2023-12-20 16:28:00	1	73.43	PLANNED INTENTIONAL	Non-storm
SW23122000632	SOFLD9088	2023	2023-12-20 15:16:34	2023-12-20 17:19:12	3	367.23	ANIMAL	Non-storm
SW23122000643	SOFLD8912	2023	2023-12-20 15:16:50	2023-12-20 17:19:15	3	367.24	EQUIPMENT FAILURE	Non-storm
NE23122000636	SAVOY8711	2023	2023-12-20 15:17:48	2023-12-20 16:52:12	15	1414.16	ANIMAL	Non-storm
SW23122000791	CUSTR0317	2023	2023-12-20 15:22:26	2023-12-20 18:18:46	6	515.74	TREEBROW	Non-storm
SE23122000821	WHITR2809	2023	2023-12-20 16:33:06	2023-12-20 19:37:25	9	1657.47	EQUIPMENT FAILURE	Non-storm
NW23122000794	NOLAN9790	2023	2023-12-20 16:46:16	2023-12-20 17:50:22	2	127.94	ANIMAL	Non-storm
NW23122000802	NOLAN9790	2023	2023-12-20 16:46:19	2023-12-20 17:50:18	1	63.98	EQUIPMENT FAILURE	Non-storm
SW23122000750	POPLR9885	2023	2023-12-20 16:55:09	2023-12-20 19:19:34	1	144.42	EQUIPMENT FAILURE	Non-storm
NE23122000822	APLGT0312	2023	2023-12-20 16:58:30	2023-12-20 17:09:25	1	10.92	EQUIPMENT FAILURE	Non-storm
NE23122000813	CHTNT9095	2023	2023-12-20 16:58:48	2023-12-21 11:30:35	1	1111.78	EQUIPMENT FAILURE	Non-storm
SE23122000788	WHITR2809	2023	2023-12-20 18:04:52	2023-12-20 21:10:13	13	2500.28	EQUIPMENT FAILURE	Non-storm
SE23122000742	WAYBN1161	2023	2023-12-20 19:02:25	2023-12-20 19:15:42	1	13.28	EQUIPMENT FAILURE	Non-storm
NE23122000752	CAPAC8013	2023	2023-12-20 19:38:38	2023-12-20 20:06:46	1	28.13	EQUIPMENT FAILURE	Non-storm
SE23121900689	REDFD1285	2023	2023-12-20 22:12:34	2023-12-20 22:36:39	1	24.08	EQUIPMENT FAILURE	Non-storm
NE23122100008	PERU9444	2023	2023-12-21 00:34:46	2023-12-21 10:40:02	1	605.27	EQUIPMENT FAILURE	Non-storm
SW23122100054	POPLR9885	2023	2023-12-21 07:42:44	2023-12-21 09:34:29	22	2451.72	EQUIPMENT FAILURE	Non-storm
NE23122100078	NINMI2474	2023	2023-12-21 08:28:15	2023-12-21 08:43:10	1	14.92	PLANNED INTENTIONAL	Non-storm
NE23122100091	CASVL8819	2023	2023-12-21 08:41:03	2023-12-21 11:45:55	14	2586.04	ANIMAL	Non-storm
SW23122100107	SALIN9794	2023	2023-12-21 08:57:42	2023-12-21 10:58:34	1	120.87	PUBLIC INTERFERENCE	Non-storm
NE23122100125	VERNR2043	2023	2023-12-21 08:59:05	2023-12-21 09:08:17	1	9.2	EQUIPMENT FAILURE	Non-storm
NE23122100119	MILTN0302	2023	2023-12-21 09:19:21	2023-12-21 10:47:30	1	88.15	NO ISSUES FOUND	Non-storm
SW23122100168	RENO2927	2023	2023-12-21 09:41:54	2023-12-21 13:36:43	1	234.82	EQUIPMENT FAILURE	Non-storm
SE23122100147	PULFD2155	2023	2023-12-21 09:42:30	2023-12-21 12:02:37	1	140.12	PLANNED INTENTIONAL	Non-storm
NW23122100120	SPKNE8842	2023	2023-12-21 09:46:45	2023-12-21 09:57:10	1	10.42	PLANNED INTENTIONAL	Non-storm
NW23122100152	COLFX8186	2023	2023-12-21 09:55:28	2023-12-21 10:52:48	1	57.33	PLANNED INTENTIONAL	Non-storm
SE23122100162	GDRIV2220	2023	2023-12-21 10:09:40	2023-12-21 11:58:54	1	109.23	PLANNED INTENTIONAL	Non-storm
SE23122100173	GNSTN1319	2023	2023-12-21 10:21:09	2023-12-21 11:14:01	1	52.87	PLANNED INTENTIONAL	Non-storm
SE23122100182	GDRIV1050	2023	2023-12-21 10:26:23	2023-12-21 11:24:50	1	58.45	PLANNED INTENTIONAL	Non-storm
SE23122100197	LAMBT1524	2023	2023-12-21 10:28:52	2023-12-21 11:07:29	1	38.62	NO ISSUES FOUND	Non-storm
NW23122100207	ALPNE8921	2023	2023-12-21 10:33:45	2023-12-21 10:52:35	1	18.83	PLANNED INTENTIONAL	Non-storm
NE23122100164	PINGV0325	2023	2023-12-21 10:36:43	2023-12-21 11:43:49	1	67.1	PLANNED INTENTIONAL	Non-storm
SW23122100187	GLBRT9373	2023	2023-12-21 10:39:15	2023-12-21 12:10:52	1	91.62	PLANNED INTENTIONAL	Non-storm
SW23122100212	GLBRT9373	2023	2023-12-21 10:39:15	2023-12-21 12:10:51	2	183.2	PLANNED INTENTIONAL	Non-storm
SW23122100344	GLBRT9373	2023	2023-12-21 10:39:56	2023-12-21 13:41:01	1	181.08	PLANNED INTENTIONAL	Non-storm
NW23122100198	WOLFH8822	2023	2023-12-21 10:50:36	2023-12-21 12:08:07	1	77.52	PLANNED INTENTIONAL	Non-storm
NE23122100200	ARMAD0302	2023	2023-12-21 10:55:07	2023-12-21 11:01:20	1	6.22	PLANNED INTENTIONAL	Non-storm
NE23122100273	NUNLY1936	2023	2023-12-21 11:02:36	2023-12-21 11:44:25	1	41.82	EQUIPMENT FAILURE	Non-storm
SE23122100218	KENT0046	2023	2023-12-21 11:04:58	2023-12-21 12:21:51	1	76.88	PLANNED INTENTIONAL	Non-storm
SE23122100219	KENT0046	2023	2023-12-21 11:05:06	2023-12-21 12:21:59	1	76.88	PLANNED INTENTIONAL	Non-storm
NW23122100117	ORION8966	2023	2023-12-21 11:08:38	2023-12-21 11:31:52	1	23.23	TREEROW	Non-storm
SE23122100295	GDRIV1297	2023	2023-12-21 11:33:33	2023-12-21 13:49:40	1	136.12	TROUBLE INTENTIONAL	Non-storm
SE23122100226	GDRIV1297	2023	2023-12-21 11:33:37	2023-12-21 13:49:48	10	1354.81	PLANNED INTENTIONAL	Non-storm
SE23122100234	LINWD1103	2023	2023-12-21 11:34:03	2023-12-22 02:09:00	4	3499.31	PLANNED INTENTIONAL	Non-storm
SE23122100650	LINWD1103	2023	2023-12-21 11:34:03	2023-12-22 02:09:04	20	17496.73	PLANNED INTENTIONAL	Non-storm
NE23122100228	ROSVL1756	2023	2023-12-21 11:44:04	2023-12-21 13:11:46	9	787.97	PLANNED INTENTIONAL	Non-storm
SW23122100232	GLBRT9381	2023	2023-12-21 11:53:31	2023-12-21 12:05:58	2	24.9	PLANNED INTENTIONAL	Non-storm
NE23122100245	LNDIS8164	2023	2023-12-21 11:58:22	2023-12-21 12:06:46	2	16.8	PLANNED INTENTIONAL	Non-storm
NE23122100268	ARMAD0302	2023	2023-12-21 12:32:29	2023-12-21 12:46:17	1	13.8	PLANNED INTENTIONAL	Non-storm
NE23122100256	NINMI2474	2023	2023-12-21 12:37:17	2023-12-21 13:21:00	1	43.72	PLANNED INTENTIONAL	Non-storm
NW23122100286	COLFX8186	2023	2023-12-21 12:47:45	2023-12-21 14:06:52	1	79.12	PLANNED INTENTIONAL	Non-storm
SE23122100287	ROTUN8329	2023	2023-12-21 12:49:41	2023-12-21 13:56:51	1	53.75	EQUIPMENT FAILURE	Non-storm
NE23122100318	SDF012641	2023	2023-12-21 13:00:20	2023-12-21 15:13:48	1	133.47	EQUIPMENT FAILURE	Non-storm
SE23122100323	LINWD2142	2023	2023-12-21 13:00:30	2023-12-21 16:59:24	414	98776.06	EQUIPMENT FAILURE	Non-storm
SE23122200148	STOPL1078	2023	2023-12-21 13:00:38	2023-12-21 16:58:28	1	237.83	EQUIPMENT FAILURE	Non-storm
NW23122100296	COLFX8186	2023	2023-12-21 13:03:00	2023-12-21 14:45:59	2	205.56	PLANNED INTENTIONAL	Non-storm
SE23122100265	CORTL1015	2023	2023-12-21 13:16:04	2023-12-21 13:34:53	1	18.82	NO CAUSE	Non-storm
NW23122100533	CODY8824	2023	2023-12-21 13:27:36	2023-12-21 15:25:05	1	117.48	LIGHTNING	Non-storm
NW23122100404	CODY8824	2023	2023-12-21 13:27:37	2023-12-21 15:25:06	1	117.48	LIGHTNING	Non-storm
NW23122100389	CODY8824	2023	2023-12-21 13:27:43	2023-12-21 15:26:22	84	9962.55	LIGHTNING	Non-storm
NW23122100393	CODY8824	2023	2023-12-21 13:27:48	2023-12-21 15:22:56	1	115.13	LIGHTNING	Non-storm
NE23122100366	PINGV0325	2023	2023-12-21 13:33:15	2023-12-21 14:50:53	1	77.63	PLANNED INTENTIONAL	Non-storm
NE23122100592	BRUCE8953	2023	2023-12-21 13:39:39	2023-12-21 22:17:23	1	517.73	NO ISSUES FOUND	Non-storm
NW23122100358	WMSTN9857	2023	2023-12-21 13:45:01	2023-12-21 14:24:38	1	39.62	PLANNED INTENTIONAL	Non-storm
NE23122100594	MALTA9130	2023	2023-12-21 13:52:00	2023-12-21 16:20:55	336	49944.98	EQUIPMENT FAILURE	Non-storm
SW23122100421	PERU9440	2023	2023-12-21 13:53:22	2023-12-21 15:38:40	1	105.3	PLANNED INTENTIONAL	Non-storm
NW23122100420	ALPNE8921	2023	2023-12-21 13:57:17	2023-12-21 14:24:05	4	105.35	PLANNED INTENTIONAL	Non-storm
NW23122100449	ALPNE8921	2023	2023-12-21 13:57:21	2023-12-21 14:23:28	1	26.12	NO ISSUES FOUND	Non-storm
NW23122100061	CRWFD9083	2023	2023-12-21 14:01:24	2023-12-21 14:09:50	1	8.43	EQUIPMENT FAILURE	Non-storm
SE23122100446	GLEND2025	2023	2023-12-21 14:14:20	2023-12-21 15:15:36	1	61.27	PLANNED INTENTIONAL	Non-storm
NE23122100459	BOYNE8739	2023	2023-12-21 14:17:51	2023-12-21 14:24:35	1	6.73	PLANNED INTENTIONAL	Non-storm
NW23122100640	TAMRK9096	2023	2023-12-21 14:22:07	2023-12-22 09:02:43	1	1120.6	EQUIPMENT FAILURE	Non-storm
SW23122100503	HASKL1619	2023	2023-12-21 14:57:02	2023-12-21 17:06:13	66	8513.14	EQUIPMENT FAILURE	Non-storm
NE23122100495	BOYNE8739	2023	2023-12-21 15:12:26	2023-12-21 15:22:03	1	9.62	PLANNED INTENTIONAL	Non-storm
SE23122100437	ESTLD1146	2023	2023-12-21 15:19:18	2023-12-21 15:41:44	1	22.43	CUSTOMER EQUIPMENT	Non-storm
SE23122100541	ANNCH1588	2023	2023-12-21 16:18:48	2023-12-21 19:33:43	1	194.92	WIND	Non-storm
NE23122000847	SHORS2507	2023	2023-12-21 17:08:37	2023-12-21 17:21:27	1	12.83	WIND	Non-storm
SW23122100589	FRMTN1712	2023	2023-12-21 17:11:51	2023-12-22 13:46:02	13	14928.79	EQUIPMENT FAILURE	Non-storm
NE23122100673	YALE2633	2023	2023-12-21 17:52:44	2023-12-21 18:08:30	124	2268.43	PLANNED INTENTIONAL	Non-storm
SE23122100696	STLIS2075	2023	2023-12-21 19:29:45	2023-12-21 20:16:04	15	690.28	TROUBLE INTENTIONAL	Non-storm
NE23122100699	BECK8689	2023	2023-12-21 19:36:20	2023-12-21 20:26:26	42	2107.12	TROUBLE INTENTIONAL	Non-storm
NE23122100700	BECK8689	2023	2023-12-21 19:36:21	2023-12-21 20:26:26	2	100.16	TREEROW	Non-storm
SW23122100738	FRMTN1712	2023	2023-12-21 20:17:42	2023-12-22 13:45:08	1	1047.43	NO CAUSE	Non-storm
SW23122200222	FRMTN1726	2023	2023-12-21 20:18:56	2023-12-22 13:55:26	12	12677.17	EQUIPMENT FAILURE	Non-storm
SE23122200001	MACMB8506	2023	2023-12-22 00:01:10	2023-12-22 03:47:34	120	21237.84	EQUIPMENT FAILURE	Non-storm
NE23122200008	MACMB8506	2023	2023-12-22 00:01:15	2023-12-22 03:47:43	2	452.64	EQUIPMENT FAILURE	Non-storm
NW23122200056	LOCDL8909	2023	2023-12-22 08:04:32	2023-12-22 08:51:55	5	236.31	ANIMAL	Non-storm
SE23122200039	FOX1648	2023	2023-12-22 08:33:27	2023-12-22 11:13:58	1	79.88	TREEROW	Non-storm
NW23122200068	MALTA8423	2023	2023-12-22 08:34:38	2023-12-22 09:20:24	58	2633.5	ANIMAL	Non-storm
NW23122200219	WOLFH8822	2023	2023-12-22 08:58:32	2023-12-22 12:43:19	1	224.78	OTHER UTILITY EQUIP	Non-storm
NW23122200105	WOLFH8822	2023	2023-12-22 08:58:35	2023-12-22 12:43:21	1	224.77	TREEROW	Non-storm
NW23122200245	WOLFH8822	2023	2023-12-22 08:58:35	2023-12-22 12:43:21	1	224.77	TREEROW	Non-storm
SE23122200106	KENT0046	2023	2023-12-22 09:17:21	2023-12-22 11:52:59	6	932.86	PLANNED INTENTIONAL	Non-storm
NW23122200110	ALPNE8921	2023	2023-12-22 09:17:37	2023-12-22 09:33:38	2	32.04	EQUIPMENT FAILURE	Non-storm
NW23122200095	ALPNE8921	2023	2023-12-22 09:17:39	2023-12-22 09:33:41	1	16.03	PLANNED INTENTIONAL	Non-storm
SW23122200112	ZEBRA9476	2023	2023-12-22 09:19:06	2023-12-22 14:29:39	4	1242.06	ANIMAL	Non-storm
NW23122200109	HURST9853	2023	2023-12-22 09:21:56	2023-12-22 09:28:03	1	6.12	PLANNED INTENTIONAL	Non-storm
SE23122200099	GLEND2025	2023	2023-12-22 09:24:47	2023-12-22 10:26:40	2	118.17	PLANNED INTENTIONAL	Non-storm
SE23122200114	PULFD2224	2023	2023-12-22 09:25:04	2023-12-22 12:35:25	14	2655.97	PLANNED INTENTIONAL	Non-storm
NE23122200125	LEXTN8770	2023	2023-12-22 09:29:20	2023-12-22 11:33:08	1	123.8	EQUIPMENT FAILURE	Non-storm
SE23122200143	LAMBT1524	2023	2023-12-22 09:40:40	2023-12-22 10:34:49	1	54.15	PLANNED INTENTIONAL	Non-storm
SE23122200124	LAMBT1524	2023	2023-12-22 09:46:18	2023-12-22 09:58:44	4	49.49	PLANNED INTENTIONAL	Non-storm
SE23122200136	LAMBT1524	2023	2023-12-22 09:46:19	2023-12-22 09:58:40	1	12.35	PLANNED INTENTIONAL	Non-storm
SE23122200128	MLVDL2105	2023	2023-12-22 09:46:59	2023-12-22 12:01:37	31	1875.69	PLANNED INTENTIONAL	Non-storm
NE23122200157	FRASR1720	2023	2023-12-22 09:49:50	2023-12-22 11:08:14	1	78.4	NO ISSUES FOUND	Non-storm
NE23122200168	FRASR2437	2023	2023-12-22 10:04:38	2023-12-22 13:52:31	1	227.88	CUSTOMER EQUIPMENT	Non-storm
NW23122200150	HURST9853	2023	2023-12-22 10:05:50	2023-12-22 10:17:15	1	11.42	PLANNED INTENTIONAL	Non-storm
SW23122200140	PERU9440	2023	2023-12-22 10:09:35	2023-12-22 11:03:13	1	53.63	PLANNED INTENTIONAL	Non-storm
SW23122200176	SEVLE9367	2023	2023-12-22 10:12:53	2023-12-22 11:26:14	30	768.06	PLANNED INTENTIONAL	Non-storm
SW23122100587	YOST9427	2023	2023-12-22 10:21:01	2023-12-22 10:51:39	1	30.63	EQUIPMENT FAILURE	Non-storm
SE23122200164	LAUDR1272	2023	2023-12-22 10:27:33	2023-12-22 11:30:35	1	63.03	PLANNED INTENTIONAL	Non-storm
SE23122200169	GARY1376	2023	2023-12-22 10:52:49	2023-12-22 13:04:33	1	90.21	EQUIPMENT FAILURE	Non-storm
NW23122200198	ALPNE8921	2023	2023-12-22 11:04:17	2023-12-22 11:53:51	6	295.41	PLANNED INTENTIONAL	Non-storm
SE23122200209	GNSTN1226	2023	2023-12-22 11:17:18	2023-12-22 12:26:50	1	69.53	PLANNED INTENTIONAL	Non-storm
SE23122200231	MLVDL2105	2023	2023-12-22 11:17:32	2023-12-22 12:01:38	1	44.1	PLANNED INTENTIONAL	Non-storm
NW23122200252	LOCDL8909	2023	2023-12-22 11:28:25	2023-12-22 20:20:37	3	1596.56	EQUIPMENT FAILURE	Non-storm
NE23122200288	BAKER2418	2023	2023-12-22 11:38:45	2023-12-22 15:48:40	1	249.92	CUSTOMER EQUIPMENT	Non-storm
SE23122200220	GLEND1013	2023	2023-12-22 11:45:41	2023-12-22 12:11:36	1	25.92	PLANNED INTENTIONAL	Non-storm
SE23122200232	WAREN8362	2023	2023-12-22 11:50:05	2023-12-22 13:45:12	6	688.9	ANIMAL	Non-storm
SE23122200227	WAREN8362	2023	2023-12-22 11:50:12	2023-12-22 13:45:10	130	14923.85	ANIMAL	Non-storm
SW23122200238	SEVLE9367	2023	2023-12-22 11:57:37	2023-12-22 12:33:48	9	323.8	PLANNED INTENTIONAL	Non-storm
SE23122200154	TURNR1114	2023	2023-12-22 12:04:44	2023-12-22 12:12:24	1	7.67	EQUIPMENT FAILURE	Non-storm
NE23122200254	REDRN8733	2023	2023-12-22 12:17:10	2023-12-22 13:43:09	18	1544.83	EQUIPMENT FAILURE	Non-storm
NW23122200279	EUCLD9058	2023	2023-12-22 12:43:07	2023-12-22 18:00:07	5	1583.06	EQUIPMENT FAILURE	Non-storm
SW23122200280	DIMND9859	2023	2023-12-22 12:44:43	2023-12-22 13:19:59	1	35.27	NO ISSUES FOUND	Non-storm
SW23122200265	SPRUC9827	2023	2023-12-22 12:44:44	2023-12-22 13:20:08	2	70.5	NO ISSUES FOUND	Non-storm
SW23122200270	SEVLE9367	2023	2023-12-22 13:05:50	2023-12-22 13:58:19	8	418.58	PLANNED INTENTIONAL	Non-storm
SE23122200267	FRISB1275	2023	2023-12-22 13:20:30	2023-12-22 13:26:02	1	5.53	NO CAUSE	Non-storm
NW23122200318	SPKNE8842	2023	2023-12-22 13:29:30	2023-12-22 14:15:07	16	698.97	PLANNED INTENTIONAL	Non-storm
SW23122200329	SOFLD8912	2023	2023-12-22 13:59:37	2023-12-22 20:41:44	12	4817.58	EQUIPMENT FAILURE	Non-storm
SE23122200300	LAMBT1485	2023	2023-12-22 14:24:05	2023-12-22 15:18:27	1	54.37	EQUIPMENT FAILURE	Non-storm
SE23122200355	MADSN0659	2023	2023-12-22 14:26:02	2023-12-22 20:15:51	1	349.82	EQUIPMENT FAILURE	Non-storm
SE23122200308	VERNR1503	2023	2023-12-22 14:34:50	2023-12-22 14:51:17	1	16.45	EQUIPMENT FAILURE	Non-storm
NW23122200359	STERL8628	2023	2023-12-22 14:39:20	2023-12-22 16:21:18	75	7623.59	EQUIPMENT FAILURE	Non-storm
SE23122200366	CREWD8332	2023	2023-12-22 14:42:57	2023-12-22 17:09:34	8	2738.42	EQUIPMENT FAILURE	Non-storm
NW23122200377	JASON8143	2023	2023-12-22 15:11:29	2023-12-22 16:32:38	194	16132.03	PUBLIC INTERFERENCE	Non-storm
NW23122200448	JASON8143	2023	2023-12-22 15:11:30	2023-12-22 18:17:24	34	6211.52	PUBLIC INTERFERENCE	Non-storm
SE23122200530	FRISB2117	2023	2023-12-22 15:13:11	2023-12-23 12:31:45	1	1278.57	TREEROW	Non-storm
NW23122200333	MILFD9245	2023	2023-12-22 17:41:58	2023-12-22 18:34:08	1	52.17	EQUIPMENT FAILURE	Non-storm
SE23122200477	CREWD8314	2023	2023-12-22 19:01:39	2023-12-22 19:14:59	19	249.99	EQUIPMENT FAILURE	Non-storm
NE23122200501	MEDNA8533	2023	2023-12-22 20:53:04	2023-12-23 11:59:38	64	58013.76	EQUIPMENT FAILURE	Non-storm
SW23122200505	SALIN9840	2023	2023-12-22 21:24:26	2023-12-23 09:20:40	41	28483.19	EQUIPMENT FAILURE	Non-storm
SE23122200462	STOPL2231	2023	2023-12-22 21:47:17	2023-12-23 09:13:12	2	45.38	TREEROW	Non-storm
NE23122200527	AGSTA8700	2023	2023-12-22 22:43:20	2023-12-23 00:09:04	12	1028.63	EQUIPMENT FAILURE	Non-storm
NW23122200511	COLFX8186	2023	2023-12-22 23:01:24	2023-12-23 23:10:04	1	8.67	EQUIPMENT FAILURE	Non-storm
SE23122200408	APPOL1871	2023	2023-12-22 23:14:59	2023-12-22 23:44:42	1	29.72	EQUIPMENT FAILURE	Non-storm
NE23122200537	SLATR2652	2023	2023-12-22 23:20:48	2023-12-23 03:38:14	1	257.43	EQUIPMENT FAILURE	Non-storm
SE23122300441	PULFD2224	2023	2023-12-22 23:31:57	2023-12-24 02:10:45	1	1598.8	EQUIPMENT FAILURE	Non-storm
NE23122300058	MARLT8281	2023	2023-12-22 23:40:23	2023-12-23 08:47:47	1	547.4	EQUIPMENT FAILURE	Non-storm
SE23122200437	EMPIR1378	2023	2023-12-23 01:46:42	2023-12-23 02:08:00	1	21.3	TREEBROW	Non-storm
SW23122300016	NBURG9412	2023	2023-12-23 02:08:40	2023-12-23 08:54:06	34	13769.78	TREEROW	Non-storm
SE23122300018	LAMBT1524	2023	2023-12-23 02:12:40	2023-12-23 05:43:24	573	120625.57	TREEROW	Non-storm
SE23122300083	LAMBT1524	2023	2023-12-23 02:12:56	2023-12-23 05:42:21	1	209.42	NO ISSUES FOUND	Non-storm
NW23122300068	CHILS9877	2023	2023-12-23 02:32:47	2023-12-23 09:26:05	13	5369.65	TREEROW	Non-storm
SW23122300092	SNSET9497	2023	2023-12-23 05:22:57	2023-12-23 07:51:28	9	1334.07	NO ISSUES FOUND	Non-storm
SW23122300189	COLNS9829	2023	2023-12-23 06:50:48	2023-12-23 10:01:24	1	190.6	EQUIPMENT FAILURE	Non-storm

NE23122300284	MTMRA8035	2023	2023-12-23 08:55:46	2023-12-23 15:19:46	1	384	NO ISSUES FOUND	Non-storm
NE23122300192	HARPR2575	2023	2023-12-23 09:04:01	2023-12-23 14:33:15	21	6244.58	EQUIPMENT FAILURE	Non-storm
NE23122300188	HARPR2575	2023	2023-12-23 09:04:02	2023-12-23 14:26:17	25	7473.25	EQUIPMENT FAILURE	Non-storm
NE23122300200	HARPR2575	2023	2023-12-23 09:04:02	2023-12-23 14:31:30	12	3661.15	EQUIPMENT FAILURE	Non-storm
SW23122300124	SUMTR9498	2023	2023-12-23 09:05:01	2023-12-23 11:40:47	162	24946.53	EQUIPMENT FAILURE	Non-storm
SE23122300103	REDFD1240	2023	2023-12-23 09:40:39	2023-12-23 09:46:33	1	5.9	EQUIPMENT FAILURE	Non-storm
SE23122300215	CHTNT8293	2023	2023-12-23 09:45:48	2023-12-23 10:20:09	1	34.35	TREEBROW	Non-storm
NE23122300218	BRAY8780	2023	2023-12-23 09:49:36	2023-12-23 13:31:26	1	182.4	EQUIPMENT FAILURE	Non-storm
NW23122300224	PROUD9516	2023	2023-12-23 10:04:59	2023-12-23 11:50:15	1	105.27	ANIMAL	Non-storm
SW23122300216	ELM9480	2023	2023-12-23 10:07:20	2023-12-23 12:12:34	10	1064.54	PLANNED INTENTIONAL	Non-storm
SE23122300232	FERND2698	2023	2023-12-23 10:51:17	2023-12-23 13:10:34	17	2354.49	PLANNED INTENTIONAL	Non-storm
SE23122300233	FERND2698	2023	2023-12-23 10:51:18	2023-12-23 13:10:36	11	1529.93	PLANNED INTENTIONAL	Non-storm
SW23122300261	HEMLK1910	2023	2023-12-23 11:19:44	2023-12-23 12:46:02	2	172.52	NO ISSUES FOUND	Non-storm
SW23122300247	HEMLK1910	2023	2023-12-23 11:19:46	2023-12-23 12:46:02	1	86.27	NO ISSUES FOUND	Non-storm
NE23122300195	ASPEN8811	2023	2023-12-23 11:21:37	2023-12-23 12:13:46	1	52.15	EQUIPMENT FAILURE	Non-storm
SE23122100676	PURTN1173	2023	2023-12-23 12:06:17	2023-12-23 12:35:40	1	29.38	EQUIPMENT FAILURE	Non-storm
NW23122300266	CLYDE8910	2023	2023-12-23 12:07:49	2023-12-23 14:57:37	1	169.8	ANIMAL	Non-storm
NE23122300281	CASVL8819	2023	2023-12-23 12:38:47	2023-12-23 14:25:14	10	1061.17	EQUIPMENT FAILURE	Non-storm
SW23122300310	LIMA9892	2023	2023-12-23 13:09:56	2023-12-23 15:22:48	1	132.87	EQUIPMENT FAILURE	Non-storm
SE23122300013	VILLA1555	2023	2023-12-23 13:18:41	2023-12-23 14:11:53	1	46.34	EQUIPMENT FAILURE	Non-storm
SE23122300320	GDRIV0495	2023	2023-12-23 13:21:03	2023-12-23 20:36:25	1	435.37	EQUIPMENT FAILURE	Non-storm
NE23122300308	VICTR8547	2023	2023-12-23 13:21:28	2023-12-23 18:29:31	1	308.05	EQUIPMENT FAILURE	Non-storm
SW23122300317	SYRAC1903	2023	2023-12-23 14:18:11	2023-12-23 16:39:33	1	141.37	NO ISSUES FOUND	Non-storm
SE23122300271	REDFD1240	2023	2023-12-23 14:34:43	2023-12-23 14:45:22	1	10.65	CUSTOMER EQUIPMENT	Non-storm
SW23122300332	FREDM9808	2023	2023-12-23 14:48:22	2023-12-23 22:26:20	1	457.97	EQUIPMENT FAILURE	Non-storm
NE23122300335	BOYNE8512	2023	2023-12-23 14:58:56	2023-12-23 17:05:02	2	252.2	EQUIPMENT FAILURE	Non-storm
SW23122300357	SPRUC9843	2023	2023-12-23 16:13:33	2023-12-23 17:34:26	114	9199.18	TREEIROW	Non-storm
NW23122300316	WATFD8967	2023	2023-12-23 16:32:39	2023-12-23 17:00:12	1	27.55	TREEIROW	Non-storm
NE23122300378	REMER8807	2023	2023-12-23 16:33:15	2023-12-23 18:36:26	48	5932.19	PUBLIC INTERFERENCE	Non-storm
SE23122300355	BERKY2681	2023	2023-12-23 17:15:19	2023-12-23 17:29:01	13	175.43	EQUIPMENT FAILURE	Non-storm
SW23122400216	BRIST9350	2023	2023-12-23 18:18:14	2023-12-24 13:39:00	1	1160.77	EQUIPMENT FAILURE	Non-storm
SW23122300443	OKRDG9673	2023	2023-12-23 19:45:18	2023-12-23 20:04:26	1	19.13	EQUIPMENT FAILURE	Non-storm
SE23122300460	BRAZL8833	2023	2023-12-23 22:14:44	2023-12-23 22:28:35	2	21.36	EQUIPMENT FAILURE	Non-storm
NE23122300472	MACMB8506	2023	2023-12-23 23:34:10	2023-12-24 09:27:36	120	68591.81	EQUIPMENT FAILURE	Non-storm
NW23122400025	WHTLK8009	2023	2023-12-24 00:42:25	2023-12-24 08:35:47	1	473.37	EQUIPMENT FAILURE	Non-storm
NW23122400050	WHTLK8009	2023	2023-12-24 00:42:25	2023-12-24 08:34:51	1	472.43	EQUIPMENT FAILURE	Non-storm
SW23122400045	TAYLR8286	2023	2023-12-24 03:39:41	2023-12-24 06:21:21	2	323.28	EQUIPMENT FAILURE	Non-storm
SW23122400034	TAYLR8286	2023	2023-12-24 03:39:52	2023-12-24 06:21:31	1	161.65	EQUIPMENT FAILURE	Non-storm
SW23122400040	TAHOE9510	2023	2023-12-24 04:11:44	2023-12-24 09:27:41	7	2211.06	EQUIPMENT FAILURE	Non-storm
SW23122400101	DIMND9866	2023	2023-12-24 06:01:07	2023-12-24 08:12:02	1	130.92	NO ISSUES FOUND	Non-storm
SW23122400068	KNGSY0330	2023	2023-12-24 06:01:08	2023-12-24 08:12:17	41	5345.94	EQUIPMENT FAILURE	Non-storm
SW23122400070	TFANY8038	2023	2023-12-24 06:05:07	2023-12-24 06:20:23	1	15.27	NO ISSUES FOUND	Non-storm
SW23122400054	TAYLR8286	2023	2023-12-24 06:05:09	2023-12-24 06:21:32	663	17256.03	EQUIPMENT FAILURE	Non-storm
SW23122400076	TAYLR8286	2023	2023-12-24 06:05:10	2023-12-24 06:21:29	32	518.48	TROUBLE INTENTIONAL	Non-storm
SW23122400071	TAYLR8286	2023	2023-12-24 06:05:11	2023-12-24 06:21:23	1	16.2	EQUIPMENT FAILURE	Non-storm
SW23122400072	TAYLR8286	2023	2023-12-24 06:05:11	2023-12-24 06:21:29	34	550.9	TROUBLE INTENTIONAL	Non-storm
NW23122400069	DAVIS8202	2023	2023-12-24 06:12:56	2023-12-24 09:28:17	6	1169.51	EQUIPMENT FAILURE	Non-storm
NW23122400089	COMLK9525	2023	2023-12-24 06:46:15	2023-12-24 09:09:27	49	7005.79	EQUIPMENT FAILURE	Non-storm
NW23122400103	MILFD9247	2023	2023-12-24 07:49:34	2023-12-24 09:34:38	30	3136.55	EQUIPMENT FAILURE	Non-storm
NW23122400102	MILFD9246	2023	2023-12-24 07:49:36	2023-12-24 09:34:06	6	623.78	EQUIPMENT FAILURE	Non-storm
SW23122400106	PERU9432	2023	2023-12-24 07:52:17	2023-12-24 11:16:40	44	7759.62	EQUIPMENT FAILURE	Non-storm
SW23122400108	PERU9432	2023	2023-12-24 07:52:18	2023-12-24 11:43:48	4	771.59	NO ISSUES FOUND	Non-storm
NW23122400044	COLFX9880	2023	2023-12-24 07:55:29	2023-12-24 08:12:53	3	52.06	EQUIPMENT FAILURE	Non-storm
NW23122400239	MILFD9247	2023	2023-12-24 08:17:34	2023-12-24 13:00:50	1	161.93	NO ISSUES FOUND	Non-storm
NW23122400116	SENCA8890	2023	2023-12-24 08:25:49	2023-12-24 09:57:10	55	5008.99	EQUIPMENT FAILURE	Non-storm
NW23122400118	SENCA8890	2023	2023-12-24 08:25:56	2023-12-24 09:57:08	2	182.16	NO ISSUES FOUND	Non-storm
NE23122400153	HARPR2407	2023	2023-12-24 09:05:35	2023-12-24 09:45:28	13	515.86	ANIMAL	Non-storm
NE23122400150	HARPR2515	2023	2023-12-24 09:05:38	2023-12-24 09:45:31	110	4365.22	ANIMAL	Non-storm
NW23122400051	GRFIN9883	2023	2023-12-24 09:08:29	2023-12-24 10:07:34	1	59.08	EQUIPMENT FAILURE	Non-storm
NE23122400155	ARMAD0302	2023	2023-12-24 09:23:31	2023-12-24 11:09:57	1	106.43	EQUIPMENT FAILURE	Non-storm
SE23122400095	BRAZL8833	2023	2023-12-24 09:25:03	2023-12-24 11:57:46	1	33.34	EQUIPMENT FAILURE	Non-storm
NW23122400156	WLNUT9013	2023	2023-12-24 09:25:07	2023-12-24 11:16:13	18	1992.88	NO ISSUES FOUND	Non-storm
SW23122400168	FOUTN9720	2023	2023-12-24 09:28:09	2023-12-24 16:43:39	4	1741.36	EQUIPMENT FAILURE	Non-storm
SE23122300450	OUTDR1304	2023	2023-12-24 09:39:35	2023-12-24 09:57:41	1	18.1	EQUIPMENT FAILURE	Non-storm
NW23122400177	MILFD9247	2023	2023-12-24 09:50:53	2023-12-24 14:14:53	8	2110.86	EQUIPMENT FAILURE	Non-storm
NW23122400170	CRWFD8316	2023	2023-12-24 09:54:30	2023-12-24 11:21:17	5	432.77	ANIMAL	Non-storm
SE23122400200	VERNR1215	2023	2023-12-24 10:14:13	2023-12-24 12:34:31	1	21.6	EQUIPMENT FAILURE	Non-storm
SW23122400185	SALEM9926	2023	2023-12-24 10:20:52	2023-12-24 11:49:52	16	1419.92	TREEIROW	Non-storm
NW23122400193	COMLK9539	2023	2023-12-24 10:58:42	2023-12-24 16:32:48	17	5679.38	EQUIPMENT FAILURE	Non-storm
SW23122400223	TAYLR8286	2023	2023-12-24 11:45:25	2023-12-24 12:51:48	1	66.38	EQUIPMENT FAILURE	Non-storm
SE23122400218	PINGR0400	2023	2023-12-24 11:46:30	2023-12-24 12:52:24	10	622.02	EQUIPMENT FAILURE	Non-storm
SE23122400228	PINGR0400	2023	2023-12-24 12:01:03	2023-12-24 12:52:25	25	846.43	EQUIPMENT FAILURE	Non-storm
NE23122400205	LAKSD2540	2023	2023-12-24 12:09:51	2023-12-24 13:07:50	2	115.96	EQUIPMENT FAILURE	Non-storm
NW23122400232	MILFD9247	2023	2023-12-24 12:26:14	2023-12-24 13:23:26	30	1691.04	EQUIPMENT FAILURE	Non-storm
NW23122400231	MILFD9246	2023	2023-12-24 12:26:16	2023-12-24 13:23:12	6	338.33	EQUIPMENT FAILURE	Non-storm
SE23122400158	WAYBN2048	2023	2023-12-24 12:34:53	2023-12-24 12:56:38	1	21.75	EQUIPMENT FAILURE	Non-storm
SE23122400246	TURNR1148	2023	2023-12-24 15:20:39	2023-12-24 15:36:18	1	15.65	EQUIPMENT FAILURE	Non-storm
NE23122400266	ORION8966	2023	2023-12-24 15:32:45	2023-12-24 17:20:33	12	1292.4	EQUIPMENT FAILURE	Non-storm
NE23122400289	WORTH0301	2023	2023-12-24 16:35:42	2023-12-24 18:06:03	45	4060.35	EQUIPMENT FAILURE	Non-storm
NW23122400309	NOLAN9839	2023	2023-12-24 17:07:57	2023-12-24 21:04:12	22	5093.22	EQUIPMENT FAILURE	Non-storm
SW23122200526	HANCK9045	2023	2023-12-24 17:39:09	2023-12-24 21:33:00	1	233.85	EQUIPMENT FAILURE	Non-storm
NE23122400342	STEPH8707	2023	2023-12-24 17:52:12	2023-12-25 09:49:45	1	957.55	EQUIPMENT FAILURE	Non-storm
NW23122400323	JORDN0396	2023	2023-12-24 17:56:17	2023-12-24 20:36:42	2	320.8	EQUIPMENT FAILURE	Non-storm
SW23122400322	CALLA9923	2023	2023-12-24 17:59:04	2023-12-24 19:50:20	108	11993.98	TREEIROW	Non-storm
SW23122400329	CALLA9923	2023	2023-12-24 18:00:58	2023-12-24 19:50:28	14	1528.17	TREEIROW	Non-storm
NW23122400347	CRWFD9076	2023	2023-12-24 19:22:16	2023-12-25 04:13:22	12	6117.86	EQUIPMENT FAILURE	Non-storm
NW23122400357	EUCLD9084	2023	2023-12-24 19:29:36	2023-12-24 22:30:29	22	3962.05	EQUIPMENT FAILURE	Non-storm
SE23122400361	CORTL0673	2023	2023-12-24 21:19:36	2023-12-24 21:28:13	1	8.62	EQUIPMENT FAILURE	Non-storm
SW23122400370	SNSET9497	2023	2023-12-24 21:46:40	2023-12-25 04:23:56	13	3610.25	EQUIPMENT FAILURE	Non-storm
NW23122500011	HAMLN9024	2023	2023-12-25 00:24:49	2023-12-25 03:10:56	868	143897.48	EQUIPMENT FAILURE	Non-storm
NW23122500021	DOVER8204	2023	2023-12-25 00:24:50	2023-12-25 03:10:59	2	331.95	NO ISSUES FOUND	Non-storm
NW23122500098	CLYDE8910	2023	2023-12-25 06:35:35	2023-12-25 16:58:44	1	623.15	ANIMAL	Non-storm
SE23122500049	FOX2676	2023	2023-12-25 08:08:58	2023-12-25 11:24:18	1	195.33	EQUIPMENT FAILURE	Non-storm
NW23122500060	COMLK9524	2023	2023-12-25 08:20:09	2023-12-25 11:50:21	3	630.16	EQUIPMENT FAILURE	Non-storm
NW23122500081	STRFD9093	2023	2023-12-25 08:38:59	2023-12-25 15:07:39	1	388.67	ANIMAL	Non-storm
NE23122500223	CHEST8513	2023	2023-12-25 08:46:13	2023-12-25 18:30:37	1	584.4	EQUIPMENT FAILURE	Non-storm
SE23122400383	BALFR2038	2023	2023-12-25 08:51:11	2023-12-25 09:17:08	1	25.95	EQUIPMENT FAILURE	Non-storm
NE23122500087	STEPH8707	2023	2023-12-25 08:54:00	2023-12-25 09:37:05	17	726.21	ANIMAL	Non-storm
NW23122500088	WMSTN8033	2023	2023-12-25 08:55:06	2023-12-25 10:09:24	4	296.48	ANIMAL	Non-storm
SE23122500048	EVRGN1257	2023	2023-12-25 08:56:24	2023-12-25 09:57:15	1	60.85	METER / BLOCKS	Non-storm
NW23122500090	MILFD9245	2023	2023-12-25 09:13:36	2023-12-25 10:24:12	6	422.38	NO ISSUES FOUND	Non-storm
NW23122500100	WMSTN9857	2023	2023-12-25 09:50:08	2023-12-25 11:30:46	4	402.1	ANIMAL	Non-storm
SE23122500057	FRISB2117	2023	2023-12-25 10:00:37	2023-12-25 10:38:36	1	37.98	EQUIPMENT FAILURE	Non-storm
SE23122400313	VERNR2062	2023	2023-12-25 10:02:39	2023-12-25 10:24:50	1	22.18	EQUIPMENT FAILURE	Non-storm
SE23122500054	NRLND9018	2023	2023-12-25 10:07:07	2023-12-25 10:29:25	1	22.3	EQUIPMENT FAILURE	Non-storm
SW23122400399	DIMND9866	2023	2023-12-25 10:07:07	2023-12-25 11:19:01	1	542.9	EQUIPMENT FAILURE	Non-storm
SW23122500121	OKRDG9626	2023	2023-12-25 10:33:23	2023-12-25 12:30:50	49	5744.57	EQUIPMENT FAILURE	Non-storm
SE23122500136	JUPTR8390	2023	2023-12-25 11:25:01	2023-12-25 15:32:59	92	18682.6	EQUIPMENT FAILURE	Non-storm
SW23122500135	NBURG8075	2023	2023-12-25 12:45:11	2023-12-25 14:14:12	1	89.02	EQUIPMENT FAILURE	Non-storm
NW23122500149	FLINT9797	2023	2023-12-25 12:46:00	2023-12-25 13:31:01	91	4081.45	ANIMAL	Non-storm
SW23122500156	WICK9334	2023	2023-12-25 13:08:32	2023-12-25 15:22:06	91	12145.67	ANIMAL	Non-storm
SW23122500163	WICK9334	2023	2023-12-25 13:08:35	2023-12-25 15:22:05	8	1066.88	NO ISSUES FOUND	Non-storm
SW23122500155	WSTLD9494	2023	2023-12-25 13:12:16	2023-12-25 13:18:12	1	5.93	EQUIPMENT FAILURE	Non-storm
NE23122500142	WDTRK0024	2023	2023-12-25 13:24:54	2023-12-25 13:32:07	1	7.22	EQUIPMENT FAILURE	Non-storm
NW23122600090	BLMFD9121	2023	2023-12-25 14:00:45	2023-12-26 17:47:17	5	7663.82	ANIMAL	Non-storm
SE23122500378	EIGMI1535	2023	2023-12-25 14:32:07	2023-12-26 00:45:24	1	613.28	TREEIROW	Non-storm
SW23122500185	PIONR9793	2023	2023-12-25 14:48:36	2023-12-25 22:03:04	3	1298.39	EQUIPMENT FAILURE	Non-storm
NE23122500182	CAPAC8013	2023	2023-12-25 14:57:10	2023-12-25 19:09:31	52	13115.58	EQUIPMENT FAILURE	Non-storm
NW23122500187	CODY8824	2023	2023-12-25 15:02:37	2023-12-25 17:42:07	2	318.97	EQUIPMENT FAILURE	Non-storm
NW23122500194	DOVER8204	2023	2023-12-25 15:06:18	2023-12-25 19:31:49	1	265.52	EQUIPMENT FAILURE	Non-storm
NE23122500204	BREWR8840	2023	2023-12-25 15:47:21	2023-12-25 19:03:19	1	195.97	ANIMAL	Non-storm
NE23122500252	SDF152999	2023	2023-12-25 17:11:02	2023-12-25 20:16:52	1	185.83	CUSTOMER EQUIPMENT	Non-storm
NW23122100028	LILY9120	2023	2023-12-25 18:02:51	2023-12-25 18:50:22	1	47.52	METER / BLOCKS	Non-storm
SE23122500237	PULFD2224	2023	2023-12-25 19:28:06	2023-12-25 20:12:14	1	44.13	TREEBROW	Non-storm
NW23122500260	COATS8039	2023	2023-12-25 19:29:43	2023-12-26 08:54:10	1	804.45	EQUIPMENT FAILURE	Non-storm
SW23122500258	QUAKR9236	2023	2023-12-25 19:33:06	2023-12-26 14:18:22	4	231.09	PUBLIC INTERFERENCE	Non-storm
NW23122500264	PINCK8229	2023	2023-12-25 19:42:56	2023-12-25 20:38:55	639	35726.9	TROUBLE INTENTIONAL	Non-storm
NW23122500319	PINCK9886	2023	2023-12-25 19:42:59	2023-12-25 20:38:54	1	55.92	NO ISSUES FOUND	Non-storm
NW23122500335	PINCK8229	2023	2023-12-25 19:42:59	2023-12-25 20:38:54	1	55.92	NO ISSUES FOUND	Non-storm
NW23122500365	LILY9105	2023	2023-12-25 21:24:27	2023-12-25 22:11:14	9	419.31	NO ISSUES FOUND	Non-storm
NW23122500342	HANCK8976	2023	2023-12-25 21:24:30	2023-12-25 22:11:04	547	24282.98	PLANNED INTENTIONAL	Non-storm
NW23122500358	COMLK9524	2023	2023-12-25 21:24:33	2023-12-25 22:11:02	2	92.97	EQUIPMENT FAILURE	Non-storm
SW23122500340	SNSET9497	2023	2023-12-25 21:24:54	2023-12-26 03:53:00	5	194.49	EQUIPMENT FAILURE	Non-storm
NE23122500334	STEPH8522	2023	2023-12-25 21:49:07	2023-12-26 19:27:38	1	1298.52	EQUIPMENT FAILURE	Non-storm
SE23122500381	CORTL0673	2023	2023-12-25 22:40:30	2023-12-26 02:08:05	1	207.58	METER / BLOCKS	Non-storm
NW23122600158	ORION9080	2023	2023-12-25 23:58:58	2023-12-26 12:03:41	1	724.72	EQUIPMENT FAILURE	Non-storm
NW23122600136	PINCK9886	2023	2023-12-26 00:01:15	2023-12-26 10:21:21	1	620.1	TREEBROW	Non-storm
SW23122600074	HOOVR0365	2023	2023-12-26 00:20:12	2023-12-26 09:57:57	1	577.75	EQUIPMENT FAILURE	Non-storm
SE23122600013	GULLY2219	2023	2023-12-26 00:34:37	2023-12-26 11:19:17	1	644.67	TREEBROW	Non-storm
SW23122600050	GAY1926	2023	2023-12-26 00:48:30	2023-12-26 07:00:29	1	371.98	EQUIPMENT FAILURE	Non-storm
SW23122600019	WSTLD8170	2023	2023-12-26 00:57:08	2023-12-26 02:37:48	27	2714.12	TREEIROW	Non-storm
SW23122600015	WSTLD8170	2023	2023-12-26 00:57:09	2023-12-26 02:37:49	283	28416.45	TREEIROW	Non-storm
SW23122600029	WSTLD8170	2023	2023-12-26 00:57:10	2023-12-26 02:37:48	56	5629.38	TREEIROW	Non-storm
SW23122600028	WSTLD8170	2023	2023-12-26 00:57:12	2023-12-26 02:37:48	108	10855.62	TREEIROW	Non-storm
SW23122600027	WSTLD8170	2023	2023-12-26 00:57:15	2023-12-26 02:37:45	1	100.5	NO ISSUES FOUND	Non-storm
SE23122600056	JUPTR8336	2023	2023-12-26 00:58:29	2023-12-26 10:12:32	1	554.05	TREEBROW	Non-storm
NW23122600226	WHTLK8009	2023	2023-12-26 01:38:09	2023-12-27 01:31:24	4	5730.71	EQUIPMENT FAILURE	Non-storm
SE23122600038	ESTLD1440	2023	2023-12-26 01:40:23	2023-12-26 15:42:10	1	841.78	EQUIPMENT FAILURE	Non-storm
SE23122600061	BALFR1207	2023	2023-12-26 01:48:17	2023-12-26 09:57:45	1	489.47	TREEBROW	Non-storm
SE23122600039	HIKRY8174	2023	2023-12-26 01:55:49	2023-12-26 05:44:37	24	3185.24	EQUIPMENT FAILURE	Non-storm
NW23122600040	BRONC8593	2023	2023-12-26 01:56:49	2023-12-26 09:13:15	62	4731.06	EQUIPMENT FAILURE	Non-storm
NE23122600042	ROBIN8750	2023	2023-12-26 02:06:14	2023-12-26 05:10:58	1	184.73	EQUIPMENT FAILURE	Non-storm
SE23122600048	MAUME8241	2023	2023-12-26 02:09:11	2023-12-26 17:36:53	1	927.7	EQUIPMENT FAILURE	Non-storm
NW23122600058	DISCO8104	2023	2023-12-26 04:28:17	2023-12-26 05:01:07	15	490.79	TROUBLE INTENTIONAL	Non-storm
SE23122600062	WEBST1809	2023	2023-12-26 05:04:24	2023-12-26 09:54:22	34	9850.95	EQUIPMENT FAILURE	Non-storm
NE23122600070	KILGR8772	2023	2023-12-26 05:15:39	2023-12-26 14:55:35	1	579.93	EQUIPMENT FAILURE	Non-storm
NE23122600065	MENLO8806	2023	2023-12-26 05:54:06	2023-12-26 11:16:41	19	3083.81	EQUIPMENT FAILURE	Non-storm
SW23122600110	COLNS9868	2023	2023-12-26 05:54:17	2023-12-26 10:54:21	1	300.07	TREEBROW	Non-storm
SE23122600169	ANNCH1588	2023	2023-12-26 06:06:49	2023-12-26 13:08:45	1	421.93	TREEBROW	Non-storm
NW23122600073	PROUD9475	2023	2023-12-26 06:14:07	2023-12-26 10:30:53	1	256.77	EQUIPMENT FAILURE	Non-storm
SW23122600219	JAKSN0311	2023	2023-12-26 07:36:36	2023-12-26 14:46:18	1	429.7	ANIMAL	Non-storm
SW23122600115	BRIST9350	2023	2023-12-26 08:32:15	2023-12-26 16:55:07	4	2010.21	EQUIPMENT FAILURE	Non-storm

NE23122600745	SHAW0312	2023	2023-12-26 08:36:10	2023-12-26 22:05:06	1	808.93	EQUIPMENT FAILURE	Non-storm
NW23122600501	HAMBG9943	2023	2023-12-26 09:41:48	2023-12-26 15:51:32	1	369.73	TREEROW	Non-storm
NW23122600198	HAMLN9024	2023	2023-12-26 10:40:05	2023-12-26 12:22:06	9	918	EQUIPMENT FAILURE	Non-storm
NW23122600201	HAMLN9024	2023	2023-12-26 10:40:05	2023-12-26 12:22:04	2	203.96	EQUIPMENT FAILURE	Non-storm
SE23122600769	LAUDR1400	2023	2023-12-26 10:54:23	2023-12-27 06:34:08	1	74.83	NO ISSUES FOUND	Non-storm
NW23122600217	HANCK8142	2023	2023-12-26 11:23:44	2023-12-26 18:06:15	1	148.75	EQUIPMENT FAILURE	Non-storm
SE23122600191	BALFR2097	2023	2023-12-26 11:34:39	2023-12-26 11:40:40	1	6.02	EQUIPMENT FAILURE	Non-storm
NW23122600142	BALDW8979	2023	2023-12-26 11:36:41	2023-12-26 11:45:39	1	8.97	EQUIPMENT FAILURE	Non-storm
SW23122600384	INKST2027	2023	2023-12-26 11:52:42	2023-12-26 12:00:06	1	7.4	TREEROW	Non-storm
NE23122600238	SAVOY8714	2023	2023-12-26 12:10:02	2023-12-26 15:53:15	2320	519660	EQUIPMENT FAILURE	Non-storm
NE23122700596	SAVOY8714	2023	2023-12-26 12:10:04	2023-12-27 17:48:00	9	2133.61	EQUIPMENT FAILURE	Non-storm
NE23122600358	SAVOY8714	2023	2023-12-26 12:10:10	2023-12-26 15:52:17	1	222.12	EQUIPMENT FAILURE	Non-storm
NE23122600316	SAVOY8714	2023	2023-12-26 12:10:12	2023-12-26 15:52:19	1	222.12	EQUIPMENT FAILURE	Non-storm
NE23122600549	SAVOY8714	2023	2023-12-26 12:10:12	2023-12-26 15:52:20	1	222.13	EQUIPMENT FAILURE	Non-storm
NE23122600335	BUNRT8110	2023	2023-12-26 12:17:19	2023-12-26 15:14:40	13	2304.41	ANIMAL	Non-storm
NW23122600367	COLRD9100	2023	2023-12-26 12:26:35	2023-12-26 18:28:41	1	362.1	NO ISSUES FOUND	Non-storm
NW23122600354	COLRD9100	2023	2023-12-26 12:26:48	2023-12-26 18:29:50	9	3261.71	EQUIPMENT FAILURE	Non-storm
NW23122600792	COLRD9100	2023	2023-12-26 12:26:50	2023-12-27 07:50:54	1	1164.07	ANIMAL	Non-storm
NW23122600397	GRAYL8517	2023	2023-12-26 13:11:29	2023-12-26 13:53:23	9	373.23	EQUIPMENT FAILURE	Non-storm
SE23122600222	DALY1738	2023	2023-12-26 13:30:08	2023-12-26 13:36:24	2	12.4	EQUIPMENT FAILURE	Non-storm
SE23122600399	DALY1738	2023	2023-12-26 13:30:10	2023-12-26 13:36:30	2	12.42	EQUIPMENT FAILURE	Non-storm
SE23122600225	DALY1738	2023	2023-12-26 13:30:13	2023-12-26 13:36:28	2	12.4	EQUIPMENT FAILURE	Non-storm
NW23122700526	HILL0364	2023	2023-12-26 13:30:38	2023-12-27 17:28:45	1	1668.8	EQUIPMENT FAILURE	Non-storm
SE23122600414	BROKS8153	2023	2023-12-26 14:09:36	2023-12-26 15:32:39	15	1236.03	ANIMAL	Non-storm
NW23122600370	HOWEL2933	2023	2023-12-26 14:17:40	2023-12-26 14:49:34	1	31.9	TREEBROW	Non-storm
NE23122600428	BADAX8749	2023	2023-12-26 14:25:56	2023-12-26 16:16:09	58	5777.48	TREEROW	Non-storm
NE23122700591	SAVOY8714	2023	2023-12-26 15:06:20	2023-12-27 15:12:33	1	239.29	EQUIPMENT FAILURE	Non-storm
NW23122600485	CHILS9845	2023	2023-12-26 15:14:20	2023-12-26 19:06:33	22	5106.39	EQUIPMENT FAILURE	Non-storm
SW23122700015	TAYLR9483	2023	2023-12-26 15:51:18	2023-12-27 01:08:31	12	2408.12	EQUIPMENT FAILURE	Non-storm
SW23122700130	TAYLR9483	2023	2023-12-26 15:51:18	2023-12-27 04:36:22	458	238882.36	NO ISSUES FOUND	Non-storm
SW23122600498	TAYLR9483	2023	2023-12-26 15:51:20	2023-12-26 18:07:11	14	1894.5	EQUIPMENT FAILURE	Non-storm
SW23122600510	HASKL1627	2023	2023-12-26 15:51:20	2023-12-27 02:13:45	14	8704.87	NO ISSUES FOUND	Non-storm
SW23122600623	TAYLR9483	2023	2023-12-26 15:51:20	2023-12-27 02:13:48	72	44772.47	EQUIPMENT FAILURE	Non-storm
SW23122600803	TAYLR9483	2023	2023-12-26 15:51:21	2023-12-26 22:12:49	38	4669.35	EQUIPMENT FAILURE	Non-storm
SW23122600732	TAYLR9483	2023	2023-12-26 15:51:23	2023-12-27 04:36:21	35	21441.25	EQUIPMENT FAILURE	Non-storm
SW23122600770	TAYLR9483	2023	2023-12-26 16:27:38	2023-12-26 21:48:12	2	153.57	EQUIPMENT FAILURE	Non-storm
SW23122700167	TAYLR9483	2023	2023-12-26 17:07:10	2023-12-27 04:20:22	1	612.57	NO ISSUES FOUND	Non-storm
NW23122600583	WLNUT9013	2023	2023-12-26 17:10:19	2023-12-27 12:01:34	2	2261.75	TREEBROW	Non-storm
NE23122600538	NEFF0312	2023	2023-12-26 17:29:58	2023-12-26 18:00:32	1	30.57	EQUIPMENT FAILURE	Non-storm
NW23122600599	NIXON8943	2023	2023-12-26 17:41:13	2023-12-26 19:12:14	46	4148.31	EQUIPMENT FAILURE	Non-storm
NW23122600530	WHTLK8009	2023	2023-12-26 18:11:52	2023-12-26 18:50:11	111	4941.71	EQUIPMENT FAILURE	Non-storm
NW23122600637	WHTLK8009	2023	2023-12-26 18:12:10	2023-12-26 18:50:10	2	76	NO ISSUES FOUND	Non-storm
SW23122600802	TAYLR9483	2023	2023-12-26 18:16:53	2023-12-27 00:57:44	1	160.28	NO ISSUES FOUND	Non-storm
SE23122600587	GLEND2212	2023	2023-12-26 18:57:23	2023-12-26 20:15:40	173	13517.81	TROUBLE INTENTIONAL	Non-storm
SE23122600750	GLEND2212	2023	2023-12-26 18:57:34	2023-12-27 03:14:57	129	28729.1	TREEROW	Non-storm
NW23122600672	SLOAN8527	2023	2023-12-26 19:25:36	2023-12-26 19:44:57	88	1686.3	TROUBLE INTENTIONAL	Non-storm
NW23122600673	SLOAN8527	2023	2023-12-26 19:25:47	2023-12-26 19:44:57	1	19.17	TROUBLE INTENTIONAL	Non-storm
SW23122600651	MAYBE9615	2023	2023-12-26 20:28:00	2023-12-26 20:51:45	1	23.75	EQUIPMENT FAILURE	Non-storm
NE23122600697	ERIN2453	2023	2023-12-26 20:28:02	2023-12-26 20:36:11	566	4492.15	TROUBLE INTENTIONAL	Non-storm
NE23122600740	ERIN2453	2023	2023-12-26 20:28:05	2023-12-26 20:36:04	1	7.98	NO ISSUES FOUND	Non-storm
SE23122600083	WEBST1812	2023	2023-12-26 20:56:38	2023-12-26 21:25:50	1	29.2	EQUIPMENT FAILURE	Non-storm
SE23122600784	SRGNT8247	2023	2023-12-26 21:31:52	2023-12-27 10:39:28	1	787.6	WIND	Non-storm
SW23122700234	LUZON8097	2023	2023-12-26 22:29:18	2023-12-27 11:19:14	1	769.93	EQUIPMENT FAILURE	Non-storm
SW23122600785	BREST9922	2023	2023-12-26 22:29:56	2023-12-27 00:36:54	1	126.97	EQUIPMENT FAILURE	Non-storm
NE23122600789	NELSN0003	2023	2023-12-26 22:43:58	2023-12-27 00:25:40	1	101.7	EQUIPMENT FAILURE	Non-storm
NW23122700003	PINCK8229	2023	2023-12-26 23:55:46	2023-12-27 05:18:57	23	7432.26	TREEROW	Non-storm
SW23122700016	TAYLR9483	2023	2023-12-26 23:56:27	2023-12-27 00:32:31	29	788.56	EQUIPMENT FAILURE	Non-storm
NW23122700001	WLNUT9007	2023	2023-12-27 00:00:30	2023-12-27 09:07:06	31	16939.95	TREEROW	Non-storm
SW23122700028	RGENT0357	2023	2023-12-27 00:24:45	2023-12-27 04:07:02	30	3555.43	EQUIPMENT FAILURE	Non-storm
SW23122700029	DUVAL9489	2023	2023-12-27 01:31:55	2023-12-27 03:52:09	49	6864.86	EQUIPMENT FAILURE	Non-storm
NW23122700192	WMSTN8033	2023	2023-12-27 01:45:38	2023-12-27 09:52:41	1	487.05	EQUIPMENT FAILURE	Non-storm
NE23122700055	BRAZL8495	2023	2023-12-27 02:14:59	2023-12-27 03:52:42	707	37649.1	TREEROW	Non-storm
NW23122700064	BALDW8979	2023	2023-12-27 02:19:41	2023-12-27 06:21:40	191	45483.38	ANIMAL	Non-storm
SW23122700068	JEFSN9409	2023	2023-12-27 02:22:41	2023-12-27 06:57:45	8	2198.21	EQUIPMENT FAILURE	Non-storm
SE23122700035	WSEND1038	2023	2023-12-27 02:35:02	2023-12-27 05:28:17	110	2411.68	OTHER UTILITY EQUIP	Non-storm
SE23122700138	WSEND1038	2023	2023-12-27 02:35:02	2023-12-27 05:28:11	55	1193.67	PUBLIC INTERFERENCE	Non-storm
NW23122700074	MALTA8814	2023	2023-12-27 02:35:17	2023-12-27 11:19:10	1	523.88	TREEROW	Non-storm
NE23122700181	AGSTA8737	2023	2023-12-27 03:07:56	2023-12-27 20:14:12	2	2052.52	EQUIPMENT FAILURE	Non-storm
NE23122700141	ARMAD8550	2023	2023-12-27 03:15:10	2023-12-27 10:54:03	47	19127.6	EQUIPMENT FAILURE	Non-storm
NE23122700161	BRAZL8495	2023	2023-12-27 03:19:51	2023-12-27 03:52:31	1	32.67	NO ISSUES FOUND	Non-storm
SW23122700194	DIMND9859	2023	2023-12-27 03:39:34	2023-12-27 16:23:06	3	1256.8	EQUIPMENT FAILURE	Non-storm
SW23122700123	SPRUC9874	2023	2023-12-27 04:09:45	2023-12-27 05:40:32	8	716.99	EQUIPMENT FAILURE	Non-storm
NE23122700179	COTAG8743	2023	2023-12-27 04:17:02	2023-12-27 09:24:33	1	307.52	EQUIPMENT FAILURE	Non-storm
SE23122700159	WSEND1038	2023	2023-12-27 05:18:36	2023-12-27 05:27:59	1	9.38	PUBLIC INTERFERENCE	Non-storm
NE23122700301	PTHUR2304	2023	2023-12-27 05:37:38	2023-12-27 11:57:59	1	380.35	EQUIPMENT FAILURE	Non-storm
NW23122700189	WIXOM8239	2023	2023-12-27 06:39:58	2023-12-27 09:58:36	46	10052.9	NO ISSUES FOUND	Non-storm
NE23122700219	MARLT8281	2023	2023-12-27 06:44:09	2023-12-27 12:28:26	1	344.28	WIND	Non-storm
NE23122700221	NEAST8437	2023	2023-12-27 08:17:59	2023-12-27 12:39:10	9	2350.09	EQUIPMENT FAILURE	Non-storm
NE23122700222	NEAST8437	2023	2023-12-27 08:17:59	2023-12-27 12:39:08	7	1827.86	EQUIPMENT FAILURE	Non-storm
SE23122700232	MLVDL2105	2023	2023-12-27 08:21:34	2023-12-27 10:52:50	18	856.46	PLANNED INTENTIONAL	Non-storm
SE23122600755	TURNR1189	2023	2023-12-27 09:07:31	2023-12-27 09:13:13	1	5.7	EQUIPMENT FAILURE	Non-storm
NE23122700291	GOLF8436	2023	2023-12-27 09:08:40	2023-12-27 10:17:13	4	273.9	PLANNED INTENTIONAL	Non-storm
SE23122700285	MLVDL2105	2023	2023-12-27 09:08:41	2023-12-27 10:24:46	13	986.62	PLANNED INTENTIONAL	Non-storm
SW23122700299	FLRDA8178	2023	2023-12-27 09:29:09	2023-12-27 12:15:44	53	8410.55	EQUIPMENT FAILURE	Non-storm
SW23122700298	FLRDA8178	2023	2023-12-27 09:29:17	2023-12-27 15:59:43	29	8445.06	CUSTOMER EQUIPMENT	Non-storm
NW23122700320	FRANK1764	2023	2023-12-27 09:41:10	2023-12-27 15:29:06	1	347.93	TREEBROW	Non-storm
SE23122600579	HAZPK1208	2023	2023-12-27 09:58:50	2023-12-27 10:08:05	1	9.25	TREEBROW	Non-storm
SW23122700334	SNSET9497	2023	2023-12-27 10:02:09	2023-12-27 11:22:10	8	638.4	EQUIPMENT FAILURE	Non-storm
SE23122700346	KENT0046	2023	2023-12-27 10:02:14	2023-12-27 11:48:54	1	106.67	PLANNED INTENTIONAL	Non-storm
SE23122700339	PULFD2155	2023	2023-12-27 10:05:37	2023-12-27 12:57:22	12	1833.67	PLANNED INTENTIONAL	Non-storm
SE23122700345	GDRIV2199	2023	2023-12-27 10:17:22	2023-12-27 10:41:08	1	23.77	PLANNED INTENTIONAL	Non-storm
NW23122700600	NOLAN9852	2023	2023-12-27 10:21:20	2023-12-27 17:19:19	1	417.98	EQUIPMENT FAILURE	Non-storm
SW23122700354	HEMLK1910	2023	2023-12-27 10:24:39	2023-12-27 12:18:38	16	1821.19	PLANNED INTENTIONAL	Non-storm
SW23122700356	BURTN2950	2023	2023-12-27 10:24:42	2023-12-27 12:18:31	1	113.82	NO ISSUES FOUND	Non-storm
SW23122700329	BURTN2950	2023	2023-12-27 10:24:47	2023-12-27 12:18:37	2	227.65	PLANNED INTENTIONAL	Non-storm
SW23122600144	WAYNE9414	2023	2023-12-27 10:26:27	2023-12-27 10:51:34	4	100.34	ANIMAL	Non-storm
SW23122600548	WAYNE9414	2023	2023-12-27 10:26:28	2023-12-27 10:51:33	1	25.08	NO ISSUES FOUND	Non-storm
SW23122700398	HEMLK1910	2023	2023-12-27 10:26:31	2023-12-27 11:55:21	6	532.35	PLANNED INTENTIONAL	Non-storm
NW23122700370	WOLFH8822	2023	2023-12-27 10:31:57	2023-12-27 12:20:33	13	1403.77	EQUIPMENT FAILURE	Non-storm
SE23122700326	MLVDL2105	2023	2023-12-27 10:35:53	2023-12-27 11:41:11	18	943.43	PLANNED INTENTIONAL	Non-storm
NE23122800167	LEXTN8770	2023	2023-12-27 10:40:05	2023-12-28 11:22:42	1	1482.62	EQUIPMENT FAILURE	Non-storm
NE23122700358	PINGV0325	2023	2023-12-27 10:45:57	2023-12-27 11:17:23	1	31.43	PLANNED INTENTIONAL	Non-storm
SE23122700452	MEYRS1691	2023	2023-12-27 10:51:31	2023-12-27 11:00:58	1	9.45	EQUIPMENT FAILURE	Non-storm
SW23122700353	HEMLK1910	2023	2023-12-27 10:53:15	2023-12-27 11:59:46	17	1127.79	PLANNED INTENTIONAL	Non-storm
SW23122700257	ARIZA9835	2023	2023-12-27 10:59:35	2023-12-27 11:49:26	1	49.85	EQUIPMENT FAILURE	Non-storm
SW23122700199	RVRVW2824	2023	2023-12-27 11:12:38	2023-12-27 11:45:29	1	32.85	TREEBROW	Non-storm
SW23122700202	DIMND9859	2023	2023-12-27 11:26:23	2023-12-27 11:33:49	1	7.43	EQUIPMENT FAILURE	Non-storm
NW23122700424	EUCLD9084	2023	2023-12-27 11:34:35	2023-12-27 14:57:29	22	4446.37	EQUIPMENT FAILURE	Non-storm
SE23122700322	STLUS1099	2023	2023-12-27 11:38:23	2023-12-27 12:12:26	1	34.05	TREEBROW	Non-storm
NW23122600694	ORION9080	2023	2023-12-27 11:43:56	2023-12-27 12:30:49	1	46.88	EQUIPMENT FAILURE	Non-storm
NE23122700447	AGSTA8424	2023	2023-12-27 11:47:34	2023-12-27 12:12:09	8	195.68	EQUIPMENT FAILURE	Non-storm
SE23122700418	GDRIV2199	2023	2023-12-27 11:58:24	2023-12-27 13:30:07	1	91.72	PLANNED INTENTIONAL	Non-storm
SW23122700390	PERU9440	2023	2023-12-27 12:00:23	2023-12-27 14:35:41	9	1161.4	PLANNED INTENTIONAL	Non-storm
NE23122700311	REDRN8690	2023	2023-12-27 12:03:32	2023-12-27 12:38:11	1	34.65	EQUIPMENT FAILURE	Non-storm
NE23122700449	LNDIS8164	2023	2023-12-27 12:04:30	2023-12-27 12:29:18	3	74.38	PLANNED INTENTIONAL	Non-storm
SW23122600649	TWEMI0355	2023	2023-12-27 12:09:14	2023-12-27 12:27:54	1	18.67	EQUIPMENT FAILURE	Non-storm
SE23122700395	SIXMI1200	2023	2023-12-27 12:17:27	2023-12-28 13:58:52	1	1541.42	NO CAUSE	Non-storm
NE23122700496	LIBER1056	2023	2023-12-27 12:21:34	2023-12-27 13:31:39	1	70.08	PLANNED INTENTIONAL	Non-storm
SW23122700489	ARIZA9823	2023	2023-12-27 12:41:59	2023-12-27 12:59:44	11	194.76	PLANNED INTENTIONAL	Non-storm
SW23122700469	OMAHA8240	2023	2023-12-27 12:51:31	2023-12-27 13:11:44	1	20.22	PLANNED INTENTIONAL	Non-storm
SW23122700486	HEMLK1910	2023	2023-12-27 12:53:17	2023-12-27 13:29:18	1	36.02	PLANNED INTENTIONAL	Non-storm
NW23122700494	BISMK8414	2023	2023-12-27 13:02:24	2023-12-27 14:31:57	1	89.55	EQUIPMENT FAILURE	Non-storm
NW23122800220	MILFD9249	2023	2023-12-27 13:04:29	2023-12-28 13:02:45	1	1438.27	EQUIPMENT FAILURE	Non-storm
SW23122700507	CODY9537	2023	2023-12-27 13:14:50	2023-12-27 13:20:58	1	6.13	PLANNED INTENTIONAL	Non-storm
NE23122700510	PINGV0325	2023	2023-12-27 13:28:17	2023-12-27 14:03:41	1	35.4	PLANNED INTENTIONAL	Non-storm
SE23122700517	MLVDL2105	2023	2023-12-27 13:36:13	2023-12-27 14:37:41	6	367.92	PLANNED INTENTIONAL	Non-storm
SE23122700521	MLVDL2114	2023	2023-12-27 13:36:14	2023-12-27 14:37:38	2	122.64	OTHER UTILITY EQUIP	Non-storm
SW23122700513	TAYLR9483	2023	2023-12-27 13:38:58	2023-12-27 15:56:00	2	274.08	PLANNED INTENTIONAL	Non-storm
NW23122700548	WOLFH8838	2023	2023-12-27 13:45:12	2023-12-27 18:41:46	1	296.57	ANIMAL	Non-storm
NW23122700534	SPKNE8842	2023	2023-12-27 13:59:52	2023-12-27 15:37:36	14	1363.9	PLANNED INTENTIONAL	Non-storm
SW23122600080	DRAKE9074	2023	2023-12-27 14:00:05	2023-12-27 14:15:02	1	14.95	EQUIPMENT FAILURE	Non-storm
NW23122700393	LNGLK8956	2023	2023-12-27 14:02:36	2023-12-27 14:35:43	107	5309.51	TREEROW	Non-storm
NW23122700569	LNGLK8956	2023	2023-12-27 14:02:48	2023-12-27 14:34:50	91	2908.98	TROUBLE INTENTIONAL	Non-storm
NE23122700554	NINMI2474	2023	2023-12-27 14:13:34	2023-12-27 15:31:32	1	77.97	PLANNED INTENTIONAL	Non-storm
SW23122700549	SOFLD9082	2023	2023-12-27 14:36:28	2023-12-27 14:56:49	1	20.35	PLANNED INTENTIONAL	Non-storm
SE23122700579	MALTA8469	2023	2023-12-27 14:53:27	2023-12-27 16:35:22	8	814.68	ANIMAL	Non-storm
NE23122700567	FRASR2437	2023	2023-12-27 15:11:46	2023-12-29 04:28:52	1	1453.31	WIND	Non-storm
SE23122700571	TIRMN1223	2023	2023-12-27 15:14:01	2023-12-27 15:37:35	1	23.57	CUSTOMER EQUIPMENT	Non-storm
SE23122700606	EMPIR2221	2023	2023-12-27 15:34:25	2023-12-27 16:55:10	1	31.46	EQUIPMENT FAILURE	Non-storm
NE23122700362	BUNRT8404	2023	2023-12-27 15:40:38	2023-12-27 17:07:00	1	86.37	EQUIPMENT FAILURE	Non-storm
SW23122700680	ACME9499	2023	2023-12-27 15:55:50	2023-12-27 16:44:42	1	48.87	NO ISSUES FOUND	Non-storm
SE23122800933	GLEND2025	2023	2023-12-27 16:26:20	2023-12-29 07:48:06	1	101.53	EQUIPMENT FAILURE	Non-storm
NW23122700668	SENCA8997	2023	2023-12-27 17:02:47	2023-12-27 18:25:38	1	82.85	NO ISSUES FOUND	Non-storm
NW23122700679	SENCA8997	2023	2023-12-27 17:02:47	2023-12-27 18:25:39	1	82.87	EQUIPMENT FAILURE	Non-storm
NW23122700324	BARTL4032	2023	2023-12-27 17:12:35	2023-12-27 17:24:41	1	12.1	EQUIPMENT FAILURE	Non-storm
NW23122700553	COLFX8186	2023	2023-12-27 17:20:12	2023-12-27 17:59:34	1	39.37	EQUIPMENT FAILURE	Non-storm
NE23122800333	CAROO303	2023	2023-12-27 17:49:44	2023-12-28 10:27:53	1	221.87	EQUIPMENT FAILURE	Non-storm
SE23122700690	HAZPK1951	2023	2023-12-27 18:05:46	2023-12-27 19:33:56	57	4978.5	TROUBLE INTENTIONAL	Non-storm
SW23122700713	HAGER9396	2023	2023-12-27 19:03:05	2023-12-27 21:22:26	45	6268.42	ANIMAL	Non-storm
NW23122700729	LILAC9814	2023	2023-12-27 19:42:05	2023-12-27 21:44:31	207	24774.5	TREEROW	Non-storm
NW23122800436	LILAC9814	2023	2023-12-27 19:42:05	2023-12-27 21:43:43	1	121.63	WIND	Non-storm
NW23122700790	LILAC9814	2023	2023-12-27 19:42:07	2023-12-27 21:44:30	171	20795.16	TREEBROW	Non-storm
NE23122700785	SEBEW0312	2023	2023-12-27 20:05:59	2023-12-27 23:09:17	1	183.3	EQUIPMENT LOADING	Non-storm
SE23122700786	REDFD1363	2023	2023-12-27 20:09:59	2023-12-28 03:29:48	20	5379.08	TREEROW	Non-storm
SE23122700649	GULLY1998	2023	2023-12-27 21:19:28	2023-12-27 21:35:47	1	16.32	TREEBROW	Non-storm
NE23122700797	MACMB8510	2023	2023-12-27 21:52:14	2023-12-28 00:06:16	33	4412.76	EQUIPMENT FAILURE	Non-storm
NE23122800016	MACMB8510	2023	2023-12-27 21:52:25	2023-12-28 10:23:43	5	3755.84	EQUIPMENT FAILURE	Non-storm
NW23122800019	BALDW8979	2023	2023-12-28 00:22:28	2023-12-28 01:21:07	1	58.65	EQUIPMENT FAILURE	Non-storm
NW23122800013	BALDW8979	2023	2023-12-28 00:22:35	2023-12-28 01:21:22	2	117.28	ANIMAL	Non-storm
NW23122800014	BALDW8979	2023	2023-12-28 00:22:35	2023-12-28 01:21:19	2	117.3	ANIMAL	Non-storm
SW23122800074	DIMND9875	2023	2023-12-28 02:39:26	2023-12-28 12:54:11	14	8349.28	EQUIPMENT FAILURE	Non-storm
NE23122800069	GLOBE8034	2023	2023-12-28 02:43:23	2023-12-28 11:26:44	2	849.58	NO ISSUES FOUND	Non-storm

NW23122800070	MILFD9249	2023	2023-12-28 02:45:15	2023-12-28 11:37:56	22	11716.16	EQUIPMENT FAILURE	Non-storm
NE23122800092	HUNTC8761	2023	2023-12-28 03:22:23	2023-12-28 05:16:49	47	5365.62	TREEROW	Non-storm
NE23122800029	GLOBE8034	2023	2023-12-28 03:51:22	2023-12-28 11:24:23	184	57255.16	NO ISSUES FOUND	Non-storm
NE23122800095	LEXTN8770	2023	2023-12-28 04:06:02	2023-12-28 09:51:19	2	690.5	TREEROW	Non-storm
NE23122800096	LEXTN8770	2023	2023-12-28 04:06:03	2023-12-28 09:51:18	1	345.25	EQUIPMENT FAILURE	Non-storm
SW23122800103	ODELL9337	2023	2023-12-28 05:10:00	2023-12-28 07:39:53	1	149.88	TREEROW	Non-storm
NE23122800027	DERBY2604	2023	2023-12-28 05:12:28	2023-12-28 11:27:37	3	996.14	NO ISSUES FOUND	Non-storm
SW23122800101	DAYTN9466	2023	2023-12-28 05:13:50	2023-12-28 06:16:42	1	62.87	METER / BLOCKS	Non-storm
NE23122800049	GLOBE8034	2023	2023-12-28 06:20:06	2023-12-28 11:28:41	194	61503.08	NO ISSUES FOUND	Non-storm
NE23122800041	GLOBE8034	2023	2023-12-28 06:22:32	2023-12-28 11:24:22	54	16686.03	EQUIPMENT FAILURE	Non-storm
NE23122800079	GLOBE8034	2023	2023-12-28 06:22:32	2023-12-28 11:24:48	44	13289.51	NO ISSUES FOUND	Non-storm
NE23122800040	GLOBE8034	2023	2023-12-28 06:22:34	2023-12-28 11:24:23	31	9593.02	EQUIPMENT FAILURE	Non-storm
NE23122800159	DERBY2635	2023	2023-12-28 06:22:37	2023-12-28 11:23:54	2	602.18	NO ISSUES FOUND	Non-storm
NE23122800138	DERBY2604	2023	2023-12-28 06:22:40	2023-12-28 11:24:12	3	904.13	NO ISSUES FOUND	Non-storm
NE23122800145	DERBY2604	2023	2023-12-28 06:22:48	2023-12-28 11:24:04	1	301.27	NO ISSUES FOUND	Non-storm
NW23122800125	CAMDN8282	2023	2023-12-28 06:26:24	2023-12-28 07:20:43	17	910.36	ANIMAL	Non-storm
SW23122800155	SOFLD9082	2023	2023-12-28 06:50:59	2023-12-29 10:59:12	1	1688.22	TREEBROW	Non-storm
SW23122800158	OMAHA8233	2023	2023-12-28 08:05:22	2023-12-28 09:54:08	5	543.11	EQUIPMENT FAILURE	Non-storm
SE23122700768	WDSID2660	2023	2023-12-28 08:14:27	2023-12-28 08:25:06	2	21.06	EQUIPMENT FAILURE	Non-storm
SW23122800234	CALLA9923	2023	2023-12-28 08:22:53	2023-12-28 18:41:38	1	618.75	EQUIPMENT LOADING	Non-storm
NW23122800169	PINCK8229	2023	2023-12-28 08:41:13	2023-12-28 09:08:24	2	54.38	EQUIPMENT FAILURE	Non-storm
NE23122700775	FRMNT1250	2023	2023-12-28 08:42:47	2023-12-28 09:00:11	1	17.4	TREEROW	Non-storm
NW23122800181	CARTR8878	2023	2023-12-28 08:49:19	2023-12-28 11:17:08	31	4577.43	EQUIPMENT FAILURE	Non-storm
NW23122800183	CARTR8878	2023	2023-12-28 08:49:19	2023-12-28 11:17:01	8	1181.3	EQUIPMENT FAILURE	Non-storm
NW23122800187	CARTR8878	2023	2023-12-28 08:49:21	2023-12-28 11:17:01	1	147.67	EQUIPMENT FAILURE	Non-storm
NW23122800200	CARTR8878	2023	2023-12-28 08:49:22	2023-12-28 11:17:01	1	147.65	EQUIPMENT FAILURE	Non-storm
SW23122800193	WAYNE9501	2023	2023-12-28 08:52:39	2023-12-28 10:08:13	2	151.1	ANIMAL	Non-storm
NE23122800204	ARMAD8550	2023	2023-12-28 09:06:44	2023-12-29 09:17:13	4	123.1	EQUIPMENT FAILURE	Non-storm
NW23122800203	HANCK8198	2023	2023-12-28 09:09:38	2023-12-28 18:25:57	2	1112.56	PUBLIC INTERFERENCE	Non-storm
SW23122800195	SDF339897	2023	2023-12-28 09:14:46	2023-12-28 09:27:22	4	49.52	PLANNED INTENTIONAL	Non-storm
NE23122800146	BENSN8720	2023	2023-12-28 09:40:52	2023-12-28 10:24:27	6	260.76	EQUIPMENT FAILURE	Non-storm
NE23122800227	BENSN8720	2023	2023-12-28 09:41:01	2023-12-28 10:24:28	1	43.45	EQUIPMENT FAILURE	Non-storm
SW23122800232	DIMND9866	2023	2023-12-28 09:51:16	2023-12-28 13:08:30	1	197.23	EQUIPMENT FAILURE	Non-storm
NE23122800497	STRFD9093	2023	2023-12-28 10:11:38	2023-12-28 16:54:32	1	402.9	ANIMAL	Non-storm
SE23122700073	GLEND2212	2023	2023-12-28 10:12:00	2023-12-28 10:32:57	1	20.95	TREEROW	Non-storm
SE23122800304	SRGNT8250	2023	2023-12-28 10:31:42	2023-12-28 14:22:29	2	461.56	ANIMAL	Non-storm
SE23122800219	ZENON2206	2023	2023-12-28 10:33:15	2023-12-28 15:44:35	2	41.8	EQUIPMENT FAILURE	Non-storm
SE23122800109	EVRGN1257	2023	2023-12-28 10:35:59	2023-12-28 10:47:01	1	11.03	EQUIPMENT FAILURE	Non-storm
NW23122800299	COLFX8186	2023	2023-12-28 10:38:17	2023-12-28 11:56:06	1	77.82	PLANNED INTENTIONAL	Non-storm
SW23122800389	BREST9350	2023	2023-12-28 10:45:05	2023-12-28 13:48:06	2	366.02	EQUIPMENT FAILURE	Non-storm
SE23122700681	HAWTH2020	2023	2023-12-28 11:09:15	2023-12-28 11:18:29	1	9.23	EQUIPMENT FAILURE	Non-storm
SW23122800332	SDF339897	2023	2023-12-28 11:17:18	2023-12-28 11:30:06	6	76.44	PLANNED INTENTIONAL	Non-storm
SW23122700270	YOST9403	2023	2023-12-28 11:26:15	2023-12-28 11:47:54	1	21.65	TREEROW	Non-storm
NE23122700673	NEAST8631	2023	2023-12-28 11:39:06	2023-12-28 11:48:15	1	9.15	EQUIPMENT FAILURE	Non-storm
SW23122800373	MOTT9789	2023	2023-12-28 11:46:58	2023-12-28 12:49:08	37	2296.72	EQUIPMENT FAILURE	Non-storm
NE23122800387	BECK8689	2023	2023-12-28 11:55:06	2023-12-28 15:14:11	22	4377.58	EQUIPMENT FAILURE	Non-storm
NE23122800395	BADAX8749	2023	2023-12-28 11:56:23	2023-12-28 13:21:28	6	334.32	EQUIPMENT FAILURE	Non-storm
SE23122800399	CHTNT8929	2023	2023-12-28 11:58:38	2023-12-28 18:11:24	1	372.77	EQUIPMENT FAILURE	Non-storm
SE23122800668	GLEND1013	2023	2023-12-28 12:46:39	2023-12-28 16:41:17	1	234.63	TREEBROW	Non-storm
SE23122800429	NRLND9018	2023	2023-12-28 13:01:57	2023-12-28 15:09:42	21	2679.19	EQUIPMENT FAILURE	Non-storm
NW23122800465	TAMRK9063	2023	2023-12-28 13:33:59	2023-12-28 13:39:20	2	712.7	EQUIPMENT FAILURE	Non-storm
NW23122800469	PROUD9475	2023	2023-12-28 13:41:16	2023-12-28 16:37:15	18	3165.12	TREEROW	Non-storm
SW23122800487	SALEM9900	2023	2023-12-28 14:00:53	2023-12-28 15:09:23	7	475.6	EQUIPMENT FAILURE	Non-storm
NW23122800811	KENSL9858	2023	2023-12-28 14:05:41	2023-12-28 21:33:19	1	447.63	EQUIPMENT FAILURE	Non-storm
NW23122800517	WLNUT9007	2023	2023-12-28 14:25:59	2023-12-28 14:47:29	48	1058.37	TROUBLE INTENTIONAL	Non-storm
SE23122800434	STOPL1078	2023	2023-12-28 14:30:16	2023-12-28 14:45:55	1	15.65	TREEBROW	Non-storm
SW23122700195	ELM9448	2023	2023-12-28 14:39:52	2023-12-28 14:59:25	1	19.55	TREEROW	Non-storm
NW23122800605	HURST9842	2023	2023-12-28 14:40:36	2023-12-28 16:50:49	1	130.22	NO ISSUES FOUND	Non-storm
NW23122800537	KELOG8121	2023	2023-12-28 14:40:38	2023-12-28 16:51:05	233	30338.8	TREEROW	Non-storm
NW23122800603	KELOG8121	2023	2023-12-28 14:40:39	2023-12-28 16:50:54	2	260.44	NO ISSUES FOUND	Non-storm
NW23122800778	KELOG8121	2023	2023-12-28 14:40:43	2023-12-28 16:50:56	1	130.22	NO ISSUES FOUND	Non-storm
NW23122800670	BRONC8544	2023	2023-12-28 15:16:31	2023-12-28 15:22:45	1	6.23	TREEROW	Non-storm
SE23122800528	VENIC1475	2023	2023-12-28 15:17:29	2023-12-28 19:08:18	14	2640.13	TREEBROW	Non-storm
NE23122800773	COTAG8743	2023	2023-12-28 16:04:29	2023-12-29 10:14:36	1	1090.12	EQUIPMENT FAILURE	Non-storm
NE23122800718	BUNRT8426	2023	2023-12-28 16:38:30	2023-12-28 22:57:29	1240	182325.33	TREEROW	Non-storm
NE23122900016	BUNRT8426	2023	2023-12-28 16:38:31	2023-12-28 20:11:19	1	212.8	CUSTOMER EQUIPMENT	Non-storm
NW23122800777	PINCK9886	2023	2023-12-28 16:57:55	2023-12-28 18:31:21	1	93.43	EQUIPMENT FAILURE	Non-storm
NW23122800786	PINCK9886	2023	2023-12-28 16:57:55	2023-12-28 18:31:21	1	93.43	NO ISSUES FOUND	Non-storm
NE23122800390	NEAST8437	2023	2023-12-28 17:21:22	2023-12-28 19:11:51	31	2198.39	TREEROW	Non-storm
SE23122800682	VENIC1514	2023	2023-12-28 17:30:37	2023-12-28 19:07:59	1	97.37	METER / BLOCKS	Non-storm
SE23122800683	ZENON2206	2023	2023-12-28 17:31:33	2023-12-28 20:47:59	1	31.32	WIND	Non-storm
SW23122800660	WAYNE9402	2023	2023-12-28 18:02:10	2023-12-28 18:07:33	1	5.38	EQUIPMENT FAILURE	Non-storm
SW23122800526	YOST9403	2023	2023-12-28 18:09:05	2023-12-28 19:02:29	7	373.55	TREEBROW	Non-storm
SW23122800839	WSTLD9500	2023	2023-12-28 18:28:45	2023-12-29 13:18:45	12	13559.01	NO ISSUES FOUND	Non-storm
SE23122800844	CHTNT8839	2023	2023-12-28 18:41:55	2023-12-28 21:39:59	6	1067.23	EQUIPMENT FAILURE	Non-storm
SE23122800850	CHTNT8839	2023	2023-12-28 18:42:01	2023-12-28 21:40:42	2	356.65	EQUIPMENT FAILURE	Non-storm
NE23122600676	MEDNA8533	2023	2023-12-28 18:42:48	2023-12-29 03:32:19	1	529.52	TREEBROW	Non-storm
SE23122800870	ANGLA9258	2023	2023-12-28 18:53:26	2023-12-29 04:57:03	1	744.74	TREEROW	Non-storm
SE23122800858	BRAZL8827	2023	2023-12-28 19:06:09	2023-12-28 20:31:48	10	855.23	EQUIPMENT FAILURE	Non-storm
SE23122800867	NRLND9018	2023	2023-12-28 19:20:09	2023-12-29 04:21:32	10	5411.94	EQUIPMENT FAILURE	Non-storm
SE23122800872	NRLND9018	2023	2023-12-28 19:20:10	2023-12-29 04:22:13	2	1083.22	EQUIPMENT FAILURE	Non-storm
SE23122900619	ZENON2206	2023	2023-12-28 19:22:18	2023-12-29 15:43:25	1	15.01	EQUIPMENT FAILURE	Non-storm
NE23122900430	BUNRT8426	2023	2023-12-28 19:24:09	2023-12-28 22:57:12	1	213.05	EQUIPMENT FAILURE	Non-storm
NW23122800897	STKWL4002	2023	2023-12-28 20:45:05	2023-12-28 23:48:24	19	3468.61	EQUIPMENT FAILURE	Non-storm
NW23122800899	CATLB9136	2023	2023-12-28 20:45:08	2023-12-28 23:47:30	2	364.63	NO ISSUES FOUND	Non-storm
NW23122800910	STKWL4002	2023	2023-12-28 20:45:08	2023-12-28 23:48:22	1	183.23	NO ISSUES FOUND	Non-storm
NW23122800898	STKWL4002	2023	2023-12-28 20:45:09	2023-12-28 23:47:28	1	182.32	NO ISSUES FOUND	Non-storm
NW23122800902	STKWL4002	2023	2023-12-28 20:45:09	2023-12-28 23:47:28	1	182.32	NO ISSUES FOUND	Non-storm
NW23122800903	STKWL4002	2023	2023-12-28 20:45:09	2023-12-28 23:48:18	2	365.55	EQUIPMENT FAILURE	Non-storm
NW23122800088	HANCK9023	2023	2023-12-28 21:05:28	2023-12-28 21:53:19	1	47.85	METER / BLOCKS	Non-storm
SE23122800920	PURTN1246	2023	2023-12-28 21:23:44	2023-12-29 00:41:59	1	1398.25	NO ISSUES FOUND	Non-storm
SE23122800684	ZENON2468	2023	2023-12-28 21:51:23	2023-12-28 22:15:58	1	24.58	EQUIPMENT FAILURE	Non-storm
NE23122800917	GLOBE8034	2023	2023-12-28 23:51:57	2023-12-29 00:32:24	1	40.45	EQUIPMENT FAILURE	Non-storm
SW23122900079	HINES9378	2023	2023-12-28 23:54:45	2023-12-29 19:06:42	2	2280.08	EQUIPMENT FAILURE	Non-storm
SW23122900048	ZEBRA9474	2023	2023-12-29 03:00:28	2023-12-29 04:56:04	68	7649.57	NO ISSUES FOUND	Non-storm
NW23122900054	ALPNE9724	2023	2023-12-29 03:27:46	2023-12-29 03:37:59	1	10.22	EQUIPMENT FAILURE	Non-storm
SW23122900210	SALEM9926	2023	2023-12-29 07:56:09	2023-12-29 10:53:42	1	177.55	EQUIPMENT FAILURE	Non-storm
NW23122900092	CODY9537	2023	2023-12-29 07:56:11	2023-12-29 10:53:46	756	51702.94	EQUIPMENT FAILURE	Non-storm
SE23122800221	JUPTR8344	2023	2023-12-29 08:04:46	2023-12-29 08:23:16	1	18.5	EQUIPMENT FAILURE	Non-storm
NW23122900159	BISMK8439	2023	2023-12-29 08:47:57	2023-12-29 09:48:34	21	1266.73	EQUIPMENT FAILURE	Non-storm
NE23122900025	ELKTN0302	2023	2023-12-29 08:50:41	2023-12-29 09:33:52	1	43.18	EQUIPMENT FAILURE	Non-storm
SE23122800882	CRTIS2104	2023	2023-12-29 08:52:19	2023-12-29 09:25:02	1	32.72	EQUIPMENT FAILURE	Non-storm
SE23122900174	SAVAN1086	2023	2023-12-29 09:09:00	2023-12-29 09:23:47	1	14.78	PLANNED INTENTIONAL	Non-storm
SW23122900171	HEMLK1910	2023	2023-12-29 09:09:21	2023-12-29 12:09:01	16	2817.13	PLANNED INTENTIONAL	Non-storm
NE23122900179	CYPRS8754	2023	2023-12-29 09:21:21	2023-12-29 09:48:43	159	4947.95	EQUIPMENT FAILURE	Non-storm
NE23122900242	CYPRS8754	2023	2023-12-29 09:21:21	2023-12-29 11:53:26	207	31421.54	EQUIPMENT FAILURE	Non-storm
NE23122900403	CYPRS8754	2023	2023-12-29 09:21:21	2023-12-29 11:53:16	1	151.92	CUSTOMER EQUIPMENT	Non-storm
SE23122900187	CYPRS8754	2023	2023-12-29 09:21:32	2023-12-29 09:47:47	1	26.25	EQUIPMENT FAILURE	Non-storm
NE23122900197	BUNRT1658	2023	2023-12-29 09:24:41	2023-12-29 10:07:27	1	42.77	PLANNED INTENTIONAL	Non-storm
SW23122800918	VENOY9422	2023	2023-12-29 09:24:46	2023-12-29 11:11:34	18	1919.51	TREEROW	Non-storm
NW23122900273	DOVER8204	2023	2023-12-29 09:29:27	2023-12-29 13:21:49	1	232.37	ANIMAL	Non-storm
NW23122900218	JEWEL8569	2023	2023-12-29 09:36:01	2023-12-29 12:12:28	62	9689.04	EQUIPMENT FAILURE	Non-storm
NW23122900216	PROUD9475	2023	2023-12-29 09:36:09	2023-12-29 10:17:21	77	3154.77	NO ISSUES FOUND	Non-storm
NW23122900212	PROUD9475	2023	2023-12-29 09:36:10	2023-12-29 10:17:19	74	3033.05	ANIMAL	Non-storm
SE23122900169	MLVDL2105	2023	2023-12-29 09:42:22	2023-12-29 10:41:41	1	59.32	PLANNED INTENTIONAL	Non-storm
SE23122900143	SHADK1093	2023	2023-12-29 09:44:25	2023-12-29 09:50:11	1	5.77	METER / BLOCKS	Non-storm
NE23122900236	LNDIS8164	2023	2023-12-29 09:45:10	2023-12-29 12:24:09	7	1111.7	PLANNED INTENTIONAL	Non-storm
SW23122900214	SDF339897	2023	2023-12-29 09:49:47	2023-12-29 11:01:39	2	143.72	PLANNED INTENTIONAL	Non-storm
NE23122800499	NUNLY0367	2023	2023-12-29 09:54:10	2023-12-29 10:12:15	1	18.08	EQUIPMENT FAILURE	Non-storm
SE23122900237	DCATR1271	2023	2023-12-29 09:54:39	2023-12-29 11:43:45	2	218.05	PLANNED INTENTIONAL	Non-storm
SW23122900239	GULLY1985	2023	2023-12-29 09:55:25	2023-12-29 12:05:24	17	2205.92	PLANNED INTENTIONAL	Non-storm
SW23122900252	GULLY1985	2023	2023-12-29 09:55:38	2023-12-29 12:05:25	1	129.78	EQUIPMENT FAILURE	Non-storm
NW23122900261	TINKN9111	2023	2023-12-29 09:56:36	2023-12-29 13:45:08	1	228.53	PLANNED INTENTIONAL	Non-storm
NW23122900253	TINKN9111	2023	2023-12-29 09:56:39	2023-12-29 13:45:27	43	9741.49	PLANNED INTENTIONAL	Non-storm
NE23122900259	CHEST8430	2023	2023-12-29 09:59:49	2023-12-29 11:16:22	4	305.56	ANIMAL	Non-storm
SE23122900265	GDRIV0495	2023	2023-12-29 10:07:36	2023-12-29 10:52:34	1	44.97	PLANNED INTENTIONAL	Non-storm
NW23122900483	TINKN9111	2023	2023-12-29 10:08:50	2023-12-29 13:45:14	1	216.4	NO ISSUES FOUND	Non-storm
SW23122900301	SALEM9900	2023	2023-12-29 10:24:14	2023-12-29 10:53:04	7	200.46	EQUIPMENT FAILURE	Non-storm
NW23122900749	SALEM9900	2023	2023-12-29 10:24:16	2023-12-29 22:35:05	12	496.35	NO ISSUES FOUND	Non-storm
NW23122900375	CODY9537	2023	2023-12-29 10:24:18	2023-12-29 10:53:06	1	28.8	NO ISSUES FOUND	Non-storm
SW23122900748	CODY9537	2023	2023-12-29 10:24:20	2023-12-30 03:42:17	3	147.15	TREEBROW	Non-storm
SW23122900753	CODY9537	2023	2023-12-29 10:24:23	2023-12-30 03:42:01	2	96.25	NO ISSUES FOUND	Non-storm
NW23122900517	CODY9537	2023	2023-12-29 10:24:25	2023-12-29 10:52:05	1	27.67	NO ISSUES FOUND	Non-storm
NE23122900336	BREWR8840	2023	2023-12-29 10:26:12	2023-12-29 10:36:16	1	10.07	PLANNED INTENTIONAL	Non-storm
SW23122900323	HEMLK1910	2023	2023-12-29 10:35:26	2023-12-29 12:35:55	28	3370.64	PLANNED INTENTIONAL	Non-storm
SE23122900223	ECORS2077	2023	2023-12-29 10:36:15	2023-12-29 10:45:07	1	8.87	EQUIPMENT FAILURE	Non-storm
NW23122900585	DAVIS9081	2023	2023-12-29 10:39:33	2023-12-29 11:12:14	1	32.68	EQUIPMENT FAILURE	Non-storm
SE23122900337	MLVDL2105	2023	2023-12-29 10:45:58	2023-12-29 11:29:33	1	43.58	PLANNED INTENTIONAL	Non-storm
SW23122900335	HEMLK1910	2023	2023-12-29 10:48:47	2023-12-29 12:54:41	28	3518.51	PLANNED INTENTIONAL	Non-storm
NE23122900154	ANDER0312	2023	2023-12-29 11:05:37	2023-12-29 16:06:59	1	64.49	METER / BLOCKS	Non-storm
SW23122900353	SPKNE8842	2023	2023-12-29 11:16:58	2023-12-29 12:29:55	7	510.47	PLANNED INTENTIONAL	Non-storm
NW23122900754	CODY9537	2023	2023-12-29 11:34:39	2023-12-29 21:24:53	1	56.08	NO ISSUES FOUND	Non-storm
SE23122900381	PURTN2095	2023	2023-12-29 11:38:56	2023-12-29 12:11:46	1	32.83	NO ISSUES FOUND	Non-storm
SE23122900183	EIGMI1507	2023	2023-12-29 11:59:26	2023-12-29 12:28:41	1	29.25	EQUIPMENT FAILURE	Non-storm
SE23122900392	MLVDL2105	2023	2023-12-29 12:00:04	2023-12-29 12:23:02	1	22.97	PLANNED INTENTIONAL	Non-storm
NW23122900752	CODY9537	2023	2023-12-29 12:06:07	2023-12-30 02:01:21	1	49.04	TREEBROW	Non-storm
NW23122900786	CODY9537	2023	2023-12-29 12:06:07	2023-12-30 02:01:28	1	49.17	NO ISSUES FOUND	Non-storm
SE23122900017	GLEND2212	2023	2023-12-29 12:06:45	2023-12-29 12:13:18	1	6.55	EQUIPMENT FAILURE	Non-storm
NW23122900397	COLFX8186	2023	2023-12-29 12:08:27	2023-12-29 12:43:17	1	34.83	PLANNED INTENTIONAL	Non-storm
SW23122900399	SDF339897	2023	2023-12-29 12:12:18	2023-12-29 13:03:29	4	203.98	PLANNED INTENTIONAL	Non-storm
SE23122900411	MALTA8469	2023	2023-12-29 12:16:40	2023-12-29 13:02:50	17	783.96	ANIMAL	Non-storm
SE23122900436	GDRIV1297	2023	2023-12-29 12:19:24	2023-12-29 12:34:47	1	15.38	PLANNED INTENTIONAL	Non-storm
NW23122900421	GENOA8217	2023	2023-12-29 12:28:42	2023-12-29 14:50:24	9	1272.68	TREEBROW	Non-storm
NW23122900420	GENOA8217	2023	2023-12-29 12:28:43	2023-12-29 14:50:08	1	141.42	NO ISSUES FOUND	Non-storm
SE23122800446	APPOL1318	2023	2023-12-29 12:47:07	2023-12-29 13:01:33	1	14.43	EQUIPMENT FAILURE	Non-storm
NE23122900446	MALTA9600	2023	2023-12-29 12:52:30	2023-12-29 13:30:30	36	1360.87	ANIMAL	Non-storm
NW23122900484	GENOA8217	2023	2023-12-29 13:28:13	2023-12-29 14:50:39	9	740.45	TREEBROW	Non-storm
NW23122900499	GENOA8217	2023	2023-12-29 13:28:17	2023-12-29 14:50:09	1	81.87	NO ISSUES FOUND	Non-storm
NW23122900486	GENOA8217	2023	2023-12-29 13:28:24	2023-12-29 14:50:16	1	81.87	NO ISSUES FOUND	Non-storm
NW23122900509	GENOA8217	2023	2023-12-29 13:28:25	2023-12-29 14:50:17	1	81.87	NO ISSUES FOUND	Non-storm
SE23122900464	WAREN8374	2023	2023-12-29 13:50:28	2023-12-29 13:59:50	1	9.37	EQUIPMENT FAILURE	Non-storm
NE23122900498	NINMI2474	2023	2023-12-29 13:58:33	2023-12-29 14:30:38	1	32.08	PLANNED INTENTIONAL	Non-storm

SE23122900599	REDFD1064	2023	2023-12-29 14:10:32	2023-12-29 19:52:06	1	341.57	TREEROW	Non-storm
NE23122900450	ROBIN8750	2023	2023-12-29 15:52:22	2023-12-29 16:06:44	1	14.37	CUSTOMER EQUIPMENT	Non-storm
NE23122900584	ROBIN8750	2023	2023-12-29 15:58:47	2023-12-29 18:52:27	1	173.67	EQUIPMENT FAILURE	Non-storm
NW23122900356	WALTN2674	2023	2023-12-29 16:18:42	2023-12-29 22:00:13	1	341.52	TREEROW	Non-storm
SE23122900438	CHIGO1463	2023	2023-12-29 17:09:57	2023-12-29 17:50:19	1	40.37	WIND	Non-storm
SE23122900366	DENVR2094	2023	2023-12-29 17:33:16	2023-12-29 17:49:36	1	16.33	EQUIPMENT FAILURE	Non-storm
SE23122900513	WEBST0373	2023	2023-12-29 17:45:00	2023-12-29 18:34:09	1	49.15	EQUIPMENT FAILURE	Non-storm
SW23122900652	ZEBRA9476	2023	2023-12-29 17:51:36	2023-12-30 12:39:01	1	1127.42	TREEBROW	Non-storm
NW23122900656	SPKNE8825	2023	2023-12-29 18:07:52	2023-12-29 19:51:41	45	4309.03	EQUIPMENT FAILURE	Non-storm
SE23122900474	EVRGN1062	2023	2023-12-29 18:17:49	2023-12-29 18:25:21	1	7.53	EQUIPMENT FAILURE	Non-storm
SW23122900667	PERU9432	2023	2023-12-29 18:26:47	2023-12-29 18:50:06	1	23.32	NO ISSUES FOUND	Non-storm
SW23122800788	PERU9432	2023	2023-12-29 18:26:48	2023-12-29 18:50:09	7	163.25	EQUIPMENT FAILURE	Non-storm
SE23122800797	EVRGN2135	2023	2023-12-29 18:56:56	2023-12-29 19:13:42	1	16.77	EQUIPMENT FAILURE	Non-storm
SE23122900358	COOLG1263	2023	2023-12-29 19:07:27	2023-12-29 19:28:33	1	21.1	EQUIPMENT FAILURE	Non-storm
NW23123000274	CODY9537	2023	2023-12-29 19:07:55	2023-12-30 16:21:21	1	1273.43	EQUIPMENT FAILURE	Non-storm
SW23122900687	DIMND9859	2023	2023-12-29 19:11:17	2023-12-29 22:25:54	23	4470.49	EQUIPMENT FAILURE	Non-storm
NW23122900709	MILFD9247	2023	2023-12-29 20:28:17	2023-12-29 21:13:09	541	24215.63	TROUBLE INTENTIONAL	Non-storm
NW23122900756	MILFD9247	2023	2023-12-29 20:28:43	2023-12-29 21:13:04	1	44.35	NO ISSUES FOUND	Non-storm
NW23122900733	TEGER8872	2023	2023-12-29 20:33:30	2023-12-30 02:42:35	1	369.08	EQUIPMENT FAILURE	Non-storm
SE23122900757	STLUS1206	2023	2023-12-29 21:39:30	2023-12-30 08:05:16	1	625.77	EQUIPMENT FAILURE	Non-storm
SW23122900758	GLBRT8106	2023	2023-12-29 21:53:07	2023-12-30 00:47:37	15	2616.22	EQUIPMENT FAILURE	Non-storm
NW23122900755	CODY9537	2023	2023-12-29 22:08:02	2023-12-29 22:35:20	1	27.3	NO ISSUES FOUND	Non-storm
NW23122900751	CODY9537	2023	2023-12-29 22:20:46	2023-12-29 22:35:00	1	14.23	NO ISSUES FOUND	Non-storm
NW23122900763	DUDLY1675	2023	2023-12-29 22:52:14	2023-12-30 08:14:48	1	380.05	TREEBROW	Non-storm
NW23122900745	HAMBG9909	2023	2023-12-30 00:01:37	2023-12-30 10:03:56	1	602.32	TREEBROW	Non-storm
NE23123000020	MENLO8815	2023	2023-12-30 01:05:28	2023-12-30 02:46:38	42	4239.68	EQUIPMENT FAILURE	Non-storm
NE23123000022	MENLO8815	2023	2023-12-30 01:05:40	2023-12-30 02:46:37	1	100.95	EQUIPMENT FAILURE	Non-storm
NW23123000038	CODY9537	2023	2023-12-30 03:21:52	2023-12-30 03:42:17	1	20.42	NO ISSUES FOUND	Non-storm
SE23123000053	EVRGN1281	2023	2023-12-30 05:27:44	2023-12-30 09:36:09	2	485.87	TREEROW	Non-storm
SW23123000055	TAYLR8286	2023	2023-12-30 05:53:45	2023-12-30 10:38:39	2	569.6	EQUIPMENT FAILURE	Non-storm
NE23123000094	DERBY2604	2023	2023-12-30 07:29:43	2023-12-30 10:41:42	1	191.98	EQUIPMENT FAILURE	Non-storm
SE23122900534	VERNR1481	2023	2023-12-30 07:43:53	2023-12-30 08:18:41	1	34.8	EQUIPMENT FAILURE	Non-storm
NE23123000091	PIGON8771	2023	2023-12-30 08:07:20	2023-12-30 09:50:46	9	928.52	EQUIPMENT FAILURE	Non-storm
SE23122900653	LAUDR1400	2023	2023-12-30 08:19:25	2023-12-30 08:30:10	1	10.75	EQUIPMENT FAILURE	Non-storm
SW23123000133	HEMLK1952	2023	2023-12-30 09:23:53	2023-12-30 12:59:32	1	79.08	TREEROW	Non-storm
NE23123000136	JACOB8698	2023	2023-12-30 09:53:08	2023-12-30 10:28:33	2	70.84	ANIMAL	Non-storm
NE23123000137	JACOB8698	2023	2023-12-30 09:53:08	2023-12-30 10:28:36	8	283.32	EQUIPMENT FAILURE	Non-storm
SE23123000098	GLEND1417	2023	2023-12-30 11:00:39	2023-12-30 13:18:49	1	138.17	EQUIPMENT FAILURE	Non-storm
NE23123000158	MALTA9600	2023	2023-12-30 11:07:18	2023-12-30 12:33:32	36	3097.59	EQUIPMENT FAILURE	Non-storm
SW23123000161	ZACRY9502	2023	2023-12-30 11:10:00	2023-12-30 11:41:05	1778	54819.17	EQUIPMENT FAILURE	Non-storm
SW23123000284	ZACRY9502	2023	2023-12-30 11:10:08	2023-12-30 11:40:58	1	30.83	NO ISSUES FOUND	Non-storm
SW23123000196	ZACRY9502	2023	2023-12-30 11:10:15	2023-12-30 11:41:05	1	30.83	EQUIPMENT FAILURE	Non-storm
SW23123000517	ZACRY9502	2023	2023-12-30 11:10:17	2023-12-30 11:41:07	1	30.83	NO ISSUES FOUND	Non-storm
SW23123000201	ZACRY9502	2023	2023-12-30 11:10:19	2023-12-30 11:41:09	1	30.83	EQUIPMENT FAILURE	Non-storm
NW23123000273	GENOA8217	2023	2023-12-30 11:12:46	2023-12-30 15:08:57	1	180.93	EQUIPMENT FAILURE	Non-storm
SW23123000174	SNSET9497	2023	2023-12-30 11:23:12	2023-12-30 15:23:58	110	26451.06	EQUIPMENT FAILURE	Non-storm
NW23123000336	WOLFH8838	2023	2023-12-30 11:28:24	2023-12-30 17:57:43	1	389.32	EQUIPMENT FAILURE	Non-storm
SE23123000205	FERND2698	2023	2023-12-30 11:53:13	2023-12-30 12:25:16	9	282.63	PLANNED INTENTIONAL	Non-storm
NE23123000206	BECK8466	2023	2023-12-30 12:01:03	2023-12-30 12:44:29	2	86.76	ANIMAL	Non-storm
SW23123000211	LUZON9392	2023	2023-12-30 12:08:51	2023-12-30 14:24:06	60	7758.91	TREEBROW	Non-storm
SE23123000249	GDRY2074	2023	2023-12-30 12:12:07	2023-12-30 14:33:54	1	141.78	TREEBROW	Non-storm
NW23122900762	PINCK9886	2023	2023-12-30 12:24:45	2023-12-30 13:15:27	28	2250.31	EQUIPMENT FAILURE	Non-storm
NE23123000116	EMMET0301	2023	2023-12-30 12:31:29	2023-12-30 15:20:50	1	169.35	EQUIPMENT FAILURE	Non-storm
SW23123000185	OMAHA8200	2023	2023-12-30 12:38:58	2023-12-30 13:51:18	10	720	EQUIPMENT FAILURE	Non-storm
SW23123000244	RGENT0357	2023	2023-12-30 12:41:54	2023-12-30 13:02:58	1	21.07	EQUIPMENT FAILURE	Non-storm
SW23123000262	OMAHA8200	2023	2023-12-30 12:45:46	2023-12-30 15:56:19	1	23.32	EQUIPMENT FAILURE	Non-storm
NE23123000173	PLUTO8480	2023	2023-12-30 12:53:35	2023-12-30 13:22:42	1	29.12	TREEBROW	Non-storm
SE23123000060	STLUS1394	2023	2023-12-30 12:56:09	2023-12-30 13:03:48	1	7.65	EQUIPMENT FAILURE	Non-storm
SE23123000115	WAYBN2164	2023	2023-12-30 13:09:29	2023-12-30 13:47:26	1	37.95	TREEROW	Non-storm
NE23123000243	LEXTN8770	2023	2023-12-30 13:46:10	2023-12-30 13:57:59	1	11.82	CUSTOMER EQUIPMENT	Non-storm
SE23123000258	ANGLA8862	2023	2023-12-30 13:53:55	2023-12-30 17:42:05	2045	390278.12	ANIMAL	Non-storm
SE23123000374	ANGLA8862	2023	2023-12-30 13:53:57	2023-12-30 17:41:44	1	227.78	ANIMAL	Non-storm
SE23123000368	ANGLA9060	2023	2023-12-30 13:54:02	2023-12-30 17:42:44	1	228.7	NO ISSUES FOUND	Non-storm
SE23123100024	ANGLA8862	2023	2023-12-30 13:54:04	2023-12-30 17:41:49	1	227.75	NO ISSUES FOUND	Non-storm
SE23123000341	ANGLA8896	2023	2023-12-30 13:54:11	2023-12-30 15:59:57	1	125.77	ANIMAL	Non-storm
SE23123000362	ESTLD1440	2023	2023-12-30 14:26:06	2023-12-30 14:34:26	1	8.33	EQUIPMENT FAILURE	Non-storm
NE23123000346	BRAYB780	2023	2023-12-30 14:36:46	2023-12-30 14:56:24	36	683.13	NO ISSUES FOUND	Non-storm
SE23123000187	GULLY2219	2023	2023-12-30 15:28:58	2023-12-30 17:51:53	1	142.92	EQUIPMENT FAILURE	Non-storm
NE23123000430	BREWR8840	2023	2023-12-30 16:58:04	2023-12-30 17:41:45	1	43.68	NO ISSUES FOUND	Non-storm
SW23122900268	HINES9378	2023	2023-12-30 17:19:20	2023-12-30 17:24:25	1	5.08	EQUIPMENT FAILURE	Non-storm
NE23123000407	MTCLM1870	2023	2023-12-30 17:21:55	2023-12-30 17:46:55	1	17.51	TREEBROW	Non-storm
SW23123000138	MERRD1879	2023	2023-12-30 17:23:11	2023-12-30 17:35:24	13	218.79	EQUIPMENT FAILURE	Non-storm
NE23123000473	MACMB8283	2023	2023-12-30 18:29:30	2023-12-30 19:45:08	60	4515.28	TREEROW	Non-storm
SE23123000459	GRPTE0036	2023	2023-12-30 20:01:09	2023-12-30 20:08:52	1	7.72	NO ISSUES FOUND	Non-storm
SE23123000447	GRPTE2073	2023	2023-12-30 20:01:10	2023-12-30 20:09:10	21	162.13	TREEBROW	Non-storm
SE23123100062	GRPTE2073	2023	2023-12-30 20:01:12	2023-12-30 20:08:55	1	7.72	EQUIPMENT FAILURE	Non-storm
SE23123000457	GRPTE2073	2023	2023-12-30 20:01:13	2023-12-30 20:08:56	1	7.72	TREEBROW	Non-storm
NE23123000470	ALGON8748	2023	2023-12-30 22:14:06	2023-12-30 22:23:28	1	9.37	EQUIPMENT FAILURE	Non-storm
NE23123100017	ATICA0302	2023	2023-12-31 01:20:56	2023-12-31 11:18:30	26	15536.23	EQUIPMENT FAILURE	Non-storm
SW24010100130	KOPNK9407	2023	2023-12-31 01:31:12	2024-01-01 11:16:36	1	2025.4	EQUIPMENT FAILURE	Non-storm
SE23123100014	FRSB1288	2023	2023-12-31 07:46:46	2023-12-31 07:54:16	1	7.5	EQUIPMENT FAILURE	Non-storm
NE23123100039	OTIS8030	2023	2023-12-31 07:59:34	2023-12-31 08:52:21	74	3888.9	NO ISSUES FOUND	Non-storm
NW23123100070	SAVGE8117	2023	2023-12-31 08:24:12	2023-12-31 10:48:13	3	431.76	ANIMAL	Non-storm
SE23123100019	TIRMN1541	2023	2023-12-31 09:06:04	2023-12-31 09:17:41	13	147.33	EQUIPMENT FAILURE	Non-storm
NE23123100031	BADAX8787	2023	2023-12-31 09:07:39	2023-12-31 11:05:09	3	274.53	EQUIPMENT FAILURE	Non-storm
NW23123100069	HURST9826	2023	2023-12-31 09:25:03	2023-12-31 10:16:13	1	51.17	EQUIPMENT FAILURE	Non-storm
SE23123100042	MEYRS1599	2023	2023-12-31 09:32:58	2023-12-31 10:07:00	26	878.02	WIND	Non-storm
SE23123100080	TWEMI1551	2023	2023-12-31 09:47:13	2023-12-31 13:42:45	17	3991.13	NO ISSUES FOUND	Non-storm
SE23123000507	SIXMI2011	2023	2023-12-31 09:53:25	2023-12-31 10:24:04	1	30.65	EQUIPMENT FAILURE	Non-storm
NE23123100097	NEAST8500	2023	2023-12-31 10:00:57	2023-12-31 12:34:54	1	153.95	EQUIPMENT FAILURE	Non-storm
SE23123000426	GRANT1306	2023	2023-12-31 10:00:59	2023-12-31 10:10:48	1	9.82	EQUIPMENT FAILURE	Non-storm
SE23123100120	TWEMI1551	2023	2023-12-31 10:09:53	2023-12-31 13:42:49	16	3416.31	NO ISSUES FOUND	Non-storm
SE23123000504	SAVAN1086	2023	2023-12-31 10:17:48	2023-12-31 11:05:54	1	48.1	NO ISSUES FOUND	Non-storm
SE23123000449	MCGRW0552	2023	2023-12-31 10:56:39	2023-12-31 16:00:19	1	303.67	EQUIPMENT FAILURE	Non-storm
SE23123000240	SYRAC2017	2023	2023-12-31 11:02:01	2023-12-31 11:07:29	1	5.47	EQUIPMENT FAILURE	Non-storm
SW23123100126	FRUDG8042	2023	2023-12-31 11:36:28	2023-12-31 12:47:55	1	71.45	ANIMAL	Non-storm
SW23123100132	PITTS0382	2023	2023-12-31 12:03:01	2023-12-31 12:18:57	10	159	TROUBLE INTENTIONAL	Non-storm
SW23123100113	PERU9432	2023	2023-12-31 12:16:28	2024-01-01 03:11:06	1	894.63	CUSTOMER EQUIPMENT	Non-storm
SW23123100136	JEFSN9404	2023	2023-12-31 12:19:49	2023-12-31 13:24:07	8	514.04	ANIMAL	Non-storm
NE23123100241	HUNTC8761	2023	2023-12-31 12:29:48	2023-12-31 18:12:25	1	342.62	ANIMAL	Non-storm
SW23123100143	LILY9038	2023	2023-12-31 12:43:15	2023-12-31 14:59:43	26	3546.38	EQUIPMENT FAILURE	Non-storm
SW23123100066	WILSN8101	2023	2023-12-31 12:47:29	2023-12-31 12:53:53	1	6.4	NO ISSUES FOUND	Non-storm
SE23123100265	GRPTE1375	2023	2023-12-31 12:50:11	2023-12-31 15:41:48	1	141.25	TREEBROW	Non-storm
NW23123100294	HAMBG9968	2023	2023-12-31 13:15:47	2023-12-31 18:01:13	329	93814.95	TREEBROW	Non-storm
NW23123100156	HAMBG9968	2023	2023-12-31 13:15:48	2023-12-31 18:01:17	1498	427244.81	TREEBROW	Non-storm
SW23123100286	POPLR9885	2023	2023-12-31 13:15:49	2023-12-31 18:00:59	1	285.17	TREEBROW	Non-storm
NW23123100310	HAMBG9968	2023	2023-12-31 13:15:52	2023-12-31 18:01:07	1	285.25	NO ISSUES FOUND	Non-storm
NW23123100295	HAMBG9968	2023	2023-12-31 13:15:53	2023-12-31 18:01:17	2	570.42	NO ISSUES FOUND	Non-storm
SW23123100244	SPRUC9874	2023	2023-12-31 13:16:02	2023-12-31 18:01:14	1	285.2	EQUIPMENT FAILURE	Non-storm
NW23123100186	COATS8039	2023	2023-12-31 13:23:52	2023-12-31 14:58:18	2	188.12	TROUBLE INTENTIONAL	Non-storm
NW23123100183	COATS8039	2023	2023-12-31 13:23:58	2023-12-31 14:57:37	51	4776.11	PLANNED INTENTIONAL	Non-storm
SE23123100128	DENVR2139	2023	2023-12-31 13:33:38	2023-12-31 14:17:29	1	43.85	EQUIPMENT FAILURE	Non-storm
NW23123100145	MALTA8423	2023	2023-12-31 14:02:02	2023-12-31 14:24:30	1	22.47	EQUIPMENT FAILURE	Non-storm
SE23123000200	INDIN1549	2023	2023-12-31 14:10:19	2023-12-31 15:27:11	1	76.87	TREEROW	Non-storm
NE23123100215	CASVL8805	2023	2023-12-31 14:24:34	2023-12-31 15:21:17	11	623.47	EQUIPMENT FAILURE	Non-storm
SW23123100239	ELM9365	2023	2023-12-31 14:48:58	2023-12-31 16:08:25	19	1508.16	ANIMAL	Non-storm
SW23122700535	SUMTR9498	2023	2023-12-31 16:18:02	2023-12-31 16:37:02	1	19	EQUIPMENT FAILURE	Non-storm
SE23123100263	SCOTN2042	2023	2023-12-31 16:26:00	2023-12-31 17:06:17	1	40.28	EQUIPMENT FAILURE	Non-storm
SE23123000503	KORTE1469	2023	2023-12-31 16:41:02	2023-12-31 16:46:24	1	5.37	EQUIPMENT FAILURE	Non-storm
SW23123100288	DUBLN8205	2023	2023-12-31 17:06:52	2023-12-31 18:05:13	1	58.35	EQUIPMENT FAILURE	Non-storm
NW23123100284	CAMDN8276	2023	2023-12-31 17:08:10	2023-12-31 18:38:45	1	90.58	EQUIPMENT FAILURE	Non-storm
SE23123000235	BLTMR2086	2023	2023-12-31 17:20:36	2023-12-31 18:33:22	1	72.77	EQUIPMENT FAILURE	Non-storm
SE23123100317	HLTRD9758	2023	2023-12-31 17:51:35	2023-12-31 17:59:02	1	7.45	TREEBROW	Non-storm
NW23123100149	WLNUT9013	2023	2023-12-31 18:13:15	2023-12-31 19:08:35	1	55.33	EQUIPMENT FAILURE	Non-storm
SE23123100291	ZENON1725	2023	2023-12-31 18:48:17	2023-12-31 19:12:16	1	23.98	EQUIPMENT FAILURE	Non-storm
NE23123100299	MELRO2412	2023	2023-12-31 20:29:30	2024-01-01 09:09:57	1	760.45	EQUIPMENT FAILURE	Non-storm
NW24010100261	KERN9026	2023	2023-12-31 23:33:23	2024-01-01 22:26:01	1	1372.63	EQUIPMENT FAILURE	Non-storm
SE24010100002	PURTN2095	2023	2023-12-31 23:50:13	2024-01-01 04:14:20	1	264.12	PUBLIC INTERFERENCE	Non-storm
SE24010100181	CHIGO2081	2023	2023-12-31 23:56:33	2024-01-01 19:27:09	1	1170.6	PUBLIC INTERFERENCE	Non-storm
SE24010100027	PURTN2110	2023	2023-12-31 23:58:01	2024-01-01 17:41:32	1	1063.52	PUBLIC INTERFERENCE	Non-storm

MPSC Case No: U-21534

Requester: MNSC

Question No.: MNSCDE-3.26a

Respondent: S. Deol

Page: 1 of 1

Question: Refer generally to the Company's subtransmission system.

a. Provide a list of equipment outages on the Company's subtransmission system by year from 2018 to 2023.

Answer: The Company objects for the reason that the request is unduly burdensome, overly broad, oppressive and calculated to cause unreasonable expense to DTE Electric and its customers. The Company also objects because the information requested is not relevant, nor is it reasonably calculated to lead to the discovery of relevant evidence. Without waiving these objections, but subject to them, based upon currently available information the Company responds as follows:
Please see attached file.

Attachment: *U-21534 MNSCDE3.26-01 Subtransmission Outages*

Co-respondent: Legal

MPSC Case No: U-21534

Requester: MNSC

Question No.: MNSCDE-3.26bi

Respondent: S. Deol

Page: 1 of 1

Question: Refer generally to the Company's subtransmission system.

b. Refer to the list of equipment outages provided in response to subpart (a) above. For each equipment outage listed, provide:

i. The date and duration of the equipment outage;

Answer: The Company objects for the reason that the request is unduly burdensome, overly broad, oppressive and calculated to cause unreasonable expense to DTE Electric and its customers. The Company also objects because the information requested is not relevant, nor is it reasonably calculated to lead to the discovery of relevant evidence. Without waiving these objections, but subject to them, based upon currently available information the Company responds as follows:

See MNSCDE-3.26a.

Attachment: None

Co-respondent: Legal

MPSC Case No: U-21534

Requester: MNSC

Question No.: MNSCDE-3.26bii

Respondent: S. Deol

Page: 1 of 1

Question: Refer generally to the Company's subtransmission system.

b. Refer to the list of equipment outages provided in response to subpart (a) above. For each equipment outage listed, provide:

ii. The date of any service interruptions on the distribution system resulting from the subtransmission equipment outage; and

Answer: The Company objects for the reason that the request is unduly burdensome, overly broad, oppressive and calculated to cause unreasonable expense to DTE Electric and its customers. The Company also objects because the information requested is not relevant, nor is it reasonably calculated to lead to the discovery of relevant evidence. Without waiving these objections, but subject to them, based upon currently available information the Company responds as follows:

See MNSCDE-3.26a

Attachment: None.

Co-respondent: Legal

MPSC Case No: U-21534

Requester: MNSC

Question No.: MNSCDE-3.26biii

Respondent: S. Deol

Page: 1 of 1

Question: Refer generally to the Company's subtransmission system.

b. Refer to the list of equipment outages provided in response to subpart (a) above. For each equipment outage listed, provide:

iii. The counts of customers interruptions (CI) and customer minutes interrupted (CMI) associated with each service interruption on the distribution system resulting from the subtransmission equipment outage.

Answer:

The Company objects for the reason that the request is unduly burdensome, overly broad, oppressive and calculated to cause unreasonable expense to DTE Electric and its customers. The Company also objects because the information requested is not relevant, nor is it reasonably calculated to lead to the discovery of relevant evidence. Without waiving these objections, but subject to them, based upon currently available information the Company responds as follows:

See MNSCDE-3.26a

Attachment: None.

Co-respondent: Legal

START TIME	CLOSE TIME	OUTAGE LEVEL	Extent	TRK/TIE	AMI Cust Impacted	Cust Mins	Cause Code
1/4/2019 15:17	1/4/2019 18:40	Subtransmission	None	TIE 2648			ANIMAL
1/16/2019 9:32	1/16/2019 21:03	Subtransmission	None	TRK 7062			ANIMAL
1/16/2019 9:23	1/16/2019 11:50	Subtransmission	None	TRK 7062			ANIMAL
10/19/2019 10:43	10/19/2019 15:40	Subtransmission	None	TRK 2032			ANIMAL
12/13/2019 9:05	12/13/2019 14:54	Subtransmission	None	TIE 1544			ANIMAL
12/13/2019 9:15	12/15/2019 22:48	Subtransmission	None	TIE 1544			ANIMAL
5/18/2020 8:42	5/18/2020 16:06	Subtransmission	None	TRK 6842			ANIMAL
6/21/2020 8:06	6/21/2020 23:12	Subtransmission	None	TRK 2523			ANIMAL
6/22/2020 6:08	6/22/2020 7:37	Subtransmission	Distribution	TRK 2523	8	745	ANIMAL
6/29/2021 6:43	6/29/2021 17:00	Subtransmission	Distribution	TRK 2002	53	2080	ANIMAL
5/29/2022 8:25	5/29/2022 20:19	Subtransmission	None	TRK 4301			ANIMAL
8/10/2022 9:16	8/10/2022 13:46	Subtransmission	None	TRK 6941			ANIMAL
4/5/2023 1:47	4/5/2023 14:07	Subtransmission		TRK 2742			ANIMAL
6/8/2023 7:50	6/8/2023 14:56	Subtransmission		TRK 6938			ANIMAL
1/8/2018 8:07	1/8/2018 14:18	Subtransmission	None	TIE 5823			EQUIPMENT FAILURE
4/30/2018 16:28	5/1/2018 14:48	Subtransmission	None	TIE 4505			EQUIPMENT FAILURE
6/16/2018 6:29	6/16/2018 20:22	Subtransmission	None	TRK 1527			EQUIPMENT FAILURE
6/22/2018 13:50	6/22/2018 14:25	Subtransmission	None	TIE 1423			EQUIPMENT FAILURE
6/23/2018 15:59	6/23/2018 21:32	Subtransmission	None	TIE 1423			EQUIPMENT FAILURE
6/23/2018 4:24	6/23/2018 14:33	Subtransmission	None	TIE 1423			EQUIPMENT FAILURE
7/3/2018 4:42	7/3/2018 13:20	Subtransmission	None	TRK 7386			EQUIPMENT FAILURE
7/15/2018 8:54	7/15/2018 14:05	Subtransmission	None	TRK 2308			EQUIPMENT FAILURE
8/1/2018 4:43	8/2/2018 12:38	Subtransmission	None	TRK 2918			EQUIPMENT FAILURE
8/4/2018 13:24	8/4/2018 17:49	Subtransmission	None	TIE 810			EQUIPMENT FAILURE
9/23/2018 13:00	9/23/2018 14:45	Subtransmission	None	TIE4105			EQUIPMENT FAILURE
9/24/2018 16:17	9/24/2018 20:44	Subtransmission	None	TRK 2027			EQUIPMENT FAILURE
9/24/2018 21:49	9/26/2018 11:38	Subtransmission	None	TRK 2027			EQUIPMENT FAILURE
11/30/2018 20:14	11/30/2018 22:39	Subtransmission	None	TRK 1243			EQUIPMENT FAILURE
12/27/2018 14:20	12/27/2018 20:38	Subtransmission	None	TRK 2305			EQUIPMENT FAILURE
1/23/2019 0:53	1/23/2019 5:20	Subtransmission	None	TRK 2313			EQUIPMENT FAILURE
1/28/2019 18:24	1/29/2019 2:19	Subtransmission	None	TRK 2510			EQUIPMENT FAILURE
1/28/2019 19:43	1/28/2019 21:44	Subtransmission	None	TRK 2742			EQUIPMENT FAILURE
2/24/2019 14:42	2/24/2019 20:30	Subtransmission	Distribution	TRK 2038	195	78113	EQUIPMENT FAILURE
7/1/2019 18:55	7/1/2019 21:30	Subtransmission	Distribution	TIE 6147	1495	27909	EQUIPMENT FAILURE
7/1/2019 20:25	7/1/2019 21:23	Subtransmission	Distribution	TIE 6147	2584	43834	EQUIPMENT FAILURE
7/3/2019 15:58	7/4/2019 15:38	Subtransmission	None	TRK 3632			EQUIPMENT FAILURE
9/15/2019 15:39	9/15/2019 20:52	Subtransmission	None	TRK 1527			EQUIPMENT FAILURE
9/24/2019 7:39	9/24/2019 20:20	Subtransmission	None	TRK 346			EQUIPMENT FAILURE
9/28/2019 12:38	9/28/2019 15:44	Subtransmission	None	TRK 7130			EQUIPMENT FAILURE
9/29/2019 9:11	10/1/2019 14:24	Subtransmission	None	TRK 1527			EQUIPMENT FAILURE
10/27/2019 4:29	10/28/2019 15:00	Subtransmission	Distribution	TIE 7621	4	8038	EQUIPMENT FAILURE
10/27/2019 4:58	10/28/2019 15:01	Subtransmission	None	TIE 7621			EQUIPMENT FAILURE
12/26/2019 12:51	12/26/2019 14:48	Subtransmission	None	TRK 1346			EQUIPMENT FAILURE
12/30/2019 22:20	12/31/2019 16:26	Subtransmission	None	TIE 1531			EQUIPMENT FAILURE
4/29/2020 11:05	4/29/2020 12:54	Subtransmission	None	TRK 5917			EQUIPMENT FAILURE
5/25/2020 4:45	5/25/2020 15:25	Subtransmission	None	TRK 7909			EQUIPMENT FAILURE
5/27/2020 21:23	5/28/2020 6:17	Subtransmission	None	TRK 7909			EQUIPMENT FAILURE
5/27/2020 9:26	5/27/2020 21:12	Subtransmission	None	TRK 7909			EQUIPMENT FAILURE
6/9/2020 23:40	6/10/2020 5:10	Subtransmission	None	TRK 6842			EQUIPMENT FAILURE
9/2/2020 11:12	9/2/2020 16:13	Subtransmission	None	TRK 9303			EQUIPMENT FAILURE
10/5/2020 19:52	10/5/2020 21:49	Subtransmission	None	TRK 4351			EQUIPMENT FAILURE
10/21/2020 3:21	10/21/2020 11:08	Subtransmission	None	TRK 2313			EQUIPMENT FAILURE
10/21/2020 7:01	10/21/2020 11:08	Subtransmission	None	TRK 2313			EQUIPMENT FAILURE
11/13/2020 14:20	11/14/2020 16:53	Subtransmission	None	TIE 3800			EQUIPMENT FAILURE
11/17/2020 15:19	11/18/2020 15:58	Subtransmission	None	TRK 3511			EQUIPMENT FAILURE
11/26/2020 15:54	11/26/2020 16:45	Subtransmission	Distribution	TIE 6621	704	36323	EQUIPMENT FAILURE
11/26/2020 15:55	11/26/2020 16:45	Subtransmission	Distribution	TIE 6621	1202	62147	EQUIPMENT FAILURE
11/28/2020 12:43	11/29/2020 18:33	Subtransmission	None	TRK 1232			EQUIPMENT FAILURE
11/28/2020 16:02	11/28/2020 17:40	Subtransmission	None	TRK 1232			EQUIPMENT FAILURE
1/22/2021 9:00	1/22/2021 16:48	Subtransmission	None	TRK 2301			EQUIPMENT FAILURE
5/3/2021 7:34	5/3/2021 11:06	Subtransmission	None	TIE 1318			EQUIPMENT FAILURE
5/3/2021 7:05	5/3/2021 12:25	Subtransmission	None	TIE 1318			EQUIPMENT FAILURE
5/30/2021 18:38	5/31/2021 5:37	Subtransmission	None	TIE 7430			EQUIPMENT FAILURE
6/9/2021 5:06	6/10/2021 14:05	Subtransmission	None	TRK 5145			EQUIPMENT FAILURE
8/19/2021 6:20	8/19/2021 21:31	Subtransmission	None	TRK 2922			EQUIPMENT FAILURE
9/30/2021 16:31	9/30/2021 17:32	Subtransmission	None	TIE 1531			EQUIPMENT FAILURE
11/9/2021 16:33	11/10/2021 6:01	Subtransmission	None	TIE 2819			EQUIPMENT FAILURE
11/30/2021 8:32	11/30/2021 11:56	Subtransmission	None	TIE 6931			EQUIPMENT FAILURE
1/11/2022 9:12	1/11/2022 12:52	Subtransmission	None	TRK 4419			EQUIPMENT FAILURE
4/4/2022 10:53	4/4/2022 20:29	Subtransmission	None	TRK 3536			EQUIPMENT FAILURE
4/25/2022 14:27	4/25/2022 16:56	Subtransmission	None	TRK 3650			EQUIPMENT FAILURE
9/11/2022 18:40	9/13/2022 17:57	Subtransmission	None	TRK 2305			EQUIPMENT FAILURE
9/29/2022 11:18	9/29/2022 18:28	Subtransmission	None	TIE 8014			EQUIPMENT FAILURE
3/4/2023 2:52	3/6/2023 12:20	Subtransmission		TRK 1303			EQUIPMENT FAILURE
6/16/2023 17:12	6/18/2023 8:50	Subtransmission		TRK 2907			EQUIPMENT FAILURE
6/24/2023 20:39	7/2/2023 23:58	Subtransmission		TRK 1303			EQUIPMENT FAILURE
8/29/2023 19:09	2/8/2024 22:40	Subtransmission		TIE 1318			EQUIPMENT FAILURE
11/7/2023 13:09	11/7/2023 21:01	Subtransmission		TRK 6842			EQUIPMENT FAILURE
2/11/2022 9:13	2/11/2022 9:40	Subtransmission	Distribution	TIE 7430	213	5318	INTENTIONAL
8/29/2021 20:54	8/30/2021 13:54	Subtransmission	None	TIE 4501			LIGHTNING
8/29/2021 19:45	8/29/2021 21:05	Subtransmission	Distribution	TIE 4501	346	26873	LIGHTNING
8/13/2018 18:47	8/14/2018 6:01	Subtransmission	None	TIE 3417			TREE
8/13/2018 18:42	8/14/2018 11:49	Subtransmission	None	TIE 3417			TREE
5/26/2019 15:13	5/27/2019 12:53	Subtransmission	None	TIE 3203			TREE
6/20/2020 17:55	6/20/2020 19:14	Subtransmission	None	TRK 2523			TREE
6/20/2020 17:01	6/20/2020 21:35	Subtransmission	None	TRK 2523			TREE
8/2/2020 12:41	8/2/2020 20:31	Subtransmission	None	TIE 3208			TREE
4/10/2021 20:52	4/11/2021 0:45	Subtransmission	Distribution	TIE 8033	66	48782	TREE
4/10/2021 18:34	4/10/2021 20:47	Subtransmission	Distribution	TIE 8033	65	8010	TREE
12/1/2019 23:25	12/2/2019 13:54	Subtransmission	None	TRK 4301			ANIMAL
12/1/2019 13:31	12/1/2019 16:54	Subtransmission	None	TRK 4301			ANIMAL
12/2/2019 17:19	12/2/2019 22:46	Subtransmission	None	TRK 4301			ANIMAL
3/11/2020 23:51	3/12/2020 5:45	Subtransmission	None	TIE 3318			ANIMAL
1/23/2018 8:01	1/23/2018 15:04	Subtransmission	None	TRK 2713			EQUIPMENT FAILURE
4/4/2018 17:34	4/5/2018 12:15	Subtransmission	None	TRK 5938			EQUIPMENT FAILURE
4/5/2018 9:21	4/5/2018 10:30	Subtransmission	None	TIE 3208			EQUIPMENT FAILURE
4/5/2018 8:51	4/5/2018 10:30	Subtransmission	None	TIE 3208			EQUIPMENT FAILURE
4/5/2018 8:50	4/5/2018 10:32	Subtransmission	None	TIE 3208			EQUIPMENT FAILURE
6/7/2018 22:28	6/7/2018 22:44	Subtransmission	Distribution	TIE 9123	409	6507	EQUIPMENT FAILURE
6/7/2018 20:12	6/8/2018 6:57	Subtransmission	None	TIE 9123			EQUIPMENT FAILURE
6/8/2018 14:39	6/8/2018 17:30	Subtransmission	Distribution	TIE 7520	414	70454	EQUIPMENT FAILURE
6/8/2018 14:39	6/8/2018 15:34	Subtransmission	Distribution	TIE 7520	171	9344	EQUIPMENT FAILURE
6/8/2018 14:39	6/8/2018 15:34	Subtransmission	Distribution	TIE 7520	364	20030	EQUIPMENT FAILURE
6/8/2018 14:44	6/8/2018 21:07	Subtransmission	None	TIE 7520			EQUIPMENT FAILURE

7/12/2018 17:01	7/17/2018 19:26	Subtransmission	None	TIE 5513			EQUIPMENT FAILURE
8/27/2018 8:50	8/28/2018 14:01	Subtransmission	None	TIE 7504			EQUIPMENT FAILURE
10/14/2018 12:43	10/15/2018 14:17	Subtransmission	None	TRK 2002			EQUIPMENT FAILURE
10/30/2018 11:36	10/31/2018 16:47	Subtransmission	None	TIE 7733			EQUIPMENT FAILURE
11/26/2018 8:42	11/26/2018 11:11	Subtransmission	None	TRK 2439			EQUIPMENT FAILURE
12/15/2018 10:51	12/15/2018 19:02	Subtransmission	None	TRK 1303			EQUIPMENT FAILURE
12/27/2018 11:25	12/27/2018 13:39	Subtransmission	None	TIE 9123			EQUIPMENT FAILURE
1/14/2019 12:42	1/15/2019 10:57	Subtransmission	None	TIE 4501			EQUIPMENT FAILURE
1/23/2019 9:35	1/23/2019 16:58	Subtransmission	None	TIE 4104			EQUIPMENT FAILURE
1/23/2019 10:25	1/23/2019 17:10	Subtransmission	None	TIE 4104			EQUIPMENT FAILURE
2/2/2019 3:53	2/2/2019 4:48	Subtransmission	Distribution	TIE 4104	1054	61323	EQUIPMENT FAILURE
2/2/2019 1:36	2/2/2019 20:30	Subtransmission	None	TIE 4104			EQUIPMENT FAILURE
2/22/2019 7:51	2/22/2019 10:49	Subtransmission	None	TIE 6147			EQUIPMENT FAILURE
5/15/2019 16:59	5/16/2019 20:05	Subtransmission	None	TIE 810			EQUIPMENT FAILURE
5/25/2019 13:23	5/25/2019 19:47	Subtransmission	None	TRK 3546			EQUIPMENT FAILURE
7/4/2019 8:16	7/4/2019 15:17	Subtransmission	None	TRK 9107			EQUIPMENT FAILURE
9/4/2019 15:52	9/4/2019 19:59	Subtransmission	None	TRK 830			EQUIPMENT FAILURE
9/5/2019 15:13	9/5/2019 15:24	Subtransmission	None	TRK 830			EQUIPMENT FAILURE
9/6/2019 10:56	9/6/2019 13:57	Subtransmission	None	TRK 830			EQUIPMENT FAILURE
9/12/2019 9:38	9/12/2019 12:30	Subtransmission	None	TRK 6172			EQUIPMENT FAILURE
9/21/2019 18:57	9/22/2019 16:08	Subtransmission	None	TRK 3646			EQUIPMENT FAILURE
9/28/2019 8:54	9/28/2019 14:23	Subtransmission	None	TIE 4412			EQUIPMENT FAILURE
9/29/2019 8:13	10/30/2019 10:51	Subtransmission	None	TRK 4301			EQUIPMENT FAILURE
12/8/2019 13:31	12/8/2019 16:20	Subtransmission	Distribution	TIE 9111	514	81858	EQUIPMENT FAILURE
12/8/2019 13:45	12/8/2019 21:17	Subtransmission	None	TIE 9111			EQUIPMENT FAILURE
1/18/2020 13:34	1/18/2020 15:43	Subtransmission	None	TRK 1248			EQUIPMENT FAILURE
1/20/2020 12:27	1/20/2020 19:59	Subtransmission	None	TRK 1248			EQUIPMENT FAILURE
1/27/2020 9:57	1/27/2020 12:05	Subtransmission	None	TRK 2308			EQUIPMENT FAILURE
2/25/2020 4:44	2/25/2020 7:43	Subtransmission	None	TRK 1303			EQUIPMENT FAILURE
2/25/2020 4:09	2/25/2020 20:12	Subtransmission	None	TRK 1303			EQUIPMENT FAILURE
4/15/2020 12:22	4/15/2020 13:30	Subtransmission	None	TRK 1243			EQUIPMENT FAILURE
5/21/2020 21:54	5/22/2020 5:03	Subtransmission	None	TRK 5817			EQUIPMENT FAILURE
7/9/2020 19:32	7/9/2020 21:00	Subtransmission	Distribution	TIE 8033	64	20827	EQUIPMENT FAILURE
7/9/2020 19:47	7/10/2020 14:49	Subtransmission	None	TIE 8033			EQUIPMENT FAILURE
7/10/2020 2:04	7/10/2020 2:20	Subtransmission	Distribution	TIE 8033	340	6653	EQUIPMENT FAILURE
7/10/2020 3:52	7/10/2020 16:00	Subtransmission	Distribution	TIE 8033			EQUIPMENT FAILURE
7/10/2020 2:21	7/10/2020 8:36	Subtransmission	None	TIE 8033			EQUIPMENT FAILURE
7/10/2020 2:55	7/10/2020 5:41	Subtransmission	None	TIE 8033			EQUIPMENT FAILURE
8/27/2020 14:44	8/27/2020 20:43	Subtransmission	None	TIE 4109			EQUIPMENT FAILURE
2/3/2021 15:31	2/3/2021 18:30	Subtransmission	None	TIE 6117			EQUIPMENT FAILURE
2/15/2021 10:46	2/15/2021 11:47	Subtransmission	None	TIE 1473			EQUIPMENT FAILURE
2/15/2021 10:42	2/15/2021 11:47	Subtransmission	None	TIE 1473			EQUIPMENT FAILURE
3/11/2021 12:42	3/11/2021 19:36	Subtransmission	None	TRK 4301			EQUIPMENT FAILURE
3/11/2021 11:15	3/11/2021 12:31	Subtransmission	Distribution	TRK 7729	793	22309	EQUIPMENT FAILURE
3/11/2021 11:31	3/11/2021 16:36	Subtransmission	None	TRK 7729			EQUIPMENT FAILURE
3/29/2021 16:22	3/29/2021 21:01	Subtransmission	None	TIE 3402			EQUIPMENT FAILURE
4/4/2021 18:03	4/4/2021 23:17	Subtransmission	None	TRK 4301			EQUIPMENT FAILURE
4/4/2021 18:15	4/5/2021 5:46	Subtransmission	None	TRK 4301			EQUIPMENT FAILURE
4/21/2021 16:07	4/21/2021 18:15	Subtransmission	None	TIE 3205			EQUIPMENT FAILURE
4/27/2021 10:10	4/27/2021 15:16	Subtransmission	None	TIE 4109			EQUIPMENT FAILURE
5/2/2021 6:56	5/2/2021 14:49	Subtransmission	None	TRK 3208			EQUIPMENT FAILURE
6/8/2021 16:38	6/10/2021 18:17	Subtransmission	None	TRK 5140			EQUIPMENT FAILURE
6/11/2021 13:36	6/12/2021 14:30	Subtransmission	None	TIE 3205			EQUIPMENT FAILURE
6/12/2021 7:29	6/12/2021 14:30	Subtransmission	None	TIE 3205			EQUIPMENT FAILURE
6/14/2021 8:44	6/14/2021 15:23	Subtransmission	None	TRK 7106			EQUIPMENT FAILURE
7/15/2021 8:29	7/15/2021 21:51	Subtransmission	None	TRK 2659			EQUIPMENT FAILURE
7/20/2021 17:52	7/20/2021 22:47	Subtransmission	None	TIE 3417			EQUIPMENT FAILURE
7/30/2021 12:48	7/30/2021 17:48	Subtransmission	None	TRK 2032			EQUIPMENT FAILURE
8/25/2021 12:56	8/27/2021 17:48	Subtransmission	None	TIE 6907			EQUIPMENT FAILURE
9/15/2021 18:44	9/16/2021 11:49	Subtransmission	None	TRK 2032			EQUIPMENT FAILURE
11/1/2021 13:52	11/1/2021 17:28	Subtransmission	None	TRK 2826			EQUIPMENT FAILURE
11/5/2021 1:15	11/5/2021 2:34	Subtransmission	Distribution	TRK 853	885	70006	EQUIPMENT FAILURE
11/5/2021 1:20	11/10/2021 9:24	Subtransmission	None	TRK 853			EQUIPMENT FAILURE
11/5/2021 1:15	11/5/2021 2:34	Subtransmission	Distribution	TRK 853	611	48324	EQUIPMENT FAILURE
3/28/2022 11:32	3/28/2022 18:06	Subtransmission	None	TRK 2016			EQUIPMENT FAILURE
4/23/2022 7:12	4/23/2022 16:52	Subtransmission	None	TRK 2054			EQUIPMENT FAILURE
6/16/2022 11:22	6/18/2022 7:48	Subtransmission	None	TIE 2812			EQUIPMENT FAILURE
7/3/2022 17:08	7/3/2022 19:39	Subtransmission	None	TRK 4301			EQUIPMENT FAILURE
8/30/2022 9:37	8/30/2022 21:16	Subtransmission	None	TRK 6508			EQUIPMENT FAILURE
9/11/2022 9:09	9/11/2022 16:57	Subtransmission	None	TIE 3323			EQUIPMENT FAILURE
9/12/2022 12:40	9/12/2022 13:10	Subtransmission	Distribution	TRK 1229	1	75	EQUIPMENT FAILURE
9/12/2022 12:43	9/12/2022 13:14	Subtransmission	Distribution	TRK 1229	2	148	EQUIPMENT FAILURE
9/12/2022 14:09	9/12/2022 17:09	Subtransmission	None	TRK 1229			EQUIPMENT FAILURE
9/12/2022 4:18	9/12/2022 16:51	Subtransmission	None	TRK 1229			EQUIPMENT FAILURE
2/10/2023 12:21	2/13/2023 12:55	Subtransmission		TRK 6941			EQUIPMENT FAILURE
3/16/2023 10:49	3/16/2023 17:20	Subtransmission		TIE 6602			EQUIPMENT FAILURE
4/7/2023 7:32	4/8/2023 0:38	Subtransmission		TIE 2812			EQUIPMENT FAILURE
5/31/2023 6:58	6/16/2023 9:23	Subtransmission		TIE 9310			EQUIPMENT FAILURE
6/15/2023 9:15	6/15/2023 14:12	Subtransmission		TIE 3208			EQUIPMENT FAILURE
6/16/2023 9:13	7/10/2023 22:35	Subtransmission		TIE 9310			EQUIPMENT FAILURE
6/20/2023 10:54	8/29/2023 11:35	Subtransmission		TIE 3208			EQUIPMENT FAILURE
6/20/2023 8:28	6/20/2023 10:56	Subtransmission		TIE 3208			EQUIPMENT FAILURE
7/23/2023 23:16	7/24/2023 3:19	Subtransmission	Subtransmission	TIE 810	2245	4660368	EQUIPMENT FAILURE
7/23/2023 21:45	7/24/2023 7:09	Subtransmission		TIE 810			EQUIPMENT FAILURE
7/26/2023 17:10	7/28/2023 16:35	Subtransmission	Subtransmission	TRK 2918	15	43032	EQUIPMENT FAILURE
8/24/2023 23:08	8/26/2023 12:43	Subtransmission		TIE 2025			EQUIPMENT FAILURE
9/1/2023 14:05	9/9/2023 9:43	Subtransmission		TIE 6907			EQUIPMENT FAILURE
9/17/2023 16:15	9/18/2023 18:04	Subtransmission		TIE 2812			EQUIPMENT FAILURE
5/20/2020 9:01	5/20/2020 9:09	Subtransmission	Distribution	TRK 2806	481	4954	INTENTIONAL
8/24/2023 19:21	8/26/2023 12:20	Subtransmission		TIE 6602			LIGHTNING
8/21/2022 14:14	8/21/2022 21:41	Subtransmission	None	TRK 6508			TREE
7/26/2023 19:39	7/29/2023 4:22	Subtransmission		TRK 2918			WIND
11/4/2023 18:54	1/10/2024 14:08	Subtransmission		TRK 2519			EQUIPMENT FAILURE
11/4/2023 18:26	11/4/2023 18:56	Subtransmission		TRK 2519			EQUIPMENT FAILURE
4/5/2018 7:54	4/5/2018 23:07	Subtransmission	None	TIE 3502			TREE
2/18/2020 19:50	2/18/2020 21:34	Subtransmission	None	TRK 2301			ANIMAL
6/23/2018 1:50	6/23/2018 5:30	Subtransmission	Distribution	TIE 4507	1096	36493	EQUIPMENT FAILURE
4/5/2019 8:57	4/5/2019 11:30	Subtransmission	None	TRK 7078			ANIMAL
4/16/2019 14:56	4/16/2019 20:48	Subtransmission	None	TRK 6125			ANIMAL
6/1/2019 9:44	6/1/2019 14:42	Subtransmission	None	TIE 6931			ANIMAL
6/1/2019 12:02	6/1/2019 12:22	Subtransmission	Distribution	TIE 6931	1272	28851	ANIMAL
6/29/2019 19:22	6/30/2019 13:46	Subtransmission	None	TIE 1423			ANIMAL
3/16/2020 15:34	3/16/2020 20:13	Subtransmission	None	TIE 2812			ANIMAL
3/16/2020 12:18	3/16/2020 13:02	Subtransmission	None	TIE 2812			ANIMAL
3/29/2021 22:49	3/30/2021 0:00	Subtransmission	Distribution	TIE 226	1398	144595	ANIMAL

3/29/2021 15:41	3/30/2021 3:19	Subtransmission	None	TIE 226			ANIMAL
3/29/2021 22:50	3/30/2021 0:30	Subtransmission	Distribution	TIE 226	1325	138094	ANIMAL
5/3/2021 7:32	5/3/2021 11:40	Subtransmission	None	TIE 3220			ANIMAL
5/3/2021 7:08	5/3/2021 11:24	Subtransmission	None	TIE 3220			ANIMAL
12/11/2021 10:27	12/11/2021 20:00	Subtransmission	Distribution	TRK 5239	757	171614	ANIMAL
5/16/2023 6:27	5/16/2023 13:24	Subtransmission	Circuit Level	TRK 3536	366	69094	ANIMAL
5/16/2023 6:28	5/16/2023 13:16	Subtransmission	Circuit Level	TRK 3536	520	98167	ANIMAL
5/16/2023 6:27	5/16/2023 13:21	Subtransmission	Circuit Level	TRK 3536			ANIMAL
5/16/2023 6:55	5/16/2023 13:11	Subtransmission	Circuit Level	TRK 3536	1	5	ANIMAL
5/16/2023 6:28	5/16/2023 13:13	Subtransmission	Circuit Level	TRK 3536	939	177279	ANIMAL
5/16/2023 6:27	5/16/2023 13:23	Subtransmission	Circuit Level	TRK 3536			ANIMAL
5/16/2023 6:29	5/16/2023 13:09	Subtransmission	Device (I)	TRK 3536	476	89859	ANIMAL
1/15/2018 17:22	1/16/2018 0:24	Subtransmission	None	TIE 185			EQUIPMENT FAILURE
1/16/2018 13:46	1/16/2018 20:37	Subtransmission	None	TIE 185			EQUIPMENT FAILURE
1/16/2018 10:17	1/16/2018 19:01	Subtransmission	None	TIE 3416			EQUIPMENT FAILURE
1/21/2018 9:05	1/21/2018 15:59	Subtransmission	None	TRK 2027			EQUIPMENT FAILURE
1/22/2018 20:27	1/22/2018 21:54	Subtransmission	Distribution	TIE 9205	1163	98996	EQUIPMENT FAILURE
1/22/2018 20:27	1/22/2018 21:54	Subtransmission	Distribution	TIE 9205	135	11497	EQUIPMENT FAILURE
1/22/2018 20:27	1/22/2018 21:54	Subtransmission	Distribution	TIE 9205	416	35576	EQUIPMENT FAILURE
1/22/2018 20:27	1/22/2018 21:54	Subtransmission	Distribution	TIE 9205	202	17248	EQUIPMENT FAILURE
1/22/2018 20:36	1/22/2018 22:11	Subtransmission	None	TIE 9205			EQUIPMENT FAILURE
1/23/2018 17:49	1/23/2018 22:00	Subtransmission	Distribution	TRK 5510	971	165766	EQUIPMENT FAILURE
1/25/2018 11:17	2/7/2018 7:20	Subtransmission	None	TIE 1423			EQUIPMENT FAILURE
2/1/2018 12:46	2/1/2018 16:15	Subtransmission	None	TRK 2931			EQUIPMENT FAILURE
2/1/2018 12:46	2/1/2018 16:15	Subtransmission	None	TRK 2931			EQUIPMENT FAILURE
2/1/2018 13:36	2/1/2018 14:19	Subtransmission	Distribution	TRK 2931	689	33513	EQUIPMENT FAILURE
2/5/2018 20:38	2/6/2018 2:50	Subtransmission	Distribution	TIE 3416	125	46532	EQUIPMENT FAILURE
2/19/2018 17:52	2/20/2018 3:56	Subtransmission	None	TRK 2824			EQUIPMENT FAILURE
2/23/2018 15:41	2/23/2018 20:26	Subtransmission	None	TIE 4901			EQUIPMENT FAILURE
3/5/2018 23:50	3/6/2018 5:49	Subtransmission	None	TIE 810			EQUIPMENT FAILURE
3/14/2018 12:31	3/14/2018 23:43	Subtransmission	None	TRK 2237			EQUIPMENT FAILURE
3/20/2018 18:30	3/21/2018 13:05	Subtransmission	None	TRK 2411			EQUIPMENT FAILURE
3/26/2018 13:47	3/26/2018 20:42	Subtransmission	None	TRK 2411			EQUIPMENT FAILURE
3/29/2018 11:37	3/29/2018 16:30	Subtransmission	None	TIE 226			EQUIPMENT FAILURE
3/30/2018 12:55	3/30/2018 14:19	Subtransmission	None	TIE 4412			EQUIPMENT FAILURE
4/2/2018 5:36	4/2/2018 8:11	Subtransmission	Distribution	TRK 1728	1052	191425	EQUIPMENT FAILURE
4/2/2018 8:19	4/2/2018 19:24	Subtransmission	None	TRK 1728			EQUIPMENT FAILURE
4/2/2018 5:36	4/2/2018 8:11	Subtransmission	Distribution	TRK 1728	448	77492	EQUIPMENT FAILURE
4/2/2018 5:37	4/2/2018 8:20	Subtransmission	Distribution	TRK 1728	26	5716	EQUIPMENT FAILURE
4/2/2018 5:36	4/2/2018 8:12	Subtransmission	Distribution	TRK 1728	672	141019	EQUIPMENT FAILURE
4/2/2018 5:53	4/2/2018 8:20	Subtransmission	Distribution	TRK 1728	28	5543	EQUIPMENT FAILURE
4/3/2018 19:40	4/3/2018 23:29	Subtransmission	None	TRK 448			EQUIPMENT FAILURE
4/3/2018 19:30	4/3/2018 20:24	Subtransmission	Subtransmission	TRK 448	847	45654	EQUIPMENT FAILURE
4/3/2018 22:14	4/5/2018 21:28	Subtransmission	None	TRK 448			EQUIPMENT FAILURE
4/3/2018 19:30	4/3/2018 20:24	Subtransmission	Subtransmission	TRK 448	947	50924	EQUIPMENT FAILURE
4/3/2018 19:30	4/3/2018 20:24	Subtransmission	Subtransmission	TRK 448	972	52956	EQUIPMENT FAILURE
4/6/2018 5:55	4/6/2018 7:30	Subtransmission	Subtransmission	TRK 3511	874	83585	EQUIPMENT FAILURE
4/6/2018 10:56	4/13/2018 17:20	Subtransmission	None	TRK 3511			EQUIPMENT FAILURE
4/6/2018 5:55	4/6/2018 7:30	Subtransmission	Subtransmission	TRK 3511	816	77216	EQUIPMENT FAILURE
4/7/2018 12:54	4/7/2018 21:47	Subtransmission	None	TRK 2250			EQUIPMENT FAILURE
4/9/2018 15:51	4/12/2018 14:36	Subtransmission	None	TRK 2250			EQUIPMENT FAILURE
4/11/2018 13:15	4/11/2018 23:21	Subtransmission	None	TRK 448			EQUIPMENT FAILURE
4/13/2018 19:47	4/14/2018 17:55	Subtransmission	Distribution	TIE 7504	951	1278675	EQUIPMENT FAILURE
4/13/2018 19:47	4/13/2018 20:51	Subtransmission	Distribution	TIE 7504	71	4419	EQUIPMENT FAILURE
4/13/2018 19:47	4/14/2018 17:55	Subtransmission	Distribution	TIE 7504	626	863591	EQUIPMENT FAILURE
4/13/2018 19:47	4/14/2018 6:27	Subtransmission	Distribution	TIE 7504	337	215371	EQUIPMENT FAILURE
4/13/2018 19:47	4/13/2018 20:51	Subtransmission	Distribution	TIE 7504	231	14414	EQUIPMENT FAILURE
4/15/2018 11:03	4/16/2018 18:14	Subtransmission	None	TRK 2032			EQUIPMENT FAILURE
4/15/2018 10:58	4/19/2018 12:58	Subtransmission	None	TRK 2032			EQUIPMENT FAILURE
4/20/2018 15:48	2/26/2019 14:33	Subtransmission	None	TRK 1423			EQUIPMENT FAILURE
4/27/2018 14:52	4/27/2018 20:28	Subtransmission	None	TIE 3705			EQUIPMENT FAILURE
5/4/2018 17:59	5/5/2018 19:56	Subtransmission	None	TIE 1473			EQUIPMENT FAILURE
5/4/2018 13:02	5/5/2018 5:21	Subtransmission	Subtransmission	TIE 1473	711	381726	EQUIPMENT FAILURE
5/4/2018 14:02	5/4/2018 21:15	Subtransmission	Distribution	TIE 1473			EQUIPMENT FAILURE
5/4/2018 10:30	5/6/2018 13:56	Subtransmission	None	TIE 1473			EQUIPMENT FAILURE
5/4/2018 13:32	5/5/2018 13:30	Subtransmission	Distribution	TIE 226	1820	2552858	EQUIPMENT FAILURE
5/8/2018 16:46	5/16/2018 7:59	Subtransmission	None	TIE 2648			EQUIPMENT FAILURE
5/8/2018 23:02	5/9/2018 6:56	Subtransmission	Distribution	TRK 2111	135	65491	EQUIPMENT FAILURE
5/8/2018 23:02	5/9/2018 6:35	Subtransmission	Distribution	TRK 2111	147	51656	EQUIPMENT FAILURE
5/8/2018 23:02	5/9/2018 6:54	Subtransmission	Distribution	TRK 2111	140	67390	EQUIPMENT FAILURE
5/9/2018 8:07	5/11/2018 0:46	Subtransmission	None	TRK 7411			EQUIPMENT FAILURE
5/21/2018 15:06	5/31/2018 14:36	Subtransmission	None	TIE 1423			EQUIPMENT FAILURE
5/23/2018 16:40	5/23/2018 21:03	Subtransmission	None	TIE 6138			EQUIPMENT FAILURE
5/23/2018 16:41	5/23/2018 21:03	Subtransmission	None	TIE 6138			EQUIPMENT FAILURE
5/25/2018 16:44	5/25/2018 22:21	Subtransmission	None	TRK 359			EQUIPMENT FAILURE
5/27/2018 8:10	5/27/2018 18:19	Subtransmission	None	TRK 7122			EQUIPMENT FAILURE
6/1/2018 9:21	6/1/2018 20:10	Subtransmission	Distribution	TIE 1473	1	167	EQUIPMENT FAILURE
6/1/2018 9:37	6/1/2018 17:14	Subtransmission	None	TIE 1473			EQUIPMENT FAILURE
6/1/2018 9:06	6/1/2018 20:19	Subtransmission	None	TIE 1473			EQUIPMENT FAILURE
6/1/2018 8:57	6/1/2018 17:05	Subtransmission	Distribution	TIE 1473	588	230357	EQUIPMENT FAILURE
6/1/2018 9:29	6/1/2018 14:34	Subtransmission	None	TIE 1473			EQUIPMENT FAILURE
6/1/2018 9:27	6/1/2018 11:00	Subtransmission	Distribution	TIE 1473			EQUIPMENT FAILURE
6/1/2018 9:24	6/1/2018 14:43	Subtransmission	None	TIE 1473			EQUIPMENT FAILURE
6/1/2018 9:35	6/1/2018 14:34	Subtransmission	None	TIE 1473			EQUIPMENT FAILURE
6/1/2018 0:18	6/1/2018 17:15	Subtransmission	Distribution	TIE 1473	626	318509	EQUIPMENT FAILURE
6/1/2018 9:23	6/1/2018 14:33	Subtransmission	None	TIE 1473			EQUIPMENT FAILURE
6/1/2018 9:37	6/1/2018 14:41	Subtransmission	None	TIE 1473			EQUIPMENT FAILURE
6/1/2018 9:27	6/1/2018 14:35	Subtransmission	None	TIE 1473			EQUIPMENT FAILURE
6/14/2018 19:07	6/14/2018 23:44	Subtransmission	None	TRK 2907			EQUIPMENT FAILURE
6/15/2018 14:17	6/15/2018 14:57	Subtransmission	None	TRK 829			EQUIPMENT FAILURE
6/18/2018 16:58	6/19/2018 17:31	Subtransmission	None	TRK 385			EQUIPMENT FAILURE
6/18/2018 7:19	6/18/2018 10:47	Subtransmission	None	TRK 385			EQUIPMENT FAILURE
6/20/2018 17:38	6/21/2018 15:18	Subtransmission	None	TIE 5513			EQUIPMENT FAILURE
7/5/2018 11:16	7/6/2018 3:55	Subtransmission	None	TRK 7130			EQUIPMENT FAILURE
7/5/2018 11:27	7/5/2018 19:23	Subtransmission	None	TRK 7130			EQUIPMENT FAILURE
7/14/2018 7:01	7/15/2018 11:46	Subtransmission	None	TIE 1531			EQUIPMENT FAILURE
7/14/2018 4:12	7/14/2018 5:10	Subtransmission	None	TIE 1531			EQUIPMENT FAILURE
7/27/2018 14:36	8/2/2018 7:31	Subtransmission	None	TIE 4523			EQUIPMENT FAILURE
8/21/2018 2:38	8/21/2018 5:50	Subtransmission	Distribution	TIE 6907	368	78634	EQUIPMENT FAILURE
8/27/2018 20:50	8/28/2018 4:46	Subtransmission	None	TIE 3203			EQUIPMENT FAILURE
8/27/2018 19:03	8/27/2018 20:39	Subtransmission	None	TIE 3203			EQUIPMENT FAILURE
8/30/2018 22:50	8/30/2018 23:07	Subtransmission	Distribution	TIE 7504	135	2202	EQUIPMENT FAILURE
8/30/2018 2:17	8/30/2018 5:29	Subtransmission	None	TRK 4911			EQUIPMENT FAILURE
9/3/2018 12:08	9/4/2018 3:42	Subtransmission	None	TIE 4708			EQUIPMENT FAILURE
9/3/2018 15:16	9/4/2018 1:15	Subtransmission	Distribution	TIE 4708	314	222026	EQUIPMENT FAILURE

9/3/2018 20:58	9/4/2018 20:31	Subtransmission	None	TIE 6907			EQUIPMENT FAILURE
9/13/2018 8:02	9/13/2018 8:45	Subtransmission	Distribution	TIE 4501	357	15407	EQUIPMENT FAILURE
9/25/2018 8:37	9/25/2018 13:10	Subtransmission	Distribution	TIE 3203	978	277388	EQUIPMENT FAILURE
9/25/2018 8:49	9/25/2018 14:15	Subtransmission	None	TIE 3203			EQUIPMENT FAILURE
9/26/2018 15:36	11/12/2018 16:16	Subtransmission	None	TRK 7389			EQUIPMENT FAILURE
9/27/2018 6:48	9/27/2018 20:57	Subtransmission	None	TRK 2455			EQUIPMENT FAILURE
10/3/2018 16:37	10/18/2018 21:12	Subtransmission	None	TRK 2455			EQUIPMENT FAILURE
10/6/2018 8:21	10/6/2018 20:27	Subtransmission	None	TRK 2002			EQUIPMENT FAILURE
10/7/2018 3:05	10/7/2018 22:33	Subtransmission	None	TRK 1527			EQUIPMENT FAILURE
10/15/2018 6:57	10/15/2018 17:07	Subtransmission	None	TRK 4351			EQUIPMENT FAILURE
10/29/2018 16:41	10/29/2018 22:36	Subtransmission	None	TRK 724			EQUIPMENT FAILURE
10/31/2018 18:08	10/31/2018 21:27	Subtransmission	None	TIE 3432			EQUIPMENT FAILURE
11/8/2018 7:02	11/8/2018 8:19	Subtransmission	Distribution	TRK 662	165	12845	EQUIPMENT FAILURE
11/8/2018 7:02	11/8/2018 8:19	Subtransmission	Distribution	TRK 662	573	44644	EQUIPMENT FAILURE
11/8/2018 7:21	11/8/2018 8:19	Subtransmission	Distribution	TRK 662	13	1002	EQUIPMENT FAILURE
11/8/2018 7:02	11/8/2018 8:19	Subtransmission	Distribution	TRK 662	1153	92831	EQUIPMENT FAILURE
11/9/2018 20:47	11/9/2018 22:49	Subtransmission	None	TRK 5938			EQUIPMENT FAILURE
11/14/2018 9:07	11/14/2018 10:08	Subtransmission	Distribution	TIE 7430	2	12	EQUIPMENT FAILURE
11/14/2018 9:07	11/14/2018 18:00	Subtransmission	Distribution	TIE 7430	878	354270	EQUIPMENT FAILURE
12/16/2018 12:59	12/16/2018 18:21	Subtransmission	None	TRK 3526			EQUIPMENT FAILURE
1/16/2019 8:38	1/16/2019 10:54	Subtransmission	None	TIE 7745			EQUIPMENT FAILURE
1/16/2019 7:26	1/16/2019 9:14	Subtransmission	None	TRK 1232			EQUIPMENT FAILURE
1/16/2019 7:18	1/16/2019 8:37	Subtransmission	Distribution	TRK 1232	1232	136668	EQUIPMENT FAILURE
1/17/2019 12:15	1/17/2019 12:46	Subtransmission	Distribution	TRK 445	82	2651	EQUIPMENT FAILURE
1/17/2019 12:14	1/17/2019 12:46	Subtransmission	Distribution	TRK 445	1165	37667	EQUIPMENT FAILURE
1/17/2019 12:15	1/17/2019 12:46	Subtransmission	Distribution	TRK 445	2230	72130	EQUIPMENT FAILURE
1/21/2019 23:57	1/22/2019 2:14	Subtransmission	None	TIE 7745			EQUIPMENT FAILURE
1/22/2019 0:37	1/22/2019 19:28	Subtransmission	None	TIE 7745			EQUIPMENT FAILURE
1/23/2019 16:18	1/23/2019 21:28	Subtransmission	None	TRK 4911			EQUIPMENT FAILURE
1/23/2019 16:23	1/23/2019 18:53	Subtransmission	None	TRK 4911			EQUIPMENT FAILURE
2/1/2019 15:46	2/1/2019 22:46	Subtransmission	None	TRK 2218			EQUIPMENT FAILURE
2/1/2019 13:24	2/1/2019 15:56	Subtransmission	None	TRK 2218			EQUIPMENT FAILURE
2/1/2019 10:55	2/1/2019 17:57	Subtransmission	None	TRK 2218			EQUIPMENT FAILURE
2/3/2019 9:51	2/3/2019 12:59	Subtransmission	None	TRK 1303			EQUIPMENT FAILURE
2/3/2019 9:42	2/3/2019 13:11	Subtransmission	Distribution	TRK 1303	1949	307102	EQUIPMENT FAILURE
2/3/2019 9:41	2/3/2019 12:29	Subtransmission	Subtransmission	TRK 1303	173	28930	EQUIPMENT FAILURE
2/3/2019 9:42	2/3/2019 13:11	Subtransmission	Distribution	TRK 1303	840	93219	EQUIPMENT FAILURE
2/3/2019 9:41	2/3/2019 13:11	Subtransmission	Distribution	TRK 1303	717	94937	EQUIPMENT FAILURE
2/8/2019 12:21	2/8/2019 14:40	Subtransmission	None	TIE 3205			EQUIPMENT FAILURE
2/8/2019 4:33	2/8/2019 15:02	Subtransmission	None	TIE 3205			EQUIPMENT FAILURE
2/12/2019 8:51	2/13/2019 12:48	Subtransmission	None	TRK 446			EQUIPMENT FAILURE
2/12/2019 9:02	2/12/2019 12:05	Subtransmission	None	TRK 446			EQUIPMENT FAILURE
2/14/2019 4:40	2/18/2019 17:13	Subtransmission	None	TIE 1531			EQUIPMENT FAILURE
2/14/2019 0:33	2/14/2019 2:45	Subtransmission	None	TIE 1531			EQUIPMENT FAILURE
2/15/2019 15:00	2/15/2019 19:30	Subtransmission	Distribution	TIE 4104	1141	307784	EQUIPMENT FAILURE
2/16/2019 7:56	2/16/2019 14:28	Subtransmission	None	TRK 3534			EQUIPMENT FAILURE
2/23/2019 5:01	2/23/2019 14:50	Subtransmission	None	TRK 2247			EQUIPMENT FAILURE
2/24/2019 19:14	2/26/2019 14:14	Subtransmission	None	TIE 3245			EQUIPMENT FAILURE
2/24/2019 19:41	2/26/2019 14:14	Subtransmission	None	TIE 3245			EQUIPMENT FAILURE
2/24/2019 18:54	2/24/2019 20:53	Subtransmission	Distribution	TIE 3245	274	32516	EQUIPMENT FAILURE
2/25/2019 6:57	2/27/2019 17:27	Subtransmission	None	TIE 9111			EQUIPMENT FAILURE
2/25/2019 14:06	2/25/2019 16:19	Subtransmission	None	TRK 7104			EQUIPMENT FAILURE
3/9/2019 18:17	3/9/2019 22:49	Subtransmission	None	TIE 6138			EQUIPMENT FAILURE
3/9/2019 17:54	3/9/2019 19:07	Subtransmission	Distribution	TIE 6138	283	32737	EQUIPMENT FAILURE
3/9/2019 17:56	3/9/2019 19:00	Subtransmission	Subtransmission	TIE 6138	1585	89676	EQUIPMENT FAILURE
3/9/2019 17:56	3/9/2019 19:00	Subtransmission	Subtransmission	TIE 6138	1179	64156	EQUIPMENT FAILURE
3/9/2019 17:55	3/9/2019 19:07	Subtransmission	Subtransmission	TIE 6138	1561	288504	EQUIPMENT FAILURE
3/9/2019 17:54	3/9/2019 19:09	Subtransmission	Subtransmission	TIE 6138	2519	158514	EQUIPMENT FAILURE
3/10/2019 17:07	3/10/2019 21:27	Subtransmission	None	TIE 7430			EQUIPMENT FAILURE
3/11/2019 18:14	3/11/2019 22:41	Subtransmission	None	TIE 7430			EQUIPMENT FAILURE
3/11/2019 19:47	3/11/2019 22:48	Subtransmission	None	TIE 7430			EQUIPMENT FAILURE
3/11/2019 21:54	3/12/2019 16:39	Subtransmission	None	TIE 7430			EQUIPMENT FAILURE
3/20/2019 4:14	3/20/2019 16:15	Subtransmission	None	TIE 4104			EQUIPMENT FAILURE
3/23/2019 13:36	3/23/2019 21:03	Subtransmission	None	TRK 8215			EQUIPMENT FAILURE
3/31/2019 0:20	3/31/2019 20:24	Subtransmission	None	TIE 6602			EQUIPMENT FAILURE
3/31/2019 0:19	3/31/2019 1:41	Subtransmission	None	TIE 6602			EQUIPMENT FAILURE
4/6/2019 10:51	4/6/2019 11:58	Subtransmission	None	TIE 5513			EQUIPMENT FAILURE
4/6/2019 10:42	4/6/2019 11:36	Subtransmission	Substation	TIE 5513	578	28186	EQUIPMENT FAILURE
4/6/2019 11:12	4/6/2019 16:37	Subtransmission	None	TIE 5513			EQUIPMENT FAILURE
4/12/2019 13:49	4/12/2019 16:23	Subtransmission	Distribution	TIE 586	641	87998	EQUIPMENT FAILURE
4/19/2019 9:39	4/19/2019 12:22	Subtransmission	Distribution	TRK 2611	517	84548	EQUIPMENT FAILURE
4/19/2019 9:39	4/19/2019 12:22	Subtransmission	Distribution	TRK 2611	792	129297	EQUIPMENT FAILURE
4/19/2019 9:39	4/19/2019 12:22	Subtransmission	Distribution	TRK 2636	404	78924	EQUIPMENT FAILURE
4/19/2019 17:40	4/19/2019 18:30	Subtransmission	Distribution	TRK 2636	1199	34161	EQUIPMENT FAILURE
4/26/2019 16:19	4/26/2019 20:18	Subtransmission	None	TRK 4419			EQUIPMENT FAILURE
4/27/2019 6:59	4/28/2019 5:10	Subtransmission	None	TRK 4419			EQUIPMENT FAILURE
4/28/2019 11:56	4/28/2019 17:08	Subtransmission	None	TIE 1544			EQUIPMENT FAILURE
4/28/2019 13:38	4/30/2019 18:43	Subtransmission	None	TRK 4419			EQUIPMENT FAILURE
5/13/2019 17:30	5/13/2019 21:15	Subtransmission	None	TRK 1403			EQUIPMENT FAILURE
5/13/2019 6:53	5/20/2019 14:14	Subtransmission	None	TRK 1403			EQUIPMENT FAILURE
5/19/2019 7:08	5/19/2019 17:34	Subtransmission	None	TRK 1403			EQUIPMENT FAILURE
5/21/2019 10:10	5/21/2019 13:57	Subtransmission	None	TRK 7106			EQUIPMENT FAILURE
5/22/2019 15:56	5/22/2019 21:21	Subtransmission	None	TRK 5838			EQUIPMENT FAILURE
5/22/2019 15:39	5/22/2019 17:40	Subtransmission	Distribution	TRK 5838	704	85815	EQUIPMENT FAILURE
5/26/2019 9:43	5/26/2019 11:47	Subtransmission	Distribution	TRK 1602	766	82919	EQUIPMENT FAILURE
5/26/2019 9:43	5/26/2019 12:02	Subtransmission	Distribution	TRK 1602	76	10562	EQUIPMENT FAILURE
5/26/2019 9:43	5/26/2019 13:27	Subtransmission	Distribution	TRK 1602	165	36982	EQUIPMENT FAILURE
5/26/2019 19:15	5/26/2019 19:38	Subtransmission	Subtransmission	TRK 5838	706	17675	EQUIPMENT FAILURE
5/26/2019 19:15	5/26/2019 19:38	Subtransmission	Subtransmission	TRK 8538	323	8061	EQUIPMENT FAILURE
5/26/2019 19:14	5/26/2019 19:38	Subtransmission	Subtransmission	TRK 8538	526	13178	EQUIPMENT FAILURE
5/27/2019 10:54	5/27/2019 20:18	Subtransmission	None	TIE 1473			EQUIPMENT FAILURE
5/27/2019 11:07	5/27/2019 14:15	Subtransmission	Distribution	TIE 1473			EQUIPMENT FAILURE
5/27/2019 11:21	5/27/2019 19:03	Subtransmission	None	TIE 1473			EQUIPMENT FAILURE
5/27/2019 10:53	5/27/2019 15:51	Subtransmission	None	TIE 1473			EQUIPMENT FAILURE
5/29/2019 4:21	5/30/2019 22:34	Subtransmission	None	TRK 5404			EQUIPMENT FAILURE
5/30/2019 6:54	5/30/2019 13:44	Subtransmission	None	TIE 1473			EQUIPMENT FAILURE
5/31/2019 19:47	6/2/2019 8:51	Subtransmission	None	TRK 3650			EQUIPMENT FAILURE
6/1/2019 14:22	6/3/2019 3:45	Subtransmission	None	TRK 1251			EQUIPMENT FAILURE
6/2/2019 16:12	6/3/2019 3:45	Subtransmission	None	TRK 1251			EQUIPMENT FAILURE
6/2/2019 11:25	6/2/2019 13:16	Subtransmission	Substation	TRK 1251	633	73268	EQUIPMENT FAILURE
6/2/2019 7:50	6/2/2019 20:37	Subtransmission	None	TRK 3526			EQUIPMENT FAILURE
6/3/2019 11:42	6/3/2019 14:11	Subtransmission	None	TRK 1251			EQUIPMENT FAILURE
6/5/2019 7:08	6/5/2019 9:45	Subtransmission	Distribution	TIE 6621	925	124256	EQUIPMENT FAILURE
6/5/2019 7:24	6/5/2019 9:34	Subtransmission	None	TIE 6621			EQUIPMENT FAILURE
6/5/2019 10:19	6/5/2019 14:23	Subtransmission	None	TIE 6621			EQUIPMENT FAILURE

6/5/2019 17:36	6/5/2019 21:00	Subtransmission	Distribution	TRK 4301	355	46853	EQUIPMENT FAILURE
6/5/2019 7:24	6/5/2019 9:34	Subtransmission	None	TIE 6621			EQUIPMENT FAILURE
6/6/2019 18:21	6/6/2019 20:23	Subtransmission	None	TRK 2611			EQUIPMENT FAILURE
6/10/2019 8:43	6/10/2019 20:45	Subtransmission	None	TIE 7733			EQUIPMENT FAILURE
6/13/2019 19:45	6/13/2019 22:30	Subtransmission	Distribution	TIE 3220	1613	260969	EQUIPMENT FAILURE
6/13/2019 19:53	6/14/2019 11:05	Subtransmission	None	TIE 3220			EQUIPMENT FAILURE
6/17/2019 19:24	6/18/2019 1:48	Subtransmission	None	TIE 5829			EQUIPMENT FAILURE
6/17/2019 19:20	6/18/2019 3:58	Subtransmission	None	TIE 5829			EQUIPMENT FAILURE
6/28/2019 13:30	6/28/2019 19:01	Subtransmission	None	TIE 3646			EQUIPMENT FAILURE
6/28/2019 13:38	6/28/2019 19:43	Subtransmission	None	TRK 3646			EQUIPMENT FAILURE
6/28/2019 13:37	6/28/2019 19:43	Subtransmission	None	TRK 3646			EQUIPMENT FAILURE
7/1/2019 12:10	7/1/2019 14:20	Subtransmission	Distribution	TRK 1418	2	261	EQUIPMENT FAILURE
7/1/2019 6:48	7/2/2019 21:39	Subtransmission	None	TRK 5938			EQUIPMENT FAILURE
7/5/2019 17:41	7/6/2019 20:34	Subtransmission	None	TIE 3205			EQUIPMENT FAILURE
7/5/2019 15:08	7/5/2019 21:33	Subtransmission	Distribution	TRK 3662	237	90420	EQUIPMENT FAILURE
7/5/2019 15:08	7/5/2019 21:54	Subtransmission	Subtransmission	TRK 3662	1216	452984	EQUIPMENT FAILURE
7/5/2019 13:02	7/5/2019 22:35	Subtransmission	Subtransmission	TRK 3662	736	340701	EQUIPMENT FAILURE
7/5/2019 15:08	7/5/2019 21:45	Subtransmission	Distribution	TRK 3662	786	308405	EQUIPMENT FAILURE
7/6/2019 5:38	7/6/2019 15:00	Subtransmission	None	TIE 7745			EQUIPMENT FAILURE
7/9/2019 11:41	7/10/2019 18:22	Subtransmission	None	TRK 2107			EQUIPMENT FAILURE
7/11/2019 12:30	7/11/2019 16:02	Subtransmission	None	TRK 6125			EQUIPMENT FAILURE
7/11/2019 13:52	7/11/2019 14:30	Subtransmission	Distribution	TRK 6938	1797	59722	EQUIPMENT FAILURE
7/11/2019 13:52	7/11/2019 14:25	Subtransmission	Subtransmission	TRK 6938	2654	88473	EQUIPMENT FAILURE
7/11/2019 15:04	7/12/2019 6:14	Subtransmission	None	TRK 6938			EQUIPMENT FAILURE
7/20/2019 22:25	7/22/2019 20:01	Subtransmission	None	TIE 9303			EQUIPMENT FAILURE
7/20/2019 18:58	7/21/2019 14:03	Subtransmission	None	TIE 9303			EQUIPMENT FAILURE
7/20/2019 19:09	7/22/2019 20:01	Subtransmission	None	TIE 9303			EQUIPMENT FAILURE
7/21/2019 1:04	7/21/2019 19:49	Subtransmission	None	TIE 9205			EQUIPMENT FAILURE
7/21/2019 1:02	7/25/2019 15:15	Subtransmission	None	TIE 9205			EQUIPMENT FAILURE
7/21/2019 0:55	7/21/2019 13:29	Subtransmission	None	TRK 2439			EQUIPMENT FAILURE
7/21/2019 7:28	7/25/2019 16:23	Subtransmission	None	TRK 385			EQUIPMENT FAILURE
7/21/2019 18:46	7/22/2019 21:07	Subtransmission	None	TRK 7065			EQUIPMENT FAILURE
7/22/2019 5:09	7/23/2019 5:11	Subtransmission	None	TIE 9205			EQUIPMENT FAILURE
7/22/2019 1:15	7/22/2019 20:01	Subtransmission	None	TIE 9303			EQUIPMENT FAILURE
7/22/2019 1:13	7/23/2019 5:25	Subtransmission	None	TRK 385			EQUIPMENT FAILURE
7/22/2019 1:20	8/5/2019 10:24	Subtransmission	None	TRK 7065			EQUIPMENT FAILURE
7/23/2019 19:16	7/24/2019 16:30	Subtransmission	None	TRK 2247			EQUIPMENT FAILURE
7/23/2019 21:46	7/24/2019 16:27	Subtransmission	None	TRK 2247			EQUIPMENT FAILURE
7/24/2019 0:13	7/25/2019 17:22	Subtransmission	None	TRK 385			EQUIPMENT FAILURE
7/26/2019 7:51	7/26/2019 15:24	Subtransmission	None	TRK 2247			EQUIPMENT FAILURE
7/28/2019 15:16	7/28/2019 20:06	Subtransmission	None	TIE 1467			EQUIPMENT FAILURE
7/28/2019 12:58	7/28/2019 20:00	Subtransmission	Distribution	TIE 1467	169	26147	EQUIPMENT FAILURE
7/29/2019 15:03	7/30/2019 15:04	Subtransmission	Distribution	TIE 6147	1284	94358	EQUIPMENT FAILURE
7/29/2019 22:01	7/30/2019 18:00	Subtransmission	Distribution	TIE 6147	416	30797	EQUIPMENT FAILURE
7/30/2019 13:41	7/31/2019 4:40	Subtransmission	None	TRK 2205			EQUIPMENT FAILURE
7/30/2019 16:00	8/1/2019 5:48	Subtransmission	None	TRK 2247			EQUIPMENT FAILURE
8/1/2019 2:08	8/1/2019 18:43	Subtransmission	None	TIE 6602			EQUIPMENT FAILURE
8/5/2019 19:25	8/6/2019 5:40	Subtransmission	None	TRK 2118			EQUIPMENT FAILURE
8/12/2019 22:23	8/13/2019 14:51	Subtransmission	None	TIE 1540			EQUIPMENT FAILURE
8/12/2019 17:52	8/13/2019 4:40	Subtransmission	None	TIE 7745			EQUIPMENT FAILURE
8/12/2019 13:42	8/12/2019 16:15	Subtransmission	None	TRK 1555			EQUIPMENT FAILURE
8/20/2019 16:59	8/20/2019 21:27	Subtransmission	Distribution	TRK 7324	1320	353767	EQUIPMENT FAILURE
8/20/2019 16:16	8/20/2019 22:15	Subtransmission	Distribution	TRK 7324	1086	47490	EQUIPMENT FAILURE
8/20/2019 16:16	8/20/2019 17:00	Subtransmission	Distribution	TRK 7324	123	5341	EQUIPMENT FAILURE
8/20/2019 16:16	8/20/2019 17:00	Subtransmission	Distribution	TRK 7324	603	26194	EQUIPMENT FAILURE
8/20/2019 16:16	8/20/2019 17:00	Subtransmission	Distribution	TRK 7324	938	40931	EQUIPMENT FAILURE
8/20/2019 16:27	8/21/2019 14:42	Subtransmission	None	TRK 7324			EQUIPMENT FAILURE
8/21/2019 16:25	8/21/2019 18:50	Subtransmission	Distribution	TIE 3206	515	72806	EQUIPMENT FAILURE
8/21/2019 16:31	8/22/2019 20:31	Subtransmission	None	TIE 3206			EQUIPMENT FAILURE
8/21/2019 6:54	8/21/2019 14:42	Subtransmission	None	TRK 7324			EQUIPMENT FAILURE
8/23/2019 16:08	8/23/2019 23:55	Subtransmission	None	TRK 1110			EQUIPMENT FAILURE
9/1/2019 12:33	9/1/2019 20:00	Subtransmission	Distribution	TRK 5510	400	73623	EQUIPMENT FAILURE
9/2/2019 10:17	9/11/2019 0:02	Subtransmission	None	TRK 2038			EQUIPMENT FAILURE
9/2/2019 15:36	9/3/2019 6:51	Subtransmission	None	TRK 5510			EQUIPMENT FAILURE
9/4/2019 1:02	9/4/2019 11:36	Subtransmission	None	TRK 3511			EQUIPMENT FAILURE
9/9/2019 16:48	9/15/2019 13:23	Subtransmission	None	TRK 1403			EQUIPMENT FAILURE
9/9/2019 10:37	9/9/2019 17:21	Subtransmission	None	TRK 2032			EQUIPMENT FAILURE
9/10/2019 21:17	9/10/2019 22:45	Subtransmission	Subtransmission	TIE 4109	408	35771	EQUIPMENT FAILURE
9/10/2019 21:17	9/10/2019 22:45	Subtransmission	Subtransmission	TIE 4109	94	8169	EQUIPMENT FAILURE
9/10/2019 21:06	9/10/2019 22:22	Subtransmission	Subtransmission	TIE 4109	829	177241	EQUIPMENT FAILURE
9/11/2019 17:29	9/12/2019 17:04	Subtransmission	Distribution	TRK 2922	933	1211533	EQUIPMENT FAILURE
9/16/2019 7:51	9/17/2019 20:26	Subtransmission	None	TRK 346			EQUIPMENT FAILURE
9/16/2019 15:09	9/17/2019 20:25	Subtransmission	None	TRK 346			EQUIPMENT FAILURE
9/21/2019 16:41	9/21/2019 19:05	Subtransmission	None	TRK 2054			EQUIPMENT FAILURE
9/21/2019 16:39	9/21/2019 18:05	Subtransmission	None	TRK 2054			EQUIPMENT FAILURE
9/21/2019 16:47	9/21/2019 22:06	Subtransmission	None	TRK 2054			EQUIPMENT FAILURE
9/21/2019 16:50	9/21/2019 19:05	Subtransmission	None	TRK 2054			EQUIPMENT FAILURE
9/21/2019 16:45	9/21/2019 17:05	Subtransmission	None	TRK 2054			EQUIPMENT FAILURE
9/21/2019 16:45	9/22/2019 11:23	Subtransmission	None	TRK 2054			EQUIPMENT FAILURE
9/21/2019 16:51	9/21/2019 21:05	Subtransmission	None	TRK 2054			EQUIPMENT FAILURE
9/25/2019 13:42	9/25/2019 14:10	Subtransmission	None	TRK 2519			EQUIPMENT FAILURE
9/25/2019 15:39	9/25/2019 19:39	Subtransmission	None	TRK 2519			EQUIPMENT FAILURE
9/25/2019 16:30	9/25/2019 20:37	Subtransmission	None	TRK 2519			EQUIPMENT FAILURE
9/25/2019 16:09	9/25/2019 20:34	Subtransmission	None	TRK 2519			EQUIPMENT FAILURE
9/25/2019 16:01	9/25/2019 19:39	Subtransmission	None	TRK 2519			EQUIPMENT FAILURE
9/25/2019 16:23	9/25/2019 20:36	Subtransmission	Distribution	TRK 2519	1	235	EQUIPMENT FAILURE
9/25/2019 15:46	9/25/2019 20:49	Subtransmission	None	TRK 2519			EQUIPMENT FAILURE
9/25/2019 15:46	9/25/2019 20:49	Subtransmission	None	TRK 2519			EQUIPMENT FAILURE
9/25/2019 15:32	9/25/2019 19:32	Subtransmission	Distribution	TRK 2519	1057	250697	EQUIPMENT FAILURE
9/25/2019 15:47	9/25/2019 21:08	Subtransmission	None	TRK 2519			EQUIPMENT FAILURE
9/25/2019 15:49	9/25/2019 21:27	Subtransmission	None	TRK 2519			EQUIPMENT FAILURE
9/25/2019 15:50	9/25/2019 20:35	Subtransmission	None	TRK 2519			EQUIPMENT FAILURE
9/25/2019 16:00	9/25/2019 20:35	Subtransmission	None	TRK 2519			EQUIPMENT FAILURE
9/25/2019 15:35	9/25/2019 20:47	Subtransmission	Distribution	TRK 2519	977	305640	EQUIPMENT FAILURE
9/25/2019 15:35	9/25/2019 19:32	Subtransmission	Distribution	TRK 2519	839	190652	EQUIPMENT FAILURE
9/25/2019 15:47	9/25/2019 21:05	Subtransmission	None	TRK 2519			EQUIPMENT FAILURE
10/2/2019 17:32	10/3/2019 1:44	Subtransmission	None	TIE 3208			EQUIPMENT FAILURE
10/7/2019 14:56	10/8/2019 7:17	Subtransmission	None	TIE 3208			EQUIPMENT FAILURE
10/10/2019 11:09	10/10/2019 12:08	Subtransmission	None	TRK 7062			EQUIPMENT FAILURE
10/14/2019 11:04	10/14/2019 13:28	Subtransmission	Distribution	TRK 7389	461	59381	EQUIPMENT FAILURE
10/14/2019 11:04	10/14/2019 13:28	Subtransmission	Distribution	TRK 7389	102	13136	EQUIPMENT FAILURE
10/14/2019 11:04	10/14/2019 13:28	Subtransmission	Distribution	TRK 7389	104	13393	EQUIPMENT FAILURE
10/20/2019 4:30	10/20/2019 13:17	Subtransmission	None	TRK 7389			EQUIPMENT FAILURE
10/20/2019 4:19	10/20/2019 14:00	Subtransmission	Distribution	TRK 7389	458	65266	EQUIPMENT FAILURE
10/20/2019 4:19	10/20/2019 8:15	Subtransmission	Distribution	TRK 7389	18	4205	EQUIPMENT FAILURE

10/20/2019 4:19	10/20/2019 6:40	Subtransmission	Distribution	TRK 7389	14	3765	EQUIPMENT FAILURE
10/21/2019 20:52	10/21/2019 21:54	Subtransmission	None	TRK 721			EQUIPMENT FAILURE
10/23/2019 17:02	10/24/2019 21:53	Subtransmission	None	TRK 7389			EQUIPMENT FAILURE
11/9/2019 10:00	11/9/2019 12:30	Subtransmission	Distribution	TRK 5906	1	188	EQUIPMENT FAILURE
11/26/2019 2:52	11/26/2019 21:02	Subtransmission	None	TRK 1403			EQUIPMENT FAILURE
11/26/2019 3:09	11/27/2019 6:25	Subtransmission	None	TRK 1403			EQUIPMENT FAILURE
11/27/2019 17:03	11/29/2019 5:00	Subtransmission	Distribution	TRK 1403	2	3645	EQUIPMENT FAILURE
11/27/2019 9:38	11/30/2019 5:32	Subtransmission	None	TRK 1403			EQUIPMENT FAILURE
11/29/2019 0:29	11/29/2019 16:06	Subtransmission	None	TRK 2250			EQUIPMENT FAILURE
11/29/2019 0:29	11/29/2019 16:07	Subtransmission	None	TRK 2250			EQUIPMENT FAILURE
11/30/2019 19:27	11/30/2019 22:28	Subtransmission	None	TRK 2250			EQUIPMENT FAILURE
12/7/2019 11:51	12/7/2019 22:38	Subtransmission	None	TRK 2713			EQUIPMENT FAILURE
12/9/2019 15:16	12/9/2019 17:37	Subtransmission	None	TRK 2437			EQUIPMENT FAILURE
12/29/2019 20:00	12/30/2019 19:34	Subtransmission	None	TRK 1527			EQUIPMENT FAILURE
12/29/2019 4:13	12/29/2019 13:53	Subtransmission	None	TRK 1527			EQUIPMENT FAILURE
12/29/2019 3:31	12/29/2019 18:03	Subtransmission	None	TRK 1527			EQUIPMENT FAILURE
12/31/2019 11:12	12/31/2019 20:59	Subtransmission	None	TIE 1467			EQUIPMENT FAILURE
12/31/2019 9:01	1/2/2020 6:50	Subtransmission	None	TIE 1467			EQUIPMENT FAILURE
12/31/2019 12:54	12/31/2019 16:45	Subtransmission	Subtransmission	TIE 1467	7	252	EQUIPMENT FAILURE
1/7/2020 0:54	1/7/2020 3:03	Subtransmission	Subtransmission	TRK 3511	299	38301	EQUIPMENT FAILURE
1/7/2020 0:54	1/7/2020 3:03	Subtransmission	Subtransmission	TRK 3511	17	2176	EQUIPMENT FAILURE
1/7/2020 1:31	1/7/2020 2:06	Subtransmission	None	TRK 3511			EQUIPMENT FAILURE
1/9/2020 23:34	1/10/2020 6:15	Subtransmission	None	TIE 7733			EQUIPMENT FAILURE
1/9/2020 23:22	1/10/2020 1:33	Subtransmission	Distribution	TIE 7733	603	79994	EQUIPMENT FAILURE
1/9/2020 23:22	1/10/2020 1:33	Subtransmission	Distribution	TIE 7733	537	71326	EQUIPMENT FAILURE
1/9/2020 23:22	1/10/2020 0:36	Subtransmission	Distribution	TIE 7733	1550	116038	EQUIPMENT FAILURE
1/9/2020 23:22	1/10/2020 0:36	Subtransmission	Distribution	TIE 7733	333	25438	EQUIPMENT FAILURE
1/9/2020 23:22	1/10/2020 1:33	Subtransmission	Distribution	TIE 7733	2	280	EQUIPMENT FAILURE
1/9/2020 23:22	1/10/2020 1:33	Subtransmission	Distribution	TIE 7733	93	12311	EQUIPMENT FAILURE
1/9/2020 23:22	1/10/2020 1:33	Subtransmission	Distribution	TIE 7733	2831	375745	EQUIPMENT FAILURE
1/9/2020 23:22	1/10/2020 0:36	Subtransmission	Distribution	TIE 7733	328	25319	EQUIPMENT FAILURE
1/11/2020 18:25	1/13/2020 19:41	Subtransmission	None	TIE 3208			EQUIPMENT FAILURE
1/11/2020 11:06	1/11/2020 13:27	Subtransmission	None	TIE 7733			EQUIPMENT FAILURE
1/11/2020 10:56	1/11/2020 11:40	Subtransmission	Distribution	TIE 7733	320	14245	EQUIPMENT FAILURE
1/11/2020 10:56	1/11/2020 11:40	Subtransmission	Distribution	TIE 7733	1322	58864	EQUIPMENT FAILURE
1/11/2020 10:56	1/11/2020 11:40	Subtransmission	Distribution	TIE 7733	333	294000	EQUIPMENT FAILURE
1/11/2020 11:05	1/11/2020 13:29	Subtransmission	None	TIE 7733			EQUIPMENT FAILURE
1/11/2020 11:01	1/11/2020 13:44	Subtransmission	None	TIE 7733			EQUIPMENT FAILURE
1/11/2020 11:09	1/11/2020 12:53	Subtransmission	None	TIE 7733			EQUIPMENT FAILURE
1/11/2020 11:02	1/11/2020 13:03	Subtransmission	None	TIE 7733			EQUIPMENT FAILURE
1/11/2020 11:01	1/11/2020 11:51	Subtransmission	None	TIE 7733			EQUIPMENT FAILURE
1/11/2020 10:59	1/11/2020 12:53	Subtransmission	None	TIE 7733			EQUIPMENT FAILURE
1/11/2020 11:00	1/11/2020 13:28	Subtransmission	None	TIE 7733			EQUIPMENT FAILURE
1/11/2020 11:54	1/11/2020 15:37	Subtransmission	None	TIE 7733			EQUIPMENT FAILURE
1/11/2020 11:06	1/11/2020 11:51	Subtransmission	None	TIE 7733			EQUIPMENT FAILURE
1/11/2020 10:56	1/11/2020 11:40	Subtransmission	Distribution	TIE 7733	539	24011	EQUIPMENT FAILURE
1/11/2020 11:06	1/11/2020 11:40	Subtransmission	Distribution	TIE 7733	88	3897	EQUIPMENT FAILURE
1/11/2020 10:57	1/11/2020 11:40	Subtransmission	Distribution	TIE 7733	2840	126528	EQUIPMENT FAILURE
1/11/2020 9:26	1/11/2020 11:47	Subtransmission	Distribution	TIE 7733	604	26855	EQUIPMENT FAILURE
1/11/2020 11:03	1/11/2020 19:42	Subtransmission	None	TIE 7733			EQUIPMENT FAILURE
1/11/2020 11:31	1/12/2020 15:30	Subtransmission	None	TIE 7733			EQUIPMENT FAILURE
1/11/2020 11:06	1/11/2020 11:52	Subtransmission	None	TIE 7733			EQUIPMENT FAILURE
1/11/2020 11:07	1/11/2020 11:52	Subtransmission	None	TIE 7733			EQUIPMENT FAILURE
1/12/2020 21:09	1/13/2020 3:06	Subtransmission	None	TRK 3518			EQUIPMENT FAILURE
1/14/2020 9:37	1/14/2020 15:15	Subtransmission	Distribution	TRK 474	1055	321268	EQUIPMENT FAILURE
1/14/2020 11:30	1/14/2020 15:45	Subtransmission	Distribution	TRK 474	12	4237	EQUIPMENT FAILURE
1/23/2020 17:02	1/24/2020 20:17	Subtransmission	None	TRK 1110			EQUIPMENT FAILURE
1/26/2020 21:42	1/27/2020 3:17	Subtransmission	Distribution	TRK 5906	1	212	EQUIPMENT FAILURE
2/19/2020 19:27	2/20/2020 15:00	Subtransmission	None	TRK 2301			EQUIPMENT FAILURE
3/8/2020 22:12	3/8/2020 22:28	Subtransmission	None	TRK 2418			EQUIPMENT FAILURE
3/17/2020 16:53	3/17/2020 19:42	Subtransmission	None	TRK 620			EQUIPMENT FAILURE
3/17/2020 16:58	3/17/2020 19:45	Subtransmission	None	TRK 620			EQUIPMENT FAILURE
3/17/2020 22:28	3/18/2020 4:54	Subtransmission	None	TRK 620			EQUIPMENT FAILURE
3/19/2020 16:27	3/20/2020 20:58	Subtransmission	None	TRK 620			EQUIPMENT FAILURE
3/20/2020 23:21	3/21/2020 11:06	Subtransmission	None	TRK 1243			EQUIPMENT FAILURE
3/20/2020 23:26	3/20/2020 23:46	Subtransmission	None	TRK 1243			EQUIPMENT FAILURE
3/20/2020 23:26	3/21/2020 2:13	Subtransmission	None	TRK 1243			EQUIPMENT FAILURE
3/21/2020 7:09	3/21/2020 12:27	Subtransmission	None	TRK 1243			EQUIPMENT FAILURE
3/26/2020 12:09	3/28/2020 14:42	Subtransmission	None	TIE 1540			EQUIPMENT FAILURE
3/29/2020 13:03	3/29/2020 17:14	Subtransmission	None	TRK 2931			EQUIPMENT FAILURE
3/29/2020 13:14	3/29/2020 17:21	Subtransmission	None	TRK 2931			EQUIPMENT FAILURE
3/29/2020 13:58	3/29/2020 18:28	Subtransmission	None	TRK 446			EQUIPMENT FAILURE
3/30/2020 4:51	3/30/2020 15:45	Subtransmission	None	TIE 7745			EQUIPMENT FAILURE
4/4/2020 21:18	4/4/2020 21:36	Subtransmission	None	TIE 1268			EQUIPMENT FAILURE
4/4/2020 21:16	4/4/2020 21:23	Subtransmission	None	TIE 1268			EQUIPMENT FAILURE
4/4/2020 21:15	4/5/2020 0:44	Subtransmission	Distribution	TIE 1268	785	46675	EQUIPMENT FAILURE
4/4/2020 21:18	4/5/2020 0:44	Subtransmission	Distribution	TIE 1268	392	22303	EQUIPMENT FAILURE
4/4/2020 21:36	4/5/2020 5:15	Subtransmission	None	TIE 1268			EQUIPMENT FAILURE
4/4/2020 21:18	4/5/2020 0:44	Subtransmission	Distribution	TIE 1268	383	39974	EQUIPMENT FAILURE
4/4/2020 21:39	4/5/2020 5:14	Subtransmission	None	TIE 1268			EQUIPMENT FAILURE
4/4/2020 21:15	4/5/2020 0:44	Subtransmission	Distribution	TIE 1268	383	67050	EQUIPMENT FAILURE
4/4/2020 21:15	4/5/2020 0:44	Subtransmission	Distribution	TIE 1268	41	7013	EQUIPMENT FAILURE
4/4/2020 21:15	4/5/2020 0:44	Subtransmission	Distribution	TIE 1268	301	31670	EQUIPMENT FAILURE
4/4/2020 21:15	4/5/2020 0:44	Subtransmission	Distribution	TIE 1268	674	42101	EQUIPMENT FAILURE
4/5/2020 21:20	4/5/2020 23:21	Subtransmission	None	TIE 1568			EQUIPMENT FAILURE
4/13/2020 19:37	4/14/2020 3:01	Subtransmission	None	TRK 3536			EQUIPMENT FAILURE
4/13/2020 19:50	4/14/2020 7:39	Subtransmission	None	TRK 3536			EQUIPMENT FAILURE
4/13/2020 19:38	4/13/2020 22:54	Subtransmission	None	TRK 3536			EQUIPMENT FAILURE
4/17/2020 20:13	4/18/2020 12:56	Subtransmission	None	TRK 8403			EQUIPMENT FAILURE
4/18/2020 13:49	4/18/2020 16:55	Subtransmission	None	TRK 8403			EQUIPMENT FAILURE
4/27/2020 19:22	4/27/2020 21:01	Subtransmission	Distribution	TRK 720	501	47185	EQUIPMENT FAILURE
4/27/2020 19:22	4/27/2020 21:30	Subtransmission	Substation	TRK 721	673	78753	EQUIPMENT FAILURE
4/27/2020 20:45	4/27/2020 21:23	Subtransmission	Distribution	TRK 721	1	117	EQUIPMENT FAILURE
4/27/2020 21:39	4/27/2020 23:20	Subtransmission	None	TRK 721			EQUIPMENT FAILURE
5/15/2020 8:50	5/16/2020 0:35	Subtransmission	None	TRK 5817			EQUIPMENT FAILURE
5/15/2020 6:54	5/15/2020 14:03	Subtransmission	None	TRK 5817			EQUIPMENT FAILURE
5/16/2020 5:38	5/16/2020 19:17	Subtransmission	None	TIE4105			EQUIPMENT FAILURE
5/16/2020 15:45	5/17/2020 15:00	Subtransmission	None	TRK 5817			EQUIPMENT FAILURE
5/26/2020 18:40	5/27/2020 3:24	Subtransmission	None	TIE 6602			EQUIPMENT FAILURE
5/26/2020 18:29	5/27/2020 4:45	Subtransmission	Distribution	TIE 6602	1972	553482	EQUIPMENT FAILURE
5/27/2020 18:09	5/27/2020 20:00	Subtransmission	Distribution	TIE 1467	160	17489	EQUIPMENT FAILURE
5/27/2020 5:25	5/27/2020 8:30	Subtransmission	Distribution	TIE 6602			EQUIPMENT FAILURE
5/27/2020 14:18	5/30/2020 19:22	Subtransmission	None	TRK 2455			EQUIPMENT FAILURE
5/28/2020 20:12	5/28/2020 22:10	Subtransmission	None	TRK 4405			EQUIPMENT FAILURE
5/29/2020 21:38	5/30/2020 20:46	Subtransmission	None	TIE 329			EQUIPMENT FAILURE

5/29/2020 5:18	6/1/2020 14:55	Subtransmission	None	TRK 372			EQUIPMENT FAILURE
5/29/2020 5:53	6/1/2020 14:56	Subtransmission	None	TRK 372			EQUIPMENT FAILURE
5/30/2020 7:44	5/30/2020 18:19	Subtransmission	None	TRK 3534			EQUIPMENT FAILURE
6/2/2020 18:44	6/2/2020 22:25	Subtransmission	None	TRK 372			EQUIPMENT FAILURE
6/2/2020 12:03	6/2/2020 19:58	Subtransmission	None	TRK 372			EQUIPMENT FAILURE
6/3/2020 18:09	6/3/2020 20:08	Subtransmission	None	TIE 9111			EQUIPMENT FAILURE
6/4/2020 17:10	6/5/2020 15:43	Subtransmission	None	TRK 372			EQUIPMENT FAILURE
6/10/2020 21:43	6/11/2020 12:16	Subtransmission	None	TIE 6147			EQUIPMENT FAILURE
6/10/2020 16:12	6/11/2020 11:45	Subtransmission	Distribution	TIE 6147	1464	1426588	EQUIPMENT FAILURE
6/10/2020 16:49	6/11/2020 11:41	Subtransmission	Distribution	TIE 6147	2998	2817944	EQUIPMENT FAILURE
6/11/2020 14:23	6/12/2020 16:58	Subtransmission	None	TRK 3509			EQUIPMENT FAILURE
6/14/2020 18:08	6/14/2020 20:29	Subtransmission	Distribution	TIE 1568	1	175	EQUIPMENT FAILURE
6/14/2020 20:38	6/15/2020 4:58	Subtransmission	None	TRK 3509			EQUIPMENT FAILURE
6/16/2020 8:43	6/17/2020 5:47	Subtransmission	None	TRK 2107			EQUIPMENT FAILURE
6/21/2020 8:01	6/21/2020 15:08	Subtransmission	None	TRK 1232			EQUIPMENT FAILURE
6/21/2020 11:56	6/22/2020 12:05	Subtransmission	None	TRK 2250			EQUIPMENT FAILURE
6/21/2020 13:05	6/23/2020 1:04	Subtransmission	None	TRK 2250			EQUIPMENT FAILURE
6/22/2020 19:47	6/23/2020 0:52	Subtransmission	None	TIE 7745			EQUIPMENT FAILURE
6/23/2020 11:17	6/28/2020 20:29	Subtransmission	None	TRK 2250			EQUIPMENT FAILURE
6/30/2020 16:12	6/30/2020 18:55	Subtransmission	Subtransmission	TRK 2237	406	63098	EQUIPMENT FAILURE
6/30/2020 16:12	6/30/2020 18:25	Subtransmission	Subtransmission	TRK 2237	623	83168	EQUIPMENT FAILURE
6/30/2020 16:12	6/30/2020 18:55	Subtransmission	Subtransmission	TRK 2237	672	123792	EQUIPMENT FAILURE
6/30/2020 16:12	6/30/2020 20:42	Subtransmission	Subtransmission	TRK 2237	1268	311714	EQUIPMENT FAILURE
7/9/2020 21:20	7/10/2020 3:34	Subtransmission	Distribution	TIE 3705	415	156044	EQUIPMENT FAILURE
7/9/2020 21:20	7/10/2020 3:34	Subtransmission	Distribution	TIE 3705	1286	486202	EQUIPMENT FAILURE
7/9/2020 21:38	7/10/2020 4:12	Subtransmission	None	TIE 3705			EQUIPMENT FAILURE
7/10/2020 13:10	7/10/2020 22:25	Subtransmission	Subtransmission	TRK 3646	1450	807190	EQUIPMENT FAILURE
7/10/2020 15:23	7/11/2020 8:14	Subtransmission	None	TRK 3646			EQUIPMENT FAILURE
7/11/2020 10:33	7/11/2020 18:45	Subtransmission	None	TRK 2205			EQUIPMENT FAILURE
7/11/2020 12:18	7/12/2020 12:00	Subtransmission	Distribution	TRK 2205			EQUIPMENT FAILURE
7/17/2020 17:40	7/19/2020 16:21	Subtransmission	None	TIE 6138			EQUIPMENT FAILURE
7/19/2020 13:11	7/19/2020 17:00	Subtransmission	Distribution	TIE 6138			EQUIPMENT FAILURE
7/19/2020 13:54	7/19/2020 18:25	Subtransmission	Distribution	TIE 6138			EQUIPMENT FAILURE
7/19/2020 10:50	7/19/2020 12:38	Subtransmission	Subtransmission	TIE 6138	2397	256417	EQUIPMENT FAILURE
7/19/2020 10:51	7/19/2020 10:58	Subtransmission	None	TIE 6138			EQUIPMENT FAILURE
7/19/2020 10:51	7/19/2020 10:57	Subtransmission	None	TIE 6138			EQUIPMENT FAILURE
7/19/2020 10:51	7/19/2020 10:58	Subtransmission	None	TIE 6138			EQUIPMENT FAILURE
7/19/2020 10:53	7/19/2020 10:59	Subtransmission	None	TIE 6138			EQUIPMENT FAILURE
7/19/2020 10:52	7/19/2020 11:04	Subtransmission	None	TIE 6138			EQUIPMENT FAILURE
7/19/2020 10:53	7/19/2020 11:00	Subtransmission	None	TIE 6138			EQUIPMENT FAILURE
7/19/2020 10:51	7/19/2020 11:06	Subtransmission	None	TIE 6138			EQUIPMENT FAILURE
7/19/2020 12:59	7/19/2020 13:06	Subtransmission	None	TIE 6138			EQUIPMENT FAILURE
7/19/2020 10:52	7/19/2020 10:58	Subtransmission	None	TIE 6138			EQUIPMENT FAILURE
7/19/2020 10:53	7/19/2020 11:00	Subtransmission	None	TIE 6138			EQUIPMENT FAILURE
7/19/2020 10:51	7/19/2020 11:05	Subtransmission	None	TIE 6138			EQUIPMENT FAILURE
7/19/2020 10:54	7/19/2020 11:00	Subtransmission	None	TIE 6138			EQUIPMENT FAILURE
7/19/2020 10:51	7/19/2020 10:57	Subtransmission	None	TIE 6138			EQUIPMENT FAILURE
7/19/2020 10:53	7/19/2020 11:00	Subtransmission	None	TIE 6138			EQUIPMENT FAILURE
7/19/2020 8:47	7/19/2020 20:27	Subtransmission	Distribution	TIE 6138	8	550	EQUIPMENT FAILURE
7/19/2020 11:07	7/19/2020 14:40	Subtransmission	None	TIE 6138			EQUIPMENT FAILURE
7/19/2020 11:05	7/19/2020 16:06	Subtransmission	None	TIE 6138			EQUIPMENT FAILURE
7/19/2020 10:50	7/19/2020 20:21	Subtransmission	Distribution	TIE 6138	3	191	EQUIPMENT FAILURE
7/19/2020 10:50	7/19/2020 20:37	Subtransmission	Distribution	TIE 6138	5	1389	EQUIPMENT FAILURE
7/19/2020 10:52	7/19/2020 20:33	Subtransmission	Distribution	TIE 6138	42	30855	EQUIPMENT FAILURE
7/19/2020 10:50	7/19/2020 20:39	Subtransmission	Distribution	TIE 6138	2026	401149	EQUIPMENT FAILURE
7/19/2020 10:53	7/19/2020 20:08	Subtransmission	Distribution	TIE 6138	543	182948	EQUIPMENT FAILURE
7/19/2020 10:50	7/19/2020 18:00	Subtransmission	Distribution	TIE 6138	396	77864	EQUIPMENT FAILURE
7/19/2020 22:22	7/21/2020 15:47	Subtransmission	None	TRK 2010			EQUIPMENT FAILURE
7/19/2020 22:01	7/20/2020 13:34	Subtransmission	None	TRK 2038			EQUIPMENT FAILURE
7/19/2020 11:22	7/19/2020 19:54	Subtransmission	None	TRK 5838			EQUIPMENT FAILURE
7/20/2020 14:23	7/21/2020 15:11	Subtransmission	None	TRK 2038			EQUIPMENT FAILURE
7/21/2020 17:22	7/21/2020 19:30	Subtransmission	None	TRK 2038			EQUIPMENT FAILURE
8/2/2020 6:32	8/3/2020 8:55	Subtransmission	Distribution	TRK 1602	394	27597	EQUIPMENT FAILURE
8/3/2020 2:09	8/3/2020 8:55	Subtransmission	Distribution	TRK 1602	753	51979	EQUIPMENT FAILURE
8/3/2020 7:49	8/3/2020 8:55	Subtransmission	Distribution	TRK 1602	29	1971	EQUIPMENT FAILURE
8/3/2020 7:49	8/3/2020 8:55	Subtransmission	Distribution	TRK 1602	978	67259	EQUIPMENT FAILURE
8/3/2020 7:49	8/3/2020 8:55	Subtransmission	Distribution	TRK 1602	218	14921	EQUIPMENT FAILURE
8/3/2020 7:49	8/3/2020 8:55	Subtransmission	Distribution	TRK 1602	390	26737	EQUIPMENT FAILURE
8/3/2020 7:49	8/3/2020 8:55	Subtransmission	Distribution	TRK 1602	222	15282	EQUIPMENT FAILURE
8/3/2020 7:49	8/3/2020 8:55	Subtransmission	Distribution	TRK 1602	661	45225	EQUIPMENT FAILURE
8/3/2020 7:49	8/3/2020 8:55	Subtransmission	Distribution	TRK 1602	654	44568	EQUIPMENT FAILURE
8/3/2020 7:49	8/3/2020 8:55	Subtransmission	Distribution	TRK 1602	678	47030	EQUIPMENT FAILURE
8/4/2020 8:06	8/4/2020 13:39	Subtransmission	None	TRK 1303			EQUIPMENT FAILURE
8/12/2020 22:51	8/13/2020 0:44	Subtransmission	None	TRK 648			EQUIPMENT FAILURE
8/12/2020 22:59	8/13/2020 0:46	Subtransmission	None	TRK 648			EQUIPMENT FAILURE
8/12/2020 22:58	8/13/2020 0:46	Subtransmission	None	TRK 648			EQUIPMENT FAILURE
8/12/2020 22:59	8/13/2020 0:46	Subtransmission	None	TRK 648			EQUIPMENT FAILURE
8/12/2020 22:59	8/13/2020 0:46	Subtransmission	None	TRK 648			EQUIPMENT FAILURE
8/12/2020 22:48	8/13/2020 0:14	Subtransmission	Distribution	TRK 648	1238	115247	EQUIPMENT FAILURE
8/15/2020 7:47	8/15/2020 23:53	Subtransmission	None	TRK 1232			EQUIPMENT FAILURE
8/16/2020 8:02	8/16/2020 10:05	Subtransmission	None	TRK 2016			EQUIPMENT FAILURE
8/16/2020 8:11	8/16/2020 10:05	Subtransmission	None	TRK 2016			EQUIPMENT FAILURE
8/16/2020 16:26	8/16/2020 17:43	Subtransmission	Distribution	TRK 2016	317	19269	EQUIPMENT FAILURE
8/19/2020 12:11	8/19/2020 13:45	Subtransmission	None	TRK 2016			EQUIPMENT FAILURE
8/21/2020 12:42	8/21/2020 14:39	Subtransmission	None	TRK 441			EQUIPMENT FAILURE
8/21/2020 12:48	8/21/2020 14:39	Subtransmission	None	TRK 441			EQUIPMENT FAILURE
8/21/2020 12:45	8/21/2020 14:39	Subtransmission	None	TRK 441			EQUIPMENT FAILURE
8/21/2020 12:44	8/21/2020 14:39	Subtransmission	None	TRK 441			EQUIPMENT FAILURE
8/21/2020 12:37	8/21/2020 14:20	Subtransmission	Subtransmission	TRK 441	1116	44364	EQUIPMENT FAILURE
8/22/2020 15:58	8/22/2020 19:00	Subtransmission	Distribution	TRK 474	11	1518	EQUIPMENT FAILURE
8/23/2020 17:19	8/23/2020 20:00	Subtransmission	Distribution	TIE 1318	3116	23425	EQUIPMENT FAILURE
8/23/2020 17:19	8/23/2020 18:00	Subtransmission	Distribution	TIE 1318	732	283160	EQUIPMENT FAILURE
8/23/2020 17:25	8/23/2020 21:45	Subtransmission	Distribution	TIE 1318	980	380094	EQUIPMENT FAILURE
8/23/2020 17:48	8/23/2020 23:00	Subtransmission	None	TIE 1318			EQUIPMENT FAILURE
8/24/2020 2:01	8/24/2020 5:15	Subtransmission	Distribution	TIE 1318			EQUIPMENT FAILURE
8/29/2020 8:48	8/30/2020 12:18	Subtransmission	None	TRK 1403			EQUIPMENT FAILURE
8/29/2020 16:20	8/30/2020 4:57	Subtransmission	None	TRK 346			EQUIPMENT FAILURE
8/30/2020 15:45	8/31/2020 11:01	Subtransmission	Distribution	TRK 346	1	137	EQUIPMENT FAILURE
8/30/2020 8:53	8/30/2020 17:26	Subtransmission	None	TRK 346			EQUIPMENT FAILURE
9/13/2020 9:41	9/13/2020 12:02	Subtransmission	Substation	TIE 1568	272	28681	EQUIPMENT FAILURE
9/13/2020 9:41	9/13/2020 13:00	Subtransmission	Distribution	TIE 1568	237	60194	EQUIPMENT FAILURE
9/23/2020 13:55	9/23/2020 15:09	Subtransmission	Distribution	TRK 8215	1877	141895	EQUIPMENT FAILURE
9/23/2020 14:19	9/23/2020 21:50	Subtransmission	None	TRK 8215			EQUIPMENT FAILURE
9/23/2020 13:55	9/23/2020 15:09	Subtransmission	Distribution	TRK 8215	844	63791	EQUIPMENT FAILURE
9/23/2020 13:55	9/23/2020 17:15	Subtransmission	Distribution	TRK 8215	1518	114085	EQUIPMENT FAILURE

9/23/2020 13:55	9/23/2020 15:09	Subtransmission	Distribution	TRK 8215	889	66820	EQUIPMENT FAILURE
9/24/2020 16:33	9/29/2020 19:59	Subtransmission	None	TRK 2107			EQUIPMENT FAILURE
9/24/2020 16:29	9/25/2020 23:31	Subtransmission	None	TRK 2107			EQUIPMENT FAILURE
9/24/2020 12:16	9/24/2020 13:35	Subtransmission	Subtransmission	TRK 2247	1	95	EQUIPMENT FAILURE
9/24/2020 12:05	9/24/2020 13:35	Subtransmission	Distribution	TRK 2247	7	666	EQUIPMENT FAILURE
9/24/2020 12:19	9/24/2020 13:35	Subtransmission	Subtransmission	TRK 2247	1	90	EQUIPMENT FAILURE
9/24/2020 12:05	9/24/2020 13:35	Subtransmission	Subtransmission	TRK 2247	764	69359	EQUIPMENT FAILURE
9/24/2020 12:05	9/24/2020 13:35	Subtransmission	Subtransmission	TRK 2247	908	86275	EQUIPMENT FAILURE
9/24/2020 13:52	10/14/2020 14:36	Subtransmission	None	TRK 2247			EQUIPMENT FAILURE
9/24/2020 12:09	9/24/2020 19:39	Subtransmission	None	TRK 2247			EQUIPMENT FAILURE
9/25/2020 1:03	9/25/2020 7:10	Subtransmission	None	TRK 1110			EQUIPMENT FAILURE
10/4/2020 9:51	10/4/2020 17:00	Subtransmission	Distribution	TIE 4109			EQUIPMENT FAILURE
10/7/2020 5:36	10/7/2020 10:15	Subtransmission	Distribution	TIE 5829	44	10596	EQUIPMENT FAILURE
10/7/2020 6:04	10/7/2020 20:43	Subtransmission	None	TIE 5829			EQUIPMENT FAILURE
10/7/2020 5:42	10/7/2020 12:35	Subtransmission	None	TIE 5829			EQUIPMENT FAILURE
10/7/2020 5:36	10/7/2020 15:05	Subtransmission	Distribution	TIE 5829	65	34793	EQUIPMENT FAILURE
10/7/2020 5:46	10/7/2020 15:34	Subtransmission	None	TIE 5829			EQUIPMENT FAILURE
10/7/2020 5:47	10/7/2020 17:49	Subtransmission	None	TIE 5829			EQUIPMENT FAILURE
10/7/2020 5:36	10/7/2020 9:02	Subtransmission	Distribution	TIE 5829	1081	204653	EQUIPMENT FAILURE
10/7/2020 6:46	10/7/2020 11:16	Subtransmission	None	TRK 2247			EQUIPMENT FAILURE
10/11/2020 16:48	10/12/2020 15:12	Subtransmission	None	TRK 2247			EQUIPMENT FAILURE
10/14/2020 6:06	10/14/2020 12:30	Subtransmission	Distribution	TIE 6138	82	31666	EQUIPMENT FAILURE
10/14/2020 4:28	10/14/2020 6:37	Subtransmission	None	TIE 6138			EQUIPMENT FAILURE
10/14/2020 6:57	10/14/2020 11:13	Subtransmission	Subtransmission	TIE 6138	294	121185	EQUIPMENT FAILURE
10/14/2020 4:21	10/14/2020 11:13	Subtransmission	Distribution	TIE 6138	1360	484816	EQUIPMENT FAILURE
10/14/2020 4:21	10/14/2020 10:21	Subtransmission	Subtransmission	TIE 6138	666	219451	EQUIPMENT FAILURE
10/23/2020 14:25	10/24/2020 3:43	Subtransmission	None	TIE 3410			EQUIPMENT FAILURE
10/23/2020 14:07	10/23/2020 16:49	Subtransmission	Distribution	TIE 3410	331	41047	EQUIPMENT FAILURE
10/23/2020 14:07	10/23/2020 21:30	Subtransmission	Distribution	TIE 3410	241	101429	EQUIPMENT FAILURE
10/23/2020 14:27	10/25/2020 9:51	Subtransmission	None	TRK 3646			EQUIPMENT FAILURE
10/23/2020 14:09	10/23/2020 22:57	Subtransmission	None	TRK 3646			EQUIPMENT FAILURE
10/28/2020 15:24	11/20/2020 14:47	Subtransmission	None	TRK 2523			EQUIPMENT FAILURE
11/1/2020 12:39	11/1/2020 18:59	Subtransmission	Distribution	TRK 2035	512	134910	EQUIPMENT FAILURE
11/5/2020 8:06	11/5/2020 11:15	Subtransmission	None	TIE 6931			EQUIPMENT FAILURE
11/16/2020 8:57	11/21/2020 13:35	Subtransmission	None	TIE 3205			EQUIPMENT FAILURE
11/16/2020 14:57	11/18/2020 13:45	Subtransmission	None	TIE 9205			EQUIPMENT FAILURE
11/16/2020 8:20	11/17/2020 21:14	Subtransmission	None	TIE 9205			EQUIPMENT FAILURE
11/16/2020 17:28	11/17/2020 19:38	Subtransmission	None	TRK 6941			EQUIPMENT FAILURE
11/25/2020 6:27	11/25/2020 12:42	Subtransmission	Distribution	TRK 2826	414	92449	EQUIPMENT FAILURE
12/13/2020 21:38	12/14/2020 12:13	Subtransmission	None	TRK 1761			EQUIPMENT FAILURE
12/16/2020 16:29	12/16/2020 23:58	Subtransmission	None	TIE 3207			EQUIPMENT FAILURE
12/20/2020 5:20	12/20/2020 17:23	Subtransmission	None	TRK 3617			EQUIPMENT FAILURE
12/20/2020 5:10	12/20/2020 17:23	Subtransmission	None	TRK 3617			EQUIPMENT FAILURE
12/20/2020 5:16	12/20/2020 15:45	Subtransmission	None	TRK 3617			EQUIPMENT FAILURE
12/20/2020 5:33	12/21/2020 14:28	Subtransmission	None	TRK 3617			EQUIPMENT FAILURE
12/20/2020 5:09	12/20/2020 22:39	Subtransmission	Distribution	TRK 3617			EQUIPMENT FAILURE
12/20/2020 5:09	12/20/2020 12:20	Subtransmission	None	TRK 3617			EQUIPMENT FAILURE
12/20/2020 5:18	12/20/2020 17:20	Subtransmission	None	TRK 3617			EQUIPMENT FAILURE
1/4/2021 3:04	1/5/2021 4:00	Subtransmission	None	TRK 2470			EQUIPMENT FAILURE
1/14/2021 11:14	1/14/2021 15:26	Subtransmission	None	TRK 7745			EQUIPMENT FAILURE
1/23/2021 17:36	1/23/2021 19:28	Subtransmission	Distribution	TRK 6304	586	65761	EQUIPMENT FAILURE
1/23/2021 17:45	1/23/2021 22:51	Subtransmission	None	TRK 6304			EQUIPMENT FAILURE
1/23/2021 17:53	1/23/2021 22:49	Subtransmission	None	TRK 6304			EQUIPMENT FAILURE
1/26/2021 14:19	1/26/2021 20:47	Subtransmission	None	TRK 6125			EQUIPMENT FAILURE
2/3/2021 20:04	2/4/2021 1:42	Subtransmission	None	TRK 6304			EQUIPMENT FAILURE
2/3/2021 19:54	2/4/2021 1:03	Subtransmission	Distribution	TRK 6304	423	82624	EQUIPMENT FAILURE
2/3/2021 19:54	2/3/2021 22:15	Subtransmission	Distribution	TRK 6304	573	42736	EQUIPMENT FAILURE
2/20/2021 13:00	2/20/2021 19:31	Subtransmission	None	TRK 2715			EQUIPMENT FAILURE
2/20/2021 13:12	2/20/2021 19:55	Subtransmission	None	TRK 2715			EQUIPMENT FAILURE
2/21/2021 15:26	2/21/2021 19:45	Subtransmission	None	TIE 1568			EQUIPMENT FAILURE
2/27/2021 12:26	2/27/2021 13:19	Subtransmission	Distribution	TRK 1645	652	35307	EQUIPMENT FAILURE
2/27/2021 12:26	2/27/2021 13:19	Subtransmission	Distribution	TRK 1645	571	30957	EQUIPMENT FAILURE
2/27/2021 12:26	2/27/2021 13:19	Subtransmission	Distribution	TRK 1645	239	12945	EQUIPMENT FAILURE
2/27/2021 13:16	2/27/2021 13:42	Subtransmission	None	TRK 1646			EQUIPMENT FAILURE
2/27/2021 12:34	2/27/2021 13:42	Subtransmission	None	TRK 1646			EQUIPMENT FAILURE
2/27/2021 12:31	2/27/2021 15:50	Subtransmission	None	TRK 1646			EQUIPMENT FAILURE
2/28/2021 21:43	2/28/2021 23:45	Subtransmission	Subtransmission	TRK 2110	1134	122734	EQUIPMENT FAILURE
2/28/2021 21:43	2/28/2021 23:45	Subtransmission	Subtransmission	TRK 2110	787	85037	EQUIPMENT FAILURE
2/28/2021 21:54	3/1/2021 2:19	Subtransmission	None	TRK 2110			EQUIPMENT FAILURE
3/5/2021 13:24	3/5/2021 18:32	Subtransmission	None	TIE 3410			EQUIPMENT FAILURE
3/17/2021 20:07	3/18/2021 13:27	Subtransmission	None	TIE4105			EQUIPMENT FAILURE
3/24/2021 23:50	3/25/2021 1:10	Subtransmission	None	TRK 1276			EQUIPMENT FAILURE
3/25/2021 3:39	3/25/2021 8:30	Subtransmission	None	TRK 1276			EQUIPMENT FAILURE
3/26/2021 11:37	3/26/2021 13:56	Subtransmission	None	TRK 2087			EQUIPMENT FAILURE
3/26/2021 10:20	3/26/2021 13:42	Subtransmission	None	TRK 2087			EQUIPMENT FAILURE
3/26/2021 4:50	3/26/2021 12:53	Subtransmission	Distribution	TRK 2087	3	1336	EQUIPMENT FAILURE
3/26/2021 4:50	3/26/2021 12:53	Subtransmission	Distribution	TRK 2087	8	3566	EQUIPMENT FAILURE
3/26/2021 6:56	3/26/2021 13:10	Subtransmission	None	TRK 2087			EQUIPMENT FAILURE
3/26/2021 4:50	3/26/2021 12:53	Subtransmission	Distribution	TRK 2087	7	3122	EQUIPMENT FAILURE
3/26/2021 4:50	3/26/2021 12:53	Subtransmission	Distribution	TRK 2087	60	26778	EQUIPMENT FAILURE
3/26/2021 9:11	3/26/2021 19:47	Subtransmission	None	TRK 2629			EQUIPMENT FAILURE
3/28/2021 6:41	3/29/2021 5:36	Subtransmission	None	TRK 4301			EQUIPMENT FAILURE
3/31/2021 15:00	4/1/2021 4:02	Subtransmission	None	TRK 2629			EQUIPMENT FAILURE
4/1/2021 9:22	4/1/2021 12:18	Subtransmission	None	TRK 1276			EQUIPMENT FAILURE
4/7/2021 17:09	4/8/2021 15:48	Subtransmission	None	TRK 1276			EQUIPMENT FAILURE
4/7/2021 17:08	4/7/2021 20:33	Subtransmission	None	TRK 1276			EQUIPMENT FAILURE
4/7/2021 16:58	4/7/2021 17:30	Subtransmission	Distribution	TRK 1276			EQUIPMENT FAILURE
4/7/2021 21:01	4/8/2021 4:27	Subtransmission	None	TRK 1276			EQUIPMENT FAILURE
4/8/2021 15:16	4/8/2021 15:50	Subtransmission	None	TRK 1276			EQUIPMENT FAILURE
4/8/2021 6:23	4/8/2021 8:00	Subtransmission	Distribution	TRK 746	262	25375	EQUIPMENT FAILURE
4/8/2021 6:23	4/8/2021 8:00	Subtransmission	Distribution	TRK 746	557	53850	EQUIPMENT FAILURE
4/8/2021 6:23	4/8/2021 8:00	Subtransmission	Distribution	TRK 746	223	21535	EQUIPMENT FAILURE
4/8/2021 6:23	4/8/2021 8:00	Subtransmission	Distribution	TRK 746	284	27454	EQUIPMENT FAILURE
4/10/2021 11:48	4/10/2021 20:46	Subtransmission	None	TIE 7520			EQUIPMENT FAILURE
4/11/2021 14:32	4/11/2021 17:23	Subtransmission	None	TRK 1276			EQUIPMENT FAILURE
4/15/2021 13:19	4/15/2021 21:12	Subtransmission	None	TRK 2659			EQUIPMENT FAILURE
4/15/2021 19:05	4/16/2021 0:49	Subtransmission	None	TRK 2907			EQUIPMENT FAILURE
4/15/2021 6:48	4/15/2021 17:19	Subtransmission	None	TRK 746			EQUIPMENT FAILURE
4/15/2021 6:46	4/15/2021 16:25	Subtransmission	None	TRK 746			EQUIPMENT FAILURE
5/1/2021 14:42	5/1/2021 19:17	Subtransmission	None	TRK 1303			EQUIPMENT FAILURE
5/1/2021 16:35	5/2/2021 20:17	Subtransmission	None	TRK 3646			EQUIPMENT FAILURE
5/2/2021 15:06	5/3/2021 5:28	Subtransmission	None	TRK 1303			EQUIPMENT FAILURE
5/3/2021 7:22	5/3/2021 11:38	Subtransmission	None	TRK 1303			EQUIPMENT FAILURE
5/10/2021 9:22	5/10/2021 15:04	Subtransmission	None	TRK 2742			EQUIPMENT FAILURE
5/19/2021 15:29	5/27/2021 11:10	Subtransmission	None	TRK 2218			EQUIPMENT FAILURE

6/7/2021 19:26	6/8/2021 4:21	Subtransmission	None	TRK 1761			EQUIPMENT FAILURE
6/8/2021 17:24	6/8/2021 20:35	Subtransmission	Distribution	TRK 2054	1298	172433	EQUIPMENT FAILURE
6/8/2021 22:39	6/9/2021 14:00	Subtransmission	Distribution	TRK 2054	1	22	EQUIPMENT FAILURE
6/8/2021 17:53	6/8/2021 23:57	Subtransmission	None	TRK 2054			EQUIPMENT FAILURE
6/8/2021 22:54	6/9/2021 13:00	Subtransmission	Distribution	TRK 2054			EQUIPMENT FAILURE
6/8/2021 23:16	6/9/2021 12:00	Subtransmission	Distribution	TRK 2054			EQUIPMENT FAILURE
6/8/2021 17:56	6/8/2021 22:59	Subtransmission	None	TRK 2054			EQUIPMENT FAILURE
6/8/2021 17:34	6/9/2021 5:06	Subtransmission	None	TRK 2054			EQUIPMENT FAILURE
6/8/2021 17:24	6/8/2021 18:33	Subtransmission	Distribution	TRK 2054	920	54380	EQUIPMENT FAILURE
6/13/2021 13:21	6/13/2021 16:07	Subtransmission	None	TRK 3526			EQUIPMENT FAILURE
6/13/2021 15:32	6/13/2021 23:52	Subtransmission	None	TRK 3526			EQUIPMENT FAILURE
6/15/2021 7:31	6/17/2021 5:02	Subtransmission	None	TRK 3526			EQUIPMENT FAILURE
6/16/2021 20:12	6/17/2021 1:16	Subtransmission	None	TRK 7122			EQUIPMENT FAILURE
6/17/2021 1:46	6/17/2021 14:43	Subtransmission	None	TRK 8215			EQUIPMENT FAILURE
6/17/2021 1:53	6/17/2021 9:55	Subtransmission	None	TRK 8215			EQUIPMENT FAILURE
6/18/2021 22:38	6/19/2021 1:44	Subtransmission	None	TRK 3518			EQUIPMENT FAILURE
6/19/2021 12:43	6/19/2021 15:17	Subtransmission	None	TRK 3518			EQUIPMENT FAILURE
6/21/2021 7:32	6/21/2021 20:50	Subtransmission	None	TRK 1518			EQUIPMENT FAILURE
6/28/2021 15:51	6/29/2021 11:42	Subtransmission	None	TIE 6931			EQUIPMENT FAILURE
6/28/2021 17:57	6/29/2021 2:00	Subtransmission	Distribution	TIE 6931	2829	1073832	EQUIPMENT FAILURE
6/28/2021 16:53	6/29/2021 1:04	Subtransmission	Distribution	TIE 6931	1733	559960	EQUIPMENT FAILURE
6/28/2021 18:25	6/28/2021 21:35	Subtransmission	None	TIE 6931			EQUIPMENT FAILURE
6/28/2021 17:57	6/29/2021 2:00	Subtransmission	Distribution	TIE 6931	2742	1018093	EQUIPMENT FAILURE
6/28/2021 17:57	6/29/2021 0:37	Subtransmission	Distribution	TIE 6931	2448	851160	EQUIPMENT FAILURE
6/28/2021 18:04	6/28/2021 20:24	Subtransmission	None	TIE 6931			EQUIPMENT FAILURE
6/29/2021 7:37	6/29/2021 11:02	Subtransmission	None	TIE 6931			EQUIPMENT FAILURE
6/29/2021 14:46	6/30/2021 9:00	Subtransmission	Subtransmission	TRK 4301	1909	162557	EQUIPMENT FAILURE
6/29/2021 19:00	6/30/2021 9:00	Subtransmission	Subtransmission	TRK 4301	881	72637	EQUIPMENT FAILURE
6/29/2021 15:30	6/30/2021 9:00	Subtransmission	Subtransmission	TRK 4301	3	3999	EQUIPMENT FAILURE
6/30/2021 6:33	6/30/2021 9:00	Subtransmission	Subtransmission	TRK 4301	2	120	EQUIPMENT FAILURE
6/30/2021 6:33	6/30/2021 9:00	Subtransmission	Subtransmission	TRK 4301	512	42181	EQUIPMENT FAILURE
7/5/2021 18:26	7/5/2021 18:34	Subtransmission	None	TIE 3220			EQUIPMENT FAILURE
7/5/2021 19:05	7/5/2021 21:00	Subtransmission	Subtransmission	TIE 3220	1685	182841	EQUIPMENT FAILURE
7/5/2021 15:10	7/5/2021 21:00	Subtransmission	Subtransmission	TIE 3220	536	58213	EQUIPMENT FAILURE
7/5/2021 15:53	7/5/2021 19:40	Subtransmission	Distribution	TIE 6907	375	73849	EQUIPMENT FAILURE
7/5/2021 15:53	7/5/2021 21:45	Subtransmission	Distribution	TIE 6907	1967	635536	EQUIPMENT FAILURE
7/5/2021 16:18	7/5/2021 21:45	Subtransmission	Distribution	TIE 6907	246	79486	EQUIPMENT FAILURE
7/5/2021 15:53	7/5/2021 21:09	Subtransmission	Distribution	TIE 6907	1206	347194	EQUIPMENT FAILURE
7/5/2021 15:53	7/5/2021 20:45	Subtransmission	Distribution	TIE 6907	874	251334	EQUIPMENT FAILURE
7/5/2021 15:53	7/5/2021 21:16	Subtransmission	Distribution	TIE 6907	71	22007	EQUIPMENT FAILURE
7/5/2021 15:53	7/5/2021 21:34	Subtransmission	Distribution	TIE 6907	759	254886	EQUIPMENT FAILURE
7/5/2021 15:53	7/5/2021 16:20	Subtransmission	Distribution	TIE 6907			EQUIPMENT FAILURE
7/5/2021 15:53	7/5/2021 20:45	Subtransmission	Distribution	TIE 6907			EQUIPMENT FAILURE
7/5/2021 17:28	7/5/2021 20:54	Subtransmission	None	TIE 6907			EQUIPMENT FAILURE
7/5/2021 17:25	7/5/2021 20:22	Subtransmission	None	TIE 6907			EQUIPMENT FAILURE
7/5/2021 15:53	7/5/2021 21:34	Subtransmission	Distribution	TIE 6907	756	253916	EQUIPMENT FAILURE
7/5/2021 16:20	7/6/2021 5:36	Subtransmission	None	TIE 6907			EQUIPMENT FAILURE
7/6/2021 16:42	7/8/2021 14:11	Subtransmission	None	TIE 3220			EQUIPMENT FAILURE
7/6/2021 20:32	7/7/2021 20:14	Subtransmission	None	TRK 853			EQUIPMENT FAILURE
7/6/2021 19:02	7/7/2021 0:30	Subtransmission	Distribution	TRK 853	838	257399	EQUIPMENT FAILURE
7/6/2021 19:00	7/6/2021 23:48	Subtransmission	None	TRK 853			EQUIPMENT FAILURE
7/7/2021 15:49	7/8/2021 6:23	Subtransmission	None	TRK 7150			EQUIPMENT FAILURE
7/7/2021 15:05	7/9/2021 18:00	Subtransmission	Distribution	TRK 7150	388	1081919	EQUIPMENT FAILURE
7/10/2021 22:27	7/11/2021 14:36	Subtransmission	None	TRK 2218			EQUIPMENT FAILURE
7/11/2021 6:21	7/11/2021 13:17	Subtransmission	None	TRK 853			EQUIPMENT FAILURE
7/11/2021 13:08	7/11/2021 16:18	Subtransmission	None	TRK 853			EQUIPMENT FAILURE
7/13/2021 16:57	7/13/2021 20:30	Subtransmission	Distribution	TIE 1467	271	46784	EQUIPMENT FAILURE
7/13/2021 16:57	7/13/2021 20:30	Subtransmission	Distribution	TIE 1467	433	74823	EQUIPMENT FAILURE
7/13/2021 17:00	7/13/2021 20:30	Subtransmission	Distribution	TIE 1467	1	173	EQUIPMENT FAILURE
7/13/2021 18:23	7/14/2021 21:51	Subtransmission	None	TIE 4708			EQUIPMENT FAILURE
7/14/2021 10:41	7/15/2021 13:22	Subtransmission	None	TIE 4708			EQUIPMENT FAILURE
7/15/2021 12:04	7/16/2021 9:24	Subtransmission	None	TIE 5823			EQUIPMENT FAILURE
7/15/2021 12:08	7/15/2021 20:06	Subtransmission	None	TIE 5823			EQUIPMENT FAILURE
7/15/2021 12:03	7/15/2021 14:02	Subtransmission	None	TIE 5823			EQUIPMENT FAILURE
7/16/2021 17:30	7/16/2021 21:44	Subtransmission	Distribution	TRK 2611	593	75331	EQUIPMENT FAILURE
7/17/2021 17:18	7/18/2021 21:42	Subtransmission	None	TRK 2218			EQUIPMENT FAILURE
7/17/2021 7:51	7/17/2021 10:00	Subtransmission	Distribution	TRK 2611	513	29885	EQUIPMENT FAILURE
7/17/2021 7:51	7/17/2021 10:30	Subtransmission	Distribution	TRK 2611	952	55486	EQUIPMENT FAILURE
7/17/2021 7:52	7/17/2021 10:00	Subtransmission	Distribution	TRK 2611	402	23426	EQUIPMENT FAILURE
7/17/2021 8:08	7/18/2021 6:52	Subtransmission	None	TRK 2611			EQUIPMENT FAILURE
7/20/2021 17:24	7/20/2021 23:00	Subtransmission	Distribution	TIE 3241	1827	240520	EQUIPMENT FAILURE
7/20/2021 17:14	7/21/2021 1:00	Subtransmission	Distribution	TIE 3241	311	70853	EQUIPMENT FAILURE
7/20/2021 17:40	7/20/2021 19:48	Subtransmission	Distribution	TIE 3241	498	65176	EQUIPMENT FAILURE
7/20/2021 17:39	7/21/2021 1:00	Subtransmission	Distribution	TIE 3241	420	94434	EQUIPMENT FAILURE
7/20/2021 17:43	7/20/2021 19:48	Subtransmission	Distribution	TIE 3241	268	35068	EQUIPMENT FAILURE
7/20/2021 17:38	7/20/2021 23:00	Subtransmission	Subtransmission	TIE 3241	528	118218	EQUIPMENT FAILURE
7/20/2021 8:03	7/20/2021 9:05	Subtransmission	Distribution	TRK 2038	538	33325	EQUIPMENT FAILURE
7/20/2021 8:03	7/20/2021 9:51	Subtransmission	Distribution	TRK 2038			EQUIPMENT FAILURE
7/20/2021 8:03	7/20/2021 9:05	Subtransmission	Distribution	TRK 2038	1211	75063	EQUIPMENT FAILURE
7/20/2021 8:03	7/20/2021 9:05	Subtransmission	Distribution	TRK 2038	565	35043	EQUIPMENT FAILURE
7/20/2021 8:03	7/20/2021 9:05	Subtransmission	Distribution	TRK 2038	700	43360	EQUIPMENT FAILURE
7/20/2021 10:38	7/20/2021 14:08	Subtransmission	None	TRK 2038			EQUIPMENT FAILURE
7/20/2021 8:03	7/20/2021 8:52	Subtransmission	Distribution	TRK 2038	621	30560	EQUIPMENT FAILURE
7/20/2021 8:03	7/20/2021 8:52	Subtransmission	Distribution	TRK 2038	986	48504	EQUIPMENT FAILURE
7/20/2021 8:03	7/20/2021 8:52	Subtransmission	Distribution	TRK 2038	158	7774	EQUIPMENT FAILURE
7/20/2021 8:04	7/20/2021 8:37	Subtransmission	Distribution	TRK 2038	1480	51123	EQUIPMENT FAILURE
7/25/2021 5:58	7/25/2021 15:44	Subtransmission	None	TIE 1268			EQUIPMENT FAILURE
7/25/2021 20:20	7/26/2021 5:31	Subtransmission	None	TIE 1268			EQUIPMENT FAILURE
7/25/2021 10:49	7/25/2021 18:46	Subtransmission	None	TRK 6722			EQUIPMENT FAILURE
7/26/2021 0:13	7/26/2021 14:13	Subtransmission	Distribution	TRK 6722			EQUIPMENT FAILURE
7/26/2021 0:13	7/26/2021 20:54	Subtransmission	Distribution	TRK 6722	1	11	EQUIPMENT FAILURE
7/26/2021 16:54	7/27/2021 16:01	Subtransmission	None	TRK 6722			EQUIPMENT FAILURE
8/5/2021 16:48	8/8/2021 20:17	Subtransmission	None	TRK 2628			EQUIPMENT FAILURE
8/5/2021 16:42	8/7/2021 21:16	Subtransmission	None	TRK 2628			EQUIPMENT FAILURE
8/5/2021 16:16	8/6/2021 14:05	Subtransmission	None	TRK 2628			EQUIPMENT FAILURE
8/5/2021 16:38	8/5/2021 21:00	Subtransmission	None	TRK 2628			EQUIPMENT FAILURE
8/9/2021 14:56	8/9/2021 17:27	Subtransmission	Distribution	TRK 2528	585	53653	EQUIPMENT FAILURE
8/9/2021 14:56	8/9/2021 17:26	Subtransmission	Distribution	TRK 2528	1249	118395	EQUIPMENT FAILURE
8/9/2021 15:07	8/31/2021 22:54	Subtransmission	None	TRK 2528			EQUIPMENT FAILURE
8/9/2021 19:18	8/10/2021 17:00	Subtransmission	None	TRK 2528			EQUIPMENT FAILURE
8/11/2021 23:33	8/12/2021 3:57	Subtransmission	None	TIE 3800			EQUIPMENT FAILURE
8/11/2021 23:44	8/12/2021 3:57	Subtransmission	None	TIE 3800			EQUIPMENT FAILURE
8/11/2021 15:33	8/13/2021 20:30	Subtransmission	Distribution	TRK 2931	958	3014202	EQUIPMENT FAILURE
8/11/2021 15:39	8/13/2021 12:00	Subtransmission	Distribution	TRK 2931	79	271492	EQUIPMENT FAILURE
8/11/2021 15:34	8/13/2021 17:15	Subtransmission	Distribution	TRK 2931	1091	2480890	EQUIPMENT FAILURE

8/11/2021 15:34	8/13/2021 18:20	Subtransmission	Distribution	TRK 2931	849	1951103	EQUIPMENT FAILURE
8/11/2021 16:01	8/11/2021 19:36	Subtransmission	None	TRK 2931			EQUIPMENT FAILURE
8/11/2021 15:28	8/12/2021 12:50	Subtransmission	Distribution	TRK 4419	1480	498034	EQUIPMENT FAILURE
8/12/2021 0:11	8/12/2021 19:00	Subtransmission	Distribution	TIE 3800	761	814033	EQUIPMENT FAILURE
8/12/2021 15:39	8/12/2021 20:05	Subtransmission	None	TIE 3800			EQUIPMENT FAILURE
8/12/2021 0:29	8/12/2021 19:16	Subtransmission	None	TIE 3800			EQUIPMENT FAILURE
8/12/2021 14:17	8/14/2021 20:00	Subtransmission	None	TIE 7430			EQUIPMENT FAILURE
8/12/2021 3:02	8/12/2021 21:12	Subtransmission	None	TIE 7745			EQUIPMENT FAILURE
8/12/2021 4:00	8/18/2021 7:51	Subtransmission	None	TRK 1409			EQUIPMENT FAILURE
8/12/2021 3:15	8/12/2021 20:08	Subtransmission	None	TRK 4338			EQUIPMENT FAILURE
8/12/2021 10:27	8/14/2021 14:17	Subtransmission	None	TRK 4338			EQUIPMENT FAILURE
8/13/2021 9:33	8/13/2021 15:16	Subtransmission	None	TIE 2819			EQUIPMENT FAILURE
8/28/2021 20:34	8/29/2021 15:25	Subtransmission	None	TIE 3417			EQUIPMENT FAILURE
8/28/2021 11:30	8/29/2021 1:17	Subtransmission	None	TRK 5923			EQUIPMENT FAILURE
8/28/2021 12:43	8/30/2021 15:35	Subtransmission	None	TRK 5923			EQUIPMENT FAILURE
8/28/2021 6:35	8/28/2021 10:30	Subtransmission	Substation	TRK 5923	612	125934	EQUIPMENT FAILURE
8/29/2021 11:12	8/29/2021 15:18	Subtransmission	None	TRK 5923			EQUIPMENT FAILURE
8/29/2021 14:43	8/29/2021 18:45	Subtransmission	None	TRK 5923			EQUIPMENT FAILURE
8/29/2021 14:48	8/30/2021 15:34	Subtransmission	None	TRK 5923			EQUIPMENT FAILURE
8/31/2021 12:59	8/31/2021 18:12	Subtransmission	None	TRK 2247			EQUIPMENT FAILURE
9/1/2021 15:23	9/2/2021 14:37	Subtransmission	None	TRK 2247			EQUIPMENT FAILURE
9/2/2021 10:39	9/3/2021 5:22	Subtransmission	None	TRK 2038			EQUIPMENT FAILURE
9/2/2021 4:39	9/2/2021 6:32	Subtransmission	None	TRK 2038			EQUIPMENT FAILURE
9/2/2021 4:07	9/2/2021 8:30	Subtransmission	Distribution	TRK 2038	617	94405	EQUIPMENT FAILURE
9/2/2021 4:07	9/2/2021 8:24	Subtransmission	Distribution	TRK 2038	985	150632	EQUIPMENT FAILURE
9/2/2021 4:07	9/2/2021 19:30	Subtransmission	Distribution	TRK 2038	11	7249	EQUIPMENT FAILURE
9/2/2021 4:07	9/2/2021 8:25	Subtransmission	Distribution	TRK 2038	158	24172	EQUIPMENT FAILURE
9/2/2021 4:07	9/2/2021 8:19	Subtransmission	Distribution	TRK 2038	6	1151	EQUIPMENT FAILURE
9/2/2021 4:19	9/2/2021 12:22	Subtransmission	None	TRK 2038			EQUIPMENT FAILURE
9/2/2021 9:56	9/2/2021 10:10	Subtransmission	Distribution	TRK 2840	12	155	EQUIPMENT FAILURE
9/2/2021 9:25	9/2/2021 9:40	Subtransmission	Distribution	TRK 2840	14	158	EQUIPMENT FAILURE
9/4/2021 7:49	9/4/2021 9:42	Subtransmission	Distribution	TRK 7104	366	41114	EQUIPMENT FAILURE
9/4/2021 7:49	9/4/2021 9:42	Subtransmission	Distribution	TRK 7104	679	76271	EQUIPMENT FAILURE
9/4/2021 7:49	9/4/2021 9:42	Subtransmission	Distribution	TRK 7104	417	46883	EQUIPMENT FAILURE
9/4/2021 7:49	9/4/2021 9:12	Subtransmission	Distribution	TRK 7104	82	9207	EQUIPMENT FAILURE
9/4/2021 8:02	9/4/2021 10:00	Subtransmission	None	TRK 7104			EQUIPMENT FAILURE
9/6/2021 7:46	9/6/2021 20:43	Subtransmission	None	TRK 7104			EQUIPMENT FAILURE
9/7/2021 15:49	9/7/2021 20:46	Subtransmission	None	TRK 7520			EQUIPMENT FAILURE
9/9/2021 16:42	9/10/2021 4:55	Subtransmission	None	TRK 652			EQUIPMENT FAILURE
9/12/2021 22:27	9/13/2021 21:14	Subtransmission	Distribution	TRK 829	923	235163	EQUIPMENT FAILURE
9/13/2021 13:49	9/13/2021 18:56	Subtransmission	None	TRK 6304			EQUIPMENT FAILURE
9/13/2021 13:24	9/13/2021 18:30	Subtransmission	Distribution	TRK 6304	2491	313626	EQUIPMENT FAILURE
9/13/2021 13:26	9/13/2021 20:15	Subtransmission	Distribution	TRK 6304	336	85825	EQUIPMENT FAILURE
9/13/2021 13:26	9/13/2021 19:50	Subtransmission	Distribution	TRK 6304	593	230582	EQUIPMENT FAILURE
9/13/2021 13:40	9/13/2021 16:28	Subtransmission	None	TRK 6304			EQUIPMENT FAILURE
9/13/2021 13:31	9/13/2021 21:14	Subtransmission	Distribution	TRK 829	8	1988	EQUIPMENT FAILURE
9/18/2021 21:54	9/26/2021 13:08	Subtransmission	None	TRK 2002			EQUIPMENT FAILURE
9/18/2021 9:39	9/18/2021 18:30	Subtransmission	Distribution	TRK 2002	586	306820	EQUIPMENT FAILURE
9/23/2021 14:29	9/25/2021 13:00	Subtransmission	Distribution	TRK 2247	951	168730	EQUIPMENT FAILURE
9/24/2021 11:06	9/25/2021 16:00	Subtransmission	Distribution	TRK 2247	662	117169	EQUIPMENT FAILURE
9/25/2021 12:48	9/25/2021 16:39	Subtransmission	Distribution	TRK 2218	803	142092	EQUIPMENT FAILURE
9/25/2021 12:48	9/25/2021 16:29	Subtransmission	Distribution	TRK 2218	943	166409	EQUIPMENT FAILURE
9/25/2021 12:48	9/25/2021 16:27	Subtransmission	Distribution	TRK 2218	822	145373	EQUIPMENT FAILURE
9/25/2021 12:48	9/25/2021 16:39	Subtransmission	Distribution	TRK 2218	1179	208147	EQUIPMENT FAILURE
9/25/2021 12:45	9/25/2021 18:30	Subtransmission	Distribution	TRK 2218	1304	230656	EQUIPMENT FAILURE
9/25/2021 12:48	9/25/2021 16:21	Subtransmission	Distribution	TRK 2218	1007	178063	EQUIPMENT FAILURE
9/25/2021 12:48	9/25/2021 16:20	Subtransmission	Distribution	TRK 2247	899	158694	EQUIPMENT FAILURE
9/25/2021 12:48	9/25/2021 18:30	Subtransmission	Distribution	TRK 2247	947	167160	EQUIPMENT FAILURE
9/25/2021 10:57	9/26/2021 15:16	Subtransmission	None	TRK 4316			EQUIPMENT FAILURE
9/25/2021 14:31	9/26/2021 0:00	Subtransmission	Distribution	TRK 636	357	201370	EQUIPMENT FAILURE
9/25/2021 14:31	9/26/2021 0:00	Subtransmission	Distribution	TRK 636	39	21789	EQUIPMENT FAILURE
9/26/2021 8:21	9/26/2021 12:53	Subtransmission	None	TRK 2247			EQUIPMENT FAILURE
10/3/2021 22:22	10/4/2021 0:44	Subtransmission	Subtransmission	TRK 8215	812	51231	EQUIPMENT FAILURE
10/3/2021 22:22	10/4/2021 0:42	Subtransmission	Subtransmission	TRK 8215	816	51267	EQUIPMENT FAILURE
10/3/2021 22:37	10/4/2021 14:48	Subtransmission	None	TRK 8215			EQUIPMENT FAILURE
10/8/2021 7:38	10/9/2021 9:50	Subtransmission	None	TIE 6147			EQUIPMENT FAILURE
10/11/2021 9:33	10/11/2021 16:00	Subtransmission	Distribution	TRK 1525	14	5185	EQUIPMENT FAILURE
10/11/2021 9:22	10/11/2021 16:01	Subtransmission	Distribution	TRK 1525	2	755	EQUIPMENT FAILURE
10/11/2021 9:30	10/11/2021 16:00	Subtransmission	Distribution	TRK 1525	412	152831	EQUIPMENT FAILURE
10/11/2021 9:39	10/11/2021 16:00	Subtransmission	Distribution	TRK 1525	12	4443	EQUIPMENT FAILURE
10/11/2021 9:33	10/11/2021 16:00	Subtransmission	Distribution	TRK 1525	28	10406	EQUIPMENT FAILURE
10/11/2021 9:29	10/11/2021 16:00	Subtransmission	Distribution	TRK 1525	591	219246	EQUIPMENT FAILURE
10/11/2021 9:15	10/11/2021 16:00	Subtransmission	Distribution	TRK 1525	804	303195	EQUIPMENT FAILURE
10/11/2021 9:31	10/11/2021 16:00	Subtransmission	Distribution	TRK 1525	42	15571	EQUIPMENT FAILURE
10/11/2021 9:20	10/11/2021 16:00	Subtransmission	Distribution	TRK 1525	418	152715	EQUIPMENT FAILURE
10/11/2021 9:34	10/11/2021 16:00	Subtransmission	Distribution	TRK 1525			EQUIPMENT FAILURE
10/13/2021 8:20	10/13/2021 9:08	Subtransmission	Distribution	TRK 447	498	24732	EQUIPMENT FAILURE
10/13/2021 8:20	10/13/2021 9:08	Subtransmission	Distribution	TRK 447	506	24999	EQUIPMENT FAILURE
10/13/2021 8:20	10/13/2021 9:08	Subtransmission	Distribution	TRK 447	539	26782	EQUIPMENT FAILURE
10/13/2021 8:20	10/13/2021 9:08	Subtransmission	Distribution	TRK 447	269	13264	EQUIPMENT FAILURE
10/13/2021 8:21	10/13/2021 9:08	Subtransmission	Distribution	TRK 447	434	21297	EQUIPMENT FAILURE
10/13/2021 8:20	10/13/2021 9:08	Subtransmission	Distribution	TRK 447	496	24652	EQUIPMENT FAILURE
10/14/2021 17:53	10/14/2021 19:29	Subtransmission	Distribution	TIE 3705			EQUIPMENT FAILURE
10/14/2021 17:50	10/14/2021 21:44	Subtransmission	Distribution	TIE 3705			EQUIPMENT FAILURE
10/14/2021 17:56	10/15/2021 4:48	Subtransmission	None	TIE 3705			EQUIPMENT FAILURE
10/21/2021 11:57	10/21/2021 16:30	Subtransmission	Subtransmission	TRK 5938	956	265027	EQUIPMENT FAILURE
10/21/2021 11:57	10/21/2021 13:05	Subtransmission	Subtransmission	TRK 5938	502	35487	EQUIPMENT FAILURE
10/21/2021 11:57	10/21/2021 13:07	Subtransmission	Subtransmission	TRK 5938	177	12483	EQUIPMENT FAILURE
10/21/2021 11:57	10/21/2021 13:05	Subtransmission	Subtransmission	TRK 5938	328	25608	EQUIPMENT FAILURE
10/21/2021 11:57	10/21/2021 13:05	Subtransmission	Subtransmission	TRK 5938	1051	74273	EQUIPMENT FAILURE
11/3/2021 17:46	11/4/2021 13:35	Subtransmission	None	TIE 1467			EQUIPMENT FAILURE
11/11/2021 13:58	11/11/2021 14:11	Subtransmission	None	TIE 226			EQUIPMENT FAILURE
11/11/2021 14:07	11/11/2021 21:14	Subtransmission	Distribution	TIE 226	9	3444	EQUIPMENT FAILURE
11/11/2021 13:50	11/11/2021 15:54	Subtransmission	None	TIE 226			EQUIPMENT FAILURE
11/11/2021 14:01	12/6/2021 12:53	Subtransmission	None	TIE 226			EQUIPMENT FAILURE
11/11/2021 13:40	11/11/2021 15:31	Subtransmission	Distribution	TIE 226			EQUIPMENT FAILURE
11/11/2021 14:39	11/11/2021 22:12	Subtransmission	Distribution	TIE 6621			EQUIPMENT FAILURE
11/11/2021 14:33	11/12/2021 0:13	Subtransmission	Distribution	TIE 6621	601	221654	EQUIPMENT FAILURE
11/11/2021 14:33	11/12/2021 0:09	Subtransmission	Distribution	TIE 6621	582	241445	EQUIPMENT FAILURE
11/11/2021 14:33	11/12/2021 0:15	Subtransmission	Distribution	TIE 6621	199	65975	EQUIPMENT FAILURE
11/12/2021 15:03	11/12/2021 15:36	Subtransmission	None	TIE 226			EQUIPMENT FAILURE
11/12/2021 7:13	11/12/2021 16:22	Subtransmission	None	TIE 226			EQUIPMENT FAILURE
11/23/2021 4:24	11/23/2021 10:30	Subtransmission	Distribution	TRK 2466	182	57073	EQUIPMENT FAILURE
11/23/2021 4:23	11/23/2021 9:54	Subtransmission	Subtransmission	TRK 2466	170	57037	EQUIPMENT FAILURE
11/23/2021 4:23	11/23/2021 10:15	Subtransmission	Distribution	TRK 2466	214	50837	EQUIPMENT FAILURE

11/23/2021 4:23	11/23/2021 10:15	Subtransmission	Distribution	TRK 2466	262	89447	EQUIPMENT FAILURE
11/26/2021 12:00	11/26/2021 15:40	Subtransmission	None	TRK 2466			EQUIPMENT FAILURE
11/27/2021 1:08	11/27/2021 8:36	Subtransmission	None	TRK 1276			EQUIPMENT FAILURE
11/27/2021 10:04	11/27/2021 16:20	Subtransmission	None	TRK 1276			EQUIPMENT FAILURE
11/28/2021 16:29	12/11/2021 10:53	Subtransmission	None	TRK 1276			EQUIPMENT FAILURE
12/4/2021 5:28	12/4/2021 8:30	Subtransmission	None	TRK 7324			EQUIPMENT FAILURE
12/4/2021 22:03	12/5/2021 5:32	Subtransmission	None	TRK 7324			EQUIPMENT FAILURE
12/11/2021 20:44	12/12/2021 7:34	Subtransmission	None	TIE 5513			EQUIPMENT FAILURE
12/11/2021 11:24	12/12/2021 18:03	Subtransmission	None	TIE 6602			EQUIPMENT FAILURE
12/11/2021 10:59	12/12/2021 12:04	Subtransmission	None	TIE 6602			EQUIPMENT FAILURE
12/11/2021 10:38	12/12/2021 16:39	Subtransmission	Distribution	TRK 1403	1	1934	EQUIPMENT FAILURE
12/11/2021 10:34	12/12/2021 16:39	Subtransmission	Distribution	TRK 1403	1	1934	EQUIPMENT FAILURE
12/11/2021 11:21	12/13/2021 12:01	Subtransmission	None	TRK 1403			EQUIPMENT FAILURE
12/12/2021 8:55	12/12/2021 14:30	Subtransmission	None	TIE 3705			EQUIPMENT FAILURE
12/12/2021 8:08	12/12/2021 14:29	Subtransmission	None	TIE 3705			EQUIPMENT FAILURE
1/29/2022 7:20	1/29/2022 8:30	Subtransmission	Distribution	TRK 4338	1091	77532	EQUIPMENT FAILURE
1/29/2022 7:20	1/29/2022 8:30	Subtransmission	Distribution	TRK 4338	859	61169	EQUIPMENT FAILURE
1/29/2022 8:36	1/29/2022 16:07	Subtransmission	None	TRK 4338			EQUIPMENT FAILURE
1/29/2022 7:20	1/29/2022 8:30	Subtransmission	Distribution	TRK 4338	7	498	EQUIPMENT FAILURE
1/29/2022 7:20	1/29/2022 8:30	Subtransmission	Distribution	TRK 4338	530	37668	EQUIPMENT FAILURE
1/29/2022 7:30	1/29/2022 10:37	Subtransmission	Distribution	TRK 4338			EQUIPMENT FAILURE
1/29/2022 7:20	1/29/2022 10:36	Subtransmission	Distribution	TRK 4338			EQUIPMENT FAILURE
1/29/2022 7:20	1/29/2022 10:39	Subtransmission	Distribution	TRK 4338			EQUIPMENT FAILURE
1/29/2022 7:57	1/29/2022 10:42	Subtransmission	Distribution	TRK 4338	1	71	EQUIPMENT FAILURE
1/29/2022 7:20	1/29/2022 10:41	Subtransmission	Distribution	TRK 4338			EQUIPMENT FAILURE
1/29/2022 7:20	1/29/2022 10:40	Subtransmission	Distribution	TRK 4338			EQUIPMENT FAILURE
1/29/2022 7:20	1/29/2022 10:40	Subtransmission	Distribution	TRK 4338			EQUIPMENT FAILURE
1/29/2022 7:49	1/29/2022 8:30	Subtransmission	Distribution	TRK 4338	1	71	EQUIPMENT FAILURE
1/30/2022 3:30	1/30/2022 10:43	Subtransmission	None	TRK 2250			EQUIPMENT FAILURE
1/30/2022 9:20	1/30/2022 18:54	Subtransmission	None	TRK 2250			EQUIPMENT FAILURE
1/30/2022 3:41	1/30/2022 12:04	Subtransmission	None	TRK 2250			EQUIPMENT FAILURE
1/31/2022 7:26	2/1/2022 16:32	Subtransmission	None	TRK 2250			EQUIPMENT FAILURE
2/15/2022 10:23	2/15/2022 21:08	Subtransmission	Distribution	TIE 9111	1	12	EQUIPMENT FAILURE
2/20/2022 12:12	2/20/2022 19:54	Subtransmission	None	TRK 1525			EQUIPMENT FAILURE
3/2/2022 16:23	3/2/2022 18:20	Subtransmission	None	TRK 1719			EQUIPMENT FAILURE
3/2/2022 16:39	3/2/2022 17:18	Subtransmission	None	TRK 1719			EQUIPMENT FAILURE
3/13/2022 10:02	3/13/2022 17:47	Subtransmission	None	TRK 8407			EQUIPMENT FAILURE
3/19/2022 14:46	3/19/2022 21:00	Subtransmission	Distribution	TIE 1473	108	25441	EQUIPMENT FAILURE
3/20/2022 5:11	3/21/2022 8:31	Subtransmission	None	TRK 1527			EQUIPMENT FAILURE
3/30/2022 9:37	4/3/2022 14:56	Subtransmission	None	TRK 2255			EQUIPMENT FAILURE
3/31/2022 10:01	3/31/2022 14:28	Subtransmission	Distribution	TIE 3241	329	84293	EQUIPMENT FAILURE
3/31/2022 9:12	3/31/2022 14:27	Subtransmission	Distribution	TIE 3241	533	136597	EQUIPMENT FAILURE
3/31/2022 8:37	3/31/2022 14:28	Subtransmission	Distribution	TIE 3241	433	198021	EQUIPMENT FAILURE
3/31/2022 9:12	3/31/2022 15:43	Subtransmission	Distribution	TIE 3241	281	93076	EQUIPMENT FAILURE
3/31/2022 9:12	3/31/2022 15:42	Subtransmission	Distribution	TIE 3241	1973	654183	EQUIPMENT FAILURE
3/31/2022 10:02	3/31/2022 15:42	Subtransmission	Distribution	TIE 3241	493	163328	EQUIPMENT FAILURE
3/31/2022 13:09	4/1/2022 15:30	Subtransmission	None	TIE 3241			EQUIPMENT FAILURE
3/31/2022 9:32	4/1/2022 15:38	Subtransmission	None	TIE 3241			EQUIPMENT FAILURE
3/31/2022 5:56	3/31/2022 19:10	Subtransmission	Distribution	TRK 5411	575	367001	EQUIPMENT FAILURE
4/5/2022 17:16	4/5/2022 18:59	Subtransmission	Distribution	TRK 824	608	51814	EQUIPMENT FAILURE
4/11/2022 11:29	4/11/2022 19:20	Subtransmission	None	TRK 1232			EQUIPMENT FAILURE
4/12/2022 15:30	4/13/2022 0:12	Subtransmission	None	TRK 7151			EQUIPMENT FAILURE
4/14/2022 19:16	4/15/2022 16:20	Subtransmission	None	TRK 2443			EQUIPMENT FAILURE
4/23/2022 7:11	4/23/2022 16:52	Subtransmission	None	TRK 2002			EQUIPMENT FAILURE
4/24/2022 14:39	4/24/2022 15:52	Subtransmission	Distribution	TRK 2636	712	52397	EQUIPMENT FAILURE
4/24/2022 14:52	4/24/2022 21:10	Subtransmission	None	TRK 2636			EQUIPMENT FAILURE
4/28/2022 10:07	4/28/2022 21:14	Subtransmission	None	TIE 6621			EQUIPMENT FAILURE
5/7/2022 9:21	5/7/2022 10:58	Subtransmission	Distribution	TRK 2118	1141	110074	EQUIPMENT FAILURE
5/7/2022 9:22	5/7/2022 10:58	Subtransmission	Distribution	TRK 2118	623	59782	EQUIPMENT FAILURE
5/7/2022 9:21	5/7/2022 10:58	Subtransmission	Distribution	TRK 2118	514	49890	EQUIPMENT FAILURE
5/7/2022 9:22	5/7/2022 10:58	Subtransmission	Distribution	TRK 2118	596	55763	EQUIPMENT FAILURE
5/7/2022 9:22	5/7/2022 10:58	Subtransmission	Distribution	TRK 2118	711	67588	EQUIPMENT FAILURE
5/7/2022 9:22	5/7/2022 10:58	Subtransmission	Distribution	TRK 2118	1130	105837	EQUIPMENT FAILURE
5/7/2022 9:21	5/7/2022 10:58	Subtransmission	Distribution	TRK 2118	495	47539	EQUIPMENT FAILURE
5/11/2022 13:08	5/11/2022 19:44	Subtransmission	None	TRK 2659			EQUIPMENT FAILURE
5/11/2022 13:03	5/11/2022 19:44	Subtransmission	None	TRK 2659			EQUIPMENT FAILURE
5/11/2022 13:18	5/11/2022 19:44	Subtransmission	None	TRK 2659			EQUIPMENT FAILURE
5/11/2022 13:10	5/11/2022 19:44	Subtransmission	None	TRK 2659			EQUIPMENT FAILURE
5/11/2022 13:15	5/11/2022 19:49	Subtransmission	None	TRK 2659			EQUIPMENT FAILURE
5/15/2022 16:40	5/15/2022 19:42	Subtransmission	Substation	TRK 3508	850	140465	EQUIPMENT FAILURE
5/15/2022 16:40	5/15/2022 19:43	Subtransmission	Distribution	TRK 3508	763	126149	EQUIPMENT FAILURE
5/15/2022 16:40	5/15/2022 19:42	Subtransmission	Subtransmission	TRK 3508	1548	255405	EQUIPMENT FAILURE
5/15/2022 17:07	5/15/2022 23:40	Subtransmission	None	TRK 3508			EQUIPMENT FAILURE
5/17/2022 19:33	5/17/2022 20:35	Subtransmission	Distribution	TIE 6931	2747	169140	EQUIPMENT FAILURE
5/17/2022 19:34	5/17/2022 20:35	Subtransmission	Distribution	TIE 6931	1327	81612	EQUIPMENT FAILURE
5/17/2022 11:07	5/17/2022 20:35	Subtransmission	Distribution	TIE 6931	2205	135375	EQUIPMENT FAILURE
5/18/2022 21:07	5/18/2022 23:16	Subtransmission	Distribution	TIE 1423	806	105203	EQUIPMENT FAILURE
5/18/2022 21:07	5/19/2022 1:00	Subtransmission	Distribution	TIE 1423	2141	279522	EQUIPMENT FAILURE
5/18/2022 21:18	5/19/2022 5:49	Subtransmission	None	TIE 1423			EQUIPMENT FAILURE
5/20/2022 19:38	5/21/2022 14:35	Subtransmission	None	TRK 2918			EQUIPMENT FAILURE
5/20/2022 17:21	5/21/2022 2:00	Subtransmission	Distribution	TRK 2918	321	11745	EQUIPMENT FAILURE
5/21/2022 8:55	5/21/2022 20:23	Subtransmission	None	TRK 3536			EQUIPMENT FAILURE
5/21/2022 10:30	5/22/2022 16:20	Subtransmission	None	TRK 1403			EQUIPMENT FAILURE
5/21/2022 16:43	5/21/2022 19:08	Subtransmission	None	TRK 1403			EQUIPMENT FAILURE
5/27/2022 16:24	5/28/2022 6:30	Subtransmission	Distribution	TIE 3220	2043	255091	EQUIPMENT FAILURE
6/7/2022 14:43	6/7/2022 16:35	Subtransmission	Subtransmission	TRK 662	640	71517	EQUIPMENT FAILURE
6/7/2022 14:43	6/7/2022 16:35	Subtransmission	Subtransmission	TRK 662	386	43128	EQUIPMENT FAILURE
6/7/2022 14:42	6/7/2022 16:35	Subtransmission	Subtransmission	TRK 662	1049	117325	EQUIPMENT FAILURE
6/7/2022 14:43	6/7/2022 16:35	Subtransmission	Subtransmission	TRK 662	208	23219	EQUIPMENT FAILURE
6/7/2022 14:43	6/7/2022 16:35	Subtransmission	Subtransmission	TRK 662	176	19666	EQUIPMENT FAILURE
6/7/2022 14:43	6/7/2022 17:20	Subtransmission	Subtransmission	TRK 662	396	61974	EQUIPMENT FAILURE
6/7/2022 14:43	6/7/2022 16:35	Subtransmission	Subtransmission	TRK 662	460	51411	EQUIPMENT FAILURE
6/10/2022 15:18	6/10/2022 22:08	Subtransmission	Subtransmission	TRK 2418	638	248282	EQUIPMENT FAILURE
6/10/2022 15:18	6/10/2022 21:56	Subtransmission	Subtransmission	TRK 2418	821	252791	EQUIPMENT FAILURE
6/10/2022 15:18	6/10/2022 22:14	Subtransmission	Distribution	TRK 2418	804	313299	EQUIPMENT FAILURE
6/10/2022 15:18	6/10/2022 20:25	Subtransmission	Substation	TRK 2418	546	106890	EQUIPMENT FAILURE
6/10/2022 15:18	6/10/2022 21:30	Subtransmission	Subtransmission	TRK 2418	936	328219	EQUIPMENT FAILURE
6/10/2022 15:18	6/10/2022 20:25	Subtransmission	Subtransmission	TRK 2418	956	294577	EQUIPMENT FAILURE
6/16/2022 12:06	6/17/2022 2:05	Subtransmission	None	TRK 722			EQUIPMENT FAILURE
6/16/2022 9:04	6/16/2022 20:41	Subtransmission	None	TIE 3318			EQUIPMENT FAILURE
6/16/2022 15:58	6/19/2022 15:12	Subtransmission	None	TRK 2418			EQUIPMENT FAILURE
6/20/2022 10:04	6/20/2022 13:45	Subtransmission	Distribution	TRK 5838	294	68455	EQUIPMENT FAILURE
6/20/2022 10:13	6/20/2022 15:41	Subtransmission	None	TRK 5838			EQUIPMENT FAILURE
6/22/2022 14:53	6/23/2022 10:57	Subtransmission	None	TRK 2038			EQUIPMENT FAILURE
6/24/2022 22:24	6/25/2022 4:20	Subtransmission	Distribution	TRK 2806			EQUIPMENT FAILURE

6/24/2022 18:51	6/24/2022 22:30	Subtransmission	Distribution	TRK 2806	6	1605	EQUIPMENT FAILURE
6/24/2022 18:57	6/24/2022 22:30	Subtransmission	Distribution	TRK 2806	4	1070	EQUIPMENT FAILURE
6/24/2022 18:54	6/24/2022 22:30	Subtransmission	Distribution	TRK 2806	5	1338	EQUIPMENT FAILURE
6/24/2022 18:50	6/24/2022 22:30	Subtransmission	Distribution	TRK 2806	27	7224	EQUIPMENT FAILURE
6/24/2022 18:51	6/24/2022 22:30	Subtransmission	Distribution	TRK 2806	37	9899	EQUIPMENT FAILURE
6/24/2022 18:51	6/24/2022 22:30	Subtransmission	Distribution	TRK 2806	3	803	EQUIPMENT FAILURE
6/24/2022 18:53	6/24/2022 22:30	Subtransmission	Distribution	TRK 2806	53	14181	EQUIPMENT FAILURE
6/24/2022 18:51	6/24/2022 22:30	Subtransmission	Distribution	TRK 2806	34	9097	EQUIPMENT FAILURE
6/24/2022 18:55	6/24/2022 22:30	Subtransmission	Distribution	TRK 2806	3	803	EQUIPMENT FAILURE
6/24/2022 18:55	6/24/2022 22:30	Subtransmission	Distribution	TRK 2806	3	803	EQUIPMENT FAILURE
6/24/2022 18:56	6/24/2022 22:30	Subtransmission	Distribution	TRK 2806	5	1338	EQUIPMENT FAILURE
6/24/2022 18:59	6/24/2022 22:30	Subtransmission	Distribution	TRK 2806	4	1070	EQUIPMENT FAILURE
6/24/2022 18:57	6/24/2022 22:30	Subtransmission	Distribution	TRK 2806			EQUIPMENT FAILURE
6/24/2022 18:51	6/24/2022 22:30	Subtransmission	Distribution	TRK 2806	5	1338	EQUIPMENT FAILURE
6/24/2022 19:00	6/24/2022 22:30	Subtransmission	Distribution	TRK 2806	3	803	EQUIPMENT FAILURE
6/24/2022 22:42	6/25/2022 0:45	Subtransmission	Distribution	TRK 2806	664	36285	EQUIPMENT FAILURE
6/24/2022 18:50	6/25/2022 12:08	Subtransmission	Distribution	TRK 2806			EQUIPMENT FAILURE
6/24/2022 8:46	6/24/2022 20:41	Subtransmission	Distribution	TRK 2806	3222	359066	EQUIPMENT FAILURE
6/29/2022 14:41	6/29/2022 16:00	Subtransmission	Distribution	TIE 1423			EQUIPMENT FAILURE
6/29/2022 14:39	6/29/2022 16:00	Subtransmission	Distribution	TIE 1423			EQUIPMENT FAILURE
6/29/2022 15:14	6/29/2022 16:00	Subtransmission	Distribution	TIE 1423			EQUIPMENT FAILURE
6/29/2022 15:28	6/29/2022 16:00	Subtransmission	Distribution	TIE 1423			EQUIPMENT FAILURE
6/29/2022 15:05	6/29/2022 15:20	Subtransmission	Subtransmission	TIE 1423			EQUIPMENT FAILURE
6/29/2022 14:47	6/29/2022 16:00	Subtransmission	Distribution	TIE 1423			EQUIPMENT FAILURE
6/29/2022 14:34	6/29/2022 16:00	Subtransmission	Distribution	TIE 1423			EQUIPMENT FAILURE
6/29/2022 14:18	6/29/2022 16:00	Subtransmission	Distribution	TIE 1423			EQUIPMENT FAILURE
6/29/2022 15:05	6/29/2022 16:00	Subtransmission	Distribution	TIE 1423			EQUIPMENT FAILURE
6/29/2022 14:04	6/29/2022 14:52	Subtransmission	Subtransmission	TIE 1423	2133	103491	EQUIPMENT FAILURE
6/29/2022 14:04	6/29/2022 14:52	Subtransmission	Subtransmission	TIE 1423	810	39505	EQUIPMENT FAILURE
6/29/2022 16:19	6/29/2022 20:18	Subtransmission	None	TIE 1423			EQUIPMENT FAILURE
7/2/2022 5:49	7/3/2022 18:17	Subtransmission	None	TRK 3646			EQUIPMENT FAILURE
7/2/2022 7:48	7/2/2022 18:12	Subtransmission	None	TRK 5906			EQUIPMENT FAILURE
7/6/2022 14:41	7/7/2022 2:50	Subtransmission	Distribution	TIE 2025	1761	137497	EQUIPMENT FAILURE
7/6/2022 14:16	7/6/2022 21:00	Subtransmission	Distribution	TIE 2025			EQUIPMENT FAILURE
7/6/2022 15:03	7/7/2022 10:36	Subtransmission	None	TIE 2025			EQUIPMENT FAILURE
7/6/2022 14:49	7/7/2022 9:07	Subtransmission	None	TIE 2025			EQUIPMENT FAILURE
7/6/2022 9:24	7/6/2022 12:46	Subtransmission	None	TIE 4104			EQUIPMENT FAILURE
7/12/2022 22:43	7/13/2022 14:52	Subtransmission	None	TRK 6854			EQUIPMENT FAILURE
7/16/2022 9:17	7/16/2022 14:15	Subtransmission	None	TRK 7122			EQUIPMENT FAILURE
7/19/2022 14:27	7/19/2022 23:47	Subtransmission	Distribution	TRK 1642	503	267411	EQUIPMENT FAILURE
7/19/2022 14:27	7/19/2022 17:00	Subtransmission	Distribution	TRK 1642	293	22323	EQUIPMENT FAILURE
7/19/2022 14:27	7/19/2022 19:34	Subtransmission	Distribution	TRK 1642	474	138176	EQUIPMENT FAILURE
7/19/2022 14:27	7/19/2022 21:23	Subtransmission	Distribution	TRK 1642	317	131870	EQUIPMENT FAILURE
7/19/2022 14:27	7/19/2022 17:14	Subtransmission	Distribution	TRK 1642	816	110500	EQUIPMENT FAILURE
7/19/2022 18:29	7/19/2022 20:04	Subtransmission	Distribution	TRK 1656	655	56941	EQUIPMENT FAILURE
7/19/2022 18:29	7/19/2022 20:04	Subtransmission	Distribution	TRK 1656	434	44863	EQUIPMENT FAILURE
7/19/2022 18:29	7/19/2022 20:04	Subtransmission	Distribution	TRK 1656	644	57835	EQUIPMENT FAILURE
7/19/2022 18:29	7/19/2022 20:04	Subtransmission	Distribution	TRK 1656	612	58229	EQUIPMENT FAILURE
7/19/2022 14:36	7/20/2022 4:00	Subtransmission	Distribution	TRK 1656	565	90314	EQUIPMENT FAILURE
7/19/2022 18:29	7/19/2022 21:11	Subtransmission	Distribution	TRK 1656	877	133866	EQUIPMENT FAILURE
7/19/2022 18:29	7/20/2022 4:00	Subtransmission	Distribution	TRK 1656	451	163894	EQUIPMENT FAILURE
7/19/2022 18:29	7/20/2022 4:00	Subtransmission	Distribution	TRK 1656	500	181115	EQUIPMENT FAILURE
7/19/2022 18:28	7/20/2022 1:50	Subtransmission	Distribution	TRK 1656	226	100113	EQUIPMENT FAILURE
7/23/2022 17:08	7/24/2022 7:09	Subtransmission	Distribution	TIE 8014	718	109351	EQUIPMENT FAILURE
7/24/2022 4:38	7/24/2022 12:32	Subtransmission	Distribution	TIE 8014	406	187774	EQUIPMENT FAILURE
7/24/2022 4:38	7/24/2022 13:10	Subtransmission	Distribution	TIE 8014			EQUIPMENT FAILURE
7/24/2022 4:40	7/24/2022 12:30	Subtransmission	Distribution	TIE 8014			EQUIPMENT FAILURE
7/24/2022 4:35	7/24/2022 9:40	Subtransmission	Distribution	TIE 8014	290	85939	EQUIPMENT FAILURE
7/24/2022 4:35	7/24/2022 15:05	Subtransmission	Distribution	TIE 8014			EQUIPMENT FAILURE
7/24/2022 4:36	7/24/2022 14:00	Subtransmission	Distribution	TIE 8014			EQUIPMENT FAILURE
7/24/2022 4:36	7/24/2022 14:20	Subtransmission	Distribution	TIE 8014			EQUIPMENT FAILURE
7/24/2022 4:46	7/24/2022 11:58	Subtransmission	Distribution	TIE 8014			EQUIPMENT FAILURE
7/24/2022 4:35	7/24/2022 9:41	Subtransmission	Distribution	TIE 8014	124	36872	EQUIPMENT FAILURE
7/24/2022 4:35	7/25/2022 10:00	Subtransmission	Distribution	TIE 8014	1	1740	EQUIPMENT FAILURE
7/24/2022 4:49	7/24/2022 14:27	Subtransmission	None	TIE 8014			EQUIPMENT FAILURE
7/24/2022 1:23	7/24/2022 9:41	Subtransmission	Distribution	TIE 8014	230	68502	EQUIPMENT FAILURE
7/27/2022 15:28	7/27/2022 19:16	Subtransmission	None	TIE 3220			EQUIPMENT FAILURE
7/27/2022 16:25	7/27/2022 20:36	Subtransmission	None	TIE 3220			EQUIPMENT FAILURE
8/2/2022 21:26	8/3/2022 5:20	Subtransmission	Subtransmission	TRK 2247	832	230793	EQUIPMENT FAILURE
8/2/2022 21:26	8/3/2022 5:20	Subtransmission	Subtransmission	TRK 2247	866	242875	EQUIPMENT FAILURE
8/2/2022 21:26	8/3/2022 5:20	Subtransmission	Subtransmission	TRK 2247	545	153341	EQUIPMENT FAILURE
8/2/2022 21:26	8/3/2022 5:21	Subtransmission	Subtransmission	TRK 2247	572	159355	EQUIPMENT FAILURE
8/2/2022 21:26	8/3/2022 5:20	Subtransmission	Subtransmission	TRK 2247	813	226479	EQUIPMENT FAILURE
8/2/2022 21:26	8/3/2022 5:20	Subtransmission	Subtransmission	TRK 2247	1263	354319	EQUIPMENT FAILURE
8/2/2022 21:26	8/3/2022 5:20	Subtransmission	Subtransmission	TRK 2247	642	180637	EQUIPMENT FAILURE
8/2/2022 21:26	8/3/2022 5:20	Subtransmission	Subtransmission	TRK 2247	384	108061	EQUIPMENT FAILURE
8/2/2022 21:26	8/3/2022 5:20	Subtransmission	Subtransmission	TRK 2247	608	169433	EQUIPMENT FAILURE
8/2/2022 9:49	8/2/2022 22:51	Subtransmission	Substation	TRK 2247	298	22574	EQUIPMENT FAILURE
8/2/2022 16:06	8/3/2022 5:20	Subtransmission	Subtransmission	TRK 2247	401	111335	EQUIPMENT FAILURE
8/3/2022 20:57	8/4/2022 10:17	Subtransmission	Distribution	TIE 3705			EQUIPMENT FAILURE
8/3/2022 18:51	8/4/2022 2:00	Subtransmission	Distribution	TIE 3705	1550	370615	EQUIPMENT FAILURE
8/3/2022 20:00	8/4/2022 3:08	Subtransmission	Distribution	TIE 3705	284	127770	EQUIPMENT FAILURE
8/3/2022 18:51	8/4/2022 2:34	Subtransmission	Distribution	TIE 3705	1055	252398	EQUIPMENT FAILURE
8/3/2022 20:35	8/4/2022 2:25	Subtransmission	None	TRK 1229			EQUIPMENT FAILURE
8/4/2022 8:41	8/4/2022 19:49	Subtransmission	None	TIE 3800			EQUIPMENT FAILURE
8/4/2022 8:29	8/4/2022 20:31	Subtransmission	None	TRK 1229			EQUIPMENT FAILURE
8/9/2022 0:33	8/9/2022 5:39	Subtransmission	None	TRK 7324			EQUIPMENT FAILURE
8/20/2022 14:08	8/20/2022 20:57	Subtransmission	None	TRK 2002			EQUIPMENT FAILURE
8/20/2022 14:02	8/21/2022 2:09	Subtransmission	None	TRK 2002			EQUIPMENT FAILURE
8/20/2022 18:33	8/21/2022 14:20	Subtransmission	Distribution	TRK 7324	1313	538616	EQUIPMENT FAILURE
8/21/2022 4:19	8/21/2022 14:27	Subtransmission	Distribution	TRK 7324	872	269063	EQUIPMENT FAILURE
8/21/2022 4:19	8/21/2022 14:29	Subtransmission	Distribution	TRK 7324	1137	575153	EQUIPMENT FAILURE
8/21/2022 4:19	8/21/2022 14:30	Subtransmission	Distribution	TRK 7324	146	38501	EQUIPMENT FAILURE
8/21/2022 4:19	8/21/2022 14:10	Subtransmission	Distribution	TRK 7324	996	504253	EQUIPMENT FAILURE
8/21/2022 4:19	8/21/2022 14:27	Subtransmission	Distribution	TRK 7324	659	127792	EQUIPMENT FAILURE
8/21/2022 4:18	8/21/2022 14:28	Subtransmission	Distribution	TRK 7324	830	254626	EQUIPMENT FAILURE
8/21/2022 4:28	8/21/2022 12:06	Subtransmission	None	TRK 7324			EQUIPMENT FAILURE
8/23/2022 17:18	8/23/2022 21:05	Subtransmission	None	TRK 2002			EQUIPMENT FAILURE
8/27/2022 19:48	8/28/2022 14:09	Subtransmission	None	TRK 2439			EQUIPMENT FAILURE
8/29/2022 7:45	8/29/2022 11:36	Subtransmission	None	TRK 2439			EQUIPMENT FAILURE
8/29/2022 17:42	8/31/2022 11:43	Subtransmission	Distribution	TRK 2826	503	1464085	EQUIPMENT FAILURE
8/29/2022 17:42	8/31/2022 11:41	Subtransmission	Distribution	TRK 2826	646	1592352	EQUIPMENT FAILURE
8/29/2022 17:42	8/31/2022 12:30	Subtransmission	Distribution	TRK 2826	302	740757	EQUIPMENT FAILURE
8/30/2022 10:25	8/31/2022 11:14	Subtransmission	None	TRK 6304			EQUIPMENT FAILURE
8/30/2022 12:43	8/31/2022 18:55	Subtransmission	None	TRK 2826			EQUIPMENT FAILURE

8/31/2022 8:01	8/31/2022 21:08	Subtransmission	None	TIE 6907			EQUIPMENT FAILURE
8/31/2022 7:48	8/31/2022 12:39	Subtransmission	None	TIE 6907			EQUIPMENT FAILURE
9/12/2022 10:03	9/13/2022 12:57	Subtransmission	None	TIE 3220			EQUIPMENT FAILURE
9/12/2022 1:29	9/12/2022 4:17	Subtransmission	None	TRK 2826			EQUIPMENT FAILURE
9/19/2022 21:05	9/19/2022 23:58	Subtransmission	None	TRK 3543			EQUIPMENT FAILURE
9/25/2022 20:51	9/26/2022 5:30	Subtransmission	None	TRK 2255			EQUIPMENT FAILURE
9/25/2022 11:19	9/25/2022 14:48	Subtransmission	None	TRK 2255			EQUIPMENT FAILURE
9/29/2022 17:05	9/29/2022 20:53	Subtransmission	None	TRK 2237			EQUIPMENT FAILURE
10/6/2022 20:39	10/7/2022 1:46	Subtransmission	None	TIE 3220			EQUIPMENT FAILURE
10/6/2022 20:46	10/7/2022 17:19	Subtransmission	None	TIE 3220			EQUIPMENT FAILURE
10/6/2022 20:44	10/6/2022 21:05	Subtransmission	Distribution	TIE 3220	1	51	EQUIPMENT FAILURE
10/6/2022 20:39	10/6/2022 21:05	Subtransmission	Distribution	TIE 3220	1	51	EQUIPMENT FAILURE
10/7/2022 0:16	10/7/2022 0:40	Subtransmission	None	TIE 3220			EQUIPMENT FAILURE
10/13/2022 10:04	10/13/2022 15:25	Subtransmission	None	TRK 2038			EQUIPMENT FAILURE
10/15/2022 16:54	10/16/2022 2:13	Subtransmission	None	TRK 7913			EQUIPMENT FAILURE
10/16/2022 22:23	10/17/2022 16:16	Subtransmission	None	TIE 3800			EQUIPMENT FAILURE
10/16/2022 4:39	10/16/2022 13:38	Subtransmission	None	TRK 4351			EQUIPMENT FAILURE
10/17/2022 18:22	10/18/2022 5:37	Subtransmission	None	TRK 605			EQUIPMENT FAILURE
10/17/2022 17:39	10/18/2022 4:43	Subtransmission	None	TIE 3208			EQUIPMENT FAILURE
10/25/2022 22:27	10/26/2022 5:28	Subtransmission	Distribution	TIE 226	1265	424094	EQUIPMENT FAILURE
10/25/2022 22:27	10/26/2022 5:12	Subtransmission	Distribution	TIE 226	1446	495995	EQUIPMENT FAILURE
10/25/2022 22:33	10/26/2022 4:16	Subtransmission	Distribution	TIE 226	1285	349868	EQUIPMENT FAILURE
10/25/2022 22:29	10/26/2022 4:18	Subtransmission	Distribution	TIE 226	107	37367	EQUIPMENT FAILURE
10/25/2022 23:18	10/26/2022 4:57	Subtransmission	None	TIE 226			EQUIPMENT FAILURE
10/25/2022 22:40	10/26/2022 4:53	Subtransmission	None	TIE 226			EQUIPMENT FAILURE
11/13/2022 11:31	11/13/2022 18:24	Subtransmission	Distribution	TRK 2313	655	264670	EQUIPMENT FAILURE
11/27/2022 14:34	11/27/2022 15:15	Subtransmission	None	TIE 5823			EQUIPMENT FAILURE
11/27/2022 14:32	11/27/2022 16:42	Subtransmission	Distribution	TIE 5823	590	77527	EQUIPMENT FAILURE
11/27/2022 14:37	11/27/2022 20:20	Subtransmission	Distribution	TIE 5823	402	58952	EQUIPMENT FAILURE
11/27/2022 14:33	11/27/2022 15:22	Subtransmission	Distribution	TIE 5823	1	10	EQUIPMENT FAILURE
11/27/2022 14:32	11/27/2022 16:45	Subtransmission	Distribution	TIE 5823	271	36455	EQUIPMENT FAILURE
12/22/2022 21:51	12/24/2022 13:15	Subtransmission	Distribution	TIE 3800	1290	1456476	EQUIPMENT FAILURE
12/22/2022 14:15	12/22/2022 21:07	Subtransmission	None	TRK 2918			EQUIPMENT FAILURE
12/23/2022 12:43	12/23/2022 19:06	Subtransmission	Distribution	TIE 4605	613	28363	EQUIPMENT FAILURE
12/23/2022 13:50	12/23/2022 19:06	Subtransmission	Distribution	TIE 4605	916	27158	EQUIPMENT FAILURE
12/23/2022 17:08	12/24/2022 9:07	Subtransmission	Distribution	TIE 4605	3	3385	EQUIPMENT FAILURE
1/25/2023 16:59	1/25/2023 22:43	Subtransmission	None	TRK 1502			EQUIPMENT FAILURE
1/25/2023 11:37	1/25/2023 18:28	Subtransmission	None	TRK 2313			EQUIPMENT FAILURE
1/28/2023 14:01	1/28/2023 21:02	Subtransmission	None	TIE 810			EQUIPMENT FAILURE
2/17/2023 11:29	2/17/2023 13:58	Subtransmission	Device (II)	TRK 2005	1	719	EQUIPMENT FAILURE
2/17/2023 13:23	2/17/2023 19:58	Subtransmission		TRK 2005			EQUIPMENT FAILURE
2/17/2023 11:29	2/17/2023 20:40	Subtransmission		TRK 2005			EQUIPMENT FAILURE
2/17/2023 11:20	2/17/2023 13:59	Subtransmission	Device (II)	TRK 2005	13	6349	EQUIPMENT FAILURE
2/17/2023 12:08	2/18/2023 17:36	Subtransmission		TRK 2005			EQUIPMENT FAILURE
2/17/2023 21:01	2/18/2023 16:03	Subtransmission		TRK 2005			EQUIPMENT FAILURE
2/19/2023 18:15	2/20/2023 4:47	Subtransmission		TRK 2005			EQUIPMENT FAILURE
2/19/2023 18:27	2/20/2023 5:08	Subtransmission		TRK 2005			EQUIPMENT FAILURE
2/20/2023 1:15	2/20/2023 2:46	Subtransmission	Device (II)	TRK 2005	298	21333	EQUIPMENT FAILURE
2/22/2023 22:00	2/25/2023 7:39	Subtransmission		TIE 1568			EQUIPMENT FAILURE
2/22/2023 22:07	2/25/2023 7:40	Subtransmission		TIE 2819			EQUIPMENT FAILURE
2/22/2023 21:09	2/25/2023 7:38	Subtransmission		TIE 6621			EQUIPMENT FAILURE
2/22/2023 16:39	2/26/2023 23:04	Subtransmission	Subtransmission	TIE 6621	1599	7531171	EQUIPMENT FAILURE
2/22/2023 18:21	2/25/2023 17:59	Subtransmission	Substation	TRK 2035	1170	1572023	EQUIPMENT FAILURE
2/24/2023 9:51	2/26/2023 9:34	Subtransmission		TIE 5513			EQUIPMENT FAILURE
2/25/2023 11:54	2/25/2023 20:33	Subtransmission		TIE 6517			EQUIPMENT FAILURE
3/1/2023 3:08	3/1/2023 4:16	Subtransmission	Substation	TIE 6138	2	329	EQUIPMENT FAILURE
3/1/2023 3:27	3/3/2023 6:17	Subtransmission		TIE 6138			EQUIPMENT FAILURE
3/3/2023 17:49	3/6/2023 10:11	Subtransmission		TRK 2107			EQUIPMENT FAILURE
3/3/2023 17:49	3/4/2023 21:36	Subtransmission	Circuit Level	TRK 2107			EQUIPMENT FAILURE
3/3/2023 22:07	3/5/2023 17:00	Subtransmission		TRK 6842			EQUIPMENT FAILURE
3/4/2023 7:28	3/8/2023 17:27	Subtransmission		TRK 6842			EQUIPMENT FAILURE
3/17/2023 14:03	3/22/2023 23:14	Subtransmission		TRK 2002			EQUIPMENT FAILURE
3/20/2023 15:19	3/21/2023 6:11	Subtransmission		TRK 5938			EQUIPMENT FAILURE
3/31/2023 22:55	3/31/2023 23:11	Subtransmission	Device (II)	TRK 3557			EQUIPMENT FAILURE
3/31/2023 22:42	4/1/2023 14:49	Subtransmission		TRK 3557			EQUIPMENT FAILURE
3/31/2023 22:31	4/5/2023 13:07	Subtransmission		TRK 3557			EQUIPMENT FAILURE
3/31/2023 22:28	3/31/2023 23:18	Subtransmission	Circuit Level	TRK 3557			EQUIPMENT FAILURE
3/31/2023 22:55	3/31/2023 23:10	Subtransmission	Circuit Level	TRK 3557			EQUIPMENT FAILURE
4/1/2023 14:40	4/4/2023 13:31	Subtransmission		TRK 3557			EQUIPMENT FAILURE
4/12/2023 10:02	4/14/2023 17:42	Subtransmission		TRK 4227			EQUIPMENT FAILURE
4/23/2023 16:58	4/30/2023 21:22	Subtransmission		TRK 2308			EQUIPMENT FAILURE
4/30/2023 18:14	5/1/2023 22:59	Subtransmission		TRK 5145			EQUIPMENT FAILURE
5/7/2023 8:40	5/7/2023 16:26	Subtransmission		TRK 1218			EQUIPMENT FAILURE
5/26/2023 6:41	5/26/2023 9:15	Subtransmission	Circuit Level	TRK 564	223	18654	EQUIPMENT FAILURE
5/26/2023 6:41	5/26/2023 9:07	Subtransmission	Circuit Level	TRK 564	356	29718	EQUIPMENT FAILURE
5/26/2023 6:41	5/26/2023 9:15	Subtransmission	Circuit Level	TRK 564	340	28450	EQUIPMENT FAILURE
5/26/2023 6:30	5/26/2023 9:07	Subtransmission	Circuit Level	TRK 564	97	8117	EQUIPMENT FAILURE
5/30/2023 17:54	5/31/2023 13:05	Subtransmission		TIE 7621			EQUIPMENT FAILURE
5/31/2023 17:38	6/1/2023 5:26	Subtransmission		TRK 2629			EQUIPMENT FAILURE
6/1/2023 18:44	6/2/2023 3:09	Subtransmission		TRK 824	1	373	EQUIPMENT FAILURE
6/1/2023 18:38	6/2/2023 2:11	Subtransmission	Subtransmission	TRK 824	1727	646197	EQUIPMENT FAILURE
6/2/2023 2:59	6/2/2023 11:04	Subtransmission	Single Customer	TRK 824			EQUIPMENT FAILURE
6/13/2023 9:27	6/14/2023 20:37	Subtransmission	Service Secondary	TIE 7733			EQUIPMENT FAILURE
6/14/2023 10:08	6/14/2023 12:55	Subtransmission	Circuit Level	TRK 4911	475	17566	EQUIPMENT FAILURE
6/15/2023 18:40	6/17/2023 8:45	Subtransmission		TRK 2002			EQUIPMENT FAILURE
6/15/2023 16:36	6/18/2023 8:53	Subtransmission		TRK 3632			EQUIPMENT FAILURE
6/16/2023 0:43	1/11/2024 22:33	Subtransmission		TRK 2002			EQUIPMENT FAILURE
6/23/2023 8:08	6/23/2023 14:59	Subtransmission	Circuit Level	TRK 2032	1838	522622	EQUIPMENT FAILURE
6/23/2023 8:09	6/23/2023 15:30	Subtransmission	Circuit Level	TRK 2032	1944	678713	EQUIPMENT FAILURE
6/23/2023 7:53	6/23/2023 8:13	Subtransmission		TRK 2032			EQUIPMENT FAILURE
6/23/2023 8:26	6/23/2023 11:25	Subtransmission	Single Customer	TRK 2032			EQUIPMENT FAILURE
6/25/2023 15:22	6/25/2023 16:21	Subtransmission		TRK 5127			EQUIPMENT FAILURE
6/25/2023 16:30	6/25/2023 21:53	Subtransmission		TRK 5127			EQUIPMENT FAILURE
6/25/2023 16:23	6/25/2023 21:35	Subtransmission	Subtransmission	TRK 5127	1669	292441	EQUIPMENT FAILURE
6/25/2023 16:23	6/26/2023 14:26	Subtransmission	Subtransmission	TRK 5127	3220	715814	EQUIPMENT FAILURE
6/26/2023 10:03	6/26/2023 11:29	Subtransmission		TIE 7702			EQUIPMENT FAILURE
6/26/2023 0:47	6/27/2023 13:58	Subtransmission		TIE 7702			EQUIPMENT FAILURE
6/26/2023 7:08	6/27/2023 10:35	Subtransmission		TIE 7702			EQUIPMENT FAILURE
6/26/2023 7:29	6/27/2023 10:48	Subtransmission	Single Customer	TIE 7702	1	1951	EQUIPMENT FAILURE
6/28/2023 22:40	6/29/2023 11:51	Subtransmission	Subtransmission	TRK 5127	2192	568704	EQUIPMENT FAILURE
6/28/2023 22:40	6/29/2023 11:50	Subtransmission	Subtransmission	TRK 5127	1674	434756	EQUIPMENT FAILURE
6/29/2023 3:19	6/29/2023 9:03	Subtransmission	Circuit Level	TRK 5127	682	387281	EQUIPMENT FAILURE
6/29/2023 3:20	6/29/2023 9:01	Subtransmission	Circuit Level	TRK 5127	381	217371	EQUIPMENT FAILURE
6/29/2023 3:16	6/29/2023 8:29	Subtransmission	Single Customer	TRK 5127			EQUIPMENT FAILURE
6/29/2023 4:37	6/29/2023 8:24	Subtransmission	Single Customer	TRK 5127			EQUIPMENT FAILURE

7/2/2023 1:51	7/5/2023 18:16	Subtransmission		TIE 2819			EQUIPMENT FAILURE
7/2/2023 1:43	7/2/2023 9:26	Subtransmission	Service Transformer	TIE 2819	7	581	EQUIPMENT FAILURE
7/2/2023 1:40	7/2/2023 16:12	Subtransmission	Substation	TIE 2819	4829	400312	EQUIPMENT FAILURE
7/9/2023 15:46	7/10/2023 2:15	Subtransmission		TIE 817			EQUIPMENT FAILURE
7/9/2023 21:30	7/9/2023 22:18	Subtransmission	Single Customer	TIE 817	1	316	EQUIPMENT FAILURE
7/9/2023 15:43	7/10/2023 3:20	Subtransmission	Subtransmission	TIE 817	6318	2204582	EQUIPMENT FAILURE
7/9/2023 16:02	7/10/2023 0:27	Subtransmission		TIE 817			EQUIPMENT FAILURE
7/11/2023 20:34	7/12/2023 11:41	Subtransmission	Subtransmission	TRK 1418	247	68086	EQUIPMENT FAILURE
7/19/2023 13:19	7/19/2023 14:51	Subtransmission	Circuit Level	TIE 9303			EQUIPMENT FAILURE
7/19/2023 13:56	7/19/2023 20:55	Subtransmission		TIE 9303			EQUIPMENT FAILURE
7/19/2023 13:20	7/20/2023 1:02	Subtransmission	Single Customer	TIE 9303			EQUIPMENT FAILURE
7/20/2023 16:18	7/22/2023 14:08	Subtransmission		TIE 6117			EQUIPMENT FAILURE
7/20/2023 19:11	7/21/2023 12:46	Subtransmission		TRK 359			EQUIPMENT FAILURE
7/26/2023 16:26	7/27/2023 5:30	Subtransmission		TRK 4911			EQUIPMENT FAILURE
7/26/2023 16:18	7/28/2023 17:09	Subtransmission		TRK 4911			EQUIPMENT FAILURE
7/27/2023 13:24	7/27/2023 21:04	Subtransmission	Subtransmission	TRK 4911	601	78962	EQUIPMENT FAILURE
7/27/2023 7:39	7/28/2023 17:40	Subtransmission	Circuit Level	TRK 2922	88	5561	EQUIPMENT FAILURE
8/6/2023 21:11	8/7/2023 10:10	Subtransmission		TRK 2543			EQUIPMENT FAILURE
8/6/2023 16:32	8/6/2023 18:51	Subtransmission		TRK 2543			EQUIPMENT FAILURE
8/7/2023 22:11	8/9/2023 8:49	Subtransmission		TRK 776			EQUIPMENT FAILURE
8/8/2023 7:35	8/8/2023 16:09	Subtransmission	Subtransmission	TRK 2826	500	44038	EQUIPMENT FAILURE
8/8/2023 7:49	8/8/2023 13:17	Subtransmission	Single Customer	TRK 2826	1	88	EQUIPMENT FAILURE
8/8/2023 10:53	8/8/2023 23:40	Subtransmission	Circuit Level	TRK 2826	1558	48285	EQUIPMENT FAILURE
8/8/2023 7:44	8/8/2023 17:40	Subtransmission	Single Customer	TRK 2826	1	88	EQUIPMENT FAILURE
8/8/2023 9:07	8/8/2023 18:39	Subtransmission	Single Customer	TRK 2826			EQUIPMENT FAILURE
8/8/2023 8:41	8/8/2023 16:50	Subtransmission	Subtransmission	TRK 2826	1219	107367	EQUIPMENT FAILURE
8/8/2023 8:24	8/10/2023 11:42	Subtransmission		TRK 2826			EQUIPMENT FAILURE
8/8/2023 9:17	8/8/2023 13:53	Subtransmission		TRK 2826			EQUIPMENT FAILURE
8/21/2023 5:16	8/21/2023 9:29	Subtransmission	Circuit Level	TIE 1467	10	3233	EQUIPMENT FAILURE
8/24/2023 11:49	8/28/2023 23:22	Subtransmission		TRK 1340			EQUIPMENT FAILURE
8/24/2023 22:14	8/26/2023 9:14	Subtransmission		TIE 6138			EQUIPMENT FAILURE
8/25/2023 15:00	8/26/2023 20:33	Subtransmission	Circuit Level	TIE 6147	2778	3410845	EQUIPMENT FAILURE
8/25/2023 11:13	8/25/2023 13:52	Subtransmission		TIE 6147			EQUIPMENT FAILURE
8/25/2023 1:59	8/26/2023 16:02	Subtransmission		TRK 2439			EQUIPMENT FAILURE
9/5/2023 2:48	9/16/2023 15:09	Subtransmission		TRK 4338			EQUIPMENT FAILURE
9/28/2023 15:57	9/28/2023 19:20	Subtransmission		TRK 5938			EQUIPMENT FAILURE
10/27/2023 19:28	10/28/2023 0:34	Subtransmission	Device (II)	TRK 1251	28	5212	EQUIPMENT FAILURE
11/17/2023 22:28	11/18/2023 19:49	Subtransmission	Device (II)	TRK 2010	31	49117	EQUIPMENT FAILURE
12/18/2023 15:41	12/19/2023 6:14	Subtransmission		TRK 5145			EQUIPMENT FAILURE
12/24/2023 21:57	12/29/2023 10:50	Subtransmission		TRK 3124			EQUIPMENT FAILURE
6/2/2020 7:27	6/2/2020 10:58	Subtransmission	None	TRK 7106			EQUIPMENT LOADING
6/2/2020 17:40	6/2/2020 18:42	Subtransmission	Distribution	TRK 7106	1285	68185	EQUIPMENT LOADING
6/11/2022 6:29	6/11/2022 16:16	Subtransmission	None	TRK 2418			EQUIPMENT LOADING
6/13/2022 1:27	6/13/2022 6:31	Subtransmission	None	TRK 2471			EQUIPMENT LOADING
9/4/2023 19:13	9/5/2023 3:08	Subtransmission	Circuit Level	TRK 359			EQUIPMENT LOADING
9/4/2023 19:41	9/5/2023 3:08	Subtransmission	Circuit Level	TRK 359			EQUIPMENT LOADING
9/4/2023 19:13	9/5/2023 3:05	Subtransmission	Circuit Level	TRK 359			EQUIPMENT LOADING
9/4/2023 19:34	9/5/2023 3:08	Subtransmission	Circuit Level	TRK 359			EQUIPMENT LOADING
2/23/2023 8:09	2/25/2023 7:43	Subtransmission		TIE 4501			ICE
2/23/2023 6:51	2/25/2023 7:42	Subtransmission		TRK 7702			ICE
2/25/2023 7:52	2/25/2023 17:07	Subtransmission		TIE 8804			ICE
3/4/2023 9:25	3/4/2023 20:01	Subtransmission		TRK 2918			ICE
6/24/2018 9:35	6/24/2018 18:33	Subtransmission	None	TIE 9111			LIGHTNING
2/26/2018 10:35	2/26/2018 14:37	Subtransmission	None	TRK 2510			PUBLIC INTERFERENCE
1/7/2019 12:48	1/8/2019 15:30	Subtransmission	None	TRK 7909			PUBLIC INTERFERENCE
2/21/2019 8:16	2/21/2019 13:01	Subtransmission	None	TRK 4351			PUBLIC INTERFERENCE
3/22/2019 8:53	3/22/2019 16:05	Subtransmission	None	TRK 2715			PUBLIC INTERFERENCE
4/26/2019 17:56	4/26/2019 20:59	Subtransmission	None	TIE 3245			PUBLIC INTERFERENCE
5/11/2019 9:19	5/11/2019 19:39	Subtransmission	None	TRK 2510			PUBLIC INTERFERENCE
5/26/2019 7:03	5/26/2019 10:22	Subtransmission	None	TRK 2519			PUBLIC INTERFERENCE
5/28/2019 12:02	5/29/2019 7:18	Subtransmission	None	TRK 7411			PUBLIC INTERFERENCE
6/27/2019 22:31	6/28/2019 5:24	Subtransmission	None	TRK 3646			PUBLIC INTERFERENCE
12/8/2019 22:35	12/9/2019 13:28	Subtransmission	None	TRK 7150			PUBLIC INTERFERENCE
12/8/2019 20:24	12/9/2019 6:31	Subtransmission	None	TRK 7150			PUBLIC INTERFERENCE
9/24/2020 8:18	9/24/2020 9:47	Subtransmission	Distribution	TIE 7520	193	11335	PUBLIC INTERFERENCE
9/24/2020 8:26	9/24/2020 18:44	Subtransmission	None	TIE 7520			PUBLIC INTERFERENCE
9/24/2020 8:19	9/24/2020 9:45	Subtransmission	Distribution	TIE 7520	21	1220	PUBLIC INTERFERENCE
9/24/2020 8:16	9/24/2020 9:45	Subtransmission	Distribution	TIE 7520	159	17898	PUBLIC INTERFERENCE
10/11/2021 4:21	10/11/2021 6:11	Subtransmission	None	TIE 5823			PUBLIC INTERFERENCE
10/11/2021 4:10	10/11/2021 5:19	Subtransmission	Distribution	TIE 5823	688	45764	PUBLIC INTERFERENCE
10/11/2021 4:36	10/11/2021 12:29	Subtransmission	None	TIE 5823			PUBLIC INTERFERENCE
10/11/2021 4:38	10/11/2021 12:13	Subtransmission	None	TIE 5823			PUBLIC INTERFERENCE
11/29/2021 9:53	11/29/2021 11:23	Subtransmission	None	TIE 6602			PUBLIC INTERFERENCE
5/2/2022 15:29	5/3/2022 0:57	Subtransmission	None	TRK 346			PUBLIC INTERFERENCE
9/3/2022 7:38	9/3/2022 17:33	Subtransmission	None	TRK 4316			PUBLIC INTERFERENCE
9/3/2022 7:26	9/3/2022 17:10	Subtransmission	Distribution	TRK 4316	5	2895	PUBLIC INTERFERENCE
9/3/2022 7:36	9/3/2022 17:33	Subtransmission	None	TRK 4316			PUBLIC INTERFERENCE
11/16/2022 17:50	11/17/2022 0:59	Subtransmission	None	TRK 4316			PUBLIC INTERFERENCE
11/18/2022 8:29	11/18/2022 14:26	Subtransmission	None	TRK 3508			PUBLIC INTERFERENCE
8/25/2023 9:34	8/25/2023 15:14	Subtransmission		TRK 781			PUBLIC INTERFERENCE
11/18/2023 22:22	11/29/2023 20:08	Subtransmission		TRK 2806			PUBLIC INTERFERENCE
11/18/2023 22:12	11/19/2023 5:24	Subtransmission	Device (II)	TRK 2806	484	37346	PUBLIC INTERFERENCE
2/23/2018 11:53	2/23/2018 15:00	Subtransmission	Distribution	TIE 4109	133	18760	TREE
2/23/2018 7:23	2/23/2018 10:00	Subtransmission	Distribution	TIE 4109	781	109650	TREE
2/23/2018 7:45	2/23/2018 18:36	Subtransmission	None	TIE 4109			TREE
2/23/2018 7:23	2/23/2018 9:05	Subtransmission	Distribution	TIE 4109	417	38224	TREE
2/23/2018 7:23	2/23/2018 9:06	Subtransmission	Distribution	TIE 4109	645	59825	TREE
2/25/2018 15:59	2/27/2018 1:22	Subtransmission	None	TIE4105			TREE
4/14/2018 19:27	4/15/2018 19:49	Subtransmission	None	TIE 3208			TREE
4/14/2018 9:22	4/14/2018 18:17	Subtransmission	None	TIE 3208			TREE
4/15/2018 7:05	4/15/2018 23:00	Subtransmission	Distribution	TIE 1467	1154	931231	TREE
4/15/2018 7:05	4/15/2018 12:43	Subtransmission	Distribution	TIE 1467	420	129082	TREE
4/15/2018 7:05	4/15/2018 21:30	Subtransmission	Distribution	TIE 1467	731	647929	TREE
4/15/2018 8:18	4/15/2018 18:39	Subtransmission	None	TRK 2002			TREE
4/15/2018 8:39	4/15/2018 17:30	Subtransmission	None	TRK 2002			TREE
4/15/2018 8:16	4/15/2018 18:38	Subtransmission	None	TRK 2002			TREE
5/5/2018 12:02	5/8/2018 0:58	Subtransmission	None	TIE 4109			TREE
5/8/2018 8:31	5/8/2018 15:08	Subtransmission	None	TIE 2812			TREE
5/8/2018 10:45	5/8/2018 20:14	Subtransmission	None	TRK 7150			TREE
5/27/2018 12:30	5/27/2018 15:46	Subtransmission	None	TRK 2636			TREE
5/27/2018 15:47	5/27/2018 21:24	Subtransmission	None	TRK 2636			TREE
5/29/2018 14:32	5/30/2018 1:26	Subtransmission	None	TRK 7062			TREE
5/30/2018 22:42	5/31/2018 14:03	Subtransmission	None	TIE 5843			TREE
7/15/2018 22:04	7/16/2018 10:24	Subtransmission	Distribution	TRK 4416	845	624346	TREE
7/15/2018 23:05	7/16/2018 0:56	Subtransmission	None	TRK 4416			TREE

7/16/2018 16:25	7/17/2018 6:35	Subtransmission	None	TIE 6147			TREE
7/16/2018 16:17	7/16/2018 22:29	Subtransmission	Distribution	TIE 6147	277	99561	TREE
7/26/2018 21:09	7/27/2018 19:45	Subtransmission	Distribution	TIE 1544	464	74568	TREE
8/2/2018 12:53	8/2/2018 14:14	Subtransmission	Subtransmission	TIE 4109	390	31375	TREE
8/2/2018 12:53	8/2/2018 14:14	Subtransmission	Subtransmission	TIE 4109	633	51273	TREE
8/2/2018 12:58	8/2/2018 23:52	Subtransmission	None	TIE 4109			TREE
8/2/2018 12:52	8/2/2018 21:40	Subtransmission	Distribution	TIE 4109	747	241650	TREE
10/17/2018 9:27	10/17/2018 18:42	Subtransmission	None	TRK 2025			TREE
12/27/2018 18:46	12/27/2018 22:42	Subtransmission	Distribution	TIE 9111	406	69809	TREE
12/27/2018 19:55	12/28/2018 4:26	Subtransmission	None	TIE 9111			TREE
12/27/2018 19:50	12/27/2018 22:42	Subtransmission	Distribution	TIE 9111	673	117081	TREE
12/28/2018 17:14	12/28/2018 20:24	Subtransmission	None	TRK 7122			TREE
12/28/2018 17:14	12/28/2018 18:11	Subtransmission	None	TRK 7122			TREE
12/28/2018 17:17	12/28/2018 20:16	Subtransmission	None	TRK 7122			TREE
12/31/2018 23:06	1/1/2019 14:32	Subtransmission	None	TIE 3245			TREE
12/31/2018 22:56	1/1/2019 0:52	Subtransmission	Distribution	TIE 3245	345	41048	TREE
1/2/2019 15:32	1/2/2019 20:04	Subtransmission	None	TRK 5145			TREE
1/7/2019 7:00	1/7/2019 15:21	Subtransmission	Distribution	TIE 4109	685	298827	TREE
1/7/2019 7:58	1/7/2019 15:15	Subtransmission	Distribution	TIE 4109	477	207740	TREE
1/7/2019 7:58	1/7/2019 12:15	Subtransmission	Distribution	TIE 4109	803	209534	TREE
2/7/2019 23:02	2/8/2019 16:25	Subtransmission	None	TIE 7621			TREE
2/19/2019 21:03	2/19/2019 23:15	Subtransmission	None	TIE 182			TREE
2/24/2019 15:20	2/24/2019 20:48	Subtransmission	None	TIE 4501			TREE
2/24/2019 23:00	2/25/2019 3:02	Subtransmission	Distribution	TIE 4708	478	119679	TREE
2/24/2019 23:00	2/25/2019 17:00	Subtransmission	Distribution	TIE 4708	580	640007	TREE
2/24/2019 23:08	2/25/2019 17:53	Subtransmission	None	TIE 4708			TREE
2/24/2019 23:00	2/25/2019 3:30	Subtransmission	Distribution	TIE 4708	1564	381393	TREE
2/24/2019 23:07	2/25/2019 3:30	Subtransmission	Distribution	TIE 4708	1	243	TREE
2/24/2019 23:00	2/25/2019 3:00	Subtransmission	Distribution	TIE 4708	657	221569	TREE
2/24/2019 19:25	2/25/2019 3:02	Subtransmission	Distribution	TIE 4708	529	129200	TREE
2/24/2019 14:35	2/24/2019 16:48	Subtransmission	Subtransmission	TIE 6138	1636	200145	TREE
2/24/2019 14:40	2/24/2019 18:20	Subtransmission	Distribution	TIE 6138	1406	171770	TREE
2/24/2019 14:31	2/25/2019 1:00	Subtransmission	Distribution	TIE 6138	1532	343187	TREE
2/24/2019 12:12	2/24/2019 18:14	Subtransmission	Distribution	TIE 6138	2461	366895	TREE
2/24/2019 15:40	2/25/2019 14:09	Subtransmission	Distribution	TIE 6602	323	409805	TREE
2/24/2019 15:40	2/24/2019 20:40	Subtransmission	Distribution	TIE 6602	137	41051	TREE
2/24/2019 11:08	2/25/2019 20:10	Subtransmission	None	TRK 5145			TREE
2/24/2019 13:37	2/25/2019 19:05	Subtransmission	None	TRK 5145			TREE
2/24/2019 10:30	2/24/2019 21:13	Subtransmission	None	TRK 5404			TREE
2/25/2019 7:04	2/25/2019 15:29	Subtransmission	None	TIE 4708			TREE
2/25/2019 11:52	2/25/2019 21:13	Subtransmission	None	TIE 4708			TREE
2/25/2019 7:08	2/25/2019 12:32	Subtransmission	None	TIE 6138			TREE
2/25/2019 1:02	2/25/2019 20:19	Subtransmission	None	TRK 5145			TREE
3/11/2019 16:45	3/12/2019 3:13	Subtransmission	None	TIE 3410			TREE
3/30/2019 5:48	3/30/2019 8:54	Subtransmission	None	TIE 3402			TREE
3/30/2019 5:10	3/30/2019 12:54	Subtransmission	None	TIE 3402			TREE
3/30/2019 5:17	3/30/2019 6:50	Subtransmission	Distribution	TIE 3402	311	29037	TREE
4/13/2019 13:40	4/13/2019 19:45	Subtransmission	None	TIE 807			TREE
4/13/2019 15:21	4/13/2019 21:16	Subtransmission	None	TIE 807			TREE
4/13/2019 10:57	4/13/2019 12:45	Subtransmission	None	TIE 807			TREE
4/14/2019 20:04	4/14/2019 22:00	Subtransmission	Subtransmission	TIE 3208	511	60815	TREE
4/14/2019 20:04	4/14/2019 22:00	Subtransmission	Subtransmission	TIE 3208	477	56668	TREE
4/28/2019 4:51	4/28/2019 8:30	Subtransmission	Distribution	TIE 2648	1560	27435	TREE
4/28/2019 4:50	4/28/2019 8:30	Subtransmission	Distribution	TIE 2648	771	21337	TREE
4/28/2019 4:59	4/28/2019 8:00	Subtransmission	Distribution	TIE 2648	1287	60533	TREE
4/28/2019 5:03	4/28/2019 16:44	Subtransmission	None	TIE 2648			TREE
5/23/2019 6:29	5/23/2019 13:07	Subtransmission	Distribution	TIE 1473	874	261946	TREE
5/23/2019 5:58	5/23/2019 11:28	Subtransmission	None	TIE 3417			TREE
7/3/2019 0:51	7/4/2019 1:10	Subtransmission	None	TRK 1232			TREE
7/5/2019 17:09	7/5/2019 20:00	Subtransmission	None	TIE 7745			TREE
7/5/2019 17:25	7/5/2019 20:38	Subtransmission	None	TIE 7745			TREE
7/5/2019 17:05	7/6/2019 15:06	Subtransmission	None	TIE 7745			TREE
7/5/2019 16:57	7/5/2019 21:35	Subtransmission	None	TIE 7745			TREE
7/7/2019 7:34	7/7/2019 15:43	Subtransmission	None	TRK 7122			TREE
7/20/2019 7:53	7/20/2019 16:58	Subtransmission	None	TIE 1544			TREE
7/20/2019 22:30	7/21/2019 21:06	Subtransmission	None	TIE 3245			TREE
7/20/2019 21:37	7/21/2019 11:30	Subtransmission	Distribution	TIE 3245	3	3486	TREE
7/22/2019 0:38	7/23/2019 14:28	Subtransmission	None	TIE 4501			TREE
7/27/2019 16:57	7/28/2019 16:33	Subtransmission	None	TIE 9107			TREE
7/28/2019 19:26	8/1/2019 11:57	Subtransmission	None	TIE 6147			TREE
7/28/2019 17:15	7/29/2019 0:30	Subtransmission	Distribution	TIE 6147	552	238137	TREE
8/17/2019 18:22	8/18/2019 19:57	Subtransmission	None	TIE 3241			TREE
8/26/2019 12:17	8/27/2019 10:30	Subtransmission	Distribution	TIE 3241	1	6	TREE
9/5/2019 12:44	9/5/2019 13:28	Subtransmission	None	TIE 5513			TREE
9/5/2019 12:48	9/5/2019 18:06	Subtransmission	None	TIE 5513			TREE
9/11/2019 11:38	9/11/2019 17:55	Subtransmission	None	TIE 3205			TREE
9/11/2019 11:37	9/11/2019 14:38	Subtransmission	None	TIE 3205			TREE
9/13/2019 15:20	9/13/2019 23:01	Subtransmission	None	TIE 4501			TREE
9/23/2019 11:41	9/23/2019 17:43	Subtransmission	None	TIE 3203			TREE
9/23/2019 14:01	9/23/2019 18:00	Subtransmission	Distribution	TIE 3203	518	112016	TREE
9/23/2019 12:25	9/23/2019 18:25	Subtransmission	None	TIE 3203			TREE
10/17/2019 13:34	10/17/2019 16:34	Subtransmission	Distribution	TRK 5145	1039	161273	TREE
10/17/2019 13:34	10/17/2019 16:34	Subtransmission	Distribution	TRK 5145	170	26298	TREE
10/17/2019 13:34	10/17/2019 16:44	Subtransmission	Distribution	TRK 5145	361	63359	TREE
10/17/2019 13:34	10/17/2019 16:40	Subtransmission	Distribution	TRK 5145	640	110725	TREE
10/17/2019 13:34	10/17/2019 16:42	Subtransmission	Distribution	TRK 5145	407	69982	TREE
10/17/2019 13:34	10/17/2019 16:34	Subtransmission	Distribution	TRK 5145	403	58473	TREE
10/19/2019 10:35	10/19/2019 11:53	Subtransmission	Distribution	TIE 3410	6	484	TREE
10/19/2019 13:58	10/19/2019 19:19	Subtransmission	Distribution	TIE 3410	41	8280	TREE
10/19/2019 14:07	10/19/2019 21:00	Subtransmission	None	TIE 3410			TREE
10/22/2019 0:07	10/22/2019 5:28	Subtransmission	None	TIE 3241			TREE
10/22/2019 0:09	10/22/2019 4:50	Subtransmission	None	TIE 3241			TREE
10/27/2019 5:09	10/27/2019 15:09	Subtransmission	None	TIE 7140			TREE
10/27/2019 11:11	10/27/2019 14:45	Subtransmission	None	TIE 7430			TREE
10/27/2019 4:29	10/27/2019 14:45	Subtransmission	Distribution	TIE 7430	1531	591662	TREE
11/1/2019 0:21	11/1/2019 20:39	Subtransmission	None	TIE 3410			TREE
11/20/2019 10:38	11/20/2019 20:06	Subtransmission	None	TIE 3209			TREE
11/27/2019 14:35	11/27/2019 20:47	Subtransmission	None	TIE 3417			TREE
11/27/2019 13:15	11/27/2019 20:09	Subtransmission	None	TIE 3417			TREE
12/1/2019 3:21	12/1/2019 10:30	Subtransmission	Distribution	TIE 5829	1191	228806	TREE
12/5/2019 13:16	12/5/2019 22:03	Subtransmission	None	TIE 3323			TREE
12/5/2019 16:37	12/5/2019 18:48	Subtransmission	None	TIE 3323			TREE
12/26/2019 10:53	12/26/2019 20:26	Subtransmission	None	TIE 3208			TREE
12/30/2019 7:33	12/30/2019 10:27	Subtransmission	None	TIE 4605			TREE
12/30/2019 11:46	12/30/2019 16:00	Subtransmission	Distribution	TIE 4605	179	41708	TREE

3/10/2020 17:36	3/10/2020 18:29	Subtransmission	None	TIE 3208			TREE
3/17/2020 5:32	3/17/2020 12:53	Subtransmission	None	TIE 3323			TREE
3/17/2020 14:57	3/17/2020 22:47	Subtransmission	None	TIE 3323			TREE
4/13/2020 15:32	4/13/2020 20:38	Subtransmission	None	TIE 3206			TREE
4/13/2020 17:10	4/13/2020 22:09	Subtransmission	None	TIE 3206			TREE
4/21/2020 0:27	4/21/2020 0:34	Subtransmission	None	TRK 6125			TREE
4/21/2020 0:20	4/21/2020 2:32	Subtransmission	Distribution	TRK 6125	163	26880	TREE
4/21/2020 7:05	4/21/2020 19:08	Subtransmission	None	TRK 6125			TREE
5/28/2020 18:43	5/28/2020 20:30	Subtransmission	Distribution	TRK 2010	11	189	TREE
5/28/2020 18:53	6/1/2020 12:58	Subtransmission	None	TRK 2010			TREE
6/3/2020 3:40	6/3/2020 13:08	Subtransmission	Distribution	TIE 6931	1062	537363	TREE
6/3/2020 4:01	6/3/2020 16:05	Subtransmission	None	TIE 6931			TREE
6/3/2020 11:47	6/3/2020 15:58	Subtransmission	Distribution	TIE 6931	163	40395	TREE
6/10/2020 14:13	6/11/2020 22:13	Subtransmission	Distribution	TIE 3209	608	1062043	TREE
6/10/2020 16:09	6/11/2020 7:17	Subtransmission	Distribution	TIE 4523	392	160996	TREE
6/10/2020 16:46	6/13/2020 13:26	Subtransmission	None	TIE 4523			TREE
6/10/2020 16:05	6/11/2020 1:30	Subtransmission	Distribution	TIE 4523	600	250665	TREE
6/11/2020 21:27	6/14/2020 6:37	Subtransmission	None	TIE 8505			TREE
6/11/2020 21:45	6/12/2020 2:15	Subtransmission	None	TIE 8505			TREE
7/19/2020 10:21	7/19/2020 16:50	Subtransmission	Distribution	TIE 4708	537	351823	TREE
7/19/2020 10:27	7/19/2020 21:15	Subtransmission	None	TIE 4708			TREE
8/10/2020 16:27	8/10/2020 16:53	Subtransmission	Distribution	TRK 6759	1266	25477	TREE
8/18/2020 10:33	8/18/2020 21:04	Subtransmission	None	TRK 2035			TREE
8/29/2020 1:56	8/29/2020 16:42	Subtransmission	None	TRK 7114			TREE
8/29/2020 2:01	8/29/2020 9:29	Subtransmission	None	TRK 7114			TREE
8/31/2020 10:34	8/31/2020 15:07	Subtransmission	None	TRK 7114			TREE
9/2/2020 10:10	9/2/2020 14:53	Subtransmission	None	TRK 7114			TREE
9/11/2020 16:45	9/11/2020 20:32	Subtransmission	None	TRK 1563			TREE
9/11/2020 1:52	9/11/2020 14:56	Subtransmission	None	TRK 1563			TREE
9/11/2020 1:41	9/11/2020 2:40	Subtransmission	Distribution	TRK 1563	204	16268	TREE
9/12/2020 10:25	9/15/2020 19:02	Subtransmission	None	TRK 1563			TREE
10/4/2020 9:26	10/4/2020 11:27	Subtransmission	None	TRK 5145			TREE
10/23/2020 13:51	10/23/2020 22:34	Subtransmission	Distribution	TIE 7702	539	280793	TREE
10/31/2020 13:46	10/31/2020 14:48	Subtransmission	Subtransmission	TIE 9111	1144	142654	TREE
10/31/2020 13:56	11/1/2020 0:42	Subtransmission	Distribution	TIE 9111			TREE
10/31/2020 14:04	10/31/2020 20:15	Subtransmission	None	TIE 9111			TREE
11/15/2020 13:56	11/17/2020 18:12	Subtransmission	None	TIE 3318			TREE
11/15/2020 14:50	11/16/2020 19:21	Subtransmission	None	TIE 3318			TREE
11/16/2020 13:15	11/18/2020 20:48	Subtransmission	None	TIE 4109			TREE
11/18/2020 15:44	11/18/2020 17:10	Subtransmission	Distribution	TIE 4109	166	14318	TREE
12/24/2020 4:12	12/24/2020 10:58	Subtransmission	None	TIE 226			TREE
12/24/2020 4:12	12/24/2020 14:11	Subtransmission	None	TIE 226			TREE
12/24/2020 4:10	12/24/2020 12:08	Subtransmission	Distribution	TIE 226	1032	238732	TREE
12/24/2020 4:40	12/24/2020 10:00	Subtransmission	Distribution	TIE 226	16	3165	TREE
12/24/2020 4:31	12/24/2020 6:07	Subtransmission	Distribution	TIE 226	1444	141474	TREE
12/24/2020 4:49	12/24/2020 14:32	Subtransmission	None	TIE 226			TREE
12/24/2020 4:28	12/24/2020 4:44	Subtransmission	None	TIE 226			TREE
12/24/2020 4:28	12/24/2020 6:07	Subtransmission	Distribution	TIE 226	1292	129328	TREE
12/24/2020 15:53	12/24/2020 22:21	Subtransmission	None	TIE 8511			TREE
12/24/2020 4:35	12/24/2020 12:30	Subtransmission	Distribution	TIE 8511	1	439	TREE
12/24/2020 4:48	12/24/2020 6:17	Subtransmission	Distribution	TIE 8511	45	3725	TREE
3/4/2021 5:39	3/4/2021 15:10	Subtransmission	None	TIE 3241			TREE
6/8/2021 16:17	6/8/2021 18:00	Subtransmission	Distribution	TRK 8215	867	82249	TREE
6/8/2021 17:04	6/8/2021 18:37	Subtransmission	None	TRK 8215			TREE
6/9/2021 17:06	6/9/2021 20:53	Subtransmission	None	TIE 1540			TREE
6/20/2021 23:18	6/22/2021 21:03	Subtransmission	None	TRK 2659			TREE
7/1/2021 0:09	7/1/2021 1:28	Subtransmission	Distribution	TIE 6147	2132	170928	TREE
7/1/2021 0:13	7/1/2021 3:44	Subtransmission	None	TIE 6147			TREE
7/1/2021 11:34	7/1/2021 18:31	Subtransmission	None	TIE 6147			TREE
7/1/2021 12:12	7/1/2021 20:58	Subtransmission	None	TIE 6147			TREE
7/6/2021 16:02	7/6/2021 16:43	Subtransmission	None	TRK 7062			TREE
7/6/2021 18:45	7/6/2021 22:40	Subtransmission	Distribution	TRK 7062	1250	226595	TREE
7/6/2021 19:36	7/6/2021 22:50	Subtransmission	Distribution	TRK 7062	678	132787	TREE
7/6/2021 19:37	7/6/2021 22:50	Subtransmission	Distribution	TRK 7062	89	17250	TREE
7/6/2021 19:57	7/7/2021 17:06	Subtransmission	None	TRK 7062			TREE
7/7/2021 15:21	7/8/2021 10:00	Subtransmission	Distribution	TIE 4509	436	191247	TREE
7/7/2021 15:06	7/9/2021 15:00	Subtransmission	Distribution	TRK 4405	307	969312	TREE
7/7/2021 17:05	7/7/2021 17:56	Subtransmission	None	TRK 4405			TREE
7/7/2021 15:06	7/8/2021 23:29	Subtransmission	Subtransmission	TRK 4405	453	878590	TREE
7/7/2021 9:51	7/8/2021 4:04	Subtransmission	Distribution	TRK 4405	184	642365	TREE
7/7/2021 15:05	7/8/2021 21:45	Subtransmission	Subtransmission	TRK 4405	377	680897	TREE
7/8/2021 4:39	7/8/2021 21:16	Subtransmission	None	TRK 7122			TREE
7/20/2021 21:39	7/23/2021 10:40	Subtransmission	None	TIE 1531			TREE
7/20/2021 20:07	7/20/2021 23:00	Subtransmission	Distribution	TIE 1531	2453	411979	TREE
7/20/2021 20:07	7/21/2021 6:30	Subtransmission	Distribution	TIE 1531	1179	700205	TREE
7/23/2021 7:01	7/23/2021 11:21	Subtransmission	None	TIE 8014			TREE
7/24/2021 19:38	7/26/2021 9:48	Subtransmission	Distribution	TIE 8014	793	329233	TREE
7/25/2021 15:21	7/26/2021 20:02	Subtransmission	None	TRK 7122			TREE
7/25/2021 17:28	7/25/2021 20:54	Subtransmission	None	TRK 7122			TREE
7/25/2021 17:20	7/25/2021 18:48	Subtransmission	None	TRK 7122			TREE
7/29/2021 5:01	7/30/2021 14:59	Subtransmission	None	TIE 3205			TREE
8/9/2021 20:30	8/10/2021 14:30	Subtransmission	Distribution	TRK 6759			TREE
8/9/2021 18:08	8/10/2021 19:29	Subtransmission	None	TRK 6759			TREE
8/9/2021 19:14	8/10/2021 17:31	Subtransmission	None	TRK 6759			TREE
8/9/2021 19:01	8/10/2021 5:57	Subtransmission	None	TRK 6759			TREE
8/9/2021 17:49	8/10/2021 19:15	Subtransmission	None	TRK 6759			TREE
8/9/2021 15:32	8/10/2021 17:43	Subtransmission	None	TRK 6759			TREE
8/9/2021 0:08	8/10/2021 0:31	Subtransmission	Subtransmission	TRK 6759	821	433757	TREE
8/11/2021 16:24	8/13/2021 4:00	Subtransmission	Distribution	TIE4105			TREE
8/11/2021 15:37	8/14/2021 22:30	Subtransmission	Distribution	TRK 1340	588	643066	TREE
8/11/2021 22:30	8/13/2021 11:18	Subtransmission	None	TRK 1340			TREE
8/11/2021 15:38	8/13/2021 15:30	Subtransmission	Distribution	TRK 1340	772	1173129	TREE
8/11/2021 15:31	8/14/2021 22:45	Subtransmission	Subtransmission	TRK 2035	523	2602822	TREE
8/11/2021 15:31	8/14/2021 20:30	Subtransmission	Distribution	TRK 2035	776	3271963	TREE
8/11/2021 22:27	8/13/2021 20:30	Subtransmission	None	TRK 2035			TREE
8/24/2021 21:57	8/25/2021 14:46	Subtransmission	Distribution	TRK 7062	580	581150	TREE
8/27/2021 18:00	8/29/2021 1:27	Subtransmission	Distribution	TIE 3206	131	115458	TREE
8/28/2021 4:05	8/29/2021 1:27	Subtransmission	Distribution	TIE 3206	379	311753	TREE
9/4/2021 11:38	9/7/2021 8:03	Subtransmission	None	TRK 565			TREE
9/7/2021 20:36	9/8/2021 18:00	Subtransmission	Distribution	TRK 1276	1674	316268	TREE
9/15/2021 1:07	9/15/2021 21:14	Subtransmission	None	TRK 2659			TREE
9/22/2021 17:20	9/23/2021 21:32	Subtransmission	Distribution	TIE 3402	969	2742772	TREE
9/22/2021 20:16	9/24/2021 20:11	Subtransmission	None	TIE4105			TREE
9/22/2021 19:48	9/24/2021 19:51	Subtransmission	None	TIE4105			TREE
9/22/2021 19:26	9/24/2021 19:30	Subtransmission	Distribution	TIE4105	547	636676	TREE

9/23/2021 8:59	9/23/2021 20:06	Subtransmission	None	TIE 3205			TREE
11/11/2021 14:44	11/12/2021 12:34	Subtransmission	None	TIE 6621			TREE
11/11/2021 14:48	11/11/2021 23:26	Subtransmission	None	TIE 6621			TREE
12/11/2021 14:36	12/13/2021 19:16	Subtransmission	None	TIE 4105			TREE
12/11/2021 12:56	12/11/2021 18:38	Subtransmission	None	TIE 4105			TREE
12/11/2021 10:11	12/11/2021 14:45	Subtransmission	None	TIE 8033			TREE
12/11/2021 9:58	12/11/2021 21:22	Subtransmission	None	TIE 8033			TREE
12/11/2021 9:53	12/11/2021 15:30	Subtransmission	Distribution	TIE 8033	808	314869	TREE
12/11/2021 12:48	12/12/2021 14:20	Subtransmission	Distribution	TIE 8033	358	542988	TREE
12/11/2021 10:42	12/11/2021 13:23	Subtransmission	None	TIE 8033			TREE
12/11/2021 10:49	12/13/2021 15:45	Subtransmission	Distribution	TIE 8033	86	273091	TREE
12/11/2021 9:58	12/11/2021 19:00	Subtransmission	Distribution	TIE 8033	163	73569	TREE
12/11/2021 10:08	12/13/2021 20:02	Subtransmission	None	TIE 8033			TREE
12/11/2021 10:58	12/12/2021 17:01	Subtransmission	None	TRK 2824			TREE
12/11/2021 11:56	12/12/2021 11:35	Subtransmission	Distribution	TRK 7062	89	124655	TREE
12/11/2021 12:09	12/13/2021 16:59	Subtransmission	None	TRK 7062			TREE
12/12/2021 9:02	12/13/2021 6:04	Subtransmission	None	TRK 2824			TREE
12/12/2021 8:52	12/12/2021 21:45	Subtransmission	None	TRK 7062			TREE
12/16/2021 14:25	12/16/2021 19:30	Subtransmission	Distribution	TIE 3705	1479	452124	TREE
12/16/2021 14:25	12/16/2021 20:00	Subtransmission	Distribution	TIE 3705	465	140642	TREE
12/19/2021 16:34	12/20/2021 11:54	Subtransmission	None	TIE 3705			TREE
12/20/2021 9:38	12/20/2021 20:45	Subtransmission	None	TIE 3705			TREE
3/2/2022 12:07	3/3/2022 16:30	Subtransmission	None	TRK 2411			TREE
3/6/2022 9:44	3/6/2022 17:16	Subtransmission	None	TIE 4708			TREE
3/6/2022 9:29	3/6/2022 17:00	Subtransmission	Distribution	TIE 4708	481	77233	TREE
3/31/2022 5:03	3/31/2022 15:58	Subtransmission	None	TIE 6931			TREE
3/31/2022 5:47	3/31/2022 13:25	Subtransmission	None	TIE 6931			TREE
4/15/2022 12:47	4/15/2022 21:17	Subtransmission	Distribution	TIE 9111	260	115132	TREE
4/15/2022 13:18	4/15/2022 21:13	Subtransmission	None	TIE 9111			TREE
4/15/2022 20:46	4/17/2022 21:00	Subtransmission	None	TIE 9111			TREE
4/15/2022 12:47	4/15/2022 21:16	Subtransmission	Distribution	TIE 9111	618	211124	TREE
4/15/2022 13:49	4/15/2022 21:17	Subtransmission	None	TIE 9111			TREE
4/21/2022 10:53	4/21/2022 20:39	Subtransmission	None	TIE 226			TREE
4/21/2022 10:50	4/21/2022 20:25	Subtransmission	None	TIE 226			TREE
5/4/2022 11:51	5/5/2022 10:08	Subtransmission	None	TIE 3205			TREE
5/4/2022 22:10	5/5/2022 1:20	Subtransmission	Distribution	TIE 3205	1944	361463	TREE
6/1/2022 12:51	6/2/2022 20:52	Subtransmission	None	TRK 2005			TREE
6/1/2022 22:43	6/2/2022 20:53	Subtransmission	None	TRK 2005			TREE
6/2/2022 9:03	6/2/2022 20:18	Subtransmission	None	TIE 2025			TREE
6/3/2022 7:56	6/3/2022 14:30	Subtransmission	None	TIE 2025			TREE
6/16/2022 8:19	6/16/2022 11:30	Subtransmission	Distribution	TRK 2806	1425	95620	TREE
6/16/2022 8:08	6/16/2022 10:23	Subtransmission	Distribution	TRK 2806	654	68990	TREE
6/16/2022 8:09	6/16/2022 10:23	Subtransmission	Distribution	TRK 2806	450	55980	TREE
6/16/2022 8:47	6/16/2022 13:37	Subtransmission	None	TRK 2806			TREE
6/18/2022 1:35	6/18/2022 2:19	Subtransmission	None	TRK 1232			TREE
6/18/2022 0:58	6/18/2022 20:56	Subtransmission	None	TRK 1232			TREE
6/18/2022 1:21	6/18/2022 3:09	Subtransmission	None	TRK 1232			TREE
6/18/2022 0:58	6/18/2022 20:54	Subtransmission	Distribution	TRK 1232	13	960	TREE
6/18/2022 0:58	6/18/2022 2:13	Subtransmission	Distribution	TRK 1232	746	55115	TREE
6/18/2022 1:20	6/18/2022 2:18	Subtransmission	None	TRK 1232			TREE
6/18/2022 0:58	6/18/2022 2:13	Subtransmission	Distribution	TRK 1232	1581	116851	TREE
6/18/2022 0:58	6/18/2022 20:54	Subtransmission	Distribution	TRK 1232	10	739	TREE
6/18/2022 0:58	6/18/2022 20:58	Subtransmission	Distribution	TRK 1232	12	883	TREE
6/18/2022 0:58	6/18/2022 20:54	Subtransmission	Distribution	TRK 1232	3	757	TREE
6/18/2022 0:58	6/18/2022 20:57	Subtransmission	None	TRK 1232			TREE
6/18/2022 1:10	6/18/2022 6:05	Subtransmission	None	TRK 1232			TREE
6/18/2022 0:58	6/18/2022 14:20	Subtransmission	Distribution	TRK 1232	245	90828	TREE
6/18/2022 1:18	6/18/2022 13:30	Subtransmission	Distribution	TRK 1232	423	157453	TREE
6/29/2022 23:52	6/30/2022 6:45	Subtransmission	Distribution	TRK 3508			TREE
6/29/2022 23:48	6/30/2022 4:30	Subtransmission	Distribution	TRK 3508			TREE
8/3/2022 18:24	8/4/2022 13:40	Subtransmission	Distribution	TIE 4523	666	768789	TREE
8/3/2022 18:27	8/4/2022 13:17	Subtransmission	None	TIE 4523			TREE
8/3/2022 18:19	8/4/2022 20:27	Subtransmission	Distribution	TRK 7114	1212	194468	TREE
8/3/2022 18:24	8/4/2022 21:33	Subtransmission	None	TRK 7114			TREE
8/3/2022 19:20	8/4/2022 14:10	Subtransmission	None	TRK 7114			TREE
8/11/2022 0:59	8/11/2022 14:17	Subtransmission	None	TIE 5843			TREE
8/29/2022 20:05	8/31/2022 7:43	Subtransmission	None	TIE 3203			TREE
8/29/2022 18:33	8/30/2022 19:30	Subtransmission	Distribution	TRK 4911	3096	4535609	TREE
8/29/2022 20:03	8/30/2022 15:46	Subtransmission	None	TRK 4911			TREE
9/1/2022 14:33	9/2/2022 17:51	Subtransmission	None	TRK 5513			TREE
9/21/2022 10:21	9/21/2022 20:50	Subtransmission	None	TIE 3203			TREE
9/21/2022 19:57	9/22/2022 16:23	Subtransmission	Distribution	TRK 7150	494	284173	TREE
9/22/2022 7:25	9/22/2022 16:38	Subtransmission	None	TRK 7150			TREE
9/22/2022 6:33	9/22/2022 16:23	Subtransmission	Distribution	TRK 7150	394	225182	TREE
9/22/2022 7:12	9/22/2022 16:38	Subtransmission	None	TRK 7150			TREE
9/22/2022 6:33	9/22/2022 16:00	Subtransmission	Distribution	TRK 7150	543	310384	TREE
9/22/2022 6:53	9/22/2022 16:38	Subtransmission	None	TRK 7150			TREE
9/22/2022 6:33	9/22/2022 16:23	Subtransmission	Distribution	TRK 7150	509	290923	TREE
9/22/2022 6:47	9/22/2022 9:25	Subtransmission	None	TRK 7150			TREE
9/22/2022 7:10	9/22/2022 17:14	Subtransmission	None	TRK 7150			TREE
9/22/2022 6:40	9/22/2022 16:45	Subtransmission	Distribution	TRK 7150	579	304818	TREE
9/25/2022 6:12	9/25/2022 10:21	Subtransmission	Distribution	TRK 3617	208	51269	TREE
9/25/2022 6:30	9/25/2022 11:46	Subtransmission	None	TRK 3617			TREE
12/3/2022 8:16	12/3/2022 19:25	Subtransmission	None	TIE 1467			TREE
2/7/2023 16:11	2/8/2023 7:41	Subtransmission		TRK 1251			TREE
2/7/2023 15:27	2/8/2023 17:12	Subtransmission		TRK 1251			TREE
2/15/2023 15:28	2/16/2023 20:07	Subtransmission		TIE 3245			TREE
2/15/2023 15:26	2/15/2023 21:36	Subtransmission	Subtransmission	TIE 810	378	75185	TREE
2/22/2023 18:25	2/24/2023 6:28	Subtransmission		TIE 1544			TREE
2/22/2023 18:44	2/26/2023 10:52	Subtransmission		TIE 1544			TREE
2/22/2023 18:14	2/22/2023 21:17	Subtransmission	Subtransmission	TIE 1544	10	18932	TREE
3/17/2023 13:51	3/17/2023 23:07	Subtransmission	Circuit Level	TRK 2002	591	235575	TREE
3/25/2023 18:47	3/26/2023 16:31	Subtransmission		TRK 2806			TREE
5/19/2023 23:16	5/20/2023 19:21	Subtransmission		TIE 4501			TREE
5/19/2023 23:11	5/20/2023 19:00	Subtransmission		TIE 4501			TREE
5/19/2023 23:13	5/20/2023 17:13	Subtransmission		TIE 4501	1	338	TREE
5/19/2023 23:11	5/20/2023 17:14	Subtransmission	Circuit Level	TIE 4501	195	82820	TREE
5/19/2023 23:07	5/20/2023 5:20	Subtransmission	Device (II)	TIE 4501	20	6829	TREE
5/19/2023 23:07	5/20/2023 5:20	Subtransmission	Device (II)	TIE 4501	67	22645	TREE
5/19/2023 23:07	5/20/2023 5:20	Subtransmission	Device (II)	TIE 4501	42	17137	TREE
5/19/2023 23:07	5/20/2023 5:28	Subtransmission	Device (II)	TIE 4501			TREE
5/19/2023 23:11	5/20/2023 5:20	Subtransmission	Device (II)	TIE 4501	26	8788	TREE
5/19/2023 23:13	5/20/2023 5:28	Subtransmission	Single Customer	TIE 4501	1	338	TREE
5/19/2023 23:07	5/21/2023 11:02	Subtransmission	Subtransmission	TIE 4501	357	48804	TREE
5/20/2023 3:07	5/20/2023 5:21	Subtransmission	Single Customer	TIE 4501	1	338	TREE

5/30/2023 21:55	5/31/2023 6:44	Subtransmission	Subtransmission	TIE 4501	2	140	TREE
5/30/2023 1:50	5/30/2023 21:43	Subtransmission	Circuit Level	TIE 4501	5	3094	TREE
5/30/2023 16:09	5/30/2023 18:11	Subtransmission	Device (I)	TIE 4501			TREE
5/30/2023 17:58	5/30/2023 20:55	Subtransmission	Device (I)	TIE 4501	28	18351	TREE
5/30/2023 16:07	5/30/2023 20:56	Subtransmission	Service Secondary	TIE 4501			TREE
5/30/2023 16:26	5/31/2023 8:43	Subtransmission	Service Secondary	TIE 4501	2	1066	TREE
5/30/2023 17:41	5/30/2023 20:55	Subtransmission	Service Secondary	TIE 4501			TREE
5/30/2023 21:02	5/31/2023 11:06	Subtransmission	Service Secondary	TIE 4501	1	534	TREE
5/30/2023 15:29	5/30/2023 18:36	Subtransmission	Single Customer	TIE 4501			TREE
5/30/2023 16:19	5/31/2023 2:10	Subtransmission	Single Customer	TIE 4501			TREE
5/30/2023 17:11	5/30/2023 20:55	Subtransmission	Single Customer	TIE 4501			TREE
5/30/2023 21:10	5/31/2023 10:03	Subtransmission	Single Customer	TIE 4501			TREE
5/30/2023 21:34	5/31/2023 10:04	Subtransmission	Single Customer	TIE 4501			TREE
5/30/2023 20:30	5/31/2023 2:33	Subtransmission	Subtransmission	TIE 4501	646	555168	TREE
5/30/2023 10:20	5/30/2023 22:44	Subtransmission	Device (II)	TIE 4501			TREE
6/25/2023 18:35	6/26/2023 10:35	Subtransmission		TIE 4501			TREE
7/20/2023 15:22	7/21/2023 8:28	Subtransmission	Subtransmission	TIE 9303	4558	2769524	TREE
7/20/2023 18:26	7/24/2023 15:57	Subtransmission		TIE 9303			TREE
7/20/2023 15:47	7/21/2023 7:42	Subtransmission		TIE 9303			TREE
7/20/2023 15:49	7/21/2023 7:42	Subtransmission		TIE 9303			TREE
7/26/2023 15:30	7/27/2023 22:13	Subtransmission	Device (II)	TIE 4501			TREE
7/26/2023 15:06	7/27/2023 21:04	Subtransmission	Subtransmission	TIE 5513	416	738237	TREE
7/26/2023 16:05	7/28/2023 16:58	Subtransmission		TRK 1340			TREE
7/26/2023 16:07	7/28/2023 13:54	Subtransmission		TRK 4338			TREE
7/26/2023 15:42	7/27/2023 21:07	Subtransmission	Device (II)	TIE 4501			TREE
7/26/2023 17:11	7/27/2023 22:47	Subtransmission		TIE 4501			TREE
7/26/2023 15:41	7/27/2023 22:13	Subtransmission	Device (II)	TIE 4501			TREE
7/26/2023 16:11	7/28/2023 17:07	Subtransmission		TIE 4501			TREE
7/26/2023 22:21	7/28/2023 20:56	Subtransmission		TIE 7430			TREE
7/26/2023 16:09	7/28/2023 11:15	Subtransmission	Subtransmission	TRK 1303	1594	1871969	TREE
7/26/2023 16:09	7/28/2023 14:16	Subtransmission	Circuit Level	TRK 1303	1228	3437160	TREE
7/26/2023 16:06	7/28/2023 17:06	Subtransmission		TRK 1303			TREE
7/26/2023 16:11	7/29/2023 22:30	Subtransmission		TRK 1340			TREE
7/26/2023 19:24	7/28/2023 20:31	Subtransmission		TRK 4338			TREE
7/27/2023 19:44	7/28/2023 12:01	Subtransmission		TIE 5513			TREE
7/27/2023 6:57	7/28/2023 13:30	Subtransmission	Service Transformer	TRK 1303			TREE
7/27/2023 17:01	7/28/2023 15:13	Subtransmission		TRK 1303			TREE
8/14/2023 16:02	8/15/2023 5:08	Subtransmission		TIE 3209			TREE
8/14/2023 15:56	8/14/2023 19:55	Subtransmission	Subtransmission	TIE 3209	1262	179028	TREE
8/18/2023 14:17	8/18/2023 15:40	Subtransmission		TIE 2819			TREE
8/18/2023 15:40	9/13/2023 7:01	Subtransmission		TIE 2819			TREE
8/18/2023 11:01	8/18/2023 20:00	Subtransmission	Subtransmission	TIE 4105	1851	537984	TREE
8/18/2023 11:28	8/18/2023 22:02	Subtransmission	Service Transformer	TIE 4105	5	1066	TREE
8/18/2023 11:39	8/18/2023 20:35	Subtransmission		TIE 4105			TREE
8/18/2023 12:08	8/18/2023 19:57	Subtransmission		TIE 4105			TREE
8/18/2023 11:27	8/18/2023 22:03	Subtransmission	Service Transformer	TIE 4105	12	2560	TREE
8/24/2023 22:15	8/26/2023 11:50	Subtransmission		TIE 5829			TREE
8/24/2023 2:45	8/27/2023 17:30	Subtransmission	Circuit Level	TIE 5843	703	2076932	TREE
8/24/2023 22:02	8/29/2023 21:35	Subtransmission	Device (I)	TIE 5843	5	34812	TREE
8/24/2023 22:22	8/25/2023 21:29	Subtransmission		TIE 5843			TREE
8/24/2023 3:44	8/26/2023 9:31	Subtransmission		TIE 6147			TREE
8/24/2023 21:54	8/26/2023 9:11	Subtransmission	Subtransmission	TIE 6147	5630	4664028	TREE
8/24/2023 3:32	8/25/2023 8:44	Subtransmission	Circuit Level	TIE 6147	1	585	TREE
8/24/2023 22:10	8/26/2023 9:03	Subtransmission		TIE 6147			TREE
8/24/2023 22:07	8/26/2023 9:31	Subtransmission		TIE 8014			TREE
8/24/2023 14:26	8/26/2023 7:40	Subtransmission	Subtransmission	TRK 8407			TREE
8/29/2023 1:45	8/30/2023 15:44	Subtransmission		TIE 5208			TREE
8/29/2023 1:46	8/30/2023 16:01	Subtransmission		TIE 6138			TREE
11/21/2023 0:14	11/21/2023 13:56	Subtransmission		TRK 8407			TREE
8/3/2022 18:22	8/4/2022 18:55	Subtransmission	None	TRK 7114			WIND
2/15/2023 10:14	2/16/2023 22:58	Subtransmission		TRK 4316			WIND
2/21/2023 18:28	2/22/2023 4:29	Subtransmission		TRK 3511			WIND
2/22/2023 22:41	2/25/2023 7:41	Subtransmission		TIE 5208			WIND
2/22/2023 21:23	2/25/2023 7:58	Subtransmission		TRK 2035			WIND
2/22/2023 21:47	2/25/2023 7:53	Subtransmission		TRK 2806			WIND
2/22/2023 21:49	2/25/2023 7:38	Subtransmission		TRK 2812			WIND
2/24/2023 13:10	2/25/2023 7:58	Subtransmission		TRK 1470			WIND
2/24/2023 23:17	2/25/2023 7:57	Subtransmission		TRK 3632			WIND
2/27/2023 15:23	3/2/2023 11:01	Subtransmission		TIE 3205			WIND
3/5/2023 15:59	3/5/2023 23:49	Subtransmission	Substation	TRK 463			WIND
3/25/2023 15:11	3/26/2023 14:13	Subtransmission		TRK 1403			WIND
8/1/2021 9:42	8/1/2021 11:01	Subtransmission	Distribution	TRK 3417	679	54744	ANIMAL
3/27/2022 21:47	3/27/2022 21:53	Subtransmission	None	TRK 3536			EQUIPMENT FAILURE
3/27/2022 14:43	3/27/2022 16:22	Subtransmission	None	TRK 3536			EQUIPMENT FAILURE
3/27/2022 14:42	3/27/2022 16:22	Subtransmission	None	TRK 3536			EQUIPMENT FAILURE
3/27/2022 14:42	3/27/2022 17:43	Subtransmission	None	TRK 3536			EQUIPMENT FAILURE
3/27/2022 14:39	3/27/2022 18:30	Subtransmission	Distribution	TRK 3536			EQUIPMENT FAILURE
3/27/2022 14:39	3/27/2022 17:00	Subtransmission	Distribution	TRK 3536			EQUIPMENT FAILURE
3/27/2022 14:47	3/27/2022 17:42	Subtransmission	None	TRK 3536			EQUIPMENT FAILURE
3/27/2022 14:48	3/27/2022 17:43	Subtransmission	None	TRK 3536			EQUIPMENT FAILURE
3/27/2022 16:19	3/27/2022 22:14	Subtransmission	None	TRK 3536			EQUIPMENT FAILURE
3/27/2022 14:51	3/28/2022 2:41	Subtransmission	None	TRK 3536			EQUIPMENT FAILURE
3/27/2022 16:01	3/27/2022 17:44	Subtransmission	None	TRK 3536			EQUIPMENT FAILURE
3/27/2022 14:50	3/27/2022 17:43	Subtransmission	None	TRK 3536			EQUIPMENT FAILURE
6/28/2020 6:05	6/28/2020 11:18	Subtransmission	Distribution	TRK 416	171	20224	ANIMAL
7/15/2018 18:47	7/15/2018 20:36	Subtransmission	Distribution	TRK 2806	465	50303	EQUIPMENT FAILURE
7/15/2018 18:46	7/15/2018 20:44	Subtransmission	Distribution	TRK 2806	2925	332550	EQUIPMENT FAILURE
7/15/2018 21:03	7/18/2018 6:59	Subtransmission	None	TRK 2806			EQUIPMENT FAILURE
8/23/2018 9:32	8/23/2018 21:44	Subtransmission	None	TRK 6759			EQUIPMENT FAILURE
9/20/2018 10:40	9/20/2018 15:56	Subtransmission	None	TRK 2027			EQUIPMENT FAILURE
9/20/2018 15:39	9/20/2018 18:21	Subtransmission	None	TRK 2027			EQUIPMENT FAILURE
1/21/2019 8:23	1/21/2019 15:55	Subtransmission	None	TRK 3508			EQUIPMENT FAILURE
1/24/2019 1:19	1/25/2019 14:55	Subtransmission	None	TRK 3508			EQUIPMENT FAILURE
4/30/2019 9:13	4/30/2019 10:45	Subtransmission	Distribution	TIE 6931	1535	242436	EQUIPMENT FAILURE
4/30/2019 9:13	4/30/2019 10:46	Subtransmission	Distribution	TIE 6931	2426	225640	EQUIPMENT FAILURE
5/24/2020 14:02	5/24/2020 21:34	Subtransmission	None	TRK 4227			EQUIPMENT FAILURE
6/9/2020 20:36	6/11/2020 3:06	Subtransmission	None	TRK 3509			EQUIPMENT FAILURE
6/9/2020 20:20	6/9/2020 21:06	Subtransmission	None	TRK 3509			EQUIPMENT FAILURE
6/9/2020 20:29	6/9/2020 21:45	Subtransmission	None	TRK 3509			EQUIPMENT FAILURE
6/28/2020 19:02	6/28/2020 20:00	Subtransmission	Distribution	TRK 2237	559	26482	EQUIPMENT FAILURE
6/28/2020 19:05	6/28/2020 23:09	Subtransmission	Distribution	TRK 2237	350	13133	EQUIPMENT FAILURE
6/28/2020 19:02	6/28/2020 20:00	Subtransmission	Distribution	TRK 2237	932	44726	EQUIPMENT FAILURE
6/28/2020 19:02	6/28/2020 20:00	Subtransmission	Distribution	TRK 2237	823	38940	EQUIPMENT FAILURE
6/28/2020 19:02	6/28/2020 20:00	Subtransmission	Distribution	TRK 2237	641	79340	EQUIPMENT FAILURE
6/28/2020 19:02	6/28/2020 20:00	Subtransmission	Distribution	TRK 2237	879	41671	EQUIPMENT FAILURE

6/28/2020 15:12	6/28/2020 20:00	Subtransmission	Distribution	TRK 2237	1191	56827	EQUIPMENT FAILURE
6/28/2020 19:02	6/28/2020 20:00	Subtransmission	Distribution	TRK 2237	1073	50850	EQUIPMENT FAILURE
7/2/2020 22:37	7/3/2020 1:11	Subtransmission	None	TRK 2305			EQUIPMENT FAILURE
7/2/2020 19:14	7/3/2020 5:55	Subtransmission	None	TRK 2305			EQUIPMENT FAILURE
7/2/2020 18:54	7/3/2020 5:37	Subtransmission	Distribution	TRK 2305	1	618	EQUIPMENT FAILURE
7/2/2020 18:42	7/3/2020 5:07	Subtransmission	Distribution	TRK 2305	1	611	EQUIPMENT FAILURE
7/2/2020 19:08	7/3/2020 1:10	Subtransmission	None	TRK 2305			EQUIPMENT FAILURE
7/3/2020 8:42	7/4/2020 11:02	Subtransmission	None	TRK 2742			EQUIPMENT FAILURE
7/13/2020 9:51	7/13/2020 13:17	Subtransmission	None	TRK 7150			EQUIPMENT FAILURE
11/22/2020 18:05	11/23/2020 15:19	Subtransmission	None	TRK 1444			EQUIPMENT FAILURE
11/23/2020 1:57	11/23/2020 11:08	Subtransmission	Distribution	TRK 1444	24	11961	EQUIPMENT FAILURE
11/24/2020 19:30	11/25/2020 14:42	Subtransmission	None	TRK 1444			EQUIPMENT FAILURE
5/7/2021 2:54	5/7/2021 5:05	Subtransmission	Subtransmission	TIE 7733	79	10053	EQUIPMENT FAILURE
7/29/2020 15:18	7/30/2020 0:15	Subtransmission	Distribution	TRK 1303	1225	179615	TREE
7/29/2020 15:44	7/30/2020 4:48	Subtransmission	None	TRK 1303			TREE
7/29/2020 15:52	7/30/2020 10:00	Subtransmission	Distribution	TRK 1303	4	4253	TREE
10/23/2020 15:40	10/23/2020 21:34	Subtransmission	None	TIE 9111			ANIMAL
7/20/2021 8:28	7/20/2021 16:32	Subtransmission	None	TRK 2038			ANIMAL
1/3/2018 10:00	1/3/2018 15:21	Subtransmission	None	TRK 1225			EQUIPMENT FAILURE
1/4/2018 10:30	1/4/2018 21:20	Subtransmission	None	TRK 7913			EQUIPMENT FAILURE
1/11/2018 9:43	1/11/2018 17:46	Subtransmission	None	TIE 3208			EQUIPMENT FAILURE
1/21/2018 21:17	1/21/2018 22:09	Subtransmission	None	TRK 2032			EQUIPMENT FAILURE
1/31/2018 15:10	1/31/2018 20:22	Subtransmission	None	TRK 2218			EQUIPMENT FAILURE
2/15/2018 5:40	2/15/2018 10:29	Subtransmission	None	TIE 201			EQUIPMENT FAILURE
2/17/2018 23:00	2/18/2018 1:16	Subtransmission	None	TRK 3632			EQUIPMENT FAILURE
2/20/2018 9:40	2/20/2018 12:09	Subtransmission	None	TIE 3842			EQUIPMENT FAILURE
2/22/2018 11:54	2/22/2018 14:51	Subtransmission	None	TRK 0359			EQUIPMENT FAILURE
3/10/2018 11:50	3/10/2018 19:35	Subtransmission	None	TRK 6938			EQUIPMENT FAILURE
3/10/2018 11:55	3/10/2018 23:28	Subtransmission	None	TRK 6938			EQUIPMENT FAILURE
3/28/2018 0:59	3/28/2018 2:26	Subtransmission	Subtransmission	TRK 465	362	31960	EQUIPMENT FAILURE
3/28/2018 0:59	3/28/2018 2:26	Subtransmission	Subtransmission	TRK 465	358	31586	EQUIPMENT FAILURE
3/28/2018 0:58	3/28/2018 2:26	Subtransmission	Subtransmission	TRK 465	38	3341	EQUIPMENT FAILURE
3/28/2018 0:58	3/28/2018 2:26	Subtransmission	Subtransmission	TRK 465	1183	104727	EQUIPMENT FAILURE
3/28/2018 0:59	3/28/2018 2:26	Subtransmission	Subtransmission	TRK 465	281	24803	EQUIPMENT FAILURE
3/30/2018 9:11	3/30/2018 15:28	Subtransmission	None	TRK 4962			EQUIPMENT FAILURE
4/4/2018 11:31	4/5/2018 7:12	Subtransmission	None	TIE 3203			EQUIPMENT FAILURE
4/14/2018 16:58	4/14/2018 21:21	Subtransmission	None	TIE 2812			EQUIPMENT FAILURE
4/15/2018 13:33	4/16/2018 20:01	Subtransmission	None	TRK 2715			EQUIPMENT FAILURE
4/24/2018 14:52	5/7/2018 16:49	Subtransmission	None	TRK 7106			EQUIPMENT FAILURE
5/3/2018 3:58	5/3/2018 13:41	Subtransmission	None	TRK 1473			EQUIPMENT FAILURE
5/4/2018 13:27	5/9/2018 20:35	Subtransmission	None	TIE 1423			EQUIPMENT FAILURE
5/4/2018 13:54	5/9/2018 14:52	Subtransmission	None	TRK 2648			EQUIPMENT FAILURE
5/5/2018 7:36	5/8/2018 15:11	Subtransmission	None	TIE 3205			EQUIPMENT FAILURE
5/19/2018 19:03	5/20/2018 18:34	Subtransmission	None	TRK 1563			EQUIPMENT FAILURE
5/25/2018 15:48	5/27/2018 10:01	Subtransmission	None	TIE 4412			EQUIPMENT FAILURE
6/4/2018 13:49	6/5/2018 0:24	Subtransmission	None	TIE 3402			EQUIPMENT FAILURE
6/7/2018 18:03	6/8/2018 4:48	Subtransmission	None	TRK 3124			EQUIPMENT FAILURE
6/16/2018 6:24	6/16/2018 17:37	Subtransmission	None	TIE 4109			EQUIPMENT FAILURE
7/9/2018 9:18	7/9/2018 12:10	Subtransmission	None	TRK 2002			EQUIPMENT FAILURE
7/15/2018 20:51	7/16/2018 17:34	Subtransmission	None	TRK 2439			EQUIPMENT FAILURE
7/17/2018 9:06	7/17/2018 21:15	Subtransmission	None	TRK 4405			EQUIPMENT FAILURE
7/20/2018 13:31	7/20/2018 19:26	Subtransmission	None	TIE 7504			EQUIPMENT FAILURE
7/26/2018 8:49	7/26/2018 8:56	Subtransmission	None	TIE 1540			EQUIPMENT FAILURE
7/26/2018 14:28	7/26/2018 16:19	Subtransmission	None	TRK 2218			EQUIPMENT FAILURE
7/27/2018 10:28	7/27/2018 19:41	Subtransmission	None	TIE 3209			EQUIPMENT FAILURE
7/29/2018 15:36	7/30/2018 1:45	Subtransmission	None	TRK 7130			EQUIPMENT FAILURE
8/8/2018 3:38	8/8/2018 14:00	Subtransmission	Distribution	TIE 3402	299	179773	EQUIPMENT FAILURE
8/8/2018 3:43	8/8/2018 16:45	Subtransmission	None	TIE 3402			EQUIPMENT FAILURE
8/8/2018 3:48	8/8/2018 14:00	Subtransmission	None	TIE 3402			EQUIPMENT FAILURE
8/8/2018 9:05	8/8/2018 21:00	Subtransmission	None	TIE 8014			EQUIPMENT FAILURE
8/8/2018 2:14	8/8/2018 16:13	Subtransmission	None	TRK 3632			EQUIPMENT FAILURE
8/19/2018 13:36	8/19/2018 20:50	Subtransmission	None	TRK 2027			EQUIPMENT FAILURE
8/29/2018 7:08	8/29/2018 20:08	Subtransmission	None	TIE 4104			EQUIPMENT FAILURE
9/3/2018 7:27	9/4/2018 0:49	Subtransmission	None	TIE 4104			EQUIPMENT FAILURE
9/7/2018 9:36	10/1/2018 5:20	Subtransmission	None	TIE 6621			EQUIPMENT FAILURE
9/8/2018 13:21	9/8/2018 14:20	Subtransmission	None	TRK 5404			EQUIPMENT FAILURE
9/10/2018 10:12	9/10/2018 17:49	Subtransmission	None	TIE 5526			EQUIPMENT FAILURE
9/10/2018 10:00	9/10/2018 17:46	Subtransmission	None	TIE 5526			EQUIPMENT FAILURE
9/20/2018 9:44	9/20/2018 22:58	Subtransmission	None	TRK 5239			EQUIPMENT FAILURE
9/21/2018 19:37	9/23/2018 11:14	Subtransmission	None	TIE 4428			EQUIPMENT FAILURE
10/1/2018 15:16	10/1/2018 18:06	Subtransmission	None	TIE 9211			EQUIPMENT FAILURE
10/10/2018 19:54	10/11/2018 6:23	Subtransmission	None	TRK 6508			EQUIPMENT FAILURE
10/25/2018 20:57	10/26/2018 21:02	Subtransmission	None	TRK 6759			EQUIPMENT FAILURE
11/6/2018 23:26	11/7/2018 12:07	Subtransmission	None	TRK 2227			EQUIPMENT FAILURE
12/12/2018 11:46	12/12/2018 16:57	Subtransmission	None	TIE 810			EQUIPMENT FAILURE
12/20/2018 0:24	12/20/2018 5:00	Subtransmission	Distribution	TIE 4104	1027	277941	EQUIPMENT FAILURE
12/20/2018 0:42	12/20/2018 7:30	Subtransmission	None	TIE 4104			EQUIPMENT FAILURE
12/20/2018 0:24	12/20/2018 5:00	Subtransmission	Distribution	TIE 4104	1097	299611	EQUIPMENT FAILURE
12/20/2018 0:43	12/28/2018 19:56	Subtransmission	None	TIE 4104			EQUIPMENT FAILURE
12/20/2018 0:41	12/20/2018 6:33	Subtransmission	None	TIE 4104			EQUIPMENT FAILURE
12/20/2018 0:56	12/20/2018 9:18	Subtransmission	None	TIE 4104			EQUIPMENT FAILURE
12/23/2018 10:55	12/23/2018 15:19	Subtransmission	None	TRK 4301			EQUIPMENT FAILURE
1/14/2019 9:14	1/14/2019 19:14	Subtransmission	None	TIE 1473			EQUIPMENT FAILURE
1/18/2019 12:06	1/18/2019 19:16	Subtransmission	None	TIE 1473			EQUIPMENT FAILURE
1/19/2019 2:05	1/19/2019 15:48	Subtransmission	None	TIE 1473			EQUIPMENT FAILURE
2/2/2019 13:38	2/2/2019 21:20	Subtransmission	None	TRK 5906			EQUIPMENT FAILURE
2/4/2019 20:39	2/5/2019 21:09	Subtransmission	None	TIE 5843			EQUIPMENT FAILURE
2/18/2019 11:28	2/18/2019 23:31	Subtransmission	None	TIE 9211			EQUIPMENT FAILURE
2/24/2019 9:58	2/24/2019 20:34	Subtransmission	None	TRK 4301			EQUIPMENT FAILURE
3/6/2019 13:40	3/6/2019 18:02	Subtransmission	None	TIE4105			EQUIPMENT FAILURE
4/11/2019 12:23	4/11/2019 21:04	Subtransmission	None	TIE 1473			EQUIPMENT FAILURE
4/19/2019 7:44	4/19/2019 9:18	Subtransmission	None	TIE 4501			EQUIPMENT FAILURE
4/24/2019 12:41	4/26/2019 13:03	Subtransmission	None	TRK 7106			EQUIPMENT FAILURE
4/30/2019 2:28	5/1/2019 13:21	Subtransmission	None	TIE 1467			EQUIPMENT FAILURE
5/21/2019 20:07	5/22/2019 0:03	Subtransmission	None	TIE 6907			EQUIPMENT FAILURE
5/24/2019 14:54	5/24/2019 20:51	Subtransmission	None	TIE 7745			EQUIPMENT FAILURE
6/1/2019 22:19	6/2/2019 13:15	Subtransmission	Distribution	TIE 5829	53	14508	EQUIPMENT FAILURE
6/2/2019 10:15	6/2/2019 14:29	Subtransmission	None	TIE 5829			EQUIPMENT FAILURE
6/3/2019 12:26	6/3/2019 23:54	Subtransmission	None	TRK 4316			EQUIPMENT FAILURE
6/4/2019 16:04	6/5/2019 16:32	Subtransmission	None	TRK 1303			EQUIPMENT FAILURE
6/15/2019 16:20	6/16/2019 19:25	Subtransmission	None	TIE 4105			EQUIPMENT FAILURE
6/15/2019 16:20	6/16/2019 19:25	Subtransmission	None	TIE 4105			EQUIPMENT FAILURE
7/21/2019 7:17	7/22/2019 20:39	Subtransmission	None	TRK 2218			EQUIPMENT FAILURE
7/21/2019 16:17	7/24/2019 16:31	Subtransmission	None	TRK 2250			EQUIPMENT FAILURE
7/22/2019 0:43	7/24/2019 16:29	Subtransmission	None	TRK 2250			EQUIPMENT FAILURE

7/28/2019 15:16	7/28/2019 21:15	Subtransmission	None	TIE 1467			EQUIPMENT FAILURE
7/29/2019 16:21	7/30/2019 6:10	Subtransmission	None	TIE 4708			EQUIPMENT FAILURE
7/29/2019 15:40	7/29/2019 17:40	Subtransmission	Distribution	TIE 4708	586	69766	EQUIPMENT FAILURE
7/29/2019 15:40	7/29/2019 19:00	Subtransmission	Distribution	TIE 4708	3043	363530	EQUIPMENT FAILURE
7/30/2019 12:28	7/30/2019 16:21	Subtransmission	None	TIE 4708			EQUIPMENT FAILURE
8/7/2019 13:23	8/7/2019 20:31	Subtransmission	None	TRK 8215			EQUIPMENT FAILURE
8/8/2019 5:18	8/8/2019 20:32	Subtransmission	Distribution	TIE 9111	439	146393	EQUIPMENT FAILURE
8/8/2019 5:18	8/8/2019 20:30	Subtransmission	Distribution	TIE 9111	296	153803	EQUIPMENT FAILURE
8/14/2019 0:58	8/14/2019 3:09	Subtransmission	None	TIE 3800			EQUIPMENT FAILURE
8/18/2019 16:31	8/19/2019 20:14	Subtransmission	None	TRK 2715			EQUIPMENT FAILURE
8/19/2019 4:40	8/19/2019 11:23	Subtransmission	None	TRK 2715			EQUIPMENT FAILURE
8/26/2019 17:40	8/27/2019 5:50	Subtransmission	None	TRK 3557			EQUIPMENT FAILURE
8/29/2019 23:51	8/30/2019 1:12	Subtransmission	None	TRK 830			EQUIPMENT FAILURE
8/29/2019 23:13	8/30/2019 1:51	Subtransmission	None	TRK 830			EQUIPMENT FAILURE
8/29/2019 23:32	8/30/2019 12:45	Subtransmission	None	TRK 830			EQUIPMENT FAILURE
8/30/2019 0:38	8/30/2019 16:39	Subtransmission	None	TIE 817			EQUIPMENT FAILURE
9/25/2019 10:15	9/26/2019 19:11	Subtransmission	None	TRK 2087			EQUIPMENT FAILURE
9/28/2019 8:25	9/28/2019 17:17	Subtransmission	None	TIE 4523			EQUIPMENT FAILURE
9/28/2019 0:31	9/28/2019 6:20	Subtransmission	Distribution	TRK 1555	1388	488566	EQUIPMENT FAILURE
9/28/2019 0:53	9/28/2019 9:09	Subtransmission	None	TRK 1555			EQUIPMENT FAILURE
10/2/2019 3:16	10/2/2019 6:18	Subtransmission	None	TIE 4105			EQUIPMENT FAILURE
10/2/2019 3:14	10/2/2019 17:26	Subtransmission	None	TIE 4105			EQUIPMENT FAILURE
10/2/2019 9:56	10/2/2019 18:13	Subtransmission	None	TIE 4105			EQUIPMENT FAILURE
10/12/2019 0:10	10/12/2019 14:05	Subtransmission	None	TRK 1303			EQUIPMENT FAILURE
10/12/2019 0:12	10/12/2019 13:37	Subtransmission	None	TRK 1303			EQUIPMENT FAILURE
10/21/2019 16:47	10/22/2019 0:10	Subtransmission	None	TIE 3417			EQUIPMENT FAILURE
10/27/2019 4:11	10/27/2019 15:22	Subtransmission	None	TIE 1540			EQUIPMENT FAILURE
10/28/2019 18:15	10/29/2019 5:30	Subtransmission	None	TIE 1540			EQUIPMENT FAILURE
11/28/2019 9:25	11/29/2019 17:46	Subtransmission	None	TIE 3205			EQUIPMENT FAILURE
12/29/2019 23:37	12/30/2019 21:11	Subtransmission	None	TIE 5823			EQUIPMENT FAILURE
12/29/2019 8:00	12/30/2019 13:07	Subtransmission	None	TRK 2659			EQUIPMENT FAILURE
2/11/2020 19:17	2/12/2020 5:52	Subtransmission	None	TRK 7324			EQUIPMENT FAILURE
2/11/2020 19:03	2/12/2020 5:51	Subtransmission	None	TRK 7324			EQUIPMENT FAILURE
3/6/2020 10:55	3/6/2020 19:48	Subtransmission	None	TRK 5917			EQUIPMENT FAILURE
3/6/2020 10:18	3/6/2020 14:56	Subtransmission	Distribution	TRK 5917	22	6366	EQUIPMENT FAILURE
3/10/2020 9:37	3/10/2020 20:35	Subtransmission	None	TRK 2107			EQUIPMENT FAILURE
3/10/2020 5:33	3/10/2020 16:49	Subtransmission	None	TRK 2107			EQUIPMENT FAILURE
3/10/2020 2:27	3/10/2020 5:43	Subtransmission	None	TRK 6722			EQUIPMENT FAILURE
3/14/2020 15:19	3/15/2020 14:46	Subtransmission	None	TIE 3410			EQUIPMENT FAILURE
3/15/2020 13:10	3/18/2020 3:50	Subtransmission	None	TIE 4105			EQUIPMENT FAILURE
3/15/2020 14:00	3/15/2020 20:30	Subtransmission	Distribution	TIE 4105	108	1577	EQUIPMENT FAILURE
3/21/2020 0:43	3/21/2020 14:33	Subtransmission	None	TRK 7104			EQUIPMENT FAILURE
3/21/2020 9:03	3/21/2020 12:29	Subtransmission	Distribution	TRK 7104	383	18617	EQUIPMENT FAILURE
3/21/2020 16:07	3/21/2020 17:07	Subtransmission	None	TRK 7104			EQUIPMENT FAILURE
4/2/2020 14:43	4/3/2020 6:52	Subtransmission	None	TIE 1544			EQUIPMENT FAILURE
4/3/2020 10:04	4/3/2020 14:12	Subtransmission	None	TIE 1544			EQUIPMENT FAILURE
4/20/2020 20:56	4/21/2020 0:01	Subtransmission	None	TRK 1232			EQUIPMENT FAILURE
4/20/2020 20:57	4/20/2020 21:12	Subtransmission	None	TRK 1232			EQUIPMENT FAILURE
4/20/2020 21:02	4/21/2020 5:07	Subtransmission	None	TRK 1232			EQUIPMENT FAILURE
4/23/2020 16:43	4/23/2020 23:20	Subtransmission	None	TIE 3410			EQUIPMENT FAILURE
4/29/2020 12:34	4/29/2020 15:31	Subtransmission	None	TRK 2840			EQUIPMENT FAILURE
4/29/2020 11:02	4/29/2020 14:20	Subtransmission	Distribution	TRK 2840			EQUIPMENT FAILURE
4/29/2020 12:28	4/29/2020 13:53	Subtransmission	None	TRK 2840			EQUIPMENT FAILURE
4/29/2020 19:02	4/30/2020 13:04	Subtransmission	None	TRK 2840			EQUIPMENT FAILURE
4/29/2020 12:34	4/30/2020 10:10	Subtransmission	None	TRK 2840			EQUIPMENT FAILURE
5/8/2020 11:02	5/8/2020 15:42	Subtransmission	None	TRK 7035			EQUIPMENT FAILURE
5/12/2020 13:01	5/12/2020 14:33	Subtransmission	None	TIE 3416			EQUIPMENT FAILURE
5/16/2020 2:10	5/16/2020 4:13	Subtransmission	Substation	TIE 4104	108	13174	EQUIPMENT FAILURE
5/16/2020 2:09	5/16/2020 3:33	Subtransmission	Subtransmission	TIE 4104	1095	91992	EQUIPMENT FAILURE
5/16/2020 2:29	5/16/2020 18:42	Subtransmission	None	TIE 4104			EQUIPMENT FAILURE
5/20/2020 14:43	5/20/2020 17:00	Subtransmission	None	TIE 3410			EQUIPMENT FAILURE
5/22/2020 11:22	5/22/2020 16:34	Subtransmission	None	TIE 4105			EQUIPMENT FAILURE
5/22/2020 13:53	5/22/2020 21:06	Subtransmission	None	TIE 4105			EQUIPMENT FAILURE
6/11/2020 23:02	6/16/2020 5:17	Subtransmission	None	TIE 810			EQUIPMENT FAILURE
6/11/2020 21:54	6/12/2020 19:28	Subtransmission	None	TIE 810			EQUIPMENT FAILURE
6/12/2020 18:13	6/12/2020 19:09	Subtransmission	None	TIE 7621			EQUIPMENT FAILURE
6/13/2020 13:02	6/16/2020 14:22	Subtransmission	None	TRK 7717			EQUIPMENT FAILURE
6/23/2020 10:05	6/24/2020 2:48	Subtransmission	None	TRK 2636			EQUIPMENT FAILURE
6/23/2020 5:45	6/26/2020 20:49	Subtransmission	None	TRK 2636			EQUIPMENT FAILURE
6/23/2020 5:48	6/23/2020 13:18	Subtransmission	None	TRK 2636			EQUIPMENT FAILURE
6/27/2020 7:04	6/27/2020 18:00	Subtransmission	Distribution	TRK 2931	530	100007	EQUIPMENT FAILURE
6/27/2020 8:28	6/27/2020 20:27	Subtransmission	None	TRK 2931			EQUIPMENT FAILURE
6/27/2020 7:08	6/27/2020 9:00	Subtransmission	None	TRK 2931			EQUIPMENT FAILURE
6/27/2020 7:38	6/27/2020 17:45	Subtransmission	None	TRK 2931			EQUIPMENT FAILURE
6/27/2020 0:09	6/27/2020 19:30	Subtransmission	Distribution	TRK 2931	2980	2036375	EQUIPMENT FAILURE
7/7/2020 13:03	7/9/2020 17:39	Subtransmission	None	TRK 1243			EQUIPMENT FAILURE
7/10/2020 15:33	7/10/2020 20:15	Subtransmission	Distribution	TRK 7062	5	209	EQUIPMENT FAILURE
7/10/2020 15:08	7/11/2020 19:59	Subtransmission	Distribution	TRK 7062	124	154745	EQUIPMENT FAILURE
7/10/2020 14:41	7/10/2020 16:21	Subtransmission	None	TRK 7062			EQUIPMENT FAILURE
7/10/2020 14:59	7/10/2020 16:06	Subtransmission	None	TRK 7062			EQUIPMENT FAILURE
7/10/2020 14:58	7/10/2020 16:05	Subtransmission	None	TRK 7062			EQUIPMENT FAILURE
7/10/2020 14:57	7/10/2020 16:05	Subtransmission	None	TRK 7062			EQUIPMENT FAILURE
7/10/2020 15:36	7/10/2020 20:15	Subtransmission	Distribution	TRK 7062	3	94	EQUIPMENT FAILURE
7/10/2020 15:40	7/10/2020 20:15	Subtransmission	Distribution	TRK 7062	5	220	EQUIPMENT FAILURE
7/10/2020 16:45	7/10/2020 20:15	Subtransmission	Distribution	TRK 7062			EQUIPMENT FAILURE
7/10/2020 14:59	7/10/2020 19:05	Subtransmission	None	TRK 7062			EQUIPMENT FAILURE
7/10/2020 14:56	7/10/2020 15:06	Subtransmission	None	TRK 7062			EQUIPMENT FAILURE
7/10/2020 14:56	7/10/2020 16:05	Subtransmission	None	TRK 7062			EQUIPMENT FAILURE
7/10/2020 14:56	7/10/2020 15:06	Subtransmission	None	TRK 7062			EQUIPMENT FAILURE
7/10/2020 15:27	7/10/2020 22:41	Subtransmission	Distribution	TRK 7062	688	268060	EQUIPMENT FAILURE
7/10/2020 15:27	7/10/2020 21:59	Subtransmission	Distribution	TRK 7062	90	34244	EQUIPMENT FAILURE
7/10/2020 16:37	7/11/2020 16:00	Subtransmission	None	TRK 7062			EQUIPMENT FAILURE
7/21/2020 7:03	7/21/2020 12:05	Subtransmission	Subtransmission	TIE 3800	804	260177	EQUIPMENT FAILURE
7/21/2020 7:02	7/21/2020 12:05	Subtransmission	Subtransmission	TIE 3800	1088	351092	EQUIPMENT FAILURE
7/21/2020 7:15	7/21/2020 16:22	Subtransmission	None	TIE 3800			EQUIPMENT FAILURE
7/28/2020 9:36	7/28/2020 19:27	Subtransmission	None	TRK 462			EQUIPMENT FAILURE
8/9/2020 19:31	8/10/2020 0:37	Subtransmission	None	TIE 3318			EQUIPMENT FAILURE
8/16/2020 10:24	8/21/2020 22:32	Subtransmission	None	TRK 1403			EQUIPMENT FAILURE
8/17/2020 14:01	8/19/2020 11:01	Subtransmission	None	TRK 4301			EQUIPMENT FAILURE
8/18/2020 12:32	8/18/2020 18:21	Subtransmission	None	TIE 3209			EQUIPMENT FAILURE
8/28/2020 7:30	8/29/2020 19:05	Subtransmission	None	TRK 2038			EQUIPMENT FAILURE
8/29/2020 22:31	8/30/2020 19:16	Subtransmission	None	TRK 4301			EQUIPMENT FAILURE
8/29/2020 22:30	8/30/2020 19:16	Subtransmission	None	TRK 4301			EQUIPMENT FAILURE
9/7/2020 3:08	9/7/2020 7:46	Subtransmission	None	TRK 1527			EQUIPMENT FAILURE
9/7/2020 3:03	9/8/2020 5:13	Subtransmission	None	TRK 1527			EQUIPMENT FAILURE

11/1/2020 11:55	11/1/2020 21:20	Subtransmission	None	TIE 6621			EQUIPMENT FAILURE
11/13/2020 7:33	11/13/2020 10:43	Subtransmission	None	TRK 3646			EQUIPMENT FAILURE
11/13/2020 11:51	11/14/2020 20:04	Subtransmission	None	TRK 3646			EQUIPMENT FAILURE
11/13/2020 7:24	11/14/2020 1:01	Subtransmission	None	TRK 3646			EQUIPMENT FAILURE
11/15/2020 12:07	11/18/2020 20:00	Subtransmission	Distribution	TIE 1473	116	317176	EQUIPMENT FAILURE
11/15/2020 12:48	11/15/2020 16:00	Subtransmission	None	TRK 2027			EQUIPMENT FAILURE
11/16/2020 1:52	11/17/2020 15:51	Subtransmission	None	TRK 1232			EQUIPMENT FAILURE
11/25/2020 13:43	12/2/2020 9:20	Subtransmission	None	TIE 6621			EQUIPMENT FAILURE
12/24/2020 3:06	12/24/2020 4:31	Subtransmission	Subtransmission	TRK 6304	599	47975	EQUIPMENT FAILURE
12/24/2020 3:14	12/24/2020 17:59	Subtransmission	None	TRK 6304			EQUIPMENT FAILURE
1/22/2021 8:34	1/22/2021 14:40	Subtransmission	None	TIE 810			EQUIPMENT FAILURE
2/4/2021 12:10	2/4/2021 18:22	Subtransmission	None	TIE 4501			EQUIPMENT FAILURE
2/17/2021 11:15	2/17/2021 14:40	Subtransmission	None	TRK 1134			EQUIPMENT FAILURE
3/11/2021 9:28	3/11/2021 18:40	Subtransmission	None	TIE 3416			EQUIPMENT FAILURE
3/18/2021 15:58	3/19/2021 19:00	Subtransmission	None	TIE 7702			EQUIPMENT FAILURE
3/24/2021 10:22	3/24/2021 21:11	Subtransmission	None	TIE 4708			EQUIPMENT FAILURE
3/28/2021 14:49	3/28/2021 15:40	Subtransmission	Distribution	TIE 3417	607	25514	EQUIPMENT FAILURE
3/28/2021 14:48	3/28/2021 15:40	Subtransmission	Distribution	TIE 3417	180	7103	EQUIPMENT FAILURE
3/28/2021 14:21	3/28/2021 16:20	Subtransmission	Distribution	TIE 3417	617	50571	EQUIPMENT FAILURE
4/29/2021 16:10	4/29/2021 22:38	Subtransmission	None	TRK 3536			EQUIPMENT FAILURE
4/29/2021 18:36	4/30/2021 3:20	Subtransmission	None	TRK 7913			EQUIPMENT FAILURE
5/24/2021 0:49	5/24/2021 16:42	Subtransmission	None	TRK 2418			EQUIPMENT FAILURE
5/26/2021 9:15	5/26/2021 21:02	Subtransmission	None	TRK 2255			EQUIPMENT FAILURE
5/28/2021 13:50	5/28/2021 15:10	Subtransmission	Distribution	TIE 3822	51	3835	EQUIPMENT FAILURE
5/28/2021 14:04	5/28/2021 15:22	Subtransmission	None	TIE 3822			EQUIPMENT FAILURE
5/28/2021 14:28	5/28/2021 15:22	Subtransmission	None	TIE 3822			EQUIPMENT FAILURE
5/28/2021 14:12	5/29/2021 7:05	Subtransmission	None	TIE 3822			EQUIPMENT FAILURE
6/12/2021 20:41	6/13/2021 15:13	Subtransmission	None	TIE 4523			EQUIPMENT FAILURE
6/16/2021 13:55	6/16/2021 15:13	Subtransmission	None	TIE 9123			EQUIPMENT FAILURE
6/16/2021 15:06	6/17/2021 5:04	Subtransmission	None	TRK 1229			EQUIPMENT FAILURE
6/28/2021 5:46	6/28/2021 13:04	Subtransmission	None	TRK 2840			EQUIPMENT FAILURE
6/28/2021 5:46	6/28/2021 13:04	Subtransmission	None	TRK 2840			EQUIPMENT FAILURE
6/28/2021 5:58	6/28/2021 9:09	Subtransmission	None	TRK 2840			EQUIPMENT FAILURE
6/28/2021 5:51	6/28/2021 15:37	Subtransmission	None	TRK 2840			EQUIPMENT FAILURE
6/29/2021 19:51	6/30/2021 13:00	Subtransmission	None	TIE 2812			EQUIPMENT FAILURE
6/29/2021 16:13	6/29/2021 20:04	Subtransmission	None	TIE 2812			EQUIPMENT FAILURE
7/7/2021 17:16	7/8/2021 13:57	Subtransmission	None	TRK 2308			EQUIPMENT FAILURE
7/8/2021 15:25	7/9/2021 14:11	Subtransmission	None	TIE 3402			EQUIPMENT FAILURE
7/21/2021 11:22	7/21/2021 13:56	Subtransmission	None	TIE 3800			EQUIPMENT FAILURE
8/3/2021 10:13	8/4/2021 1:32	Subtransmission	None	TRK 6172			EQUIPMENT FAILURE
8/12/2021 15:35	8/16/2021 13:09	Subtransmission	None	TIE 1473			EQUIPMENT FAILURE
8/12/2021 11:06	8/13/2021 16:43	Subtransmission	None	TRK 5838			EQUIPMENT FAILURE
9/1/2021 11:11	9/1/2021 23:06	Subtransmission	None	TIE 807			EQUIPMENT FAILURE
9/30/2021 10:21	9/30/2021 12:38	Subtransmission	None	TRK 4911			EQUIPMENT FAILURE
10/3/2021 13:26	10/3/2021 14:46	Subtransmission	None	TRK 6172			EQUIPMENT FAILURE
10/5/2021 17:52	10/6/2021 12:45	Subtransmission	None	TRK 7035			EQUIPMENT FAILURE
10/14/2021 11:11	10/14/2021 15:06	Subtransmission	None	TRK 1518			EQUIPMENT FAILURE
11/30/2021 12:56	11/30/2021 16:01	Subtransmission	None	TIE 3220			EQUIPMENT FAILURE
11/30/2021 10:32	11/30/2021 12:41	Subtransmission	None	TIE 3220			EQUIPMENT FAILURE
12/5/2021 17:04	12/6/2021 15:29	Subtransmission	None	TRK 2715			EQUIPMENT FAILURE
12/11/2021 19:14	12/13/2021 14:35	Subtransmission	None	TRK 5838			EQUIPMENT FAILURE
1/29/2022 3:39	1/29/2022 20:30	Subtransmission	Distribution	TIE 1473	203	23169	EQUIPMENT FAILURE
1/29/2022 20:32	1/29/2022 22:38	Subtransmission	None	TIE 1473			EQUIPMENT FAILURE
1/29/2022 17:56	1/29/2022 22:37	Subtransmission	None	TIE 1473			EQUIPMENT FAILURE
1/29/2022 3:49	1/30/2022 19:13	Subtransmission	None	TIE 1473			EQUIPMENT FAILURE
1/29/2022 3:41	1/29/2022 14:00	Subtransmission	Distribution	TIE 1473	258	30131	EQUIPMENT FAILURE
1/29/2022 18:45	1/29/2022 22:37	Subtransmission	None	TIE 1473			EQUIPMENT FAILURE
1/29/2022 6:29	1/29/2022 9:47	Subtransmission	None	TIE 1473			EQUIPMENT FAILURE
1/29/2022 3:39	1/29/2022 14:00	Subtransmission	Distribution	TIE 1473	183	22171	EQUIPMENT FAILURE
3/7/2022 10:02	3/7/2022 14:56	Subtransmission	None	TRK 1248			EQUIPMENT FAILURE
3/18/2022 20:10	3/19/2022 5:58	Subtransmission	None	TRK 4971			EQUIPMENT FAILURE
3/18/2022 20:04	3/19/2022 5:15	Subtransmission	None	TRK 4971			EQUIPMENT FAILURE
3/29/2022 23:00	3/30/2022 1:40	Subtransmission	None	TIE 3205			EQUIPMENT FAILURE
3/31/2022 12:30	3/31/2022 20:37	Subtransmission	None	TIE 3208			EQUIPMENT FAILURE
4/14/2022 17:28	4/15/2022 16:09	Subtransmission	None	TIE 1568			EQUIPMENT FAILURE
4/23/2022 11:00	4/25/2022 4:35	Subtransmission	None	TIE 3209			EQUIPMENT FAILURE
4/24/2022 18:52	4/25/2022 4:49	Subtransmission	None	TIE 3410			EQUIPMENT FAILURE
5/4/2022 2:14	5/4/2022 12:45	Subtransmission	Substation	TRK 4301	636	101563	EQUIPMENT FAILURE
5/4/2022 2:24	5/4/2022 9:17	Subtransmission	None	TRK 4301			EQUIPMENT FAILURE
5/21/2022 10:38	5/21/2022 20:15	Subtransmission	Distribution	TRK 7062	87	53189	EQUIPMENT FAILURE
5/21/2022 10:38	5/21/2022 20:15	Subtransmission	Distribution	TRK 7062	672	411690	EQUIPMENT FAILURE
5/21/2022 10:45	5/21/2022 21:35	Subtransmission	None	TRK 7062			EQUIPMENT FAILURE
6/6/2022 16:20	6/7/2022 16:37	Subtransmission	None	TRK 8403			EQUIPMENT FAILURE
6/7/2022 13:43	6/8/2022 4:26	Subtransmission	None	TIE 3822			EQUIPMENT FAILURE
6/7/2022 13:31	6/7/2022 15:54	Subtransmission	Subtransmission	TIE 3822	2482	328297	EQUIPMENT FAILURE
6/7/2022 13:45	6/7/2022 15:54	Subtransmission	Subtransmission	TIE 3822	310	40983	EQUIPMENT FAILURE
6/7/2022 14:12	6/7/2022 16:16	Subtransmission	None	TIE 3822			EQUIPMENT FAILURE
6/7/2022 13:50	6/7/2022 16:26	Subtransmission	None	TIE 3822			EQUIPMENT FAILURE
6/15/2022 15:01	6/15/2022 17:20	Subtransmission	Distribution	TIE 1467	160	25048	EQUIPMENT FAILURE
6/16/2022 9:08	6/16/2022 20:13	Subtransmission	None	TIE 3417			EQUIPMENT FAILURE
6/20/2022 21:01	6/22/2022 11:26	Subtransmission	Distribution	TRK 2541			EQUIPMENT FAILURE
6/20/2022 14:02	7/30/2022 15:25	Subtransmission	None	TRK 2541			EQUIPMENT FAILURE
6/20/2022 16:53	6/20/2022 21:37	Subtransmission	Subtransmission	TRK 2541	1356	302942	EQUIPMENT FAILURE
6/20/2022 16:54	6/20/2022 19:06	Subtransmission	Subtransmission	TRK 2541	517	63598	EQUIPMENT FAILURE
6/20/2022 8:53	6/20/2022 20:10	Subtransmission	Subtransmission	TRK 2541	819	160604	EQUIPMENT FAILURE
6/25/2022 17:41	6/25/2022 22:17	Subtransmission	None	TIE 810			EQUIPMENT FAILURE
6/27/2022 13:43	6/29/2022 15:08	Subtransmission	None	TIE 810			EQUIPMENT FAILURE
7/14/2022 16:40	7/15/2022 5:31	Subtransmission	None	TIE 1467			EQUIPMENT FAILURE
7/17/2022 8:19	7/19/2022 6:22	Subtransmission	None	TRK 1444			EQUIPMENT FAILURE
7/20/2022 6:19	7/20/2022 14:51	Subtransmission	None	TIE 1312			EQUIPMENT FAILURE
7/21/2022 17:39	7/22/2022 12:58	Subtransmission	None	TRK 1322			EQUIPMENT FAILURE
7/22/2022 12:39	7/23/2022 12:43	Subtransmission	None	TRK 1322			EQUIPMENT FAILURE
7/22/2022 0:31	7/22/2022 14:00	Subtransmission	None	TRK 7756			EQUIPMENT FAILURE
7/24/2022 15:12	7/24/2022 22:05	Subtransmission	None	TRK 2411			EQUIPMENT FAILURE
7/28/2022 10:08	7/28/2022 18:51	Subtransmission	None	TIE 4105			EQUIPMENT FAILURE
8/3/2022 18:07	8/3/2022 20:16	Subtransmission	None	TRK 2027			EQUIPMENT FAILURE
8/3/2022 17:42	8/3/2022 20:15	Subtransmission	Distribution	TRK 2027	7	408	EQUIPMENT FAILURE
8/3/2022 18:56	8/4/2022 0:11	Subtransmission	Distribution	TRK 2027	1866	322691	EQUIPMENT FAILURE
8/3/2022 19:17	8/8/2022 14:40	Subtransmission	None	TRK 2027			EQUIPMENT FAILURE
8/4/2022 22:49	8/5/2022 13:15	Subtransmission	None	TRK 2027			EQUIPMENT FAILURE
8/4/2022 9:24	8/4/2022 15:11	Subtransmission	None	TRK 2027			EQUIPMENT FAILURE
8/29/2022 19:50	8/30/2022 20:41	Subtransmission	None	TIE 6907			EQUIPMENT FAILURE
8/30/2022 11:01	9/3/2022 20:18	Subtransmission	None	TRK 1444			EQUIPMENT FAILURE
8/30/2022 10:23	8/31/2022 14:57	Subtransmission	None	TRK 3534			EQUIPMENT FAILURE
8/31/2022 18:16	9/1/2022 21:04	Subtransmission	None	TRK 3534			EQUIPMENT FAILURE

9/1/2022 14:49	9/2/2022 8:20	Subtransmission	None	TRK 5145			EQUIPMENT FAILURE
9/2/2022 10:29	9/3/2022 20:30	Subtransmission	None	TRK 5145			EQUIPMENT FAILURE
9/19/2022 6:01	9/19/2022 21:38	Subtransmission	None	TRK 2719			EQUIPMENT FAILURE
9/20/2022 8:19	9/20/2022 16:32	Subtransmission	None	TRK 1518			EQUIPMENT FAILURE
9/21/2022 10:51	9/23/2022 8:39	Subtransmission	None	TIE 9205			EQUIPMENT FAILURE
9/22/2022 14:11	9/22/2022 16:57	Subtransmission	None	TIE 9205			EQUIPMENT FAILURE
10/26/2022 5:32	10/26/2022 14:30	Subtransmission	Distribution	TIE1340	156	84810	EQUIPMENT FAILURE
10/26/2022 5:32	10/26/2022 7:33	Subtransmission	Distribution	TRK 1340	815	88477	EQUIPMENT FAILURE
10/26/2022 5:32	10/26/2022 7:33	Subtransmission	Distribution	TRK 1340	622	66672	EQUIPMENT FAILURE
10/26/2022 6:00	10/26/2022 11:12	Subtransmission	None	TRK 1340			EQUIPMENT FAILURE
10/26/2022 5:45	10/26/2022 15:09	Subtransmission	None	TRK 1340			EQUIPMENT FAILURE
10/26/2022 7:39	10/26/2022 9:34	Subtransmission	Distribution	TRK 1340			EQUIPMENT FAILURE
10/26/2022 8:05	10/26/2022 8:59	Subtransmission	Distribution	TRK 1340			EQUIPMENT FAILURE
10/27/2022 7:59	10/28/2022 5:46	Subtransmission	None	TRK 7150			EQUIPMENT FAILURE
11/9/2022 7:23	11/9/2022 15:53	Subtransmission	None	TRK 2922			EQUIPMENT FAILURE
1/10/2023 12:29	1/11/2023 12:00	Subtransmission	None	TRK 2038			EQUIPMENT FAILURE
2/15/2023 13:10	2/20/2023 7:17	Subtransmission		TIE 9123			EQUIPMENT FAILURE
2/17/2023 2:07	2/17/2023 14:45	Subtransmission		TRK 3124			EQUIPMENT FAILURE
2/22/2023 18:12	2/25/2023 7:37	Subtransmission		TIE 1540			EQUIPMENT FAILURE
2/22/2023 18:04	2/28/2023 10:32	Subtransmission	Subtransmission	TIE 1540	42	177059	EQUIPMENT FAILURE
2/23/2023 10:49	2/25/2023 7:44	Subtransmission		TIE 1318			EQUIPMENT FAILURE
2/23/2023 6:56	2/25/2023 7:54	Subtransmission		TRK 2237			EQUIPMENT FAILURE
2/23/2023 11:05	2/25/2023 10:35	Subtransmission		TIE 1540			EQUIPMENT FAILURE
2/23/2023 0:38	2/23/2023 21:44	Subtransmission		TRK 2237			EQUIPMENT FAILURE
2/28/2023 20:37	3/3/2023 16:42	Subtransmission		TRK 1467			EQUIPMENT FAILURE
3/3/2023 17:30	3/4/2023 11:20	Subtransmission		TRK 2032			EQUIPMENT FAILURE
3/11/2023 2:19	3/11/2023 20:22	Subtransmission		TRK 2742			EQUIPMENT FAILURE
3/24/2023 3:10	3/24/2023 21:07	Subtransmission	Single Customer	TRK 2455	1	72	EQUIPMENT FAILURE
3/25/2023 18:12	3/27/2023 7:40	Subtransmission		TRK 4301			EQUIPMENT FAILURE
3/27/2023 1:55	3/27/2023 13:48	Subtransmission		TRK 3661			EQUIPMENT FAILURE
4/5/2023 13:35	4/6/2023 18:59	Subtransmission		TRK 2302			EQUIPMENT FAILURE
4/28/2023 11:15	5/2/2023 1:13	Subtransmission		TIE 1318			EQUIPMENT FAILURE
4/29/2023 10:45	4/29/2023 11:30	Subtransmission	Service Secondary	TRK 1418	15	5859	EQUIPMENT FAILURE
4/29/2023 4:11	4/29/2023 11:08	Subtransmission	Subtransmission	TRK 1418	208	81214	EQUIPMENT FAILURE
4/29/2023 2:45	4/29/2023 16:28	Subtransmission		TRK 1418			EQUIPMENT FAILURE
5/2/2023 8:34	6/1/2023 22:27	Subtransmission		TRK 3534			EQUIPMENT FAILURE
5/11/2023 18:31	5/12/2023 5:50	Subtransmission	Circuit Level	TRK 4971	1	771	EQUIPMENT FAILURE
5/23/2023 11:39	6/2/2023 22:27	Subtransmission		TIE 7504			EQUIPMENT FAILURE
5/27/2023 21:50	5/28/2023 13:24	Subtransmission		TIE 1467			EQUIPMENT FAILURE
5/28/2023 14:53	5/28/2023 21:18	Subtransmission	Subtransmission	TIE 1467	1612	50140	EQUIPMENT FAILURE
5/28/2023 14:50	5/28/2023 21:14	Subtransmission	Single Customer	TIE 1467	1	50	EQUIPMENT FAILURE
5/28/2023 15:37	5/28/2023 21:15	Subtransmission	Single Customer	TIE 1467	1	50	EQUIPMENT FAILURE
5/28/2023 15:38	5/28/2023 21:16	Subtransmission	Single Customer	TIE 1467	1	49	EQUIPMENT FAILURE
5/28/2023 15:43	5/28/2023 21:17	Subtransmission	Single Customer	TIE 1467	1	49	EQUIPMENT FAILURE
6/11/2023 18:55	6/13/2023 6:09	Subtransmission		TRK 7078			EQUIPMENT FAILURE
7/13/2023 8:10	7/13/2023 14:38	Subtransmission		TRK 3124			EQUIPMENT FAILURE
7/15/2023 6:57	7/16/2023 13:58	Subtransmission		TRK 5127			EQUIPMENT FAILURE
7/20/2023 23:25	7/24/2023 16:12	Subtransmission		TRK 6919			EQUIPMENT FAILURE
7/20/2023 15:59	7/22/2023 14:09	Subtransmission		TRK 1229			EQUIPMENT FAILURE
7/20/2023 16:30	7/21/2023 10:28	Subtransmission		TRK 1229	1	1500	EQUIPMENT FAILURE
7/20/2023 16:44	7/20/2023 21:25	Subtransmission		TRK 1229			EQUIPMENT FAILURE
7/20/2023 16:48	7/20/2023 21:03	Subtransmission		TRK 1229			EQUIPMENT FAILURE
7/20/2023 17:16	7/22/2023 10:26	Subtransmission		TRK 1229			EQUIPMENT FAILURE
7/20/2023 17:24	7/21/2023 21:50	Subtransmission		TRK 1229			EQUIPMENT FAILURE
7/20/2023 17:31	7/20/2023 20:22	Subtransmission		TRK 1229			EQUIPMENT FAILURE
7/20/2023 17:38	7/22/2023 13:58	Subtransmission		TRK 1229			EQUIPMENT FAILURE
7/20/2023 17:57	7/21/2023 14:20	Subtransmission		TRK 1229			EQUIPMENT FAILURE
7/20/2023 17:56	7/21/2023 21:25	Subtransmission	Device (I)	TRK 1229	22	33407	EQUIPMENT FAILURE
7/20/2023 16:35	7/21/2023 20:50	Subtransmission	Single Customer	TRK 1229			EQUIPMENT FAILURE
7/20/2023 17:31	7/21/2023 21:27	Subtransmission	Single Customer	TRK 1229	1	26	EQUIPMENT FAILURE
7/20/2023 18:11	7/21/2023 21:27	Subtransmission	Single Customer	TRK 1229			EQUIPMENT FAILURE
7/21/2023 17:03	7/22/2023 14:01	Subtransmission		TRK 1229			EQUIPMENT FAILURE
7/22/2023 19:25	7/22/2023 21:05	Subtransmission		TRK 6919			EQUIPMENT FAILURE
7/22/2023 21:23	7/29/2023 16:57	Subtransmission		TRK 6919			EQUIPMENT FAILURE
7/26/2023 19:23	7/27/2023 10:36	Subtransmission		TIE 6517			EQUIPMENT FAILURE
7/26/2023 18:58	7/28/2023 17:07	Subtransmission		TRK 2035			EQUIPMENT FAILURE
7/26/2023 17:59	7/28/2023 16:59	Subtransmission		TRK 5526			EQUIPMENT FAILURE
7/26/2023 16:34	8/14/2023 19:28	Subtransmission		TIE 3205			EQUIPMENT FAILURE
7/26/2023 17:05	7/29/2023 4:23	Subtransmission		TIE 3402			EQUIPMENT FAILURE
7/26/2023 15:58	7/28/2023 13:05	Subtransmission		TRK 5906			EQUIPMENT FAILURE
7/26/2023 15:35	7/27/2023 16:19	Subtransmission		TRK 5906			EQUIPMENT FAILURE
7/26/2023 15:40	7/27/2023 16:14	Subtransmission		TRK 5906			EQUIPMENT FAILURE
7/26/2023 15:53	7/27/2023 16:13	Subtransmission		TRK 5906			EQUIPMENT FAILURE
7/26/2023 15:58	7/27/2023 16:12	Subtransmission		TRK 5906			EQUIPMENT FAILURE
7/26/2023 16:06	7/28/2023 13:35	Subtransmission		TRK 5906			EQUIPMENT FAILURE
7/26/2023 18:15	8/3/2023 17:09	Subtransmission		TRK 5906			EQUIPMENT FAILURE
7/26/2023 16:02	7/27/2023 16:12	Subtransmission	Circuit Level	TRK 5906	1867	2420381	EQUIPMENT FAILURE
7/26/2023 16:41	7/27/2023 10:23	Subtransmission	Circuit Level	TRK 5906	864	1220349	EQUIPMENT FAILURE
7/26/2023 16:05	7/28/2023 14:34	Subtransmission	Device (II)	TRK 5906	54	133803	EQUIPMENT FAILURE
7/26/2023 16:34	7/28/2023 12:22	Subtransmission	Single Customer	TRK 5906			EQUIPMENT FAILURE
7/30/2023 0:56	8/24/2023 5:21	Subtransmission		TIE 3107			EQUIPMENT FAILURE
8/9/2023 14:49	8/11/2023 13:26	Subtransmission		TIE 4105			EQUIPMENT FAILURE
8/15/2023 5:23	8/24/2023 5:24	Subtransmission		TRK 2005			EQUIPMENT FAILURE
8/16/2023 15:05	8/17/2023 12:00	Subtransmission		TRK 2025			EQUIPMENT FAILURE
8/17/2023 13:43	8/17/2023 18:23	Subtransmission		TIE 9303	1	104	EQUIPMENT FAILURE
8/17/2023 15:19	8/17/2023 16:53	Subtransmission	Single Customer	TIE 9303			EQUIPMENT FAILURE
8/17/2023 15:25	8/17/2023 16:54	Subtransmission	Single Customer	TIE 9303	1	105	EQUIPMENT FAILURE
8/17/2023 15:25	8/17/2023 16:55	Subtransmission	Single Customer	TIE 9303			EQUIPMENT FAILURE
8/17/2023 15:26	8/17/2023 16:55	Subtransmission	Single Customer	TIE 9303	1	105	EQUIPMENT FAILURE
8/17/2023 15:31	8/17/2023 16:55	Subtransmission	Single Customer	TIE 9303			EQUIPMENT FAILURE
8/17/2023 15:35	8/17/2023 16:55	Subtransmission	Single Customer	TIE 9303	1	105	EQUIPMENT FAILURE
8/17/2023 15:49	8/17/2023 16:57	Subtransmission	Single Customer	TIE 9303	1	105	EQUIPMENT FAILURE
8/17/2023 16:05	8/17/2023 16:58	Subtransmission	Single Customer	TIE 9303	1	105	EQUIPMENT FAILURE
8/17/2023 16:11	8/17/2023 16:59	Subtransmission	Single Customer	TIE 9303			EQUIPMENT FAILURE
8/17/2023 16:28	8/17/2023 16:59	Subtransmission	Single Customer	TIE 9303	1	105	EQUIPMENT FAILURE
8/17/2023 16:43	8/17/2023 16:58	Subtransmission	Single Customer	TIE 9303	1	105	EQUIPMENT FAILURE
8/17/2023 16:44	8/17/2023 16:59	Subtransmission	Single Customer	TIE 9303			EQUIPMENT FAILURE
8/17/2023 14:22	8/17/2023 16:49	Subtransmission		TIE 9303	1	104	EQUIPMENT FAILURE
8/17/2023 13:31	8/17/2023 16:39	Subtransmission	Subtransmission	TIE 9303	1508	158104	EQUIPMENT FAILURE
8/17/2023 14:24	8/17/2023 16:49	Subtransmission		TIE 9303			EQUIPMENT FAILURE
8/17/2023 13:53	8/17/2023 18:07	Subtransmission		TIE 9303	1	104	EQUIPMENT FAILURE
8/17/2023 13:35	8/17/2023 18:24	Subtransmission		TIE 9303			EQUIPMENT FAILURE
8/17/2023 13:36	8/17/2023 18:21	Subtransmission		TIE 9303	1	104	EQUIPMENT FAILURE
8/17/2023 14:47	8/17/2023 16:49	Subtransmission		TIE 9303			EQUIPMENT FAILURE
8/17/2023 13:44	8/18/2023 5:54	Subtransmission		TIE 9303			EQUIPMENT FAILURE

8/17/2023 13:48	8/17/2023 21:00	Subtransmission		TIE 9303			EQUIPMENT FAILURE
8/17/2023 12:00	2/8/2024 22:39	Subtransmission		TRK 2025			EQUIPMENT FAILURE
8/24/2023 23:35	8/27/2023 1:54	Subtransmission		TIE 7430			EQUIPMENT FAILURE
8/24/2023 23:44	8/29/2023 21:17	Subtransmission		TIE 1224			EQUIPMENT FAILURE
8/24/2023 18:33	8/29/2023 20:43	Subtransmission		TIE 1224			EQUIPMENT FAILURE
8/25/2023 2:09	8/29/2023 1:16	Subtransmission		TRK 2218			EQUIPMENT FAILURE
8/25/2023 3:05	8/29/2023 1:14	Subtransmission		TIE 1224			EQUIPMENT FAILURE
8/25/2023 1:51	8/29/2023 1:18	Subtransmission		TRK 2806			EQUIPMENT FAILURE
8/25/2023 5:39	8/25/2023 20:15	Subtransmission		TRK 3124			EQUIPMENT FAILURE
8/27/2023 15:23	8/29/2023 1:17	Subtransmission		TRK 2301			EQUIPMENT FAILURE
8/29/2023 2:00	8/31/2023 20:13	Subtransmission		TRK 2931			EQUIPMENT FAILURE
8/30/2023 4:02	9/15/2023 23:17	Subtransmission		TRK 1322			EQUIPMENT FAILURE
9/5/2023 20:35	9/6/2023 3:08	Subtransmission	Subtransmission	TRK 1444			EQUIPMENT FAILURE
9/12/2023 4:03	9/12/2023 19:20	Subtransmission	Device (II)	TIE 4105			EQUIPMENT FAILURE
10/1/2023 18:59	10/2/2023 10:53	Subtransmission		TIE 4105			EQUIPMENT FAILURE
10/4/2023 15:20	10/5/2023 5:48	Subtransmission		TRK 7104			EQUIPMENT FAILURE
10/25/2023 12:04	10/25/2023 15:56	Subtransmission	Substation	TRK 2319	4959	660827	EQUIPMENT FAILURE
11/17/2023 11:24	11/18/2023 2:03	Subtransmission		TRK 2715			EQUIPMENT FAILURE
11/17/2023 11:16	11/17/2023 16:55	Subtransmission		TRK 2715			EQUIPMENT FAILURE
11/17/2023 17:04	11/17/2023 20:41	Subtransmission	Device (II)	TRK 2715	84	43537	EQUIPMENT FAILURE
11/17/2023 15:25	11/17/2023 22:51	Subtransmission	Single Customer	TRK 2715			EQUIPMENT FAILURE
11/17/2023 14:49	11/17/2023 20:48	Subtransmission	Device (II)	TRK 2715	115	47139	EQUIPMENT FAILURE
12/9/2023 13:57	12/10/2023 8:25	Subtransmission		TIE 1568			EQUIPMENT FAILURE
12/12/2023 10:38	12/12/2023 20:04	Subtransmission		TIE 6138			EQUIPMENT FAILURE
2/23/2023 19:33	2/25/2023 7:56	Subtransmission		TRK 2931			ICE
10/23/2020 8:15	10/23/2020 13:48	Subtransmission	None	TIE 9111			LIGHTNING
10/23/2020 15:30	10/23/2020 17:25	Subtransmission	Distribution	TIE 9111	299	33906	LIGHTNING
10/23/2020 14:55	10/23/2020 17:25	Subtransmission	Distribution	TIE 9111	483	71760	LIGHTNING
10/23/2020 15:32	10/24/2020 18:51	Subtransmission	None	TIE 9111			LIGHTNING
6/10/2020 17:20	6/10/2020 18:06	Subtransmission	None	TIE 9303			NO ISSUES FOUND
7/2/2020 18:30	7/3/2020 14:54	Subtransmission	None	TRK 6304			PUBLIC INTERFERENCE
7/2/2020 18:34	7/3/2020 2:38	Subtransmission	None	TRK 6304			PUBLIC INTERFERENCE
8/21/2020 8:54	8/21/2020 12:00	Subtransmission	None	TRK 1418			PUBLIC INTERFERENCE
10/12/2020 20:29	10/12/2020 21:18	Subtransmission	Distribution	TIE 6621			PUBLIC INTERFERENCE
10/12/2020 20:32	10/12/2020 21:07	Subtransmission	Distribution	TIE 6621			PUBLIC INTERFERENCE
10/12/2020 20:47	10/13/2020 15:38	Subtransmission	None	TIE 6621			PUBLIC INTERFERENCE
10/12/2020 20:31	10/12/2020 21:13	Subtransmission	Distribution	TIE 6621			PUBLIC INTERFERENCE
11/5/2020 17:33	11/6/2020 19:36	Subtransmission	None	TRK 824			PUBLIC INTERFERENCE
4/15/2018 10:00	4/18/2018 20:51	Subtransmission	None	TIE 1540			TREE
4/15/2018 8:55	4/18/2018 20:30	Subtransmission	Distribution	TIE 1540	1	4956	TREE
5/4/2018 14:35	5/9/2018 20:16	Subtransmission	None	TRK 1303			TREE
5/4/2018 13:15	5/5/2018 20:00	Subtransmission	Distribution	TRK 1303	1176	2099911	TREE
5/6/2018 21:09	5/9/2018 3:30	Subtransmission	None	TRK 4419			TREE
8/28/2018 22:00	8/29/2018 5:19	Subtransmission	None	TIE 3205			TREE
8/29/2018 14:26	8/29/2018 20:13	Subtransmission	None	TIE 3205			TREE
10/20/2018 21:13	10/22/2018 19:52	Subtransmission	None	TIE 3323			TREE
11/26/2018 10:35	11/26/2018 19:22	Subtransmission	None	TIE 4104			TREE
11/26/2018 6:16	11/26/2018 21:16	Subtransmission	None	TIE 4105			TREE
11/26/2018 8:58	11/26/2018 10:40	Subtransmission	None	TIE 4105			TREE
11/26/2018 6:13	11/26/2018 9:18	Subtransmission	None	TIE 4105			TREE
11/26/2018 12:14	11/26/2018 19:56	Subtransmission	None	TIE 4105			TREE
11/26/2018 12:01	11/26/2018 16:05	Subtransmission	Distribution	TIE 4105	419	101647	TREE
1/7/2019 15:25	1/7/2019 23:21	Subtransmission	Distribution	TIE 3205	576	273468	TREE
1/7/2019 15:25	1/7/2019 23:21	Subtransmission	Distribution	TIE 3205	460	218986	TREE
1/7/2019 16:27	1/8/2019 20:14	Subtransmission	None	TIE 3205			TREE
2/8/2019 5:51	2/9/2019 7:08	Subtransmission	None	TIE 3208			TREE
3/10/2019 15:15	3/10/2019 20:40	Subtransmission	None	TIE 3410			TREE
3/30/2019 12:41	3/31/2019 19:49	Subtransmission	None	TIE 3205			TREE
4/14/2019 22:27	4/15/2019 10:02	Subtransmission	Distribution	TIE 3416	730	77931	TREE
4/15/2019 1:17	4/15/2019 18:50	Subtransmission	None	TIE 3416			TREE
4/15/2019 0:47	4/15/2019 5:34	Subtransmission	None	TIE 3416			TREE
5/23/2019 6:52	5/23/2019 21:25	Subtransmission	None	TIE 8014			TREE
7/4/2019 8:12	7/4/2019 18:43	Subtransmission	None	TIE 1467			TREE
7/17/2019 8:00	7/18/2019 1:11	Subtransmission	None	TRK 2087			TREE
8/18/2019 19:48	8/19/2019 5:14	Subtransmission	None	TRK 2027			TREE
8/18/2019 16:32	8/19/2019 1:02	Subtransmission	None	TRK 2027			TREE
8/18/2019 23:50	8/19/2019 15:00	Subtransmission	Distribution	TRK 2027	5	4088	TREE
8/19/2019 12:36	8/19/2019 15:20	Subtransmission	None	TRK 2027			TREE
11/1/2019 19:44	11/2/2019 13:22	Subtransmission	None	TIE 3205			TREE
12/23/2019 9:49	12/23/2019 20:55	Subtransmission	None	TIE 7430			TREE
12/23/2019 9:27	12/23/2019 13:40	Subtransmission	Distribution	TIE 7430	812	205389	TREE
1/11/2020 10:56	1/11/2020 11:40	Subtransmission	Distribution	TIE 1473	2	89	TREE
1/11/2020 11:31	1/11/2020 16:37	Subtransmission	None	TIE 1473			TREE
4/9/2020 12:42	4/9/2020 20:49	Subtransmission	None	TRK 2005			TREE
4/10/2020 22:00	4/11/2020 5:19	Subtransmission	None	TIE 4104			TREE
4/29/2020 14:53	4/30/2020 13:31	Subtransmission	None	TRK 7717			TREE
6/10/2020 17:08	6/10/2020 19:06	Subtransmission	None	TIE 9303			TREE
6/10/2020 17:19	6/11/2020 1:22	Subtransmission	Distribution	TIE 9303	1983	410278	TREE
6/10/2020 17:07	6/10/2020 20:57	Subtransmission	None	TIE 9303			TREE
6/10/2020 15:31	6/11/2020 19:30	Subtransmission	Distribution	TIE 9303	1052	450288	TREE
6/27/2020 0:14	6/27/2020 16:25	Subtransmission	Distribution	TIE 1467	274	268371	TREE
6/27/2020 0:14	6/27/2020 16:25	Subtransmission	Distribution	TIE 1467	756	438331	TREE
6/27/2020 1:48	6/27/2020 15:04	Subtransmission	None	TIE 1467			TREE
6/27/2020 22:12	6/28/2020 20:44	Subtransmission	None	TRK 2010			TREE
7/19/2020 22:16	7/20/2020 15:46	Subtransmission	None	TRK 2025			TREE
7/20/2020 11:10	7/20/2020 21:46	Subtransmission	None	TIE 7733			TREE
9/8/2020 9:16	9/8/2020 17:39	Subtransmission	None	TIE 1473			TREE
9/8/2020 8:43	9/8/2020 16:10	Subtransmission	Distribution	TIE 1473	979	278047	TREE
9/28/2020 23:37	9/29/2020 15:55	Subtransmission	None	TIE 4605			TREE
10/7/2020 14:13	10/7/2020 19:31	Subtransmission	None	TIE 4523			TREE
11/16/2020 9:12	11/17/2020 20:59	Subtransmission	None	TIE 4105			TREE
5/7/2021 19:57	5/8/2021 15:42	Subtransmission	None	TIE 1473			TREE
5/7/2021 17:03	5/8/2021 3:31	Subtransmission	None	TIE 1473			TREE
5/8/2021 8:42	5/8/2021 17:46	Subtransmission	None	TIE 1473			TREE
7/6/2021 18:59	7/7/2021 20:00	Subtransmission	Distribution	TRK 6759	1457	1916030	TREE
7/6/2021 18:58	7/7/2021 20:00	Subtransmission	Distribution	TRK 6759	43	25173	TREE
7/6/2021 19:30	7/7/2021 20:30	Subtransmission	None	TRK 6759			TREE
7/6/2021 19:22	7/7/2021 2:57	Subtransmission	None	TRK 6759			TREE
7/6/2021 21:22	7/7/2021 6:15	Subtransmission	Distribution	TRK 7909	1	199	TREE
7/6/2021 23:02	7/7/2021 0:43	Subtransmission	None	TRK 7909			TREE
7/6/2021 22:12	7/6/2021 23:24	Subtransmission	None	TRK 7909			TREE
7/6/2021 21:06	7/7/2021 2:19	Subtransmission	Distribution	TRK 7909	865	182435	TREE
7/6/2021 21:12	7/8/2021 18:20	Subtransmission	None	TRK 7909			TREE
7/6/2021 21:18	7/8/2021 16:23	Subtransmission	None	TRK 7909			TREE
7/6/2021 21:30	7/7/2021 17:10	Subtransmission	Distribution	TRK 7909	8	2898	TREE

7/6/2021 21:16	7/7/2021 22:43	Subtransmission	Distribution	TRK 7909	2426	1901741	TREE
7/6/2021 23:46	7/7/2021 5:43	Subtransmission	None	TRK 7909			TREE
7/6/2021 21:17	7/7/2021 16:36	Subtransmission	Distribution	TRK 7909	1851	664941	TREE
7/6/2021 21:56	7/7/2021 17:45	Subtransmission	Distribution	TRK 7909	1264	539725	TREE
7/6/2021 21:15	7/7/2021 16:36	Subtransmission	Distribution	TRK 7909	3073	1060910	TREE
7/7/2021 15:09	7/9/2021 3:30	Subtransmission	Subtransmission	TIE 4505	182	332478	TREE
7/7/2021 21:34	7/8/2021 14:42	Subtransmission	None	TRK 6759			TREE
7/7/2021 11:42	7/7/2021 16:42	Subtransmission	None	TRK 6759			TREE
7/7/2021 13:16	7/8/2021 2:21	Subtransmission	None	TRK 7909			TREE
7/7/2021 11:57	7/7/2021 16:36	Subtransmission	Distribution	TRK 7909	789	163081	TREE
7/24/2021 22:38	7/26/2021 19:06	Subtransmission	None	TIE 6117			TREE
12/11/2021 14:07	12/12/2021 13:30	Subtransmission	Distribution	TIE4105	692	944027	TREE
12/11/2021 8:27	12/12/2021 15:00	Subtransmission	Distribution	TIE4105	691	948253	TREE
3/31/2022 10:04	3/31/2022 20:26	Subtransmission	None	TIE 3203			TREE
3/31/2022 16:12	4/1/2022 21:00	Subtransmission	None	TIE 3203			TREE
3/31/2022 9:59	4/1/2022 21:00	Subtransmission	None	TIE 3203			TREE
7/20/2022 21:20	7/21/2022 9:05	Subtransmission	None	TIE 6907			TREE
7/20/2022 14:49	7/21/2022 5:40	Subtransmission	None	TIE 6907			TREE
8/29/2022 19:55	8/30/2022 15:59	Subtransmission	None	TIE 810			TREE
8/29/2022 18:21	8/30/2022 21:00	Subtransmission	Distribution	TIE 810	327	531671	TREE
8/30/2022 20:44	9/1/2022 14:11	Subtransmission	Distribution	TIE 4523	8	31816	TREE
8/30/2022 9:11	8/31/2022 18:03	Subtransmission	None	TIE 4523			TREE
8/30/2022 10:55	8/31/2022 20:54	Subtransmission	None	TIE 4523			TREE
11/5/2022 19:23	11/7/2022 15:31	Subtransmission	None	TIE 1473			TREE
11/5/2022 13:19	11/5/2022 16:29	Subtransmission	None	TIE 1473			TREE
11/5/2022 12:11	11/5/2022 18:00	Subtransmission	Distribution	TIE4105	708	248730	TREE
12/15/2022 0:53	12/15/2022 2:18	Subtransmission	None	TIE 3205			TREE
12/15/2022 0:34	12/15/2022 15:04	Subtransmission	None	TIE 3205			TREE
12/23/2022 12:51	12/23/2022 16:53	Subtransmission	None	TIE 3205			TREE
2/16/2023 16:51	2/17/2023 3:55	Subtransmission		TIE 3245			TREE
5/31/2023 12:47	2/16/2024 22:39	Subtransmission		TIE 2025			TREE
8/23/2023 9:15	8/24/2023 21:16	Subtransmission		TIE 9123			TREE
8/23/2023 8:47	8/23/2023 19:53	Subtransmission	Subtransmission	TIE 9123	1402	658293	TREE
8/24/2023 20:22	8/25/2023 16:31	Subtransmission		TIE 1531			TREE
8/24/2023 22:21	8/25/2023 21:32	Subtransmission		TIE 4523			TREE
8/24/2023 22:26	8/25/2023 23:02	Subtransmission	Device (II)	TIE 6621	49	41607	TREE
8/24/2023 22:15	8/25/2023 20:11	Subtransmission	Device (I)	TIE 6621	25	27380	TREE
8/24/2023 22:14	8/25/2023 20:11	Subtransmission	Device (I)	TIE 6621	9	9681	TREE
8/24/2023 23:40	8/26/2023 12:43	Subtransmission		TIE 6621			TREE
8/24/2023 22:16	8/26/2023 6:24	Subtransmission	Subtransmission	TIE 6621	7399	8054275	TREE
8/24/2023 1:57	8/27/2023 12:57	Subtransmission	Device (II)	TIE 7621	215	535969	TREE
8/24/2023 21:56	8/27/2023 19:55	Subtransmission	Device (II)	TIE 7621	66	260342	TREE
8/24/2023 21:59	8/27/2023 14:45	Subtransmission	Device (II)	TIE 7621	93	344061	TREE
8/24/2023 22:19	8/26/2023 11:40	Subtransmission		TIE 7621			TREE
8/24/2023 2:23	8/27/2023 12:57	Subtransmission	Device (I)	TIE 7621	21	102970	TREE
8/24/2023 1:38	8/27/2023 22:48	Subtransmission	Device (II)	TIE 7621	3	15965	TREE
8/24/2023 22:31	8/27/2023 20:02	Subtransmission	Device (II)	TRK 4301	136	556241	TREE
8/24/2023 22:38	8/26/2023 21:38	Subtransmission	Circuit Level	TRK 462	461	1238045	TREE
8/24/2023 22:49	8/26/2023 20:36	Subtransmission	Circuit Level	TRK 462	928	2523101	TREE
8/24/2023 22:35	8/27/2023 15:38	Subtransmission		TRK 8215			TREE
8/24/2023 22:37	8/26/2023 20:05	Subtransmission	Circuit Level	TRK 8215	1273	1697135	TREE
8/25/2023 7:00	8/26/2023 20:08	Subtransmission		TIE 4523			TREE
8/25/2023 20:05	8/27/2023 20:57	Subtransmission	Device (I)	TIE 1531	25	104021	TREE
8/25/2023 0:14	8/27/2023 10:54	Subtransmission	Device (II)	TIE 7621	29	101616	TREE
8/25/2023 0:24	8/27/2023 12:59	Subtransmission	Service Transformer	TIE 7621	2	7008	TREE
8/25/2023 1:37	8/29/2023 15:10	Subtransmission		TRK 6508			TREE
8/26/2023 7:08	8/27/2023 19:02	Subtransmission		TIE 1531			TREE
8/26/2023 5:04	8/26/2023 13:02	Subtransmission		TIE 7621	1	2375	TREE
11/12/2023 11:08	11/13/2023 15:54	Subtransmission		TIE 4605			TREE
11/12/2023 10:57	11/12/2023 15:15	Subtransmission	Circuit Level	TIE 4605	1570	142571	TREE
11/21/2023 7:59	11/21/2023 16:04	Subtransmission		TIE 6907			TREE
11/21/2023 8:05	11/21/2023 10:12	Subtransmission	Device (II)	TIE 6907			TREE
2/23/2023 18:59	2/25/2023 7:12	Subtransmission		TIE 4104			WIND
2/14/2020 5:03	2/14/2020 17:30	Subtransmission	None	TRK 1527			EQUIPMENT FAILURE
2/14/2020 4:42	2/14/2020 8:30	Subtransmission	Distribution	TRK 1527	1811	295046	EQUIPMENT FAILURE
6/3/2021 20:57	6/4/2021 0:30	Subtransmission	None	TRK 2087			EQUIPMENT FAILURE
3/1/2018 14:40	3/1/2018 23:32	Subtransmission	None	TRK 1525			EQUIPMENT FAILURE
3/1/2018 14:16	3/1/2018 23:31	Subtransmission	None	TRK 1525			EQUIPMENT FAILURE
4/26/2018 6:35	4/26/2018 9:02	Subtransmission	Distribution	TRK 4962	963	142576	EQUIPMENT FAILURE
4/26/2018 6:35	4/26/2018 9:02	Subtransmission	Distribution	TRK 4962	276	40794	EQUIPMENT FAILURE
4/26/2018 6:35	4/26/2018 9:52	Subtransmission	Distribution	TRK 4962	2574	507342	EQUIPMENT FAILURE
4/26/2018 6:35	4/26/2018 9:52	Subtransmission	Distribution	TRK 4962	3160	622408	EQUIPMENT FAILURE
7/12/2018 16:53	7/12/2018 22:30	Subtransmission	Distribution	TIE 5513	612	70466	EQUIPMENT FAILURE
6/6/2019 12:25	6/6/2019 17:28	Subtransmission	None	TIE 226			EQUIPMENT FAILURE
2/9/2020 12:47	2/10/2020 20:26	Subtransmission	None	TRK 7130			EQUIPMENT FAILURE
2/11/2020 6:55	2/17/2020 18:54	Subtransmission	None	TRK 7130			EQUIPMENT FAILURE
3/29/2022 19:33	3/29/2022 20:57	Subtransmission	None	TIE 3205			EQUIPMENT FAILURE
5/10/2020 9:53	5/10/2020 11:20	Subtransmission	Distribution	TRK 5906	2	113	ANIMAL
5/10/2020 9:58	5/10/2020 10:06	Subtransmission	None	TRK 5906			ANIMAL
5/10/2020 17:58	5/10/2020 21:05	Subtransmission	Distribution	TRK 5906			ANIMAL
5/10/2020 9:53	5/10/2020 11:00	Subtransmission	Distribution	TRK 5906	69	3803	ANIMAL
5/24/2022 9:41	5/24/2022 10:16	Subtransmission	Distribution	TRK 6919	20	629	ANIMAL
6/14/2022 8:59	6/15/2022 14:07	Subtransmission	None	TRK 6919			ANIMAL
5/1/2018 9:37	5/1/2018 14:27	Subtransmission	None	TIE 4105			EQUIPMENT FAILURE
10/20/2018 13:42	10/20/2018 15:30	Subtransmission	Subtransmission	TIE 6147	2040	242916	EQUIPMENT FAILURE
10/11/2019 10:24	10/11/2019 14:51	Subtransmission	None	TRK 6125			EQUIPMENT FAILURE
5/20/2020 18:48	5/21/2020 0:00	Subtransmission	Distribution	TRK 2233	8	803	EQUIPMENT FAILURE
5/20/2020 19:05	5/21/2020 5:00	Subtransmission	Distribution	TRK 2233	1	101	EQUIPMENT FAILURE
5/20/2020 18:48	5/21/2020 3:00	Subtransmission	Distribution	TRK 2233	9	903	EQUIPMENT FAILURE
5/20/2020 19:08	5/20/2020 22:12	Subtransmission	None	TRK 2233			EQUIPMENT FAILURE
1/19/2021 14:49	1/19/2021 21:29	Subtransmission	None	TIE 3208			EQUIPMENT FAILURE
1/19/2021 17:03	1/20/2021 3:02	Subtransmission	None	TIE 3208			EQUIPMENT FAILURE
6/16/2022 17:53	6/16/2022 20:57	Subtransmission	None	TRK 3546			EQUIPMENT FAILURE
7/31/2021 22:35	8/1/2021 12:48	Subtransmission	Distribution	TIE 3417	1	868	LIGHTNING
3/1/2018 20:57	3/3/2018 12:14	Subtransmission	None	TRK 2806			TREE
3/1/2018 22:42	3/2/2018 1:00	Subtransmission	Distribution	TRK 2806	125	21371	TREE
3/1/2018 23:18	3/3/2018 16:50	Subtransmission	Distribution	TRK 2806	15	36642	TREE
8/11/2021 23:24	8/12/2021 18:11	Subtransmission	None	TIE 4105			TREE
11/30/2022 10:07	11/30/2022 15:10	Subtransmission	Distribution	TIE 1568	85	9085	TREE
11/30/2022 10:25	11/30/2022 11:29	Subtransmission	None	TIE 1568			TREE
10/7/2018 12:49	10/8/2018 11:08	Subtransmission	None	TRK 4911			ANIMAL
7/9/2019 7:41	7/9/2019 15:27	Subtransmission	None	TRK 1323			ANIMAL
12/8/2019 6:07	12/8/2019 16:48	Subtransmission	None	TRK 853			ANIMAL
7/3/2021 15:43	7/3/2021 19:40	Subtransmission	None	TRK 6125			ANIMAL
8/3/2021 6:40	8/3/2021 9:00	Subtransmission	None	TRK 1563			ANIMAL

1/12/2018 12:18	1/12/2018 17:44	Subtransmission	None	TIE 3402			EQUIPMENT FAILURE
3/17/2018 16:42	3/17/2018 19:44	Subtransmission	None	TIE 4109			EQUIPMENT FAILURE
3/17/2018 15:46	3/19/2018 4:02	Subtransmission	None	TRK 3536			EQUIPMENT FAILURE
3/17/2018 10:47	3/17/2018 18:19	Subtransmission	None	TRK 3536			EQUIPMENT FAILURE
3/17/2018 10:56	3/18/2018 0:01	Subtransmission	None	TRK 3536			EQUIPMENT FAILURE
3/27/2018 5:25	3/27/2018 18:15	Subtransmission	None	TRK 4416			EQUIPMENT FAILURE
4/15/2018 12:17	4/18/2018 1:01	Subtransmission	None	TRK 3646			EQUIPMENT FAILURE
5/4/2018 14:04	5/10/2018 11:24	Subtransmission	None	TRK 2308			EQUIPMENT FAILURE
5/4/2018 14:44	5/5/2018 16:12	Subtransmission	None	TRK 2308			EQUIPMENT FAILURE
5/5/2018 16:54	5/8/2018 11:43	Subtransmission	None	TRK 2027			EQUIPMENT FAILURE
6/5/2018 17:37	6/7/2018 11:40	Subtransmission	None	TIE 3220			EQUIPMENT FAILURE
6/27/2018 8:47	6/27/2018 13:40	Subtransmission	Distribution	TIE 6138	1537	256545	EQUIPMENT FAILURE
6/27/2018 17:50	6/27/2018 18:01	Subtransmission	Distribution	TIE 6138	940	11690	EQUIPMENT FAILURE
6/27/2018 17:50	6/27/2018 18:01	Subtransmission	Distribution	TIE 6138	627	7787	EQUIPMENT FAILURE
6/27/2018 9:01	6/27/2018 10:34	Subtransmission	Distribution	TIE 6138	1596	119703	EQUIPMENT FAILURE
6/27/2018 8:36	6/28/2018 17:35	Subtransmission	None	TIE 6138			EQUIPMENT FAILURE
6/27/2018 9:02	6/27/2018 13:45	Subtransmission	Distribution	TIE 6138	614	163602	EQUIPMENT FAILURE
6/27/2018 9:00	6/27/2018 10:15	Subtransmission	Distribution	TIE 6138	1347	97753	EQUIPMENT FAILURE
6/27/2018 9:00	6/27/2018 10:16	Subtransmission	Distribution	TIE 6138	2388	179965	EQUIPMENT FAILURE
8/2/2018 14:12	8/3/2018 15:31	Subtransmission	None	TRK 2713			EQUIPMENT FAILURE
8/19/2018 19:18	8/19/2018 22:36	Subtransmission	None	TRK 5938			EQUIPMENT FAILURE
11/9/2018 7:07	11/9/2018 18:22	Subtransmission	None	TIE 2621			EQUIPMENT FAILURE
12/27/2018 20:55	12/30/2018 19:46	Subtransmission	None	TIE 4104			EQUIPMENT FAILURE
1/22/2019 20:42	1/23/2019 6:58	Subtransmission	None	TRK 2002			EQUIPMENT FAILURE
2/7/2019 21:08	2/9/2019 15:02	Subtransmission	None	TRK 3536			EQUIPMENT FAILURE
2/8/2019 8:30	2/8/2019 20:48	Subtransmission	None	TRK 3536			EQUIPMENT FAILURE
3/9/2019 18:53	3/10/2019 13:39	Subtransmission	None	TIE 6147			EQUIPMENT FAILURE
3/15/2019 1:25	3/15/2019 11:00	Subtransmission	None	TRK 853			EQUIPMENT FAILURE
5/1/2019 5:27	5/1/2019 12:09	Subtransmission	None	TRK 4911			EQUIPMENT FAILURE
5/1/2019 5:47	5/1/2019 6:57	Subtransmission	None	TRK 4911			EQUIPMENT FAILURE
5/1/2019 6:49	5/1/2019 9:38	Subtransmission	None	TRK 4911			EQUIPMENT FAILURE
5/31/2019 13:19	6/1/2019 6:47	Subtransmission	None	TRK 3661			EQUIPMENT FAILURE
5/31/2019 13:08	5/31/2019 19:15	Subtransmission	Distribution	TRK 3661	5	1584	EQUIPMENT FAILURE
7/9/2019 7:21	7/9/2019 10:38	Subtransmission	None	TRK 2907			EQUIPMENT FAILURE
7/19/2019 19:28	7/25/2019 15:47	Subtransmission	None	TRK 8014			EQUIPMENT FAILURE
8/24/2019 15:15	8/24/2019 18:10	Subtransmission	None	TRK 3632			EQUIPMENT FAILURE
9/11/2019 18:50	9/12/2019 17:02	Subtransmission	Distribution	TRK 2002	821	1062873	EQUIPMENT FAILURE
9/11/2019 18:35	9/12/2019 17:00	Subtransmission	Distribution	TRK 2002	533	403978	EQUIPMENT FAILURE
9/12/2019 17:01	9/12/2019 20:27	Subtransmission	None	TRK 2002			EQUIPMENT FAILURE
9/12/2019 21:50	9/13/2019 15:02	Subtransmission	None	TRK 2002			EQUIPMENT FAILURE
9/18/2019 9:18	9/18/2019 10:21	Subtransmission	None	TIE 4105			EQUIPMENT FAILURE
9/18/2019 9:18	9/18/2019 10:21	Subtransmission	None	TIE 4105			EQUIPMENT FAILURE
9/27/2019 12:28	9/27/2019 18:01	Subtransmission	None	TIE 6147			EQUIPMENT FAILURE
9/27/2019 4:44	9/27/2019 7:00	Subtransmission	Distribution	TIE 6147	2080	191618	EQUIPMENT FAILURE
10/24/2019 12:41	10/24/2019 22:49	Subtransmission	None	TIE 7504			EQUIPMENT FAILURE
11/1/2019 7:32	11/1/2019 11:53	Subtransmission	None	TRK 3536			EQUIPMENT FAILURE
11/27/2019 10:28	11/29/2019 20:13	Subtransmission	None	TIE 1423			EQUIPMENT FAILURE
1/9/2020 16:42	1/10/2020 4:54	Subtransmission	None	TIE 9205			EQUIPMENT FAILURE
1/9/2020 13:18	1/9/2020 17:44	Subtransmission	None	TIE 9205			EQUIPMENT FAILURE
1/23/2020 11:04	1/23/2020 17:15	Subtransmission	None	TRK 7062			EQUIPMENT FAILURE
1/23/2020 10:28	1/23/2020 17:16	Subtransmission	None	TRK 7078			EQUIPMENT FAILURE
3/5/2020 4:54	3/5/2020 17:58	Subtransmission	None	TRK 5838			EQUIPMENT FAILURE
4/9/2020 14:42	4/9/2020 15:21	Subtransmission	None	TRK 2316			EQUIPMENT FAILURE
5/3/2020 7:18	5/5/2020 15:14	Subtransmission	None	TRK 7035			EQUIPMENT FAILURE
5/27/2020 11:48	5/28/2020 13:00	Subtransmission	None	TIE 4104			EQUIPMENT FAILURE
6/11/2020 2:55	6/12/2020 17:00	Subtransmission	Distribution	TIE 4105	108	195450	EQUIPMENT FAILURE
7/8/2020 23:57	7/9/2020 5:15	Subtransmission	None	TRK 3543			EQUIPMENT FAILURE
7/29/2020 5:23	7/29/2020 14:03	Subtransmission	None	TRK 6759			EQUIPMENT FAILURE
12/22/2020 18:02	12/22/2020 21:30	Subtransmission	None	TRK 7062			EQUIPMENT FAILURE
3/3/2021 13:30	3/3/2021 20:03	Subtransmission	Distribution	TRK 4416			EQUIPMENT FAILURE
3/3/2021 13:00	3/3/2021 20:00	Subtransmission	Distribution	TRK 4416	1	356	EQUIPMENT FAILURE
3/9/2021 12:16	3/9/2021 13:15	Subtransmission	None	TIE 3205			EQUIPMENT FAILURE
5/7/2021 17:51	5/7/2021 18:35	Subtransmission	None	TIE 6147			EQUIPMENT FAILURE
5/7/2021 17:50	5/7/2021 18:40	Subtransmission	None	TIE 6147			EQUIPMENT FAILURE
5/7/2021 17:59	5/8/2021 4:35	Subtransmission	None	TIE 6147			EQUIPMENT FAILURE
5/28/2021 0:11	5/28/2021 13:22	Subtransmission	None	TIE 3417			EQUIPMENT FAILURE
6/17/2021 15:31	6/17/2021 18:49	Subtransmission	None	TRK 6304			EQUIPMENT FAILURE
6/17/2021 15:26	6/17/2021 18:49	Subtransmission	None	TRK 6304			EQUIPMENT FAILURE
6/17/2021 15:28	6/17/2021 18:49	Subtransmission	None	TRK 6304			EQUIPMENT FAILURE
6/17/2021 15:20	6/17/2021 18:30	Subtransmission	Distribution	TRK 6304	586	43017	EQUIPMENT FAILURE
6/17/2021 15:52	6/17/2021 18:49	Subtransmission	Distribution	TRK 6304	1	126	EQUIPMENT FAILURE
6/17/2021 15:44	6/17/2021 19:59	Subtransmission	None	TRK 6304			EQUIPMENT FAILURE
6/17/2021 15:37	6/17/2021 19:43	Subtransmission	None	TRK 6304			EQUIPMENT FAILURE
7/10/2021 7:28	7/11/2021 20:58	Subtransmission	None	TRK 1232			EQUIPMENT FAILURE
7/15/2021 12:38	7/15/2021 20:17	Subtransmission	None	TRK 2205			EQUIPMENT FAILURE
8/12/2021 11:54	8/12/2021 20:28	Subtransmission	None	TRK 7117			EQUIPMENT FAILURE
8/13/2021 8:23	8/13/2021 10:53	Subtransmission	None	TRK 7117			EQUIPMENT FAILURE
8/13/2021 10:15	8/13/2021 20:26	Subtransmission	None	TRK 7117			EQUIPMENT FAILURE
8/22/2021 17:38	8/23/2021 13:20	Subtransmission	None	TRK 4523			EQUIPMENT FAILURE
8/29/2021 11:46	8/29/2021 22:45	Subtransmission	Subtransmission	TRK 3124	1327	253240	EQUIPMENT FAILURE
8/29/2021 19:43	8/30/2021 2:32	Subtransmission	None	TRK 3124			EQUIPMENT FAILURE
8/30/2021 5:17	8/30/2021 16:03	Subtransmission	None	TRK 3124			EQUIPMENT FAILURE
9/14/2021 12:52	9/16/2021 4:43	Subtransmission	None	TIE 1568			EQUIPMENT FAILURE
10/4/2021 15:54	10/4/2021 20:38	Subtransmission	None	TIE 4109			EQUIPMENT FAILURE
10/4/2021 16:31	10/4/2021 20:11	Subtransmission	None	TIE 4109			EQUIPMENT FAILURE
12/24/2021 22:42	12/25/2021 5:24	Subtransmission	None	TIE 4428			EQUIPMENT FAILURE
2/2/2022 5:16	2/2/2022 13:02	Subtransmission	None	TRK 1276			EQUIPMENT FAILURE
3/24/2022 15:34	3/25/2022 5:04	Subtransmission	None	TIE4105			EQUIPMENT FAILURE
3/31/2022 18:04	4/1/2022 15:29	Subtransmission	Distribution	TRK 2715	1	56	EQUIPMENT FAILURE
4/4/2022 10:23	4/4/2022 20:30	Subtransmission	None	TRK 3617			EQUIPMENT FAILURE
4/4/2022 10:09	4/4/2022 18:19	Subtransmission	None	TRK 3617			EQUIPMENT FAILURE
5/4/2022 0:41	5/4/2022 2:08	Subtransmission	None	TIE 817			EQUIPMENT FAILURE
5/4/2022 6:53	5/4/2022 15:21	Subtransmission	None	TIE 817			EQUIPMENT FAILURE
5/31/2022 7:04	5/31/2022 14:33	Subtransmission	None	TRK 3508			EQUIPMENT FAILURE
7/14/2022 23:14	7/15/2022 4:00	Subtransmission	Distribution	TIE 5843	13	3643	EQUIPMENT FAILURE
7/14/2022 23:28	7/15/2022 7:21	Subtransmission	None	TIE 5843			EQUIPMENT FAILURE
1/26/2023 1:48	1/26/2023 5:16	Subtransmission	None	TRK 1502			EQUIPMENT FAILURE
4/24/2023 0:39	4/24/2023 8:03	Subtransmission	Circuit Level	TRK 1248	2	76	EQUIPMENT FAILURE
4/24/2023 0:21	4/24/2023 8:04	Subtransmission	Device (II)	TRK 1248	1	9	EQUIPMENT FAILURE
4/24/2023 0:16	4/24/2023 8:04	Subtransmission	Circuit Level	TRK 1248			EQUIPMENT FAILURE
4/24/2023 0:36	4/24/2023 19:02	Subtransmission		TRK 1248			EQUIPMENT FAILURE
6/3/2023 14:51	6/4/2023 15:50	Subtransmission		TIE 6931			EQUIPMENT FAILURE
7/25/2023 16:49	7/25/2023 22:24	Subtransmission		TIE 6602			EQUIPMENT FAILURE
7/26/2023 19:04	7/27/2023 23:30	Subtransmission		TRK 5935			EQUIPMENT FAILURE
7/26/2023 15:47	7/27/2023 23:31	Subtransmission	Substation	TRK 5935	468	882334	EQUIPMENT FAILURE

8/18/2023 12:03	8/20/2023 2:42	Subtransmission	Subtransmission	TRK 7187			EQUIPMENT FAILURE
8/18/2023 11:18	8/19/2023 5:35	Subtransmission		TRK 7187			EQUIPMENT FAILURE
8/24/2023 9:43	8/24/2023 12:04	Subtransmission		TRK 7187	1	219	EQUIPMENT FAILURE
8/24/2023 2:18	8/24/2023 16:32	Subtransmission	Circuit Level	TRK 7187	230	50142	EQUIPMENT FAILURE
8/24/2023 2:29	8/25/2023 16:39	Subtransmission		TRK 7187			EQUIPMENT FAILURE
8/24/2023 2:18	8/24/2023 21:58	Subtransmission		TRK 7187			EQUIPMENT FAILURE
8/24/2023 1:59	8/24/2023 13:20	Subtransmission	Circuit Level	TRK 7187	856	187088	EQUIPMENT FAILURE
8/24/2023 7:34	8/24/2023 21:43	Subtransmission	Circuit Level	TRK 7187	697	152356	EQUIPMENT FAILURE
6/18/2021 14:19	6/18/2021 19:02	Subtransmission	None	TIE 4428			LIGHTNING
7/22/2022 1:14	7/22/2022 20:22	Subtransmission	None	TIE 9107			LIGHTNING
9/14/2019 19:04	9/15/2019 17:55	Subtransmission	None	TRK 346			PUBLIC INTERFERENCE
4/6/2020 17:01	4/7/2020 10:49	Subtransmission	None	TRK 2027			PUBLIC INTERFERENCE
3/6/2019 17:49	3/7/2019 18:20	Subtransmission	None	TIE 6138			TREE
3/28/2019 11:25	3/28/2019 13:30	Subtransmission	Distribution	TIE 3705	464	55780	TREE
3/28/2019 11:42	3/28/2019 20:58	Subtransmission	None	TIE 3705			TREE
4/16/2019 22:14	4/17/2019 4:41	Subtransmission	None	TIE 3205			TREE
10/27/2019 3:51	10/27/2019 4:36	Subtransmission	Distribution	TIE 3241	46	3485	TREE
10/27/2019 3:31	10/27/2019 17:55	Subtransmission	None	TIE 3241			TREE
10/27/2019 6:54	10/27/2019 15:30	Subtransmission	Distribution	TIE 3241			TREE
10/27/2019 3:21	10/27/2019 4:36	Subtransmission	Distribution	TIE 3241	2195	163241	TREE
11/27/2019 10:57	11/29/2019 18:09	Subtransmission	None	TIE 1473			TREE
11/27/2019 10:17	11/27/2019 19:30	Subtransmission	Distribution	TIE 1473	705	181283	TREE
4/13/2020 13:36	4/13/2020 16:00	Subtransmission	Distribution	TIE 4505	64	7599	TREE
7/25/2020 16:17	7/26/2020 14:09	Subtransmission	None	TRK 2250			TREE
7/25/2020 11:01	7/27/2020 16:40	Subtransmission	None	TRK 2250			TREE
7/25/2020 13:06	7/26/2020 0:09	Subtransmission	None	TRK 2250			TREE
11/15/2020 2:38	11/15/2020 5:11	Subtransmission	Distribution	TIE 9303	1565	173821	TREE
11/15/2020 2:54	11/15/2020 14:10	Subtransmission	None	TIE 9303			TREE
6/29/2021 17:34	6/30/2021 10:41	Subtransmission	None	TRK 4301			TREE
6/29/2021 15:01	6/29/2021 20:42	Subtransmission	None	TRK 4301			TREE
1/11/2022 8:38	1/12/2022 16:59	Subtransmission	None	TIE 6931			EQUIPMENT FAILURE
9/12/2022 15:11	9/13/2022 14:36	Subtransmission	None	TIE 8014			EQUIPMENT FAILURE
11/17/2022 14:29	11/18/2022 2:05	Subtransmission	None	TRK 4316			EQUIPMENT FAILURE
5/29/2018 21:18	5/30/2018 0:28	Subtransmission	None	TRK 3526			EQUIPMENT FAILURE
5/29/2018 21:10	5/30/2018 18:43	Subtransmission	None	TRK 3526			EQUIPMENT FAILURE
4/9/2020 9:39	4/9/2020 12:35	Subtransmission	None	TRK 7122			ANIMAL
6/15/2018 21:49	7/1/2018 14:28	Subtransmission	None	TRK 1456			EQUIPMENT FAILURE
5/14/2023 1:18	5/14/2023 6:51	Subtransmission		TRK 2510			EQUIPMENT FAILURE
5/18/2023 12:07	5/19/2023 9:30	Subtransmission	Subtransmission	TRK 3511	324	15410	EQUIPMENT FAILURE
6/11/2022 21:28	6/12/2022 12:17	Subtransmission	None	TIE 3417			LIGHTNING
2/8/2018 16:20	2/8/2018 18:28	Subtransmission	None	TIE 4523			NO ISSUES FOUND
3/1/2018 23:06	3/2/2018 12:56	Subtransmission	None	TIE 3822			NO ISSUES FOUND
3/20/2018 4:13	3/20/2018 15:23	Subtransmission	None	TRK 2411			NO ISSUES FOUND
4/3/2018 10:06	4/3/2018 18:10	Subtransmission	None	TIE9303			NO ISSUES FOUND
4/4/2018 13:27	4/4/2018 19:43	Subtransmission	None	TRK 2411			NO ISSUES FOUND
4/11/2018 13:51	4/11/2018 20:26	Subtransmission	None	TIE 4512			NO ISSUES FOUND
5/14/2018 18:20	5/15/2018 15:34	Subtransmission	None	TIE 7745			NO ISSUES FOUND
5/26/2018 18:07	5/26/2018 22:52	Subtransmission	None	TRK 1276			NO ISSUES FOUND
5/27/2018 7:32	5/27/2018 11:36	Subtransmission	None	TIE 4523			NO ISSUES FOUND
5/27/2018 7:50	5/27/2018 12:03	Subtransmission	None	TIE 810			NO ISSUES FOUND
5/30/2018 18:45	6/4/2018 7:12	Subtransmission	None	TRK 3124			NO ISSUES FOUND
5/31/2018 7:48	5/31/2018 18:52	Subtransmission	None	TIE 5823			NO ISSUES FOUND
5/31/2018 2:58	5/31/2018 14:50	Subtransmission	None	TRK 385			NO ISSUES FOUND
5/31/2018 18:30	6/16/2018 11:09	Subtransmission	None	TRK 385			NO ISSUES FOUND
6/9/2018 8:48	6/9/2018 10:49	Subtransmission	None	TRK 1303			NO ISSUES FOUND
6/11/2018 17:21	6/11/2018 22:32	Subtransmission	None	TRK 1525			NO ISSUES FOUND
6/19/2018 7:38	6/19/2018 15:15	Subtransmission	None	TIE 1540			NO ISSUES FOUND
6/27/2018 17:40	6/27/2018 21:08	Subtransmission	None	TIE4105			NO ISSUES FOUND
6/27/2018 6:55	6/27/2018 11:00	Subtransmission	None	TRK 7035			NO ISSUES FOUND
6/29/2018 19:49	6/29/2018 20:45	Subtransmission	None	TRK 361			NO ISSUES FOUND
7/10/2018 16:26	7/10/2018 19:08	Subtransmission	None	TIE 6310			NO ISSUES FOUND
7/10/2018 0:20	7/10/2018 9:16	Subtransmission	None	TIE 6310			NO ISSUES FOUND
7/15/2018 8:53	7/15/2018 14:55	Subtransmission	None	TRK 2302			NO ISSUES FOUND
7/17/2018 7:29	7/17/2018 10:28	Subtransmission	None	TRK 4962			NO ISSUES FOUND
7/20/2018 10:30	7/20/2018 12:54	Subtransmission	None	TIE 8014			NO ISSUES FOUND
7/21/2018 8:19	7/22/2018 7:06	Subtransmission	None	TRK 2018			NO ISSUES FOUND
7/26/2018 21:29	10/1/2018 5:22	Subtransmission	None	TIE 1568			NO ISSUES FOUND
7/26/2018 14:12	7/27/2018 17:13	Subtransmission	None	TRK 5144			NO ISSUES FOUND
7/29/2018 14:44	7/29/2018 20:15	Subtransmission	None	TRK 2628			NO ISSUES FOUND
8/12/2018 18:41	8/13/2018 11:38	Subtransmission	None	TIE 7745			NO ISSUES FOUND
8/25/2018 9:01	8/25/2018 14:11	Subtransmission	None	TIE 7513			NO ISSUES FOUND
9/21/2018 14:29	9/21/2018 22:07	Subtransmission	None	TIE 4708			NO ISSUES FOUND
9/25/2018 22:15	9/26/2018 4:00	Subtransmission	None	TIE 1318			NO ISSUES FOUND
10/4/2018 22:27	10/5/2018 0:55	Subtransmission	None	TRK 3534			NO ISSUES FOUND
10/11/2018 10:37	10/12/2018 8:19	Subtransmission	None	TIE 2648			NO ISSUES FOUND
10/31/2018 9:18	10/31/2018 13:02	Subtransmission	None	TRK 853			NO ISSUES FOUND
11/2/2018 14:56	11/2/2018 19:46	Subtransmission	None	TIE 4105			NO ISSUES FOUND
11/3/2018 18:23	11/3/2018 23:03	Subtransmission	None	TRK 2439			NO ISSUES FOUND
11/25/2018 10:48	11/25/2018 14:40	Subtransmission	None	TRK 1346			NO ISSUES FOUND
11/26/2018 14:17	11/27/2018 12:26	Subtransmission	None	TIE 1586			NO ISSUES FOUND
11/26/2018 13:22	11/26/2018 14:56	Subtransmission	None	TIE 1586			NO ISSUES FOUND
11/27/2018 16:20	11/27/2018 20:53	Subtransmission	None	TRK 4316			NO ISSUES FOUND
12/9/2018 10:33	12/9/2018 18:50	Subtransmission	None	TIE 9123			NO ISSUES FOUND
12/11/2018 16:28	12/11/2018 22:54	Subtransmission	None	TRK 4316			NO ISSUES FOUND
12/31/2018 22:47	1/1/2019 22:47	Subtransmission	None	TIE 3205			NO ISSUES FOUND
12/31/2018 23:04	1/1/2019 1:12	Subtransmission	None	TIE 3205			NO ISSUES FOUND
1/5/2019 11:28	1/5/2019 17:29	Subtransmission	None	TIE 1544			NO ISSUES FOUND
1/8/2019 18:12	1/9/2019 4:53	Subtransmission	None	TIE 2813			NO ISSUES FOUND
1/17/2019 13:22	1/17/2019 17:28	Subtransmission	None	TRK 6125			NO ISSUES FOUND
1/20/2019 19:04	1/21/2019 3:21	Subtransmission	None	TRK 3508			NO ISSUES FOUND
1/20/2019 19:09	1/20/2019 22:29	Subtransmission	None	TRK 3508			NO ISSUES FOUND
1/22/2019 21:49	1/23/2019 13:06	Subtransmission	None	TRK 2308			NO ISSUES FOUND
1/24/2019 8:35	1/24/2019 11:25	Subtransmission	None	TRK 2308			NO ISSUES FOUND
1/24/2019 8:37	1/24/2019 12:30	Subtransmission	None	TRK 2313			NO ISSUES FOUND
3/14/2019 20:05	3/15/2019 12:53	Subtransmission	None	TRK 428			NO ISSUES FOUND
3/31/2019 12:26	3/31/2019 19:31	Subtransmission	None	TRK 3536			NO ISSUES FOUND
4/12/2019 21:23	4/13/2019 10:09	Subtransmission	None	TIE 5829			NO ISSUES FOUND
4/12/2019 15:30	4/13/2019 3:47	Subtransmission	None	TRK 2942			NO ISSUES FOUND
4/13/2019 12:59	4/13/2019 20:32	Subtransmission	None	TIE 3205			NO ISSUES FOUND
4/20/2019 16:06	4/20/2019 20:03	Subtransmission	None	TIE 1544			NO ISSUES FOUND
4/21/2019 7:56	4/22/2019 0:45	Subtransmission	None	TRK 357			NO ISSUES FOUND
4/24/2019 9:16	4/24/2019 12:25	Subtransmission	None	TRK 6741			NO ISSUES FOUND
5/2/2019 3:11	5/2/2019 9:20	Subtransmission	None	TIE 3417			NO ISSUES FOUND
5/11/2019 2:47	5/11/2019 6:01	Subtransmission	None	TRK 3304			NO ISSUES FOUND
5/16/2019 12:54	5/16/2019 19:15	Subtransmission	None	TRK 4605			NO ISSUES FOUND

5/19/2019 14:22	5/19/2019 19:38	Subtransmission	None	TRK 428			NO ISSUES FOUND
5/25/2019 17:57	5/26/2019 17:57	Subtransmission	None	TRK 3203			NO ISSUES FOUND
5/29/2019 0:41	5/29/2019 5:45	Subtransmission	None	TRK 2305			NO ISSUES FOUND
5/29/2019 22:04	5/30/2019 2:51	Subtransmission	None	TRK 5404			NO ISSUES FOUND
6/1/2019 6:26	6/1/2019 14:00	Subtransmission	None	TRK 5923			NO ISSUES FOUND
6/2/2019 15:02	6/2/2019 20:39	Subtransmission	None	TIE 2901			NO ISSUES FOUND
6/6/2019 9:24	6/6/2019 12:48	Subtransmission	None	TRK 2510			NO ISSUES FOUND
6/10/2019 15:27	6/10/2019 20:18	Subtransmission	None	TIE 9111			NO ISSUES FOUND
6/19/2019 6:42	6/19/2019 19:43	Subtransmission	None	TRK 3511			NO ISSUES FOUND
6/25/2019 2:48	6/25/2019 9:40	Subtransmission	None	TIE 3417			NO ISSUES FOUND
6/26/2019 1:18	6/26/2019 5:07	Subtransmission	None	TRK 853			NO ISSUES FOUND
6/27/2019 2:30	6/27/2019 12:51	Subtransmission	None	TIE 2819			NO ISSUES FOUND
6/29/2019 7:01	6/30/2019 15:57	Subtransmission	None	TIE 1381			NO ISSUES FOUND
7/4/2019 17:39	7/4/2019 19:41	Subtransmission	None	TIE 7104			NO ISSUES FOUND
7/15/2019 17:07	7/16/2019 6:46	Subtransmission	None	TIE 7520			NO ISSUES FOUND
7/16/2019 4:48	7/16/2019 7:00	Subtransmission	None	TRK 2543			NO ISSUES FOUND
7/16/2019 5:06	7/16/2019 12:48	Subtransmission	None	TRK 2543			NO ISSUES FOUND
7/19/2019 17:16	7/25/2019 18:24	Subtransmission	None	TIE 7702			NO ISSUES FOUND
7/19/2019 19:41	7/20/2019 12:42	Subtransmission	None	TIE 9107			NO ISSUES FOUND
7/20/2019 16:50	7/25/2019 14:56	Subtransmission	None	TIE 8033			NO ISSUES FOUND
7/20/2019 7:40	7/20/2019 12:47	Subtransmission	None	TIE 8033			NO ISSUES FOUND
7/24/2019 5:33	7/24/2019 9:50	Subtransmission	None	TRK 0361			NO ISSUES FOUND
8/9/2019 11:43	8/9/2019 21:32	Subtransmission	None	TRK 1531			NO ISSUES FOUND
8/10/2019 6:23	8/10/2019 16:35	Subtransmission	None	TIE 6128			NO ISSUES FOUND
8/12/2019 23:59	8/13/2019 5:38	Subtransmission	None	TRK 2319			NO ISSUES FOUND
8/19/2019 17:11	8/20/2019 1:29	Subtransmission	None	TIE 9705			NO ISSUES FOUND
9/8/2019 0:17	9/8/2019 9:53	Subtransmission	None	TIE 3417			NO ISSUES FOUND
9/11/2019 15:25	9/11/2019 22:14	Subtransmission	None	TRK 7386			NO ISSUES FOUND
9/16/2019 17:03	9/17/2019 14:52	Subtransmission	None	TRK 1411			NO ISSUES FOUND
9/18/2019 8:06	9/18/2019 14:48	Subtransmission	None	TIE 6907			NO ISSUES FOUND
9/22/2019 6:50	9/22/2019 18:07	Subtransmission	None	TRK 3205			NO ISSUES FOUND
10/1/2019 11:53	10/1/2019 16:55	Subtransmission	None	TRK 853			NO ISSUES FOUND
10/9/2019 13:56	10/9/2019 18:13	Subtransmission	None	TRK 5239			NO ISSUES FOUND
10/16/2019 6:46	10/16/2019 9:00	Subtransmission	None	TIE 4105			NO ISSUES FOUND
10/16/2019 6:46	10/16/2019 9:00	Subtransmission	None	TIE 4105			NO ISSUES FOUND
10/23/2019 18:34	10/23/2019 22:43	Subtransmission	None	TRK 2439			NO ISSUES FOUND
12/6/2019 22:25	12/7/2019 5:49	Subtransmission	None	TRK 853			NO ISSUES FOUND
12/25/2019 7:48	12/25/2019 13:10	Subtransmission	None	TRK 1527			NO ISSUES FOUND
1/12/2020 10:22	1/12/2020 12:54	Subtransmission	None	TIE 1268			NO ISSUES FOUND
1/15/2020 16:27	1/15/2020 21:41	Subtransmission	None	TRK 4416			NO ISSUES FOUND
1/25/2020 14:17	1/25/2020 21:21	Subtransmission	None	TIE 1531			NO ISSUES FOUND
2/2/2020 16:11	2/2/2020 22:16	Subtransmission	None	TIE 2648			NO ISSUES FOUND
2/3/2020 10:07	2/5/2020 9:23	Subtransmission	None	TRK 5935			NO ISSUES FOUND
2/5/2020 12:37	2/5/2020 14:48	Subtransmission	None	TRK 7324			NO ISSUES FOUND
2/5/2020 12:15	2/5/2020 16:02	Subtransmission	None	TRK 7324			NO ISSUES FOUND
2/13/2020 18:25	2/13/2020 21:04	Subtransmission	None	TIE 4523			NO ISSUES FOUND
2/13/2020 18:39	2/20/2020 7:45	Subtransmission	None	TIE 4523			NO ISSUES FOUND
2/17/2020 17:21	2/17/2020 21:26	Subtransmission	None	TIE 6931			NO ISSUES FOUND
2/17/2020 7:19	2/17/2020 11:07	Subtransmission	None	TRK 2437			NO ISSUES FOUND
2/21/2020 21:39	2/22/2020 12:56	Subtransmission	None	TRK 2205			NO ISSUES FOUND
2/24/2020 20:23	2/24/2020 22:33	Subtransmission	None	TIE 3241			NO ISSUES FOUND
3/10/2020 18:29	3/10/2020 22:57	Subtransmission	None	TIE 5823			NO ISSUES FOUND
3/11/2020 11:37	3/11/2020 14:51	Subtransmission	None	TIE 1568			NO ISSUES FOUND
3/21/2020 8:44	3/21/2020 12:19	Subtransmission	None	TRK 2439			NO ISSUES FOUND
3/25/2020 11:11	3/25/2020 16:00	Subtransmission	None	TIE 1544			NO ISSUES FOUND
3/28/2020 3:13	3/28/2020 6:08	Subtransmission	None	TRK 1232			NO ISSUES FOUND
4/1/2020 7:33	4/1/2020 12:07	Subtransmission	None	TRK 8215			NO ISSUES FOUND
4/2/2020 17:38	4/2/2020 23:13	Subtransmission	None	TRK 3518			NO ISSUES FOUND
4/4/2020 14:08	4/4/2020 18:57	Subtransmission	None	TRK 1470			NO ISSUES FOUND
4/7/2020 11:54	4/7/2020 15:26	Subtransmission	None	TRK 2027			NO ISSUES FOUND
4/10/2020 20:12	4/11/2020 5:07	Subtransmission	None	TRK 7035			NO ISSUES FOUND
4/11/2020 12:28	4/11/2020 17:05	Subtransmission	None	TRK 2922			NO ISSUES FOUND
4/13/2020 7:43	4/13/2020 10:51	Subtransmission	None	TRK 7324			NO ISSUES FOUND
4/19/2020 23:51	4/20/2020 4:57	Subtransmission	None	TRK 7114			NO ISSUES FOUND
4/23/2020 3:20	4/23/2020 15:28	Subtransmission	None	TRK 1423			NO ISSUES FOUND
4/26/2020 6:57	4/26/2020 11:56	Subtransmission	None	TIE 9107			NO ISSUES FOUND
5/2/2020 0:53	5/2/2020 5:13	Subtransmission	None	TIE 6147			NO ISSUES FOUND
5/12/2020 13:23	5/12/2020 14:55	Subtransmission	None	TRK 2437			NO ISSUES FOUND
5/15/2020 17:02	5/15/2020 20:17	Subtransmission	None	TRK 2922			NO ISSUES FOUND
5/18/2020 7:29	5/18/2020 12:11	Subtransmission	None	TIE 3323			NO ISSUES FOUND
5/20/2020 9:15	5/20/2020 14:03	Subtransmission	None	TRK 1525			NO ISSUES FOUND
6/3/2020 3:23	6/3/2020 13:57	Subtransmission	None	TRK 3557			NO ISSUES FOUND
6/4/2020 18:48	6/5/2020 11:40	Subtransmission	None	TIE 8014			NO ISSUES FOUND
6/4/2020 11:44	6/4/2020 12:45	Subtransmission	Distribution	TIE 8014			NO ISSUES FOUND
6/5/2020 10:15	6/6/2020 18:09	Subtransmission	None	TIE 8505			NO ISSUES FOUND
6/10/2020 15:49	6/12/2020 14:14	Subtransmission	None	TIE 7504			NO ISSUES FOUND
6/10/2020 21:20	6/12/2020 14:33	Subtransmission	None	TIE 9123			NO ISSUES FOUND
6/14/2020 22:14	6/15/2020 22:28	Subtransmission	None	TRK 2032			NO ISSUES FOUND
6/19/2020 9:48	6/19/2020 14:08	Subtransmission	None	TRK 2107			NO ISSUES FOUND
6/20/2020 7:38	6/20/2020 15:31	Subtransmission	None	TIE 4412			NO ISSUES FOUND
6/23/2020 21:56	6/23/2020 23:36	Subtransmission	Distribution	TRK 853	1	91	NO ISSUES FOUND
6/23/2020 22:08	6/24/2020 3:48	Subtransmission	None	TRK 853			NO ISSUES FOUND
6/29/2020 16:19	6/30/2020 15:14	Subtransmission	None	TIE 8014			NO ISSUES FOUND
6/29/2020 18:10	6/29/2020 21:04	Subtransmission	None	TRK 1116			NO ISSUES FOUND
7/1/2020 6:58	7/1/2020 10:39	Subtransmission	None	TRK 2032			NO ISSUES FOUND
7/2/2020 7:42	7/2/2020 10:30	Subtransmission	None	TRK 3534			NO ISSUES FOUND
7/8/2020 17:45	7/8/2020 23:38	Subtransmission	None	TIE 1318			NO ISSUES FOUND
7/9/2020 0:22	7/9/2020 1:50	Subtransmission	None	TRK 2806			NO ISSUES FOUND
7/10/2020 10:06	7/10/2020 20:44	Subtransmission	None	TIE 2648			NO ISSUES FOUND
7/12/2020 15:43	7/12/2020 19:32	Subtransmission	None	TRK 1314			NO ISSUES FOUND
7/17/2020 13:35	7/17/2020 16:50	Subtransmission	None	TIE 1224			NO ISSUES FOUND
7/17/2020 7:24	7/17/2020 10:14	Subtransmission	None	TRK 7115			NO ISSUES FOUND
7/19/2020 11:29	7/20/2020 11:35	Subtransmission	None	TRK 5817			NO ISSUES FOUND
7/19/2020 11:32	7/20/2020 11:36	Subtransmission	None	TRK 5823			NO ISSUES FOUND
7/25/2020 11:08	7/25/2020 18:28	Subtransmission	None	TRK 2218			NO ISSUES FOUND
7/30/2020 7:56	7/30/2020 17:13	Subtransmission	None	TRK 5855			NO ISSUES FOUND
8/2/2020 21:13	8/3/2020 13:48	Subtransmission	None	TIE 7702			NO ISSUES FOUND
8/11/2020 12:46	8/12/2020 17:14	Subtransmission	None	TRK 6304			NO ISSUES FOUND
8/14/2020 1:42	8/14/2020 16:02	Subtransmission	None	TIE 9107			NO ISSUES FOUND
8/18/2020 7:34	8/18/2020 10:20	Subtransmission	None	TIE 6621			NO ISSUES FOUND
8/22/2020 17:09	8/23/2020 0:52	Subtransmission	None	TRK 3508			NO ISSUES FOUND
8/22/2020 14:54	8/22/2020 19:33	Subtransmission	None	TRK 6941			NO ISSUES FOUND
8/25/2020 13:43	8/25/2020 20:10	Subtransmission	None	TIE 6907			NO ISSUES FOUND
8/26/2020 7:41	8/26/2020 16:13	Subtransmission	None	TIE 2648			NO ISSUES FOUND
8/28/2020 3:14	8/28/2020 10:00	Subtransmission	None	TIE 8511			NO ISSUES FOUND

8/28/2020 4:07	8/28/2020 16:03	Subtransmission	None	TRK 2742			NO ISSUES FOUND
8/28/2020 6:59	8/29/2020 10:15	Subtransmission	None	TRK 2742			NO ISSUES FOUND
9/1/2020 19:57	9/2/2020 4:57	Subtransmission	None	TIE 4105			NO ISSUES FOUND
9/7/2020 11:39	9/7/2020 16:35	Subtransmission	None	TRK 5145			NO ISSUES FOUND
9/7/2020 12:22	9/7/2020 20:29	Subtransmission	Distribution	TRK 5145	1	817	NO ISSUES FOUND
9/29/2020 8:31	9/30/2020 3:31	Subtransmission	None	TRK 4501			NO ISSUES FOUND
10/10/2020 17:04	10/10/2020 20:04	Subtransmission	None	TRK 1303			NO ISSUES FOUND
10/11/2020 11:02	10/11/2020 12:43	Subtransmission	None	TRK 3632			NO ISSUES FOUND
10/16/2020 16:31	10/16/2020 23:41	Subtransmission	None	TIE 810			NO ISSUES FOUND
10/23/2020 17:04	10/25/2020 12:54	Subtransmission	None	TRK 2305			NO ISSUES FOUND
10/27/2020 13:48	10/27/2020 17:56	Subtransmission	None	TIE 2810			NO ISSUES FOUND
10/27/2020 23:55	10/28/2020 1:03	Subtransmission	None	TRK 2523			NO ISSUES FOUND
11/11/2020 8:16	11/11/2020 15:02	Subtransmission	None	TRK 4416			NO ISSUES FOUND
12/31/2020 0:25	12/31/2020 4:25	Subtransmission	None	TIE 1224			NO ISSUES FOUND
1/2/2021 16:31	1/4/2021 1:03	Subtransmission	None	TIE 5820			NO ISSUES FOUND
2/12/2021 9:04	2/12/2021 11:27	Subtransmission	None	TRK 5923			NO ISSUES FOUND
2/21/2021 13:46	2/21/2021 19:20	Subtransmission	None	TRK 4301			NO ISSUES FOUND
3/8/2021 23:04	3/9/2021 15:45	Subtransmission	None	TIE 3209			NO ISSUES FOUND
3/9/2021 21:59	3/10/2021 7:28	Subtransmission	None	TRK 1218			NO ISSUES FOUND
3/9/2021 12:22	3/9/2021 15:53	Subtransmission	None	TRK 3617			NO ISSUES FOUND
3/11/2021 15:37	3/11/2021 18:55	Subtransmission	None	TRK 7150			NO ISSUES FOUND
3/12/2021 0:15	3/12/2021 11:57	Subtransmission	None	TIE 7504			NO ISSUES FOUND
3/24/2021 20:40	3/25/2021 11:37	Subtransmission	None	TRK 1502			NO ISSUES FOUND
4/1/2021 7:12	4/1/2021 9:37	Subtransmission	None	TRK 7602			NO ISSUES FOUND
4/6/2021 23:24	4/7/2021 15:36	Subtransmission	None	TIE 3220			NO ISSUES FOUND
4/9/2021 17:37	4/11/2021 6:22	Subtransmission	None	TIE 8033			NO ISSUES FOUND
4/9/2021 15:34	4/9/2021 21:47	Subtransmission	None	TRK 1444			NO ISSUES FOUND
4/10/2021 11:23	4/10/2021 16:24	Subtransmission	None	TRK 7386			NO ISSUES FOUND
4/12/2021 7:58	4/12/2021 18:44	Subtransmission	None	TIE 7430			NO ISSUES FOUND
4/30/2021 20:13	5/1/2021 10:42	Subtransmission	None	TRK 2543			NO ISSUES FOUND
5/14/2021 7:46	5/14/2021 12:03	Subtransmission	None	TIE 1473			NO ISSUES FOUND
5/27/2021 6:43	5/27/2021 9:35	Subtransmission	None	TRK 1218			NO ISSUES FOUND
5/29/2021 10:44	5/29/2021 17:51	Subtransmission	None	TRK 2319			NO ISSUES FOUND
5/29/2021 17:43	5/30/2021 0:16	Subtransmission	None	TRK 6508			NO ISSUES FOUND
5/30/2021 6:17	5/31/2021 14:08	Subtransmission	None	TRK 2319			NO ISSUES FOUND
6/2/2021 17:54	6/2/2021 23:09	Subtransmission	None	TRK 2319			NO ISSUES FOUND
6/2/2021 16:45	6/2/2021 18:28	Subtransmission	None	TRK 2543			NO ISSUES FOUND
6/2/2021 8:27	6/2/2021 14:50	Subtransmission	None	TRK 7106			NO ISSUES FOUND
6/3/2021 14:18	6/3/2021 18:53	Subtransmission	None	TRK 2510			NO ISSUES FOUND
6/5/2021 14:17	6/6/2021 13:30	Subtransmission	None	TRK 2508			NO ISSUES FOUND
6/9/2021 21:44	6/10/2021 12:58	Subtransmission	None	TRK 1418			NO ISSUES FOUND
6/18/2021 11:28	6/20/2021 5:38	Subtransmission	None	TRK 1502			NO ISSUES FOUND
6/20/2021 21:11	6/22/2021 21:43	Subtransmission	None	TIE 8804			NO ISSUES FOUND
6/21/2021 4:48	6/22/2021 19:10	Subtransmission	None	TRK 5404			NO ISSUES FOUND
6/24/2021 9:29	6/25/2021 8:38	Subtransmission	None	TIE 3203			NO ISSUES FOUND
6/29/2021 16:08	6/29/2021 21:58	Subtransmission	None	TIE 6621			NO ISSUES FOUND
7/1/2021 3:48	7/1/2021 8:36	Subtransmission	None	TRK 1502			NO ISSUES FOUND
7/2/2021 8:03	7/2/2021 16:54	Subtransmission	None	TRK 2038			NO ISSUES FOUND
7/4/2021 17:55	7/4/2021 20:06	Subtransmission	None	TRK 2611			NO ISSUES FOUND
7/6/2021 3:10	7/6/2021 14:42	Subtransmission	None	TIE 8511			NO ISSUES FOUND
7/6/2021 16:00	7/6/2021 21:09	Subtransmission	None	TRK 6508			NO ISSUES FOUND
7/8/2021 10:50	7/8/2021 22:33	Subtransmission	None	TIE 3220			NO ISSUES FOUND
7/12/2021 14:16	7/12/2021 17:22	Subtransmission	None	TRK 6828			NO ISSUES FOUND
7/17/2021 8:33	7/17/2021 12:44	Subtransmission	None	TIE 1318			NO ISSUES FOUND
7/23/2021 7:56	7/24/2021 12:04	Subtransmission	None	TRK 7150			NO ISSUES FOUND
7/24/2021 10:02	7/24/2021 19:14	Subtransmission	None	TRK 6841			NO ISSUES FOUND
7/29/2021 22:35	7/30/2021 20:11	Subtransmission	None	TIE 2648			NO ISSUES FOUND
8/7/2021 15:15	8/7/2021 18:33	Subtransmission	None	TIE 1318			NO ISSUES FOUND
8/7/2021 15:09	8/7/2021 16:00	Subtransmission	Distribution	TIE 1318			NO ISSUES FOUND
8/8/2021 16:37	8/14/2021 13:26	Subtransmission	None	TRK 1403			NO ISSUES FOUND
8/21/2021 13:05	8/21/2021 14:00	Subtransmission	Subtransmission	TIE 1318			NO ISSUES FOUND
8/21/2021 13:04	8/21/2021 14:00	Subtransmission	Distribution	TIE 1318			NO ISSUES FOUND
8/21/2021 13:07	8/21/2021 14:00	Subtransmission	Distribution	TIE 1318			NO ISSUES FOUND
8/21/2021 13:17	8/21/2021 16:02	Subtransmission	None	TIE 1318			NO ISSUES FOUND
9/17/2021 19:14	9/17/2021 21:23	Subtransmission	None	TRK 2439			NO ISSUES FOUND
9/23/2021 15:01	9/27/2021 7:49	Subtransmission	None	TIE 2812			NO ISSUES FOUND
10/8/2021 7:41	10/8/2021 16:07	Subtransmission	None	TIE 3800			NO ISSUES FOUND
10/15/2021 4:56	10/15/2021 13:26	Subtransmission	None	TIE 1423			NO ISSUES FOUND
10/15/2021 6:55	10/15/2021 13:32	Subtransmission	None	TRK 2301			NO ISSUES FOUND
10/26/2021 20:45	10/29/2021 18:28	Subtransmission	None	TRK 5522			NO ISSUES FOUND
11/21/2021 0:42	11/23/2021 22:29	Subtransmission	None	TRK 2027			NO ISSUES FOUND
12/18/2021 20:30	12/19/2021 12:22	Subtransmission	None	TRK 2313			NO ISSUES FOUND
12/18/2021 11:03	12/19/2021 13:33	Subtransmission	None	TRK 2411			NO ISSUES FOUND
1/3/2022 2:13	1/4/2022 11:20	Subtransmission	None	TRK 1276			NO ISSUES FOUND
1/5/2022 10:43	1/5/2022 13:39	Subtransmission	None	TIE 1473			NO ISSUES FOUND
1/5/2022 10:38	1/5/2022 13:00	Subtransmission	Distribution	TIE 1473			NO ISSUES FOUND
1/24/2022 17:31	1/25/2022 13:52	Subtransmission	None	TRK 1276			NO ISSUES FOUND
1/24/2022 15:10	1/24/2022 19:43	Subtransmission	None	TRK 1276			NO ISSUES FOUND
2/11/2022 10:55	2/11/2022 14:34	Subtransmission	None	TRK 7150			NO ISSUES FOUND
2/18/2022 10:18	2/18/2022 15:26	Subtransmission	None	TRK 1248			NO ISSUES FOUND
2/19/2022 4:11	2/19/2022 12:32	Subtransmission	None	TIE 9211			NO ISSUES FOUND
2/28/2022 7:23	2/28/2022 13:37	Subtransmission	None	TIE 3417			NO ISSUES FOUND
2/28/2022 1:56	2/28/2022 13:57	Subtransmission	None	TIE 6907			NO ISSUES FOUND
3/6/2022 13:13	3/6/2022 16:28	Subtransmission	None	TRK 2443			NO ISSUES FOUND
3/6/2022 10:35	3/8/2022 0:20	Subtransmission	None	TRK 2611			NO ISSUES FOUND
3/19/2022 9:15	3/19/2022 17:41	Subtransmission	None	TIE 6117			NO ISSUES FOUND
3/23/2022 17:46	3/26/2022 7:37	Subtransmission	None	TIE 8033			NO ISSUES FOUND
3/31/2022 6:11	3/31/2022 15:19	Subtransmission	None	TIE 226			NO ISSUES FOUND
3/31/2022 2:55	3/31/2022 12:13	Subtransmission	None	TIE 3402			NO ISSUES FOUND
3/31/2022 5:00	4/1/2022 20:47	Subtransmission	None	TIE 6147			NO ISSUES FOUND
3/31/2022 19:23	4/1/2022 0:37	Subtransmission	None	TIE 9123			NO ISSUES FOUND
3/31/2022 8:42	3/31/2022 14:44	Subtransmission	None	TRK 6172			NO ISSUES FOUND
4/3/2022 15:58	4/3/2022 21:06	Subtransmission	None	TRK 1502			NO ISSUES FOUND
4/6/2022 10:39	4/7/2022 8:28	Subtransmission	None	TRK 2319			NO ISSUES FOUND
4/10/2022 9:17	4/10/2022 13:04	Subtransmission	None	TRK 2250			NO ISSUES FOUND
4/13/2022 13:54	4/13/2022 19:20	Subtransmission	None	TRK 5404			NO ISSUES FOUND
4/14/2022 16:22	4/15/2022 13:14	Subtransmission	None	TIE 3205			NO ISSUES FOUND
4/14/2022 15:16	4/15/2022 18:35	Subtransmission	None	TIE 4412			NO ISSUES FOUND
4/14/2022 15:21	4/15/2022 21:34	Subtransmission	None	TIE 9205			NO ISSUES FOUND
4/14/2022 14:16	4/14/2022 17:22	Subtransmission	None	TRK 2107			NO ISSUES FOUND
4/15/2022 15:29	4/16/2022 1:17	Subtransmission	None	TIE 3417			NO ISSUES FOUND
4/18/2022 20:42	4/19/2022 4:56	Subtransmission	None	TIE 6931			NO ISSUES FOUND
4/18/2022 17:12	4/18/2022 22:13	Subtransmission	None	TIE 6931			NO ISSUES FOUND
4/19/2022 8:06	4/19/2022 21:18	Subtransmission	None	TIE 226			NO ISSUES FOUND
4/20/2022 11:30	4/21/2022 4:32	Subtransmission	None	TIE 4105			NO ISSUES FOUND

4/23/2022 8:45	4/23/2022 13:09	Subtransmission	None	TIE 1473	NO ISSUES FOUND
4/26/2022 8:00	4/27/2022 2:37	Subtransmission	None	TRK 7106	NO ISSUES FOUND
4/28/2022 0:41	4/29/2022 23:55	Subtransmission	None	TIE 1568	NO ISSUES FOUND
5/1/2022 3:48	5/1/2022 9:33	Subtransmission	None	TRK 1346	NO ISSUES FOUND
5/3/2022 13:01	5/4/2022 10:51	Subtransmission	None	TRK 8414	NO ISSUES FOUND
5/9/2022 8:45	5/9/2022 10:00	Subtransmission	Distribution	TRK 2107	NO ISSUES FOUND
5/14/2022 18:21	5/15/2022 1:43	Subtransmission	None	TIE 3417	NO ISSUES FOUND
5/24/2022 15:23	5/24/2022 20:39	Subtransmission	None	TRK 2027	NO ISSUES FOUND
5/24/2022 7:50	5/24/2022 14:42	Subtransmission	None	TRK 5935	NO ISSUES FOUND
5/25/2022 16:25	5/25/2022 21:59	Subtransmission	None	TIE 3800	NO ISSUES FOUND
5/26/2022 15:17	5/26/2022 18:10	Subtransmission	None	TIE 7621	NO ISSUES FOUND
5/31/2022 18:49	5/31/2022 21:06	Subtransmission	None	TIE 3417	NO ISSUES FOUND
6/1/2022 20:52	6/2/2022 19:54	Subtransmission	None	TRK 346	NO ISSUES FOUND
6/6/2022 17:02	6/9/2022 16:39	Subtransmission	None	TIE4105	NO ISSUES FOUND
6/8/2022 21:51	6/9/2022 14:29	Subtransmission	None	TRK 1502	NO ISSUES FOUND
6/12/2022 7:03	6/12/2022 9:02	Subtransmission	None	TRK 2466	NO ISSUES FOUND
6/16/2022 6:03	6/17/2022 10:27	Subtransmission	None	TIE 9123	NO ISSUES FOUND
6/20/2022 10:31	6/20/2022 15:22	Subtransmission	None	TRK 4428	NO ISSUES FOUND
6/24/2022 7:50	6/24/2022 10:18	Subtransmission	None	TRK 2439	NO ISSUES FOUND
6/25/2022 20:21	6/26/2022 11:10	Subtransmission	None	TIE 1467	NO ISSUES FOUND
7/2/2022 16:22	7/2/2022 22:44	Subtransmission	None	TRK 7324	NO ISSUES FOUND
7/4/2022 11:40	7/5/2022 15:40	Subtransmission	None	TIE 4428	NO ISSUES FOUND
7/5/2022 7:10	7/5/2022 15:55	Subtransmission	None	TRK 1243	NO ISSUES FOUND
7/5/2022 7:06	7/8/2022 2:06	Subtransmission	None	TRK 2918	NO ISSUES FOUND
7/5/2022 7:09	7/5/2022 11:11	Subtransmission	None	TRK 6828	NO ISSUES FOUND
7/7/2022 8:47	7/7/2022 11:39	Subtransmission	None	TRK 7733	NO ISSUES FOUND
7/7/2022 10:32	7/7/2022 18:27	Subtransmission	None	TIE 6310	NO ISSUES FOUND
7/7/2022 19:33	7/8/2022 0:55	Subtransmission	None	TRK 2918	NO ISSUES FOUND
7/8/2022 7:50	7/8/2022 10:47	Subtransmission	None	TRK 6854	NO ISSUES FOUND
7/10/2022 18:44	7/10/2022 22:17	Subtransmission	None	TRK 2466	NO ISSUES FOUND
7/11/2022 17:34	7/11/2022 21:36	Subtransmission	None	TRK 2005	NO ISSUES FOUND
7/14/2022 12:27	7/14/2022 19:41	Subtransmission	None	TRK 3508	NO ISSUES FOUND
7/24/2022 0:43	7/24/2022 6:42	Subtransmission	None	TRK 2027	NO ISSUES FOUND
7/28/2022 19:40	7/29/2022 2:34	Subtransmission	None	TRK 3518	NO ISSUES FOUND
8/1/2022 12:55	8/1/2022 19:57	Subtransmission	None	TIE 5513	NO ISSUES FOUND
8/2/2022 10:36	8/2/2022 13:08	Subtransmission	None	TIE 1467	NO ISSUES FOUND
8/8/2022 14:43	8/10/2022 0:29	Subtransmission	None	TIE4105	NO ISSUES FOUND
8/8/2022 9:11	8/8/2022 18:15	Subtransmission	None	TIE 5823	NO ISSUES FOUND
8/10/2022 8:27	8/10/2022 13:40	Subtransmission	None	TRK 1276	NO ISSUES FOUND
8/14/2022 20:22	8/15/2022 2:26	Subtransmission	None	TRK 7106	NO ISSUES FOUND
8/21/2022 11:23	8/21/2022 15:23	Subtransmission	None	TIE 7745	NO ISSUES FOUND
8/27/2022 20:47	8/28/2022 12:51	Subtransmission	None	TRK 1502	NO ISSUES FOUND
8/30/2022 10:22	8/30/2022 11:54	Subtransmission	None	TRK 2027	NO ISSUES FOUND
8/30/2022 7:49	8/30/2022 10:31	Subtransmission	None	TIE 1568	NO ISSUES FOUND
8/30/2022 7:47	8/31/2022 16:56	Subtransmission	None	TRK 1527	NO ISSUES FOUND
8/30/2022 10:18	9/2/2022 23:42	Subtransmission	None	TRK 4412	NO ISSUES FOUND
8/30/2022 10:32	8/30/2022 12:29	Subtransmission	None	TRK 5923	NO ISSUES FOUND
9/3/2022 1:51	9/4/2022 15:57	Subtransmission	None	TIE 4523	NO ISSUES FOUND
9/3/2022 19:39	9/4/2022 1:01	Subtransmission	None	TIE 1318	NO ISSUES FOUND
9/3/2022 12:16	9/4/2022 13:09	Subtransmission	None	TRK 1502	NO ISSUES FOUND
9/4/2022 10:38	9/5/2022 20:41	Subtransmission	None	TIE 1467	NO ISSUES FOUND
9/5/2022 14:15	9/5/2022 21:13	Subtransmission	None	TIE 8014	NO ISSUES FOUND
9/5/2022 8:06	9/7/2022 16:04	Subtransmission	None	TIE 9111	NO ISSUES FOUND
9/5/2022 14:39	9/5/2022 20:58	Subtransmission	None	TRK 2027	NO ISSUES FOUND
9/7/2022 9:15	9/9/2022 7:49	Subtransmission	None	TIE 2819	NO ISSUES FOUND
9/8/2022 9:27	9/10/2022 20:24	Subtransmission	None	TRK 5855	NO ISSUES FOUND
9/9/2022 18:45	9/11/2022 8:08	Subtransmission	None	TRK 5510	NO ISSUES FOUND
9/11/2022 23:05	9/12/2022 20:28	Subtransmission	None	TRK 2027	NO ISSUES FOUND
9/18/2022 3:26	9/18/2022 10:59	Subtransmission	None	TIE 185	NO ISSUES FOUND
9/19/2022 12:27	9/19/2022 20:55	Subtransmission	None	TIE 3417	NO ISSUES FOUND
9/20/2022 23:00	9/23/2022 20:05	Subtransmission	None	TRK 8215	NO ISSUES FOUND
9/21/2022 4:08	9/26/2022 10:23	Subtransmission	None	TRK 4338	NO ISSUES FOUND
9/22/2022 2:57	9/22/2022 8:24	Subtransmission	None	TRK 2636	NO ISSUES FOUND
9/23/2022 14:18	9/26/2022 14:08	Subtransmission	None	TIE 2025	NO ISSUES FOUND
9/25/2022 12:28	9/25/2022 15:38	Subtransmission	None	TIE 185	NO ISSUES FOUND
9/25/2022 16:14	9/26/2022 17:49	Subtransmission	None	TRK 2301	NO ISSUES FOUND
9/26/2022 14:21	9/28/2022 14:23	Subtransmission	None	TIE 8033	NO ISSUES FOUND
10/5/2022 14:13	10/8/2022 16:18	Subtransmission	None	TRK 8414	NO ISSUES FOUND
10/6/2022 21:06	10/7/2022 12:51	Subtransmission	None	TIE 8014	NO ISSUES FOUND
10/9/2022 9:45	10/9/2022 13:04	Subtransmission	None	TRK 2918	NO ISSUES FOUND
10/14/2022 0:19	10/14/2022 16:03	Subtransmission	None	TIE 3241	NO ISSUES FOUND
10/14/2022 0:07	10/15/2022 12:58	Subtransmission	None	TIE 3241	NO ISSUES FOUND
10/21/2022 13:03	10/22/2022 11:52	Subtransmission	None	TIE 3417	NO ISSUES FOUND
10/23/2022 16:06	10/24/2022 3:35	Subtransmission	None	TIE 226	NO ISSUES FOUND
10/26/2022 14:29	10/31/2022 11:56	Subtransmission	None	TIE 6172	NO ISSUES FOUND
11/5/2022 11:59	11/5/2022 18:02	Subtransmission	None	TIE 9123	NO ISSUES FOUND
11/21/2022 11:57	11/21/2022 16:41	Subtransmission	None	TRK 1303	NO ISSUES FOUND
11/27/2022 15:23	11/27/2022 18:54	Subtransmission	None	TRK 6941	NO ISSUES FOUND
11/29/2022 7:47	11/30/2022 11:32	Subtransmission	None	TRK 2439	NO ISSUES FOUND
11/30/2022 17:52	12/1/2022 16:29	Subtransmission	None	TIE 4109	NO ISSUES FOUND
12/3/2022 8:10	12/19/2022 19:21	Subtransmission	None	TIE 9211	NO ISSUES FOUND
12/5/2022 13:49	12/8/2022 22:37	Subtransmission	None	TRK 7324	NO ISSUES FOUND
12/12/2022 16:34	12/12/2022 23:49	Subtransmission	None	TIE 6907	NO ISSUES FOUND
12/15/2022 5:27	12/15/2022 10:27	Subtransmission	None	TIE 3323	NO ISSUES FOUND
12/22/2022 14:11	12/22/2022 17:18	Subtransmission	None	TRK 5526	NO ISSUES FOUND
12/23/2022 1:15	12/23/2022 17:16	Subtransmission	None	TIE4105	NO ISSUES FOUND
12/23/2022 12:53	12/24/2022 21:07	Subtransmission	None	TIE 3206	NO ISSUES FOUND
12/23/2022 15:13	12/24/2022 20:15	Subtransmission	None	TIE 817	NO ISSUES FOUND
12/24/2022 11:43	12/24/2022 21:07	Subtransmission	None	TIE4105	NO ISSUES FOUND
12/30/2022 2:19	12/30/2022 10:28	Subtransmission	None	TRK 1502	NO ISSUES FOUND
1/1/2023 8:50	1/1/2023 19:49	Subtransmission	None	TRK 2027	NO ISSUES FOUND
1/4/2023 11:29	1/5/2023 8:02	Subtransmission	None	TIE 2812	NO ISSUES FOUND
1/19/2023 10:12	1/19/2023 17:21	Subtransmission	None	TIE 3205	NO ISSUES FOUND
1/23/2023 7:56	1/23/2023 14:23	Subtransmission	None	TRK 2087	NO ISSUES FOUND
1/25/2023 15:28	1/25/2023 21:02	Subtransmission	None	TRK 1232	NO ISSUES FOUND
1/26/2023 0:50	1/28/2023 10:34	Subtransmission	None	TIE 4428	NO ISSUES FOUND
1/28/2023 12:51	1/28/2023 14:22	Subtransmission	None	TIE 4428	NO ISSUES FOUND
2/9/2023 8:56	2/9/2023 13:21	Subtransmission		TRK 1862	NO ISSUES FOUND
2/10/2023 18:22	2/12/2023 7:48	Subtransmission		TRK 7729	NO ISSUES FOUND
2/10/2023 18:35	2/10/2023 21:24	Subtransmission		TRK 7729	NO ISSUES FOUND
2/10/2023 18:10	2/11/2023 0:04	Subtransmission	Subtransmission	TRK 7729	NO ISSUES FOUND
2/15/2023 16:33	2/16/2023 21:47	Subtransmission	Single Customer	TIE 3245	NO ISSUES FOUND
2/15/2023 14:52	2/16/2023 22:55	Subtransmission		TIE 9211	NO ISSUES FOUND
2/15/2023 15:33	2/16/2023 16:14	Subtransmission		TIE 3245	NO ISSUES FOUND
2/15/2023 14:26	2/16/2023 17:13	Subtransmission		TIE 3245	NO ISSUES FOUND

2/22/2023 17:58	2/24/2023 20:26	Subtransmission		TIE 3205			NO ISSUES FOUND
2/22/2023 18:17	2/22/2023 18:47	Subtransmission	Substation	TRK 2054			NO ISSUES FOUND
2/22/2023 18:09	2/22/2023 21:43	Subtransmission	Substation	TRK 2054	1	109	NO ISSUES FOUND
2/23/2023 9:12	2/26/2023 16:57	Subtransmission		TRK 1340			NO ISSUES FOUND
2/27/2023 16:00	3/3/2023 6:18	Subtransmission		TIE 3212			NO ISSUES FOUND
2/27/2023 15:27	3/3/2023 6:16	Subtransmission		TIE 3323			NO ISSUES FOUND
2/27/2023 14:28	2/28/2023 2:13	Subtransmission		TRK 2826			NO ISSUES FOUND
3/3/2023 17:26	3/4/2023 5:06	Subtransmission		TRK 2918			NO ISSUES FOUND
3/3/2023 21:24	3/5/2023 8:08	Subtransmission	Substation	TRK 6919	1	1142	NO ISSUES FOUND
3/4/2023 16:21	3/5/2023 8:20	Subtransmission		TIE 6931			NO ISSUES FOUND
3/4/2023 2:54	3/4/2023 13:51	Subtransmission		TRK 141			NO ISSUES FOUND
3/4/2023 0:12	3/4/2023 16:55	Subtransmission		TRK 1544			NO ISSUES FOUND
3/4/2023 0:38	3/6/2023 8:42	Subtransmission		TRK 2308			NO ISSUES FOUND
3/4/2023 8:12	3/6/2023 18:54	Subtransmission		TRK 2659			NO ISSUES FOUND
3/4/2023 11:54	3/4/2023 17:30	Subtransmission		TRK 7187			NO ISSUES FOUND
3/5/2023 0:32	3/7/2023 16:45	Subtransmission		TIE 1531			NO ISSUES FOUND
3/6/2023 11:35	3/6/2023 17:39	Subtransmission		TRK 4405			NO ISSUES FOUND
3/7/2023 17:29	3/11/2023 21:08	Subtransmission		TIE 1540			NO ISSUES FOUND
3/15/2023 13:20	3/27/2023 7:39	Subtransmission		TRK 1218			NO ISSUES FOUND
3/15/2023 10:52	3/15/2023 13:10	Subtransmission		TRK 385			NO ISSUES FOUND
3/15/2023 10:49	3/15/2023 14:18	Subtransmission	Circuit Level	TRK 385			NO ISSUES FOUND
3/15/2023 13:14	3/15/2023 20:07	Subtransmission	Subtransmission	TRK 1218			NO ISSUES FOUND
3/16/2023 6:46	3/16/2023 7:10	Subtransmission	Circuit Level	TRK 362			NO ISSUES FOUND
3/17/2023 14:09	3/17/2023 15:09	Subtransmission	Circuit Level	TRK 2022			NO ISSUES FOUND
3/17/2023 19:14	3/20/2023 12:10	Subtransmission	Subtransmission	TIE 1568			NO ISSUES FOUND
3/17/2023 14:09	3/17/2023 15:10	Subtransmission	Circuit Level	TRK 2022			NO ISSUES FOUND
3/23/2023 13:16	3/23/2023 16:04	Subtransmission		TRK 2301			NO ISSUES FOUND
3/25/2023 15:04	3/26/2023 8:50	Subtransmission		TIE 6517			NO ISSUES FOUND
3/25/2023 15:20	3/27/2023 7:42	Subtransmission		TRK 1423			NO ISSUES FOUND
3/25/2023 16:35	3/26/2023 11:39	Subtransmission		TRK 2016			NO ISSUES FOUND
3/25/2023 15:38	3/27/2023 7:42	Subtransmission		TRK 2107			NO ISSUES FOUND
3/25/2023 16:24	3/27/2023 7:42	Subtransmission		TRK 2308			NO ISSUES FOUND
3/25/2023 16:44	3/27/2023 7:40	Subtransmission		TRK 3511			NO ISSUES FOUND
3/25/2023 15:19	3/27/2023 7:41	Subtransmission		TRK 4911			NO ISSUES FOUND
3/25/2023 15:43	3/26/2023 16:38	Subtransmission		TRK 6508			NO ISSUES FOUND
4/1/2023 12:27	4/1/2023 15:32	Subtransmission		TRK 2506			NO ISSUES FOUND
4/1/2023 9:05	4/4/2023 7:55	Subtransmission		TRK 5938			NO ISSUES FOUND
4/2/2023 11:38	4/4/2023 2:55	Subtransmission		TIE 3203			NO ISSUES FOUND
4/2/2023 10:29	4/4/2023 2:56	Subtransmission		TIE 3416			NO ISSUES FOUND
4/5/2023 8:39	4/6/2023 0:33	Subtransmission		TIE 3241			NO ISSUES FOUND
4/5/2023 11:08	4/6/2023 0:35	Subtransmission		TIE 3241			NO ISSUES FOUND
4/5/2023 3:06	4/5/2023 14:24	Subtransmission		TIE 7520			NO ISSUES FOUND
4/5/2023 8:51	4/6/2023 0:33	Subtransmission		TIE 9205			NO ISSUES FOUND
4/5/2023 15:45	4/6/2023 0:36	Subtransmission		TRK 4911			NO ISSUES FOUND
4/6/2023 16:23	4/7/2023 5:33	Subtransmission		TIE 3417			NO ISSUES FOUND
4/6/2023 15:33	4/6/2023 15:39	Subtransmission	Subtransmission	TRK 2027			NO ISSUES FOUND
4/6/2023 4:15	4/6/2023 5:37	Subtransmission	Device (II)	TRK 2247			NO ISSUES FOUND
4/6/2023 4:15	4/6/2023 5:41	Subtransmission	Circuit Level	TRK 2247			NO ISSUES FOUND
4/6/2023 4:15	4/6/2023 5:36	Subtransmission	Circuit Level	TRK 2247	1	6	NO ISSUES FOUND
4/6/2023 4:15	4/6/2023 5:35	Subtransmission	Circuit Level	TRK 2247			NO ISSUES FOUND
4/6/2023 4:15	4/6/2023 5:41	Subtransmission	Device (II)	TRK 2247			NO ISSUES FOUND
4/6/2023 3:56	4/6/2023 13:01	Subtransmission		TRK 2247			NO ISSUES FOUND
4/6/2023 5:45	4/6/2023 17:00	Subtransmission		TRK 2659			NO ISSUES FOUND
4/10/2023 21:06	4/11/2023 0:16	Subtransmission		TRK 2111			NO ISSUES FOUND
4/10/2023 8:17	4/10/2023 10:31	Subtransmission		TRK 3650			NO ISSUES FOUND
4/16/2023 13:29	4/17/2023 6:01	Subtransmission		TIE 9123			NO ISSUES FOUND
4/19/2023 0:15	4/19/2023 19:20	Subtransmission		TIE 2812			NO ISSUES FOUND
4/23/2023 16:53	4/24/2023 6:16	Subtransmission	Circuit Level	TRK 2308			NO ISSUES FOUND
5/6/2023 11:11	5/6/2023 18:01	Subtransmission	Single Customer	TRK 2439			NO ISSUES FOUND
5/11/2023 19:10	5/12/2023 23:52	Subtransmission		TRK 4971			NO ISSUES FOUND
5/18/2023 10:23	5/22/2023 23:46	Subtransmission	Subtransmission	TRK 3546			NO ISSUES FOUND
5/19/2023 0:53	5/19/2023 22:01	Subtransmission		TIE 9205			NO ISSUES FOUND
5/21/2023 7:56	5/21/2023 17:44	Subtransmission		TRK 7035			NO ISSUES FOUND
5/27/2023 12:32	5/27/2023 13:49	Subtransmission		TRK 1525			NO ISSUES FOUND
5/27/2023 6:57	5/28/2023 20:30	Subtransmission		TRK 2313			NO ISSUES FOUND
5/27/2023 5:24	5/27/2023 9:44	Subtransmission	Circuit Level	TRK 2523			NO ISSUES FOUND
6/6/2023 10:10	6/6/2023 13:07	Subtransmission	Device (II)	TIE 4570			NO ISSUES FOUND
6/7/2023 21:02	6/8/2023 3:42	Subtransmission		TIE 1312			NO ISSUES FOUND
6/7/2023 20:41	6/8/2023 4:32	Subtransmission	Substation	TIE 1312			NO ISSUES FOUND
6/8/2023 10:33	6/11/2023 14:48	Subtransmission		TRK 5938			NO ISSUES FOUND
6/8/2023 10:28	6/8/2023 13:43	Subtransmission	Device (II)	TRK 5938			NO ISSUES FOUND
6/9/2023 9:54	6/9/2023 19:17	Subtransmission		TIE 6602			NO ISSUES FOUND
6/11/2023 22:01	6/15/2023 10:55	Subtransmission		TIE 2819			NO ISSUES FOUND
6/11/2023 10:45	6/11/2023 17:16	Subtransmission		TIE 6907			NO ISSUES FOUND
6/11/2023 17:19	6/15/2023 13:17	Subtransmission		TRK 2931			NO ISSUES FOUND
6/11/2023 8:09	6/11/2023 16:27	Subtransmission		TRK 7065			NO ISSUES FOUND
6/11/2023 16:49	6/15/2023 13:19	Subtransmission		TRK 7065			NO ISSUES FOUND
6/14/2023 3:21	6/14/2023 11:46	Subtransmission		TIE 4104			NO ISSUES FOUND
6/15/2023 15:23	6/19/2023 15:53	Subtransmission		TIE 3206			NO ISSUES FOUND
6/18/2023 9:48	6/19/2023 7:40	Subtransmission		TIE 2648			NO ISSUES FOUND
6/23/2023 14:12	6/24/2023 19:09	Subtransmission		TRK 6741			NO ISSUES FOUND
6/23/2023 9:55	6/23/2023 14:41	Subtransmission		TRK 6854			NO ISSUES FOUND
6/23/2023 8:37	6/27/2023 14:08	Subtransmission		TRK 7130			NO ISSUES FOUND
6/24/2023 18:08	6/27/2023 11:15	Subtransmission		TRK 2418			NO ISSUES FOUND
6/26/2023 4:05	6/27/2023 1:55	Subtransmission		TRK 2659			NO ISSUES FOUND
6/27/2023 19:19	6/29/2023 12:30	Subtransmission		TRK 2713			NO ISSUES FOUND
6/28/2023 4:40	7/2/2023 8:26	Subtransmission		TRK 5906			NO ISSUES FOUND
6/28/2023 10:08	6/29/2023 12:29	Subtransmission		TRK 2713			NO ISSUES FOUND
7/1/2023 9:52	7/8/2023 5:53	Subtransmission		TIE 9111			NO ISSUES FOUND
7/2/2023 19:26	7/26/2023 7:57	Subtransmission		TRK 2918			NO ISSUES FOUND
7/2/2023 8:42	7/7/2023 21:30	Subtransmission		TRK 5935			NO ISSUES FOUND
7/2/2023 15:56	7/5/2023 19:51	Subtransmission		TRK 6741			NO ISSUES FOUND
7/3/2023 11:13	7/5/2023 23:02	Subtransmission		TRK 2826			NO ISSUES FOUND
7/4/2023 13:26	7/7/2023 21:31	Subtransmission		TIE 6138			NO ISSUES FOUND
7/6/2023 15:32	7/7/2023 21:31	Subtransmission		TRK 4227			NO ISSUES FOUND
7/7/2023 5:46	7/7/2023 14:28	Subtransmission		TIE 5513			NO ISSUES FOUND
7/13/2023 1:03	7/13/2023 10:28	Subtransmission	Substation	TRK 5935	1	5	NO ISSUES FOUND
7/14/2023 14:18	7/15/2023 22:14	Subtransmission		TIE 3318			NO ISSUES FOUND
7/14/2023 16:16	7/16/2023 20:29	Subtransmission		TIE 5208			NO ISSUES FOUND
7/14/2023 16:14	7/16/2023 21:25	Subtransmission		TRK 2931			NO ISSUES FOUND
7/14/2023 16:42	7/17/2023 7:56	Subtransmission		TRK 5140			NO ISSUES FOUND
7/15/2023 21:54	7/20/2023 22:59	Subtransmission		TIE 3205			NO ISSUES FOUND
7/15/2023 6:34	7/17/2023 7:56	Subtransmission		TRK 6842			NO ISSUES FOUND
7/20/2023 16:26	7/22/2023 10:54	Subtransmission		TIE 2025			NO ISSUES FOUND
7/20/2023 16:20	7/21/2023 10:22	Subtransmission		TIE 2819			NO ISSUES FOUND

7/20/2023 16:30	7/21/2023 17:23	Subtransmission		TIE 5829			NO ISSUES FOUND
7/20/2023 15:06	7/22/2023 11:16	Subtransmission		TIE 9111			NO ISSUES FOUND
7/20/2023 18:20	7/21/2023 13:22	Subtransmission		TRK 1251			NO ISSUES FOUND
7/20/2023 17:31	7/22/2023 14:05	Subtransmission		TRK 1340			NO ISSUES FOUND
7/20/2023 15:43	7/22/2023 14:10	Subtransmission		TRK 2525			NO ISSUES FOUND
7/20/2023 16:28	7/22/2023 11:42	Subtransmission		TRK 6125			NO ISSUES FOUND
7/21/2023 7:48	7/21/2023 12:39	Subtransmission		TRK 6854			NO ISSUES FOUND
7/21/2023 0:36	7/21/2023 11:20	Subtransmission		TIE 226			NO ISSUES FOUND
7/24/2023 8:20	7/26/2023 14:30	Subtransmission		TIE 8623			NO ISSUES FOUND
7/24/2023 18:59	7/29/2023 4:06	Subtransmission		TRK 7130			NO ISSUES FOUND
7/25/2023 12:41	7/28/2023 17:06	Subtransmission		TIE 3241			NO ISSUES FOUND
7/26/2023 20:54	7/28/2023 12:33	Subtransmission		TIE 1268			NO ISSUES FOUND
7/26/2023 15:55	7/28/2023 16:25	Subtransmission		TIE 1531			NO ISSUES FOUND
7/26/2023 18:07	7/28/2023 17:00	Subtransmission		TIE 2812			NO ISSUES FOUND
7/26/2023 17:56	7/28/2023 15:07	Subtransmission		TIE 7408			NO ISSUES FOUND
7/26/2023 15:31	7/26/2023 22:28	Subtransmission	Subtransmission	TIE 8014			NO ISSUES FOUND
7/26/2023 13:05	7/31/2023 6:54	Subtransmission		TIE 9111			NO ISSUES FOUND
7/26/2023 15:42	7/28/2023 20:28	Subtransmission	Subtransmission	TRK 2002	27	39490	NO ISSUES FOUND
7/26/2023 18:27	7/28/2023 17:00	Subtransmission		TRK 2443			NO ISSUES FOUND
7/26/2023 18:01	7/28/2023 10:32	Subtransmission		TRK 6304			NO ISSUES FOUND
7/26/2023 16:02	7/28/2023 16:56	Subtransmission		TRK 6722			NO ISSUES FOUND
7/26/2023 18:32	7/28/2023 11:51	Subtransmission		TRK 7130			NO ISSUES FOUND
7/26/2023 16:09	7/28/2023 17:01	Subtransmission		TRK 8414			NO ISSUES FOUND
7/26/2023 18:06	7/28/2023 16:23	Subtransmission		TIE 1531			NO ISSUES FOUND
7/28/2023 21:49	7/30/2023 20:44	Subtransmission		TIE 3800			NO ISSUES FOUND
7/28/2023 15:42	7/28/2023 23:06	Subtransmission	Circuit Level	TRK 2002	805	2569724	NO ISSUES FOUND
7/28/2023 17:19	7/29/2023 4:24	Subtransmission		TRK 2911			NO ISSUES FOUND
7/30/2023 5:12	8/20/2023 21:49	Subtransmission		TIE 4708			NO ISSUES FOUND
7/30/2023 17:04	7/30/2023 21:45	Subtransmission		TRK 7150			NO ISSUES FOUND
7/30/2023 17:06	7/30/2023 21:04	Subtransmission		TRK 7150			NO ISSUES FOUND
8/8/2023 13:45	8/9/2023 4:14	Subtransmission		TIE 3417			NO ISSUES FOUND
8/10/2023 1:34	8/10/2023 19:20	Subtransmission		TIE 9107			NO ISSUES FOUND
8/11/2023 22:27	8/12/2023 11:56	Subtransmission	Substation	TRK 1276	1	5	NO ISSUES FOUND
8/11/2023 22:58	8/20/2023 21:53	Subtransmission		TRK 5906			NO ISSUES FOUND
8/11/2023 22:11	8/20/2023 21:52	Subtransmission		TRK 7150			NO ISSUES FOUND
8/11/2023 22:30	8/13/2023 18:32	Subtransmission		TRK 1276			NO ISSUES FOUND
8/12/2023 16:47	8/14/2023 19:02	Subtransmission		TRK 1303			NO ISSUES FOUND
8/15/2023 2:40	8/15/2023 12:58	Subtransmission		TIE 3417			NO ISSUES FOUND
8/17/2023 15:27	8/17/2023 21:26	Subtransmission		TRK 1303			NO ISSUES FOUND
8/23/2023 13:03	8/26/2023 9:31	Subtransmission		TRK 6304			NO ISSUES FOUND
8/24/2023 23:53	8/25/2023 9:16	Subtransmission		TIE 2812			NO ISSUES FOUND
8/24/2023 23:45	8/27/2023 17:28	Subtransmission		TIE 2819			NO ISSUES FOUND
8/24/2023 21:15	8/25/2023 16:09	Subtransmission		TIE 3220			NO ISSUES FOUND
8/24/2023 23:42	8/26/2023 12:31	Subtransmission		TIE 4412			NO ISSUES FOUND
8/24/2023 23:01	8/25/2023 17:24	Subtransmission		TIE 6931			NO ISSUES FOUND
8/24/2023 22:24	8/26/2023 15:26	Subtransmission		TRK 1232			NO ISSUES FOUND
8/24/2023 3:13	8/28/2023 1:03	Subtransmission		TRK 5239			NO ISSUES FOUND
8/24/2023 2:14	8/24/2023 12:54	Subtransmission		TRK 5906			NO ISSUES FOUND
8/24/2023 23:50	8/25/2023 16:32	Subtransmission		TIE 1540			NO ISSUES FOUND
8/24/2023 23:48	8/25/2023 16:33	Subtransmission		TIE 1544			NO ISSUES FOUND
8/24/2023 21:26	8/25/2023 14:34	Subtransmission		TIE 3220			NO ISSUES FOUND
8/24/2023 23:18	8/27/2023 17:18	Subtransmission		TIE 6517			NO ISSUES FOUND
8/25/2023 7:06	8/25/2023 18:21	Subtransmission		TIE 5208			NO ISSUES FOUND
8/25/2023 2:38	8/26/2023 12:04	Subtransmission		TRK 1502			NO ISSUES FOUND
8/25/2023 2:37	8/26/2023 12:15	Subtransmission		TRK 1525			NO ISSUES FOUND
8/25/2023 2:33	8/25/2023 16:14	Subtransmission		TRK 1563			NO ISSUES FOUND
8/25/2023 2:22	8/26/2023 10:47	Subtransmission		TRK 2107			NO ISSUES FOUND
8/25/2023 1:50	8/26/2023 11:51	Subtransmission		TRK 5817			NO ISSUES FOUND
8/25/2023 1:46	8/25/2023 12:14	Subtransmission		TRK 5935			NO ISSUES FOUND
8/25/2023 0:56	8/26/2023 12:32	Subtransmission		TRK 8407			NO ISSUES FOUND
8/25/2023 16:46	8/25/2023 22:43	Subtransmission		TRK 845			NO ISSUES FOUND
8/26/2023 9:48	8/28/2023 1:12	Subtransmission		TIE 1312			NO ISSUES FOUND
8/26/2023 8:28	8/29/2023 10:16	Subtransmission		TIE 8033			NO ISSUES FOUND
8/26/2023 21:33	8/27/2023 18:14	Subtransmission		TRK 1340			NO ISSUES FOUND
8/26/2023 13:54	8/26/2023 23:53	Subtransmission		TIE 6602			NO ISSUES FOUND
8/27/2023 7:46	8/27/2023 18:41	Subtransmission		TIE 8804			NO ISSUES FOUND
8/27/2023 19:10	8/30/2023 5:56	Subtransmission		TRK 7035			NO ISSUES FOUND
8/28/2023 8:02	8/29/2023 18:35	Subtransmission		TIE 8014			NO ISSUES FOUND
9/2/2023 18:28	9/15/2023 23:19	Subtransmission		TRK 5855			NO ISSUES FOUND
9/3/2023 17:15	9/8/2023 13:23	Subtransmission		TIE 6138			NO ISSUES FOUND
9/3/2023 20:16	9/4/2023 9:59	Subtransmission		TRK 2233			NO ISSUES FOUND
9/5/2023 20:47	9/6/2023 1:55	Subtransmission		TRK 2032			NO ISSUES FOUND
9/5/2023 17:18	9/7/2023 17:14	Subtransmission	Substation	TRK 385	9	564	NO ISSUES FOUND
9/12/2023 10:42	9/14/2023 11:32	Subtransmission		TIE 4708			NO ISSUES FOUND
9/12/2023 10:12	9/14/2023 11:31	Subtransmission		TIE 5208			NO ISSUES FOUND
9/14/2023 7:07	9/15/2023 23:18	Subtransmission		TIE 5823			NO ISSUES FOUND
9/18/2023 4:58	9/18/2023 23:12	Subtransmission		TRK 1518			NO ISSUES FOUND
9/20/2023 17:06	9/20/2023 20:35	Subtransmission		TRK 1563			NO ISSUES FOUND
10/5/2023 13:13	10/5/2023 15:29	Subtransmission		TRK 7756			NO ISSUES FOUND
10/11/2023 5:13	10/12/2023 19:00	Subtransmission		TRK 4416			NO ISSUES FOUND
11/4/2023 21:46	11/6/2023 3:25	Subtransmission		TRK 2443			NO ISSUES FOUND
11/6/2023 8:39	11/6/2023 10:34	Subtransmission	Subtransmission	TIE 6138	6	1575	NO ISSUES FOUND
11/9/2023 17:10	11/30/2023 7:51	Subtransmission		TIE 3822			NO ISSUES FOUND
11/19/2023 17:46	11/20/2023 8:55	Subtransmission		TRK 5548			NO ISSUES FOUND
11/22/2023 7:30	11/29/2023 16:57	Subtransmission		TRK 3661			NO ISSUES FOUND
11/27/2023 14:16	11/29/2023 20:44	Subtransmission		TIE 1224			NO ISSUES FOUND
11/29/2023 21:30	11/30/2023 3:20	Subtransmission	Single Customer	TRK 1719			NO ISSUES FOUND
11/30/2023 11:23	11/30/2023 19:14	Subtransmission		TRK 1563			NO ISSUES FOUND
12/4/2023 5:49	12/8/2023 15:02	Subtransmission		TIE 4605			NO ISSUES FOUND
12/20/2023 11:20	12/22/2023 16:56	Subtransmission		TRK 7602			NO ISSUES FOUND
12/23/2023 7:23	12/23/2023 10:51	Subtransmission		TRK 7187			NO ISSUES FOUND
12/28/2023 11:23	12/31/2023 18:53	Subtransmission		TRK 1303			NO ISSUES FOUND
12/30/2023 7:27	12/31/2023 18:50	Subtransmission		TRK 5817			NO ISSUES FOUND
6/4/2018 23:33	6/5/2018 1:36	Subtransmission	None	TRK 4405			PUBLIC INTERFERENCE
6/4/2018 23:36	6/5/2018 1:56	Subtransmission	None	TRK 4405			PUBLIC INTERFERENCE
6/18/2018 23:48	6/19/2018 3:19	Subtransmission	None	TRK 333			PUBLIC INTERFERENCE
8/12/2018 18:26	8/12/2018 19:27	Subtransmission	None	TRK 5239			PUBLIC INTERFERENCE
2/16/2020 22:25	2/17/2020 14:05	Subtransmission	None	TRK 1251			PUBLIC INTERFERENCE
2/25/2020 17:28	2/25/2020 19:17	Subtransmission	None	TRK 2523			PUBLIC INTERFERENCE
7/21/2020 10:08	7/21/2020 16:23	Subtransmission	None	TRK 6741			PUBLIC INTERFERENCE
4/24/2021 17:04	4/24/2021 22:13	Subtransmission	None	TRK 6938			PUBLIC INTERFERENCE
5/22/2021 21:43	5/23/2021 8:54	Subtransmission	None	TIE 8014			PUBLIC INTERFERENCE
5/28/2021 0:53	5/30/2021 10:03	Subtransmission	None	TRK 5938			PUBLIC INTERFERENCE
7/24/2021 15:05	7/24/2021 22:27	Subtransmission	None	TRK 8414			PUBLIC INTERFERENCE
3/31/2023 16:43	3/31/2023 21:07	Subtransmission		TRK 2508			PUBLIC INTERFERENCE

5/4/2023 13:36	5/4/2023 20:35	Subtransmission		TRK 2519			PUBLIC INTERFERENCE
10/26/2023 18:21	10/27/2023 2:55	Subtransmission		TRK 2742			PUBLIC INTERFERENCE
7/2/2018 19:52	7/2/2018 21:46	Subtransmission	None	TRK 1527			TREE
6/4/2019 21:42	6/5/2019 13:16	Subtransmission	None	TRK 2016			TREE
10/21/2019 22:22	10/22/2019 4:51	Subtransmission	None	TIE 1531			TREE
10/22/2019 4:49	10/22/2019 13:40	Subtransmission	None	TIE 1531			TREE
3/4/2022 13:00	3/5/2022 15:33	Subtransmission	None	TIE 3417			TREE
3/21/2022 17:13	3/21/2022 23:08	Subtransmission	None	TIE 4105			TREE
5/27/2022 14:59	5/27/2022 21:40	Subtransmission	None	TIE 3241			TREE
6/16/2022 9:07	6/16/2022 21:51	Subtransmission	None	TIE 3209			TREE
9/1/2022 5:54	9/2/2022 15:25	Subtransmission	None	TRK 2302			TREE
2/16/2023 17:21	2/18/2023 1:11	Subtransmission	Service Transformer	TIE 3245	2	57	TREE
2/16/2023 6:57	2/16/2023 20:01	Subtransmission		TIE 3245			TREE
2/16/2023 16:18	2/16/2023 19:54	Subtransmission	Single Customer	TIE 3245	1	367	TREE
2/16/2023 16:41	2/18/2023 0:57	Subtransmission	Single Customer	TIE 3245	1	27	TREE
2/16/2023 16:43	2/17/2023 16:31	Subtransmission	Single Customer	TIE 3245	1	28	TREE
2/16/2023 16:46	2/17/2023 16:31	Subtransmission	Single Customer	TIE 3245	1	28	TREE
2/16/2023 17:09	2/17/2023 16:35	Subtransmission	Single Customer	TIE 3245	1	28	TREE
2/22/2023 22:05	2/25/2023 13:43	Subtransmission		TRK 7717			TREE
2/22/2023 21:15	2/23/2023 23:33	Subtransmission		TRK 7909			TREE
2/22/2023 21:06	2/22/2023 22:17	Subtransmission	Subtransmission	TRK 7909	130	13474	TREE
2/22/2023 20:33	2/23/2023 21:23	Subtransmission	Circuit Level	TRK 7909	1948	2628588	TREE
2/23/2023 9:01	3/1/2023 18:09	Subtransmission	Circuit Level	TRK 416			TREE
2/28/2023 10:21	3/1/2023 13:45	Subtransmission		TIE 1540			TREE
3/3/2023 21:05	3/5/2023 8:58	Subtransmission		TIE 8033			TREE
3/4/2023 2:46	3/6/2023 8:46	Subtransmission		TRK 830			TREE
3/25/2023 20:41	3/27/2023 7:38	Subtransmission		TIE 6117			TREE
3/25/2023 18:41	3/26/2023 10:44	Subtransmission	Single Customer	TRK 2806			TREE
3/25/2023 20:35	3/26/2023 14:40	Subtransmission	Single Customer	TIE 6117			TREE
3/25/2023 18:37	3/26/2023 9:30	Subtransmission	Subtransmission	TRK 2806	485	67920	TREE
3/25/2023 18:39	3/25/2023 20:51	Subtransmission	Single Customer	TRK 2806			TREE
3/25/2023 18:39	3/25/2023 21:07	Subtransmission	Single Customer	TRK 2806			TREE
4/2/2023 10:33	4/3/2023 22:44	Subtransmission		TIE 3205			TREE
4/27/2023 12:38	4/28/2023 3:03	Subtransmission		TIE 3209			TREE
7/20/2023 15:48	7/22/2023 9:29	Subtransmission	Subtransmission	TIE 810	8	13589	TREE
7/20/2023 18:12	7/22/2023 22:13	Subtransmission		TRK 2305			TREE
7/26/2023 19:20	7/28/2023 17:08	Subtransmission		TIE 6602			TREE
7/26/2023 18:35	7/28/2023 11:57	Subtransmission		TRK 7151			TREE
7/26/2023 21:31	7/27/2023 10:53	Subtransmission		TIE 6602			TREE
7/28/2023 19:52	7/30/2023 0:03	Subtransmission		TRK 3107			TREE
8/3/2023 18:45	8/3/2023 19:34	Subtransmission		TIE 7504			TREE
8/3/2023 18:30	8/3/2023 20:49	Subtransmission	Subtransmission	TIE 7504	2574	142297	TREE
8/3/2023 18:56	8/4/2023 12:45	Subtransmission		TIE 7504			TREE
8/12/2023 10:21	10/2/2023 11:31	Subtransmission		TIE 4523			TREE
8/23/2023 8:42	8/23/2023 21:18	Subtransmission	Subtransmission	TIE 9107	792	75608	TREE
8/23/2023 8:58	8/24/2023 9:08	Subtransmission		TIE 9107	1	95	TREE
8/30/2023 3:59	8/30/2023 21:19	Subtransmission		TIE 8014			TREE
9/16/2023 9:50	9/16/2023 19:03	Subtransmission		TIE 4105			TREE
9/16/2023 9:21	9/16/2023 18:26	Subtransmission	Subtransmission	TIE 4105	2044	543923	TREE
9/16/2023 11:13	9/16/2023 20:13	Subtransmission	Single Customer	TIE 4105			TREE
7/11/2023 17:32	7/11/2023 21:44	Subtransmission	Subtransmission	TRK 7062	683	85371	WIND
7/20/2023 16:30	7/21/2023 13:13	Subtransmission	Subtransmission	TRK 7062	282	349452	WIND
7/20/2022 13:20	7/21/2022 13:04	Subtransmission	None	TIE 1467			ANIMAL
6/12/2023 8:47	6/12/2023 18:24	Subtransmission		TRK 2826			ANIMAL
6/12/2023 18:24	10/26/2023 7:24	Subtransmission		TRK 2826			ANIMAL
1/8/2018 6:27	1/8/2018 20:56	Subtransmission	None	TRK 2038			EQUIPMENT FAILURE
1/8/2018 6:17	1/9/2018 15:52	Subtransmission	None	TRK 2038			EQUIPMENT FAILURE
2/25/2018 10:25	2/26/2018 20:03	Subtransmission	None	TIE 3205			EQUIPMENT FAILURE
2/25/2018 10:16	2/25/2018 11:02	Subtransmission	Subtransmission	TIE 3205	2044	34352	EQUIPMENT FAILURE
2/25/2018 10:16	2/25/2018 11:01	Subtransmission	Subtransmission	TIE 3205	1894	31846	EQUIPMENT FAILURE
3/20/2018 13:49	3/25/2018 20:24	Subtransmission	None	TRK 1403			EQUIPMENT FAILURE
3/21/2018 3:49	3/22/2018 12:11	Subtransmission	None	TRK 2713			EQUIPMENT FAILURE
3/31/2018 14:28	4/1/2018 4:59	Subtransmission	None	TIE 3203			EQUIPMENT FAILURE
3/31/2018 17:50	4/1/2018 4:47	Subtransmission	None	TIE 3203			EQUIPMENT FAILURE
5/4/2018 17:41	5/7/2018 19:03	Subtransmission	None	TIE 3417			EQUIPMENT FAILURE
5/4/2018 18:33	5/8/2018 21:19	Subtransmission	None	TIE 3417			EQUIPMENT FAILURE
5/4/2018 15:36	5/6/2018 17:13	Subtransmission	None	TIE 3417			EQUIPMENT FAILURE
5/4/2018 14:36	7/11/2018 1:43	Subtransmission	None	TRK 4338			EQUIPMENT FAILURE
5/5/2018 10:40	5/7/2018 15:58	Subtransmission	None	TRK 2455			EQUIPMENT FAILURE
5/6/2018 10:12	5/6/2018 21:12	Subtransmission	None	TIE 9107			EQUIPMENT FAILURE
5/17/2018 1:42	5/17/2018 7:11	Subtransmission	None	TRK 2313			EQUIPMENT FAILURE
5/18/2018 17:07	5/21/2018 7:48	Subtransmission	None	TRK 7122			EQUIPMENT FAILURE
5/27/2018 3:19	5/27/2018 5:12	Subtransmission	None	TRK 2313			EQUIPMENT FAILURE
5/28/2018 17:16	5/28/2018 23:10	Subtransmission	None	TRK 2659			EQUIPMENT FAILURE
5/28/2018 14:39	5/28/2018 20:00	Subtransmission	Distribution	TRK 2659	715	222551	EQUIPMENT FAILURE
6/2/2018 21:24	6/2/2018 22:50	Subtransmission	Subtransmission	TRK 2206	813	65422	EQUIPMENT FAILURE
6/2/2018 21:24	6/2/2018 22:50	Subtransmission	Subtransmission	TRK 2206	871	74962	EQUIPMENT FAILURE
6/2/2018 21:24	6/2/2018 22:50	Subtransmission	Subtransmission	TRK 2206	882	70795	EQUIPMENT FAILURE
6/2/2018 21:24	6/2/2018 22:50	Subtransmission	Subtransmission	TRK 2206	903	72972	EQUIPMENT FAILURE
6/2/2018 23:10	6/2/2018 23:20	Subtransmission	Subtransmission	TRK 2206			EQUIPMENT FAILURE
6/2/2018 16:30	6/2/2018 22:50	Subtransmission	Subtransmission	TRK 2206	837	72130	EQUIPMENT FAILURE
6/2/2018 21:24	6/2/2018 22:50	Subtransmission	Subtransmission	TRK 2206	1270	110543	EQUIPMENT FAILURE
6/2/2018 21:24	6/2/2018 22:50	Subtransmission	Subtransmission	TRK 2206	1097	88291	EQUIPMENT FAILURE
6/2/2018 21:24	6/2/2018 22:50	Subtransmission	Subtransmission	TRK 2206	831	70781	EQUIPMENT FAILURE
6/12/2018 12:48	6/12/2018 17:03	Subtransmission	None	TRK 6938			EQUIPMENT FAILURE
6/17/2018 13:42	6/17/2018 16:36	Subtransmission	None	TRK 3546			EQUIPMENT FAILURE
6/17/2018 13:58	6/17/2018 21:33	Subtransmission	None	TRK 3546			EQUIPMENT FAILURE
8/6/2018 16:02	8/6/2018 18:49	Subtransmission	None	TIE 5513			EQUIPMENT FAILURE
9/13/2018 13:27	9/13/2018 18:32	Subtransmission	None	TIE 3209			EQUIPMENT FAILURE
9/13/2018 14:36	9/13/2018 18:00	Subtransmission	Distribution	TIE 3209	573	105726	EQUIPMENT FAILURE
9/21/2018 16:09	9/21/2018 17:50	Subtransmission	None	TRK 2302			EQUIPMENT FAILURE
9/25/2018 12:00	9/25/2018 17:36	Subtransmission	None	TRK 1248			EQUIPMENT FAILURE
10/6/2018 18:56	10/8/2018 3:48	Subtransmission	None	TIE 3705			EQUIPMENT FAILURE
10/6/2018 18:30	10/7/2018 16:21	Subtransmission	None	TIE 3705			EQUIPMENT FAILURE
10/6/2018 18:21	10/7/2018 21:30	Subtransmission	Distribution	TIE 3705	113	129529	EQUIPMENT FAILURE
11/9/2018 18:40	11/9/2018 21:18	Subtransmission	None	TRK 5917			EQUIPMENT FAILURE
12/8/2018 16:00	12/8/2018 16:16	Subtransmission	None	TIE 5829			EQUIPMENT FAILURE
1/7/2019 17:33	1/8/2019 14:00	Subtransmission	None	TIE 9123			EQUIPMENT FAILURE
2/8/2019 6:45	2/8/2019 15:39	Subtransmission	None	TIE 4523			EQUIPMENT FAILURE
2/24/2019 11:40	2/25/2019 15:52	Subtransmission	None	TIE 4105			EQUIPMENT FAILURE
2/24/2019 11:40	2/25/2019 15:52	Subtransmission	None	TIE 4105			EQUIPMENT FAILURE
2/24/2019 17:44	2/25/2019 19:13	Subtransmission	Distribution	TIE 4105	506	637615	EQUIPMENT FAILURE
2/24/2019 21:43	2/25/2019 4:44	Subtransmission	Distribution	TIE 4105	459	192714	EQUIPMENT FAILURE
2/24/2019 21:43	2/25/2019 4:44	Subtransmission	Distribution	TIE 4105	459	192714	EQUIPMENT FAILURE
2/24/2019 20:23	2/26/2019 13:52	Subtransmission	None	TIE 4105			EQUIPMENT FAILURE

2/24/2019 20:23	2/26/2019 13:52	Subtransmission	None	TIE 4105			EQUIPMENT FAILURE
2/24/2019 21:42	2/25/2019 4:44	Subtransmission	Distribution	TIE 4105	820	345745	EQUIPMENT FAILURE
2/24/2019 21:45	2/25/2019 20:00	Subtransmission	Distribution	TIE 4105	85	107258	EQUIPMENT FAILURE
2/25/2019 10:01	2/26/2019 10:20	Subtransmission	None	TIE 4105			EQUIPMENT FAILURE
3/9/2019 20:27	3/10/2019 3:22	Subtransmission	None	TRK 8403			EQUIPMENT FAILURE
3/13/2019 10:44	3/13/2019 14:42	Subtransmission	None	TIE 6602			EQUIPMENT FAILURE
3/13/2019 10:38	3/13/2019 12:35	Subtransmission	Distribution	TIE 6602	1216	142402	EQUIPMENT FAILURE
3/15/2019 19:33	3/16/2019 1:37	Subtransmission	None	TIE 6602			EQUIPMENT FAILURE
3/15/2019 21:35	3/17/2019 2:15	Subtransmission	None	TIE 6602			EQUIPMENT FAILURE
3/15/2019 20:50	3/16/2019 20:56	Subtransmission	Distribution	TIE 6602	2	38	EQUIPMENT FAILURE
4/2/2019 20:01	4/2/2019 20:50	Subtransmission	Substation	TRK 7035	2599	146244	EQUIPMENT FAILURE
4/12/2019 18:14	4/13/2019 5:06	Subtransmission	None	TRK 1340			EQUIPMENT FAILURE
4/12/2019 17:42	4/12/2019 19:40	Subtransmission	Distribution	TRK 1340	615	70496	EQUIPMENT FAILURE
4/12/2019 17:59	4/12/2019 20:41	Subtransmission	None	TRK 1340			EQUIPMENT FAILURE
4/12/2019 17:52	4/12/2019 19:54	Subtransmission	None	TRK 1340			EQUIPMENT FAILURE
4/12/2019 17:42	4/12/2019 19:40	Subtransmission	Distribution	TRK 1340	765	87683	EQUIPMENT FAILURE
4/14/2019 11:47	4/14/2019 15:15	Subtransmission	None	TIE 4523			EQUIPMENT FAILURE
6/25/2019 19:45	6/26/2019 0:15	Subtransmission	None	TRK 1418			EQUIPMENT FAILURE
6/25/2019 8:51	6/25/2019 19:15	Subtransmission	None	TRK 1418			EQUIPMENT FAILURE
6/25/2019 19:23	6/25/2019 21:53	Subtransmission	None	TRK 1418			EQUIPMENT FAILURE
7/15/2019 15:45	7/17/2019 19:31	Subtransmission	None	TIE 9205			EQUIPMENT FAILURE
7/19/2019 20:41	7/28/2019 22:26	Subtransmission	None	TRK 1525			EQUIPMENT FAILURE
7/19/2019 23:48	7/20/2019 2:19	Subtransmission	None	TRK 1525			EQUIPMENT FAILURE
7/19/2019 20:03	7/20/2019 23:34	Subtransmission	Subtransmission	TRK 5510	431	687899	EQUIPMENT FAILURE
7/19/2019 20:05	7/20/2019 23:42	Subtransmission	Distribution	TRK 5510	595	960059	EQUIPMENT FAILURE
7/19/2019 20:03	7/20/2019 23:33	Subtransmission	Subtransmission	TRK 5510	730	1300793	EQUIPMENT FAILURE
7/19/2019 20:04	7/20/2019 23:41	Subtransmission	Subtransmission	TRK 5510	30	48233	EQUIPMENT FAILURE
7/20/2019 8:35	7/21/2019 18:07	Subtransmission	None	TRK 5510			EQUIPMENT FAILURE
7/29/2019 14:17	7/30/2019 6:50	Subtransmission	None	TRK 1525			EQUIPMENT FAILURE
8/6/2019 9:54	8/6/2019 11:14	Subtransmission	None	TIE 5513			EQUIPMENT FAILURE
8/25/2019 5:16	8/25/2019 14:26	Subtransmission	None	TRK 620			EQUIPMENT FAILURE
8/27/2019 7:30	8/27/2019 20:36	Subtransmission	None	TRK 2308			EQUIPMENT FAILURE
9/14/2019 22:44	9/15/2019 19:06	Subtransmission	None	TIE 3417			EQUIPMENT FAILURE
9/28/2019 1:17	9/28/2019 4:08	Subtransmission	Distribution	TRK 3646	2074	363970	EQUIPMENT FAILURE
10/9/2019 8:10	10/9/2019 9:26	Subtransmission	None	TRK 2308			EQUIPMENT FAILURE
10/21/2019 22:21	10/22/2019 5:02	Subtransmission	None	TRK 1444			EQUIPMENT FAILURE
11/24/2019 6:33	11/24/2019 16:08	Subtransmission	None	TRK 2247			EQUIPMENT FAILURE
11/27/2019 8:52	11/29/2019 16:12	Subtransmission	None	TRK 3646			EQUIPMENT FAILURE
11/27/2019 8:35	11/27/2019 10:01	Subtransmission	None	TRK 3646			EQUIPMENT FAILURE
11/27/2019 12:52	11/27/2019 15:30	Subtransmission	None	TRK 7909			EQUIPMENT FAILURE
12/1/2019 7:01	12/1/2019 10:53	Subtransmission	None	TIE 4105			EQUIPMENT FAILURE
12/1/2019 6:39	12/1/2019 20:00	Subtransmission	Distribution	TIE 4105	182	127742	EQUIPMENT FAILURE
12/1/2019 6:39	12/1/2019 20:00	Subtransmission	Distribution	TIE 4105	182	127742	EQUIPMENT FAILURE
12/1/2019 6:39	12/1/2019 12:25	Subtransmission	Subtransmission	TIE 4105	108	36662	EQUIPMENT FAILURE
12/1/2019 6:39	12/1/2019 12:25	Subtransmission	Subtransmission	TIE 4105	108	36662	EQUIPMENT FAILURE
12/1/2019 6:52	12/1/2019 10:55	Subtransmission	None	TIE 4105			EQUIPMENT FAILURE
12/1/2019 6:39	12/1/2019 12:25	Subtransmission	Subtransmission	TIE 4105	942	323939	EQUIPMENT FAILURE
12/1/2019 6:09	12/1/2019 12:25	Subtransmission	Subtransmission	TIE 4105	552	225437	EQUIPMENT FAILURE
12/1/2019 6:09	12/1/2019 12:25	Subtransmission	Subtransmission	TIE 4105	552	225437	EQUIPMENT FAILURE
12/1/2019 6:39	12/1/2019 12:25	Subtransmission	Subtransmission	TIE4105	942	323939	EQUIPMENT FAILURE
12/1/2019 6:52	12/1/2019 10:55	Subtransmission	None	TIE4105			EQUIPMENT FAILURE
12/1/2019 7:01	12/1/2019 10:53	Subtransmission	None	TIE4105			EQUIPMENT FAILURE
12/30/2019 6:42	12/30/2019 20:46	Subtransmission	None	TRK 1346			EQUIPMENT FAILURE
12/30/2019 14:03	12/31/2019 11:36	Subtransmission	None	TRK 7150			EQUIPMENT FAILURE
1/7/2020 17:26	1/8/2020 2:38	Subtransmission	None	TIE 4105			EQUIPMENT FAILURE
2/8/2020 14:27	2/8/2020 14:41	Subtransmission	None	TRK 5510			EQUIPMENT FAILURE
3/14/2020 11:17	3/14/2020 16:23	Subtransmission	None	TRK 4971			EQUIPMENT FAILURE
3/30/2020 16:02	3/31/2020 3:52	Subtransmission	None	TIE 2025			EQUIPMENT FAILURE
4/8/2020 9:33	4/9/2020 5:39	Subtransmission	None	TRK 8405			EQUIPMENT FAILURE
4/13/2020 13:04	4/13/2020 18:59	Subtransmission	Distribution	TIE 2809	327	105672	EQUIPMENT FAILURE
4/13/2020 16:55	4/14/2020 14:07	Subtransmission	None	TIE 3208			EQUIPMENT FAILURE
4/29/2020 18:14	4/30/2020 1:30	Subtransmission	Distribution	TRK 2806	1213	135470	EQUIPMENT FAILURE
5/15/2020 22:34	5/16/2020 2:40	Subtransmission	Distribution	TIE 4104	67	15119	EQUIPMENT FAILURE
6/7/2020 8:56	6/7/2020 18:54	Subtransmission	None	TIE 6938			EQUIPMENT FAILURE
6/7/2020 8:56	6/7/2020 18:54	Subtransmission	None	TIE 6938			EQUIPMENT FAILURE
6/12/2020 10:07	6/12/2020 19:36	Subtransmission	None	TIE 3417			EQUIPMENT FAILURE
6/19/2020 0:06	6/19/2020 15:01	Subtransmission	None	TIE 4105			EQUIPMENT FAILURE
7/10/2020 17:52	7/12/2020 17:54	Subtransmission	None	TRK 3206			EQUIPMENT FAILURE
7/14/2020 12:28	7/14/2020 14:35	Subtransmission	None	TIE 1467			EQUIPMENT FAILURE
7/19/2020 20:26	7/22/2020 14:03	Subtransmission	None	TRK 2027			EQUIPMENT FAILURE
7/19/2020 22:19	7/20/2020 15:50	Subtransmission	None	TRK 2027			EQUIPMENT FAILURE
8/8/2020 2:41	8/9/2020 20:02	Subtransmission	None	TRK 1121			EQUIPMENT FAILURE
8/9/2020 19:03	8/10/2020 8:59	Subtransmission	None	TIE 3208			EQUIPMENT FAILURE
8/9/2020 18:50	8/10/2020 4:02	Subtransmission	None	TIE 3208			EQUIPMENT FAILURE
8/28/2020 8:16	8/28/2020 16:18	Subtransmission	Distribution	TRK 2305	3	206	EQUIPMENT FAILURE
8/28/2020 9:12	8/28/2020 12:07	Subtransmission	None	TRK 2305			EQUIPMENT FAILURE
8/28/2020 6:26	8/28/2020 20:45	Subtransmission	None	TRK 2305			EQUIPMENT FAILURE
9/17/2020 8:47	9/17/2020 8:55	Subtransmission	None	TIE 3205			EQUIPMENT FAILURE
10/21/2020 1:29	10/21/2020 5:41	Subtransmission	None	TRK 5404			EQUIPMENT FAILURE
10/28/2020 17:40	10/28/2020 21:29	Subtransmission	None	TRK 2418			EQUIPMENT FAILURE
10/28/2020 16:01	10/28/2020 18:21	Subtransmission	None	TRK 2418			EQUIPMENT FAILURE
10/30/2020 21:38	10/31/2020 2:36	Subtransmission	None	TRK 2313			EQUIPMENT FAILURE
10/30/2020 21:45	10/30/2020 23:47	Subtransmission	None	TRK 2313			EQUIPMENT FAILURE
11/15/2020 14:36	11/18/2020 15:05	Subtransmission	None	TRK 2319			EQUIPMENT FAILURE
11/16/2020 8:09	11/19/2020 18:54	Subtransmission	None	TIE 3417			EQUIPMENT FAILURE
11/18/2020 6:41	11/18/2020 10:53	Subtransmission	None	TIE 3417			EQUIPMENT FAILURE
11/20/2020 9:14	12/5/2020 18:58	Subtransmission	None	TIE 1473			EQUIPMENT FAILURE
11/22/2020 13:45	11/22/2020 19:15	Subtransmission	None	TIE 1318			EQUIPMENT FAILURE
11/22/2020 20:14	11/23/2020 0:34	Subtransmission	Distribution	TRK 2319	123	23518	EQUIPMENT FAILURE
12/1/2020 1:02	12/1/2020 20:21	Subtransmission	None	TIE 3417			EQUIPMENT FAILURE
12/18/2020 18:43	12/18/2020 20:12	Subtransmission	Distribution	TIE 3535	1615	62098	EQUIPMENT FAILURE
12/26/2020 15:08	12/26/2020 17:35	Subtransmission	None	TIE 9111			EQUIPMENT FAILURE
1/9/2021 11:38	1/10/2021 5:26	Subtransmission	None	TRK 5935			EQUIPMENT FAILURE
1/12/2021 11:23	1/12/2021 14:56	Subtransmission	None	TRK 2742			EQUIPMENT FAILURE
2/16/2021 6:24	2/16/2021 15:21	Subtransmission	None	TRK 4316			EQUIPMENT FAILURE
2/16/2021 6:02	2/16/2021 11:05	Subtransmission	None	TRK 4316			EQUIPMENT FAILURE
3/2/2021 10:10	3/2/2021 12:07	Subtransmission	None	TRK 2002			EQUIPMENT FAILURE
3/11/2021 15:10	3/11/2021 21:24	Subtransmission	None	TRK 2250			EQUIPMENT FAILURE
3/18/2021 10:36	3/18/2021 20:53	Subtransmission	None	TRK 2713			EQUIPMENT FAILURE
3/18/2021 17:38	3/19/2021 13:26	Subtransmission	None	TRK 4911			EQUIPMENT FAILURE
3/25/2021 23:59	3/26/2021 8:41	Subtransmission	Distribution	TIE 1224	451	227080	EQUIPMENT FAILURE
3/25/2021 22:24	3/26/2021 0:10	Subtransmission	Distribution	TIE 1224	923	63267	EQUIPMENT FAILURE
3/25/2021 22:24	3/26/2021 0:10	Subtransmission	Distribution	TIE 1224	366	25455	EQUIPMENT FAILURE
3/26/2021 2:58	3/26/2021 20:31	Subtransmission	None	TRK 1251			EQUIPMENT FAILURE
3/26/2021 7:43	3/26/2021 20:29	Subtransmission	Distribution	TRK 1251	1	450	EQUIPMENT FAILURE

3/26/2021 16:37	3/26/2021 21:36	Subtransmission	Distribution	TRK 2005	1	318	EQUIPMENT FAILURE
3/26/2021 21:16	3/28/2021 21:22	Subtransmission	None	TRK 2005			EQUIPMENT FAILURE
3/26/2021 23:05	3/27/2021 5:30	Subtransmission	Distribution	TRK 2005	2	1000	EQUIPMENT FAILURE
3/26/2021 6:40	3/26/2021 19:14	Subtransmission	None	TRK 2005			EQUIPMENT FAILURE
3/28/2021 8:21	3/28/2021 10:20	Subtransmission	Distribution	TIE 9107	558	68836	EQUIPMENT FAILURE
3/28/2021 8:21	3/28/2021 10:20	Subtransmission	Distribution	TIE 9107	21	2585	EQUIPMENT FAILURE
4/15/2021 17:06	4/15/2021 17:31	Subtransmission	Subtransmission	TIE 4428	910	18526	EQUIPMENT FAILURE
4/15/2021 17:06	4/15/2021 17:57	Subtransmission	Subtransmission	TIE 4428	1096	22318	EQUIPMENT FAILURE
4/15/2021 17:06	4/15/2021 17:31	Subtransmission	Subtransmission	TIE 4428	823	16792	EQUIPMENT FAILURE
4/15/2021 16:45	4/16/2021 5:15	Subtransmission	Distribution	TRK 2918	1	470	EQUIPMENT FAILURE
4/15/2021 18:55	4/15/2021 19:07	Subtransmission	Distribution	TRK 2918	2127	18559	EQUIPMENT FAILURE
4/15/2021 18:57	4/15/2021 19:07	Subtransmission	Distribution	TRK 2918	51	445	EQUIPMENT FAILURE
4/16/2021 1:03	4/16/2021 2:30	Subtransmission	Distribution	TRK 2918	5	442	EQUIPMENT FAILURE
4/16/2021 1:20	4/16/2021 5:15	Subtransmission	None	TRK 2918			EQUIPMENT FAILURE
4/29/2021 16:53	4/29/2021 21:01	Subtransmission	Distribution	TRK 6919	1	38	EQUIPMENT FAILURE
5/19/2021 17:03	5/19/2021 18:06	Subtransmission	None	TRK 2107			EQUIPMENT FAILURE
5/23/2021 1:32	5/23/2021 14:40	Subtransmission	None	TRK 3124			EQUIPMENT FAILURE
5/24/2021 9:25	5/24/2021 10:07	Subtransmission	Distribution	TRK 2806	493	21489	EQUIPMENT FAILURE
5/24/2021 9:25	5/24/2021 10:07	Subtransmission	Distribution	TRK 2806	285	12400	EQUIPMENT FAILURE
5/24/2021 10:50	5/24/2021 14:36	Subtransmission	None	TRK 2806			EQUIPMENT FAILURE
5/27/2021 10:55	5/27/2021 20:13	Subtransmission	None	TRK 385			EQUIPMENT FAILURE
6/30/2021 7:29	6/30/2021 9:04	Subtransmission	None	TRK 4301			EQUIPMENT FAILURE
6/30/2021 7:05	6/30/2021 9:06	Subtransmission	None	TRK 4301			EQUIPMENT FAILURE
6/30/2021 7:00	7/1/2021 19:26	Subtransmission	None	TRK 4301			EQUIPMENT FAILURE
7/7/2021 17:29	7/8/2021 8:26	Subtransmission	None	TRK 5906			EQUIPMENT FAILURE
8/12/2021 18:27	8/13/2021 15:20	Subtransmission	None	TIE 2812			EQUIPMENT FAILURE
8/12/2021 2:24	8/13/2021 19:34	Subtransmission	None	TIE 5208			EQUIPMENT FAILURE
8/14/2021 22:03	8/15/2021 19:05	Subtransmission	None	TIE 1423			EQUIPMENT FAILURE
8/17/2021 17:15	8/19/2021 15:13	Subtransmission	None	TRK 4316			EQUIPMENT FAILURE
8/18/2021 17:30	8/18/2021 20:11	Subtransmission	None	TRK 7909			EQUIPMENT FAILURE
8/18/2021 17:02	8/18/2021 17:29	Subtransmission	None	TRK 7913			EQUIPMENT FAILURE
8/25/2021 7:06	8/25/2021 17:35	Subtransmission	Distribution	TRK 2301	1	1175	EQUIPMENT FAILURE
8/25/2021 0:12	8/25/2021 20:24	Subtransmission	None	TRK 2301			EQUIPMENT FAILURE
8/25/2021 7:06	8/26/2021 17:37	Subtransmission	None	TRK 2301			EQUIPMENT FAILURE
8/30/2021 7:51	8/30/2021 13:04	Subtransmission	None	TIE 1568			EQUIPMENT FAILURE
9/15/2021 22:17	9/16/2021 18:01	Subtransmission	None	TRK 4316			EQUIPMENT FAILURE
9/21/2021 21:44	9/22/2021 19:38	Subtransmission	None	TRK 6508			EQUIPMENT FAILURE
9/22/2021 12:02	9/24/2021 20:34	Subtransmission	None	TIE 3208			EQUIPMENT FAILURE
9/22/2021 11:58	9/25/2021 0:51	Subtransmission	Distribution	TIE 3208	1263	3965392	EQUIPMENT FAILURE
9/22/2021 11:49	9/22/2021 12:59	Subtransmission	Distribution	TIE 3208	208	26786	EQUIPMENT FAILURE
9/22/2021 6:22	9/22/2021 22:36	Subtransmission	Distribution	TRK 6508	1	581	EQUIPMENT FAILURE
9/24/2021 12:24	9/27/2021 18:55	Subtransmission	None	TRK 5411			EQUIPMENT FAILURE
10/29/2021 19:28	11/5/2021 15:33	Subtransmission	None	TIE 1568			EQUIPMENT FAILURE
11/15/2021 8:02	11/15/2021 14:56	Subtransmission	None	TIE 3220			EQUIPMENT FAILURE
11/18/2021 14:47	11/18/2021 17:57	Subtransmission	None	TRK 1459			EQUIPMENT FAILURE
11/22/2021 13:41	11/23/2021 10:34	Subtransmission	None	TIE 3417			EQUIPMENT FAILURE
11/22/2021 17:12	11/22/2021 21:07	Subtransmission	None	TIE 3417			EQUIPMENT FAILURE
12/2/2021 15:53	12/3/2021 23:06	Subtransmission	None	TRK 1267			EQUIPMENT FAILURE
12/6/2021 14:39	12/9/2021 19:52	Subtransmission	None	TRK 4301			EQUIPMENT FAILURE
12/13/2021 14:31	12/13/2021 16:34	Subtransmission	None	TIE 6138			EQUIPMENT FAILURE
12/13/2021 14:11	12/14/2021 4:52	Subtransmission	None	TIE 6138			EQUIPMENT FAILURE
12/19/2021 12:49	12/19/2021 22:31	Subtransmission	None	TRK 8409			EQUIPMENT FAILURE
1/10/2022 11:17	1/12/2022 15:45	Subtransmission	None	TIE4105			EQUIPMENT FAILURE
1/22/2022 2:10	1/22/2022 20:00	Subtransmission	None	TRK 4911			EQUIPMENT FAILURE
1/23/2022 15:04	1/23/2022 16:30	Subtransmission	None	TRK 4911			EQUIPMENT FAILURE
2/1/2022 19:27	2/2/2022 3:02	Subtransmission	Distribution	TRK 3536	199	91475	EQUIPMENT FAILURE
2/21/2022 12:41	2/21/2022 14:39	Subtransmission	None	TRK 2907			EQUIPMENT FAILURE
2/25/2022 14:09	2/25/2022 20:47	Subtransmission	None	TRK 6741			EQUIPMENT FAILURE
3/5/2022 12:26	3/6/2022 17:55	Subtransmission	None	TRK 4301			EQUIPMENT FAILURE
3/19/2022 12:31	3/19/2022 14:28	Subtransmission	None	TRK 2918			EQUIPMENT FAILURE
3/19/2022 13:12	3/19/2022 20:00	Subtransmission	Distribution	TRK 2918	656	215158	EQUIPMENT FAILURE
3/23/2022 5:20	3/23/2022 21:21	Subtransmission	None	TRK 4911			EQUIPMENT FAILURE
3/31/2022 15:58	4/1/2022 21:10	Subtransmission	None	TIE 3205			EQUIPMENT FAILURE
3/31/2022 11:17	3/31/2022 16:41	Subtransmission	None	TIE 3205			EQUIPMENT FAILURE
3/31/2022 8:21	4/1/2022 21:16	Subtransmission	None	TRK 6508			EQUIPMENT FAILURE
4/6/2022 23:47	4/7/2022 5:11	Subtransmission	Distribution	TIE 1268	148	47767	EQUIPMENT FAILURE
4/6/2022 23:47	4/7/2022 5:11	Subtransmission	Distribution	TIE 1268	376	120965	EQUIPMENT FAILURE
4/6/2022 23:47	4/7/2022 5:48	Subtransmission	Distribution	TIE 1268	431	159046	EQUIPMENT FAILURE
4/6/2022 23:48	4/7/2022 3:11	Subtransmission	Distribution	TRK 1243	535	81233	EQUIPMENT FAILURE
4/6/2022 23:47	4/7/2022 3:11	Subtransmission	Distribution	TRK 1243	367	55711	EQUIPMENT FAILURE
4/6/2022 23:48	4/7/2022 5:48	Subtransmission	Distribution	TRK 1280	308	99045	EQUIPMENT FAILURE
4/6/2022 23:50	4/7/2022 5:07	Subtransmission	Subtransmission	TRK 1280	210	67522	EQUIPMENT FAILURE
4/6/2022 23:47	4/7/2022 6:32	Subtransmission	Distribution	TRK 1280	822	330567	EQUIPMENT FAILURE
4/6/2022 11:01	4/7/2022 6:32	Subtransmission	Distribution	TRK 1280	1657	593725	EQUIPMENT FAILURE
4/6/2022 23:47	4/7/2022 5:10	Subtransmission	Distribution	TRK 1280	1887	606927	EQUIPMENT FAILURE
4/6/2022 23:48	4/7/2022 5:13	Subtransmission	Distribution	TRK 1280	40	13273	EQUIPMENT FAILURE
4/7/2022 0:08	4/7/2022 6:15	Subtransmission	None	TIE 1268			EQUIPMENT FAILURE
4/7/2022 6:55	4/7/2022 23:12	Subtransmission	None	TIE 1268			EQUIPMENT FAILURE
4/7/2022 0:04	4/7/2022 21:36	Subtransmission	None	TIE 1268			EQUIPMENT FAILURE
4/7/2022 0:32	4/7/2022 6:13	Subtransmission	Distribution	TRK 1280	2	807	EQUIPMENT FAILURE
4/13/2022 15:51	4/13/2022 23:40	Subtransmission	None	TRK 2027			EQUIPMENT FAILURE
4/19/2022 19:45	4/20/2022 5:02	Subtransmission	Distribution	TRK 5935	2217	256603	EQUIPMENT FAILURE
4/19/2022 19:51	4/21/2022 4:36	Subtransmission	None	TRK 5935			EQUIPMENT FAILURE
4/22/2022 8:36	4/22/2022 15:22	Subtransmission	None	TRK 2027			EQUIPMENT FAILURE
5/10/2022 16:07	5/11/2022 20:30	Subtransmission	None	TRK 3124			EQUIPMENT FAILURE
5/18/2022 16:26	5/18/2022 19:00	Subtransmission	Distribution	TRK 2931	633	62865	EQUIPMENT FAILURE
5/18/2022 16:35	5/19/2022 0:16	Subtransmission	None	TRK 2931			EQUIPMENT FAILURE
6/1/2022 12:34	6/1/2022 20:35	Subtransmission	None	TRK 7756			EQUIPMENT FAILURE
6/1/2022 12:28	6/2/2022 11:31	Subtransmission	None	TRK 7756			EQUIPMENT FAILURE
6/1/2022 12:32	6/1/2022 20:35	Subtransmission	None	TRK 7756			EQUIPMENT FAILURE
6/1/2022 12:20	6/1/2022 20:35	Subtransmission	Substation	TRK 7756	18	8244	EQUIPMENT FAILURE
6/7/2022 7:06	6/7/2022 9:40	Subtransmission	Distribution	TRK 2308			EQUIPMENT FAILURE
6/7/2022 9:03	6/7/2022 9:58	Subtransmission	None	TRK 2308			EQUIPMENT FAILURE
6/7/2022 7:14	6/7/2022 20:48	Subtransmission	None	TRK 2308			EQUIPMENT FAILURE
6/7/2022 7:15	6/7/2022 12:47	Subtransmission	None	TRK 2308			EQUIPMENT FAILURE
6/9/2022 6:15	6/9/2022 11:16	Subtransmission	None	TRK 2715			EQUIPMENT FAILURE
6/13/2022 21:04	6/14/2022 6:48	Subtransmission	Distribution	TIE 1473	231	88987	EQUIPMENT FAILURE
6/14/2022 6:41	6/14/2022 14:02	Subtransmission	None	TIE 1473			EQUIPMENT FAILURE
6/27/2022 18:26	6/28/2022 13:02	Subtransmission	None	TRK 6722			EQUIPMENT FAILURE
6/27/2022 17:09	6/27/2022 18:58	Subtransmission	Distribution	TRK 6722	1577	174909	EQUIPMENT FAILURE
6/27/2022 17:09	6/27/2022 18:58	Subtransmission	Distribution	TRK 6722	1180	131443	EQUIPMENT FAILURE
6/28/2022 17:15	7/2/2022 23:32	Subtransmission	None	TRK 6722			EQUIPMENT FAILURE
6/28/2022 11:37	6/29/2022 3:22	Subtransmission	None	TRK 6722			EQUIPMENT FAILURE
7/6/2022 12:59	7/6/2022 18:53	Subtransmission	None	TIE 1318			EQUIPMENT FAILURE
7/6/2022 11:17	7/6/2022 11:30	Subtransmission	Distribution	TIE 1318	1	11	EQUIPMENT FAILURE

7/6/2022 11:17	7/6/2022 18:00	Subtransmission	Distribution	TIE 1318	2852	497660	EQUIPMENT FAILURE
7/6/2022 11:23	7/6/2022 11:30	Subtransmission	Distribution	TIE 1318			EQUIPMENT FAILURE
7/6/2022 11:19	7/6/2022 18:00	Subtransmission	Distribution	TIE 1318			EQUIPMENT FAILURE
7/6/2022 12:59	7/6/2022 18:53	Subtransmission	None	TIE 1318			EQUIPMENT FAILURE
7/6/2022 11:18	7/6/2022 18:00	Subtransmission	Distribution	TIE 1318	1712	298734	EQUIPMENT FAILURE
7/6/2022 13:04	7/6/2022 18:53	Subtransmission	None	TIE 1318			EQUIPMENT FAILURE
7/6/2022 12:54	7/6/2022 16:20	Subtransmission	None	TIE 1318			EQUIPMENT FAILURE
7/6/2022 13:03	7/6/2022 16:46	Subtransmission	None	TIE 1318			EQUIPMENT FAILURE
7/6/2022 12:56	7/6/2022 17:13	Subtransmission	None	TIE 1318			EQUIPMENT FAILURE
7/6/2022 15:12	7/7/2022 13:25	Subtransmission	None	TRK 7756			EQUIPMENT FAILURE
7/6/2022 15:38	7/6/2022 18:20	Subtransmission	None	TRK 7756			EQUIPMENT FAILURE
7/29/2022 15:35	7/30/2022 1:28	Subtransmission	None	TRK 3543			EQUIPMENT FAILURE
8/21/2022 1:18	8/21/2022 16:50	Subtransmission	Distribution	TRK 3124	1257	169436	EQUIPMENT FAILURE
8/29/2022 19:13	9/1/2022 20:49	Subtransmission	None	TRK 2313			EQUIPMENT FAILURE
8/29/2022 18:12	8/31/2022 12:15	Subtransmission	Distribution	TRK 6938	2840	7035793	EQUIPMENT FAILURE
8/29/2022 19:49	8/31/2022 20:01	Subtransmission	None	TRK 6938			EQUIPMENT FAILURE
8/29/2022 18:13	8/31/2022 12:15	Subtransmission	Distribution	TRK 6938	250	619065	EQUIPMENT FAILURE
8/30/2022 9:43	8/31/2022 22:24	Subtransmission	Distribution	TRK 2713	1	413	EQUIPMENT FAILURE
8/30/2022 11:06	8/30/2022 20:58	Subtransmission	None	TRK 5938			EQUIPMENT FAILURE
8/30/2022 10:30	8/30/2022 19:30	Subtransmission	None	TRK 5938			EQUIPMENT FAILURE
9/26/2022 16:40	9/26/2022 23:18	Subtransmission	Distribution	TRK 2027	1683	109079	EQUIPMENT FAILURE
9/26/2022 16:47	9/27/2022 21:12	Subtransmission	None	TRK 2027			EQUIPMENT FAILURE
9/26/2022 17:10	9/27/2022 4:33	Subtransmission	None	TRK 2027			EQUIPMENT FAILURE
10/2/2022 14:38	10/3/2022 0:39	Subtransmission	Distribution	TIE 6907	1	128	EQUIPMENT FAILURE
10/17/2022 16:39	10/18/2022 6:01	Subtransmission	None	TRK 1418			EQUIPMENT FAILURE
10/17/2022 16:28	10/17/2022 23:30	Subtransmission	Distribution	TRK 1418	1145	227453	EQUIPMENT FAILURE
10/19/2022 11:20	10/19/2022 20:10	Subtransmission	Distribution	TIE 6907	21	8350	EQUIPMENT FAILURE
10/26/2022 9:06	10/26/2022 9:13	Subtransmission	None	TRK 3107			EQUIPMENT FAILURE
11/5/2022 13:34	11/7/2022 20:46	Subtransmission	None	TRK 2032			EQUIPMENT FAILURE
11/5/2022 20:35	11/6/2022 15:05	Subtransmission	Distribution	TRK 4316	1063	714206	EQUIPMENT FAILURE
11/5/2022 21:53	11/6/2022 14:25	Subtransmission	Distribution	TRK 4316	1026	1079506	EQUIPMENT FAILURE
11/5/2022 21:05	11/6/2022 15:43	Subtransmission	None	TRK 4316			EQUIPMENT FAILURE
11/25/2022 17:09	11/25/2022 17:18	Subtransmission	None	TIE 3417			EQUIPMENT FAILURE
11/25/2022 3:23	11/25/2022 4:45	Subtransmission	Distribution	TRK 2250	1	80	EQUIPMENT FAILURE
11/27/2022 18:20	11/27/2022 21:51	Subtransmission	None	TIE 2812			EQUIPMENT FAILURE
11/27/2022 14:41	11/27/2022 21:25	Subtransmission	None	TIE 6310			EQUIPMENT FAILURE
12/6/2022 11:54	12/6/2022 17:10	Subtransmission	None	TRK 1518			EQUIPMENT FAILURE
12/26/2022 16:32	12/27/2022 2:58	Subtransmission	None	TIE 4109			EQUIPMENT FAILURE
12/30/2022 23:58	12/31/2022 19:15	Subtransmission	Distribution	TIE 1540	1	1161	EQUIPMENT FAILURE
12/31/2022 0:33	12/31/2022 21:23	Subtransmission	None	TIE 1540			EQUIPMENT FAILURE
2/6/2023 17:39	4/13/2023 22:29	Subtransmission		TRK 1251			EQUIPMENT FAILURE
2/6/2023 15:15	2/6/2023 18:03	Subtransmission		TRK 1251			EQUIPMENT FAILURE
2/16/2023 11:16	2/18/2023 23:23	Subtransmission		TIE 7733			EQUIPMENT FAILURE
2/19/2023 10:22	5/10/2023 10:53	Subtransmission		TIE 2812			EQUIPMENT FAILURE
2/19/2023 2:57	2/19/2023 10:23	Subtransmission		TIE 2812			EQUIPMENT FAILURE
2/25/2023 6:09	2/25/2023 20:53	Subtransmission		TRK 3632			EQUIPMENT FAILURE
2/27/2023 14:39	3/4/2023 10:03	Subtransmission		TRK 2027			EQUIPMENT FAILURE
3/3/2023 19:44	3/4/2023 21:38	Subtransmission		TIE 7745			EQUIPMENT FAILURE
3/3/2023 19:42	3/4/2023 18:03	Subtransmission		TIE 7745			EQUIPMENT FAILURE
3/8/2023 4:20	3/8/2023 20:35	Subtransmission		TRK 652			EQUIPMENT FAILURE
3/9/2023 11:44	3/9/2023 15:34	Subtransmission		TRK 7035			EQUIPMENT FAILURE
3/25/2023 15:50	3/27/2023 14:55	Subtransmission		TRK 2027			EQUIPMENT FAILURE
3/25/2023 15:38	3/31/2023 11:09	Subtransmission		TRK 2027			EQUIPMENT FAILURE
3/26/2023 5:30	3/28/2023 15:17	Subtransmission		TRK 2027			EQUIPMENT FAILURE
3/27/2023 18:52	4/4/2023 17:05	Subtransmission		TRK 2027			EQUIPMENT FAILURE
3/27/2023 14:55	2/20/2024 6:17	Subtransmission		TRK 2027			EQUIPMENT FAILURE
3/31/2023 11:52	7/11/2023 22:30	Subtransmission		TRK 4316			EQUIPMENT FAILURE
4/1/2023 13:10	4/1/2023 15:08	Subtransmission	Circuit Level	TRK 2038			EQUIPMENT FAILURE
4/1/2023 20:25	7/9/2023 20:24	Subtransmission		TRK 2038			EQUIPMENT FAILURE
4/1/2023 12:48	4/5/2023 11:54	Subtransmission	Device (II)	TRK 2038			EQUIPMENT FAILURE
4/1/2023 12:53	4/1/2023 20:27	Subtransmission		TRK 2038			EQUIPMENT FAILURE
4/1/2023 12:53	4/1/2023 19:49	Subtransmission		TRK 2038			EQUIPMENT FAILURE
4/1/2023 13:14	4/1/2023 21:57	Subtransmission	Circuit Level	TRK 2038	2841	479881	EQUIPMENT FAILURE
4/1/2023 12:43	4/5/2023 11:55	Subtransmission	Device (II)	TRK 2038			EQUIPMENT FAILURE
4/9/2023 11:24	4/10/2023 5:33	Subtransmission	Service Transformer	TRK 3557	11	453	EQUIPMENT FAILURE
4/9/2023 15:18	4/10/2023 3:00	Subtransmission		TRK 3557			EQUIPMENT FAILURE
4/12/2023 8:13	6/19/2023 22:29	Subtransmission		TIE 1467			EQUIPMENT FAILURE
4/12/2023 19:03	4/21/2023 9:34	Subtransmission		TRK 2016			EQUIPMENT FAILURE
4/12/2023 15:23	4/13/2023 5:32	Subtransmission		TRK 3557			EQUIPMENT FAILURE
4/13/2023 11:24	4/24/2023 6:58	Subtransmission		TIE 1268			EQUIPMENT FAILURE
4/13/2023 16:30	4/16/2023 5:16	Subtransmission		TRK 3557			EQUIPMENT FAILURE
4/16/2023 14:06	4/21/2023 14:01	Subtransmission		TRK 5938			EQUIPMENT FAILURE
4/17/2023 12:38	5/2/2023 8:52	Subtransmission		TRK 7602			EQUIPMENT FAILURE
4/17/2023 7:00	4/17/2023 12:40	Subtransmission		TRK 7602			EQUIPMENT FAILURE
4/18/2023 14:09	4/18/2023 21:33	Subtransmission	Subtransmission	TIE 7733	7081	664604	EQUIPMENT FAILURE
4/18/2023 9:40	4/18/2023 17:19	Subtransmission		TRK 3557			EQUIPMENT FAILURE
4/21/2023 9:34	2/20/2024 6:18	Subtransmission		TRK 2016			EQUIPMENT FAILURE
4/21/2023 14:01	7/11/2023 16:13	Subtransmission		TRK 5938			EQUIPMENT FAILURE
4/22/2023 11:44	4/22/2023 16:45	Subtransmission	Device (II)	TIE 7430	794	133555	EQUIPMENT FAILURE
4/22/2023 13:03	4/22/2023 17:36	Subtransmission	Single Customer	TIE 7430	1	165	EQUIPMENT FAILURE
4/22/2023 8:10	4/22/2023 16:49	Subtransmission		TIE 7430			EQUIPMENT FAILURE
4/22/2023 8:10	4/26/2023 21:07	Subtransmission		TIE 7430			EQUIPMENT FAILURE
4/22/2023 8:19	4/22/2023 17:37	Subtransmission		TIE 7430			EQUIPMENT FAILURE
4/22/2023 8:06	4/22/2023 11:10	Subtransmission	Device (II)	TIE 7430			EQUIPMENT FAILURE
4/22/2023 15:03	4/28/2023 12:42	Subtransmission		TIE 7733			EQUIPMENT FAILURE
4/26/2023 9:15	6/6/2023 22:28	Subtransmission		TIE 4605			EQUIPMENT FAILURE
5/2/2023 12:32	7/11/2023 16:26	Subtransmission		TRK 1340			EQUIPMENT FAILURE
5/2/2023 7:10	5/4/2023 10:05	Subtransmission		TRK 4911			EQUIPMENT FAILURE
5/3/2023 14:02	6/2/2023 22:26	Subtransmission		TRK 4911			EQUIPMENT FAILURE
5/8/2023 1:55	5/8/2023 4:23	Subtransmission	Substation	TRK 1525	636	75291	EQUIPMENT FAILURE
5/8/2023 2:14	5/8/2023 4:23	Subtransmission		TRK 1525			EQUIPMENT FAILURE
5/8/2023 1:29	5/8/2023 4:23	Subtransmission	Subtransmission	TRK 1525			EQUIPMENT FAILURE
5/10/2023 16:00	9/22/2023 13:51	Subtransmission		TRK 7035			EQUIPMENT FAILURE
5/31/2023 17:59	6/1/2023 1:23	Subtransmission	Device (I)	TRK 5404	7835	1795368	EQUIPMENT FAILURE
5/31/2023 17:55	5/31/2023 18:55	Subtransmission		TRK 5404			EQUIPMENT FAILURE
5/31/2023 17:49	6/1/2023 5:23	Subtransmission		TRK 5404			EQUIPMENT FAILURE
6/11/2023 23:04	6/12/2023 17:21	Subtransmission	Device (II)	TIE 7621	320	250279	EQUIPMENT FAILURE
6/11/2023 21:51	6/12/2023 1:05	Subtransmission	Subtransmission	TRK 2824	1300	126165	EQUIPMENT FAILURE
6/11/2023 22:03	6/11/2023 23:29	Subtransmission		TRK 2824			EQUIPMENT FAILURE
6/11/2023 21:51	6/14/2023 0:20	Subtransmission		TRK 2824			EQUIPMENT FAILURE
6/15/2023 18:14	6/16/2023 5:18	Subtransmission		TIE 1268			EQUIPMENT FAILURE
6/25/2023 18:31	6/26/2023 13:14	Subtransmission		TRK 1525			EQUIPMENT FAILURE
6/26/2023 13:14	7/19/2023 9:47	Subtransmission		TRK 1525			EQUIPMENT FAILURE
6/26/2023 1:19	7/5/2023 9:24	Subtransmission		TRK 5239			EQUIPMENT FAILURE
6/28/2023 19:37	8/23/2023 9:16	Subtransmission		TRK 5239			EQUIPMENT FAILURE

7/6/2023 13:48	7/7/2023 6:42	Subtransmission		TIE 7745			EQUIPMENT FAILURE
7/7/2023 6:42	9/21/2023 22:32	Subtransmission		TIE 7745			EQUIPMENT FAILURE
7/13/2023 10:03	7/15/2023 7:56	Subtransmission		TRK 7909			EQUIPMENT FAILURE
7/14/2023 16:51	7/15/2023 2:24	Subtransmission		TIE 1423			EQUIPMENT FAILURE
7/14/2023 19:47	7/15/2023 7:07	Subtransmission	Substation	TIE 1423			EQUIPMENT FAILURE
7/14/2023 17:01	7/15/2023 2:24	Subtransmission	Subtransmission	TIE 1423	2198	224070	EQUIPMENT FAILURE
7/19/2023 16:35	7/20/2023 4:32	Subtransmission		TIE 6602			EQUIPMENT FAILURE
7/20/2023 15:59	7/20/2023 22:37	Subtransmission	Subtransmission	TIE 2812	747	343525	EQUIPMENT FAILURE
7/20/2023 16:16	7/21/2023 17:23	Subtransmission		TIE 2812			EQUIPMENT FAILURE
7/20/2023 4:32	10/15/2023 6:54	Subtransmission		TIE 6602			EQUIPMENT FAILURE
7/20/2023 15:33	7/22/2023 0:14	Subtransmission	Subtransmission	TIE 6931	7186	4956133	EQUIPMENT FAILURE
7/20/2023 15:26	7/21/2023 19:58	Subtransmission		TIE 6931			EQUIPMENT FAILURE
7/20/2023 19:40	7/21/2023 5:17	Subtransmission		TIE 6931			EQUIPMENT FAILURE
7/20/2023 15:22	7/21/2023 13:37	Subtransmission		TIE 6931			EQUIPMENT FAILURE
7/20/2023 22:12	8/2/2023 9:28	Subtransmission		TIE 6931			EQUIPMENT FAILURE
7/20/2023 16:58	7/22/2023 14:05	Subtransmission		TIE 6931			EQUIPMENT FAILURE
7/20/2023 21:59	7/21/2023 21:38	Subtransmission	Circuit Level	TIE 6931	2413	4178512	EQUIPMENT FAILURE
7/21/2023 14:53	11/9/2023 22:35	Subtransmission		TRK 3650			EQUIPMENT FAILURE
7/24/2023 22:41	7/25/2023 0:33	Subtransmission		TIE 6907			EQUIPMENT FAILURE
7/25/2023 4:45	7/25/2023 6:00	Subtransmission		TIE 6907			EQUIPMENT FAILURE
7/26/2023 16:02	7/28/2023 20:13	Subtransmission		TRK 7756			EQUIPMENT FAILURE
7/26/2023 14:53	7/27/2023 19:10	Subtransmission	Circuit Level	TIE 6621	461	705127	EQUIPMENT FAILURE
7/26/2023 14:53	7/27/2023 19:13	Subtransmission	Circuit Level	TIE 6621	672	1027357	EQUIPMENT FAILURE
7/26/2023 15:27	7/27/2023 20:56	Subtransmission		TIE 6621			EQUIPMENT FAILURE
7/26/2023 15:00	7/29/2023 2:49	Subtransmission	Circuit Level	TIE 6621	969	3333567	EQUIPMENT FAILURE
7/26/2023 15:04	7/27/2023 21:49	Subtransmission	Subtransmission	TIE 6621	623	1086812	EQUIPMENT FAILURE
7/26/2023 15:42	7/28/2023 2:26	Subtransmission		TIE 6621	1	1745	EQUIPMENT FAILURE
7/26/2023 17:20	7/28/2023 3:24	Subtransmission		TIE 6621	1	1745	EQUIPMENT FAILURE
7/26/2023 15:54	7/28/2023 3:22	Subtransmission		TIE 6621			EQUIPMENT FAILURE
7/26/2023 14:58	7/27/2023 22:07	Subtransmission	Circuit Level	TIE 6621	1350	2449601	EQUIPMENT FAILURE
7/26/2023 16:21	7/28/2023 17:08	Subtransmission		TIE 6621			EQUIPMENT FAILURE
7/26/2023 18:50	8/3/2023 7:12	Subtransmission		TRK 1243			EQUIPMENT FAILURE
7/26/2023 16:15	7/28/2023 18:17	Subtransmission	Device (II)	TRK 1563	17	2762	EQUIPMENT FAILURE
7/26/2023 15:53	7/28/2023 15:52	Subtransmission		TRK 1563			EQUIPMENT FAILURE
7/26/2023 15:47	7/28/2023 15:42	Subtransmission	Subtransmission	TRK 2922	11	4600	EQUIPMENT FAILURE
7/26/2023 15:24	7/27/2023 19:32	Subtransmission		TRK 2931			EQUIPMENT FAILURE
7/26/2023 16:09	7/27/2023 21:12	Subtransmission		TRK 2931			EQUIPMENT FAILURE
7/26/2023 16:00	7/28/2023 15:15	Subtransmission		TRK 2931			EQUIPMENT FAILURE
7/26/2023 15:42	7/28/2023 15:31	Subtransmission	Subtransmission	TRK 2931	31	120467	EQUIPMENT FAILURE
7/28/2023 11:48	7/29/2023 19:07	Subtransmission		TRK 1563			EQUIPMENT FAILURE
7/28/2023 15:14	8/9/2023 5:12	Subtransmission		TRK 2922			EQUIPMENT FAILURE
8/2/2023 17:13	8/3/2023 14:16	Subtransmission		TIE 1540			EQUIPMENT FAILURE
8/3/2023 14:15	9/19/2023 11:54	Subtransmission		TIE 1540			EQUIPMENT FAILURE
8/4/2023 7:41	8/4/2023 10:05	Subtransmission		TRK 5906			EQUIPMENT FAILURE
8/4/2023 9:56	10/3/2023 22:33	Subtransmission		TRK 5906			EQUIPMENT FAILURE
8/7/2023 11:23	8/8/2023 20:20	Subtransmission	Subtransmission	TIE 3208	195	16604	EQUIPMENT FAILURE
8/7/2023 13:52	8/8/2023 1:23	Subtransmission	Subtransmission	TIE 3208	209	14209	EQUIPMENT FAILURE
8/11/2023 15:50	8/22/2023 8:53	Subtransmission		TIE 1540			EQUIPMENT FAILURE
8/22/2023 8:52	10/2/2023 11:30	Subtransmission		TIE 1540			EQUIPMENT FAILURE
8/24/2023 10:49	8/29/2023 1:20	Subtransmission		TRK 315			EQUIPMENT FAILURE
8/24/2023 10:43	8/28/2023 14:46	Subtransmission		TRK 315			EQUIPMENT FAILURE
8/24/2023 6:09	8/24/2023 14:56	Subtransmission		TRK 4405			EQUIPMENT FAILURE
8/24/2023 2:23	8/25/2023 21:17	Subtransmission	Circuit Level	TRK 4405	487	632516	EQUIPMENT FAILURE
8/24/2023 2:39	8/26/2023 12:09	Subtransmission		TRK 4405			EQUIPMENT FAILURE
8/24/2023 2:24	8/25/2023 20:09	Subtransmission	Device (II)	TRK 4509	215	113541	EQUIPMENT FAILURE
8/25/2023 2:50	8/29/2023 10:47	Subtransmission		TRK 1322			EQUIPMENT FAILURE
8/25/2023 2:41	8/26/2023 12:36	Subtransmission		TRK 1346			EQUIPMENT FAILURE
8/25/2023 17:11	1/11/2024 22:33	Subtransmission		TRK 4227			EQUIPMENT FAILURE
8/29/2023 1:49	8/29/2023 22:50	Subtransmission		TRK 2250			EQUIPMENT FAILURE
9/2/2023 4:11	9/3/2023 7:47	Subtransmission		TRK 462			EQUIPMENT FAILURE
9/3/2023 7:47	9/19/2023 9:04	Subtransmission		TRK 462			EQUIPMENT FAILURE
9/6/2023 16:54	9/6/2023 20:43	Subtransmission		TIE 7745			EQUIPMENT FAILURE
9/6/2023 10:31	9/20/2023 16:55	Subtransmission		TIE 7745			EQUIPMENT FAILURE
9/6/2023 10:42	9/6/2023 15:28	Subtransmission		TIE 7745			EQUIPMENT FAILURE
9/7/2023 10:03	9/19/2023 17:34	Subtransmission		TIE 7745			EQUIPMENT FAILURE
9/11/2023 15:47	9/19/2023 17:37	Subtransmission		TRK 2038			EQUIPMENT FAILURE
9/19/2023 17:33	10/30/2023 12:57	Subtransmission		TIE 7745			EQUIPMENT FAILURE
9/19/2023 17:37	10/30/2023 22:31	Subtransmission		TRK 2038			EQUIPMENT FAILURE
9/19/2023 17:34	12/2/2023 18:55	Subtransmission		TRK 2922			EQUIPMENT FAILURE
10/2/2023 15:06	10/3/2023 8:13	Subtransmission		TRK 3526			EQUIPMENT FAILURE
10/28/2023 13:23	10/29/2023 20:43	Subtransmission		TRK 2218			EQUIPMENT FAILURE
11/2/2023 15:00	11/3/2023 16:44	Subtransmission		TIE 1467			EQUIPMENT FAILURE
11/11/2023 8:22	11/14/2023 8:45	Subtransmission		TRK 1546			EQUIPMENT FAILURE
11/14/2023 8:45	2/5/2024 22:37	Subtransmission		TRK 1546			EQUIPMENT FAILURE
11/14/2023 6:13	12/13/2023 6:32	Subtransmission		TRK 6508			EQUIPMENT FAILURE
12/18/2023 9:10	12/18/2023 16:37	Subtransmission	Subtransmission	TIE 4109	1808	262188	EQUIPMENT FAILURE
12/18/2023 9:16	12/18/2023 16:50	Subtransmission		TIE 4109			EQUIPMENT FAILURE
12/18/2023 9:30	12/18/2023 16:51	Subtransmission	Single Customer	TIE 4109	1	145	EQUIPMENT FAILURE
12/18/2023 9:22	12/18/2023 13:04	Subtransmission	Single Customer	TIE 4109	1	144	EQUIPMENT FAILURE
12/18/2023 9:11	12/18/2023 20:21	Subtransmission	Subtransmission	TIE 4109	334	48431	EQUIPMENT FAILURE
12/18/2023 12:57	12/18/2023 17:03	Subtransmission	Subtransmission	TIE 4109			EQUIPMENT FAILURE
12/18/2023 9:11	12/18/2023 16:49	Subtransmission		TIE 4109	1	144	EQUIPMENT FAILURE
12/18/2023 13:53	2/6/2024 6:24	Subtransmission		TRK 2826			EQUIPMENT FAILURE
12/18/2023 11:33	12/18/2023 13:53	Subtransmission		TRK 2826			EQUIPMENT FAILURE
11/9/2021 10:01	11/9/2021 12:00	Subtransmission	Distribution	TRK 5127	306	36424	INTENTIONAL
4/25/2018 15:55	4/25/2018 22:56	Subtransmission	None	TRK 2032			PUBLIC INTERFERENCE
5/10/2018 14:35	5/10/2018 18:40	Subtransmission	Distribution	TRK 2659	701	172992	PUBLIC INTERFERENCE
7/5/2018 9:50	7/5/2018 11:49	Subtransmission	None	TRK 2237			PUBLIC INTERFERENCE
7/5/2018 10:06	7/5/2018 16:53	Subtransmission	None	TRK 2237			PUBLIC INTERFERENCE
8/27/2018 6:55	8/27/2018 20:53	Subtransmission	None	TRK 3646			PUBLIC INTERFERENCE
8/27/2018 12:30	8/27/2018 20:29	Subtransmission	None	TRK 3646			PUBLIC INTERFERENCE
8/28/2018 17:21	8/31/2018 20:55	Subtransmission	None	TRK 3646			PUBLIC INTERFERENCE
8/28/2018 10:37	8/28/2018 17:12	Subtransmission	None	TRK 3646			PUBLIC INTERFERENCE
9/4/2018 10:39	9/4/2018 15:37	Subtransmission	None	TRK 5411			PUBLIC INTERFERENCE
10/14/2018 6:36	10/14/2018 19:24	Subtransmission	None	TIE 185			PUBLIC INTERFERENCE
10/18/2018 20:55	10/19/2018 5:35	Subtransmission	None	TIE 6517			PUBLIC INTERFERENCE
11/14/2018 10:31	11/14/2018 17:54	Subtransmission	None	TRK 2016			PUBLIC INTERFERENCE
11/14/2018 10:36	11/14/2018 23:28	Subtransmission	None	TRK 2016			PUBLIC INTERFERENCE
11/26/2018 23:04	11/27/2018 0:42	Subtransmission	Subtransmission	TIE 5823	691	73325	PUBLIC INTERFERENCE
11/26/2018 23:04	11/27/2018 0:42	Subtransmission	Subtransmission	TIE 5823	1049	105834	PUBLIC INTERFERENCE
11/26/2018 23:04	11/27/2018 6:15	Subtransmission	Distribution	TIE 5823	244	49881	PUBLIC INTERFERENCE
11/26/2018 23:15	11/27/2018 7:43	Subtransmission	None	TIE 5823			PUBLIC INTERFERENCE
11/28/2018 23:42	11/29/2018 6:55	Subtransmission	None	TIE 5823			PUBLIC INTERFERENCE
12/12/2018 22:17	12/13/2018 0:54	Subtransmission	None	TRK 2824			PUBLIC INTERFERENCE
12/21/2018 0:04	12/21/2018 1:29	Subtransmission	None	TRK 4316			PUBLIC INTERFERENCE

1/16/2019 8:01	1/16/2019 9:05	Subtransmission	Distribution	TRK 2519	1208	75443	PUBLIC INTERFERENCE
1/18/2019 23:21	1/19/2019 20:40	Subtransmission	Distribution	TRK 1502	2	2559	PUBLIC INTERFERENCE
3/16/2019 10:43	3/18/2019 14:30	Subtransmission	None	TIE 7621			PUBLIC INTERFERENCE
8/17/2019 3:36	8/17/2019 7:00	Subtransmission	None	TRK 1303			PUBLIC INTERFERENCE
9/29/2019 17:31	9/29/2019 22:18	Subtransmission	None	TIE 7745			PUBLIC INTERFERENCE
11/17/2019 18:48	11/17/2019 21:54	Subtransmission	None	TIE 4104			PUBLIC INTERFERENCE
12/2/2019 10:17	12/2/2019 11:56	Subtransmission	None	TRK 3646			PUBLIC INTERFERENCE
12/16/2019 23:28	12/17/2019 1:56	Subtransmission	None	TRK 3646			PUBLIC INTERFERENCE
2/28/2020 21:39	2/29/2020 3:01	Subtransmission	None	TIE 3705			PUBLIC INTERFERENCE
3/13/2020 12:43	3/13/2020 21:23	Subtransmission	None	TRK 7151			PUBLIC INTERFERENCE
3/13/2020 12:24	3/13/2020 17:10	Subtransmission	Distribution	TRK 7151	2	567	PUBLIC INTERFERENCE
5/1/2020 1:11	5/2/2020 4:56	Subtransmission	None	TRK 620			PUBLIC INTERFERENCE
7/3/2020 20:37	7/4/2020 19:11	Subtransmission	None	TRK 2313			PUBLIC INTERFERENCE
7/4/2020 16:44	7/4/2020 18:22	Subtransmission	Distribution	TRK 2313	1	53	PUBLIC INTERFERENCE
7/26/2020 11:29	7/26/2020 12:44	Subtransmission	None	TRK 2510			PUBLIC INTERFERENCE
8/7/2020 6:53	8/7/2020 14:30	Subtransmission	None	TIE 3822			PUBLIC INTERFERENCE
8/7/2020 6:20	8/7/2020 6:59	Subtransmission	Distribution	TIE 3822	54	24539	PUBLIC INTERFERENCE
8/7/2020 6:34	8/7/2020 14:57	Subtransmission	None	TIE 3822			PUBLIC INTERFERENCE
8/7/2020 6:50	8/7/2020 7:11	Subtransmission	None	TIE 3822			PUBLIC INTERFERENCE
8/7/2020 6:21	8/7/2020 6:59	Subtransmission	Distribution	TIE 3822	1629	63900	PUBLIC INTERFERENCE
8/7/2020 7:25	8/7/2020 13:30	Subtransmission	Distribution	TIE 3822			PUBLIC INTERFERENCE
10/4/2020 11:22	10/4/2020 23:31	Subtransmission	None	TIE 1423			PUBLIC INTERFERENCE
1/8/2021 5:23	1/8/2021 7:33	Subtransmission	None	TIE 6117			PUBLIC INTERFERENCE
1/13/2021 18:05	1/14/2021 5:13	Subtransmission	None	TRK 2418			PUBLIC INTERFERENCE
1/13/2021 19:15	1/15/2021 8:40	Subtransmission	None	TRK 2418			PUBLIC INTERFERENCE
1/22/2021 8:51	1/22/2021 13:26	Subtransmission	None	TIE 7745			PUBLIC INTERFERENCE
1/31/2021 16:46	1/31/2021 21:48	Subtransmission	None	TRK 5817			PUBLIC INTERFERENCE
2/6/2021 9:10	2/6/2021 10:14	Subtransmission	None	TRK 6508			PUBLIC INTERFERENCE
2/6/2021 9:07	2/6/2021 15:20	Subtransmission	None	TRK 6508			PUBLIC INTERFERENCE
2/26/2021 12:19	2/26/2021 21:06	Subtransmission	None	TRK 541			PUBLIC INTERFERENCE
3/1/2021 19:12	3/1/2021 21:28	Subtransmission	None	TRK 6304			PUBLIC INTERFERENCE
3/19/2021 15:46	3/20/2021 5:48	Subtransmission	Distribution	TIE 201	97	80469	PUBLIC INTERFERENCE
3/19/2021 22:50	3/20/2021 1:11	Subtransmission	None	TRK 6304			PUBLIC INTERFERENCE
3/28/2021 15:43	3/28/2021 17:30	Subtransmission	None	TRK 3124			PUBLIC INTERFERENCE
5/8/2021 9:47	5/8/2021 18:26	Subtransmission	None	TIE 3402			PUBLIC INTERFERENCE
6/1/2021 18:44	6/2/2021 1:48	Subtransmission	None	TRK 7122			PUBLIC INTERFERENCE
9/29/2021 19:43	9/29/2021 21:10	Subtransmission	None	TRK 5935			PUBLIC INTERFERENCE
9/29/2021 20:06	9/29/2021 21:15	Subtransmission	None	TRK 5935			PUBLIC INTERFERENCE
9/29/2021 8:21	9/29/2021 15:30	Subtransmission	Distribution	TRK 5935	270	56209	PUBLIC INTERFERENCE
9/29/2021 8:31	9/29/2021 19:59	Subtransmission	None	TRK 5935			PUBLIC INTERFERENCE
10/8/2021 7:33	10/8/2021 16:56	Subtransmission	None	TRK 2713			PUBLIC INTERFERENCE
10/22/2021 7:47	10/22/2021 9:59	Subtransmission	None	TRK 2659			PUBLIC INTERFERENCE
11/27/2021 2:45	11/27/2021 6:13	Subtransmission	None	TIE 2812			PUBLIC INTERFERENCE
1/23/2022 23:26	1/24/2022 3:33	Subtransmission	None	TRK 1218			PUBLIC INTERFERENCE
2/1/2022 16:11	2/1/2022 22:00	Subtransmission	None	TRK 7909			PUBLIC INTERFERENCE
2/10/2022 12:28	2/10/2022 23:33	Subtransmission	None	TIE 7745			PUBLIC INTERFERENCE
2/14/2022 8:33	2/14/2022 11:59	Subtransmission	None	TRK 1303			PUBLIC INTERFERENCE
2/14/2022 8:09	2/14/2022 13:02	Subtransmission	None	TRK 1303			PUBLIC INTERFERENCE
3/18/2022 2:41	3/18/2022 5:21	Subtransmission	None	TRK 2313			PUBLIC INTERFERENCE
4/17/2022 11:06	4/17/2022 14:17	Subtransmission	Distribution	TRK 2038	3081	541783	PUBLIC INTERFERENCE
5/17/2022 9:44	5/17/2022 12:54	Subtransmission	Distribution	TIE 6931			PUBLIC INTERFERENCE
5/18/2022 1:54	5/18/2022 3:23	Subtransmission	Distribution	TRK 2636	246	22947	PUBLIC INTERFERENCE
5/20/2022 8:24	5/20/2022 10:30	Subtransmission	Distribution	TRK 3546	1113	104532	PUBLIC INTERFERENCE
5/21/2022 10:15	5/27/2022 6:30	Subtransmission	None	TRK 3546			PUBLIC INTERFERENCE
6/4/2022 0:20	6/4/2022 22:45	Subtransmission	None	TRK 2247			PUBLIC INTERFERENCE
6/18/2022 0:24	6/18/2022 6:10	Subtransmission	None	TRK 2411			PUBLIC INTERFERENCE
9/19/2022 12:16	9/19/2022 15:00	Subtransmission	Distribution	TIE 3417	15	2444	PUBLIC INTERFERENCE
9/30/2022 23:40	10/1/2022 1:50	Subtransmission	Distribution	TIE 4708	547	77547	PUBLIC INTERFERENCE
9/30/2022 23:39	10/1/2022 1:50	Subtransmission	Distribution	TIE 4708	627	88892	PUBLIC INTERFERENCE
10/15/2022 5:17	10/15/2022 7:07	Subtransmission	None	TRK 2313			PUBLIC INTERFERENCE
12/10/2022 8:00	12/11/2022 8:57	Subtransmission	None	TIE 9303			PUBLIC INTERFERENCE
1/12/2023 12:35	1/13/2023 5:31	Subtransmission	None	TIE 810			PUBLIC INTERFERENCE
5/13/2023 21:54	6/1/2023 7:08	Subtransmission		TIE 1423			PUBLIC INTERFERENCE
5/13/2023 20:52	5/14/2023 0:27	Subtransmission		TRK 2543			PUBLIC INTERFERENCE
5/14/2023 3:04	5/14/2023 15:26	Subtransmission		TRK 2543			PUBLIC INTERFERENCE
6/6/2023 16:46	10/24/2023 9:00	Subtransmission		TRK 2302			PUBLIC INTERFERENCE
6/6/2023 14:42	6/6/2023 16:47	Subtransmission		TRK 2302			PUBLIC INTERFERENCE
8/28/2023 17:05	9/14/2023 21:36	Subtransmission		TRK 1251			PUBLIC INTERFERENCE
8/28/2023 14:16	8/30/2023 18:54	Subtransmission		TRK 2313			PUBLIC INTERFERENCE
9/17/2023 9:17	9/18/2023 4:45	Subtransmission		TRK 5145			PUBLIC INTERFERENCE
9/17/2023 8:41	9/17/2023 21:25	Subtransmission		TRK 5145			PUBLIC INTERFERENCE
10/16/2023 13:22	10/17/2023 6:07	Subtransmission		TRK 2250			PUBLIC INTERFERENCE
11/20/2023 18:37	11/21/2023 6:57	Subtransmission		TRK 2107			PUBLIC INTERFERENCE
11/20/2023 18:33	11/21/2023 0:01	Subtransmission		TRK 2107			PUBLIC INTERFERENCE
12/4/2023 13:30	12/5/2023 13:53	Subtransmission		TRK 1248			PUBLIC INTERFERENCE
5/4/2018 19:15	5/5/2018 21:15	Subtransmission	None	TIE 3241			TREE
5/4/2018 13:08	5/4/2018 18:15	Subtransmission	None	TIE 4104			TREE
5/4/2018 18:11	5/9/2018 5:03	Subtransmission	None	TIE 4104			TREE
5/4/2018 18:22	5/7/2018 18:14	Subtransmission	None	TIE 4105			TREE
5/4/2018 16:40	5/7/2018 12:47	Subtransmission	None	TIE 4105			TREE
5/4/2018 18:34	5/8/2018 14:07	Subtransmission	None	TIE 4105			TREE
2/14/2019 13:14	2/15/2019 14:59	Subtransmission	None	TIE4105			TREE
2/24/2019 21:42	2/25/2019 4:44	Subtransmission	Distribution	TIE4105	820	345745	TREE
2/24/2019 21:45	2/25/2019 20:00	Subtransmission	Distribution	TIE4105	85	107258	TREE
2/24/2019 17:44	2/25/2019 19:13	Subtransmission	Distribution	TIE4105	506	637615	TREE
5/3/2019 12:13	5/4/2019 15:02	Subtransmission	None	TRK 5411			TREE
7/20/2019 18:22	7/25/2019 18:00	Subtransmission	Distribution	TIE 4105	346	1135226	TREE
7/20/2019 18:45	7/21/2019 20:22	Subtransmission	None	TIE 4105			TREE
7/7/2021 15:08	7/7/2021 20:45	Subtransmission	Distribution	TRK 1225	1108	378873	TREE
7/7/2021 15:08	7/8/2021 7:33	Subtransmission	Distribution	TRK 1225	1055	366057	TREE
7/7/2021 15:09	7/9/2021 3:30	Subtransmission	Subtransmission	TRK 1225	71	130080	TREE
7/7/2021 15:13	7/9/2021 3:35	Subtransmission	Distribution	TRK 1225	528	1008331	TREE
7/7/2021 15:09	7/8/2021 13:18	Subtransmission	Distribution	TRK 1225	1454	962312	TREE
7/7/2021 15:15	7/9/2021 3:34	Subtransmission	Distribution	TRK 1225	220	405027	TREE
7/7/2021 15:08	7/9/2021 3:31	Subtransmission	Subtransmission	TRK 1225	488	980508	TREE
7/7/2021 15:09	7/8/2021 20:00	Subtransmission	Distribution	TRK 1225	613	1338801	TREE
7/7/2021 15:15	7/9/2021 3:34	Subtransmission	Distribution	TRK 1225	373	688048	TREE
7/7/2021 21:16	7/11/2021 14:12	Subtransmission	None	TRK 4045			TREE
7/8/2021 5:47	7/8/2021 19:51	Subtransmission	None	TRK 5923			TREE
7/20/2021 15:22	7/20/2021 17:30	Subtransmission	Distribution	TIE 3402	329	42187	TREE
7/20/2021 15:30	7/20/2021 23:42	Subtransmission	None	TIE 3402			TREE
8/29/2022 19:53	8/30/2022 14:51	Subtransmission	None	TIE 9303			TREE
8/29/2022 18:10	8/31/2022 19:50	Subtransmission	Distribution	TIE 9303	1612	4748921	TREE
8/29/2022 18:14	8/31/2022 13:15	Subtransmission	Distribution	TIE 9303	989	1363371	TREE
8/30/2022 10:42	8/30/2022 15:48	Subtransmission	None	TIE 9303			TREE

11/5/2022 12:23	11/5/2022 20:18	Subtransmission	None	TIE 4105			TREE
11/5/2022 12:11	11/5/2022 17:00	Subtransmission	Distribution	TIE 4105	107	29209	TREE
12/22/2022 14:11	12/24/2022 15:45	Subtransmission	Distribution	TIE 3241	381	93459	TREE
12/22/2022 11:39	12/23/2022 12:30	Subtransmission	Distribution	TIE 3241	2	428	TREE
12/23/2022 13:15	12/26/2022 21:03	Subtransmission	None	TIE 3241			TREE
12/23/2022 18:35	12/24/2022 12:33	Subtransmission	None	TIE 3241			TREE
12/23/2022 13:35	12/23/2022 18:47	Subtransmission	Distribution	TIE 3241			TREE
2/27/2023 18:02	2/28/2023 10:41	Subtransmission	Subtransmission	TIE 4605	1582	178676	TREE
2/28/2023 7:29	3/1/2023 19:31	Subtransmission	Circuit Level	TIE 4605	505	362915	TREE
2/28/2023 13:15	3/8/2023 10:35	Subtransmission		TIE 4605			TREE
2/28/2023 7:36	3/3/2023 6:18	Subtransmission		TIE 4605			TREE
7/5/2023 9:23	7/7/2023 13:04	Subtransmission		TRK 5239			TREE
7/13/2023 5:40	7/13/2023 20:10	Subtransmission		TIE 810			TREE
7/26/2023 16:15	7/29/2023 20:22	Subtransmission		TIE 1540			TREE
7/26/2023 16:05	7/28/2023 18:11	Subtransmission	Subtransmission	TIE 1540	5	5760	TREE
7/26/2023 17:00	7/28/2023 10:31	Subtransmission	Single Customer	TIE 1540			TREE
7/26/2023 17:05	7/27/2023 5:06	Subtransmission		TIE 1540			TREE
7/26/2023 15:50	7/30/2023 15:57	Subtransmission	Circuit Level	TIE 1540	92	518626	TREE
7/26/2023 17:15	7/28/2023 15:33	Subtransmission		TRK 4301			TREE
7/27/2023 19:30	7/29/2023 22:04	Subtransmission		TIE 1467			TREE
7/27/2023 17:07	7/29/2023 14:57	Subtransmission		TRK 4301			TREE
7/28/2023 17:12	7/30/2023 8:34	Subtransmission	Device (II)	TRK 4301	1057	4400060	TREE
7/29/2023 4:18	7/30/2023 18:33	Subtransmission		TRK 4301			TREE
7/29/2023 9:26	7/30/2023 19:52	Subtransmission		TRK 4301			TREE
7/30/2023 11:06	7/30/2023 17:33	Subtransmission		TIE 1540			TREE
8/24/2023 15:55	8/25/2023 1:14	Subtransmission	Single Customer	TIE 1318			TREE
8/24/2023 10:02	8/29/2023 13:51	Subtransmission	Subtransmission	TIE 1318	4049	13258755	TREE
8/24/2023 10:58	8/24/2023 15:26	Subtransmission		TIE 1423			TREE
8/24/2023 0:22	8/28/2023 10:03	Subtransmission	Device (II)	TIE 1423	1305	4235917	TREE
8/24/2023 8:46	8/26/2023 22:27	Subtransmission	Device (II)	TIE 1423	30	97534	TREE
8/26/2023 16:39	8/29/2023 16:21	Subtransmission		TIE 1423			TREE
8/27/2023 19:33	8/29/2023 15:57	Subtransmission		TIE 1423			TREE
9/6/2023 22:06	9/7/2023 7:48	Subtransmission	Device (II)	TIE 6138	269	33454	TREE
9/6/2023 22:56	9/7/2023 17:46	Subtransmission		TIE 6138			TREE
9/19/2023 9:07	9/19/2023 11:38	Subtransmission		TRK 3526			TREE
9/20/2023 18:38	10/2/2023 15:06	Subtransmission		TRK 3526			TREE
5/2/2023 8:10	5/2/2023 11:48	Subtransmission		TRK 4911			WIND
10/19/2018 13:08	10/19/2018 15:23	Subtransmission	None	TRK 7122			ANIMAL
10/19/2018 13:18	10/19/2018 16:14	Subtransmission	None	TRK 7122			ANIMAL
12/7/2018 7:54	12/7/2018 14:49	Subtransmission	None	TRK 7122			ANIMAL
12/7/2018 17:02	12/7/2018 22:08	Subtransmission	None	TRK 7122			ANIMAL
12/7/2018 17:48	12/7/2018 21:22	Subtransmission	None	TRK 7122			ANIMAL
8/8/2020 13:52	8/8/2020 15:30	Subtransmission	None	TIE 7702			ANIMAL
8/25/2020 18:51	8/26/2020 14:19	Subtransmission	None	TRK 2907			ANIMAL
5/14/2021 14:28	5/15/2021 12:52	Subtransmission	None	TIE 6931			ANIMAL
10/12/2021 7:55	10/12/2021 10:40	Subtransmission	None	TRK 3650			ANIMAL
11/24/2021 10:19	11/29/2021 6:55	Subtransmission	None	TRK 4338			ANIMAL
7/23/2022 7:06	7/24/2022 10:46	Subtransmission	None	TRK 7114			ANIMAL
7/24/2022 7:31	7/24/2022 10:41	Subtransmission	None	TRK 7114			ANIMAL
7/24/2022 11:39	7/24/2022 17:05	Subtransmission	None	TRK 7114			ANIMAL
1/20/2018 7:58	1/20/2018 10:29	Subtransmission	None	TRK 3650			EQUIPMENT FAILURE
3/8/2018 10:48	3/8/2018 14:32	Subtransmission	None	TIE 4104			EQUIPMENT FAILURE
3/27/2018 11:32	3/27/2018 14:30	Subtransmission	Distribution	TIE 4505	1949	321725	EQUIPMENT FAILURE
3/27/2018 16:03	3/27/2018 20:02	Subtransmission	None	TRK 2107			EQUIPMENT FAILURE
1/15/2019 15:09	1/15/2019 20:00	Subtransmission	None	TIE 810			EQUIPMENT FAILURE
3/4/2019 1:45	3/4/2019 4:35	Subtransmission	None	TIE 2819			EQUIPMENT FAILURE
7/19/2019 12:23	7/19/2019 15:11	Subtransmission	None	TRK 141			EQUIPMENT FAILURE
8/28/2019 4:19	8/28/2019 22:48	Subtransmission	None	TIE 7745			EQUIPMENT FAILURE
9/13/2019 17:31	9/13/2019 20:56	Subtransmission	None	TIE 4105			EQUIPMENT FAILURE
9/13/2019 17:19	9/13/2019 19:28	Subtransmission	Distribution	TIE 4105	703	76667	EQUIPMENT FAILURE
9/13/2019 17:31	9/13/2019 20:56	Subtransmission	Distribution	TIE 4105	1	109	EQUIPMENT FAILURE
9/13/2019 18:00	9/13/2019 19:28	Subtransmission	Distribution	TIE 4105	220	24072	EQUIPMENT FAILURE
9/13/2019 23:11	9/14/2019 19:58	Subtransmission	None	TIE 4105			EQUIPMENT FAILURE
9/13/2019 18:32	9/13/2019 20:19	Subtransmission	Distribution	TIE 4105	1	110	EQUIPMENT FAILURE
9/13/2019 17:37	9/13/2019 20:56	Subtransmission	None	TIE4105			EQUIPMENT FAILURE
9/13/2019 17:19	9/14/2019 17:06	Subtransmission	Distribution	TIE4105	108	169881	EQUIPMENT FAILURE
9/13/2019 18:39	9/13/2019 19:28	Subtransmission	Distribution	TIE4105			EQUIPMENT FAILURE
9/13/2019 17:31	9/13/2019 20:56	Subtransmission	None	TIE4105			EQUIPMENT FAILURE
9/14/2019 17:33	9/14/2019 19:53	Subtransmission	None	TIE 4105			EQUIPMENT FAILURE
9/14/2019 17:33	9/14/2019 19:53	Subtransmission	None	TIE4105			EQUIPMENT FAILURE
9/16/2019 14:25	9/16/2019 18:09	Subtransmission	None	TIE 5843			EQUIPMENT FAILURE
9/18/2019 17:09	9/24/2019 12:51	Subtransmission	None	TIE 5513			EQUIPMENT FAILURE
9/22/2019 13:25	9/22/2019 13:32	Subtransmission	None	TIE 6621			EQUIPMENT FAILURE
9/22/2019 13:26	9/22/2019 13:38	Subtransmission	None	TIE 6621			EQUIPMENT FAILURE
9/22/2019 13:25	9/22/2019 13:32	Subtransmission	None	TIE 6621			EQUIPMENT FAILURE
9/22/2019 13:25	9/22/2019 13:35	Subtransmission	None	TIE 6621			EQUIPMENT FAILURE
9/22/2019 13:28	9/22/2019 13:42	Subtransmission	None	TIE 6621			EQUIPMENT FAILURE
9/22/2019 13:24	9/22/2019 13:30	Subtransmission	None	TIE 6621			EQUIPMENT FAILURE
9/22/2019 13:24	9/22/2019 13:33	Subtransmission	None	TIE 6621			EQUIPMENT FAILURE
9/22/2019 13:16	9/22/2019 13:41	Subtransmission	None	TIE 6621			EQUIPMENT FAILURE
9/22/2019 13:38	9/23/2019 2:47	Subtransmission	None	TIE 6621			EQUIPMENT FAILURE
9/22/2019 15:04	9/23/2019 2:19	Subtransmission	None	TIE 6621			EQUIPMENT FAILURE
9/25/2019 16:29	9/25/2019 19:33	Subtransmission	None	TRK 1518			EQUIPMENT FAILURE
3/6/2020 7:24	3/6/2020 11:38	Subtransmission	None	TIE 1568			EQUIPMENT FAILURE
3/18/2020 20:33	3/18/2020 21:28	Subtransmission	None	TIE 4428			EQUIPMENT FAILURE
3/18/2020 18:46	3/18/2020 20:22	Subtransmission	Distribution	TIE 4428	872	84408	EQUIPMENT FAILURE
3/18/2020 18:46	3/18/2020 20:22	Subtransmission	Distribution	TIE 4428	660	63969	EQUIPMENT FAILURE
3/18/2020 18:56	3/19/2020 3:01	Subtransmission	None	TIE 4428			EQUIPMENT FAILURE
3/18/2020 18:52	3/18/2020 21:26	Subtransmission	None	TIE 4428			EQUIPMENT FAILURE
3/18/2020 18:46	3/18/2020 20:28	Subtransmission	Distribution	TIE 4428	888	85574	EQUIPMENT FAILURE
3/18/2020 20:56	3/18/2020 21:19	Subtransmission	None	TIE 4428			EQUIPMENT FAILURE
3/18/2020 18:46	3/18/2020 20:28	Subtransmission	Distribution	TIE 4428	1835	176596	EQUIPMENT FAILURE
3/18/2020 18:46	3/18/2020 20:27	Subtransmission	Distribution	TIE 4428	1753	222779	EQUIPMENT FAILURE
3/18/2020 20:58	3/18/2020 21:40	Subtransmission	Distribution	TIE 4428			EQUIPMENT FAILURE
3/18/2020 21:11	3/18/2020 21:20	Subtransmission	None	TIE 4428			EQUIPMENT FAILURE
3/18/2020 20:58	3/18/2020 22:16	Subtransmission	None	TIE 4428			EQUIPMENT FAILURE
3/18/2020 20:44	3/18/2020 21:18	Subtransmission	None	TIE 4428			EQUIPMENT FAILURE
3/18/2020 20:36	3/18/2020 21:17	Subtransmission	None	TIE 4428			EQUIPMENT FAILURE
6/10/2020 21:53	6/11/2020 9:01	Subtransmission	None	TIE 2812			EQUIPMENT FAILURE
6/10/2020 16:07	6/12/2020 14:15	Subtransmission	Distribution	TIE 2812	1108	222284	EQUIPMENT FAILURE
6/10/2020 16:23	6/11/2020 13:52	Subtransmission	None	TIE 2812			EQUIPMENT FAILURE
10/22/2020 8:05	10/22/2020 11:57	Subtransmission	None	TRK 6842			EQUIPMENT FAILURE
10/22/2020 8:02	10/22/2020 17:37	Subtransmission	None	TRK 6842			EQUIPMENT FAILURE
12/9/2020 11:34	12/9/2020 17:46	Subtransmission	None	TRK 2218			EQUIPMENT FAILURE
1/14/2021 7:55	1/14/2021 15:21	Subtransmission	None	TIE 7745			EQUIPMENT FAILURE

1/25/2021 9:17	1/25/2021 17:23	Subtransmission	None	TRK 3536			EQUIPMENT FAILURE
3/26/2021 17:07	3/26/2021 20:01	Subtransmission	None	TIE 226			EQUIPMENT FAILURE
8/11/2021 21:10	8/15/2021 19:30	Subtransmission	None	TIE 1473			EQUIPMENT FAILURE
8/11/2021 15:24	8/16/2021 18:15	Subtransmission	Distribution	TIE 1473	4	16918	EQUIPMENT FAILURE
8/11/2021 15:24	8/16/2021 18:15	Subtransmission	Distribution	TIE 1473	299	145308	EQUIPMENT FAILURE
8/16/2021 19:42	8/18/2021 13:06	Subtransmission	Distribution	TIE 1473	1	14	EQUIPMENT FAILURE
8/16/2021 5:00	8/16/2021 18:15	Subtransmission	Distribution	TIE 1473	7	16651	EQUIPMENT FAILURE
8/16/2021 14:09	8/16/2021 18:15	Subtransmission	Distribution	TIE 1473	11	16855	EQUIPMENT FAILURE
8/16/2021 19:29	8/18/2021 14:07	Subtransmission	None	TIE 1473			EQUIPMENT FAILURE
9/20/2021 8:36	9/20/2021 12:46	Subtransmission	None	TRK 2032			EQUIPMENT FAILURE
10/14/2021 9:39	10/14/2021 17:45	Subtransmission	None	TRK 2713			EQUIPMENT FAILURE
10/25/2021 11:59	10/25/2021 21:12	Subtransmission	None	TIE 1531			EQUIPMENT FAILURE
10/25/2021 2:19	10/25/2021 5:59	Subtransmission	None	TIE 1531			EQUIPMENT FAILURE
10/25/2021 2:33	10/25/2021 14:31	Subtransmission	None	TIE 1531			EQUIPMENT FAILURE
4/2/2022 6:59	4/3/2022 20:22	Subtransmission	None	TRK 3536			EQUIPMENT FAILURE
5/9/2022 9:05	5/9/2022 21:17	Subtransmission	None	TRK 2107			EQUIPMENT FAILURE
5/10/2022 16:15	5/16/2022 20:56	Subtransmission	None	TRK 2107			EQUIPMENT FAILURE
6/26/2022 21:34	6/28/2022 12:37	Subtransmission	None	TIE 4428			EQUIPMENT FAILURE
8/28/2022 17:36	9/2/2022 14:02	Subtransmission	Distribution	TRK 1303	51	141432	EQUIPMENT FAILURE
8/28/2022 14:39	8/28/2022 18:12	Subtransmission	Distribution	TRK 1303	1	5	EQUIPMENT FAILURE
8/28/2022 14:36	8/31/2022 17:08	Subtransmission	Distribution	TRK 1303	3332	17504	EQUIPMENT FAILURE
8/28/2022 14:47	8/28/2022 18:32	Subtransmission	None	TRK 1303			EQUIPMENT FAILURE
8/28/2022 14:55	8/28/2022 15:49	Subtransmission	None	TRK 1303			EQUIPMENT FAILURE
9/2/2022 9:10	9/3/2022 11:51	Subtransmission	None	TIE 4412			EQUIPMENT FAILURE
9/20/2022 21:46	9/21/2022 1:45	Subtransmission	Distribution	TIE 4523	555	128614	EQUIPMENT FAILURE
9/20/2022 21:58	9/21/2022 16:00	Subtransmission	None	TIE 4523			EQUIPMENT FAILURE
12/15/2022 7:23	12/15/2022 16:51	Subtransmission	Distribution	TIE 3241	278	158652	EQUIPMENT FAILURE
12/15/2022 7:23	12/15/2022 17:05	Subtransmission	Distribution	TIE 3241	2000	1151895	EQUIPMENT FAILURE
12/15/2022 7:23	12/15/2022 17:10	Subtransmission	Distribution	TIE 3241	331	201091	EQUIPMENT FAILURE
12/15/2022 7:23	12/15/2022 17:10	Subtransmission	Distribution	TIE 3241	426	253165	EQUIPMENT FAILURE
12/15/2022 7:23	12/15/2022 17:00	Subtransmission	Distribution	TIE 3241	543	330236	EQUIPMENT FAILURE
2/9/2023 15:40	2/9/2023 23:03	Subtransmission		TIE 2812			EQUIPMENT FAILURE
2/17/2023 2:46	2/17/2023 13:04	Subtransmission	Subtransmission	TRK 6508	1426	201241	EQUIPMENT FAILURE
3/15/2023 10:55	3/15/2023 15:51	Subtransmission		TIE 6931	1	98	EQUIPMENT FAILURE
3/15/2023 11:01	3/15/2023 18:22	Subtransmission		TIE 6931			EQUIPMENT FAILURE
3/15/2023 11:05	3/15/2023 18:22	Subtransmission		TIE 6931	1	195	EQUIPMENT FAILURE
3/15/2023 11:25	3/17/2023 16:59	Subtransmission		TIE 6931	1	195	EQUIPMENT FAILURE
3/15/2023 9:34	3/15/2023 15:53	Subtransmission	Device (I)	TIE 6931	19	4398	EQUIPMENT FAILURE
6/5/2023 20:44	6/6/2023 5:34	Subtransmission	Circuit Level	TRK 2218	973	275976	EQUIPMENT FAILURE
6/5/2023 20:46	6/6/2023 4:56	Subtransmission	Circuit Level	TRK 2218	35	14910	EQUIPMENT FAILURE
6/5/2023 20:44	6/6/2023 4:32	Subtransmission	Circuit Level	TRK 2218	1031	376156	EQUIPMENT FAILURE
6/17/2023 10:04	6/17/2023 17:24	Subtransmission		TIE 1268			EQUIPMENT FAILURE
8/10/2023 11:16	8/10/2023 13:49	Subtransmission		TRK 1340			EQUIPMENT FAILURE
8/24/2023 7:06	8/25/2023 20:30	Subtransmission	Circuit Level	TIE 7702	334	156487	EQUIPMENT FAILURE
8/24/2023 4:39	8/25/2023 17:50	Subtransmission	Circuit Level	TIE 7702	206	103429	EQUIPMENT FAILURE
8/24/2023 2:40	8/30/2023 21:30	Subtransmission		TIE 7702			EQUIPMENT FAILURE
8/28/2023 7:55	8/30/2023 17:16	Subtransmission		TIE 2025			EQUIPMENT FAILURE
8/28/2023 23:46	8/29/2023 10:28	Subtransmission		TIE 7702			EQUIPMENT FAILURE
8/29/2023 10:41	8/30/2023 7:41	Subtransmission		TIE 1312			EQUIPMENT FAILURE
9/4/2023 10:52	9/4/2023 18:01	Subtransmission		TIE 1540			EQUIPMENT FAILURE
9/4/2023 18:07	9/5/2023 15:02	Subtransmission		TIE 1540			EQUIPMENT FAILURE
11/17/2023 10:57	11/17/2023 14:17	Subtransmission		TRK 2250			EQUIPMENT FAILURE
11/30/2023 12:08	12/1/2023 5:03	Subtransmission		TRK 3508			EQUIPMENT FAILURE
12/19/2023 13:15	12/20/2023 5:04	Subtransmission		TRK 5145			EQUIPMENT FAILURE
12/21/2023 13:22	12/22/2023 6:26	Subtransmission		TIE 2648			EQUIPMENT FAILURE
12/28/2023 18:27	12/28/2023 23:10	Subtransmission		TIE 1423			EQUIPMENT FAILURE
11/21/2023 22:00	11/22/2023 1:16	Subtransmission	Subtransmission	TIE 3800	1150	202164	INTENTIONAL
11/21/2023 22:00	11/22/2023 2:54	Subtransmission	Subtransmission	TIE 3800	866	152287	INTENTIONAL
6/10/2020 14:12	6/11/2020 19:30	Subtransmission	Distribution	TIE 7520	418	729321	LIGHTNING
6/4/2020 19:56	6/5/2020 7:11	Subtransmission	None	TIE 2819			PUBLIC INTERFERENCE
6/4/2020 19:58	6/5/2020 0:58	Subtransmission	None	TIE 2819			PUBLIC INTERFERENCE
6/4/2020 19:54	6/4/2020 23:32	Subtransmission	Distribution	TIE 2819	3155	467010	PUBLIC INTERFERENCE
6/4/2020 20:26	6/5/2020 0:58	Subtransmission	None	TIE 2819			PUBLIC INTERFERENCE
6/4/2020 21:05	6/5/2020 0:58	Subtransmission	None	TIE 2819			PUBLIC INTERFERENCE
6/4/2020 20:05	6/4/2020 23:45	Subtransmission	Distribution	TIE 2819	1	220	PUBLIC INTERFERENCE
6/4/2020 20:29	6/4/2020 23:50	Subtransmission	Distribution	TIE 2819	1	219	PUBLIC INTERFERENCE
6/4/2020 20:07	6/4/2020 22:05	Subtransmission	None	TIE 2819			PUBLIC INTERFERENCE
6/4/2020 20:06	6/4/2020 23:36	Subtransmission	Distribution	TIE 2819	1	220	PUBLIC INTERFERENCE
6/4/2020 20:09	6/5/2020 2:09	Subtransmission	None	TIE 2819			PUBLIC INTERFERENCE
6/5/2020 6:08	6/5/2020 8:00	Subtransmission	Distribution	TIE 2819	1	697	PUBLIC INTERFERENCE
6/5/2020 6:15	6/5/2020 9:08	Subtransmission	None	TIE 2819			PUBLIC INTERFERENCE
6/5/2020 10:07	6/5/2020 13:22	Subtransmission	None	TIE 2819			PUBLIC INTERFERENCE
5/24/2022 17:33	5/25/2022 12:14	Subtransmission	None	TIE 3323			PUBLIC INTERFERENCE
3/5/2018 15:00	3/5/2018 20:59	Subtransmission	None	TIE 9205			TREE
3/6/2018 7:08	3/6/2018 20:21	Subtransmission	None	TIE 9205			TREE
11/1/2020 16:48	11/2/2020 16:46	Subtransmission	None	TIE 4104			TREE
12/16/2021 7:19	12/16/2021 10:29	Subtransmission	None	TIE 4412			TREE
12/16/2021 7:28	12/16/2021 10:29	Subtransmission	None	TIE 4412			TREE
12/16/2021 7:32	12/16/2021 17:17	Subtransmission	None	TIE 4412			TREE
11/7/2022 9:07	11/7/2022 12:02	Subtransmission	None	TIE 2901			TREE
8/16/2021 17:55	8/16/2021 19:36	Subtransmission	None	TIE 1473			WIND
1/22/2018 15:42	1/23/2018 13:41	Subtransmission	None	TIE 3220			EQUIPMENT FAILURE
1/22/2018 15:45	1/22/2018 19:39	Subtransmission	None	TIE 3220			EQUIPMENT FAILURE
1/28/2018 14:12	1/28/2018 20:12	Subtransmission	None	TIE 3320			EQUIPMENT FAILURE
3/28/2018 15:00	3/28/2018 17:21	Subtransmission	None	TRK 2411			EQUIPMENT FAILURE
5/1/2018 12:14	5/1/2018 14:31	Subtransmission	None	TIE 4605			EQUIPMENT FAILURE
6/22/2018 19:46	6/22/2018 20:19	Subtransmission	None	TIE 3410			EQUIPMENT FAILURE
8/19/2018 22:48	8/20/2018 16:37	Subtransmission	None	TRK 5411			EQUIPMENT FAILURE
11/17/2018 15:10	11/17/2018 15:56	Subtransmission	None	TRK 1525			EQUIPMENT FAILURE
11/17/2018 15:07	11/17/2018 18:47	Subtransmission	None	TRK 1525			EQUIPMENT FAILURE
4/7/2019 12:05	4/7/2019 17:54	Subtransmission	None	TRK 4316			EQUIPMENT FAILURE
7/19/2019 19:57	7/23/2019 14:00	Subtransmission	Distribution	TIE 4501	272	374517	EQUIPMENT FAILURE
12/30/2019 20:30	12/30/2019 20:41	Subtransmission	Distribution	TIE 810			EQUIPMENT FAILURE
12/30/2019 17:17	12/31/2019 5:22	Subtransmission	None	TIE 810			EQUIPMENT FAILURE
3/31/2020 22:24	4/1/2020 4:00	Subtransmission	Distribution	TRK 2659	839	205976	EQUIPMENT FAILURE
2/17/2021 15:24	2/17/2021 21:17	Subtransmission	None	TRK 6172			EQUIPMENT FAILURE
8/26/2021 12:53	8/29/2021 18:42	Subtransmission	None	TIE 9111			EQUIPMENT FAILURE
7/11/2022 19:06	7/12/2022 12:46	Subtransmission	None	TRK 1121			EQUIPMENT FAILURE
11/30/2022 19:04	12/2/2022 8:37	Subtransmission	None	TRK 7062			EQUIPMENT FAILURE
11/30/2022 12:29	11/30/2022 13:50	Subtransmission	None	TRK 7062			EQUIPMENT FAILURE
1/30/2023 23:49	1/31/2023 14:56	Subtransmission	None	TRK 3727			EQUIPMENT FAILURE
2/22/2023 14:46	2/25/2023 11:54	Subtransmission	Device (II)	TIE 1467	594	1797030	EQUIPMENT FAILURE
3/25/2023 14:24	3/25/2023 17:10	Subtransmission	Subtransmission	TIE 1467	1799	77157	EQUIPMENT FAILURE
3/25/2023 14:43	3/27/2023 7:41	Subtransmission		TIE 1467			EQUIPMENT FAILURE
7/17/2023 17:08	7/18/2023 8:34	Subtransmission	Subtransmission	TRK 8215			EQUIPMENT FAILURE

9/13/2019 7:05	9/13/2019 20:46	Subtransmission	None	TRK 2437			PUBLIC INTERFERENCE
9/10/2020 0:50	9/10/2020 6:21	Subtransmission	None	TRK 1303			PUBLIC INTERFERENCE
9/10/2020 0:35	9/10/2020 13:37	Subtransmission	Distribution	TRK 1303	72	52405	PUBLIC INTERFERENCE
1/30/2021 10:49	1/30/2021 13:51	Subtransmission	None	TIE 2648			PUBLIC INTERFERENCE
6/2/2021 14:10	6/2/2021 16:08	Subtransmission	Subtransmission	TIE 9111	598	70998	PUBLIC INTERFERENCE
6/2/2021 14:10	6/2/2021 16:08	Subtransmission	Subtransmission	TIE 9111	230	27311	PUBLIC INTERFERENCE
6/2/2021 14:10	6/2/2021 16:08	Subtransmission	Subtransmission	TIE 9111	397	47151	PUBLIC INTERFERENCE
6/2/2021 14:18	6/3/2021 1:13	Subtransmission	None	TIE 9111			PUBLIC INTERFERENCE
10/1/2018 8:45	10/3/2018 6:49	Subtransmission	None	TRK 5585			EQUIPMENT FAILURE
8/15/2019 17:04	8/20/2019 18:30	Subtransmission	None	TIE 2901			EQUIPMENT FAILURE
4/22/2020 18:53	4/23/2020 3:06	Subtransmission	None	TRK 6508			EQUIPMENT FAILURE
4/22/2020 19:36	4/23/2020 3:12	Subtransmission	Distribution	TRK 6508	1	423	EQUIPMENT FAILURE
8/27/2022 8:51	8/27/2022 12:30	Subtransmission	Distribution	TRK 1276			EQUIPMENT FAILURE
8/27/2022 8:48	8/27/2022 21:51	Subtransmission	None	TRK 1276			EQUIPMENT FAILURE
8/30/2022 9:03	8/30/2022 21:38	Subtransmission	None	TRK 5838			TREE
1/4/2019 13:46	1/4/2019 16:46	Subtransmission	None	TRK 5923			ANIMAL
5/7/2019 13:58	5/7/2019 17:11	Subtransmission	None	TRK 5917			ANIMAL
2/16/2020 11:57	2/16/2020 20:50	Subtransmission	None	TRK 2301			ANIMAL
3/26/2020 0:17	3/26/2020 1:45	Subtransmission	None	TRK 1251			ANIMAL
7/29/2021 19:44	7/29/2021 22:19	Subtransmission	None	TRK 7122			ANIMAL
9/19/2021 18:25	9/19/2021 18:41	Subtransmission	Distribution	TRK 2032			ANIMAL
9/19/2021 18:47	9/20/2021 15:06	Subtransmission	None	TRK 2032			ANIMAL
12/30/2020 5:04	12/30/2020 17:43	Subtransmission	None	TRK 7729			CUSTOMER EQUIPMENT
4/5/2018 14:25	4/5/2018 17:25	Subtransmission	Distribution	TRK 7122	71	13136	EQUIPMENT FAILURE
4/5/2018 14:32	4/5/2018 21:34	Subtransmission	None	TRK 7122			EQUIPMENT FAILURE
4/16/2018 17:17	4/17/2018 20:21	Subtransmission	None	TRK 3534			EQUIPMENT FAILURE
5/3/2018 0:27	5/3/2018 3:10	Subtransmission	Distribution	TIE 1473	197	32079	EQUIPMENT FAILURE
5/3/2018 0:27	5/3/2018 3:10	Subtransmission	Distribution	TIE 1473	871	140783	EQUIPMENT FAILURE
5/3/2018 0:27	5/3/2018 3:10	Subtransmission	Distribution	TIE 1473	454	73952	EQUIPMENT FAILURE
5/12/2018 7:07	5/12/2018 10:45	Subtransmission	None	TRK 7386			EQUIPMENT FAILURE
5/12/2018 6:47	5/12/2018 7:37	Subtransmission	Distribution	TRK 7386	2015	101610	EQUIPMENT FAILURE
5/12/2018 6:47	5/12/2018 7:20	Subtransmission	None	TRK 7386			EQUIPMENT FAILURE
5/12/2018 6:44	5/12/2018 7:37	Subtransmission	Distribution	TRK 7386	1934	97467	EQUIPMENT FAILURE
6/7/2018 19:48	6/7/2018 22:44	Subtransmission	Distribution	TIE 9123	364	64166	EQUIPMENT FAILURE
6/9/2018 19:57	6/10/2018 5:20	Subtransmission	None	TRK 2016			EQUIPMENT FAILURE
6/9/2018 20:20	6/10/2018 5:14	Subtransmission	None	TRK 2016			EQUIPMENT FAILURE
6/16/2018 6:48	6/16/2018 8:33	Subtransmission	Distribution	TRK 7150			EQUIPMENT FAILURE
6/16/2018 6:56	6/16/2018 8:33	Subtransmission	Distribution	TRK 7150	259	27118	EQUIPMENT FAILURE
6/16/2018 6:56	6/16/2018 14:29	Subtransmission	None	TRK 7150			EQUIPMENT FAILURE
6/16/2018 7:00	6/16/2018 10:45	Subtransmission	Distribution	TRK 7150	103	24176	EQUIPMENT FAILURE
7/21/2018 12:51	7/23/2018 14:25	Subtransmission	None	TRK 1862			EQUIPMENT FAILURE
8/7/2018 21:42	8/8/2018 17:22	Subtransmission	None	TRK 630			EQUIPMENT FAILURE
8/22/2018 17:40	8/22/2018 18:28	Subtransmission	Distribution	TIE 7702	182	8960	EQUIPMENT FAILURE
9/20/2018 12:15	9/20/2018 12:45	Subtransmission	Distribution	TRK 3534	180	4849	EQUIPMENT FAILURE
10/1/2018 13:44	10/1/2018 16:23	Subtransmission	None	TIE 3534			EQUIPMENT FAILURE
10/11/2018 17:29	10/12/2018 3:24	Subtransmission	None	TRK 1544			EQUIPMENT FAILURE
11/21/2018 15:00	11/21/2018 16:55	Subtransmission	Distribution	TRK 2418	1022	117791	EQUIPMENT FAILURE
11/21/2018 15:00	11/21/2018 16:55	Subtransmission	Distribution	TRK 2418	929	120677	EQUIPMENT FAILURE
11/21/2018 15:00	11/21/2018 16:55	Subtransmission	Distribution	TRK 2418	608	71003	EQUIPMENT FAILURE
11/21/2018 15:07	11/23/2018 18:26	Subtransmission	None	TRK 2418			EQUIPMENT FAILURE
11/21/2018 15:09	11/21/2018 20:00	Subtransmission	None	TRK 2418			EQUIPMENT FAILURE
11/21/2018 15:00	11/21/2018 16:55	Subtransmission	Distribution	TRK 2418	1043	115670	EQUIPMENT FAILURE
11/30/2018 13:46	3/29/2019 6:13	Subtransmission	None	TRK 2418			EQUIPMENT FAILURE
12/28/2018 9:44	12/28/2018 12:05	Subtransmission	None	TIE 4104			EQUIPMENT FAILURE
12/28/2018 16:54	12/28/2018 18:28	Subtransmission	Distribution	TIE 4104	927	79546	EQUIPMENT FAILURE
12/28/2018 16:54	12/28/2018 18:28	Subtransmission	Distribution	TIE 4104	1096	94878	EQUIPMENT FAILURE
2/23/2019 16:16	2/23/2019 22:21	Subtransmission	None	TIE 1544			EQUIPMENT FAILURE
4/18/2019 10:36	4/18/2019 16:31	Subtransmission	None	TIE 807			EQUIPMENT FAILURE
5/9/2019 1:02	5/9/2019 6:42	Subtransmission	None	TIE 6310			EQUIPMENT FAILURE
5/9/2019 4:59	5/9/2019 12:53	Subtransmission	Distribution	TIE 6310	2	360	EQUIPMENT FAILURE
5/9/2019 17:06	5/9/2019 22:09	Subtransmission	None	TIE 6310			EQUIPMENT FAILURE
7/2/2019 19:48	7/2/2019 20:51	Subtransmission	Distribution	TRK 5838	725	45536	EQUIPMENT FAILURE
7/2/2019 19:48	7/2/2019 20:51	Subtransmission	Distribution	TRK 5838	241	64563	EQUIPMENT FAILURE
7/2/2019 19:48	7/2/2019 20:51	Subtransmission	Distribution	TRK 5838	535	38989	EQUIPMENT FAILURE
7/5/2019 15:38	7/5/2019 22:32	Subtransmission	None	TRK 2519			EQUIPMENT FAILURE
7/5/2019 15:20	7/5/2019 22:31	Subtransmission	None	TRK 2519			EQUIPMENT FAILURE
7/5/2019 15:20	7/5/2019 22:30	Subtransmission	None	TRK 2519			EQUIPMENT FAILURE
8/27/2019 17:00	8/27/2019 19:22	Subtransmission	None	TRK 3661			EQUIPMENT FAILURE
8/27/2019 22:21	9/5/2019 21:36	Subtransmission	None	TRK 3661			EQUIPMENT FAILURE
9/13/2019 17:31	9/13/2019 20:56	Subtransmission	None	TIE 4105			EQUIPMENT FAILURE
9/13/2019 18:01	9/13/2019 20:56	Subtransmission	None	TIE 4105			EQUIPMENT FAILURE
9/13/2019 17:19	9/13/2019 19:28	Subtransmission	Distribution	TIE 4105	703	76667	EQUIPMENT FAILURE
9/13/2019 17:31	9/13/2019 20:56	Subtransmission	None	TIE 4105			EQUIPMENT FAILURE
9/13/2019 17:31	9/13/2019 20:56	Subtransmission	Distribution	TIE 4105	1	109	EQUIPMENT FAILURE
9/13/2019 18:00	9/13/2019 19:28	Subtransmission	Distribution	TIE 4105	220	24072	EQUIPMENT FAILURE
9/13/2019 17:19	9/14/2019 17:06	Subtransmission	Distribution	TIE 4105	108	169881	EQUIPMENT FAILURE
9/13/2019 18:39	9/13/2019 19:28	Subtransmission	Distribution	TIE 4105			EQUIPMENT FAILURE
9/13/2019 23:11	9/14/2019 19:58	Subtransmission	None	TIE 4105			EQUIPMENT FAILURE
9/13/2019 17:37	9/13/2019 20:56	Subtransmission	None	TIE 4105			EQUIPMENT FAILURE
9/13/2019 18:32	9/13/2019 20:19	Subtransmission	Distribution	TIE 4105	1	110	EQUIPMENT FAILURE
10/14/2019 23:25	10/15/2019 0:20	Subtransmission	Distribution	TIE 1467	164	6429	EQUIPMENT FAILURE
10/14/2019 23:25	10/15/2019 0:20	Subtransmission	Distribution	TIE 1467	749	33809	EQUIPMENT FAILURE
10/21/2019 23:52	10/22/2019 2:01	Subtransmission	Distribution	TIE 3241	510	5760	EQUIPMENT FAILURE
10/21/2019 23:52	10/22/2019 2:01	Subtransmission	Distribution	TIE 3241	419	5073	EQUIPMENT FAILURE
10/21/2019 23:54	10/22/2019 2:01	Subtransmission	Distribution	TIE 3241	1953	252625	EQUIPMENT FAILURE
10/21/2019 23:56	10/22/2019 2:00	Subtransmission	Distribution	TIE 3241	495	64881	EQUIPMENT FAILURE
10/21/2019 23:52	10/22/2019 2:01	Subtransmission	Distribution	TIE 3241	437	5334	EQUIPMENT FAILURE
10/21/2019 23:52	10/22/2019 2:01	Subtransmission	Distribution	TIE 3241	320	40908	EQUIPMENT FAILURE
10/21/2019 23:55	10/22/2019 2:01	Subtransmission	Distribution	TIE 3241	257	32835	EQUIPMENT FAILURE
11/25/2019 19:54	11/25/2019 21:45	Subtransmission	Substation	TRK 648	1250	89858	EQUIPMENT FAILURE
11/25/2019 19:54	11/25/2019 21:00	Subtransmission	Distribution	TRK 648	575	41259	EQUIPMENT FAILURE
11/25/2019 19:54	11/25/2019 21:30	Subtransmission	Substation	TRK 648	547	39268	EQUIPMENT FAILURE
12/1/2019 8:53	12/1/2019 10:23	Subtransmission	Distribution	TIE 4109	496	41636	EQUIPMENT FAILURE
12/1/2019 8:53	12/1/2019 10:23	Subtransmission	Distribution	TIE 4109	690	58209	EQUIPMENT FAILURE
12/1/2019 9:12	12/1/2019 11:19	Subtransmission	None	TIE 4109			EQUIPMENT FAILURE
12/1/2019 8:53	12/1/2019 10:23	Subtransmission	Distribution	TIE 4109	124	10393	EQUIPMENT FAILURE
12/1/2019 8:53	12/1/2019 11:00	Subtransmission	Substation	TIE 4109	870	101201	EQUIPMENT FAILURE
12/24/2019 8:31	12/24/2019 15:31	Subtransmission	None	TRK 2301			EQUIPMENT FAILURE
12/24/2019 8:40	12/24/2019 17:14	Subtransmission	Distribution	TRK 2301	1	25	EQUIPMENT FAILURE
2/20/2020 2:20	2/20/2020 15:54	Subtransmission	None	TIE 7702			EQUIPMENT FAILURE
3/6/2020 10:19	3/6/2020 11:56	Subtransmission	Distribution	TRK 5906	1014	99096	EQUIPMENT FAILURE
3/6/2020 10:19	3/6/2020 11:56	Subtransmission	Distribution	TRK 5906	873	85535	EQUIPMENT FAILURE
3/6/2020 10:18	3/6/2020 11:56	Subtransmission	Distribution	TRK 5906	1767	171731	EQUIPMENT FAILURE
3/6/2020 10:19	3/6/2020 11:56	Subtransmission	Distribution	TRK 5906	917	89486	EQUIPMENT FAILURE
3/6/2020 10:30	3/6/2020 20:53	Subtransmission	None	TRK 5906			EQUIPMENT FAILURE

4/26/2020 12:43	4/26/2020 16:36	Subtransmission	None	TRK 2824			EQUIPMENT FAILURE
5/7/2020 15:20	5/7/2020 21:22	Subtransmission	None	TIE 4105			EQUIPMENT FAILURE
5/25/2020 17:51	5/25/2020 20:50	Subtransmission	Distribution	TRK 3508	2004	313975	EQUIPMENT FAILURE
5/25/2020 18:29	5/25/2020 20:50	Subtransmission	Distribution	TRK 3508	1962	277735	EQUIPMENT FAILURE
5/26/2020 0:29	5/26/2020 9:47	Subtransmission	None	TRK 3509			EQUIPMENT FAILURE
5/30/2020 9:01	5/31/2020 16:51	Subtransmission	None	TIE 7408			EQUIPMENT FAILURE
6/10/2020 18:00	6/13/2020 17:01	Subtransmission	None	TRK 1563			EQUIPMENT FAILURE
6/27/2020 1:54	6/28/2020 21:44	Subtransmission	None	TRK 1563			EQUIPMENT FAILURE
6/30/2020 16:56	6/30/2020 17:05	Subtransmission	None	TIE 8014			EQUIPMENT FAILURE
6/30/2020 16:59	6/30/2020 17:19	Subtransmission	None	TIE 8014			EQUIPMENT FAILURE
6/30/2020 16:49	6/30/2020 17:19	Subtransmission	None	TIE 8014			EQUIPMENT FAILURE
6/30/2020 16:39	6/30/2020 17:17	Subtransmission	None	TIE 8014			EQUIPMENT FAILURE
6/30/2020 16:46	6/30/2020 17:18	Subtransmission	None	TIE 8014			EQUIPMENT FAILURE
6/30/2020 16:40	6/30/2020 17:17	Subtransmission	None	TIE 8014			EQUIPMENT FAILURE
6/30/2020 16:46	6/30/2020 17:18	Subtransmission	None	TIE 8014			EQUIPMENT FAILURE
6/30/2020 17:03	6/30/2020 17:17	Subtransmission	None	TIE 8014			EQUIPMENT FAILURE
6/30/2020 16:47	6/30/2020 17:18	Subtransmission	None	TIE 8014			EQUIPMENT FAILURE
6/30/2020 16:51	6/30/2020 17:05	Subtransmission	None	TIE 8014			EQUIPMENT FAILURE
6/30/2020 16:49	6/30/2020 17:18	Subtransmission	None	TIE 8014			EQUIPMENT FAILURE
6/30/2020 16:17	6/30/2020 16:58	Subtransmission	None	TIE 8014			EQUIPMENT FAILURE
6/30/2020 20:34	6/30/2020 20:43	Subtransmission	None	TIE 8014			EQUIPMENT FAILURE
7/10/2020 13:10	7/10/2020 22:28	Subtransmission	Subtransmission	TRK 7389	437	242745	EQUIPMENT FAILURE
7/15/2020 23:21	7/16/2020 1:00	Subtransmission	Distribution	TRK 7106	873	88208	EQUIPMENT FAILURE
7/15/2020 23:21	7/16/2020 1:00	Subtransmission	Distribution	TRK 7106	595	9777	EQUIPMENT FAILURE
7/15/2020 23:21	7/16/2020 1:00	Subtransmission	Distribution	TRK 7106	899	90623	EQUIPMENT FAILURE
7/15/2020 23:21	7/16/2020 1:00	Subtransmission	Distribution	TRK 7106	326	30969	EQUIPMENT FAILURE
7/15/2020 23:29	7/16/2020 4:53	Subtransmission	None	TRK 7106			EQUIPMENT FAILURE
7/16/2020 0:46	7/16/2020 1:00	Subtransmission	Distribution	TRK 7106	1464	23486	EQUIPMENT FAILURE
7/16/2020 0:46	7/16/2020 1:00	Subtransmission	Distribution	TRK 7106	128	2165	EQUIPMENT FAILURE
7/16/2020 0:46	7/16/2020 1:00	Subtransmission	Distribution	TRK 7106	921	14758	EQUIPMENT FAILURE
7/16/2020 1:25	7/16/2020 13:50	Subtransmission	Distribution	TRK 7106	1	896	EQUIPMENT FAILURE
7/17/2020 19:32	7/20/2020 15:22	Subtransmission	None	TRK 7106			EQUIPMENT FAILURE
7/24/2020 20:05	7/24/2020 20:58	Subtransmission	Subtransmission	TRK 620	1481	73672	EQUIPMENT FAILURE
7/24/2020 20:05	7/24/2020 20:58	Subtransmission	Subtransmission	TRK 620	692	34407	EQUIPMENT FAILURE
7/24/2020 20:05	7/24/2020 20:58	Subtransmission	Subtransmission	TRK 620	1233	61312	EQUIPMENT FAILURE
7/28/2020 16:16	7/28/2020 18:11	Subtransmission	Distribution	TRK 6722	1188	127538	EQUIPMENT FAILURE
7/28/2020 16:16	7/28/2020 20:32	Subtransmission	Distribution	TRK 6722	1123	279405	EQUIPMENT FAILURE
7/28/2020 23:43	7/29/2020 8:25	Subtransmission	None	TRK 6722			EQUIPMENT FAILURE
7/28/2020 16:16	7/28/2020 18:33	Subtransmission	Distribution	TRK 6722	1622	209870	EQUIPMENT FAILURE
7/28/2020 16:16	7/28/2020 18:11	Subtransmission	Distribution	TRK 6722	435	46769	EQUIPMENT FAILURE
7/28/2020 16:30	7/28/2020 20:43	Subtransmission	None	TRK 6722			EQUIPMENT FAILURE
7/28/2020 15:29	7/28/2020 19:15	Subtransmission	None	TRK 6722			EQUIPMENT FAILURE
7/28/2020 16:28	7/28/2020 22:06	Subtransmission	None	TRK 6722			EQUIPMENT FAILURE
8/9/2020 7:35	8/9/2020 10:31	Subtransmission	None	TRK 620			EQUIPMENT FAILURE
8/21/2020 16:24	8/22/2020 14:21	Subtransmission	None	TIE 1473			EQUIPMENT FAILURE
9/11/2020 17:31	9/11/2020 19:01	Subtransmission	None	TIE 6147			EQUIPMENT FAILURE
9/11/2020 16:02	9/11/2020 17:58	Subtransmission	Distribution	TIE 6147	1862	218124	EQUIPMENT FAILURE
9/11/2020 17:34	9/11/2020 19:01	Subtransmission	None	TIE 6147			EQUIPMENT FAILURE
9/11/2020 17:36	9/11/2020 19:01	Subtransmission	None	TIE 6147			EQUIPMENT FAILURE
9/11/2020 16:02	9/11/2020 17:58	Subtransmission	Distribution	TIE 6147	2116	199166	EQUIPMENT FAILURE
10/10/2020 21:58	10/10/2020 22:50	Subtransmission	Distribution	TIE 3208	532	32752	EQUIPMENT FAILURE
10/25/2020 12:04	10/25/2020 12:25	Subtransmission	None	TRK 5510			EQUIPMENT FAILURE
11/26/2020 8:46	11/26/2020 19:48	Subtransmission	None	TIE 3140			EQUIPMENT FAILURE
12/3/2020 4:33	12/3/2020 6:00	Subtransmission	Subtransmission	TRK 2470	751	65135	EQUIPMENT FAILURE
12/3/2020 4:33	12/3/2020 6:00	Subtransmission	Subtransmission	TRK 2470	379	32930	EQUIPMENT FAILURE
12/3/2020 4:33	12/3/2020 6:00	Subtransmission	Subtransmission	TRK 2470	56	4855	EQUIPMENT FAILURE
2/27/2021 1:52	2/27/2021 13:10	Subtransmission	None	TRK 2087			EQUIPMENT FAILURE
2/27/2021 1:47	2/28/2021 0:36	Subtransmission	None	TRK 2087			EQUIPMENT FAILURE
3/26/2021 3:33	3/27/2021 11:21	Subtransmission	None	TIE 2025			EQUIPMENT FAILURE
6/10/2021 19:07	6/10/2021 20:39	Subtransmission	None	TRK 787			EQUIPMENT FAILURE
6/20/2021 11:15	6/20/2021 14:26	Subtransmission	Distribution	TRK 3646	1	26	EQUIPMENT FAILURE
6/20/2021 11:06	6/20/2021 12:10	Subtransmission	Distribution	TRK 3646			EQUIPMENT FAILURE
6/20/2021 3:30	6/20/2021 5:56	Subtransmission	None	TRK 3646			EQUIPMENT FAILURE
6/20/2021 11:15	6/20/2021 16:13	Subtransmission	None	TRK 3646			EQUIPMENT FAILURE
6/27/2021 7:54	6/28/2021 12:38	Subtransmission	None	TIE 3205			EQUIPMENT FAILURE
7/10/2021 7:03	7/11/2021 2:50	Subtransmission	None	TRK 2233			EQUIPMENT FAILURE
7/11/2021 15:54	7/12/2021 15:02	Subtransmission	None	TIE 1467			EQUIPMENT FAILURE
7/27/2021 11:29	7/27/2021 15:00	Subtransmission	None	TIE 6147			EQUIPMENT FAILURE
7/27/2021 11:13	7/27/2021 13:48	Subtransmission	Distribution	TIE 6147			EQUIPMENT FAILURE
7/27/2021 11:13	7/27/2021 18:00	Subtransmission	Subtransmission	TIE 6147	2156	504553	EQUIPMENT FAILURE
8/11/2021 21:13	8/12/2021 3:42	Subtransmission	None	TRK 1403			EQUIPMENT FAILURE
8/11/2021 15:50	8/16/2021 16:00	Subtransmission	None	TRK 1403			EQUIPMENT FAILURE
8/14/2021 8:39	8/14/2021 13:20	Subtransmission	None	TRK 2002			EQUIPMENT FAILURE
9/12/2021 20:56	9/15/2021 20:25	Subtransmission	None	TIE 4605			EQUIPMENT FAILURE
10/30/2021 9:23	11/4/2021 13:35	Subtransmission	None	TIE 1467			EQUIPMENT FAILURE
11/2/2021 10:36	11/2/2021 11:04	Subtransmission	Distribution	TRK 2528	610	17247	EQUIPMENT FAILURE
11/2/2021 10:36	11/2/2021 11:04	Subtransmission	Distribution	TRK 2528	404	11380	EQUIPMENT FAILURE
11/2/2021 10:36	11/2/2021 11:04	Subtransmission	Distribution	TRK 2528	1271	35858	EQUIPMENT FAILURE
12/11/2021 21:33	12/13/2021 20:29	Subtransmission	None	TIE 2824			EQUIPMENT FAILURE
12/11/2021 11:34	12/12/2021 12:25	Subtransmission	None	TIE 4605			EQUIPMENT FAILURE
12/29/2021 0:59	12/31/2021 11:47	Subtransmission	None	TRK 2535			EQUIPMENT FAILURE
1/14/2022 10:14	1/14/2022 20:01	Subtransmission	None	TRK 1251			EQUIPMENT FAILURE
1/21/2022 23:24	1/23/2022 11:44	Subtransmission	None	TRK 4405			EQUIPMENT FAILURE
1/22/2022 18:32	1/23/2022 10:56	Subtransmission	None	TRK 448			EQUIPMENT FAILURE
1/22/2022 17:58	1/22/2022 20:30	Subtransmission	None	TRK 448			EQUIPMENT FAILURE
1/22/2022 18:27	1/23/2022 17:54	Subtransmission	None	TRK 448			EQUIPMENT FAILURE
1/22/2022 18:03	1/23/2022 13:55	Subtransmission	None	TRK 448			EQUIPMENT FAILURE
1/29/2022 18:29	1/30/2022 5:53	Subtransmission	None	TRK 1403			EQUIPMENT FAILURE
1/29/2022 18:12	1/30/2022 8:33	Subtransmission	None	TRK 1470			EQUIPMENT FAILURE
1/31/2022 8:37	2/5/2022 0:39	Subtransmission	None	TRK 2305			EQUIPMENT FAILURE
2/9/2022 3:23	2/11/2022 7:47	Subtransmission	None	TIE 5823			EQUIPMENT FAILURE
2/11/2022 20:13	2/13/2022 13:23	Subtransmission	None	TRK 3511			EQUIPMENT FAILURE
2/11/2022 20:26	2/12/2022 4:19	Subtransmission	None	TRK 3511			EQUIPMENT FAILURE
2/22/2022 10:28	2/22/2022 15:14	Subtransmission	None	TIE 6147			EQUIPMENT FAILURE
2/22/2022 21:26	2/23/2022 8:37	Subtransmission	None	TRK 2418			EQUIPMENT FAILURE
2/28/2022 10:12	2/28/2022 12:51	Subtransmission	None	TRK 1251			EQUIPMENT FAILURE
3/23/2022 17:08	3/24/2022 17:53	Subtransmission	None	TRK 7114			EQUIPMENT FAILURE
4/3/2022 0:54	4/3/2022 2:17	Subtransmission	Distribution	TIE 1467	717	60636	EQUIPMENT FAILURE
4/9/2022 3:36	4/9/2022 16:13	Subtransmission	None	TRK 1527			EQUIPMENT FAILURE
4/21/2022 5:10	4/22/2022 20:48	Subtransmission	None	TRK 440			EQUIPMENT FAILURE
5/4/2022 16:46	5/4/2022 22:09	Subtransmission	None	TIE 1467			EQUIPMENT FAILURE
5/4/2022 16:34	5/4/2022 18:18	Subtransmission	Distribution	TIE 1467	162	16957	EQUIPMENT FAILURE
5/5/2022 1:33	5/5/2022 4:30	Subtransmission	None	TRK 3124			EQUIPMENT FAILURE
5/5/2022 0:34	5/5/2022 6:43	Subtransmission	None	TRK 3124			EQUIPMENT FAILURE
5/13/2022 15:39	5/13/2022 19:44	Subtransmission	None	TRK 2742			EQUIPMENT FAILURE

5/13/2022 6:49	5/13/2022 11:01	Subtransmission	None	TRK 2742			EQUIPMENT FAILURE
5/14/2022 17:43	5/14/2022 22:10	Subtransmission	None	TIE 3209			EQUIPMENT FAILURE
5/14/2022 17:44	5/14/2022 20:30	Subtransmission	None	TIE 3209			EQUIPMENT FAILURE
6/3/2022 7:59	6/3/2022 14:30	Subtransmission	None	TRK 2005			EQUIPMENT FAILURE
6/9/2022 16:14	6/13/2022 14:18	Subtransmission	None	TRK 1525			EQUIPMENT FAILURE
6/11/2022 7:39	6/11/2022 14:00	Subtransmission	Distribution	TRK 5906	19	1868	EQUIPMENT FAILURE
6/11/2022 7:52	6/11/2022 21:50	Subtransmission	None	TRK 5906			EQUIPMENT FAILURE
6/11/2022 7:39	6/11/2022 8:27	Subtransmission	None	TRK 5906			EQUIPMENT FAILURE
6/11/2022 7:39	6/11/2022 8:36	Subtransmission	None	TRK 5906			EQUIPMENT FAILURE
6/11/2022 7:39	6/11/2022 8:38	Subtransmission	None	TRK 5906			EQUIPMENT FAILURE
6/15/2022 20:46	6/16/2022 5:02	Subtransmission	None	TIE 7520			EQUIPMENT FAILURE
6/16/2022 9:02	6/17/2022 8:34	Subtransmission	None	TIE 7504			EQUIPMENT FAILURE
6/26/2022 16:54	6/27/2022 3:50	Subtransmission	None	TIE 722			EQUIPMENT FAILURE
7/2/2022 6:47	7/2/2022 12:06	Subtransmission	None	TRK 1248			EQUIPMENT FAILURE
7/8/2022 19:26	7/8/2022 21:09	Subtransmission	Distribution	TRK 1761	148	8073	EQUIPMENT FAILURE
7/8/2022 19:26	7/8/2022 21:09	Subtransmission	Distribution	TRK 1761	842	45958	EQUIPMENT FAILURE
7/8/2022 19:26	7/8/2022 21:09	Subtransmission	Distribution	TRK 1761	1313	71681	EQUIPMENT FAILURE
7/13/2022 0:25	7/13/2022 1:28	Subtransmission	Distribution	TRK 4316	1342	85213	EQUIPMENT FAILURE
7/13/2022 0:24	7/13/2022 1:28	Subtransmission	Distribution	TRK 4316	525	33318	EQUIPMENT FAILURE
7/13/2022 0:24	7/13/2022 1:28	Subtransmission	Distribution	TRK 4316	161	10144	EQUIPMENT FAILURE
7/13/2022 0:25	7/13/2022 1:28	Subtransmission	Distribution	TRK 4316	1038	65884	EQUIPMENT FAILURE
7/13/2022 0:36	7/13/2022 7:07	Subtransmission	None	TRK 4316			EQUIPMENT FAILURE
7/17/2022 8:33	7/18/2022 5:17	Subtransmission	None	TRK 3028			EQUIPMENT FAILURE
7/23/2022 4:49	7/23/2022 20:05	Subtransmission	None	TRK 7106			EQUIPMENT FAILURE
7/23/2022 2:05	7/23/2022 5:54	Subtransmission	None	TRK 7106			EQUIPMENT FAILURE
7/23/2022 15:23	7/23/2022 17:57	Subtransmission	None	TRK 7106			EQUIPMENT FAILURE
7/24/2022 4:55	7/25/2022 16:00	Subtransmission	None	TIE 5823			EQUIPMENT FAILURE
7/24/2022 17:07	7/24/2022 21:01	Subtransmission	Subtransmission	TRK 853			EQUIPMENT FAILURE
7/24/2022 17:07	7/24/2022 19:30	Subtransmission	Subtransmission	TRK 853	610	82036	EQUIPMENT FAILURE
7/24/2022 17:07	7/24/2022 19:30	Subtransmission	Subtransmission	TRK 853	847	113965	EQUIPMENT FAILURE
8/8/2022 8:25	8/8/2022 9:26	Subtransmission	Distribution	TRK 2027	1437	77578	EQUIPMENT FAILURE
8/8/2022 8:30	8/8/2022 9:26	Subtransmission	Distribution	TRK 2027	260	14012	EQUIPMENT FAILURE
8/17/2022 16:04	8/19/2022 11:27	Subtransmission	None	TRK 4338			EQUIPMENT FAILURE
8/20/2022 14:13	8/20/2022 20:49	Subtransmission	None	TIE 3417			EQUIPMENT FAILURE
8/25/2022 1:10	8/25/2022 20:25	Subtransmission	None	TRK 1303			EQUIPMENT FAILURE
8/25/2022 1:19	8/26/2022 0:23	Subtransmission	None	TRK 1303			EQUIPMENT FAILURE
8/29/2022 21:10	9/2/2022 13:48	Subtransmission	None	TRK 1527			EQUIPMENT FAILURE
8/29/2022 18:14	9/1/2022 12:00	Subtransmission	Distribution	TRK 2418	30	1060	EQUIPMENT FAILURE
8/29/2022 23:18	9/2/2022 23:50	Subtransmission	None	TRK 4419			EQUIPMENT FAILURE
8/30/2022 10:57	8/31/2022 18:54	Subtransmission	None	TIE 2812			EQUIPMENT FAILURE
8/30/2022 18:57	9/1/2022 14:25	Subtransmission	None	TRK 3124			EQUIPMENT FAILURE
9/5/2022 19:22	9/5/2022 20:59	Subtransmission	None	TRK 4316			EQUIPMENT FAILURE
9/17/2022 16:49	9/17/2022 20:25	Subtransmission	None	TIE 187			EQUIPMENT FAILURE
9/30/2022 23:44	10/1/2022 2:03	Subtransmission	None	TIE 4708			EQUIPMENT FAILURE
10/5/2022 13:50	10/6/2022 7:20	Subtransmission	None	TIE 2812			EQUIPMENT FAILURE
10/5/2022 13:37	10/5/2022 15:00	Subtransmission	Distribution	TIE 2812			EQUIPMENT FAILURE
10/10/2022 13:23	10/10/2022 18:50	Subtransmission	None	TIE 3209			EQUIPMENT FAILURE
10/13/2022 9:00	10/13/2022 10:11	Subtransmission	Distribution	TIE 3241	280	19857	EQUIPMENT FAILURE
10/13/2022 9:00	10/13/2022 10:11	Subtransmission	Distribution	TIE 3241	426	25516	EQUIPMENT FAILURE
10/13/2022 9:00	10/13/2022 10:00	Subtransmission	Distribution	TIE 3241	540	32333	EQUIPMENT FAILURE
10/13/2022 9:00	10/13/2022 10:00	Subtransmission	Distribution	TIE 3241	337	20174	EQUIPMENT FAILURE
10/13/2022 9:00	10/13/2022 10:10	Subtransmission	Distribution	TIE 3241	1990	141300	EQUIPMENT FAILURE
10/13/2022 9:26	10/13/2022 10:12	Subtransmission	Distribution	TIE 3241	492	34908	EQUIPMENT FAILURE
10/19/2022 15:24	10/21/2022 14:56	Subtransmission	None	TRK 2054			EQUIPMENT FAILURE
11/5/2022 19:14	11/6/2022 19:00	Subtransmission	None	TIE 3417			EQUIPMENT FAILURE
11/25/2022 8:21	11/25/2022 14:16	Subtransmission	None	TIE 1544			EQUIPMENT FAILURE
11/25/2022 8:04	11/25/2022 9:00	Subtransmission	Distribution	TIE 1544			EQUIPMENT FAILURE
1/1/2023 9:10	1/2/2023 8:51	Subtransmission	None	TRK 6938			EQUIPMENT FAILURE
1/22/2023 11:49	1/23/2023 16:39	Subtransmission	None	TRK 3150			EQUIPMENT FAILURE
1/28/2023 9:12	1/28/2023 15:23	Subtransmission	Subtransmission	TRK 1645	194	15036	EQUIPMENT FAILURE
1/28/2023 9:14	1/28/2023 15:23	Subtransmission	Subtransmission	TRK 1645	434	33852	EQUIPMENT FAILURE
1/28/2023 14:06	1/28/2023 15:23	Subtransmission	Subtransmission	TRK 1645	9	699	EQUIPMENT FAILURE
2/13/2023 15:05	2/13/2023 18:01	Subtransmission		TRK 1862			EQUIPMENT FAILURE
2/21/2023 6:17	2/21/2023 7:55	Subtransmission		TIE 7702			EQUIPMENT FAILURE
2/23/2023 21:10	3/4/2023 18:49	Subtransmission		TIE 7702			EQUIPMENT FAILURE
2/24/2023 19:20	2/24/2023 23:00	Subtransmission		TIE 4104			EQUIPMENT FAILURE
2/26/2023 4:24	2/26/2023 7:07	Subtransmission		TRK 4045			EQUIPMENT FAILURE
3/1/2023 10:03	3/2/2023 11:52	Subtransmission		TRK 3512			EQUIPMENT FAILURE
3/17/2023 3:42	3/17/2023 14:44	Subtransmission	Circuit Level	TIE 4105	685	118200	EQUIPMENT FAILURE
3/17/2023 3:59	3/17/2023 14:45	Subtransmission	Circuit Level	TIE 4105	545	93498	EQUIPMENT FAILURE
3/17/2023 3:46	3/17/2023 16:48	Subtransmission	Circuit Level	TIE 4105	704	136643	EQUIPMENT FAILURE
3/19/2023 0:10	3/19/2023 5:08	Subtransmission	Circuit Level	TRK 3526	61	19898	EQUIPMENT FAILURE
3/19/2023 0:10	3/19/2023 5:07	Subtransmission	Circuit Level	TRK 3526	2	652	EQUIPMENT FAILURE
4/29/2023 6:43	4/29/2023 12:22	Subtransmission		TRK 2087			EQUIPMENT FAILURE
5/7/2023 12:50	5/13/2023 23:44	Subtransmission		TIE 3705			EQUIPMENT FAILURE
5/7/2023 12:28	5/7/2023 17:40	Subtransmission	Subtransmission	TIE 3705	2583	175439	EQUIPMENT FAILURE
5/11/2023 22:00	5/12/2023 4:42	Subtransmission	Device (II)	TRK 7971			EQUIPMENT FAILURE
5/11/2023 18:39	5/12/2023 4:23	Subtransmission	Single Customer	TRK 7971	1	180	EQUIPMENT FAILURE
5/18/2023 8:46	5/18/2023 13:26	Subtransmission		TIE 4595			EQUIPMENT FAILURE
5/30/2023 13:24	5/30/2023 17:21	Subtransmission		TRK 2806			EQUIPMENT FAILURE
5/30/2023 13:30	5/30/2023 19:56	Subtransmission	Device (II)	TRK 2806	610	102713	EQUIPMENT FAILURE
6/25/2023 13:18	6/26/2023 8:30	Subtransmission		TIE 9123			EQUIPMENT FAILURE
7/20/2023 17:21	7/21/2023 15:29	Subtransmission		TRK 7909			EQUIPMENT FAILURE
8/14/2023 17:30	8/14/2023 19:50	Subtransmission	Single Customer	TIE 7513	1	94	EQUIPMENT FAILURE
8/14/2023 16:06	8/14/2023 19:53	Subtransmission	Service Transformer	TIE 7513	1	123	EQUIPMENT FAILURE
8/14/2023 16:05	8/14/2023 19:50	Subtransmission	Single Customer	TIE 7513	1	171	EQUIPMENT FAILURE
8/14/2023 16:14	8/14/2023 19:54	Subtransmission	Single Customer	TIE 7513			EQUIPMENT FAILURE
8/14/2023 18:49	8/14/2023 20:04	Subtransmission	Single Customer	TIE 7513	1	171	EQUIPMENT FAILURE
8/18/2023 21:22	8/24/2023 4:02	Subtransmission		TRK 3511			EQUIPMENT FAILURE
8/20/2023 20:49	8/21/2023 6:33	Subtransmission	Subtransmission	TIE 1467	22	18785	EQUIPMENT FAILURE
8/20/2023 19:35	8/21/2023 4:51	Subtransmission		TIE 1467			EQUIPMENT FAILURE
8/24/2023 22:12	8/25/2023 17:09	Subtransmission		TIE 8033			EQUIPMENT FAILURE
8/25/2023 15:59	8/30/2023 21:02	Subtransmission		TRK 2025			EQUIPMENT FAILURE
8/30/2023 10:29	8/30/2023 16:08	Subtransmission	Service Transformer	TIE 1473	2	256	EQUIPMENT FAILURE
9/6/2023 14:28	9/6/2023 21:34	Subtransmission		TRK 4962			EQUIPMENT FAILURE
9/23/2023 12:47	9/23/2023 21:33	Subtransmission	Subtransmission	TIE 1467	1736	21956	EQUIPMENT FAILURE
10/26/2023 22:25	11/6/2023 14:39	Subtransmission		TRK 5938			EQUIPMENT FAILURE
11/5/2023 4:54	11/5/2023 18:09	Subtransmission		TRK 2010			EQUIPMENT FAILURE
11/5/2023 13:47	11/5/2023 22:26	Subtransmission		TRK 2444			EQUIPMENT FAILURE
12/6/2023 3:57	12/6/2023 6:06	Subtransmission	Subtransmission	TRK 1645	805	57782	EQUIPMENT FAILURE
12/6/2023 4:05	12/6/2023 6:05	Subtransmission	Subtransmission	TRK 1645	306	21951	EQUIPMENT FAILURE
7/1/2019 18:07	7/1/2019 22:15	Subtransmission	Subtransmission	TRK 7324	1060	161743	EQUIPMENT LOADING
7/1/2019 18:07	7/1/2019 22:15	Subtransmission	Subtransmission	TRK 7324	141	21484	EQUIPMENT LOADING
7/1/2019 18:07	7/1/2019 22:15	Subtransmission	Subtransmission	TRK 7324	876	159546	EQUIPMENT LOADING
7/1/2019 18:07	7/1/2019 22:15	Subtransmission	Subtransmission	TRK 7324	847	154520	EQUIPMENT LOADING

7/1/2019 18:07	7/1/2019 22:15	Subtransmission	Subtransmission	TRK 7324	1104	253465	EQUIPMENT LOADING
7/1/2019 18:07	7/1/2019 22:15	Subtransmission	Subtransmission	TRK 7324	1501	233503	EQUIPMENT LOADING
7/1/2019 18:07	7/1/2019 22:15	Subtransmission	Subtransmission	TRK 7324	664	101400	EQUIPMENT LOADING
7/1/2020 17:19	7/1/2020 18:14	Subtransmission	None	TRK 7106			EQUIPMENT LOADING
7/1/2020 17:08	7/1/2020 18:13	Subtransmission	Substation	TRK 7106	1311	71203	EQUIPMENT LOADING
3/30/2021 10:52	3/30/2021 12:58	Subtransmission	None	TIE 8033			EQUIPMENT LOADING
2/1/2023 15:09	2/1/2023 15:37	Subtransmission	Subtransmission	TRK 3161	24	1846	EQUIPMENT LOADING
7/19/2023 11:25	7/19/2023 17:13	Subtransmission	Subtransmission	TIE 9310	12	419	EQUIPMENT LOADING
2/23/2023 18:56	2/24/2023 17:21	Subtransmission	Single Customer	TIE 4104			ICE
2/23/2023 18:41	2/24/2023 17:16	Subtransmission	Single Customer	TIE 4104			ICE
2/23/2023 18:41	2/24/2023 17:21	Subtransmission	Single Customer	TIE 4104			ICE
2/23/2023 18:42	2/24/2023 17:20	Subtransmission	Single Customer	TIE 4104			ICE
2/23/2023 18:48	2/24/2023 17:19	Subtransmission	Single Customer	TIE 4104			ICE
2/23/2023 18:31	2/25/2023 19:37	Subtransmission	Subtransmission	TIE 4104	2181	1253428	ICE
3/14/2018 8:44	3/14/2018 14:52	Subtransmission	None	TRK 2525			INTENTIONAL
5/22/2020 11:59	5/22/2020 14:00	Subtransmission	Distribution	TIE 3416	207	23934	INTENTIONAL
5/5/2021 6:09	5/5/2021 6:50	Subtransmission	Distribution	TIE 3241	416	15311	INTENTIONAL
5/5/2021 22:29	5/5/2021 23:30	Subtransmission	Distribution	TIE 3241			INTENTIONAL
10/8/2022 12:32	10/8/2022 13:30	Subtransmission	Distribution	TRK 2493	2	64	INTENTIONAL
10/8/2022 12:26	10/8/2022 13:55	Subtransmission	Distribution	TRK 2493	3	146	INTENTIONAL
10/8/2022 10:55	10/8/2022 12:00	Subtransmission	Distribution	TRK 2493	3	130	INTENTIONAL
10/8/2022 11:38	10/8/2022 12:40	Subtransmission	Distribution	TRK 2493	1	28	INTENTIONAL
11/20/2023 14:57	1/13/2024 9:36	Subtransmission		TRK 2016			INTENTIONAL
12/10/2023 17:45	12/10/2023 20:57	Subtransmission		TRK 2439			INTENTIONAL
6/3/2020 2:49	6/3/2020 4:58	Subtransmission	Distribution	TIE 7520	426	55956	LIGHTNING
6/3/2020 2:49	6/3/2020 4:59	Subtransmission	Distribution	TIE 7520	189	25584	LIGHTNING
6/3/2020 2:49	6/3/2020 4:58	Subtransmission	Distribution	TIE 7520	381	48202	LIGHTNING
6/1/2021 19:17	6/8/2021 3:11	Subtransmission	None	TRK 5140			NO ISSUES FOUND
2/12/2018 10:57	2/12/2018 14:40	Subtransmission	None	TRK 1418			PUBLIC INTERFERENCE
2/12/2018 11:07	2/12/2018 12:49	Subtransmission	Distribution	TRK 1418	247	29126	PUBLIC INTERFERENCE
5/14/2018 2:45	5/14/2018 12:13	Subtransmission	None	TRK 2308			PUBLIC INTERFERENCE
6/12/2018 15:31	6/12/2018 15:58	Subtransmission	Subtransmission	TRK 7356	32	1665	PUBLIC INTERFERENCE
6/12/2018 15:02	6/12/2018 15:51	Subtransmission	Subtransmission	TRK 7356	1948	101889	PUBLIC INTERFERENCE
6/12/2018 14:59	6/12/2018 15:58	Subtransmission	Subtransmission	TRK 7356	1985	103906	PUBLIC INTERFERENCE
6/12/2018 15:45	6/12/2018 17:53	Subtransmission	None	TRK 7386			PUBLIC INTERFERENCE
6/27/2018 10:50	6/27/2018 20:19	Subtransmission	None	TRK 6938			PUBLIC INTERFERENCE
6/30/2018 17:01	6/30/2018 20:06	Subtransmission	None	TRK 5935			PUBLIC INTERFERENCE
6/30/2018 16:48	6/30/2018 19:17	Subtransmission	Distribution	TRK 5935	1025	149121	PUBLIC INTERFERENCE
6/30/2018 16:49	6/30/2018 19:17	Subtransmission	Distribution	TRK 5935	48	7034	PUBLIC INTERFERENCE
6/30/2018 16:49	6/30/2018 19:17	Subtransmission	Distribution	TRK 5935	1605	235058	PUBLIC INTERFERENCE
5/4/2018 18:42	5/5/2018 19:24	Subtransmission	None	TIE 3245			TREE
5/4/2018 13:11	5/6/2018 18:49	Subtransmission	None	TIE 4605			TREE
5/6/2018 12:22	5/17/2018 23:21	Subtransmission	None	TIE 6941			TREE
6/12/2018 14:56	6/12/2018 17:26	Subtransmission	None	TRK 1502			TREE
7/2/2018 11:26	7/2/2018 12:10	Subtransmission	Distribution	TIE 7504	941	35591	TREE
7/5/2018 19:24	7/6/2018 20:17	Subtransmission	None	TIE 3205			TREE
8/2/2018 17:13	8/2/2018 18:30	Subtransmission	Distribution	TIE 3208	476	38945	TREE
9/21/2018 0:24	9/21/2018 16:52	Subtransmission	None	TIE 3205			TREE
10/20/2018 16:53	10/21/2018 21:05	Subtransmission	None	TRK 2038			TREE
10/20/2018 16:54	10/21/2018 21:04	Subtransmission	None	TRK 2087			TREE
5/25/2019 4:29	5/25/2019 15:08	Subtransmission	None	TIE 3220			TREE
6/25/2019 9:25	6/25/2019 16:13	Subtransmission	None	TIE 3209			TREE
8/18/2019 14:37	8/18/2019 17:24	Subtransmission	None	TIE 4109			TREE
8/18/2019 14:37	8/18/2019 20:58	Subtransmission	None	TIE 4109			TREE
10/16/2019 22:42	10/17/2019 0:08	Subtransmission	Distribution	TIE 3205	564	56387	TREE
10/16/2019 22:23	10/17/2019 0:08	Subtransmission	Distribution	TIE 3205	469	47895	TREE
10/16/2019 22:33	10/17/2019 5:28	Subtransmission	None	TIE 3205			TREE
11/7/2019 15:48	11/7/2019 20:55	Subtransmission	None	TIE 4105			TREE
3/2/2020 16:41	3/2/2020 22:15	Subtransmission	Distribution	TIE 3206	595	194565	TREE
3/2/2020 17:06	3/2/2020 23:12	Subtransmission	None	TIE 3206			TREE
3/6/2020 13:02	3/7/2020 3:04	Subtransmission	None	TIE 3203			TREE
5/26/2020 19:53	5/26/2020 22:05	Subtransmission	None	TRK 1243			TREE
6/11/2020 20:37	6/12/2020 1:13	Subtransmission	None	TIE 3205			TREE
8/6/2020 11:09	8/6/2020 23:58	Subtransmission	None	TIE 9123			TREE
10/21/2020 8:30	10/21/2020 13:22	Subtransmission	None	TIE 1473			TREE
11/15/2020 20:21	11/16/2020 13:15	Subtransmission	None	TIE 4109			TREE
2/6/2021 0:47	2/7/2021 0:19	Subtransmission	None	TIE 1467			TREE
4/10/2021 21:47	4/11/2021 0:23	Subtransmission	Distribution	TIE 6147	1685	264262	TREE
4/10/2021 21:46	4/11/2021 0:23	Subtransmission	Subtransmission	TIE 6147	1481	231977	TREE
6/16/2021 8:57	6/16/2021 15:05	Subtransmission	None	TRK 7106			TREE
6/20/2021 22:31	6/21/2021 2:12	Subtransmission	None	TRK 5510			TREE
6/20/2021 22:27	6/22/2021 17:15	Subtransmission	None	TRK 5510			TREE
9/7/2021 15:40	9/7/2021 17:17	Subtransmission	Distribution	TIE 7520	433	42471	TREE
9/7/2021 15:40	9/7/2021 20:12	Subtransmission	Distribution	TIE 7520	187	51006	TREE
9/7/2021 15:40	9/7/2021 20:21	Subtransmission	Distribution	TIE 7520	390	119596	TREE
9/23/2021 20:15	9/24/2021 20:18	Subtransmission	None	TIE 4104			TREE
12/17/2021 13:29	12/17/2021 18:43	Subtransmission	None	TIE 4104			TREE
5/23/2022 17:53	5/23/2022 21:03	Subtransmission	None	TIE 7621			TREE
5/27/2022 3:45	5/27/2022 5:46	Subtransmission	None	TIE 1568			TREE
9/3/2022 14:23	9/4/2022 14:00	Subtransmission	Distribution	TIE 2819			TREE
9/3/2022 5:34	9/3/2022 14:28	Subtransmission	None	TIE 2819			TREE
9/3/2022 5:33	9/3/2022 14:12	Subtransmission	Distribution	TIE 2819	1	140	TREE
9/3/2022 5:29	9/3/2022 18:00	Subtransmission	Distribution	TIE 2819	48	8530	TREE
9/3/2022 5:36	9/3/2022 9:33	Subtransmission	None	TIE 2819			TREE
12/31/2022 12:39	12/31/2022 14:08	Subtransmission	Distribution	TRK 4227	1	38	TREE
2/22/2023 17:32	2/23/2023 22:03	Subtransmission	Circuit Level	TIE 4501	110	299846	TREE
2/22/2023 21:24	2/23/2023 9:08	Subtransmission	Substation	TIE 4501	505	1125138	TREE
2/24/2023 21:55	2/26/2023 10:43	Subtransmission		TIE 4104			TREE
2/24/2023 17:55	2/26/2023 18:46	Subtransmission		TIE 4501			TREE
2/25/2023 14:44	2/25/2023 21:00	Subtransmission	Circuit Level	TIE 4501	186	735938	TREE
6/11/2023 17:59	6/11/2023 19:37	Subtransmission	Circuit Level	TIE 3241	265	26199	TREE
6/11/2023 17:58	6/11/2023 19:37	Subtransmission	Circuit Level	TIE 3241	479	47391	TREE
6/11/2023 18:07	6/12/2023 1:28	Subtransmission	Circuit Level	TIE 3241	1954	208516	TREE
6/11/2023 20:42	6/12/2023 4:37	Subtransmission		TIE 3241			TREE
6/11/2023 17:59	6/12/2023 16:50	Subtransmission	Single Customer	TIE 3241			TREE
6/11/2023 18:04	6/13/2023 16:25	Subtransmission		TIE 3241			TREE
7/11/2023 17:13	7/11/2023 22:15	Subtransmission		TRK 6941			TREE
7/19/2023 11:13	7/19/2023 14:47	Subtransmission	Circuit Level	TIE 9103	1523	215573	TREE
7/20/2023 16:33	7/22/2023 14:07	Subtransmission		TIE 2648			TREE
8/24/2023 22:27	8/25/2023 20:17	Subtransmission	Device (I)	TRK 3124			TREE
8/24/2023 23:02	8/25/2023 20:38	Subtransmission	Subtransmission	TRK 3124	745	963531	TREE
8/24/2023 22:32	8/25/2023 20:18	Subtransmission	Circuit Level	TRK 3124	362	41759	TREE
10/7/2023 13:31	10/7/2023 19:51	Subtransmission	Subtransmission	TRK 3304	5	307	TREE
10/7/2023 13:34	10/7/2023 18:11	Subtransmission	Circuit Level	TRK 3304	510	38617	TREE
1/1/2018 10:19	1/1/2018 13:10	Subtransmission	None	TIE 7430			UNKNOWN/NO DATA

1/10/2018 12:10	1/11/2018 5:52	Subtransmission	None	TRK 2659			UNKNOWN/NO DATA
1/12/2018 11:32	1/13/2018 3:55	Subtransmission	None	TIE 1423			UNKNOWN/NO DATA
1/20/2018 6:48	1/20/2018 13:11	Subtransmission	None	TIE 1467			UNKNOWN/NO DATA
1/29/2018 8:00	1/29/2018 15:17	Subtransmission	None	TIE 2812			UNKNOWN/NO DATA
2/5/2018 20:54	2/6/2018 3:02	Subtransmission	None	TIE 3416			UNKNOWN/NO DATA
2/6/2018 19:12	2/7/2018 5:36	Subtransmission	None	TIE 6138			UNKNOWN/NO DATA
2/6/2018 11:48	2/6/2018 16:18	Subtransmission	None	TRK 6919			UNKNOWN/NO DATA
2/9/2018 20:36	2/9/2018 22:22	Subtransmission	None	TIE 1568			UNKNOWN/NO DATA
2/19/2018 19:29	2/20/2018 13:40	Subtransmission	None	TRK 2713			UNKNOWN/NO DATA
2/19/2018 13:11	2/19/2018 16:36	Subtransmission	None	TRK 620			UNKNOWN/NO DATA
2/20/2018 9:19	2/20/2018 10:13	Subtransmission	Subtransmission	TIE 3822	2279	123995	UNKNOWN/NO DATA
2/27/2018 13:45	2/27/2018 20:55	Subtransmission	None	TIE 1423			UNKNOWN/NO DATA
3/5/2018 7:51	3/5/2018 16:31	Subtransmission	None	TRK 2237			UNKNOWN/NO DATA
3/7/2018 6:52	3/14/2018 8:34	Subtransmission	None	TIE 9111			UNKNOWN/NO DATA
3/12/2018 11:17	3/13/2018 6:56	Subtransmission	None	TIE 5823			UNKNOWN/NO DATA
3/12/2018 11:20	3/13/2018 9:44	Subtransmission	None	TRK 3650			UNKNOWN/NO DATA
3/25/2018 9:51	3/25/2018 12:19	Subtransmission	None	TRK 7062			UNKNOWN/NO DATA
4/3/2018 19:14	4/5/2018 7:10	Subtransmission	None	TRK 1527			UNKNOWN/NO DATA
4/4/2018 13:23	4/5/2018 14:17	Subtransmission	None	TIE 4109			UNKNOWN/NO DATA
4/4/2018 13:00	4/4/2018 20:58	Subtransmission	Distribution	TIE 4109	57	26607	UNKNOWN/NO DATA
4/5/2018 4:35	4/6/2018 14:09	Subtransmission	None	TRK 704			UNKNOWN/NO DATA
4/12/2018 17:49	4/13/2018 7:49	Subtransmission	None	TRK 428			UNKNOWN/NO DATA
4/15/2018 9:08	4/16/2018 18:17	Subtransmission	None	TIE 2025			UNKNOWN/NO DATA
4/15/2018 9:05	4/16/2018 15:01	Subtransmission	None	TIE 2025			UNKNOWN/NO DATA
4/15/2018 7:04	4/15/2018 8:41	Subtransmission	None	TRK 2918			UNKNOWN/NO DATA
4/26/2018 1:47	4/26/2018 13:38	Subtransmission	None	TRK 7062			UNKNOWN/NO DATA
5/1/2018 17:51	5/2/2018 1:46	Subtransmission	None	TRK 2250			UNKNOWN/NO DATA
5/4/2018 13:04	5/5/2018 20:55	Subtransmission	Distribution	TIE 3205	616	1124013	UNKNOWN/NO DATA
5/4/2018 19:19	5/6/2018 19:06	Subtransmission	None	TIE 3208			UNKNOWN/NO DATA
5/4/2018 16:17	5/8/2018 14:18	Subtransmission	None	TRK 2443			UNKNOWN/NO DATA
5/5/2018 7:34	5/5/2018 15:49	Subtransmission	None	TIE 7504			UNKNOWN/NO DATA
5/19/2018 16:28	5/21/2018 14:34	Subtransmission	None	TRK 2826			UNKNOWN/NO DATA
5/24/2018 11:55	5/25/2018 6:45	Subtransmission	None	TIE 4412			UNKNOWN/NO DATA
5/26/2018 5:50	5/26/2018 15:00	Subtransmission	None	TIE 7504			UNKNOWN/NO DATA
5/28/2018 21:11	5/30/2018 18:47	Subtransmission	None	TIE 4512			UNKNOWN/NO DATA
5/28/2018 16:09	5/28/2018 21:50	Subtransmission	None	TIE 4523			UNKNOWN/NO DATA
5/29/2018 16:26	5/30/2018 5:07	Subtransmission	None	TIE 4523			UNKNOWN/NO DATA
5/29/2018 16:19	5/30/2018 15:15	Subtransmission	None	TIE 4523			UNKNOWN/NO DATA
5/31/2018 7:35	5/31/2018 14:23	Subtransmission	None	TIE 7702			UNKNOWN/NO DATA
5/31/2018 7:39	5/31/2018 12:55	Subtransmission	None	TRK 3124			UNKNOWN/NO DATA
6/1/2018 17:45	6/4/2018 6:43	Subtransmission	None	TIE 7430			UNKNOWN/NO DATA
6/9/2018 19:00	6/14/2018 20:13	Subtransmission	None	TRK 2418			UNKNOWN/NO DATA
6/18/2018 23:49	6/19/2018 14:39	Subtransmission	None	TRK 1346			UNKNOWN/NO DATA
6/18/2018 11:51	6/18/2018 15:56	Subtransmission	None	TRK 2636			UNKNOWN/NO DATA
6/18/2018 17:34	6/19/2018 9:46	Subtransmission	None	TRK 7114			UNKNOWN/NO DATA
6/20/2018 6:42	6/20/2018 12:05	Subtransmission	None	TRK 1346			UNKNOWN/NO DATA
6/22/2018 8:55	6/22/2018 12:37	Subtransmission	None	TRK 1276			UNKNOWN/NO DATA
6/24/2018 9:27	6/24/2018 13:06	Subtransmission	None	TRK 1340			UNKNOWN/NO DATA
6/24/2018 3:24	6/24/2018 7:20	Subtransmission	Distribution	TRK 1340	603	143259	UNKNOWN/NO DATA
6/26/2018 11:36	6/26/2018 14:42	Subtransmission	None	TIE 2901			UNKNOWN/NO DATA
6/27/2018 8:23	6/27/2018 13:34	Subtransmission	None	TIE 2819			UNKNOWN/NO DATA
7/1/2018 17:10	7/1/2018 18:57	Subtransmission	None	TIE 2901			UNKNOWN/NO DATA
7/2/2018 15:58	7/2/2018 20:21	Subtransmission	None	TRK 7104			UNKNOWN/NO DATA
7/3/2018 12:23	7/3/2018 15:36	Subtransmission	None	TRK 5935			UNKNOWN/NO DATA
7/5/2018 12:10	7/5/2018 20:39	Subtransmission	None	TIE 6138			UNKNOWN/NO DATA
7/5/2018 7:13	7/5/2018 12:15	Subtransmission	None	TRK 7104			UNKNOWN/NO DATA
7/6/2018 9:59	7/6/2018 14:58	Subtransmission	None	TIE 8623			UNKNOWN/NO DATA
7/9/2018 9:47	7/9/2018 11:16	Subtransmission	Distribution	TRK 641	816	73220	UNKNOWN/NO DATA
7/9/2018 9:47	7/9/2018 11:16	Subtransmission	Distribution	TRK 641	308	27275	UNKNOWN/NO DATA
7/9/2018 9:47	7/9/2018 11:16	Subtransmission	Distribution	TRK 641	93	8405	UNKNOWN/NO DATA
7/9/2018 9:47	7/9/2018 11:15	Subtransmission	Distribution	TRK 641	10	880	UNKNOWN/NO DATA
7/10/2018 19:51	7/10/2018 22:27	Subtransmission	None	TRK 2918			UNKNOWN/NO DATA
7/13/2018 0:38	7/13/2018 6:51	Subtransmission	None	TIE 1540			UNKNOWN/NO DATA
7/15/2018 6:32	7/15/2018 16:20	Subtransmission	None	TRK 2523			UNKNOWN/NO DATA
7/16/2018 18:18	7/17/2018 7:59	Subtransmission	None	TIE 2819			UNKNOWN/NO DATA
7/16/2018 10:44	7/16/2018 15:56	Subtransmission	None	TIE 4523			UNKNOWN/NO DATA
7/16/2018 15:34	7/17/2018 17:33	Subtransmission	None	TIE 4523			UNKNOWN/NO DATA
7/17/2018 14:15	7/18/2018 6:37	Subtransmission	None	TIE 6621			UNKNOWN/NO DATA
7/17/2018 7:52	7/18/2018 6:38	Subtransmission	None	TIE 6621			UNKNOWN/NO DATA
7/22/2018 6:45	7/22/2018 17:24	Subtransmission	None	TIE 3220			UNKNOWN/NO DATA
7/29/2018 9:13	7/30/2018 8:33	Subtransmission	None	TIE 8014			UNKNOWN/NO DATA
8/1/2018 0:05	8/1/2018 9:10	Subtransmission	None	TIE 9107			UNKNOWN/NO DATA
8/1/2018 12:01	8/1/2018 21:03	Subtransmission	None	TRK 7122			UNKNOWN/NO DATA
8/3/2018 7:03	8/3/2018 13:48	Subtransmission	None	TRK 1276			UNKNOWN/NO DATA
8/5/2018 15:49	8/6/2018 7:27	Subtransmission	None	TIE 1467			UNKNOWN/NO DATA
8/5/2018 11:27	8/5/2018 14:08	Subtransmission	None	TIE 8014			UNKNOWN/NO DATA
8/8/2018 16:17	8/9/2018 1:01	Subtransmission	None	TRK 775			UNKNOWN/NO DATA
8/9/2018 14:35	8/11/2018 17:12	Subtransmission	None	TRK 7324			UNKNOWN/NO DATA
8/11/2018 23:46	8/12/2018 7:35	Subtransmission	None	TIE 4412			UNKNOWN/NO DATA
8/11/2018 17:41	8/11/2018 20:37	Subtransmission	None	TRK 2005			UNKNOWN/NO DATA
8/13/2018 2:14	8/13/2018 8:16	Subtransmission	None	TIE 6621			UNKNOWN/NO DATA
8/15/2018 1:59	8/15/2018 8:29	Subtransmission	None	TIE 3416			UNKNOWN/NO DATA
8/18/2018 21:15	8/19/2018 17:49	Subtransmission	None	TIE 7745			UNKNOWN/NO DATA
8/19/2018 12:39	8/22/2018 13:02	Subtransmission	None	TRK 5855			UNKNOWN/NO DATA
8/19/2018 7:28	8/19/2018 17:08	Subtransmission	None	TRK 775			UNKNOWN/NO DATA
8/21/2018 16:55	8/22/2018 5:25	Subtransmission	None	TIE 3205			UNKNOWN/NO DATA
8/22/2018 9:04	10/1/2018 5:01	Subtransmission	None	TIE 6621			UNKNOWN/NO DATA
8/24/2018 10:45	8/24/2018 14:15	Subtransmission	None	TRK 5838			UNKNOWN/NO DATA
8/27/2018 6:38	8/28/2018 6:24	Subtransmission	None	TIE 226			UNKNOWN/NO DATA
8/28/2018 21:44	8/29/2018 5:24	Subtransmission	None	TIE 3209			UNKNOWN/NO DATA
8/28/2018 22:33	8/31/2018 9:41	Subtransmission	None	TIE 3245			UNKNOWN/NO DATA
8/28/2018 11:18	8/28/2018 19:47	Subtransmission	None	TIE 3417			UNKNOWN/NO DATA
8/30/2018 8:24	8/30/2018 15:45	Subtransmission	None	TIE 5823			UNKNOWN/NO DATA
9/1/2018 17:31	9/2/2018 15:35	Subtransmission	None	TIE 4104			UNKNOWN/NO DATA
9/2/2018 12:32	9/3/2018 16:39	Subtransmission	None	TIE 1568			UNKNOWN/NO DATA
9/3/2018 0:41	9/3/2018 12:25	Subtransmission	None	TIE 3205			UNKNOWN/NO DATA
9/3/2018 9:24	9/4/2018 6:51	Subtransmission	None	TIE 8014			UNKNOWN/NO DATA
9/3/2018 13:19	9/3/2018 19:32	Subtransmission	None	TRK 2038			UNKNOWN/NO DATA
9/3/2018 16:57	9/3/2018 19:09	Subtransmission	None	TRK 2713			UNKNOWN/NO DATA
9/4/2018 10:27	9/5/2018 15:45	Subtransmission	None	TRK 4338			UNKNOWN/NO DATA
9/16/2018 19:09	9/17/2018 4:15	Subtransmission	None	TRK 5127			UNKNOWN/NO DATA
9/17/2018 12:48	9/17/2018 14:10	Subtransmission	Distribution	TRK 2027	1891	157507	UNKNOWN/NO DATA
9/21/2018 16:53	9/21/2018 20:22	Subtransmission	None	TIE 3705			UNKNOWN/NO DATA
9/21/2018 11:24	9/21/2018 13:05	Subtransmission	None	TIE 4501			UNKNOWN/NO DATA
9/21/2018 11:15	9/21/2018 12:30	Subtransmission	Distribution	TIE 4501	350	20926	UNKNOWN/NO DATA

9/24/2018 17:05	9/24/2018 21:31	Subtransmission	None	TRK 2611			UNKNOWN/NO DATA
9/25/2018 8:48	9/25/2018 14:41	Subtransmission	None	TIE 3245			UNKNOWN/NO DATA
9/29/2018 11:37	9/29/2018 16:30	Subtransmission	None	TRK 3508			UNKNOWN/NO DATA
10/1/2018 6:32	10/1/2018 15:27	Subtransmission	None	TIE 3205			UNKNOWN/NO DATA
10/3/2018 6:53	10/18/2018 8:14	Subtransmission	None	TRK 4351			UNKNOWN/NO DATA
10/4/2018 5:47	10/4/2018 11:20	Subtransmission	None	TIE 5823			UNKNOWN/NO DATA
10/6/2018 12:45	10/18/2018 14:13	Subtransmission	None	TIE 7745			UNKNOWN/NO DATA
10/6/2018 3:56	10/18/2018 11:36	Subtransmission	None	TRK 2032			UNKNOWN/NO DATA
10/6/2018 9:56	10/6/2018 16:09	Subtransmission	None	TRK 2301			UNKNOWN/NO DATA
10/9/2018 16:52	10/11/2018 8:23	Subtransmission	None	TIE 7513			UNKNOWN/NO DATA
10/10/2018 9:26	10/10/2018 17:52	Subtransmission	None	TRK 5127			UNKNOWN/NO DATA
10/11/2018 16:52	10/11/2018 23:43	Subtransmission	None	TRK 4316			UNKNOWN/NO DATA
10/14/2018 17:27	10/15/2018 22:06	Subtransmission	None	TRK 1527			UNKNOWN/NO DATA
10/16/2018 11:06	10/16/2018 16:45	Subtransmission	None	TRK 6938			UNKNOWN/NO DATA
10/17/2018 22:31	10/18/2018 11:14	Subtransmission	None	TIE 9107			UNKNOWN/NO DATA
10/17/2018 23:28	10/18/2018 4:03	Subtransmission	None	TRK 1340			UNKNOWN/NO DATA
10/21/2018 19:38	10/23/2018 8:18	Subtransmission	None	TRK 1340			UNKNOWN/NO DATA
10/23/2018 8:51	10/23/2018 18:57	Subtransmission	None	TIE 3416			UNKNOWN/NO DATA
10/23/2018 9:11	10/23/2018 15:11	Subtransmission	None	TIE 3416			UNKNOWN/NO DATA
10/24/2018 17:07	10/24/2018 20:03	Subtransmission	None	TIE 6138			UNKNOWN/NO DATA
11/6/2018 8:14	11/6/2018 16:28	Subtransmission	None	TIE 6907			UNKNOWN/NO DATA
11/6/2018 13:59	11/7/2018 2:44	Subtransmission	None	TRK 1527			UNKNOWN/NO DATA
11/7/2018 12:34	11/7/2018 16:17	Subtransmission	None	TIE 3500			UNKNOWN/NO DATA
11/8/2018 9:59	11/8/2018 12:39	Subtransmission	None	TRK 1243			UNKNOWN/NO DATA
11/9/2018 9:56	11/9/2018 14:05	Subtransmission	None	TRK 5935			UNKNOWN/NO DATA
11/14/2018 3:51	11/14/2018 21:01	Subtransmission	None	TIE 5513			UNKNOWN/NO DATA
11/15/2018 13:24	11/15/2018 16:57	Subtransmission	None	TRK 1346			UNKNOWN/NO DATA
11/26/2018 15:50	11/26/2018 19:25	Subtransmission	None	TIE 3208			UNKNOWN/NO DATA
11/26/2018 17:09	11/27/2018 1:37	Subtransmission	None	TRK 6938			UNKNOWN/NO DATA
11/30/2018 12:19	11/30/2018 17:04	Subtransmission	None	TIE 1531			UNKNOWN/NO DATA
12/1/2018 23:20	12/3/2018 8:30	Subtransmission	None	TIE 7702			UNKNOWN/NO DATA
12/5/2018 22:18	12/8/2018 8:55	Subtransmission	None	TIE 1531			UNKNOWN/NO DATA
12/6/2018 10:55	12/6/2018 13:32	Subtransmission	None	TRK 6759			UNKNOWN/NO DATA
12/8/2018 1:05	12/8/2018 13:59	Subtransmission	None	TRK 8215			UNKNOWN/NO DATA
12/12/2018 13:11	12/12/2018 15:36	Subtransmission	None	TRK 3536			UNKNOWN/NO DATA
12/12/2018 12:20	12/12/2018 16:12	Subtransmission	None	TRK 372			UNKNOWN/NO DATA
12/22/2018 16:21	12/22/2018 20:04	Subtransmission	None	TRK 620			UNKNOWN/NO DATA
12/24/2018 6:42	12/24/2018 17:35	Subtransmission	None	TIE 4104			UNKNOWN/NO DATA
12/26/2018 9:32	12/26/2018 16:19	Subtransmission	None	TRK 4316			UNKNOWN/NO DATA
12/28/2018 18:44	12/28/2018 20:37	Subtransmission	None	TRK 1251			UNKNOWN/NO DATA
1/1/2019 15:41	1/1/2019 17:57	Subtransmission	None	TRK 5855			UNKNOWN/NO DATA
1/5/2019 15:18	1/5/2019 21:04	Subtransmission	None	TRK 2528			UNKNOWN/NO DATA
1/7/2019 13:25	1/7/2019 21:07	Subtransmission	None	TRK 2659			UNKNOWN/NO DATA
1/13/2019 9:46	1/13/2019 14:45	Subtransmission	None	TIE 2648			UNKNOWN/NO DATA
1/13/2019 21:52	1/14/2019 2:39	Subtransmission	None	TRK 7065			UNKNOWN/NO DATA
1/18/2019 10:03	1/18/2019 14:32	Subtransmission	None	TRK 7065			UNKNOWN/NO DATA
1/23/2019 10:22	1/23/2019 17:41	Subtransmission	None	TIE 4708			UNKNOWN/NO DATA
1/26/2019 12:43	1/26/2019 22:24	Subtransmission	None	TIE 5823			UNKNOWN/NO DATA
2/13/2019 11:32	2/13/2019 16:14	Subtransmission	None	TIE 3212			UNKNOWN/NO DATA
2/18/2019 19:23	2/18/2019 19:37	Subtransmission	None	TRK 3526			UNKNOWN/NO DATA
2/20/2019 18:10	2/20/2019 22:48	Subtransmission	None	TIE 185			UNKNOWN/NO DATA
2/24/2019 19:04	2/26/2019 20:35	Subtransmission	None	TIE 3417			UNKNOWN/NO DATA
2/24/2019 17:57	2/24/2019 19:53	Subtransmission	Distribution	TIE 3417	589	61903	UNKNOWN/NO DATA
2/24/2019 9:56	2/24/2019 14:36	Subtransmission	None	TIE 7745			UNKNOWN/NO DATA
2/24/2019 6:03	2/24/2019 11:31	Subtransmission	None	TRK 5917			UNKNOWN/NO DATA
2/25/2019 13:05	2/25/2019 13:11	Subtransmission	None	TIE 9211			UNKNOWN/NO DATA
3/8/2019 14:21	3/8/2019 18:05	Subtransmission	None	TRK 3526			UNKNOWN/NO DATA
3/9/2019 7:55	3/9/2019 15:50	Subtransmission	None	TRK 6938			UNKNOWN/NO DATA
3/10/2019 9:25	3/10/2019 22:22	Subtransmission	None	TIE 6602			UNKNOWN/NO DATA
3/10/2019 9:14	3/10/2019 10:26	Subtransmission	Distribution	TIE 6602	130	9311	UNKNOWN/NO DATA
3/14/2019 20:51	3/14/2019 22:00	Subtransmission	Distribution	TIE 9107	524	36237	UNKNOWN/NO DATA
3/14/2019 20:51	3/14/2019 22:00	Subtransmission	Distribution	TIE 9107	258	17725	UNKNOWN/NO DATA
3/14/2019 20:51	3/14/2019 22:00	Subtransmission	Distribution	TIE 9107	11	757	UNKNOWN/NO DATA
3/14/2019 23:32	3/15/2019 19:08	Subtransmission	None	TIE 9107			UNKNOWN/NO DATA
3/16/2019 7:32	3/16/2019 16:35	Subtransmission	None	TIE 807			UNKNOWN/NO DATA
3/18/2019 19:11	3/19/2019 6:00	Subtransmission	None	TRK 1527			UNKNOWN/NO DATA
3/19/2019 16:01	3/20/2019 0:03	Subtransmission	None	TRK 2918			UNKNOWN/NO DATA
3/26/2019 12:20	3/26/2019 12:57	Subtransmission	None	TIE 810			UNKNOWN/NO DATA
3/26/2019 17:10	3/26/2019 18:38	Subtransmission	None	TRK 7035			UNKNOWN/NO DATA
3/31/2019 16:08	3/31/2019 19:15	Subtransmission	None	TIE 3206			UNKNOWN/NO DATA
3/31/2019 8:33	3/31/2019 15:26	Subtransmission	None	TIE 5843			UNKNOWN/NO DATA
3/31/2019 18:50	3/31/2019 23:51	Subtransmission	None	TRK 1502			UNKNOWN/NO DATA
4/1/2019 21:05	4/2/2019 4:28	Subtransmission	None	TRK 2247			UNKNOWN/NO DATA
4/1/2019 13:58	4/1/2019 17:21	Subtransmission	None	TRK 4962			UNKNOWN/NO DATA
4/3/2019 13:48	4/3/2019 18:13	Subtransmission	None	TIE 3205			UNKNOWN/NO DATA
4/6/2019 9:09	4/6/2019 12:30	Subtransmission	None	TRK 2301			UNKNOWN/NO DATA
4/8/2019 15:14	4/8/2019 18:19	Subtransmission	None	TRK 1243			UNKNOWN/NO DATA
4/12/2019 18:26	4/12/2019 21:22	Subtransmission	None	TIE 5843			UNKNOWN/NO DATA
4/15/2019 17:16	4/15/2019 18:58	Subtransmission	None	TRK 3646			UNKNOWN/NO DATA
4/23/2019 0:32	4/23/2019 11:55	Subtransmission	None	TRK 4601			UNKNOWN/NO DATA
5/3/2019 11:44	5/3/2019 17:18	Subtransmission	None	TRK 2218			UNKNOWN/NO DATA
5/12/2019 11:41	5/12/2019 21:16	Subtransmission	None	TRK 1403			UNKNOWN/NO DATA
5/17/2019 4:46	5/17/2019 17:40	Subtransmission	None	TRK 7114			UNKNOWN/NO DATA
5/23/2019 16:18	5/25/2019 14:44	Subtransmission	None	TRK 6938			UNKNOWN/NO DATA
5/24/2019 8:49	5/24/2019 9:18	Subtransmission	None	TIE 2025			UNKNOWN/NO DATA
5/25/2019 8:54	5/25/2019 14:20	Subtransmission	None	TIE 2025			UNKNOWN/NO DATA
5/25/2019 13:41	5/25/2019 17:50	Subtransmission	None	TRK 7035			UNKNOWN/NO DATA
5/26/2019 1:18	5/26/2019 5:41	Subtransmission	None	TIE 1473			UNKNOWN/NO DATA
5/26/2019 19:21	5/27/2019 7:33	Subtransmission	None	TRK 5853			UNKNOWN/NO DATA
5/28/2019 12:38	5/28/2019 17:36	Subtransmission	None	TRK 2510			UNKNOWN/NO DATA
5/29/2019 12:27	5/29/2019 20:36	Subtransmission	None	TIE 2812			UNKNOWN/NO DATA
6/1/2019 15:24	6/2/2019 5:57	Subtransmission	None	TIE 3203			UNKNOWN/NO DATA
6/2/2019 8:51	6/2/2019 10:23	Subtransmission	None	TRK 7389			UNKNOWN/NO DATA
6/3/2019 20:05	6/4/2019 6:03	Subtransmission	None	TRK 2742			UNKNOWN/NO DATA
6/4/2019 15:32	6/4/2019 17:10	Subtransmission	None	TIE 2812			UNKNOWN/NO DATA
6/7/2019 2:36	6/7/2019 16:14	Subtransmission	None	TIE 6907			UNKNOWN/NO DATA
6/7/2019 18:40	6/7/2019 20:04	Subtransmission	None	TRK 2054			UNKNOWN/NO DATA
6/9/2019 12:14	6/9/2019 20:30	Subtransmission	None	TIE 3402			UNKNOWN/NO DATA
6/10/2019 18:53	6/11/2019 0:24	Subtransmission	None	TIE 226			UNKNOWN/NO DATA
6/10/2019 8:37	6/10/2019 16:18	Subtransmission	None	TIE 6621			UNKNOWN/NO DATA
6/10/2019 14:40	6/11/2019 6:06	Subtransmission	None	TRK 1243			UNKNOWN/NO DATA
6/10/2019 10:41	6/10/2019 14:18	Subtransmission	None	TRK 2466			UNKNOWN/NO DATA
6/12/2019 22:27	6/13/2019 11:48	Subtransmission	None	TRK 1409			UNKNOWN/NO DATA
6/13/2019 8:43	6/13/2019 11:55	Subtransmission	None	TIE 810			UNKNOWN/NO DATA
6/15/2019 18:44	6/16/2019 4:10	Subtransmission	None	TRK 1409			UNKNOWN/NO DATA

6/16/2019 17:03	6/16/2019 20:01	Subtransmission	None	TRK 1232			UNKNOWN/NO DATA
6/19/2019 14:32	6/19/2019 20:36	Subtransmission	None	TRK 2237			UNKNOWN/NO DATA
6/23/2019 8:49	6/23/2019 18:42	Subtransmission	None	TRK 3661			UNKNOWN/NO DATA
6/23/2019 16:42	6/24/2019 6:22	Subtransmission	None	TRK 7389			UNKNOWN/NO DATA
6/26/2019 17:44	6/27/2019 2:44	Subtransmission	None	TRK 7389			UNKNOWN/NO DATA
6/27/2019 2:28	6/27/2019 15:03	Subtransmission	None	TRK 2840			UNKNOWN/NO DATA
6/28/2019 11:30	6/29/2019 13:15	Subtransmission	None	TIE 3209			UNKNOWN/NO DATA
6/28/2019 10:46	6/28/2019 11:50	Subtransmission	Distribution	TIE 4109	665	42495	UNKNOWN/NO DATA
6/28/2019 10:46	6/28/2019 12:20	Subtransmission	Distribution	TIE 4109	685	61963	UNKNOWN/NO DATA
6/28/2019 10:46	6/28/2019 11:50	Subtransmission	Distribution	TIE 4109	223	13718	UNKNOWN/NO DATA
6/28/2019 9:14	6/29/2019 10:24	Subtransmission	None	TRK 2038			UNKNOWN/NO DATA
6/30/2019 10:56	6/30/2019 21:36	Subtransmission	None	TRK 5906			UNKNOWN/NO DATA
7/2/2019 21:52	7/3/2019 3:46	Subtransmission	None	TIE 1423			UNKNOWN/NO DATA
7/4/2019 12:07	7/4/2019 18:06	Subtransmission	None	TRK 7106			UNKNOWN/NO DATA
7/5/2019 6:46	7/5/2019 11:35	Subtransmission	None	TIE 8014			UNKNOWN/NO DATA
7/5/2019 16:59	7/5/2019 22:05	Subtransmission	None	TRK 446			UNKNOWN/NO DATA
7/6/2019 22:08	7/7/2019 10:09	Subtransmission	None	TIE 1544			UNKNOWN/NO DATA
7/6/2019 2:03	7/7/2019 15:25	Subtransmission	None	TIE 3209			UNKNOWN/NO DATA
7/7/2019 11:36	7/7/2019 21:30	Subtransmission	None	TIE 3205			UNKNOWN/NO DATA
7/7/2019 1:54	7/7/2019 12:12	Subtransmission	None	TIE 8033			UNKNOWN/NO DATA
7/11/2019 12:03	7/11/2019 18:24	Subtransmission	None	TIE 8014			UNKNOWN/NO DATA
7/11/2019 13:05	7/11/2019 17:20	Subtransmission	None	TIE 817			UNKNOWN/NO DATA
7/11/2019 12:03	7/11/2019 15:49	Subtransmission	None	TRK 3632			UNKNOWN/NO DATA
7/17/2019 19:34	7/18/2019 2:26	Subtransmission	None	TIE 1568			UNKNOWN/NO DATA
7/19/2019 20:05	7/20/2019 15:22	Subtransmission	None	TIE 2812			UNKNOWN/NO DATA
7/19/2019 19:45	7/25/2019 15:49	Subtransmission	None	TIE 5843			UNKNOWN/NO DATA
7/19/2019 23:01	7/22/2019 18:32	Subtransmission	None	TIE 7621			UNKNOWN/NO DATA
7/19/2019 22:13	7/21/2019 21:14	Subtransmission	None	TRK 1563			UNKNOWN/NO DATA
7/19/2019 14:12	7/25/2019 14:59	Subtransmission	None	TRK 2826			UNKNOWN/NO DATA
7/19/2019 19:21	7/25/2019 15:42	Subtransmission	None	TRK 6304			UNKNOWN/NO DATA
7/19/2019 19:06	7/20/2019 5:52	Subtransmission	None	TRK 6919			UNKNOWN/NO DATA
7/19/2019 16:15	7/25/2019 11:59	Subtransmission	None	TRK 7756			UNKNOWN/NO DATA
7/20/2019 7:38	7/20/2019 20:29	Subtransmission	None	TIE 4523			UNKNOWN/NO DATA
7/20/2019 10:21	7/25/2019 14:57	Subtransmission	None	TIE 7621			UNKNOWN/NO DATA
7/21/2019 0:59	7/21/2019 20:10	Subtransmission	None	TIE 4104			UNKNOWN/NO DATA
7/21/2019 0:56	7/25/2019 12:27	Subtransmission	None	TRK 5404			UNKNOWN/NO DATA
7/22/2019 1:18	7/22/2019 18:50	Subtransmission	None	TIE 9107			UNKNOWN/NO DATA
7/23/2019 16:10	7/26/2019 11:09	Subtransmission	None	TIE 4105			UNKNOWN/NO DATA
7/23/2019 17:48	7/25/2019 14:58	Subtransmission	None	TIE 5823			UNKNOWN/NO DATA
7/23/2019 17:58	7/24/2019 6:47	Subtransmission	None	TRK 6828			UNKNOWN/NO DATA
7/27/2019 7:16	7/28/2019 1:24	Subtransmission	None	TRK 1502			UNKNOWN/NO DATA
7/28/2019 13:29	7/28/2019 16:29	Subtransmission	None	TRK 2628			UNKNOWN/NO DATA
7/29/2019 13:35	7/29/2019 20:30	Subtransmission	None	TIE 5823			UNKNOWN/NO DATA
7/29/2019 16:47	7/29/2019 23:17	Subtransmission	None	TIE 5843			UNKNOWN/NO DATA
8/3/2019 8:27	8/3/2019 19:30	Subtransmission	None	TIE 3209			UNKNOWN/NO DATA
8/7/2019 3:43	8/7/2019 23:59	Subtransmission	None	TIE 1531			UNKNOWN/NO DATA
8/8/2019 15:44	8/8/2019 22:32	Subtransmission	None	TIE 1531			UNKNOWN/NO DATA
8/11/2019 21:59	8/11/2019 22:54	Subtransmission	None	TIE 7745			UNKNOWN/NO DATA
8/11/2019 18:33	8/11/2019 22:41	Subtransmission	None	TRK 1303			UNKNOWN/NO DATA
8/17/2019 18:24	8/18/2019 19:46	Subtransmission	None	TIE 3220			UNKNOWN/NO DATA
8/17/2019 23:42	8/18/2019 15:17	Subtransmission	None	TIE 9107			UNKNOWN/NO DATA
8/18/2019 20:44	8/19/2019 3:00	Subtransmission	Subtransmission	TIE 1473	54	19788	UNKNOWN/NO DATA
8/18/2019 20:43	8/19/2019 3:30	Subtransmission	Subtransmission	TIE 1473	105	37489	UNKNOWN/NO DATA
8/18/2019 21:26	8/19/2019 11:53	Subtransmission	None	TIE 810			UNKNOWN/NO DATA
8/18/2019 14:26	8/18/2019 20:58	Subtransmission	None	TRK 7062			UNKNOWN/NO DATA
8/19/2019 0:15	8/19/2019 0:58	Subtransmission	None	TRK 5145			UNKNOWN/NO DATA
8/21/2019 8:09	8/23/2019 13:07	Subtransmission	None	TIE 2819			UNKNOWN/NO DATA
8/21/2019 19:15	8/21/2019 20:24	Subtransmission	Distribution	TIE 3208	263	16847	UNKNOWN/NO DATA
8/21/2019 19:15	8/21/2019 20:24	Subtransmission	Distribution	TIE 3208	134	8672	UNKNOWN/NO DATA
8/21/2019 19:15	8/21/2019 20:28	Subtransmission	Distribution	TIE 3208	380	24590	UNKNOWN/NO DATA
8/21/2019 19:30	8/22/2019 4:53	Subtransmission	None	TIE 3208			UNKNOWN/NO DATA
8/24/2019 11:19	8/24/2019 21:03	Subtransmission	None	TRK 1403			UNKNOWN/NO DATA
8/26/2019 12:29	8/27/2019 10:36	Subtransmission	None	TRK 1134			UNKNOWN/NO DATA
8/27/2019 14:26	8/27/2019 21:39	Subtransmission	None	TIE 8014			UNKNOWN/NO DATA
8/28/2019 13:29	8/28/2019 21:30	Subtransmission	None	TRK 1243			UNKNOWN/NO DATA
8/29/2019 7:32	8/31/2019 6:09	Subtransmission	None	TRK 2541			UNKNOWN/NO DATA
9/1/2019 15:11	9/1/2019 19:22	Subtransmission	None	TRK 4301			UNKNOWN/NO DATA
9/2/2019 15:46	9/4/2019 2:19	Subtransmission	None	TIE 8033			UNKNOWN/NO DATA
9/3/2019 18:38	9/3/2019 20:58	Subtransmission	None	TRK 2523			UNKNOWN/NO DATA
9/5/2019 12:51	9/6/2019 1:35	Subtransmission	None	TIE 5513			UNKNOWN/NO DATA
9/7/2019 11:28	9/7/2019 14:20	Subtransmission	None	TIE 3705			UNKNOWN/NO DATA
9/9/2019 12:13	9/9/2019 17:58	Subtransmission	None	TRK 5145			UNKNOWN/NO DATA
9/10/2019 8:29	9/10/2019 14:36	Subtransmission	None	TIE 3209			UNKNOWN/NO DATA
9/10/2019 21:11	9/11/2019 6:47	Subtransmission	None	TIE 3417			UNKNOWN/NO DATA
9/11/2019 12:51	9/11/2019 15:12	Subtransmission	None	TIE 3417			UNKNOWN/NO DATA
9/11/2019 19:01	9/12/2019 11:09	Subtransmission	None	TRK 2087			UNKNOWN/NO DATA
9/11/2019 13:59	9/11/2019 17:18	Subtransmission	None	TRK 346			UNKNOWN/NO DATA
9/11/2019 14:16	9/17/2019 9:16	Subtransmission	None	TRK 6508			UNKNOWN/NO DATA
9/11/2019 16:03	9/11/2019 17:41	Subtransmission	None	TRK 6854			UNKNOWN/NO DATA
9/14/2019 8:33	9/15/2019 14:42	Subtransmission	None	TIE 8014			UNKNOWN/NO DATA
9/17/2019 9:02	9/17/2019 14:54	Subtransmission	None	TRK 2087			UNKNOWN/NO DATA
9/19/2019 4:53	9/21/2019 6:17	Subtransmission	None	TRK 2087			UNKNOWN/NO DATA
9/19/2019 10:58	9/19/2019 19:20	Subtransmission	None	TRK 6919			UNKNOWN/NO DATA
9/20/2019 11:03	9/21/2019 5:00	Subtransmission	Distribution	TIE 4412			UNKNOWN/NO DATA
9/21/2019 20:23	9/22/2019 5:00	Subtransmission	None	TIE 817			UNKNOWN/NO DATA
9/21/2019 19:10	9/22/2019 9:24	Subtransmission	None	TRK 2506			UNKNOWN/NO DATA
9/23/2019 6:52	9/23/2019 23:04	Subtransmission	None	TIE 3205			UNKNOWN/NO DATA
9/23/2019 8:56	9/23/2019 14:29	Subtransmission	None	TIE 3417			UNKNOWN/NO DATA
9/23/2019 8:11	9/23/2019 14:19	Subtransmission	None	TIE 5823			UNKNOWN/NO DATA
9/23/2019 17:57	9/24/2019 5:39	Subtransmission	None	TRK 4301			UNKNOWN/NO DATA
9/24/2019 11:28	9/27/2019 14:35	Subtransmission	None	TRK 2523			UNKNOWN/NO DATA
9/25/2019 11:52	9/25/2019 20:22	Subtransmission	None	TIE 3209			UNKNOWN/NO DATA
9/28/2019 15:58	9/28/2019 20:56	Subtransmission	None	TRK 3124			UNKNOWN/NO DATA
10/1/2019 13:56	10/1/2019 22:41	Subtransmission	None	TIE 3417			UNKNOWN/NO DATA
10/2/2019 12:19	10/2/2019 17:42	Subtransmission	None	TIE 3206			UNKNOWN/NO DATA
10/2/2019 1:09	10/2/2019 2:35	Subtransmission	None	TIE 4605			UNKNOWN/NO DATA
10/2/2019 10:41	10/2/2019 14:53	Subtransmission	None	TRK 2806			UNKNOWN/NO DATA
10/13/2019 21:52	10/14/2019 5:02	Subtransmission	None	TIE 9205			UNKNOWN/NO DATA
10/13/2019 13:55	10/13/2019 15:06	Subtransmission	None	TRK 6919			UNKNOWN/NO DATA
10/17/2019 20:51	10/18/2019 13:52	Subtransmission	None	TRK 4416			UNKNOWN/NO DATA
10/18/2019 8:47	10/21/2019 4:23	Subtransmission	None	TRK 7324			UNKNOWN/NO DATA
10/23/2019 12:44	10/26/2019 6:47	Subtransmission	None	TRK 1248			UNKNOWN/NO DATA
10/29/2019 22:36	10/30/2019 2:22	Subtransmission	None	TRK 2523			UNKNOWN/NO DATA
10/29/2019 17:13	10/29/2019 22:10	Subtransmission	None	TRK 5510			UNKNOWN/NO DATA
11/4/2019 9:44	11/4/2019 13:54	Subtransmission	None	TRK 1276			UNKNOWN/NO DATA

11/4/2019 5:35	11/15/2019 12:04	Subtransmission	None	TRK 3540			UNKNOWN/NO DATA
11/12/2019 7:24	11/12/2019 10:56	Subtransmission	None	TRK 2439			UNKNOWN/NO DATA
11/17/2019 14:45	11/18/2019 14:39	Subtransmission	None	TRK 3540			UNKNOWN/NO DATA
11/23/2019 11:51	11/23/2019 16:26	Subtransmission	None	TIE 5823			UNKNOWN/NO DATA
11/25/2019 13:50	11/25/2019 19:44	Subtransmission	None	TIE 3208			UNKNOWN/NO DATA
11/27/2019 12:42	11/29/2019 1:56	Subtransmission	None	TIE 8033			UNKNOWN/NO DATA
11/27/2019 12:18	11/27/2019 19:26	Subtransmission	None	TRK 2826			UNKNOWN/NO DATA
12/6/2019 16:59	12/7/2019 10:39	Subtransmission	None	TRK 7122			UNKNOWN/NO DATA
12/15/2019 18:51	12/16/2019 14:37	Subtransmission	None	TIE 4523			UNKNOWN/NO DATA
12/16/2019 18:56	12/16/2019 23:27	Subtransmission	None	TIE 9205			UNKNOWN/NO DATA
12/17/2019 13:27	12/17/2019 18:10	Subtransmission	None	TRK 2301			UNKNOWN/NO DATA
12/22/2019 7:57	12/24/2019 18:26	Subtransmission	None	TRK 7122			UNKNOWN/NO DATA
12/25/2019 23:49	12/26/2019 13:17	Subtransmission	None	TRK 6919			UNKNOWN/NO DATA
12/30/2019 0:21	12/30/2019 6:25	Subtransmission	None	TRK 2918			UNKNOWN/NO DATA
1/1/2020 8:43	1/3/2020 7:03	Subtransmission	None	TIE 5823			UNKNOWN/NO DATA
1/1/2020 12:38	1/1/2020 12:46	Subtransmission	Subtransmission	TIE 5823			UNKNOWN/NO DATA
1/1/2020 4:03	1/1/2020 9:32	Subtransmission	None	TRK 4351			UNKNOWN/NO DATA
1/6/2020 11:00	1/8/2020 9:35	Subtransmission	None	TIE 6931			UNKNOWN/NO DATA
1/9/2020 15:42	1/9/2020 21:23	Subtransmission	None	TIE 3402			UNKNOWN/NO DATA
1/10/2020 14:47	1/10/2020 21:50	Subtransmission	None	TRK 1527			UNKNOWN/NO DATA
1/11/2020 12:21	1/11/2020 14:14	Subtransmission	Subtransmission	TIE 4605	627	71039	UNKNOWN/NO DATA
1/11/2020 12:21	1/11/2020 14:14	Subtransmission	Subtransmission	TIE 4605	886	100536	UNKNOWN/NO DATA
1/11/2020 23:19	1/12/2020 21:08	Subtransmission	None	TIE 9111			UNKNOWN/NO DATA
1/12/2020 15:47	1/12/2020 19:48	Subtransmission	None	TRK 5917			UNKNOWN/NO DATA
1/14/2020 5:36	1/14/2020 17:12	Subtransmission	None	TRK 8215			UNKNOWN/NO DATA
1/24/2020 7:15	1/24/2020 13:51	Subtransmission	None	TIE 7733			UNKNOWN/NO DATA
2/7/2020 8:24	2/7/2020 10:37	Subtransmission	None	TRK 1134			UNKNOWN/NO DATA
2/15/2020 9:15	2/15/2020 10:27	Subtransmission	None	TRK 7078			UNKNOWN/NO DATA
2/26/2020 11:25	2/26/2020 14:59	Subtransmission	None	TIE 2901			UNKNOWN/NO DATA
3/2/2020 20:00	3/3/2020 13:08	Subtransmission	None	TRK 2218			UNKNOWN/NO DATA
3/2/2020 16:44	3/2/2020 19:50	Subtransmission	Distribution	TRK 2218			UNKNOWN/NO DATA
3/2/2020 16:58	3/2/2020 22:06	Subtransmission	Distribution	TRK 2218	1	9	UNKNOWN/NO DATA
3/11/2020 9:01	3/11/2020 19:19	Subtransmission	None	TIE 3220			UNKNOWN/NO DATA
3/11/2020 14:16	3/11/2020 16:24	Subtransmission	None	TRK 2218			UNKNOWN/NO DATA
4/1/2020 13:48	4/1/2020 16:04	Subtransmission	None	TRK 3546			UNKNOWN/NO DATA
4/7/2020 23:06	4/8/2020 14:17	Subtransmission	None	TIE 1473			UNKNOWN/NO DATA
4/7/2020 20:56	4/8/2020 0:41	Subtransmission	None	TIE 2812			UNKNOWN/NO DATA
4/7/2020 21:19	4/8/2020 2:56	Subtransmission	None	TIE 8014			UNKNOWN/NO DATA
4/8/2020 9:39	4/8/2020 16:58	Subtransmission	None	TIE 3705			UNKNOWN/NO DATA
4/11/2020 7:13	4/11/2020 10:16	Subtransmission	None	TIE 5823			UNKNOWN/NO DATA
4/14/2020 10:57	4/14/2020 16:56	Subtransmission	None	TIE 3800			UNKNOWN/NO DATA
4/16/2020 14:10	4/16/2020 17:31	Subtransmission	None	TRK 5817			UNKNOWN/NO DATA
4/25/2020 19:43	4/26/2020 12:28	Subtransmission	None	TIE 5823			UNKNOWN/NO DATA
4/26/2020 12:42	4/26/2020 16:34	Subtransmission	None	TIE 2819			UNKNOWN/NO DATA
4/27/2020 7:49	4/27/2020 14:41	Subtransmission	None	TIE 4428			UNKNOWN/NO DATA
4/29/2020 13:17	4/29/2020 20:54	Subtransmission	None	TRK 5404			UNKNOWN/NO DATA
5/10/2020 8:26	5/10/2020 15:34	Subtransmission	None	TIE 3203			UNKNOWN/NO DATA
5/14/2020 1:59	5/14/2020 14:35	Subtransmission	None	TIE 3205			UNKNOWN/NO DATA
5/14/2020 1:58	5/14/2020 7:01	Subtransmission	None	TIE 3212			UNKNOWN/NO DATA
5/14/2020 16:56	5/14/2020 17:45	Subtransmission	None	TIE 3800			UNKNOWN/NO DATA
5/19/2020 0:29	5/19/2020 4:15	Subtransmission	None	TRK 5817			UNKNOWN/NO DATA
5/20/2020 16:28	5/20/2020 21:02	Subtransmission	None	TIE 2901			UNKNOWN/NO DATA
5/27/2020 12:55	5/29/2020 7:58	Subtransmission	None	TRK 2319			UNKNOWN/NO DATA
5/27/2020 8:25	5/29/2020 7:53	Subtransmission	None	TRK 6508			UNKNOWN/NO DATA
6/3/2020 19:34	6/3/2020 23:10	Subtransmission	None	TRK 2319			UNKNOWN/NO DATA
6/3/2020 15:19	6/3/2020 18:12	Subtransmission	None	TRK 446			UNKNOWN/NO DATA
6/3/2020 3:32	6/3/2020 11:10	Subtransmission	None	TRK 7150			UNKNOWN/NO DATA
6/7/2020 8:41	6/8/2020 8:47	Subtransmission	None	TIE 6138			UNKNOWN/NO DATA
6/9/2020 17:48	6/9/2020 19:41	Subtransmission	None	TIE 5513			UNKNOWN/NO DATA
6/10/2020 21:55	6/11/2020 19:35	Subtransmission	None	TIE 5208			UNKNOWN/NO DATA
6/10/2020 14:03	6/10/2020 23:01	Subtransmission	None	TIE 5829			UNKNOWN/NO DATA
6/11/2020 21:06	6/13/2020 11:00	Subtransmission	None	TIE 6931			UNKNOWN/NO DATA
6/18/2020 22:03	6/19/2020 12:41	Subtransmission	None	TIE 4105			UNKNOWN/NO DATA
6/18/2020 8:18	6/18/2020 17:41	Subtransmission	None	TRK 7130			UNKNOWN/NO DATA
6/19/2020 18:38	6/19/2020 23:01	Subtransmission	None	TRK 7130			UNKNOWN/NO DATA
6/20/2020 23:41	6/21/2020 11:32	Subtransmission	None	TIE 4523			UNKNOWN/NO DATA
6/20/2020 6:49	6/20/2020 12:37	Subtransmission	None	TRK 1276			UNKNOWN/NO DATA
6/23/2020 6:38	6/23/2020 17:22	Subtransmission	None	TIE 3208			UNKNOWN/NO DATA
6/23/2020 11:33	6/26/2020 20:03	Subtransmission	None	TIE 3705			UNKNOWN/NO DATA
6/23/2020 11:31	6/23/2020 14:23	Subtransmission	None	TIE 8623			UNKNOWN/NO DATA
6/23/2020 17:56	6/25/2020 15:44	Subtransmission	None	TRK 2918			UNKNOWN/NO DATA
7/1/2020 9:18	7/1/2020 14:17	Subtransmission	None	TIE 8014			UNKNOWN/NO DATA
7/1/2020 12:12	7/1/2020 16:28	Subtransmission	None	TIE 8014			UNKNOWN/NO DATA
7/2/2020 9:59	7/2/2020 15:30	Subtransmission	None	TRK 3107			UNKNOWN/NO DATA
7/3/2020 16:57	7/3/2020 18:25	Subtransmission	None	TIE 8014			UNKNOWN/NO DATA
7/3/2020 19:32	7/3/2020 22:28	Subtransmission	None	TIE 8014			UNKNOWN/NO DATA
7/3/2020 16:54	7/3/2020 18:26	Subtransmission	None	TIE 8014			UNKNOWN/NO DATA
7/4/2020 14:58	7/4/2020 19:02	Subtransmission	None	TRK 1229			UNKNOWN/NO DATA
7/4/2020 2:57	7/4/2020 22:36	Subtransmission	None	TRK 315			UNKNOWN/NO DATA
7/7/2020 16:50	7/8/2020 5:18	Subtransmission	None	TIE 3212			UNKNOWN/NO DATA
7/8/2020 14:29	7/8/2020 18:50	Subtransmission	None	TRK 6828			UNKNOWN/NO DATA
7/10/2020 13:14	7/12/2020 17:28	Subtransmission	None	TIE 3206			UNKNOWN/NO DATA
7/11/2020 17:37	7/16/2020 19:52	Subtransmission	None	TRK 5127			UNKNOWN/NO DATA
7/13/2020 18:54	7/14/2020 4:10	Subtransmission	None	TIE 7702			UNKNOWN/NO DATA
7/14/2020 20:56	7/14/2020 22:07	Subtransmission	None	TRK 2218			UNKNOWN/NO DATA
7/14/2020 7:41	7/16/2020 22:30	Subtransmission	None	TRK 4405			UNKNOWN/NO DATA
7/16/2020 11:40	7/17/2020 15:28	Subtransmission	None	TRK 7114			UNKNOWN/NO DATA
7/17/2020 13:37	7/17/2020 20:04	Subtransmission	None	TIE 2621			UNKNOWN/NO DATA
7/17/2020 9:50	7/18/2020 6:36	Subtransmission	None	TRK 2010			UNKNOWN/NO DATA
7/18/2020 17:23	7/19/2020 9:37	Subtransmission	None	TIE 3209			UNKNOWN/NO DATA
7/19/2020 16:49	7/21/2020 17:57	Subtransmission	None	TIE 2025			UNKNOWN/NO DATA
7/20/2020 0:07	7/20/2020 14:40	Subtransmission	None	TRK 6938			UNKNOWN/NO DATA
7/21/2020 12:15	7/21/2020 12:45	Subtransmission	Distribution	TRK 2027	2379	367572	UNKNOWN/NO DATA
7/25/2020 12:03	7/28/2020 12:29	Subtransmission	None	TIE 4708			UNKNOWN/NO DATA
7/29/2020 17:29	7/31/2020 5:56	Subtransmission	None	TRK 1346			UNKNOWN/NO DATA
7/29/2020 20:23	7/29/2020 23:03	Subtransmission	None	TRK 7150			UNKNOWN/NO DATA
7/31/2020 5:33	7/31/2020 10:07	Subtransmission	None	TRK 1303			UNKNOWN/NO DATA
8/2/2020 6:45	8/2/2020 12:38	Subtransmission	None	TRK 824			UNKNOWN/NO DATA
8/2/2020 2:03	8/2/2020 12:08	Subtransmission	None	TRK 824			UNKNOWN/NO DATA
8/3/2020 19:00	8/3/2020 20:00	Subtransmission	Distribution	TRK 1303	17	307	UNKNOWN/NO DATA
8/5/2020 9:11	8/7/2020 5:25	Subtransmission	None	TRK 3124			UNKNOWN/NO DATA
8/21/2020 12:05	8/22/2020 6:01	Subtransmission	None	TRK 4405			UNKNOWN/NO DATA
8/23/2020 17:51	8/25/2020 12:13	Subtransmission	None	TIE 8804			UNKNOWN/NO DATA
8/26/2020 6:57	8/26/2020 14:37	Subtransmission	None	TIE 3241			UNKNOWN/NO DATA
8/26/2020 11:05	8/27/2020 13:58	Subtransmission	None	TIE 5823			UNKNOWN/NO DATA

8/26/2020 11:02	8/27/2020 15:51	Subtransmission	None	TIE 5823			UNKNOWN/NO DATA
8/26/2020 11:03	8/27/2020 14:37	Subtransmission	None	TIE 5823			UNKNOWN/NO DATA
8/26/2020 9:02	8/26/2020 14:18	Subtransmission	None	TRK 6741			UNKNOWN/NO DATA
8/28/2020 14:45	8/28/2020 17:33	Subtransmission	None	TIE 9111			UNKNOWN/NO DATA
8/29/2020 17:14	8/30/2020 9:47	Subtransmission	None	TIE 2819			UNKNOWN/NO DATA
9/3/2020 13:39	9/3/2020 22:49	Subtransmission	None	TIE 3209			UNKNOWN/NO DATA
9/4/2020 14:29	9/4/2020 20:07	Subtransmission	None	TIE 4105			UNKNOWN/NO DATA
9/8/2020 10:50	9/8/2020 16:42	Subtransmission	None	TRK 2032			UNKNOWN/NO DATA
9/9/2020 4:23	9/9/2020 11:57	Subtransmission	None	TIE 7520			UNKNOWN/NO DATA
9/11/2020 9:47	9/12/2020 6:55	Subtransmission	None	TRK 4405			UNKNOWN/NO DATA
9/14/2020 15:45	9/14/2020 20:18	Subtransmission	None	TRK 5817			UNKNOWN/NO DATA
9/18/2020 13:49	9/19/2020 14:05	Subtransmission	None	TIE 2819			UNKNOWN/NO DATA
9/23/2020 17:12	9/23/2020 20:26	Subtransmission	None	TRK 2027			UNKNOWN/NO DATA
9/29/2020 22:17	9/30/2020 10:37	Subtransmission	None	TIE 3416			UNKNOWN/NO DATA
10/1/2020 10:02	10/1/2020 15:39	Subtransmission	None	TRK 2016			UNKNOWN/NO DATA
10/1/2020 13:43	10/1/2020 20:45	Subtransmission	None	TRK 7150			UNKNOWN/NO DATA
10/2/2020 16:39	10/2/2020 18:48	Subtransmission	None	TRK 2418			UNKNOWN/NO DATA
10/3/2020 16:19	10/3/2020 21:22	Subtransmission	None	TRK 4351			UNKNOWN/NO DATA
10/7/2020 12:36	10/7/2020 20:18	Subtransmission	Distribution	TIE 1473	1	24	UNKNOWN/NO DATA
10/9/2020 9:50	10/9/2020 11:53	Subtransmission	None	TRK 7122			UNKNOWN/NO DATA
10/12/2020 14:12	10/12/2020 17:27	Subtransmission	None	TRK 3646			UNKNOWN/NO DATA
10/14/2020 19:33	10/15/2020 13:51	Subtransmission	None	TRK 5411			UNKNOWN/NO DATA
10/18/2020 4:40	10/18/2020 11:40	Subtransmission	None	TIE 3417			UNKNOWN/NO DATA
10/19/2020 17:08	10/19/2020 19:58	Subtransmission	None	TRK 1527			UNKNOWN/NO DATA
10/22/2020 15:29	10/22/2020 16:28	Subtransmission	None	TRK 2719			UNKNOWN/NO DATA
10/22/2020 3:56	10/22/2020 7:21	Subtransmission	None	TRK 5239			UNKNOWN/NO DATA
10/23/2020 15:33	10/24/2020 19:42	Subtransmission	None	TIE 3208			UNKNOWN/NO DATA
10/23/2020 15:52	10/24/2020 5:45	Subtransmission	None	TIE 4104			UNKNOWN/NO DATA
10/25/2020 15:04	10/25/2020 18:00	Subtransmission	Distribution	TRK 2038			UNKNOWN/NO DATA
10/26/2020 14:11	10/26/2020 19:25	Subtransmission	None	TRK 5127			UNKNOWN/NO DATA
11/3/2020 12:14	11/15/2020 6:53	Subtransmission	None	TRK 1248			UNKNOWN/NO DATA
11/7/2020 10:57	11/7/2020 11:54	Subtransmission	None	TRK 5510			UNKNOWN/NO DATA
11/12/2020 12:39	11/12/2020 20:04	Subtransmission	None	TIE 3208			UNKNOWN/NO DATA
11/15/2020 18:10	11/18/2020 16:15	Subtransmission	None	TIE 3208			UNKNOWN/NO DATA
11/15/2020 16:09	11/21/2020 13:27	Subtransmission	None	TRK 2918			UNKNOWN/NO DATA
11/16/2020 9:20	11/16/2020 12:12	Subtransmission	None	TRK 2719			UNKNOWN/NO DATA
11/16/2020 12:13	11/25/2020 17:47	Subtransmission	None	TRK 7150			UNKNOWN/NO DATA
11/17/2020 12:30	11/18/2020 10:47	Subtransmission	None	TRK 3632			UNKNOWN/NO DATA
11/18/2020 18:59	11/18/2020 22:42	Subtransmission	None	TRK 1276			UNKNOWN/NO DATA
11/18/2020 17:03	11/18/2020 19:21	Subtransmission	None	TRK 1276			UNKNOWN/NO DATA
11/18/2020 16:24	11/18/2020 20:29	Subtransmission	None	TRK 3632			UNKNOWN/NO DATA
11/18/2020 8:29	11/18/2020 14:29	Subtransmission	None	TRK 7909			UNKNOWN/NO DATA
11/25/2020 8:03	11/25/2020 16:41	Subtransmission	None	TRK 7150			UNKNOWN/NO DATA
12/3/2020 12:17	12/4/2020 1:12	Subtransmission	None	TIE 7702			UNKNOWN/NO DATA
12/5/2020 8:09	12/5/2020 12:58	Subtransmission	None	TRK 2301			UNKNOWN/NO DATA
12/7/2020 16:57	12/8/2020 15:36	Subtransmission	None	TRK 4316			UNKNOWN/NO DATA
12/7/2020 17:06	12/9/2020 1:15	Subtransmission	None	TRK 4316			UNKNOWN/NO DATA
12/31/2020 17:36	12/31/2020 22:59	Subtransmission	None	TIE 3220			UNKNOWN/NO DATA
1/3/2021 10:42	1/4/2021 1:01	Subtransmission	None	TIE 8033			UNKNOWN/NO DATA
1/6/2021 8:24	1/6/2021 11:25	Subtransmission	None	TRK 620			UNKNOWN/NO DATA
1/17/2021 13:01	1/17/2021 17:25	Subtransmission	None	TIE 2025			UNKNOWN/NO DATA
1/18/2021 0:44	1/18/2021 7:09	Subtransmission	None	TRK 7324			UNKNOWN/NO DATA
1/23/2021 13:59	1/23/2021 16:49	Subtransmission	None	TRK 2506			UNKNOWN/NO DATA
1/26/2021 11:22	1/26/2021 15:12	Subtransmission	None	TRK 1303			UNKNOWN/NO DATA
2/14/2021 9:01	2/14/2021 11:19	Subtransmission	None	TRK 3536			UNKNOWN/NO DATA
2/16/2021 19:58	2/17/2021 0:25	Subtransmission	None	TRK 1346			UNKNOWN/NO DATA
2/21/2021 14:36	2/21/2021 17:54	Subtransmission	None	TRK 7386			UNKNOWN/NO DATA
2/22/2021 7:50	2/23/2021 8:14	Subtransmission	None	TIE 1544			UNKNOWN/NO DATA
3/12/2021 16:39	3/12/2021 21:21	Subtransmission	None	TRK 2032			UNKNOWN/NO DATA
3/17/2021 18:39	3/17/2021 23:25	Subtransmission	None	TRK 2032			UNKNOWN/NO DATA
3/18/2021 13:30	3/18/2021 14:19	Subtransmission	None	TIE 4105			UNKNOWN/NO DATA
3/26/2021 7:56	3/26/2021 20:57	Subtransmission	None	TIE 3323			UNKNOWN/NO DATA
3/28/2021 16:16	3/28/2021 19:26	Subtransmission	None	TIE 4104			UNKNOWN/NO DATA
3/28/2021 17:20	3/29/2021 12:02	Subtransmission	None	TIE 7520			UNKNOWN/NO DATA
3/28/2021 17:37	3/29/2021 12:20	Subtransmission	None	TRK 1251			UNKNOWN/NO DATA
3/28/2021 14:06	3/28/2021 17:53	Subtransmission	None	TRK 1251			UNKNOWN/NO DATA
3/30/2021 17:04	3/31/2021 16:10	Subtransmission	None	TRK 428			UNKNOWN/NO DATA
4/5/2021 11:56	4/5/2021 16:07	Subtransmission	None	TIE 4911			UNKNOWN/NO DATA
4/7/2021 17:24	4/7/2021 23:49	Subtransmission	None	TRK 7324			UNKNOWN/NO DATA
4/9/2021 11:56	4/9/2021 16:55	Subtransmission	None	TRK 6125			UNKNOWN/NO DATA
4/10/2021 11:50	4/10/2021 18:13	Subtransmission	None	TIE 3416			UNKNOWN/NO DATA
4/15/2021 0:03	4/15/2021 11:03	Subtransmission	None	TIE 9107			UNKNOWN/NO DATA
4/16/2021 9:00	4/16/2021 12:41	Subtransmission	None	TRK 1527			UNKNOWN/NO DATA
4/18/2021 6:28	4/19/2021 6:06	Subtransmission	None	TIE 1531			UNKNOWN/NO DATA
4/20/2021 22:48	4/21/2021 14:32	Subtransmission	None	TRK 7106			UNKNOWN/NO DATA
4/25/2021 3:31	4/25/2021 12:10	Subtransmission	None	TRK 4971			UNKNOWN/NO DATA
5/2/2021 1:42	5/2/2021 21:43	Subtransmission	None	TRK 1563			UNKNOWN/NO DATA
5/3/2021 15:41	5/3/2021 20:16	Subtransmission	None	TRK 2319			UNKNOWN/NO DATA
5/3/2021 1:33	5/3/2021 5:25	Subtransmission	None	TRK 467			UNKNOWN/NO DATA
5/4/2021 1:21	5/4/2021 5:30	Subtransmission	None	TIE 7702			UNKNOWN/NO DATA
5/5/2021 17:37	5/6/2021 3:19	Subtransmission	None	TIE 6138			UNKNOWN/NO DATA
5/7/2021 15:50	5/7/2021 20:58	Subtransmission	None	TRK 2305			UNKNOWN/NO DATA
5/8/2021 6:38	5/9/2021 2:01	Subtransmission	None	TIE 1467			UNKNOWN/NO DATA
5/15/2021 12:32	5/15/2021 14:43	Subtransmission	None	TRK 5127			UNKNOWN/NO DATA
5/17/2021 3:00	5/17/2021 7:24	Subtransmission	None	TIE 3417			UNKNOWN/NO DATA
5/19/2021 6:10	5/19/2021 13:28	Subtransmission	None	TIE 1423			UNKNOWN/NO DATA
5/19/2021 13:39	5/19/2021 18:39	Subtransmission	None	TIE 7430			UNKNOWN/NO DATA
5/20/2021 16:17	5/20/2021 20:48	Subtransmission	None	TRK 7122			UNKNOWN/NO DATA
5/21/2021 10:37	5/21/2021 14:20	Subtransmission	None	TRK 5510			UNKNOWN/NO DATA
5/26/2021 21:47	5/27/2021 10:46	Subtransmission	None	TIE 7430			UNKNOWN/NO DATA
5/27/2021 4:21	5/27/2021 15:09	Subtransmission	None	TIE 5829			UNKNOWN/NO DATA
5/28/2021 13:52	5/30/2021 9:00	Subtransmission	None	TRK 1232			UNKNOWN/NO DATA
6/3/2021 16:10	6/3/2021 23:14	Subtransmission	None	TRK 3241			UNKNOWN/NO DATA
6/12/2021 9:09	6/12/2021 17:33	Subtransmission	None	TRK 2010			UNKNOWN/NO DATA
6/13/2021 17:04	6/13/2021 23:19	Subtransmission	None	TIE 1467			UNKNOWN/NO DATA
6/14/2021 3:38	6/14/2021 17:10	Subtransmission	None	TRK 2206			UNKNOWN/NO DATA
6/17/2021 7:49	6/18/2021 15:17	Subtransmission	None	TRK 1276			UNKNOWN/NO DATA
6/18/2021 10:09	6/18/2021 12:41	Subtransmission	None	TRK 2713			UNKNOWN/NO DATA
6/19/2021 6:50	6/19/2021 19:51	Subtransmission	None	TIE 3209			UNKNOWN/NO DATA
6/22/2021 15:25	6/22/2021 20:28	Subtransmission	None	TIE 3208			UNKNOWN/NO DATA
6/22/2021 14:48	6/22/2021 21:35	Subtransmission	None	TIE 9111			UNKNOWN/NO DATA
6/22/2021 14:37	6/22/2021 16:44	Subtransmission	Distribution	TIE 9111	1102	128098	UNKNOWN/NO DATA
6/24/2021 12:03	6/27/2021 20:26	Subtransmission	None	TIE 226			UNKNOWN/NO DATA
6/26/2021 8:16	6/26/2021 20:34	Subtransmission	None	TRK 2107			UNKNOWN/NO DATA
6/27/2021 0:00	6/27/2021 7:47	Subtransmission	None	TIE 7745			UNKNOWN/NO DATA

6/27/2021 9:30	6/28/2021 2:30	Subtransmission	None	TRK 4316			UNKNOWN/NO DATA
6/28/2021 20:13	6/29/2021 12:40	Subtransmission	None	TRK 2002			UNKNOWN/NO DATA
6/29/2021 4:58	6/29/2021 12:07	Subtransmission	None	TRK 2002			UNKNOWN/NO DATA
6/29/2021 5:22	6/29/2021 12:49	Subtransmission	None	TRK 2002			UNKNOWN/NO DATA
6/29/2021 5:01	6/29/2021 14:08	Subtransmission	None	TRK 2002			UNKNOWN/NO DATA
6/29/2021 5:22	6/29/2021 10:55	Subtransmission	None	TRK 2002			UNKNOWN/NO DATA
6/29/2021 5:30	6/30/2021 18:18	Subtransmission	None	TRK 2205			UNKNOWN/NO DATA
6/29/2021 16:26	6/30/2021 20:51	Subtransmission	None	TRK 2205			UNKNOWN/NO DATA
6/29/2021 7:21	6/30/2021 22:09	Subtransmission	None	TRK 2233			UNKNOWN/NO DATA
7/2/2021 12:00	7/6/2021 12:22	Subtransmission	None	TRK 1276			UNKNOWN/NO DATA
7/4/2021 20:22	7/4/2021 23:48	Subtransmission	None	TRK 1232			UNKNOWN/NO DATA
7/4/2021 20:26	7/4/2021 23:52	Subtransmission	None	TRK 1232			UNKNOWN/NO DATA
7/5/2021 5:39	7/5/2021 11:08	Subtransmission	None	TIE 810			UNKNOWN/NO DATA
7/5/2021 10:14	7/5/2021 12:12	Subtransmission	None	TIE 9310			UNKNOWN/NO DATA
7/5/2021 7:53	7/5/2021 16:50	Subtransmission	None	TRK 7035			UNKNOWN/NO DATA
7/6/2021 18:36	7/7/2021 21:20	Subtransmission	None	TRK 1243			UNKNOWN/NO DATA
7/6/2021 17:51	7/6/2021 21:53	Subtransmission	None	TRK 1403			UNKNOWN/NO DATA
7/6/2021 7:33	7/7/2021 20:21	Subtransmission	None	TRK 2205			UNKNOWN/NO DATA
7/6/2021 19:38	7/7/2021 16:25	Subtransmission	None	TRK 4911			UNKNOWN/NO DATA
7/7/2021 15:51	7/12/2021 15:43	Subtransmission	None	TRK 1243			UNKNOWN/NO DATA
7/7/2021 20:16	7/8/2021 2:32	Subtransmission	None	TRK 5938			UNKNOWN/NO DATA
7/8/2021 11:50	7/8/2021 17:34	Subtransmission	None	TIE 4532			UNKNOWN/NO DATA
7/9/2021 7:57	7/9/2021 16:54	Subtransmission	None	TRK 7114			UNKNOWN/NO DATA
7/13/2021 15:06	7/13/2021 18:43	Subtransmission	None	TIE 807			UNKNOWN/NO DATA
7/14/2021 18:50	7/14/2021 21:52	Subtransmission	None	TRK 2218			UNKNOWN/NO DATA
7/17/2021 12:54	7/19/2021 8:36	Subtransmission	None	TIE 2648			UNKNOWN/NO DATA
7/21/2021 10:58	7/22/2021 8:05	Subtransmission	None	TIE 8511			UNKNOWN/NO DATA
7/21/2021 23:54	7/22/2021 8:43	Subtransmission	None	TIE 9107			UNKNOWN/NO DATA
7/21/2021 3:19	7/21/2021 3:39	Subtransmission	None	TRK 5935			UNKNOWN/NO DATA
7/21/2021 6:28	7/21/2021 17:42	Subtransmission	None	TRK 5935			UNKNOWN/NO DATA
7/21/2021 11:02	7/21/2021 15:17	Subtransmission	None	TRK 6919			UNKNOWN/NO DATA
7/22/2021 10:07	7/23/2021 8:43	Subtransmission	Distribution	TIE 8014	777	87445	UNKNOWN/NO DATA
7/22/2021 10:40	7/24/2021 6:41	Subtransmission	None	TIE 9111			UNKNOWN/NO DATA
7/22/2021 9:58	7/22/2021 12:51	Subtransmission	None	TRK 2107			UNKNOWN/NO DATA
7/24/2021 16:22	7/24/2021 20:15	Subtransmission	Distribution	TIE 3208	211	41684	UNKNOWN/NO DATA
7/24/2021 19:55	7/25/2021 20:59	Subtransmission	None	TIE 6138			UNKNOWN/NO DATA
7/24/2021 22:37	7/26/2021 12:51	Subtransmission	None	TRK 2443			UNKNOWN/NO DATA
7/24/2021 16:39	7/24/2021 20:25	Subtransmission	None	TRK 3208			UNKNOWN/NO DATA
7/28/2021 9:43	8/2/2021 2:20	Subtransmission	None	TIE 5829			UNKNOWN/NO DATA
7/28/2021 21:32	7/29/2021 16:25	Subtransmission	None	TIE 810			UNKNOWN/NO DATA
7/29/2021 10:09	8/1/2021 14:55	Subtransmission	None	TRK 1232			UNKNOWN/NO DATA
7/29/2021 19:02	7/30/2021 6:49	Subtransmission	None	TRK 1303			UNKNOWN/NO DATA
7/31/2021 9:08	7/31/2021 13:23	Subtransmission	None	TIE 3402			UNKNOWN/NO DATA
8/1/2021 10:01	8/1/2021 17:57	Subtransmission	None	TIE 3417			UNKNOWN/NO DATA
8/1/2021 14:51	8/1/2021 19:04	Subtransmission	None	TIE 4605			UNKNOWN/NO DATA
8/1/2021 6:35	8/1/2021 9:36	Subtransmission	None	TIE 7504			UNKNOWN/NO DATA
8/1/2021 16:11	8/2/2021 1:15	Subtransmission	None	TRK 1232			UNKNOWN/NO DATA
8/3/2021 22:55	8/4/2021 0:39	Subtransmission	None	TRK 6854			UNKNOWN/NO DATA
8/7/2021 7:31	8/8/2021 0:13	Subtransmission	None	TRK 2032			UNKNOWN/NO DATA
8/7/2021 9:27	8/7/2021 14:19	Subtransmission	None	TRK 2611			UNKNOWN/NO DATA
8/8/2021 6:39	8/8/2021 13:51	Subtransmission	None	TIE 7408			UNKNOWN/NO DATA
8/9/2021 16:43	8/10/2021 20:10	Subtransmission	None	TRK 3518			UNKNOWN/NO DATA
8/11/2021 1:28	8/11/2021 21:02	Subtransmission	None	TIE 3205			UNKNOWN/NO DATA
8/11/2021 1:20	8/11/2021 6:13	Subtransmission	None	TIE 3212			UNKNOWN/NO DATA
8/11/2021 1:30	8/11/2021 12:45	Subtransmission	None	TIE 3416			UNKNOWN/NO DATA
8/11/2021 15:06	8/13/2021 20:19	Subtransmission	None	TIE 4523			UNKNOWN/NO DATA
8/11/2021 22:49	8/12/2021 14:01	Subtransmission	None	TRK 2010			UNKNOWN/NO DATA
8/12/2021 16:16	8/13/2021 19:32	Subtransmission	None	TIE 6621			UNKNOWN/NO DATA
8/12/2021 21:43	8/15/2021 14:25	Subtransmission	None	TRK 2824			UNKNOWN/NO DATA
8/16/2021 14:24	8/21/2021 22:56	Subtransmission	None	TRK 6125			UNKNOWN/NO DATA
8/19/2021 14:01	8/21/2021 23:02	Subtransmission	None	TIE 4109			UNKNOWN/NO DATA
8/23/2021 18:51	8/24/2021 15:26	Subtransmission	None	TRK 3661			UNKNOWN/NO DATA
8/24/2021 22:30	8/25/2021 8:00	Subtransmission	None	TRK 5140			UNKNOWN/NO DATA
8/27/2021 15:07	8/27/2021 20:27	Subtransmission	None	TIE 3323			UNKNOWN/NO DATA
8/27/2021 13:11	8/28/2021 20:01	Subtransmission	None	TRK 1340			UNKNOWN/NO DATA
8/28/2021 5:26	8/28/2021 13:32	Subtransmission	None	TIE 4109			UNKNOWN/NO DATA
8/29/2021 19:45	9/1/2021 9:06	Subtransmission	None	TIE 2812			UNKNOWN/NO DATA
8/29/2021 18:04	8/30/2021 20:21	Subtransmission	None	TIE 3203			UNKNOWN/NO DATA
8/29/2021 18:39	8/30/2021 0:31	Subtransmission	Distribution	TIE 4104	1133	229132	UNKNOWN/NO DATA
8/29/2021 20:31	8/30/2021 3:40	Subtransmission	None	TIE 4104			UNKNOWN/NO DATA
8/29/2021 18:15	8/31/2021 13:12	Subtransmission	None	TIE 9111			UNKNOWN/NO DATA
9/1/2021 8:33	9/2/2021 3:31	Subtransmission	None	TIE 3323			UNKNOWN/NO DATA
9/1/2021 22:19	9/3/2021 12:51	Subtransmission	None	TIE 3417			UNKNOWN/NO DATA
9/2/2021 11:35	9/2/2021 16:36	Subtransmission	None	TRK 6125			UNKNOWN/NO DATA
9/3/2021 20:20	9/4/2021 14:20	Subtransmission	None	TIE 9111			UNKNOWN/NO DATA
9/4/2021 9:22	9/5/2021 20:18	Subtransmission	None	TIE 4523			UNKNOWN/NO DATA
9/7/2021 20:35	9/8/2021 6:00	Subtransmission	None	TIE 1568			UNKNOWN/NO DATA
9/7/2021 18:09	9/10/2021 0:00	Subtransmission	None	TIE 3318			UNKNOWN/NO DATA
9/7/2021 15:25	9/7/2021 22:03	Subtransmission	None	TRK 2918			UNKNOWN/NO DATA
9/7/2021 5:55	9/7/2021 10:23	Subtransmission	None	TRK 4338			UNKNOWN/NO DATA
9/8/2021 8:08	9/8/2021 20:03	Subtransmission	None	TIE 1568			UNKNOWN/NO DATA
9/8/2021 17:45	9/11/2021 8:42	Subtransmission	None	TIE 7621			UNKNOWN/NO DATA
9/10/2021 14:33	9/10/2021 20:40	Subtransmission	None	TRK 7104			UNKNOWN/NO DATA
9/11/2021 12:54	9/11/2021 18:44	Subtransmission	None	TRK 3536			UNKNOWN/NO DATA
9/15/2021 10:55	9/16/2021 11:12	Subtransmission	None	TIE 6931			UNKNOWN/NO DATA
9/17/2021 19:42	9/18/2021 1:58	Subtransmission	None	TRK 2005			UNKNOWN/NO DATA
9/17/2021 19:45	9/18/2021 0:26	Subtransmission	None	TRK 2005			UNKNOWN/NO DATA
9/18/2021 4:09	9/18/2021 6:37	Subtransmission	None	TIE 9205			UNKNOWN/NO DATA
9/20/2021 17:20	9/21/2021 4:21	Subtransmission	None	TIE 7520			UNKNOWN/NO DATA
9/20/2021 19:43	9/21/2021 16:46	Subtransmission	None	TIE 7520			UNKNOWN/NO DATA
9/20/2021 11:49	9/21/2021 0:34	Subtransmission	None	TRK 5127			UNKNOWN/NO DATA
9/23/2021 16:11	9/24/2021 17:38	Subtransmission	None	TIE 3323			UNKNOWN/NO DATA
9/23/2021 19:30	9/24/2021 0:05	Subtransmission	None	TIE 9111			UNKNOWN/NO DATA
9/24/2021 12:25	9/24/2021 18:37	Subtransmission	None	TRK 2233			UNKNOWN/NO DATA
10/9/2021 15:03	10/10/2021 13:16	Subtransmission	None	TRK 2032			UNKNOWN/NO DATA
10/20/2021 1:14	10/20/2021 5:19	Subtransmission	None	TRK 3650			UNKNOWN/NO DATA
10/20/2021 8:40	10/20/2021 10:15	Subtransmission	None	TRK 5145			UNKNOWN/NO DATA
10/20/2021 10:24	10/21/2021 7:06	Subtransmission	None	TRK 5145			UNKNOWN/NO DATA
10/23/2021 9:27	10/23/2021 14:27	Subtransmission	None	TRK 6125			UNKNOWN/NO DATA
10/30/2021 12:00	10/30/2021 17:56	Subtransmission	None	TIE 3822			UNKNOWN/NO DATA
11/4/2021 15:59	11/4/2021 19:32	Subtransmission	None	TIE 1568			UNKNOWN/NO DATA
11/5/2021 20:59	11/6/2021 3:12	Subtransmission	Distribution	TRK 117	1	84	UNKNOWN/NO DATA
11/11/2021 19:04	11/11/2021 21:13	Subtransmission	None	TIE 9111			UNKNOWN/NO DATA
11/11/2021 18:58	11/14/2021 10:09	Subtransmission	None	TIE 9111			UNKNOWN/NO DATA
11/11/2021 18:58	11/12/2021 2:11	Subtransmission	None	TIE 9111			UNKNOWN/NO DATA

11/11/2021 19:00	11/12/2021 3:40	Subtransmission	None	TIE 9111			UNKNOWN/NO DATA
11/11/2021 18:54	11/12/2021 1:43	Subtransmission	None	TIE 9111			UNKNOWN/NO DATA
11/13/2021 6:02	11/13/2021 13:00	Subtransmission	Distribution	TRK 2918	1	418	UNKNOWN/NO DATA
11/14/2021 17:52	11/14/2021 20:15	Subtransmission	None	TRK 4227			UNKNOWN/NO DATA
11/15/2021 23:55	11/16/2021 3:32	Subtransmission	None	TRK 1243			UNKNOWN/NO DATA
11/20/2021 11:47	11/21/2021 15:10	Subtransmission	None	TRK 2035			UNKNOWN/NO DATA
11/21/2021 12:16	11/21/2021 14:10	Subtransmission	None	TRK 1276			UNKNOWN/NO DATA
11/24/2021 17:31	12/27/2021 10:28	Subtransmission	None	TIE 3220			UNKNOWN/NO DATA
11/24/2021 10:57	11/29/2021 6:55	Subtransmission	None	TRK 1303			UNKNOWN/NO DATA
11/24/2021 10:00	11/24/2021 15:41	Subtransmission	None	TRK 6125			UNKNOWN/NO DATA
11/29/2021 9:14	11/29/2021 14:29	Subtransmission	None	TIE 4428			UNKNOWN/NO DATA
12/4/2021 20:28	12/5/2021 3:57	Subtransmission	None	TRK 1276			UNKNOWN/NO DATA
12/10/2021 8:20	12/10/2021 10:27	Subtransmission	None	TRK 3557			UNKNOWN/NO DATA
12/11/2021 13:36	12/13/2021 16:55	Subtransmission	None	TIE 1318			UNKNOWN/NO DATA
12/11/2021 21:31	12/13/2021 19:58	Subtransmission	None	TIE 2812			UNKNOWN/NO DATA
12/11/2021 15:25	12/13/2021 17:20	Subtransmission	None	TIE 7702			UNKNOWN/NO DATA
12/11/2021 12:50	12/12/2021 15:11	Subtransmission	Distribution	TIE 9111	1	1635	UNKNOWN/NO DATA
12/11/2021 11:37	12/12/2021 19:52	Subtransmission	None	TIE 9111			UNKNOWN/NO DATA
12/11/2021 10:43	12/11/2021 11:00	Subtransmission	Subtransmission	TIE 9111	255	3388	UNKNOWN/NO DATA
12/12/2021 8:09	12/14/2021 9:21	Subtransmission	None	TIE 9111			UNKNOWN/NO DATA
12/16/2021 11:36	12/16/2021 18:02	Subtransmission	None	TIE 3205			UNKNOWN/NO DATA
12/25/2021 1:24	12/25/2021 15:24	Subtransmission	None	TRK 1502			UNKNOWN/NO DATA
12/27/2021 6:55	12/30/2021 18:14	Subtransmission	None	TIE 1467			UNKNOWN/NO DATA
12/28/2021 13:05	12/29/2021 15:47	Subtransmission	None	TIE 7702			UNKNOWN/NO DATA
12/30/2021 12:16	12/30/2021 18:13	Subtransmission	None	TIE 7745			UNKNOWN/NO DATA
4/29/2022 15:42	4/30/2022 19:50	Subtransmission	None	TRK 5404			UNKNOWN/NO DATA
5/20/2022 2:10	5/21/2022 4:10	Subtransmission	None	TRK 7913			UNKNOWN/NO DATA
5/26/2022 14:42	5/26/2022 20:06	Subtransmission	None	TRK 2611			UNKNOWN/NO DATA
5/31/2022 20:03	6/1/2022 4:16	Subtransmission	None	TRK 7122			UNKNOWN/NO DATA
6/7/2022 1:52	6/8/2022 10:27	Subtransmission	None	TRK 4419			UNKNOWN/NO DATA
6/7/2022 23:55	6/8/2022 5:14	Subtransmission	None	TRK 7062			UNKNOWN/NO DATA
6/20/2022 10:47	6/20/2022 20:25	Subtransmission	None	TRK 5510			UNKNOWN/NO DATA
6/27/2022 7:39	7/1/2022 6:40	Subtransmission	None	TRK 2010			UNKNOWN/NO DATA
7/1/2022 7:39	7/1/2022 14:18	Subtransmission	None	TRK 7909			UNKNOWN/NO DATA
7/10/2022 6:38	7/10/2022 17:07	Subtransmission	None	TRK 7909			UNKNOWN/NO DATA
7/17/2022 7:33	7/18/2022 5:40	Subtransmission	None	TRK 6125			UNKNOWN/NO DATA
7/22/2022 16:36	7/23/2022 10:17	Subtransmission	None	TRK 4962			UNKNOWN/NO DATA
7/24/2022 0:26	7/24/2022 9:37	Subtransmission	None	TRK 2016			UNKNOWN/NO DATA
7/28/2022 0:07	7/28/2022 5:33	Subtransmission	None	TRK 7062			UNKNOWN/NO DATA
7/30/2022 3:49	7/30/2022 14:53	Subtransmission	None	TRK 2233			UNKNOWN/NO DATA
7/30/2022 3:48	7/30/2022 17:19	Subtransmission	None	TRK 2233			UNKNOWN/NO DATA
7/31/2022 16:28	8/1/2022 6:14	Subtransmission	None	TRK 7035			UNKNOWN/NO DATA
8/4/2022 23:21	8/6/2022 5:22	Subtransmission	None	TRK 2305			UNKNOWN/NO DATA
8/6/2022 23:06	8/7/2022 18:26	Subtransmission	None	TRK 7106			UNKNOWN/NO DATA
8/10/2022 17:31	8/10/2022 21:59	Subtransmission	None	TRK 346			UNKNOWN/NO DATA
8/16/2022 7:40	8/16/2022 11:40	Subtransmission	None	TRK 6919			UNKNOWN/NO DATA
9/15/2022 12:32	9/15/2022 21:08	Subtransmission	None	TRK 2016			UNKNOWN/NO DATA
10/6/2022 18:14	10/7/2022 12:50	Subtransmission	None	TRK 5838			UNKNOWN/NO DATA
10/10/2022 13:17	10/10/2022 16:55	Subtransmission	None	TRK 5510			UNKNOWN/NO DATA
4/6/2023 14:34	4/6/2023 15:00	Subtransmission	Circuit Level	TRK 2611			UNKNOWN/NO DATA
4/6/2023 14:34	4/6/2023 15:01	Subtransmission	Circuit Level	TRK 2611			UNKNOWN/NO DATA
2/18/2022 11:16	2/18/2022 11:51	Subtransmission	None	TRK 8407			WIND
3/23/2022 17:59	3/24/2022 15:31	Subtransmission	None	TIE 9303			WIND
3/31/2022 13:43	4/2/2022 5:11	Subtransmission	None	TRK 7913			WIND
4/14/2022 15:54	4/14/2022 22:34	Subtransmission	None	TIE 6621			WIND
4/15/2022 17:18	4/23/2022 9:59	Subtransmission	None	TIE 6147			WIND
5/8/2022 4:29	5/9/2022 4:29	Subtransmission	None	TIE 2812			WIND
5/9/2022 13:13	5/10/2022 4:26	Subtransmission	None	TIE 6621			WIND
6/3/2022 15:37	6/3/2022 20:52	Subtransmission	None	TIE 9123			WIND
7/20/2022 15:46	7/23/2022 12:58	Subtransmission	None	TIE 7702			WIND
7/25/2022 19:31	7/26/2022 1:15	Subtransmission	None	TRK 1346			WIND
7/28/2022 17:45	7/29/2022 21:29	Subtransmission	None	TRK 1502			WIND
8/2/2022 10:49	8/2/2022 18:07	Subtransmission	None	TIE1467			WIND
8/3/2022 9:14	8/3/2022 19:41	Subtransmission	None	TRK 1502			WIND
8/9/2022 1:02	8/10/2022 23:08	Subtransmission	None	TRK 1473			WIND
8/30/2022 7:46	8/30/2022 15:59	Subtransmission	None	TIE 810			WIND
9/20/2022 18:28	9/21/2022 20:54	Subtransmission	None	TIE 5513			WIND
10/8/2022 11:42	10/8/2022 16:18	Subtransmission	None	TRK 2943			WIND
10/12/2022 11:41	10/13/2022 21:06	Subtransmission	None	TRK 6125			WIND
10/17/2022 18:57	10/17/2022 23:55	Subtransmission	None	TRK 1232			WIND
11/5/2022 14:05	11/6/2022 20:48	Subtransmission	None	TIE 3206			WIND
11/5/2022 19:12	11/6/2022 20:12	Subtransmission	None	TIE 9211			WIND
12/3/2022 8:10	12/7/2022 7:22	Subtransmission	None	TIE 7430			WIND
12/10/2022 16:29	12/10/2022 19:00	Subtransmission	None	TRK 5855			WIND
12/17/2022 12:31	12/17/2022 15:20	Subtransmission	None	TIE 5823			WIND
12/23/2022 6:23	12/24/2022 15:04	Subtransmission	None	TIE 7430			WIND
12/23/2022 7:03	12/24/2022 22:44	Subtransmission	None	TIE 9211			WIND
1/19/2023 7:49	1/19/2023 17:03	Subtransmission	None	TIE 3800			WIND
2/15/2023 13:52	2/16/2023 16:39	Subtransmission		TIE 3210			WIND
2/15/2023 13:41	2/15/2023 15:31	Subtransmission	Subtransmission	TIE 3410	222	23158	WIND
2/15/2023 11:34	2/15/2023 15:32	Subtransmission	Subtransmission	TIE 810	3	666	WIND
2/22/2023 18:48	2/23/2023 0:57	Subtransmission		TRK 2931			WIND
2/27/2023 15:58	3/3/2023 6:16	Subtransmission		TIE 3416			WIND
3/3/2023 17:57	3/5/2023 2:21	Subtransmission		TRK 5510			WIND
3/4/2023 2:39	3/4/2023 13:08	Subtransmission	Circuit Level	TIE 807	1	846	WIND
7/18/2023 16:24	7/22/2023 6:28	Subtransmission		TRK 1610			WIND
7/28/2023 16:59	7/29/2023 8:31	Subtransmission	Subtransmission	TRK 1340	103	247550	WIND
8/24/2023 23:04	8/25/2023 18:19	Subtransmission		TIE 1473			WIND
8/24/2023 23:20	8/25/2023 16:27	Subtransmission		TIE 3705			WIND
8/25/2023 2:44	8/29/2023 1:15	Subtransmission		TRK 1340			WIND
8/25/2023 3:08	8/29/2023 10:19	Subtransmission		TIE 2621			WIND
8/28/2023 8:23	9/4/2023 18:27	Subtransmission		TIE 1473			WIND
10/14/2023 9:13	10/15/2023 15:39	Subtransmission		TRK 3543			WIND
11/30/2023 11:50	12/3/2023 9:05	Subtransmission		TIE 226			WIND
3/26/2021 4:05	3/26/2021 14:57	Subtransmission	None	TRK 4301			EQUIPMENT FAILURE

MPSC Case No: U-21534

Requester: MNSC

Question No.: MNSCDE-1.8a

Respondent: J. Kryscynski

Page: 1 of 3

Question: 8. Refer to Kryscynski direct, p. 61, lines 4-8:
a. Produce the detailed analyses based on historical data, engineering assessments, and field feedback that were used to quantify each investment's benefits within each impact dimension (to the extent different than the assessments requested in the prior question), including workpapers and source documents.

Answer: DTE Electric objects to the request for the reasons that the request is overly broad, seeks excessive detail, seeks confidential, proprietary research, or commercial information belonging to DTE Electric, the disclosure of which would cause DTE Electric and its customers competitive or commercial harm, seeks information involving Cyber Security, CEII (either critical energy infrastructure information or critical electric infrastructure information), North American Electric Reliability Corporation (NERC) NERC-CIP (including but not limited to BES Cyber Asset information subject to protection under the Information Protection Program pursuant to NERC Reliability Standards CIP-003-6 and CIP-011-2), Supervisory Control and Data Acquisition (SCADA), confidential Midcontinent Independent System Operation (MISO) and ITC Holdings Corp and/or its affiliate companies' information in the possession of DTE Electric, U.S. export control laws and regulations, including but not limited to 10 C.F.R. Part 810 et. seq., or 10 CFR Part 2.390.

Subject to and without waiving this objection the following documents have been designated as containing Critical Energy Infrastructure Information or Critical Electric Infrastructure Information and are being provided subject to the protective order in this case as they include information about DTE Electric's system or assets, whether physical or virtual, the incapacity or destruction of which would negatively affect national security, economic security, public health or safety, or any combination of such matters:

MPSC Case No: U-21534

Requester: MNSC

Question No.: MNSCDE-1.8a

Respondent: J. Kryscynski

Page: 2 of 3

1. DTE Electric's unredacted GPM
2. DTE Electric's Load Relief Model, which will be made available for review on a read-only portal Link: https://dteenergy.sharepoint.com/sites/DiscoveryPortal/Elec/21534CEII/Documents/Forms/AllItems.aspx
3. DTE Electric's Substation Risk Model, which will be made available for virtual review at a mutually agreeable time.

Please also see WP AJK U-21534 (the Company's Reliability Model), which is an input to the GPM.

A summary of the data and impact dimensions is provided in the table below.

Impact Dimension	Analysis and data provided to quantity benefits
Reduce Electrical Hazards	The full version of the GPM, which is being provided under the protective order, contains historical wiredown information, and the assessed benefit for any projects that will reduce the frequency of wiredowns.
Overload Relief	As stated above, DTEE's Load Relief Model is being provided under the protective order. This Excel file contains the underlying historical loading data and assessment of Overload Relief provided by proposed projects.
SAIDI SAIFI	The GPM workpaper contains historical circuit level reliability data (both SAIDI and SAIFI) and the assessment of the reduction of SAIDI and SAIFI that projects evaluated in the GPM will deliver.
Regulatory Compliance	The GPM workpaper scores two investments as being applicable for a Regulatory Compliance Score: PTMM and CEMI.
Major Event Risk	While the overall Major Event Risk scores are provided in the GPM workpaper, DTEE's underlying substation risk model is discussed below.
Capacity Relief	As stated above, DTEE's Load Relief Model is being provided under the protective order. This Excel file contains the underlying historical loading data and assessment of Capacity Relief provided by proposed projects.

MPSC Case No: U-21534

Requester: MNSC

Question No.: MNSCDE-1.8a

Respondent: J. Kryscynski

Page: 3 of 3

Impact Dimension	Analysis and data provided to quantity benefits
Investment in EJ Communities	The calculations for this impact dimension, which is a count of customers in census tract with MiEJScreen score above 80 impact by a project, divided by total customer impacted by a project, multiplied by 100, are provided in the GPM workpaper.
O&M Avoidance	The GPM workpaper contains historical circuit level event volume and the assessed reduction in event volume by project or program, which is the basis for O&M Avoidance. The GPM workpaper also contains the calculations for avoided Tree Trim, which contributes to avoided O&M.
Capital Avoidance	The GPM workpaper contains historical circuit level event volume and the assessed reduction in event volume by project or program, which is the basis for Capital Avoidance.

Attachment: NDA CEII U-21534 MNSCDE-1.8a GPM
NDA CEII U-21534 MNSCDE-1.8a DTEE Load Relief Model

GPM Results - Ranked and Sorted

138

GPM Ranking	GPM Project ID	Project/Program Name	A12 Tab	A12 Line Number	Capital Investment	Reduce Electrical Hazards	Overload Relief	Capacity Relief	Regulatory Compliance	Investment in EJ communities	Major Event Risk	SAIDI	SAIFI	O&M Avoidance	Capital Avoidance	Total Score	Reduce Electrical Hazards Checked	Overload Relief Checked	Capacity Relief Checked	Regulatory Compliance Checked	Investment in EJ communities Checked	Major Event Risk Checked	SAIDI Checked	SAIFI Checked	O&M Avoidance Checked	Capital Avoidance Checked
1	2005	ADMS: DMS/OMS	A-12 BS.4 Tech	3	$ 91,844,058	0	0	0	0	53	233	752	277	7	85	1,407					x	x	x	x	x	x
2	2008	Pole and Pole Top Maintenance and Modernization (PTMM)	A-12 BS.4 Resilience	13	$ 715,450,000	65	0	0	200	53	0	291	353	166	132	1,260	x				x		x	x	x	x
3	2007	Frequent Outage Program (CEMI)	A-12 BS.4 Resilience	15	$ 48,049,745	0	0	0	200	53	0	334	367	97	77	1,128				x	x		x	x	x	x
4	20201014	Subtransmission Redesign & Rebuild: Tie 1568	A-12 BS.4 Redesign	16	$ 723,145	0	442	448	0	0	108	0	0	0	0	998		x	x			x				
5	1015	40 kV: Automatic Pole Top Switch	A-12 BS.4 Resilience	20	$ 31,800,000	0	0	0	0	53	0	356	416	0	48	873					x		x	x	x	
6	20201053	4.8 kV CC: Hawthorne Relief and Circuit Conversion	A-12 BS.4 Redesign	47	$ 94,029,812	230	9	8	0	24	19	146	125	191	97	848	x	x	x		x	x	x	x	x	x
7	2001	4.8 kV Hardening	A-12 BS.4 Resilience	12	$ 259,000,000	125	0	0	0	173	0	75	126	146	116	761	x				x		x	x	x	x
8	20191015	CODI: Charlotte Network Upgrade	A-12 BS.4 Redesign	28	$ 76,879,246	588	3	2	0	119	20	0	0	0	0	732	x	x	x		x	x				
9	2017	Distribution Automation	A-12 BS.4 Tech	2	$ 1,162,788,221	286	0	0	0	53	0	208	138	0	0	685	x						x	x		
10	20191069	Subtransmission Redesign & Rebuild: Trunk 2237-ST	A-12 BS.4 Redesign	9	$ 1,535,072	0	417	211	0	0	0	0	0	0	0	628		x	x							
11	20191016	CODI: Garfield Network Upgrade	A-12 BS.4 Redesign	81	$ 171,851,783	367	4	1	0	179	24	4	4	9	3	596	x	x	x		x	x	x	x	x	x
12	20230023	Subtransmission Redesign & Rebuild: Trunk 7105	Planned for IRM		$ 2,647,505	0	302	130	0	122	0	0	0	0	0	554		x	x							
13	20191042	Substation Risk: Savage	A-12 BS.4 Resilience	5	$ 2,631,389	0	0	0	0	0	532	0	0	0	0	532						x				
14	20191067	Subtransmission Redesign & Rebuild: Trunk 7106	A-12 BS.4 Redesign	7	$ 2,667,402	0	300	197	0	0	0	0	0	0	0	497		x	x							
15	2029	4.8 kV CC: ISO Conversion Program	A-12 BS.4 Redesign	87	$ 25,350,000	130	0	0	0	81	0	70	0	100	80	461	x				x		x		x	x
16	20230006	4.8 kV CC: Zenon Circuit Conversion Phase 2	A-12 BS.4 Redesign	83	$ 155,800,000	71	0	1	0	195	0	30	36	59	25	417	x		x		x		x	x	x	x
17	20201046	Subtransmission Redesign & Rebuild: Trunk 2419	Planned for IRM		$ 3,267,267	0	196	50	0	165	0	0	0	0	0	410			x							
18	20191019	CODI: Howard Conversion	A-12 BS.4 Redesign	36	$ 115,099,345	213	3	1	0	174	3	0	2	2	1	401	x	x	x		x	x	x	x	x	x
19	20191034	4.8 kV CC: McKinstry Sub Decommission	A-12 BS.4 Redesign	43	$ 4,001,399	0	0	0	0	0	0	0	0	372	0	372										
20	20191005	Substation Risk: Port Huron	A-12 BS.4 Resilience	7	$ 7,093,864	0	0	0	0	0	351	0	0	0	0	351						x				
21	20191082	8.3 kV CC: Pontiac Overhead/Underground Conversion	A-12 BS.4 Redesign	90	$ 174,407,073	20	0	1	0	200	19	24	34	27	16	340	x		x			x	x	x	x	x
22	20191025	4.8 kV CC: Grosse Pointe Substation and Circuit Conversion	Planned for IRM		$ 330,838,051	78	1	1	0	77	20	41	30	60	31	340	x	x	x		x	x	x	x	x	x
23	20191065	Subtransmission Redesign & Rebuild: Trunk 2255	A-12 BS.4 Redesign	8	$ 3,403,341	0	188	95	0	0	46	0	0	0	0	329		x	x			x				
24	20230020	4.8kV CC: Barber Substation and Circuit Conversion	Planned for IRM		$ 44,056,537	65	15	14	0	131	0	21	25	29	21	320	x	x	x		x		x	x	x	x
25	20231006	Subtransmission Redesign & Rebuild - Trunk 2448	Planned for IRM		$ 3,135,957	0	102	26	0	189	0	0	0	0	0	317		x	x		x					
26	2035	CODI: Targeted Network Secondary Cable Replacement	A-12 BS.4 Redesign	29	$ 7,600,000	309	0	0	0	0	0	0	0	0	0	309	x						x	x	x	x
27	20191012	4.8 kV CC: I-94 Substation and Circuit Conversion (Promenade)	A-12 BS.4 Redesign	39	$ 247,198,258	40	1	1	0	192	2	17	12	27	14	305	x		x		x	x	x	x	x	x
28	20191079	Substation Risk: Chestnut	A-12 BS.4 Resilience	4	$ 15,988,931	0	0	0	0	139	156	0	0	0	0	295					x	x				
29	2003	Cable Replacement Program	A-12 BS.4 Resilience	14	$ 91,501,597	0	0	0	0	53	190	5	0	0	39	287					x	x	x			x
30	20231004	Subtransmission Redesign & Rebuild: Trunk 1444	Planned for IRM		$ 714,972	0	280	0	0	0	0	0	0	0	0	280		x								
31	20191023	CODI: Islandview Substation	A-12 BS.4 Redesign	31	$ 225,872,109	28	3	1	0	196	12	6	7	16	7	277	x	x	x		x	x	x	x	x	x
32	20230052	Subtransmission Redesign & Rebuild: Tie 3416 Reconductoring	Planned for IRM		$ 5,238,462	0	160	62	0	0	15	0	0	34	0	271		x	x						x	
33	20201026	Subtransmission Redesign & Rebuild: Bernard	Planned for IRM		$ 764,131	0	0	265	0	0	0	0	0	0	0	265			x							
34	20191017	CODI: Kent/Gibson Conversion	A-12 BS.4 Redesign	82	$ 149,818,241	14	0	1	0	187	8	9	10	14	6	248	x		x		x	x	x	x	x	x
35	20230027	Subtransmission Redesign & Rebuild: Trunk 7386	Planned for IRM		$ 5,404,170	0	148	60	0	36	0	0	0	0	0	244			x							
36	2004	URD Replacement Program	A-12 BS.4 Resilience	18	$ 72,041,398	0	0	0	0	53	0	50	0	15	122	240					x		x		x	x
37	20191066	Subtransmission Redesign & Rebuild: Trunk 7333	A-12 BS.4 Redesign	10	$ 4,699,265	0	170	69	0	0	0	0	0	0	0	239		x	x							
38	20191014	CODI: Alfred Substation Expansion	A-12 BS.4 Redesign	35	$ 24,704,232	0	28	11	0	200	0	0	0	0	0	238		x	x		x					
39	20201012	Subtransmission Redesign & Rebuild: Trunk 4217	A-12 BS.4 Redesign	17	$ 7,202,159	0	111	22	0	47	54	0	0	0	0	235		x	x		x	x				
40	20191037	4.8 kV CC: Birmingham Decommissioning and Circuit Conversion	A-12 BS.4 Redesign	86	$ 53,720,709	44	1	3	0	0	75	26	24	43	15	233	x	x	x			x	x	x	x	x
41	20201007	Subtransmission Redesign & Rebuild: Trunk 2455	Planned for IRM		$ 3,710,315	0	0	33	0	175	21	0	0	0	0	229			x			x				
42	20230029	Subtransmission Redesign & Rebuild: Hurst	Planned for IRM		$ 3,748,493	0	53	173	0	0	0	0	0	0	0	226		x	x							
43	20230005	4.8 kV CC: Cortland / Oakman / Linwood Consolidation	A-12 BS.4 Redesign	37	$ 9,595,144	0	17	13	0	190	0	0	0	0	0	219		x	x		x					
44	20191070	Subtransmission Redesign & Rebuild: Tie 6907	Planned for IRM		$ 2,431,018	0	0	216	0	0	0	0	0	0	0	216			x							
45	20230042	Subtransmission Redesign & Rebuild: Cortland Station Expansion	A-12 BS.4 Redesign	78	$ 7,655,693	0	0	0	0	191	20	0	0	0	0	212					x	x				
46	2002	Breaker Replacement Program	A-12 BS.4 Resilience	16	$ 70,799,000	0	0	0	0	53	19	29	0	27	80	207					x	x	x		x	x
47	20230011	Substation Risk: McGraw	A-12 BS.4 Resilience	9	$ 51,496,903	0	0	0	0	194	9	0	0	0	0	203					x	x				
48	20201054	4.8 kV CC: Belleville Substation and Circuit Conversion	Planned for IRM		$ 11,385,184	26	0	14	0	0	27	37	46	32	14	197	x					x	x	x	x	x
49	20191062	Subtransmission Redesign & Rebuild: Sandusky Transformer 101 Breaker	A-12 BS.4 Redesign	11	$ 4,069,635	0	196	0	0	0	0	0	0	0	0	196		x								
50	20230033	Subtransmission Redesign & Rebuild: Waterman	Planned for IRM		$ 5,507,060	0	0	0	0	185	0	0	0	0	0	185					x				x	x
51	20191044	4.8 kV CC: Buckler Circuit Conversion	A-12 BS.4 Redesign	42	$ 20,723,990	52	0	0	0	0	0	18	29	53	24	176	x						x	x	x	x
52	20230004	4.8 kV CC: MAUME 8241 Downtown Clawson Conversion	A-12 BS.4 Redesign	49	$ 2,627,140	0	0	0	0	0	0	65	0	73	34	172							x		x	x
53	20201050	Subtransmission Redesign & Rebuild: Trunk 3546	Planned for IRM		$ 6,583,929	0	97	49	0	0	24	0	0	0	0	170			x			x				
54	20201011	Subtransmission Redesign & Rebuild: Trunk 3509	A-12 BS.4 Redesign	18	$ 6,080,116	0	105	27	0	25	13	0	0	0	0	169		x	x		x	x				
55	20230026	Subtransmission Redesign & Rebuild: Oak Beach Capacitor	A-12 BS.4 Redesign	25	$ 1,229,133	0	163	0	0	0	0	0	0	0	0	163		x								
56	20230019	4.8kV CC: Yale-Slater Decommissioning and Circuit Conversion	Planned for IRM		$ 43,951,541	24	8	5	0	0	0	27	23	44	14	144	x	x	x				x	x	x	x
57	20241001	Substation Risk: Savage Switchgear Replacement	A-12 BS.4 Resilience	34	$ 10,040,000	0	0	0	0	0	139	0	0	0	0	139						x				
58	20191024	4.8 kV CC: Royal Oak Substation and Circuit Conversion	Planned for IRM		$ 547,652,366	27	0	0	0	22	4	27	18	20	10	129	x		x			x	x	x	x	x
59	20230049	Station Upgrade: Navarre	A-12 BS.4 Resilience	32	$ 9,835,596	0	0	0	0	128	0	0	0	0	0	128										
60	20191029	Substation Risk: Apache	A-12 BS.4 Resilience	6	$ 19,740,974	0	0	0	0	0	126	0	0	0	0	126						x				
61	20230062	Station Upgrade: Warren (Relay Replacement)	A-12 BS.4 Resilience	23	$ 11,276,899	0	0	0	0	0	0	0	0	126	0	126										
62	20191058	Subtransmission Redesign & Rebuild: Boyne	A-12 BS.4 Redesign	12	$ 28,620,273	3	28	30	0	34	0	7	13	7	3	126	x		x		x		x	x	x	x
63	20230013	4.8kV CC: Hemlock Decommissioning and Circuit Conversion	A-12 BS.4 Redesign	88	$ 68,039,683	32	0	1	0	0	0	29	25	25	12	124	x		x				x	x	x	x
64	20230054	4.8 kV CC: Hilton Substation and Circuit Conversion	A-12 BS.4 Redesign	54	$ 286,168,275	28	0	0	0	31	14	0	12	23	11	120	x		x			x		x		
65	20201013	Subtransmission Redesign & Rebuild: Trunk 2308	A-12 BS.4 Redesign	70	$ 11,384,227	0	0	14	0	53	0	6	16	17	6	112			x		x		x	x	x	x
66	20230016	Substation Risk: Belleville Switchgear Decommission	A-12 BS.4 Resilience	8	$ 2,849,868	0	0	0	0	0	109	0	0	0	0	109						x				
67	20230037	Subtransmission Redesign & Rebuild: 40kV Capacitor Banks at Armada and Adair	A-12 BS.4 Redesign	24	$ 6,696,067	0	30	79	0	0	0	0	0	0	0	108		x								

68	20201064	4.8kV CC: Rochester Decommissioning and Tienken Relief	Planned for IRM	$	27,790,000	25	3	2	0	0	6	26	11	16	8	97	x	x	x		x	x	x	x	x
69	20191039	System Loading: Jewell	A-12 BS.4 Redesign	100	$ 45,484,280	8	8	12	0	0	26	17	13	9	4	95	x	x	x		x	x	x	x	x
70	20230028	Subtransmission Redesign & Rebuild: Tie 3705	Planned for IRM	$	8,942,988	0	94	0	0	0	0	0	0	0	0	94		x							
71	20230007	4.8kV CC: SCOTN	A-12 BS.4 Redesign	52	$ 2,975,622	0	0	0	0	0	0	0	0	91	0	91									
72	20201021	4.8 kV CC: Calla Circuit Conversion and Phase 2	A-12 BS.4 Redesign	84	$ 11,804,072	0	0	21	0	0	0	11	15	36	6	89			x				x	x	x	x
73	20201015	Subtransmission Redesign & Rebuild: Tie 6602	Planned for IRM	$	6,000,228	1	0	27	0	0	0	6	8	40	3	84	x		x				x	x	x	x
74	20241002	Substation Risk: Seville	A-12 BS.4 Resilience	35	$ 4,909,000	0	0	4	0	0	79	0	0	0	0	83			x		x					
75	20191068	Subtransmission Redesign & Rebuild: Trunk 4245	A-12 BS.4 Redesign	75	$ 12,744,727	0	0	54	0	22	6	0	0	0	0	82			x	x	x					
76	20201016	Subtransmission Redesign & Rebuild: Trunk 4266	A-12 BS.4 Redesign	19	$ 8,897,277	0	0	18	0	2	61	0	0	0	0	81			x	x	x					
77	20201060	System Loading: Macomb/Golf	A-12 BS.4 Redesign	97	$ 37,871,153	2	15	25	0	0	0	7	18	5	3	75	x	x	x				x	x	x	x
78	20191074	CODI: Corktown Substation	A-12 BS.4 Redesign	30	$ 18,512,911	0	0	12	0	0	63	0	0	0	0	75	x	x	x							
79	20201004	Subtransmission Redesign & Rebuild: Badax Transformer 102 Addition	A-12 BS.4 Redesign	74	$ 11,637,905	0	17	56	0	0	0	0	0	0	0	73		x	x							
80	20230050	Station Upgrade: Northeast (Relay Replacement)	A-12 BS.4 Resilience	24	$ 19,888,076	0	0	0	0	0	0	0	0	72	0	72										
81	20231001	Substation Risk: Hood	A-12 BS.4 Resilience	26	$ 8,145,117	0	0	0	0	70	0	0	0	0	0	70										
82	20201001	System Loading: Globe	A-12 BS.4 Redesign	63	$ 2,903,000	0	0	63	0	0	0	0	0	3	2	68			x						x	x
83	20201024	System Loading: Richmond/Armada	A-12 BS.4 Redesign	94	$ 54,095,999	1	4	5	0	0	37	4	5	8	2	66	x	x	x		x	x	x	x	x	x
84	20201006	Subtransmission Redesign & Rebuild: Derby	Planned for IRM	$	8,847,165	0	23	41	0	0	0	0	0	0	0	64		x	x							
85	20201018	Subtransmission Redesign & Rebuild: Trunk 4911	A-12 BS.4 Redesign	76	$ 26,471,265	0	38	12	0	0	0	0	0	13	0	63		x	x						x	
86	20191077	System Loading: Diamond	A-12 BS.4 Redesign	104	$ 3,983,877	0	0	61	0	0	0	0	0	0	0	61			x							
87	20241009	System Loading: Kings Point	A-12 BS.4 Redesign	110	$ 84,170,796	5	12	14	0	15	0	4	4	3	2	60	x	x	x				x	x	x	x
88	20191063	Subtransmission Redesign & Rebuild: Custer Republic	A-12 BS.4 Redesign	77	$ 1,816,728	0	0	0	0	60	0	0	0	0	0	60	x			x	x	x	x	x	x
89	2021	Subtransmission Redesign & Rebuild: Thumb Electric Fault Isolation	Planned for IRM	$	1,183,107	0	0	0	0	0	0	0	0	0	58	58										x
90	20191001	System Loading: Port Sanilac	A-12 BS.4 Redesign	93	$ 85,321,374	9	2	1	0	0	0	19	18	6	3	58	x	x	x				x	x	x	x
91	20191045	System Loading: Carleton	A-12 BS.4 Redesign	58	$ 4,201,354	0	48	10	0	0	0	0	0	0	0	57		x	x							
92	20201027	Subtransmission Breaker Short Circuit Violations	A-12 BS.4 Redesign	22	$ 4,575,933	0	0	0	0	53	0	0	0	0	0	53										
93	20241011	4.8 kV CC: Unionville DC 301 B1 Conversion	A-12 BS.4 Redesign	56	$ 2,953,167	12	0	0	0	0	0	6	11	17	6	52	x						x	x	x	x
94	20230012	4.8kV CC: Pittsfield Substation and Circuit Conversion	Planned for IRM	$	65,820,138	21	0	1	0	0	0	0	0	21	8	50			x							
95	20191075	4.8 kV CC: Almont Relief and Circuit Conversion (Midas)	A-12 BS.4 Redesign	41	$ 30,730,922	2	0	6	0	0	28	5	3	4	1	50	x		x		x	x	x	x	x	x
96	20201057	System Loading: Grenada	A-12 BS.4 Redesign	98	$ 67,750,600	4	0	2	0	0	0	11	8	19	3	48	x		x				x	x	x	x
97	20231016	System Loading: New Baltimore/Chesterfield	A-12 BS.4 Redesign	109	$ 46,591,044	11	6	10	0	0	0	3	3	8	4	45	x	x	x				x	x	x	x
98	20230014	System Loading: Tahoe	A-12 BS.4 Redesign	108	$ 7,539,720	0	0	43	0	0	0	0	0	0	0	43			x							
99	20191080	System Loading: Lark/Spruce	A-12 BS.4 Redesign	99	$ 10,696,321	2	0	9	0	0	0	6	6	16	3	42	x		x				x	x	x	x
100	20201058	4.8 kV CC: Unionville Decommissioning and Circuit Conversion	Planned for IRM	$	21,168,712	3	19	5	0	0	0	2	3	6	2	41	x	x	x				x	x	x	x
101	20241003	Substation Risk: Imlay	A-12 BS.4 Resilience	36	$ 38,766,721	13	0	3	0	0	0	0	0	17	6	39	x		x						x	x
102	20201063	System Loading: Disco	A-12 BS.4 Redesign	107	$ 5,146,388	0	16	24	0	0	0	0	0	0	0	39		x	x							
103	20191036	System Loading: Wixom	A-12 BS.4 Redesign	103	$ 65,432,875	0	2	6	0	0	20	3	3	2	1	38		x	x		x	x	x	x	x	x
104	20191057	Subtransmission Redesign & Rebuild: Tie 7504	A-12 BS.4 Redesign	67	$ 38,318,301	3	5	10	0	0	0	2	3	14	1	38	x	x	x				x	x	x	x
105	20191055	Subtransmission Redesign & Rebuild: Tie 810	A-12 BS.4 Redesign	66	$ 83,331,406	2	2	6	0	0	0	4	5	14	2	35	x	x	x				x	x	x	x
106	20191056	Subtransmission Redesign & Rebuild: Tie 4105	A-12 BS.4 Redesign	13	$ 78,990,459	2	0	0	0	0	0	6	10	16	1	34	x						x	x	x	x
107	20201035	Subtransmission Redesign & Rebuild: Slocum	A-12 BS.4 Redesign	23	$ 572,679	0	0	0	0	0	0	0	0	33	0	33									x	
108	20230024	Subtransmission Redesign & Rebuild: Tie 5208	Planned for IRM	$	12,253,084	0	26	7	0	0	0	0	0	0	0	33			x							
109	20191041	System Loading: Goodison	A-12 BS.4 Redesign	102	$ 18,125,405	0	9	16	0	0	0	2	2	2	1	32		x	x				x	x	x	x
110	20230053	4.8 kV CC: GRFIN & WMSTN Conversions	A-12 BS.4 Redesign	51	$ 14,727,443	0	0	1	0	0	0	0	0	27	3	31			x							
111	20191040	4.8 kV CC: White Lake Decommissioning and Circuit Conversion	A-12 BS.4 Redesign	89	$ 40,400,000	4	7	4	0	0	0	4	4	6	2	31	x	x	x				x	x	x	x
112	20230048	Station Upgrade: Lincoln	A-12 BS.4 Resilience	29	$ 9,835,596	0	0	0	0	30	0	0	0	0	0	30										
113	20191059	Subtransmission Redesign & Rebuild: Tie 4104	A-12 BS.4 Redesign	73	$ 36,624,495	2	0	0	0	0	0	4	4	17	1	29	x						x	x	x	x
114	20230021	4.8 kV CC: Pinegrove Substation Relocation and Conversion	A-12 BS.4 Redesign	45	$ 80,881,749	8	0	0	0	0	0	7	5	4	3	27	x						x	x	x	x
115	20191038	System Loading: Sterling	A-12 BS.4 Redesign	106	$ 10,882,978	0	0	7	0	0	0	4	8	5	3	27			x				x	x	x	x
116	20191004	System Loading: Brown City	A-12 BS.4 Redesign	92	$ 84,509,290	2	13	6	0	0	0	0	2	3	1	27	x	x	x					x	x	x
117	20191013	CODI: Midtown Substation Expansion	A-12 BS.4 Redesign	34	$ 14,421,842	0	6	21	0	0	0	0	0	0	0	27		x	x							
118	20201003	System Loading: Mayville	A-12 BS.4 Redesign	101	$ 23,807,623	1	10	7	0	0	0	1	1	2	1	23	x	x	x				x	x	x	x
119	20191008	4.8 kV CC: Lapeer - Elba Expansion and Circuit Conversion (Apollo)	A-12 BS.4 Redesign	85	$ 69,402,541	2	5	4	0	0	0	3	3	4	1	23	x	x	x				x	x	x	x
120	20230025	Subtransmission Redesign & Rebuild: Trunk 4601	Planned for IRM	$	32,234,935	0	6	16	0	0	0	0	0	0	0	23		x	x							
121	20201062	System Loading: Otsego/Capac/Shaw	A-12 BS.4 Redesign	96	$ 191,850,771	0	2	2	0	0	0	3	5	9	2	22		x	x				x	x	x	
122	20191028	CODI: CATO Substation Expansion	A-12 BS.4 Redesign	79	$ 41,541,157	0	13	7	0	0	0	0	0	0	0	21		x	x							
123	20201034	Subtransmission Redesign & Rebuild: Pigeon Area Improvement	Planned for IRM	$	51,007,908	0	4	6	0	0	0	0	0	9	0	19		x	x						x	
124	20191030	System Loading: Cody	A-12 BS.4 Redesign	95	$ 71,600,000	0	6	7	0	0	0	1	2	2	1	19		x	x				x	x	x	x
125	20201040	Subtransmission Redesign & Rebuild: Tie 3205	A-12 BS.4 Redesign	71	$ 53,037,411	2	0	0	0	0	0	0	0	13	0	16	x							x	x	
126	20201032	Subtransmission Redesign & Rebuild: STPS6	Planned for IRM	$	432,915	0	0	0	0	0	0	0	0	13	0	13									x	
127	20201002	4.8 kV CC: Quincy Conversion	A-12 BS.4 Redesign	44	$ 5,403,456	2	0	0	0	0	0	2	1	5	1	10	x						x	x	x	x
128	20201065	System Loading: Spokane/Seneca	A-12 BS.4 Redesign	105	$ 29,085,914	0	0	10	0	0	0	0	0	0	0	10			x							
129	20201022	Ann Arbor System Improvements	A-12 BS.4 Redesign	2	$ 110,578,343	0	0	1	0	0	1	0	0	1	0	2			x							
130	20230045	4.8 kV CC: Ann Arbor AC Network Conversion	Planned for IRM	$	44,237,706	0	0	0	0	0	0	0	0	0	0	0	x		x							
131	20230047	4.8 kV CC: Power line Conversion of MADSN 17SL-W	A-12 BS.4 Redesign	50	$ 685,201	0	0	0	0	0	0	0	0	0	0	0	x						x	x	x	
132	20230044	Substation Risk: Voyager	A-12 BS.4 Resilience	10	$ 202,280	0	0	0	0	0	0	0	0	0	0	0					x	x	x			
133	20230043	Subtransmission Redesign & Rebuild: Maxwell Amherst	A-12 BS.4 Redesign	6	$ 9,560,912	0	0	0	0	0	0	0	0	0	0	0	x				x					
134	20230036	Subtransmission Redesign & Rebuild: Small Projects & Reserve	A-12 BS.4 Redesign	21	$ 2,832,000	0	0	0	0	0	0	0	0	0	0	0		x								
135	20230031	Subtransmission Redesign & Rebuild: Tempest Phase II	Planned for IRM	$	8,352,729	0	0	0	0	0	0	0	0	0	0	0	x				x					
136	20230030	Subtransmission Redesign & Rebuild: Praxair	A-12 BS.4 Redesign	20	$ 2,554,617	0	0	0	0	0	0	0	0	0	0	0	x						x	x		
137	20230008	4.8 kV CC: Crestwood Substation	A-12 BS.4 Redesign	48	$ 665,152	0	0	0	0	0	0	0	0	0	0	0										
138	20201030	Subtransmission Redesign & Rebuild: Mohican	Planned for IRM	$	625,926	0	0	0	0	0	0	0	0	0	0	0	x								x	

MPSC Case No: U-21534

Requester: MNSC

Question No.: MNSCDE-5.4a

Respondent: S. Deol

Page: 1 of 1

Question: 4. Refer to U-21534 Testimony - Part 1 S. S. DEOL Page SSD-52, line 9 which states: "Additionally, rebuilding the subtransmission system will also remove aging equipment reducing the probability of equipment failures."

a. Please provide the "probability of equipment failures" for each subtransmission line included in the referenced statement. Please include all calculations, workpapers, data used, and data sources.

Answer: DTE Electric objects to the request for the reasons that the request is overly broad, seeks excessive detail, seeks confidential, proprietary research, or commercial information belonging to DTE Electric, the disclosure of which would cause DTE Electric and its customers competitive or commercial harm, seeks information involving Cyber Security, CEII (either critical energy infrastructure information or critical electric infrastructure information), North American Electric Reliability Corporation (NERC) NERC-CIP (including but not limited to BES Cyber Asset information subject to protection under the Information Protection Program pursuant to NERC Reliability Standards CIP-003-6 and CIP-011-2), Supervisory Control and Data Acquisition (SCADA), confidential Midcontinent Independent System Operation (MISO) and ITC Holdings Corp and/or its affiliate companies' information in the possession of DTE Electric, U.S. export control laws and regulations, including but not limited to 10 C.F.R. Part 810 et. seq., or 10 CFR Part 2.390 and is otherwise not reasonably calculated to lead to the discovery of admissible evidence. Subject to this objection and without waiver thereof, the Company would answer as follows:

Equipment life expectancy is shown in Exhibit 4.3.1.1 Asset Age Summary in Exhibit A-23 Schedule M8.

Additional information is provided in the subtransmission redesign and rebuild projects in Exhibit A-23 Schedule M6.

Attachment: None

Co-respondent: Legal

MPSC Case No: U-21534

Requester: MNSC

Question No.: MNSCDE-5.4b

Respondent: S. Deol

Page: 1 of 1

Question: 4. Refer to U-21534 Testimony - Part 1 S. S. DEOL Page SSD-52, line 9 which states: "Additionally, rebuilding the subtransmission system will also remove aging equipment reducing the probability of equipment failures."

b. For each subtransmission line proposed for rebuild, provide the probability of equipment failures before the rebuild and the estimated probability of equipment failures after the rebuild. Please include all calculations, workpapers, data used, and data sources.

Answer: See response to MNSCDE5.4a.

Attachment: None

MPSC Case No: U-21534

Requester: MNSC

Question No.: MNSCDE-5.4c

Respondent: S. Deol

Page: 1 of 1

Question: 4. Refer to U-21534 Testimony - Part 1 S. S. DEOL Page SSD-52, line 9 which states: "Additionally, rebuilding the subtransmission system will also remove aging equipment reducing the probability of equipment failures."

c. For each subtransmission line proposed for rebuild, estimate the consequences of associated equipment failures in dollars. :

Answer: See response to MNSCDE5.4a.

Attachment: None

MPSC Case No: U-21534

Requester: MNSC

Question No.: MNSCDE-8.5a

Respondent: J. Kryscynski

Page: 1 of 2

Question: 5. Refer to Mr. Kryscynski's testimony at page 56, which states "The engineering team evaluates alternatives to meet the system needs and selects the best project or program to move forward. If necessary, a BCA takes place as part of the engineering process to select the best option. The solution which is selected to move forward is scored in the GPM for prioritization." Refer also to NDA U-21534 MNSCDE-1.8a GPM CONFIDENTIAL, which provides GPM scores for 138 different projects in tab "GPM Results".

a. Provide every benefit-cost analyses completed on any of these particular 138 projects. Please also provide any alternatives to these 138 projects that were considered.

Answer: The Company has performed two benefit-cost analyses, one for PTMM and one for strategic undergrounding, which were provided in MNSC3.10b.

The Company has also provided a provided a prioritization model for Distribution Automation in MNSCDE-12.13 which is not a cost-benefit model but does use costs and benefits as a part of prioritization.

A summary of alternatives considered for many of 138 programs and projects listed in the GPM are provided in the attachment MNSCDE-8.5a Project Alternatives.

While some projects may not have specific alternatives listed in this attachment, alternatives were likely considered during the early phases of the engineering process. During initial planning stages of large projects, multiple design options are often explored as different engineering groups collaborate to brainstorm high-level solutions. An initial set of solutions will be narrowed down if some solutions are determined to be unsuitable for reasons such as, but not limited to, the following:

- Does not adhere to DTE engineering standards and practices
- Availability or lead time of equipment is too long
- An extended outage duration is required to complete project
- Alternative is overly complex and not markedly better than other options

MPSC Case No: U-21534

Requester: MNSC

Question No.: MNSCDE-8.5a

Respondent: J. Kryscynski

Page: 2 of 2

In the early stages of project development, alternatives are often not documented because of the high number of proposed solutions and the ability to dismiss some alternatives without significant engineering analysis. Initial engineering investigations narrow down the high number of proposed alternatives to a select few or sometimes single project scope to be further reviewed.

Even if no suitable alternative solution is developed, the proposed solution is reviewed by subject matter experts to confirm that the solution is the best engineering solution to the problem and a reasonable and prudent use of capital funds.

Attachment: U-21534 MNSCDE-8.5a-01 Project Alternatives

GPM Results - Ranked and Sorted

138

GPM Ranking	GPM Project ID	Project/Program Name	A12 Tab	Alternatives
1	2005	ADMS: DMS/OMS	A-12 B5.4 Tech	
2	2008	Pole and Pole Top Maintenance and Modernization (PTMM)	A-12 B5.4 Resilience	
3	2007	Frequent Outage Program (CEMI)	A-12 B5.4 Resilience	
4	20201014	Subtransmission Redesign & Rebuild: Tie 1568	A-12 B5.4 Redesign	1. Increase amount of load blocked: Adjust setting at CROWN substation.
5	1015	40 kV: Automatic Pole Top Switch	A-12 B5.4 Resilience	
6	20201053	4.8 kV CC: Hawthorne Relief and Circuit Conversion	A-12 B5.4 Redesign	
7	2001	4.8 kV Hardening	A-12 B5.4 Resilience	
8	20191015	CODI: Charlotte Network Upgrade	A-12 B5.4 Redesign	1. Eliminate AC Network and convert to radial system 2. Rebuild existing system at 4.8kV with direct replacements
9	2017	Distribution Automation	A-12 B5.4 Tech	
10	20191069	Subtransmission Redesign & Rebuild: Trunk 2237-ST	A-12 B5.4 Redesign	
11	20191016	CODI: Garfield Network Upgrade	A-12 B5.4 Redesign	1. Converting to a below grade vault-based system was investigated at the start of the CODI initiative. Peer utility visits were conducted, and analysis was completed comparing cost, operability, and impact on the project schedule
12	20230023	Subtransmission Redesign & Rebuild: Trunk 7105	Planned for IRM	
13	20191042	Substation Risk: Savage	A-12 B5.4 Resilience	1. Build a new substation which was not adopted as footprint was not available.
14	20191067	Subtransmission Redesign & Rebuild: Trunk 7106	A-12 B5.4 Redesign	1. Parallel existing cables with new cables 2. Replace existing cables for only a segment of the line
15	2029	4.8 kV CC: ISO Conversion Program	A-12 B5.4 Redesign	
16	20230006	4.8 kV CC: Zenon Circuit Conversion Phase 2	A-12 B5.4 Redesign	
17	20201046	Subtransmission Redesign & Rebuild: Trunk 2419	Planned for IRM	
18	20191019	CODI: Howard Conversion	A-12 B5.4 Redesign	1. Eliminate AC Network and convert to radial system. 2. Rebuild existing system at 4.8kV with direct replacements
19	20191034	4.8 kV CC: McKinstry Sub Decommission	A-12 B5.4 Redesign	
20	20191005	Substation Risk: Port Huron	A-12 B5.4 Resilience	1. Transfer all load from PTHUR to Surrounding Substations. 2. Install Switchgear/Reclosers Outside 3. Install new Breakers in Basement of Building 4. Decommission PTHUR and Build a new 13.2kV Substation at a new site 5. Install 9 poisiton indoor switchgear and maintain existing circuit configurations
21	20191082	8.3 kV CC: Pontiac Overhead/Underground Conversion	A-12 B5.4 Redesign	1. Replace / update 8.3kV substation equipment which was not adopted as voltage class is not compatible with DTE inventory.
22	20191025	4.8 kV CC: Grosse Pointe Substation and Circuit Conversion	Planned for IRM	
23	20191065	Subtransmission Redesign & Rebuild: Trunk 2255	A-12 B5.4 Redesign	
24	20230020	4.8kV CC: Barber Substation and Circuit Conversion	Planned for IRM	1. Property close to existing BUNRT substation was considered, however properties environmental and survey results proved this site less than ideal
25	20231006	Subtransmission Redesign & Rebuild - Trunk 2448	Planned for IRM	
26	2035	CODI: Targeted Network Secondary Cable Replacement	A-12 B5.4 Redesign	
27	20191012	4.8 kV CC: I-94 Substation and Circuit Conversion (Promenade)	A-12 B5.4 Redesign	
28	20191079	Substation Risk: Chestnut	A-12 B5.4 Resilience	
29	2003	Cable Replacement Program	A-12 B5.4 Resilience	
30	20231004	Subtransmission Redesign & Rebuild: Trunk 1444	Planned for IRM	
31	20191023	CODI: Islandview Substation	A-12 B5.4 Redesign	
32	20230052	Subtransmission Redesign & Rebuild: Tie 3416 Reconductoring	Planned for IRM	
33	20201026	Subtransmission Redesign & Rebuild: Bernard	Planned for IRM	1. Reconductor all of tie 3220 to correct voltage issues. This would be a significantely greater scope and cost.
34	20191017	CODI: Kent/Gibson Conversion	A-12 B5.4 Redesign	
35	20230027	Subtransmission Redesign & Rebuild: Trunk 7386	Planned for IRM	
36	2004	URD Replacement Program	A-12 B5.4 Resilience	
37	20191066	Subtransmission Redesign & Rebuild: Trunk 7333	A-12 B5.4 Redesign	1. Replace exsiting cable of 7333T line.
38	20191014	CODI: Alfred Substation Expansion	A-12 B5.4 Redesign	1. Build a new 13.2kV substation and transfer load from Midtown
39	20201012	Subtransmission Redesign & Rebuild: Trunk 4217	A-12 B5.4 Redesign	1. Parallel existing cable with new cable
40	20191037	4.8 kV CC: Birmingham Decommissioning and Circuit Conversion	A-12 B5.4 Redesign	
41	20201007	Subtransmission Redesign & Rebuild: Trunk 2455	Planned for IRM	1. Replacing underground cable with overhead cables 2. Reroute cables around conduit crossing at M-10/8-mile
42	20230029	Subtransmission Redesign & Rebuild: Hurst	Planned for IRM	
43	20230005	4.8 kV CC: Cortland / Oakman / Linwood Consolidation	A-12 B5.4 Redesign	1. Like for like replacement of aging infrastructure at 4.8kV & 24kV (rejected due to benefits of consolidation)
44	20191070	Subtransmission Redesign & Rebuild: Tie 6907	Planned for IRM	1. Relocate portions of circuit to underground 2. Decomission TRK 6941 and reroute as TIE 6907
45	20230042	Subtransmission Redesign & Rebuild: Cortland Station Expansion	A-12 B5.4 Redesign	
46	2002	Breaker Replacement Program	A-12 B5.4 Resilience	
47	20230011	Substation Risk: McGraw	A-12 B5.4 Resilience	1. Change source side of station from 40kV to 120kV 2. Convert distibution side to 13.2kV 3. Construct new 120/13.2kV substation
48	20201054	4.8 kV CC: Belleville Substation and Circuit Conversion	Planned for IRM	1. Construct class T substation on existing property 2. Construct Class A substation on existing property
49	20191062	Subtransmission Redesign & Rebuild: Sandusky Transformer 101 Breaker	A-12 B5.4 Redesign	1. Add section breaker to reduce outage window

50	20230033	Subtransmission Redesign & Rebuild: Waterman	Planned for IRM	
51	20191044	4.8 kV CC: Buckler Circuit Conversion	A-12 B5.4 Redesign	1. Keeping ARGO Substation and the circuits at 4.8kV
52	20230004	4.8 kV CC: MAUME 8241 Downtown Clawson Conversion	A-12 B5.4 Redesign	
53	20201050	Subtransmission Redesign & Rebuild: Trunk 3546	Planned for IRM	
54	20201011	Subtransmission Redesign & Rebuild: Trunk 3509	A-12 B5.4 Redesign	1. Replace section of TRK 3509 cable
55	20230026	Subtransmission Redesign & Rebuild: Oak Beach Capacitor	A-12 B5.4 Redesign	
56	20230019	4.8kV CC: Yale-Slater Decommissioning and Circuit Conversion	Planned for IRM	1. Upgrade existing YALE and SLATR substations 2. Installing an STDF substation at YALE
57	20241001	Substation Risk: Savage Switchgear Replacement	A-12 B5.4 Resilience	1. Construct new substation
58	20191024	4.8 kV CC: Royal Oak Substation and Circuit Conversion	Planned for IRM	
59	20230049	Station Upgrade: Navarre	A-12 B5.4 Resilience	
60	20191029	Substation Risk: Apache	A-12 B5.4 Resilience	1. Construct new substation
61	20230062	Station Upgrade: Warren (Relay Replacement)	A-12 B5.4 Resilience	
62	20191058	Subtransmission Redesign & Rebuild: Boyne	A-12 B5.4 Redesign	1. Non wire alternative – New 5MW Solar or Battery generation at Selfridge 2. Reconductor TRK 7909 only
63	20230013	4.8kV CC: Hemlock Decommissioning and Circuit Conversion	A-12 B5.4 Redesign	1. Decomission neighboring substations - SPRUC, and PDMNT. 2. Acquire property between HEMLK and JAKSN for new substation
64	20230054	4.8 kV CC: Hilton Substation and Circuit Conversion	A-12 B5.4 Redesign	
65	20201013	Subtransmission Redesign & Rebuild: Trunk 2308	A-12 B5.4 Redesign	1. Adjust blocking setting at Benson Substation resulting in more load shed.
66	20230016	Substation Risk: Belleville Switchgear Decommission	A-12 B5.4 Resilience	1. Replace Switchgear, rejected due to increased cost and goal to convert area to 13.2kV. 2. Replace TRF #1 with 13.2kV transformer and convert portions of 4.8kV circuits to 13.2kV
67	20230037	Subtransmission Redesign & Rebuild: 40kV Capacitor Banks at Armada and Adair	A-12 B5.4 Redesign	
68	20201064	4.8kV CC: Rochester Decommissioning and Tienken Relief	Planned for IRM	
69	20191039	System Loading: Jewell	A-12 B5.4 Redesign	1. Load transfers to Washington substation 2. Not enough capacity to utilize spare positions at Jewell substation. 3. Evaluated for Non Wire Alternatives, was determined not to be a candidate.
70	20230028	Subtransmission Redesign & Rebuild: Tie 3705	Planned for IRM	
71	20230007	4.8kV CC: SCOTN	A-12 B5.4 Redesign	1. EPPM to replace all (36) breakers at SCOTN substation with no circuit level work
72	20201021	4.8 kV CC: Calla Circuit Conversion and Phase 2	A-12 B5.4 Redesign	1. Pole top maintenance and/or line clearance
73	20201015	Subtransmission Redesign & Rebuild: Tie 6602	Planned for IRM	
74	20241002	Substation Risk: Seville	A-12 B5.4 Resilience	1. Do nothing. Rejected since the circuits are in an abnormal configuration putting increased risk on other circuits/substations.
75	20191068	Subtransmission Redesign & Rebuild: Trunk 4245	A-12 B5.4 Redesign	1. Alternative routes were considered that would result in more cable and conduit
76	20201016	Subtransmission Redesign & Rebuild: Trunk 4266	A-12 B5.4 Redesign	1. Only replace the two sections("D" & "G") of cable which are over emergency ratings 2. Installing 650 EPR for all cable replacements
77	20201060	System Loading: Macomb/Golf	A-12 B5.4 Redesign	1. MEDNA New Split Double Bus Class A Sub conversion 2. Evaluated for Non Wire Alternatives, was determined not to be a candidate.
78	20191074	CODI: Corktown Substation	A-12 B5.4 Redesign	
79	20201004	Subtransmission Redesign & Rebuild: Badax Transformer 102 Addition	A-12 B5.4 Redesign	
80	20230050	Station Upgrade: Northeast (Relay Replacement)	A-12 B5.4 Resilience	
81	20231001	Substation Risk: Hood	A-12 B5.4 Resilience	1. Construct new substation
82	20201001	System Loading: Globe	A-12 B5.4 Redesign	1. Build new STDF substation at Globe 2. Replace 2.5 MVA Transformer with 7.5MVA Transformer (New Class T Sub) 3. Install a Skid-mount Substation or Class R at the recent acquired property 4. Evaluated Non Wire Alternative (NWA) options either thru EWR or install a battery unit.
83	20201024	System Loading: Richmond/Armada	A-12 B5.4 Redesign	1. Install a new class A substation at new GRAMER station site 2. Richmond substation upgrade project is not a potential NWA candidate 3. Evaluated for Non Wire Alternatives, was determined not to be a candidate.
84	20201006	Subtransmission Redesign & Rebuild: Derby	Planned for IRM	1. Reconductor all of TIE 9107, Tie 9111, and Tie 9123.
85	20201018	Subtransmission Redesign & Rebuild: Trunk 4911	A-12 B5.4 Redesign	1. Reconductor all of Trunk 4911 2. Construct new 40kV trunk line from Boyne station to feed Chesterfield Transformer 3 and Cotton Transformer 1
86	20191077	System Loading: Diamond	A-12 B5.4 Redesign	1. Load transfers to neighboring areas 2. Evaluated for Non Wire Alternatives, was determined not to be a candidate.
87	20241009	System Loading: Kings Point	A-12 B5.4 Redesign	1. Evaluated for Non Wire Alternatives, was determined not to be a candidate.
88	20191063	Subtransmission Redesign & Rebuild: Custer Republic	A-12 B5.4 Redesign	
89	2021	Subtransmission Redesign & Rebuild: Thumb Electric Fault Isolation	Planned for IRM	
90	20191001	System Loading: Port Sanilac	A-12 B5.4 Redesign	1. Build new subsation at exsiting PTSAN property, converting everything from 4.8kV to 13.2kV 2. Evaluated for Non Wire Alternatives, was determined not to be a candidate.
91	20191045	System Loading: Carleton	A-12 B5.4 Redesign	
91	20191045	System Loading: Carleton	A-12 B5.4 Redesign	1. Evaluated for Non Wire Alternatives, was determined not to be a candidate.
92	20201027	Subtransmission Breaker Short Circuit Violations	A-12 B5.4 Redesign	
93	20241011	4.8 kV CC: Unionville DC 301 B1 Conversion	A-12 B5.4 Redesign	1. Convert Downstream of B4 Fuse 2. Reconductor ~6.1 Miles of OH 3. Feed Complaining Customers from Quail 312
94	20230012	4.8kV CC: Pittsfield Substation and Circuit Conversion	Planned for IRM	1. Crown Substation Transformer Replacement and PDC Replacement. 2. Purchase New Substation property between Wolverine and Crown Substations.

95	20191075	4.8 kV CC: Almont Relief and Circuit Conversion (Midas)	A-12 B5.4 Redesign	1. Build MIDAS as Class A Substaion 2. Feed MIDAS with 40kV - 120kV feed chosen due to close proximity of transmission lines (approx. ¼ MI) and improved reliability 3. Skidmounted Substation - Costly to expand to Class A substation if needed in the future
96	20201057	System Loading: Grenada	A-12 B5.4 Redesign	1. A 120-13.2kV substation scope was analyzed with ITC 2. The scope for a 40kV Class 'B' substation was also analyzed and will be revisited in the future at time of third transformer installation. 3. Evaluated for Non Wire Alternatives, was determined not to be a candidate.
97	20231016	System Loading: New Baltimore/Chesterfield	A-12 B5.4 Redesign	1. Installing third TRF at NBALT 13.2 but limited space. 2. Moving all NBALT load to JACOB 3. Evaluated for Non Wire Alternatives, was determined not to be a candidate.
98	20230014	System Loading: Tahoe	A-12 B5.4 Redesign	1. Use capacity at Wixom after upgrade to transfer load off of TAHOE 2. Multiple Reconfigurion alternatives for TRK 5906 at the intersection of 10 mile and Novi Road 3. Evaluated for Non Wire Alternatives, was determined not to be a candidate.
99	20191080	System Loading: Lark/Spruce	A-12 B5.4 Redesign	1. Building a new substation in an alternate location on new property and installing a third transformer at SPRUC. 2. Evaluated for Non Wire Alternatives, was determined not to be a candidate.
100	20201058	4.8 kV CC: Unionville Decommissioning and Circuit Conversion	Planned for IRM	1. Upgrade UNVIL substation was considered but choosing to relocate at Randolph Station allowed us to take load off FGROV as well
101	20241003	Substation Risk: Imlay	A-12 B5.4 Resilience	
102	20201063	System Loading: Disco	A-12 B5.4 Redesign	1. Building 3 new distribution circuits on BRONC and upgrading DISCO XFMR 1 2. Evaluated for Non Wire Alternatives, was determined not to be a candidate.
103	20191036	System Loading: Wixom	A-12 B5.4 Redesign	1. Construct New substation 2. Utilize TAHOE Substation 3. Use HANCK and/or WALLK substations 4. Evaluated for Non Wire Alternatives, was determined not to be a candidate.
104	20191057	Subtransmission Redesign & Rebuild: Tie 7504	A-12 B5.4 Redesign	1. Alternate routes were not found to be advantageous
105	20191055	Subtransmission Redesign & Rebuild: Tie 810	A-12 B5.4 Redesign	1. Reconductor or replace all non-standard specified conductor/cable with standard specified 636AL OH conductor and 650 EPR UG cable. 2. New 345kV / 40 kV Station Split tie 810 into three separate tie lines. 3. New 120kV / 13.2kV Substation
106	20191056	Subtransmission Redesign & Rebuild: Tie 4105	A-12 B5.4 Redesign	1. Build a class B station (switching station) next to CROSW or APLGT and split TIE4105 into 2 tie lines. 2. Reconfigure TIE4105 3. Alternative routes have been considered for rebuilding the different sections of TIE4105 in the case we are not able to obtain easements or ROW for the routes proposed.
107	20201035	Subtransmission Redesign & Rebuild: Slocum	A-12 B5.4 Redesign	
108	20230024	Subtransmission Redesign & Rebuild: Tie 5208	Planned for IRM	
109	20191041	System Loading: Goodison	A-12 B5.4 Redesign	1. Using DTE Gas property – DTE gas property is limited due to gas lines going through ITC corridor. 2. Build new ITC station and DTE substation from 345KV to 120kV to 13.2kV 3. Evaluated for Non Wire Alternatives, was determined not to be a candidate.
110	20230053	4.8 kV CC: GRFIN & WMSTN Conversions	A-12 B5.4 Redesign	1. Building underneath existing subtransmission lines 2. Build new STDF at GRFIN substation or on new property.
111	20191040	4.8 kV CC: White Lake Decommissioning and Circuit Conversion	A-12 B5.4 Redesign	
112	20230048	Station Upgrade: Lincoln	A-12 B5.4 Resilience	
113	20191059	Subtransmission Redesign & Rebuild: Tie 4104	A-12 B5.4 Redesign	1. Two alternative line routes were evalauted.
114	20230021	4.8 kV CC: Pinegrove Substation Relocation and Conversion	A-12 B5.4 Redesign	
115	20191038	System Loading: Sterling	A-12 B5.4 Redesign	1. Evaluated for Non Wire Alternatives, was determined not to be a candidate.
116	20191004	System Loading: Brown City	A-12 B5.4 Redesign	1. 120-13.2kV Class T at BENET 2. Evaluated for Non Wire Alternatives, was determined not to be a candidate.
117	20191013	CODI: Midtown Substation Expansion	A-12 B5.4 Redesign	1. Build a new 13.2kV substation and transfer load from Midtown
118	20201003	System Loading: Mayville	A-12 B5.4 Redesign	1. This project was considered for higher voltage distribution pilot substation. 2. Peaker Sites in the area for property usage of new substation were evaluated. 3. Evaluated for Non Wire Alternatives, was determined not to be a candidate.
119	20191008	4.8 kV CC: Lapeer - Elba Expansion and Circuit Conversion (Apollo)	A-12 B5.4 Redesign	1. Feed new Apollo substation with 40kV instead of 120kV 2. Upgrade Fawn Class "R" substation to Class "A" instead of build new Apollo substation
120	20230025	Subtransmission Redesign & Rebuild: Trunk 4601	Planned for IRM	
121	20201062	System Loading: Otsego/Capac/Shaw	A-12 B5.4 Redesign	1. Evaluated for Non Wire Alternatives, was determined not to be a candidate.
122	20191028	CODI: CATO Substation Expansion	A-12 B5.4 Redesign	1. Architecturally expand Cato substation into the parking lot to accomodate the third 120kV feed/circuit switcher proposed by ITC 2. Convert Cato 4.8kV in Project 1 to nearby 13.2kV circuits to avoid additional cable cutover/conversions in Project 4
123	20201034	Subtransmission Redesign & Rebuild: Pigeon Area Improvement	Planned for IRM	1. Multiple powerflow analysis were competed using PSSE and TARA to study a wide spread area and propose the most beneficial solution for the system.
124	20191030	System Loading: Cody	A-12 B5.4 Redesign	1. Use neigboring substations TAHOE & NITRO to reduce loading on CODY 2. NWA considered while using neighboring substation to decrease loading on CODY
125	20201040	Subtransmission Redesign & Rebuild: Tie 3205	A-12 B5.4 Redesign	
126	20201032	Subtransmission Redesign & Rebuild: STPS6	Planned for IRM	

127	20201002	4.8 kV CC: Quincy Conversion	A-12 B5.4 Redesign	1. Replace with 4.8 kV transformer within the existing fence 2. Install 3-833 kVA 4.8 kV overhead STDF 3. Replace with 13.2 kV 5 MVA or 7.5 MVA STDF at existing site and install 4 ISO's 4. Install 13.2 kV skid mount STDF closer to Kilgore to reduce/eliminate the 40kV tap distance 5. Evaluated against a traditional class T substation
128	20201065	System Loading: Spokane/Seneca	A-12 B5.4 Redesign	1. Evaluated for Non Wire Alternatives, was determined not to be a candidate.
129	20201022	Ann Arbor System Improvements	A-12 B5.4 Redesign	1. Keeping ARGO Substation and the circuits at 4.8kV was not considered due to the new customer load growth in the area and inability to support load growth at 4.8kV.
130	20230045	4.8 kV CC: Ann Arbor AC Network Conversion	Planned for IRM	1. Removal of the AC Network System in downtown Ann Arbor and conversion to traditional URD construction.
131	20230047	4.8 kV CC: Power line Conversion of MADSN 175L-W	A-12 B5.4 Redesign	
132	20230044	Substation Risk: Voyager	A-12 B5.4 Resilience	1. Considered having both underground and OH work completed consecutevely.
133	20230043	Subtransmission Redesign & Rebuild: Maxwell Amherst	A-12 B5.4 Redesign	
134	20230036	Subtransmission Redesign & Rebuild: Small Projects & Reserve	A-12 B5.4 Redesign	
135	20230031	Subtransmission Redesign & Rebuild: Tempest Phase II	Planned for IRM	
136	20230030	Subtransmission Redesign & Rebuild: Praxair	A-12 B5.4 Redesign	1. ITC to install in-and-out (normally-closed breakers) 2. DTE to install main-tie-main configuration with a normally-open section breakers and line breakers 3. Customer to install automatic throw-over at Praxair distribution level
137	20230008	4.8 kV CC: Crestwood Substation	A-12 B5.4 Redesign	
138	20201030	Subtransmission Redesign & Rebuild: Mohican	Planned for IRM	

DTE Energy

Appropriation Request
Summary Sheet

Project Name:	Midas Subs - Below grade, Conduit Midas Subs - Above grade, OH, Cable	Capital Budget / Project #:	I-000404-0027 (MEP) I-000801-0001 (DO)
Utility/Non-Utility:	Utility	Project Type:	Distribution
Business Segment:	Electric Utility	Business unit within budget?:	Yes
Business Unit:	MEP / DO	Project Start Date:	Mar-2019
Project Sponsor:	Joi Harris / Sharon Pfeuffer	In-Service Date:	2022, 2023
		Post Investment Evaluation Date:	2025

Current Approval Request ($Millions):	$28.9
Previous Request(s) ($Millions):	$1.4
Total Project ($Millions):	$30.3

Financial Summary ($Millions)

	2020 & Prior Years	2021	2022	2023	2024	2025	Beyond	Total
Current Capital Approval Request	$0.0	$21.3	$6.3	$1.3	$0.0	$0.0	$0.0	**$28.9**
Previous Request(s)	0.8	0.6	0.0	0.0	0.0	0.0	0.0	**1.4**
Total Project Request	0.8	21.9	6.3	1.3	0.0	0.0	0.0	**30.3**
Operating After-Tax Cash Flow	(679)	(17,017)	(10,235)	2,811	2,828	2,723	50,892	**31,323**
Net Income	17	310	1,185	1,448	1,395	1,340	19,921	**25,616**

Hurdle Rate	IRR	NPV	Payback(years)	First 5 Yrs Avg. Net Income	Customer cost (savings)*
6.1%	6.1%	$264	15	$ 871	$36,182

Project Description and Approval

The purpose of this request is to obtain full appropriation for the Midas project.

MEP Project Scope:
- Design a new 120kV to 13.2kV Class RR substation (Midas) in Almont Township
- Construct all below grade elements of the new Midas substation
- Create Class R standards as part of the substation design
- Design and install all new system conduit to facilitate the OH circuit work starting outside of substation property

DO Project Scope:
Construct the above grade elements of the new Midas Class RR substation including testing and commissioning. Substation includes two (2) 15/20/25 120 - 13.2 kV transformers and four (4) line positions, Class RR. The future Midas substation will have provisions for expansion to a Class A substation with installation of a future (12) position PDC. Also included is the transfer and partial conversion of two (2) existing Almont 4.8 kV distribution circuits to four (4) future Midas circuits with both 13.2 and 4.8 kV service. After transfer of the Almont circuits to Midas, the existing Almont substation will be de-commissioned.

Cash Flow	2020 & Prior	2021	2022	2023
MEP	$ 0.7	$ 8.2	$ 0.5	
DO	$ 0.1	$ 13.7	$ 5.8	$ 1.3

Major Risk and Risk Mitigants

MEP:
- Unexpected hazards during below grade construction
- Pandemic delays/loss or productivity
- Delays due to substation redesign
- Municipality construction and environmental permitting requirements are not defined which can result in increased cost and schedule delays.
- Interferences/hazards discovered
- Inclement weather delays above allowance
- Scope errors or omissions for substation scope
- Increase in A&G allocations

DO :
- Almont special land use and site plan approvals. Mitigants: Early communication with Almont community and flexibility in addressing concerns.
- Concerns from residents directly north of Midas site. Mitigant: Relocate station foot print farther from subdivision.
- Complete inputs from System Protection and Automation for design of necessary relay panels. Mitigant: Engage SP&A group to assure delivery.
- New Class R substation standard not completed as needed. Mitigant: Install per design provided by MEP using earlier Standards
- MEP completion of below-grade work is late. Mitigant: Start equipment setting while below-grade work is in progress.
- DO substation labor resources not available to erect substation. Mitigant: Engage qualified contractor to erect.
- Long lead equipment delivery cycles do not support schedule. Mitigant: Obtain leadership approval to order prior to full Gate 2 approval.

Approval Level (per FC20)	Finance Committee	Required yes	Required no
Business Unit President		yes	
Corporate Staff Review		yes	
Ed Solomon	4/23/2021		
Corporate Development *	**Date**	yes	
DTE Controller Review	**Date**		no
Growth & Value Creation Committee Review		yes	
Chief Financial Officer		yes	
Chief Operating Officer		yes	
Chief Executive Officer			no
Finance Committee			no
Board of Directors			no

Final Approval Signatures

Sharon Pfeuffer	4/20/2021
Project Sponsor, Distribution Operations	**Date**
/s Joi Harris	**4/21/2021**
Project Sponsor, Major Enterprise Projects	**Date**
Trevor Lauer	4/21/2021
Business Unit President	**Date**
Dave Ruud	4/23/2021
Chief Financial Officer	**Date**
Jerry Norcia	4/23/2021
Chief Executive Officer / Chief Operating Officer	**Date**

* Corporate Development indicates that Corporate Staff Review is complete. See page 2 for any comments from Corporate Staff

DTE Energy

Appropriation Request
Corporate Staff Review

Project Name:	Midas Subs - Below grade, ConduitMidas Subs - Above	Capital Budget / Project #:	I-000404-0027 (MEP)I-000801-0001
Executive Sponsor:	Joi Harris / Sharon Pfeuffer		

Corporate Staff Review				Comments and Issues
Natalie Graves **Corporate Finance and Development**	4/20/2021 **Date**	X **Support**	 **Do Not Support**	
Chris Allen **Business Unit Controllers**	4/20/2021 **Date**	X **Support**	 **Do Not Support**	
Jill Farris **Corporate Accounting**	4/15/2021 **Date**	X **Support**	 **Do Not Support**	
John D Miller **Corporate Tax**	4/20/2021 **Date**	X **Support**	 **Do Not Support**	
Todd Baker **Environmental**	4/19/2021 **Date**	X **Support**	 **Do Not Support**	
Matthew Misiak **Legal**	4/16/2021 **Date**	X **Support**	 **Do Not Support**	
Lori Taylor-Wallace **Purchasing**	4/15/2021 **Date**	X **Support**	 **Do Not Support**	
Habeeb Maroun **Regulatory Affairs**	19-Apr **Date**	X **Support**	 **Do Not Support**	This project had an estimated spend of $13.2M 2019-2021 in U-20561 while current proposal projecting $21.3M in 2020-2021. Project team should be prepared to support increased spend from the last case in our next electric rate case.
Jeff Fowler **Risk Management**	4/20/2021 **Date**	X **Support**	 **Do Not Support**	

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DTE Energy

Appropriation Request

Summary Sheet

Project Name:	RELI0366-01 Tie4105 Reconductoring APLGT to CARSN	Capital Budget / Project #:	I-000827-0001-0021
Utility/Non-Utility:	Utility	Project Type:	Infrastructure Redesign
Business Segment:	Electric Utility	Business unit within budget?:	Yes
Business Unit:	Distribution Operations	Project Start Date:	08/01/2020
Project Sponsor:	Sharon Pfeuffer / Heather Rivard	In-Service Date:	3/31/2022
		Post Investment Evaluation Date:	11/21/2023

Current Approval Request ($000s):	$12,333
Previous Request(s) ($000s):	$0
Total Project ($000s):	$12,333

Financial Summary ($000s)

	Prior Years	2020	2021	2022	2023	2024	Beyond	Total
Current Capital Approval Request	$0	$100	$12,233	$0	$0	$0	$0	**$12,333**
Previous Request(s)	0	0	0	0	0	0	0	**0**
Total Project Request	0	100	12,233	0	0	0	0	**12,333**
Operating After-Tax Cash Flow	0	0	0	0	0	0	0	**0**
Net Income	0	0	0	0	0	0	0	**0**

Hurdle Rate	IRR	NPV	Payback(years)	First 5 Yrs Avg. Net Income	Customer cost (savings)*
6.1%	6.1%	$152	15	$495	$12.0

Project Description and Approval

TIE 4105 has experienced frequent outages resulting in escalated customer complaints. The existing conductor and poles are near end of life and the tie line is currently built in deep right of way resulting in longer patrol and repair durations. Routine maintenance on this tie line has not resulted in an overall improvement in circuit performance. Approximately 35 miles of TIE4105 has been proposed to be rebuilt using current design standards and planned for relocation to road right of way wherever possible. This initiative to rebuild TIE4105 will be split up into 5 separate projects. The worst performing section of TIE4105 has been identified as the section between Applegate Substation and Carsonville Substation and is being prioritized as the first of five projects for rebuild/relocation. Approximately 6.7 miles of TIE4105 will be rebuilt under this project planned for construction in 2021.Once the initiative is completed, circuit performance should be greatly improved as 77% of the outages over the last 5 years are in the sections planned for rebuild, TIE4105 will be more accessible for maintenance and trouble events, the circuit will have adequate lightning protection, the voltage violations on TIE4105 will be resolved, and customer satisfaction will be improved.

Major Risk and Risk Mitigants

Input

Approval Level (per FC20) Finance Committee

		Required yes	Required no
Business Unit President		yes	
Corporate Staff Review		yes	
Ed Solomon	12/21/2020		
Corporate Development *	**Date**	yes	
DTE Controller Review	**Date**		no
Growth & Value Creation Committee Review		yes	
Chief Financial Officer		yes	
Chief Operating Officer		yes	
Chief Executive Officer		yes	
Finance Committee		yes	
Board of Directors			no

Final Approval Signatures

Project Sponsor	**Date**
Heather Rivard	**1/7/2021**
Business Unit President	**Date**
Chief Financial Officer	**Date**
Chief Executive Officer / Chief Operating Officer	**Date**

* Corporate Development indicates that Corporate Staff Review is complete. See page 2 for any comments from Corporate Staff

DTE Energy

Appropriation Request
Corporate Staff Review

Project Name:	RELI0366-01 Tie4105 Reconductoring APLGT to CARS	Capital Budget / Project #:	I-000827-0001-0021
Executive Sponsor:	Sharon Pfeuffer / Heather Rivard		

Corporate Staff Review	Date	Support	Do Not Support	Comments and Issues
Gregery Rocco **Corporate Finance and Development**	12/18/2020	X		
Chris Allen **Business Unit Controllers**	12/18/2020	X		
Jill Farris **Corporate Accounting**	12/16/2020	x		
John D Miller **Corporate Tax**	12/17/2020	X		
Robert J Lee **Environmental**	12/16/2020	X		EM&S team to coordinate with DO's design team and owner's engineer to support environmental permitting needs and review
Matthew Misiak **Legal**	12/18/2020	X		
Lori Taylor-Wallace **Purchasing**	12/16/2020	X		
Habeeb Maroun **Regulatory Affairs**	12/17/2020	x		Projected risk-based capital carries risk of disallowance in a rate case unless the spend is adequately supported; this would result in a regulatory lag to the following case after the spend occurs.
Jeff Fowler **Risk Management**	12/16/2020	X		

DTE Energy

Appropriation Request

Summary Sheet

Project Name:	RELI0366-03 TIE4105 Reconductoring APLGT	Capital Budget / Project #:	I-000827-0001-0040
Utility/Non-Utility:	Utility	Project Type:	Infrastructure Redesign
Business Segment:	Electric Utility	Business unit within budget?:	Yes
Business Unit:	Distribution Operations	Project Start Date:	10-1-2022
Project Sponsor:	Sharon G. Pfeuffer, Ryan Stowe/ Matthew T. Paul	In-Service Date:	7-30-2025
		Post Investment Evaluation Date:	7/20/2027

Current Approval Request ($000s):	$16.2
Previous Request(s) ($000s):	$0
Total Project ($000s):	$16.2

Financial Summary ($000s)

	Prior Years	2022	2023	2024	2025	2026	Beyond	Total
Current Capital Approval Request	$0	$0	$2.9	$10.1	$3.3	$0	$0	$ 16.2
Previous Request(s)	0	0	0	0	0	0	0	0
Total Project Request	0	0	2.9	10.1	3.3	0	0	$ 16.2
Operating After-Tax Cash Flow	(2,688)	(9,183)	(1,832)	1,519	1,460	1,405	23,997	$ 14,678
Net Income	69	376	680	731	701	671	8,776	$ 12,004

Hurdle Rate	IRR	NPV	Payback(years)	First 5 Yrs Avg. Net Income	Customer cost (savings)*
6.1%	6.1%	$212	15	$ 371	$20,534

Project Description and Approval

This project will rebuild 6.7 miles of 40KV overhead construction and relocate the tie line out of deep easement to improve accessibility for future maintenance and repairs. Install 6.7 miles of 636 Al conductor with 1/0 ACSR shield wire for lightning protection. New steel poles will be installed per DTE standards, Install 2 new SEECO automatic switches. All new infrastructure we be built to Distribution Operation standards and modernize the distribution system. This supports the long term strategy for the thumb area by reconductoring to 636 Al

Major Risk and Risk Mitigants

Shut downs and weather conditions.

Approval Level (per FC20)	Business Unit President	Required yes	Required no
Business Unit President		yes	
Corporate Staff Review		yes	
Corporate Development *	Timothy J Lapczyk 11/18/2022 Date	yes	
DTE Controller Review	Date		no
Growth & Value Creation Committee Review			no
Chief Financial Officer			no
Chief Operating Officer			no
Chief Executive Officer			no
Finance Committee			no
Board of Directors			no

Final Approval Signatures

Ryan Stowe 11/9/2022
Project Sponsor **Date**

Business Unit President **Date**

* Corporate Development indicates that Corporate Staff Review is complete. See page 2 for any comments from Corporate Staff

DTE Energy

Appropriation Request
Corporate Staff Review

Project Name:	RELI0366-03 TIE4105 Reconductoring APLGT	Capital Budget / Project #:	I-000827-0001-0040
Executive Sponsor:	Sharon G. Pfeuffer, Ryan Stowe/ Matthew T. Paul		

Corporate Staff Review	Date	Support	Do Not Support	Comments and Issues
Chad Detrich **Corporate Finance and Development**	11/17/2022	x		
Case Lancaster **Business Unit Controllers**	11/15/2022	X		Project is included in DTEE's long-term capital plan
Matt Przybysz **Corporate Accounting**	11/17/2022	X		No accounting issues noted.
John Miller **Corporate Tax**	11/15/2022	X		
Amanda Kosch **Environmental**	11/15/2022	X		Please ensure an environmental change checklist is submitted for this project and an action plan is in place.
Matthew Misiak **Legal**	11/15/2022	X		
Lori Wallace **Purchasing**	11/15/2022	X		
Habeeb Maroun **Regulatory Affairs**	11/15/2022	X		Most Recent Regulatory Capital Info by Year *To be completed by project team 2020 2021 2022 2023 Beyond $- 5.8 10.0 19.9 $- Project team should be prepared to demonstrate prudency of projected capital spend in the Company's upcoming rate case. There is a risk of delay in recovery of contingency in the next case until the funds are spent and prudency demonstrated in the subsequent case.
Logan Morgan **IT Cybersecurity**	11/18/2022	X		*Note if the project is an acquisition, physical security must also approve
Daniel Northey **Risk Management**	11/17/2022	X		ERM has evaluated this project and noted no risk categories rated above low
Mick Darin **Corporate Insurance**	11/15/2022	X		

DTE Energy

Appropriation Request

Summary Sheet

Project Name:	RELI0366-04 TIE4105 Sandusky & Carsonville	Capital Budget / Project #:	I-000827-0001-00XX
Utility/Non-Utility:	Utility	Project Type:	Infrastructure Redesign and Modernization
Business Segment:	Electric Utility	Business unit within budget?:	Yes
Business Unit:	DO/ MEP	Project Start Date:	8/8/2022
Project Sponsor:	Renee M. Tomina, Ryan Stowe - Matthew T. Paul	In-Service Date:	3/16/2028
		Post Investment Evaluation Date:	9/7/2029

Current Approval Request ($000s):	$25,702
Previous Request(s) ($000s):	$0
Total Project ($000s):	$25,702

Financial Summary ($000s)

	Prior Years	2023	2024	2025	2026	2027	Beyond	Total
Current Capital Approval Request	$0	$0	$8,084	$12,217	$5,401	$0	$0	**$25,702**
Previous Request(s)	0	0	0	0	0	0	0	**0**
Total Project Request	0	0	8,084	12,217	5,401	0	0	**25,702**
Operating After-Tax Cash Flow	0	(7,747)	(10,629)	(3,033)	2,500	2,405	41,700	**25,195**
Net Income	0	198	681	1,076	1,161	1,113	15,103	**19,334**

Hurdle Rate	IRR	NPV	Payback(years)	First 5 Yrs Avg. Net Income	Customer cost (savings)*
6.5%	6.7%	$398	13	$ 846	$32,648

Project Description and Approval

Segment 4 (SANDU to CARSN) will rebuild approximately 7.5 miles built to the new 40kV standard with 4.8kV under build (built to 13.2kV standard). Utilize 40kV steel pole construction standards.
Update 1 pole top switch.
Rebuild 7.5 miles of 4.8kV. distribution under-build on the new steel poles. This distribution will be built to the 13.2kV standard.
Relocate Tie 4105 segment 4 from deep easement to Road ROW to allow the timeline to be truck accessible for future maintenance

Major Risk and Risk Mitigants

RISK : Challenges coordinating with Thumb Electric customers (TEC) that could lead to delays in construction MITIGATION: Communication will be utilized to coordinate and receive feedback from customers throughout project execution including mailers, emails, paid and organic social media, Empowering Michigan blogs, door hangers, customer e-publications/newsletters
Regional Relations and Community Engagement will work with city and community leaders to share project plans, milestones and other project information to build positive relationships
RISK:Delays in Permits and/or Easement acquisition. MITIGATION: Leverage Regional relations to facilitate permitting discussions with City of Croswell and Sandusky prior to customer engagement
Identify potential easements/land use requirements early in project and evaluate alternate route/solution with Engineering
Maintain engagement with DTE ROW facilitator throughout project design
Break out railroad easements with separate work orders

Approval Level (per FC20) UC (CEO & CFO)

	Date	Required yes	Required no
Business Unit President		yes	
Corporate Staff Review		yes	
Corporate Development *	Date	yes	
DTE Controller Review	Date		no
Growth & Value Creation Committee Review		yes	
Chief Financial Officer		yes	
Chief Operating Officer		yes	
Chief Executive Officer			no
Finance Committee			no
Board of Directors			no

Final Approval Signatures

Renee Tomina (email)	3/18/2024
Project Sponsor	**Date**
Matt Paul (email)	3/18/2024
Business Unit President	**Date**
Chief Financial Officer	**Date**
Chief Executive Officer / Chief Operating Officer	**Date**

* Corporate Development indicates that Corporate Staff Review is complete. See page 2 for any comments from Corporate Staff

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DTE Energy

Appropriation Request
Corporate Staff Review

Project Name:	RELI0366-04 TIE4105 Sandusky & Carsonville	Capital Budget / Project #:	I-000827-0001-00XX
Executive Sponsor:	Renee M. Tomina, Ryan Stowe - Matthew T. Paul		

Corporate Staff Review	Date	Support	Do Not Support	Comments and Issues
Tim Lepczyk **Corporate Finance and Development**	2/29/2024	X		
Case Lancaster **Business Unit Controllers**	2/28/2024	X		
Jill Farrs **Corporate Accounting**	3/4/2024	X		
John Miller **Corporate Tax**	2/29/2024	X		
Todd Baker **Environmental**	2/28/2024	X		
Onnie Jacque **Legal**	3/1/2024	X		
Lori Wallace **Purchasing**	2/27/2024	X		
Thomas Lacey **Regulatory Affairs**	2/28/2024	X		Most Recent Regulatory Capital Info by Year (*To be completed by project team) 2020: $- 2021: $- 2022: $- 2023: $- Beyond: $- Project team should be prepared to demonstrate prudence of project spend and ready to explain differences between rate case projections and forecast. If contingency is included in the rate case, there is a risk of delay in recovery until the subsequent case after the amounts are spent and prudency is demonstrated.
Logan Morgan **IT Cybersecurity**	3/4/2024	X		*Note if the project is an acquisition, physical security must also approve
Daniel Northey **Risk Management**	3/1/2024	X		ERM has evaluated this project and each risk category received a low score.
Mick Darin **Corporate Insurance**	2/28/2024	X		

MPSC Case No: U-21534

Requester: MNSC

Question No.: MNSCDE-8.18di

Respondent: J. Kryscynski

Page: 1 of 1

Question: 18. Refer to Exhibit A-12, Schedule B5.4, page 14-16, and to the 4.8kV circuit conversions and related projects listed on lines 28-56 and 79-91. Refer also to Exhibit A-33, Schedule X1, line 1, and to "Conversions" budgets proposed for the IRM in 2026 and 2027.

d. Refer to the responses to subparts (a) and (b) above. Explain how the Conversions program budget was established for each of the following years, and provide a list of circuits or projects and capital dollars budgeted by circuit for each year:

i. 2023

Answer: The Company develops the long-term vision for the grid and 5-year investment plans for distribution programs and projects using the process described in the 2021 and 2023 Distribution Grid Plans (DGP). The DGP investments address aging infrastructure, improvements to reliability, resiliency, and safety, and current and projected future capacity constraints. Investments are prioritized using the GPM as well as other considerations, as discussed in Witness Kryscynski's testimony.

The 5-year investment plan is a key reference when developing the annual distribution budgets. The annual budget planning process includes the 5-year DGP plan, updated information on grid needs including reliability data, and regulatory feedback obtained through rate cases. For 2023 investments, the 2021 DGP is the supportive grid planning reference.

The capital investment associated with each conversion project for 2023 where the Company is seeking recovery through the current case can be found in Exhibit A-12, Schedule B5.4, page 14-16, lines 28-56 and 79-91.

In addition, the Commission's Order in Case No. U-21297 authorized IRM treatment for additional program investment as part of "IRM Year 1" which runs from December 1, 2023, through December 31, 2024. The Company was not required to identify what portion of that investment was to occur in December 2023 vs. calendar year 2024. The investments associated with the IRM Year 1 were presented in the Company's 2024 IRM Investment Plan.

Attachment: None

MPSC Case No: U-21534

Requester: MNSC

Question No.: MNSCDE-8.18dii

Respondent: J. Kryscynski

Page: 1 of 1

Question: 18. Refer to Exhibit A-12, Schedule B5.4, page 14-16, and to the 4.8kV circuit conversions and related projects listed on lines 28-56 and 79-91. Refer also to Exhibit A-33, Schedule X1, line 1, and to "Conversions" budgets proposed for the IRM in 2026 and 2027.

d. Refer to the responses to subparts (a) and (b) above. Explain how the Conversions program budget was established for each of the following years, and provide a list of circuits or projects and capital dollars budgeted by circuit for each year:

ii. 2024

Answer: The Company develops the long-term vision for the grid and 5-year investment plans for distribution programs and projects using the process described in the 2021 and 2023 Distribution Grid Plans (DGP). The DGP investments address aging infrastructure, improvements to reliability, resiliency, and safety, and current and projected future capacity constraints. Investments are prioritized using the GPM as well as other considerations, as discussed in Witness Kryscynski's testimony.

The 5-year investment plan is a key reference when developing the annual distribution budgets. The annual budget planning process includes the 5-year DGP plan, updated information on grid needs including reliability data, and regulatory feedback obtained through rate cases. For 2024 investments, the 2023 DGP is the supportive grid planning reference.

A portion of the 2024 Conversions budget was authorized for IRM treatment in Case No. U-21297 as reflected in Exhibit A-33, Schedule X1, Page 1, Line 2. The projects associated with this investment were presented in the Company's 2024 IRM Investment Plan. The remaining planned capital investment is being proposed for recovery in this case as reflected in Exhibit A-12, Schedule B5.4, Pages 14-15, lines 28-56 and 79-91.

Attachment: *None*

MPSC Case No: U-21534

Requester: MNSC

Question No.: MNSCDE-8.18diii

Respondent: J. Kryscynski

Page: 1 of 1

Question: 18. Refer to Exhibit A-12, Schedule B5.4, page 14-16, and to the 4.8kV circuit conversions and related projects listed on lines 28-56 and 79-91. Refer also to Exhibit A-33, Schedule X1, line 1, and to "Conversions" budgets proposed for the IRM in 2026 and 2027.

d. Refer to the responses to subparts (a) and (b) above. Explain how the Conversions program budget was established for each of the following years, and provide a list of circuits or projects and capital dollars budgeted by circuit for each year:

iii. 2025

Answer: The Company develops the long-term vision for the grid and 5-year investment plans for distribution programs and projects using the process described in the 2021 and 2023 Distribution Grid Plans (DGP). The DGP investments address aging infrastructure, improvements to reliability, resiliency, and safety, and current and projected future capacity constraints. Investments are prioritized using the GPM as well as other considerations, as discussed in Witness Kryscynski's testimony.

The 5-year investment plan is a key reference when developing the annual distribution budgets. The annual budget planning process includes the 5-year DGP plan, updated information on grid needs including reliability data, and regulatory feedback obtained through rate cases. For 2025 investments, the 2023 DGP is the supportive grid planning reference.

A portion of the 2025 Conversions budget was authorized for IRM treatment in Case No. U-21297 as reflected in Exhibit A-33, Schedule X1, Page 1, Line 2. The projects associated with this investment will be presented in the Company's 2025 IRM Investment Plan, consistent with the Commission's Order authorizing the IRM in Case No. U-21297. The remaining planned capital investment is being proposed for recovery in this case as reflected in Exhibit A-12, Schedule B5.4, Pages 14-15, lines 28-56 and 79-91.

Attachment: *None*

MPSC Case No: U-21534

Requester: MNSC

Question No.: MNSCDE-8.18div

Respondent: J. Kryscynski

Page: 1 of 1

Question: 18. Refer to Exhibit A-12, Schedule B5.4, page 14-16, and to the 4.8kV circuit conversions and related projects listed on lines 28-56 and 79-91. Refer also to Exhibit A-33, Schedule X1, line 1, and to "Conversions" budgets proposed for the IRM in 2026 and 2027.

d. Refer to the responses to subparts (a) and (b) above. Explain how the Conversions program budget was established for each of the following years, and provide a list of circuits or projects and capital dollars budgeted by circuit for each year:

iv. 2026

Answer: The Company develops the long-term vision for the grid and 5-year investment plans for distribution programs and projects using the process described in the 2021 and 2023 Distribution Grid Plans (DGP). The DGP investments address aging infrastructure, improvements to reliability, resiliency, and safety, and current and projected future capacity constraints. Investments are prioritized using the GPM as well as other considerations, as discussed in Witness Kryscynski's testimony.

The 5-year investment plan is a key reference when developing the annual distribution budgets. The annual budget planning process includes the 5-year DGP plan, updated information on grid needs including reliability data, and regulatory feedback obtained through rate cases. For 2026 investments, the 2023 DGP is the supportive grid planning reference.

The Company has proposed in this case that $190.0 million of 2026 Conversions investment be authorized for IRM treatment as reflected in Exhibit A-33, Schedule X1, Page 1, Line 2. If approved, a list of projects associated with the IRM investment will be presented as part of the Company's 2026 IRM Investment Plan, consistent with the Commission's Order authorizing the IRM in Case No. U-21297. Remaining conversion investment for 2026 is outside this rate case scope.

Attachment: *None*

MPSC Case No: U-21534

Requester: MNSC

Question No.: MNSCDE-8.18dv

Respondent: J. Kryscynski

Page: 1 of 1

Question: 18. Refer to Exhibit A-12, Schedule B5.4, page 14-16, and to the 4.8kV circuit conversions and related projects listed on lines 28-56 and 79-91. Refer also to Exhibit A-33, Schedule X1, line 1, and to "Conversions" budgets proposed for the IRM in 2026 and 2027.

d. Refer to the responses to subparts (a) and (b) above. Explain how the Conversions program budget was established for each of the following years, and provide a list of circuits or projects and capital dollars budgeted by circuit for each year:

v. 2027

Answer: The Company develops the long-term vision for the grid and 5-year investment plans for distribution programs and projects using the process described in the 2021 and 2023 Distribution Grid Plans (DGP). The DGP investments address aging infrastructure, improvements to reliability, resiliency, and safety, and current and projected future capacity constraints. Investments are prioritized using the GPM as well as other considerations, as discussed in Witness Kryscynski's testimony.

The 5-year investment plan is a key reference when developing the annual distribution budgets. The annual budget planning process includes the 5-year DGP plan, updated information on grid needs including reliability data, and regulatory feedback obtained through rate cases. For 2027 investments, the 2023 DGP is the supportive grid planning reference.

The Company has proposed in this case that $240.0 million of 2027 Conversions investment be authorized for IRM treatment as reflected in Exhibit A-33, Schedule X1, Page 1, Line 2. If approved, a list of projects associated with the IRM investment will be presented as part of the Company's 2027 IRM Investment Plan, consistent with the Commission's Order authorizing the IRM in Case No. U-21297. Remaining conversion investment for 2027 is outside this rate case scope.

Attachment: *None*

EXHIBIT MEC-23

RESERVED

DTE Electric Company
One Energy Plaza, 1635 WCB
Detroit, MI 48226-1279



Paula Johnson-Bacon
(313) 235-7052
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August 30, 2024

Lisa Felice
Executive Secretary
Michigan Public Service Commission
7109 West Saginaw Highway
Lansing, MI 48917

RE: In the matter of the Application of **DTE ELECTRIC COMPANY** for authority to increase its rates, amend its rate schedules and rules governing the distribution and supply of electric energy, and for miscellaneous accounting authority
MPSC Case No(s). U-21297 and U-21354

Dear Ms. Felice:

Attached in the above captioned matter is DTE Electric Company's 2025 Investment Recovery Mechanism (IRM) Investment Plan. Also attached is the Proof of Service.

Very truly yours,

Paula Johnson-Bacon

Digitally signed by Paula Johnson-Bacon
Date: 2024.08.30 12:28:09 -04'00'

Paula Johnson-Bacon

PJB/erb
Attachment

cc: Service List

DTE Electric Company

2025 Investment Recovery Mechanism (IRM) Plan

August 30, 2024

DTE

Table of Contents

1 Introduction 1
2 Circuit Conversions
2.1 Selection Criteria & Targets 2
2.2 2025 Circuit Conversion IRM Plan 3
3 Subtransmission Redesign & Rebuild
3.1 Selection Criteria & Targets 5
3.2 2025 Subtransmission Redesign & Rebuild Plan 6
4 Breaker Replacement
4.1 Selection Criteria & Targets 7
4.2 2025 Breaker Replacement IRM Plan 8
5 Underground Residential Distribution Replacement
5.1 Selection Criteria & Targets 10
5.2 2025 URD Replacement IRM Plan 11
6 4.8kV Circuit Automation
6.1 Selection Criteria & Targets 18
6.2 2025 4.8kV Circuit Automation IRM Plan 19

1 Introduction

In the Order dated December 1, 2023 in Case No. U-21297, DTE Electric (DTEE) received approval for a two-year distribution investment recovery mechanism (IRM) for the following five programs: (1) conversions, (2) subtransmission redesign & rebuild, (3) breaker replacement, (4) underground residential distribution (URD) replacement, and (5) 4.8kV circuit automation. The Commission directed DTEE to file an IRM Investment Plan at least four months prior to the start of each plan year to allow for a meaningful review by both Michigan Public Service Commission (MPSC) Staff and other interested stakeholders. In addition, the Company will hold a forum two months prior to the start of the plan year. The forum provides the opportunity for interested parties to raise concerns and allows for additional collaboration and input into the proposed investments. A formal reconciliation process will be filed as a contested case proceeding after the end of an IRM year to provide transparency and an opportunity for review of the reasonableness and prudence of the company's expenditures.

For the IRM Plan Year 2 (12 months ending December 31, 2025), the Commission approved the following investment and in-servicing to be included in the IRM (in $ millions):

Program	Investment	In-service[1]
Circuit conversions	185.8	139.8
Subtransmission redesign & rebuild	53.8	41.8
Breaker replacement	12.6	12.6
URD replacement	13.5	13.5
4.8kV circuit automation	24.4	24.4
Total	**290.1**	**232.1**

The following sections provide the selection criteria, targets, and project details of the investment for each program that will be in-serviced in Year 2 of the IRM and relevant to the associated IRM surcharge. The IRM surcharge is based only on in-serviced investment amounts, so that is the focus for each of the plans.

[1] For Breaker replacement, URD replacement, and 4.8kV circuit automation the investment and in-service amounts match because the assets are generally put into service as soon as the investment occurs (similar to the DTE Gas IRM). For circuit conversions and subtransmission redesign & rebuild, the numbers are different to account for some investment occurring before the asset goes into service

2 Circuit Conversions

2.1 Selection Criteria & Targets

The benefits of conversion of the 4.8kV system include increasing capacity as well as addressing the reliability risks of aged substation equipment. Therefore, the primary factors considered when developing conversion projects are substation over firm rating, circuit overloads, wire downs per overhead mile, and substation risk ranking. Consistent with other strategic projects and programs, 4.8kV conversion projects are evaluated and prioritized using the global prioritization model (GPM), which takes into account the factors above, in addition to reliability improvements and investment in environmental justice (EJ) communities.

The Company operates some circuits as isolation (ISO) downs, which are 4.8kV circuits that are fed from a 13.2kV substation. On these circuits, the higher voltage is stepped down to 4.8kV by a transformer and the rest of the circuit downstream of that transformer operates in a 4.8kV delta configuration. As part of DTEE's long term vision to convert the 4.8kV system, converting the ISO down areas to a higher voltage will also be required.

The 4.8kV isolation down (ISO) circuits are already fed from a 13.2kV substation which removes the substation firm rating and the substation risk ranking from prioritization consideration. Without the need to consider substation factors, the following become the driving factors of 4.8kV ISO down conversions: safety (wire down reduction), reliability (customer minute interruptions), and costs (avoided O&M and capital).

Program execution metrics and associated targets for the selected conversion project that DTEE is planning to report in the reconciliation process are as follows:

Metric	Target
Overhead (OH) line miles pre-converted	49.7-51.8
Average cost per OH line mile pre-converted	$1.4M
Overhead (OH) line miles converted	43.1-44.3
Average cost per OH line mile converted	$0.5M
Conduit miles installed	3.7-4.8[2]

[2] Conduit mile work on the AC network can include conduit banks, manholes, primary switch cabinets, netbank platforms and other equipment; as such, actual project costs (rather than average unit costs) will be provided in the reconciliation process

2.2 2025 Circuit Conversion IRM Plan

Project	Substation/ Circuit	Area	Municipality	Scope of Work	Estimated 2025 In-service ($000s)
CODI: Garfield Radial (Midtown Circuits)	Garfield	SE	Detroit	3.5-3.8 miles OH pre-conversion[3]	6,000-6,500
CODI: Islandview Substation - System Conduit	Islandview	SE	Detroit	1.6-1.8 conduit miles	18,000-20,000
CODI: Islandview Substation - DC9620 & DC9636	Islandview	SE	Detroit	4.4-4.6 miles OH pre-conversion	9,500-10,000
CODI: Kent/Gibson Conversion - CORKT8492	Corktown	SE	Detroit	1.0-1.2 miles OH pre-conversion	1,700-2,000
CODI: Howard AC Network Conversion	Howard	SE	Detroit	1.2-1.4 conduit miles	10,300-12,000
4.8 kV CC: Calla Circuit Conversion Phase 2	Calla	SW	Ann Arbor	6.8-7.0 miles OH conversion	3,400-3,500
4.8 kV CC: I-94 Substation and Circuit Conversion (Promenade) - System Conduit	Promenade	SE	Detroit	0.6-0.95 conduit miles	6,300-10,000
4.8 kV CC: Lapeer - Elba Expansion and Circuit Conversion (Apollo)	Apollo	NE	Lapeer-Elba	0.3-0.6 conduit miles	4,700-5,000
4.8 kV CC: Hawthorne Relief and Circuit Conversion - MALRD9375 OH Work	Hawthorne	SW	Dearborn Heights	6.5-6.7 miles OH conversion	10,000-10,400
4.8 kV CC: Belleville Substation and Circuit Conversion	Belleville	SW	Belleville	8.8-9.0 miles OH conversion	1,800-2,000
4.8 kV CC: Pittsfield Substation and Circuit Conversion	Pittsfield	SW	Ann Arbor	3.5-3.7 miles OH pre-conversion	2,800-3,000
4.8 kV CC: Hemlock Decommissioning and Circuit Conversion	Hemlock	SW	Ann Arbor	2.4-2.5 miles OH pre-conversion	900-1,000

[3] OH pre-conversion scope of work includes 1) rebuilding pole tops, replacing poles and transformers as needed, and installing neutral wire, 2) reconductoring OH lines as needed, 3) installing controls and automation as needed, and 4) removing ISO down transformers

U-21534 | September 4, 2024
MNSC Hearing Exhibits
Ex MEC-24 | Source: DTE's 2025 IRM Investment Plan
Page 6 of 29

Project	Substation/ Circuit	Area	Municipality	Scope of Work	Estimated 2025 In-service ($000s)
4.8 kV CC: Hilton Circuit Conversion Phase 2	Hilton	SE	Ferndale	1.1-1.2 miles OH pre-conversion ~0.1 conduit miles	4,000-4,200
ISO Gilbert	Gilbert	SW	Romulus	8.9-9.1 miles OH conversion	4,000-4,100
ISO Kern	Kern	NW	Pontiac	2.8-3.0 miles OH pre-conversion 5.3-5.5 mile OH conversion	3,800-4,000
ISO Biddle	Biddle	SW	Wayne	13.9-14.2 miles OH pre-conversion 6.8-7.0 miles OH conversion	19,500-20,000
ISO Venoy	Venoy	SW	Westland	14.2-14.5 miles OH pre-conversion	19,500-20,000
ISO HEMLK (SPRUC/PDMNT)	Hemlock	SW	Ann Arbor	2.9-3.1 miles OH pre-conversion	3,800-4,000
Total In-serviced Investment					**130,000-141,700**

U-21534 | September 4, 2024
MNSC Hearing Exhibits
Ex MEC-24 | Source: DTE's 2025 IRM Investment Plan
Page 7 of 29

3 Subtransmission Redesign & Rebuild

3.1 Selection Criteria & Targets

DTEE considers six criteria when prioritizing subtransmission redesign & rebuild projects. The first four criteria are part of what are called planning criteria violations. A planning criteria violation means that in either normal state or single contingency state, the system does not have adequate capacity to serve the existing load without exceeding equipment ratings or voltage standards. The six criteria and associated definitions for each criterion are as follows:

- Load loss for single contingency: total load that will be shed in certain conditions when a subtransmission line can no longer support the substation and does not have a back-up,
- Load over emergency rating for single contingency: load in excess of the emergency rating of a subtransmission line during a contingency event (i.e., outage),
- Load over day-to-day rating, normal conditions: Load in excess of the rating of a subtransmission line during normal conditions,
- Voltage violation: voltage drop on a subtransmission line exceeds standards when it is not in its normal configuration (i.e., due to an outage),
- Strong load growth prospect: lines that are predicted to experience load growth, and
- Reliability: history of outages or equipment failures on the subtransmission circuit.

Consistent with other strategic projects and programs, subtransmission redesign & rebuild projects are evaluated and prioritized using the GPM. Projects which provide a higher level of benefits per dollar invested will receive higher GPM scores.

The specific program execution metrics and associated targets that DTEE is proposing to report for the three subtransmission redesign & rebuild projects are as follows:

Metric	Target
OH line miles	22.2-23.1
Average cost per OH line mile[4]	$1.1-2.5M
UG line miles	4.1-4.6
Average cost per UG line mile[4]	$1.3-3.5M

[4] Projects may require distributed generation to support the required shutdowns to work on the system and/or mitigation of adjacent hazards to maintain safe working conditions, resulting in a wider variance of potential costs

3.2 2025 Subtransmission Redesign & Rebuild IRM Plan

Project	Circuit	Region	Scope of Work	Estimated 2025 In-service ($000s)
TRK 4266	TRK 4266	NE	Station work (breaker, transformer, relay panel replacement, and 60 ft of cable replacement)	3,900-4,400
TRK 2419	TRK 2419	NW	0.30-0.32 miles of underground	2,900-3,300
TIE4105-4 (EI-S20-36-R3)	TIE4105	NE	Install 5.0-5.5 miles OH 40kV conductor Decommission ~3.0 miles OH 40kV conductor	19,400-21,600
TRK4911 (EI-S22-67)	TRK4950	NE	Install 0.3-0.4 miles of underground Install 0.8-1.0 miles of overhead	2,700-3,000
TIE 810	TIE 9505 TIE 9514 TRK 4938	NE	2.2-2.3 Miles Seg 8 OH 3.7-3.8 Miles Seg 9 OH 6.9-7.0 Miles Seg 1 OH	14,000-15,000
TIE 6602	TIE 6602	SW	4.4-4.5 miles OH	5,200-5,500
Total In-service Investment				**48,100-52,800**

U-21534 | September 4, 2024
MNSC Hearing Exhibits
Ex MEC-24 | Source: DTE's 2025 IRM Investment Plan
Page 9 of 29

4 Breaker Replacement

4.1 Selection Criteria & Targets

The Company has approximately 6,000 breakers on the electrical distribution and subtransmission systems. As stated in the Company's September 2023 Distribution Grid Plan (page 79), 60% of all breakers are beyond expected useful life and 53% are candidates for replacement based on the findings in the asset health assessment. Included in this 53% are approximately 2,090 oil-filled breakers that require replacement due to a combination of multiple risk factors associated with that equipment, such as the environmental concerns of possible leaks. Replacement factors and their associated impacts include:

- Interrupting medium: known issues such as oil breakers being an environmental concern due to possible leaks and air magnetic breakers being prone to failure due to issues extinguishing arcs within the breaker,
- High maintenance costs: high maintenance costs due to more frequent repairs required, longer time to troubleshoot issues, and/or shorter maintenance cycles,
- Unavailable parts: parts are obsolete or difficult and/or expensive to replace, and
- Known performance issues: higher failure rates or frequent failures to operate.

The Company has identified 29 breaker replacements for inclusion in the 2025 IRM. The specific program execution metrics and associated targets that the Company is proposing to report for the breaker replacement program are as follows:

Metric	Target
Number of breakers replaced	29
Average cost per 4.8kV breaker (000s)	$440
Average cost per recloser breaker (000s)	$391
Average cost per subtransmission breaker (000s)	$598

4.2 2025 Breaker Replacement IRM Plan

Equip. Type	Region	Station	Substation Municipality	Scope of Work	Estimated 2025 In-service ($000s)
4.8kV Breaker	N	COOLG	Detroit	COOLG Pos Q Breaker Replacement	440
4.8kV Breaker	N	COOLG	Detroit	COOLG Pos E Breaker Replacement	440
4.8kV Breaker	N	WDTRK	Port Huron	WDTRK Pos BC Breaker Replacement	440
4.8kV Breaker	SE	VILLA	Redford	VILLA Pos A Breaker Replacement	440
4.8kV Breaker	SE	FRISB	Detroit	FRISB Pos R Breaker Replacement	440
4.8kV Breaker	N	FRISB	Detroit	FRISB Pos Z Breaker Replacement	440
4.8kV Breaker	N	FRISB	Detroit	FRISB Pos S Breaker Replacement	440
4.8kV Breaker	SE	FRISB	Detroit	FRISB Pos W Breaker Replacement	440
4.8kV Breaker	SE	FRISB	Detroit	FRISB Pos X Breaker Replacement	440
4.8kV Breaker	SE	FRISB	Detroit	FRISB Pos BX Breaker Replacement	440
4.8kV Breaker	SE	FRISB	Detroit	FRISB Pos BW Breaker Replacement	440
4.8kV Breaker	N	EVRSB	Detroit	EVRSB Pos F Breaker Replacement	440
4.8kV Breaker	SE	MOUND	Warren	MOUND Pos O Breaker Replacement	440
Recloser	SE	PDMNT	Ann Arbor	PDMNT Pos J Breaker Replacement	391
Recloser	SE	ATLAN	Reese	ATLAN Pos Trf 2 Breaker Replacement	391

U-21534 | September 4, 2024
MNSC Hearing Exhibits
Ex MEC-24 | Source: DTE's 2025 IRM Investment Plan
Page 11 of 29

Equip. Type	Region	Station	Substation Municipality	Scope of Work	Estimated 2025 In-service ($000s)
Recloser	SE	KILGR	Kenockee	KILGR Pos D Breaker Replacement	391
Recloser	SE	COTAG	Burtchville Township	COTAG Pos F Breaker Replacement	391
Recloser	SE	ELM	Taylor	ELM Pos D Breaker Replacement	391
Recloser	SE	ELM	Taylor	ELM Pos I Breaker Replacement	391
Recloser	SE	ELM	Taylor	ELM Pos C Breaker Replacement	391
Recloser	SE	PLACD	Clarkston	PLACD Pos HE Breaker Replacement	391
Recloser	SE	PLACD	Clarkston	PLACD Pos HL Breaker Replacement	391
Recloser	SW	PAGE	Milford	PAGE Pos D Breaker Replacement	391
Recloser	N	SLKRK	Brighton	SLKRK Pos N Breaker Replacement	391
Recloser	N	SLKRK	Brighton	SLKRK Pos O Breaker Replacement	391
Recloser	N	MACK	Detroit	MACK Pos TRF1-L Breaker Replacement	391
Subtrans	SE	COLFX	Fowlerville	COLFX Pos RM Breaker Replacement	598
Subtrans	SE	COLFX	Fowlerville	COLFX Pos RR Breaker Replacement	598
Subtrans	SE	TCOLA	Caro	TCOLA Pos RJ Breaker Replacement	598

U-21534 | September 4, 2024
MNSC Hearing Exhibits
Ex MEC-24 | Source: DTE's 2025 IRM Investment Plan
Page 12 of 29

5 URD Replacement

5.1 Selection Criteria & Targets

URD is a specific type of cable designed for underground residential use on the Company's secondary electric system. URD consists of small diameter cable surrounded by polyethylene insulation and is either directly buried into the ground or installed inside conduit. Based on age and other factors, 41% of URD cables (about 4,500 miles) are candidates for replacement based on findings of the Company's asset health assessment, as stated in the Company's September 2023 Distribution Grid Plan (page 79). Replacement factors and their associated impacts include:

- Manufacturing year: pre-1985 the insulation is XLPE (non-tree retardant) while post-1985 the insulation is TR-XLPE (tree retardant) and
- Number of outages: the rate of URD cable failures increases with the age of the cable, and the rate further increases once a cable experiences its first failure.

The Company has identified 111 URD replacement jobs for a total of approximately 287 thousand feet for inclusion in the 2025 IRM. The specific program execution metrics and associated targets that the Company is proposing to report for the URD replacement program are as follows:

Metric	Target
Feet of URD replaced (000s)	287
Average cost per thousand feet of URD replaced (000s)	$47

5.1 2025 URD Replacement IRM Plan

Region	Substation Municipality	URD Map	Circuit	Feeder	Scope Length (000s ft)	Estimated 2025 In-service ($000s)
NE	Lapeer	LPR5	LAPER8785	PF848	3.434	158
NW	Brighton	BTN 86	NOLAN9790	PFK755	3.600	166
SE	Allen Park	DET6 19	JUPTR8373	PF3442	1.209	56
SE	Allen Park	DET6-25	JUPTR8390	PFA041	0.470	22
NE	Warren	WRN 54	LNDIS8048	PFB674	1.835	84
NE	Warren	WRN 54	LNDIS8132	PFB678	0.706	32
SW	Northville	N0V13	HAGER9425	PFH196	3.085	142
NW	Wixom	NOV76	WIXOM9532	PFH3245	4.861	224
NW	West Bloomfield	WBL59	LILY 9126	PFH1529	4.118	189
NW	Bloomfield	BLM 3	LNGLK9110	PF192	4.635	213
SW	Ypsilanti	PIT46	CROWN9832	PFJ321	5.105	235
SW	Novi	FAR79	QUAKR9236	PFH3476	2.790	128
SW	Farmington Hills	FAR62	DRAKE9066	PFH1475	1.598	74
SW	Novi	FAR79	QUAKR9237	PFH1866	9.165	422
NE	Clinton Township	CLN 100	MACMB8521	PFB819	1.014	47
SE	Southfield	SFD110	HIKRY8209	PFH2021	0.678	31

U-21534 | September 4, 2024
MNSC Hearing Exhibits
Ex MEC-24 | Source: DTE's 2025 IRM Investment Plan
Page 14 of 29

Region	Substation Municipality	URD Map	Circuit	Feeder	Scope Length (000s ft)	Estimated 2025 In-service ($000s)
NW	Sterling Heights	STG 35	BISMK8439	PFB041	2.597	119
NW	Rochester Hills	AVN 4	TINKN8850	PF1703	0.240	11
NW	Sterling Heights	STG 35	BISMK8439	PFB042	2.369	109
NE	Clinton Township	CLN 100	MACMB8521	PFB817	3.126	144
NW	Lake Orion	OAK 75	GODSN8134	PFH2159	6.800	313
NW	Auburn Hills	PON16	CARTR9115	PFH2596	2.753	130
NW	Clarkston	IND20	CLKSN8860	PFH1550	3.247	154
NW	Troy	TRY22	APACE8978	PFH2773	2.956	140
NW	Troy	TRY84	APACE9072	PFH1927	5.344	253
NW	Brighton	GEN1	NOLAN9852	PFK475	2.357	112
NW	Orion Township	ORI11	BALDW8945	PFH789	3.422	162
NW	Waterford Township	WLK22	LARDO8973	PFH1828	6.851	325
NW	Shelby Township	SBY 41	BRONC8677	PFB1057	1.747	83
NW	Rochester Hills	AVN 4	TINKN8850	PFH474	5.894	279
NE	Fort Gratiot	FTG 15	PRKRD8760	PFC107	2.285	108
SE	Southfield	SFD 2	LCSTR8858	PF190	2.822	134
SE	Southfield	SFD 119	LCSTR9092	PFH2264	0.706	33
SW	Ann Arbor	PIT 17	PIONR9795	PF2643	3.169	150

Region	Substation Municipality	URD Map	Circuit	Feeder	Scope Length (000s ft)	Estimated 2025 In-service ($000s)
NE	Clinton Township	CLN 145	MACMB8409	PFB840	3.302	156
NW	Whitmore Lake	HBG 19	HAMBG9909	PFK226	3.919	186
SE	Detroit	DET1 20	ALFRD8165	PFA053	3.459	164
NW	Troy	PON22	APACE9041	PFH2285	0.422	20
SE	Detroit	DET1-1s5	ALFRD8216	PFA181	28.018	1328
NW	Rochester Hills	AVN 4	TINKN8850	PFH325	0.457	22
NE	Marysville	STC1	CYPRS8812	PFC2101	0.175	8
NW	Rochester Hills	AVN 12	SPKNE9108	PFH111	0.532	25
NW	Rochester Hills	AVN 3	TINKN8914	PFH547	0.847	40
NW	Rochester Hills	AVN 6	ROCHR1838	PFH2396	0.702	33
NW	Rochester Hills	AVN 3	TINKN8914	PFH433	0.490	23
NW	Rochester Hills	AVN 3	TINKN8884	PFH3701	0.584	28
NW	Sterling Heights	AVN 3	MALTA8482	PFH3856	4.225	200
NW	Rochester Hills	AVN 4	TINKN8850	PFH480	1.990	94
NW	Bruce Township	BRU 6	BRUCE8953	PFB632	1.649	78
NW	Bruce Township	BRU 6	BRUCE8953	PFB574	2.270	108
NW	Rochester Hills	AVN 31	TINKN8922	PFH924	2.200	104
NW	Rochester Hills	AVN 31	TINKN8922	PFH818	1.819	86

Region	Substation Municipality	URD Map	Circuit	Feeder	Scope Length (000s ft)	Estimated 2025 In-service ($000s)
NW	Rochester Hills	AVN 3	TINKN8884	PFH3745	0.444	21
NW	Rochester Hills	AVN 4	TINKN8850	PF1443	0.582	28
NW	Rochester Hills	AVN 4	TINKN8850	PFH483	1.322	63
NE	Burtchville Twp	BUR 1	COTAG8743	PFC014	0.763	36
NW	Rochester Hills	AVN 3	TINKN8884	PF3760	0.725	34
NW	Rochester Hills	AVN 3	TINKN8884	PF3752	0.642	30
NW	Rochester Hills	AVN 12	SPKNE9108	PF2785	1.030	49
NW	Rochester Hills	AVN 12	SPKNE9108	PF3756	0.946	45
NW	Rochester Hills	AVN 12	SPKNE9108	PF3790	1.688	80
NW	Rochester Hills	AVN 12	SPKNE8820	PF3795	1.040	49
NW	Rochester Hills	AVN 4	TINKN8850	PFH321	0.557	26
NW	Rochester Hills	AVN 3	TINKN8884	PFH3711	0.564	27
NW	Shelby Township	SBY 41	BRONC8677	PFB1056	1.460	69
NW	Rochester Hills	AVN 4	TINKN8850	PFH2470	1.123	53
NW	Rochester Hills	AVN 31	TINKN8922	PFH909	1.289	61
NW	Rochester Hills	AVN 6	ROCHR1838	PF2728	0.965	46
NW	Rochester Hills	AVN 3	TINKN8884	PF3754	0.581	28
NE	Marysville	STC1	CYPRS8812	PFC718	1.377	65

Region	Substation Municipality	URD Map	Circuit	Feeder	Scope Length (000s ft)	Estimated 2025 In-service ($000s)
NW	Rochester Hills	AVN 12	SPKNE9108	PFH101	1.046	50
NW	Rochester Hills	AVN 12	SPKNE9108	PFH108	0.990	47
NW	Rochester Hills	AVN 31	TINKN8922	PFH1389	1.700	81
NW	Rochester Hills	AVN 4	TINKN8850	PFH628	0.966	46
NW	Rochester Hills	AVN 4	TINKN8884	PFH185	0.314	15
NW	Rochester Hills	AVN 3	TINKN8884	PFH1995	1.497	71
NW	Shelby Township	SBY 41	BRONC8677	PFB949	1.683	80
NW	Rochester Hills	AVN 3	TINKN8884	PF1910	0.283	13
NW	Rochester Hills	AVN 31	TINKN8922	PFH799	2.274	108
NW	Rochester Hills	AVN 31	TINKN8922	PFH808	3.050	144
NW	Rochester Hills	AVN 31	TINKN8922	PFH1393	1.436	68
NE	Addison Township	ADD 6	BREWR8840	PFH2092	3.561	169
NW	West Bloomfield	AVN 4	WLNUT8994	PFH314	0.605	29
SW	Canton	CAN 27	WAYNE9413	PFM570	0.888	42
NW	West Bloomfield	WBL71	LILY 9105	PFH1877	0.980	46
SW	Ypsilanti	YPS 23	CROWN9850	PF3291	1.033	49
NW	Sterling Heights	SBY 49	STERL8442	PFB1101	1.225	58
NE	Chesterfield Township	CHS 37	CHEST8430	PFB1008	1.336	63

U-21534 | September 4, 2024
MNSC Hearing Exhibits
Ex MEC-24 | Source: DTE's 2025 IRM Investment Plan
Page 18 of 29

Region	Substation Municipality	URD Map	Circuit	Feeder	Scope Length (000s ft)	Estimated 2025 In-service ($000s)
SW	Northville	LIV 56	HAGER9411	PFM1038	1.522	72
SW	Belleville	VAB 4	SHELD8190	PFM192	2.010	95
NW	Lake Orion	OAK 36	GODSN8134	PFH1657	2.027	96
NE	Ubly	BHM 1	BNGHM0301	PFD024	2.398	114
NW	Troy Township	TRY14	CRWFD8301	PF1799	2.405	114
SW	Ypsilanti	SUP 9	MOTT 9789	PFJ318	2.444	116
NE	New Baltimore	CHS 30	NBALT8428	PFB647	2.451	116
SW	Saline	SLN5	SALIN9794	PFJ427	2.520	119
NW	Commerce Township	COM26	HANCK8142	PFH1433	2.561	121
NE	Oxford	OXF 3	STRFD9093	PFH072	2.577	122
NW	Milford	COM3	MILFD9248	PFH3734	2.609	124
SW	Ypsilanti	VAB 25	MOTT 9783	PF1022	2.742	130
NE	Chesterfield Township	CHS 41	CHEST8430	PFB1059	2.758	131
NW	Waterford	WFD 5	NIXON9141	PFH2555	2.928	139
SW	Ypsilanti	SUP 2	MOTT 9789	PF2613	3.009	143
NW	West Bloomfield	WBL90	LILY 9126	PFH2359	3.598	170
NE	Sterling Heights	CLN 82	MALTA8999	PFB716	4.169	198
NW	Sterling Heights	STG 100	STERL8435	PFB836	4.269	202

Region	Substation Municipality	URD Map	Circuit	Feeder	Scope Length (000s ft)	Estimated 2025 In-service ($000s)
SW	Ann Arbor	SCI 17	SPRUC9874	PFJ516	4.913	233
NW	Auburn Hills	WFD49	JSLYN9140	PFH1545	5.710	271
NE	Macomb	MCB 61	AGSTA8737	PFB2220	6.231	295
SW	Farmington Hills	FAR 21	DREXL9036	PF1494	6.806	322
SW	Ann Arbor	PIT 51	PIONR9793	PFJ398	8.020	380

U-21534 | September 4, 2024
MNSC Hearing Exhibits
Ex MEC-24 | Source: DTE's 2025 IRM Investment Plan
Page 20 of 29

6 4.8kV Circuit Automation

6.1 Selection Criteria & Targets

The key factors for 4.8kV circuit automation prioritization are the safety benefits associated with de-energizing down wires, the reliability benefits associated with reduced customer interruptions and outage durations, and the improved operational efficiencies associated with improved system monitoring and control. Special weighting was given to 1) 4.8kV circuits that have experienced high levels of wire downs, 2) completing all circuits associated with a particular substation transformer to ensure ground isolation coordination, and 3) 4.8kv circuits that have experienced poor reliability.

The Company has identified 65 circuits for automation for inclusion in the 2025 IRM, for a total of 168 reclosers. The scope of work for circuit automation includes installing SCADA enabled reclosers at the station cable poles, sectionalizing points, and switching points as applicable. The specific program execution metrics and associated targets that the Company is proposing to report for the 4.8kV Circuit Automation program are as follows:

Metric	Target
Reclosers Installed	168
Average cost per recloser (000s)	$150

6.1 2025 4.8kV Circuit Automation IRM Plan

Circuit	Region	Substation Municipality	Reclosers Installed	Estimated 2025 In-service ($000s)
YPSIL0317	SW	Ypsilanti	3	450
YPSIL0305	SW	Ypsilanti	3	450
YPSIL0314	SW	Ypsilanti	3	450
YPSIL0318	SW	Ypsilanti	3	450
NEFF 0314	NE	Harbor Beach	3	450
NEFF 0011	NE	Harbor Beach	1	150
MLVDL2277	SE	Melvindale	3	450
MLVDL2010	SE	Melvindale	3	450
MLVDL2008	SE	Melvindale	3	450
MLVDL2259	SE	Melvindale	1	150
MLVDL0196	SE	Melvindale	1	150
FLANE1840	SE	Detroit	3	450
FLANE1839	SE	Detroit	3	450
GARY 1365	SE	Detroit	3	450
GARY 1376	SE	Detroit	3	450
GARY 2115	SE	Detroit	3	450

U-21534 | September 4, 2024
MNSC Hearing Exhibits
Ex MEC-24 | Source: DTE's 2025 IRM Investment Plan
Page 22 of 29

Circuit	Region	Substation Municipality	Reclosers Installed	Estimated 2025 In-service ($000s)
GARY 1399	SE	Detroit	3	450
GARY 1920	SE	Detroit	2	300
MEYRS1691	SE	Detroit	3	450
MEYRS1599	SE	Detroit	3	450
MEYRS1896	SE	Detroit	3	450
PURTN1044	SE	Detroit	2	300
PURTN1020	SE	Detroit	2	300
KENEY1461	NE	Warren	3	450
KENEY2697	NE	Warren	3	450
SUTTN1751	NE	Clinton Township	3	450
SUTTN2408	NE	Clinton Township	3	450
SUTTN1637	NE	Clinton Township	3	450
TIRMN1196	SE	Detroit	5	750
TIRMN2144	SE	Detroit	3	450
TIRMN2093	SE	Detroit	5	750
EMPIR1367	SE	Detroit	1	150
EMPIR1011	SE	Detroit	3	450
EMPIR1129	SE	Detroit	3	450

U-21534 | September 4, 2024
MNSC Hearing Exhibits
Ex MEC-24 | Source: DTE's 2025 IRM Investment Plan
Page 23 of 29

Circuit	Region	Substation Municipality	Reclosers Installed	Estimated 2025 In-service ($000s)
EMPIR0221	SE	Detroit	1	150
STLUS1394	SE	Detroit	3	450
STLUS1099	SE	Detroit	3	450
STLUS0368	SE	Detroit	1	150
MLVDL1516	SE	Melvindale	3	450
MLVDL2114	SE	Melvindale	3	450
MLVDL2105	SE	Melvindale	3	450
MLVDL0389	SE	Melvindale	1	150
MLVDL0528	SE	Melvindale	1	150
EVRGN1925	SE	Detroit	1	150
EVRGN2135	SE	Detroit	1	150
EVRGN0675	SE	Detroit	1	150
ANNCH1361	SE	Detroit	3	450
ANNCH1588	SE	Detroit	3	450
MILTN0302	NE	Millington	3	450
MILTN0301	NE	Millington	1	150
WHTLK0307	NW	White Lake	3	450
MANDY0308	SE	Royal Oak	3	450

U-21534 | September 4, 2024
MNSC Hearing Exhibits
Ex MEC-24 | Source: DTE's 2025 IRM Investment Plan
Page 24 of 29

Circuit	Region	Substation Municipality	Reclosers Installed	Estimated 2025 In-service ($000s)
MANDY2735	SE	Royal Oak	3	450
MANDY2689	SE	Royal Oak	3	450
MANDY0903	SE	Royal Oak	1	150
NHAVN0312	NE	New Haven	3	450
NHAVN0311	NE	New Haven	3	450
PLYMO0300	SW	Plymouth	3	450
PLYMO0306	SW	Plymouth	3	450
PLYMO0004	SW	Plymouth	3	450
QTNRD0322	NW	Birmingham	3	450
QTNRD0326	NW	Birmingham	3	450
QTNRD0323	NW	Birmingham	1	150
FRMNT1593	SE	Detroit	3	450
FRMNT1487	SE	Detroit	3	450

U-21534 | September 4, 2024
MNSC Hearing Exhibits
Ex MEC-24 | Source: DTE's 2025 IRM Investment Plan
Page 25 of 29

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of **DTE ELECTRIC COMPANY** for authority to increase its rates, amend its rate schedules and rules governing the distribution and supply of electric energy, and for miscellaneous accounting authority	))))))	Case No. U-21297

PROOF OF SERVICE

STATE OF MICHIGAN)
) ss.
COUNTY OF WAYNE)

ESTELLA R. BRANSON states that on August 30, 2024, she served a copy of DTE Electric Company's 2025 Investment Recovery Mechanism (IRM) Investment Plan in the above captioned matter, via electronic mail, upon the persons listed on the attached service list.

Estella R. Branson

Digitally signed by Estella R. Branson
Date: 2024.08.30 12:29:15 -04'00'

ESTELLA R. BRANSON

MPSC Case No(s). U-21297 & U-21534
Service List
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MPSC Case No(s). U-21297 & U-21534
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MPSC Case No(s). U-21297 & U-21534
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MPSC Case No: U-21534

Requester: MNSC

Question No.: MNSCDE-18.2a

Respondent: N. Foley

Page: 1 of 1

Question: 2. Refer to Foley rebuttal, Q&A21-23 and Q&A26-27, and Foley revised direct, Q&A57-59:

a. Produce all internal presentations and all presentations to Staff that the witness created, helped create, or reviewed concerning the proposal to extend the IRM and/or the proposal to increase IRM spending amounts. (The question seeks materials that discuss either topic as well as any materials that discuss both topics.)

Answer: See attached documents for requested information.

Attachment: *MNSCDE-18.2a-01 IRM Proposal Doc 1 (2024.03.21)*
MNSCDE-18.2a-02 IRM Proposal Doc 2 (2024.03.11)
MNSCDE-18.2a-03 IRM Proposal Doc 3 (2024.02.26)
MNSCDE-18.2a-04 IRM Proposal Doc 4 (2024.02.08)
MNSCDE-18.2a-05 IRM Proposal Doc 5 (2024.02.05)
MNSCDE-18.2a-06 IRM Proposal Doc 6 (2024.01.29)
MNSCDE-18.2a-07 IRM Proposal Doc 7 (2023.12.15)
MNSCDE-18.2a-08 IRM Proposal Doc 8 (2023.12.04)

The rate case also contains two proposals that are aimed at ensuring that the necessary reliability investments are executed and that the company is held accountable

Goals

- Hold the utility accountable for making the investments that will drive reliability improvements or return funds to customers if unable to do so
- Ensure that very extreme weather does not impact the company's financial ability to execute these investments



Rate case proposals
(details on next pages)

1. **Distribution IRM Extension**
2. **Storm restoration cost sharing mechanism**

Once implemented, PBR can further hold utilities accountable for meeting reliability improvement targets

IRM: we will propose an extension of the Distribution IRM to ensure it, and its associated benefits, do not lapse at the end of 2025

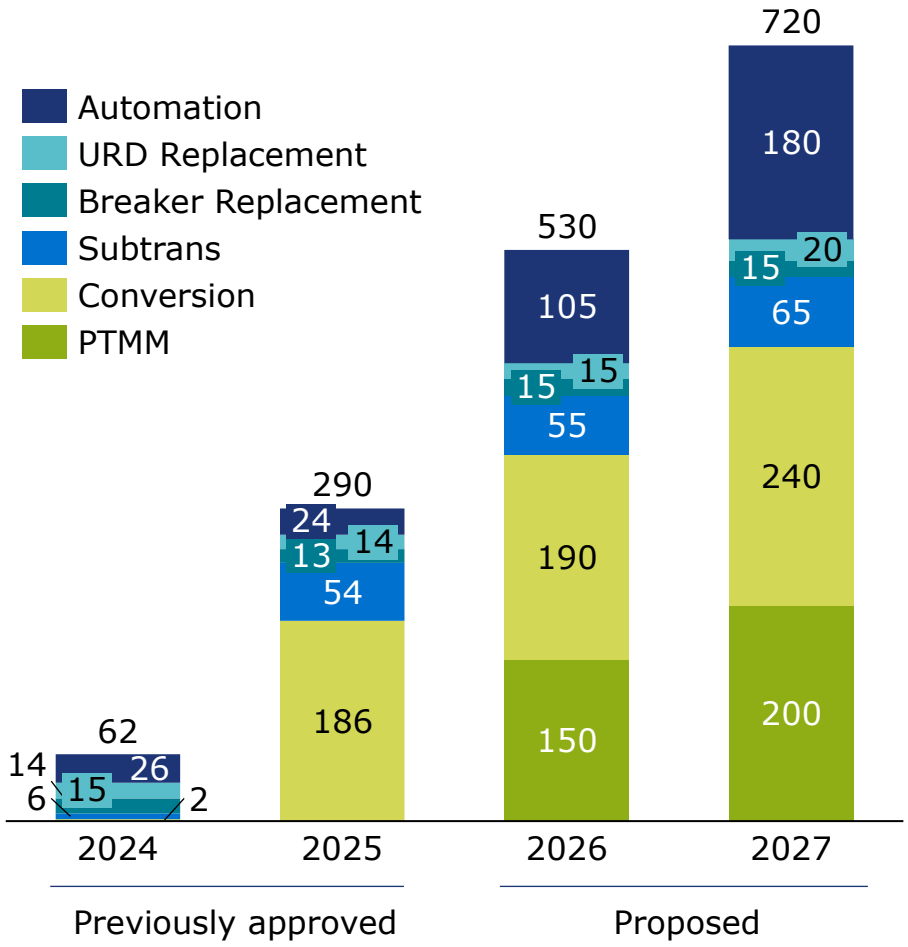
Distribution IRM Proposal:

- Extend the Distribution IRM through 2027 (currently approved through 2025) with proposed level of investment and in-service capital
- Proposed scope changes starting in 2026:
  - Authorize Pole & Pole Top Maintenance & Modernization (PTMM) for IRM treatment
  - Modify scope of automation investment from previous "4.8 kV Automation" to "Distribution Automation"

Benefits:

- Grow the benefits associated with the IRM (e.g., customer protections, additional transparency, etc.)
- Ensure its continued operation while the separate cases on PBR and the Distribution Audit conclude – we plan to incorporate findings from these cases in our next rate case, as appropriate

Electric Distribution IRM
($M capital investment)



IRM: in addition, we would be supportive of incremental IRM authorization in 2025 to address the Commission's concerns about investment execution

Commission guidance:

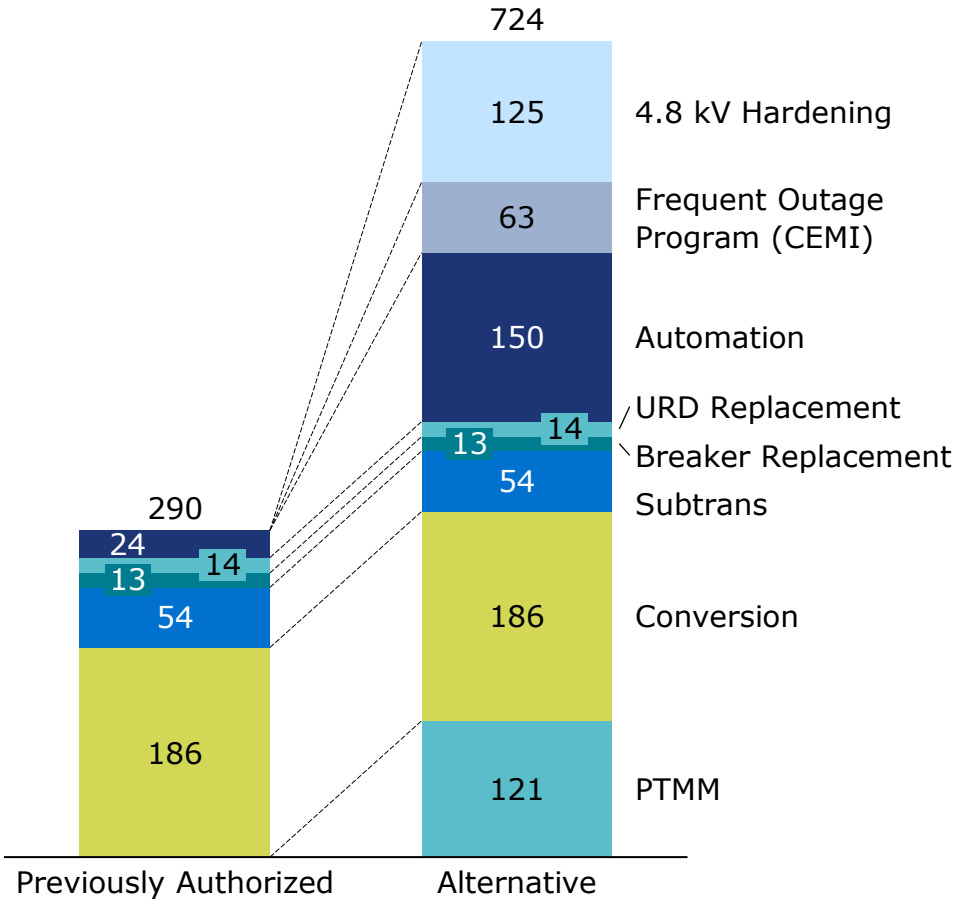
"…where we see repeated instances where dollars collected in a forward test year environment from customers are not spent on the elements for which they were approved we believe that this ultimately reflects an abuse of the forward test year construct, and **would like to see a greater tie between those investments specifically approved for specific projects and the ultimate investments made."**

(Commission Chair Scripps; March 1, 2024)

DTE Alternative 2025 Proposal:

- Increase 2025 IRM authorization by $434M
  - PTMM - $121M
  - Automation - $126M
  - Frequent Outage Program - $63M
  - 4.8 kV Hardening - $125M
- IRM ensures investments are made for the intended purpose approved by the Commission or collected funds are returned to customers

2025 Electric Distribution IRM
($M capital investment)



The rate case also contains two proposals that are aimed at ensuring that the necessary reliability investments are executed and that the company is held accountable

Goals

- Hold the utility accountable for making the investments that will drive reliability improvements or return funds to customers if unable to do so
- Ensure that very extreme weather does not impact the company's financial ability to execute these investments



IRM Extension

Extend the Distribution IRM and add PTMM to the scope for 2026-2027

- Creates alignment for where investments are made
- Protects customers if investments are not made
- Can be updated during each rate case and include findings from the current Distribution Audit

Storm Cost Recovery Mechanism

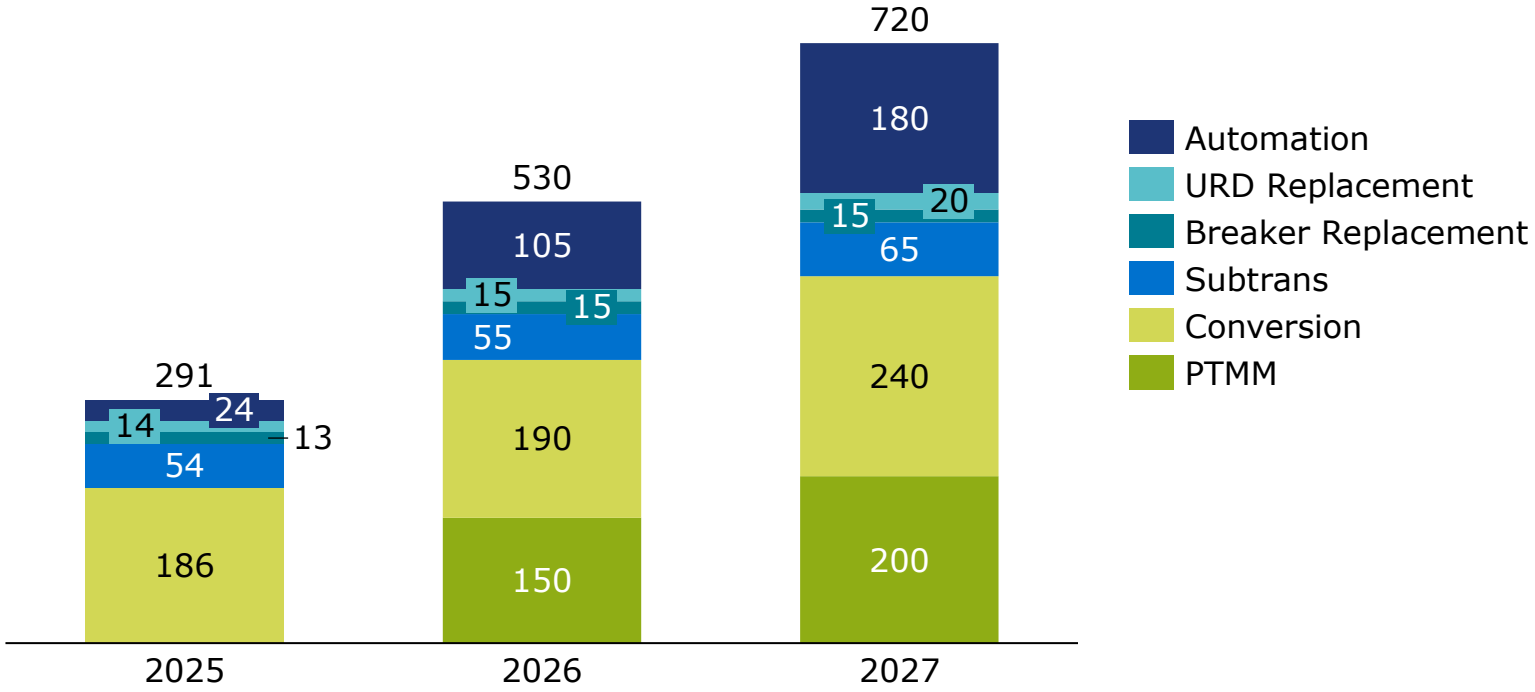
Implement an O&M storm tracker and cost sharing mechanism

- Any costs above or below the 5-year average would be equally shared by DTE and its customers
- Ensures that DTE has a continued incentive to reduce costs
- Provides a benefit to customers in years with lower storm expense

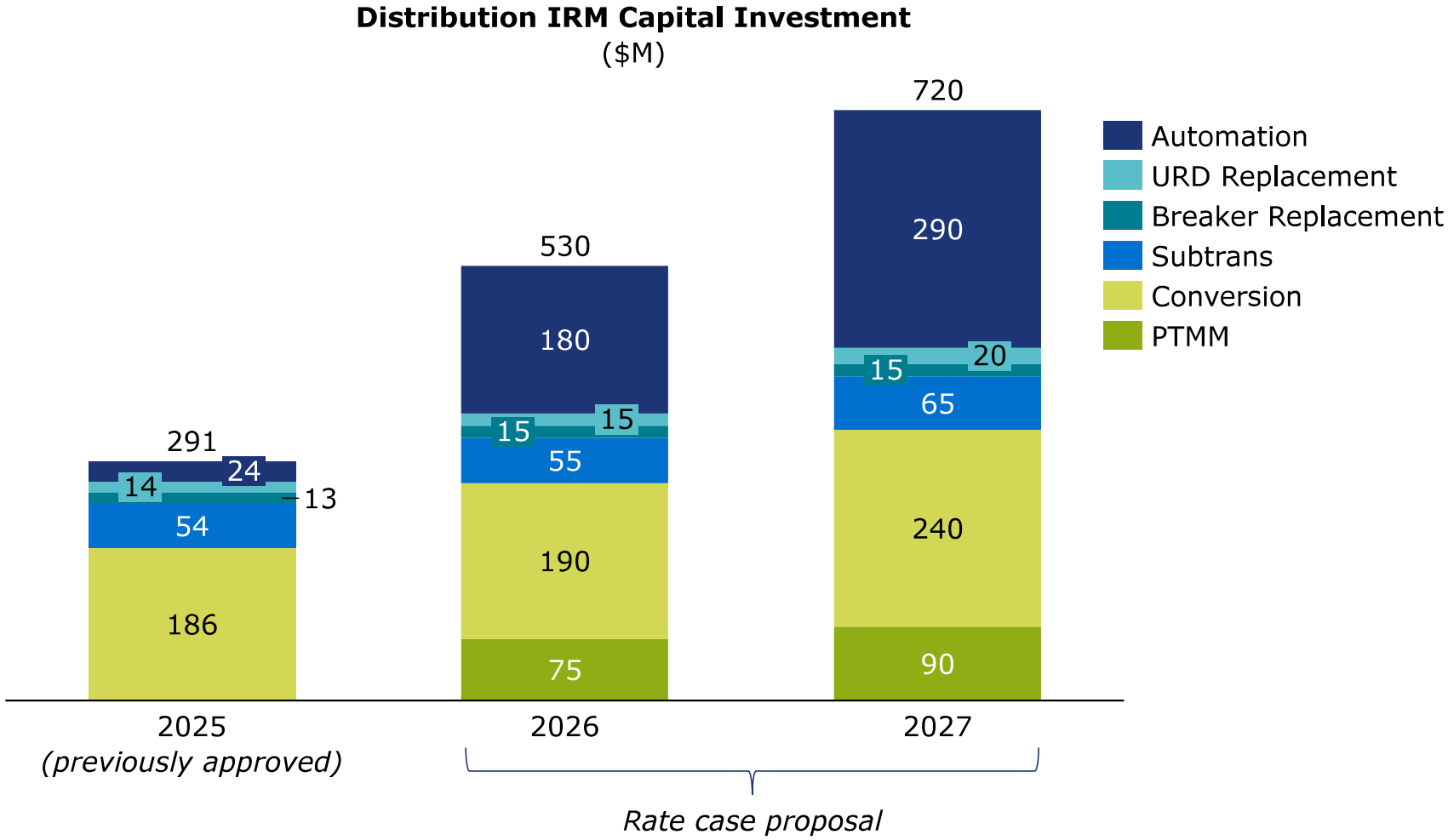
Once implemented, PBR can further hold utilities accountable for meeting reliability improvement targets

DTE

2026 / 2027 IRM funding

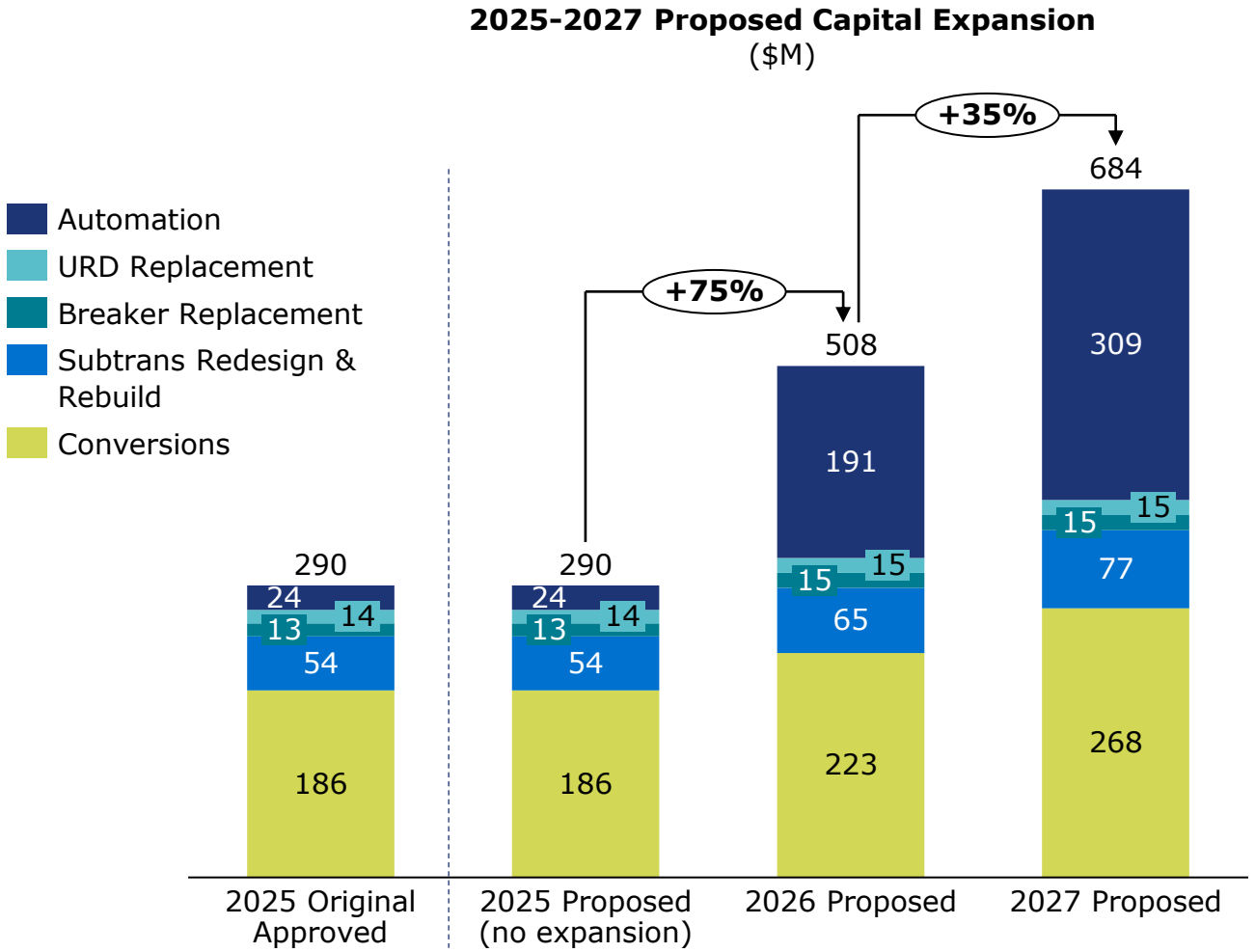


We will propose an extension and expansion of our Distribution IRM in the upcoming rate case



DTE

Option 1



2025: No Change

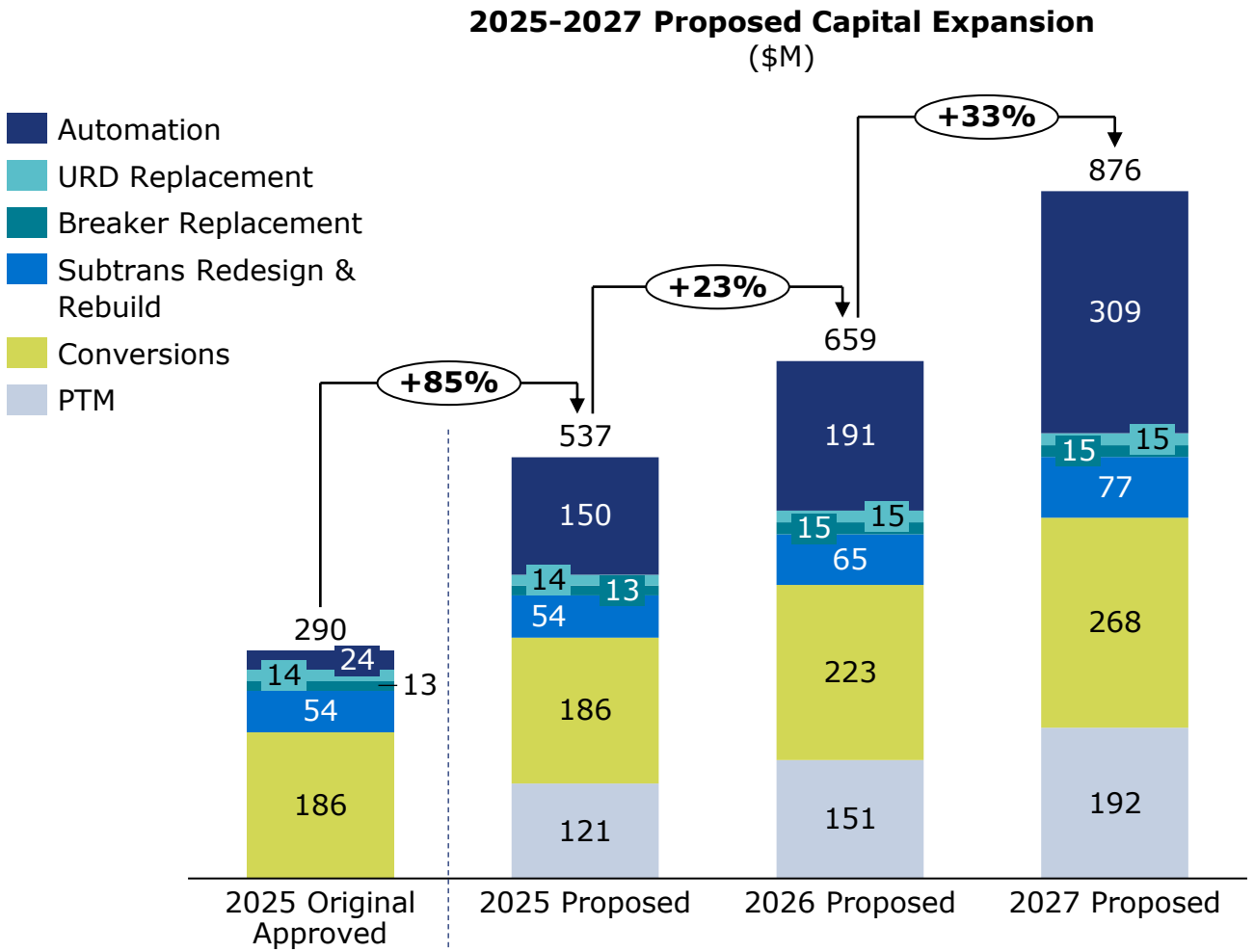
2026:

- Flow all "Distribution Automation" investment through the IRM
- Increase conversions and subtrans investment by 20% vs. 2025
- Flow total investment for all other programs through IRM in line with latest capital plan

2026

- Increase conversions and subtrans investment by 20% vs. 2026 (+$48M)
- Flow total investment for all other programs through IRM in line with latest capital plan (+$74 vs. 2025)

Option 2



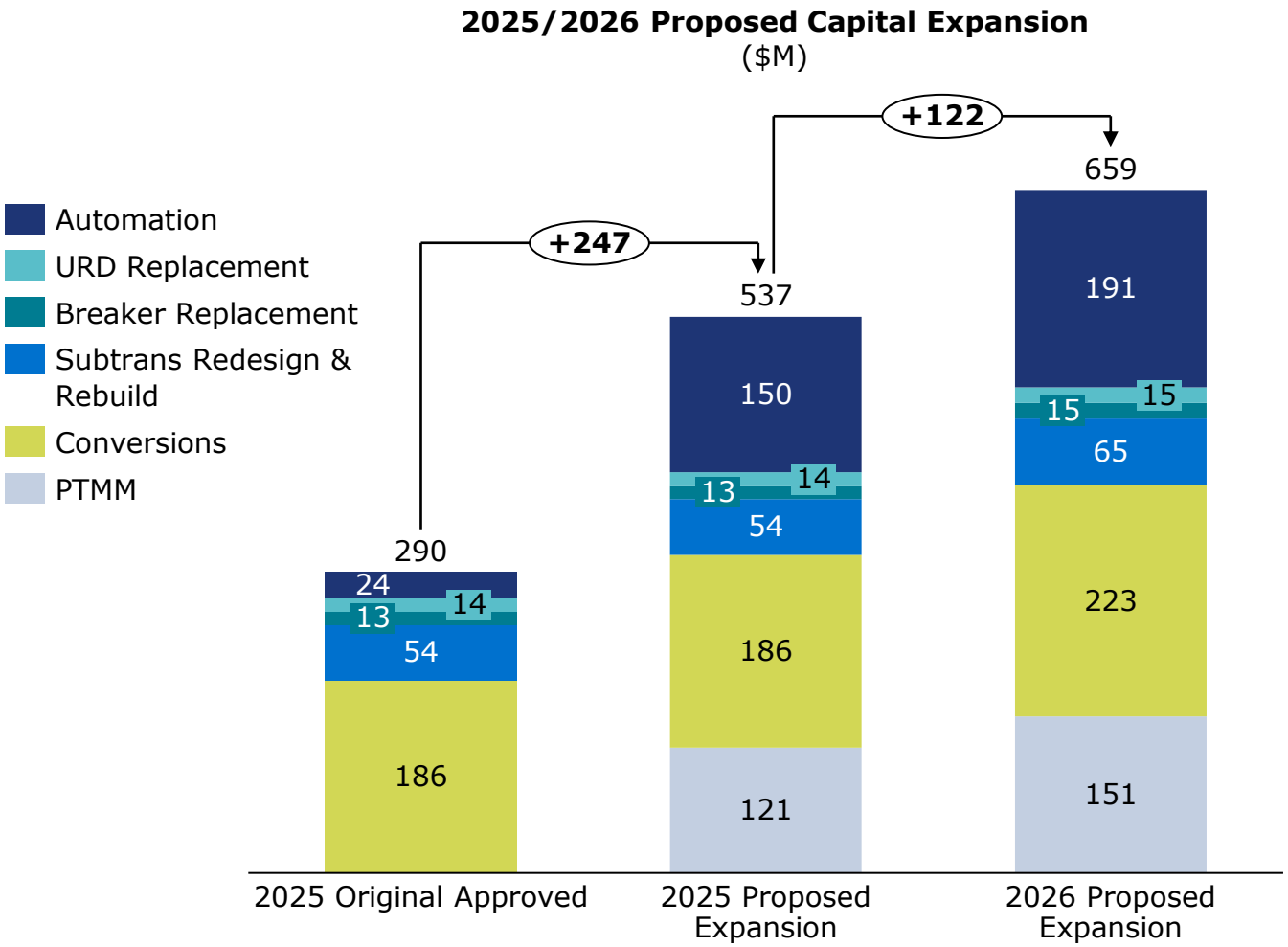
2025:

- Flow all "Distribution Automation" investment through the IRM
- Flow all PTMM investment through the IRM

2026/2027:

- Increase conversions and subtrans investment by 20% per year
- Flow total investment for all other programs through IRM in line with latest capital plan

IRM expansion proposal



2025:

- Flow all "Distribution Automation" investment through the IRM (+$126M)
- Flow all PTMM investment through the IRM (+$121M)

2026

- Increase conversions and subtrans investment by 20% vs. 2025 (+$48M) vs. 2025)
- Flow total investment for all other programs through IRM in line with latest capital plan (+$74 vs. 2025)

We have identified two additional non-capital proposals that could be made in the upcoming case

Potential non-capital proposals

1

Simple one-year extension of the Distribution IRM (through 2026)

- The Commission approved a two-year IRM (i.e., through 2025), citing the ongoing DO Audit and Performance Based Ratemaking (PBR) efforts as reasons to not approve the third year
- However, if we do not propose an extension in this case the IRM will likely lapse at the end of 2025 and not be renewed until sometime in 2026 at the conclusion of a potential 2025 rate case
- Such a lapse would challenge the newly established planning and reconciliation processes and make it more difficult to make the IRM "business as usual"
- Given these dynamics we are planning to propose a simple one-year extension (e.g., same programs and funding levels as 2025) to allow the DO Audit and PBR workgroup to complete

2

Storm O&M cost tracker

- Being discussed at January 9 Regulatory & Policy (RP) meeting

There are two near term actions that DTE must urgently complete

1

- Finalize and submit IRM Investment Plan for IRM Plan Year 1 (i.e., 12/1/2023 to 12/31/2024)
  - Plan information consistent with Foley testimony (i.e., no Commission guidance on changes from what was proposed)
  - Submit to all intervening parties
  - Schedule stakeholder session
- [TBD] Should target end of year to submit investment plan, with stakeholder session scheduled for January

2

- Determine what will be proposed in the upcoming 2024 Electric Rate Case
  - Dec 1 order: "approval is limited to Plan Years 1 and 2. As noted on the record, there is ongoing discussion regarding PBR in Case No. U-21400 and an ongoing audit in Case No. U-21305. Therefore, the Commission finds that limiting the approval to the first two years will allow the company to move forward with the IRM without precluding the incorporation of any potential insights gained from those proceedings to better inform the potential continuation of the IRM."
  - 2024 and 2025 IRM approval is potentially inconsistent with DGP and internal planning investment levels given updates made post-ice storm and captured in DGP

U-21534 | September 4, 2024
MNSC Hearing Exhibits
Ex MEC-25 | Source: MNSCDE-18.2a with Atts
Page 12 of 13

Options for IRM in the upcoming rate case

	Option 1: No proposal	Option 2: Simple extension	Option 3: Extension, Scope Growth, & PBR
Proposal	• Do not propose any changes to approved IRM	• Either no change to 2025 or update 2025 investment levels to align with DGP/internal plans • **Extend IRM through 2026** at DGP investment levels, keeping same programs in IRM	• Update 2025 investment levels to align with DGP/internal plans • Extend IRM through 2026 or 2027 at DGP investment levels, potentially including additional programs (e.g., 13.2 kV circuit automation, PTMM, etc.) • **Propose PBR mechanism** based on Commission's updated straw proposal
Pros	• Allows time to establish IRM and begin new annual processes without having to already argue for changes	• Simplest extension, arguing: – IRM needs to be extended in order to avoid inefficient stopping/starting – PBR and Distribution Audit activities given time to complete	• Allows IRM scope, investment levels, and/or duration to grow • Mitigates Commission and intervenor concerns about not having PBR
Cons	• Depending on timing of 2025 rate case, could have a gap in IRM in early 2026 – stopping/starting could challenge establishing IRM as "new normal"	• Does not meaningfully grow IRM scope, investment levels, or 3-year duration • Does not address PBR of DO Audit	• Does not address Commission's concerns about ongoing Distribution Audit activities • Would propose PBR before separate case is complete

U-21534 | September 4, 2024
MNSC Hearing Exhibits
Ex MEC-25 | Source: MNSCDE-18.2a with Atts
Page 13 of 13

MPSC Case No: U-21534

Requester: MNSC

Question No.: MNSCDE-18.2b.

Respondent: N. Foley

Page: 1 of 2

Question: 2. Refer to Foley rebuttal, Q&A21-23 and Q&A26-27, and Foley revised direct, Q&A57-59:

b. Produce all emails that the witness sent or received concerning the proposal to extend the IRM and/or the proposal to increase IRM spending amounts. (The question seeks materials that discuss either topic as well as any materials that discuss both topics.)

Answer: The Company objects for the reason that the information requested consists of confidential and privileged attorney-client communications, information prepared in anticipation of litigation, or attorney work product.

Subject to this objection, and without waiving this objection, the Company responds as follows:

See attached documents for requested information.

Attachment: *MNSCDE-18.2b-01 IRM Proposal Email 1 (2024.03.18)*
MNSCDE-18.2b-02 IRM Proposal Email 2 (2024.03.18)
MNSCDE-18.2b-03 IRM Proposal Email 3 (2024.03.17)
MNSCDE-18.2b-04 IRM Proposal Email 4 (2024.03.15)
MNSCDE-18.2b-05 IRM Proposal Email 5 (2024.03.13)
MNSCDE-18.2b-06 IRM Proposal Email 6 (2024.02.23)
MNSCDE-18.2b-07 IRM Proposal Email 7 (2024.02.23)
MNSCDE-18.2b-08 IRM Proposal Email 8 (2024.02.14)
MNSCDE-18.2b-09 IRM Proposal Email 9 (2024.02.13)
MNSCDE-18.2b-10 IRM Proposal Email 10 (2024.02.13)
MNSCDE-18.2b-11 IRM Proposal Email 11 (2024.02.10)
MNSCDE-18.2b-12 IRM Proposal Email 12 (2024.02.08)
MNSCDE-18.2b-13 IRM Proposal Email 13 (2024.02.05)
MNSCDE-18.2b-14 IRM Proposal Email 14 (2024.02.05)
MNSCDE-18.2b-15 IRM Proposal Email 15 (2024.01.31)

Co-respondent: Legal

MPSC Case No: U-21534

Requester: MNSC

Question No.: MNSCDE-18.2b.

Respondent: N. Foley

Page: 2 of 2

MNSCDE-18.2b-16 IRM Proposal Email 16 (2024.01.29)
MNSCDE-18.2b-17 IRM Proposal Email 17 (2024.01.29)
MNSCDE-18.2b-18 IRM Proposal Email 18 (2024.01.29)
MNSCDE-18.2b-19 IRM Proposal Email 19 (2024.01.25)
MNSCDE-18.2b-20 IRM Proposal Email 20 (2024.01.25)

Co-respondent: Legal

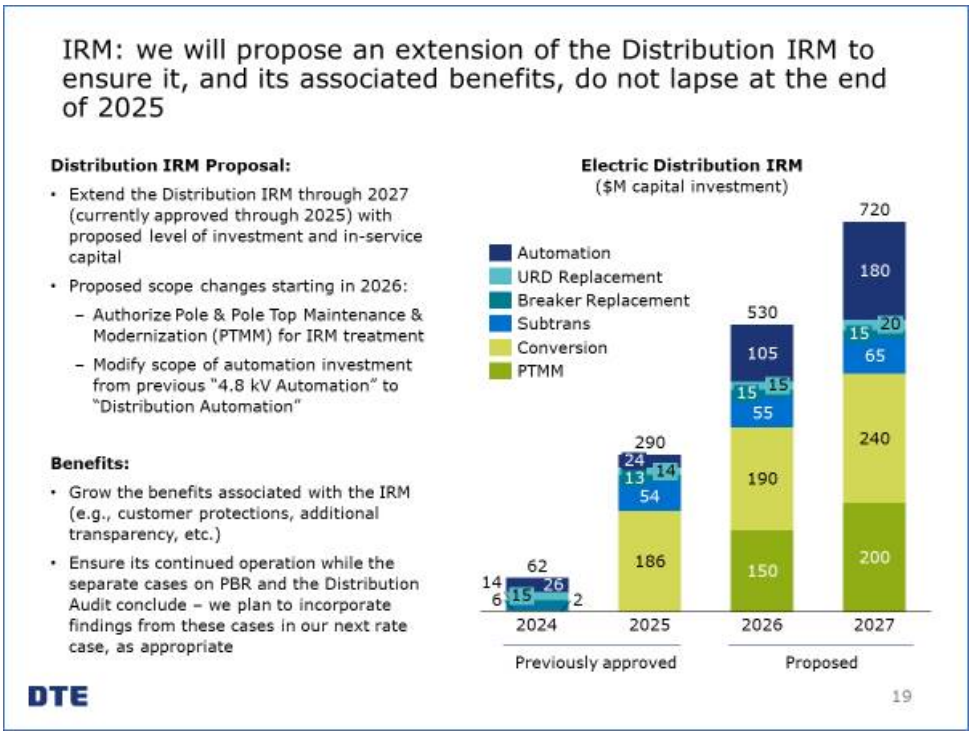
Neal T Foley

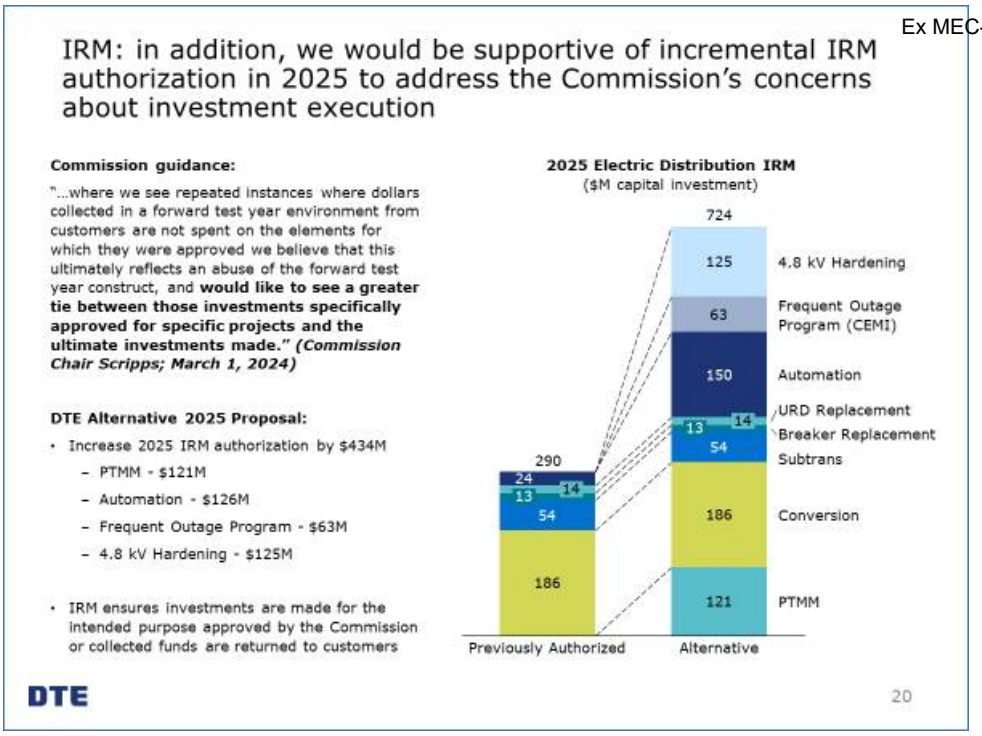
From: Marco A Bruzzano
Sent: Monday, March 18, 2024 5:09 PM
To: Neal T Foley
Subject: Re: IRM alternative

nice page

From: Neal T Foley <neal.foley@dteenergy.com>
Sent: Monday, March 18, 2024 4:51:53 PM
To: Marco A Bruzzano <marco.bruzzano@dteenergy.com>; Trevor F Lauer <trevor.lauer@dteenergy.com>; Matthew T Paul <matthew.paul@dteenergy.com>
Subject: RE: IRM alternative

Good timing! I already built a page to potentially include in the rate case overview we're giving to Staff on Thursday. IRM pages are attached (screenshots below – 2025 alternative is the second one).





Just let me know what else you need,

Neal Foley
Director of Regulatory Affairs | DTE Energy
C: 248-933-1472
neal.foley@dteenergy.com

From: Marco A Bruzzano <marco.bruzzano@dteenergy.com>
Sent: Monday, March 18, 2024 4:15 PM
To: Neal T Foley <neal.foley@dteenergy.com>; Trevor F Lauer <trevor.lauer@dteenergy.com>; Matthew T Paul <matthew.paul@dteenergy.com>
Subject: IRM alternative

Neal, when you come up for air, can you develop a page for Trevor and Matt that summarizes the IRM alternative?

Thanks

Neal T Foley

From: Marco A Bruzzano
Sent: Monday, March 18, 2024 12:02 PM
To: Matthew T Paul; Neal T Foley
Cc: Bill Chiu; Renee M Tomina; Ryan Stowe; Hope L Allen; Jamie Kryscynski; Edward Karpiel; Ledian Dibra; Kelsey O Peterson; Bryant F Miller
Subject: Re: For review: proposed capital programs to be suggested for 2025 IRM inclusion

I agree that going larger would be a stretch… this provides options for them to consider

Thanks

From: Matthew T Paul <matthew.paul@dteenergy.com>
Sent: Monday, March 18, 2024 11:25:57 AM
To: Neal T Foley <neal.foley@dteenergy.com>; Marco A Bruzzano <marco.bruzzano@dteenergy.com>
Cc: Bill Chiu <bill.chiu@dteenergy.com>; Renee M Tomina <renee.tomina@dteenergy.com>; Ryan Stowe <ryan.stowe@dteenergy.com>; Hope L Allen <hope.allen@dteenergy.com>; Jamie Kryscynski <jamie.kryscynski@dteenergy.com>; Edward Karpiel <edward.karpiel@dteenergy.com>; Ledian Dibra <ledian.dibra@dteenergy.com>; Kelsey O Peterson <kelsey.peterson@dteenergy.com>; Bryant F Miller <bryant.miller@dteenergy.com>
Subject: RE: For review: proposed capital programs to be suggested for 2025 IRM inclusion

OK, thanks Neal. I'm good with this recommendation.
Marco – what do you think? Seems like it would be a significant stretch to increase much higher.
Thanks all –
Matt.

From: Neal T Foley <neal.foley@dteenergy.com>
Sent: Monday, March 18, 2024 11:18 AM
To: Matthew T Paul <matthew.paul@dteenergy.com>; Marco A Bruzzano <marco.bruzzano@dteenergy.com>
Cc: Bill Chiu <bill.chiu@dteenergy.com>; Renee M Tomina <renee.tomina@dteenergy.com>; Ryan Stowe <ryan.stowe@dteenergy.com>; Hope L Allen <hope.allen@dteenergy.com>; Jamie Kryscynski <jamie.kryscynski@dteenergy.com>; Edward Karpiel <edward.karpiel@dteenergy.com>; Ledian Dibra <ledian.dibra@dteenergy.com>; Kelsey O Peterson <kelsey.peterson@dteenergy.com>; Bryant F Miller <bryant.miller@dteenergy.com>
Subject: RE: For review: proposed capital programs to be suggested for 2025 IRM inclusion

For 2025, right now we have authorized $290M of investment ($232M of which goes into service) worth about $23M of revenue.

Adding the $434M would bring us to $724M of investment ($666M of which goes into service) worth about $52M of revenue. The revenue number is a bit rough "rule of thumb" but shouldn't be too far off.

Neal Foley
Director of Regulatory Affairs | DTE Energy
C: 248-933-1472
neal.foley@dteenergy.com

From: Matthew T Paul <matthew.paul@dteenergy.com>
Sent: Monday, March 18, 2024 11:10 AM
To: Neal T Foley <neal.foley@dteenergy.com>; Marco A Bruzzano <marco.bruzzano@dteenergy.com>
Cc: Bill Chiu <bill.chiu@dteenergy.com>; Renee M Tomina <renee.tomina@dteenergy.com>; Ryan Stowe <ryan.stowe@dteenergy.com>; Hope L Allen <hope.allen@dteenergy.com>; Jamie Kryscynski <jamie.kryscynski@dteenergy.com>; Edward Karpiel <edward.karpiel@dteenergy.com>; Ledian Dibra <ledian.dibra@dteenergy.com>; Kelsey O Peterson <kelsey.peterson@dteenergy.com>; Bryant F Miller <bryant.miller@dteenergy.com>
Subject: RE: For review: proposed capital programs to be suggested for 2025 IRM inclusion

Thanks Neal.
So what would the total IRM amount be with this 434 added? Both capital and revenue.

From: Neal T Foley <neal.foley@dteenergy.com>
Sent: Monday, March 18, 2024 11:05 AM
To: Matthew T Paul <matthew.paul@dteenergy.com>; Marco A Bruzzano <marco.bruzzano@dteenergy.com>
Cc: Bill Chiu <bill.chiu@dteenergy.com>; Renee M Tomina <renee.tomina@dteenergy.com>; Ryan Stowe <ryan.stowe@dteenergy.com>; Hope L Allen <hope.allen@dteenergy.com>; Jamie Kryscynski <jamie.kryscynski@dteenergy.com>; Edward Karpiel <edward.karpiel@dteenergy.com>; Ledian Dibra <ledian.dibra@dteenergy.com>; Kelsey O Peterson <kelsey.peterson@dteenergy.com>; Bryant F Miller <bryant.miller@dteenergy.com>
Subject: For review: proposed capital programs to be suggested for 2025 IRM inclusion

Matt/Marco – Coming out of Jerry's request over the weekend, a small group of us met earlier today to discuss what programs could be good candidates to be added to the IRM in 2025 if the Commission finds it appropriate to do so. In practice, I will add a couple of Q/As to my testimony (1) highlighting our support of more 2025 IRM capital (i.e., shifting recovery from base rates to IRM surcharge) given the associated benefits and the Commission's stated concerns, and (2) providing a list of programs we think would be good candidates. This does not impact any other part of the case.

We think the following four programs would be good candidates for 2025 IRM Recovery (highlighted in yellow):

- Distribution Automation (amount not already flowing through the IRM) - $126M
- PTMM - $121M
- 4.8 kV Hardening - $125M
- Frequent Outage Program (CEMI) - $63M

All of these programs have annual in-servicing. In total this is $434M of capital investment worth about $29M of revenue. One note from the team that these programs have about $95M of capital that was added in mid-January above our current internal budget. All other programs are generally smaller (i.e., not much capital going into service in 2025) where their inclusion wouldn't meaningfully impact our rate relief request.

Please let us know if you have any questions/concerns.

	2025		
CAPITAL INVESTMENTS	U-21297 Approved IRM	Rate Case	Total Investment
Additions to PLANT IN SERVICE			
Conversions	139,761	25,121	164,882
Subtransmission Redesign & Rebuild	41,750	9,116	50,866
Breaker Replacement Program	12,628	-	12,628
URD Replacement Program	13,500	-	13,500
Distribution Automation	24,375	125,625	150,000
Pole and Pole Top Maintenance & Modernization	-	121,000	121,000
4.8kV Hardening	-	125,000	125,000
Frequent Outage Program (CEMI)	-	62,504	62,504
System Loading	-	2,700	2,700
Cable Replacement Program	-	16,501	16,501
40 kV: Automatic Pole Top Switch	-	4,995	4,995
Disconnect and Switcher Replacement	-	4,900	4,900
Steel Pole Highway Crossings	-	5,000	5,000
Batteries and Chargers Replacement Program	-	3,030	3,030
Mobile Fleet Program	-	1,500	1,500
SCADA Pole Top Device Replacement	-	1,529	1,529
Substation Regulator Replacement	-	616	616
Station Upgrade: 120kV Relays Upgrade for ITC Projects	-	1,864	1,864
Distribution Sensing and Monitoring (incldg Line Sensors)	-	1,000	1,000
CVR/VVO	-	8,100	8,100
Total	232,015	520,100	752,115

Thanks,

Neal Foley
Director of Regulatory Affairs | DTE Energy
C: 248-933-1472
neal.foley@dteenergy.com

Neal T Foley

From: Marco A Bruzzano
Sent: Sunday, March 17, 2024 3:14 PM
To: Jerry Norcia; Trevor F Lauer; Matthew T Paul; Joi M Harris; David Ruud
Cc: Neal T Foley
Subject: 2025 IRM expansion

Jerry - just confirming that we are identifying potential 2025 programs to add to the IRM as an alternative in case the Commission is not comfortable approving all the test year investments given the uncertainty around us spending the $'s in the areas that are approved. We will include this as an alternative in Neal's testimony.

We will estimate what this could mean for the headline rate relief number tomorrow.

Marco

Neal T Foley

From: Adrienne R Baldwin
Sent: Friday, March 15, 2024 10:58 AM
To: Christina J Hajj; Neal T Foley
Subject: RE: IRM question for DTEE SIS

Thanks Neal!

From: Christina J Hajj <christina.hajj@dteenergy.com>
Sent: Friday, March 15, 2024 10:11 AM
To: Neal T Foley <neal.foley@dteenergy.com>; Adrienne R Baldwin <adrienne.baldwin@dteenergy.com>
Subject: RE: IRM question for DTEE SIS

Thanks, Neal. We made this adjustment to the SIS

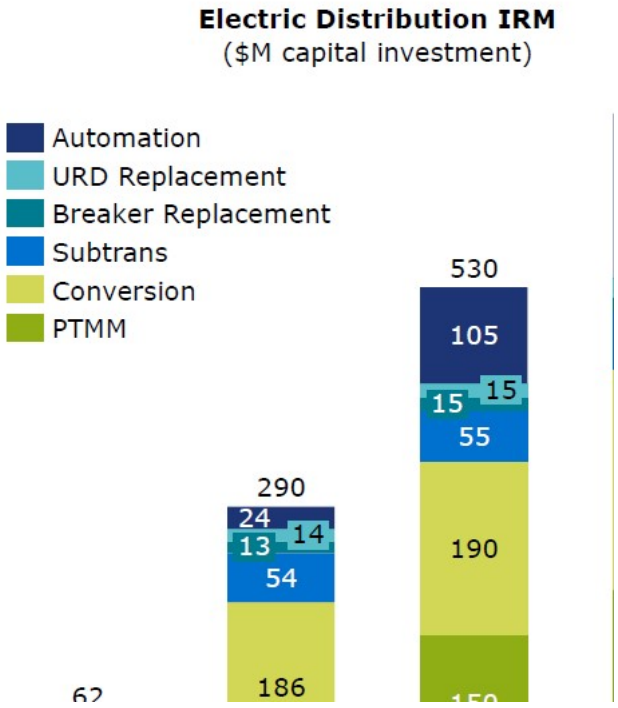
From: Neal T Foley <neal.foley@dteenergy.com>
Sent: Friday, March 15, 2024 10:06 AM
To: Adrienne R Baldwin <adrienne.baldwin@dteenergy.com>
Cc: Christina J Hajj <christina.hajj@dteenergy.com>
Subject: RE: IRM question for DTEE SIS

Hey Adrienne – We really haven't set a 2030 target for the IRM beyond continuing to grow it to the point where we can stay out of rate cases. The only formal plans we have are in the upcoming rate case where we'll propose that it grows to $720M by 2027 (see below).

I would probably say "Continue to grow the IRM to provide certainty of capital recovery and potentially extend the time between rate cases; in the upcoming case we will propose to grow the IRM to $720M by 2027"

I think it's certainly our aspiration to grow the IRM beyond $720M, just haven't set a specific target. Important to remember the IRM is still brand new for DTEE.

Hope that helps.



Neal Foley
Director of Regulatory Affairs | DTE Energy
C: 248-933-1472
neal.foley@dteenergy.com

From: Adrienne R Baldwin <adrienne.baldwin@dteenergy.com>
Sent: Friday, March 15, 2024 9:29 AM
To: Neal T Foley <neal.foley@dteenergy.com>
Cc: Christina J Hajj <christina.hajj@dteenergy.com>
Subject: IRM question for DTEE SIS

Hi Neal,

We are polishing up the DTEE SIS for Matt's March 20 discussion with Jerry and Joi. Is it accurate to say "Expand Distribution IRM to $750M to $1B by 2030." ?

Thanks,
Adrienne

Adrienne R. Long Baldwin
DTE Energy | Business Planning & Development
One Energy Plaza, Detroit, MI 48226
[m] 717.715.9960
adrienne.baldwin@dteenergy.com
she/her/hers

Neal T Foley

From: Neal T Foley
Sent: Wednesday, March 13, 2024 1:49 PM
To: Bryant F Miller; Kirk Vangilder; Hope L Allen
Cc: Theresa M Uzenski; Kelsey O Peterson; Habeeb J Maroun; Aaron Willis; Jie Dong
Subject: RE: Cosmetic changes to IRM capital exhibit

Looks great to me. Thanks for the quick update.

Neal Foley
Director of Regulatory Affairs | DTE Energy
C: 248-933-1472
neal.foley@dteenergy.com

From: Bryant F Miller <bryant.miller@dteenergy.com>
Sent: Wednesday, March 13, 2024 11:08 AM
To: Kirk Vangilder <kirk.vangilder@dteenergy.com>; Hope L Allen <hope.allen@dteenergy.com>; Neal T Foley <neal.foley@dteenergy.com>
Cc: Theresa M Uzenski <theresa.uzenski@dteenergy.com>; Kelsey O Peterson <kelsey.peterson@dteenergy.com>; Habeeb J Maroun <habeeb.maroun@dteenergy.com>; Aaron Willis <aaron.willis@dteenergy.com>; Jie Dong <jie.dong@dteenergy.com>
Subject: RE: Cosmetic changes to IRM capital exhibit

Let me know if this is what you are looking for:

Michigan Public Service Commission — Case No.:
DTE Electric Company — Exhibit:
Projected Capital Expenditures — Schedule:
Distribution - Infrastructure Recovery Mechanism (IRM) — Witness:
Proposed Investment and In-Service Levels — Page:
($000)

Line No.	(a) Description	(b) U-21297 Approved 2024 13 mos. ending 12/31/2024	(c) U-21297 Approved 2025 12 mos. ending 12/31/2025	(d) U-21534 Proposed 2026 12 mos. ending 12/31/2026
1	CAPITAL INVESTMENTS			
2	Conversions	1,608	185,812	190,000

From: Kirk Vangilder <kirk.vangilder@dteenergy.com>
Sent: Wednesday, March 13, 2024 9:37 AM
To: Hope L Allen <hope.allen@dteenergy.com>; Bryant F Miller <bryant.miller@dteenergy.com>; Neal T Foley <neal.foley@dteenergy.com>
Cc: Theresa M Uzenski <theresa.uzenski@dteenergy.com>; Kelsey O Peterson <kelsey.peterson@dteenergy.com>; Habeeb J Maroun <habeeb.maroun@dteenergy.com>; Aaron Willis <aaron.willis@dteenergy.com>; Jie Dong <jie.dong@dteenergy.com>
Subject: RE: Cosmetic changes to IRM capital exhibit

X4 and X5 have been updated accordingly

From: Hope L Allen <hope.allen@dteenergy.com>
Sent: Wednesday, March 13, 2024 8:33 AM
To: Bryant F Miller <bryant.miller@dteenergy.com>; Neal T Foley <neal.foley@dteenergy.com>
Cc: Theresa M Uzenski <theresa.uzenski@dteenergy.com>; Kelsey O Peterson <kelsey.peterson@dteenergy.com>; Habeeb J Maroun <habeeb.maroun@dteenergy.com>; Aaron Willis <aaron.willis@dteenergy.com>; Kirk Vangilder <kirk.vangilder@dteenergy.com>; Jie Dong <jie.dong@dteenergy.com>
Subject: RE: Cosmetic changes to IRM capital exhibit

Adding Jie, who had cleaned up the A-12 exhibit yesterday for the filing so she is in the loop

---

From: Bryant F Miller <bryant.miller@dteenergy.com>
Sent: Wednesday, March 13, 2024 8:30 AM
To: Neal T Foley <neal.foley@dteenergy.com>
Cc: Theresa M Uzenski <theresa.uzenski@dteenergy.com>; Kelsey O Peterson <kelsey.peterson@dteenergy.com>; Hope L Allen <hope.allen@dteenergy.com>; Habeeb J Maroun <habeeb.maroun@dteenergy.com>; Aaron Willis <aaron.willis@dteenergy.com>; Kirk Vangilder <kirk.vangilder@dteenergy.com>
Subject: RE: Cosmetic changes to IRM capital exhibit

I think this can easily be accomplished, just need to know if the exhibit has been locked down for even cosmetic changes. I know this has to start being assembled soon, so if Theresa and her team is ok with me making some changes today I can have it ready for review in an hour or so.

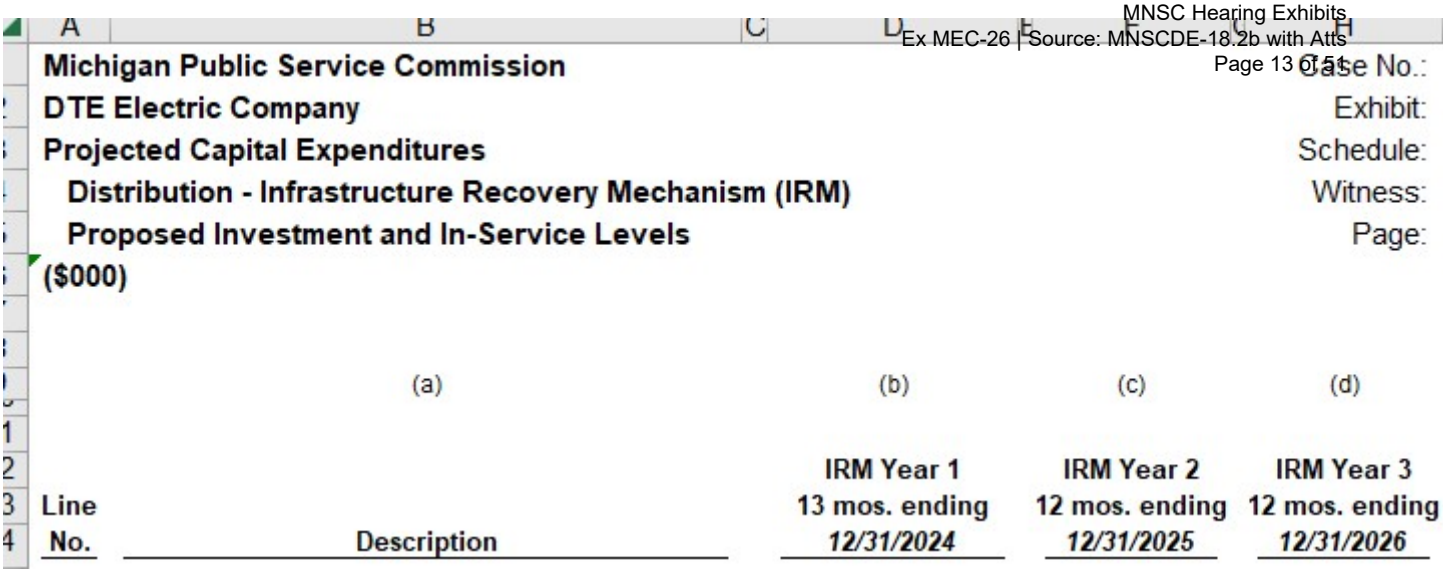
From: Neal T Foley <neal.foley@dteenergy.com>
Sent: Wednesday, March 13, 2024 8:21 AM
To: Bryant F Miller <bryant.miller@dteenergy.com>
Cc: Theresa M Uzenski <theresa.uzenski@dteenergy.com>; Kelsey O Peterson <kelsey.peterson@dteenergy.com>; Hope L Allen <hope.allen@dteenergy.com>; Habeeb J Maroun <habeeb.maroun@dteenergy.com>; Aaron Willis <aaron.willis@dteenergy.com>; Kirk Vangilder <kirk.vangilder@dteenergy.com>
Subject: Cosmetic changes to IRM capital exhibit

Hey Bryant – I put a screenshot of my current IRM capital exhibit below. I'm wondering if we can make the following changes:

- We've moved away from the "IRM Year" labeling in the case. Can we just change these to 2024, 2025, 2026, etc.? Can add a footnote that 2024 actually includes 13 months starting 12/1/2023.
- Can we clearly label 2024 and 2025 as "previously approved" and 2026 and 2027 as "proposed"? I'd like to make it very clear that 2024/2025 are in there for informational purposes only.

Kirk/Habeeb/Aaron – Should make sure your exhibits are consistent with this approach.

Thanks!



	A	B	C	D	E	F	G	H
1	**Michigan Public Service Commission**							Case No.:
2	**DTE Electric Company**							Exhibit:
3	**Projected Capital Expenditures**							Schedule:
4	**Distribution - Infrastructure Recovery Mechanism (IRM)**							Witness:
5	**Proposed Investment and In-Service Levels**							Page:
6	**($000)**							
7								
8								
9		(a)		(b)		(c)		(d)
10								
11								
12				**IRM Year 1**		**IRM Year 2**		**IRM Year 3**
13	**Line**			**13 mos. ending**		**12 mos. ending**		**12 mos. ending**
14	**No.**	**Description**		***12/31/2024***		***12/31/2025***		***12/31/2026***

Neal Foley
Director of Regulatory Affairs | DTE Energy
C: 248-933-1472
neal.foley@dteenergy.com

Neal T Foley

From: Matthew T Paul
Sent: Friday, February 23, 2024 12:00 PM
To: Marco A Bruzzano
Cc: Renee M Tomina; Ryan Stowe; Jamie Kryscynski; Neal T Foley; Sharon G Pfeuffer; Bill Chiu
Subject: Re: Updated IRM proposal

I support. Thank you.

Get Outlook for iOS

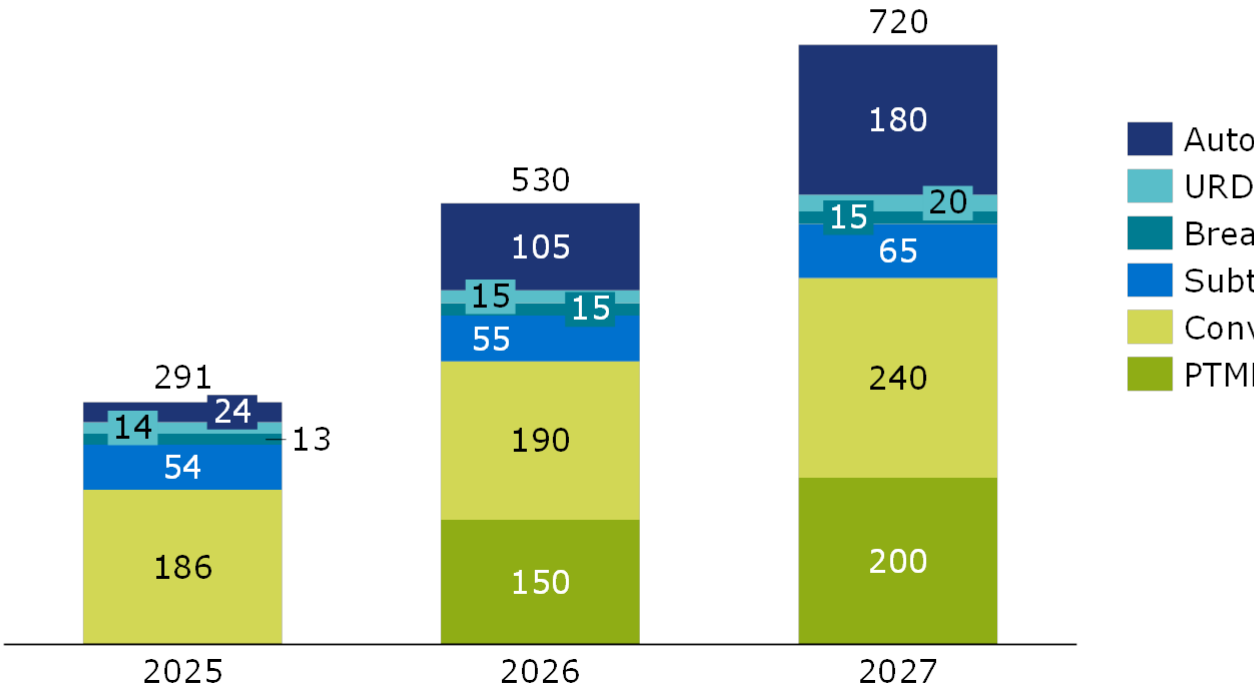
From: Marco A Bruzzano <marco.bruzzano@dteenergy.com>
Sent: Friday, February 23, 2024 9:32:04 AM
To: Matthew T Paul <matthew.paul@dteenergy.com>
Cc: Renee M Tomina <renee.tomina@dteenergy.com>; Ryan Stowe <ryan.stowe@dteenergy.com>; Jamie Kryscynski <jamie.kryscynski@dteenergy.com>; Neal T Foley <neal.foley@dteenergy.com>; Sharon G Pfeuffer <sharon.pfeuffer@dteenergy.com>; Bill Chiu <bill.chiu@dteenergy.com>
Subject: Updated IRM proposal

Matt,

We had some quick problem solving on the IRM this morning. The group's consensus is that we should propose growing PTMM as it fits the profile of what should be in the IRMM well (it's a lot like replacing cast iron main). We might as well advocate for a program we feel strongly about (as Jamie K advocated originally). I was initially concerned, but my mind has hanged over the last few days given more positive signals.

Thanks

2026 / 2027 IRM funding



Neal T Foley

From: Renee M Tomina
Sent: Friday, February 23, 2024 9:41 AM
To: Ledian Dibra; Adella F Crozier; Marco A Bruzzano; Jamie Kryscynski; Sharon G Pfeuffer; Bill Chiu; Ryan Stowe; Neal T Foley; Bryant F Miller; Kelsey O Peterson
Subject: Re: Time sensitive

Thanks Ledian.

Renee

From: Ledian Dibra <ledian.dibra@dteenergy.com>
Sent: Friday, February 23, 2024 9:39 AM
To: Adella F Crozier <adella.crozier@dteenergy.com>; Marco A Bruzzano <marco.bruzzano@dteenergy.com>; Renee M Tomina <renee.tomina@dteenergy.com>; Jamie Kryscynski <jamie.kryscynski@dteenergy.com>; Sharon G Pfeuffer <sharon.pfeuffer@dteenergy.com>; Bill Chiu <bill.chiu@dteenergy.com>; Ryan Stowe <ryan.stowe@dteenergy.com>; Neal T Foley <neal.foley@dteenergy.com>; Bryant F Miller <bryant.miller@dteenergy.com>; Kelsey O Peterson <kelsey.peterson@dteenergy.com>
Subject: RE: Time sensitive

We provided an update yesterday to Renee and Ryan on our biweekly IRM Update meeting and in the same deck we covered both the slides to be reviewed with intervenors as well as two other topics, future potential IRM plan/budget being one of them. I know that led to the confusion this morning that we may be presenting future plans in intervenors meeting so I apologize for that.

On the expansion of PTMM into the IRM, I am excited to see that!

From: Adella F Crozier <adella.crozier@dteenergy.com>
Sent: Friday, February 23, 2024 9:14 AM
To: Marco A Bruzzano <marco.bruzzano@dteenergy.com>; Renee M Tomina <renee.tomina@dteenergy.com>; Jamie Kryscynski <jamie.kryscynski@dteenergy.com>; Sharon G Pfeuffer <sharon.pfeuffer@dteenergy.com>; Bill Chiu <bill.chiu@dteenergy.com>; Ryan Stowe <ryan.stowe@dteenergy.com>; Neal T Foley <neal.foley@dteenergy.com>; Bryant F Miller <bryant.miller@dteenergy.com>; Kelsey O Peterson <kelsey.peterson@dteenergy.com>; Ledian Dibra <ledian.dibra@dteenergy.com>
Subject: Re: Time sensitive

Hello All,

The stakeholder meeting was at 8:30 AM today. We only shared what was in the plan we submitted a couple of weeks ago. Years discussed were 2024 and 2025.

From: Marco A Bruzzano <marco.bruzzano@dteenergy.com>
Sent: Friday, February 23, 2024 8:54 AM
To: Renee M Tomina <renee.tomina@dteenergy.com>; Jamie Kryscynski <jamie.kryscynski@dteenergy.com>; Sharon G Pfeuffer <sharon.pfeuffer@dteenergy.com>; Bill Chiu <bill.chiu@dteenergy.com>; Ryan Stowe <ryan.stowe@dteenergy.com>; Neal T Foley <neal.foley@dteenergy.com>; Bryant F Miller <bryant.miller@dteenergy.com>; Kelsey O Peterson <kelsey.peterson@dteenergy.com>; Ledian Dibra

<ledian.dibra@dteenergy.com>
Cc: Adella F Crozier <adella.crozier@dteenergy.com>
Subject: Time sensitive

Hi all,

Renee and I just spoke. When talking to any external groups we can only discuss what was approved. Please always run materials that are being reviewed with intervenors by Regulatory

---

From: Renee M Tomina <renee.tomina@dteenergy.com>
Sent: Friday, February 23, 2024 8:49 AM
To: Marco A Bruzzano <marco.bruzzano@dteenergy.com>; Jamie Kryscynski <jamie.kryscynski@dteenergy.com>; Matthew T Paul <matthew.paul@dteenergy.com>; Sharon G Pfeuffer <sharon.pfeuffer@dteenergy.com>; Bill Chiu <bill.chiu@dteenergy.com>; Ryan Stowe <ryan.stowe@dteenergy.com>; Neal T Foley <neal.foley@dteenergy.com>
Subject: Re: IRM / PTMM

I support this change.

Would this mean that the entire PTMM budget would not be in the IRM? We (PMO) would be very supportive of this.

One item to note - the team is meeting with Intervenors tonight to review the currently proposed IRM for 2024-2027 levels - is there an issue if we change it?

Renee

From: Marco A Bruzzano <marco.bruzzano@dteenergy.com>
Sent: Friday, February 23, 2024 8:36:34 AM
To: Jamie Kryscynski <jamie.kryscynski@dteenergy.com>; Matthew T Paul <matthew.paul@dteenergy.com>; Sharon G Pfeuffer <sharon.pfeuffer@dteenergy.com>; Bill Chiu <bill.chiu@dteenergy.com>; Ryan Stowe <ryan.stowe@dteenergy.com>; Renee M Tomina <renee.tomina@dteenergy.com>; Neal T Foley <neal.foley@dteenergy.com>
Subject: Re: IRM / PTMM

I would not change current budgets right now … I think that is too many moving parts

---

From: Jamie Kryscynski <jamie.kryscynski@dteenergy.com>
Sent: Friday, February 23, 2024 8:35:35 AM
To: Marco A Bruzzano <marco.bruzzano@dteenergy.com>; Matthew T Paul <matthew.paul@dteenergy.com>; Sharon G Pfeuffer <sharon.pfeuffer@dteenergy.com>; Bill Chiu <bill.chiu@dteenergy.com>; Ryan Stowe <ryan.stowe@dteenergy.com>; Renee M Tomina <renee.tomina@dteenergy.com>; Neal T Foley <neal.foley@dteenergy.com>
Subject: RE: IRM / PTMM

One clarifying question – are we sticking with the current levels of PTMM that we have projected in 2026 and 2027 (rate case + IRM)? Or is there also a desire to increase the total overall?

From: Jamie Kryscynski
Sent: Friday, February 23, 2024 8:34 AM
To: Marco A Bruzzano <Marco.Bruzzano@dteenergy.com>; Matthew T Paul <Matthew.Paul@dteenergy.com>; Sharon G Pfeuffer <Sharon.Pfeuffer@dteenergy.com>; Bill Chiu <bill.chiu@dteenergy.com>; Ryan Stowe <Ryan.Stowe@dteenergy.com>; Renee M Tomina <Renee.Tomina@dteenergy.com>; Neal T Foley

<neal.foley@dteenergy.com>
Subject: RE: IRM / PTMM

Will do

From: Marco A Bruzzano <marco.bruzzano@dteenergy.com>
Sent: Friday, February 23, 2024 8:33 AM
To: Jamie Kryscynski <jamie.kryscynski@dteenergy.com>; Matthew T Paul <matthew.paul@dteenergy.com>; Sharon G Pfeuffer <sharon.pfeuffer@dteenergy.com>; Bill Chiu <bill.chiu@dteenergy.com>; Ryan Stowe <ryan.stowe@dteenergy.com>; Renee M Tomina <renee.tomina@dteenergy.com>; Neal T Foley <neal.foley@dteenergy.com>
Subject: RE: IRM / PTMM

Can you please develop an alternative IRM spend profile so we can run it by Matt to get “final” signoff? I am not a fan of late changes to anything, but this one feels justified….

From: Jamie Kryscynski <jamie.kryscynski@dteenergy.com>
Sent: Friday, February 23, 2024 8:30 AM
To: Marco A Bruzzano <marco.bruzzano@dteenergy.com>; Matthew T Paul <matthew.paul@dteenergy.com>; Sharon G Pfeuffer <sharon.pfeuffer@dteenergy.com>; Bill Chiu <bill.chiu@dteenergy.com>; Ryan Stowe <ryan.stowe@dteenergy.com>; Renee M Tomina <renee.tomina@dteenergy.com>; Neal T Foley <neal.foley@dteenergy.com>
Subject: RE: IRM / PTMM

Another data point – I had another meeting with the auditors yesterday and they said that the two programs they feel are highest priority are 1) Tree Trim and 2) PTMM. There is very little chance that the audit report doesn’t come out very strongly in favor of increased investment in this area.

Jamie

From: Marco A Bruzzano <marco.bruzzano@dteenergy.com>
Sent: Friday, February 23, 2024 8:24 AM
To: Jamie Kryscynski <jamie.kryscynski@dteenergy.com>; Matthew T Paul <matthew.paul@dteenergy.com>; Sharon G Pfeuffer <sharon.pfeuffer@dteenergy.com>; Bill Chiu <bill.chiu@dteenergy.com>; Ryan Stowe <ryan.stowe@dteenergy.com>; Renee M Tomina <renee.tomina@dteenergy.com>; Neal T Foley <neal.foley@dteenergy.com>
Subject: RE: IRM / PTMM

It’s a simple adjustment because the rate case only covers 2025 and we are not changing that

---

From: Jamie Kryscynski <jamie.kryscynski@dteenergy.com>
Sent: Friday, February 23, 2024 8:05 AM
To: Marco A Bruzzano <marco.bruzzano@dteenergy.com>; Matthew T Paul <matthew.paul@dteenergy.com>; Sharon G Pfeuffer <sharon.pfeuffer@dteenergy.com>; Bill Chiu <bill.chiu@dteenergy.com>; Ryan Stowe <ryan.stowe@dteenergy.com>; Renee M Tomina <renee.tomina@dteenergy.com>; Neal T Foley <neal.foley@dteenergy.com>
Subject: Re: IRM / PTMM

I, of course, agree. As long as we can agree on "cuts" to the other programs in the IRM. Obviously we would just shift investment back to the rate case for anything cut.

Get Outlook for iOS

From: Marco A Bruzzano <marco.bruzzano@dteenergy.com>
Sent: Friday, February 23, 2024 8:00:29 AM
To: Matthew T Paul <matthew.paul@dteenergy.com>; Sharon G Pfeuffer <sharon.pfeuffer@dteenergy.com>; Bill Chiu <bill.chiu@dteenergy.com>; Jamie Kryscynski <jamie.kryscynski@dteenergy.com>; Ryan Stowe <ryan.stowe@dteenergy.com>; Renee M Tomina <renee.tomina@dteenergy.com>; Neal T Foley <neal.foley@dteenergy.com>
Subject: IRM / PTMM

All,

I know we (I) have been bouncing around on this issue, but given the positive signals on PTMM that are coming form the Audit and our conviction of the importance of the program, I wanted to go back to Jamie's recommendation that we increase the level of PTMM in the IRM in 2026 and 2027.

Recognizing that I was voice of opposition on this given prior Commission signals, things seem to be shifting significantly, especially post Feb 15 meeting. PTMM could now be an easier program to get into the IRM than the rapid expansion of Automation.

Please weigh in with your thoughts.

Thanks,

Marco

Neal T Foley

From: Marco A Bruzzano
Sent: Wednesday, February 14, 2024 8:51 AM
To: Neal T Foley
Subject: RE: Conversions budget

Thanks Neal,

I think the other change was increasing Hardening and Automation, which took some of the planned investments

---

From: Neal T Foley <neal.foley@dteenergy.com>
Sent: Wednesday, February 14, 2024 7:46 AM
To: Marco A Bruzzano <marco.bruzzano@dteenergy.com>
Subject: RE: Conversions budget

Figured out what I was anchoring off of.

In the last rate case, we had proposed $372M for conversions in 2026 (the year that was rejected by the Commission). Since then we have apparently reduced 2026 planned conversions investment by $120M to the numbers that Ed sent last night.

I think Dave's push is still worth exploring. If we proposed $372M in 2026 last time, why are we only proposing $190 (roughly half) this time? Even in 2027 we're only proposing $240M.

I think the answer is we're concerned about execution, but should probably make sure we're comfortable with the answer if asked.

Neal Foley
Director of Regulatory Affairs | DTE Energy
C: 248-933-1472
neal.foley@dteenergy.com

From: Marco A Bruzzano <marco.bruzzano@dteenergy.com>
Sent: Tuesday, February 13, 2024 6:11 PM
To: Neal T Foley <neal.foley@dteenergy.com>
Subject: RE: Conversions budget

That's what I thought… tomorrow is good

From: Neal T Foley <neal.foley@dteenergy.com>
Sent: Tuesday, February 13, 2024 6:09 PM
To: Marco A Bruzzano <marco.bruzzano@dteenergy.com>
Subject: Re: Conversions budget

Let me look in a bit. I thought total conversions was a lot higher but there's been a lot of numbers...

Sent from my Verizon, Samsung Galaxy smartphone
Get Outlook for Android

From: Marco A Bruzzano <marco.bruzzano@dteenergy.com>
Sent: Tuesday, February 13, 2024 6:06:45 PM
To: Neal T Foley <neal.foley@dteenergy.com>
Subject: Conversions budget

Neal,

Below are the total numbers for Conversions and how they split between IRM and rate case. The overall ramp in total $'s from 2025 to 2026 is pretty flat. Does this sink up with your understanding?

Thanks

Marco

	2025	2026	2027
Conversion - Total	**$ 246**	**$ 256**	**$ 305**
IRM	$ 186	$ 190	$ 240
Rate Case	$ 60	$ 66	$ 65

Neal T Foley

From: Morgan Elliott Andahazy
Sent: Tuesday, February 13, 2024 7:31 PM
To: Neal T Foley; Jamie Kryscynski
Cc: Bryant F Miller; Hope L Allen; Kelsey O Peterson; Robbie Kelley
Subject: RE: IRM proposal

Just to clarify, we are adding PTMM into the IRM stating in 2026? And for only a portion of the investment? I thought we wanted all or nothing for PTMM?

And do I need to put anything my testimony for the IRM pertaining to PTMM since it doesn't start until 2026? Please advise - thanks!

Morgan Elliott Andahazy
#(313)910-3458
DTE Energy
She/her/hers

From: Neal T Foley <neal.foley@dteenergy.com>
Sent: Tuesday, February 13, 2024 8:59 AM
To: Morgan Elliott Andahazy <morgan.elliott-andahazy@dteenergy.com>; Shannen M Hartwick <shannen.palmer@dteenergy.com>; Satvir S Deol <satvir.deol@dteenergy.com>; Jamie Kryscynski <jamie.kryscynski@dteenergy.com>
Cc: Bryant F Miller <bryant.miller@dteenergy.com>; Hope L Allen <hope.allen@dteenergy.com>; Kelsey O Peterson <kelsey.peterson@dteenergy.com>
Subject: FW: IRM proposal

Hey team – As you may have heard, Matt approved the updated IRM expansion proposal (sorry Morgan we couldn't keep PTM out!).

Plan hasn't changed from last week. I'm going to update my testimony over the next couple of days and then turn my attention to the DO witness testimonies to "tie it all together". No action for your at the moment but will let you know when I have something drafted that you can review.

Thanks!

Neal Foley
Director of Regulatory Affairs | DTE Energy
C: 248-933-1472
neal.foley@dteenergy.com

From: Matthew T Paul <matthew.paul@dteenergy.com>
Sent: Monday, February 12, 2024 11:48 AM
To: Marco A Bruzzano <marco.bruzzano@dteenergy.com>; Cynthia J Parise <cynthia.parise@dteenergy.com>
Cc: Renee M Tomina <renee.tomina@dteenergy.com>; Ryan Stowe <ryan.stowe@dteenergy.com>; Sharon G Pfeuffer <sharon.pfeuffer@dteenergy.com>; Bill Chiu <bill.chiu@dteenergy.com>; Jamie Kryscynski <jamie.kryscynski@dteenergy.com>; Edward Karpiel <edward.karpiel@dteenergy.com>; Bryant F Miller <bryant.miller@dteenergy.com>; Hope L Allen <hope.allen@dteenergy.com>; Neal T Foley

<neal.foley@dteenergy.com>
Subject: RE: IRM proposal

Team –
Nice work – thank you for the quick turnaround!
I'm good if the team is good.
Matt.

From: Marco A Bruzzano <marco.bruzzano@dteenergy.com>
Sent: Monday, February 12, 2024 11:25 AM
To: Matthew T Paul <matthew.paul@dteenergy.com>; Cynthia J Parise <cynthia.parise@dteenergy.com>
Cc: Renee M Tomina <renee.tomina@dteenergy.com>; Ryan Stowe <ryan.stowe@dteenergy.com>; Sharon G Pfeuffer <sharon.pfeuffer@dteenergy.com>; Bill Chiu <bill.chiu@dteenergy.com>; Jamie Kryscynski <jamie.kryscynski@dteenergy.com>; Edward Karpiel <edward.karpiel@dteenergy.com>; Bryant F Miller <bryant.miller@dteenergy.com>; Hope L Allen <hope.allen@dteenergy.com>; Neal T Foley <neal.foley@dteenergy.com>
Subject: IRM proposal

Matt,

The team did some quick work this morning to develop the proposal below (thanks everyone). Can you take a look and let us know if you have any additional questions?

Thanks,

Marco

From: Edward Karpiel <edward.karpiel@dteenergy.com>

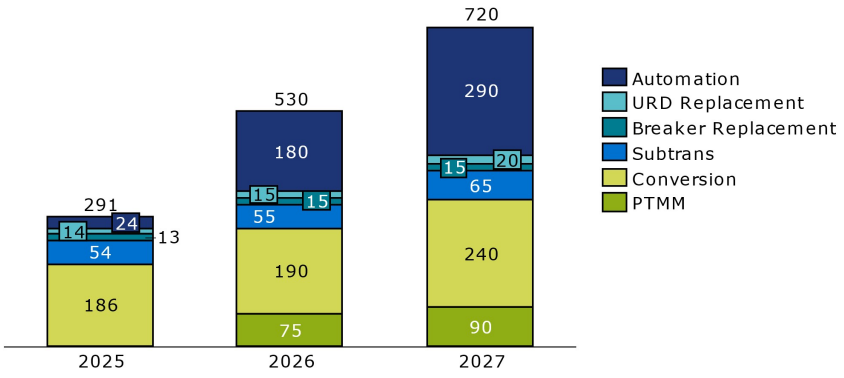
Hi everyone-

Jamie, Bryant and I discussed an updated profile for the IRM to follow the guidance Matt provided and our discussion from this morning. I've attached a ppt chart and put a copy below of the proposed IRM for 2026/2027.

- Aligns with top line targets of $530/$720
- PTMM funding for 2026 and 2027 was what we agreed upon during the discussion
- Given some of the current challenges, keeping Subtrans mostly flat into 2026 and increasing by 20% for 2027
- Small reductions to Automation given that not everything can be in-serviced in the same year
- We feel comfortable with the Conversion levels given what is in the budget and excluding the projects that are going to likely stay in the rate case and wouldn't be a good fit for the IRM

-Ed

2026 / 2027 IRM funding



DTE

1

Neal T Foley

From: Marco A Bruzzano
Sent: Tuesday, February 13, 2024 5:47 PM
To: Edward Karpiel; Jamie Kryscynski; Neal T Foley
Subject: RE: Overall budget vs IRM

Thanks Ed

From: Edward Karpiel <edward.karpiel@dteenergy.com>
Sent: Tuesday, February 13, 2024 5:45 PM
To: Marco A Bruzzano <marco.bruzzano@dteenergy.com>; Jamie Kryscynski <jamie.kryscynski@dteenergy.com>; Neal T Foley <neal.foley@dteenergy.com>
Subject: RE: Overall budget vs IRM

This is what I have for these areas

	2025	2026	2027
Automation - Total	$ 150	$ 190	$ 308
IRM	$ 24	$ 180	$ 290
Rate Case	$ 126	$ 10	$ 18
Subtransmission - Total	$ 99	$ 104	$ 104
IRM	$ 54	$ 55	$ 65
Rate Case	$ 45	$ 49	$ 39
Conversion - Total	$ 246	$ 256	$ 305
IRM	$ 186	$ 190	$ 240
Rate Case	$ 60	$ 66	$ 65
PTMM - Total	$ 121	$ 151	$ 192
IRM		$ 75	$ 90
Rate Case	$ 121	$ 76	$ 102

From: Marco A Bruzzano <marco.bruzzano@dteenergy.com>
Sent: Tuesday, February 13, 2024 5:32 PM
To: Jamie Kryscynski <jamie.kryscynski@dteenergy.com>; Edward Karpiel <edward.karpiel@dteenergy.com>; Neal T Foley <neal.foley@dteenergy.com>
Subject: Overall budget vs IRM

Jamie, Ed,

Can you share what the total budget is for 2025, 2026, 2027 and how much of that is in the IRM for

Automation

Conversions
Subtransmission
PTMM

A simple spreadsheet with two rows for each program would be great.

Thanks,

Marco

Neal T Foley

From: Matthew T Paul
Sent: Saturday, February 10, 2024 9:24 AM
To: Jamie Kryscynski; Marco A Bruzzano; Neal T Foley
Cc: Renee M Tomina; Ryan Stowe; Sharon G Pfeuffer; Bill Chiu
Subject: Re: Updated IRM expansion proposal for review

Great news thanks Jamie

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From: Jamie Kryscynski <jamie.kryscynski@dteenergy.com>
Sent: Friday, February 9, 2024 4:10:13 PM
To: Marco A Bruzzano <marco.bruzzano@dteenergy.com>; Matthew T Paul <matthew.paul@dteenergy.com>; Neal T Foley <neal.foley@dteenergy.com>
Cc: Renee M Tomina <renee.tomina@dteenergy.com>; Ryan Stowe <ryan.stowe@dteenergy.com>; Sharon G Pfeuffer <sharon.pfeuffer@dteenergy.com>; Bill Chiu <bill.chiu@dteenergy.com>
Subject: RE: Updated IRM expansion proposal for review

As an FYI if it impacts the final decision, I had an interview this week with the auditors. I got a VERY strong impression that they are going to come out in firm support of an expanded PTMM program. I think we might have some wind in the PTMM sails post audit report.

From: Marco A Bruzzano <marco.bruzzano@dteenergy.com>
Sent: Friday, February 9, 2024 4:01 PM
To: Jamie Kryscynski <jamie.kryscynski@dteenergy.com>; Matthew T Paul <matthew.paul@dteenergy.com>; Neal T Foley <neal.foley@dteenergy.com>
Cc: Renee M Tomina <renee.tomina@dteenergy.com>; Ryan Stowe <ryan.stowe@dteenergy.com>; Sharon G Pfeuffer <sharon.pfeuffer@dteenergy.com>; Bill Chiu <bill.chiu@dteenergy.com>
Subject: RE: Updated IRM expansion proposal for review

Thanks for looking it over Jamie

We are trying to balance overall size of IRM and its acceptability, given MPSC questions on PTMM…. We have some of the other programs also both in and out

---

From: Jamie Kryscynski <jamie.kryscynski@dteenergy.com>
Sent: Friday, February 9, 2024 3:51 PM
To: Matthew T Paul <matthew.paul@dteenergy.com>; Neal T Foley <neal.foley@dteenergy.com>
Cc: Marco A Bruzzano <marco.bruzzano@dteenergy.com>; Renee M Tomina <renee.tomina@dteenergy.com>; Ryan Stowe <ryan.stowe@dteenergy.com>; Sharon G Pfeuffer <sharon.pfeuffer@dteenergy.com>; Bill Chiu <bill.chiu@dteenergy.com>
Subject: RE: Updated IRM expansion proposal for review

My only comment is that we should try to put PTMM all the way in if we can. Having the program half in the IRM and half out would be difficult to manage in my opinion. Also, it's the perfect type of program for the IRM – everything goes into service in the same year and very little risk of carryover or project delays.

Jamie

From: Matthew T Paul <matthew.paul@dteenergy.com>
Sent: Friday, February 9, 2024 3:08 PM
To: Neal T Foley <neal.foley@dteenergy.com>
Cc: Marco A Bruzzano <marco.bruzzano@dteenergy.com>; Renee M Tomina <renee.tomina@dteenergy.com>; Ryan Stowe <ryan.stowe@dteenergy.com>; Sharon G Pfeuffer <sharon.pfeuffer@dteenergy.com>; Jamie Kryscynski <jamie.kryscynski@dteenergy.com>
Subject: RE: Updated IRM expansion proposal for review

Neal –
Marco and I just talked and aligned on the following:

1. Ramp at something like 290, 530, 700-720
2. Introduce PTMM in 2026 as a bucket (maybe at 70-75M level)
3. Attempt to treat the buckets (automation, PTMM, subtrans, conversions, other) consistently, i.e., growing at 20% or whatever (note – because hardening sunsets, we were not thinking to including it).
4. Final connection with key team members to make sure it passes smell test for them

Happy to entertain feedback from the team if there are significant concerns, but trying to nail this down today or Monday.
Thanks –
Matt.

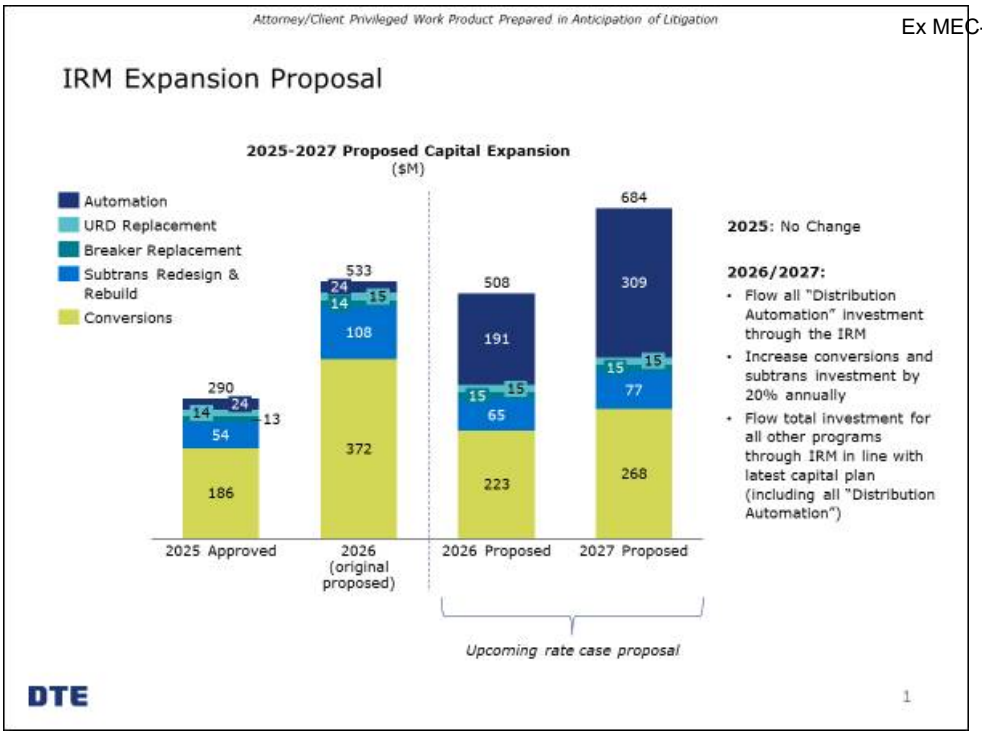
From: Neal T Foley <neal.foley@dteenergy.com>
Sent: Wednesday, February 7, 2024 8:22 AM
To: Matthew T Paul <matthew.paul@dteenergy.com>
Cc: Marco A Bruzzano <marco.bruzzano@dteenergy.com>
Subject: Updated IRM expansion proposal for review

Hi Matt – I've adjusted the IRM expansion proposal to align with your and Marco's thinking over the past couple of days (screenshot below). Essentially:

- 2025: no change to what was previously approved
- 2026/2027:
  - Grow conversions and subtrans by 20% per year
  - Flow all other covered program spend through the IRM in line with our current capital plan (including all "Distribution Automation")

As you'll see on the chart, that results in proposed investment of $508M in 2026 which is similar to the $533M we proposed for 2026 in the last rate case. A slightly different mix (i.e., more automation and less conversions/subtrans) but similar scale.

Let us know what you think.



Thanks,

Neal Foley
Director of Regulatory Affairs | DTE Energy
C: 248-933-1472
neal.foley@dteenergy.com

Neal T Foley

From: Neal T Foley
Sent: Thursday, February 8, 2024 12:37 PM
To: Kelsey O Peterson
Cc: Bryant F Miller
Subject: RE: IRM updates

Sure, something like this:

- In our upcoming rate case we are planning to propose an extension of the IRM through 2027
- We will propose that the IRM grow in 2026 and 2027 compared to what was previously approved for 2025 (~$290M of investment)
- The specific programs and investment levels to be proposed are in the process of being finalized
- Once the proposal is finalized, it will be integrated into the rate case; Regulatory Affairs (Neal) will be the main sponsoring witness supported by DO Witnesses (Jamie, Shannen, Satvir, and Morgan) and other technical SMEs (revenue requirement, cost of service, etc.)

Just waiting on Matt's sign-off and then we should be off and running. Hopefully comes today.

Thanks,

Neal Foley
Director of Regulatory Affairs | DTE Energy
C: 248-933-1472
neal.foley@dteenergy.com

From: Kelsey O Peterson <kelsey.peterson@dteenergy.com>
Sent: Thursday, February 8, 2024 12:28 PM
To: Neal T Foley <neal.foley@dteenergy.com>
Cc: Bryant F Miller <bryant.miller@dteenergy.com>
Subject: RE: IRM updates

Hi Neal,

If there's not a slide available, are there high-level bullet points we can use to discuss where the IRM expansion proposal sits as of now?

Thanks-
Kelsey

Kelsey Peterson
Manager, Long-Term Planning & Strategy
Cell: 312.519.2574 |Desk: 313.235.6831

From: Neal T Foley <neal.foley@dteenergy.com>
Sent: Wednesday, February 7, 2024 12:16 PM
To: Kelsey O Peterson <kelsey.peterson@dteenergy.com>
Cc: Bryant F Miller <bryant.miller@dteenergy.com>
Subject: RE: IRM updates

Hey Kelsey – Sure why don't you go ahead and add me. Took a look at the deck, couple of quick reactions:

Page 4:

- I'm not sure we should remove top-line investment since that's what was in my testimony and included in the order. Instead, I might add a page that just describes the dynamics – there is top-line investment, and then for programs with longer-term projects there is in-service projections which drive the revenue requirement and surcharges
- For cost evaluation, I'm not sure we want to proactively talk too much about the reconciliation process is a time for intervenors to challenge our costs. Instead I think our messaging should highlight that the planning process and stakeholder forums provide a good way for interested parties to raise questions or concerns about our costs; these costs are formally reviewed during the reconciliation process

Page 6:

- We are still waiting on final sign-off from Matt on the IRM expansion proposal; we might get that sign-off today, but if not I would just take this page out and we can give a verbal update (either way – the page you currently have in there is outdated so we'll need to do something with it)

Thanks and hope that helps!

Neal Foley
Director of Regulatory Affairs | DTE Energy
C: 248-933-1472
neal.foley@dteenergy.com

From: Kelsey O Peterson <kelsey.peterson@dteenergy.com>
Sent: Wednesday, February 7, 2024 9:16 AM
To: Neal T Foley <neal.foley@dteenergy.com>
Cc: Bryant F Miller <bryant.miller@dteenergy.com>
Subject: IRM updates

Hi Neal,

Would you want to attend our IRM Review with Renee tomorrow at 4? Let me know, and I can forward you the invite. Either way, I'd appreciate your help with the slides:

- Review MPSC debrief on slide 4
- Update IRM rate case strategy / expansion on slide 6

240208_IRM Review.pptx

Let me know if you have any questions – thanks!
Kelsey

Kelsey Peterson
Manager, Long-Term Planning & Strategy
Cell: 312.519.2574 |Desk: 313.235.6831

Neal T Foley

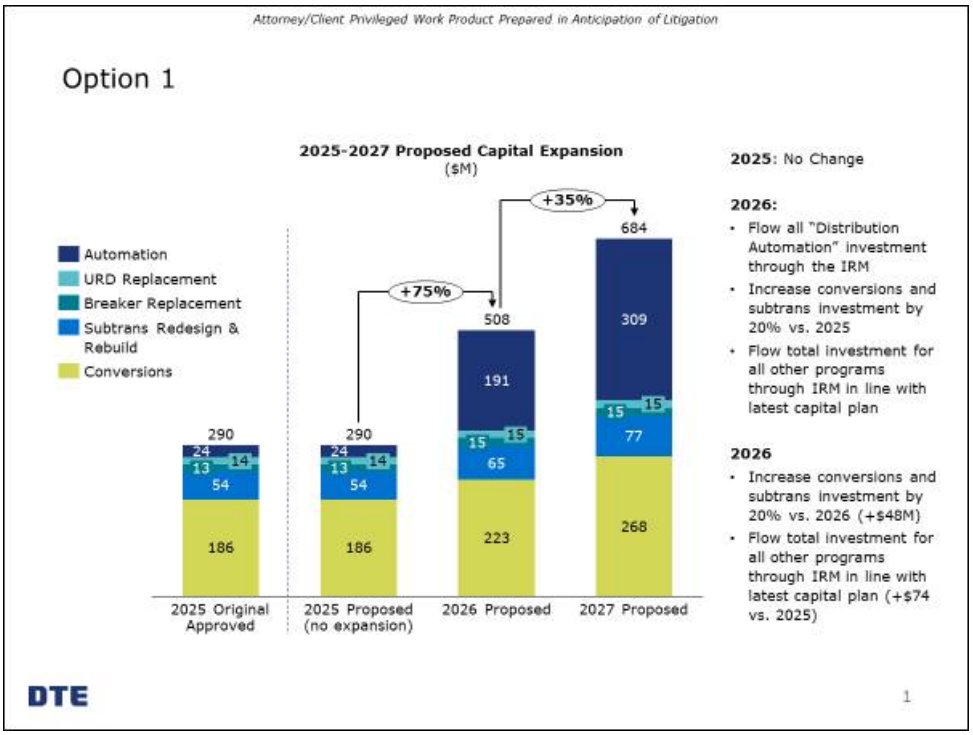
From: Neal T Foley
Sent: Monday, February 5, 2024 10:04 AM
To: Matthew T Paul
Cc: Marco A Bruzzano
Subject: Updated IRM expansion options for review
Attachments: 2024.02.05 IRM Expansion v3.pdf

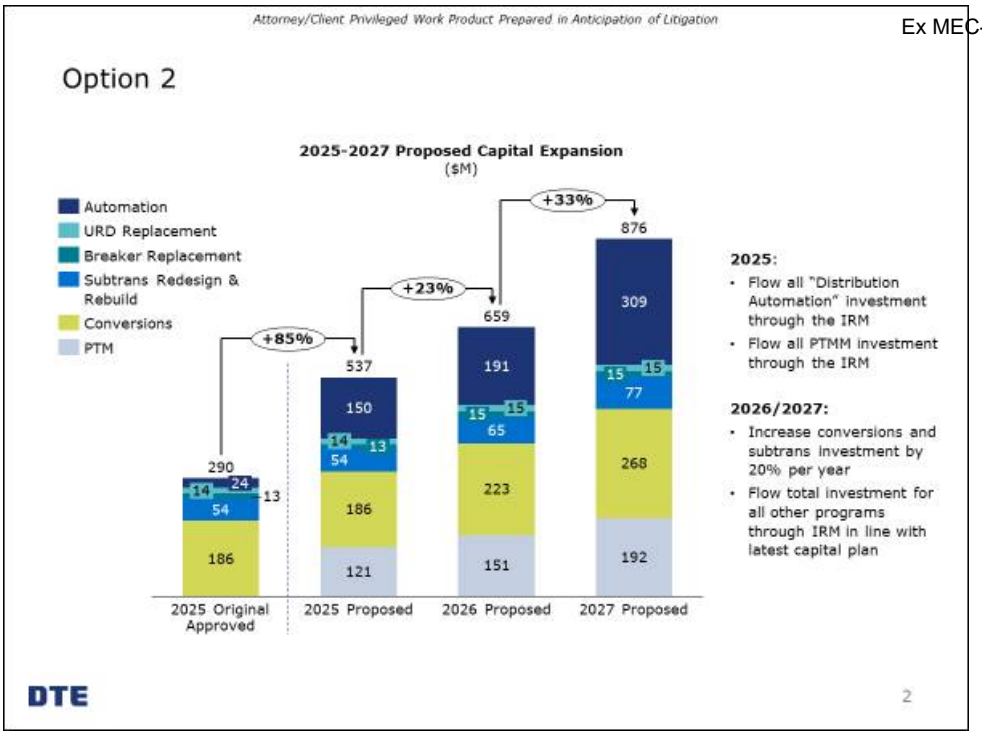
Hey Matt – We've built a couple of IRM expansion scenarios aligned to your and Marco's conversations last week (attached as PDF and screenshots below). In short:

- Option 1 (moderate expansion; no PTM)
  - 2025: consistent with prior order
  - 2026/2027: grows conversions/subtrans by 20% per year and flows all other program investment (consistent with latest capital plan) through IRM, including a significant increase in Distribution Automation

- Option 2: (more significant expansion; includes PTM
  - 2025: flows PTM and all Distribution Automation through IRM
  - 2026/2027: grows conversions/subtrans by 20% per year and flows all other program investment (consistent with latest capital plan) through IRM

Thanks and let us know what you think. Happy to hop on a quick call to discuss the details if helpful.



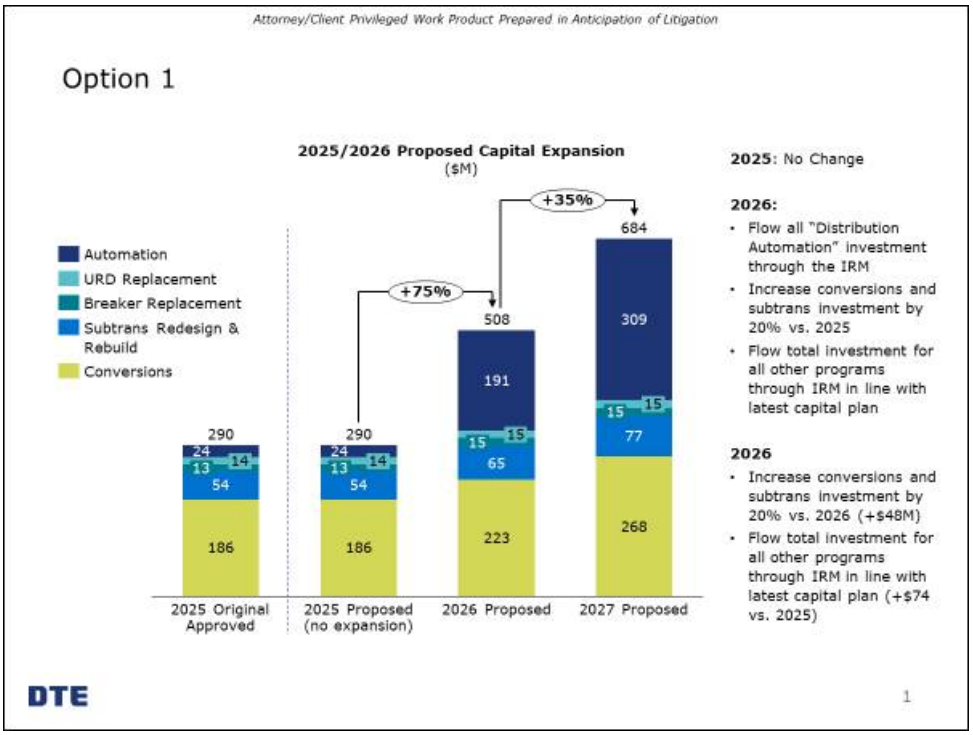


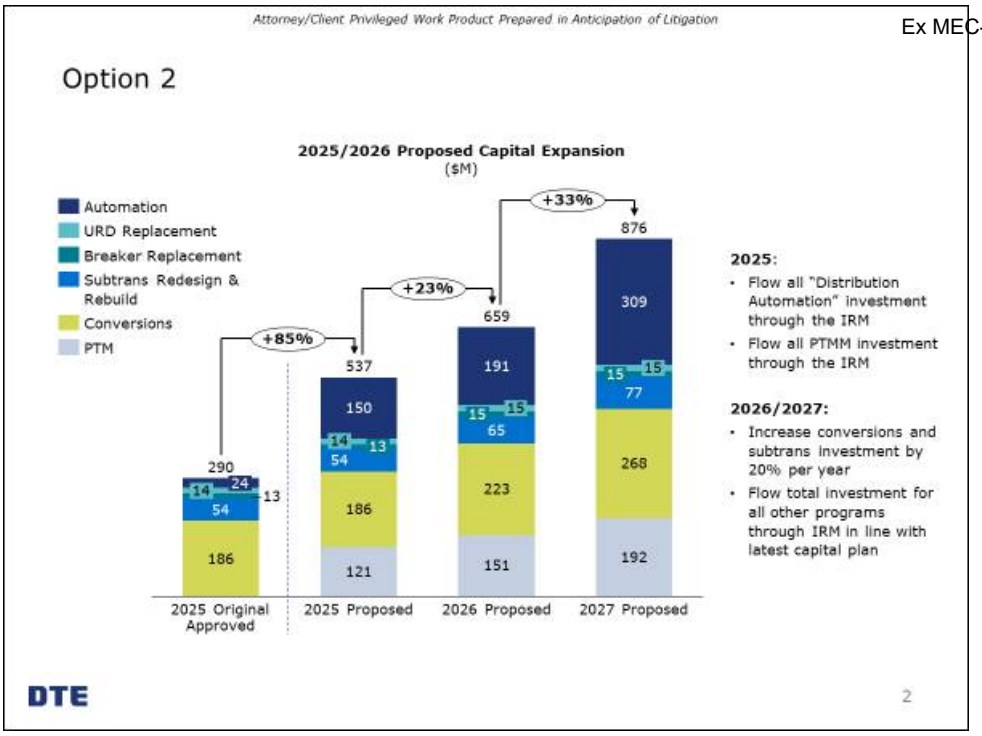
Neal Foley
Director of Regulatory Affairs | DTE Energy
C: 248-933-1472
neal.foley@dteenergy.com

Neal T Foley

From: Neal T Foley
Sent: Monday, February 5, 2024 8:54 AM
To: Marco A Bruzzano
Subject: New IRM expansion scenarios
Attachments: 2024.02.05 IRM Expansion v3.pdf

Hey Marco – Sketched out two new IRM expansion scenarios in-line with your and Matt's conversation last week (screenshots below). Thought there might be a few minutes left after the Commissioner prep meeting so wanted to get these in front of you.




Attorney/Client Privileged Work Product Prepared in Anticipation of Litigation
Option 2
2025/2026 Proposed Capital Expansion
($M)
Automation
URD Replacement
Breaker Replacement
Subtrans Redesign & Rebuild
Conversions
PTM
+85%
+23%
+33%
290
14
24
54
13
186
537
150
14
13
54
186
121
659
191
15
15
65
223
151
876
309
15
15
77
268
192
2025 Original Approved
2025 Proposed
2026 Proposed
2027 Proposed
2025:
• Flow all "Distribution Automation" investment through the IRM
• Flow all PTMM investment through the IRM
2026/2027:
• Increase conversions and subtrans investment by 20% per year
• Flow total investment for all other programs through IRM in line with latest capital plan
DTE
2

Thanks,

Neal T Foley

From: Marco A Bruzzano
Sent: Wednesday, January 31, 2024 4:23 PM
To: Matthew T Paul; Neal T Foley
Cc: Renee M Tomina; Ryan Stowe; Sharon G Pfeuffer; Bill Chiu
Subject: Re: Proposed IRM expansion in upcoming rate case

All,

I had the chance to discuss with Matt. He is OK with the program as designed, but has a couple of other follow-ups I will work on with him.

Thanks,

Marco

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From: Matthew T Paul <matthew.paul@dteenergy.com>
Sent: Wednesday, January 31, 2024 3:39:05 PM
To: Neal T Foley <neal.foley@dteenergy.com>
Cc: Renee M Tomina <renee.tomina@dteenergy.com>; Ryan Stowe <ryan.stowe@dteenergy.com>; Sharon G Pfeuffer <sharon.pfeuffer@dteenergy.com>; Bill Chiu <bill.chiu@dteenergy.com>; Marco A Bruzzano <marco.bruzzano@dteenergy.com>
Subject: RE: Proposed IRM expansion in upcoming rate case

Thank you Neal.
Have Sharon/Bill and Renee and Ryan reviewed this…..and do they support?
Also – I have a few questions – it would be good to discuss this briefly as a team.
Thanks.
Matt.

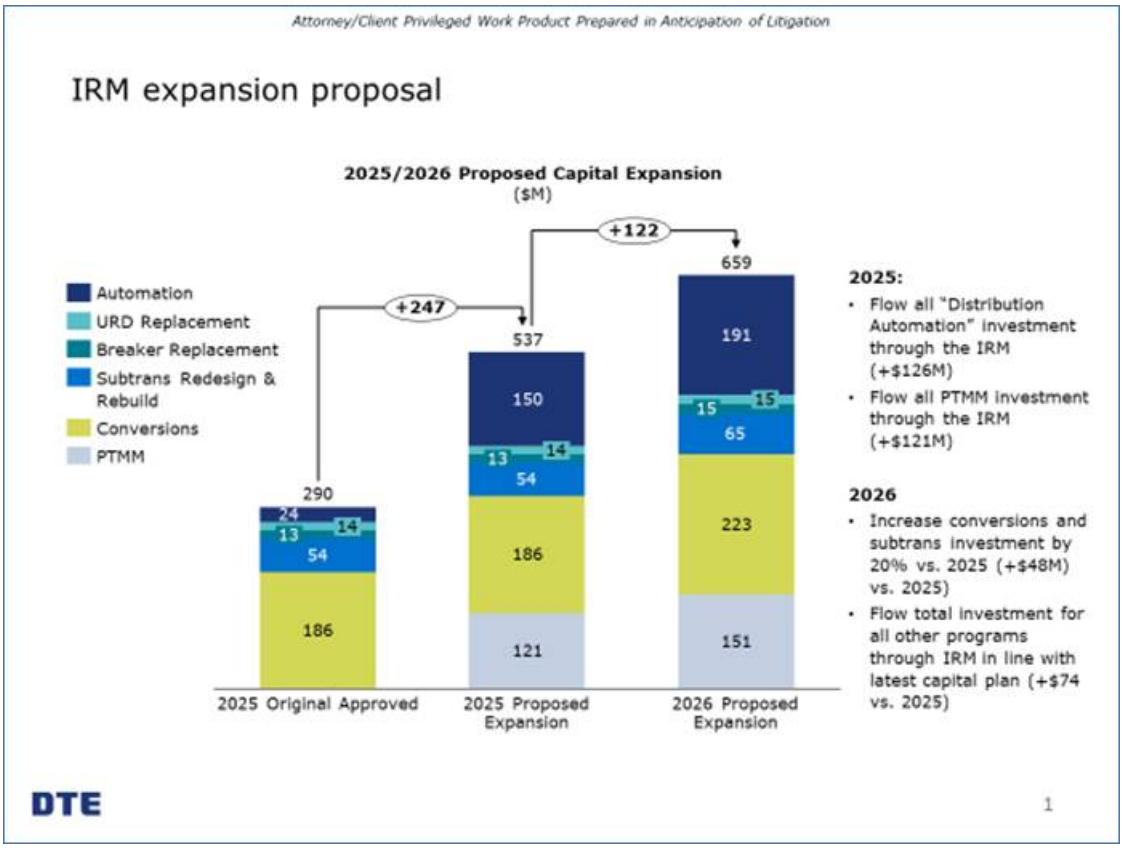
From: Neal T Foley <neal.foley@dteenergy.com>
Sent: Tuesday, January 30, 2024 7:46 PM
To: Matthew T Paul <matthew.paul@dteenergy.com>
Cc: Renee M Tomina <renee.tomina@dteenergy.com>; Ryan Stowe <ryan.stowe@dteenergy.com>; Sharon G Pfeuffer <sharon.pfeuffer@dteenergy.com>; Bill Chiu <bill.chiu@dteenergy.com>; Marco A Bruzzano <marco.bruzzano@dteenergy.com>
Subject: Proposed IRM expansion in upcoming rate case

Hey Matt – Over the past few days we have been working with the DO/PMO teams to put together an IRM expansion proposal to include in the upcoming rate case. I've attached a one page summary of the proposal (also screenshot below), which includes the following:

- In 2025:
  - Include PTM (+$121M over what was previously approved for 2025)
  - Include the balance of Distribution Automation (+$126M over what was previously approved)
- In 2026

- For conversions and subtrans redesign/rebuild, increase investment by 20% over 2025 levels (+$48M vs. 2025)
- For all other programs, propose investment consistent with our current 2026 capital plan (+$74M vs. 2025)

As you can see on the chart, this equates to $537M of proposed IRM investment in 2025 and $659M in 2026 which represents a significant expansion from what was previously approved. The witnesses and support teams are gearing up to include this in the case, but wanted to give you a chance to review and provide any thoughts/feedback you may have.



Thanks and let us know what you think,

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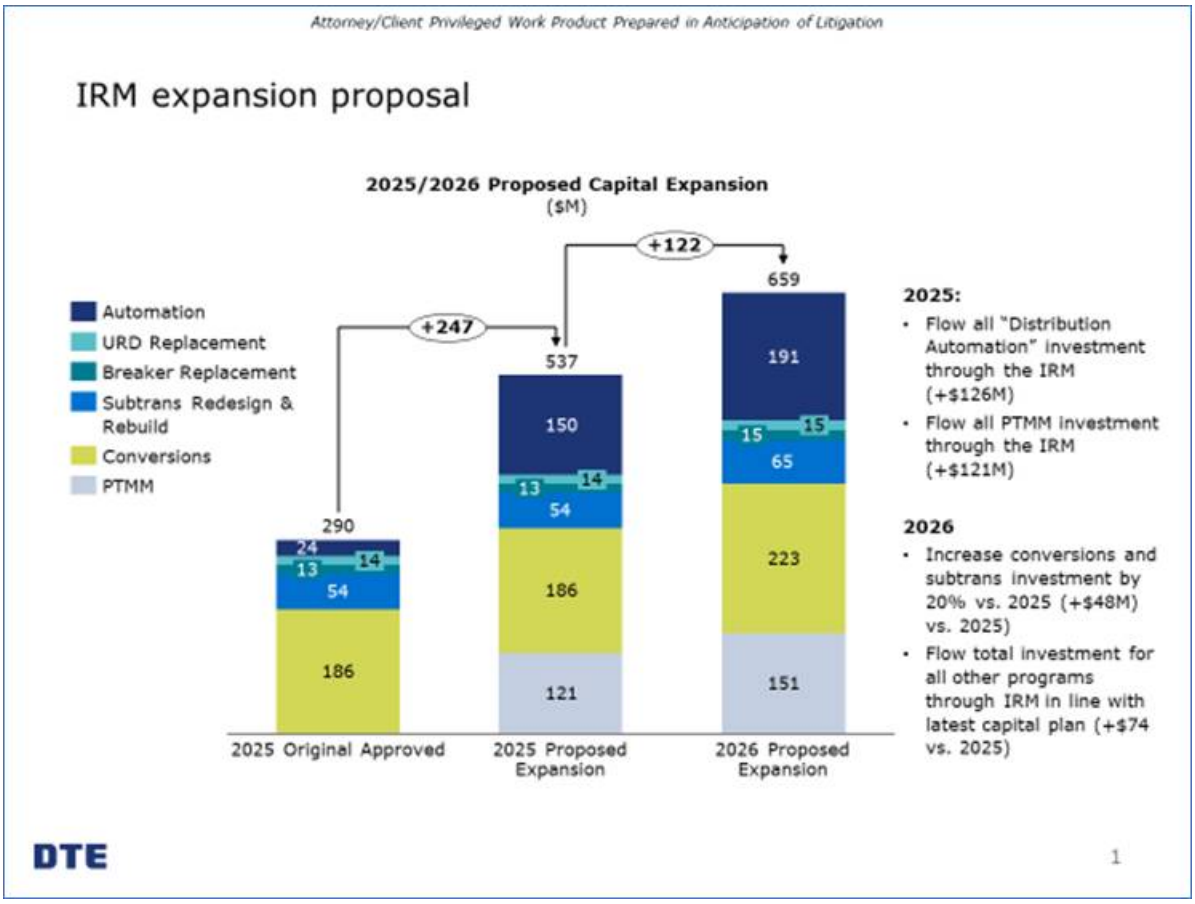
Neal T Foley

From: Marco A Bruzzano
Sent: Monday, January 29, 2024 5:10 PM
To: Neal T Foley
Subject: RE: Updated IRM expansion proposal

I like it… would be pretty awesome

From: Neal T Foley <neal.foley@dteenergy.com>
Sent: Monday, January 29, 2024 5:08 PM
To: Marco A Bruzzano <marco.bruzzano@dteenergy.com>
Subject: RE: Updated IRM expansion proposal

Looks more reasonable. Could even increase it more if we wanted to. Maybe a good thing to decide on during tomorrow morning's meeting.



Neal Foley
Director of Regulatory Affairs | DTE Energy
C: 248-933-1472
neal.foley@dteenergy.com

From: Marco A Bruzzano <marco.bruzzano@dteenergy.com>
Sent: Monday, January 29, 2024 5:04 PM

To: Neal T Foley <neal.foley@dteenergy.com>
Subject: Re: Updated IRM expansion proposal

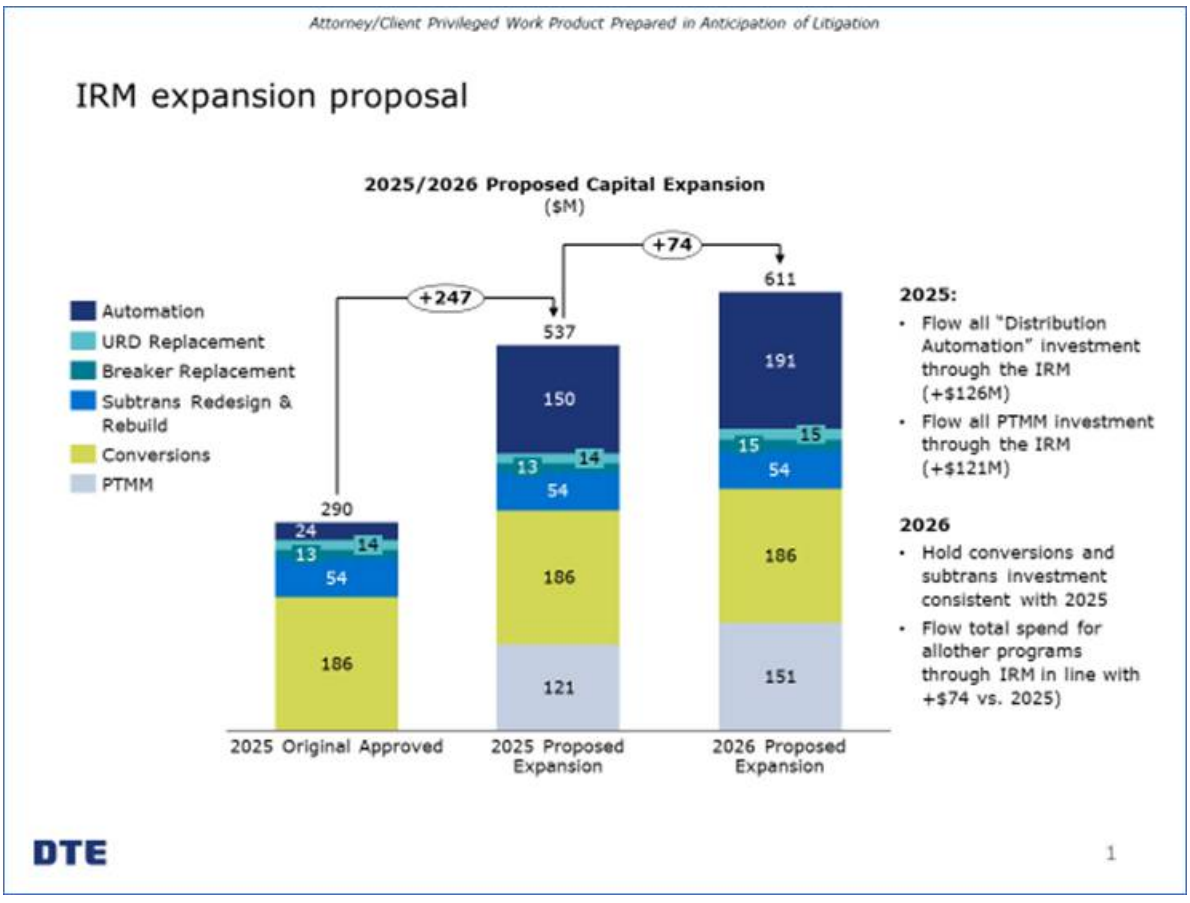
Thx - I would increase them by the 20% - thx

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From: Neal T Foley <neal.foley@dteenergy.com>
Sent: Monday, January 29, 2024 5:03:03 PM
To: Marco A Bruzzano <marco.bruzzano@dteenergy.com>
Subject: Updated IRM expansion proposal

I'll send this to tomorrow morning's attendees shortly, but in case you wanted to give it a first look here's the updated IRM expansion proposal.

If we don't think the 2026 growth is large enough, we also talked about increasing conversions and subtrans by a modest amount like 20% to show growth, but not as severe as what's currently in the 2026 capital plan.



Thanks and let me know what you think,

Neal Foley
Director of Regulatory Affairs | DTE Energy
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neal.foley@dteenergy.com

Neal T Foley

From: Neal T Foley
Sent: Monday, January 29, 2024 2:36 PM
To: Edward Karpiel
Subject: RE: IRM 2025/2026 Expansion

Thanks Ed.

Neal Foley
Director of Regulatory Affairs | DTE Energy
C: 248-933-1472
neal.foley@dteenergy.com

From: Edward Karpiel <edward.karpiel@dteenergy.com>
Sent: Monday, January 29, 2024 9:43 AM
To: Neal T Foley <neal.foley@dteenergy.com>
Cc: Shannen M Hartwick <shannen.palmer@dteenergy.com>; Satvir S Deol <satvir.deol@dteenergy.com>; Morgan Elliott Andahazy <morgan.elliott-andahazy@dteenergy.com>
Subject: RE: IRM 2025/2026 Expansion

Sure, here is the budget file in more detail. This was essentially the budget sent out in mid-December

---

From: Neal T Foley <neal.foley@dteenergy.com>
Sent: Monday, January 29, 2024 8:44 AM
To: Edward Karpiel <edward.karpiel@dteenergy.com>
Cc: Shannen M Hartwick <shannen.palmer@dteenergy.com>
Subject: FW: IRM 2025/2026 Expansion

Hey Ed – Can you send over the 2026 capital plan numbers to Shannen/Satvir/Morgan? Or is it alright if I send around the table you provided me last week?

So you have it, here's the latest thinking on the IRM expansion.

Thanks,

Neal Foley
Director of Regulatory Affairs | DTE Energy
C: 248-933-1472
neal.foley@dteenergy.com

From: Shannen M Hartwick <shannen.palmer@dteenergy.com>
Sent: Friday, January 26, 2024 3:53 PM
To: Neal T Foley <neal.foley@dteenergy.com>; Ledian Dibra <ledian.dibra@dteenergy.com>; Bryant F Miller <bryant.miller@dteenergy.com>; Kelsey O Peterson <kelsey.peterson@dteenergy.com>; Jamie Kryscynski <jamie.kryscynski@dteenergy.com>; Satvir S Deol <satvir.deol@dteenergy.com>; Morgan Elliott Andahazy <morgan.elliott-andahazy@dteenergy.com>; Hope L Allen <hope.allen@dteenergy.com>
Cc: Ryan Stowe <ryan.stowe@dteenergy.com>
Subject: Re: IRM 2025/2026 Expansion

I don't believe I have seen those numbers - if you could share prior to the mtg so I could digest them it would be greatly appreciated.

Thanks

Shannen Hartwick
(she/her/hers)

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From: Neal T Foley <neal.foley@dteenergy.com>
Sent: Friday, January 26, 2024 3:52:31 PM
To: Shannen M Hartwick <shannen.palmer@dteenergy.com>; Ledian Dibra <ledian.dibra@dteenergy.com>; Bryant F Miller <bryant.miller@dteenergy.com>; Kelsey O Peterson <kelsey.peterson@dteenergy.com>; Jamie Kryscynski <jamie.kryscynski@dteenergy.com>; Satvir S Deol <satvir.deol@dteenergy.com>; Morgan Elliott Andahazy <morgan.elliott-andahazy@dteenergy.com>; Hope L Allen <hope.allen@dteenergy.com>
Cc: Ryan Stowe <ryan.stowe@dteenergy.com>
Subject: RE: IRM 2025/2026 Expansion

Ed K provided me with the latest 2026 capital plan amounts for the IRM programs. Not sure how closely they link to DGP amounts.

Neal Foley
Director of Regulatory Affairs | DTE Energy
C: 248-933-1472
neal.foley@dteenergy.com

From: Shannen M Hartwick <shannen.palmer@dteenergy.com>
Sent: Friday, January 26, 2024 3:51 PM
To: Neal T Foley <neal.foley@dteenergy.com>; Ledian Dibra <ledian.dibra@dteenergy.com>; Bryant F Miller <bryant.miller@dteenergy.com>; Kelsey O Peterson <kelsey.peterson@dteenergy.com>; Jamie Kryscynski <jamie.kryscynski@dteenergy.com>; Satvir S Deol <satvir.deol@dteenergy.com>; Morgan Elliott Andahazy <morgan.elliott-andahazy@dteenergy.com>; Hope L Allen <hope.allen@dteenergy.com>
Cc: Ryan Stowe <ryan.stowe@dteenergy.com>
Subject: Re: IRM 2025/2026 Expansion

Oh thanks for the clarification

When you say capital plan - what numbers are you referencing for 2026? The DGP amounts?

Shannen Hartwick
(she/her/hers)

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From: Neal T Foley <neal.foley@dteenergy.com>
Sent: Friday, January 26, 2024 3:49:08 PM
To: Ledian Dibra <ledian.dibra@dteenergy.com>; Bryant F Miller <bryant.miller@dteenergy.com>; Kelsey O Peterson <kelsey.peterson@dteenergy.com>; Jamie Kryscynski <jamie.kryscynski@dteenergy.com>; Satvir S Deol

<satvir.deol@dteenergy.com>; Morgan Elliott Andahazy <morgan.elliott-andahazy@dteenergy.com>; Shannen M Hartwick <shannen.palmer@dteenergy.com>; Hope L Allen <hope.allen@dteenergy.com>
Cc: Ryan Stowe <ryan.stowe@dteenergy.com>
Subject: RE: IRM 2025/2026 Expansion

No – I mean the programs that have been authorized (or proposed) for the IRM:

- Conversions
- Subtrans Redesign/Rebuild
- URD Replacement
- Breaker Replacement
- Automation
- PTMM

Hope that helps,

Neal Foley
Director of Regulatory Affairs | DTE Energy
C: 248-933-1472
neal.foley@dteenergy.com

From: Ledian Dibra <ledian.dibra@dteenergy.com>
Sent: Friday, January 26, 2024 3:36 PM
To: Neal T Foley <neal.foley@dteenergy.com>; Bryant F Miller <bryant.miller@dteenergy.com>; Kelsey O Peterson <kelsey.peterson@dteenergy.com>; Jamie Kryscynski <jamie.kryscynski@dteenergy.com>; Satvir S Deol <satvir.deol@dteenergy.com>; Morgan Elliott Andahazy <morgan.elliott-andahazy@dteenergy.com>; Shannen M Hartwick <shannen.palmer@dteenergy.com>; Hope L Allen <hope.allen@dteenergy.com>
Cc: Ryan Stowe <ryan.stowe@dteenergy.com>
Subject: RE: IRM 2025/2026 Expansion

Thanks Neil. On your third bullets, “Match 2026 investment for all programs…”, by programs, do you mean all program work going through Morgan’s pillar, including 4.8kV hardening?

From: Neal T Foley <neal.foley@dteenergy.com>
Sent: Friday, January 26, 2024 3:16 PM
To: Bryant F Miller <bryant.miller@dteenergy.com>; Kelsey O Peterson <kelsey.peterson@dteenergy.com>; Jamie Kryscynski <jamie.kryscynski@dteenergy.com>; Satvir S Deol <satvir.deol@dteenergy.com>; Morgan Elliott Andahazy <morgan.elliott-andahazy@dteenergy.com>; Shannen M Hartwick <shannen.palmer@dteenergy.com>; Hope L Allen <hope.allen@dteenergy.com>
Cc: Ryan Stowe <ryan.stowe@dteenergy.com>; Ledian Dibra <ledian.dibra@dteenergy.com>
Subject: RE: IRM 2025/2026 Expansion

Hello all – In advance of Monday’s meeting on an IRM expansion, we’ve put together an initial proposal (attached). Essentially, an expanded IRM could do the following:

- Flow PTMM through the IRM starting in 2025 (+$121M over what was previously approved for 2025)
- Flow all automation through the IRM starting in 2025 (+$126M over what was previously approved for 2025)
- Match 2026 investment for all programs to our current capital plan (+$282M over expanded 2025 investment)

I’d like to spend Monday’s meeting getting your reaction and raising any concerns you see with this proposal. Can also talk more specifically about how this will flow through the rate case.

Thanks and have a great weekend!

Neal Foley
Director of Regulatory Affairs | DTE Energy
C: 248-933-1472
neal.foley@dteenergy.com

-----Original Appointment-----
From: Neal T Foley
Sent: Wednesday, January 24, 2024 4:20 PM
To: Neal T Foley; Bryant F Miller; Kelsey O Peterson; Jamie Kryscynski; Satvir S Deol; Morgan Elliott Andahazy; Shannen M Hartwick; Hope L Allen
Cc: Ryan Stowe; Ledian Dibra
Subject: IRM 2025/2026 Expansion
When: Monday, January 29, 2024 3:30 PM-4:30 PM (UTC-05:00) Eastern Time (US & Canada).
Where: Microsoft Teams Meeting

Hello all – Purpose of this discussion is to develop a proposal for IRM expansion in 2025/2026 (i.e., additional programs and/or spending levels).

Appreciate it's unlikely everyone can make this time on short notice so we can circle back with the folks that cannot.

Thanks,

Neal

Microsoft Teams meeting

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+1 313-261-5237,,986601542# United States, Detroit
Phone Conference ID: 986 601 542#
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Neal T Foley

From: Marco A Bruzzano
Sent: Monday, January 29, 2024 8:52 AM
To: Jamie Kryscynski; Neal T Foley; Theresa M Uzenski; Bryant F Miller; Kelsey O Peterson; Ledian Dibra; Morgan Elliott Andahazy; Shannen M Hartwick; Satvir S Deol; Kirk Vangilder; Seth Shpargel
Cc: Case R Lancaster; Reema A Biel; Patrick D Daly; Hope L Allen
Subject: Re: Rate case: pivoting to proposing an IRM expansion in 2025/2026

Neal has a proposal

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From: Jamie Kryscynski <jamie.kryscynski@dteenergy.com>
Sent: Monday, January 29, 2024 8:36:38 AM
To: Neal T Foley <neal.foley@dteenergy.com>; Theresa M Uzenski <theresa.uzenski@dteenergy.com>; Bryant F Miller <bryant.miller@dteenergy.com>; Kelsey O Peterson <kelsey.peterson@dteenergy.com>; Ledian Dibra <ledian.dibra@dteenergy.com>; Morgan Elliott Andahazy <morgan.elliott-andahazy@dteenergy.com>; Shannen M Hartwick <shannen.palmer@dteenergy.com>; Satvir S Deol <satvir.deol@dteenergy.com>; Kirk Vangilder <kirk.vangilder@dteenergy.com>; Seth Shpargel <seth.shpargel@dteenergy.com>
Cc: Case R Lancaster <case.lancaster@dteenergy.com>; Reema A Biel <reema.biel@dteenergy.com>; Patrick D Daly <patrick.daly@dteenergy.com>; Marco A Bruzzano <marco.bruzzano@dteenergy.com>; Hope L Allen <hope.allen@dteenergy.com>
Subject: RE: Rate case: pivoting to proposing an IRM expansion in 2025/2026

Is there a dollar value that is being targeted for the expansion (an increase of $50M for example)?

I agree that automation and PTMM are good candidates to include in the expansion.

Jamie

From: Neal T Foley <neal.foley@dteenergy.com>
Sent: Monday, January 29, 2024 8:35 AM
To: Theresa M Uzenski <theresa.uzenski@dteenergy.com>; Bryant F Miller <bryant.miller@dteenergy.com>; Kelsey O Peterson <kelsey.peterson@dteenergy.com>; Ledian Dibra <ledian.dibra@dteenergy.com>; Jamie Kryscynski <jamie.kryscynski@dteenergy.com>; Morgan Elliott Andahazy <morgan.elliott-andahazy@dteenergy.com>; Shannen M Hartwick <shannen.palmer@dteenergy.com>; Satvir S Deol <satvir.deol@dteenergy.com>; Kirk Vangilder <kirk.vangilder@dteenergy.com>; Seth Shpargel <seth.shpargel@dteenergy.com>
Cc: Case R Lancaster <case.lancaster@dteenergy.com>; Reema A Biel <reema.biel@dteenergy.com>; Patrick D Daly <patrick.daly@dteenergy.com>; Marco A Bruzzano <marco.bruzzano@dteenergy.com>; Hope L Allen <hope.allen@dteenergy.com>
Subject: RE: Rate case: pivoting to proposing an IRM expansion in 2025/2026

Thanks Theresa – We can talk more during our upcoming meetings, but at the moment I am thinking we'll probably need "alternative" exhibits for the following:

- DO Capital; will depend on final proposal but likely the Resilience & Hardening and Technology & Automation portions if we end up going with PTMM and Automation in the alternative expansion proposal
- Revenue Deficiency (some subset of the A-11 exhibits)

- IRM Capital (A-33, X1)
- IRM Revenue Requirement (A-33, X4)

I think this is consistent with the last case where we also had "alternative" exhibits in case the Commission rejected the IRM.

Like I said, we can talk more during our upcoming meetings but please let me know if you have any thoughts on what we'll need to provide.

Thanks,

Neal Foley
Director of Regulatory Affairs | DTE Energy
C: 248-933-1472
neal.foley@dteenergy.com

From: Theresa M Uzenski <theresa.uzenski@dteenergy.com>
Sent: Sunday, January 28, 2024 4:30 PM
To: Marco A Bruzzano <marco.bruzzano@dteenergy.com>; Neal T Foley <neal.foley@dteenergy.com>; Bryant F Miller <bryant.miller@dteenergy.com>; Kelsey O Peterson <kelsey.peterson@dteenergy.com>; Ledian Dibra <ledian.dibra@dteenergy.com>; Jamie Kryscynski <jamie.kryscynski@dteenergy.com>; Morgan Elliott Andahazy <morgan.elliott-andahazy@dteenergy.com>; Shannen M Hartwick <shannen.palmer@dteenergy.com>; Satvir S Deol <satvir.deol@dteenergy.com>
Cc: Renee M Tomina <renee.tomina@dteenergy.com>; Ryan Stowe <ryan.stowe@dteenergy.com>; Sharon G Pfeuffer <sharon.pfeuffer@dteenergy.com>; Bill Chiu <bill.chiu@dteenergy.com>; Case R Lancaster <case.lancaster@dteenergy.com>; Reema A Biel <reema.biel@dteenergy.com>; Patrick D Daly <patrick.daly@dteenergy.com>
Subject: Re: Rate case: pivoting to proposing an IRM expansion in 2025/2026

We created a folder called ALT IRM on the prep drive and an ALT DO capex file. It is available for updates once we get specific direction from Neal.

Sent from my Verizon, Samsung Galaxy smartphone
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From: Marco A Bruzzano <marco.bruzzano@dteenergy.com>
Sent: Sunday, January 28, 2024 9:45:46 AM
To: Neal T Foley <neal.foley@dteenergy.com>; Bryant F Miller <bryant.miller@dteenergy.com>; Kelsey O Peterson <kelsey.peterson@dteenergy.com>; Ledian Dibra <ledian.dibra@dteenergy.com>; Jamie Kryscynski <jamie.kryscynski@dteenergy.com>; Morgan Elliott Andahazy <morgan.elliott-andahazy@dteenergy.com>; Satvir S Deol <satvir.deol@dteenergy.com>; Shannen M Hartwick <shannen.palmer@dteenergy.com>
Cc: Renee M Tomina <renee.tomina@dteenergy.com>; Ryan Stowe <ryan.stowe@dteenergy.com>; Sharon G Pfeuffer <sharon.pfeuffer@dteenergy.com>; Bill Chiu <bill.chiu@dteenergy.com>; Case R Lancaster <case.lancaster@dteenergy.com>; Theresa M Uzenski <theresa.uzenski@dteenergy.com>
Subject: RE: Rate case: pivoting to proposing an IRM expansion in 2025/2026

All,

Just want to make sure the path forward is 100% clear. The IRM expansion is not a shift from what we have been working towards, just an added option. The main case submission is not changing. For the IRM we are simply requesting at extension of 2025 surcharge into 2026.

At the same time, we will be adding as an alternative to expand the IRM that simply takes some of the investments in the main case (i.e., PTMM, all of Automation) and creating a larger surcharge.

This will not change your testimony, as it is simply an alternative cost-recovery mechanism for the same investments.

Thanks,

Marco

From: Neal T Foley <neal.foley@dteenergy.com>
Sent: Wednesday, January 24, 2024 4:05 PM
To: Bryant F Miller <bryant.miller@dteenergy.com>; Kelsey O Peterson <kelsey.peterson@dteenergy.com>; Ledian Dibra <ledian.dibra@dteenergy.com>; Jamie Kryscynski <jamie.kryscynski@dteenergy.com>; Morgan Elliott Andahazy <morgan.elliott-andahazy@dteenergy.com>; Satvir S Deol <satvir.deol@dteenergy.com>; Shannen M Hartwick <shannen.palmer@dteenergy.com>
Cc: Marco A Bruzzano <marco.bruzzano@dteenergy.com>; Renee M Tomina <renee.tomina@dteenergy.com>; Ryan Stowe <ryan.stowe@dteenergy.com>; Sharon G Pfeuffer <sharon.pfeuffer@dteenergy.com>; Bill Chiu <bill.chiu@dteenergy.com>
Subject: Rate case: pivoting to proposing an IRM expansion in 2025/2026

Hello all – As some of you may have heard, yesterday it was decided that we will propose an expansion of the IRM for 2025 and 2026 in the upcoming rate case. This is obviously a bit of a deviation from the path that we were on which only had us proposing a simple extension through 2026.

The first thing we need to determine is what new programs and/or investment levels we want to propose in 2025 and 2026. As such, I'm planning on setting up a meeting with a small group to develop a proposal. An initial hypothesis is to include PTMM and additional automation investment, but this is hardly set in stone and we'll be looking to this group to quickly determine what is most appropriate.

Once the programs and spending levels have been determined, we'll engage more meaningfully with the Regulatory Accounting, Cost of Service, and Rate Design teams to make sure the rate case financials are reflective of our proposal. We'll also likely include an "alternative proposal" which is the simple extension we've been working toward.

This is developing quickly so more to come, including an invitation for the working session.

VP Team – Please feel free to add anything I may have missed.

Thanks,

Neal Foley
Director of Regulatory Affairs | DTE Energy
C: 248-933-1472
neal.foley@dteenergy.com

Neal T Foley

From: Marco A Bruzzano
Sent: Thursday, January 25, 2024 5:13 PM
To: Neal T Foley
Subject: RE: Potential IRM expansion proposal

Sounds good – we can talk tomorrow

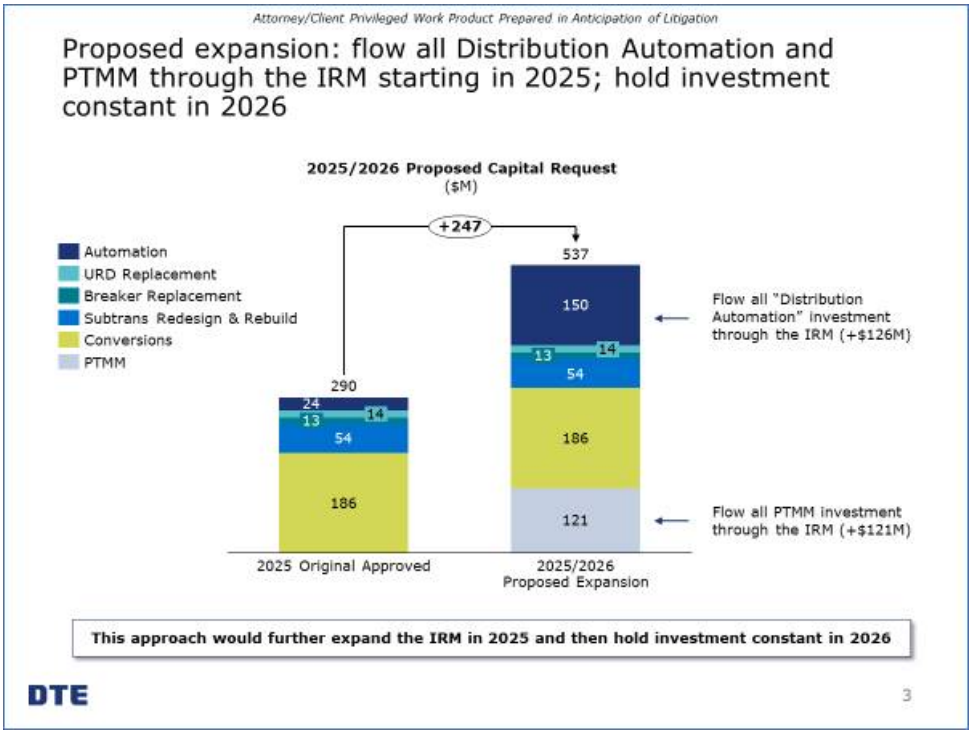
From: Neal T Foley <neal.foley@dteenergy.com>
Sent: Thursday, January 25, 2024 9:06 AM
To: Marco A Bruzzano <marco.bruzzano@dteenergy.com>
Subject: Potential IRM expansion proposal

Hey Marco – For the IRM expansion, I put down what I think could be a reasonable proposal to be included in the rate case (see screenshot below). Essentially, we would:

- Flow all Distribution Automation through the IRM starting in 2025 (increase of $126)
- Flow all PTMM through the IRM in 2026 (increase of $121M)
- Hold Conversions, Subtrans, Breaker Replacement, and URD Replacement constant with what was approved in 2025
- Hold all investment in 2026 consistent with 2025

Another option could be to propose a continued expansion in 2026, so I've asked the DO team to give me the latest capital plans.

Let me know what you think. Given the time constraints, I'm hoping to put a proposal in front of the DO team they can simply approve.



Thanks,

Neal Foley
Director of Regulatory Affairs | DTE Energy
C: 248-933-1472
neal.foley@dteenergy.com

Neal T Foley

From: Neal T Foley
Sent: Thursday, January 25, 2024 1:31 PM
To: Edward Karpiel
Cc: Jamie Kryscynski; Hope L Allen
Subject: RE: 2026 capital forecast for IRM programs?

Sorry – ignore that last email. I had it backwards.

Capital exhibit is correct. Your table needs to be updated.

Thanks again,

Neal Foley
Director of Regulatory Affairs | DTE Energy
C: 248-933-1472
neal.foley@dteenergy.com

From: Neal T Foley
Sent: Thursday, January 25, 2024 1:29 PM
To: Edward Karpiel <Edward.Karpiel@dteenergy.com>
Cc: Jamie Kryscynski <jamie.kryscynski@dteenergy.com>; Hope L Allen <Hope.Allen@dteenergy.com>
Subject: RE: 2026 capital forecast for IRM programs?

Gotcha – So the $125,625k in the capital exhibit will become $145,625k?

I wasn't aware the capital exhibits/models were still changing, but I'm also not super close to that part of the process.

Thanks gain,

Neal Foley
Director of Regulatory Affairs | DTE Energy
C: 248-933-1472
neal.foley@dteenergy.com

From: Edward Karpiel <edward.karpiel@dteenergy.com>
Sent: Thursday, January 25, 2024 1:24 PM
To: Neal T Foley <neal.foley@dteenergy.com>
Cc: Jamie Kryscynski <jamie.kryscynski@dteenergy.com>; Hope L Allen <hope.allen@dteenergy.com>
Subject: RE: 2026 capital forecast for IRM programs?

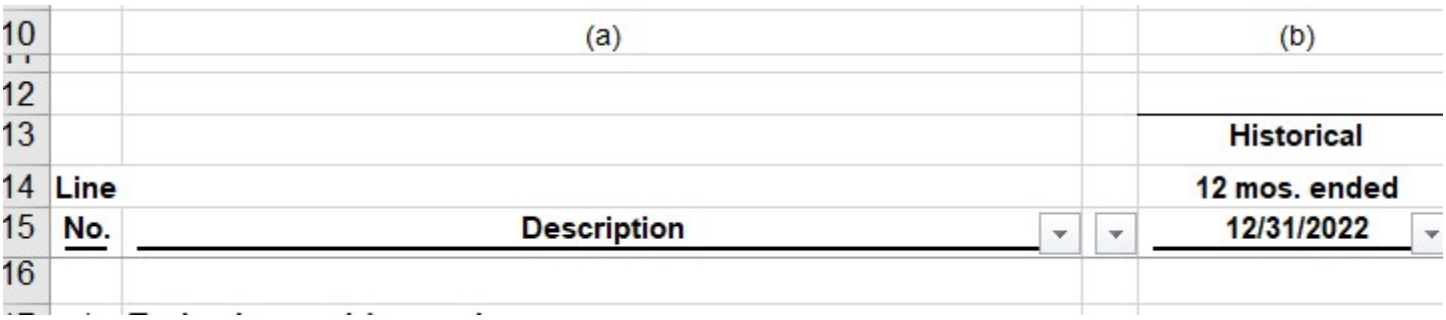
Someone texted me to add $20m to the automation budget in 2025 and it didn't make its way into that file yet, so yes $150m for 2025

From: Neal T Foley <neal.foley@dteenergy.com>
Sent: Thursday, January 25, 2024 1:21 PM
To: Edward Karpiel <edward.karpiel@dteenergy.com>

Cc: Jamie Kryscynski <jamie.kryscynski@dteenergy.com>; Hope L Allen <hope.allen@dteenergy.com>
Subject: RE: 2026 capital forecast for IRM programs?

Thanks Ed – One quick question for you on automation. In your table below it looks like there is $130M for circuit automation in the "2025 Rate Case Budget". However, when I pop open the DO capital exhibits I see $125.6M (see screenshot below in addition to the $24.4M already approved through the IRM (~$150M total).

How should I think about the $130M you have on your table below vs. the $150M in the case/IRM?



10		(a)		(b)
12				
13				Historical
14	Line			12 mos. ended
15	No.	Description		12/31/2022
16				

Thanks again,

Neal Foley
Director of Regulatory Affairs | DTE Energy
C: 248-933-1472
neal.foley@dteenergy.com

From: Edward Karpiel <edward.karpiel@dteenergy.com>
Sent: Thursday, January 25, 2024 11:26 AM
To: Neal T Foley <neal.foley@dteenergy.com>
Cc: Jamie Kryscynski <jamie.kryscynski@dteenergy.com>; Hope L Allen <hope.allen@dteenergy.com>
Subject: RE: 2026 capital forecast for IRM programs?

Neal – Here's what we had in our DGP budget

Primary Key	New IRM fun	Investment Name		2024 Rate Case Budget	
Total RES02	**x**	**Pole and Pole Top Maintenance and Modernization (PTMM)**	**$**	**63,450,000**	**$**
Total RES07	**x**	**Total Breaker Replacement**	**$**	**13,171,000**	**$**
Total RES12	**x**	**Total URD Replacement Program**	**$**	**13,541,398**	**$**
Total RED01	**x**	**Total Subtransmission Redesign & Rebuild**	**$**	**82,161,767**	**$**
Total RED02	**x**	**Total CODI**	**$**	**109,178,895**	**$**
Total RED04	**x**	**Total 4.8 kV and 8.3 kV CC**	**$**	**119,383,707**	**$**
DIST0001	x	13.2kV Circuit Automation	$	14,000,000	$
RELI0455	x	4.8kV Circuit Automation	$	25,000,000	$
DIST0007	x	Circuit Rebuild for Automation	$	5,588,221	$

From: Neal T Foley <neal.foley@dteenergy.com>
Sent: Thursday, January 25, 2024 8:48 AM

To: Edward Karpiel <edward.karpiel@dteenergy.com>
Cc: Jamie Kryscynski <jamie.kryscynski@dteenergy.com>
Subject: 2026 capital forecast for IRM programs?

Hey Ed – In late-breaking news, we're now considering proposing an expansion of the IRM in the upcoming rate case (instead of a simple extension). As such, can you send me our latest 2026 capital forecast for the following programs:

- Conversions
- Subtrans Redesign/Rebuild
- Breaker Replacement
- URD Replacement
- Distribution Automaton (I'm not exactly sure how we're splitting up different automation spend)
- PTMM

It's possible we may propose that all 2026 spend for these programs flow through the IRM. Happy to hop on a quick call to discuss if it's not as simple as I'm making it.

Thanks,

Neal Foley
Director of Regulatory Affairs | DTE Energy
C: 248-933-1472
neal.foley@dteenergy.com

MPSC Case No: U-21534

Requester: MNSC

Question No.: MNSCDE-18.5a

Respondent: N. Foley

Page: 1 of 1

Question: 5. Refer to Foley rebuttal, Q&A42:

a. Identify by specific location – and value if available – any and all productivity gains embedded in company exhibits and any such gains embedded in company workpapers.

Answer: The Company does not maintain a comprehensive list of its Continuous Improvement (CI) initiatives or the estimated productivity gains that may be realized through those initiatives. It therefore cannot provide the requested information.

The Company notes that any productivity gains realized through the historic test year in this case (i.e., Calendar Year 2022) would already be embedded in the historic test year financials presented in the Company's exhibits.

Attachment: *None*

MPSC Case No: U-21534

Requester: MNSC

Question No.: MNSCDE-18.5b

Respondent: N. Foley

Page: 1 of 1

Question: 5. Refer to Foley rebuttal, Q&A42:

b. Explain in detail the company's methodology (if any) for estimating productivity gains in business unit financial exhibits. If the methodology differs among business units, explain how.

Answer: The Company does not have a standard methodology for estimating productivity gains in Business Unit (BU) financial exhibits.

Attachment: *None*

MPSC Case No: U-21534

Requester: MNSC

Question No.: MNSCDE-18.5c

Respondent: N. Foley

Page: 1 of 1

Question: 5. Refer to Foley rebuttal, Q&A42:

c. Produce any and all research, white papers, presentations, and point-of-view documents in the witness's possession or control regarding this topic.

Answer: The Company objects for the reason that the request is unclear, vague, and incapable of answer in its present form. More specifically, the Company is unclear as to the meaning of "this topic."

Subject to this objection, and without waiving this objection, the Company responds as follows:

Assuming "this topic" is referring to the estimation of productivity gains in business unit financial exhibits, I do not have any research, white papers, presentations, and/or point-of-view documents in my possession.

Attachment: *None*

Co-respondent: Legal

EXHIBIT MEC-28

RESERVED

MPSC Case No: U-21534

Requester: MNSC

Question No.: MNSCDE-17.16b

Respondent: J. Kryscynski

Page: 1 of 1

Question: 16. Refer to the rebuttal testimony of Witness Kryscynski, Q&A 16.

b. Refer to Exhibit 4.3.1.1 (Asset Age Summary) in the 2023 DGP (Ex A-23 Sch M8). Identify the basis or source for the Life Expectancy (Years) data shown in the chart.

Answer: See the 2023 DGP, pages 41 and 42, in Section 4.3.1. The Company's internal subject matter experts draw from a broad set of sources to determine life expectancy, including ongoing review of technical papers, attending industry conferences, meeting with manufacturers, and gaining specific experience with the performance of the assets on the Company's electrical system.

Attachment: *N/A*

MPSC Case No: U-21534

Requester: MNSC

Question No.: MNSCDE-17.24

Respondent: J. Kryscynski

Page: 1 of 1

Question: 24. Refer to the rebuttal testimony of Witness Kryscynski, Q&A 24 and Exhibit A-43 Schs HH2 and HH3. Please clarify whether the Q&A reference to “this journal article” is discussing the relationship between spending and reliability as documented in the LBNL study (Sch HH2) or the Eto study (Sch HH3).

Answer: Q&A 24 in my rebuttal testimony references Tables A.4 and A.5 which are found in schedule HH3. The papers contained in schedules HH2 and HH3 are based on the same study, however, and not two different studies. The underlying data used, which is summarized in Tables 3 and 4 in both exhibits, are identical. Therefore, I am discussing the relationship between O&M spending and reliability for both schedules HH2 and HH3, as they are the same.

Attachment: *N/A*

MPSC Case No: U-21534

Requester: MNSC

Question No.: MNSCDE-18.7

Respondent: J. Kryscynski

Page: 1 of 1

Question: 7. Refer to the rebuttal testimony of Witness Kryscynski, Q&A 26. How does DTE determine and document the outage cause that is entered into the "cause code field" in the outage management system? Explain in detail.

Answer: Upon assessing an outage event in the field, field crews will update the cause code based upon their observations using their mobile data terminals.

Attachment: *None*

MPSC Case No: U-21534

Requester: MNSC

Question No.: MNSCDE-18.10

Respondent: J. Kryscynski

Page: 1 of 1

Question: 10. Refer to the rebuttal testimony of Witness Kryscynski, Q&A 27 and Figure 1, and to the 2023 DGP (Ex A-23 Sch M8), Exhibit 4.2.2.3. Please explain all differences between the data sources and analyses in Figure 1 and Exhibit 4.2.2.3.

Answer: Figure 1 represents the percentage, by cause code, of the number of customers interrupted, or SAIFI, excluding MEDs, from 2019-2023.

Exhibit 4.2.2.3 represents the percentage, by cause code, of the number of outage events, for all weather, from 2018-2022.

Both charts utilize Company outage data, however, Figure 1 uses a slightly different timeframe and utilizes data excluding MEDs (a subset of all weather data).

Attachment: *N/A*

MPSC Case No: U-21534

Requester: MNSC

Question No.: MNSCDE-19.37a.

Respondent: J. Kryscynski

Page: 1 of 1

Question: Refer to the rebuttal testimony of Witness Kryscynski, Q&A 53, and Figure 2. Provide any analyses DTE has completed to validate the accuracy of the scores output by the subjective assessment methodology at predicting equipment failure or test failure.

Answer: The Company has not completed the analysis as described. Figure 2 represents a quantitatively based risk assessment methodology developed by Company subject matter experts. The intent of Figure 2 is to identify characteristics such as design factors and age that can impact relative risk of failure, proactively before failures occur, and therefore, supports the Company's ability to prioritize replacement of equipment.

Attachment: *None*

MPSC Case No: U-21534

Requester: MNSC

Question No.: MNSCDE-19.37b.

Respondent: J. Kryscynski

Page: 1 of 1

Question: Refer to the rebuttal testimony of Witness Kryscynski, Q&A 53, and Figure 2. Provide any analyses DTE has completed to compare the accuracy of the scores output by the subjective assessment methodology to the accuracy of the functional and diagnostic testing the Company completes on critical equipment.

Answer: This question assumes that the results of the Company's risk scoring methodology are functionally comparable to the results of diagnostic asset health inspections, which is not accurate, and the Company has not completed the analysis. The scores in the quantitatively based risk assessment methodology developed by Company subject matter experts in Figure 2 are determined objectively. For example, a switchgear is either "across-the-aisle" design type or not.

The Company does in fact do functional and diagnostic testing on some equipment, which can provide information about the equipment. The information gained during this testing is used by the subject matter experts to inform equipment risk scoring criteria. The equipment risk scoring is intended to comprehensively and proactively identify risk before failures occur, and therefore, supports the Company's ability to prioritize replacement of equipment.

Attachment: *None*

MPSC Case No: U-21534

Requester: MNSC

Question No.: MNSCDE-19.37c.

Respondent: J. Kryscynski

Page: 1 of 1

Question: Refer to the rebuttal testimony of Witness Kryscynski, Q&A 53, and Figure 2.

Provide any analyses DTE has completed that compares the benefits and costs of replacing equipment as identified by the subjective scoring methodology and/or Global Prioritization Model outputs to the benefits and costs of replacing equipment as identified by functional and diagnostic testing.

Answer: The Company has not completed the requested analysis.

The Company is continuing to explore more comprehensive BCAs, as noted in Witness Kryscynski rebuttal testimony, issue number 5, beginning on page 20.

Attachment: *None*

MPSC Case No: U-21534

Requester: MNSC

Question No.: MNSCDE-19.37d.

Respondent: J. Kryscynski

Page: 1 of 1

Question: Refer to the rebuttal testimony of Witness Kryscynski, Q&A 53, and Figure 2. Provide any analyses DTE has completed to validate the accuracy of the scores output by the subjective assessment methodology at predicting equipment failure or test failure. If DTE has completed no such validation, please explain why not.

Answer: Refer to response MNSCDE-19.37a.

Attachment: *None*

MPSC Case No: U-21534

Requester: MNSC

Question No.: MNSCDE-15.20c

Respondent: J. Kryscynski

Question: 20. Refer to the Company's reliability improvement model (WP AJK U-21534 Reliability Model) generally. Please explain the rationale for:

c. Separating history and projections into Tree and non-Tree events.

Answer: As stated in response to MNSCDE-15.20b, the nature of each outage event may differ. Tree-related outages may require additional support, such as a tree-trim crew, to resolve. These differences ultimately lead to variations in average outage duration per event. Additionally, different reliability programs target different types of outages. In the model, the Tree Trim program is the only program that reduces tree related outages. Therefore, it is important to separate the tree related outages so that the model can accurately reflect the effectiveness of the tree trim program. Other programs, such as PTMM, reduce non-tree outages, so for modeling purposes, we need to have the events separated to maximize accuracy.

Attachment: *N/A*

MPSC Case No: U-21534

Requester: MNSC

Question No.: MNSCDE-17.19

Respondent: R. Steudle

Page: 1 of 1

Question: 19. Refer to the rebuttal testimony of Witness Kryscynski, Q&A 19. Does the Company track outages caused by out of right of way trees? If so, please provide the number caused by out of right of way trees and in right of way trees for 2021, 2022, and 2023, on a circuit basis if available.

Answer: Tree caused outages are typically coded as one of the following cause codes, tree in ROW, tree out ROW and WIND. The Company has not performed an analysis to determine the split of outages caused by tree from in and out of right of way for the WIND cause code outages. Outage data by cause code has been provided in discovery response MNSCDE-3.1a.

Attachment: *N/A*

MPSC Case No: U-21534

Requester: MNSC

Question No.: MNSCDE-3.1a

Respondent: S. Deol

Page: 1 of 1

Question: 1. Refer to Case No. U-21297, the Company's discovery responses attachment labeled "U-21297 MNSCDE-2.3", and the supplemental attachment labeled "U-21297 MNSCDE-2.3 outages w Field Notes" which provided a spreadsheet of outages with a separate tab which provided the "Field Notes":

a. Please provide, in the same format as provided above, the outages for the years 2017 through 2023. Please provide the field notes on the same sheet as the interruptions such that the field notes line up with the associated interruptions.

Answer: The Company objects for the reason that the request is unduly burdensome, overly broad, oppressive and calculated to cause unreasonable expense to DTE Electric and its customers as there are well over a million field notes associated with this request. The Company also objects because the information requested is not relevant, nor is it reasonably calculated to lead to the discovery of relevant evidence, because the information requested may be subject to attorney/client privileged and/or because the information requested may contain customer information that is prohibited from disclosure by law. Without waiving these objections, but subject to them, based upon currently available information the Company responds as follows:

See attachment U-21534 MNSCDE-3.1-01 Outages 2017-2023

Attachment: U-21534 MNSCDE-3.1-01 Outages 2017-2023

U-21534 MNSCDE-3.1-01 Outages 2017-2023

Incident ID	Circuit	Outage Year	Outage Start Date/Time	Outage End Date/Time	Count of Total Customers Interrupted	Customer Minutes Interrupted	Primary Cause Category	Weather
W17010100008	PERU9432	2017	2017-01-01 00:17:00	2017-01-01 03:32:00	1	195	OTHER	Non-storm
D17010100001	CRTIS2031	2017	2017-01-01 00:26:00	2017-01-01 01:22:00	1	56	WIND	Non-storm
D17010100003	TIRMN1196	2017	2017-01-01 00:42:00	2017-01-01 05:37:00	1	295	EQUIPMENT FAILURE	Non-storm
W17010100010	SWANC9445	2017	2017-01-01 00:48:00	2017-01-01 08:29:00	1	461	EQUIPMENT FAILURE	Non-storm
N17010100005	WIXOM9491	2017	2017-01-01 01:12:00	2017-01-01 02:51:00	23	2277	UNKNOWN	Non-storm
D17010100009	INKST0326	2017	2017-01-01 01:43:00	2017-01-01 04:14:00	1	151	EQUIPMENT FAILURE	Non-storm
N17010100011	PINCK9869	2017	2017-01-01 01:49:00	2017-01-01 03:04:00	1	75	EQUIPMENT FAILURE	Non-storm
W17010100011	SWANC9445	2017	2017-01-01 01:56:00	2017-01-01 08:29:00	2	786	EQUIPMENT FAILURE	Non-storm
D17010100016	LAUDR1272	2017	2017-01-01 03:34:00	2017-01-01 06:41:00	1	187	METER / BLOCKS	Non-storm
N17010100015	CLYDE9079	2017	2017-01-01 04:48:00	2017-01-01 10:00:00	1	312	EQUIPMENT FAILURE	Non-storm
T17010100002	HOSTN8773	2017	2017-01-01 07:00:00	2017-01-01 09:36:00	1	156	EQUIPMENT FAILURE	Non-storm
D17010100022	STLUS0150	2017	2017-01-01 07:43:00	2017-01-01 13:49:00	1	366	TREE	Non-storm
W17010100018	VENOY9422	2017	2017-01-01 08:50:00	2017-01-01 10:27:00	1	97	UNKNOWN	Non-storm
N17010100023	MILFD9249	2017	2017-01-01 09:00:00	2017-01-01 10:22:00	1	82	METER / BLOCKS	Non-storm
N17010100024	MALTA8501	2017	2017-01-01 09:09:00	2017-01-01 13:59:00	1	290	EQUIPMENT FAILURE	Non-storm
D17010100026	TURNR2165	2017	2017-01-01 09:16:00	2017-01-01 11:52:00	1	156	EQUIPMENT FAILURE	Non-storm
T17010100005	BRAY8780	2017	2017-01-01 09:24:00	2017-01-01 11:29:00	1	125	EQUIPMENT FAILURE	Non-storm
W17010100012	POPLR9885	2017	2017-01-01 09:29:00	2017-01-01 10:47:00	2	156	TREE	Non-storm
N17010100029	ROMEO0300	2017	2017-01-01 09:33:00	2017-01-01 11:46:00	1	133	EQUIPMENT FAILURE	Non-storm
W17010100023	ARGO0329	2017	2017-01-01 09:37:00	2017-01-01 19:15:00	1	578	EQUIPMENT FAILURE	Non-storm
T17010100006	REMER8747	2017	2017-01-01 09:43:00	2017-01-01 13:59:00	1	256	EQUIPMENT FAILURE	Non-storm
D17010100031	PULFD2155	2017	2017-01-01 10:03:00	2017-01-01 11:58:00	1	115	PUBLIC INTEFERENCE	Non-storm
N17010100030	CLKSN8860	2017	2017-01-01 10:25:00	2017-01-01 12:16:00	1	111	EQUIPMENT FAILURE	Non-storm
N17010100034	MALTA8515	2017	2017-01-01 10:26:00	2017-01-01 13:47:00	23	2019	EQUIPMENT FAILURE	Non-storm
T17010100007	NHAVN0311	2017	2017-01-01 10:35:00	2017-01-01 13:29:00	1	174	CUSTOMER EQUIPMENT	Non-storm
W17010100020	DREXL8848	2017	2017-01-01 10:35:00	2017-01-01 11:39:00	15	960	EQUIPMENT FAILURE	Non-storm
W17010100021	HEMLK1952	2017	2017-01-01 10:39:00	2017-01-01 12:57:00	11	1518	EQUIPMENT FAILURE	Non-storm
N17010100036	PINCK9869	2017	2017-01-01 10:50:00	2017-01-01 11:45:00	1	55	EQUIPMENT FAILURE	Non-storm
T17010100010	YALE2633	2017	2017-01-01 10:55:00	2017-01-01 17:20:00	18	6930	EQUIPMENT FAILURE	Non-storm
D17010100037	EIGMI1512	2017	2017-01-01 11:12:00	2017-01-01 13:48:00	1	156	EQUIPMENT FAILURE	Non-storm
W17010100025	VENOY9422	2017	2017-01-01 11:25:00	2017-01-01 12:39:00	1	74	CUSTOMER EQUIPMENT	Non-storm
D17010100039	GLEND1408	2017	2017-01-01 11:28:00	2017-01-01 13:14:00	1	106	METER / BLOCKS	Non-storm
W17010100029	YPSIL0302	2017	2017-01-01 12:05:00	2017-01-01 12:23:00	75	1350	EQUIPMENT FAILURE	Non-storm
T17010100016	LIND58164	2017	2017-01-01 12:10:00	2017-01-01 13:18:00	1	68	ANIMAL	Non-storm
T17010100017	ASPEN8811	2017	2017-01-01 12:28:00	2017-01-01 16:44:00	1	256	EQUIPMENT FAILURE	Non-storm
D17010100046	WSEND1038	2017	2017-01-01 13:06:00	2017-01-01 14:56:00	1	110	EQUIPMENT FAILURE	Non-storm
D17010100047	LYNCH2227	2017	2017-01-01 13:08:00	2017-01-01 15:29:00	1	141	EQUIPMENT FAILURE	Non-storm
T17010100018	WORTH0302	2017	2017-01-01 13:18:00	2017-01-01 21:19:00	1	481	UNKNOWN	Non-storm
N17010100057	APACE9046	2017	2017-01-01 13:24:00	2017-01-01 14:16:00	46	2392	EQUIPMENT FAILURE	Non-storm
N17010100058	APACE9046	2017	2017-01-01 13:24:00	2017-01-01 14:27:00	95	5985	EQUIPMENT FAILURE	Non-storm
D17010100052	WAYBN1152	2017	2017-01-01 13:26:00	2017-01-01 15:12:00	1	106	UNKNOWN	Non-storm
D17010100053	GRPTE2053	2017	2017-01-01 13:38:00	2017-01-01 14:42:00	1	64	UNKNOWN	Non-storm
T17010100020	BERND0342	2017	2017-01-01 13:51:00	2017-01-01 17:17:00	1	206	EQUIPMENT FAILURE	Non-storm
N17010100059	NIXON8943	2017	2017-01-01 14:09:00	2017-01-01 16:26:00	4	548	UNKNOWN	Non-storm
D17010100057	DERBN1051	2017	2017-01-01 14:39:00	2017-01-01 18:54:00	1	255	EQUIPMENT FAILURE	Non-storm
T17010100026	FRMNT1250	2017	2017-01-01 14:43:00	2017-01-01 19:53:00	1	310	EQUIPMENT FAILURE	Non-storm
D17010100060	FRMNT1066	2017	2017-01-01 15:06:00	2017-01-01 17:59:00	1	173	PUBLIC INTEFERENCE	Non-storm
T17010100028	JACOB8670	2017	2017-01-01 15:24:00	2017-01-01 20:09:00	1	285	CUSTOMER EQUIPMENT	Non-storm
N17010100061	CLYDE9079	2017	2017-01-01 15:26:00	2017-01-01 18:27:00	1	181	EQUIPMENT FAILURE	Non-storm
D17010100065	EMPIR2232	2017	2017-01-01 16:24:00	2017-01-01 19:14:00	1	170	CUSTOMER EQUIPMENT	Non-storm
T17010100033	CONAT1362	2017	2017-01-01 16:30:00	2017-01-01 17:32:00	1	62	METER / BLOCKS	Non-storm
N17010100063	CRWFD8318	2017	2017-01-01 16:36:00	2017-01-01 17:03:00	13	351	TREE	Non-storm
D17010100066	FRMNT1066	2017	2017-01-01 16:41:00	2017-01-01 19:04:00	1	143	UNKNOWN	Non-storm
N17010100019	SENCA8997	2017	2017-01-01 16:56:12	2017-01-02 02:14:12	1	558	UNKNOWN	Non-storm
W17010100036	FLRDA8032	2017	2017-01-01 18:07:58	2017-01-01 22:56:58	1	289	UNKNOWN	Non-storm
W17010100038	POPLR9885	2017	2017-01-01 18:33:00	2017-01-01 18:39:00	2	12	TREE	Non-storm
N17010100064	CHILS9877	2017	2017-01-01 19:21:00	2017-01-01 21:11:00	1	110	EQUIPMENT FAILURE	Non-storm
N17010100065	BOND8058	2017	2017-01-01 19:22:00	2017-01-01 21:35:00	1	133	EQUIPMENT FAILURE	Non-storm
T17010100041	STEPH8522	2017	2017-01-01 21:11:00	2017-01-01 22:53:00	20	2040	EQUIPMENT FAILURE	Non-storm
N17010100068	APACE9164	2017	2017-01-01 21:29:00	2017-01-02 02:10:00	1	281	EQUIPMENT FAILURE	Non-storm
W17010100046	PLYMO0300	2017	2017-01-01 21:56:00	2017-01-02 10:34:00	1	758	UNKNOWN	Non-storm
T17010100047	NBALT8428	2017	2017-01-01 23:22:00	2017-01-02 01:20:00	1	118	UNKNOWN	Non-storm
T17010200002	BREWR9229	2017	2017-01-02 04:17:00	2017-01-02 07:29:00	1	192	EQUIPMENT FAILURE	Non-storm
W17010200003	POPLR9885	2017	2017-01-02 05:26:00	2017-01-02 10:33:00	1	307	EQUIPMENT FAILURE	Non-storm
D17010200013	ESTLD1146	2017	2017-01-02 05:45:00	2017-01-02 09:15:00	1	210	EQUIPMENT FAILURE	Non-storm
W17010200006	POPLR9885	2017	2017-01-02 05:59:00	2017-01-02 10:33:00	1	274	OTHER	Non-storm
D17010200019	CHIGO1584	2017	2017-01-02 06:13:00	2017-01-02 09:50:00	1	97	THEFT	Non-storm
N17010200013	TAMRK9545	2017	2017-01-02 08:54:00	2017-01-02 10:14:00	1	80	TREE	Non-storm
N17010200014	MILFD9245	2017	2017-01-02 09:05:00	2017-01-02 11:03:00	1	118	EQUIPMENT FAILURE	Non-storm
W17010200008	NBURG8075	2017	2017-01-02 09:34:20	2017-01-02 11:57:20	1	143	EQUIPMENT FAILURE	Non-storm
T17010200015	MACMB8277	2017	2017-01-02 09:35:00	2017-01-02 11:47:00	8	1056	EQUIPMENT FAILURE	Non-storm
D17010200028	SIXMI2145	2017	2017-01-02 09:44:00	2017-01-02 12:09:00	1	145	METER / BLOCKS	Non-storm
D17010200035	PULFD2155	2017	2017-01-02 10:12:00	2017-01-02 10:51:00	1	39	EQUIPMENT FAILURE	Non-storm
W17010200018	GRENA9820	2017	2017-01-02 10:16:00	2017-01-02 15:47:00	2	662	ANIMAL	Non-storm
T17010200022	AGSTA8700	2017	2017-01-02 10:24:00	2017-01-02 17:22:00	1	418	UNKNOWN	Non-storm
W17010200005	MOTY9789	2017	2017-01-02 10:45:00	2017-01-02 17:07:00	1	382	LIGHTNING	Non-storm
N17010200021	WATFD8854	2017	2017-01-02 11:11:00	2017-01-02 18:19:00	1	428	EQUIPMENT FAILURE	Non-storm
W17010200027	SPRUC9825	2017	2017-01-02 11:11:16	2017-01-02 13:37:16	1	146	ANIMAL	Non-storm
T17010200014	HOSTN8773	2017	2017-01-02 11:20:00	2017-01-02 12:44:00	3	252	EQUIPMENT FAILURE	Non-storm
T17010200026	ROBIN9309	2017	2017-01-02 11:20:00	2017-01-03 04:45:00	11	11495	EQUIPMENT FAILURE	Non-storm
T17010200069	ROBIN9309	2017	2017-01-02 11:20:00	2017-01-03 04:44:00	22	22968	TREE	Non-storm
D17010200046	SCOTN1068	2017	2017-01-02 11:39:00	2017-01-02 12:38:00	1	59	UNKNOWN	Non-storm
W17010200007	SOFLD9054	2017	2017-01-02 11:44:28	2017-01-02 17:59:28	1	375	EQUIPMENT FAILURE	Non-storm
D17010200048	EMPIR1378	2017	2017-01-02 11:47:00	2017-01-02 14:35:00	1	168	EQUIPMENT FAILURE	Non-storm
N17010200029	HURST9842	2017	2017-01-02 12:40:00	2017-01-02 14:56:00	1	136	EQUIPMENT FAILURE	Non-storm
N17010200032	STERL8061	2017	2017-01-02 13:09:00	2017-01-02 15:49:00	1	160	UNKNOWN	Non-storm
D17010200061	CHIGO1420	2017	2017-01-02 13:16:00	2017-01-02 14:40:00	1	84	EQUIPMENT FAILURE	Non-storm
N17010200035	SLOAN9148	2017	2017-01-02 13:52:00	2017-01-02 21:37:00	1	465	EQUIPMENT FAILURE	Non-storm
W17010200021	VENOY9383	2017	2017-01-02 13:58:53	2017-01-02 16:58:53	1	180	UNKNOWN	Non-storm
T17010200040	BEACH8673	2017	2017-01-02 13:58:00	2017-01-02 14:50:00	13	663	ANIMAL	Non-storm
N17010200038	CODY8824	2017	2017-01-02 14:27:00	2017-01-02 17:00:00	1	153	UNKNOWN	Non-storm
N17010200041	JEWEL8569	2017	2017-01-02 14:41:00	2017-01-02 17:39:00	26	2270	ANIMAL	Non-storm
N17010200044	ORION8966	2017	2017-01-02 14:43:00	2017-01-02 17:01:00	3	414	EQUIPMENT FAILURE	Non-storm
N17010200020	COATS8039	2017	2017-01-02 15:11:38	2017-01-02 20:02:38	1	291	EQUIPMENT FAILURE	Non-storm
T17010200050	DERBY2635	2017	2017-01-02 15:29:00	2017-01-02 17:36:00	1	127	EQUIPMENT FAILURE	Non-storm
N17010200049	ORION8966	2017	2017-01-02 15:39:00	2017-01-02 22:35:00	1	416	EQUIPMENT FAILURE	Non-storm
T17010200051	LIBER1815	2017	2017-01-02 15:44:00	2017-01-02 17:25:00	1	101	UNKNOWN	Non-storm
D17010200080	STOPL2231	2017	2017-01-02 15:57:00	2017-01-02 17:29:00	1	92	UNKNOWN	Non-storm
T17010200054	TCOMA8311	2017	2017-01-02 16:41:00	2017-01-03 00:45:00	1	484	EQUIPMENT FAILURE	Non-storm
W17010200041	RGENT0352	2017	2017-01-02 17:18:00	2017-01-02 18:45:00	13	1131	TREE	Non-storm
D17010200091	TWEMI1551	2017	2017-01-02 17:22:00	2017-01-02 20:00:00	1	158	THEFT	Non-storm
W17010200026	GAY20829	2017	2017-01-02 17:29:43	2017-01-02 21:12:43	1	223	EQUIPMENT FAILURE	Non-storm
D17010200092	LAUDR1411	2017	2017-01-02 17:30:00	2017-01-03 20:36:00	1	1626	EQUIPMENT FAILURE	Non-storm
W17010200044	STATE8137	2017	2017-01-02 17:34:00	2017-01-02 18:50:00	1	76	OTHER	Non-storm
N17010200050	TAMRK9031	2017	2017-01-02 17:36:00	2017-01-02 18:04:00	2	56	EQUIPMENT FAILURE	Non-storm
T17010200057	EMMET0302	2017	2017-01-02 17:41:00	2017-01-02 22:30:00	1	289	EQUIPMENT FAILURE	Non-storm
N17010200047	CALMT0345	2017	2017-01-02 17:52:48	2017-01-02 19:16:48	1	84	EQUIPMENT FAILURE	Non-storm
D17010200100	TIRMN2093	2017	2017-01-02 18:08:00	2017-01-03 10:05:00	1	957	TREE	Non-storm
W17010200048	NANKN1693	2017	2017-01-02 18:48:00	2017-01-02 20:01:00	1	73	UNKNOWN	Non-storm
W17010200034	SNSET9497	2017	2017-01-02 19:18:03	2017-01-02 23:40:03	1	262	UNKNOWN	Non-storm
W17010200051	RGENT0352	2017	2017-01-02 19:29:00	2017-01-02 21:00:00	13	1183	EQUIPMENT FAILURE	Non-storm
T17010200091	ROBIN9309	2017	2017-01-02 19:31:00	2017-01-03 03:42:00	4	1964	EQUIPMENT FAILURE	Non-storm
W17010200053	DRAKE8969	2017	2017-01-02 19:46:00	2017-01-02 20:54:00	32	2176	TREE	Non-storm
D17010200110	ANNCH1588	2017	2017-01-02 19:53:00	2017-01-03 12:15:00	1	982	EQUIPMENT FAILURE	Non-storm
T17010200083	PIGON8771	2017	2017-01-02 20:55:00	2017-01-03 04:42:00	1	467	EQUIPMENT FAILURE	Non-storm
N17010200057	SLKRK9828	2017	2017-01-02 21:15:00	2017-01-02 22:27:00	36	2592	EQUIPMENT FAILURE	Non-storm
D17010200123	CHAND0065	2017	2017-01-02 21:33:00	2017-01-03 02:08:00	263	72325	THEFT	Non-storm
N17010200058	WOLFH8838	2017	2017-01-02 21:34:00	2017-01-03 10:17:00	1	763	TREE	Non-storm
W17010200065	GRENA9820	2017	2017-01-02 21:36:00	2017-01-03 01:31:00	1	235	UNKNOWN	Non-storm
D17010200132	GLEND2198	2017	2017-01-02 21:58:00	2017-01-03 01:03:00	20	3700	EQUIPMENT FAILURE	Non-storm
T17010200092	TCOMA8311	2017	2017-01-02 22:11:00	2017-01-03 01:23:00	454	87168	TREE	Non-storm
N17010200067	WOLFH8838	2017	2017-01-02 23:05:00	2017-01-03 03:32:00	2	534	EQUIPMENT FAILURE	Non-storm
N17010200066	MILFD9245	2017	2017-01-02 23:15:00	2017-01-03 00:30:00	1	75	EQUIPMENT FAILURE	Non-storm
N17010200068	NIXON8926	2017	2017-01-02 23:40:00	2017-01-03 08:11:00	79	13562	UNKNOWN	Non-storm
W17010200069	FRMTN8892	2017	2017-01-02 23:54:00	2017-01-03 04:44:00	250	40786	EQUIPMENT FAILURE	Non-storm
W17010300001	INDIN1423	2017	2017-01-03 00:00:00	2017-01-03 02:47:00	2	334	OTHER	Non-storm
W17010300005	TFANY8024	2017	2017-01-03 00:06:00	2017-01-03 01:43:00	433	42001	EQUIPMENT FAILURE	Non-storm
T17010300004	MTMRA8035	2017	2017-01-03 00:08:00	2017-01-03 02:33:00	92	13340	TREE	Non-storm
T17010300012	MTMRA8035	2017	2017-01-03 00:08:00	2017-01-03 06:28:00	1	380	OTHER	Non-storm
W17010200061	GRENA9820	2017	2017-01-03 00:14:00	2017-01-03 01:31:00	9	693	EQUIPMENT FAILURE	Non-storm
N17010300077	TEGER9133	2017	2017-01-03 00:41:00	2017-01-03 07:12:00	3	1173	TREE	Non-storm
N17010300024	DISCO8403	2017	2017-01-03 00:42:00	2017-01-03 05:12:00	2489	209784	TREE	Non-storm
N17010300095	DISCO8403	2017	2017-01-03 00:42:00	2017-01-03 06:00:00	86	27348	TREE	Non-storm
D17010300010	GRPTE2053	2017	2017-01-03 01:09:00	2017-01-03 10:28:00	1	559	TREE	Non-storm
Z17010200069	FRMTN8892	2017	2017-01-03 01:11:00	2017-01-03 02:47:00	14	1344	EQUIPMENT FAILURE	Non-storm
W17010300012	ODELL9337	2017	2017-01-03 01:59:00	2017-01-03 10:54:00	1	535	TREE	Non-storm
T17010200160	CAPAC8013	2017	2017-01-03 02:10:00	2017-01-03 02:19:00	102	918	EQUIPMENT FAILURE	Non-storm
W17010300015	PHENX9804	2017	2017-01-03 02:25:00	2017-01-03 05:19:00	1	174	INTENTIONAL	Non-storm
W17010300017	PHENX9804	2017	2017-01-03 03:19:00	2017-01-03 05:01:00	10	1020	INTENTIONAL	Non-storm
T17010300023	WABSH8797	2017	2017-01-03 03:24:00	2017-01-03 11:30:00	140	68040	TREE	Non-storm
D17010300033	TWEMI1551	2017	2017-01-03 05:00:00	2017-01-03 09:46:00	1	286	UNKNOWN	Non-storm
T17010300041	JACOB8698	2017	2017-01-03 05:50:00	2017-01-03 08:10:00	10	1400	WIND	Non-storm
N17010300183	GRAYL8473	2017	2017-01-03 06:12:00	2017-01-03 12:02:00	12	4200	EQUIPMENT FAILURE	Non-storm
T17010300050	LAPER8765	2017	2017-01-03 06:36:00	2017-01-03 09:53:00	49	9653	EQUIPMENT FAILURE	Non-storm
W17010300029	SHERW0322	2017	2017-01-03 06:43:00	2017-01-03 07:12:00	1	29	OTHER	Non-storm
D17010300043	CRTIS2104	2017	2017-01-03 06:51:00	2017-01-03 16:22:00	1	571	TREE	Non-storm
D17010300048	GARY1858	2017	2017-01-03 07:30:00	2017-01-03 18:28:00	1	658	TREE	Non-storm
T17010300055	ALGON8748	2017	2017-01-03 07:53:00	2017-01-03 08:16:00	1	23	UNKNOWN	Non-storm
D17010300051	LAMBT1456	2017	2017-01-03 08:17:00	2017-01-03 14:18:00	1	361	EQUIPMENT FAILURE	Non-storm
N17010300146	STERL8628	2017	2017-01-03 08:20:00	2017-01-03 09:32:00	1018	73296	EQUIPMENT FAILURE	Non-storm
T17010300057	BECK8689	2017	2017-01-03 08:30:00	2017-01-03 11:14:00	1	164	EQUIPMENT FAILURE	Non-storm
N17010300234	ADAMS8429	2017	2017-01-03 08:31:00	2017-01-03 09:41:00	18	1260	ANIMAL	Non-storm

U-21534 MNSCDE-3.1-01 Outages 2017-2023

N17010300235	CLYDE9079	2017	2017-01-03 08:45:00	2017-01-03 11:13:00	1	148	EQUIPMENT FAILURE	Non-storm
N17010300237	STERL8435	2017	2017-01-03 08:51:00	2017-01-03 13:03:00	1	252	UNKNOWN	Non-storm
W17010300046	OKRDS9626	2017	2017-01-03 09:05:00	2017-01-03 10:11:00	56	3696	TREE	Non-storm
D17010300069	GNSTN1287	2017	2017-01-03 09:12:00	2017-01-03 11:04:00	1	112	EQUIPMENT FAILURE	Non-storm
N17010300241	WALTN0324	2017	2017-01-03 09:20:00	2017-01-03 11:18:00	1	118	CUSTOMER EQUIPMENT	Non-storm
D17010300074	APPOL1383	2017	2017-01-03 09:22:00	2017-01-03 13:30:00	1	248	TREE	Non-storm
D17010300086	CONAT2235	2017	2017-01-03 09:36:00	2017-01-03 11:08:00	1	92	METER / BLOCKS	Non-storm
T17010300078	MEDNA8408	2017	2017-01-03 09:40:00	2017-01-03 12:28:00	1	168	UNKNOWN	Non-storm
N17010300248	CATLI9136	2017	2017-01-03 09:45:00	2017-01-03 11:59:00	20	2680	INTENTIONAL	Non-storm
N17010300252	STERL8628	2017	2017-01-03 09:48:00	2017-01-03 10:23:00	123	4305	UNKNOWN	Non-storm
N17010300255	SENCA8890	2017	2017-01-03 09:48:00	2017-01-03 11:57:00	2	258	INTENTIONAL	Non-storm
T17010300098	FAWN8799	2017	2017-01-03 10:28:00	2017-01-03 11:03:00	3	180	EQUIPMENT FAILURE	Non-storm
D17010300098	GDRIV0495	2017	2017-01-03 10:05:00	2017-01-03 16:50:00	1	405	METER / BLOCKS	Non-storm
W17010300073	VENOY9383	2017	2017-01-03 10:31:00	2017-01-03 12:08:00	1	97	UNKNOWN	Non-storm
N17010300266	DISCO8090	2017	2017-01-03 10:35:00	2017-01-03 11:21:00	10	460	EQUIPMENT FAILURE	Non-storm
W17010300076	ALNPK1916	2017	2017-01-03 10:37:00	2017-01-03 13:17:00	1	160	UNKNOWN	Non-storm
N17010300270	WOLFH8838	2017	2017-01-03 10:48:00	2017-01-03 11:30:00	1	42	UNKNOWN	Non-storm
T17010300105	BISHP1755	2017	2017-01-03 10:50:00	2017-01-03 12:31:00	1	101	UNKNOWN	Non-storm
D17010300130	FERND2713	2017	2017-01-03 10:53:00	2017-01-03 12:52:00	7	225	INTENTIONAL	Non-storm
T17010300128	BERND0341	2017	2017-01-03 11:12:00	2017-01-03 13:59:00	1	167	UNKNOWN	Non-storm
D17010300139	PURTN1307	2017	2017-01-03 11:17:00	2017-01-03 13:00:00	1	103	METER / BLOCKS	Non-storm
N17010300278	LILY9126	2017	2017-01-03 11:24:00	2017-01-03 13:59:00	1	155	EQUIPMENT FAILURE	Non-storm
W17010300097	HAMBG9968	2017	2017-01-03 12:07:00	2017-01-03 12:21:00	307	4298	TREE	Non-storm
D17010300156	WAGNR1350	2017	2017-01-03 12:12:00	2017-01-03 13:30:00	1	78	METER / BLOCKS	Non-storm
T17010300179	STRFO9142	2017	2017-01-03 12:23:00	2017-01-03 13:31:00	9	612	TREE	Non-storm
T17010300180	IRA0311	2017	2017-01-03 12:26:00	2017-01-03 14:30:00	1	124	INTENTIONAL	Non-storm
D17010300123	STOPL2231	2017	2017-01-03 12:41:00	2017-01-03 18:30:00	1	349	EQUIPMENT FAILURE	Non-storm
T17010300187	CLIFF0302	2017	2017-01-03 12:41:00	2017-01-03 19:11:00	1	390	EQUIPMENT FAILURE	Non-storm
W17010300106	HEMLK1958	2017	2017-01-03 12:45:00	2017-01-03 13:59:00	12	888	INTENTIONAL	Non-storm
T17010300200	BUNRT1658	2017	2017-01-03 13:08:00	2017-01-03 18:05:00	1	297	UNKNOWN	Non-storm
D17010300194	APPOL1270	2017	2017-01-03 13:17:00	2017-01-03 16:00:00	1	163	THEFT	Non-storm
D17010300198	KENEY2697	2017	2017-01-03 13:25:00	2017-01-03 17:48:00	1	263	TREE	Non-storm
D17010300205	EVRGN2134	2017	2017-01-03 13:43:00	2017-01-03 16:45:00	1	182	UNKNOWN	Non-storm
T17010300212	BREWR9229	2017	2017-01-03 13:49:00	2017-01-03 14:00:00	2	22	INTENTIONAL	Non-storm
T17010300213	BREWR9229	2017	2017-01-03 13:49:00	2017-01-03 14:00:00	5	55	INTENTIONAL	Non-storm
T17010300214	BREWR9229	2017	2017-01-03 13:52:00	2017-01-03 14:01:00	1	9	INTENTIONAL	Non-storm
D17010300209	ANGLA9060	2017	2017-01-03 14:01:00	2017-01-03 17:42:00	1	221	UNKNOWN	Non-storm
T17010300115	NRBRN8808	2017	2017-01-03 14:01:00	2017-01-03 14:37:00	519	18684	TREE	Non-storm
T17010300222	BENSN8407	2017	2017-01-03 14:09:00	2017-01-03 15:34:00	9	765	EQUIPMENT FAILURE	Non-storm
D17010300215	VERNR2051	2017	2017-01-03 14:12:00	2017-01-03 15:59:00	1	107	EQUIPMENT FAILURE	Non-storm
D17010300218	EVRGN2134	2017	2017-01-03 14:15:00	2017-01-03 15:20:00	14	910	EQUIPMENT FAILURE	Non-storm
T17010300223	NEAST8500	2017	2017-01-03 14:25:00	2017-01-03 15:54:00	27	2403	ANIMAL	Non-storm
W17010300138	PAUL0351	2017	2017-01-03 14:34:00	2017-01-03 15:21:00	16	752	INTENTIONAL	Non-storm
N17010300300	CODY9542	2017	2017-01-03 14:37:00	2017-01-03 16:24:00	1	107	PUBLIC INTEFERENCE	Non-storm
D17010300235	CHANO2047	2017	2017-01-03 14:38:00	2017-01-03 15:32:00	1	54	EQUIPMENT FAILURE	Non-storm
T17010300207	CASVL8805	2017	2017-01-03 14:39:00	2017-01-03 16:21:00	159	16218	INTENTIONAL	Non-storm
D17010300244	GRANT2195	2017	2017-01-03 14:55:00	2017-01-03 16:05:00	1	70	TREE	Non-storm
T17010300236	QUAIL0312	2017	2017-01-03 15:07:00	2017-01-03 18:04:00	14	2478	INTENTIONAL	Non-storm
W17010300151	SOFLD9082	2017	2017-01-03 15:10:00	2017-01-03 15:38:00	7	196	INTENTIONAL	Non-storm
W17010300147	DIMND9875	2017	2017-01-03 15:12:00	2017-01-03 21:30:00	1	366	EQUIPMENT FAILURE	Non-storm
D17010300257	FRISB2117	2017	2017-01-03 15:35:00	2017-01-03 19:22:00	1	227	EQUIPMENT FAILURE	Non-storm
T17010300244	MARLT8281	2017	2017-01-03 15:45:00	2017-01-03 19:29:00	1	224	EQUIPMENT FAILURE	Non-storm
W17010300155	MALRD9387	2017	2017-01-03 15:45:00	2017-01-03 17:39:00	1	114	TREE	Non-storm
W17010300115	SOFLD9082	2017	2017-01-03 16:10:50	2017-01-03 19:38:50	1	208	UNKNOWN	Non-storm
W17010300111	SOFLD9082	2017	2017-01-03 16:10:55	2017-01-03 19:23:55	1	193	INTENTIONAL	Non-storm
T17010300251	BRAZL8402	2017	2017-01-03 16:33:00	2017-01-03 18:00:00	1	87	EQUIPMENT FAILURE	Non-storm
T17010300253	CASVL8805	2017	2017-01-03 16:41:00	2017-01-03 18:04:00	702	58266	TREE	Non-storm
D17010300277	LAUDR1400	2017	2017-01-03 16:42:00	2017-01-03 18:30:00	1	108	EQUIPMENT FAILURE	Non-storm
N17010300316	PINCK9878	2017	2017-01-03 16:42:00	2017-01-03 18:49:00	1	127	UNKNOWN	Non-storm
D17010300279	SIXMI1251	2017	2017-01-03 16:49:00	2017-01-03 20:11:00	1	202	UNKNOWN	Non-storm
N17010300319	CATLI9136	2017	2017-01-03 16:59:00	2017-01-03 19:00:00	1	121	UNKNOWN	Non-storm
D17010300297	EMPIR1224	2017	2017-01-03 17:39:00	2017-01-03 20:35:00	1	176	EQUIPMENT FAILURE	Non-storm
D17010300303	EVRGN1783	2017	2017-01-03 17:43:00	2017-01-03 20:13:00	1	150	EQUIPMENT FAILURE	Non-storm
T17010300300	ANDER0312	2017	2017-01-03 17:48:00	2017-01-04 00:07:00	112	42448	TREE	Non-storm
T17010300291	STEPH8522	2017	2017-01-03 18:00:00	2017-01-04 01:32:00	1	452	EQUIPMENT FAILURE	Non-storm
T17010300296	VICTR8699	2017	2017-01-03 18:29:00	2017-01-03 22:30:00	1	241	EQUIPMENT FAILURE	Non-storm
W17010300153	EMRCK2926	2017	2017-01-03 18:34:00	2017-01-03 18:42:00	1	8	EQUIPMENT FAILURE	Non-storm
D17010300306	OUTDR2032	2017	2017-01-03 18:37:00	2017-01-03 19:29:00	1	52	EQUIPMENT FAILURE	Non-storm
T17010300303	DERBY2635	2017	2017-01-03 19:02:00	2017-01-03 22:10:00	1	188	EQUIPMENT FAILURE	Non-storm
T17010300304	ROSVL0310	2017	2017-01-03 19:11:00	2017-01-03 21:09:00	1	118	CUSTOMER EQUIPMENT	Non-storm
T17010300307	BOYNE8739	2017	2017-01-03 19:29:00	2017-01-04 03:24:00	1	475	EQUIPMENT FAILURE	Non-storm
T17010300315	CENTR2440	2017	2017-01-03 20:13:00	2017-01-03 22:12:00	4	476	EQUIPMENT FAILURE	Non-storm
T17010300314	NEAST8500	2017	2017-01-03 20:17:00	2017-01-03 22:12:00	11	1265	EQUIPMENT FAILURE	Non-storm
D17010300316	CHIGO1584	2017	2017-01-03 21:11:00	2017-01-03 23:14:00	1	123	EQUIPMENT FAILURE	Non-storm
N17010300327	CLYDE8910	2017	2017-01-03 21:59:00	2017-01-04 01:18:00	1	199	METER / BLOCKS	Non-storm
T17010300274	ANDER0312	2017	2017-01-03 22:22:00	2017-01-04 00:07:00	113	11865	TREE	Non-storm
D17010300305	WDSID1234	2017	2017-01-03 22:30:52	2017-01-04 03:36:52	1	306	METER / BLOCKS	Non-storm
N17010300329	BISMR8414	2017	2017-01-03 23:55:00	2017-01-04 00:29:00	1	94	EQUIPMENT FAILURE	Non-storm
T17010300322	TCOLA8766	2017	2017-01-03 23:06:00	2017-01-04 01:25:00	7	973	PUBLIC INTEFERENCE	Non-storm
W17010400002	YPSIL0318	2017	2017-01-04 00:28:00	2017-01-04 00:49:00	15	315	TREE	Non-storm
W17010400003	YPSIL0318	2017	2017-01-04 00:37:00	2017-01-04 02:22:00	1	105	WIND	Non-storm
N17010400002	NOLAN9790	2017	2017-01-04 02:35:00	2017-01-04 03:12:00	9	333	TREE	Non-storm
N17010400006	BONDB058	2017	2017-01-04 03:30:00	2017-01-04 04:50:00	3	240	TREE	Non-storm
D17010400005	BLAIR0328	2017	2017-01-04 03:38:00	2017-01-05 04:17:00	11	6554	TREE	Non-storm
N17010400008	KELOG8121	2017	2017-01-04 03:42:00	2017-01-04 06:19:00	1	157	EQUIPMENT FAILURE	Non-storm
D17010400004	BLAIR0328	2017	2017-01-04 03:51:00	2017-01-04 17:30:00	14	4018	TREE	Non-storm
T17010400007	BENSN8720	2017	2017-01-04 04:01:00	2017-01-04 05:49:00	11	1188	EQUIPMENT FAILURE	Non-storm
N17010400012	CLYDE8910	2017	2017-01-04 04:03:00	2017-01-04 09:08:00	15	4575	WIND	Non-storm
W17010400006	POPLR9885	2017	2017-01-04 04:07:00	2017-01-04 12:08:00	3	1443	TREE	Non-storm
N17010400010	PINCK9886	2017	2017-01-04 04:17:00	2017-01-04 05:33:00	162	12312	EQUIPMENT FAILURE	Non-storm
D17010400009	PULFD0416	2017	2017-01-04 04:35:00	2017-01-04 06:20:00	1	105	EQUIPMENT FAILURE	Non-storm
W17010400007	MILAN9902	2017	2017-01-04 04:53:00	2017-01-04 08:43:00	8	1840	EQUIPMENT FAILURE	Non-storm
T17010400009	OTSGO8762	2017	2017-01-04 05:25:00	2017-01-04 11:04:00	80	27120	TREE	Non-storm
N17010400031	GRFIN9883	2017	2017-01-04 05:40:00	2017-01-04 11:14:00	1	334	EQUIPMENT FAILURE	Non-storm
N17010400033	WRNSI1869	2017	2017-01-04 05:43:00	2017-01-04 08:10:00	91	13377	TREE	Non-storm
W17010400071	SHERW0322	2017	2017-01-04 05:56:00	2017-01-04 10:51:00	74	21830	TREE	Non-storm
W17010400044	HEMLK1910	2017	2017-01-04 06:03:00	2017-01-04 08:48:00	147	24255	WIND	Non-storm
T17010400028	LAPER8793	2017	2017-01-04 06:09:00	2017-01-04 09:43:00	318	68052	TREE	Non-storm
W17010400061	HEMLK1910	2017	2017-01-04 06:10:00	2017-01-04 08:48:00	1	158	EQUIPMENT FAILURE	Non-storm
T17010400034	CYPRS8754	2017	2017-01-04 06:17:00	2017-01-04 08:05:00	202	21816	TREE	Non-storm
N17010400039	GENOA9806	2017	2017-01-04 06:19:00	2017-01-04 16:32:00	1	613	WIND	Non-storm
W17010400088	MOTTF9783	2017	2017-01-04 06:20:00	2017-01-04 08:12:00	65	7280	EQUIPMENT FAILURE	Non-storm
W17010400118	RENO2927	2017	2017-01-04 06:55:00	2017-01-04 12:27:00	7	2324	EQUIPMENT FAILURE	Non-storm
W17010400131	SHERW0322	2017	2017-01-04 06:56:28	2017-01-04 10:52:28	1	236	UNKNOWN	Non-storm
W17010400110	SWANC9408	2017	2017-01-04 07:01:00	2017-01-04 08:22:00	91	7371	EQUIPMENT FAILURE	Non-storm
W17010400123	MDBLT2014	2017	2017-01-04 07:15:00	2017-01-04 08:30:00	15	1125	EQUIPMENT FAILURE	Non-storm
W17010400124	MAYBE0313	2017	2017-01-04 07:22:00	2017-01-04 10:47:00	1	205	WIND	Non-storm
T17010400046	ATICA0302	2017	2017-01-04 07:30:00	2017-01-04 16:13:00	20	10460	TREE	Non-storm
N17010400052	MILFD9249	2017	2017-01-04 07:42:00	2017-01-04 14:19:00	1	397	TREE	Non-storm
D17010400023	OHIO1528	2017	2017-01-04 07:47:00	2017-01-04 13:49:00	353	127786	TREE	Non-storm
D17010400086	OHIO1528	2017	2017-01-04 07:47:00	2017-01-04 17:29:00	49	28518	TREE	Non-storm
N17010400053	SPKNE8825	2017	2017-01-04 07:47:00	2017-01-04 10:32:00	1	165	UNKNOWN	Non-storm
D17010400027	MEYRS1656	2017	2017-01-04 07:52:00	2017-01-04 12:32:00	1	280	UNKNOWN	Non-storm
W17010400143	MERRD1879	2017	2017-01-04 08:06:00	2017-01-04 12:57:00	1	291	TREE	Non-storm
W17010400144	SALIN9867	2017	2017-01-04 08:07:00	2017-01-04 10:31:00	10	1440	TREE	Non-storm
W17010400148	MERRD1879	2017	2017-01-04 08:20:00	2017-01-04 12:57:00	1	277	UNKNOWN	Non-storm
N17010400058	HAMBG9943	2017	2017-01-04 08:31:00	2017-01-04 10:35:00	101	12524	TREE	Non-storm
T17010400074	BAKER0206	2017	2017-01-04 08:31:00	2017-01-04 10:57:00	13	1898	WIND	Non-storm
T17010400061	BRSLK0302	2017	2017-01-04 08:38:00	2017-01-04 10:57:00	31	4309	WIND	Non-storm
D17010400067	GNSTN0444	2017	2017-01-04 08:43:00	2017-01-04 09:17:00	1	34	TREE	Non-storm
N17010400068	SPKNE8842	2017	2017-01-04 08:43:00	2017-01-04 11:04:00	1	141	EQUIPMENT FAILURE	Non-storm
T17010400080	CYPRS8754	2017	2017-01-04 08:45:00	2017-01-04 09:11:00	134	3484	TREE	Non-storm
W17010400191	DUVAL9518	2017	2017-01-04 08:46:00	2017-01-04 12:59:00	161	40733	TREE	Non-storm
T17010400066	LAPER8765	2017	2017-01-04 08:47:00	2017-01-04 14:02:00	1	315	EQUIPMENT FAILURE	Non-storm
T17010400067	BAKER2597	2017	2017-01-04 08:48:00	2017-01-04 10:58:00	11	1430	WIND	Non-storm
W17010400183	RAISN0305	2017	2017-01-04 08:50:00	2017-01-04 10:32:00	50	5100	TREE	Non-storm
N17010400062	WOLFH8838	2017	2017-01-04 08:53:00	2017-01-04 12:15:00	1	202	EQUIPMENT FAILURE	Non-storm
D17010400084	PULFD2224	2017	2017-01-04 08:56:00	2017-01-04 10:32:00	1	96	UNKNOWN	Non-storm
D17010400099	GRANT2195	2017	2017-01-04 08:59:00	2017-01-04 11:29:00	2	300	WIND	Non-storm
W17010400189	KOPNK9437	2017	2017-01-04 09:01:00	2017-01-04 10:28:00	1	87	UNKNOWN	Non-storm
W17010400065	SHERW0321	2017	2017-01-04 09:04:00	2017-01-04 10:50:00	467	49502	TREE	Non-storm
Z17010400071	SHERW0322	2017	2017-01-04 09:04:00	2017-01-04 10:52:00	611	65988	TREE	Non-storm
T17010400380	MENLO8815	2017	2017-01-04 09:06:00	2017-01-04 20:27:00	2	1362	TREE	Non-storm
D17010400094	SIXMI2173	2017	2017-01-04 09:09:00	2017-01-04 17:19:00	1	490	EQUIPMENT FAILURE	Non-storm
W17010400220	SHERW0322	2017	2017-01-04 09:11:00	2017-01-04 12:39:00	1	208	EQUIPMENT FAILURE	Non-storm
W17010400225	MILAN9902	2017	2017-01-04 09:13:00	2017-01-04 10:53:00	1	100	WIND	Non-storm
W17010400060	PINCK9886	2017	2017-01-04 09:15:00	2017-01-04 09:35:00	12	240	INTENTIONAL	Non-storm
D17010400112	LINWD1106	2017	2017-01-04 09:20:00	2017-01-04 12:02:00	16	2592	TREE	Non-storm
N17010400074	GENOA9806	2017	2017-01-04 09:20:00	2017-01-04 15:01:00	1	341	EQUIPMENT FAILURE	Non-storm
N17010400077	LARDO8946	2017	2017-01-04 09:22:00	2017-01-04 11:30:00	2	256	INTENTIONAL	Non-storm
W17010400230	FRMTN1717	2017	2017-01-04 09:24:00	2017-01-04 13:01:00	1	217	UNKNOWN	Non-storm
W17010400231	SUMTR9498	2017	2017-01-04 09:24:00	2017-01-04 10:53:00	1	89	UNKNOWN	Non-storm
N17010400078	WRNSI1869	2017	2017-01-04 09:30:00	2017-01-04 13:07:00	203	44051	TREE	Non-storm
W17010400160	DUVAL9518	2017	2017-01-04 09:34:00	2017-01-04 12:59:00	66	13530	TREE	Non-storm
W17010400237	POPLR9885	2017	2017-01-04 09:34:00	2017-01-04 14:07:00	60	16380	TREE	Non-storm
T17010400104	SEBEW0312	2017	2017-01-04 09:35:00	2017-01-04 14:00:00	1	265	EQUIPMENT FAILURE	Non-storm
D17010400117	FLANE1839	2017	2017-01-04 09:37:00	2017-01-04 13:34:00	1	237	TREE	Non-storm
D17010400118	GDRIV2074	2017	2017-01-04 09:38:00	2017-01-04 09:56:00	1	18	CUSTOMER EQUIPMENT	Non-storm
D17010400146	ANGLA8862	2017	2017-01-04 09:45:00	2017-01-04 14:03:00	2	516	TREE	Non-storm
N17010400088	HURST9842	2017	2017-01-04 09:49:00	2017-01-04 11:14:00	10	850	TREE	Non-storm
T17010400117	HOSTN8746	2017	2017-01-04 09:51:00	2017-01-04 18:29:00	1	518	OTHER	Non-storm
N17010400086	WLNUT9029	2017	2017-01-04 09:54:00	2017-01-04 10:47:00	1	53	OTHER UTILITY EQUIP	Non-storm
W17010400247	WAYNE9435	2017	2017-01-04 09:59:00	2017-01-04 12:01:00	138	16836	EQUIPMENT FAILURE	Non-storm
W17010400251	WAYNE9435	2017	2017-01-04 09:59:00	2017-01-04 12:01:00	3	366	EQUIPMENT FAILURE	Non-storm

U-21534 MNSCDE-3.1-01 Outages 2017-2023

W17010400252	MOTT9789	2017	2017-01-04 10:00:00	2017-01-04 12:46:00	12	1992	TREE	Non-storm
W17010400305	SHERW0321	2017	2017-01-04 10:04:02	2017-01-04 12:21:02	1	137	TREE	Non-storm
W17010400260	MACON8049	2017	2017-01-04 10:08:00	2017-01-04 12:52:00	9	1476	EQUIPMENT FAILURE	Non-storm
N17010400106	WHMLK8080	2017	2017-01-04 10:09:00	2017-01-04 10:35:00	1	26	WIND	Non-storm
N17010400095	WMSTN8033	2017	2017-01-04 10:18:00	2017-01-04 12:23:00	86	10750	TREE	Non-storm
D17010400218	GRANT2195	2017	2017-01-04 10:30:00	2017-01-04 10:45:00	3	45	TREE	Non-storm
W17010400265	WAYNE9435	2017	2017-01-04 10:32:00	2017-01-04 12:01:00	6	534	WIND	Non-storm
N17010400099	ALPNE8916	2017	2017-01-04 10:33:00	2017-01-04 18:12:00	1	459	EQUIPMENT FAILURE	Non-storm
W17010400268	WAYNE9435	2017	2017-01-04 10:38:00	2017-01-04 12:05:00	1	87	EQUIPMENT FAILURE	Non-storm
N17010400102	STERL8061	2017	2017-01-04 10:45:00	2017-01-04 12:56:00	1	131	UNKNOWN	Non-storm
T17010400146	MENLO8815	2017	2017-01-04 10:48:00	2017-01-04 13:17:00	47	7003	TREE	Non-storm
N17010400104	COATS8039	2017	2017-01-04 10:50:00	2017-01-04 12:16:00	6	516	TREE	Non-storm
D17010400177	SCOTN2042	2017	2017-01-04 10:55:00	2017-01-04 12:50:00	1	115	EQUIPMENT FAILURE	Non-storm
T17010400179	KILGR8772	2017	2017-01-04 10:55:00	2017-01-04 15:23:00	167	44756	TREE	Non-storm
T17010400154	LAKPT2624	2017	2017-01-04 10:59:00	2017-01-04 18:27:00	6	2688	TREE	Non-storm
W17010400271	WAYNE9435	2017	2017-01-04 10:59:46	2017-01-04 14:02:46	1	183	UNKNOWN	Non-storm
T17010400159	TLBOT8051	2017	2017-01-04 11:01:00	2017-01-04 14:59:00	1	238	EQUIPMENT FAILURE	Non-storm
D17010400183	STLUS1206	2017	2017-01-04 11:02:00	2017-01-04 12:09:00	1	67	UNKNOWN	Non-storm
D17010400184	GDRIV2199	2017	2017-01-04 11:03:00	2017-01-04 12:30:00	1	87	TREE	Non-storm
W17010400288	DAYTN9466	2017	2017-01-04 11:05:00	2017-01-04 14:30:00	13	2665	TREE	Non-storm
N17010400115	CODY9537	2017	2017-01-04 11:12:00	2017-01-04 12:12:00	22	1320	ANIMAL	Non-storm
T17010400166	OTSGO8762	2017	2017-01-04 11:12:00	2017-01-04 13:00:00	1	108	OTHER	Non-storm
W17010400295	VENOY9349	2017	2017-01-04 11:30:00	2017-01-04 13:35:00	1	125	UNKNOWN	Non-storm
W17010400301	BIDLE9358	2017	2017-01-04 11:43:00	2017-01-04 12:45:00	1	62	WIND	Non-storm
D17010400232	VILLA1553	2017	2017-01-04 11:48:00	2017-01-04 17:33:00	1	345	OTHER UTILITY EQUIP	Non-storm
D17010400234	GARY1729	2017	2017-01-04 11:49:00	2017-01-04 18:29:00	4	1600	TREE	Non-storm
T17010400206	SANDU8238	2017	2017-01-04 11:49:00	2017-01-04 20:18:00	1	509	UNKNOWN	Non-storm
D17010400242	CHAND1100	2017	2017-01-04 11:51:00	2017-01-04 13:19:00	8	704	EQUIPMENT FAILURE	Non-storm
N17010400138	FLINT9784	2017	2017-01-04 12:02:00	2017-01-04 14:14:00	1	132	WIND	Non-storm
W17010400313	BLCRK9330	2017	2017-01-04 12:04:00	2017-01-04 14:54:00	1	170	WIND	Non-storm
D17010400248	WAYBN2136	2017	2017-01-04 12:09:00	2017-01-04 13:48:00	1	99	TREE	Non-storm
T17010400097	YALE2633	2017	2017-01-04 12:09:00	2017-01-04 13:10:00	31	1891	WIND	Non-storm
N17010400139	WMSTN9856	2017	2017-01-04 12:21:00	2017-01-04 16:17:00	4	944	TREE	Non-storm
W17010400327	BELVL1698	2017	2017-01-04 12:26:00	2017-01-04 14:30:00	1	124	METER / BLOCKS	Non-storm
W17010400323	SHERW0322	2017	2017-01-04 12:29:00	2017-01-04 20:10:00	17	2417	TREE	Non-storm
T17010400230	NRBRN2606	2017	2017-01-04 12:33:00	2017-01-04 14:28:00	2	230	TREE	Non-storm
T17010400231	NRBRN2606	2017	2017-01-04 12:33:00	2017-01-04 14:28:00	6	690	TREE	Non-storm
D17010400268	ANNCH1003	2017	2017-01-04 12:36:00	2017-01-04 19:17:00	1	401	LOADING	Non-storm
T17010400233	PRKRD8757	2017	2017-01-04 12:50:00	2017-01-04 22:41:00	1	591	EQUIPMENT FAILURE	Non-storm
N17010400145	HANCK8142	2017	2017-01-04 12:59:00	2017-01-04 18:30:00	1	331	TREE	Non-storm
T17010400237	BREWR8840	2017	2017-01-04 13:02:00	2017-01-04 20:07:00	1	425	EQUIPMENT FAILURE	Non-storm
D17010400137	STLUS1394	2017	2017-01-04 13:04:00	2017-01-04 17:05:00	1	241	TREE	Non-storm
W17010400286	NVILL9336	2017	2017-01-04 13:04:06	2017-01-04 17:01:06	1	237	OTHER	Non-storm
N17010400146	BOND8058	2017	2017-01-04 13:05:00	2017-01-04 20:00:00	1	415	EQUIPMENT FAILURE	Non-storm
T17010400249	VICTR8699	2017	2017-01-04 13:17:00	2017-01-04 15:13:00	81	9396	EQUIPMENT FAILURE	Non-storm
D17010400287	PATON8847	2017	2017-01-04 13:22:00	2017-01-04 15:16:00	1	114	TREE	Non-storm
D17010400288	VILLA1555	2017	2017-01-04 13:24:00	2017-01-04 20:35:00	1	431	UNKNOWN	Non-storm
T17010400263	ROBIN9309	2017	2017-01-04 13:29:00	2017-01-04 16:06:00	96	15072	EQUIPMENT FAILURE	Non-storm
W17010400363	PIONR9795	2017	2017-01-04 13:31:00	2017-01-04 15:08:00	462	44814	EQUIPMENT FAILURE	Non-storm
T17010400264	OTSGO8762	2017	2017-01-04 13:32:00	2017-01-04 13:54:00	1	22	UNKNOWN	Non-storm
D17010400300	LINWD2142	2017	2017-01-04 13:37:00	2017-01-04 14:31:00	1	54	METER / BLOCKS	Non-storm
W17010400270	SYRAC1902	2017	2017-01-04 13:39:46	2017-01-04 16:58:46	1	199	UNKNOWN	Non-storm
T17010400294	ASPEN8811	2017	2017-01-04 13:48:00	2017-01-04 17:10:00	1	202	EQUIPMENT FAILURE	Non-storm
T17010400296	OTSGO8762	2017	2017-01-04 13:51:00	2017-01-04 14:59:00	1	68	UNKNOWN	Non-storm
W17010400396	MERRD1866	2017	2017-01-04 13:55:00	2017-01-04 16:29:00	1	154	EQUIPMENT FAILURE	Non-storm
T17010400156	CAPAC8013	2017	2017-01-04 14:10:00	2017-01-04 14:39:00	73	2117	EQUIPMENT FAILURE	Non-storm
D17010400331	CRTIS2098	2017	2017-01-04 14:12:00	2017-01-04 18:29:00	5	1285	TREE	Non-storm
D17010400332	CRTIS2098	2017	2017-01-04 14:13:00	2017-01-04 18:29:00	1	256	TREE	Non-storm
W17010400409	FLAG1680	2017	2017-01-04 14:14:00	2017-01-04 18:08:00	1	234	EQUIPMENT FAILURE	Non-storm
N17010400162	PINCK9886	2017	2017-01-04 14:18:00	2017-01-04 16:21:00	2	246	EQUIPMENT FAILURE	Non-storm
N17010400163	PINCK9886	2017	2017-01-04 14:18:00	2017-01-04 16:28:00	3	390	EQUIPMENT FAILURE	Non-storm
N17010400166	PINCK9886	2017	2017-01-04 14:18:00	2017-01-04 16:21:00	4	492	WIND	Non-storm
N17010400167	PINCK9886	2017	2017-01-04 14:18:00	2017-01-04 16:28:00	3	390	EQUIPMENT FAILURE	Non-storm
W17010400410	NVILL9336	2017	2017-01-04 14:19:00	2017-01-04 14:40:00	11	231	TREE	Non-storm
W17010400415	SYRAC1902	2017	2017-01-04 14:28:00	2017-01-04 16:29:00	1	121	CUSTOMER EQUIPMENT	Non-storm
N17010400171	GODSN8134	2017	2017-01-04 14:38:00	2017-01-04 15:28:00	2	100	TREE	Non-storm
W17010400417	DUBLN8205	2017	2017-01-04 14:39:00	2017-01-04 16:14:00	1	95	TREE	Non-storm
W17010400424	MACON8049	2017	2017-01-04 14:51:00	2017-01-04 19:07:00	1	256	EQUIPMENT FAILURE	Non-storm
D17010400369	GARY1858	2017	2017-01-04 15:04:00	2017-01-04 18:13:00	2	378	TREE	Non-storm
N17010400180	BISMK8458	2017	2017-01-04 15:08:00	2017-01-04 16:31:00	10	830	EQUIPMENT FAILURE	Non-storm
T17010400338	OTSGO8762	2017	2017-01-04 15:14:00	2017-01-04 16:03:00	1	49	OTHER	Non-storm
D17010400130	LINCN0356	2017	2017-01-04 15:14:39	2017-01-04 15:32:39	1	18	UNKNOWN	Non-storm
T17010400339	CAPAC8013	2017	2017-01-04 15:16:00	2017-01-04 20:06:00	1	290	EQUIPMENT FAILURE	Non-storm
Z17010400263	ROBIN9309	2017	2017-01-04 15:16:00	2017-01-04 16:06:00	505	25250	EQUIPMENT FAILURE	Non-storm
W17010400441	QUEEN0335	2017	2017-01-04 15:25:00	2017-01-04 16:54:00	1	89	EQUIPMENT FAILURE	Non-storm
D17010400394	GARY1376	2017	2017-01-04 15:28:00	2017-01-04 18:12:00	13	2132	TREE	Non-storm
D17010400395	REDFD1240	2017	2017-01-04 15:28:00	2017-01-04 17:06:00	1	98	UNKNOWN	Non-storm
T17010400267	MENLO8768	2017	2017-01-04 15:30:00	2017-01-04 19:00:00	29	6090	UNKNOWN	Non-storm
D17010400400	GARY1376	2017	2017-01-04 15:32:00	2017-01-04 18:13:00	1	161	WIND	Non-storm
D17010400403	EVRGN1925	2017	2017-01-04 15:33:00	2017-01-05 04:00:00	1	747	THEFT	Non-storm
T17010400367	LAPER8788	2017	2017-01-04 15:33:00	2017-01-04 21:31:00	1	358	UNKNOWN	Non-storm
D17010400404	GDRIV2199	2017	2017-01-04 15:39:00	2017-01-04 16:35:00	1	56	EQUIPMENT FAILURE	Non-storm
D17010400406	PULFD2224	2017	2017-01-04 15:42:00	2017-01-04 18:02:00	1	140	UNKNOWN	Non-storm
D17010400407	CRTIS1343	2017	2017-01-04 15:43:00	2017-01-04 21:33:00	1	350	WIND	Non-storm
W17010400446	DAYTN9466	2017	2017-01-04 15:46:00	2017-01-04 16:26:00	43	1720	EQUIPMENT FAILURE	Non-storm
Z17010400363	PIONR9795	2017	2017-01-04 15:47:00	2017-01-04 16:58:00	267	18957	EQUIPMENT FAILURE	Non-storm
D17010400412	CHAND1213	2017	2017-01-04 15:49:00	2017-01-04 16:45:00	1	56	WIND	Non-storm
N17010400190	UTICA2411	2017	2017-01-04 15:51:00	2017-01-04 17:42:00	1	111	EQUIPMENT FAILURE	Non-storm
D17010400416	DENVR1462	2017	2017-01-04 15:56:00	2017-01-04 17:26:00	1	90	TREE	Non-storm
T17010400387	OTTER0301	2017	2017-01-04 15:57:00	2017-01-04 19:14:00	1	197	OTHER	Non-storm
T17010400375	HOSTN8746	2017	2017-01-04 15:58:00	2017-01-04 18:29:00	4	604	EQUIPMENT FAILURE	Non-storm
D17010400423	TIRMN1368	2017	2017-01-04 16:00:00	2017-01-05 14:15:00	1	1335	METER / BLOCKS	Non-storm
N17010400192	BOND8058	2017	2017-01-04 16:08:00	2017-01-04 19:59:00	1	231	EQUIPMENT FAILURE	Non-storm
W17010400461	MALRD9375	2017	2017-01-04 16:08:00	2017-01-04 18:26:00	1	138	UNKNOWN	Non-storm
D17010400246	OAKPK2663	2017	2017-01-04 16:11:20	2017-01-04 18:53:20	1	162	EQUIPMENT FAILURE	Non-storm
D17010400449	INDIN1014	2017	2017-01-04 16:31:00	2017-01-04 18:35:00	1	124	EQUIPMENT FAILURE	Non-storm
T17010400392	CENTR1818	2017	2017-01-04 16:32:00	2017-01-04 20:04:00	419	39290	EQUIPMENT FAILURE	Non-storm
W17010400470	ELM9448	2017	2017-01-04 16:32:00	2017-01-04 19:40:00	15	2820	EQUIPMENT FAILURE	Non-storm
T17010400396	CENTR1818	2017	2017-01-04 16:38:00	2017-01-04 18:04:00	1	86	UNKNOWN	Non-storm
D17010400454	APPOL1346	2017	2017-01-04 16:40:00	2017-01-05 00:50:00	1	490	TREE	Non-storm
T17010400401	NEFF0314	2017	2017-01-04 16:43:00	2017-01-04 23:20:00	119	47243	OTHER	Non-storm
D17010400154	LAKPT2624	2017	2017-01-04 17:01:00	2017-01-04 18:27:00	7	602	TREE	Non-storm
W17010400475	SHERW0322	2017	2017-01-04 17:06:00	2017-01-04 17:59:00	1	53	CUSTOMER EQUIPMENT	Non-storm
W17010400478	SHERW0322	2017	2017-01-04 17:18:00	2017-01-04 18:00:00	1	42	EQUIPMENT FAILURE	Non-storm
T17010400424	SAVOY8711	2017	2017-01-04 17:20:00	2017-01-04 19:09:00	17	1853	EQUIPMENT FAILURE	Non-storm
N17010400208	PINCK9886	2017	2017-01-04 17:22:00	2017-01-04 18:12:00	1	50	UNKNOWN	Non-storm
N17010400209	WMSTN9857	2017	2017-01-04 17:22:00	2017-01-04 19:44:00	1	142	EQUIPMENT FAILURE	Non-storm
D17010400475	DENVR1462	2017	2017-01-04 17:25:00	2017-01-04 18:17:00	45	2340	TREE	Non-storm
D17010400473	MLVDL1516	2017	2017-01-04 17:26:00	2017-01-04 19:38:00	1	132	UNKNOWN	Non-storm
D17010400476	GDRIV1182	2017	2017-01-04 17:28:00	2017-01-04 18:34:00	1	66	EQUIPMENT FAILURE	Non-storm
N17010400212	SLOAN9148	2017	2017-01-04 17:28:00	2017-01-04 20:13:00	1	165	EQUIPMENT FAILURE	Non-storm
N17010400217	ALPNE8916	2017	2017-01-04 17:35:00	2017-01-04 18:08:00	2	66	EQUIPMENT FAILURE	Non-storm
W17010400483	HOOVR0365	2017	2017-01-04 17:37:00	2017-01-04 19:44:00	1	127	UNKNOWN	Non-storm
N17010400216	GRAYL8540	2017	2017-01-04 17:42:00	2017-01-04 19:43:00	1	121	EQUIPMENT FAILURE	Non-storm
D17010400320	CRTIS2098	2017	2017-01-04 17:47:00	2017-01-04 18:28:00	30	1230	TREE	Non-storm
T17010400436	ROBIN9309	2017	2017-01-04 17:49:00	2017-01-04 20:45:00	1	176	EQUIPMENT FAILURE	Non-storm
D17010400486	BALFR1207	2017	2017-01-04 18:00:00	2017-01-04 19:05:00	1	65	THEFT	Non-storm
D17010400347	EMPIR1224	2017	2017-01-04 18:03:00	2017-01-05 13:46:00	1	1183	TREE	Non-storm
W17010400469	SHELD8190	2017	2017-01-04 18:08:49	2017-01-04 20:04:49	1	116	EQUIPMENT FAILURE	Non-storm
D17010400482	CRTIS1159	2017	2017-01-04 18:12:00	2017-01-04 18:56:00	1	44	EQUIPMENT FAILURE	Non-storm
N17010400220	HOWEL2934	2017	2017-01-04 18:15:00	2017-01-04 20:40:00	1	145	UNKNOWN	Non-storm
D17010400496	ANNCH1003	2017	2017-01-04 18:44:00	2017-01-04 20:26:00	1	102	UNKNOWN	Non-storm
D17010400497	CRTIS1337	2017	2017-01-04 18:49:00	2017-01-05 00:50:00	1	361	EQUIPMENT FAILURE	Non-storm
W17010400444	CUSTR0006	2017	2017-01-04 18:58:03	2017-01-04 19:38:03	1	40	UNKNOWN	Non-storm
N17010400189	SENCA8890	2017	2017-01-04 19:14:34	2017-01-05 00:08:34	1	294	EQUIPMENT FAILURE	Non-storm
D17010400503	TIRMN1541	2017	2017-01-04 19:17:00	2017-01-05 14:04:00	1	1127	TREE	Non-storm
T17010400451	VICTR8699	2017	2017-01-04 19:17:00	2017-01-04 20:30:00	1	73	WIND	Non-storm
D17010400504	GNSTN1287	2017	2017-01-04 19:22:00	2017-01-04 21:54:00	1	152	PUBLIC INTEFERENCE	Non-storm
D17010400415	ANNCH1003	2017	2017-01-04 19:48:00	2017-01-04 20:25:00	453	16761	INTENTIONAL	Non-storm
T17010400456	REMER8795	2017	2017-01-04 19:51:00	2017-01-04 21:19:00	1	208	UNKNOWN	Non-storm
D17010400514	BALFR2162	2017	2017-01-04 19:59:00	2017-01-04 22:25:00	1	146	TREE	Non-storm
T17010400458	LAKPT2624	2017	2017-01-04 20:02:00	2017-01-04 23:29:00	1	207	WIND	Non-storm
D17010400517	CONAT2235	2017	2017-01-04 20:21:00	2017-01-04 22:30:00	1	129	EQUIPMENT FAILURE	Non-storm
T17010400464	MACMB8506	2017	2017-01-04 20:27:00	2017-01-04 22:52:00	1	145	UNKNOWN	Non-storm
W17010400352	LUZON8097	2017	2017-01-04 20:44:24	2017-01-05 03:09:24	1	385	EQUIPMENT FAILURE	Non-storm
T17010400467	LEXTN8770	2017	2017-01-04 21:00:00	2017-01-04 23:55:00	1	175	UNKNOWN	Non-storm
N17010400207	PROUD9475	2017	2017-01-04 21:40:45	2017-01-05 02:42:45	1	302	UNKNOWN	Non-storm
N17010400232	SPKNE8842	2017	2017-01-04 21:43:29	2017-01-04 23:19:29	1	96	EQUIPMENT FAILURE	Non-storm
W17010400498	HEMLK1958	2017	2017-01-04 21:47:00	2017-01-05 02:02:00	1	255	UNKNOWN	Non-storm
N17010400233	PLACD8917	2017	2017-01-04 21:53:00	2017-01-05 00:06:00	1	133	UNKNOWN	Non-storm
W17010400493	BLCRK9344	2017	2017-01-04 22:07:02	2017-01-05 01:37:02	1	210	EQUIPMENT FAILURE	Non-storm
W17010500001	GAY1791	2017	2017-01-05 00:38:00	2017-01-05 01:26:00	1	48	EQUIPMENT FAILURE	Non-storm
D17010500004	CONAT1269	2017	2017-01-05 01:02:00	2017-01-05 01:59:00	1	57	METER / BLOCKS	Non-storm
D17010500011	PURTN1044	2017	2017-01-05 04:26:00	2017-01-05 10:42:00	1	376	EQUIPMENT FAILURE	Non-storm
T17010500006	HOSTN8746	2017	2017-01-05 04:38:00	2017-01-05 06:42:00	1	124	EQUIPMENT FAILURE	Non-storm
N17010500005	BVRLY0356	2017	2017-01-05 05:57:00	2017-01-05 11:39:00	1	342	METER / BLOCKS	Non-storm
D17010500027	TWEMI1551	2017	2017-01-05 06:24:41	2017-01-05 07:16:41	1	52	UNKNOWN	Non-storm
T17010500012	STRFD9093	2017	2017-01-05 07:17:00	2017-01-05 11:19:00	1	242	EQUIPMENT FAILURE	Non-storm
D17010500018	VENIC2205	2017	2017-01-05 07:29:00	2017-01-05 09:30:00	1	121	TREE	Non-storm
D17010500020	SIXMI2173	2017	2017-01-05 07:46:00	2017-01-05 15:10:00	1	444	THEFT	Non-storm
W17010500008	SUMTR9498	2017	2017-01-05 07:59:00	2017-01-05 09:47:00	1	108	EQUIPMENT FAILURE	Non-storm
T17010500016	CAPAC8756	2017	2017-01-05 08:11:00	2017-01-05 20:24:00	1	733	OTHER	Non-storm
D17010500033	TIRMN2093	2017	2017-01-05 08:30:00	2017-01-05 13:00:00	1	270	TREE	Non-storm
T17010500020	KILGR8772	2017	2017-01-05 08:31:00	2017-01-05 19:49:00	1	678	EQUIPMENT FAILURE	Non-storm

T1703160024	KILGR8772	2017	2017-03-16 07:33:00	2017-03-17 16:31:00	1	1978	UNKNOWN	Storm
N1703160019	WOLFH8822	2017	2017-03-16 07:36:00	2017-03-16 12:30:00	1	294	TREE	Storm
D1703160048	VENIC2013	2017	2017-03-16 07:49:00	2017-03-16 18:36:00	1	647	UNKNOWN	Storm
D1703160049	MLVDL0389	2017	2017-03-16 07:51:00	2017-03-16 11:34:00	1	223	EQUIPMENT FAILURE	Storm
T1703160028	TCOMA8311	2017	2017-03-16 07:53:00	2017-03-16 19:40:00	1	707	EQUIPMENT FAILURE	Storm
N1703160021	STERL8435	2017	2017-03-16 08:00:00	2017-03-16 19:34:00	1	694	UNKNOWN	Storm
D1703160055	CRTIS2098	2017	2017-03-16 08:03:00	2017-03-17 14:00:00	1	1797	TREE	Storm
N1703160024	ALPNE9724	2017	2017-03-16 08:06:00	2017-03-16 14:25:00	1	379	WIND	Storm
W1703160031	BIDLE1616	2017	2017-03-16 08:12:00	2017-03-16 21:10:00	1	778	METER / BLOCKS	Storm
T1703160030	SAVOY8711	2017	2017-03-16 08:17:00	2017-03-16 20:59:00	1	762	WIND	Storm
N1703160027	WATFD2684	2017	2017-03-16 08:23:00	2017-03-17 05:29:00	1	1266	EQUIPMENT FAILURE	Storm
D1703160068	FRMNT1593	2017	2017-03-16 08:28:00	2017-03-17 14:01:00	1	1773	UNKNOWN	Storm
N1703160029	WCHTR1937	2017	2017-03-16 08:30:00	2017-03-16 10:40:00	9	1170	UNKNOWN	Storm
T1703160035	TCOMA8311	2017	2017-03-16 08:31:00	2017-03-17 19:01:00	1	2070	UNKNOWN	Storm
T1703160038	BUNRT8426	2017	2017-03-16 08:32:00	2017-03-16 16:00:00	1	448	EQUIPMENT FAILURE	Storm
W1703160037	BELVL9356	2017	2017-03-16 08:34:00	2017-03-16 17:29:00	1	535	EQUIPMENT FAILURE	Storm
W1703160044	WICK9453	2017	2017-03-16 08:42:00	2017-03-17 01:39:00	1	1017	OTHER	Storm
T1703160043	NEAST8631	2017	2017-03-16 08:43:00	2017-03-16 11:38:00	1	175	UNKNOWN	Storm
D1703160079	REDFD1064	2017	2017-03-16 08:47:00	2017-03-16 13:21:00	1	274	UNKNOWN	Storm
W1703160051	NVILL9461	2017	2017-03-16 08:55:00	2017-03-16 17:25:00	1	510	WIND	Storm
D1703160108	GNSTN1319	2017	2017-03-16 09:14:00	2017-03-16 17:05:00	1	471	UNKNOWN	Storm
D1703160111	HAYES1094	2017	2017-03-16 09:15:00	2017-03-17 14:02:00	1	1727	UNKNOWN	Storm
N1703160052	ADAMS9131	2017	2017-03-16 09:25:00	2017-03-16 11:57:00	1	152	EQUIPMENT FAILURE	Storm
W1703160065	SOFLD9088	2017	2017-03-16 09:30:00	2017-03-16 11:47:00	1	137	WIND	Storm
N1703160056	GRFIN9799	2017	2017-03-16 09:34:00	2017-03-16 23:01:00	1	807	EQUIPMENT FAILURE	Storm
D1703160141	GARFD1132	2017	2017-03-16 09:38:00	2017-03-16 21:09:00	1	691	EQUIPMENT FAILURE	Storm
W1703160021	HINES9416	2017	2017-03-16 09:38:12	2017-03-16 13:17:12	1	219	EQUIPMENT FAILURE	Storm
D1703110911	CONAT1451	2017	2017-03-16 09:41:00	2017-03-16 18:38:00	1	537	WIND	Storm
D1703120583	CONAT2235	2017	2017-03-16 09:41:00	2017-03-16 18:37:00	1	536	UNKNOWN	Storm
D1703150641	CONAT1451	2017	2017-03-16 09:41:00	2017-03-16 18:38:00	1	537	UNKNOWN	Storm
D1703090526	CORTL0472	2017	2017-03-16 09:42:00	2017-03-16 12:22:00	1	160	EQUIPMENT FAILURE	Storm
D1703150227	CONAT2235	2017	2017-03-16 09:42:00	2017-03-16 18:38:00	1	536	UNKNOWN	Storm
D1703150334	CONAT2235	2017	2017-03-16 09:42:00	2017-03-16 18:38:00	1	536	UNKNOWN	Storm
D1703150477	GIBSN1276	2017	2017-03-16 09:43:00	2017-03-16 15:06:00	1	323	UNKNOWN	Storm
N1703160063	ARNLD2731	2017	2017-03-16 09:43:00	2017-03-16 19:30:00	1	587	UNKNOWN	Storm
D1703150755	GIBSN1276	2017	2017-03-16 09:44:00	2017-03-17 14:01:00	1	1697	UNKNOWN	Storm
N1703160023	SENCA8934	2017	2017-03-16 09:46:44	2017-03-16 14:54:44	1	308	UNKNOWN	Storm
N1703160033	SENCA8934	2017	2017-03-16 09:46:45	2017-03-16 14:21:45	1	275	UNKNOWN	Storm
D1703160056	MOUND1453	2017	2017-03-16 09:47:00	2017-03-17 14:01:00	1	1694	EQUIPMENT FAILURE	Storm
D1703160148	EVRGN2134	2017	2017-03-16 09:49:00	2017-03-19 10:07:00	1	4338	TREE	Storm
D1703160149	REDFD1064	2017	2017-03-16 09:49:00	2017-03-17 20:50:00	1	2101	OTHER	Storm
W1703160073	HAGER9425	2017	2017-03-16 09:50:00	2017-03-16 15:00:00	1	310	OTHER	Storm
D1703160155	DERBN1316	2017	2017-03-16 09:55:00	2017-03-17 13:11:00	1	1636	UNKNOWN	Storm
W1703160072	HINES9416	2017	2017-03-16 09:55:47	2017-03-16 13:25:47	1	210	EQUIPMENT FAILURE	Storm
D1703160158	STOPL2231	2017	2017-03-16 09:57:00	2017-03-17 14:01:00	1	1684	UNKNOWN	Storm
W1703160084	FLRDA8032	2017	2017-03-16 09:57:00	2017-03-16 12:01:00	10	1240	INTENTIONAL	Storm
W1703160081	SOFLD9088	2017	2017-03-16 10:00:00	2017-03-16 10:50:00	14	700	WIND	Storm
D1703160171	LINCN0349	2017	2017-03-16 10:03:00	2017-03-16 21:15:00	1	672	EQUIPMENT FAILURE	Storm
N1703160070	MILFD9245	2017	2017-03-16 10:05:00	2017-03-16 12:45:00	6	960	EQUIPMENT FAILURE	Storm
N1703160075	MILFD9245	2017	2017-03-16 10:05:00	2017-03-16 12:44:00	5	795	EQUIPMENT FAILURE	Storm
N1703160073	NOLAN9790	2017	2017-03-16 10:09:00	2017-03-16 16:08:00	1	359	EQUIPMENT FAILURE	Storm
T1703160069	REMER8807	2017	2017-03-16 10:09:00	2017-03-16 10:29:00	1	20	WIND	Storm
W1703160083	YOST9371	2017	2017-03-16 10:13:00	2017-03-16 16:09:00	1	356	WIND	Storm
D1703160178	REDFD1363	2017	2017-03-16 10:17:00	2017-03-17 16:30:00	1	1813	UNKNOWN	Storm
D1703160180	PULFD0413	2017	2017-03-16 10:18:00	2017-03-16 15:59:00	18	6138	EQUIPMENT FAILURE	Storm
D1703160181	GARY1407	2017	2017-03-16 10:18:00	2017-03-17 20:25:00	1	2047	EQUIPMENT FAILURE	Storm
D1703160184	STOPL1465	2017	2017-03-16 10:19:00	2017-03-16 18:59:00	1	520	TREE	Storm
D1703160187	MANDY2805	2017	2017-03-16 10:20:00	2017-03-17 14:13:00	1	1673	UNKNOWN	Storm
T1703160072	NUNLY0364	2017	2017-03-16 10:21:00	2017-03-16 11:48:00	13	1131	TREE	Storm
D1703160192	WAYBN2048	2017	2017-03-16 10:23:00	2017-03-16 21:52:00	1	689	EQUIPMENT FAILURE	Storm
D1703160571	ALNPK2197	2017	2017-03-16 10:25:37	2017-03-17 14:17:37	1	1672	UNKNOWN	Storm
D1703160197	STOPL1465	2017	2017-03-16 10:28:00	2017-03-16 19:49:00	1	561	EQUIPMENT FAILURE	Storm
W1703160095	PDMNT9881	2017	2017-03-16 10:30:00	2017-03-16 16:00:00	1	330	EQUIPMENT FAILURE	Storm
T1703160073	ATLAN8790	2017	2017-03-16 10:32:00	2017-03-16 13:43:00	14	2674	INTENTIONAL	Storm
D1703160209	BALFR1061	2017	2017-03-16 10:36:00	2017-03-17 10:25:00	1	1429	METER / BLOCKS	Storm
D1703160207	ESTLD2238	2017	2017-03-16 10:37:00	2017-03-16 18:33:00	1	476	UNKNOWN	Storm
W1703160096	LIMA9896	2017	2017-03-16 10:41:00	2017-03-16 16:06:00	1	325	UNKNOWN	Storm
D1703160214	DCATR2140	2017	2017-03-16 10:42:00	2017-03-17 16:00:00	1	1758	CUSTOMER EQUIPMENT	Storm
T1703160076	ARMAD8550	2017	2017-03-16 10:44:00	2017-03-17 11:45:00	1	1501	OTHER	Storm
T1703160077	BUNRT1779	2017	2017-03-16 10:50:00	2017-03-17 15:37:00	1	1727	UNKNOWN	Storm
N1703160017	NIKON8932	2017	2017-03-16 10:50:57	2017-03-17 17:29:57	1	1839	UNKNOWN	Storm
T1703160078	NUNLY2428	2017	2017-03-16 10:51:00	2017-03-18 15:03:00	1	3132	OTHER	Storm
W1703160113	SRGNT8262	2017	2017-03-16 10:52:00	2017-03-16 11:25:00	1	33	UNKNOWN	Storm
D1703160224	ANGLA9112	2017	2017-03-16 10:54:00	2017-03-17 15:30:00	1	1716	TREE	Storm
T1703160085	ALGON0307	2017	2017-03-16 10:54:00	2017-03-16 19:39:00	13	6825	WIND	Storm
N1703160085	NIXON9141	2017	2017-03-16 10:56:00	2017-03-16 17:57:00	1	421	WIND	Storm
T1703160093	ALGON0307	2017	2017-03-16 11:00:00	2017-03-16 19:45:00	5	2625	WIND	Storm
N1703160086	STRFD9093	2017	2017-03-16 11:01:00	2017-03-16 13:13:00	1	132	UNKNOWN	Storm
D1703160237	DENVR1341	2017	2017-03-16 11:02:00	2017-03-17 18:40:00	1	1898	WIND	Storm
D1703160250	NAVAR1172	2017	2017-03-16 11:13:00	2017-03-17 16:41:00	1	1768	EQUIPMENT FAILURE	Storm
D1703160257	CHTNT9042	2017	2017-03-16 11:13:00	2017-03-16 16:10:00	1	297	OTHER	Storm
T1703160092	WDTRK0024	2017	2017-03-16 11:14:00	2017-03-16 13:18:00	1	124	CUSTOMER EQUIPMENT	Storm
D1703160255	WAREN8362	2017	2017-03-16 11:16:00	2017-03-17 12:19:00	1	1503	EQUIPMENT FAILURE	Storm
N1703160091	TINKN8933	2017	2017-03-16 11:16:00	2017-03-17 06:59:00	1	1183	UNKNOWN	Storm
W1703160117	YOST9403	2017	2017-03-16 11:18:00	2017-03-16 13:52:00	1	154	OTHER	Storm
D1703160268	EVRGN1228	2017	2017-03-16 11:24:00	2017-03-17 20:45:00	1	2001	UNKNOWN	Storm
D1703160269	GENSE2147	2017	2017-03-16 11:24:00	2017-03-17 21:15:00	1	2031	EQUIPMENT FAILURE	Storm
D1703160274	STOPL0690	2017	2017-03-16 11:24:00	2017-03-17 13:18:00	1	1554	TREE	Storm
N1703160123	WLNUT9029	2017	2017-03-16 11:27:00	2017-03-16 11:49:00	8	176	EQUIPMENT FAILURE	Storm
W1703160126	SOFLD8912	2017	2017-03-16 11:31:00	2017-03-16 14:37:00	1	186	UNKNOWN	Storm
D1703160286	HAZPK1208	2017	2017-03-16 11:34:00	2017-03-16 16:30:00	1	296	EQUIPMENT FAILURE	Storm
N1703160102	PADOK4018	2017	2017-03-16 11:35:00	2017-03-16 15:37:00	1	242	UNKNOWN	Storm
D1703160284	WSEND1040	2017	2017-03-16 11:36:00	2017-03-16 19:17:00	1	461	UNKNOWN	Storm
N1703160103	LNGLK8977	2017	2017-03-16 11:36:00	2017-03-16 18:35:00	1	419	UNKNOWN	Storm
N1703160105	WLNUT9029	2017	2017-03-16 11:37:06	2017-03-16 14:14:06	166	26062	TREE	Storm
D1703160290	APACE8996	2017	2017-03-16 11:40:00	2017-03-17 18:08:00	1	1828	METER / BLOCKS	Storm
N1703160107	LITICA2411	2017	2017-03-16 11:40:00	2017-03-17 06:38:00	1	1138	UNKNOWN	Storm
N1703160114	LILY9038	2017	2017-03-16 11:42:00	2017-03-16 22:38:00	1	656	UNKNOWN	Storm
D1703160293	MLVDL2105	2017	2017-03-16 11:44:00	2017-03-16 12:58:00	1	74	CUSTOMER EQUIPMENT	Storm
T1703160101	VICTR8721	2017	2017-03-16 11:44:00	2017-03-16 14:00:00	1	136	EQUIPMENT FAILURE	Storm
N1703160126	WMSTN9856	2017	2017-03-16 11:46:00	2017-03-16 20:30:00	1	524	EQUIPMENT FAILURE	Storm
N1703160108	SLYON0301	2017	2017-03-16 11:49:00	2017-03-16 13:49:00	481	57720	TREE	Storm
N1703160109	SLYON0302	2017	2017-03-16 11:49:00	2017-03-16 13:49:00	293	35160	TREE	Storm
D1703160317	ANNCH1361	2017	2017-03-16 12:02:00	2017-03-17 11:58:00	1	1436	UNKNOWN	Storm
N1703160141	CODY9537	2017	2017-03-16 12:05:00	2017-03-16 16:18:00	2	506	TREE	Storm
T1703160110	NHAVN2560	2017	2017-03-16 12:06:00	2017-03-16 17:27:00	1	321	WIND	Storm
D1703160321	CHAND2047	2017	2017-03-16 12:07:00	2017-03-16 16:25:00	1	258	EQUIPMENT FAILURE	Storm
D1703160328	INDIN1549	2017	2017-03-16 12:10:00	2017-03-16 19:12:00	1	422	UNKNOWN	Storm
D1703160330	FRISB2117	2017	2017-03-16 12:11:00	2017-03-16 16:01:00	1	230	EQUIPMENT FAILURE	Storm
N1703160152	MILFD9248	2017	2017-03-16 12:16:00	2017-03-17 14:58:00	1	1602	UNKNOWN	Storm
D1703160343	TIRMN2088	2017	2017-03-16 12:21:00	2017-03-17 12:38:00	1	1457	TREE	Storm
D1703160344	CORTL0476	2017	2017-03-16 12:22:00	2017-03-17 12:37:00	1	1455	UNKNOWN	Storm
T1703160111	HOSTN8773	2017	2017-03-16 12:24:00	2017-03-16 12:51:00	1	27	INTENTIONAL	Storm
N1703160160	LNGLK8977	2017	2017-03-16 12:25:14	2017-03-16 13:22:14	3	171	ANIMAL	Storm
D1703160351	MOUND1453	2017	2017-03-16 12:28:00	2017-03-17 18:50:00	1	1822	WIND	Storm
D1703150928	CHAND0065	2017	2017-03-16 12:42:00	2017-03-16 12:53:00	11	121	EQUIPMENT FAILURE	Storm
N1703160174	ALPNE8921	2017	2017-03-16 12:44:52	2017-03-16 16:24:52	26	5720	INTENTIONAL	Storm
D1703160364	CHAND2024	2017	2017-03-16 12:46:00	2017-03-17 14:06:00	1	1520	UNKNOWN	Storm
N1703160168	MILFD9248	2017	2017-03-16 12:46:00	2017-03-16 17:21:00	1	275	WIND	Storm
D1703160367	WSEND2264	2017	2017-03-16 12:48:00	2017-03-17 16:28:00	1	1660	UNKNOWN	Storm
T1703160116	SUTTN1637	2017	2017-03-16 12:53:00	2017-03-17 13:25:00	1	1472	EQUIPMENT FAILURE	Storm
D1703160371	BALFR2038	2017	2017-03-16 12:55:00	2017-03-17 18:57:00	1	1802	CUSTOMER EQUIPMENT	Storm
T1703160118	CAROO302	2017	2017-03-16 12:55:00	2017-03-16 20:07:00	22	9504	TREE	Storm
D1703160379	APPOL1383	2017	2017-03-16 12:59:00	2017-03-16 18:51:00	62	21824	EQUIPMENT FAILURE	Storm
W1703160187	WAYNE9421	2017	2017-03-16 13:06:00	2017-03-16 21:10:00	1	484	EQUIPMENT FAILURE	Storm
D1703160386	VERNR1592	2017	2017-03-16 13:11:00	2017-03-16 21:37:00	1	506	EQUIPMENT FAILURE	Storm
N1703160189	CODY9537	2017	2017-03-16 13:11:00	2017-03-16 16:16:00	2	370	TREE	Storm
D1703160387	LINCN1566	2017	2017-03-16 13:12:00	2017-03-17 13:44:00	1	1472	UNKNOWN	Storm
N1703160176	AUBRN8843	2017	2017-03-16 13:13:00	2017-03-19 19:21:00	1	4688	EQUIPMENT FAILURE	Storm
N1703160125	CODY9537	2017	2017-03-16 13:16:00	2017-03-16 16:15:00	593	106147	TREE	Storm
N1703160190	HANCK8198	2017	2017-03-16 13:21:00	2017-03-16 15:05:00	1	104	WIND	Storm
D1703160397	LAMBT2078	2017	2017-03-16 13:23:00	2017-03-17 13:11:00	1	1428	UNKNOWN	Storm
D1703160402	COOLG2080	2017	2017-03-16 13:23:00	2017-03-17 01:42:00	181	133759	EQUIPMENT FAILURE	Storm
D1703160401	SYRAC1813	2017	2017-03-16 13:24:00	2017-03-17 18:00:00	1	1716	EQUIPMENT FAILURE	Storm
D1703160412	COOLG1209	2017	2017-03-16 13:33:00	2017-03-17 14:51:00	1	1518	EQUIPMENT FAILURE	Storm
D1703160429	VILLA1553	2017	2017-03-16 13:38:00	2017-03-16 15:19:00	69	6969	TREE	Storm
T1703160130	KILGR8772	2017	2017-03-16 13:38:00	2017-03-16 19:29:00	1	351	UNKNOWN	Storm
D1703160416	TIRMN2088	2017	2017-03-16 13:40:00	2017-03-16 18:18:00	1	278	UNKNOWN	Storm
W1703160207	MACON8049	2017	2017-03-16 13:40:00	2017-03-16 18:59:00	1	319	OTHER	Storm
D1703160417	VERNR1592	2017	2017-03-16 13:41:00	2017-03-16 21:38:00	1	477	EQUIPMENT FAILURE	Storm
W1703160215	DRAKE9066	2017	2017-03-16 13:42:00	2017-03-16 16:25:00	3	489	INTENTIONAL	Storm
N1703160193	KENSL9858	2017	2017-03-16 13:45:00	2017-03-16 21:09:00	1	444	CUSTOMER EQUIPMENT	Storm
W1703160041	ELGIN1690	2017	2017-03-16 13:49:00	2017-03-17 17:48:00	51	85629	INTENTIONAL	Storm
D1703160428	CRTIS1410	2017	2017-03-16 13:52:00	2017-03-17 12:29:00	1	1357	EQUIPMENT FAILURE	Storm
D1703160430	NAVAR0691	2017	2017-03-16 13:54:00	2017-03-17 15:20:00	1	1526	EQUIPMENT FAILURE	Storm
D1703160431	VENIC2013	2017	2017-03-16 13:57:00	2017-03-16 16:59:00	23	4186	TREE	Storm
D1703160432	APACE8996	2017	2017-03-16 13:58:00	2017-03-17 18:08:00	1	1690	UNKNOWN	Storm
T1703160136	HOSTN8773	2017	2017-03-16 14:05:00	2017-03-16 15:23:00	122	9516	TREE	Storm
T1703160216	HOSTN8773	2017	2017-03-16 14:05:00	2017-03-16 17:47:00	37	8214	TREE	Storm
N1703160054	COMLK9525	2017	2017-03-16 14:09:32	2017-03-17 00:40:32	1	631	UNKNOWN	Storm
T1703160139	FRFAX8758	2017	2017-03-16 14:10:00	2017-03-16 16:00:00	1	110	WIND	Storm
N1703160208	CLKSN9113	2017	2017-03-16 14:11:00	2017-03-16 18:24:00	36	9108	EQUIPMENT FAILURE	Storm
W1703160219	WICK9453	2017	2017-03-16 14:13:00	2017-03-16 17:10:00	6	1062	ANIMAL	Storm
D1703160449	ESTLD2238	2017	2017-03-16 14:21:00	2017-03-16 18:33:00	1	252	UNKNOWN	Storm

N17031800162	OKRDG9626	2017	2017-03-16 14:33:00	2017-03-19 00:30:00	1	3477	EQUIPMENT FAILURE	Storm
D17031600459	DENVR2139	2017	2017-03-16 14:35:00	2017-03-17 17:22:00	1	1607	WIND	Storm
D17031600460	NAVAR1278	2017	2017-03-16 14:35:00	2017-03-16 19:23:00	1	288	UNKNOWN	Storm
D17031600462	GNSTN1226	2017	2017-03-16 14:36:00	2017-03-17 13:11:00	1	1355	UNKNOWN	Storm
D17031600469	KORTE2034	2017	2017-03-16 14:38:00	2017-03-17 14:04:00	1	1406	METER / BLOCKS	Storm
D17031600476	SIKMI1200	2017	2017-03-16 14:50:00	2017-03-17 14:06:00	1	1396	UNKNOWN	Storm
N17031600220	PADOK4018	2017	2017-03-16 14:52:00	2017-03-17 01:49:00	4	2628	EQUIPMENT FAILURE	Storm
W17031600238	MOTT9789	2017	2017-03-16 14:57:00	2017-03-16 16:53:00	1	116	EQUIPMENT FAILURE	Storm
N17031600223	WLNUT9029	2017	2017-03-16 15:01:00	2017-03-16 19:29:00	7	1876	EQUIPMENT FAILURE	Storm
T17031600161	ARMAD8550	2017	2017-03-16 15:06:00	2017-03-17 12:00:00	1	1254	EQUIPMENT FAILURE	Storm
D17031600493	LINCN2800	2017	2017-03-16 15:10:00	2017-03-16 17:59:00	1	169	WIND	Storm
D17031600511	PULFD0413	2017	2017-03-16 15:11:00	2017-03-16 17:59:00	23	3864	EQUIPMENT FAILURE	Storm
W17031400111	RAVIN1666	2017	2017-03-16 15:14:00	2017-03-17 13:56:00	1	1362	TREE	Storm
N17031600229	FRANK1736	2017	2017-03-16 15:18:00	2017-03-16 17:06:00	5	540	EQUIPMENT FAILURE	Storm
D17031600505	EMPIR1010	2017	2017-03-16 15:21:00	2017-03-17 20:44:00	1	1763	EQUIPMENT FAILURE	Storm
T17031600172	KENEY1461	2017	2017-03-16 15:25:00	2017-03-16 16:28:00	26	1638	EQUIPMENT FAILURE	Storm
N17031600254	HOWEL2932	2017	2017-03-16 15:32:00	2017-03-16 15:56:00	61	732	OTHER	Storm
D17031600168	BRAZL8833	2017	2017-03-16 15:33:10	2017-03-19 06:51:10	1	1899	EQUIPMENT FAILURE	Storm
D17031600518	EIGMI1512	2017	2017-03-16 15:38:00	2017-03-18 12:32:00	1	1347	UNKNOWN	Storm
D17031600521	CHAND0065	2017	2017-03-16 15:38:00	2017-03-16 17:52:00	8	536	NO CAUSE	Storm
T17031600173	VICTR8699	2017	2017-03-16 15:40:00	2017-03-17 00:20:00	2	520	EQUIPMENT FAILURE	Storm
W17031600252	FRLDG8042	2017	2017-03-16 15:42:00	2017-03-16 19:38:00	1	118	UNKNOWN	Storm
T17031600182	WORTH0301	2017	2017-03-16 15:45:00	2017-03-16 18:13:00	7	518	INTENTIONAL	Storm
D17031600524	GRANT1306	2017	2017-03-16 15:48:00	2017-03-18 13:20:00	1	1366	UNKNOWN	Storm
D17031600532	VENIC2013	2017	2017-03-16 15:57:00	2017-03-18 17:53:00	1	1498	EQUIPMENT FAILURE	Storm
N17031600259	DAVIS8970	2017	2017-03-16 16:00:00	2017-03-16 19:56:00	15	1770	TREE	Storm
N17031600258	STRFD9093	2017	2017-03-16 16:01:00	2017-03-18 07:15:00	1	1177	METER / BLOCKS	Storm
N17031600269	HANCK9045	2017	2017-03-16 16:01:00	2017-03-16 19:09:00	3	282	INTENTIONAL	Storm
D17031600540	MCGRW1280	2017	2017-03-16 16:04:00	2017-03-18 17:22:00	1	1479	UNKNOWN	Storm
D17031600543	VERNR2037	2017	2017-03-16 16:10:00	2017-03-18 21:44:00	1	1607	UNKNOWN	Storm
D17031600548	HAYES1385	2017	2017-03-16 16:10:00	2017-03-18 14:20:00	1	1385	EQUIPMENT FAILURE	Storm
N17031600263	CLKSN9113	2017	2017-03-16 16:10:00	2017-03-16 16:45:00	1	35	EQUIPMENT FAILURE	Storm

Line No.

Table 4 Top 50 Strategic Capital Programs and Projects Based on GPM

Rank	Capital Program/ Project	Rank	Capital Program / Project
1	ADMS: DMS/OMS	26	Subtransmission Redesign & Rebuild: Pigeon Area Improvement
2	4.8 kV Circuit Automation	27	4.8 kV CC: Birmingham Decommissioning and Circuit Conversion
3	4.8 kV Hardening	28	Cable Replacement Program
4	CODI: Charlotte Network Upgrade	29	Subtransmission Redesign & Rebuild: Trunk 3508
5	Subtransmission Redesign & Rebuild: Thumb Electric Fault Isolation	30	Subtransmission Redesign & Rebuild: Tie 810
6	Automation: Substation	31	System Loading: Richmond/Armada
7	4.8 kV CC: Buckler Circuit Conversion	32	Subtransmission Redesign & Rebuild: Trunk 3509
8	4.8kV CC: Barber Substation and Circuit Conversion	33	Substation Risk: Apache
9	4.8 kV CC: Hawthorne Relief and Circuit Conversion	34	System Loading: Otsego/Capac/Shaw
10	4.8 kV CC: Almont Relief and Circuit Conversion (Midas)	35	System Loading: Macomb/Golf
11	4.8 kV CC: Grosse Pointe Substation and Circuit Conversion	36	Subtransmission Redesign & Rebuild: Badax Transformer 102 Addition
12	Automation: 13.2kV Circuit Distribution	37	Subtransmission Redesign & Rebuild: Sandusky Transformer 101 Breaker
13	4.8 kV CC: ISO Conversion Program	38	4.8 kV CC: Lapeer - Elba Expansion and Circuit Conversion (Apollo)
14	Subtransmission Redesign & Rebuild: Boyne	39	4.8 kV CC: I-94 Substation and Circuit Conversion (Promenade)
15	CODI: Garfield Network Upgrade	40	CODI: Islandview Substation
16	Subtransmission Redesign & Rebuild: Trunk 4217	41	Subtransmission Redesign & Rebuild: Tie 6602
17	Pole and Pole Top Hardware (PTMM)	42	CODI: Kent/Gibson Conversion
18	4.8 kV CC: Belleville Substation and Circuit Conversion	43	Subtransmission Redesign & Rebuild: Trunk 4266
19	URD Replacement Program	44	CODI: Howard Conversion
20	System Loading: Brown City	45	8.3 kV CC: Pontiac Overhead Conversion
21	Breaker Replacement Program	46	System Loading: Grenada
22	Substation Risk: Chestnut	47	System Loading: Wixom
23	Frequent Outage Program (CEMI)	48	Subtransmission Redesign & Rebuild: Trunk 2308
24	4.8kV CC: Hemlock Decommissioning and Circuit Conversion	49	System Loading: Jewell
25	Subtransmission Redesign & Rebuild: Tie 7504	50	Subtransmission Redesign & Rebuild: Derby

Q14. Are there other factors besides the GPM ranking that determine final timing of program and project selection?

MPSC Case No: U-21297

Requester: MNSC

Question No.: MNSCDE-3.30d

Respondent: J. Kryscynski

Page: 1 of 1

Question: Refer to Witness Kryscynski's testimony, Table 4 on page AJK-11, as well as to Mr. Kryscinski's statement regarding the Global Prioritization Model (GPM), page AJK-7 at 3, "Detailed analyses based on historical data, engineering assessments, and field feedback were used to quantify each investment's benefits within each impact dimension. The quantified benefits were then compared to the investment's costs to derive benefit-cost ratios" and to his statement on page AJK-8 at 4, "Each program's benefit-cost score for each impact dimension is indexed to a base range of 0-100. Projects scoring exceptionally high, above the 95th percentile, will receive a score above 100."

d. Please provide, for each of the programs and projects listed in Table 4, the scores for each impact dimension and the resulting weighted overall impact dimension score.

Answer: The impact dimension scores and overall score are provided in attachment U-21297 MNSCDE-3.30d-01 GPM scores.

Attachment: U-21297 MNSCDE-3.30d-01 GPM scores

2020 Global Prioritization Model Ranking

GPM Ranking	Project / Program	A12 Tab	A12 Line Number	Capital Investments	Total Safety	Load Relief	Regulatory Compliance	Major Event Reduction	CMI	O&M Avoidance	Capital Avoidance	GPM Score
1	ADMS: DMS/OMS	A-12 B5.4 Tech	2	$ 10,840,000	1,353	-	-	3,831	11,687	330	3,642	20,843
2	4.8 kV Circuit Automation	A-12 B5.4 Tech	39	$ 82,703,000	10,958	-	-	-	-	-	-	10,958
3	4.8 kV Hardening	A-12 B5.4 Resilience	12	$ 80,000,000	1,102	-	-	-	295	2,271	146	3,813
4	CODI: Charlotte Network Upgrade	A-12 B5.4 Redesign	60	$ 30,215,148	2,203	42	-	100	-	-	-	2,345
5	Subtransmission Redesign & Rebuild: Thumb Electric Fault Isolation	A-12 B5.4 Redesign	39	$ 1,183,107	-	-	-	-	792	-	296	1,088
6	Automation: Substation	A-12 B5.4 Tech	9	$ 190,538,836	-	-	-	218	321	298	225	1,063
7	4.8 kV CC: Buckler Circuit Conversion	A-12 B5.4 Redesign	76	$ 5,512,442	299	-	-	-	73	441	209	1,022
8	4.8kV CC: Barber Substation and Circuit Conversion	A-12 B5.4 Redesign	101	$ 72,268,116	262	242	-	-	99	204	140	947
9	4.8 kV CC: Hawthorne Relief and Circuit Conversion	A-12 B5.4 Redesign	85	$ 122,000,000	156	258	-	28	121	201	98	863
10	4.8 kV CC: Almont Relief and Circuit Conversion (Midas)	A-12 B5.4 Redesign	75	$ 3,565,012	46	100	-	466	33	85	21	751
11	4.8 kV CC: Grosse Pointe Substation and Circuit Conversion	A-12 B5.4 Redesign	102	$ 335,937,676	225	292	-	29	105	38	24	713
12	Automation: 13.2kV Circuit Distribution	A-12 B5.4 Tech	10	$ 301,677,660	-	-	-	138	203	188	142	671
13	4.8 kV CC: ISO Conversion Program	A-12 B5.4 Redesign	93	$ 217,000,000	149	-	-	-	42	244	186	622
14	Subtransmission Redesign & Rebuild: Boyne	A-12 B5.4 Redesign	15	$ 7,036,846	26	350	-	-	40	150	53	618
15	CODI: Garfield Network Upgrade	A-12 B5.4 Redesign	68	$ 213,966,019	423	108	-	38	6	5	1	581
16	Subtransmission Redesign & Rebuild: Trunk 4217	A-12 B5.4 Redesign	21	$ 4,865,120	14	400	-	155	-	-	-	570
17	Pole and Pole Top Hardware (PTMM)	A-12 B5.4 Resilience	13	$ 1,651,425,268	77	-	400	-	31	21	30	559
18	4.8 kV CC: Belleville Substation and Circuit Conversion	A-12 B5.4 Redesign	88	$ 11,385,184	134	-	-	53	92	181	84	544
19	URD Replacement Program	A-12 B5.4 Resilience	18	$ 105,000,000	-	-	-	-	63	55	423	541
20	System Loading: Brown City	A-12 B5.4 Redesign	112	$ 22,100,977	18	408	-	-	6	68	23	523
21	Breaker Replacement Program	A-12 B5.4 Resilience	16	$ 90,973,388	6	-	-	28	41	112	315	502
22	Substation Risk: Chestnut	A-12 B5.4 Resilience	4	$ 10,959,853	43	-	-	441	-	-	-	483
23	Frequent Outage Program (CEMI)	A-12 B5.4 Resilience	15	$ 222,877,157	-	-	400	-	75	3	2	480
24	4.8kV CC: Hemlock Decommissioning and Circuit Conversion	A-12 B5.4 Redesign	98	$ 53,070,674	121	-	-	-	76	176	87	460
25	Subtransmission Redesign & Rebuild: Tie 7504	A-12 B5.4 Redesign	17	$ 17,372,832	16	233	-	-	10	167	15	441
26	Subtransmission Redesign & Rebuild: Pigeon Area Improvement	A-12 B5.4 Redesign	29	$ 11,400,905	-	217	-	-	-	213	-	430

2020 Global Prioritization Model Ranking

27	4.8 kV CC: Birmingham Decommissioning and Circuit Conversion	A-12 B5.4 Redesign	87	$ 86,655,000	88	75	-	59	37	120	43	423
28	Cable Replacement Program	A-12 B5.4 Resilience	14	$ 140,171,395	44	-	-	241	6	-	129	420
29	Subtransmission Redesign & Rebuild: Trunk 3508	A-12 B5.4 Redesign	38	$ 4,079,516	60	133	-	222	-	-	-	415
30	Subtransmission Redesign & Rebuild: Tie 810	A-12 B5.4 Redesign	9	$ 69,814,992	6	300	-	-	6	86	9	408
31	System Loading: Richmond/Armada	A-12 B5.4 Redesign	115	$ 24,091,536	29	83	-	163	13	98	21	407
32	Subtransmission Redesign & Rebuild: Trunk 3509	A-12 B5.4 Redesign	22	$ 2,400,915	11	333	-	63	-	-	-	407
33	Substation Risk: Apache	A-12 B5.4 Resilience	6	$ 14,265,687	33	-	-	339	-	-	-	371
34	System Loading: Otsego/Capac/Shaw	A-12 B5.4 Redesign	117	$ 11,087,957	6	133	-	-	17	167	30	353
35	System Loading: Macomb/Golf	A-12 B5.4 Redesign	118	$ 32,400,710	4	283	-	-	14	30	19	351
36	Subtransmission Redesign & Rebuild: Badax Transformer 102 Addition	A-12 B5.4 Redesign	24	$ 9,322,792	-	350	-	-	-	-	-	350
37	Subtransmission Redesign & Rebuild: Sandusky Transformer 101 Breaker	A-12 B5.4 Redesign	14	$ 4,283,000	-	333	-	-	-	-	-	333
38	4.8 kV CC: Lapeer - Elba Expansion and Circuit Conversion (Apollo)	A-12 B5.4 Redesign	78	$ 32,263,517	28	192	-	-	14	79	17	331
39	4.8 kV CC: I-94 Substation and Circuit Conversion (Promenade)	A-12 B5.4 Redesign	74	$ 220,515,917	92	150	-	3	32	35	16	329
40	CODI: Islandview Substation	A-12 B5.4 Redesign	63	$ 185,227,181	78	150	-	29	27	26	9	320
41	Subtransmission Redesign & Rebuild: Tie 6602	A-12 B5.4 Redesign	26	$ 5,848,187	4	67	-	-	12	217	16	316
42	CODI: Kent/Gibson Conversion	A-12 B5.4 Redesign	69	$ 165,479,707	42	183	-	14	17	38	13	307
43	Subtransmission Redesign & Rebuild: Trunk 4266	A-12 B5.4 Redesign	23	$ 5,366,380	35	67	-	197	-	-	-	299
44	CODI: Howard Conversion	A-12 B5.4 Redesign	65	$ 143,700,000	240	42	-	5	0	1	0	288
45	8.3 kV CC: Pontiac Overhead Conversion	A-12 B5.4 Redesign	105	$ 127,405,100	49	-	-	50	30	107	45	281
46	System Loading: Grenada	A-12 B5.4 Redesign	119	$ 42,560,466	23	33	-	-	31	164	29	280
47	System Loading: Wixom	A-12 B5.4 Redesign	126	$ 67,037,741	4	200	-	38	4	11	4	261
48	Subtransmission Redesign & Rebuild: Trunk 2308	A-12 B5.4 Redesign	19	$ 9,274,646	-	67	-	-	19	114	36	235
49	System Loading: Jewell	A-12 B5.4 Redesign	123	$ 44,840,069	29	75	-	51	15	47	18	235
50	Subtransmission Redesign & Rebuild: Derby	A-12 B5.4 Redesign	40	$ 8,968,046	-	233	-	-	-	-	-	233

DTE Electric Company
One Energy Plaza, 1635
Detroit, MI 48226-1279

DTE

Paula Johnson-Bacon
(313) 235-7052
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June 14, 2024

Ms. Lisa Felice
Executive Secretary
Michigan Public Service Commission
7109 West Saginaw Hwy.
Lansing, MI 48917

Re: In the matter on the Commission's own motion of the investigation into methods to improve the reliability of electric service in Michigan
MPSC Case No. U-12270

Dear Ms. Felice:

Pursuant to the Commission's December 20, 2022 Order in the above-referenced matter, attached please find DTE Electric Company's 2023 MPSC Service Quality and Reliability Standards for Electric Utilities R460.731 Annual Report.

Very truly yours,

Paula Johnson-Bacon

Digitally signed by Paula Johnson-Bacon
Date: 2024.06.14 16:16:38 -04'00'

Paula Johnson-Bacon

PJB/cdm
Attachment

MPSC Service Quality and Reliability Standards for Electric Utilities
R460.731 Annual Report

Utility or Cooperative:	DTE Energy Co.
Year:	2023

SUMMARY TABLE R460.732(s)

	Meter Reading Factor R460.732 (a)	New Service Installation Factor R460.732(b)	Wire Down Relief Factor R460.732 (c)		Outage Restoration				CEMI4	
					All Conditions R460.732 (d)	Normal Conditions R460.732 (e)	Gray-Sky Conditions R460.732 (f)	Catastrophic Conditions R460.732 (g)	Sustained Interruptions R460.732 (h)(i)	
	Meter Reading Factor (Percentage)	*New Services Installed in 15 Business Days or Less (Percentage)*	*The percentage of the first responder guarded downed wires that are relieved by an electric utility representative within 120 minutes after notification in MSAs.*	*The percentage of the first responder guarded downed wires that are relieved by an electric utility representative within 180 minutes after notification in non-MSAs.*	*Percentage of Customers Restored in 36 Hours or Less*	*Percentage of Customers Restored in 8 Hours or Less*	*Percentage of Customers Restored in 24 Hours or Less*	*Percentage of Customers Restored in 48 Hours or Less*	*Percentage of Customers Served Experiencing 4 or More Sustained Interruptions*	*Number of Customers Experiencing 4 or More Sustained Interruptions*
Utility or cooperative performance during year	98.95%	95.00%	78.00%	85.15%	85.18%	93.00%	81.93%	81.64%	13.38%	301,244
MPSC Annual Performance Standard	95% or more	90% or more completed within 15 business days	90% or more within 120 minutes in MSAs	90% or more within 180 minutes in non-MSAs	90% or more customers restored in 36 hours or less	90% or more customers restored in 8 hours or less	90% or more customers restored in 24 hours or less	90% or more customers restored in 48 hours or less	6% or less before 2030; 5% or less in 2030 or later	
Did utility or cooperative comply with performance standard (Yes/No)	Yes	Yes	No	No	No	Yes	No	No	No	

A detailed explanation of the steps the electric utility or cooperative is taking to bring its performance to an acceptable level. If more than 6% of customers experienced 4 or more sustained interruptions within the year and that year was 2029 or a prior year, or if more than 5% of customers experienced 4 or more sustained interruptions within the year and that year was 2030 or a future year, a description of all catastrophic conditions experienced during the year is also required. (Can be put on a separate page.) R 460.732 (h)(ii) and R 460.732 (h)(iii).	See Appendix 1 for Actions to Improve Reliability Performance See Appendix 2 for Description of Catastrophic Conditions

CUSTOMER CREDITS PROVIDED DURING THE YEAR

Item	Sector	Number of credits provided	Total Customer Credits ($) (1)
Customer Credits Provided for Failure to Restore Service within 96 Hours of the Start of Sustained Interruption during Catastrophic Conditions R460.732(i)	*Residential*	35,977	350,009
	Commercial	2,218	7,630
	Industrial	0	0
Customer Credits Provided for Failure to Restore Service within 48 Hours of the Start of Sustained Interruption during Gray Sky Conditions R460.732(j)	*Residential*	11,417	408,211
	Commercial	1,006	34,160
	Industrial	0	0
Customer Credits Provided for Failure to Restore Service within 16 Hours of the Start of Sustained Interruption during Normal Conditions R460.732(k)	*Residential*	23,719	981,974
	Commercial	2,294	94,026
	Industrial	1	0
Customer Credits Provided to Individual Customers Who Experienced 6 or more Sustained Interruptions. R460.732(l)	*Residential*	123,671	3,824,838
	Commercial	7,701	187,566
	Industrial	0	73

WORST PERFORMING CIRCUITS DURING THE YEAR

1. For each electric utility with 1,000,000 or more customers, a list of its 10 worst performing circuits for the prior year in terms of SAIDI and SAIFI. For each listed circuit, provide the following information below. R460.732(m) and R 460.732 (o). Please see the definition of "circuit" below in (8).

2. For each electric utility or cooperative with less than 1,000,000 customers, a list of the worst performing 1% of circuits for the prior year in terms of SAIDI and SAIFI. For each listed circuit, provide the following information below. R460.732(n) and R 460.732 (o). Please see the definition of "circuit" below in (8).

U-21534 | September 5, 2024
MNSC Hearing Exhibits
Ex MEC-38 | Source: U-12270 DTE's 2023 Reliability Report
Page 2 of 52

Worst performing circuit(s) by SAIDI excluding major event days (MEDs) (7), (8), (11)										
	Circuit 1	**Circuit 2**	**Circuit 3**	**Circuit 4**	**Circuit 5**	**Circuit 6**	**Circuit 7**	**Circuit 8**	**Circuit 9**	**Circuit 10**
Circuit Name	**YPSIL0317**	**KNGSY0330**	**ARGO 0326**	**SNOVR0302**	**APLGT0311**	**LEXTN8770**	**NBOST0305**	**PULFD2155**	**SNOVR0301**	**DENVR2004**
Circuit Number	**0317**	**0330**	**0326**	**0302**	**0311**	**8770**	**0305**	**2155**	**0301**	**2004**
Location of Circuit - zip codes (2)	48198	48130	48103	48472	48401	48450	48164	48214	48472	48230
Circuit Length (miles)	11.97	48.73	8.04	53.51	28.33	131.38	11.97	7.71	20.16	5.74
SAIDI excluding MEDs	2,373.72	2,292.19	1,875.49	1,826.83	1,692.59	1,595.94	1,520.61	1,505.43	1,464.18	1,454.69
SAIFI excluding MEDs	1.06	2.25	6.26	5.06	1.52	1.76	5.08	1.66	4.80	3.16
SAIDI all conditions	3,107.39	9,126.67	7,786.53	1,826.84	1,705.40	1,601.86	5,128.29	4,223.11	1,464.69	3,317.31
SAIFI all conditions	2.04	5.03	9.66	5.06	1.53	1.77	8.12	2.67	4.82	4.16
Number of Customers Served	1,392	657	409	415	463	3,221	454	497	188	357
Substation Name	YPSIL	KNGSY	ARGO	SNOVR	APLGT	LEXTN	NBOST	PULFD	SNOVR	DENVR
Last Circuit Trim (year) (3)	2022	2023	2018	2014	2021	2022	2023	2023	2014	2021
List of Outages and Causes (can be put on a separate page) (4)	See Appendix 5	See Appendix 5	See Appendix 5	See Appendix 5	See Appendix 5	See Appendix 5	See Appendix 5	See Appendix 5	See Appendix 5	See Appendix 5
Corrective action to improve performance (can be put on a separate page)	See Appendix 3	See Appendix 3	See Appendix 3	See Appendix 3	See Appendix 3	See Appendix 3	See Appendix 3	See Appendix 3	See Appendix 3	See Appendix 3

Worst performing circuit(s) by SAIFI excluding MEDs (7), (8), (11)										
	Circuit 1	**Circuit 2**	**Circuit 3**	**Circuit 4**	**Circuit 5**	**Circuit 6**	**Circuit 7**	**Circuit 8**	**Circuit 9**	**Circuit 10**
Circuit Name	**CROWN9832**	**ARGO 0326**	**HASKL1625**	**NBOST0305**	**SNOVR0302**	**SDF012641**	**ARMAD0302**	**SNOVR0301**	**SDF339897**	**CABOT9490**
Circuit Number	**9832**	**0326**	**1625**	**0305**	**0302**	**2641**	**0302**	**0301**	**9897**	**9490**
Location of Circuit - zip codes (2)	48197	48103	48101	48164	48472	48427	48062	48472	48103	48162
Circuit Length (miles)	34.32	8.04	4.79	11.97	53.51	21.31	28.99	20.16	10.69	3.74
SAIFI excluding MEDs	6.46	6.26	5.30	5.08	5.06	5.01	4.94	4.80	4.60	4.51
SAIDI excluding MEDs	767.56	1,875.49	1,134.76	1,520.61	1,826.83	1,392.72	861.14	1,464.18	444.59	334.76
SAIFI all conditions	9.48	9.66	7.69	8.12	5.06	5.02	6.28	4.82	8.65	9.46
SAIDI all conditions	2,623.69	7,786.53	7,689.97	5,128.29	1,826.84	1,403.26	3,159.27	1,464.69	7,593.20	2,470.58
Number of Customers Served	2,006	409	580	454	415	105	358	188	358	154
Substation Name	CROWN	ARGO	HASKL	NBOST	SNOVR	SDF01	ARMAD	SNOVR	SDF33	CABOT
Last Circuit Trim (year) (3)	2022	2018	2019	2023	2014	2021	2020	2014	2020	2020
List of Outages and Causes (can be put on a separate page) (4)	See Appendix 6	See Appendix 6	See Appendix 6	See Appendix 6	See Appendix 6	See Appendix 6	See Appendix 6	See Appendix 6	See Appendix 6	See Appendix 6
Corrective action to improve performance (can be put on a separate page)	See Appendix 3	See Appendix 3	See Appendix 3	See Appendix 3	See Appendix 3	See Appendix 3	See Appendix 3	See Appendix 3	See Appendix 3	See Appendix 3

	CEMI0	CEMI1	CEMI2	CEMI3	CEMI4	CEMI5	CEMI6	CEMI7	CEMI8	CEMI9	CEMI10
CEMI Reporting for Indices CEMI0 through CEMI10+ R460.732(p) (5)	2,252,226	1,649,256	1,025,675	574,830	301,244	155,456	76,753	41,648	21,684	11,333	6,660

CELID		
CELID Reporting R460.732(q) (6)	**CELID8hours**	1,008,012
	CELID24hours	636,393
	CELID48hours	291,042

MOMENTARY INTERRUPTIONS	
Number of Non-Residential Customers Experiencing Momentary Interruptions R460.732(r)	N/A

System-wide SAIDI, SAIFI, and CAIDI (9)

	All conditions						Excludes MEDs (11)					
	SAIDI		SAIFI		CAIDI		SAIDI		SAIFI		CAIDI	
Year	Annual	5 year average	Annual	5 year average	Annual	5 year average	Annual	5 year average	Annual	5 year average	Annual	5 year average
2019	466	506	1.37	1.22	340	396	202	189	1.14	0.99	178	190
2020	352	521	1.29	1.28	274	396	142	180	1.01	1.02	140	177
2021	927	659	1.58	1.40	587	465	136	171	0.92	1.02	147	167
2022	584	563	1.25	1.37	467	405	146	161	0.98	1.02	149	157
2023	1542	774	1.72	1.44	895	513	157	157	0.86	0.98	183	159

Power Quality information (10)

Power quality information shall contain data on: **a) all power quality investigations conducted in the past year for industrial customers who have requested a power quality investigation as a result of an event originating from utility equipment; and** **b) power quality investigations conducted in the past year into any power quality event. For purposes of this form, a power quality event is defined as an event that affected customers on a single circuit or substation; resulted in damage to customer appliances, equipment, or wiring; and occurred within a 24-hour period. (Can be put on a separate page or pages.)**	See Appendix 4

DEFINITIONS AND NOTES

(1)	"Total customer credits" means the dollar amount of customer credits provided on customer bills during the year.
(2)	"Location of Circuit - zip codes" refers to the zip codes where spans of the circuit are located.
(3)	"Last circuit trim (year)" is the last year there was trimming on the circuit as part of a normal tree trim cycle (not reactive trimming)
(4)	"List of outages and causes" - please discuss outages that meet the definition of a "major interrupton" as defined by R 460.3102(j)
(5)	For CEMI0 through CEMI10+ reporting, please provide percentages. Reporting should be all conditions.
(6)	For CELID reporting, please provide percentages. Reporting should be all conditions and follow the definition of CELID Single Interruption Duration per IEEE 1366-2022 section 4.2.8. Do not double count multiple outages of that fall within the same time bracket. For example, a customer experiencing two nine-hour outages should only be reported once in CELID8hrs. Longer outages may qualify for inclusion in multiple CELID metrics. For example, a customer experiencing a 30-hour outage may be reported in CELID8hrs and CELID24hrs.
(7)	For the worst performing circuits sections, SAIDI and SAIFI should be calculated on a system basis. Worst performing circuits operated by utilities and cooperatives with less 1,000,000 customers should not be compared to worst performing circuits that are operated by utilities with 1,000,000 or more customers.
(8)	For the worst performing circuits sections, a circuit is defined as a substation feeder or line exit from a substation serving at least 10 metered customers.
(9)	The system-wide SAIDI, SAIFI, and CAIDI data is requested pursuant to MCL 460.55 and the July 7, 2023 order in Case No. U-12270.
(10)	Power quality information is being requested pursuant to the July 7, 2023 order in Case No. U-12270.
(11)	Major event day, or MED, is defined according to IEEE 1366-2022.
*	A customer shall be defined as a "metered electric service."
**	Interruptions that occur as a result of outages on customer-owned facilities, or loss of supply from another utility, should not be included in IEEE reliability index calculations.

Appendix 1 - Actions to Improve Reliability Performance

In 2023, the performance of the Company's system missed several Service Quality and Reliability metrics, including Wire Down Relief Factor, Outage Restoration under all but normal conditions, and CEMI4. The metrics are reported in the standard template.

The primary contributing factor to performance below the standard for these metrics in 2023 was multiple catastrophic storms. In particular, the Company experienced three storms that were catastrophic by the MPSC's definition (>10%) of customers impacted, including an ice storm that started in February and extended into March, as well as two severe thunderstorms, one each in July and August.

The company has taken several actions to improve the Wire Down Relief Factor metrics, including increasing the number of resources both across the Company and through external contractors that can be mobilized to secure downed wires, and increasing the capacity to dispatch resources to downed wires, including enhancing technology to optimize dispatch. The Company's investments in Distribution Automation and the associated ground detection benefits can reduce the number of energized downed wires. Maintain the improved direct communication/reporting process with fire departments.

The Company has filed a comprehensive plan to modernize and strengthen the grid with a portfolio of both near- and longer-term initiatives as part of its 2023 Distribution Grid Plan (DGP). This plan will improve both reliability and safety for our customers and improve performance relative to the Service Quality and Reliability Standards' metrics.

In general, the goals of the investments over the next five years are to:

- Stabilize the system with equipment hardening programs to eliminate outages in the face of more frequent and extreme storms. These programs will drive down the volume of wire down events, improving the Wire Down Relief Factor metric. A reduction in outage events will improve both the CEMI4 metric and Outage Restoration (all conditions).
- Increase the level of automated restorations (smart grid technology) by adding up to 10,000 reclosers to the system to reduce the size and duration of customer outages. Reclosers placed at the start of circuits will be able to detect and de-energize wire-downs, reducing electrical hazards and improving Wire Down Relief Factor. The ability to sectionalize and restore sections of circuits through automation with improve Outage Restoration metrics.
- Continue to modernize the grid through substation and circuit voltage conversion projects and subtransmission upgrades to improve reliability by replacing end of life equipment; installing the latest automation technology, which will improve safety by eliminating energized wiredowns; and adding capacity for DER and electrification. DTEE's four investment pillars help to facilitate these goals (information on each pillar is contained within DTEE's 2023 DGP's filing U-20147):
    - Tree Trimming
    - Infrastructure Resilience and Hardening
    - Infrastructure Redesign and Modernization
    - Technology and Automation

The strategic capital plan outlined in the DGP will improve performance in Wire Down Relief, Outage Restoration, and CEMI4. Many of the investments in programs and projects will provide benefits across multiple metrics of wire down events (Wire Down Relief), and outage duration (Outage Restoration) and frequency of events (CEMI4).

Appendix 2 – Description of Catastrophic Conditions

Storm Name	2023003	2023005	2023006	2023007	2023008
Date Storm Began	2/22/2023	6/25/2023	7/20/2023	7/26/2023	8/23/2023
Date Storm Ended	3/7/2023	6/28/2023	7/23/2023	7/30/2023	8/30/2023
Storm Type	Ice	Thunderstorm	Thunderstorm	Thunderstorm	Thunderstorm
Customers Interrupted (#)	866,257	161,244	177,427	364,968	462,108
Storm Duration (hours)	318.0	77.5	79.0	102.0	161.0
Duration of restoration efforts (hours)	323.0	132.0	241.0	166.0	265.0
Date restoration efforts ended	3/7/2023	6/30/2023	7/30/2023	8/2/2023	9/3/2023
spent per event ($)	$ 2,766	$ 3,670	$ 4,017	$ 3,930	$ 5,192
paid in outage credits ($)	$ 2,989,455	$ 441,840	$295,275	$381,455	$ 496,685
Non-baseload resources requested (Y/N)	Y	Y	Y	Y	Y
Company linemen used (#)	484	485	486	496	508
contractor workers used (#)	551	569	585	513	511
non-baseload workers used (#)	1,564	402	497	1,258	1,218
Company crews used (#)	86	88	66	65	75
Contractor crews used (#)	154	170	160	140	147
Non-baseload crews used (#)	441	125	142	353	336
Wire down personnel used (#)	1,318	316	270	584	296
Downed wires	14,202	1,452	1,386	3,338	4,684
Non-baseload resources cost ($)	$145,472,850	$ 16,932,512	$ 16,804,571	$ 42,328,278	$ 59,030,063

Appendix 3 - Corrective Action Plans to Improve SAIDI/SAIFI Performance

Identifier	Circuit Name and Number	Corrective Action
SAIDI-01	YPSIL0317	Circuit automation - 2024
SAIDI-02	KNGSY0330	Tree Trim - 2023
SAIDI-03	ARGO 0326	4.8kV Conversion - Ongoing
SAIDI-04	SNOVR0302	Customer Excellence – 2023 – spot tree trimming, crossarms and associated pole top hardware replaced at various locations 4.8kV Conversion – 2023 – one section of circuit converted and transferred to neighboring 13.2kV circuit
SAIDI-05	APLGT0311	Single event contributed 75% of customer-minutes resolved at that time
SAIDI-06	LEXTN8770	Single event contributed 78% of customer-minutes resolved at that time
SAIDI-07	NBOST0305	Tree Trim - 2023
SAIDI-08	PULFD2155	Tree Trim - 2023 4.8kV Conversion - Ongoing
SAIDI-09	SNOVR0301	Customer Excellence – 2023 – spot tree trimming, crossarms and associated pole top hardware replaced at various locations
SAIDI-10	DENVR2004	Reliability project – 2023 – added fusing and sectionalizing options, reconductoring at various locations, pole replacements at various locations
SAIFI-01	CROWN9832	Customer Excellence – 2023 – spot tree trimming, crossarms and associated pole top hardware replaced at various locations
SAIFI-02	ARGO 0326	4.8kV Conversion - Ongoing
SAIFI-03	HASKL1625	Circuit automation - 2024
SAIFI-04	NBOST0305	Tree Trim - 2023
SAIFI-05	SNOVR0302	Customer Excellence – 2023 – spot tree trimming, crossarms and associated pole top hardware replaced at various locations 4.8kV Conversion – 2023 – one section of circuit converted and transferred to neighboring 13.2kV circuit
SAIFI-06	SDF012641	Customer Excellence – 2023 - crossarms and associated pole top hardware replaced at various locations
SAIFI-07	ARMAD0302	Customer Excellence – 2023 - spot tree trimming, crossarms and associated pole top hardware replaced at various locations Replaced recloser that led to one of the large outages
SAIFI-08	SNOVR0301	Customer Excellence – 2023 – spot tree trimming, crossarms and associated pole top hardware replaced at various locations
SAIFI-09	SDF339897	Customer Excellence - 2023, 2024 - spot tree trimming, crossarms and associated pole top hardware replaced at various locations
SAIFI-10	CABOT9490	Customer Excellence – 2023 - spot tree trimming, crossarms and associated pole top hardware replaced at various locations

Appendix 4 – Power Quality Resolution Process

Power Quality Inquiry Process

DTE Electric (DTE) has a proven effective process in place that enables its large industrial and commercial customers typically served off the sub-transmission or transmission system to obtain resolution of power quality issues. The customers contact their assigned account representative who in turn starts the process of helping the customer by engaging the appropriate engineer in Distribution Operations. DTE and ITC Transmission (ITCT) have a very successful process concerning the transmission system events.

The response to the customer normally includes the following steps:

(1) Obtain pertinent information about what is troubling the customer (old or new equipment, one device or many)
(2) Gather the dates and times from the customer to correlate with EMS Alarm Logger events (cap switching, line trips)
(3) Correlate the customer's experiences with the power quality meters at the service point or with power quality meters in the area
(4) Meet with the customer about the correlation of system and customer events.

Based on the correlation of DTE and customer events, the following outcomes or additional steps are possible:

(1) Special power quality monitoring (DTE or customer) could be installed to determine customer equipment sensitivity and source of problem.
(2) Customer conducts site survey to determine if his operating voltage is optimal
(3) Trouble with minor sags from DTE system (sensitive equipment) - customer's responsibility to make compatible.
(4) Internal system trouble - customer's responsibility to make equipment compatible
(5) ITCT/DTE will seek resolution of problems caused on the ITCT/DTE systems where the customer equipment wouldn't be expected to have ride-through to significant voltage sags. The rate of occurrence, system exposure and service method determine if remedies are commercially feasible.

Power Quality Monitoring

DTE has an array of power quality meters across its system at key industrial, sub-transmission, and distribution buses that have proven to be very effective. New meters are installed at new or upgraded industrial substations and on sub-transmission buses.

The power quality meters at the industrial locations allow DTE to correlate the recorded voltage sags with system events from the SCADA-EMS system. This system provides DTE with information unique to the customer and a tool to track the performance of the system. The system performance data is used to prioritize capital improvements and system maintenance.

The power quality meters on the sub-transmission and distribution buses provide system performance data. This information will reduce the time and cost to find causes of voltage sags and facilitate repair the system when necessary.

Also, voltage sags on the DTE system can be correlated with faults on the ITCT system. The DTE power quality data is shared with ITCT for the benefit of resolving customer power quality issues.

2023 Power Quality Inquiries Summary

The data below indicates the number of customer inquiry and related power quality events correlated by DTE – Distribution Operations in 2023. Each power quality issue is categorized by service methods, power quality events, source of events.

Inquiries			Power Quality Event[1]		PQ Event Source			Detail[6]
Month	Total	Loc. Impacted[2]	Voltage Sag	Interruption	DTE[3]	ITCT[4]	Customer[5]	Inquiry Numbers
Jan	0	0	0	0	0	0	0	
Feb	1	1	0	1	1	0	0	10339
Mar	0	0	0	0	0	0	0	
Apr	2	2	2	0	2	0	0	10340, 10341
May	2	2	2	0	1	0	1	10342, 10343
June	0	0	0	0	0	0	0	
July	3	3	2	1	0	1	2	10344, 10345, 10346
Aug	2	2	0	2	1	1	0	10341, 10347
Sept	2	2	1	1	0	1	1	10343, 10345
Oct	2	2	1	1	0	1	1	10340, 10347
Nov	1	1	1	0	0	0	0	10348
Dec	1	1	1	0	0	1	1	10348
Year	**16**	**16**	**10**	**6**	**5**	**5**	**6**	

1 Voltages and durations (IEEE Std 1159 Table 2 – Categories & Typical Characteristics of Power System Phenomena)
2 Number of unique customer locations impacted per system event ID
3 Equipment owned by DTE (120, 40, 24, 13.2 and 4.8 kV)
4 Equipment owned by ITCT (345, 230 and 120 kV)
5 Equipment owned by the customer or other power systems not owned by DTE or ITCT
6 Inquiry numbers – event detail provided in the table below

The number of locations impacted by customer inquiries was 16 during 2023.

The follow-up investigations indicate that most of the power quality events were due to either voltage sags (62.5%) or interruptions (37.5%) and correlated with trouble occurring on the DTE (31.25%) systems, ITCT (31.25%) systems and possible customer equipment failure (37.5%).

Line clearance, system modifications such as operating practice changes, equipment replacement or maintenance, and adding animal guards/protection are all typical actions taken to reduce the occurrences of the events.

The following table lists information about each inquiry:

Inquiry	Date - Time	System Event	PQ Event	Comments
10339	02/15/2023 10:11	TIE 6931	Interruption	Unknown
10340	04/05/2023 01:27	STERLING TRK 2742	Interruption	Animal Intrusion
10340	10/26/2023 18:00	STERLING TRK 2742	Interruption	Third party interference
10341	04/05/2023 02:58	OLIVER TIE 7520	Unknown	Unknown
10341	08/14/2023 15:56	PIGEON - RANDOLPH 3209	Interruption	Line Equipment
10342	05/09/2023 18:10	Limited Data to identify affected elements	Unknown	Possible Customer
10342	05/09/2023 22:23	Limited Data to identify affected elements	Unknown	Possible Customer
10342	05/10/2023 02:06	Limited Data to identify affected elements	Unknown	Possible Customer
10342	05/10/2023 03:16	Limited Data to identify affected elements	Unknown	Possible Customer
10342	05/10/2023 20:10	Limited Data to identify affected elements	Unknown	Possible Customer
10342	05/11/2023 01:59	Limited Data to identify affected elements	Unknown	Possible Customer
10342	05/11/2023 02:03	Limited Data to identify affected elements	Unknown	Possible Customer
10342	05/15/2023 01:55	Limited Data to identify affected elements	Unknown	Possible Customer
10342	05/17/2023 01:57	Limited Data to identify affected elements	Unknown	Possible Customer
10342	05/17/2023 03:45	Limited Data to identify affected elements	Unknown	Possible Customer
10342	05/17/2023 05:20	Limited Data to identify affected elements	Unknown	Possible Customer
10343	05/22/2023 05:23	STANT DC 8393	Voltage sag	Line Equipment
10343	09/19/2023 19:38	STANT PL 8327	Voltage sag	Line Equipment
10344	07/5/2023 08:43	Limited Data to identify affected elements	Unknown	Possible Customer
10345	07/10/2023	Limited Data to identify affected elements	Unknown	Possible Customer
10345	07/13/2023*	Limited Data to identify affected elements	Unknown	Possible Customer
10345	09/09/2023 16:14*	LALLENDORF-MONROE	Interruption	Line Equipment
10346	07/30/2023 15:26	CUSTER-MONROE	Interruption	Line Equipment
10347	10/04/2023 17:33	ALFRED 120kV	Interruption	Animal Interference
10347	08/24/2023 00:35*	LINCOLN-NORTHEAST-NORTHWEST	Interruption	Storm outage
10348	11/13/2023 21:29	BROWNSTOWN-ENRICO FERMIN	Voltage sag	Unknown
10348	12/11/2023 15:18	Limited Data to identify affected elements	Unknown	Possible Customer

*System shows other customers affected during this time, but no additional complaints were found

Appendix 5

Outage and Cause Listing - Worst performing circuits by SAIDI excluding Major Event Days - Circuit Basis

Ref#	Metric	Rank	Circuit	MED	Storm	Interruption Date/Time	Customers Interrupted	Customer Minutes Interrupted	Cause[1]
SAIDI-01	SAIDI	1	YPSIL0317	-		01/25/23 14:44	1	1,742	Equipment
SAIDI-01	SAIDI	1	YPSIL0317	-		01/26/23 00:25	1	71	Other
SAIDI-01	SAIDI	1	YPSIL0317	-		01/26/23 00:25	1	71	Other
SAIDI-01	SAIDI	1	YPSIL0317	-		02/04/23 16:22	1	5	Other
SAIDI-01	SAIDI	1	YPSIL0317	MED	Cat	02/22/23 17:44	1	9,923	Other
SAIDI-01	SAIDI	1	YPSIL0317	MED	Cat	02/22/23 18:35	1	8,372	Weather
SAIDI-01	SAIDI	1	YPSIL0317	MED	Cat	02/22/23 18:38	47	139,914	Weather
SAIDI-01	SAIDI	1	YPSIL0317	MED	Cat	02/22/23 20:25	1	8,301	Weather
SAIDI-01	SAIDI	1	YPSIL0317	MED	Cat	02/22/23 20:28	1	4,235	Weather
SAIDI-01	SAIDI	1	YPSIL0317	MED	Cat	02/22/23 20:56	1	9,483	Other
SAIDI-01	SAIDI	1	YPSIL0317	MED	Cat	02/22/23 20:58	1	9,707	Other
SAIDI-01	SAIDI	1	YPSIL0317	MED	Cat	02/22/23 21:08	1	6,913	Weather
SAIDI-01	SAIDI	1	YPSIL0317	MED	Cat	02/22/23 21:21	1	9,572	Weather
SAIDI-01	SAIDI	1	YPSIL0317	MED	Cat	02/22/23 21:21	1	9,572	Weather
SAIDI-01	SAIDI	1	YPSIL0317	MED	Cat	02/22/23 21:46	2	144	Weather
SAIDI-01	SAIDI	1	YPSIL0317	MED	Cat	02/22/23 22:12	1	8,360	Other
SAIDI-01	SAIDI	1	YPSIL0317	MED	Cat	02/22/23 23:56	1	16	Other
SAIDI-01	SAIDI	1	YPSIL0317	MED	Cat	02/23/23 06:02	2	12,904	Other
SAIDI-01	SAIDI	1	YPSIL0317	MED	Cat	02/23/23 11:53	1	8,706	Weather
SAIDI-01	SAIDI	1	YPSIL0317	MED	Cat	02/23/23 14:32	2	27	Other
SAIDI-01	SAIDI	1	YPSIL0317	MED	Cat	02/23/23 15:51	4	50	Other
SAIDI-01	SAIDI	1	YPSIL0317	MED	Cat	02/23/23 23:17	1	17	Other
SAIDI-01	SAIDI	1	YPSIL0317	MED	Cat	02/23/23 23:25	142	384,548	Weather
SAIDI-01	SAIDI	1	YPSIL0317	MED	Cat	02/24/23 14:40	1	68	Other
SAIDI-01	SAIDI	1	YPSIL0317	MED	Cat	02/24/23 21:34	1	39	Other
SAIDI-01	SAIDI	1	YPSIL0317	MED	Cat	02/24/23 23:42	1	23	Other
SAIDI-01	SAIDI	1	YPSIL0317	MED	Cat	02/25/23 09:04	1	117	Other
SAIDI-01	SAIDI	1	YPSIL0317	MED	Cat	02/25/23 11:43	1	6	Other
SAIDI-01	SAIDI	1	YPSIL0317	MED	Cat	02/25/23 16:43	2	26	Other
SAIDI-01	SAIDI	1	YPSIL0317	-	Cat	02/25/23 23:09	1,293	3,259,696	Weather
SAIDI-01	SAIDI	1	YPSIL0317	-	Cat	02/25/23 23:09	1	2,544	Other
SAIDI-01	SAIDI	1	YPSIL0317	MED	Cat	02/27/23 22:48	1	15	Other
SAIDI-01	SAIDI	1	YPSIL0317	MED	Cat	02/28/23 05:32	1	8	Other
SAIDI-01	SAIDI	1	YPSIL0317	MED	Cat	02/28/23 07:26	1	6	Other
SAIDI-01	SAIDI	1	YPSIL0317	-	Cat	02/28/23 10:12	12	225	Vegetation

[1] *The “Other” category includes but is not limited to: customer equipment; intentional; and other utility causes.

SAIDI-01	SAIDI	1	YPSIL0317	-	Cat	02/28/23 10:12	1	19	Other
SAIDI-01	SAIDI	1	YPSIL0317	-	Cat	02/28/23 10:12	1	19	Other
SAIDI-01	SAIDI	1	YPSIL0317	-	Cat	02/28/23 11:16	1	25	Other
SAIDI-01	SAIDI	1	YPSIL0317	-	Cat	02/28/23 16:37	1	10	Other
SAIDI-01	SAIDI	1	YPSIL0317	-	Cat	02/28/23 21:47	1	9	Other
SAIDI-01	SAIDI	1	YPSIL0317	-	Cat	03/01/23 13:22	1	30	Other
SAIDI-01	SAIDI	1	YPSIL0317	-	Cat	03/02/23 03:35	1	8	Other
SAIDI-01	SAIDI	1	YPSIL0317	-	Cat	03/02/23 05:38	2	72	Vegetation
SAIDI-01	SAIDI	1	YPSIL0317	-	Cat	03/02/23 11:22	1	42	Other
SAIDI-01	SAIDI	1	YPSIL0317	-	Cat	03/02/23 12:16	1	137	Other
SAIDI-01	SAIDI	1	YPSIL0317	MED	Cat	03/03/23 20:27	1	2,348	Weather
SAIDI-01	SAIDI	1	YPSIL0317	MED	Cat	03/03/23 21:37	1	1,262	Other
SAIDI-01	SAIDI	1	YPSIL0317	MED	Cat	03/03/23 21:42	1	1,246	Equipment
SAIDI-01	SAIDI	1	YPSIL0317	MED	Cat	03/04/23 16:59	17	5,187	Weather
SAIDI-01	SAIDI	1	YPSIL0317	MED	Cat	03/04/23 17:12	46	28,036	Weather
SAIDI-01	SAIDI	1	YPSIL0317	-	Cat	03/05/23 11:10	1	345	Weather
SAIDI-01	SAIDI	1	YPSIL0317	-	Cat	03/07/23 08:45	1	162	Weather
SAIDI-01	SAIDI	1	YPSIL0317	-		03/09/23 10:15	1	40	Other
SAIDI-01	SAIDI	1	YPSIL0317	-		03/09/23 14:20	1	223	Other
SAIDI-01	SAIDI	1	YPSIL0317	-		03/10/23 05:12	63	20,175	Equipment
SAIDI-01	SAIDI	1	YPSIL0317	-		03/10/23 05:12	27	10,292	Equipment
SAIDI-01	SAIDI	1	YPSIL0317	-		03/15/23 07:53	8	3,623	Other
SAIDI-01	SAIDI	1	YPSIL0317	-	Small	03/27/23 08:19	1	35	Other
SAIDI-01	SAIDI	1	YPSIL0317	-		05/10/23 08:44	1	366	Other
SAIDI-01	SAIDI	1	YPSIL0317	-		06/02/23 09:06	1	7	Other
SAIDI-01	SAIDI	1	YPSIL0317	-		06/07/23 11:02	1	55	Other
SAIDI-01	SAIDI	1	YPSIL0317	-		06/11/23 17:42	1	1,138	Vegetation
SAIDI-01	SAIDI	1	YPSIL0317	-		06/16/23 19:16	1	8	Equipment
SAIDI-01	SAIDI	1	YPSIL0317	-		06/21/23 15:36	1	160	Equipment
SAIDI-01	SAIDI	1	YPSIL0317	-		06/21/23 15:36	1	160	Vegetation
SAIDI-01	SAIDI	1	YPSIL0317	MED	Small	06/25/23 18:13	2	2,894	Weather
SAIDI-01	SAIDI	1	YPSIL0317	-		07/19/23 10:20	7	303	Planned
SAIDI-01	SAIDI	1	YPSIL0317	-		07/25/23 10:08	12	429	Other
SAIDI-01	SAIDI	1	YPSIL0317	MED	Cat	07/26/23 15:08	3	13,507	Weather
SAIDI-01	SAIDI	1	YPSIL0317	MED	Cat	07/27/23 13:39	1,069	328,976	Weather
SAIDI-01	SAIDI	1	YPSIL0317	-		08/15/23 11:49	8	212	Other
SAIDI-01	SAIDI	1	YPSIL0317	-		08/15/23 11:49	1	27	Other
SAIDI-01	SAIDI	1	YPSIL0317	-		08/16/23 17:22	2	829	Equipment
SAIDI-01	SAIDI	1	YPSIL0317	MED	Cat	08/24/23 03:23	1	2,205	Other
SAIDI-01	SAIDI	1	YPSIL0317	MED	Cat	08/24/23 03:24	1	2,205	Vegetation
SAIDI-01	SAIDI	1	YPSIL0317	MED	Cat	08/24/23 22:27	2	2,336	Vegetation
SAIDI-01	SAIDI	1	YPSIL0317	-		09/12/23 11:48	2	43	Equipment
SAIDI-01	SAIDI	1	YPSIL0317	-		10/12/23 14:11	2	448	Other

SAIDI-01	SAIDI	1	YPSIL0317	-		12/03/23 18:36	1	18	Wildlife
SAIDI-01	SAIDI	1	YPSIL0317	-		12/09/23 15:42	1	9	Other
SAIDI-01	SAIDI	1	YPSIL0317	-		12/15/23 12:10	1	372	Other
SAIDI-01	SAIDI	1	YPSIL0317	-		12/23/23 14:37	1	11	Other
SAIDI-02	SAIDI	2	KNGSY0330	-		01/01/23 09:10	1	137	Equipment
SAIDI-02	SAIDI	2	KNGSY0330	-		01/08/23 10:39	1	82	Equipment
SAIDI-02	SAIDI	2	KNGSY0330	-		01/11/23 10:18	2	33	Other
SAIDI-02	SAIDI	2	KNGSY0330	-		02/02/23 12:01	1	58	Other
SAIDI-02	SAIDI	2	KNGSY0330	-		02/02/23 12:01	269	15,529	Equipment
SAIDI-02	SAIDI	2	KNGSY0330	-		02/02/23 12:01	1	58	Other
SAIDI-02	SAIDI	2	KNGSY0330	-		02/02/23 12:01	1	58	Other
SAIDI-02	SAIDI	2	KNGSY0330	-		02/13/23 12:58	1	18	Other
SAIDI-02	SAIDI	2	KNGSY0330	MED	Cat	02/22/23 21:30	497	2,903,057	Weather
SAIDI-02	SAIDI	2	KNGSY0330	MED	Cat	02/22/23 23:59	1	5,347	Weather
SAIDI-02	SAIDI	2	KNGSY0330	MED	Cat	02/23/23 10:12	1	5	Other
SAIDI-02	SAIDI	2	KNGSY0330	MED	Cat	02/23/23 11:01	1	232	Other
SAIDI-02	SAIDI	2	KNGSY0330	MED	Cat	02/23/23 12:37	1	5	Other
SAIDI-02	SAIDI	2	KNGSY0330	MED	Cat	02/23/23 13:12	1	5,919	Other
SAIDI-02	SAIDI	2	KNGSY0330	MED	Cat	02/24/23 05:07	154	788,813	Weather
SAIDI-02	SAIDI	2	KNGSY0330	MED	Cat	02/24/23 05:08	2	9,958	Other
SAIDI-02	SAIDI	2	KNGSY0330	MED	Cat	02/24/23 13:11	1	3,148	Other
SAIDI-02	SAIDI	2	KNGSY0330	-	Cat	02/26/23 12:38	1	266	Weather
SAIDI-02	SAIDI	2	KNGSY0330	-	Cat	02/26/23 17:59	1	1,277	Other
SAIDI-02	SAIDI	2	KNGSY0330	-	Cat	02/26/23 18:00	1	1,276	Other
SAIDI-02	SAIDI	2	KNGSY0330	-	Cat	02/28/23 12:39	1	33	Other
SAIDI-02	SAIDI	2	KNGSY0330	-	Cat	03/01/23 13:54	1	1,774	Other
SAIDI-02	SAIDI	2	KNGSY0330	MED	Cat	03/03/23 20:06	1	2,771	Weather
SAIDI-02	SAIDI	2	KNGSY0330	MED	Cat	03/03/23 20:50	1	2,501	Weather
SAIDI-02	SAIDI	2	KNGSY0330	MED	Cat	03/04/23 00:44	1	3,853	Weather
SAIDI-02	SAIDI	2	KNGSY0330	MED	Cat	03/04/23 07:55	1	458	Weather
SAIDI-02	SAIDI	2	KNGSY0330	MED	Cat	03/05/23 02:29	1	2,307	Weather
SAIDI-02	SAIDI	2	KNGSY0330	-	Cat	03/06/23 15:03	1	112	Weather
SAIDI-02	SAIDI	2	KNGSY0330	-		03/08/23 10:50	1	33	Other
SAIDI-02	SAIDI	2	KNGSY0330	-		03/08/23 10:50	1	34	Other
SAIDI-02	SAIDI	2	KNGSY0330	-		03/12/23 19:47	82	7,392	Equipment
SAIDI-02	SAIDI	2	KNGSY0330	-		03/12/23 19:47	5	451	Equipment
SAIDI-02	SAIDI	2	KNGSY0330	-		03/13/23 10:25	273	23,023	Equipment
SAIDI-02	SAIDI	2	KNGSY0330	-		03/16/23 11:57	3	33	Other
SAIDI-02	SAIDI	2	KNGSY0330	-		03/16/23 11:57	1	11	Other
SAIDI-02	SAIDI	2	KNGSY0330	-		03/16/23 11:57	1	11	Other
SAIDI-02	SAIDI	2	KNGSY0330	-		04/05/23 13:07	1	49	Other
SAIDI-02	SAIDI	2	KNGSY0330	-		04/21/23 18:19	1	42	Other
SAIDI-02	SAIDI	2	KNGSY0330	-		04/22/23 15:37	1	238	Other

SAIDI-02	SAIDI	2	KNGSY0330	-		04/24/23 09:22	1	7	Other
SAIDI-02	SAIDI	2	KNGSY0330	-		05/01/23 11:10	1	105	Other
SAIDI-02	SAIDI	2	KNGSY0330	-		05/01/23 11:47	1	387	Other
SAIDI-02	SAIDI	2	KNGSY0330	-		05/10/23 11:44	1	158	Other
SAIDI-02	SAIDI	2	KNGSY0330	-		05/10/23 23:14	25	1,846	Equipment
SAIDI-02	SAIDI	2	KNGSY0330	-		05/11/23 15:19	1	32	Other
SAIDI-02	SAIDI	2	KNGSY0330	-		05/16/23 09:05	1	60	Other
SAIDI-02	SAIDI	2	KNGSY0330	-		05/16/23 09:52	1	340	Equipment
SAIDI-02	SAIDI	2	KNGSY0330	-		05/16/23 12:31	1	88	Other
SAIDI-02	SAIDI	2	KNGSY0330	-		05/17/23 09:11	1	30	Other
SAIDI-02	SAIDI	2	KNGSY0330	-		05/17/23 09:16	1	87	Other
SAIDI-02	SAIDI	2	KNGSY0330	-		06/11/23 08:32	1	81	Other
SAIDI-02	SAIDI	2	KNGSY0330	-		06/22/23 14:11	1	8	Other
SAIDI-02	SAIDI	2	KNGSY0330	MED	Small	06/25/23 18:18	1	24	Weather
SAIDI-02	SAIDI	2	KNGSY0330	-		07/16/23 10:41	1	11	Other
SAIDI-02	SAIDI	2	KNGSY0330	MED		07/20/23 02:00	1	105	Other
SAIDI-02	SAIDI	2	KNGSY0330	MED		07/20/23 02:00	80	8,394	Other
SAIDI-02	SAIDI	2	KNGSY0330	MED	Small	07/20/23 15:31	1	461	Other
SAIDI-02	SAIDI	2	KNGSY0330	-	Small	07/23/23 13:00	2	340	Vegetation
SAIDI-02	SAIDI	2	KNGSY0330	-	Small	07/23/23 13:01	3	17	Other
SAIDI-02	SAIDI	2	KNGSY0330	-	Small	07/23/23 14:06	1	109	Other
SAIDI-02	SAIDI	2	KNGSY0330	-	Small	07/23/23 14:10	1	101	Other
SAIDI-02	SAIDI	2	KNGSY0330	-		07/23/23 23:35	2	1,689	Other
SAIDI-02	SAIDI	2	KNGSY0330	-		07/23/23 23:35	1	844	Equipment
SAIDI-02	SAIDI	2	KNGSY0330	-		07/23/23 23:35	1	844	Equipment
SAIDI-02	SAIDI	2	KNGSY0330	-		07/24/23 11:00	1	36	Other
SAIDI-02	SAIDI	2	KNGSY0330	MED	Cat	07/26/23 17:11	6	212	Vegetation
SAIDI-02	SAIDI	2	KNGSY0330	MED	Cat	07/26/23 17:59	60	8,531	Other
SAIDI-02	SAIDI	2	KNGSY0330	MED	Cat	07/26/23 19:15	1	31	Other
SAIDI-02	SAIDI	2	KNGSY0330	MED	Cat	07/26/23 23:37	3	62	Other
SAIDI-02	SAIDI	2	KNGSY0330	MED	Cat	07/26/23 23:47	222	100,145	Vegetation
SAIDI-02	SAIDI	2	KNGSY0330	MED	Cat	07/27/23 07:35	1	7	Other
SAIDI-02	SAIDI	2	KNGSY0330	MED	Cat	07/27/23 08:36	1	149	Other
SAIDI-02	SAIDI	2	KNGSY0330	MED	Cat	07/27/23 12:38	1	86	Other
SAIDI-02	SAIDI	2	KNGSY0330	MED	Cat	07/27/23 13:30	10	260	Other
SAIDI-02	SAIDI	2	KNGSY0330	MED	Cat	07/27/23 14:49	6	163	Other
SAIDI-02	SAIDI	2	KNGSY0330	MED	Cat	07/27/23 15:35	2	14	Other
SAIDI-02	SAIDI	2	KNGSY0330	MED	Cat	07/27/23 16:11	1	11	Other
SAIDI-02	SAIDI	2	KNGSY0330	MED	Cat	07/28/23 02:33	1	17	Other
SAIDI-02	SAIDI	2	KNGSY0330	MED	Cat	07/28/23 03:19	3	49	Other
SAIDI-02	SAIDI	2	KNGSY0330	MED	Cat	07/28/23 04:08	1	644	Weather
SAIDI-02	SAIDI	2	KNGSY0330	MED	Cat	07/28/23 04:08	644	304,007	Vegetation
SAIDI-02	SAIDI	2	KNGSY0330	MED	Cat	07/28/23 04:08	12	5,973	Vegetation

SAIDI-02	SAIDI	2	KNGSY0330	MED	Cat	07/28/23 04:08	1	644	Weather
SAIDI-02	SAIDI	2	KNGSY0330	MED	Cat	07/28/23 04:08	1	591	Other
SAIDI-02	SAIDI	2	KNGSY0330	MED	Cat	07/28/23 04:08	4	2,575	Other
SAIDI-02	SAIDI	2	KNGSY0330	MED	Cat	07/28/23 04:08	1	591	Weather
SAIDI-02	SAIDI	2	KNGSY0330	MED	Cat	07/28/23 04:08	1	591	Weather
SAIDI-02	SAIDI	2	KNGSY0330	-	Cat	07/29/23 04:35	1	2,349	Other
SAIDI-02	SAIDI	2	KNGSY0330	-	Cat	07/29/23 04:35	1	2,349	Weather
SAIDI-02	SAIDI	2	KNGSY0330	-	Cat	07/29/23 04:36	1	2,349	Weather
SAIDI-02	SAIDI	2	KNGSY0330	-	Cat	07/29/23 04:36	4	9,396	Vegetation
SAIDI-02	SAIDI	2	KNGSY0330	-	Cat	07/29/23 04:36	596	1,395,078	Vegetation
SAIDI-02	SAIDI	2	KNGSY0330	-	Cat	07/29/23 04:36	4	9,396	Vegetation
SAIDI-02	SAIDI	2	KNGSY0330	-	Cat	07/29/23 04:36	2	4,698	Vegetation
SAIDI-02	SAIDI	2	KNGSY0330	-	Cat	07/29/23 04:36	1	2,349	Weather
SAIDI-02	SAIDI	2	KNGSY0330	-		08/11/23 12:12	1	34	Planned
SAIDI-02	SAIDI	2	KNGSY0330	-		08/13/23 13:22	2	161	Equipment
SAIDI-02	SAIDI	2	KNGSY0330	MED	Cat	08/24/23 02:58	1	736	Other
SAIDI-02	SAIDI	2	KNGSY0330	MED	Cat	08/24/23 21:54	3	22	Other
SAIDI-02	SAIDI	2	KNGSY0330	MED	Cat	08/24/23 22:04	1	2,376	Other
SAIDI-02	SAIDI	2	KNGSY0330	MED	Cat	08/24/23 22:15	3	3,342	Other
SAIDI-02	SAIDI	2	KNGSY0330	MED	Cat	08/24/23 22:18	54	207,515	Weather
SAIDI-02	SAIDI	2	KNGSY0330	MED	Cat	08/24/23 22:18	25	96,071	Weather
SAIDI-02	SAIDI	2	KNGSY0330	MED	Cat	08/24/23 22:18	4	15,372	Weather
SAIDI-02	SAIDI	2	KNGSY0330	MED	Cat	08/25/23 06:05	3	18	Other
SAIDI-02	SAIDI	2	KNGSY0330	MED	Cat	08/26/23 02:21	2	2,088	Weather
SAIDI-02	SAIDI	2	KNGSY0330	-		09/11/23 13:26	1	95	Other
SAIDI-02	SAIDI	2	KNGSY0330	-		09/14/23 11:09	1	124	Other
SAIDI-02	SAIDI	2	KNGSY0330	-		09/14/23 16:30	2	178	Other
SAIDI-02	SAIDI	2	KNGSY0330	-		09/24/23 22:37	1	891	Other
SAIDI-02	SAIDI	2	KNGSY0330	-		10/02/23 12:49	1	71	Other
SAIDI-02	SAIDI	2	KNGSY0330	-		10/02/23 12:50	1	69	Planned
SAIDI-02	SAIDI	2	KNGSY0330	-		10/10/23 10:00	2	305	Other
SAIDI-02	SAIDI	2	KNGSY0330	-		10/11/23 16:06	83	8,665	Planned
SAIDI-02	SAIDI	2	KNGSY0330	-		10/14/23 09:32	1	5	Equipment
SAIDI-02	SAIDI	2	KNGSY0330	-		10/18/23 12:24	1	90	Other
SAIDI-02	SAIDI	2	KNGSY0330	-		11/01/23 09:02	1	103	Other
SAIDI-02	SAIDI	2	KNGSY0330	-		11/04/23 10:35	1	58	Other
SAIDI-02	SAIDI	2	KNGSY0330	-		11/08/23 10:38	1	49	Other
SAIDI-02	SAIDI	2	KNGSY0330	-		11/08/23 21:44	1	294	Other
SAIDI-02	SAIDI	2	KNGSY0330	-		11/10/23 09:19	1	91	Other
SAIDI-02	SAIDI	2	KNGSY0330	-		11/11/23 13:23	1	21	Other
SAIDI-02	SAIDI	2	KNGSY0330	-		11/14/23 09:23	1	27	Other
SAIDI-02	SAIDI	2	KNGSY0330	-		11/15/23 08:25	1	96	Other
SAIDI-02	SAIDI	2	KNGSY0330	-		11/19/23 09:40	2	50	Other

SAIDI-02	SAIDI	2	KNGSY0330	-		11/20/23 09:19	1	19	Other
SAIDI-02	SAIDI	2	KNGSY0330	-		11/22/23 09:46	1	220	Other
SAIDI-02	SAIDI	2	KNGSY0330	-		11/22/23 11:43	1	16	Other
SAIDI-02	SAIDI	2	KNGSY0330	-		11/23/23 10:04	1	90	Other
SAIDI-02	SAIDI	2	KNGSY0330	-		11/23/23 13:47	1	29	Other
SAIDI-02	SAIDI	2	KNGSY0330	-		11/28/23 11:06	1	153	Other
SAIDI-02	SAIDI	2	KNGSY0330	-		11/30/23 11:43	1	120	Other
SAIDI-02	SAIDI	2	KNGSY0330	-		12/06/23 12:22	2	403	Other
SAIDI-02	SAIDI	2	KNGSY0330	-		12/08/23 10:12	1	334	Other
SAIDI-02	SAIDI	2	KNGSY0330	-		12/11/23 14:35	1	6	Other
SAIDI-02	SAIDI	2	KNGSY0330	-		12/24/23 06:01	39	5,084	Equipment
SAIDI-02	SAIDI	2	KNGSY0330	-		12/24/23 06:01	6	524	Other
SAIDI-02	SAIDI	2	KNGSY0330	-		12/31/23 13:15	1	285	Other
SAIDI-03	SAIDI	3	ARGO 0326	-		01/01/23 01:54	170	90,380	Other
SAIDI-03	SAIDI	3	ARGO 0326	-		01/01/23 07:57	228	38,490	Equipment
SAIDI-03	SAIDI	3	ARGO 0326	-		01/09/23 10:27	1	54	Other
SAIDI-03	SAIDI	3	ARGO 0326	-		01/09/23 10:28	3	236	Other
SAIDI-03	SAIDI	3	ARGO 0326	-		01/10/23 10:27	13	1,265	Planned
SAIDI-03	SAIDI	3	ARGO 0326	-		01/10/23 12:56	3	200	Equipment
SAIDI-03	SAIDI	3	ARGO 0326	-		01/11/23 10:17	7	441	Planned
SAIDI-03	SAIDI	3	ARGO 0326	-		01/11/23 12:34	10	720	Planned
SAIDI-03	SAIDI	3	ARGO 0326	-		01/12/23 10:42	1	20	Other
SAIDI-03	SAIDI	3	ARGO 0326	-		01/12/23 10:42	5	100	Planned
SAIDI-03	SAIDI	3	ARGO 0326	-		01/18/23 10:17	3	468	Planned
SAIDI-03	SAIDI	3	ARGO 0326	-		01/24/23 10:21	8	946	Planned
SAIDI-03	SAIDI	3	ARGO 0326	-		01/30/23 09:55	13	1,698	Planned
SAIDI-03	SAIDI	3	ARGO 0326	-		02/01/23 15:02	1	36	Other
SAIDI-03	SAIDI	3	ARGO 0326	-		02/01/23 15:02	395	14,106	Equipment
SAIDI-03	SAIDI	3	ARGO 0326	-		02/01/23 15:03	1	36	Other
SAIDI-03	SAIDI	3	ARGO 0326	-		02/04/23 08:36	1	36	Other
SAIDI-03	SAIDI	3	ARGO 0326	-		02/06/23 10:02	10	839	Planned
SAIDI-03	SAIDI	3	ARGO 0326	-		02/06/23 10:02	2	168	Other
SAIDI-03	SAIDI	3	ARGO 0326	-		02/07/23 10:17	14	1,290	Other
SAIDI-03	SAIDI	3	ARGO 0326	-		02/10/23 13:04	3	279	Planned
SAIDI-03	SAIDI	3	ARGO 0326	-		02/14/23 10:03	4	721	Planned
SAIDI-03	SAIDI	3	ARGO 0326	-		02/17/23 10:12	1	154	Planned
SAIDI-03	SAIDI	3	ARGO 0326	-		02/18/23 10:28	6	672	Planned
SAIDI-03	SAIDI	3	ARGO 0326	MED	Cat	02/22/23 21:20	1	5,365	Other
SAIDI-03	SAIDI	3	ARGO 0326	MED	Cat	02/22/23 22:37	1	1,124	Weather
SAIDI-03	SAIDI	3	ARGO 0326	MED	Cat	02/23/23 10:40	1	323	Weather
SAIDI-03	SAIDI	3	ARGO 0326	MED	Cat	02/23/23 12:22	6	27,361	Weather
SAIDI-03	SAIDI	3	ARGO 0326	MED	Cat	02/23/23 20:40	377	114,541	Weather
SAIDI-03	SAIDI	3	ARGO 0326	MED	Cat	02/24/23 02:52	355	1,329,035	Weather

SAIDI-03	SAIDI	3	ARGO 0326	MED	Cat	02/24/23 02:52	27	97,019	Weather
SAIDI-03	SAIDI	3	ARGO 0326	-	Cat	02/26/23 16:36	1	2,598	Other
SAIDI-03	SAIDI	3	ARGO 0326	-	Cat	03/01/23 11:21	1	324	Weather
SAIDI-03	SAIDI	3	ARGO 0326	-	Cat	03/01/23 11:40	1	43	Other
SAIDI-03	SAIDI	3	ARGO 0326	-	Cat	03/01/23 18:03	5	258	Weather
SAIDI-03	SAIDI	3	ARGO 0326	MED	Cat	03/03/23 15:30	1	31	Other
SAIDI-03	SAIDI	3	ARGO 0326	MED	Cat	03/03/23 21:54	1	2,481	Weather
SAIDI-03	SAIDI	3	ARGO 0326	MED	Cat	03/04/23 03:42	1	595	Weather
SAIDI-03	SAIDI	3	ARGO 0326	-		04/15/23 23:43	4	719	Other
SAIDI-03	SAIDI	3	ARGO 0326	-		04/15/23 23:43	9	1,656	Planned
SAIDI-03	SAIDI	3	ARGO 0326	-		04/17/23 12:26	7	155	Planned
SAIDI-03	SAIDI	3	ARGO 0326	-		04/20/23 09:06	1	11	Other
SAIDI-03	SAIDI	3	ARGO 0326	-		04/21/23 07:50	1	77	Other
SAIDI-03	SAIDI	3	ARGO 0326	-		04/23/23 09:04	1	174	Planned
SAIDI-03	SAIDI	3	ARGO 0326	-		04/23/23 09:04	3	522	Other
SAIDI-03	SAIDI	3	ARGO 0326	-		04/28/23 10:29	1	7	Equipment
SAIDI-03	SAIDI	3	ARGO 0326	-		05/04/23 09:27	1	90	Other
SAIDI-03	SAIDI	3	ARGO 0326	-		05/04/23 16:27	1	101	Other
SAIDI-03	SAIDI	3	ARGO 0326	-		05/10/23 18:17	1	19	Other
SAIDI-03	SAIDI	3	ARGO 0326	-		05/17/23 09:57	1	269	Other
SAIDI-03	SAIDI	3	ARGO 0326	-		05/19/23 23:06	42	17,137	Vegetation
SAIDI-03	SAIDI	3	ARGO 0326	-		05/19/23 23:10	1	338	Vegetation
SAIDI-03	SAIDI	3	ARGO 0326	-		05/19/23 23:10	1	338	Vegetation
SAIDI-03	SAIDI	3	ARGO 0326	-		05/19/23 23:10	43	15,657	Vegetation
SAIDI-03	SAIDI	3	ARGO 0326	-		05/19/23 23:10	26	8,788	Vegetation
SAIDI-03	SAIDI	3	ARGO 0326	-		05/19/23 23:10	193	81,493	Vegetation
SAIDI-03	SAIDI	3	ARGO 0326	-		05/19/23 23:10	20	6,829	Vegetation
SAIDI-03	SAIDI	3	ARGO 0326	-		05/19/23 23:10	67	22,645	Vegetation
SAIDI-03	SAIDI	3	ARGO 0326	-		05/30/23 01:49	1	534	Other
SAIDI-03	SAIDI	3	ARGO 0326	-		05/30/23 01:49	1	534	Vegetation
SAIDI-03	SAIDI	3	ARGO 0326	-		05/30/23 01:49	2	1,066	Other
SAIDI-03	SAIDI	3	ARGO 0326	-		05/30/23 01:49	1	534	Equipment
SAIDI-03	SAIDI	3	ARGO 0326	-		05/30/23 01:49	27	18,091	Vegetation
SAIDI-03	SAIDI	3	ARGO 0326	-		05/30/23 01:49	324	172,903	Vegetation
SAIDI-03	SAIDI	3	ARGO 0326	-		05/30/23 01:49	1	533	Other
SAIDI-03	SAIDI	3	ARGO 0326	-		05/30/23 01:49	1	534	Other
SAIDI-03	SAIDI	3	ARGO 0326	-		05/30/23 01:49	7	5,168	Vegetation
SAIDI-03	SAIDI	3	ARGO 0326	-		05/30/23 01:49	28	18,351	Vegetation
SAIDI-03	SAIDI	3	ARGO 0326	-		06/01/23 14:44	1	203	Other
SAIDI-03	SAIDI	3	ARGO 0326	-		06/08/23 13:40	2	484	Planned
SAIDI-03	SAIDI	3	ARGO 0326	-		06/15/23 17:28	396	97,681	Vegetation
SAIDI-03	SAIDI	3	ARGO 0326	-		06/17/23 16:42	1	6	Equipment
SAIDI-03	SAIDI	3	ARGO 0326	MED	Small	06/25/23 18:12	2	11,418	Weather

SAIDI-03	SAIDI	3	ARGO 0326	MED	Small	06/25/23 18:12	18	43,672	Weather
SAIDI-03	SAIDI	3	ARGO 0326	MED	Small	06/25/23 18:12	3	6,684	Weather
SAIDI-03	SAIDI	3	ARGO 0326	MED	Small	06/25/23 18:12	1	2,699	Weather
SAIDI-03	SAIDI	3	ARGO 0326	MED	Small	06/25/23 18:27	2	6,587	Weather
SAIDI-03	SAIDI	3	ARGO 0326	MED	Small	06/25/23 18:40	366	424,422	Weather
SAIDI-03	SAIDI	3	ARGO 0326	MED	Small	06/25/23 18:40	1	3,890	Lightning
SAIDI-03	SAIDI	3	ARGO 0326	MED	Small	06/25/23 18:40	1	3,890	Weather
SAIDI-03	SAIDI	3	ARGO 0326	MED	Small	06/25/23 18:42	1	1,165	Other
SAIDI-03	SAIDI	3	ARGO 0326	MED	Small	06/25/23 18:43	1	1,164	Weather
SAIDI-03	SAIDI	3	ARGO 0326	-		07/03/23 16:52	9	393	Vegetation
SAIDI-03	SAIDI	3	ARGO 0326	-		07/07/23 22:20	1	92	Other
SAIDI-03	SAIDI	3	ARGO 0326	-		07/15/23 07:50	1	1,844	Vegetation
SAIDI-03	SAIDI	3	ARGO 0326	MED	Cat	07/26/23 15:01	1	2,602	Other
SAIDI-03	SAIDI	3	ARGO 0326	MED	Cat	07/26/23 15:01	65	166,873	Weather
SAIDI-03	SAIDI	3	ARGO 0326	MED	Cat	07/26/23 15:05	14	36,366	Vegetation
SAIDI-03	SAIDI	3	ARGO 0326	MED	Cat	07/28/23 11:45	3	302	Weather
SAIDI-03	SAIDI	3	ARGO 0326	-	Cat	07/28/23 18:01	9	25,829	Vegetation
SAIDI-03	SAIDI	3	ARGO 0326	-	Cat	07/28/23 18:01	14	40,180	Vegetation
SAIDI-03	SAIDI	3	ARGO 0326	-		08/01/23 11:41	1	49	Other
SAIDI-03	SAIDI	3	ARGO 0326	-		08/02/23 14:33	1	14	Other
SAIDI-03	SAIDI	3	ARGO 0326	-		08/05/23 17:45	1	7	Other
SAIDI-03	SAIDI	3	ARGO 0326	-		08/11/23 10:39	1	249	Planned
SAIDI-03	SAIDI	3	ARGO 0326	-		08/11/23 10:39	1	249	Other
SAIDI-03	SAIDI	3	ARGO 0326	MED	Cat	08/24/23 06:06	4	23	Other
SAIDI-03	SAIDI	3	ARGO 0326	MED	Cat	08/24/23 07:21	1	413	Equipment
SAIDI-03	SAIDI	3	ARGO 0326	MED	Cat	08/24/23 07:22	1	413	Equipment
SAIDI-03	SAIDI	3	ARGO 0326	MED	Cat	08/24/23 08:29	2	1,324	Other
SAIDI-03	SAIDI	3	ARGO 0326	-	Cat	08/24/23 08:30	1	662	Other
SAIDI-03	SAIDI	3	ARGO 0326	-	Cat	08/24/23 08:30	1	662	Other
SAIDI-03	SAIDI	3	ARGO 0326	MED	Cat	08/24/23 22:07	19	68,929	Weather
SAIDI-03	SAIDI	3	ARGO 0326	MED	Cat	08/24/23 22:42	75	56,201	Other
SAIDI-03	SAIDI	3	ARGO 0326	MED	Cat	08/25/23 08:30	3	148	Equipment
SAIDI-03	SAIDI	3	ARGO 0326	MED	Cat	08/25/23 08:30	1	71	Other
SAIDI-03	SAIDI	3	ARGO 0326	MED	Cat	08/25/23 09:23	2	77	Lightning
SAIDI-03	SAIDI	3	ARGO 0326	MED	Cat	08/25/23 10:15	2	12	Other
SAIDI-03	SAIDI	3	ARGO 0326	MED	Cat	08/25/23 17:37	7	57	Weather
SAIDI-03	SAIDI	3	ARGO 0326	MED	Cat	08/25/23 21:22	8	45	Other
SAIDI-03	SAIDI	3	ARGO 0326	MED	Cat	08/26/23 05:53	14	294	Other
SAIDI-03	SAIDI	3	ARGO 0326	-	Cat	08/26/23 09:10	53	32,872	Other
SAIDI-03	SAIDI	3	ARGO 0326	-		09/05/23 03:58	33	2,845	Equipment
SAIDI-03	SAIDI	3	ARGO 0326	-		09/11/23 12:23	60	6,875	Other
SAIDI-03	SAIDI	3	ARGO 0326	-		09/15/23 11:09	1	327	Other
SAIDI-03	SAIDI	3	ARGO 0326	-		09/19/23 10:16	1	202	Other

SAIDI-03	SAIDI	3	ARGO 0326	-		09/21/23 10:54	1	333	Other
SAIDI-03	SAIDI	3	ARGO 0326	-		09/22/23 15:20	1	6	Other
SAIDI-03	SAIDI	3	ARGO 0326	-		09/26/23 09:45	1	285	Other
SAIDI-03	SAIDI	3	ARGO 0326	-		09/26/23 11:06	8	791	Planned
SAIDI-03	SAIDI	3	ARGO 0326	-		09/27/23 10:08	10	907	Planned
SAIDI-03	SAIDI	3	ARGO 0326	-		09/30/23 09:50	9	1,489	Other
SAIDI-03	SAIDI	3	ARGO 0326	-		09/30/23 09:50	6	991	Planned
SAIDI-03	SAIDI	3	ARGO 0326	-		10/06/23 09:09	16	495	Other
SAIDI-03	SAIDI	3	ARGO 0326	-		10/10/23 11:29	6	969	Planned
SAIDI-03	SAIDI	3	ARGO 0326	-		10/10/23 11:39	7	754	Planned
SAIDI-03	SAIDI	3	ARGO 0326	-		10/13/23 08:49	1	283	Other
SAIDI-03	SAIDI	3	ARGO 0326	-		10/16/23 11:12	13	1,822	Planned
SAIDI-03	SAIDI	3	ARGO 0326	-		10/18/23 10:49	1	11	Planned
SAIDI-03	SAIDI	3	ARGO 0326	-		10/18/23 10:49	9	103	Other
SAIDI-03	SAIDI	3	ARGO 0326	-		10/21/23 11:44	10	1,024	Other
SAIDI-03	SAIDI	3	ARGO 0326	-		10/23/23 11:49	6	513	Planned
SAIDI-03	SAIDI	3	ARGO 0326	-		10/30/23 09:48	1	59	Other
SAIDI-03	SAIDI	3	ARGO 0326	-		10/30/23 10:01	1	81	Other
SAIDI-03	SAIDI	3	ARGO 0326	-		10/31/23 08:34	1	21	Other
SAIDI-03	SAIDI	3	ARGO 0326	-		11/01/23 10:06	38	5,485	Planned
SAIDI-03	SAIDI	3	ARGO 0326	-		11/02/23 12:05	3	482	Planned
SAIDI-03	SAIDI	3	ARGO 0326	-		11/09/23 11:42	9	1,324	Planned
SAIDI-03	SAIDI	3	ARGO 0326	-		11/10/23 10:36	1	435	Other
SAIDI-03	SAIDI	3	ARGO 0326	-		11/11/23 09:43	2	222	Other
SAIDI-03	SAIDI	3	ARGO 0326	-		11/11/23 09:43	2	222	Planned
SAIDI-03	SAIDI	3	ARGO 0326	-		11/11/23 09:43	2	222	Planned
SAIDI-03	SAIDI	3	ARGO 0326	-		11/13/23 09:22	1	203	Other
SAIDI-03	SAIDI	3	ARGO 0326	-		11/20/23 12:02	7	261	Planned
SAIDI-03	SAIDI	3	ARGO 0326	-		11/20/23 12:02	3	126	Planned
SAIDI-03	SAIDI	3	ARGO 0326	-		11/22/23 09:26	1	393	Other
SAIDI-03	SAIDI	3	ARGO 0326	-		11/27/23 11:04	2	195	Planned
SAIDI-03	SAIDI	3	ARGO 0326	-		11/27/23 11:16	2	318	Other
SAIDI-03	SAIDI	3	ARGO 0326	-		11/27/23 11:28	1	221	Planned
SAIDI-03	SAIDI	3	ARGO 0326	-		11/27/23 11:28	1	221	Planned
SAIDI-03	SAIDI	3	ARGO 0326	-		11/28/23 11:25	1	104	Planned
SAIDI-03	SAIDI	3	ARGO 0326	-		11/28/23 11:25	2	208	Other
SAIDI-03	SAIDI	3	ARGO 0326	-		11/28/23 11:25	1	104	Planned
SAIDI-03	SAIDI	3	ARGO 0326	-		11/28/23 11:25	2	208	Other
SAIDI-03	SAIDI	3	ARGO 0326	-		11/29/23 10:39	1	29	Planned
SAIDI-03	SAIDI	3	ARGO 0326	-		11/29/23 10:39	27	789	Planned
SAIDI-03	SAIDI	3	ARGO 0326	-		11/29/23 10:39	2	57	Other
SAIDI-03	SAIDI	3	ARGO 0326	-		11/29/23 10:40	11	309	Planned
SAIDI-03	SAIDI	3	ARGO 0326	-		11/29/23 10:40	14	394	Planned

SAIDI-03	SAIDI	3	ARGO 0326	-		11/29/23 10:40	1	28	Planned
SAIDI-04	SAIDI	4	SNOVR0302	-		01/01/23 01:04	696	612,258	Equipment
SAIDI-04	SAIDI	4	SNOVR0302	-		01/01/23 01:04	1	2,206	Equipment
SAIDI-04	SAIDI	4	SNOVR0302	-		01/01/23 19:23	2	2,225	Equipment
SAIDI-04	SAIDI	4	SNOVR0302	-		01/01/23 23:47	1	7	Other
SAIDI-04	SAIDI	4	SNOVR0302	-		01/02/23 13:26	1	24	Other
SAIDI-04	SAIDI	4	SNOVR0302	-		01/02/23 13:42	3	904	Other
SAIDI-04	SAIDI	4	SNOVR0302	-		01/03/23 04:12	811	19,420	Other
SAIDI-04	SAIDI	4	SNOVR0302	-		01/03/23 16:49	1	37	Other
SAIDI-04	SAIDI	4	SNOVR0302	-		01/03/23 16:49	1	37	Other
SAIDI-04	SAIDI	4	SNOVR0302	-		01/03/23 16:49	1	37	Other
SAIDI-04	SAIDI	4	SNOVR0302	-		01/11/23 21:01	1	6	Other
SAIDI-04	SAIDI	4	SNOVR0302	-		02/04/23 11:14	1	157	Equipment
SAIDI-04	SAIDI	4	SNOVR0302	-		03/15/23 18:43	1	9	Other
SAIDI-04	SAIDI	4	SNOVR0302	-		03/30/23 07:29	1	318	Other
SAIDI-04	SAIDI	4	SNOVR0302	-		03/31/23 22:34	1	1,362	Equipment
SAIDI-04	SAIDI	4	SNOVR0302	-		04/01/23 10:31	47	9,998	Weather
SAIDI-04	SAIDI	4	SNOVR0302	-		04/01/23 10:31	20	4,090	Other
SAIDI-04	SAIDI	4	SNOVR0302	-		04/05/23 11:08	1	13	Other
SAIDI-04	SAIDI	4	SNOVR0302	-		04/24/23 11:50	1	28	Planned
SAIDI-04	SAIDI	4	SNOVR0302	-		04/24/23 13:31	1	11	Other
SAIDI-04	SAIDI	4	SNOVR0302	-		04/24/23 13:34	1	11	Planned
SAIDI-04	SAIDI	4	SNOVR0302	-		04/25/23 09:36	1	145	Other
SAIDI-04	SAIDI	4	SNOVR0302	-		04/26/23 09:35	2	25	Planned
SAIDI-04	SAIDI	4	SNOVR0302	-		04/26/23 10:26	1	26	Planned
SAIDI-04	SAIDI	4	SNOVR0302	-		04/26/23 11:27	1	51	Planned
SAIDI-04	SAIDI	4	SNOVR0302	-		05/01/23 09:29	1	30	Planned
SAIDI-04	SAIDI	4	SNOVR0302	-		05/01/23 10:31	1	23	Planned
SAIDI-04	SAIDI	4	SNOVR0302	-		05/01/23 11:03	1	29	Planned
SAIDI-04	SAIDI	4	SNOVR0302	-		05/01/23 13:57	1	99	Planned
SAIDI-04	SAIDI	4	SNOVR0302	-		05/04/23 10:25	1	18	Planned
SAIDI-04	SAIDI	4	SNOVR0302	-		05/04/23 11:06	1	16	Planned
SAIDI-04	SAIDI	4	SNOVR0302	-		05/04/23 14:20	1	18	Planned
SAIDI-04	SAIDI	4	SNOVR0302	-		05/04/23 15:13	1	16	Other
SAIDI-04	SAIDI	4	SNOVR0302	-		05/08/23 09:48	1	28	Planned
SAIDI-04	SAIDI	4	SNOVR0302	-		05/08/23 13:45	1	13	Planned
SAIDI-04	SAIDI	4	SNOVR0302	-		05/08/23 14:31	1	30	Planned
SAIDI-04	SAIDI	4	SNOVR0302	-		05/09/23 11:46	1	28	Planned
SAIDI-04	SAIDI	4	SNOVR0302	-		05/09/23 12:40	1	23	Planned
SAIDI-04	SAIDI	4	SNOVR0302	-		05/09/23 15:16	1	16	Planned
SAIDI-04	SAIDI	4	SNOVR0302	-		05/10/23 09:53	1	36	Planned
SAIDI-04	SAIDI	4	SNOVR0302	-		05/10/23 12:09	1	8	Planned
SAIDI-04	SAIDI	4	SNOVR0302	-		05/10/23 12:09	4	36	Other

SAIDI-04	SAIDI	4	SNOVR0302	-		05/10/23 14:10	1	34	Planned
SAIDI-04	SAIDI	4	SNOVR0302	-		05/10/23 15:15	1	7	Other
SAIDI-04	SAIDI	4	SNOVR0302	-		05/11/23 08:38	1	6	Other
SAIDI-04	SAIDI	4	SNOVR0302	-		05/11/23 09:20	1	25	Planned
SAIDI-04	SAIDI	4	SNOVR0302	-		05/19/23 09:21	1	23	Planned
SAIDI-04	SAIDI	4	SNOVR0302	-		05/19/23 10:16	1	51	Other
SAIDI-04	SAIDI	4	SNOVR0302	-		05/19/23 11:15	1	26	Planned
SAIDI-04	SAIDI	4	SNOVR0302	-		05/19/23 12:05	1	95	Equipment
SAIDI-04	SAIDI	4	SNOVR0302	-		05/20/23 08:54	1	135	Planned
SAIDI-04	SAIDI	4	SNOVR0302	-		05/22/23 09:30	1	20	Planned
SAIDI-04	SAIDI	4	SNOVR0302	-		05/22/23 10:32	1	14	Other
SAIDI-04	SAIDI	4	SNOVR0302	-		05/22/23 10:45	1	42	Planned
SAIDI-04	SAIDI	4	SNOVR0302	-		05/22/23 11:13	1	6	Planned
SAIDI-04	SAIDI	4	SNOVR0302	-		05/22/23 11:29	1	26	Other
SAIDI-04	SAIDI	4	SNOVR0302	-		05/22/23 12:26	1	14	Other
SAIDI-04	SAIDI	4	SNOVR0302	-		05/23/23 09:35	1	42	Planned
SAIDI-04	SAIDI	4	SNOVR0302	-		05/23/23 09:53	2	116	Planned
SAIDI-04	SAIDI	4	SNOVR0302	-		05/23/23 11:47	2	48	Other
SAIDI-04	SAIDI	4	SNOVR0302	-		05/23/23 11:47	1	24	Planned
SAIDI-04	SAIDI	4	SNOVR0302	-		05/23/23 12:46	1	18	Planned
SAIDI-04	SAIDI	4	SNOVR0302	-		05/23/23 13:37	1	20	Planned
SAIDI-04	SAIDI	4	SNOVR0302	-		05/23/23 13:37	1	20	Other
SAIDI-04	SAIDI	4	SNOVR0302	-		05/24/23 09:00	1	25	Planned
SAIDI-04	SAIDI	4	SNOVR0302	-		05/24/23 10:32	1	55	Other
SAIDI-04	SAIDI	4	SNOVR0302	-		05/24/23 10:33	6	328	Other
SAIDI-04	SAIDI	4	SNOVR0302	-		06/01/23 13:12	1	94	Planned
SAIDI-04	SAIDI	4	SNOVR0302	-		06/06/23 08:11	1	108	Other
SAIDI-04	SAIDI	4	SNOVR0302	-		06/30/23 01:20	5	2,744	Vegetation
SAIDI-04	SAIDI	4	SNOVR0302	-		07/11/23 11:52	1	15	Other
SAIDI-04	SAIDI	4	SNOVR0302	-		07/13/23 01:28	1	937	Weather
SAIDI-04	SAIDI	4	SNOVR0302	-		07/13/23 01:37	4	3,680	Other
SAIDI-04	SAIDI	4	SNOVR0302	-		07/13/23 13:26	1	41	Other
SAIDI-04	SAIDI	4	SNOVR0302	-		07/17/23 11:45	2	71	Other
SAIDI-04	SAIDI	4	SNOVR0302	-		07/17/23 11:45	1	36	Other
SAIDI-04	SAIDI	4	SNOVR0302	-		07/25/23 09:51	1	53	Other
SAIDI-04	SAIDI	4	SNOVR0302	-		08/08/23 14:23	338	83,884	Equipment
SAIDI-04	SAIDI	4	SNOVR0302	MED	Cat	08/24/23 20:06	1	6	Other
SAIDI-04	SAIDI	4	SNOVR0302	-		09/18/23 10:44	1	13	Other
SAIDI-04	SAIDI	4	SNOVR0302	-		09/18/23 12:15	1	34	Other
SAIDI-04	SAIDI	4	SNOVR0302	-		09/19/23 10:47	2	15	Other
SAIDI-04	SAIDI	4	SNOVR0302	-		09/28/23 09:57	5	222	Other
SAIDI-04	SAIDI	4	SNOVR0302	-		10/18/23 15:39	74	9,897	Equipment
SAIDI-04	SAIDI	4	SNOVR0302	-		10/18/23 15:39	1	106	Other

SAIDI-04	SAIDI	4	SNOVR0302	-		10/23/23 12:43	1	41	Other
SAIDI-04	SAIDI	4	SNOVR0302	-		11/09/23 12:59	1	12	Vegetation
SAIDI-04	SAIDI	4	SNOVR0302	-		11/09/23 22:14	1	704	Equipment
SAIDI-04	SAIDI	4	SNOVR0302	-		11/10/23 20:57	5	43	Other
SAIDI-04	SAIDI	4	SNOVR0302	-		11/21/23 07:11	1	294	Equipment
SAIDI-05	SAIDI	5	APLGT0311	-		01/06/23 17:24	1	11	Other
SAIDI-05	SAIDI	5	APLGT0311	-		01/16/23 15:27	1	17	Other
SAIDI-05	SAIDI	5	APLGT0311	-		02/02/23 11:35	2	1,451	Other
SAIDI-05	SAIDI	5	APLGT0311	-		02/12/23 08:00	1	17	Other
SAIDI-05	SAIDI	5	APLGT0311	-		02/12/23 15:54	1	64	Other
SAIDI-05	SAIDI	5	APLGT0311	-	Small	02/16/23 21:50	1	2,286	Weather
SAIDI-05	SAIDI	5	APLGT0311	-		02/18/23 11:03	2	74	Other
SAIDI-05	SAIDI	5	APLGT0311	-		02/18/23 11:03	35	1,295	Planned
SAIDI-05	SAIDI	5	APLGT0311	MED	Cat	02/27/23 15:49	1	1,632	Other
SAIDI-05	SAIDI	5	APLGT0311	MED	Cat	03/04/23 00:02	2	4,296	Weather
SAIDI-05	SAIDI	5	APLGT0311	-		03/16/23 11:27	1	72	Other
SAIDI-05	SAIDI	5	APLGT0311	-	Small	03/27/23 10:59	1	46	Other
SAIDI-05	SAIDI	5	APLGT0311	-	Small	03/27/23 10:59	1	46	Other
SAIDI-05	SAIDI	5	APLGT0311	-		04/10/23 10:21	3	68	Other
SAIDI-05	SAIDI	5	APLGT0311	-		04/10/23 11:17	1	224	Other
SAIDI-05	SAIDI	5	APLGT0311	-		04/30/23 08:37	2	532	Other
SAIDI-05	SAIDI	5	APLGT0311	-		04/30/23 08:37	1	270	Equipment
SAIDI-05	SAIDI	5	APLGT0311	-		06/10/23 07:54	1	745	Other
SAIDI-05	SAIDI	5	APLGT0311	-		06/19/23 10:05	1	12	Other
SAIDI-05	SAIDI	5	APLGT0311	-		06/19/23 15:42	1	119	Equipment
SAIDI-05	SAIDI	5	APLGT0311	-		07/06/23 13:26	1	36	Other
SAIDI-05	SAIDI	5	APLGT0311	-		07/14/23 15:58	1	1,560	Other
SAIDI-05	SAIDI	5	APLGT0311	-		07/14/23 15:58	1	1,560	Other
SAIDI-05	SAIDI	5	APLGT0311	-		07/14/23 15:58	1	1,560	Other
SAIDI-05	SAIDI	5	APLGT0311	-		07/14/23 15:58	1	1,560	Other
SAIDI-05	SAIDI	5	APLGT0311	-		07/14/23 15:58	60	127,013	Weather
SAIDI-05	SAIDI	5	APLGT0311	-		07/14/23 15:58	1	1,560	Other
SAIDI-05	SAIDI	5	APLGT0311	-		07/14/23 15:58	1	1,560	Other
SAIDI-05	SAIDI	5	APLGT0311	-		07/14/23 15:58	1	1,560	Other
SAIDI-05	SAIDI	5	APLGT0311	-		07/14/23 15:58	1	1,560	Other
SAIDI-05	SAIDI	5	APLGT0311	-		07/14/23 15:58	1	1,560	Other
SAIDI-05	SAIDI	5	APLGT0311	-		07/14/23 21:31	8	9,817	Other
SAIDI-05	SAIDI	5	APLGT0311	-		07/15/23 11:19	3	1,197	Other
SAIDI-05	SAIDI	5	APLGT0311	-		07/17/23 16:48	9	2,428	Other
SAIDI-05	SAIDI	5	APLGT0311	-		07/17/23 16:48	100	23,453	Vegetation
SAIDI-05	SAIDI	5	APLGT0311	-		07/17/23 16:49	2	539	Weather
SAIDI-05	SAIDI	5	APLGT0311	-		07/19/23 11:02	4	569	Other
SAIDI-05	SAIDI	5	APLGT0311	-		08/03/23 09:38	1	65	Other

SAIDI-05	SAIDI	5	APLGT0311	-		08/04/23 14:28	1	181	Other
SAIDI-05	SAIDI	5	APLGT0311	-		08/08/23 15:51	1	1,334	Other
SAIDI-05	SAIDI	5	APLGT0311	-		08/08/23 15:51	446	595,431	Equipment
SAIDI-05	SAIDI	5	APLGT0311	-		11/29/23 13:03	1	190	Other
SAIDI-05	SAIDI	5	APLGT0311	-		11/29/23 14:01	1	27	Other
SAIDI-06	SAIDI	6	LEXTN8770	-		01/04/23 11:14	12	2,040	Planned
SAIDI-06	SAIDI	6	LEXTN8770	-		01/13/23 08:39	1	151	Weather
SAIDI-06	SAIDI	6	LEXTN8770	-		01/16/23 09:22	1	105	Equipment
SAIDI-06	SAIDI	6	LEXTN8770	-		01/16/23 09:23	1	105	Other
SAIDI-06	SAIDI	6	LEXTN8770	-		01/23/23 21:23	3	947	Other
SAIDI-06	SAIDI	6	LEXTN8770	-		01/23/23 22:42	17	266	Other
SAIDI-06	SAIDI	6	LEXTN8770	-		01/23/23 22:42	4	62	Other
SAIDI-06	SAIDI	6	LEXTN8770	-		01/23/23 22:42	10	156	Other
SAIDI-06	SAIDI	6	LEXTN8770	-		01/23/23 22:42	45	702	Other
SAIDI-06	SAIDI	6	LEXTN8770	-		01/23/23 22:42	1	16	Other
SAIDI-06	SAIDI	6	LEXTN8770	-		01/23/23 22:42	2	31	Other
SAIDI-06	SAIDI	6	LEXTN8770	-		01/23/23 22:42	3	47	Other
SAIDI-06	SAIDI	6	LEXTN8770	-		01/24/23 10:55	1	14	Other
SAIDI-06	SAIDI	6	LEXTN8770	-		01/26/23 10:40	1	5	Other
SAIDI-06	SAIDI	6	LEXTN8770	-		01/30/23 01:03	1	9	Other
SAIDI-06	SAIDI	6	LEXTN8770	-		02/04/23 13:20	1	129	Other
SAIDI-06	SAIDI	6	LEXTN8770	-		02/04/23 13:20	1	129	Other
SAIDI-06	SAIDI	6	LEXTN8770	-		02/06/23 18:36	1	45	Wildlife
SAIDI-06	SAIDI	6	LEXTN8770	-		02/09/23 11:14	1	23	Other
SAIDI-06	SAIDI	6	LEXTN8770	-		02/09/23 16:01	2	64	Equipment
SAIDI-06	SAIDI	6	LEXTN8770	-		02/14/23 08:51	2	167	Wildlife
SAIDI-06	SAIDI	6	LEXTN8770	-	Small	02/15/23 12:13	1	991	Weather
SAIDI-06	SAIDI	6	LEXTN8770	-	Small	02/15/23 12:13	25	24,772	Weather
SAIDI-06	SAIDI	6	LEXTN8770	-		02/18/23 11:03	3	111	Planned
SAIDI-06	SAIDI	6	LEXTN8770	-		02/20/23 13:05	1	68	Other
SAIDI-06	SAIDI	6	LEXTN8770	MED	Cat	02/24/23 03:51	1	513	Weather
SAIDI-06	SAIDI	6	LEXTN8770	-	Cat	02/28/23 08:05	1	257	Other
SAIDI-06	SAIDI	6	LEXTN8770	-	Cat	02/28/23 12:44	1	8	Other
SAIDI-06	SAIDI	6	LEXTN8770	-	Cat	02/28/23 14:12	1	15	Other
SAIDI-06	SAIDI	6	LEXTN8770	-	Cat	03/02/23 10:25	1	34	Other
SAIDI-06	SAIDI	6	LEXTN8770	MED	Cat	03/03/23 21:43	1	2,348	Weather
SAIDI-06	SAIDI	6	LEXTN8770	-	Cat	03/05/23 22:52	2	1,346	Weather
SAIDI-06	SAIDI	6	LEXTN8770	-		03/17/23 15:15	1	70	Other
SAIDI-06	SAIDI	6	LEXTN8770	-		04/03/23 10:11	1	159	Equipment
SAIDI-06	SAIDI	6	LEXTN8770	-		04/04/23 11:29	1	46	Other
SAIDI-06	SAIDI	6	LEXTN8770	-		04/05/23 21:54	1	1,142	Equipment
SAIDI-06	SAIDI	6	LEXTN8770	-		04/05/23 22:08	1	803	Other
SAIDI-06	SAIDI	6	LEXTN8770	-		04/07/23 12:25	1	9	Other

SAIDI-06	SAIDI	6	LEXTN8770	-		04/08/23 22:20	5	900	Equipment
SAIDI-06	SAIDI	6	LEXTN8770	-		04/12/23 13:55	1	86	Other
SAIDI-06	SAIDI	6	LEXTN8770	-		04/16/23 09:16	1	81	Wildlife
SAIDI-06	SAIDI	6	LEXTN8770	-		04/18/23 11:49	1	15	Other
SAIDI-06	SAIDI	6	LEXTN8770	-		04/22/23 14:37	1	1,552	Other
SAIDI-06	SAIDI	6	LEXTN8770	-		04/24/23 10:19	1	20	Other
SAIDI-06	SAIDI	6	LEXTN8770	-		04/24/23 12:13	1	35	Planned
SAIDI-06	SAIDI	6	LEXTN8770	-		04/25/23 10:00	1	49	Planned
SAIDI-06	SAIDI	6	LEXTN8770	-		04/25/23 11:36	1	32	Planned
SAIDI-06	SAIDI	6	LEXTN8770	-		04/25/23 12:37	1	15	Other
SAIDI-06	SAIDI	6	LEXTN8770	-		04/26/23 09:37	1	99	Planned
SAIDI-06	SAIDI	6	LEXTN8770	-		04/28/23 08:31	1	28	Other
SAIDI-06	SAIDI	6	LEXTN8770	-		04/28/23 10:48	1	10	Other
SAIDI-06	SAIDI	6	LEXTN8770	-		04/28/23 10:48	1	10	Planned
SAIDI-06	SAIDI	6	LEXTN8770	-		04/29/23 11:58	1	201	Other
SAIDI-06	SAIDI	6	LEXTN8770	-		04/29/23 21:48	1	81	Equipment
SAIDI-06	SAIDI	6	LEXTN8770	-		05/01/23 10:46	4	564	Planned
SAIDI-06	SAIDI	6	LEXTN8770	-		05/04/23 08:34	3	453	Planned
SAIDI-06	SAIDI	6	LEXTN8770	-		05/04/23 10:14	1	81	Other
SAIDI-06	SAIDI	6	LEXTN8770	-		05/04/23 12:30	1	214	Other
SAIDI-06	SAIDI	6	LEXTN8770	-		05/04/23 19:03	1	370	Other
SAIDI-06	SAIDI	6	LEXTN8770	-		05/05/23 19:47	1	72	Other
SAIDI-06	SAIDI	6	LEXTN8770	-		05/06/23 09:22	1	18	Other
SAIDI-06	SAIDI	6	LEXTN8770	-		05/07/23 00:25	3	65	Equipment
SAIDI-06	SAIDI	6	LEXTN8770	-		05/07/23 03:05	3	34	Other
SAIDI-06	SAIDI	6	LEXTN8770	-		05/07/23 08:58	1	170	Other
SAIDI-06	SAIDI	6	LEXTN8770	-		05/08/23 09:58	1	25	Other
SAIDI-06	SAIDI	6	LEXTN8770	-		05/08/23 11:08	1	109	Other
SAIDI-06	SAIDI	6	LEXTN8770	-		05/08/23 13:27	1	7	Other
SAIDI-06	SAIDI	6	LEXTN8770	-		05/08/23 13:51	1	42	Other
SAIDI-06	SAIDI	6	LEXTN8770	-		05/10/23 09:11	4	288	Planned
SAIDI-06	SAIDI	6	LEXTN8770	-		05/11/23 12:22	1	7	Other
SAIDI-06	SAIDI	6	LEXTN8770	-		05/16/23 08:10	1	155	Other
SAIDI-06	SAIDI	6	LEXTN8770	-		05/16/23 10:35	2	304	Other
SAIDI-06	SAIDI	6	LEXTN8770	-		05/17/23 08:49	1	426	Other
SAIDI-06	SAIDI	6	LEXTN8770	-		05/17/23 10:28	2	213	Planned
SAIDI-06	SAIDI	6	LEXTN8770	-		05/17/23 10:54	439	86,700	Vegetation
SAIDI-06	SAIDI	6	LEXTN8770	-		05/17/23 14:46	1	633	Equipment
SAIDI-06	SAIDI	6	LEXTN8770	-		05/18/23 20:50	1	19	Other
SAIDI-06	SAIDI	6	LEXTN8770	-		05/22/23 07:29	1	174	Other
SAIDI-06	SAIDI	6	LEXTN8770	-		05/22/23 08:24	1	132	Other
SAIDI-06	SAIDI	6	LEXTN8770	-		05/22/23 14:59	1	77	Other
SAIDI-06	SAIDI	6	LEXTN8770	-		05/26/23 12:34	1	65	Planned

SAIDI-06	SAIDI	6	LEXTN8770	-		05/27/23 10:18	1	304	Other
SAIDI-06	SAIDI	6	LEXTN8770	-		06/01/23 10:42	1	5	Other
SAIDI-06	SAIDI	6	LEXTN8770	-		06/01/23 11:47	96	9,474	Equipment
SAIDI-06	SAIDI	6	LEXTN8770	-		06/02/23 12:13	1	11	Other
SAIDI-06	SAIDI	6	LEXTN8770	-		06/02/23 12:59	1	66	Other
SAIDI-06	SAIDI	6	LEXTN8770	-		06/05/23 10:16	1	517	Other
SAIDI-06	SAIDI	6	LEXTN8770	-		06/05/23 19:56	1	13	Other
SAIDI-06	SAIDI	6	LEXTN8770	-		06/07/23 09:19	1	116	Other
SAIDI-06	SAIDI	6	LEXTN8770	-		06/09/23 09:28	1	216	Other
SAIDI-06	SAIDI	6	LEXTN8770	-		06/15/23 18:11	1	138	Other
SAIDI-06	SAIDI	6	LEXTN8770	-		06/15/23 18:11	1	138	Other
SAIDI-06	SAIDI	6	LEXTN8770	-		06/21/23 11:28	1	42	Other
SAIDI-06	SAIDI	6	LEXTN8770	-		06/22/23 08:39	1	217	Other
SAIDI-06	SAIDI	6	LEXTN8770	-		06/22/23 09:42	1	74	Planned
SAIDI-06	SAIDI	6	LEXTN8770	-		06/23/23 09:25	1	14	Other
SAIDI-06	SAIDI	6	LEXTN8770	-		06/23/23 19:43	1	1,321	Wildlife
SAIDI-06	SAIDI	6	LEXTN8770	-		06/23/23 19:43	23	30,392	Equipment
SAIDI-06	SAIDI	6	LEXTN8770	-		06/23/23 19:43	6	7,928	Other
SAIDI-06	SAIDI	6	LEXTN8770	-		06/23/23 19:43	3,030	4,004,995	Equipment
SAIDI-06	SAIDI	6	LEXTN8770	-		06/23/23 19:43	3	3,964	Equipment
SAIDI-06	SAIDI	6	LEXTN8770	-		06/23/23 19:43	1	1,321	Other
SAIDI-06	SAIDI	6	LEXTN8770	-		07/01/23 18:09	1	33	Other
SAIDI-06	SAIDI	6	LEXTN8770	-		07/03/23 09:56	1	53	Other
SAIDI-06	SAIDI	6	LEXTN8770	-		07/04/23 10:12	2	99	Other
SAIDI-06	SAIDI	6	LEXTN8770	-		07/07/23 09:03	1	17	Other
SAIDI-06	SAIDI	6	LEXTN8770	-		07/11/23 12:55	14	2,978	Lightning
SAIDI-06	SAIDI	6	LEXTN8770	-		07/11/23 12:55	15	3,190	Equipment
SAIDI-06	SAIDI	6	LEXTN8770	MED		07/11/23 14:41	4	1,010	Other
SAIDI-06	SAIDI	6	LEXTN8770	MED		07/11/23 14:41	1	334	Weather
SAIDI-06	SAIDI	6	LEXTN8770	MED		07/11/23 14:41	1	334	Weather
SAIDI-06	SAIDI	6	LEXTN8770	-		07/14/23 15:34	1	2,879	Other
SAIDI-06	SAIDI	6	LEXTN8770	-		07/14/23 15:34	292	523,246	Weather
SAIDI-06	SAIDI	6	LEXTN8770	-		07/14/23 15:43	7	17,523	Power Supply
SAIDI-06	SAIDI	6	LEXTN8770	-		07/14/23 15:43	1	4,336	Other
SAIDI-06	SAIDI	6	LEXTN8770	-		07/14/23 15:43	2	8,672	Vegetation
SAIDI-06	SAIDI	6	LEXTN8770	-		07/14/23 15:43	1	4,019	Equipment
SAIDI-06	SAIDI	6	LEXTN8770	-		07/14/23 15:44	6	6,732	Weather
SAIDI-06	SAIDI	6	LEXTN8770	-		07/14/23 15:44	2	2,244	Equipment
SAIDI-06	SAIDI	6	LEXTN8770	-		07/14/23 15:44	1	1,122	Other
SAIDI-06	SAIDI	6	LEXTN8770	-		07/14/23 15:49	1	266	Equipment
SAIDI-06	SAIDI	6	LEXTN8770	-		07/14/23 15:49	30	25,965	Equipment
SAIDI-06	SAIDI	6	LEXTN8770	-		07/14/23 15:50	4	5,345	Other

SAIDI-06	SAIDI	6	LEXTN8770	-		07/14/23 17:29	408	93,367	Weather
SAIDI-06	SAIDI	6	LEXTN8770	-		07/14/23 17:29	3	501	Equipment
SAIDI-06	SAIDI	6	LEXTN8770	-		07/14/23 20:30	1	1,216	Other
SAIDI-06	SAIDI	6	LEXTN8770	-		07/14/23 21:31	2	2,454	Equipment
SAIDI-06	SAIDI	6	LEXTN8770	-		07/14/23 21:35	1	165	Other
SAIDI-06	SAIDI	6	LEXTN8770	-		07/16/23 12:37	5	1,047	Power Supply
SAIDI-06	SAIDI	6	LEXTN8770	-		07/16/23 12:37	5	1,047	Other
SAIDI-06	SAIDI	6	LEXTN8770	-		07/16/23 12:37	1	209	Other
SAIDI-06	SAIDI	6	LEXTN8770	-		07/16/23 12:37	13	2,722	Other
SAIDI-06	SAIDI	6	LEXTN8770	-		07/16/23 12:37	1	209	Power Supply
SAIDI-06	SAIDI	6	LEXTN8770	-		07/16/23 12:37	1	209	Other
SAIDI-06	SAIDI	6	LEXTN8770	-		07/16/23 12:37	1	209	Other
SAIDI-06	SAIDI	6	LEXTN8770	-		07/16/23 16:17	1	10	Other
SAIDI-06	SAIDI	6	LEXTN8770	-		07/18/23 12:52	22	10,018	Weather
SAIDI-06	SAIDI	6	LEXTN8770	MED		07/20/23 13:45	1	15	Other
SAIDI-06	SAIDI	6	LEXTN8770	MED	Small	07/20/23 16:04	3	4,364	Weather
SAIDI-06	SAIDI	6	LEXTN8770	-	Small	07/22/23 13:55	1	25	Other
SAIDI-06	SAIDI	6	LEXTN8770	-	Small	07/23/23 11:49	1	5	Other
SAIDI-06	SAIDI	6	LEXTN8770	MED	Cat	07/26/23 14:41	1	2,688	Weather
SAIDI-06	SAIDI	6	LEXTN8770	MED	Cat	07/26/23 17:17	1	5	Other
SAIDI-06	SAIDI	6	LEXTN8770	MED	Cat	07/26/23 17:24	2	5,511	Lightning
SAIDI-06	SAIDI	6	LEXTN8770	MED	Cat	07/27/23 17:30	2	1,933	Wildlife
SAIDI-06	SAIDI	6	LEXTN8770	-	Cat	07/28/23 15:44	1	3,448	Weather
SAIDI-06	SAIDI	6	LEXTN8770	-	Cat	07/29/23 17:09	1	62	Other
SAIDI-06	SAIDI	6	LEXTN8770	-	Cat	07/30/23 04:57	1	6	Other
SAIDI-06	SAIDI	6	LEXTN8770	-		08/03/23 10:34	1	101	Other
SAIDI-06	SAIDI	6	LEXTN8770	-		08/03/23 10:34	1	101	Other
SAIDI-06	SAIDI	6	LEXTN8770	-		08/03/23 10:34	1	101	Other
SAIDI-06	SAIDI	6	LEXTN8770	-		08/03/23 10:34	1	101	Other
SAIDI-06	SAIDI	6	LEXTN8770	-		08/09/23 09:59	9	4,557	Equipment
SAIDI-06	SAIDI	6	LEXTN8770	-		08/10/23 20:27	1	55	Other
SAIDI-06	SAIDI	6	LEXTN8770	-		08/14/23 10:54	1	152	Other
SAIDI-06	SAIDI	6	LEXTN8770	-		08/16/23 10:18	1	166	Equipment
SAIDI-06	SAIDI	6	LEXTN8770	-		08/16/23 10:18	259	41,671	Planned
SAIDI-06	SAIDI	6	LEXTN8770	-		08/16/23 10:18	1	166	Other
SAIDI-06	SAIDI	6	LEXTN8770	-		08/16/23 10:18	3	370	Other
SAIDI-06	SAIDI	6	LEXTN8770	-		08/19/23 12:42	1	61	Other
SAIDI-06	SAIDI	6	LEXTN8770	-	Cat	08/30/23 11:37	1	153	Other
SAIDI-06	SAIDI	6	LEXTN8770	-		09/03/23 06:56	1	553	Equipment
SAIDI-06	SAIDI	6	LEXTN8770	-		09/06/23 10:35	1	51	Other
SAIDI-06	SAIDI	6	LEXTN8770	-		09/11/23 08:33	14	2,296	Vegetation
SAIDI-06	SAIDI	6	LEXTN8770	-		09/12/23 10:09	1	6	Other

SAIDI-06	SAIDI	6	LEXTN8770	-		09/16/23 14:04	1	739	Other
SAIDI-06	SAIDI	6	LEXTN8770	-		09/30/23 10:41	1	95	Other
SAIDI-06	SAIDI	6	LEXTN8770	-		10/05/23 10:20	1	8	Other
SAIDI-06	SAIDI	6	LEXTN8770	-		10/05/23 10:59	2	112	Other
SAIDI-06	SAIDI	6	LEXTN8770	-		10/05/23 13:34	1	9	Other
SAIDI-06	SAIDI	6	LEXTN8770	-		10/08/23 19:35	8	837	Equipment
SAIDI-06	SAIDI	6	LEXTN8770	-		10/15/23 23:13	663	163,645	Vegetation
SAIDI-06	SAIDI	6	LEXTN8770	-		10/18/23 08:39	1	113	Equipment
SAIDI-06	SAIDI	6	LEXTN8770	-		10/19/23 13:11	1	251	Other
SAIDI-06	SAIDI	6	LEXTN8770	-		10/21/23 13:02	2	506	Wildlife
SAIDI-06	SAIDI	6	LEXTN8770	-		10/26/23 10:53	1	1,752	Other
SAIDI-06	SAIDI	6	LEXTN8770	-		11/11/23 12:33	1	101	Planned
SAIDI-06	SAIDI	6	LEXTN8770	-		11/11/23 12:33	1	103	Other
SAIDI-06	SAIDI	6	LEXTN8770	-		11/16/23 11:35	1	59	Planned
SAIDI-06	SAIDI	6	LEXTN8770	-		11/16/23 11:35	2	151	Other
SAIDI-06	SAIDI	6	LEXTN8770	-		11/17/23 10:34	1	209	Equipment
SAIDI-06	SAIDI	6	LEXTN8770	-		11/27/23 07:31	2	736	Equipment
SAIDI-06	SAIDI	6	LEXTN8770	-		11/27/23 07:31	1	368	Other
SAIDI-06	SAIDI	6	LEXTN8770	-		11/27/23 08:59	1	166	Other
SAIDI-06	SAIDI	6	LEXTN8770	-		11/27/23 09:04	1	64	Planned
SAIDI-06	SAIDI	6	LEXTN8770	-		11/27/23 09:04	1	64	Other
SAIDI-06	SAIDI	6	LEXTN8770	-		11/28/23 10:08	1	23	Other
SAIDI-06	SAIDI	6	LEXTN8770	-		11/28/23 15:00	1	9	Other
SAIDI-06	SAIDI	6	LEXTN8770	-		12/05/23 12:11	1	86	Planned
SAIDI-06	SAIDI	6	LEXTN8770	-		12/05/23 18:08	1	43	Other
SAIDI-06	SAIDI	6	LEXTN8770	-		12/07/23 07:24	1	137	Other
SAIDI-06	SAIDI	6	LEXTN8770	-		12/11/23 12:36	1	60	Other
SAIDI-06	SAIDI	6	LEXTN8770	-		12/22/23 09:29	1	124	Equipment
SAIDI-06	SAIDI	6	LEXTN8770	-		12/22/23 15:58	1	11	Other
SAIDI-06	SAIDI	6	LEXTN8770	-		12/27/23 10:40	1	1,483	Equipment
SAIDI-06	SAIDI	6	LEXTN8770	-		12/27/23 12:19	1	165	Other
SAIDI-06	SAIDI	6	LEXTN8770	-		12/28/23 04:06	2	691	Vegetation
SAIDI-06	SAIDI	6	LEXTN8770	-		12/28/23 04:06	1	345	Equipment
SAIDI-06	SAIDI	6	LEXTN8770	-		12/30/23 13:46	1	12	Other
SAIDI-07	SAIDI	7	NBOST0305	MED	Cat	02/22/23 22:15	443	809,751	Weather
SAIDI-07	SAIDI	7	NBOST0305	MED	Cat	02/22/23 22:15	1	1,467	Weather
SAIDI-07	SAIDI	7	NBOST0305	-	Cat	02/25/23 22:47	401	484,802	Weather
SAIDI-07	SAIDI	7	NBOST0305	-	Cat	02/25/23 22:47	9	34,357	Other
SAIDI-07	SAIDI	7	NBOST0305	-	Cat	02/25/23 22:47	1	3,965	Other
SAIDI-07	SAIDI	7	NBOST0305	-	Cat	02/25/23 22:47	1	4,328	Weather
SAIDI-07	SAIDI	7	NBOST0305	-	Cat	02/28/23 14:25	1	7	Other
SAIDI-07	SAIDI	7	NBOST0305	-	Cat	03/01/23 11:04	1	9	Other
SAIDI-07	SAIDI	7	NBOST0305	-	Cat	03/05/23 09:51	1	122	Weather

SAIDI-07	SAIDI	7	NBOST0305	-	Cat	03/07/23 08:51	1	7	Other
SAIDI-07	SAIDI	7	NBOST0305	-	Cat	03/07/23 16:07	1	26	Weather
SAIDI-07	SAIDI	7	NBOST0305	-		03/12/23 20:09	4	1,905	Other
SAIDI-07	SAIDI	7	NBOST0305	-		03/12/23 20:09	52	8,595	Other
SAIDI-07	SAIDI	7	NBOST0305	-		03/13/23 03:26	7	273	Other
SAIDI-07	SAIDI	7	NBOST0305	-		03/16/23 10:10	2	61	Planned
SAIDI-07	SAIDI	7	NBOST0305	-		03/18/23 18:33	1	25	Other
SAIDI-07	SAIDI	7	NBOST0305	-		03/19/23 08:54	1	192	Other
SAIDI-07	SAIDI	7	NBOST0305	-		04/04/23 15:01	1	25	Equipment
SAIDI-07	SAIDI	7	NBOST0305	-		04/05/23 14:43	2	212	Equipment
SAIDI-07	SAIDI	7	NBOST0305	-		04/10/23 14:19	444	77,333	Other
SAIDI-07	SAIDI	7	NBOST0305	-		04/10/23 14:19	1	174	Other
SAIDI-07	SAIDI	7	NBOST0305	-		04/20/23 12:16	1	88	Other
SAIDI-07	SAIDI	7	NBOST0305	-		04/23/23 22:08	1	272	Wildlife
SAIDI-07	SAIDI	7	NBOST0305	-		04/24/23 10:08	1	897	Other
SAIDI-07	SAIDI	7	NBOST0305	MED		05/31/23 14:42	1	302	Other
SAIDI-07	SAIDI	7	NBOST0305	MED		05/31/23 20:28	1	894	Other
SAIDI-07	SAIDI	7	NBOST0305	-		06/11/23 21:54	1	853	Other
SAIDI-07	SAIDI	7	NBOST0305	MED	Small	06/25/23 18:18	1	1,003	Other
SAIDI-07	SAIDI	7	NBOST0305	MED	Small	06/25/23 18:18	1	1,091	Weather
SAIDI-07	SAIDI	7	NBOST0305	MED	Small	06/25/23 18:18	442	443,584	Weather
SAIDI-07	SAIDI	7	NBOST0305	MED	Small	06/25/23 18:18	1	1,004	Other
SAIDI-07	SAIDI	7	NBOST0305	MED	Small	06/26/23 13:30	1	10	Weather
SAIDI-07	SAIDI	7	NBOST0305	-		07/18/23 14:48	1	5	Other
SAIDI-07	SAIDI	7	NBOST0305	-		07/18/23 14:48	1	5	Other
SAIDI-07	SAIDI	7	NBOST0305	-		07/18/23 14:48	1	5	Other
SAIDI-07	SAIDI	7	NBOST0305	-		07/18/23 14:48	7	36	Equipment
SAIDI-07	SAIDI	7	NBOST0305	-		07/18/23 14:48	1	5	Other
SAIDI-07	SAIDI	7	NBOST0305	-		07/18/23 14:48	410	2,081	Other
SAIDI-07	SAIDI	7	NBOST0305	-		07/18/23 14:48	1	5	Vegetation
SAIDI-07	SAIDI	7	NBOST0305	-		07/18/23 14:48	1	5	Other
SAIDI-07	SAIDI	7	NBOST0305	-		07/18/23 14:48	1	5	Other
SAIDI-07	SAIDI	7	NBOST0305	-		08/03/23 20:11	1	66	Other
SAIDI-07	SAIDI	7	NBOST0305	-		08/04/23 20:38	1	37	Other
SAIDI-07	SAIDI	7	NBOST0305	-		08/10/23 17:20	1	202	Other
SAIDI-07	SAIDI	7	NBOST0305	-		08/10/23 21:59	1	143	Other
SAIDI-07	SAIDI	7	NBOST0305	-		08/11/23 04:28	1	266	Other
SAIDI-07	SAIDI	7	NBOST0305	-		08/12/23 18:32	1	21	Other
SAIDI-07	SAIDI	7	NBOST0305	-		08/14/23 17:31	1	115	Other
SAIDI-07	SAIDI	7	NBOST0305	-		08/16/23 16:56	1	313	Other
SAIDI-07	SAIDI	7	NBOST0305	MED	Cat	08/24/23 02:17	6	30,514	Vegetation
SAIDI-07	SAIDI	7	NBOST0305	MED	Cat	08/24/23 02:17	9	41,080	Vegetation
SAIDI-07	SAIDI	7	NBOST0305	MED	Cat	08/24/23 02:17	13	66,117	Vegetation

SAIDI-07	SAIDI	7	NBOST0305	MED	Cat	08/24/23 02:17	2	10,171	Vegetation
SAIDI-07	SAIDI	7	NBOST0305	MED	Cat	08/24/23 02:18	8	39,930	Vegetation
SAIDI-07	SAIDI	7	NBOST0305	MED	Cat	08/24/23 02:24	4	1,966	Vegetation
SAIDI-07	SAIDI	7	NBOST0305	MED	Cat	08/24/23 02:24	49	24,129	Equipment
SAIDI-07	SAIDI	7	NBOST0305	MED	Cat	08/24/23 02:24	388	153,536	Weather
SAIDI-07	SAIDI	7	NBOST0305	MED	Cat	08/24/23 02:24	1	492	Other
SAIDI-07	SAIDI	7	NBOST0305	MED	Cat	08/24/23 22:35	2	13	Other
SAIDI-07	SAIDI	7	NBOST0305	MED	Cat	08/25/23 07:01	2	7,203	Equipment
SAIDI-07	SAIDI	7	NBOST0305	MED	Cat	08/25/23 07:01	1	3,601	Other
SAIDI-07	SAIDI	7	NBOST0305	MED	Cat	08/25/23 23:22	2	28	Other
SAIDI-07	SAIDI	7	NBOST0305	-	Cat	08/26/23 08:57	1	33	Equipment
SAIDI-07	SAIDI	7	NBOST0305	-	Cat	08/26/23 18:30	21	893	Vegetation
SAIDI-07	SAIDI	7	NBOST0305	-	Cat	08/26/23 23:50	2	18	Other
SAIDI-07	SAIDI	7	NBOST0305	-	Cat	08/27/23 02:52	1	512	Other
SAIDI-07	SAIDI	7	NBOST0305	-	Cat	08/27/23 20:16	1	14	Other
SAIDI-07	SAIDI	7	NBOST0305	-	Cat	08/30/23 11:01	1	14	Vegetation
SAIDI-07	SAIDI	7	NBOST0305	-		09/01/23 08:02	1	89	Other
SAIDI-07	SAIDI	7	NBOST0305	-		09/01/23 16:07	1	21	Other
SAIDI-07	SAIDI	7	NBOST0305	-		09/03/23 11:17	1	9	Other
SAIDI-07	SAIDI	7	NBOST0305	-		09/15/23 16:28	1	34	Other
SAIDI-07	SAIDI	7	NBOST0305	-		09/16/23 13:57	1	76	Other
SAIDI-07	SAIDI	7	NBOST0305	-		09/17/23 09:18	1	302	Other
SAIDI-07	SAIDI	7	NBOST0305	-		09/17/23 14:59	1	11	Other
SAIDI-07	SAIDI	7	NBOST0305	-		10/02/23 10:42	1	307	Other
SAIDI-07	SAIDI	7	NBOST0305	-		10/03/23 11:43	2	81	Other
SAIDI-07	SAIDI	7	NBOST0305	-		10/04/23 11:22	1	37	Other
SAIDI-07	SAIDI	7	NBOST0305	-		10/04/23 11:22	1	41	Planned
SAIDI-07	SAIDI	7	NBOST0305	-		10/04/23 11:22	2	78	Other
SAIDI-07	SAIDI	7	NBOST0305	-		10/06/23 10:21	890	65,473	Planned
SAIDI-07	SAIDI	7	NBOST0305	-		10/06/23 10:21	2	147	Other
SAIDI-07	SAIDI	7	NBOST0305	-		10/27/23 09:26	1	185	Other
SAIDI-07	SAIDI	7	NBOST0305	-		12/01/23 17:34	1	14	Other
SAIDI-07	SAIDI	7	NBOST0305	-		12/18/23 16:10	1	6	Other
SAIDI-07	SAIDI	7	NBOST0305	-		12/22/23 10:44	1	75	Other
SAIDI-07	SAIDI	7	NBOST0305	-		12/28/23 04:24	1	45	Other
SAIDI-08	SAIDI	8	PULFD2155	-		01/19/23 12:27	2	155	Vegetation
SAIDI-08	SAIDI	8	PULFD2155	-		02/03/23 09:02	1	18	Equipment
SAIDI-08	SAIDI	8	PULFD2155	-		02/09/23 12:17	1	41	Other
SAIDI-08	SAIDI	8	PULFD2155	-		02/09/23 14:04	1	11	Other
SAIDI-08	SAIDI	8	PULFD2155	-		02/09/23 16:27	1	86	Other
SAIDI-08	SAIDI	8	PULFD2155	MED		02/22/23 14:11	1	38	Other
SAIDI-08	SAIDI	8	PULFD2155	MED	Cat	02/22/23 20:57	1	1,051	Weather
SAIDI-08	SAIDI	8	PULFD2155	MED	Cat	02/27/23 10:39	1	7	Other

SAIDI-08	SAIDI	8	PULFD2155	-	Cat	03/02/23 17:53	1	37	Other
SAIDI-08	SAIDI	8	PULFD2155	MED	Cat	03/03/23 17:41	483	1,337,211	Weather
SAIDI-08	SAIDI	8	PULFD2155	MED	Cat	03/03/23 17:41	1	2,775	Weather
SAIDI-08	SAIDI	8	PULFD2155	MED	Cat	03/03/23 17:41	1	2,775	Other
SAIDI-08	SAIDI	8	PULFD2155	-	Cat	03/06/23 13:05	1	100	Weather
SAIDI-08	SAIDI	8	PULFD2155	-	Cat	03/06/23 16:43	1	453	Other
SAIDI-08	SAIDI	8	PULFD2155	-		03/13/23 13:22	1	195	Other
SAIDI-08	SAIDI	8	PULFD2155	-		03/17/23 11:51	1	7,842	Other
SAIDI-08	SAIDI	8	PULFD2155	-		03/23/23 02:19	1	27	Other
SAIDI-08	SAIDI	8	PULFD2155	-	Small	03/26/23 18:23	1	10	Other
SAIDI-08	SAIDI	8	PULFD2155	-	Small	03/26/23 18:23	1	11	Weather
SAIDI-08	SAIDI	8	PULFD2155	-		03/28/23 00:02	1	20	Equipment
SAIDI-08	SAIDI	8	PULFD2155	-		04/17/23 14:47	1	62	Other
SAIDI-08	SAIDI	8	PULFD2155	-		04/17/23 17:46	1	636	Other
SAIDI-08	SAIDI	8	PULFD2155	-		04/29/23 13:35	1	21	Other
SAIDI-08	SAIDI	8	PULFD2155	-		05/02/23 17:01	1	904	Other
SAIDI-08	SAIDI	8	PULFD2155	-		05/06/23 15:43	1	34	Other
SAIDI-08	SAIDI	8	PULFD2155	-		05/08/23 11:47	1	16	Other
SAIDI-08	SAIDI	8	PULFD2155	-		05/15/23 08:31	1	39	Other
SAIDI-08	SAIDI	8	PULFD2155	-		06/13/23 20:27	12	10,335	Vegetation
SAIDI-08	SAIDI	8	PULFD2155	-		06/13/23 20:27	9	7,737	Other
SAIDI-08	SAIDI	8	PULFD2155	-		06/14/23 19:21	1	14	Other
SAIDI-08	SAIDI	8	PULFD2155	-		06/19/23 09:45	1	137	Other
SAIDI-08	SAIDI	8	PULFD2155	-		06/21/23 19:56	1	457	Other
SAIDI-08	SAIDI	8	PULFD2155	-	Small	06/27/23 10:31	1	35	Other
SAIDI-08	SAIDI	8	PULFD2155	-		06/29/23 10:26	1	20	Other
SAIDI-08	SAIDI	8	PULFD2155	-		06/29/23 11:08	1	20	Other
SAIDI-08	SAIDI	8	PULFD2155	-		07/07/23 11:53	1	53	Other
SAIDI-08	SAIDI	8	PULFD2155	-		07/18/23 11:22	1	90	Other
SAIDI-08	SAIDI	8	PULFD2155	-		07/18/23 11:26	1	77	Planned
SAIDI-08	SAIDI	8	PULFD2155	MED	Cat	07/27/23 13:36	1	94	Other
SAIDI-08	SAIDI	8	PULFD2155	-	Cat	07/28/23 19:43	478	659,762	Weather
SAIDI-08	SAIDI	8	PULFD2155	-		08/12/23 21:59	35	14,237	Public
SAIDI-08	SAIDI	8	PULFD2155	-		08/12/23 22:00	43	10,632	Public
SAIDI-08	SAIDI	8	PULFD2155	-		08/12/23 22:01	1	7	Other
SAIDI-08	SAIDI	8	PULFD2155	-		08/12/23 23:37	17	12,469	Public
SAIDI-08	SAIDI	8	PULFD2155	-		08/12/23 23:37	8	8,297	Other
SAIDI-08	SAIDI	8	PULFD2155	-		08/19/23 19:04	1	16	Other
SAIDI-08	SAIDI	8	PULFD2155	MED	Cat	08/24/23 09:23	8	163	Vegetation
SAIDI-08	SAIDI	8	PULFD2155	MED	Cat	08/24/23 22:26	1	2,611	Weather
SAIDI-08	SAIDI	8	PULFD2155	MED	Cat	08/24/23 22:31	1	3,924	Weather
SAIDI-08	SAIDI	8	PULFD2155	MED	Cat	08/24/23 23:02	1	42	Other
SAIDI-08	SAIDI	8	PULFD2155	-	Cat	08/26/23 12:06	1	6	Other

SAIDI-08	SAIDI	8	PULFD2155	-	Cat	08/26/23 16:41	1	6	Other
SAIDI-08	SAIDI	8	PULFD2155	-	Cat	08/30/23 15:24	1	38	Other
SAIDI-08	SAIDI	8	PULFD2155	-	Cat	08/30/23 15:24	1	38	Other
SAIDI-08	SAIDI	8	PULFD2155	-		08/31/23 19:43	1	935	Other
SAIDI-08	SAIDI	8	PULFD2155	-		10/07/23 15:07	1	9	Other
SAIDI-08	SAIDI	8	PULFD2155	-		10/13/23 17:10	4	102	Equipment
SAIDI-08	SAIDI	8	PULFD2155	-		10/14/23 02:13	1	520	Other
SAIDI-08	SAIDI	8	PULFD2155	-		10/30/23 01:45	8	125	Vegetation
SAIDI-08	SAIDI	8	PULFD2155	-		11/12/23 10:33	1	32	Other
SAIDI-08	SAIDI	8	PULFD2155	-		11/17/23 08:13	1	8	Other
SAIDI-08	SAIDI	8	PULFD2155	-		11/22/23 10:13	1	34	Other
SAIDI-08	SAIDI	8	PULFD2155	-		11/22/23 10:13	1	62	Other
SAIDI-08	SAIDI	8	PULFD2155	-		11/22/23 11:08	1	48	Other
SAIDI-08	SAIDI	8	PULFD2155	-		11/26/23 11:09	1	5	Other
SAIDI-08	SAIDI	8	PULFD2155	-		11/30/23 18:04	1	8	Other
SAIDI-08	SAIDI	8	PULFD2155	-		12/02/23 09:39	3	92	Other
SAIDI-08	SAIDI	8	PULFD2155	-		12/02/23 11:18	3	226	Other
SAIDI-08	SAIDI	8	PULFD2155	-		12/04/23 09:25	5	283	Other
SAIDI-08	SAIDI	8	PULFD2155	-		12/04/23 12:27	7	471	Other
SAIDI-08	SAIDI	8	PULFD2155	-		12/05/23 10:19	12	524	Planned
SAIDI-08	SAIDI	8	PULFD2155	-		12/05/23 10:19	11	183	Other
SAIDI-08	SAIDI	8	PULFD2155	-		12/05/23 10:51	1	22	Planned
SAIDI-08	SAIDI	8	PULFD2155	-		12/06/23 09:23	8	350	Other
SAIDI-08	SAIDI	8	PULFD2155	-		12/06/23 09:23	6	242	Planned
SAIDI-08	SAIDI	8	PULFD2155	-		12/06/23 10:20	4	131	Other
SAIDI-08	SAIDI	8	PULFD2155	-		12/06/23 11:06	3	94	Other
SAIDI-08	SAIDI	8	PULFD2155	-		12/06/23 12:06	5	56	Other
SAIDI-08	SAIDI	8	PULFD2155	-		12/08/23 13:14	5	427	Other
SAIDI-08	SAIDI	8	PULFD2155	-		12/08/23 13:14	12	1,025	Planned
SAIDI-08	SAIDI	8	PULFD2155	-		12/08/23 13:14	2	171	Planned
SAIDI-08	SAIDI	8	PULFD2155	-		12/10/23 14:25	1	12	Other
SAIDI-08	SAIDI	8	PULFD2155	-		12/10/23 21:00	1	293	Equipment
SAIDI-08	SAIDI	8	PULFD2155	-		12/13/23 10:09	2	101	Other
SAIDI-08	SAIDI	8	PULFD2155	-		12/13/23 10:12	1	48	Planned
SAIDI-08	SAIDI	8	PULFD2155	-		12/13/23 10:23	1	33	Planned
SAIDI-08	SAIDI	8	PULFD2155	-		12/13/23 13:40	1	9	Planned
SAIDI-08	SAIDI	8	PULFD2155	-		12/13/23 13:40	1	9	Other
SAIDI-08	SAIDI	8	PULFD2155	-		12/14/23 09:11	1	134	Planned
SAIDI-08	SAIDI	8	PULFD2155	-		12/14/23 09:11	2	267	Other
SAIDI-08	SAIDI	8	PULFD2155	-		12/14/23 10:27	2	193	Planned
SAIDI-08	SAIDI	8	PULFD2155	-		12/14/23 10:27	2	194	Other
SAIDI-08	SAIDI	8	PULFD2155	-		12/14/23 11:55	2	66	Other
SAIDI-08	SAIDI	8	PULFD2155	-		12/14/23 12:14	6	495	Other

SAIDI-08	SAIDI	8	PULFD2155	-		12/14/23 14:01	4	475	Other
SAIDI-08	SAIDI	8	PULFD2155	-		12/15/23 09:35	2	101	Other
SAIDI-08	SAIDI	8	PULFD2155	-		12/15/23 13:00	2	111	Other
SAIDI-08	SAIDI	8	PULFD2155	-		12/15/23 13:00	1	63	Other
SAIDI-08	SAIDI	8	PULFD2155	-		12/16/23 12:26	1	83	Planned
SAIDI-08	SAIDI	8	PULFD2155	-		12/16/23 12:27	6	495	Other
SAIDI-08	SAIDI	8	PULFD2155	-		12/19/23 10:02	4	283	Other
SAIDI-08	SAIDI	8	PULFD2155	-		12/19/23 13:42	1	90	Planned
SAIDI-08	SAIDI	8	PULFD2155	-		12/19/23 13:48	8	433	Other
SAIDI-08	SAIDI	8	PULFD2155	-		12/20/23 10:16	1	68	Planned
SAIDI-08	SAIDI	8	PULFD2155	-		12/20/23 10:16	6	462	Other
SAIDI-08	SAIDI	8	PULFD2155	-		12/20/23 13:14	3	69	Other
SAIDI-08	SAIDI	8	PULFD2155	-		12/21/23 09:42	1	140	Planned
SAIDI-08	SAIDI	8	PULFD2155	-		12/21/23 09:46	3	400	Other
SAIDI-08	SAIDI	8	PULFD2155	-		12/27/23 10:05	11	1,687	Planned
SAIDI-09	SAIDI	9	SNOVR0301	-		01/01/23 01:04	1	2,327	Other
SAIDI-09	SAIDI	9	SNOVR0301	-		01/01/23 01:04	175	107,423	Equipment
SAIDI-09	SAIDI	9	SNOVR0301	-		01/01/23 11:06	46	27,756	Equipment
SAIDI-09	SAIDI	9	SNOVR0301	-		01/01/23 11:06	2	1,207	Equipment
SAIDI-09	SAIDI	9	SNOVR0301	-		01/01/23 11:06	18	10,860	Other
SAIDI-09	SAIDI	9	SNOVR0301	-		01/01/23 21:08	115	68,839	Other
SAIDI-09	SAIDI	9	SNOVR0301	-		01/01/23 23:47	1	8	Other
SAIDI-09	SAIDI	9	SNOVR0301	-		01/03/23 03:45	127	4,811	Equipment
SAIDI-09	SAIDI	9	SNOVR0301	-		01/03/23 16:49	1	36	Other
SAIDI-09	SAIDI	9	SNOVR0301	-		01/03/23 16:49	233	8,594	Other
SAIDI-09	SAIDI	9	SNOVR0301	MED	Cat	02/24/23 11:55	1	29	Weather
SAIDI-09	SAIDI	9	SNOVR0301	MED	Cat	02/25/23 15:24	1	31	Other
SAIDI-09	SAIDI	9	SNOVR0301	-		03/20/23 22:08	1	221	Other
SAIDI-09	SAIDI	9	SNOVR0301	-		04/04/23 11:14	2	167	Planned
SAIDI-09	SAIDI	9	SNOVR0301	-		04/15/23 13:15	1	36	Other
SAIDI-09	SAIDI	9	SNOVR0301	-		05/11/23 13:30	1	70	Other
SAIDI-09	SAIDI	9	SNOVR0301	-		07/09/23 09:48	2	525	Other
SAIDI-09	SAIDI	9	SNOVR0301	-		07/25/23 13:17	1	10	Planned
SAIDI-09	SAIDI	9	SNOVR0301	MED	Cat	07/26/23 14:43	1	7	Weather
SAIDI-09	SAIDI	9	SNOVR0301	MED	Cat	07/27/23 09:49	1	30	Other
SAIDI-09	SAIDI	9	SNOVR0301	-		07/31/23 11:41	1	40	Planned
SAIDI-09	SAIDI	9	SNOVR0301	-		08/08/23 14:23	2	497	Other
SAIDI-09	SAIDI	9	SNOVR0301	-		08/08/23 14:23	166	41,198	Equipment
SAIDI-09	SAIDI	9	SNOVR0301	-		08/08/23 14:23	1	248	Other
SAIDI-09	SAIDI	9	SNOVR0301	-		08/08/23 14:23	1	248	Other
SAIDI-09	SAIDI	9	SNOVR0301	-		08/12/23 10:41	2	48	Equipment
SAIDI-09	SAIDI	9	SNOVR0301	-		08/16/23 13:19	1	9	Other
SAIDI-09	SAIDI	9	SNOVR0301	-		10/13/23 07:49	1	87	Other

SAIDI-10	SAIDI	10	DENVR2004	-	Cat	03/06/23 09:08	1	143	Weather
SAIDI-10	SAIDI	10	DENVR2004	-		03/18/23 11:22	5	204	Planned
SAIDI-10	SAIDI	10	DENVR2004	-		03/18/23 11:28	4	212	Equipment
SAIDI-10	SAIDI	10	DENVR2004	-		03/20/23 12:32	5	440	Planned
SAIDI-10	SAIDI	10	DENVR2004	-		03/24/23 09:42	4	171	Planned
SAIDI-10	SAIDI	10	DENVR2004	-		03/28/23 12:48	4	188	Planned
SAIDI-10	SAIDI	10	DENVR2004	-		03/30/23 14:47	1	72	Other
SAIDI-10	SAIDI	10	DENVR2004	-		03/30/23 20:35	1	31	Other
SAIDI-10	SAIDI	10	DENVR2004	-		04/03/23 10:11	1	21	Planned
SAIDI-10	SAIDI	10	DENVR2004	-		04/03/23 13:10	1	48	Other
SAIDI-10	SAIDI	10	DENVR2004	-		04/11/23 10:27	4	96	Other
SAIDI-10	SAIDI	10	DENVR2004	-		04/11/23 10:27	1	28	Planned
SAIDI-10	SAIDI	10	DENVR2004	-		04/11/23 12:44	1	55	Planned
SAIDI-10	SAIDI	10	DENVR2004	-		04/13/23 11:11	1	61	Planned
SAIDI-10	SAIDI	10	DENVR2004	-		04/13/23 11:17	1	48	Other
SAIDI-10	SAIDI	10	DENVR2004	-		04/13/23 12:02	1	40	Planned
SAIDI-10	SAIDI	10	DENVR2004	-		04/13/23 13:55	2	31	Other
SAIDI-10	SAIDI	10	DENVR2004	-		04/13/23 13:55	1	15	Planned
SAIDI-10	SAIDI	10	DENVR2004	-		04/14/23 10:33	6	937	Planned
SAIDI-10	SAIDI	10	DENVR2004	-		04/14/23 11:24	2	199	Planned
SAIDI-10	SAIDI	10	DENVR2004	-		04/14/23 11:24	2	200	Planned
SAIDI-10	SAIDI	10	DENVR2004	-		04/14/23 11:24	1	100	Planned
SAIDI-10	SAIDI	10	DENVR2004	-		04/24/23 10:05	13	3,165	Planned
SAIDI-10	SAIDI	10	DENVR2004	-		04/24/23 10:05	7	1,701	Planned
SAIDI-10	SAIDI	10	DENVR2004	-		04/24/23 10:07	2	483	Planned
SAIDI-10	SAIDI	10	DENVR2004	-		04/24/23 10:07	1	242	Planned
SAIDI-10	SAIDI	10	DENVR2004	-		04/24/23 10:07	1	241	Other
SAIDI-10	SAIDI	10	DENVR2004	-		04/24/23 10:14	1	234	Equipment
SAIDI-10	SAIDI	10	DENVR2004	-		05/03/23 08:43	1	447	Other
SAIDI-10	SAIDI	10	DENVR2004	-		05/18/23 12:28	1	39	Other
SAIDI-10	SAIDI	10	DENVR2004	-		05/19/23 08:44	1	102	Planned
SAIDI-10	SAIDI	10	DENVR2004	-		05/19/23 14:23	1	24	Planned
SAIDI-10	SAIDI	10	DENVR2004	-		05/19/23 14:27	1	18	Other
SAIDI-10	SAIDI	10	DENVR2004	-		06/29/23 08:32	1	7	Other
SAIDI-10	SAIDI	10	DENVR2004	-		07/02/23 20:48	337	113,504	Vegetation
SAIDI-10	SAIDI	10	DENVR2004	-		07/02/23 20:48	1	336	Other
SAIDI-10	SAIDI	10	DENVR2004	-		07/08/23 04:54	1	320	Equipment
SAIDI-10	SAIDI	10	DENVR2004	-		07/08/23 04:54	336	107,368	Equipment
SAIDI-10	SAIDI	10	DENVR2004	-		07/08/23 04:54	1	320	Other
SAIDI-10	SAIDI	10	DENVR2004	-		07/08/23 04:54	1	319	Other
SAIDI-10	SAIDI	10	DENVR2004	-		07/25/23 09:57	16	7,277	Equipment
SAIDI-10	SAIDI	10	DENVR2004	-		07/25/23 09:57	1	370	Other
SAIDI-10	SAIDI	10	DENVR2004	-		07/25/23 09:57	1	370	Other

SAIDI-10	SAIDI	10	DENVR2004	-		07/25/23 09:57	2	753	Other
SAIDI-10	SAIDI	10	DENVR2004	MED	Cat	07/26/23 15:49	2	11,730	Equipment
SAIDI-10	SAIDI	10	DENVR2004	MED	Cat	07/26/23 15:49	302	528,558	Weather
SAIDI-10	SAIDI	10	DENVR2004	MED	Cat	07/26/23 15:49	51	124,667	Vegetation
SAIDI-10	SAIDI	10	DENVR2004	-	Cat	07/28/23 20:54	8	360	Vegetation
SAIDI-10	SAIDI	10	DENVR2004	-		08/07/23 00:08	339	276,548	Vegetation
SAIDI-10	SAIDI	10	DENVR2004	-		08/07/23 00:08	1	815	Other
SAIDI-10	SAIDI	10	DENVR2004	-		09/27/23 12:55	1	23	Other
SAIDI-10	SAIDI	10	DENVR2004	-		10/26/23 14:26	1	94	Other
SAIDI-10	SAIDI	10	DENVR2004	-		11/08/23 20:47	1	507	Equipment

Appendix 6

Outage and Cause Listing - Worst performing circuits by SAIFI excluding Major Event Days - Circuit Basis

Ref#	Metric	Rank	Circuit	MED	Storm	Interruption Date/Time	Customers Interrupted	Customer Minutes Interrupted	Cause
SAIFI-01	SAIFI	1	CROWN9832	-		01/08/23 08:29	4	20	Other
SAIFI-01	SAIFI	1	CROWN9832	-		01/11/23 19:48	265	10,193	Other
SAIFI-01	SAIFI	1	CROWN9832	-		01/11/23 19:48	1	39	Other
SAIFI-01	SAIFI	1	CROWN9832	-		01/11/23 19:48	1	38	Other
SAIFI-01	SAIFI	1	CROWN9832	-	Small	02/15/23 13:20	57	5,223	Weather
SAIFI-01	SAIFI	1	CROWN9832	-	Small	02/15/23 13:20	967	88,585	Weather
SAIFI-01	SAIFI	1	CROWN9832	-	Small	02/15/23 13:20	6	550	Weather
SAIFI-01	SAIFI	1	CROWN9832	-		02/17/23 08:39	1	9	Other
SAIFI-01	SAIFI	1	CROWN9832	MED	Cat	02/22/23 20:22	48	335,689	Weather
SAIFI-01	SAIFI	1	CROWN9832	MED	Cat	02/22/23 20:22	219	1,522,979	Weather
SAIFI-01	SAIFI	1	CROWN9832	MED	Cat	02/23/23 14:19	1	51	Weather
SAIFI-01	SAIFI	1	CROWN9832	MED	Cat	02/23/23 14:19	1	51	Weather
SAIFI-01	SAIFI	1	CROWN9832	MED	Cat	02/24/23 09:34	2	7,214	Other
SAIFI-01	SAIFI	1	CROWN9832	MED	Cat	02/27/23 08:39	15	781	Other
SAIFI-01	SAIFI	1	CROWN9832	-	Cat	03/02/23 13:18	1	64	Other
SAIFI-01	SAIFI	1	CROWN9832	MED	Cat	03/03/23 19:54	1,048	967,898	Weather
SAIFI-01	SAIFI	1	CROWN9832	-	Cat	03/07/23 17:14	1	5	Weather
SAIFI-01	SAIFI	1	CROWN9832	MED	Small	03/25/23 15:22	1,709	174,621	Weather
SAIFI-01	SAIFI	1	CROWN9832	MED	Small	03/25/23 15:22	1	126	Weather
SAIFI-01	SAIFI	1	CROWN9832	MED	Small	03/25/23 16:17	1	72	Other
SAIFI-01	SAIFI	1	CROWN9832	-		04/04/23 00:22	1	378	Equipment
SAIFI-01	SAIFI	1	CROWN9832	-		04/04/23 00:22	75	28,321	Equipment
SAIFI-01	SAIFI	1	CROWN9832	-		04/04/23 00:22	1	377	Equipment
SAIFI-01	SAIFI	1	CROWN9832	-		04/04/23 00:22	1	377	Equipment
SAIFI-01	SAIFI	1	CROWN9832	-		04/04/23 00:22	1	377	Equipment
SAIFI-01	SAIFI	1	CROWN9832	-		04/04/23 00:22	1	377	Equipment
SAIFI-01	SAIFI	1	CROWN9832	-		04/04/23 00:22	1	377	Equipment
SAIFI-01	SAIFI	1	CROWN9832	-		04/04/23 00:22	1	377	Equipment
SAIFI-01	SAIFI	1	CROWN9832	-		04/04/23 00:22	1	378	Equipment
SAIFI-01	SAIFI	1	CROWN9832	-		04/04/23 00:22	84	31,719	Equipment
SAIFI-01	SAIFI	1	CROWN9832	-		04/04/23 00:22	34	12,839	Equipment
SAIFI-01	SAIFI	1	CROWN9832	-		04/04/23 00:23	1	150	Other
SAIFI-01	SAIFI	1	CROWN9832	-		04/04/23 00:23	3,470	334,006	Equipment
SAIFI-01	SAIFI	1	CROWN9832	-		04/04/23 03:17	1	32	Other
SAIFI-01	SAIFI	1	CROWN9832	-		04/09/23 19:11	1	109	Other

SAIFI-01	SAIFI	1	CROWN9832	-		06/02/23 15:25	1	123	Other
SAIFI-01	SAIFI	1	CROWN9832	-		06/02/23 15:25	1,061	102,002	Public
SAIFI-01	SAIFI	1	CROWN9832	-		06/02/23 16:37	1	52	Other
SAIFI-01	SAIFI	1	CROWN9832	-		06/03/23 12:47	2,468	565,201	Public
SAIFI-01	SAIFI	1	CROWN9832	-		06/03/23 12:47	2	615	Other
SAIFI-01	SAIFI	1	CROWN9832	-		06/03/23 12:47	1	286	Other
SAIFI-01	SAIFI	1	CROWN9832	-		06/03/23 12:47	42	9,880	Public
SAIFI-01	SAIFI	1	CROWN9832	-		06/21/23 18:07	1	116	Equipment
SAIFI-01	SAIFI	1	CROWN9832	-		06/21/23 18:07	1	116	Other
SAIFI-01	SAIFI	1	CROWN9832	-		06/21/23 18:08	5	581	Equipment
SAIFI-01	SAIFI	1	CROWN9832	-		06/21/23 18:08	1	115	Other
SAIFI-01	SAIFI	1	CROWN9832	-		06/23/23 09:22	1,682	146,357	Vegetation
SAIFI-01	SAIFI	1	CROWN9832	-		06/23/23 09:22	1	108	Other
SAIFI-01	SAIFI	1	CROWN9832	-		06/23/23 10:20	1	50	Equipment
SAIFI-01	SAIFI	1	CROWN9832	-		06/23/23 10:20	1	50	Other
SAIFI-01	SAIFI	1	CROWN9832	-		06/23/23 10:20	1	50	Other
SAIFI-01	SAIFI	1	CROWN9832	MED		06/25/23 15:56	1,012	134,217	Vegetation
SAIFI-01	SAIFI	1	CROWN9832	MED		06/25/23 15:56	1	133	Other
SAIFI-01	SAIFI	1	CROWN9832	MED		06/25/23 15:56	1	133	Other
SAIFI-01	SAIFI	1	CROWN9832	MED		06/25/23 15:56	1	133	Other
SAIFI-01	SAIFI	1	CROWN9832	MED	Small	06/25/23 16:00	675	86,705	Vegetation
SAIFI-01	SAIFI	1	CROWN9832	MED	Small	06/25/23 16:00	1	129	Other
SAIFI-01	SAIFI	1	CROWN9832	-		07/05/23 07:02	1	10	Other
SAIFI-01	SAIFI	1	CROWN9832	-		07/05/23 08:44	1	120	Other
SAIFI-01	SAIFI	1	CROWN9832	-		07/17/23 09:33	1	56	Other
SAIFI-01	SAIFI	1	CROWN9832	-		07/17/23 09:33	1	56	Planned
SAIFI-01	SAIFI	1	CROWN9832	-		07/19/23 15:03	1,550	120,253	Public
SAIFI-01	SAIFI	1	CROWN9832	-		07/19/23 15:03	3	410	Other
SAIFI-01	SAIFI	1	CROWN9832	MED	Small	07/20/23 16:27	1,048	142,534	Weather
SAIFI-01	SAIFI	1	CROWN9832	MED	Small	07/20/23 16:27	2	271	Other
SAIFI-01	SAIFI	1	CROWN9832	MED	Cat	07/26/23 15:05	266	348,349	Weather
SAIFI-01	SAIFI	1	CROWN9832	MED	Cat	07/26/23 15:05	2	1,315	Other
SAIFI-01	SAIFI	1	CROWN9832	-		08/15/23 16:09	1	13	Other
SAIFI-01	SAIFI	1	CROWN9832	-		08/15/23 16:09	1	13	Other
SAIFI-01	SAIFI	1	CROWN9832	-		08/20/23 11:07	1	113	Other
SAIFI-01	SAIFI	1	CROWN9832	-		09/05/23 10:56	1	1,364	Equipment
SAIFI-01	SAIFI	1	CROWN9832	-		09/05/23 10:56	1	1,363	Equipment
SAIFI-01	SAIFI	1	CROWN9832	-		09/06/23 14:44	2	29	Other
SAIFI-01	SAIFI	1	CROWN9832	-		09/06/23 15:23	1	1,975	Other
SAIFI-01	SAIFI	1	CROWN9832	-		09/07/23 15:05	1	6	Other
SAIFI-01	SAIFI	1	CROWN9832	-		09/09/23 13:43	1	1,037	Other
SAIFI-01	SAIFI	1	CROWN9832	-		09/21/23 08:51	1	166	Other
SAIFI-01	SAIFI	1	CROWN9832	-		09/21/23 12:34	1	66	Other

SAIFI-01	SAIFI	1	CROWN9832	-		09/27/23 10:23	1	7	Other
SAIFI-01	SAIFI	1	CROWN9832	-		10/09/23 15:37	1	16	Other
SAIFI-01	SAIFI	1	CROWN9832	-		10/16/23 05:38	1	44	Other
SAIFI-01	SAIFI	1	CROWN9832	-		10/16/23 17:09	2	169	Equipment
SAIFI-01	SAIFI	1	CROWN9832	-		10/23/23 11:41	1	312	Other
SAIFI-01	SAIFI	1	CROWN9832	-		10/23/23 14:40	2	346	Wildlife
SAIFI-01	SAIFI	1	CROWN9832	-		10/23/23 17:25	1	15	Wildlife
SAIFI-01	SAIFI	1	CROWN9832	-		10/23/23 17:25	1	15	Other
SAIFI-01	SAIFI	1	CROWN9832	-		11/02/23 10:51	1	64	Other
SAIFI-01	SAIFI	1	CROWN9832	-		11/02/23 13:31	1	177	Other
SAIFI-01	SAIFI	1	CROWN9832	-		11/28/23 12:18	80	13,588	Equipment
SAIFI-01	SAIFI	1	CROWN9832	-		12/06/23 12:14	35	1,910	Public
SAIFI-01	SAIFI	1	CROWN9832	-		12/06/23 12:14	2	109	Other
SAIFI-01	SAIFI	1	CROWN9832	-		12/06/23 12:14	1	55	Equipment
SAIFI-01	SAIFI	1	CROWN9832	-		12/06/23 12:14	1,007	55,237	Public
SAIFI-02	SAIFI	2	ARGO 0326	-		01/01/23 01:54	170	90,380	Other
SAIFI-02	SAIFI	2	ARGO 0326	-		01/01/23 07:57	228	38,490	Equipment
SAIFI-02	SAIFI	2	ARGO 0326	-		01/09/23 10:27	1	54	Other
SAIFI-02	SAIFI	2	ARGO 0326	-		01/09/23 10:28	3	236	Other
SAIFI-02	SAIFI	2	ARGO 0326	-		01/10/23 10:27	13	1,265	Planned
SAIFI-02	SAIFI	2	ARGO 0326	-		01/10/23 12:56	3	200	Equipment
SAIFI-02	SAIFI	2	ARGO 0326	-		01/11/23 10:17	7	441	Planned
SAIFI-02	SAIFI	2	ARGO 0326	-		01/11/23 12:34	10	720	Planned
SAIFI-02	SAIFI	2	ARGO 0326	-		01/12/23 10:42	1	20	Other
SAIFI-02	SAIFI	2	ARGO 0326	-		01/12/23 10:42	5	100	Planned
SAIFI-02	SAIFI	2	ARGO 0326	-		01/18/23 10:17	3	468	Planned
SAIFI-02	SAIFI	2	ARGO 0326	-		01/24/23 10:21	8	946	Planned
SAIFI-02	SAIFI	2	ARGO 0326	-		01/30/23 09:55	13	1,698	Planned
SAIFI-02	SAIFI	2	ARGO 0326	-		02/01/23 15:02	1	36	Other
SAIFI-02	SAIFI	2	ARGO 0326	-		02/01/23 15:02	395	14,106	Equipment
SAIFI-02	SAIFI	2	ARGO 0326	-		02/01/23 15:03	1	36	Other
SAIFI-02	SAIFI	2	ARGO 0326	-		02/04/23 08:36	1	36	Other
SAIFI-02	SAIFI	2	ARGO 0326	-		02/06/23 10:02	10	839	Planned
SAIFI-02	SAIFI	2	ARGO 0326	-		02/06/23 10:02	2	168	Other
SAIFI-02	SAIFI	2	ARGO 0326	-		02/07/23 10:17	14	1,290	Other
SAIFI-02	SAIFI	2	ARGO 0326	-		02/10/23 13:04	3	279	Planned
SAIFI-02	SAIFI	2	ARGO 0326	-		02/14/23 10:03	4	721	Planned
SAIFI-02	SAIFI	2	ARGO 0326	-		02/17/23 10:12	1	154	Planned
SAIFI-02	SAIFI	2	ARGO 0326	-		02/18/23 10:28	6	672	Planned
SAIFI-02	SAIFI	2	ARGO 0326	MED	Cat	02/22/23 21:20	1	5,365	Other
SAIFI-02	SAIFI	2	ARGO 0326	MED	Cat	02/22/23 22:37	1	1,124	Weather
SAIFI-02	SAIFI	2	ARGO 0326	MED	Cat	02/23/23 10:40	1	323	Weather
SAIFI-02	SAIFI	2	ARGO 0326	MED	Cat	02/23/23 12:22	6	27,361	Weather

SAIFI-02	SAIFI	2	ARGO 0326	MED	Cat	02/23/23 20:40	377	114,541	Weather
SAIFI-02	SAIFI	2	ARGO 0326	MED	Cat	02/24/23 02:52	355	1,329,035	Weather
SAIFI-02	SAIFI	2	ARGO 0326	MED	Cat	02/24/23 02:52	27	97,019	Weather
SAIFI-02	SAIFI	2	ARGO 0326	-	Cat	02/26/23 16:36	1	2,598	Other
SAIFI-02	SAIFI	2	ARGO 0326	-	Cat	03/01/23 11:21	1	324	Weather
SAIFI-02	SAIFI	2	ARGO 0326	-	Cat	03/01/23 11:40	1	43	Other
SAIFI-02	SAIFI	2	ARGO 0326	-	Cat	03/01/23 18:03	5	258	Weather
SAIFI-02	SAIFI	2	ARGO 0326	MED	Cat	03/03/23 15:30	1	31	Other
SAIFI-02	SAIFI	2	ARGO 0326	MED	Cat	03/03/23 21:54	1	2,481	Weather
SAIFI-02	SAIFI	2	ARGO 0326	MED	Cat	03/04/23 03:42	1	595	Weather
SAIFI-02	SAIFI	2	ARGO 0326	-		04/15/23 23:43	4	719	Other
SAIFI-02	SAIFI	2	ARGO 0326	-		04/15/23 23:43	9	1,656	Planned
SAIFI-02	SAIFI	2	ARGO 0326	-		04/17/23 12:26	7	155	Planned
SAIFI-02	SAIFI	2	ARGO 0326	-		04/20/23 09:06	1	11	Other
SAIFI-02	SAIFI	2	ARGO 0326	-		04/21/23 07:50	1	77	Other
SAIFI-02	SAIFI	2	ARGO 0326	-		04/23/23 09:04	1	174	Planned
SAIFI-02	SAIFI	2	ARGO 0326	-		04/23/23 09:04	3	522	Other
SAIFI-02	SAIFI	2	ARGO 0326	-		04/28/23 10:29	1	7	Equipment
SAIFI-02	SAIFI	2	ARGO 0326	-		05/04/23 09:27	1	90	Other
SAIFI-02	SAIFI	2	ARGO 0326	-		05/04/23 16:27	1	101	Other
SAIFI-02	SAIFI	2	ARGO 0326	-		05/10/23 18:17	1	19	Other
SAIFI-02	SAIFI	2	ARGO 0326	-		05/17/23 09:57	1	269	Other
SAIFI-02	SAIFI	2	ARGO 0326	-		05/19/23 23:06	42	17,137	Vegetation
SAIFI-02	SAIFI	2	ARGO 0326	-		05/19/23 23:10	1	338	Vegetation
SAIFI-02	SAIFI	2	ARGO 0326	-		05/19/23 23:10	1	338	Vegetation
SAIFI-02	SAIFI	2	ARGO 0326	-		05/19/23 23:10	43	15,657	Vegetation
SAIFI-02	SAIFI	2	ARGO 0326	-		05/19/23 23:10	26	8,788	Vegetation
SAIFI-02	SAIFI	2	ARGO 0326	-		05/19/23 23:10	193	81,493	Vegetation
SAIFI-02	SAIFI	2	ARGO 0326	-		05/19/23 23:10	20	6,829	Vegetation
SAIFI-02	SAIFI	2	ARGO 0326	-		05/19/23 23:10	67	22,645	Vegetation
SAIFI-02	SAIFI	2	ARGO 0326	-		05/30/23 01:49	1	534	Other
SAIFI-02	SAIFI	2	ARGO 0326	-		05/30/23 01:49	1	534	Vegetation
SAIFI-02	SAIFI	2	ARGO 0326	-		05/30/23 01:49	2	1,066	Other
SAIFI-02	SAIFI	2	ARGO 0326	-		05/30/23 01:49	1	534	Equipment
SAIFI-02	SAIFI	2	ARGO 0326	-		05/30/23 01:49	27	18,091	Vegetation
SAIFI-02	SAIFI	2	ARGO 0326	-		05/30/23 01:49	324	172,903	Vegetation
SAIFI-02	SAIFI	2	ARGO 0326	-		05/30/23 01:49	1	533	Other
SAIFI-02	SAIFI	2	ARGO 0326	-		05/30/23 01:49	1	534	Other
SAIFI-02	SAIFI	2	ARGO 0326	-		05/30/23 01:49	7	5,168	Vegetation
SAIFI-02	SAIFI	2	ARGO 0326	-		05/30/23 01:49	28	18,351	Vegetation
SAIFI-02	SAIFI	2	ARGO 0326	-		06/01/23 14:44	1	203	Other
SAIFI-02	SAIFI	2	ARGO 0326	-		06/08/23 13:40	2	484	Planned
SAIFI-02	SAIFI	2	ARGO 0326	-		06/15/23 17:28	396	97,681	Vegetation

SAIFI-02	SAIFI	2	ARGO 0326	-		06/17/23 16:42	1	6	Equipment
SAIFI-02	SAIFI	2	ARGO 0326	MED	Small	06/25/23 18:12	2	11,418	Weather
SAIFI-02	SAIFI	2	ARGO 0326	MED	Small	06/25/23 18:12	18	43,672	Weather
SAIFI-02	SAIFI	2	ARGO 0326	MED	Small	06/25/23 18:12	3	6,684	Weather
SAIFI-02	SAIFI	2	ARGO 0326	MED	Small	06/25/23 18:12	1	2,699	Weather
SAIFI-02	SAIFI	2	ARGO 0326	MED	Small	06/25/23 18:27	2	6,587	Weather
SAIFI-02	SAIFI	2	ARGO 0326	MED	Small	06/25/23 18:40	366	424,422	Weather
SAIFI-02	SAIFI	2	ARGO 0326	MED	Small	06/25/23 18:40	1	3,890	Lightning
SAIFI-02	SAIFI	2	ARGO 0326	MED	Small	06/25/23 18:40	1	3,890	Weather
SAIFI-02	SAIFI	2	ARGO 0326	MED	Small	06/25/23 18:42	1	1,165	Other
SAIFI-02	SAIFI	2	ARGO 0326	MED	Small	06/25/23 18:43	1	1,164	Weather
SAIFI-02	SAIFI	2	ARGO 0326	-		07/03/23 16:52	9	393	Vegetation
SAIFI-02	SAIFI	2	ARGO 0326	-		07/07/23 22:20	1	92	Other
SAIFI-02	SAIFI	2	ARGO 0326	-		07/15/23 07:50	1	1,844	Vegetation
SAIFI-02	SAIFI	2	ARGO 0326	MED	Cat	07/26/23 15:01	1	2,602	Other
SAIFI-02	SAIFI	2	ARGO 0326	MED	Cat	07/26/23 15:01	65	166,873	Weather
SAIFI-02	SAIFI	2	ARGO 0326	MED	Cat	07/26/23 15:05	14	36,366	Vegetation
SAIFI-02	SAIFI	2	ARGO 0326	MED	Cat	07/28/23 11:45	3	302	Weather
SAIFI-02	SAIFI	2	ARGO 0326	-	Cat	07/28/23 18:01	9	25,829	Vegetation
SAIFI-02	SAIFI	2	ARGO 0326	-	Cat	07/28/23 18:01	14	40,180	Vegetation
SAIFI-02	SAIFI	2	ARGO 0326	-		08/01/23 11:41	1	49	Other
SAIFI-02	SAIFI	2	ARGO 0326	-		08/02/23 14:33	1	14	Other
SAIFI-02	SAIFI	2	ARGO 0326	-		08/05/23 17:45	1	7	Other
SAIFI-02	SAIFI	2	ARGO 0326	-		08/11/23 10:39	1	249	Planned
SAIFI-02	SAIFI	2	ARGO 0326	-		08/11/23 10:39	1	249	Other
SAIFI-02	SAIFI	2	ARGO 0326	MED	Cat	08/24/23 06:06	4	23	Other
SAIFI-02	SAIFI	2	ARGO 0326	MED	Cat	08/24/23 07:21	1	413	Equipment
SAIFI-02	SAIFI	2	ARGO 0326	MED	Cat	08/24/23 07:22	1	413	Equipment
SAIFI-02	SAIFI	2	ARGO 0326	MED	Cat	08/24/23 08:29	2	1,324	Other
SAIFI-02	SAIFI	2	ARGO 0326	-	Cat	08/24/23 08:30	1	662	Other
SAIFI-02	SAIFI	2	ARGO 0326	-	Cat	08/24/23 08:30	1	662	Other
SAIFI-02	SAIFI	2	ARGO 0326	MED	Cat	08/24/23 22:07	19	68,929	Weather
SAIFI-02	SAIFI	2	ARGO 0326	MED	Cat	08/24/23 22:42	75	56,201	Other
SAIFI-02	SAIFI	2	ARGO 0326	MED	Cat	08/25/23 08:30	3	148	Equipment
SAIFI-02	SAIFI	2	ARGO 0326	MED	Cat	08/25/23 08:30	1	71	Other
SAIFI-02	SAIFI	2	ARGO 0326	MED	Cat	08/25/23 09:23	2	77	Lightning
SAIFI-02	SAIFI	2	ARGO 0326	MED	Cat	08/25/23 10:15	2	12	Other
SAIFI-02	SAIFI	2	ARGO 0326	MED	Cat	08/25/23 17:37	7	57	Weather
SAIFI-02	SAIFI	2	ARGO 0326	MED	Cat	08/25/23 21:22	8	45	Other
SAIFI-02	SAIFI	2	ARGO 0326	MED	Cat	08/26/23 05:53	14	294	Other
SAIFI-02	SAIFI	2	ARGO 0326	-	Cat	08/26/23 09:10	53	32,872	Other
SAIFI-02	SAIFI	2	ARGO 0326	-		09/05/23 03:58	33	2,845	Equipment
SAIFI-02	SAIFI	2	ARGO 0326	-		09/11/23 12:23	60	6,875	Other

SAIFI-02	SAIFI	2	ARGO 0326	-		09/15/23 11:09	1	327	Other
SAIFI-02	SAIFI	2	ARGO 0326	-		09/19/23 10:16	1	202	Other
SAIFI-02	SAIFI	2	ARGO 0326	-		09/21/23 10:54	1	333	Other
SAIFI-02	SAIFI	2	ARGO 0326	-		09/22/23 15:20	1	6	Other
SAIFI-02	SAIFI	2	ARGO 0326	-		09/26/23 09:45	1	285	Other
SAIFI-02	SAIFI	2	ARGO 0326	-		09/26/23 11:06	8	791	Planned
SAIFI-02	SAIFI	2	ARGO 0326	-		09/27/23 10:08	10	907	Planned
SAIFI-02	SAIFI	2	ARGO 0326	-		09/30/23 09:50	9	1,489	Other
SAIFI-02	SAIFI	2	ARGO 0326	-		09/30/23 09:50	6	991	Planned
SAIFI-02	SAIFI	2	ARGO 0326	-		10/06/23 09:09	16	495	Other
SAIFI-02	SAIFI	2	ARGO 0326	-		10/10/23 11:29	6	969	Planned
SAIFI-02	SAIFI	2	ARGO 0326	-		10/10/23 11:39	7	754	Planned
SAIFI-02	SAIFI	2	ARGO 0326	-		10/13/23 08:49	1	283	Other
SAIFI-02	SAIFI	2	ARGO 0326	-		10/16/23 11:12	13	1,822	Planned
SAIFI-02	SAIFI	2	ARGO 0326	-		10/18/23 10:49	1	11	Planned
SAIFI-02	SAIFI	2	ARGO 0326	-		10/18/23 10:49	9	103	Other
SAIFI-02	SAIFI	2	ARGO 0326	-		10/21/23 11:44	10	1,024	Other
SAIFI-02	SAIFI	2	ARGO 0326	-		10/23/23 11:49	6	513	Planned
SAIFI-02	SAIFI	2	ARGO 0326	-		10/30/23 09:48	1	59	Other
SAIFI-02	SAIFI	2	ARGO 0326	-		10/30/23 10:01	1	81	Other
SAIFI-02	SAIFI	2	ARGO 0326	-		10/31/23 08:34	1	21	Other
SAIFI-02	SAIFI	2	ARGO 0326	-		11/01/23 10:06	38	5,485	Planned
SAIFI-02	SAIFI	2	ARGO 0326	-		11/02/23 12:05	3	482	Planned
SAIFI-02	SAIFI	2	ARGO 0326	-		11/09/23 11:42	9	1,324	Planned
SAIFI-02	SAIFI	2	ARGO 0326	-		11/10/23 10:36	1	435	Other
SAIFI-02	SAIFI	2	ARGO 0326	-		11/11/23 09:43	2	222	Other
SAIFI-02	SAIFI	2	ARGO 0326	-		11/11/23 09:43	2	222	Planned
SAIFI-02	SAIFI	2	ARGO 0326	-		11/11/23 09:43	2	222	Planned
SAIFI-02	SAIFI	2	ARGO 0326	-		11/13/23 09:22	1	203	Other
SAIFI-02	SAIFI	2	ARGO 0326	-		11/20/23 12:02	7	261	Planned
SAIFI-02	SAIFI	2	ARGO 0326	-		11/20/23 12:02	3	126	Planned
SAIFI-02	SAIFI	2	ARGO 0326	-		11/22/23 09:26	1	393	Other
SAIFI-02	SAIFI	2	ARGO 0326	-		11/27/23 11:04	2	195	Planned
SAIFI-02	SAIFI	2	ARGO 0326	-		11/27/23 11:16	2	318	Other
SAIFI-02	SAIFI	2	ARGO 0326	-		11/27/23 11:28	1	221	Planned
SAIFI-02	SAIFI	2	ARGO 0326	-		11/27/23 11:28	1	221	Planned
SAIFI-02	SAIFI	2	ARGO 0326	-		11/28/23 11:25	1	104	Planned
SAIFI-02	SAIFI	2	ARGO 0326	-		11/28/23 11:25	2	208	Other
SAIFI-02	SAIFI	2	ARGO 0326	-		11/28/23 11:25	1	104	Planned
SAIFI-02	SAIFI	2	ARGO 0326	-		11/28/23 11:25	2	208	Other
SAIFI-02	SAIFI	2	ARGO 0326	-		11/29/23 10:39	1	29	Planned
SAIFI-02	SAIFI	2	ARGO 0326	-		11/29/23 10:39	27	789	Planned
SAIFI-02	SAIFI	2	ARGO 0326	-		11/29/23 10:39	2	57	Other

SAIFI-02	SAIFI	2	ARGO 0326	-		11/29/23 10:40	11	309	Planned
SAIFI-02	SAIFI	2	ARGO 0326	-		11/29/23 10:40	14	394	Planned
SAIFI-02	SAIFI	2	ARGO 0326	-		11/29/23 10:40	1	28	Planned
SAIFI-03	SAIFI	3	HASKL1625	-		01/09/23 15:20	1	11	Other
SAIFI-03	SAIFI	3	HASKL1625	-		02/10/23 09:20	1	6	Other
SAIFI-03	SAIFI	3	HASKL1625	-	Small	02/15/23 13:01	72	111,202	Weather
SAIFI-03	SAIFI	3	HASKL1625	-	Small	02/15/23 13:01	109	170,641	Weather
SAIFI-03	SAIFI	3	HASKL1625	-	Small	02/15/23 13:01	72	112,662	Weather
SAIFI-03	SAIFI	3	HASKL1625	-	Small	02/15/23 13:01	49	76,673	Weather
SAIFI-03	SAIFI	3	HASKL1625	-	Small	02/15/23 20:28	1	23	Weather
SAIFI-03	SAIFI	3	HASKL1625	-	Small	02/15/23 20:28	1	23	Other
SAIFI-03	SAIFI	3	HASKL1625	-		02/21/23 10:34	1	112	Equipment
SAIFI-03	SAIFI	3	HASKL1625	-		02/21/23 10:34	1	112	Equipment
SAIFI-03	SAIFI	3	HASKL1625	-		02/21/23 10:34	2	225	Planned
SAIFI-03	SAIFI	3	HASKL1625	-		02/21/23 10:34	1	112	Equipment
SAIFI-03	SAIFI	3	HASKL1625	-		02/21/23 12:05	323	18,511	Equipment
SAIFI-03	SAIFI	3	HASKL1625	-		02/21/23 12:05	109	2,314	Equipment
SAIFI-03	SAIFI	3	HASKL1625	-		02/21/23 12:05	1	21	Vegetation
SAIFI-03	SAIFI	3	HASKL1625	MED	Cat	02/24/23 08:23	2	33	Other
SAIFI-03	SAIFI	3	HASKL1625	MED	Cat	02/24/23 09:00	825	2,126,118	Vegetation
SAIFI-03	SAIFI	3	HASKL1625	-		04/14/23 10:14	37	4,472	Planned
SAIFI-03	SAIFI	3	HASKL1625	-		04/20/23 09:26	1	182	Other
SAIFI-03	SAIFI	3	HASKL1625	-		05/05/23 11:09	1	51	Other
SAIFI-03	SAIFI	3	HASKL1625	-		05/05/23 11:30	2	35	Other
SAIFI-03	SAIFI	3	HASKL1625	-		05/08/23 09:53	1	427	Other
SAIFI-03	SAIFI	3	HASKL1625	-		05/15/23 18:19	1	46	Other
SAIFI-03	SAIFI	3	HASKL1625	-		06/09/23 10:27	1	281	Other
SAIFI-03	SAIFI	3	HASKL1625	-		06/21/23 09:34	1	11	Other
SAIFI-03	SAIFI	3	HASKL1625	-		07/13/23 00:10	1	651	Other
SAIFI-03	SAIFI	3	HASKL1625	-		07/13/23 00:11	1	651	Other
SAIFI-03	SAIFI	3	HASKL1625	-		07/18/23 08:45	1	450	Other
SAIFI-03	SAIFI	3	HASKL1625	MED	Cat	07/26/23 15:43	557	1,673,287	Lightning
SAIFI-03	SAIFI	3	HASKL1625	MED	Cat	07/26/23 16:54	1	1,292	Weather
SAIFI-03	SAIFI	3	HASKL1625	MED	Cat	07/26/23 16:54	1	1,292	Other
SAIFI-03	SAIFI	3	HASKL1625	-		09/04/23 19:39	1,713	146,853	Other
SAIFI-03	SAIFI	3	HASKL1625	-		09/05/23 13:55	565	11,164	Equipment
SAIFI-03	SAIFI	3	HASKL1625	-		09/12/23 10:33	1	12	Other
SAIFI-03	SAIFI	3	HASKL1625	-		09/30/23 11:53	1	205	Other
SAIFI-03	SAIFI	3	HASKL1625	-		11/22/23 09:40	1	7	Equipment
SAIFI-03	SAIFI	3	HASKL1625	-		11/22/23 09:40	1	8	Other
SAIFI-03	SAIFI	3	HASKL1625	-		12/21/23 12:09	1	7	Other
SAIFI-04	SAIFI	4	NBOST0305	MED	Cat	02/22/23 22:15	443	809,751	Weather
SAIFI-04	SAIFI	4	NBOST0305	MED	Cat	02/22/23 22:15	1	1,467	Weather

SAIFI-04	SAIFI	4	NBOST0305	-	Cat	02/25/23 22:47	401	484,802	Weather
SAIFI-04	SAIFI	4	NBOST0305	-	Cat	02/25/23 22:47	9	34,357	Other
SAIFI-04	SAIFI	4	NBOST0305	-	Cat	02/25/23 22:47	1	3,965	Other
SAIFI-04	SAIFI	4	NBOST0305	-	Cat	02/25/23 22:47	1	4,328	Weather
SAIFI-04	SAIFI	4	NBOST0305	-	Cat	02/28/23 14:25	1	7	Other
SAIFI-04	SAIFI	4	NBOST0305	-	Cat	03/01/23 11:04	1	9	Other
SAIFI-04	SAIFI	4	NBOST0305	-	Cat	03/05/23 09:51	1	122	Weather
SAIFI-04	SAIFI	4	NBOST0305	-	Cat	03/07/23 08:51	1	7	Other
SAIFI-04	SAIFI	4	NBOST0305	-	Cat	03/07/23 16:07	1	26	Weather
SAIFI-04	SAIFI	4	NBOST0305	-		03/12/23 20:09	4	1,905	Other
SAIFI-04	SAIFI	4	NBOST0305	-		03/12/23 20:09	52	8,595	Other
SAIFI-04	SAIFI	4	NBOST0305	-		03/13/23 03:26	7	273	Other
SAIFI-04	SAIFI	4	NBOST0305	-		03/16/23 10:10	2	61	Planned
SAIFI-04	SAIFI	4	NBOST0305	-		03/18/23 18:33	1	25	Other
SAIFI-04	SAIFI	4	NBOST0305	-		03/19/23 08:54	1	192	Other
SAIFI-04	SAIFI	4	NBOST0305	-		04/04/23 15:01	1	25	Equipment
SAIFI-04	SAIFI	4	NBOST0305	-		04/05/23 14:43	2	212	Equipment
SAIFI-04	SAIFI	4	NBOST0305	-		04/10/23 14:19	444	77,333	Other
SAIFI-04	SAIFI	4	NBOST0305	-		04/10/23 14:19	1	174	Other
SAIFI-04	SAIFI	4	NBOST0305	-		04/20/23 12:16	1	88	Other
SAIFI-04	SAIFI	4	NBOST0305	-		04/23/23 22:08	1	272	Wildlife
SAIFI-04	SAIFI	4	NBOST0305	-		04/24/23 10:08	1	897	Other
SAIFI-04	SAIFI	4	NBOST0305	MED		05/31/23 14:42	1	302	Other
SAIFI-04	SAIFI	4	NBOST0305	MED		05/31/23 20:28	1	894	Other
SAIFI-04	SAIFI	4	NBOST0305	-		06/11/23 21:54	1	853	Other
SAIFI-04	SAIFI	4	NBOST0305	MED	Small	06/25/23 18:18	1	1,003	Other
SAIFI-04	SAIFI	4	NBOST0305	MED	Small	06/25/23 18:18	1	1,091	Weather
SAIFI-04	SAIFI	4	NBOST0305	MED	Small	06/25/23 18:18	442	443,584	Weather
SAIFI-04	SAIFI	4	NBOST0305	MED	Small	06/25/23 18:18	1	1,004	Other
SAIFI-04	SAIFI	4	NBOST0305	MED	Small	06/26/23 13:30	1	10	Weather
SAIFI-04	SAIFI	4	NBOST0305	-		07/18/23 14:48	1	5	Other
SAIFI-04	SAIFI	4	NBOST0305	-		07/18/23 14:48	1	5	Other
SAIFI-04	SAIFI	4	NBOST0305	-		07/18/23 14:48	1	5	Other
SAIFI-04	SAIFI	4	NBOST0305	-		07/18/23 14:48	7	36	Equipment
SAIFI-04	SAIFI	4	NBOST0305	-		07/18/23 14:48	1	5	Other
SAIFI-04	SAIFI	4	NBOST0305	-		07/18/23 14:48	410	2,081	Other
SAIFI-04	SAIFI	4	NBOST0305	-		07/18/23 14:48	1	5	Vegetation
SAIFI-04	SAIFI	4	NBOST0305	-		07/18/23 14:48	1	5	Other
SAIFI-04	SAIFI	4	NBOST0305	-		07/18/23 14:48	1	5	Other
SAIFI-04	SAIFI	4	NBOST0305	-		08/03/23 20:11	1	66	Other
SAIFI-04	SAIFI	4	NBOST0305	-		08/04/23 20:38	1	37	Other
SAIFI-04	SAIFI	4	NBOST0305	-		08/10/23 17:20	1	202	Other
SAIFI-04	SAIFI	4	NBOST0305	-		08/10/23 21:59	1	143	Other

SAIFI-04	SAIFI	4	NBOST0305	-		08/11/23 04:28	1	266	Other
SAIFI-04	SAIFI	4	NBOST0305	-		08/12/23 18:32	1	21	Other
SAIFI-04	SAIFI	4	NBOST0305	-		08/14/23 17:31	1	115	Other
SAIFI-04	SAIFI	4	NBOST0305	-		08/16/23 16:56	1	313	Other
SAIFI-04	SAIFI	4	NBOST0305	MED	Cat	08/24/23 02:17	6	30,514	Vegetation
SAIFI-04	SAIFI	4	NBOST0305	MED	Cat	08/24/23 02:17	9	41,080	Vegetation
SAIFI-04	SAIFI	4	NBOST0305	MED	Cat	08/24/23 02:17	13	66,117	Vegetation
SAIFI-04	SAIFI	4	NBOST0305	MED	Cat	08/24/23 02:17	2	10,171	Vegetation
SAIFI-04	SAIFI	4	NBOST0305	MED	Cat	08/24/23 02:18	8	39,930	Vegetation
SAIFI-04	SAIFI	4	NBOST0305	MED	Cat	08/24/23 02:24	4	1,966	Vegetation
SAIFI-04	SAIFI	4	NBOST0305	MED	Cat	08/24/23 02:24	49	24,129	Equipment
SAIFI-04	SAIFI	4	NBOST0305	MED	Cat	08/24/23 02:24	388	153,536	Weather
SAIFI-04	SAIFI	4	NBOST0305	MED	Cat	08/24/23 02:24	1	492	Other
SAIFI-04	SAIFI	4	NBOST0305	MED	Cat	08/24/23 22:35	2	13	Other
SAIFI-04	SAIFI	4	NBOST0305	MED	Cat	08/25/23 07:01	2	7,203	Equipment
SAIFI-04	SAIFI	4	NBOST0305	MED	Cat	08/25/23 07:01	1	3,601	Other
SAIFI-04	SAIFI	4	NBOST0305	MED	Cat	08/25/23 23:22	2	28	Other
SAIFI-04	SAIFI	4	NBOST0305	-	Cat	08/26/23 08:57	1	33	Equipment
SAIFI-04	SAIFI	4	NBOST0305	-	Cat	08/26/23 18:30	21	893	Vegetation
SAIFI-04	SAIFI	4	NBOST0305	-	Cat	08/26/23 23:50	2	18	Other
SAIFI-04	SAIFI	4	NBOST0305	-	Cat	08/27/23 02:52	1	512	Other
SAIFI-04	SAIFI	4	NBOST0305	-	Cat	08/27/23 20:16	1	14	Other
SAIFI-04	SAIFI	4	NBOST0305	-	Cat	08/30/23 11:01	1	14	Vegetation
SAIFI-04	SAIFI	4	NBOST0305	-		09/01/23 08:02	1	89	Other
SAIFI-04	SAIFI	4	NBOST0305	-		09/01/23 16:07	1	21	Other
SAIFI-04	SAIFI	4	NBOST0305	-		09/03/23 11:17	1	9	Other
SAIFI-04	SAIFI	4	NBOST0305	-		09/15/23 16:28	1	34	Other
SAIFI-04	SAIFI	4	NBOST0305	-		09/16/23 13:57	1	76	Other
SAIFI-04	SAIFI	4	NBOST0305	-		09/17/23 09:18	1	302	Other
SAIFI-04	SAIFI	4	NBOST0305	-		09/17/23 14:59	1	11	Other
SAIFI-04	SAIFI	4	NBOST0305	-		10/02/23 10:42	1	307	Other
SAIFI-04	SAIFI	4	NBOST0305	-		10/03/23 11:43	2	81	Other
SAIFI-04	SAIFI	4	NBOST0305	-		10/04/23 11:22	1	37	Other
SAIFI-04	SAIFI	4	NBOST0305	-		10/04/23 11:22	1	41	Planned
SAIFI-04	SAIFI	4	NBOST0305	-		10/04/23 11:22	2	78	Other
SAIFI-04	SAIFI	4	NBOST0305	-		10/06/23 10:21	890	65,473	Planned
SAIFI-04	SAIFI	4	NBOST0305	-		10/06/23 10:21	2	147	Other
SAIFI-04	SAIFI	4	NBOST0305	-		10/27/23 09:26	1	185	Other
SAIFI-04	SAIFI	4	NBOST0305	-		12/01/23 17:34	1	14	Other
SAIFI-04	SAIFI	4	NBOST0305	-		12/18/23 16:10	1	6	Other
SAIFI-04	SAIFI	4	NBOST0305	-		12/22/23 10:44	1	75	Other
SAIFI-04	SAIFI	4	NBOST0305	-		12/28/23 04:24	1	45	Other
SAIFI-05	SAIFI	5	SNOVR0302	-		01/01/23 01:04	696	612,258	Equipment

SAIFI-05	SAIFI	5	SNOVR0302	-		01/01/23 01:04	1	2,206	Equipment
SAIFI-05	SAIFI	5	SNOVR0302	-		01/01/23 19:23	2	2,225	Equipment
SAIFI-05	SAIFI	5	SNOVR0302	-		01/01/23 23:47	1	7	Other
SAIFI-05	SAIFI	5	SNOVR0302	-		01/02/23 13:26	1	24	Other
SAIFI-05	SAIFI	5	SNOVR0302	-		01/02/23 13:42	3	904	Other
SAIFI-05	SAIFI	5	SNOVR0302	-		01/03/23 04:12	811	19,420	Other
SAIFI-05	SAIFI	5	SNOVR0302	-		01/03/23 16:49	1	37	Other
SAIFI-05	SAIFI	5	SNOVR0302	-		01/03/23 16:49	1	37	Other
SAIFI-05	SAIFI	5	SNOVR0302	-		01/03/23 16:49	1	37	Other
SAIFI-05	SAIFI	5	SNOVR0302	-		01/11/23 21:01	1	6	Other
SAIFI-05	SAIFI	5	SNOVR0302	-		02/04/23 11:14	1	157	Equipment
SAIFI-05	SAIFI	5	SNOVR0302	-		03/15/23 18:43	1	9	Other
SAIFI-05	SAIFI	5	SNOVR0302	-		03/30/23 07:29	1	318	Other
SAIFI-05	SAIFI	5	SNOVR0302	-		03/31/23 22:34	1	1,362	Equipment
SAIFI-05	SAIFI	5	SNOVR0302	-		04/01/23 10:31	47	9,998	Weather
SAIFI-05	SAIFI	5	SNOVR0302	-		04/01/23 10:31	20	4,090	Other
SAIFI-05	SAIFI	5	SNOVR0302	-		04/05/23 11:08	1	13	Other
SAIFI-05	SAIFI	5	SNOVR0302	-		04/24/23 11:50	1	28	Planned
SAIFI-05	SAIFI	5	SNOVR0302	-		04/24/23 13:31	1	11	Other
SAIFI-05	SAIFI	5	SNOVR0302	-		04/24/23 13:34	1	11	Planned
SAIFI-05	SAIFI	5	SNOVR0302	-		04/25/23 09:36	1	145	Other
SAIFI-05	SAIFI	5	SNOVR0302	-		04/26/23 09:35	2	25	Planned
SAIFI-05	SAIFI	5	SNOVR0302	-		04/26/23 10:26	1	26	Planned
SAIFI-05	SAIFI	5	SNOVR0302	-		04/26/23 11:27	1	51	Planned
SAIFI-05	SAIFI	5	SNOVR0302	-		05/01/23 09:29	1	30	Planned
SAIFI-05	SAIFI	5	SNOVR0302	-		05/01/23 10:31	1	23	Planned
SAIFI-05	SAIFI	5	SNOVR0302	-		05/01/23 11:03	1	29	Planned
SAIFI-05	SAIFI	5	SNOVR0302	-		05/01/23 13:57	1	99	Planned
SAIFI-05	SAIFI	5	SNOVR0302	-		05/04/23 10:25	1	18	Planned
SAIFI-05	SAIFI	5	SNOVR0302	-		05/04/23 11:06	1	16	Planned
SAIFI-05	SAIFI	5	SNOVR0302	-		05/04/23 14:20	1	18	Planned
SAIFI-05	SAIFI	5	SNOVR0302	-		05/04/23 15:13	1	16	Other
SAIFI-05	SAIFI	5	SNOVR0302	-		05/08/23 09:48	1	28	Planned
SAIFI-05	SAIFI	5	SNOVR0302	-		05/08/23 13:45	1	13	Planned
SAIFI-05	SAIFI	5	SNOVR0302	-		05/08/23 14:31	1	30	Planned
SAIFI-05	SAIFI	5	SNOVR0302	-		05/09/23 11:46	1	28	Planned
SAIFI-05	SAIFI	5	SNOVR0302	-		05/09/23 12:40	1	23	Planned
SAIFI-05	SAIFI	5	SNOVR0302	-		05/09/23 15:16	1	16	Planned
SAIFI-05	SAIFI	5	SNOVR0302	-		05/10/23 09:53	1	36	Planned
SAIFI-05	SAIFI	5	SNOVR0302	-		05/10/23 12:09	1	8	Planned
SAIFI-05	SAIFI	5	SNOVR0302	-		05/10/23 12:09	4	36	Other
SAIFI-05	SAIFI	5	SNOVR0302	-		05/10/23 14:10	1	34	Planned
SAIFI-05	SAIFI	5	SNOVR0302	-		05/10/23 15:15	1	7	Other

SAIFI-05	SAIFI	5	SNOVR0302	-		05/11/23 08:38	1	6	Other
SAIFI-05	SAIFI	5	SNOVR0302	-		05/11/23 09:20	1	25	Planned
SAIFI-05	SAIFI	5	SNOVR0302	-		05/19/23 09:21	1	23	Planned
SAIFI-05	SAIFI	5	SNOVR0302	-		05/19/23 10:16	1	51	Other
SAIFI-05	SAIFI	5	SNOVR0302	-		05/19/23 11:15	1	26	Planned
SAIFI-05	SAIFI	5	SNOVR0302	-		05/19/23 12:05	1	95	Equipment
SAIFI-05	SAIFI	5	SNOVR0302	-		05/20/23 08:54	1	135	Planned
SAIFI-05	SAIFI	5	SNOVR0302	-		05/22/23 09:30	1	20	Planned
SAIFI-05	SAIFI	5	SNOVR0302	-		05/22/23 10:32	1	14	Other
SAIFI-05	SAIFI	5	SNOVR0302	-		05/22/23 10:45	1	42	Planned
SAIFI-05	SAIFI	5	SNOVR0302	-		05/22/23 11:13	1	6	Planned
SAIFI-05	SAIFI	5	SNOVR0302	-		05/22/23 11:29	1	26	Other
SAIFI-05	SAIFI	5	SNOVR0302	-		05/22/23 12:26	1	14	Other
SAIFI-05	SAIFI	5	SNOVR0302	-		05/23/23 09:35	1	42	Planned
SAIFI-05	SAIFI	5	SNOVR0302	-		05/23/23 09:53	2	116	Planned
SAIFI-05	SAIFI	5	SNOVR0302	-		05/23/23 11:47	2	48	Other
SAIFI-05	SAIFI	5	SNOVR0302	-		05/23/23 11:47	1	24	Planned
SAIFI-05	SAIFI	5	SNOVR0302	-		05/23/23 12:46	1	18	Planned
SAIFI-05	SAIFI	5	SNOVR0302	-		05/23/23 13:37	1	20	Planned
SAIFI-05	SAIFI	5	SNOVR0302	-		05/23/23 13:37	1	20	Other
SAIFI-05	SAIFI	5	SNOVR0302	-		05/24/23 09:00	1	25	Planned
SAIFI-05	SAIFI	5	SNOVR0302	-		05/24/23 10:32	1	55	Other
SAIFI-05	SAIFI	5	SNOVR0302	-		05/24/23 10:33	6	328	Other
SAIFI-05	SAIFI	5	SNOVR0302	-		06/01/23 13:12	1	94	Planned
SAIFI-05	SAIFI	5	SNOVR0302	-		06/06/23 08:11	1	108	Other
SAIFI-05	SAIFI	5	SNOVR0302	-		06/30/23 01:20	5	2,744	Vegetation
SAIFI-05	SAIFI	5	SNOVR0302	-		07/11/23 11:52	1	15	Other
SAIFI-05	SAIFI	5	SNOVR0302	-		07/13/23 01:28	1	937	Weather
SAIFI-05	SAIFI	5	SNOVR0302	-		07/13/23 01:37	4	3,680	Other
SAIFI-05	SAIFI	5	SNOVR0302	-		07/13/23 13:26	1	41	Other
SAIFI-05	SAIFI	5	SNOVR0302	-		07/17/23 11:45	2	71	Other
SAIFI-05	SAIFI	5	SNOVR0302	-		07/17/23 11:45	1	36	Other
SAIFI-05	SAIFI	5	SNOVR0302	-		07/25/23 09:51	1	53	Other
SAIFI-05	SAIFI	5	SNOVR0302	-		08/08/23 14:23	338	83,884	Equipment
SAIFI-05	SAIFI	5	SNOVR0302	MED	Cat	08/24/23 20:06	1	6	Other
SAIFI-05	SAIFI	5	SNOVR0302	-		09/18/23 10:44	1	13	Other
SAIFI-05	SAIFI	5	SNOVR0302	-		09/18/23 12:15	1	34	Other
SAIFI-05	SAIFI	5	SNOVR0302	-		09/19/23 10:47	2	15	Other
SAIFI-05	SAIFI	5	SNOVR0302	-		09/28/23 09:57	5	222	Other
SAIFI-05	SAIFI	5	SNOVR0302	-		10/18/23 15:39	74	9,897	Equipment
SAIFI-05	SAIFI	5	SNOVR0302	-		10/18/23 15:39	1	106	Other
SAIFI-05	SAIFI	5	SNOVR0302	-		10/23/23 12:43	1	41	Other
SAIFI-05	SAIFI	5	SNOVR0302	-		11/09/23 12:59	1	12	Vegetation

SAIFI-05	SAIFI	5	SNOVR0302	-		11/09/23 22:14	1	704	Equipment
SAIFI-05	SAIFI	5	SNOVR0302	-		11/10/23 20:57	5	43	Other
SAIFI-05	SAIFI	5	SNOVR0302	-		11/21/23 07:11	1	294	Equipment
SAIFI-06	SAIFI	6	SDF012641	-		03/17/23 03:39	102	17,492	Weather
SAIFI-06	SAIFI	6	SDF012641	-		03/17/23 03:39	1	172	Weather
SAIFI-06	SAIFI	6	SDF012641	-		04/05/23 08:56	1	504	Lightning
SAIFI-06	SAIFI	6	SDF012641	-		04/27/23 09:38	1	308	Other
SAIFI-06	SAIFI	6	SDF012641	-		05/05/23 09:41	1	17	Planned
SAIFI-06	SAIFI	6	SDF012641	-		05/05/23 12:17	1	7	Planned
SAIFI-06	SAIFI	6	SDF012641	-		05/05/23 13:09	1	10	Planned
SAIFI-06	SAIFI	6	SDF012641	-		05/05/23 13:10	1	10	Other
SAIFI-06	SAIFI	6	SDF012641	-		05/05/23 13:59	1	19	Planned
SAIFI-06	SAIFI	6	SDF012641	-		05/08/23 10:52	1	22	Planned
SAIFI-06	SAIFI	6	SDF012641	-		05/08/23 13:27	1	19	Other
SAIFI-06	SAIFI	6	SDF012641	-		05/08/23 13:27	1	19	Planned
SAIFI-06	SAIFI	6	SDF012641	-		05/11/23 08:55	1	87	Other
SAIFI-06	SAIFI	6	SDF012641	-		05/16/23 09:14	1	26	Planned
SAIFI-06	SAIFI	6	SDF012641	-		06/05/23 10:52	1	6	Other
SAIFI-06	SAIFI	6	SDF012641	MED	Small	07/20/23 22:02	1	1,106	Weather
SAIFI-06	SAIFI	6	SDF012641	-		08/01/23 10:09	1	21	Other
SAIFI-06	SAIFI	6	SDF012641	-		08/18/23 10:53	102	43,382	Equipment
SAIFI-06	SAIFI	6	SDF012641	-		09/12/23 08:34	78	17,498	Equipment
SAIFI-06	SAIFI	6	SDF012641	-		09/12/23 08:34	126	28,267	Equipment
SAIFI-06	SAIFI	6	SDF012641	-		09/16/23 09:15	102	38,219	Vegetation
SAIFI-06	SAIFI	6	SDF012641	-		12/21/23 13:00	1	133	Equipment
SAIFI-07	SAIFI	7	ARMAD0302	-		01/05/23 09:17	1	17	Other
SAIFI-07	SAIFI	7	ARMAD0302	-		02/02/23 11:12	2	45	Planned
SAIFI-07	SAIFI	7	ARMAD0302	-		02/03/23 11:55	2	89	Planned
SAIFI-07	SAIFI	7	ARMAD0302	-		02/05/23 10:57	1	9	Other
SAIFI-07	SAIFI	7	ARMAD0302	-		02/07/23 14:43	2	31	Other
SAIFI-07	SAIFI	7	ARMAD0302	-		02/11/23 14:26	1	42	Planned
SAIFI-07	SAIFI	7	ARMAD0302	-		02/13/23 11:05	2	113	Planned
SAIFI-07	SAIFI	7	ARMAD0302	-	Small	02/15/23 10:54	2	444	Weather
SAIFI-07	SAIFI	7	ARMAD0302	-	Small	02/15/23 15:19	336	68,302	Weather
SAIFI-07	SAIFI	7	ARMAD0302	-	Small	02/16/23 07:12	2	463	Weather
SAIFI-07	SAIFI	7	ARMAD0302	-		02/17/23 11:12	1	50	Planned
SAIFI-07	SAIFI	7	ARMAD0302	-		02/20/23 10:59	1	37	Planned
SAIFI-07	SAIFI	7	ARMAD0302	MED	Cat	03/03/23 22:30	159	203,260	Weather
SAIFI-07	SAIFI	7	ARMAD0302	-		03/09/23 15:27	1	37	Other
SAIFI-07	SAIFI	7	ARMAD0302	-		03/16/23 11:58	22	1,445	Other
SAIFI-07	SAIFI	7	ARMAD0302	-		03/16/23 11:59	6	740	Other
SAIFI-07	SAIFI	7	ARMAD0302	-		03/19/23 16:23	1	633	Other
SAIFI-07	SAIFI	7	ARMAD0302	-		03/20/23 20:37	3	56	Weather

SAIFI-07	SAIFI	7	ARMAD0302	-		03/21/23 10:54	1	172	Other
SAIFI-07	SAIFI	7	ARMAD0302	-		03/21/23 10:54	1	172	Other
SAIFI-07	SAIFI	7	ARMAD0302	-		03/23/23 17:44	1	118	Equipment
SAIFI-07	SAIFI	7	ARMAD0302	-		03/23/23 17:45	1	118	Equipment
SAIFI-07	SAIFI	7	ARMAD0302	-		03/29/23 12:19	1	107	Other
SAIFI-07	SAIFI	7	ARMAD0302	-		03/30/23 16:30	2	11	Other
SAIFI-07	SAIFI	7	ARMAD0302	-		04/04/23 19:04	2	46	Other
SAIFI-07	SAIFI	7	ARMAD0302	-		04/05/23 13:32	2	476	Equipment
SAIFI-07	SAIFI	7	ARMAD0302	-		04/08/23 10:09	1	1,664	Other
SAIFI-07	SAIFI	7	ARMAD0302	-		04/11/23 12:45	1	111	Other
SAIFI-07	SAIFI	7	ARMAD0302	-		04/23/23 18:58	1	194	Other
SAIFI-07	SAIFI	7	ARMAD0302	-		04/26/23 10:53	2	71	Planned
SAIFI-07	SAIFI	7	ARMAD0302	-		05/08/23 10:12	1	111	Other
SAIFI-07	SAIFI	7	ARMAD0302	-		05/08/23 10:44	1	53	Planned
SAIFI-07	SAIFI	7	ARMAD0302	-		05/08/23 15:10	1	42	Other
SAIFI-07	SAIFI	7	ARMAD0302	-		05/08/23 15:10	1	42	Planned
SAIFI-07	SAIFI	7	ARMAD0302	-		05/13/23 14:10	1	19	Planned
SAIFI-07	SAIFI	7	ARMAD0302	-		05/13/23 15:22	1	37	Other
SAIFI-07	SAIFI	7	ARMAD0302	-		05/14/23 10:36	1	52	Planned
SAIFI-07	SAIFI	7	ARMAD0302	-		05/14/23 13:08	1	66	Planned
SAIFI-07	SAIFI	7	ARMAD0302	-		05/14/23 14:56	1	56	Planned
SAIFI-07	SAIFI	7	ARMAD0302	-		05/16/23 14:13	2	80	Planned
SAIFI-07	SAIFI	7	ARMAD0302	-		05/18/23 15:30	1	62	Equipment
SAIFI-07	SAIFI	7	ARMAD0302	-		05/21/23 10:42	1	29	Other
SAIFI-07	SAIFI	7	ARMAD0302	MED		05/31/23 13:00	1	25	Other
SAIFI-07	SAIFI	7	ARMAD0302	-		06/13/23 08:55	1	134	Other
SAIFI-07	SAIFI	7	ARMAD0302	-		06/14/23 09:42	1	47	Planned
SAIFI-07	SAIFI	7	ARMAD0302	MED	Small	06/26/23 02:16	1	1,003	Weather
SAIFI-07	SAIFI	7	ARMAD0302	-	Small	06/27/23 14:52	1	167	Weather
SAIFI-07	SAIFI	7	ARMAD0302	-		07/06/23 10:05	1	14	Planned
SAIFI-07	SAIFI	7	ARMAD0302	-		07/10/23 19:17	1	33	Other
SAIFI-07	SAIFI	7	ARMAD0302	-		07/14/23 17:58	1	5	Other
SAIFI-07	SAIFI	7	ARMAD0302	-		07/17/23 21:07	318	70,672	Equipment
SAIFI-07	SAIFI	7	ARMAD0302	MED	Small	07/20/23 15:36	319	618,445	Equipment
SAIFI-07	SAIFI	7	ARMAD0302	-		07/23/23 23:12	335	79,420	Equipment
SAIFI-07	SAIFI	7	ARMAD0302	-		08/08/23 18:24	334	37,081	Equipment
SAIFI-07	SAIFI	7	ARMAD0302	-		08/15/23 07:15	1	130	Other
SAIFI-07	SAIFI	7	ARMAD0302	-		08/15/23 07:15	326	42,499	Weather
SAIFI-07	SAIFI	7	ARMAD0302	-	Cat	08/29/23 10:17	1	153	Other
SAIFI-07	SAIFI	7	ARMAD0302	-		10/06/23 12:58	1	25	Other
SAIFI-07	SAIFI	7	ARMAD0302	-		10/11/23 09:39	1	177	Other
SAIFI-07	SAIFI	7	ARMAD0302	-		10/17/23 08:50	1	142	Planned
SAIFI-07	SAIFI	7	ARMAD0302	-		10/18/23 10:32	1	81	Planned

SAIFI-07	SAIFI	7	ARMAD0302	-		10/18/23 14:17	1	12	Planned
SAIFI-07	SAIFI	7	ARMAD0302	-		10/19/23 08:56	1	18	Planned
SAIFI-07	SAIFI	7	ARMAD0302	-		10/19/23 10:54	2	41	Planned
SAIFI-07	SAIFI	7	ARMAD0302	-		10/21/23 08:48	1	58	Planned
SAIFI-07	SAIFI	7	ARMAD0302	-		10/21/23 10:40	1	21	Planned
SAIFI-07	SAIFI	7	ARMAD0302	-		10/21/23 11:36	1	13	Planned
SAIFI-07	SAIFI	7	ARMAD0302	-		10/21/23 11:36	1	13	Other
SAIFI-07	SAIFI	7	ARMAD0302	-		10/23/23 10:09	1	104	Planned
SAIFI-07	SAIFI	7	ARMAD0302	-		10/23/23 14:00	1	6	Planned
SAIFI-07	SAIFI	7	ARMAD0302	-		10/23/23 14:00	1	6	Other
SAIFI-07	SAIFI	7	ARMAD0302	-		10/25/23 09:11	2	25	Other
SAIFI-07	SAIFI	7	ARMAD0302	-		10/25/23 09:45	1	47	Planned
SAIFI-07	SAIFI	7	ARMAD0302	-		11/02/23 11:23	1	57	Other
SAIFI-07	SAIFI	7	ARMAD0302	-		11/03/23 12:43	1	48	Other
SAIFI-07	SAIFI	7	ARMAD0302	-		11/12/23 08:55	1	212	Other
SAIFI-07	SAIFI	7	ARMAD0302	-		11/15/23 10:56	1	11	Equipment
SAIFI-07	SAIFI	7	ARMAD0302	-		11/15/23 10:56	1	11	Other
SAIFI-07	SAIFI	7	ARMAD0302	-		11/15/23 13:14	1	6	Other
SAIFI-07	SAIFI	7	ARMAD0302	-		11/17/23 17:16	1	32	Other
SAIFI-07	SAIFI	7	ARMAD0302	-		11/29/23 10:13	1	7	Other
SAIFI-07	SAIFI	7	ARMAD0302	-		12/13/23 08:44	1	125	Other
SAIFI-07	SAIFI	7	ARMAD0302	-		12/20/23 09:30	1	46	Other
SAIFI-07	SAIFI	7	ARMAD0302	-		12/21/23 10:55	1	6	Planned
SAIFI-07	SAIFI	7	ARMAD0302	-		12/21/23 12:32	1	14	Planned
SAIFI-07	SAIFI	7	ARMAD0302	-		12/24/23 09:23	1	106	Equipment
SAIFI-08	SAIFI	8	SNOVR0301	-		01/01/23 01:04	1	2,327	Other
SAIFI-08	SAIFI	8	SNOVR0301	-		01/01/23 01:04	175	107,423	Equipment
SAIFI-08	SAIFI	8	SNOVR0301	-		01/01/23 11:06	46	27,756	Equipment
SAIFI-08	SAIFI	8	SNOVR0301	-		01/01/23 11:06	2	1,207	Equipment
SAIFI-08	SAIFI	8	SNOVR0301	-		01/01/23 11:06	18	10,860	Other
SAIFI-08	SAIFI	8	SNOVR0301	-		01/01/23 21:08	115	68,839	Other
SAIFI-08	SAIFI	8	SNOVR0301	-		01/01/23 23:47	1	8	Other
SAIFI-08	SAIFI	8	SNOVR0301	-		01/03/23 03:45	127	4,811	Equipment
SAIFI-08	SAIFI	8	SNOVR0301	-		01/03/23 16:49	1	36	Other
SAIFI-08	SAIFI	8	SNOVR0301	-		01/03/23 16:49	233	8,594	Other
SAIFI-08	SAIFI	8	SNOVR0301	MED	Cat	02/24/23 11:55	1	29	Weather
SAIFI-08	SAIFI	8	SNOVR0301	MED	Cat	02/25/23 15:24	1	31	Other
SAIFI-08	SAIFI	8	SNOVR0301	-		03/20/23 22:08	1	221	Other
SAIFI-08	SAIFI	8	SNOVR0301	-		04/04/23 11:14	2	167	Planned
SAIFI-08	SAIFI	8	SNOVR0301	-		04/15/23 13:15	1	36	Other
SAIFI-08	SAIFI	8	SNOVR0301	-		05/11/23 13:30	1	70	Other
SAIFI-08	SAIFI	8	SNOVR0301	-		07/09/23 09:48	2	525	Other
SAIFI-08	SAIFI	8	SNOVR0301	-		07/25/23 13:17	1	10	Planned

SAIFI-08	SAIFI	8	SNOVR0301	MED	Cat	07/26/23 14:43	1	7	Weather
SAIFI-08	SAIFI	8	SNOVR0301	MED	Cat	07/27/23 09:49	1	30	Other
SAIFI-08	SAIFI	8	SNOVR0301	-		07/31/23 11:41	1	40	Planned
SAIFI-08	SAIFI	8	SNOVR0301	-		08/08/23 14:23	2	497	Other
SAIFI-08	SAIFI	8	SNOVR0301	-		08/08/23 14:23	166	41,198	Equipment
SAIFI-08	SAIFI	8	SNOVR0301	-		08/08/23 14:23	1	248	Other
SAIFI-08	SAIFI	8	SNOVR0301	-		08/08/23 14:23	1	248	Other
SAIFI-08	SAIFI	8	SNOVR0301	-		08/12/23 10:41	2	48	Equipment
SAIFI-08	SAIFI	8	SNOVR0301	-		08/16/23 13:19	1	9	Other
SAIFI-08	SAIFI	8	SNOVR0301	-		10/13/23 07:49	1	87	Other
SAIFI-09	SAIFI	9	SDF339897	-		01/03/23 06:21	1	580	Vegetation
SAIFI-09	SAIFI	9	SDF339897	-		01/09/23 15:27	1	5	Other
SAIFI-09	SAIFI	9	SDF339897	-	Small	02/15/23 10:28	1	1,550	Weather
SAIFI-09	SAIFI	9	SDF339897	-	Small	02/15/23 21:31	1	27	Weather
SAIFI-09	SAIFI	9	SDF339897	-	Small	02/15/23 21:31	1	27	Weather
SAIFI-09	SAIFI	9	SDF339897	MED	Cat	02/22/23 17:03	12	101,820	Weather
SAIFI-09	SAIFI	9	SDF339897	MED	Cat	02/22/23 19:33	5	25,666	Weather
SAIFI-09	SAIFI	9	SDF339897	MED	Cat	02/22/23 19:33	5	42,629	Weather
SAIFI-09	SAIFI	9	SDF339897	MED	Cat	02/22/23 20:16	2	18,122	Other
SAIFI-09	SAIFI	9	SDF339897	MED	Cat	02/22/23 22:34	2	19,531	Weather
SAIFI-09	SAIFI	9	SDF339897	MED	Cat	02/22/23 23:56	1	216	Other
SAIFI-09	SAIFI	9	SDF339897	MED	Cat	02/23/23 00:51	148	360,543	Weather
SAIFI-09	SAIFI	9	SDF339897	MED	Cat	02/24/23 00:05	1	124	Weather
SAIFI-09	SAIFI	9	SDF339897	MED	Cat	02/24/23 02:50	2	70	Other
SAIFI-09	SAIFI	9	SDF339897	MED	Cat	02/24/23 03:35	1	5	Other
SAIFI-09	SAIFI	9	SDF339897	MED	Cat	02/24/23 07:13	1	6	Other
SAIFI-09	SAIFI	9	SDF339897	MED	Cat	02/24/23 11:55	84	189,711	Vegetation
SAIFI-09	SAIFI	9	SDF339897	MED	Cat	02/24/23 15:53	84	55,845	Weather
SAIFI-09	SAIFI	9	SDF339897	-	Cat	02/26/23 12:39	144	4,544	Weather
SAIFI-09	SAIFI	9	SDF339897	-	Cat	02/26/23 14:55	1	27	Other
SAIFI-09	SAIFI	9	SDF339897	-	Cat	02/26/23 19:24	1	9	Other
SAIFI-09	SAIFI	9	SDF339897	-	Cat	02/26/23 20:12	1	22	Other
SAIFI-09	SAIFI	9	SDF339897	MED	Cat	02/27/23 16:54	2	88	Weather
SAIFI-09	SAIFI	9	SDF339897	MED	Cat	02/27/23 16:54	6	265	Weather
SAIFI-09	SAIFI	9	SDF339897	MED	Cat	03/03/23 20:19	1	2,629	Other
SAIFI-09	SAIFI	9	SDF339897	MED	Cat	03/03/23 20:26	28	98,272	Weather
SAIFI-09	SAIFI	9	SDF339897	MED	Cat	03/03/23 20:26	2	7,500	Weather
SAIFI-09	SAIFI	9	SDF339897	MED	Cat	03/03/23 22:56	1	3,587	Weather
SAIFI-09	SAIFI	9	SDF339897	MED	Cat	03/04/23 02:27	2	18	Other
SAIFI-09	SAIFI	9	SDF339897	MED	Cat	03/04/23 03:24	2	14	Other
SAIFI-09	SAIFI	9	SDF339897	-	Cat	03/06/23 08:12	3	22	Vegetation
SAIFI-09	SAIFI	9	SDF339897	-	Cat	03/06/23 11:22	1	142	Weather
SAIFI-09	SAIFI	9	SDF339897	-	Cat	03/06/23 15:03	2	324	Weather

SAIFI-09	SAIFI	9	SDF339897	-	Cat	03/07/23 19:06	1	28	Other
SAIFI-09	SAIFI	9	SDF339897	-		03/17/23 12:49	1	22	Other
SAIFI-09	SAIFI	9	SDF339897	-		03/28/23 13:48	341	42,010	Other
SAIFI-09	SAIFI	9	SDF339897	-		05/02/23 19:11	1	78	Planned
SAIFI-09	SAIFI	9	SDF339897	-		05/17/23 13:07	1	27	Other
SAIFI-09	SAIFI	9	SDF339897	-		05/17/23 13:07	5	135	Other
SAIFI-09	SAIFI	9	SDF339897	-		05/19/23 23:05	340	48,696	Vegetation
SAIFI-09	SAIFI	9	SDF339897	-		05/25/23 10:22	340	21,465	Equipment
SAIFI-09	SAIFI	9	SDF339897	-		05/30/23 01:49	341	30,210	Wildlife
SAIFI-09	SAIFI	9	SDF339897	-		06/12/23 11:14	1	58	Planned
SAIFI-09	SAIFI	9	SDF339897	-		06/12/23 11:14	6	345	Other
SAIFI-09	SAIFI	9	SDF339897	-		06/15/23 17:26	1	511	Weather
SAIFI-09	SAIFI	9	SDF339897	-		06/16/23 01:06	7	353	Other
SAIFI-09	SAIFI	9	SDF339897	-		06/24/23 10:37	1	88	Wildlife
SAIFI-09	SAIFI	9	SDF339897	-		06/24/23 10:38	1	88	Other
SAIFI-09	SAIFI	9	SDF339897	-		06/24/23 10:38	1	88	Wildlife
SAIFI-09	SAIFI	9	SDF339897	MED		06/25/23 12:46	341	30,525	Weather
SAIFI-09	SAIFI	9	SDF339897	MED	Small	06/25/23 18:12	342	331,400	Weather
SAIFI-09	SAIFI	9	SDF339897	-		07/25/23 09:28	2	82	Planned
SAIFI-09	SAIFI	9	SDF339897	-		07/26/23 09:24	1	55	Other
SAIFI-09	SAIFI	9	SDF339897	-		07/26/23 09:24	1	55	Planned
SAIFI-09	SAIFI	9	SDF339897	MED	Cat	07/26/23 15:01	1	4,606	Weather
SAIFI-09	SAIFI	9	SDF339897	MED	Cat	07/26/23 15:01	26	117,412	Vegetation
SAIFI-09	SAIFI	9	SDF339897	MED	Cat	07/26/23 15:01	1	3,098	Other
SAIFI-09	SAIFI	9	SDF339897	MED	Cat	07/26/23 15:32	1	3,067	Weather
SAIFI-09	SAIFI	9	SDF339897	MED	Cat	07/26/23 15:32	13	54,822	Vegetation
SAIFI-09	SAIFI	9	SDF339897	MED	Cat	07/26/23 15:32	1	4,434	Weather
SAIFI-09	SAIFI	9	SDF339897	MED	Cat	07/26/23 15:32	288	901,339	Weather
SAIFI-09	SAIFI	9	SDF339897	MED	Cat	07/26/23 15:32	1	4,415	Weather
SAIFI-09	SAIFI	9	SDF339897	MED	Cat	07/26/23 15:32	1	3,067	Weather
SAIFI-09	SAIFI	9	SDF339897	MED	Cat	07/26/23 15:32	21	92,890	Vegetation
SAIFI-09	SAIFI	9	SDF339897	-		08/01/23 09:02	1	34	Planned
SAIFI-09	SAIFI	9	SDF339897	-		08/07/23 10:29	2	72	Other
SAIFI-09	SAIFI	9	SDF339897	-		08/08/23 09:48	5	210	Planned
SAIFI-09	SAIFI	9	SDF339897	-		08/09/23 09:16	1	37	Planned
SAIFI-09	SAIFI	9	SDF339897	-		08/09/23 10:48	5	208	Planned
SAIFI-09	SAIFI	9	SDF339897	-		08/10/23 09:33	2	77	Planned
SAIFI-09	SAIFI	9	SDF339897	-		08/10/23 11:12	7	225	Planned
SAIFI-09	SAIFI	9	SDF339897	-		08/17/23 19:05	1	32	Other
SAIFI-09	SAIFI	9	SDF339897	MED	Cat	08/24/23 22:16	21	81,469	Weather
SAIFI-09	SAIFI	9	SDF339897	-	Cat	08/27/23 12:57	30	4,202	Weather
SAIFI-09	SAIFI	9	SDF339897	-		09/06/23 12:24	1	5	Other
SAIFI-09	SAIFI	9	SDF339897	-		09/06/23 18:28	6	450	Vegetation

SAIFI-09	SAIFI	9	SDF339897	-		09/29/23 20:44	1	8	Other
SAIFI-09	SAIFI	9	SDF339897	-		09/30/23 08:44	1	348	Other
SAIFI-09	SAIFI	9	SDF339897	-		09/30/23 19:03	5	90	Other
SAIFI-09	SAIFI	9	SDF339897	-		10/14/23 09:32	2	10	Other
SAIFI-09	SAIFI	9	SDF339897	-		11/12/23 14:31	2	52	Other
SAIFI-09	SAIFI	9	SDF339897	-		11/17/23 00:18	1	134	Equipment
SAIFI-09	SAIFI	9	SDF339897	-		11/17/23 00:18	6	805	Equipment
SAIFI-09	SAIFI	9	SDF339897	-		12/28/23 09:14	4	50	Planned
SAIFI-09	SAIFI	9	SDF339897	-		12/28/23 11:17	6	76	Planned
SAIFI-09	SAIFI	9	SDF339897	-		12/28/23 11:17	1	13	Other
SAIFI-09	SAIFI	9	SDF339897	-		12/29/23 09:49	2	144	Planned
SAIFI-09	SAIFI	9	SDF339897	-		12/29/23 12:12	4	204	Planned
SAIFI-10	SAIFI	10	CABOT9490	MED	Cat	02/22/23 20:07	300	99,988	Weather
SAIFI-10	SAIFI	10	CABOT9490	MED	Cat	03/03/23 17:47	2	5,300	Weather
SAIFI-10	SAIFI	10	CABOT9490	MED	Cat	03/03/23 17:47	147	144,402	Weather
SAIFI-10	SAIFI	10	CABOT9490	MED	Cat	03/03/23 17:47	5	8,450	Other
SAIFI-10	SAIFI	10	CABOT9490	-		03/09/23 16:02	3	80	Equipment
SAIFI-10	SAIFI	10	CABOT9490	-		03/09/23 16:02	2	53	Equipment
SAIFI-10	SAIFI	10	CABOT9490	-		03/15/23 11:03	3	338	Other
SAIFI-10	SAIFI	10	CABOT9490	-		03/15/23 14:21	3	301	Planned
SAIFI-10	SAIFI	10	CABOT9490	MED	Small	03/25/23 14:23	153	10,677	Weather
SAIFI-10	SAIFI	10	CABOT9490	-		04/02/23 05:04	148	35,100	Equipment
SAIFI-10	SAIFI	10	CABOT9490	-		05/09/23 12:00	146	932	Planned
SAIFI-10	SAIFI	10	CABOT9490	-		05/28/23 14:49	4	21	Equipment
SAIFI-10	SAIFI	10	CABOT9490	-		06/15/23 23:30	30	798	Weather
SAIFI-10	SAIFI	10	CABOT9490	-		06/16/23 05:32	59	1,167	Equipment
SAIFI-10	SAIFI	10	CABOT9490	-		06/16/23 10:22	1	9	Other
SAIFI-10	SAIFI	10	CABOT9490	MED	Cat	07/27/23 13:58	150	40,364	Other
SAIFI-10	SAIFI	10	CABOT9490	-		08/20/23 23:39	1	7	Other
SAIFI-10	SAIFI	10	CABOT9490	-		08/20/23 23:39	149	1,055	Other
SAIFI-10	SAIFI	10	CABOT9490	MED	Cat	08/24/23 22:40	5	19,735	Weather
SAIFI-10	SAIFI	10	CABOT9490	-		09/23/23 12:46	146	11,694	Equipment

MPSC Case No: U-21534

Requester: MNSC

Question No.: MNSCDE-17.18

Respondent: M. Elliott Andahazy

Page: 1 of 1

Question: 18. Refer to the rebuttal testimony of Witness Kryscynski, Q&As 16 and 17. For poles replaced as part of the PTMM program in 2021, 2022, and 2023, identify for each year and circuit the average age of replaced poles.

Answer: The Company has not performed this analysis.

The analysis the Company has performed is on poles that were inspected in 2021 by the PTMM program:

2021	Pole Age Range											
Pole Category	**0-10 Years**	**11-20 Years**	**21-30 Years**	**31-40 Years**	**41-50 Years**	**51-60 Years**	**61-70 Years**	**71-80 Years**	**81-90 Years**	**91-100 Years**	**101+ Years**	**No Age Data**
Non-Reject	2,453	2,416	4,624	2,571	2,357	4,092	4,762	2,373	1,875	907	41	525
Non-Restorable Reject	0	2	19	64	252	444	303	382	392	284	9	0
Restorable Reject	1	2	12	45	98	106	183	145	87	38	0	0

Attachment: *N/A*

Co-respondent: J. Kryscynski

MPSC Case No: U-21534

Requester: MNSC

Question No.: MNSCDE-17.20

Respondent: M. Elliott Andahazy

Page: 1 of 1

Question: 20. Refer to the rebuttal testimony of Witness Kryscynski, Q&A 19. Has the Company assessed the extent of actual outage improvements (reductions in outage events, customers affected, and outage duration) associated with circuits or segments of circuits where DTE has implemented the PTMM program (i.e., outage history before and after a PTMM circuit or segment investment)? If so, describe the assessment and produce the data and all reports associated with the assessment. Also identify the total PTMM investment for each circuit or segment studied.

Answer: The Company has not performed this analysis. The Company expects to begin performing this analysis for its new annual PTMM report starting in 2025.

Attachment: N/A

MPSC Case No: U-21534

Requester: MNSC

Question No.: MNSCDE-18.27

Respondent: M. Elliott Andahazy

Page: 1 of 1

Question: 27. Refer to the rebuttal testimony of Witness Elliott Andahazy, Q&A 16. As used in this testimony, how long are hardened circuits excluded from the PTMM program, when does the Company expect would be an appropriate time to include them in future PTMM cycles?

Answer: The Company expects it to be appropriate to perform PTMM on hardened circuits 10 years after hardening work is performed.

Attachment: N/A

MPSC Case No: U-21534

Requester: MNSC

Question No.: MNSCDE-18.28

Respondent: M. Elliott Andahazy

Page: 1 of 1

Question: 28. Refer to the rebuttal testimony of Witness Elliott Andahazy, Q&A 16. Does the Company maintain written policies or procedures that address when a 4.8kV circuit that has been Hardened becomes eligible for (a) PTMM and (b) tree trimming. If so, please produce it/them.

Answer: The Company does not have written policies and procedures that determine the timing between 4.8kV Hardening work and PTMM or Tree Trimming work.

Circuits where 4.8kV Hardening is performed will be monitored and tracked in the same fashion as circuits which have had PTMM performed on them. Generally, the Company is targeting a 10-year PTMM cycle for distribution circuits.

Circuits where 4.8kV Hardening is performed will be monitored and tracked in the same fashion as circuits trimmed for maintenance in each of those years. Generally, the Company is targeting a 5-year cycle for distribution circuits.

Attachment: *N/A*

MPSC Case No: U-21534

Requester: MNSC

Question No.: MNSCDE-18.30

Respondent: M. Elliott Andahazy

Page: 1 of 1

Question: 30. Refer to the rebuttal testimony of Witness Elliott Andahazy, Q&A 16. For circuits that were hardened in each 2021, 2022, and 2023, what is the Company's planned timeline for those circuits to be trimmed under the Tree Trimming Program?

Answer: Circuits trimmed as part of the 4.8kV Hardening Program will be monitored and tracked in the same fashion as circuits trimmed for maintenance in each of those years. Generally, the Company is targeting a 5-year cycle for distribution circuits. The Company is exploring risk-based cycles, which is a more prescriptive approach to assigning cycle's lengths by circuit. Further discussion of risk-based cycles is included in Witness Steudle's direct testimony beginning on page 28.

Attachment: *N/A*

Co-Respondent(s): R. Steudle

MPSC Case No: U-21534

Requester: MNSC

Question No.: MNSCDE-18.31

Respondent: M. Elliott Andahazy

Page: 1 of 1

Question: 31. Refer to the rebuttal testimony of Witness Elliott Andahazy, Q&A 16. Identify the Company's average annual total hardening tree trim capital spend for 2021, 2022, and 2023 and the total number of miles hardened and miles trimmed for each 2021, 2022, and 2023.

Answer: 2021 4.8kV Hardening Tree Trim Capital Investment: $20,716 (thousands)
2021 4.8kV Hardening Miles Hardened: 202
2021 4.8kV Hardening Miles Trimmed: 322

2022 4.8kV Hardening Tree Trim Capital Investment: $36,226 (thousands)
2022 4.8kV Hardening Miles Hardened: 475
2022 4.8kV Hardening Miles Trimmed: 521

2023 4.8kV Hardening Tree Trim Capital Investment: $18,400 (thousands)
2023 4.8kV Hardening Miles Hardened: 373
2023 4.8kV Hardening Miles Trimmed: 243

Attachment: *N/A*

MPSC Case No: U-21534

Requester: MNSC

Question No.: MNSCDE-18.32

Respondent: M. Elliott Andahazy

Page: 1 of 1

Question: 32. Refer to the rebuttal testimony of Witness Elliott Andahazy, Q&A 16. Identify the Company's average per-circuit hardening tree trim capital spend for each circuit hardened in 2021, 2022, or 2023, and the average number of miles hardened and trimmed per circuit for each 2021, 2022, and 2023.

Answer: 2021 4.8kV Hardening Tree Trim Capital Investment avg per circuit: $276 (thousands)
2021 4.8kV Hardening Miles Hardened avg per circuit: 4.3
2021 4.8kV Hardening Miles Trimmed avg per circuit: 5.3

2022 4.8kV Hardening Tree Trim Capital Investment avg per circuit: $326 (thousands)
2022 4.8kV Hardening Miles Hardened avg per circuit: 4.9
2022 4.8kV Hardening Miles Trimmed avg per circuit: 4.6

2023 4.8kV Hardening Tree Trim Capital Investment avg per circuit: $275 (thousands)
2023 4.8kV Hardening Miles Hardened avg per circuit: 3.6
2023 4.8kV Hardening Miles Trimmed avg per circuit: 3.8

Attachment: *N/A*

Co-Respondent(s): R. Steudle

MPSC Case No: U-21534

Requester: MNSC

Question No.: MNSCDE-18.33c

Respondent: M. Elliott Andahazy

Page: 1 of 1

Question: 33. Refer to the rebuttal testimony of Witness Elliott Andahazy, Q&A 17.

c. Identify whether circuits that have been recently trimmed were removed from or included in the Control Group.

Answer: The control group is the same as was provided in discovery response U-21534 MNSCDE-3.6-01 4.8kV Hardening Data.xlsx and excludes circuits which were recently trimmed.

Attachment: *N/A*

MPSC Case No: U-21534

Requester: MNSC

Question No.: MNSCDE-18.33d

Respondent: M. Elliott Andahazy

Page: 1 of 1

Question: 33. Refer to the rebuttal testimony of Witness Elliott Andahazy, Q&A 17.

d. Identify the average length of time since the last tree trim for circuits included in the “Control Group 2018-2020)

Answer: The 2018-2020 4.8kV Hardening Control group had an average of approximately 6 years since last maintenance tree trim.

Attachment: *N/A*

MPSC Case No: U-21534

Requester: MNSC

Question No.: MNSCDE-18.33e

Respondent: M. Elliott Andahazy

Page: 1 of 1

Question: 33. Refer to the rebuttal testimony of Witness Elliott Andahazy, Q&A 17.

e. Identify the average length of time since the last tree trim for circuits included in the "Circuits Hardened 2018-2020" group.

Answer: The average length of time before last maintenance tree trim for the circuits included in the 2018-2020 Hardened circuits group is approximately 8 years.

Attachment: *N/A*

MPSC Case No: U-21534

Requester: MNSC

Question No.: MNSCDE-18.33g

Respondent: M. Elliott Andahazy

Page: 1 of 1

Question: 33. Refer to the rebuttal testimony of Witness Elliott Andahazy, Q&A 17. g. Identify the total cost to harden the circuits in the "Circuits Hardened 2018-2020" group.

Answer: The Company has not performed the analysis as requested. The Company invested the following capital totals for 4.8kV Hardening from 2018-2020:

2018: $40,325 (thousands)
2019: $48,278 (thousands)
2020: $55,165 (thousands)

Attachment: *N/A*

MPSC Case No: U-21534

Requester: MNSC

Question No.: MNSCDE-18.33h

Respondent: M. Elliott Andahazy

Page: 1 of 1

Question: 33. Refer to the rebuttal testimony of Witness Elliott Andahazy, Q&A 17.

h. Identify the total hardening tree trim capital spend for the circuits included in the “Circuits Hardened 2018-2020” group.

Answer: The Company has not performed the analysis as requested. The Company invested the following capital totals for tree trimming for 4.8kV Hardening from 2018-2020:

2018: $9,326 (thousands)
2019: $10,082 (thousands)
2020: $11,888 (thousands)

Attachment: *N/A*

MPSC Case No: U-21534

Requester: MNSC

Question No.: MNSCDE-18.34

Respondent: M. Elliott Andahazy

Page: 1 of 1

Question: 34. Refer to the rebuttal testimony of Witness Elliott Andahazy, Q&A 19, and Table 4. Refer also to Exhibit A-23 Schedule M12. Provide the analysis and supporting documentation for the “arc wire removal cost per mile: $175k - $207k.”

Answer: The Company is not able to locate this analysis.

Attachment: *N/A*

MPSC Case No: U-21534

Requester: MNSC

Question No.: MNSCDE-18.35

Respondent: M. Elliott Andahazy

Page: 1 of 1

Question: 35. Refer to the rebuttal testimony of Witness Elliott Andahazy, Q&A 19, and Table 4. Refer also to Exhibit A-23 Schedule M12. Provide the analysis and supporting documentation for the Company's estimated wire down, SAIFI, and SAIDI reductions.

Answer: Please see discovery response U-21534 MNSCDE-15.41a.

Attachment: *N/A*

MPSC Case No: U-21534

Requester: MNSC

Question No.: MNSCDE-15.41a

Respondent: M. Elliott Andahazy

Page: 1 of 1

Question: 41. Refer to Ms. Elliot-Andahazy's testimony at MEA-18,Table 2.

a. Provide all calculations, data, data sources and any other information used to arrive at the SAIDI, CAIDI, Reductions listed in this table.

Answer: The Company wishes to clarify that CAIDI in the referenced table was a typo and should instead say SAIDI.

4.8kV Hardening Program
The calculations used to determine 4.8kV Hardening SAIFI, SAIDI, and wire-down reductions are based on the 4.8kV Hardening effectiveness analysis that was shared in my direct testimony in Case No. U-21297. This analysis includes circuits hardened in 2018, 2019, and 2020 and compares 3-years average performance before vs. 1-year performance after. Please see attached file for data and calculations from Case No. U-21297.

Arc Wire Removal Only
The work scope of only removing arc wire is approximately half of the 4.8kV Hardening Program. Therefore, the Company expects approximately half of the benefits seen from the 4.8kV Hardening Program.

4.8kV Conversion and Pre-Conversion
Please see response U-21534 MNSCDE-13.11.

Microgrids
The reliability benefits from microgrids first assume that the area has been converted to replace the 4.8kV infrastructure with 13.2kV circuits constructed to our standards (see U-21534 MNSCDE-13.11). The microgrid offers additional benefits above and beyond conversion by continuing to supply power to customers within the microgrid for outage events upstream of the microgrid source. There is still the potential for outages within the microgrid footprint, thus a benefit higher than conversion, but less than a 100% improvement, was estimated as the overall reliability benefit for microgrids.

Attachment: U-21534 MNSCDE-15.41a-01 U-21297 4.8kV Hardening Source Data

MPSC Case No: U-21534

Requester: MNSC

Question No.: MNSCDE-18.36

Respondent: M. Elliott Andahazy

Page: 1 of 1

Question: 36. Refer to the rebuttal testimony of Witness Elliott Andahazy, Q&A 19, and Table 4. Refer also to Exhibit A-23 Schedule M12. For Tree Trimming, provide the cost per mile and the projected wire down, SAIFI and SAIDI reductions.

Answer: The Company has not performed an analysis that compares tree trimming to alternative approaches for 4.8kV Hardening. The effectiveness of the tree trim program is discussed in Company Witness Steudle's testimony beginning on page 8. The results provided in that section of testimony relate to circuits trimmed across the Company's service territory are specific to tree-related events.

Attachment: *N/A*

Co-respondent: R. Steudle

MPSC Case No: U-21534

Requester: MNSC

Question No.: MNSCDE-18.41

Respondent: M. Elliott Andahazy

Page: 1 of 1

Question: 41. Refer to the rebuttal testimony of Witness Elliott Andahazy, Q&A 22. Has DTE calculated the projected conversion cost for a 4.8kV circuit that was previously hardened versus a 4.8kV circuit that was not previously hardened? If so, please produce the analysis.

Answer: The Company has not completed this analysis.

Attachment: *N/A*

MPSC Case No: U-21534

Requester: MNSC

Question No.: MNSCDE-18.42

Respondent: M. Elliott Andahazy

Page: 1 of 1

Question: 42. Refer to the rebuttal testimony of Witness Elliott Andahazy, Q&A 29. How long of a delay does the Company would expect to result from a Commission order authorizing the Company to proceed with DLPD arc wire removal only in the test year? Please explain your response.

Answer: Approximately 6 months to complete construction in progress, and to review and update design packages for circuits where construction has not started.

Attachment: *N/A*

MPSC Case No: U-21534

Requester: MNSC

Question No.: MNSCDE-18.43

Respondent: M. Elliott Andahazy

Page: 1 of 1

Question: 43. Refer to the rebuttal testimony of Witness Elliott Andahazy, Q&A 30. Confirm that in Case No. 21297, the Company's requested approval from the Commission of $73.3 million in projected bridge period and $6.7 million in projected test year capital expenditures, as shown in Company Exhibit A-12 Schedule B5.4 page 8 line 12 filed in that case.

Answer: Confirmed. Please note the Commission's response to the Company's request in Case No. 21297 was to reiterate its desire for the Company to accelerate and complete the 4.8kV Hardening Program in its order dated December 1, 2023 on page 94, "Finding this work to be imperative, however, the Commission approves the requested bridge period and test year funding and expects to see results in DTE Electric's next rate case, including an accelerated removal of the arc wire discussed by the Staff."

Attachment: *N/A*

MPSC Case No: U-21534

Requester: MNSC

Question No.: MNSCDE-18.44

Respondent: M. Elliott Andahazy

Page: 1 of 1

Question: 44. Refer to the rebuttal testimony of Witness Elliott Andahazy, Q&A 30. Is it the Company's position that the Commission in Case No. U-21297 approved spending more than $6.7 million in the U-21297 test year (12 months ending 11/30/2024)? If so, please provide support for that position.

Answer: No. However, the Commission's response to the Company's request in Case No. 21297 was to reiterate its desire for the Company to accelerate and complete the 4.8kV Hardening Program in its order dated December 1, 2023 on page 94, "Finding this work to be imperative, however, the Commission approves the requested bridge period and test year funding and expects to see results in DTE Electric's next rate case, including an accelerated removal of the arc wire discussed by the Staff."

Attachment: *N/A*

MPSC Case No: U-21534

Requester: MNSC

Question No.: MNSCDE-19.12a.

Respondent: M. Elliott Andahazy

Page: 1 of 1

Question: Refer to the rebuttal testimony of Witness Elliott Andahazy, Q&A 40. For circuits where PTMM was performed in 2022 and 2023, produce the following:

For the 3 years preceding when the PTMM was performed, for each circuit, the average annual emergent reactive spending, emergent reactive pole replacements, emergent reactive pole top replacements, and truck rolls;

Answer: The Company has not performed this analysis.

Attachment: *N/A*

MPSC Case No: U-21534

Requester: MNSC

Question No.: MNSCDE-19.12b.

Respondent: M. Elliott Andahazy

Page: 1 of 1

Question: Refer to the rebuttal testimony of Witness Elliott Andahazy, Q&A 40. For circuits where PTMM was performed in 2022 and 2023, produce the following:

For the years since when the PTMM was performed, for each circuit, the annual emergent reactive spending, emergent reactive pole replacements, emergent reactive pole top replacements, and truck rolls.

Answer: The Company has not performed this analysis.

Attachment: *N/A*

MPSC Case No: U-21534

Requester: MNSC

Question No.: MNSCDE-19.16

Respondent: M. Elliott Andahazy

Page: 1 of 1

Question: Refer to the rebuttal testimony of Witness Elliott Andahazy, Q&A 40. Confirm that the emergent reactive reductions and customer outage reductions are projected over the 40- year study period. If not confirmed, please identify the benefits period.

Answer: Confirmed. The values stated on page MEA-28-Rebuttal for emergent reactive reductions across all circuits (regardless of benefit-cost ratio), and the calculated benefits from customer outage reductions (regardless of benefit-cost ratio), are based on the 40-year time frame of 2024-2063.

Attachment: *N/A*

MPSC Case No: U-21534

Requester: MNSC

Question No.: MNSCDE-19.17

Respondent: M. Elliott Andahazy

Page: 1 of 1

Question: Refer to the rebuttal testimony of Witness Elliott Andahazy, Q&A 40. Confirm that the total required PTMM investment to produce the projected emergent reactive reductions and customer outage reductions is $2,617,033,948. If not confirmed, please provide the required PTMM investment to produce the projected benefits.

Answer: Confirmed. $2,617,033,948 is the estimated capital investment required to perform PTMM on all circuits (regardless of benefit-cost ratio) in the PTMM BCA Model.

Attachment: *N/A*

MPSC Case No: U-21534

Requester: MNSC

Question No.: MNSCDE-19.19

Respondent: M. Elliott Andahazy

Page: 1 of 1

Question: Refer to the rebuttal testimony of Witness Elliott Andahazy, Q&As 40 and 43. What are the actual annual capital and O&M reductions in emergent reactive (storm and non-storm) spending resulting from the Company's actual PTMM annual investments since 2021?

Answer: The Company has not performed this analysis.

Attachment: *N/A*

MPSC Case No: U-21534

Requester: MNSC

Question No.: MNSCDE-19.35

Respondent: M. Elliott Andahazy

Page: 1 of 1

Question: Refer to the rebuttal testimony of Witness Elliott Andahazy, Q&A 27. For the Company's proposed (2024 and 2025) and historic (2021, 2022, 2023) capital investments in Hardening, on an annual basis, identify the annual investment in (a) tree trimming, (b) pole testing, (c) equipment replacement (poles, cross arms, etc), (d) DPLD arc wire removal, (e) removal of abandoned service lines, and (f) other. Please explain generally what "other" costs are.

Answer: The Company has not performed the analysis as requested.

However, per exhibit A-12, Schedule B5.4.8 in Case Nos. U-21297 and U-21534, approximately 1% is associated with inspection and testing, approximately 79% is associated with overhead construction (equipment replacement and removal), and approximately 20% is associated with line clearance (tree trimming) on average for the years spanning 2021-2025.

Attachment: N/A

MPSC Case No: U-21534

Requester: MNSC

Question No.: MNSCDE-19.36

Respondent: M. Elliott Andahazy

Page: 1 of 1

Question: Refer to the rebuttal testimony of Witness Elliott Andahazy, Q&A 19, and Table 4. Refer also to Exhibit A-23 Schedule M12. On a cost per mile basis, what portion of the cost per mile of 4.8kV Hardening is capitalized tree trimming?

Answer: As stated in discovery response U-21534 MNSCDE-19.35, approximately 20% of 4.8kV Hardening investments is associated with tree trimming.

Attachment: N/A

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Smart Grid Investment Grant Program Final Report

December 2016

TABLE OF CONTENTS

Executive Summary 5

Major Findings and Key Results 8

Lessons and Conclusions 12

Future Directions and Next Steps 13

1 | Introduction 15

1.1 | SGIG: A Shared Investment in Cutting-Edge Technologies 16

1.2 | A Pivotal Time for Smart Grid Investments 16

1.3 | SGIG Data Collection and Sharing Reduces Uncertainty 17

1.4 | Smart Grid Drives Economic Growth and Reduces Emissions 18

1.5 | U.S. Smart Grid Advanced Beyond SGIG Targets 19

2 | Major Findings and Key Results from Smart Grid Investments 21

2.1 | Synchrophasor Deployments Improve Transmission System Visibility and Help Grid Operators Prevent Large-Scale Outages 23

2.2 | DA and AMI Improve Reliability with Fewer and Shorter Outages, Faster Service Restoration, and Customer Savings 25

2.3 | Automated Controls for Voltage and Reactive Power Management Improve Efficiency and Power Factors and Reduce Energy Consumption and Costs 27

2.4 | Equipment Health Sensors Prevent Equipment Failures, Reduce Outages, and Lower O&M Costs 29

2.5 | Operational Efficiencies from AMI and DA Deliver Cost Savings and Improve Customer Service and Satisfaction 29

2.6 | AMI and Customer Systems Improve Time-Based Rate, Incentive, and DLC Programs that Reduce Peak Demand, Power Consumption, and Bills for Many Participating Customers 30

2.7 | DA and AMI Improve Integration of DER for Grid Planning and Operations 31

2.8 | SGIG Cybersecurity Policies Improve Utility Business and Technology Protection Practices to Address Emerging Threats 33

3 | Technology Deployment and Applications under SGIG 34

3.1 | Transmission Systems 36

3.2 | Distribution Systems 40

3.3 | Advanced Metering Infrastructure 41

3.4 | Customer Systems 43

4 | Cybersecurity and Interoperability in the Smart Grid 47

4.1 | Smart Grid Cybersecurity Tools and Guidelines 48

4.2 | Smart Grid Interoperability Tools and Guidelines 49

5 | Deployment Lessons Learned and Conclusions 52

5.1 | Smart Grid Project Management and Coordination 52

5.2 | Workforce Training and Expertise Development 53

5.3 | Evaluating Communication System Requirements 53

5.4 | Data Storage, Analysis, and Visualization 54

5.5 | Systems Integration 54

5.6 | Equipment and Software Testing and Modeling 55

5.7 | Cybersecurity 56

5.8 | Consumer Engagement and Education 56

6 | Future Directions and Next Steps 58

6.1 | Expected Follow-On Investments for SGIG Utilities 58

6.2 | Smart Grid Technology Development Challenges 59

6.3 | Next Steps 61

Appendix A. SGIG Project Information, Case Studies, and Key Reports 62

Final Reports on SGIG Technology Advancement 62

SGIG Program Interim Progress Reports 62

SGIG Project Information and Links to Project Pages 63

Reports on Consumer Behavior Studies 68

ARRA Smart Grid Project Case Studies 69

EXECUTIVE SUMMARY

In 2009, the U.S. Department of Energy (DOE) launched the Smart Grid Investment Grant (SGIG) program, funded by $3.4 billion invested through the American Recovery and Reinvestment Act of 2009 (ARRA) to modernize the nation's electricity system. Projects began in 2010, and the program was completed in 2015.

While the SGIG program has published an extensive series of technical reports throughout the program on SmartGrid.gov, this final report summarizes the major SGIG achievements, key project results, and lessons learned across the smart grid landscape, which included:

- Synchrophasor technologies on electric transmission systems.
- Distribution automation (DA) technologies and systems, including advanced sensors and self-healing controls.
- Advanced metering infrastructure (AMI), including smart meters and two-way communications networks.
- Customer systems, including in-home displays (IHD), programmable communicating thermostats (PCT), and direct load control devices (DLC) that enable utilities to offer time-based rates and incentives.

The SGIG program stimulated near-term economic growth, created jobs, and enhanced the reliability and resilience of the nation's electric grid through the deployment of smart grid technologies, tools, and practices. To catalyze continued investment in grid modernization, the SGIG program analyzed the impact, costs, and benefits of smart grid technologies and shared the data to help reduce the financial and technical risks for follow-on smart grid efforts.

SGIG projects were competitively selected and required a minimum 50 percent cost share, attracting an additional $4.5 billion in private, local investment during an economic downturn—bringing the total SGIG investment to $7.9 billion. Because of this public-private partnership, many utilities accelerated their grid modernization plans by as many as 10 years, or were able to broaden the scope of planned projects to benefit more customers.

SGIG projects helped to rapidly mature the smart grid vendor marketplace. By 2012, SGIG had created 12,000 direct jobs in the smart grid ecosystem of manufacturers, IT, and technical service providers, and created another 35,000 full-time equivalent positions throughout vendor supply chains.[1] As the program was expressly designed to help utilities tackle the learning curve of new technologies and functions, the projects demonstrated smart grid technology benefits and cost savings that were expected but not yet proven—and documented results and lessons learned to educate industry peers.[2]

The U.S. electricity system reached key grid modernization targets up to four years faster than expected during SGIG. By 2012, U.S. utilities had already surpassed the program's 2015 target for nationwide smart meter deployments; by 2015, nearly half of U.S. customers had smart meters—almost 65 million—a milestone that would not have been met until 2019 based on pre-ARRA utility plans and proposals.[3]

[1] U.S. Department of Energy, Economic Impact of Recovery Act Investments in the Smart Grid (April 2013).
[2] SmartGrid.gov serves as a library of SGIG project information and smart grid technology results, benefits, and lessons learned.
[3] The Edison Foundation Institute for Electric Efficiency, *Utility-Scale Smart Meter Deployments, Plans & Proposals* (September 2009).

SMART GRID INVESTMENT GRANT (SGIG) PROGRAM OVERVIEW

SGIG PROGRAMS AND FUNDING

99 competitively selected projects

228 participating utilities and organizations

6 years (2010-2015)



$7.9B
public/private investment

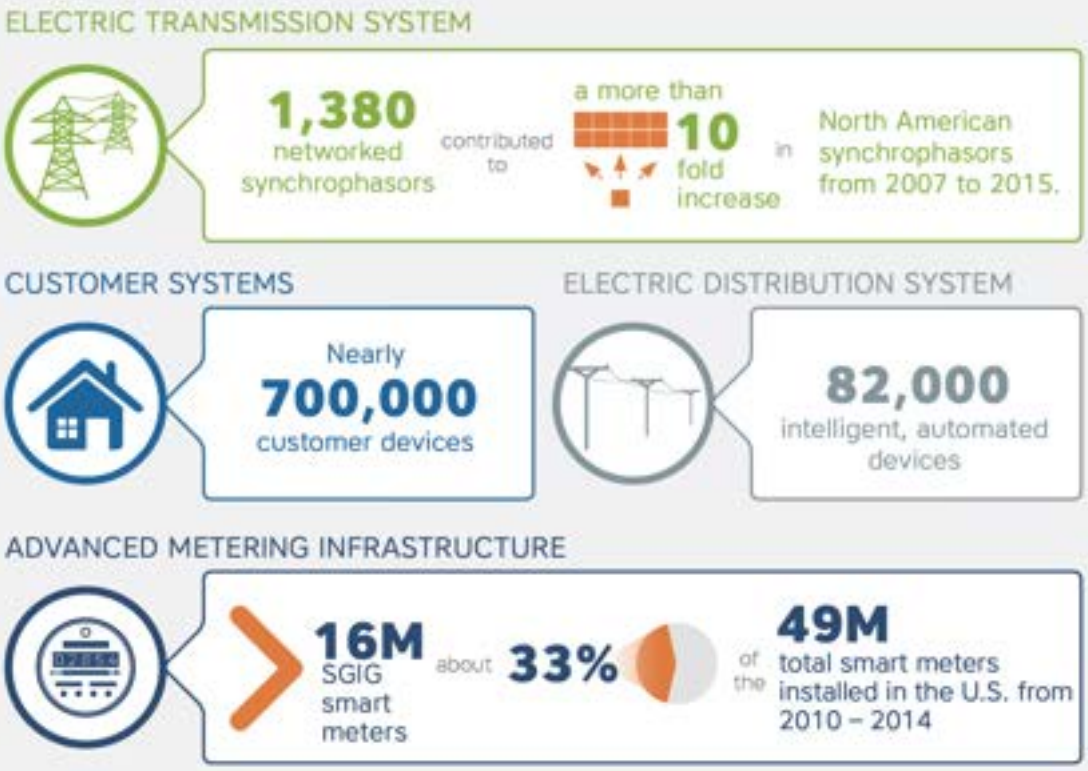


ARRA funding was matched or exceeded dollar for dollar by recipients.

SGIG PROJECT TECHNOLOGY AREAS



SGIG TECHNOLOGY DEPLOYMENTS



DEMONSTRATED SMART GRID TECHNOLOGY BENEFITS

- Increased wide-area visibility and faster situational awareness in the transmission system to prevent local disturbances from cascading into major regional blackouts.
- Fewer and shorter outages that result in less inconvenience and lower outage costs for customers.
- Improved grid resilience to extreme weather events by automatically limiting the extent of major outages and improving operator ability to diagnose and repair damaged equipment.
- Faster and more accurate outage location identification for improved repair crew dispatching and service restoration, reducing operating costs, truck rolls, and environmental emissions.
- More effective equipment monitoring and preventative maintenance that reduce operating costs and the likelihood of equipment failures, make more efficient use of capital assets, and resulting in fewer outages.
- Lower peak demand and higher power factors for improved asset utilization and deferral of capital investments in capacity additions.
- Reduced costs for metering and billing from fewer truck rolls, labor savings, more accurate and timely bills, and fewer customer disputes.
- Improved customer control to manage electricity consumption, costs, and bills from new customer tools (e.g., web portals and PCTs) and programs (e.g., time-based rates, incentives, and DLC) for shifting demand from peak to off-peak periods.

SGIG was the largest program of a broader $4.5 billion ARRA-funded grid modernization effort managed by the DOE Office of Electricity Delivery and Energy Reliability (OE).[4] This portfolio included the Smart Grid Demonstration Program, the Smart Grid Workforce Training Program, projects for regional electric transmission planning and renewable and distributed energy integration, and development of smart grid cybersecurity and interoperability standards in collaboration with the National Institute of Standards and Technology.

Major Findings and Key Results

The SGIG program helped jumpstart grid modernization by proving that an array of smart grid technologies, tools, and techniques can work effectively in utility applications and improve grid planning and operations in a variety of ways. The data collected from the projects provided evidence of grid improvements and financial benefits at different scales and utility environments.

For many participating utilities, SGIG provided an opportunity to gain confidence and experience while resolving both expected and unforeseen issues. Several utilities used SGIG funding to test the integration of new technologies and systems on a small scale, while others used the opportunity for large-scale or system-wide deployments—creating variation in costs and impacts. Many of the projects implemented some but not all of the smart grid capabilities that new devices made available, with the plan to activate more functions over time, depending on results.

DOE published technology results and lessons learned on SmartGrid.gov throughout the program to reduce investment uncertainty for utilities, regulators, and other key decision-makers.[5] Because many of the technologies and systems were new to most of the utilities, evaluating results was often a challenge, particularly when establishing baselines and estimating before-and-after grid impacts. Unprecedented volumes of data challenged utilities to develop new methods, models, and more advanced data analytics. Nevertheless, information developed under SGIG provided quantitative evidence, insights, and lessons learned for guiding future investments in grid modernization, as highlighted in the major findings below.

Synchrophasor deployments improve transmission system visibility and help grid operators prevent large-scale outages.[6]

The SGIG program deployed more than 1,300 phasor measurement units (PMUs) to enhance visibility by measuring and delivering data 100 times faster than conventional technologies, permitting grid operators to identify and correct for system instabilities, such as frequency and voltage oscillations, and operate transmission lines at higher capacity levels. The SGIG projects marked the first time that many transmission owners and operators installed modern, production-grade PMUs on an operational scale—transitioning synchrophasor technology from a research and off-line analysis tool to one that actively enhances real-time operations.

> Synchrophasors also proved valuable in detecting and diagnosing transmission and generation issues before they become threats to the power system. The American Transmission Company **identified and replaced a potentially failing transformer, avoiding an extended transmission substation outage**. The New York Independent System Operator (NYISO) **detected a malfunctioning automatic voltage regulator controller** in one generating station and a failed power system stabilizer in another.

[4] DOE OE, "ARRA Grid Modernization Investment Highlights," fact sheet (October 2015).
[5] See Appendix A. SGIG Project Information, Case Studies, and Key Reports for a detailed list of publications.
[6] DOE OE, *Advancement of Synchrophasor Technology in Projects Funded by the ARRA* (March 2016).

Before SGIG, there were fewer than 200 PMUs in the U.S. transmission system, used primarily for research. By 2015, there were more than 1,700 networked synchrophasors, providing visibility across nearly 100 percent of the U.S. transmission system at varying degrees of resolution. Grid operators across the country are beginning to use this synchrophasor data to enhance situational awareness and wide-area monitoring, improve state estimator models for better understanding of real-time grid conditions, improve dynamic planning models for better understanding of how power systems respond to grid disturbances, and provide more thorough and accurate forensic analysis of disturbances and outages.

In 2008, 14 transmission lines taken out of service by Hurricane Gustav formed an electrical island. Entergy's **synchrophasors enabled operators to detect the island and then diagnose and mitigate instabilities within that island, preventing a blackout of New Orleans and Baton Rouge.** This was a motivator for Entergy to triple its number of PMUs to 49 and expand its synchrophasor system capabilities under its SGIG project.

DA and AMI improve reliability with fewer and shorter outages, faster service restoration, and customer savings.[7]

DA technologies provided advanced capabilities for operators to detect, locate, and diagnose faults. In particular, fault location, isolation, and service restoration (FLISR) technologies can automate power restoration in seconds by automatically isolating faults and switching some customers to adjacent feeders. FLISR can reduce the number of affected customers and customer minutes of interruption by half during a feeder outage. For customers, DA operations during major storms saved one utility's customers on a 14-feeder segment $1.2 million in one year. Fully automated switching and validation typically resulted in greater reliability improvements than operator-initiated remote switching with manual validation.

FLISR and smart meters at the Electric Power Board of Chattanooga, TN helped operators **restore system-wide power about 17 hours earlier than without DA** after a July 2012 derecho. After another storm in February 2014, EPB was able to restore power **36 hours faster and reduce affected customers from 70,000 down to 33,000.**

Precise fault location enabled operators to dispatch repair crews accurately and notify customers of outage status, which reduced outage length and repair costs, reduced the burden on customers to report outages, and increased customer satisfaction. As a result, SGIG projects were able to:

- Remotely pinpoint the location and extent of outages, better direct resources, and equip repair crews with precise, real-time information—**often shaving hours or days off restoration time following major storms**. By integrating DA with AMI, utilities reduced outage duration, limited customer inconvenience, and reduced labor hours and truck rolls for outage diagnosis and restoration.
- Isolate disruptions and restore downstream customers within seconds by automating distribution tasks such as fault detection and feeder switching. For *each* outage event, **utilities reduced the number of affected customers by as much as 55 percent and reduced the total customer minutes of interruption by up to 53 percent** using "self-healing" FLISR capabilities.
- In 2013, 3 utilities reported **System Average Interruption Frequency Index (SAIFI) improvements of 17–58 percent** from pre-deployment baselines.

[7] DOE OE, *Distribution Automation: Final Report from the SGIG Program* (September 2016).

Utilities facing regular, severe weather events and storm-induced outages often have greater incentives for using AMI for outage management than those that do not.[8] AMI data integration with other information and management systems, including geographic information systems, enabled utilities to create detailed outage maps, and in some cases posted these maps on utility websites to keep the public informed on service restoration progress.

Automated controls for voltage and reactive power management improve efficiency and power factors and reduce energy consumption and costs.[9]

Automated voltage regulation and power factor correction enabled SGIG utilities to reduce peak demand, use assets more efficiently, defer capital investments, and improve power quality for customers. Several utilities used conservation voltage reduction (CVR) techniques to reduce feeder voltage levels, improve the efficiency of distribution systems, and reduce energy consumption, especially during peak demand periods.

Automated power factor correction provided new capabilities for managing reactive power flows and boosting power quality. Several utilities improved power factors to near unity through integrated volt/VAR controls, and one utility reduced reactive power requirements by about 10 to 13 percent over one year.

Several utilities found **CVR to produce energy savings of 2-4 percent** on affected feeders—a change that when applied system-wide could save hundreds of thousands of dollars in yearly energy costs and reduce power plant emissions.

Voltage monitoring provides another promising benefit stream to include in business case analysis of AMI investments. Utilities can use AMI voltage monitoring capabilities to enhance the effectiveness of automated controls for voltage and reactive power management, particularly for CVR programs.

Con Edison used its voltage control and reactive power management technologies to **increase its 4kV unit substation capability by 2.8 percent, resulting in a net savings of $15.7 million.**

Equipment health sensors prevent equipment failures, reduce outages, and lower O&M costs.[10]

Installing sensors on key components (e.g., power lines and transformer banks) to measure equipment health parameters provides real-time alerts for abnormal equipment conditions and data for new analysis tools for utility engineers to improve preventative maintenance and equipment repairs and replacement. These technologies and systems also equip grid operators with new capabilities to better dispatch repair crews based on diagnostics data.

Florida Power and Light **prevented an outage for 15,000 customers** and avoided $1 million in restoration costs by identifying and repairing a transformer before it failed.

[8] DOE OE, *Advanced Metering Infrastructure and Customer Systems: Final Report from the SGIG Program* (September 2016).
[9] DOE OE, *Distribution Automation: Final Report from the SGIG Program* (September 2016).
[10] Ibid.

Operational efficiencies from AMI and DA deliver cost savings and improve customer service and satisfaction.[11]

CenterPoint Energy reported total **AMI cost savings of more than $61 million from 2012-2014**. Tamper detection functions alone prevented revenue losses exceeding $450,000 in 2012 and $130,000 in 2014.

AMI and DA projects together reduced an estimated 17,510 metric tons of CO_2-equivalent emissions by eliminating nearly 14 million truck rolls and 71.8 million vehicle-miles[12] that were previously required to read meters, detect outages and confirm restoration, manually detect faults, inspect equipment health, and conduct manual feeder switching. Nine SGIG utilities together avoided $6.2 million in distribution operations costs over a one-year period[13] and eight utilities avoided $1.46 million in switching costs over three years.[14] AMI operations from 19 projects also cumulatively saved $316 million in O&M costs over a three-year period—an average of $16.6 million per project reporting.[15]

- Large-scale deployments and utilities with low customer densities or geographically dispersed territories had the greatest savings potential. Utilities with AMI are now able to fulfill remote service connection and disconnection orders in hours instead of days.
- Many utilities improved billing accuracy, reduced customer complaints, and used AMI data to resolve billing disputes faster. AMI enabled some utilities to proactively identify and notify customers of unusual usage patterns in advance of bills.
- Pre-pay billing plans helped customers to better manage energy consumption and costs. Several utilities improved revenue collection and cost recovery by implementing pre-pay billing programs. AMI capabilities for tamper and theft detection also enhanced revenue collection and cost recovery.

AMI and customer systems improve time-based rate, incentive, and DLC programs that reduce peak demand, power consumption, and bills for many participating customers.[16]

Oklahoma Gas & Electric reported **average annual electricity savings of $191.78 for participating residential customers** and $570.02 for commercial customers.

More than 417,000 customers participated in one or more time-based rate or incentive programs under SGIG, including critical peak pricing (CPP), variable peak pricing (VPP), time-of-use (TOU) pricing, and critical peak rebates (CPR). In particular, a subset of 10 utilities participated in the Consumer Behavior Studies (CBS)[17], which evaluated different recruitment strategies, rate structures, and customer systems for customer acceptance, retention, and response.

- CBS utilities implemented programs in which customers reduced their peak demand by up to 23.5 percent.
- Several utilities found that PCT automation enabled greater peak demand reductions than manual responses.

[11] Ibid; DOE OE, *Advanced Metering Infrastructure and Customer Systems: Final Report from the SGIG Program* (September 2016).
[12] DA operations avoided 197,000 truck rolls (reported by 16 projects) and 3.4 million vehicle-miles (reported by 18 projects) from 2011 to 2015. AMI operations avoided 13,785,708 truck rolls (reported by 42 projects) and 68,374,295 vehicle-miles (reported by 39 projects) from summer 2011 to winter 2014.
[13] Distribution operations cost savings data reported by 9 DA utilities from April 2013 to September 2014.
[14] Switching cost savings data reported by 8 DA utilities from April 2011 to March 2014.
[15] DOE OE, *Advanced Metering Infrastructure and Customer Systems: Final Report from the SGIG Program* (September 2016).
[16] DOE OE, *Customer Acceptance, Retention, and Response to Time-Based Rates from the Consumer Behavior Studies* (September 2016); DOE OE, *Advanced Metering Infrastructure and Customer Systems: Final Report from the SGIG Program* (September 2016).
[17] DOE OE, *Customer Acceptance, Retention, and Response to Time-Based Rates from the Consumer Behavior Studies* (September 2016).

- IHDs had minimal impact on demand reductions, and in many cases, participating customers declined to use them or used them for a short period of time.

DA and AMI improve integration of distributed energy resources (DER) for grid planning and operations.[18]

Grid integration of DERs requires advanced tools to monitor and dispatch DERs, and to address new power flow and control issues, such as low-voltage ride through, harmonic injection, voltage fluctuations, and reactive power management. Some SGIG utilities evaluated distributed energy resource management systems and integrated automated dispatch systems on small DER installments. A small number also tested two types of DERs: thermal energy storage for commercial and government buildings, and charging stations for electric vehicles. These projects gained valuable insight into future grid impacts of DER technologies and load patterns.

Burbank Water and Power in California used DER management systems to control ice storage systems **that made ice overnight to power daytime air conditioning loads**, which reduced the buildings' cooling requirements by about 5%.

SGIG cybersecurity policies improve utility business and technology protection practices to address emerging threats.

As top priority for every aspect of the program from its inception, cybersecurity under SGIG accelerated progress toward a more secure grid not only for participants but for the entire electric power industry. Smart digital devices added new IP-based access points to the grid, making customer privacy and cybersecurity paramount to smart grid success. All SGIG recipients were required to implement comprehensive cybersecurity plans and build cybersecurity into their policies, technologies, and business practices. SGIG expert cyber teams augmented these measures with over 300 onsite reviews to monitor project progress, including cybersecurity implementation. Two cybersecurity information exchange meetings held in 2011 and in 2012 promoted peer-to-peer sharing of best practices and lessons learned among SGIG projects.[19] Through this intensive effort, many SGIG utilities—particularly smaller ones—enhanced cybersecurity practices across their entire system and continue to use the SGIG cybersecurity plan as a model.

Lessons and Conclusions

The SGIG projects showed that further deployment of smart grid technologies, tools, and techniques can achieve favorable grid impacts and benefits for customers and utilities. Achieving these impacts and benefits involved changes in communications systems, workforce training, and business practices, especially for systems integration and cybersecurity.

Comprehensive planning for communications systems enables multiple and improved smart grid functions. Greater communications network capabilities are the backbone of grid modernization. Several SGIG utilities adopted long-term, comprehensive smart grid strategies that included building communications networks with large capacities to handle future smart grid applications, and with high bandwidth to accommodate additional services beyond electricity metering—such as gas and water metering and internet services. Network upgrades included many types of systems based on local conditions and needs including RF-based local mesh networks, high-bandwidth fiber optic cables, powerline carrier systems, and one-off microwave repeater solutions. With such systems in place, utilities can

[18] DOE OE, *Distribution Automation: Final Report from the SGIG Program* (September 2016).
[19] DOE OE, "2012 DOE Smart Grid Cybersecurity Information Exchange," workshop report (June 2013).

deploy smart grid devices faster and at full scale, and unlock additional capabilities from their investments in smart devices.

Effective systems integration is paramount for successful smart grid operations. Multiple information management and control systems all need access to a wide variety of new data streams to effectively accomplish smart grid functions. SGIG utilities installed new management information systems for meter data, distribution operations, outages, customer information, and enterprise service buses to promote interfacing between these systems. Systems integration proved to be one of the most significant challenges for many SGIG utilities, particularly for those deploying smart grid for the first time. Integration often required developing customized software for data processing, error checking, and coding.

Smarter grids require workforce training and new business practices, particularly for cybersecurity. Many of the SGIG projects made organizational changes in metering, customer service, marketing, and distribution operations, particularly in areas that require enhanced levels of integration of both new information systems and job functions. In many instances, these changes involved workforce training programs to develop new skillsets in areas such as database management, information systems, data analytics, and cybersecurity. Cybersecurity was a cornerstone of the SGIG program from its onset and required utility staff to develop and implement new cybersecurity policies, plans, and practices throughout the lifecycle of each project. This includes new levels of oversight and awareness for cybersecurity by utility managers and increased levels of time and resources devoted to it.

Future Directions and Next Steps

The majority of SGIG utilities are building on project results and planning for more technology deployments, offering successful pilot programs to more customers, and improving the integration of smart grid technologies, tools, and techniques within their electricity delivery systems. Several opportunities and challenges are guiding future grid modernization investments:

- **Many utilities have untapped opportunities to maximize the capabilities of new smart grid technologies**. For example, many utilities installed smart meters but have not yet used the embedded capabilities to monitor customer voltage levels, or have combined voltage monitoring with automated controls for voltage and reactive power management. Planned follow-on activities include expanding deployments to larger portions of service territories, expanding communications networks, and integrating various information management systems to realize untapped automation capabilities.

- **Vast amounts of new data require development of new data exchange and management capabilities, including new models and analysis tools to unlock the full value of smart grid technologies.** Smart meters, PMUs, and other devices provide timely and granular data at large volumes that require investments in high-bandwidth communications networks and advanced data analytics to better automate controls and inform operator decisions. These advanced capabilities are necessary to integrate large amounts of distributed and renewable generation, reduce susceptibility of the system to destabilizing events, and bring together utility functions for generation, transmission, distribution, and demand-side programs.

- **Cybersecurity systems, processes, and personnel continue to be a critical component of utility operations**. Smart grid technologies provide many benefits but also open up opportunities for adversaries to attack

critical infrastructure. Generation and utility operators need to continue efforts to identify and deploy protections against ever-evolving cybersecurity threats.

- **The electric power industry is exploring new business models and planning requirements to address grid modernization and integration of distributed energy resources.** Increases in DER adoption requires new approaches to resource planning, economic and environmental regulations, and market development to sustain reliability and boost resilience while involving consumers and third-parties in electricity management and generation to a much greater extent than before. Policy makers, regulators, consumer advocates, utilities, and other service providers need to continue working closely to ensure grid capabilities keep pace with changing requirements for DER integration, reliability, and security.

In addressing these and other technology, policy, and market challenges, DOE continues to be an important contributor to grid modernization through research, development, demonstration, analysis, and technology transfer activities. **SGIG showed what can be achieved in grid modernization through public-private partnerships involving DOE and the electric power industry.** New technologies are driving changes on multiple fronts and the need continues for strong national efforts to modernize the grid.

Following SGIG, grid modernization remains important national priority for DOE programs. For example, DOE recently launched a **new Grid Modernization Initiative (GMI) and released a Grid Modernization Multi-Year Program Plan (MYPP)** of proposed activities for achieving a more modern, secure, sustainable, and reliable grid. DOE plans to work toward these goals through a comprehensive set of programs and activities. The Grid Modernization Lab Consortium, a multi-year collaboration among 14 national laboratories and regional networks, is assisting DOE in developing and implementing the activities in the MYPP.[20]

[20] DOE, *Grid Modernization Multi-Year Program Plan* (November 2015).

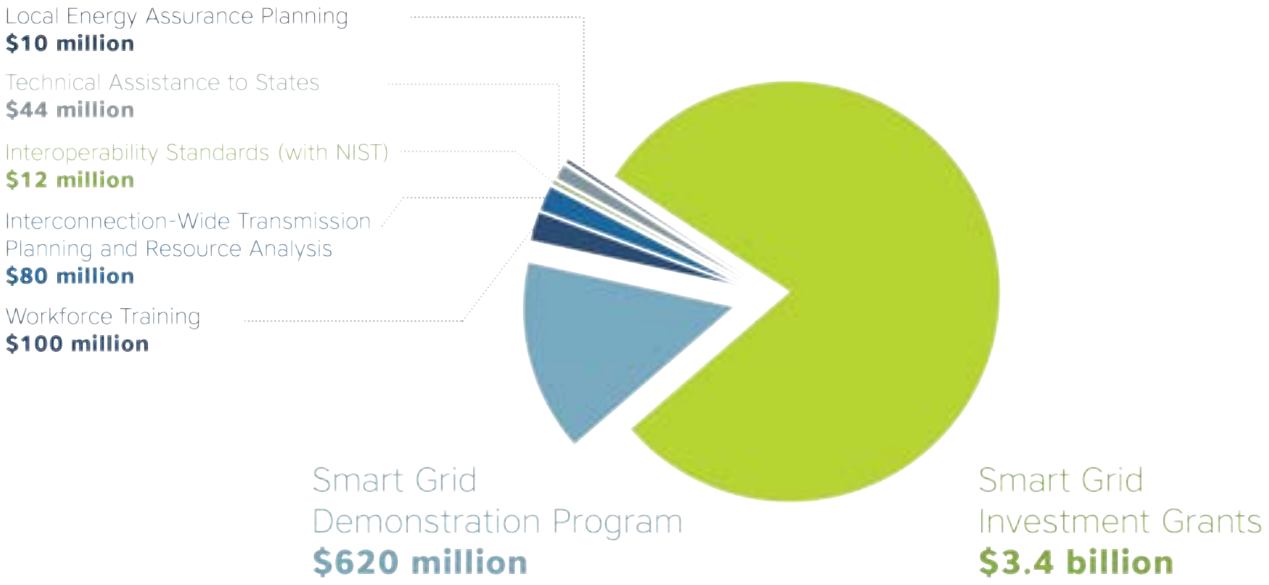
1 | INTRODUCTION

The U.S. Department of Energy's Smart Grid Investment Grant (SGIG) program was launched in 2009 amidst a major industry transition in how U.S. electricity is generated, sold, delivered, and used. The nation's growing clean energy economy is changing the sources and characteristics of electricity generation, creating a more dynamic system. Further complexity is added as distributed energy resources (DER) such as solar panels become more ubiquitous, creating two-way energy flows and changing customers from passive consumers to active market participants. Weather-related power disruptions are on the rise at a time when resilience has never been more important. The economy's reliance on reliable power continues to grow as industries, businesses, and communities increasingly perform their most basic functions using digital technologies and automated systems.

As a result, grid operators increasingly require more flexible, agile control to maintain historic levels of reliability while adding advanced capabilities to a century-old grid design. Intelligent, digital technologies hold promise to dynamically optimize grid operations, rapidly detect and mitigate disturbances, integrate diverse resources and demand response, enable customers to manage their electricity use and participate in markets, and provide strong protection against physical and cyber risks. **Yet in 2009, these advanced smart grid technologies were nascent**—still largely unproven and without an established history of performance or return on investment. Meanwhile, a significant economic downturn had slowed the rise in electricity consumption and restricted resources for grid upgrades, requiring an exceptionally strong business case for new technology investments.

The American Recovery and Reinvestment Act of 2009 (ARRA) provided $4.5 billion to the U.S. Department of Energy (DOE) Office of Electricity Delivery and Energy Reliability (OE) to jumpstart electric grid modernization at a critical time. DOE OE initiated the SGIG program and complementary grid modernization programs, including the Smart Grid Demonstration Program (SGDP), the Workforce Training and Development Program, interconnection transmission planning, state and local energy assurance planning, and standards development for systems interoperability and cybersecurity (Figure 1.1).

FIGURE 1.1 U.S. DEPARTMENT OF ENERGY ARRA GRID MODERNIZATION INVESTMENTS



Together, the ARRA grid modernization program activities represent one of the largest federal investments in new technologies for electric power delivery since the Rural Electrification Act of 1935. OE's grid modernization programs spurred innovation and investment in smart grid technologies, tools, and techniques—implementing the vision of the Energy Investment and Security Act of 2007 (EISA). Title XIII, Section 1301 of EISA made it U.S. policy to support grid modernization to maintain a reliable and secure electricity infrastructure and meet future demand growth. Section 1306 further authorized a "Federal Matching Fund for Smart Grid Investment Costs" to support adoption of smart metering, sensing, and control devices and software systems in electric transmission, distribution, and customer systems.

This report provides the final progress update for the SGIG program—including work completed since the second SGIG Progress Report, published in October 2013—and summarizes key overall program impacts, benefits, and lessons learned. While this report focuses solely on the results of the SGIG program, information about the other ARRA grid modernization programs can be found at SmartGrid.gov.

1.1 | SGIG: A Shared Investment in Cutting-Edge Technologies

The SGIG program received $3.4 billion in federal funding and was the cornerstone of DOE's ARRA grid modernization effort. SGIG funds were matched or exceeded by a minimum dollar-for-dollar industry cost share. The program was designed specifically to catalyze investment in the nation's electric power grid, demonstrate the effectiveness of advanced technologies and systems, and advance knowledge sharing among market participants and decision makers.

The SGIG program's 99 competitively selected projects involved 228 utilities and other organizations in nearly every state and touched every region of the country. Projects deployed advanced technologies, tools, and techniques for transmission, distribution, smart metering, and customer systems.

At program initiation, SGIG grant recipients planned to contribute an additional $4.4 billion, for a total budget of $7.8 billion. During the course of the projects, several teams decided to increase their funding share, raising total SGIG project expenditures to $7.9 billion.

DOE OE leads the federal government's efforts to modernize the electric grid, enhance the security and reliability of the nation's energy infrastructure, and facilitate recovery from disruptions to energy supply. Over the last five years, DOE OE managed the SGIG program to successfully achieve its original objectives. The SGIG program:

- Accelerated deployment of smart grid technologies across the transmission and distribution systems.
- Empowered customers with information to better manage their electricity consumption and costs.
- Measured the impacts and benefits of smart grid technologies to reduce uncertainty for decision makers and attract additional capital to further advance grid modernization.
- Accelerated the development and deployment of effective cybersecurity protections for smart grid technologies and systems.

1.2 | A Pivotal Time for Smart Grid Investments

The SGIG investments came at a pivotal time in the electricity industry, when a multitude of factors converged to drive the need for advanced smart grid technologies, along with the information, communications, and control

systems that can transmit and interpret the large amounts of digital information they create. Smart grid deployments are being driven in part by five key trends that continue today:

- **Changing mixes and characteristics of electricity generation sources** are shifting electricity generation from relatively few large central station plants to many smaller and sometimes variable generators. Electricity generation from natural gas and variable renewable sources is growing, while coal-based generation is declining. Energy efficiency and renewable energy policies are providing incentives for utilities and customers to install distributed generation and building energy management equipment.
- **Changing demand loads in retail electricity markets** result from demographic and economic shifts, the adoption of more energy-efficient end-use technologies, growing consumer participation, broader electrification, and use of electronic converters (rather than induction motors) on appliances and equipment. Residential consumers and commercial and industrial companies are also seeking greater control over how their electricity is produced and delivered.
- **Increased commercial availability of smart grid technologies** that can better manage progressively challenging loads offers operators new capabilities to manage complex power systems.
- **Expectations are growing for a resilient and responsive power grid** in the face of more frequent and intense weather events, cyber and physical attacks, and interdependencies with natural gas and water systems. Weather-related power disruptions are on the rise at a time when dependence on the electric grid by other critical infrastructures is growing.
- **Aging electricity infrastructure requires new technologies** to enable better failure detection, upgrade capabilities, and improve cybersecurity. While the extant electricity infrastructure provided the backbone for a healthy economy for several decades, design and capabilities of existing infrastructure date from a fundamentally different technological era, and the capabilities and scope of deployed technology are often insufficient to meet today's rapidly evolving needs.

1.3 | SGIG Data Collection and Sharing Reduces Uncertainty

Each of the 99 SGIG projects reported to DOE key data to help determine the impact and value of the new technologies and systems they implemented. Each SGIG project collected two types of metrics: 1) build metrics, including the number of installed devices and their costs, and 2) a set of impact metrics (e.g., avoided meter operations costs) that assessed the effects of the new technologies and systems on grid operations and business practices. From the outset, DOE worked with recipients to design a metrics and benefits analysis process[21] that would allow it to collect and assess four key components (see Figure 1.2):

- ***Assets*** – The device or technology installed (e.g., smart meters)
- ***Functions*** – The function that asset performs (e.g., remote service connections/disconnections and demand management)
- ***Impacts*** – The impact that function has on grid operations (e.g., reduced truck rolls and lower peak demands)
- ***Benefits*** – The value of that impact to customers and utilities, monetized when possible (e.g., lower operating costs and reduced customer bills)

[21] Electric Power Research Institute (EPRI), *Guidebook for Cost/Benefit Analysis of Smart Grid Demonstration Projects*, Revision 1 (December 2012).

FIGURE 1.2 SGIG ANALYSIS PROCESS



Because SGIG projects involved not only new technologies but also new business practices, procedures, and system designs, DOE analysis also included regular assessment of **lessons learned and best practices** from the SGIG projects. Sharing results and lessons learned throughout the course of the five-year program served to reduce uncertainty around technology effectiveness and performance for decision makers and investors.

1.4 | Smart Grid Drives Economic Growth and Reduces Emissions

The SGIG program attracted more than $4 billion in private, local investment and provided a stimulus for business development and job growth during an economic downturn. A 2013 DOE report analyzed the economic impacts of the SGIG and SGDP investments made from August 2009 through March 2012.[22] DOE estimated that for every $1 million spent in the first three years of the SGIG and SGDP programs, U.S. GDP increased by $2.5 to $2.6 million.[23] In the same time period, SGIG and SGDP project investments supported about 47,000 full-time-equivalent jobs, many which were highly technical and high paying.[24]

Smart grid investments that improve operational and energy efficiency also reduce environmental emissions. SGIG deployments produced environmental benefits that are expected to grow as deployments expand. SGIG utilities reported that they:

1. Reduced an estimated 17,510 metric tons of CO_2-equivalent emissions by eliminating nearly 14 million truck rolls and 71.8 million vehicle-miles[25] that were previously required to read meters, detect outages and confirm restoration, manually detect faults, inspect equipment health, and conduct manual feeder switching.
2. Avoided hundreds of metric tons of CO_2 emissions from electricity saved by using CVR techniques that reduced line losses and lowered peak demands, and by using customer systems and time-of-use rates that reduced peak and overall electricity use.
3. Increased use of clean and distributed energy resources and integrated electric vehicle charging stations.

The SGIG program helped to create a more intelligent grid with automated controls, better reliability and resilience, less expensive operations and maintenance, greater levels of clean energy, improved cybersecurity and interoperability, and higher levels of customer engagement in managing electricity consumption and costs.

[22] DOE OE, *Economic Impact of Recovery Act Investments in the Smart Grid* (April 2013).
[23] DOE OE, *Economic Impact of Recovery Act Investments in the Smart Grid* (April 2013).
[24] DOE OE, *Economic Impact of Recovery Act Investments in the Smart Grid* (April 2013).
[25] DA operations avoided 197,000 truck rolls (reported by 16 projects) and 3.4 million vehicle-miles (reported by 18 projects) from 2011 to 2015. AMI operations avoided 13,785,708 truck rolls (reported by 42 projects) and 68,374,295 vehicle-miles (reported by 39 projects) from summer 2011 to winter 2014.

1.5 | U.S. Smart Grid Advanced Beyond SGIG Targets

When the SGIG program began, the Office of Management and Budget identified several key targets for smart grid technology deployment and performance for the SGIG program. The targets were designed to track progress and help measure the success of the SGIG program in accelerating smart grid investment. Industry outcomes and key results from the SGIG projects, also described in greater detail throughout this report, demonstrate that the SGIG program met or exceeded each target (see Table 1.1). A check indicates targets that were met; a check-plus indicates targets that were exceeded.

TABLE 1.1 ASSESSMENT OF PRE-SGIG SMART GRID ADVANCEMENT TARGETS

	Smart Grid Target (Set in 2010)	Met?	Post-SGIG Results
DEPLOYMENT TARGETS	**By 2013,** 26 million consumers will be equipped with smart meters **(compared to 8 million in 2010).**	✓+	There were **53.3 million U.S. smart meters by 2013** and **64.7 million smart meters by 2015**. [26] SGIG utilities installed 16.3 million of those smart meters.
	By 2013, 23,000 distribution circuits will have automated equipment **(compared to approximately 15,000 circuits in 2010).**	✓+	There were **>49,000 distribution circuits with voltage optimization** by 2013.[27] SGIG utilities upgraded about 6,500 distribution circuits.
	By 2013, 1043 networked phasor measurement units will be installed **(compared to 166 in 2010) providing** nearly 100% coverage of the transmission system **(as measured by the percentage of the power flow visible to synchrophasor technology).**	✓+	By 2015, there were **>1,700 networked synchrophasors** installed throughout the transmission system, resulting in **near 100% visibility**.[28] ARRA funding was responsible for 1,380 of those PMUs.
PERFORMANCE TARGETS	**By 2015, customers with smart meters, enabling technologies, and dynamic pricing will realize a** 5% reduction in their annual electricity bills **and will have** reduced their peak demand by 5%**. (Peak demand reduction will also be stated in terms of an equivalent deferral of generation capacity, in megawatts; consumer cost savings will also be calculated.)**	✓+	Customers enrolled in dynamic pricing programs piloted at 10 utilities in the SGIG Consumer Behavior Studies saw annual **customer savings of $5 to >$500** (depending on the type of rate) and **reduced peak demand by up to 23.5%**. One SGIG utility is deferring capital investment in 170 MW of peaking generation by expanding enrollment in its time-based rate program.[29]

[26] U.S. Energy Information Administration, "Electric power sales, revenue, and energy efficiency: Form EIA-861 detailed data files," final yearly data (last release date October 6, 2016).
[27] U.S. Energy Information Administration, "Electric power sales, revenue, and energy efficiency: Form EIA-861 detailed data files," final yearly data (last release date October 6, 2016).
[28] DOE OE, *Advancement of Synchrophasor Technology in Projects Funded by the ARRA* (March 2016).
[29] DOE OE, *Advanced Metering Infrastructure and Customer Systems: Final Report from the SGIG Program* (September 2016).

	Smart Grid Target (Set in 2010)	Met?	Post-SGIG Results
PERFORMANCE TARGETS	**By 2015, utilities will realize a** 10% decrease in annual operations and maintenance costs **for distribution circuits with automated equipment.**	✓	**AMI services saved about $316 million in labor and O&M costs for 19 SGIG utilities over 3 years, while DA savings from avoided switching costs totaled >$1.46 million** for 8 SGIG utilities over 3 years. During severe storms, the avoided costs from reducing restoration time—for both utilities and customers—were also substantial.[30]
	By 2015, customers on distribution circuits with distribution automation will experience a 5% average reduction in the length of their power outages**.**	✓+	SGIG utilities **reduced the duration of an outage event by up to 53%** (total customer minutes of interruption) and **reduced the number of affected customers by as much as 55%** using DA technologies.[31]
	By 2015, 50% of transmission operators will have planning and/or operating procedures **that incorporate synchrophasor measurements.**	✓	12 of the 14 synchrophasor project participants are now using synchrophasor data to **inform operations** and 11 are using the data to **inform planning**. ARRA participants are responsible for more than 80% of U.S. load.[32]
	By 2015, the deployment of advanced control technology will result in a 5% reduction in energy wasted (line losses) **in distribution circuits.** **(The reduction in energy wasted will also be stated in terms of an equivalent reduction in the emissions of CO2, NOX and SOX.)**	✓	Several **utilities saw total energy savings of 2-4% on feeders with voltage optimization, and reduced line losses by substantial amounts**. (Emissions savings for line losses were not individually measured.)
	By 2015, customers with smart meters, enabling technologies, and dynamic pricing will have reduced emissions of CO_2, NOX and SOX associated with their electricity consumption by 1%**.** **(The contribution of peak load shifting and total load reduction will be calculated.)**	✓	DA and AMI operations **reduced CO_2-equivalent emissions by 17,510 metric tons** over a nearly 4-year reporting period by avoiding truck rolls previously required to read meters, detect outages, and confirm restoration.[33]

[30] 19 SGIG projects reporting; DOE OE, *Distribution Automation: Final Report from the SGIG Program* (September 2016).
[31] DOE OE, *Distribution Automation: Final Report from the SGIG Program* (September 2016).
[32] DOE OE, *Advancement of Synchrophasor Technology in Projects Funded by the ARRA* (March 2016).
[33] DA operations avoided 197,000 truck rolls (reported by 16 projects) and 3.4 million vehicle-miles (reported by 18 projects) from 2011 to 2015. AMI operations avoided 13,785,708 truck rolls (reported by 42 projects) and 68,374,295 vehicle-miles (reported by 39 projects) from summer 2011 to winter 2014. DOE OE, *Advanced Metering Infrastructure and Customer Systems: Final Report from the SGIG Program* (September 2016); DOE OE, *Distribution Automation: Final Report from the SGIG Program* (September 2016).

2 | MAJOR FINDINGS AND KEY RESULTS FROM SMART GRID INVESTMENTS

From 2010 to 2015, DOE and industry joined forces to deploy smart devices and systems on an accelerated timescale by sharing the financial and technological risks typical of immature technologies.

In 2010, the SGIG program began to deploy millions of nascent smart grid technologies at a critical time—the vendor landscape was small, the anticipated benefits and savings were not yet proven on a large scale, and the recent economic downturn had slowed growth in demand and constrained utility resources for investment in new technologies.

> "Without the funding, we would have waited to let the technology mature in the industry. We would have deployed the technology at a slower pace, which would have delayed the benefits to our customers."
>
> MIKE GODOROV, MANAGER OF PPL'S SMART GRID PROJECT
>
> SOURCE: PPL ELECTRIC UTILITIES, "BUILDING A SMARTER DISTRIBUTION SYSTEM IN PENNSYLVANIA," 2012.

Most SGIG utilities estimated that the SGIG program accelerated their grid modernization investment plans by 2–10 years, delivering substantial benefits to customers and the economy sooner. For many, the 50 percent cost share created the business case to deploy some advanced technologies years earlier than planned or to broaden the scope of their near-term upgrade plans to benefit more customers.

From 2009 to 2015, SGIG utilities:

- **Installed more than 1,300 synchrophasors in the transmission system and spurred the deployment of hundreds more using private funds** on the heels of the program's early successes. This resulted in near 100 percent visibility in the transmission system by 2015 and contributed to a more than tenfold increase in installed synchrophasors in North America between 2007 and 2015.
- **Deployed more than 16.3 million smart meters,** representing about 33 percent of the 49 million smart meters installed nationwide between 2009 and 2014. An estimated 58.5 million smart meters are now installed nationwide, accounting for more than 40 percent of electricity customers.[34]
- **Installed nearly 82,000 intelligent devices to upgrade about 6,500 distribution circuits,** many serving customers with critical business needs for fewer and shorter outages. While this accounts for just about 3 percent of total U.S. circuits,[35] many utilities upgraded the worst-performing substations and feeders first to achieve substantial reliability improvements.

The U.S. electricity system reached key grid modernization targets up to four years faster than expected during SGIG. Targets set at the outset of the ARRA predicted that U.S. utilities would install 26 million smart meters by 2013 and 40 million by 2015.[36] More than 43 million U.S. customers had smart meters by 2012—surpassing the 2015 target

[34] U.S. Energy Information Administration, "Electric power sales, revenue, and energy efficiency: Form EIA-861 detailed data files," final yearly data (last release date October 6, 2016).
[35] U.S. Energy Information Administration, "Electric power sales, revenue, and energy efficiency: Form EIA-861 detailed data files," final yearly data (last release date October 6, 2016).
[36] White House, "Progress Report: The Transformation to a Clean Energy Economy," Memorandum for the President from the Vice President (December 15, 2009).

three years early—and installations reached more than 64.7 million by 2015.[37] Today, nearly half of U.S. customers now have smart meters—a milestone that would not have been met until 2019 or later based on pre-ARRA utility plans and proposals.[38]

DOE reported interim SGIG costs, results, grid impacts, and key lessons on SmartGrid.gov, creating a wealth of public information designed to reduce technology performance uncertainty and help utilities more confidently assess the business case for smart grid deployments industry-wide. Sharing early project successes helped utilities justify and commit more private funds to smart grid deployments outside the program.

Analysis of SGIG technology costs, benefits, and performance also helped inform state utility regulators and other policy makers, who play a crucial role in grid modernization by setting policy objectives, approving rates and technology investment plans, overseeing cost recovery strategies, and protecting customers from potential harm, including data privacy and cybersecurity. DOE representatives shared early project results at industry conferences, regional regulatory meetings, and National Association of Regulatory Utility Commissioners (NARUC) meetings.

The SGIG program successfully demonstrated that smart grid technologies are able to deliver the types of benefits and cost savings that were anticipated but not yet proven on a large scale in a variety of settings.

Smart grid technology impacts varied from project to project, and not all utilities realized similar or equally significant benefits. This was primarily because utilities chose to deploy varying technologies at different scales based on their distinct geographic and environmental challenges, system designs, technology experience levels, local and state policies, and regulatory incentives. Some utilities opted for full-scale, system-wide implementation, while others tested integration at a pilot scale covering, for example, only a few feeders. Some utilities tested multiple new devices or functions in tandem, which often yielded synergistic benefits not seen by those utilities that tested only a limited set of functions. The maturity of utilities' existing (pre-project) technologies also affected the magnitude of benefits; for instance, utilities that upgraded from manual meter reading to advanced metering infrastructure (AMI) realized more operations and maintenance-based savings than those that began with automated meter reading.

Yet evidence from the 99 SGIG projects shows that smart grid technologies enabled new functions and capabilities that can deliver measurable net benefits to utilities and consumers alike—and deliver economic, environmental, and productivity benefits to society as a whole. Moreover, after the completion of the SGIG program, many grant recipients will continue to invest in smart grid technologies and expand deployments throughout their systems, based on evaluation of the costs and benefits of smart grid options within their unique systems.

DOE analysis of project impacts and benefits revealed a number of key outcomes:

- Synchrophasor deployments improve transmission system visibility and help grid operators prevent large-scale outages
- DA and AMI improve reliability with fewer and shorter outages, faster service restoration, and customer savings

[37] U.S. Energy Information Administration, "Electric power sales, revenue, and energy efficiency: Form EIA-861 detailed data files," final yearly data (last release date October 6, 2016).
[38] The Edison Foundation Institute for Electric Innovation, *Electric Company Smart Meter Deployments: Foundation for a Smart Grid*, prepared by Adam Cooper (October 2016); The Edison Foundation Institute for Electric Efficiency, *Utility-Scale Smart Meter Deployments, Plans & Proposals* (September 2009).

- Automated controls for voltage and reactive power management improve efficiency and power factors and reduce energy consumption and costs
- Equipment health sensors prevent equipment failures, reduce outages, and lower operations and maintenance (O&M) costs
- Operational efficiencies from AMI and DA deliver cost savings and improve customer service and satisfaction
- AMI and customer systems improve time-based rate, incentive, and DLC programs that reduce peak demand, power consumption, and bills for many participating customers
- DA and AMI improve integration of DER for grid planning and operations
- SGIG cybersecurity policies improve utility business and technology protection practices to address emerging threats

This section explores how SGIG projects achieved each of these outcomes, citing a selection of key project examples that demonstrate the potential magnitude of smart grid benefits.

2.1 | Synchrophasor Deployments Improve Transmission System Visibility and Help Grid Operators Prevent Large-Scale Outages

The SGIG program deployed phasor measurement units (PMUs) on a massive scale to help detect dangerous disturbances and prevent wide-area blackouts before they happen. PMUs provide game-changing visibility in the transmission system by measuring and delivering data on system conditions 100 times faster than conventional technology, permitting grid operators to identify and rapidly correct for system instabilities, such as frequency oscillations and low voltage, and operate transmission lines at greater capacities.

The SGIG projects marked the first time that many transmission owners and operators installed modern, production-grade PMUs on an operational scale—transitioning synchrophasor technology from a research and off-line analysis tool to one that actively enhances real-time operations. At the start of the SGIG program, the transmission grid had fewer than 166 PMUs, designed for research only; by 2015, there were more than 1,700 networked synchrophasors providing visibility into transmission systems that serve about 88% of total U.S. load.[39] Improved visibility can prevent blackouts such as the 2003 Northeast blackout that cascaded across eight states and two Canadian provinces. Investigators of that blackout concluded that a key contributing factor was grid operators' limited visibility into large-area grid operations, which prevented them from detecting and addressing a relatively minor disruption before it cascaded across regions.[40]

Independent system operators (ISOs) and regional transmission operators (RTOs) also installed or enhanced high-speed communications and data management systems to network the synchrophasors within and across large regions. PMUs enable operators to precisely sample grid conditions at very high speeds over hundreds of miles, with time-stamped data to microsecond accuracy that can be synchronized to provide a precise and comprehensive view of an entire interconnection.

Project utilities developed advanced data transmission and data concentration procedures, providing the necessary quality and trust to use synchrophasor data in engineering, design, and real-time operations to significantly improve

[39] DOE OE, *Advancement of Synchrophasor Technology in Projects Funded by the ARRA* (March 2016).
[40] U.S.-Canada Power System Outage Task Force, *Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations* (April 2004).

reliability. Synchrophasors have **prevented outages, monitored phase angles to accelerate restoration, detected and diagnosed potentially harmful oscillations, detected and managed islands to support microgrids, and helped operators detect potentially failing equipment**, such as transformers and voltage regulators.

In 2008, 14 transmission lines taken out of service by Hurricane Gustav formed an electrical island. Entergy's **synchrophasors enabled operators to detect the island and then diagnose and mitigate instabilities within that island, preventing a blackout of New Orleans and Baton Rouge**. This was a motivator for Entergy to triple its number of PMUs to 49 and expand its synchrophasor system capabilities under its SGIG project.[41]

Using synchrophasor data, the American Transmission Company **identified and replaced a potentially failing transformer, avoiding an extended transmission substation outage**. In a similar manner, The New York Independent System Operator (NYISO) used PMU data to detect a malfunctioning automatic voltage regulator controller in one generating station and a failed power system stabilizer in another.[42]

SGIG recipients also used synchrophasors to correct and validate models of nuclear, hydropower, fossil fuel, and wind generators. **Rapid model validation improved asset utilization and system efficiency, reduced operating costs, and reduced curtailment of renewable energy sources**.

Western Electricity Coordinating Council (WECC) member Bonneville Power Administration (BPA) **saved as much as $700,000 in avoided power sale losses** and contractor costs by using synchrophasor data to validate and recalibrate its 1,100-megawatt (MW) Columbia nuclear generating station—while the generator remained online.[43]

When a critical 500-kilovolt (kV) tie line between Arizona and California tripped in October 2013, near-real-time **PMU data allowed system operators at WECC to determine that the line could safely be re-energized almost immediately**—avoiding the need to re-dispatch generation and reducing the grid's vulnerability to additional outage contingencies.[44]

Synchrophasor applications have also **largely reduced the time, effort, and costs to analyze system disturbances**, validate system models, and assess the status of the grid.

The Independent System Operator of New England's (ISO-NE) event analysis applications now automatically collect and analyze synchrophasor data from PMUs all across New England, **enabling engineers to analyze two or three events per week—up from two events per year—using the same resources**.[45]

As PMUs are further networked and data quality improves, PMU data can be integrated into other control systems, allowing operators to receive real-time alerts or even automate system interventions to prevent minor disturbances from cascading into regional outages. The 2011 Southwest blackout, for example, was the result of a cascading failure that took place in seconds—too fast for human intervention. At this time, operators are mainly using PMU data for

[41] DOE OE, *Advancement of Synchrophasor Technology in Projects Funded by the ARRA* (March 2016).
[42] Ibid.
[43] Ibid.
[44] Peak Reliability, *Use Synchrophasor Data to Accelerate Reclosing of an Important Tie Line* (March 3, 2014); DOE OE, *Advancement of Synchrophasor Technology in Projects Funded by the ARRA* (March 2016).
[45] DOE OE, *Advancement of Synchrophasor Technology in Projects Funded by the ARRA* (March 2016).

system planning and forensic analysis. Over time, as data and processing capabilities improve, operators can use this technology to manage real-time power flows across wide areas.

2.2 | DA and AMI Improve Reliability with Fewer and Shorter Outages, Faster Service Restoration, and Customer Savings

Power outages following major storms cost the U.S. economy billions of dollars annually. Dependence on a reliable supply of electricity has become a pervasive aspect of modern life. As the nation's critical services and large economic sectors become more digital and automated, power disruptions have potentially greater consequences. By applying advanced communication systems with intelligent devices such as smart meters, digital controls, switches, and sensors, utilities tested advanced outage management approaches that delivered substantial benefits.

Smart meters and AMI enables utilities to remotely pinpoint the location and extent of outages, better direct resources, and equip repair crews with precise, real-time information—often shaving hours or days off restoration time following major storms.

Without AMI, utilities often relied on customer calls to identify outages and sent crews to manually verify restoration during repairs. With AMI, operators can "ping" smart meters to instantly verify their outage status and locate disruptions, reducing truck rolls and allowing utilities to dispatch repairs crews more quickly.

PECO restored service an estimated three days faster during a February 2014 storm—even though only 50% of their smart meters were deployed—and automatically restored power to about 37,000 customers in less than five minutes using automated feeder switching. PECO also avoided 6,000 truck rolls and restored power 2-3 days sooner following Superstorm Sandy in 2012 with its smart meter rollout only 10% complete. [46]

Utilities isolated disruptions and restored downstream customers within seconds by automating distribution tasks such as fault detection and feeder switching.

Automatic feeder switching devices—such as smart switches, automatic reclosers, and remote fault indicators—enabled "self-healing" fault location, isolation, and service restoration (FLISR) capabilities. When a fault occurs or a power line is damaged, these smart technologies work in tandem to detect and clear temporary faults, isolate sustained faults, and automatically re-route power around faults, often within seconds.



For *each* outage event, utilities reduced the number of affected customers by as much as 55% and reduced the duration (total customer minutes of interruption) by up to 53% using FLISR capabilities.[47] Utilities saw the most benefit from FLISR investments that modernized poorly performing or highly vulnerable substations and feeder groups. Savings from avoided switching costs also totaled more than $1.46 million for eight SGIG DA utilities that reported savings from April 2011 to March 2014.[48]

[46] DOE OE, *Smart Grid Investments Improve Grid Reliability, Resilience, and Storm Response* (November 2014).
[47] Results from 15 utilities over a three-year testing period. DOE OE, *Distribution Automation: Final Report from the SGIG Program* (2016).
[48] DOE OE, *Distribution Automation: Final Report from the SGIG Program* (2016).

Utilities also measured improvements from pre-deployment baselines in SAIFI and SAIDI, the key indices used to measure system reliability. In 2013, three utilities saw a 23-58 percent improvement compared to pre-deployment baselines in SAIFI, the primary metric used to track outage frequency.[49]

By upgrading its distribution circuits, **PPL Electric Utilities Corporation estimated a 55% drop in the average outage duration (SAIDI) and a 58% decrease in the average number of interruptions (SAIFI)** across its system in 2013. Based on these results, PPL estimates a 25% improvement in reliability over the subsequent five years through continued deployment of distribution automation.[50]

Faster and fewer outages avoided millions of dollars in damages for businesses and customers. Avoided outage costs for industrial, commercial, and residential customers are perhaps the most substantial economic benefit from the SGIG program. Productivity loss, business closures, food spoilage, and other outage costs—particularly for industrial and commercial customers—are often large but are also difficult to accurately estimate. The few utilities that were able to quantify the economic benefits to customers saw substantial savings following major storms.[51]

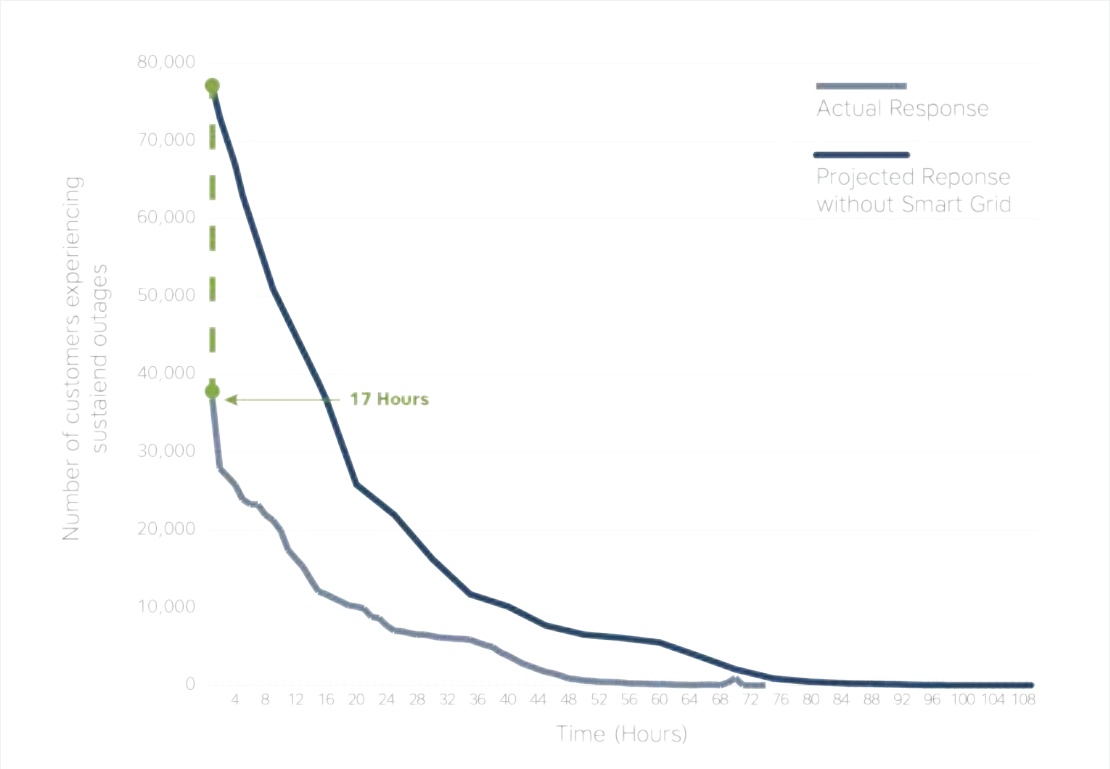
Central Maine Power (CMP) estimates its investments in substation and line reclosers saved customers more than $935,000 in 2014—and will continue to save a total of $20.7 million through 2020. Customers saved an estimated average of $18,000 per outage involving line reclosers and $29,000 per outage affecting a substation. CMP used DOE's Interruption Cost Estimate (ICE) calculator to estimate the value of an average outage hour (about $97 for 2014-2019) for an average CMP customer.[52]

Smart grid technologies reduced utility costs by $1.4 million by restoring power an estimated 1.5 days sooner following a February 2014 snowstorm at the Electric Power Board (EPB) in Chattanooga, TN. The utility used fault isolation and automated feeder switching to prevent sustained outages to about 70,000 customers, saving about 16 hours of restoration, and used AMI to "ping" smart meters, verify outage status, and redirect repair crews, shaving off another 20 hours of restoration. [53]

Two years earlier during the severe July 2012 derecho, EPB restored power to about 40,000 customers within seconds using automated feeder switching and used AMI data to **restore the system 17 hours sooner, avoiding an estimated $23 million in customer damages** and decreasing the expected outage duration by about half (see Figure 2.1).[54] Reliability improvements from DA investments save EPB's customers $26.8 million annually under normal operations, in addition to the substantial savings during individual severe weather events.

[49] DOE OE, *Distribution Automation: Final Report from the SGIG Program* (2016).
[50] DOE OE, *Distribution Automation: Final Report from the SGIG Program* (2016).
[51] DOE OE, *Distribution Automation: Final Report from the SGIG Program* (2016).
[52] DOE OE, *Distribution Automation: Final Report from the SGIG Program* (September 2016).
[53] DOE OE, *Distribution Automation: Final Report from the SGIG Program* (2016); DOE OE, *Smart Grid Investments Improve Grid Reliability, Resilience, and Storm Response* (October 2014).
[54] DOE and UT-Battelle, *ICE Calculator Case Study Overview: EPB Chattanooga Distribution Automation* (December 2015).

FIGURE 2.1 IMPROVEMENT IN SERVICE RESTORATION BY EPB FOLLOWING A JULY 2012 STORM



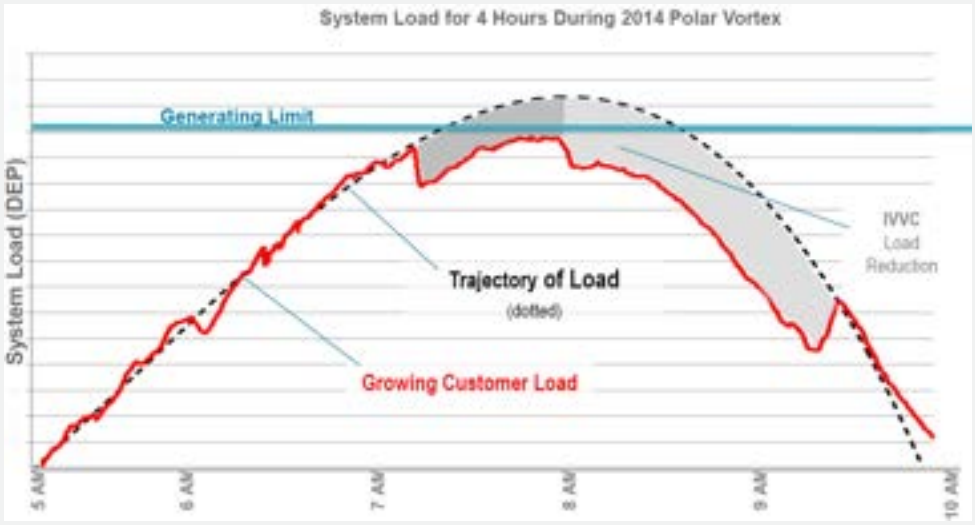
2.3 | Automated Controls for Voltage and Reactive Power Management Improve Efficiency and Power Factors and Reduce Energy Consumption and Costs

Distribution automation applications improve power factors on feeders and deliver lower voltage levels without negative effects on customers or equipment. Utilities can reduce power losses along distribution lines by dynamically optimizing voltage and reactive power levels, which helps to deliver the same amount of power to customers at a lower cost. Conservation voltage reduction (CVR) also reduces customer voltages along a distribution feeder to reduce electricity use, particularly during peak periods. By reducing peak generation, CVR can help utilities avoid fuel costs and defer capital investments in generation assets.

The result is fewer unpredictable outages and higher-quality power—which protects customers' sensitive electronic equipment from damage or limited performance—and improved system efficiencies. SGIG utilities **found that CVR could result in savings of 2–4 percent on affected feeders**—a change that may seem minor, but when applied system-wide, could result in comparable energy savings and hundreds of thousands of dollars in energy costs.

During the morning of January 7, 2014, Duke Energy Progress (DEP; formerly Progress Energy) employed integrated volt/VAR control (IVVC) technology to **avoid a projected outage of roughly 88,000 customers due to a record system load** caused by extreme cold weather from the 2014 polar vortex. As customer load grew in the early morning hours, DEP quickly approached its system generation limit. Using IVVC, DEP met peak load demand by reducing reactive power losses by optimizing the performance of IVVC components such as load tap changers, controls for capacitor banks, and line regulators. The success of voltage reduction efforts to reduce peak load has led Duke to **use IVVC as an alternative to the addition of generation capacity in its service territory**.[55]

FIGURE 2.2 DUKE ENERGY PROGRESS SYSTEM LOAD DURING JANUARY 7, 2014 POLAR VORTEX



Consolidated Edison used its voltage control and reactive power management technologies to **increase its 4kV unit substation capability by 2.8%, resulting in a net savings of $15.7 million**. It also reduced primary losses on its 4 kV systems by 2.3% under peak conditions.[56]

Glendale Water and Power estimates that a five-year CVR project on 65% of feeders can achieve **energy savings of 2%-4% and net power cost savings of $470,000 to $1.2 million per year**.[57]

Continuous voltage optimization formed the largest part of the business case by far for Duke Energy's smart grid deployment plan. It showed a net present value of $155.5 million in a 2011 third-party evaluation by the Public Utilities Commission of Ohio of the estimated revenue and benefit streams from Duke's smart grid operations over 20 years.[58]

[55] Duke Energy, "Session 2: Conservation and Optimization via Volt/VAR Control," presentation by Jay Oliver at the EPRI-DOE conference "The Smart Grid Experience: Applying Results, Reaching Beyond," Charlotte, North Carolina (October 27–29, 2014).
[56] DOE OE, *Using Smart Grid Technologies to Modernize Distribution Infrastructure in New York* (August 2014).
[57] DOE OE, *Distribution Automation: Final Report from the SGIG Program* (2016).
[58] DOE OE, *Distribution Automation: Final Report from the SGIG Program* (2016).

2.4 | Equipment Health Sensors Prevent Equipment Failures, Reduce Outages, and Lower O&M Costs

By installing intelligent sensors and controls on substation transformers and battery banks, SGIG utilities can also proactively monitor equipment health to predict and prevent costly failures. Newly installed diagnostic systems collect and interpret data from these intelligent devices in the distribution management system, giving operators unprecedented information on system performance in near-real time.

At Florida Power and Light, a newly installed monitor detected a faulty transformer before it failed, preventing an outage that would have affected several thousand customers, and allowing the utility to switch customers to another transformer while replacing the faulty one. FPL tested and replaced the unit, preventing an outage for about 15,000 customers and avoiding at least $1 million in restoration costs. [59]



Courtesy of FPL

2.5 | Operational Efficiencies from AMI and DA Deliver Cost Savings and Improve Customer Service and Satisfaction

AMI and customer systems allowed utilities to provide customers with improved service. Rapid, automated, remote meter reading delivered more accurate and timely bills and allowed service connection/disconnection in minutes instead of days. More accurate bills combined with detailed usage information reduced customer complaints and improved customer service call experiences. Improved online bill payments and pre-payment billing plans reduced bill surprises for customers. New smart meter capabilities that enabled utilities to pinpoint and diagnose outages also helped utilities to provide customers with periodic updates and more accurate estimates of service restoration schedules.

Utility O&M improvements from automated meter reading and billing were often substantial. AMI services eliminated time-consuming truck rolls and service appointments, **saving about $316 million in labor and other costs** for 19 utilities over 3 years.[60] **Per-meter O&M cost savings reported by 19 projects averaged $8.37 over a six-month period in 2014.**[61] As expected, utilities with lower customer densities per distribution line-mile observed larger savings per customer served than those with higher customer densities.

Pre-pay billing plans allow near-real-time tracking of energy use to prevent unanticipated costs and reduce service disruptions for customers. For utilities, pre-pay plans help reduce bad debt write-offs; Talquin Electric Cooperative reduced its bad debt write-offs by about 65 percent. Smart meters also provided new capabilities for meter tampering and theft detection, which prevented hundreds of thousands in revenue losses.

[59] DOE OE, *Distribution Automation: Final Report from the SGIG Program* (2016).
[60] DOE OE, *Advanced Metering Infrastructure and Customer Systems: Final Report from the SGIG Program* (2016).
[61] DOE OE, *Distribution Automation: Final Report from the SGIG Program* (2016).

Between 2011 and 2013, Tri-State Electric Membership Corporation (Tri-State) realized a **65% decrease in annual meter operations costs** (from $450,000 to about $156,000 per year) from smart meter deployments. Its pre-pay program and automated connection/disconnection capabilities also contributed to a **50% reduction in unpaid bill write-offs** (from about $52,000 to less than $25,000). Tri-State's payback period is less than five years for its entire smart metering investment.[62]

Central Maine Power's (CMP) system-wide AMI deployment reduced its meter operations costs by more than 80%, with annualized savings of about $6.7 million. Between 2012 and 2013, CMP eliminated almost 121,000 truck rolls—a 97% reduction—and decreased annual vehicle-miles traveled by about 1.4 million. Automated meter reading reduced estimated bills by more than 90%. Service connections can now be completed in less than an hour, rather than the next business day.[63]

2.6 | AMI and Customer Systems Improve Time-Based Rate, Incentive, and DLC Programs that Reduce Peak Demand, Power Consumption, and Bills for Many Participating Customers

Residential electricity consumers have traditionally had few tools with which to manage their consumption and costs. Smart meters and customer-based devices deployed under SGIG allowed customers to take advantage of time-based rates and incentive programs by reducing or shifting their electricity use from peak to off-peak periods—saving them money while reducing peak demand to keep the grid stable and avoid costly peak generation.

Under the SGIG projects, tens of thousands of customers participated for the first time in these new, AMI-enabled rate programs, which included pre-payment plans and time-of-use rates, such as critical peak pricing (CPP), variable peak pricing (VPP), and critical peak rebates (CPR). Load control switches also enabled utilities to temporarily switch off appliances like air conditioners and water heaters during peak periods in exchange for customer savings.

In-home displays (IHDs) and web dashboards provided tens of millions of consumers with better information about their energy usage, while programmable communicating thermostats (PCTs) gave them the control to reduce consumption in response to time-based rates. Web portals and mobile applications often helped customers compare their electricity use with similar users, track consumption and costs, and learn energy-efficiency strategies to reduce consumption and lower bills.

A popular "My Usage" web portal at Tri-State Electric Membership Corporation enabled its many vacation-home owners to remotely monitor usage and even fix faulty appliances after finding anomalies in their usage patterns.

Customers participating in demand-side management programs piloted at 10 utilities that participated in Consumer Behavior Studies **reduced their peak demand by up to 23.5 percent**, **with annual savings for customers ranging from $5 to more than $500**, depending on the type of rates offered.[64] IHDs had limited effect on peak demand reductions

[62] DOE OE, *Smart Meter Investments Benefit Rural Customers in Three Southern States* (March 2014); DOE OE, *Advanced Metering Infrastructure and Customer Systems: Final Report from the SGIG Program* (2016).
[63] DOE OE, *Smart Meter Investments Yield Positive Results in Maine* (January 2014).
[64] DOE OE, *Advanced Metering Infrastructure and Customer Systems: Final Report from the SGIG Program* (2016).

and were rarely cost-effective. However, empowering customers with PCTs often enabled them to achieve higher peak demand reductions of 22–45 percent, compared to reductions of -1–40 percent from customers without PCTs.[65]

The Consumer Behavior Studies evaluated customer acceptance, retention, and reduced usage in response to time-based rates. Results from each two-year study are helping participants identify the most effective rate designs, customer devices, recruitment plans, and outreach and education strategies.

> Oklahoma Gas & Electric (OG&E) averaged **annual savings of $191.78 for residential customers and $570.02 for commercial customers** and reduced load by offering variable peak pricing to about 4,670 participating customers. Based on this success, OG&E expanded the rollout of its time-based rate and PCT program to about 18% (116,000) of its customers, which are achieving 147 MW of peak demand reduction and helping to **defer capital investment in peaking generation**.[66]

2.7 | DA and AMI Improve Integration of DER for Grid Planning and Operations

Smart devices, sensors, and switches deliver their full value *only* when they are connected to a supporting backbone of advanced communications, control, and information systems. Many SGIG utilities installed and upgraded the high-bandwidth communications networks and advanced information and control systems that underpin all smart grid capabilities. For example, many SGIG projects integrated data from new AMI systems with outage management systems (OMS) and geographic information systems (GIS) to equip repair crews with precise outage locations and help prioritize those repairs.

SGIG projects removed one of the key hurdles to wide smart grid deployment by enabling utilities to upgrade these systems and test integration with a small scale of devices. Because advanced communication and control is required to operate even one smart meter or automated control device, these systems and networks represent a fixed cost for all projects, from small pilot studies to full-scale deployments. These systems provide a platform for continued smart grid acceleration over the next decade or more.

With these systems now in place, **SGIG utilities are positioned to deploy more smart grid devices faster and at full scale, and unlock additional capabilities from their smart devices.** Follow-on plans from SGIG utilities demonstrate that many utilities have only scratched the surface of the benefits their investments can provide. Most utilities are immediately building on their SGIG project success by expanding smart grid deployments to other service territories, adopting new technologies they did not test under their SGIG projects, and better networking existing technologies with additional control systems to extract more value from devices deployed under SGIG.

SGIG investments in broadband communications networks and fiber optic systems help transmit large data flows, build capacity for future data-heavy smart grid upgrades, and even automate other utility services (e.g., water and gas metering). Many municipal and public power utilities leveraged advanced communications networks and data management systems from SGIG investments to support comprehensive service upgrades.

[65] DOE OE, *Advanced Metering Infrastructure and Customer Systems: Final Report from the SGIG Program* (2016).
[66] OG&E, *OG&E Consumer Behavior Study Evaluation Report*, prepared by Farrell, M., Nichols, A., Chiccarelli, K. (August 2012); DOE OE, *Customer Acceptance, Retention, and Response to Time-Based Rates from the Consumer Behavior Studies* (September 2016).

Burbank Water and Power deployed smart meters to all electric customers and, through a non-SGIG project, to all water customers. The smart electric and water meters use the same communications networks and meter data management systems, lowering costs for the utility and its customers. These systems enable remote meter reading, remote connection and disconnection, outage detection, voltage and power quality monitoring, and tamper detection.

The city-owned Electric Power Board (EPB) of Chattanooga invested $300 million to install more than 6,000 miles of fiber optic cable, providing an advanced communications backbone for city services. Part of that fiber optic network was installed under EPB's SGIG project to support EPB's upgrade of 164 distribution circuits with smart switches, sensors, and controls. The grant allowed EPB to complete its 10-year smart grid deployment plan in less than 3 years. Yet the fiber optic network supported more than just a smart grid—it has attracted new businesses and supported economic development.



Courtesy of EPB

Chattanooga was the first city in the nation to offer ultra-high-speed internet service, up to 200 times faster than the average broadband service, to all 170,000 homeowners and businesses. The broadband network was a key element in Volkswagen's choice of Chattanooga as the site for a billion dollar car factory, according to economic development organization Connected Tennessee. The fiber optic network can provide businesses with a virtual local area network (LAN) to securely connect multiple worksites and send large files and data at speeds of 30 mbps to 1 gigabit per second.[67] The affordable broadband network has attracted small startups and provided critical support to Chattanooga's accelerator GIGTANK, which invited smart grid startups to build and test their applications using millions of anonymous live data points from EPB's smart grid system.[68]

Looking forward, advanced information, communication, and control systems are a primary enabler of grid-scale renewable energy integration and customer-based generation.

Smart metering, advanced distribution automation capabilities, and increased transmission visibility and control all lay the groundwork for utilities to safely and reliably integrate distributed energy resources (DER), including both small-scale and large-scale renewable energy and energy storage.

Synchrophasors in particular now enable operators to monitor the more dynamic state of the power system—caused by variable wind and solar generation in high concentrations—and validate renewable generation models.

The Electric Reliability Council of Texas (ERCOT) demonstrated that **synchrophasor monitoring capabilities can help integrate more wind resources while more effectively managing the impacts of wind power on the grid**. In 2014, ERCOT's synchrophasor system quickly identified a potentially damaging oscillation—undetectable by traditional power system monitoring—caused by a malfunction at a wind farm. The ERCOT operator stopped the oscillation by constraining the unit's output while the malfunction was fixed.[69]

[67] Connecticut General Assembly Office of Legislative Research, *Chattanooga High Speed Broadband Initiative*, OLR Research Report 2012-R-0515 (December 14, 2012); CBS News, "Fastest Internet service in U.S. found in an unlikely city" (February 28, 2013).
[68] Gig City, "GIGTANK 2014 Program Smart Grid" (February 26, 2014).
[69] DOE OE, *Advancement of Synchrophasor Technology in Projects Funded by the ARRA* (March 2016).

Idaho Power Company's synchrophasors reduced the time required to validate its wind plant generator model by 75% by delivering data directly to planning engineers and eliminating the need to travel to wind generation sites to collect necessary data. [70]

Increased customer adoption of clean energy and DER, such as rooftop photovoltaic arrays and plug-in electric vehicles, demands that utilities seamlessly manage two-way power flows and data transmission. An advanced metering infrastructure allows customers to participate in electricity markets as "prosumers"—both buying and selling electricity, and participating in demand response programs. SGIG projects installed hundreds of electric vehicle charging stations and tested DER integration at a very small scale, but collected key lessons that will inform future grid integration and market designs.

2.8 | SGIG Cybersecurity Policies Improve Utility Business and Technology Protection Practices to Address Emerging Threats

Smart digital devices added millions of new cyber access points to the grid, making customer privacy and cybersecurity paramount to smart grid success. That is why cybersecurity was an integral part of the SGIG program from its inception. All SGIG recipients were required to create comprehensive cybersecurity plans and build cybersecurity into their policies, technologies, and utility practices. SGIG expert teams augmented these measures with 311 onsite reviews to monitor project progress, including cybersecurity implementation.

Two cybersecurity information exchanges in 2011 and in 2012 promoted peer-to-peer sharing of best practices and lessons learned among SGIG projects. Additional cybersecurity tools and resources were made available through a dedicated website for SGIG project recipients. Through this intensive effort, many SGIG utilities—particularly smaller ones—enhanced cybersecurity practices across their entire system and continue to use the SGIG cybersecurity plan as a model. Improved cybersecurity knowledge will be essential when deploying future smart grid technology and systems. Section 4 describes these activities in greater detail.

A modern grid also relies on interoperability—the ability of networks, systems, and devices to seamlessly connect and share information securely and efficiently. Many various components from different vendors must be interoperable to enable effective, efficient, and cost-efficient system upgrades. In 2009, few interoperability standards or guidelines yet existed. SGIG recipients became active members of the interoperability community, working with DOE and the National Institute of Standards and Technology (NIST) to help identify, develop, and adopt interoperability standards; evaluate deployments; and assess needs. The SGIG program has enabled and supported several key interoperability initiatives:

- A detailed framework and roadmap produced by the National Institute of Standards and Technology[71] and action plans for development produced by the Smart Grid Interoperability Panel.
- A catalog of more than 70 standards deemed capable of meeting interoperability requirements.
- Substantial increases in adoption of industry specifications such as the National Rural Electric Cooperative Association's (NRECA's) "MultiSpeak."
- The Green Button Initiative, which supports access to electricity consumption data from utilities for more than 60 million households and businesses.

[70] DOE OE, *Advancement of Synchrophasor Technology in Projects Funded by the ARRA* (March 2016).
[71] NIST, *NIST Framework and Roadmap for Smart Grid Interoperability Standards*, Release 3.0, Special Publication 1108r3 (September 2014).

3 | TECHNOLOGY DEPLOYMENT AND APPLICATIONS UNDER SGIG

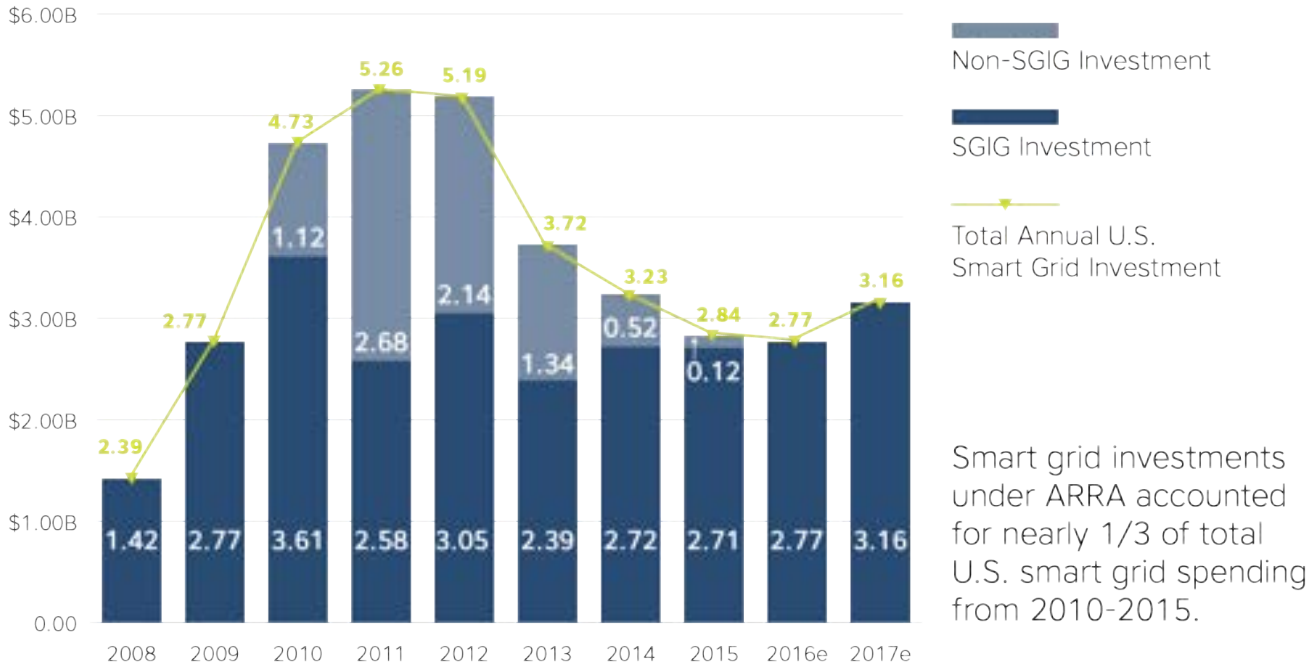
SGIG recipients deployed many smart grid technologies and systems that were in nascent stages of commercial development in 2010, when the first devices were purchased under the program. Careful application of the $7.9 billion total SGIG investment helped speed technology maturation and market deployment during the five-year program. Figure 3.1 shows combined DOE and project spending by types of technologies and systems.

FIGURE 3.1 TOTAL COST-SHARED SGIG EXPENDITURES



In all, the U.S. electricity industry as a whole spent an estimated $24.97 billion for smart grid technology deployed from 2010 through 2015 (excluding transmission system technologies; see Figure 3.2).[72] Smart grid investments under the ARRA accounted for nearly a third of spending during this period. The rate of expenditures was highest in 2010–2012, following the spirit of the ARRA to stimulate the economy. This infusion of technologies is catalyzing continued industry investment over the next several years as smart grid technologies continue to mature.

FIGURE 3.2 U.S. SMART GRID INVESTMENT (BILLIONS), 2008-2017 (ACTUAL AND EXPECTED)



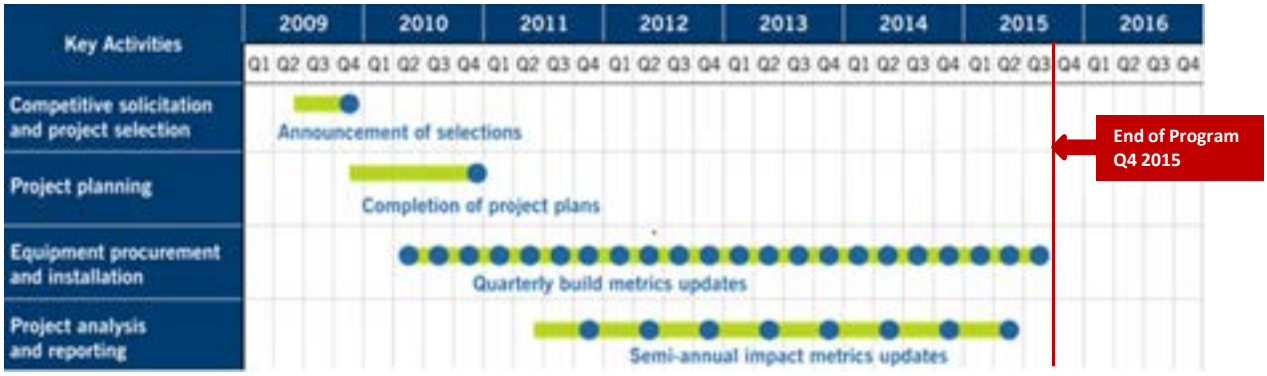
[72] Bloomberg New Energy Finance, *U.S. Smart Grid and Smart Metering Forecasts*, prepared for the U.S. Department of Energy (February 17, 2016).

The DOE Office of Electricity Delivery and Energy Reliability (OE) managed each SGIG project to ensure performance remained on schedule and on budget. The key SGIG program activities followed the schedule shown in Figure 3.3 and remained on target throughout the program.

OE extracted value from the ARRA investment in several key ways:

- **Closely monitored the overall schedule of activities and level of expenditures**, working directly with project recipients to resolve issues.
- **Tracked the deployment of technologies and systems** across all 99 projects using consistent build metrics.
- **Measured technology performance, productivity and cost benefits, and lessons learned** reported by project recipients using a detailed metrics and benefits reporting plan.
- **Published interim results to enable the industry to rapidly learn from and build on SGIG successes**. OE published two SGIG Progress Reports (the first in 2012 and the second in 2013) as well as detailed case studies of project results in key technology areas.
- **Provided technical assistance** to develop and deploy appropriate cybersecurity protections.

FIGURE 3.3 SGIG PROGRAM IMPLEMENTATION SCHEDULE



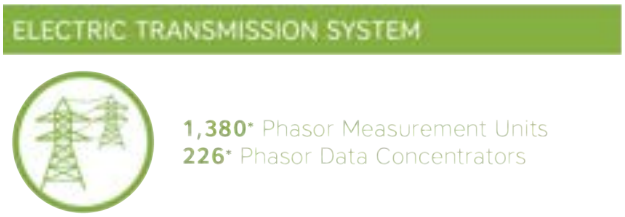
The following sections provide a brief overview of the smart grid technologies and systems deployed under SGIG, and how ARRA investments changed the smart grid technology landscape.

3.1 | Transmission Systems

The ARRA projects resulted in a dramatic expansion in the use of advanced synchrophasor devices and capabilities to improve power system planning and operations—marking the first time transmission owners and operators installed modern, production-grade PMUs and used them in real-time operations, not simply research.

PMUs are devices that take precise grid measurements at high speed, typically 30 observations per second, which is more than 100 times faster than conventional supervisory control and data acquisition (SCADA) technology. Each measurement is stamped with a common time reference and location. PMUs function as synchrophasors when measurements from different locations and utilities are combined and time-aligned (or synchronized), providing operators a precise and comprehensive view of an entire region or interconnection.

FIGURE 3.4. SGIG TRANSMISSION SYSTEM DEPLOYMENT



Transmission system project results under ARRA include 13 SGIG projects and 1 Smart Grid Demonstration Program project.

ARRA grant recipients included independent system operators (ISOs), regional transmission organizations (RTOs), and large and small utilities, participating in 13 SGIG projects and 1 project managed under the Smart Grid Demonstration Program. The SGIG transmission system projects spent approximately $507 million (including both DOE and recipient funds), which represents just 6% of the total SGIG budget. Recipients accelerated synchrophasor technology maturity in three key ways:

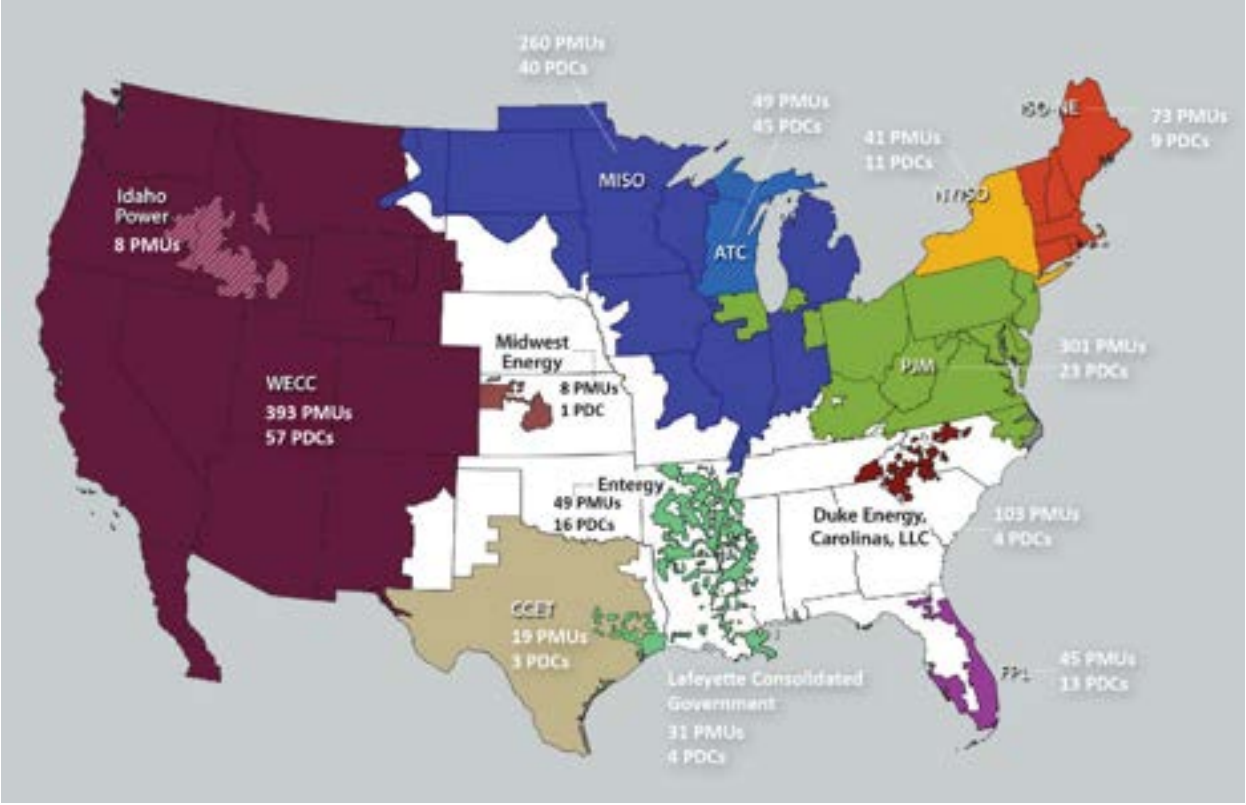
- **Installed 1,380 production-grade PMUs and 226 phasor data concentrators**, which collectively provide operators visibility into the transmission systems that serve approximately 88 percent of the total U.S. load and cover approximately two-thirds of the continental United States.[73] Operators now have near 100 percent visibility of the behavior of the entire U.S. high-voltage transmission network, due in large part to synchrophasor deployments by ARRA projects.[74]
- **Installed or enhanced region-wide, high-speed communications and data management systems** to network synchrophasors, enabling unprecedented data sharing and visibility over large areas. Project utilities developed data transmission and concentration procedures that send PMU data to operators with a 0.019-second latency.
- **Drove significant improvements in data quality by testing data validation, data storage, and advanced applications** needed for real-time aggregation and analysis of synchrophasor data. Utilities trained operators and engineers and improved data quality to the point that they can now use synchrophasor data in system engineering, design, and real-time operations. Project participants developed and implemented rigorous procedures for validating synchrophasor data, monitoring synchrophasor system performance, and restoring service to PMUs to maintain the required data quality.

Recipients also worked closely with the North American Synchrophasor Initiative (NASPI) to coordinate, share information, solve problems, accelerate the development of software applications, and accelerate standards

[73] DOE OE, *Advancement of Synchrophasor Technology in Projects Funded by the ARRA* (March 2016).
[74] DOE OE, *Advancement of Synchrophasor Technology in Projects Funded by the ARRA* (March 2016).

development to enhance the success of the ARRA-funded deployment.[75] PMUs are now in every U.S. interconnection, with expansive new phasor data communications networks.

FIGURE 3.5 SYNCHROPHASOR TECHNOLOGIES INSTALLED UNDER ARRA-FUNDED PROJECTS



Acronyms: FPL – Florida Power & Light; ISO-NE – Independent System Operator of New England; MISO – Midwest ISO; NYISO – New York ISO; WECC – Western Electricity Coordinating Council

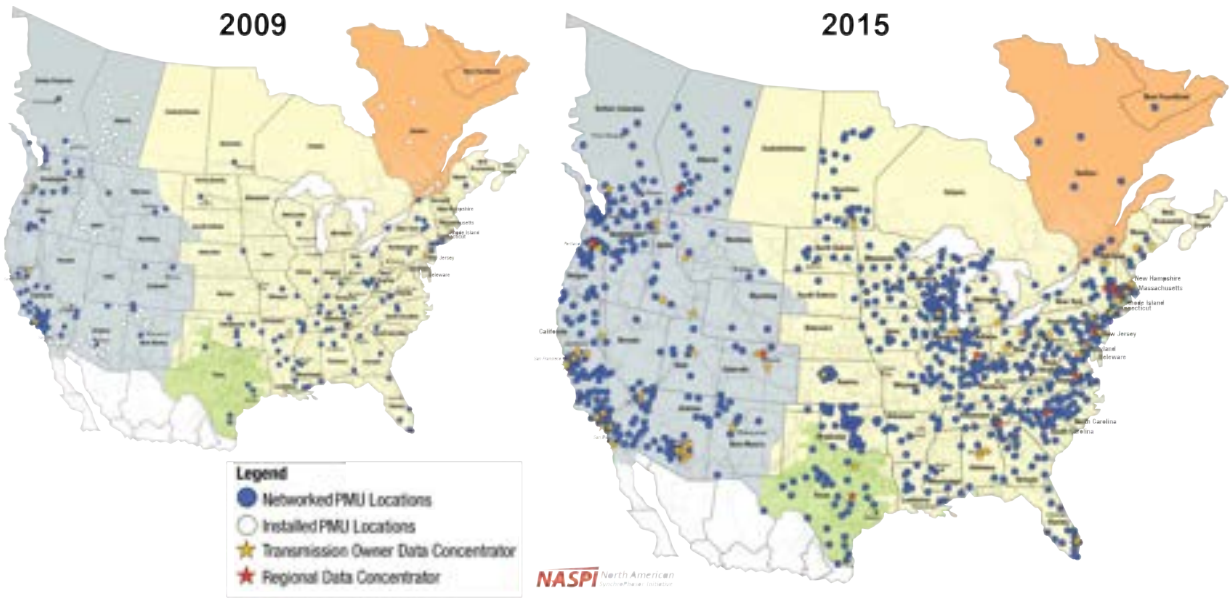
3.1.1 | Technology Maturity under SGIG

PMUs were developed in 1988 and first deployed in 1992 with initial funding from DOE, the National Science Foundation, and the Electric Power Research Institute. DOE spent seven years in research and development (R&D) on phasor measurement technology prior to ARRA. By 2009, however, only 200 research-grade PMUs (suitable for research but not grid operational monitoring) were deployed in networks across North America.[76] At the time, problems with PMU data availability and accuracy severely limited industry acceptance of synchrophasor technology.

By 2015, there were more than 1,700 production-grade PMUs deployed across the United States and Canada, streaming data and providing almost 100 percent visibility into the bulk power system (see Figure 3.6).[77] This number includes 166 original (pre-2009) PMUs, the 1,380 PMUs installed with ARRA funding, and over 150 additional PMUs installed by participants or other utilities without federal funding.[78]

[75] NASPI was collectively created by the electric industry, the North American Electric Reliability Corporation (NERC), and DOE to advance synchrophasor technology development.
[76] North American Phasor Initiative, "Synchrophasor Technology Fact Sheet" (2014).
[77] North American Phasor Initiative, *2014 Survey of Synchrophasor System Networks – Results and Findings* (2015).
[78] DOE OE, *Advancement of Synchrophasor Technology in Projects Funded by the ARRA* (March 2016).

FIGURE 3.6 ADVANCES IN SYNCHROPHASOR DEPLOYMENT ACROSS NORTH AMERICA, 2009-2015



From 2009 to 2015, ARRA-funded projects deployed 1,380 PMUs and 226 PDCs

Maps courtesy of the North American SynchroPhasor Initiative

The ARRA-funded synchrophasor projects transitioned synchrophasor technology from a research and off-line analysis tool to one that informs the real-time operation of the power grid and improves system planning. Synchrophasor applications have reduced grid costs, prevented outages, identified failing and failed equipment, improved models for improved system performance, accelerated restoration after outages, and improved grid operating efficiency.

3.1.2 | Applications Today

Synchrophasors can help maintain power grid reliability, improve system efficiency, increase use of existing assets, and increase organizational efficiency through a wide variety of real-time and study-mode applications (see Table 3.1). The accurate time resolution of synchrophasor measurements allows unprecedented visibility into system conditions, allowing operators to rapidly identify oscillations and voltage instability that cannot be seen using SCADA measurements, and determine operating limits in real time.

Operators can evaluate actual system measurements rather than using mathematical estimates and, thus, are better able to proactively prevent problems before they occur, rather than reacting to an event after the fact. Data from PMUs provide a high-resolution view of localized electrical phenomena. If PMU data are widely shared, conditions that develop across an entire interconnection can be detected and monitored. Wide area situational awareness is the capability for grid operators to see key parameters of the bulk electric power system beyond their service territory–even across an entire interconnection with enough shared data. Wide area displays allow all operators in an interconnection to have a common understanding of the condition of the overall electric grid, resulting in better collaboration and better solutions to emerging problems.

TABLE 3.1 SYNCHROPHASOR CAPABILITIES CREATE TANGIBLE SYSTEM BENEFITS

	Number of Projects	Increased System Reliability	Increased Asset Utilization & Power System Efficiency	Increased Organizational Efficiency
Real-Time Capabilities[79]				
Phase angle monitoring	12	✓	✓	
Oscillation detection and monitoring	11	✓		
Voltage stability monitoring	9	✓		
Event detection, management, & restoration	9	✓		✓
Islanding detection, management, & restoration	4	✓		
Equipment problem detection	9	✓		✓
Wide-area situational awareness	11	✓		✓
Study Mode Capabilities[80]				
Model validation and calibration	11	✓	✓	✓
Post-event analysis	11	✓		✓
Renewable resource integration	3		✓	
Operator training	6	✓		

Synchrophasor data collected during a grid disturbance also enable engineers to compare the system's predicted response (based on engineering models) with actual conditions. Engineering models simulate and explain how individual power plants and large system interconnections perform and interact as a network. Engineers design and operate the grid using these mathematical models. The engineers can then use synchrophasor information to validate and improve the models and model parameters, thus improving power grid operation.

PMUs also allow engineers to validate generator models without having to take the generators off-line. (The standard practice is to schedule a generator outage for model validation every five years.) By avoiding an outage, utilities not only save the cost of scheduling and implementing the outage, but also avoid interruption of service to any consumers.

Additional information about the SGIG synchrophasor projects is available in *Advancement of Synchrophasor Technology in Projects Funded by the ARRA*.

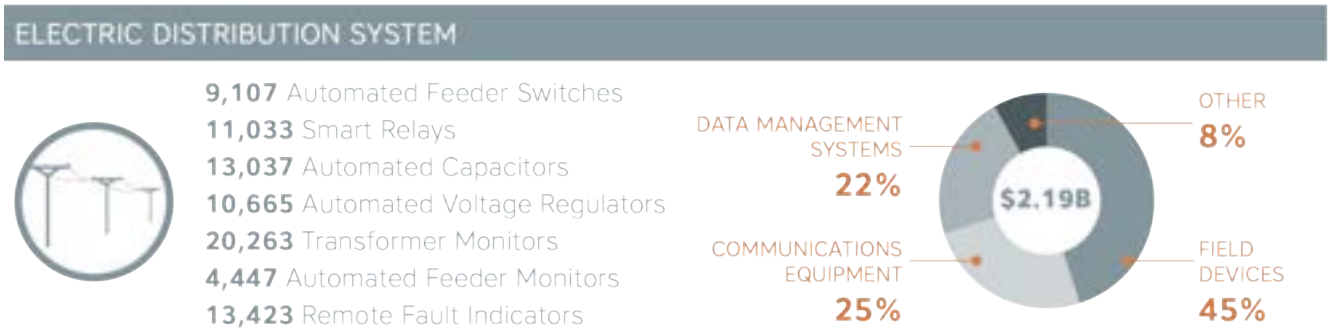
[79] Real-time capabilities are employed in the minute-by-minute operation of the electric power grid. These are generally carried out by power system operators or operational engineers.
[80] Study mode/planning capabilities, which are generally carried out by power system engineers, are employed in planning for transmission system expansions, generation additions and retirements, system protection, and studying unexpected events or system behaviors.

3.2 | Distribution Systems

SGIG electric distribution system projects installed nearly 82,000 smart digital devices and automated controls on about 6,500 distribution circuits—about 3 percent of the estimated 203,000 distribution circuits in the United States.[81] Though this percentage may seem small, utilities saw significant reliability improvements and cost savings by focusing on the worst-performing feeders first.

Distribution automation (DA) applies advanced control and communication technologies and integrates new digital controls, switches, and sensors to automate electricity delivery tasks that were previously performed using electro-mechanical or manual processes. Digital field devices can work autonomously or be monitored and controlled via communications networks linked to back office systems.

FIGURE 3.7. SGIG DISTRIBUTION SYSTEM DEPLOYMENTS AND INVESTMENT BREAKDOWN



The 62 SGIG electric distribution system projects spent approximately $2.19 billion (including both DOE and recipient funds), which represents about 28 percent of the total SGIG budget. Several projects involved deployments that covered major portions of their service territories, but the majority of projects involved smaller-scale deployments on a limited number of feeders and substations.

Utilities with DA projects not only installed new devices, but also installed or upgraded the communications networks and data management systems that enable advanced applications. Figure 3.7 shows the breakout of investment costs for the SGIG electric distribution projects. Compared to expenditures on communications and data management systems, expenditures on field devices comprise approximately 45 percent of the total. The field devices include automated capacitors, automated switches, relays, regulators, and equipment monitors.

SGIG DA projects tested several new applications for improved outage management, asset utilization, power quality, and equipment health:

- **Automated feeder switching (AFS) and fault location, isolation, and service restoration (FLISR) operations**, which use remote fault indicators, monitors, automated feeder switches, and reclosers in tandem to automate power restoration, reducing both the impact and length of power interruptions. FLISR applications can automatically isolate a fault and rapidly restore service to downstream customers by transferring them to adjacent circuits. By integrating these capabilities with their outage management systems, SGIG utilities helped target repair crews and restore services more quickly.

[81] U.S. Energy Information Administration, "Electric power sales, revenue, and energy efficiency: Form EIA-861 detailed data files," final yearly data (last release date October 6, 2016).

- **Voltage/volt–ampere reactive (volt/VAR control) and conservation voltage reduction (CVR)** using automated capacitors and voltage regulators to improve phase balancing and reactive power compensation and to optimize voltage levels on distribution circuits. These enhanced capabilities can minimize voltage levels and reactive power levels to reduce electricity requirements for real and reactive power during peak periods or for longer periods of time. These capabilities enabled SGIG utilities to maximize existing assets, reduce line losses, and save customers energy.
- **Equipment health monitoring**, using sensors and monitors to identify potentially failing equipment and perform preventative maintenance, and monitor equipment health to extend the life of key assets.

Distribution system modernization is also helping utilities to adapt and accommodate many new requirements, including greater numbers of distributed and renewable resources and demand-side programs and equipment. These include high-efficiency reciprocating engines, wind generators, plug-in electric vehicles, photovoltaic systems, microturbines, fuel cells, and energy storage systems. Grid integration requires tools to monitor and dispatch DERs, and to address electric power flow and control issues such as low-voltage ride through, harmonic injection, voltage fluctuations, and reactive power management. Several SGIG projects tested electric vehicle charging stations, automated DER dispatch and management, and operation of thermal energy storage at pilot scales, providing results that will help utilities anticipate future operating requirements and plan adaptations. These projects helped those utilities take a large step forward in preparing for high concentrations of new and clean energy resources.

Full discussion of SGIG efforts and successes in deployment of technologies to improve distribution system operations can be found in *Distribution Automation: Final Report from the SGIG Program*.

3.3 | Advanced Metering Infrastructure

AMI technologies and systems is an integrated system of smart meters, communications networks, and data management systems that enables two-way communication between utilities and customers. The system provides a number of important functions that were not previously possible or had to be performed manually, such as the ability to automatically and remotely measure electricity use, connect and disconnect service, detect tampering, identify and isolate outages, and monitor voltage. Combined with customer technologies, such as IHDs and PCTs, AMI also enables utilities to offer new time-based rate programs and incentives that encourage customers to reduce peak demand and manage energy consumption and costs.

FIGURE 3.8 SGIG SMART METER INSTALLATIONS BY CUSTOMER TYPE



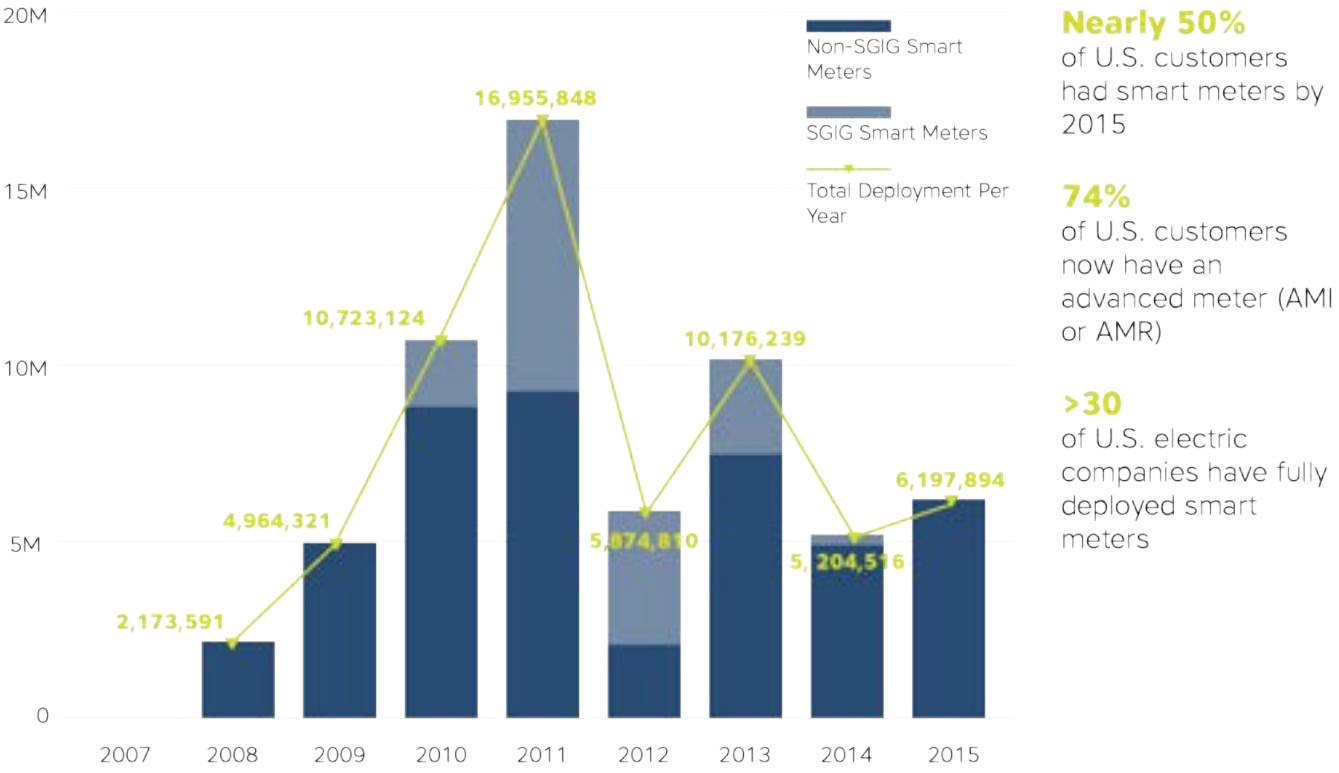
Sixty-four SGIG AMI projects collectively installed more than 16.3 million smart meters, which exceeds the planned level by 5 percent and nearly doubled the number of smart meters installed nationwide before the SGIG program began (Figure 3.8). AMI includes not only the smart meters themselves, but the communications networks, meter data management systems, and other advanced technologies and systems that enable advanced metering capabilities. Figure 3.9 shows the breakdown of SGIG expenditures for smart meters and other AMI technologies and systems. SGIG expenditures totaled about $4.44 billion with about 61 percent for smart meters, 17 percent for meter data management systems, 13 percent for communications equipment, and 9 percent for other expenses.

FIGURE 3.9 SGIG AMI DEPLOYMENTS AND INVESTMENT BREAKDOWN



Smart meters installed under SGIG represent about 33 percent of the 49 million smart meters installed nationwide between 2010 and 2014. [82] The SGIG projects supported rapid industry adoption of smart meter technology and continued, steady implementation is expected based on these successes (Figure 3.10).

FIGURE 3.10 ANNUAL U.S. SMART METER INSTALLATIONS AND SGIG CONTRIBUTIONS



Since its early days, the electric power industry traditionally used electro-mechanical induction meters that measure overall consumption, which must be read manually at regular intervals (mostly monthly) by meter readers, primarily for billing purposes. Traditional meters are incapable of recording consumption levels by time of day and are therefore not usable for time-based rate programs. While AMI systems offer many services, one of the primary applications involves processing meter readings for billing. This eliminates the need for manual meter readings and

[82] U.S. Energy Information Administration, "Electric power sales, revenue, and energy efficiency: Form EIA-861 detailed data files," final yearly data (last release date October 6, 2016).

reduces operating costs. Other applications and services that provide operational benefits include tamper detection, outage detection, and remote service connections and disconnections.

Many of the SGIG AMI projects integrated the outage detection capabilities of the smart meters with outage management and GIS to accelerate response and restoration, and a few of the projects used AMI on a small scale to collect data on voltage and power quality levels, which they coupled with distribution automation technologies and systems for voltage control and reactive power management.

3.4 | Customer Systems

Sixty-six SGIG project recipients also deployed nearly 700,000 technologies and systems to help customers understand their electricity consumption and give them greater control of their use and costs—particularly when combined with new time-based rates. Utilities deployed DLC devices, web portals (through which customers can access usage data), IHDs, and PCTs, along with the communications systems for transmitting data to and from the utilities' AMI systems and back office systems. Usage information allowed customers to take actions to reduce or shift their consumption of electricity from peak to off-peak periods.

Figure 3.11 provides information on customer system project expenditures, showing that expenditures on devices account for 42 percent of the total, which also included web portals, data management systems, and other costs.

FIGURE 3.11 SGIG CUSTOMER SYSTEM DEPLOYMENTS AND INVESTMENT BREAKDOWN (EXCLUDES DER INVESTMENTS)



Industrial and commercial grant recipients also used SGIG funds to develop new systems and devices for energy monitoring and management. These included smart appliances and associated management protocols (Whirlpool), an integrated circuit to enable communication between smart grid-enabled devices and vehicles (Qualcomm-Atheros), automated demand response technology (Honeywell), and two-way communicating load control devices for agricultural customers (M2M).

From the early days of the electric power industry, utilities, policymakers, and academics have discussed the role of customers in the electric power system primarily through offers of time-based rates for electricity.[83] The Public Utility Regulatory Policy Act (PURPA)[84] in 1978 contained the first standards calling for states to consider adoption of time-

[83] Hausman, W. J. and J. L. Neufeld (1984). "Time-of-Day Pricing in the U.S. Electric Power Industry at the Turn of the Century." The Rand Journal of Economics 15(1): 116-126.
[84] Subtitle B asked state regulatory authorities and non-regulated electric utilities to determine whether it is appropriate to implement time-of-use rates and other ratemaking policies.

based rates. The introduction of electronic meters enabled time-differentiated rates by recording the amount of energy used during on-peak and off-peak hours. During the early 1980s, evaluations of pilot time-of-use (TOU) rate programs during the early 1980s found that customers responded well to TOU rates, but the business case was insufficient to support a wide-scale installation of the required meters.[85] The implementation of smart meters and AMI under SGIG gave utilities the cost-effective capabilities needed to enact time-based rates, while the customer devices gave customers unprecedented capabilities to respond to rate changes and control their electricity costs.

Ten SGIG utilities conducted 11 Consumer Behavior Studies (CBS) to answer key questions facing decision makers on customer acceptance, retention, and demand response in time-based and incentive rate programs. Table 3.2 provides an overview of the scope of the CBS projects. The studies followed rigorous research protocols and applied randomized and controlled experimental design techniques to estimate customer responses more credibly and precisely, providing new information to improve future program designs, implementation strategies, and evaluations. Customers participating in the studies had smart meters and various types of customer systems such as PCTs, IHDs, and web portals; several studies included assessments of customer information and education programs and materials.

TABLE 3.2 SCOPE OF THE CONSUMER BEHAVIOR STUDIES

	CEIC	DTE	GMP	LE	MMLD	MP	NV	OG&E	SMUD	VEC
Rate Treatments										
Critical Peak Pricing		●	●		●	●	●	●	●	
Time-of-Use		●		●		●	●	●	●	
Variable Peak Pricing								●		●
Critical Peak Rebate	●		●							
Non- Rate Treatments										
In-Home Display	●	●	●					●	●	
Programmable Communicating Thermostat	●	●					●	●		
Education							●			
Recruitment Approaches										
Opt-In	●	●	●	●	●	●	●	●	●	●
Opt-Out				●					●	

Utility Abbreviations: First Energy – Cleveland Electric Illuminating Company (CEIC), Detroit Edison (DTE), Green Mountain Power (GMP), Lakeland Electric (LE), Marblehead Municipal Lighting Department (MMLD), Minnesota Power (MP), Nevada Energy (NV), Oklahoma Gas and Electric (OG&E), Sacramento Municipal Utility District (SMUD), Vermont Electric Cooperative (VEC)

The SGIG CBS provided unprecedented analysis of the effects of different rate treatments, opt-in vs. opt-out recruitment approaches, and offering IHDs and PCTs to participating customers.[86]

[85] Faruqui, A. and J. R. Malko (1983). "The residential demand for electricity by time-of-use: A survey of twelve experiments with peak load pricing." Energy 8(10): 781-795.
[86] DOE OE, *Customer Acceptance, Retention, and Response to Time-Based Rates from the Consumer Behavior Studies* (September 2016).

Rate Treatments

Critical peak *pricing* vs. critical peak *rebates*: Retention rates were higher for critical peak rebates (CPR) than for CPP, yet the demand reductions achieved (without a PCT) were generally lower for CPR. However, when PCTs were available as an automated control strategy, the differences in peak demand reductions between CPP and CPR were largely eliminated. This suggests that regardless of the financial incentive, PCTs can be an effective tool to mitigate a customer's loss aversion by allowing them to automate their response to critical peak events.

Effects of TOU: Customers reduced demand during the peak period by 15 percent on average with TOU rates. Responses ranged from a peak demand increase of 1 percent to a peak demand decrease of 29 percent. Customers reduced peak demand more when there was a higher ratio of peak price to off-peak price—by 6 percent on average with a 2:1 price ratio and by 18 percent on average with a price ratio greater than 4:1. Demand reductions were higher when PCTs were available as an automated control strategy, particularly when peak to off-peak price ratios were greater than 2:1. When CPP/CPR rates were overlaid on the TOU rate, average *event* peak demand reduction was 34 percent with PCTs and 24 percent without them.

Recruitment Approaches

Opt-In vs. Opt-Out: Opt-out enrollment rates were 3.5 times higher (93 percent vs. 15 percent) and peak demand reductions were generally lower than voluntary opt-in enrollment, and retention rates were largely the same for both (90 percent vs. 87 percent). While customers in opt-in programs reduced peak demand by up to 50 percent more, the low participation means that opt-out programs can expect larger *aggregate* peak demand reductions than opt-in programs offered to a similar number of customers.

Customer Technologies

Customer *Information* Technologies—IHDs: Offering free IHDs to customers did not have a measured effect on customers' peak demand reductions, and also did not make a substantial difference for enrollment and retention rates (+/- 1-4 percentage points). Because of the cost associated with offering the IHD, utilities saw a lower benefit-cost ratio for rate offerings that included IHDs. In addition, many of the CBS utilities reported significant challenges with this relatively new technology, including low customer connectivity rates and improperly functioning equipment. In one case, the IHD manufacturer decided to halt production and stop support during the study.

Customer *Control* Technologies—PCTs: Though offering customers a free PCT did not make a major difference for retention, peak demand reductions were substantially higher for those that used them. Unlike with IHDs, cost-benefit ratios for PCT offers were favorable—greater than 1.

Expanding Time-Based Rate Programs

More analysis and further studies may be needed to demonstrate to regulators and consumer advocates that these results can be replicated; yet the number of customers participating in time-based and incentive rate programs is on the rise. More than 9 million customers are enrolled in demand-side management programs (including DLC and rate programs), up from 6.7 million in 2009.[87]

[87] U.S. Energy Information Administration, "Electric power sales, revenue, and energy efficiency: Form EIA-861 detailed data files," final yearly data (last release date October 6, 2016).

Three of the 10 CBS utilities allowed participants to continue taking service under the rates after their study was completed. Four of the 10 CBS utilities chose to extend an offer of the rates tested in their study to the broader population of residential customers. For example:

- OG&E has now enrolled approximately 116,000—or about 18 percent—of its total residential customers on its SmartHours program, which includes the offer of a free PCT (taken by 90 percent of participating customers). About 86 percent (100,000) of SmartHours participants are taking service on the variable peak pricing rate tested in its CBS, and are achieving 147 MW of peak demand reduction.
- SMUD chose to make the TOU rate it tested the default for all of its residential customers, starting in 2018. More broadly, the California Public Utility Commission ordered all of the state's investor-owned utilities to make TOU the default for residential customers, citing the very positive results SMUD achieved as grounds for this decision.[88]

[88] DOE OE, *Customer Acceptance, Retention, and Response to Time-Based Rates from the Consumer Behavior Studies* (September 2016).

4 | CYBERSECURITY AND INTEROPERABILITY IN THE SMART GRID

Smart digital devices added millions of new cyber access points to the grid that could make the system more vulnerable to cyber intrusion if not adequately protected. That is why cybersecurity was a cornerstone of the SGIG program from its onset. The SGIG program aimed to accelerate the development and deployment of effective cybersecurity protections for smart grid technologies and systems using a "cradle-to-grave" approach that ensures cybersecurity protections are "built in" to smart grid technologies and systems from the beginning. This approach offers stronger and longer-lasting protection than security measures that are "bolted on" after systems are fully developed and deployed. DOE worked closely with SGIG projects to ensure that sound cybersecurity policies, plans, and practices were integrated throughout the entire project lifecycle, including design, procurement, installation, commissioning, and ongoing maintenance and support.

Key Cybersecurity Requirements and Resources of the SGIG Program

- **Required that all grant proposals address cybersecurity.** Proposals had to show how cybersecurity would be addressed in every phase of the project lifecycle and how security could be upgraded in response to changes to the threat or technological environment.
- **Required all 99 SGIG projects to develop and submit Cybersecurity Plans (CSPs).** Prior to starting work, each awardee was required to develop and submit a CSP to DOE for approval. Plans identified cybersecurity risks and how they would be mitigated, cybersecurity criteria used for vendor and device selection, relevant cybersecurity standards and/or best practices that would be followed, corporate accountability to ensure successful implementation, and how the project would support emerging smart grid cybersecurity standards.
- **Conducted two webinars to guide SGIG grant recipients through the cybersecurity requirements.** The DOE webinars helped guide recipients through the CSP development process and showed how to interpret and integrate new standards and requirements into the CSPs.
- **Formed an expert SGIG cybersecurity team to advise SGIG project teams.** Throughout the duration of the SGIG program, a core team of subject matter experts (SMEs) from national laboratories, universities, and the private sector provided grant recipients with guidance on cybersecurity strategies and system choices. During this period, the team participated in more than 100 conference calls with SGIG grant recipients. The cybersecurity SMEs participated in a total of 311 annual site visits from 2011 to 2015 to monitor progress on cybersecurity implementation. During annual project site visits, SGIG cybersecurity team members rigorously reviewed all CSPs and their implementation and, as needed, made recommendations. Year-to-year results showed improvements in nearly all projects and areas, reflecting a maturation of cybersecurity practices and management. The team established criteria used for site visits to determine the cybersecurity posture of each project.
- **Developed a dedicated website of cybersecurity resources specifically for SGIG project recipients**. DOE's secure website served as a central repository of tools, guides, presentations, and resources specifically tailored to the needs of SGIG project teams.
- **Hosted Smart Grid Cybersecurity Information Exchanges in 2011 and 2012**. The Exchanges were essential in promoting peer-to-peer discussions on lessons learned and best practices in developing and implementing cybersecurity for smart grid technologies and systems. Participants also learned about available tools, techniques, and resources for strengthening the security of cyber systems and discussed how to sustain cybersecurity processes once the ARRA projects are completed.

When the SGIG program began in 2009, DOE observed that the sophistication of cybersecurity policies, capabilities, and practices varied greatly among utilities and that few tools existed to help measure, monitor, and track performance of cybersecurity processes and systems.

Across the board, SGIG project participants improved their understanding of cybersecurity issues and specific needs in deploying smart grid technologies and systems. This was most readily apparent in smaller utilities that saw a dramatic increase in the staff's sophistication in cybersecurity practices. Although not an SGIG program requirement, many utilities intend to continue to modify and use their SGIG CSPs as foundations of their organizations' ongoing cybersecurity programs.

4.1 | Smart Grid Cybersecurity Tools and Guidelines

A key contributor to the success of SGIG cybersecurity programs was the industry's coordinated development of new cybersecurity guidelines, tools, and procurement language over the last six years. DOE has been working with utilities, vendors, national laboratories, and other partners since 2004 on advanced cybersecurity R&D and to provide cybersecurity tools, expertise, and resources to the energy sector. During the SGIG projects, DOE worked with industry partners and provided ARRA funding to the National Institute of Standards and Technology (NIST) to support the design and implementation of cybersecurity protections and tools, particularly for smart grid applications (see Table 4.1). Cybersecurity tools developed since 2009 include:

- ***Guidelines for Smart Grid Cybersecurity* (NISTIR 7628)**, published by NIST in 2010 using ARRA funds (revision published in 2014.
- ***Guide to Developing a Cybersecurity and Risk Mitigation Plan***, released by NRECA in 2011 as part of a Smart Grid Demonstration Program (SGDP) project (update released in 2014).
- ***Electricity Subsector Cybersecurity Capabilities Maturity Model* (ES-C2M2)**, a voluntary tool, published by DOE in 2012, that helps electric utilities and grid operators to assess their cybersecurity capabilities and prioritize actions and investments to improve cybersecurity.
- ***Cybersecurity Risk Management Process Guideline***, a set of DOE risk management processes developed in 2011 under the Cybersecurity for Energy Delivery Systems program. It enables organizations—regardless of size or organizational or governance structure—to apply effective and efficient risk management processes and tailor them to meet their organizational requirements. It may be used to implement a new cybersecurity program within an organization or to build upon an organization's existing internal cybersecurity policies, standard guidelines, and procedures
- ***Energy Sector Cybersecurity Framework Implementation Guidance***, issued by DOE in 2015 to help the energy sector establish or align existing cybersecurity risk management programs to meet the objectives of the **Framework for Improving Critical Infrastructure Cybersecurity**, released by NIST in 2014.
- ***Cybersecurity Procurement Language for Energy Delivery Systems***, published by DOE and the U.S. Department of Homeland Security in 2009 and revised in 2014, to provide baseline cybersecurity procurement language that asset owners, operators, integrators, and suppliers can use during the procurement process.

TABLE 4.1 CYBERSECURITY PROGRESS FOR SMART GRID SYSTEMS (2009–2015)

STATUS IN 2009	STATUS IN 2015
No common cybersecurity guidelines for smart grid technologies and systems	• NIST *Guidelines for Smart Grid Cybersecurity (NISTIR 7628)* • NRECA *Guide to Developing a Cybersecurity and Risk Mitigation Plan*
Few common tools available to utilities to assess their cybersecurity postures	• DOE *Electricity Subsector Cybersecurity Capabilities Maturity Model (ES-C2M2)* • DOE *Cybersecurity Risk Management Process Guideline* • NIST *Framework for Improving Critical Infrastructure Cybersecurity* and corresponding *Energy Sector Cybersecurity Framework Implementation Guidance*
Lack of common procurement language to assist utilities in embedding cybersecurity in the procurement of energy delivery systems	• *Cybersecurity Procurement Language for Energy Delivery Systems*

4.2 | Smart Grid Interoperability Tools and Guidelines

Interoperability is also essential in a modern grid because it enables two or more networks, systems, devices, applications, or components to share and readily use information securely and efficiently with little or no inconvenience to the user.[89] Many various components from different vendors must be interoperable to enable effective, efficient, and cost-efficient system upgrades.

By 2009, a small number of practitioners identified interoperability as an important issue for smart grid developers to address, yet had only begun to analyze possible options and approaches to standards development. Since 2009, the industry has made substantial progress in tackling key interoperability issues, and the SGIG projects have been important for evaluating deployments, assessing needs, and accomplishing key activities in accelerating interoperability development. Table 4.2 highlights key interoperability accomplishments enabled and supported by the SGIG program.

TABLE 4.2 INTEROPERABILITY PROGRESS FOR SMART GRID SYSTEMS (2009–2015)

STATUS IN 2009	STATUS IN 2015
Introductory and overview materials produced by the GridWise Architecture Council	Detailed framework and roadmap produced by the National Institutes of Standards and Technology and action plans for development produced by the Smart Grid Interoperability Panel
No standards identified as capable of meeting interoperability requirements	Catalog of more than 70 standards deemed capable of meeting interoperability requirements

[89] GridWise Architecture Council, *Introduction to Interoperability and Decision Maker's Interoperability Checklist, v1.0* (April 2007).

STATUS IN 2009	STATUS IN 2015
Few data and tools available to enable or demonstrate the value of interoperability	Substantial increases in adoption of industry specifications such as NRECA's "MultiSpeak"
No common data platforms for aggregating and displaying electricity consumption data for use by consumers	The Green Button Initiative; provides access to electricity consumption data from utilities for more than 60 million households and businesses

With funding under the ARRA, NIST formed the Smart Grid Interoperability Panel (SGIP) in 2009. The Federal Energy Regulatory Commission (FERC) released a Smart Grid Policy Statement that identified four priority functionalities for interoperability: wide-area situational awareness, demand response, electric storage, and electric transportation.

NIST used these priorities to engage a consensus-building process with industry on a smart grid interoperability roadmap. The resulting meetings provided input for the ***NIST Framework and Roadmap for Smart Grid Interoperability Standards***, which identified 75 standards that may be relevant to smart grid interoperability and specified 15 priority action plans to immediately focus work going forward. NIST assembled the SGIP as an industry–government partnership to address these initial actions and to develop new interoperability priorities going forward. NIST maintains the Framework and Roadmap document to reflect the progress made by SGIP and others, as well as new priorities to advance smart grid interoperability. Release 3.0 was published in September 2014.[90]

In 2011, in accordance with Section 1305(d) of the Energy Independence and Security Act of 2007, NIST provided FERC with five initial "families" of smart grid standards to be used for rulemakings. FERC decided not to proceed with rulemakings, indicated further work was needed, and identified the SGIP as the appropriate entity for advancing industry standards for smart grid technologies and systems.

The Green Button Initiative

An important step forward for improving interoperability and customer access to personal energy data is the Green Button Initiative, championed at the federal level by the White House, NIST, and DOE. The Green Button Initiative is an industry-led effort that responded to a White House call to action and is based on a common technical standard developed in collaboration with NIST and SGIP for providing customers with easy access to their electricity usage information. The Initiative is voluntary and aimed, in part, toward enabling software developers and other entrepreneurs to leverage a sufficiently large market to support the creation of innovative applications that can help consumers make the most of their electricity usage information. There are almost 70 organizations participating in the Green Button Initiative, including utilities, manufacturers, and government agencies, many of which have been involved in SGIG projects. Almost 40 other organizations are planning to make commitments. The number of businesses and households served by utilities participating in the Green Button Initiative now exceeds 60 million.

The SGIP has worked with standards development organizations to address priority interoperability issues in 15 completed projects. These collaborations have addressed standards for engaging demand response, energy usage, information models for electric transportation, and specifications for price, product, and energy schedule transactions. The SGIP is conducting projects in areas of substation automation, facility information models, weather

[90] National Institute of Standards and Technology, *Framework and Roadmap for Smart Grid Interoperability Standards*, Release 3.0 (September 2014).

information, microgrids, and financial data for smart grid technology deployment. Recently, the Panel launched an effort for an Open Field Message Bus (OpenFMB) standard to bring information and communications technology promulgated in the open data standards area to the power transmission and distribution automation space.

Based on the standards identified in the NIST Framework and Roadmap documents, the results of priority action efforts, and other standards brought forward by SGIP members, the SGIP developed and maintained a catalog of smart grid interoperability standards (the Catalog). The Catalog is a compendium of standards and practices considered relevant for the development and deployment of a robust, interoperable, and secure smart grid. By the end of 2014, the Catalog had over 70 entries that include reviews on their areas of relevance and cybersecurity aspects.[91]

In December 2012, SGIP evolved from a government project to an independent, privately funded organization with paying members, including many SGIG utilities and solution-provider organizations. This change underscores the commitment of the electric power industry and other smart grid stakeholders to advance interoperability standards. NIST and DOE continue to actively partner with the SGIP to advance smart grid-related activities in which interoperability plays a critical enabling role.

Development of information, tools, and standards for interoperability is an ongoing process and remains one of the keys to successful grid modernization efforts. DOE supports the GridWise Architecture Council (GWAC), a strategic group that promotes the principles of interoperability and integration approaches for deploying smart grid capabilities in the electric system. GWAC's work products have been instrumental in the SGIP and international interoperability efforts.[92]

[91] Smart Grid Interoperability Panel, "Catalog of Standards" (2015).
[92] GridWise Architecture Council, "Publications" (last updated October 2015).

5 | DEPLOYMENT LESSONS LEARNED AND CONCLUSIONS

Smart grid implementation involves the installation of thousands of devices with two-way data communications capabilities supported by high-bandwidth, low-latency communications networks. Together, this equipment forms the basis of a new set of sensing and automation capabilities, supplying grid operators with unprecedented levels of data to process, analyze, store, and turn into actionable information for optimizing grid operations and implementing automated controls.

Information management and control systems such as distribution management systems (DMS), supervisory control and data acquisition systems (SCADA), outage management systems (OMS), meter data management systems (MDMS), customer information systems (CIS), remote monitoring systems (RMS), and geographic information systems (GIS) all need access to these new data streams to accomplish many smart grid functions. In some cases, multiple systems need to access the same data stream and interoperate, such as when OMS use data from line sensors to identify faults and data from smart meters to assess service restoration progress.

As a result, SGIG projects were designed not only to deploy assets, but to enable utilities to uncover integration and operations challenges that can inform future smart grid deployments. SGIG project experiences produced a wealth of information and lessons learned that can be applied by all utilities developing and deploying smart grid systems. These lessons learned cover the gamut of smart grid program implementation, from management and planning, to technology deployment and cybersecurity, to consumer engagement and education. Key lessons learned have been distilled here, and additional lessons learned can be found in the individual project reports on SmartGrid.gov.

5.1 | Smart Grid Project Management and Coordination

Internal collaboration and coordination is essential, as increased coordination is required among partners that previously worked independently. Many smart grid projects cut across functional areas and require well-organized staffing plans and interdepartmental teams to play critical roles. Smart grid deployments often involve changes to business processes, workflow, and logistics. Management of these new system deployments requires coordination of multiple stakeholders across several departments and divisions that used to operate as stand-alone entities. This drives changes to organizational structure and behavior. Many utilities used cross-functional, interdepartmental project implementation teams to plan and monitor deployment activities. Many developed detailed process maps to streamline operating procedures; guide vendors, installers, and service technicians; and provide higher-quality customer services and issues resolution. They also trained staff on both new and old systems and specified integration requirements for vendors bidding on system development projects.

Getting buy-in from senior management and other utility staff members is critical to success. Approvals play an important role in securing appropriate levels of funding and labor resources. The utilities found that this generally involved ongoing activities and regular updates and was not accomplished all at once at the outset of projects.

Smart grid implementation often results in new ways of doing business and engaging with customers. Many of the SGIG projects made organizational changes in metering, customer service, marketing, and distribution operations, particularly in areas that require enhanced levels of integration of both new information systems and job functions. In

many instances, these changes involved workforce training programs to develop new skillsets in areas such as database management, data analytics and visualization, interoperability, and cybersecurity.

Installing a synchrophasor system across an interconnection requires significant interaction among stakeholders. Operators must be engaged early to ensure that all components of the system perform their functions properly and interoperate to form a complete wide-area monitoring system. Common language and naming standards are needed. Project teams should schedule adequate time for partnership agreements.

5.2 | Workforce Training and Expertise Development

Education and training programs for headquarters and field staff about the requirements of the new devices and systems are essential. The utilities found implementation of FLISR systems resulted in significant process changes that require greater expertise in information systems, database management, and grid analytics. AMI and DA implementation often required learning new tools and techniques for smart meter data analytics and visualization, particularly in new areas such as electricity theft detection, and for outage detection and notification and voltage-level monitoring. To increase acceptance and capitalize on synchrophasor investments, operators and engineers must be sufficiently engaged, trained, and committed to working with new synchrophasor data and potential applications. Significant engagement is needed to build awareness of the value synchrophasors can provide to their mission.

Use of cross-functional teams helped several of the utilities to find multi-disciplinary solutions. Technical teams of software and hardware engineers, data analysts, and business process specialists were typically required for success. Several utilities found field staff required the most time and attention to learn new equipment capabilities and gain confidence in its proper operations.

5.3 | Evaluating Communication System Requirements

Communications networks are foundational investments, and there is great value in designing communications systems upgrades that meet the bandwidth, latency, and capacity requirements to serve multiple existing and future smart grid applications. One of the core technologies for synchrophasors, DA, and AMI are communications networks that are capable of processing large volumes of data and accomplishing automated controls. By attempting to realize synergies in communications strategies, some projects can leverage resources and minimize training requirements, vendor interactions, information technology interfaces, software solutions, and systems integration requirements. In leveraging resources, the utilities were able to use the same networks for backhauling load data from smart meters to meter data management systems and for pinging meters during outages to determine which customers were without power.

Utilities would benefit from comprehensive evaluations for communications requirements from the start of project planning that also considers future applications. Less-than-robust radio communications can interfere with distribution automation operations. The two-way communications network must have sufficient coverage and capacity to interface and interoperate with a wide variety of technologies and systems, including various field devices and DMS, OMS, and SCADA systems. Most of the utilities chose to process meter readings at least every 60 minutes for every customer, stretching the limits of existing corporate communications networks and data management capabilities.

High-bandwidth communications networks can not only enable a smart grid, but also support smart cities. Several public power utilities have adopted long-term, comprehensive approaches to smart grid planning that include building communications networks with the capacity to integrate future smart grid applications *and* to provide city services other than electricity, such as metering for gas and water or high-speed internet access to promote business development. These investments lay the groundwork for smart applications in other sectors and allow the city to extract more value out of investments in communications infrastructure.

Designing and maintaining a low-latency communications system adequate for synchrophasor data delivery presented challenges. The high bandwidth, high frequency, and sheer volume of PMU data create special requirements when implementing analytics, visualization, and information storage and retrieval. Data delivery requires careful design, particularly because the communications infrastructure for data used in operational applications must be as resilient as the power delivery infrastructure.

5.4 | Data Storage, Analysis, and Visualization

Smart grid technologies produce large volumes of data that require additional processing capabilities. Data processing, warehousing, analysis, and visualization tools were needed, and these required significant resources and planning to develop. Tools, visualization techniques, and dashboards that can summarize the data and turn it into actionable information for grid operators are paramount and need to be considered in in the implementation process.

Build data management requirements into system designs from the start. Make use of data warehouses (for enterprise data) and data historians (for operation data) and establish policies for data storage, retention, access, and security. Many of the utilities used data historian software to support integration efforts and enable engineers and technicians to view distribution system information in real time. Data historians function as both data warehouses and analysis platforms for time series data generated from SCADA and distribution management systems.

5.5 | Systems Integration

Integration of new and legacy systems such as SCADA was a consistent challenge for virtually all of the utilities. While it is difficult to propose a one-size-fits-all solution for this challenge, several utilities favored making enhancements to existing systems when possible, or making incremental upgrades rather than substituting new systems.

Turn-key solutions were not generally available for the SGIG utilities. Most of the SGIG DA utilities functioned as test beds and in many cases assisted vendors in identifying fixes for subsequent equipment upgrades. In general, these experiences reflected the ongoing evolution of the industry at the time. Some issues were unknown before SGIG deployments and became evident only when large-scale deployments occurred.

Interoperability among technologies and systems is paramount, and often requires extra testing, coding, and systems development. Avoid investing in equipment that cannot interface easily with other devices, or requires excessive amounts of customized solutions. Conducting simulation modeling and system and equipment testing proved essential in reducing deployment errors, because testing validated interoperability and network connections. Smart grid deployments require additional steps and considerations that do not necessarily follow traditional utility asset management practices.

AMI became an essential aspect of service restoration activities and OMS operations for the many SGIG projects that implemented both DA and AMI. Last-gasp meter alerts enable grid operators to identify outage locations and dispatch repair crews to the precise locations where they are needed. Some utilities used GIS to create detailed outage maps, and some of these cases were posted on utility websites to keep the public and local media informed with service restoration progress.

In many cases, solutions for integrating meter data with other systems and functions required additional development to provide software fixes after the fact, which often resulted in unexpected costs and schedule delays. The majority of projects reported that this was one of the most important lessons learned about investments in AMI and customer systems.

Not all utilities are in a position to take on the challenges and integrate AMI with OMS, DMS, SCADA, GIS, and other distribution operations systems. While last-gasp alerts and meter pinging capabilities are available for all smart meter deployments, there are systems integration issues to tackle in making full use of them. **Utilities facing regular and severe weather events, and storm-induced outages, have greater incentives for using AMI for outage management than those that do not.** Several of the SGIG projects implemented major recovery operations following Hurricane Irene in 2011 and Superstorm Sandy in 2012. SGIG projects in the Mid-Atlantic and Northeastern states reported using AMI to support restoration efforts following these devastating storms.

Integrating a large number and variety of devices such as PMUs, PDCs, precise time clocks, and communications system components into a cohesive system is a challenging task. This task is further compounded when using equipment and protocols that do not meet accepted standards. Off-the-shelf hardware and standard communications protocols should be used whenever possible to improve system integration capability and reduce cost.

5.6 | Equipment and Software Testing and Modeling

Plan for both laboratory and field tests of all DA technologies and systems. Simulations did not catch all of the problems experienced during field operations. Extensive operational experience is also often needed before wider system deployment of new technologies and capabilities. For example, automatic switching reconfigures circuit boundaries, which can complicate the coordination of field crews during major storms. As a result, some utilities disable FLISR operations during storm events. The utilities believe this is an indicator of the need for them to gain further experience before expanding deployments.

Project plans must allow for technology evolution as well as changes in standards and regulatory requirements. For some projects, lack of technology maturity of equipment and software required continuous testing, improvements, and software updates. It was helpful to build testing and refinement periods into project schedules.

Automated devices typically need more frequent firmware and software upgrades than traditional utility equipment. Standard templates from vendors typically require customization to meet each utility's unique distribution system configurations and integrate effectively with existing SCADA systems, OMS, and DMS. As a result, more frequent field tests and evaluations were often required.

PMUs and associated intelligent components evolve at much faster rates than more traditional transmission equipment and should be planned for accordingly. PMU applications should be scalable and adaptable as the technology becomes more widespread.

New continuing maintenance processes and practices were essential for SGIG utilities. For example, battery failures are among the most common maintenance issues; addressing this often requires adding redundant power sources and implementing proactive battery replacement programs. Equipment condition monitoring devices can be deployed for remote evaluations.

5.7 | Cybersecurity

Make cybersecurity part of the company culture. A good cybersecurity plan can drive best practices and sharing of lessons learned, help to allocate resources, help to streamline regulatory structure, and create a common vocabulary to facilitate dialogue. A company should detail roles, responsibilities, and authorities of each party and maintain an organizational chain of accountability to senior management. Making the plan a living document can adapt to changing project needs and the ever-evolving threat environment.

Obtain management support. Support for cybersecurity must come from the top to ensure the cybersecurity program's success. Management support must be gained upfront and executives kept informed throughout the project. Business benefits must be explained to executives at each stage to inform their decision making.

Plan carefully. Developing cybersecurity-specific procurement contract language when procuring systems, products, and related services can prevent multiple potential issues from arising. Establishing a secure, compliant, trusted communication channel early facilitates the exchange of sensitive information. To the extent possible, systems must have upgrade capability to meet future requirements but should also strive for simplicity. Cybersecurity should not be addressed in a vacuum but rather needs to complement the major goal (i.e., maintaining a safe and reliable electric grid).

Strive to stay ahead of the trends. The cybersecurity program should be designed to support emerging smart grid cybersecurity standards. Consideration should be given to interoperability as well as device security. Utilities can learn from their peers' experiences in trends in technologies and their implementation. Becoming active in national groups to share information can help utilities stay abreast of new developments.

Actively engage and inform the customer. Communication with the customer must be a priority (e.g., contract, bill of rights, security communication, benefits to customers). Communications should specify what information is being collected and why to alleviate customer concerns. Utilities must correct misinformation and provide accurate privacy information to consumers. Utilities should undertake educational campaigns and make effective communication with customers an ongoing responsibility.

Learn from other utility cybersecurity deployments. Utilities can benefit from sharing their lessons on assessing, identifying, and mitigating risks at each stage of the development lifecycle. Taking the time for lessons learned during the pilot phase prior to full production and rollout can help ease transition to the implementation phase. Adherence to relevant cybersecurity standards and/or best practices provides a smoother implementation path.

5.8 | Consumer Engagement and Education

Several utilities found devices such as PCTs effective in assisting customers and utilities to achieve reliable peak demand reductions. IHDs were less helpful, and in many cases, participating customers declined to use them. Technical issues with their operations, including interoperability problems with smart meters, affected IHD effectiveness. At least one IHD manufacturer decided to stop making and supporting their product midway through

the SGIG program. This decision reflects the relative immaturity of the market for customer systems, and many vendors are in the process of developing new tools for customers that involve mobile phones and computers for conveying smart meter data about consumption and costs.

Conducting outreach and education for customers was valuable to encourage their involvement in web portal feedback programs and tools, and to raise awareness about smart meter deployments and counter misinformation about health effects and data privacy. Outreach efforts typically began early in the project and included educational programs with video and mailing components. Customer service representatives received focused training to effectively address customer questions and concerns. Public meetings with community groups increased the understanding of the utilities about customer needs and concerns, and enabled informative dialogs and discussions.

Utilities that tested electric vehicle charging stations found it valuable to educate not only customers but also auto dealerships, vendors, host sites, local officials, installation contractors, and others on the program and technology prior to implementation. Many initially installed a small number of chargers as demonstrations, and evaluated their use to justify larger deployments. They considered the needs of the different target markets—such as single families, multi-family housing units, fleets, employers, dealerships, and public access—and evaluated use cases for each that examine the charging patterns of those users.

6 | FUTURE DIRECTIONS AND NEXT STEPS

The SGIG program accelerated grid modernization at a critical time and demonstrated that smart grid technologies can deliver substantial benefits and cost savings to utilities and consumers alike. Yet the United States is still on the cusp of a significant transformation in the way electricity is made, sold, delivered, and stored. As the cost of customer-based and distributed generation decreases and the energy mix changes, fully modernizing the nation's entire electric transmission and distribution grid will become an even greater priority, requiring substantial additional stakeholder investment and commitment. The Electric Power Research Institute (EPRI) and others estimate this will require $338–$476 billion of new investment (in addition to investments for reliability and replacement) through 2030.[93] DOE's 2015 *Quadrennial Energy Review* (QER) recognized that continued investments in energy efficiency and smart grid technologies contribute to enhanced resilience, reduced pollution, and operational flexibility for utilities and customers over the years to come.[94]

This chapter examines how SGIG utilities plan to continue implementing smart grid over the next several years, and the next frontier of technology challenges and priorities for the industry as a whole for grid modernization in the decades to come.

6.1 | Expected Follow-On Investments for SGIG Utilities

While the combined industry and government investment of $7.9 billion was substantial, these investments represent a relatively small portion of the total level of investment that the electric power industry is expected to contribute towards grid modernization over the next several decades. For many participating utilities, the SGIG projects accelerated the early stages of larger, long-term strategies for smart grid investment.

In fact, most SGIG projects were explicitly designed to *jumpstart* grid modernization by enabling many utilities to conduct integration tests and explore smart grid technology costs and performance on a limited portion of their systems. The majority of SGIG utilities testing distribution automation capabilities deployed technologies and systems that covered 20 percent or less of their service territories. While just over half of the utilities deploying AMI had full-scale deployments, the remainder tested AMI at pilot or partial scales.

Based on the scale of their SGIG projects and their project successes, many utilities are planning to follow their SGIG projects with investments to either 1) **expand technology deployments** to more customers and greater service territories, or 2) **leverage untapped capabilities in their existing smart grid technologies** by further integrating installed smart grid technologies with communications, data management, and control systems.

AMI

Many utilities that participated in AMI projects plan to expand smart meter deployments system-wide. Several public power utilities are planning to expand smart metering to cover their other services like water and gas metering. With ongoing water shortages in California, utilities there are moving toward using smart meters to track water consumption.

[93] Electric Power Research Institute, *Estimating the Costs and Benefits of the Smart Grid* (2011).
[94] DOE, *Quadrennial Energy Review: First Installment*, Chapter III: Modernizing the Electric Grid (April 2015).

Distribution

Most utilities only partially deployed distribution automation, and now plan to use project results to prioritize modernization of additional substations and feeders. Many utilities are upgrading the worst performing substations and feeders first, or those feeders serving critical customers with high reliability requirements. Several SGIG utilities are also planning to add DA capabilities to existing deployments by upgrading communications capacity, enabling them to use DA functions embedded in existing devices and management systems.

A few SGIG projects explored using communications and controls for demand-side technologies beyond residences, such as ice storage systems for commercial buildings, load control devices for agricultural irrigation pumps, and demand management software for commercial and industrial energy management systems. DOE expects more utilities, developers, and vendors to expand the use of SGIG-enabled communications platforms to accomplish demand management objectives beyond the residential sector.

Based on the results of their projects, several SGIG utilities plan to implement centralized DMS with models of grid operations that are updated continuously based on changes in grid conditions. Other utilities are moving toward more decentralized outage management and equipment maintenance. These organizations plan to build on SGIG investments in information systems to equip field crews with more data and information for conducting maintenance, repair, and service restoration activities. Some of the SGIG municipal utilities are leveraging investments in high-bandwidth, low-latency communications.

Transmission

In the transmission system, several SGIG utilities plan to increase the density of PMUs to achieve full system coverage, further expand high-bandwidth communication systems to support PMU data transfer and management, and invest in new data management, visualization, and analysis systems.

Transmission system operators will also continue to integrate synchrophasor data into planning and operating decisions and leverage unused capabilities to extract more value from the technology. At this time, 11 of the 13 participants are using PMU data to inform power systems planning, and 12 are using the data to inform power systems operations. Most participants can expand their applications of synchrophasor technologies as they continue to build familiarity and incorporate new procedures—an elaborate and time consuming process that involves thoroughly validating the procedure over time to account for seasonal changes of systems conditions. Currently, 5 of the ARRA participants have formally implemented new procedures.

Customer Systems

AMI utilities are also planning to implement new TOU rates to encourage customers to shift consumption to off-peak periods. Several of the SGIG CBS utilities are evaluating the results of their studies to inform decisions about wider implementation of dynamic pricing programs.

6.2 | Smart Grid Technology Development Challenges

Achieving the promise of the work begun by the SGIG program demands ongoing initiatives to replace aging grid assets; develop and deploy advanced technologies, tools, and techniques; and examine technology, policy, market, and institutional barriers to private sector investments and next-generation grid operation. DOE's 2015 *Quadrennial Technology Review* cited several significant economic, environmental, security, and competitiveness challenges

relative to energy systems today. Lessons learned from SGIG align with the QTR's analysis of the challenges and technology needs for continued smart grid advancement. Several factors will shape the future of grid modernization:

Vast amounts of new data will require a new class of monitoring, control, and analytic capabilities to unlock the full value of smart grid technologies. Smart meters, PMUs, and other devices deliver extremely timely and granular data at large volumes that will require utilities to invest in high-bandwidth communications networks and advanced data analytics to transform data points into information that can be used to better automate controls and inform operator decisions. This advanced monitoring and control will be paramount to integrate large amounts of variable generation and reduce susceptibility of the system to destabilizing events. Specific technology needs include:

- **New data management, visualization, and analysis tools are needed that can use large volumes of data from PMUs in the transmission system and other smart sensors in the distribution system.** As measurement technologies improve, the analytical processing time also needs to be reduced—from tens of seconds to subseconds—to move from monitoring and visualization to automated controls. For example, the use of PMU data for automated, coordinated, system-level control remains an area of research rather than practice. System flexibility will increase as transmission operators have a wider array of sources to keep the system in balance, including spinning reserves, existing generator ramping capability, power flows between balancing areas, demand response, energy storage, and distributed energy resources. Leveraging these resources requires adequate sensors, coupled with sufficient data analysis and visualization to enable rapid operator decision-making or automated response.
- **Coupling high-resolution data streams with computational advances will enable faster, predictive capabilities as the distribution system becomes more complex, with more points of control, and load becomes less predictable.** Advanced software and models are needed to provide robust "real-time" monitoring and detection, help operators interpret and visualize data, predict conditions, and enable faster operator or automated control and mitigation to ensure reliability and safety. Synchrophasor technologies in particular provide high-speed granular data, offering benefits that are still currently constrained by the operator's ability to visualizer, interpret, and respond to the events—typically on the order of tens of seconds or minutes.
- **Fast, high-resolution, low-cost sensors for the distribution system—such as micro-synchrophasors or distribution synchrophasors—will be needed to ensure reliability and power quality as more distributed energy resources are deployed.** Currently, most distribution system operators have limited visibility into the conditions and state of the system, with the exception of distribution substation assets. Visibility deep into the system (e.g., along feeders to utility meters and possibly into buildings) is needed to enable advanced applications.
- **Further advancement is needed in the control systems, algorithms, and grid models that utilize new data streams.** More rapid and precise control of the electric power system is needed to manage the changing generation mix. Emerging control systems must coordinate and manage distributed resources across the entire system, from load to balancing area. Broad coordination adds complexity, and expands the number of control actions to be considered. High-fidelity models, tools, and simulators that are user-friendly and accessible to decision makers will also be needed, including a common framework for modeling and co-simulation of tools from disparate technical domains (e.g., power flow, communications, and markets).
- **Resilient and adaptive control systems with secure, low-latency communications networks will be needed to maintain strong physical and cyber security of the grid.** Reliable electricity operations will increasingly require high-speed data transfer with precise timing, and therefore may not tolerate the latency that might

be injected by encryption or other security measures. Increased use of distributed energy resources and smart controls in end-use devices requires new levels of data communication and coordination deployed down through the distribution system and to the end user.

Regulators and utilities must be ready as new utility business models, system architectures, and planning requirements emerge from increased grid modernization and DER integration. Large saturation of DERs in certain areas will require new approaches to long-term utility planning, regulation, and markets that can maintain reliability while involving consumers and third-parties in electricity management and generation. Policy decisions on renewable energy and DER adoption will need to consider the impact on grid operations and ensure grid modernization efforts can keep pace. As distributed generation and customer market participation proliferate, these trends may create new technical requirements for the power grid and redefine its fundamental design and operational structures. Energy storage may help to balance supply and demand and better integrate a changing generation mix, but will require a control architecture that optimally integrates storage as a resource. Critical changes are needed in the structure of controls systems, coordination frameworks, communications, and overall industry structure. It is imperative that changes to these deeply interconnected systems, models, and architectures are managed in coordination.

DOE can continue to support grid modernization by using its convening powers to support industry information sharing; continue supporting research, development, and demonstration efforts; encourage cybersecurity and interoperability standards work; and support universities, consultants, and electric industry members that are developing and enhancing devices, models, and applications. By continuing to act as an engine to drive innovation, technology development, and adoption, DOE can ensure technical hurdles are overcome. Likewise, as a cross-industry mediator and government-wide leader, DOE can also help address key policy and regulatory barriers.

6.3 | Next Steps

With the energy landscape in the United States undergoing fundamental and historic change, DOE continues to see a secure, resilient, and reliable U.S. electric grid as a critical component of our nation's infrastructure. The SGIG program has helped to lay significant groundwork toward nationwide modernization. The program's legacy includes not only wide-scale deployment but a wealth of experience in smart grid technology: information for decision makers, lessons learned by deploying utilities, more mature products, and a more experienced vendor community.

DOE has already begun to build on these successes. In January 2016, the Department announced a comprehensive new Grid Modernization Multi-Year Program Plan to follow through on the needs and opportunities identified in the first installment of the QER, released in April 2015.[95] A blueprint for modernizing the grid, the new program will invest up to $220 million in 80 grid modernization projects at the National Laboratories supporting critical R&D in advanced storage systems, clean energy integration, standards and test procedures, and other key grid modernization areas.[96]

While the first installment of the QER examined North American energy transmission, storage, and distribution infrastructure, the second installment will examine the electric system from generation to end use, including a more comprehensive look at smart grid components.[97] These and other efforts will continue DOE's commitment to a modern, secure and reliable electricity system for the 21st century.

[95] DOE, *Quadrennial Energy Review: Energy Transmission, Storage, and Distribution Infrastructure* (April 2015).
[96] DOE, "DOE Announces $220 Million in Grid Modernization Funding" (January 14, 2016).
[97] DOE, "QER 1.2: An Integrated Study of the U.S. Electricity System," Stakeholder Briefing Memo (February 4, 2016).

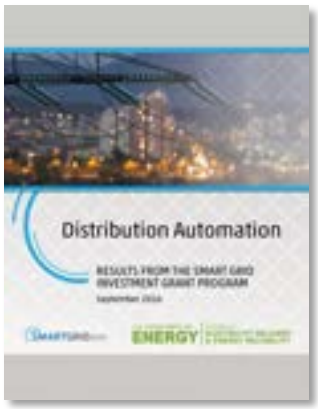
APPENDIX A. SGIG PROJECT INFORMATION, CASE STUDIES, AND KEY REPORTS

Final Reports on SGIG Technology Advancement



Advancement of Synchrophasor Technology in Projects Funded by the American Recovery and Reinvestment Act of 2009

2016



Distribution Automation: Results from the Smart Grid Investment Grant Program

2016



Advanced Metering Infrastructure and Customer Systems: Results from the Smart Grid Investment Grant Program

2016



Customer Acceptance, Retention, and Response to Time-Based Rates from the Consumer Behavior Studies

2016

SGIG Program Interim Progress Reports



Smart Grid Investment Grant Progress Report 2013

September 2013



Economic Impact of Recovery Act Investments in Smart Grid

March 2013



Smart Grid Investment Grant Progress Report 2012

July 2012

SGIG Project Information and Links to Project Pages

Table Legend: AMI – Advanced Metering Infrastructure • CS – Customer Systems • EDS – Electric Distribution Systems • ETS – Electric Transmission Systems

Note: Asterisks after recipient names indicate projects that conducted Consumer Behavior Studies

	Project Funding			Project Type			
SGIG Project Recipient	Federal	Recipient	Total	AMI	CS	EDS	ETS
American Transmission Company (I) Project Webpage | Project Factsheet	1,330,825	1,330,825	2,661,650				•
American Transmission Company (II) Project Webpage | Project Factsheet	10,890,156	10,890,156	21,780,311				•
Avista Utilities Project Webpage | Project Factsheet	20,000,000	20,128,642	40,128,642			•	
Baltimore Gas & Electric Company Project Webpage | Project Factsheet	200,000,000	259,353,902	459,353,902	•	•		
Black Hills Corporation/Colorado Electric Project Webpage | Project Factsheet	5,507,288	5,507,290	11,014,578	•	•		
Black Hills Power Project Webpage | Project Factsheet	9,322,632	9,322,636	18,645,268	•			
Burbank Water and Power, California Project Webpage | Project Factsheet	20,000,000	30,934,209	50,934,209	•	•	•	
CenterPoint Energy Houston Electric Project Webpage | Project Factsheet	200,000,000	445,295,595	645,295,595	•	•	•	
Central Lincoln People's Utility District Project Webpage | Project Factsheet	9,601,696	9,601,700	19,203,396	•	•	•	
Central Maine Power Company Project Webpage | Project Factsheet	95,369,154	96,347,461	191,716,615	•	•		
Cheyenne Light, Fuel and Power Company Project Webpage | Project Factsheet	3,881,070	3,881,070	7,762,140	•			
City of Anaheim Public Utilities Department Project Webpage | Project Factsheet	5,368,182	5,700,233	11,068,415	•		•	
City of Auburn, Indiana Project Webpage | Project Factsheet	2,075,080	2,096,294	4,171,374	•	•	•	
City of Fort Collins Utilities Project Webpage | Project Factsheet	18,101,263	18,161,679	36,262,942	•	•	•	
City of Fulton, Missouri Project Webpage | Project Factsheet	1,502,370	1,502,370	3,004,740	•	•		
City of Leesburg, Florida Project Webpage | Project Factsheet	9,748,811	9,838,445	19,587,256	•	•	•	

SGIG Project Recipient	Project Funding			Project Type			
	Federal	Recipient	Total	AMI	CS	EDS	ETS
City of Naperville, Illinois Project Webpage | Project Factsheet	10,994,110	10,994,110	21,988,220	•	•	•	
City of Quincy, Florida Project Webpage	890,355	890,355	1,780,710	•	•		
City of Ruston, Louisiana Project Webpage | Project Factsheet	4,331,650	4,435,635	8,767,285	•	•	•	
City of Tallahassee, Florida Project Webpage | Project Factsheet	7,512,953	7,512,953	15,025,907		•	•	
City of Wadsworth, Ohio Project Webpage | Project Factsheet	5,298,071	5,298,070	10,596,141	•	•	•	
Cleco Power Project Webpage | Project Factsheet	20,000,000	41,786,724	61,786,724	•			
Cobb Electric Membership Corporation Project Webpage | Project Factsheet	15,805,175	15,805,174	31,610,349	•	•		
Connecticut Municipal Electric Energy Cooperative Project Webpage | Project Factsheet	9,188,050	9,188,050	18,376,100	•	•	•	
Consolidated Edison Company of New York Project Webpage | Project Factsheet	136,029,089	136,029,089	272,058,177			•	
Cuming County Public Power District Project Webpage | Project Factsheet	1,874,994	1,874,994	3,749,988		•	•	
Denton County Electric Cooperative Project Webpage | Project Factsheet	17,205,843	23,862,310	41,068,153	•	•	•	
Detroit Edison Company* Project Webpage | Project Factsheet	83,828,878	90,674,664	174,503,542	•	•	•	
Duke Energy Business Services Project Webpage | Project Factsheet	200,000,000	364,618,749	564,618,749	•	•	•	
Duke Energy Carolinas Project Webpage | Project Factsheet	3,826,954	3,826,954	7,653,909				•
El Paso Electric Project Webpage | Project Factsheet	958,339	1,116,448	2,074,787			•	
Electric Power Board of Chattanooga, Tennessee Project Webpage | Project Factsheet	111,567,606	120,651,744	232,219,350	•	•	•	
Entergy New Orleans Project Webpage | Project Factsheet	4,854,510	4,854,510	9,709,019	•	•		
Entergy Services Project Webpage | Project Factsheet	4,610,383	4,611,201	9,221,584				•
FirstEnergy Corporation* Project Webpage | Project Factsheet	57,470,137	57,913,512	115,383,649	•	•	•	

SGIG Project Recipient	Project Funding			Project Type			
	Federal	Recipient	Total	AMI	CS	EDS	ETS
Florida Power & Light Company Project Webpage | Project Factsheet	200,000,000	378,973,324	578,973,324	•	•	•	•
Georgia System Operations Corporation Project Webpage | Project Factsheet	6,456,500	7,888,474	14,344,974				•
Glendale Water & Power Company, California Project Webpage | Project Factsheet	20,000,000	31,302,105	51,302,105	•	•	•	
Golden Spread Electric Cooperative Project Webpage | Project Factsheet	17,263,115	26,839,006	44,102,121	•	•	•	
Guam Power Authority Project Webpage | Project Factsheet	16,603,507	16,610,249	33,213,756	•	•	•	
Hawaii Electric Company Project Webpage | Project Factsheet	5,117,412	5,117,412	10,234,824			•	
Honeywell International Project Webpage | **Project Factsheet**	11,384,363	11,384,363	22,768,726		•		
Idaho Power Company Project Webpage | Project Factsheet	47,000,000	51,270,406	98,270,406	•	•	•	•
Indianapolis Power & Light Company Project Webpage | Project Factsheet	20,000,000	32,700,849	52,700,849	•	•	•	
Iowa Association of Municipal Utilities Project Webpage | Project Factsheet	2,754,628	4,147,855	6,902,483	•	•		
ISO-New England Project Webpage | Project Factsheet	5,955,740	7,939,107	13,894,847				•
Jacksonville Electric Authority Project Webpage | Project Factsheet	12,875,857	13,016,192	25,892,049	•	•		
Knoxville Utilities Board Project Webpage | Project Factsheet	3,585,022	3,894,439	7,479,461	•	•	•	
Lafayette Consolidated Government Project Webpage | Project Factsheet	11,098,802	11,098,802	22,197,604	•	•	•	•
Lakeland Electric* Project Webpage | Project Factsheet	14,849,998	20,231,502	35,081,500	•	•		
M2M Communications Project Webpage | Project Factsheet	2,171,710	2,171,710	4,343,420		•		
Madison Gas and Electric Company Project Webpage | Project Factsheet	5,550,938	5,550,941	11,101,879	•		•	
Marblehead Municipal Light Department* Project Webpage | Project Factsheet	1,346,174	1,473,266	2,819,440	•	•		
Memphis Light, Gas, and Water Division Project Webpage | Project Factsheet	5,063,469	6,420,486	11,483,955			•	

SGIG Project Recipient	Project Funding			Project Type			
	Federal	Recipient	Total	AMI	CS	EDS	ETS
Midwest Energy Project Webpage | Project Factsheet	712,257	712,257	1,424,514				•
Midwest Independent Transmission System Operator Project Webpage | Project Factsheet	16,578,596	16,578,595	33,157,191				•
Minnesota Power* Project Webpage | Project Factsheet	1,544,004	1,547,765	3,091,769	•	•	•	
Modesto Irrigation District Project Webpage | Project Factsheet	1,493,149	2,001,958	3,495,107	•	•	•	
Municipal Electric Authority of Georgia Project Webpage	12,267,350	12,267,350	24,534,700			•	•
Navajo Tribal Utility Authority Project Webpage | Project Factsheet	4,991,750	6,611,825	11,603,575	•			
New Hampshire Electric Cooperative Project Webpage | Project Factsheet	15,210,656	18,882,348	34,093,004	•	•		
New York Independent System Operator Project Webpage | Project Factsheet	35,138,211	35,198,192	70,336,403				•
Northern Virginia Electric Cooperative Project Webpage | Project Factsheet	4,999,997	5,000,000	9,999,997			•	
NSTAR Electric Company Project Webpage | Project Factsheet	10,061,882	10,203,795	20,265,677			•	
NV Energy* Project Webpage | Project Factsheet	138,877,906	138,877,906	277,755,812	•	•		
Oklahoma Gas & Electric Company* Project Webpage | Project Factsheet	130,000,000	204,914,444	334,914,444	•	•	•	
Pacific Northwest Generating Cooperative Project Webpage | Project Factsheet	19,576,743	19,576,743	39,153,486	•	•		
PECO Energy Company Project Webpage | Project Factsheet	200,000,000	215,118,676	415,118,676	•	•	•	
PJM Interconnection Project Webpage | Project Factsheet	13,688,509	13,711,210	27,399,719				•
Pepco – Atlantic City Electric Company Project Webpage | Project Factsheet	18,697,069	19,101,718	37,798,787		•	•	
Pepco – District of Columbia Project Webpage | Project Factsheet	44,576,686	48,168,646	92,745,332	•	•	•	
Pepco – Maryland Project Webpage | Project Factsheet	104,771,940	108,565,024	213,336,964	•	•	•	
Powder River Energy Corporation Project Webpage | Project Factsheet	2,554,807	2,998,421	5,553,228			•	

	Project Funding			Project Type			
SGIG Project Recipient	Federal	Recipient	Total	AMI	CS	EDS	ETS
PPL Electric Utilities Project Webpage | Project Factsheet	19,054,516	19,054,516	38,109,032			•	
Progress Energy Service Company (now Duke Energy) Project Webpage | Project Factsheet	200,000,000	326,585,524	526,585,524	•	•	•	•
Public Utility District No. 1 of Snohomish County Project Webpage | Project Factsheet	15,825,817	15,825,817	31,651,634			•	
Qualcomm Atheros Project Webpage | Project Factsheet	3,643,101	3,643,101	7,286,202		•		
Rappahannock Electric Cooperative Project Webpage | Project Factsheet	15,694,096	15,741,778	31,435,874	•	•	•	
Reliant Energy Retail Services Project Webpage | Project Factsheet	19,839,689	28,199,461	48,039,150		•		
Sacramento Municipal Utility District* Project Webpage | Project Factsheet	127,506,261	181,491,890	308,998,151	•	•	•	
Salt River Project Project Webpage | Project Factsheet	56,859,359	57,144,360	114,003,719	•	•		
San Diego Gas & Electric Company Project Webpage | Project Factsheet	28,115,051	31,704,948	59,819,999			•	•
Sioux Valley Energy Project Webpage | Project Factsheet	3,603,593	3,603,594	7,207,187	•	•		
South Kentucky Rural Electric Cooperative Corp. Project Webpage | Project Factsheet	9,538,234	10,606,374	20,144,608	•	•		
South Mississippi Electric Power Association Project Webpage | Project Factsheet	29,804,550	29,989,898	59,794,448	•	•	•	
Southern Company Services Project Webpage | Project Factsheet	164,527,160	198,066,549	362,593,709			•	•
Southwest Transmission Cooperative Project Webpage | Project Factsheet	32,244,485	32,244,485	64,488,970	•	•	•	•
Stanton County Public Power District Project Webpage | Project Factsheet	397,000	397,000	794,000	•			
Talquin Electric Cooperative Project Webpage | Project Factsheet	8,100,000	8,100,000	16,200,000	•	•	•	
Town of Danvers, Massachusetts Project Webpage | Project Factsheet	8,277,567	8,277,567	16,555,134	•	•	•	
Tri-State Electric Membership Corporation Project Webpage | Project Factsheet	1,138,060	1,290,394	2,428,454	•	•		

SGIG Project Recipient	Project Funding			Project Type			
	Federal	Recipient	Total	AMI	CS	EDS	ETS
Vermont Transco* Project Webpage | Project Factsheet	68,883,585	68,883,585	137,767,170	•	•	•	
Vineyard Power Project Webpage | Project Factsheet	376,610	452,837	829,447		•		
Wellsboro Electric Company Project Webpage | Project Factsheet	431,624	542,378	974,002	•	•		
Westar Energy Project Webpage | Project Factsheet	19,041,565	20,667,603	39,709,168	•	•	•	
Western Electricity Coordinating Council (now Peak Reliability) Project Webpage | Project Factsheet	53,890,000	53,890,000	107,780,000				•
Whirlpool Corporation Project Webpage | Project Factsheet	19,115,410	19,546,855	38,662,265		•		
Wisconsin Power and Light Company Project Webpage | Project Factsheet	3,160,651	3,206,658	6,367,309			•	
Woodruff Electric Cooperative Project Webpage | Project Factsheet	2,357,520	2,658,480	5,016,000	•			

Reports on Consumer Behavior Studies



Final Report on Customer Acceptance, Retention, and Response to Time-Based Rates from the Consumer Behavior Studies

November 2016



Interim Report on Customer Acceptance, Retention, and Response to Time-Based Rates from the Consumer Behavior Studies

June 2015



Experiences from the Consumer Behavior Studies on Engaging Customers

September 2014



Analysis of Customer Enrollment Patterns in Time-Based Rate Programs - Initial Results from the SGIG Consumer Behavior

July 2013



[Quantifying the Impacts of Time-Based Rates, Enabling Technology, and Other Treatments in Consumer Behavior Studies: Protocols and Guidelines]

July 2013



[Smart Grid Investment Grant Consumer Behavior Study Analysis: Summary of Utility Studies]

June 2013

CBS Utility Evaluation Reports

Participating Utilities	Evaluation Reports	
	Interim	**Final**
Central Vermont Public Service to "Green Mountain Power" – eEnergy Vermont	Sep 2013	Mar 2015
Detroit Edison – SmartCurrents Home Project	Jan 2014	July 2014
First Energy – Smart Grid Modernization Initiative	May 2013	Jun 2015
Lakeland Electric – Smart Metering Infrastructure Initiative	Feb 2015	Apr 2015
Marblehead Municipal Light Department – Residential Dynamic Pricing Pilot Project	May 2012	Jun 2013
Minnesota Power – AMI Behavioral Research	Mar 2014	Forthcoming
NV Energy – Nevada Dynamic Pricing Trial of the Advanced Services Delivery Project	Dec 2014	Oct 2015
Oklahoma Gas and Electric – Smart Study TOGETHER	Mar 2011	Aug 2012
Sacramento Municipal Utility District – SmartSacramento Project	Oct 2013	Sep 2014
Vermont Transco, LLC – eEnergy Vermont	Oct 2013	Jun 2015

ARRA Smart Grid Project Case Studies

Case Study	ARRA Recipient
Demonstrating Coordinated Resources in the Pacific Northwest (Oct. 2015)	Battelle
Power to the People: Advanced Meter Reading Supports Consumer Programs (Oct. 2015)	NSTAR

Case Study	ARRA Recipient
Renovating the Grid and Revitalizing a Neighborhood (Oct. 2015)	Kansas City Power & Light
Smart Grid Technologies Cut Emissions and Costs in Ohio (Oct. 2015)	AEP Ohio
Spinning a Solution to Momentary Electric Grid Disturbances (Oct. 2015)	Hazle Spindle
Voltage and Power Optimization Saves Energy and Reduces Peak Power (Oct. 2015)	American Electric Power, Battelle, Kansas City Power & Light, National Rural Electric Cooperative Association
East Penn Manufacturing Delivers New Battery Technology for Electrical Grid Support (Oct. 2015)	East Penn
Energy Storage System Firms a Renewable Resource (Oct. 2015)	Public Service Company of New Mexico
Energy Storage with Staying Power (Oct. 2015)	Aquion
Harnessing New Generation and Storage Technologies for the Grid (Oct. 2015)	Center for the Commercialization of Electric Technologies
Improving Efficiency with Dynamic Line Ratings (Oct. 2015)	New York Power Authority
Improving Security in the Growing Smart Energy Corridor (Oct. 2015)	Long Island Power Authority
Making Electricity a Value Proposition for the Consumer (Oct. 2015)	Pecan Street
New Forecasting Tools Enhance Wind Energy Integration in Idaho and Oregon (Sep. 2014)	Idaho Power Company
Automated Demand Response Benefits California Utilities and Commercial/Industrial Customers (Sep. 2014)	Honeywell International
Integrated Smart Grid Provides Wide Range of Benefits in Ohio and the Carolinas (Sep. 2014)	Duke Energy Business Services
Using Smart Grid Technologies to Modernize Distribution Infrastructure in New York (Aug. 2014)	Consolidated Edison Company of New York
Control Center and Data Management Improvements Modernize Bulk Power Operations in Georgia (Aug. 2014)	Georgia System Operations Corporation
Oncor's Pioneering Transmission Dynamic Line Rating Demonstration Lays Foundation for Follow-On Deployments (Apr. 2014)	Oncor
Smart Meter Investments Benefit Rural Customers in Three Southern States (Mar. 2014)	Tri-State Electric Membership Corporation
Smart Meter Investments Yield Positive Results in Maine (Jan. 2014)	Central Maine Power Company

Case Study	ARRA Recipient
Demand Response Defers Investment in New Power Plants in Oklahoma (Apr. 2013)	Oklahoma Gas and Electric Company
Smart Grid Solutions Strengthen Electric Reliability and Customer Services in Florida (Jul. 2012)	Florida Power & Light Company
Critical Peak Pricing Lowers Peak Demands and Electric Bills in South Dakota and Minnesota (Jun. 2012)	Sioux Valley Energy
Transforming Electricity Delivery in Florida (Apr. 2012)	Talquin Electric Cooperative
CenterPoint Energy's Smart Grid Solutions Improve Operating Efficiency and Customer Participation (Mar. 2012)	CenterPoint Energy Houston Electric
Glendale, California Municipal Invests in Smart Grid to Enhance Customer Services and Improve Operational Efficiencies (Mar. 2012)	City of Glendale Water & Power
A "Model-Centric" Approach to Smarter Electric Distribution Systems (Jan. 2012)	Consolidated Edison Company of New York
Building a Smarter Distribution System in Pennsylvania (Jan. 2012)	PPL Electric Utilities
Pacific Northwest - Battelle Smart Grid Demonstration Project 2012 Annual Report (Dec. 2011)	Battelle
Vermont Pursues a Statewide Smart Grid Strategy (Dec. 2011)	Vermont Transco
Agricultural Demand Response Program in California Helps Farmers Reduce Peak Electricity Usage, Operate More Efficiently Year–Round (Dec. 2011)	M2M Communications
At the Forefront of the Smart Grid: Empowering Consumers in Naperville, Illinois (Oct. 2011)	City of Naperville, Illinois
Smarter Meters Help Customers Budget Electric Service Costs (Oct. 2011)	Tri-State Electric Membership Corporation
Synchrophasor Technologies for a Better Grid (Aug. 2011)	American Transmission Company (2 projects); Duke Energy Carolinas LLC; Entergy Services; PJM Interconnection; ISO New England; Midwest Energy; New York Independent System Operator; Western Electricity Coordinating Council
Smart Meter Investments Support Rural Economy in Arkansas (Aug. 2011)	Woodruff Electric
Bright Lights, Big City: A Smarter Grid in New York (Jun. 2011)	Consolidated Edison Company of New York

Case Study	ARRA Recipient
A Smarter Electric Circuit: Electric Power Board of Chattanooga Makes the Switch (Jun. 2011)	Electric Power Board
Reducing Peak Demand to Defer Power Plant Construction in Oklahoma (Jun. 2011)	Oklahoma Gas and Electric Company
A Smart Grid Strategy for Assuring Reliability of the Western Grid (Jun. 2011)	Western Electricity Coordinating Council
National Rural Electric Cooperative Association - Helping America's Electric Cooperatives Build a Smarter Grid to Streamline Operations and Improve Service (May 2011)	National Rural Electric Cooperative Association



Distribution Automation

RESULTS FROM THE SMART GRID INVESTMENT GRANT PROGRAM

September 2016

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U.S. DEPARTMENT OF ENERGY | Office of Electricity Delivery and Energy Reliability

Table of Contents

Executive Summary....4

Major Findings....4

Key Lessons and Conclusions....7

Future Directions and Next Steps....8

1 Distribution Automation Deployment in the Smart Grid Investment Grants....10

1.1 DA Technologies and Functions Deployed in SGIG....11

Distribution Automation Field Devices....14

Communications Networks....15

Information Management and Control Systems....16

1.2 Project Build and Impact Metrics....18

1.3 Key Data Limitations and Considerations....18

2 Major Findings: Reliability and Outage Management....20

2.1 Remote Fault Location, Isolation, and Service Restoration using Automated Feeder Switching....21

Key Result: Measurable Improvements in Reliability....23

Key Result: Reduced Impact, Duration, and Cost of Major Storms and Outage Events....25

Key Result: Operations and Maintenance Efficiency and Savings....28

2.2 Outage Status Monitoring and Notification....31

Key Result: Improved Customer Satisfaction and Public Awareness....32

2.3 Optimized Restoration Dispatch....32

Key Result: Faster, More Targeted, and Safer Restoration....33

Case Study: Northern Virginia Electric Cooperative (NOVEC)....34

Case Study: Electric Power Board of Chattanooga (EPB)....36

Case Study: Duke Energy....40

Case Study: Consolidated Edison (Con Edison)....44

Case Study: CenterPoint Energy....46

Case Study: PPL Electric Utilities Corporation....48

Case Study: Pepco - DC....50

3 Major Findings: Voltage and Reactive Power Management....53

3.1 Integrated Volt/VAR Controls (IVVC) and Automated Voltage Regulation....55

3.2 Conservation Voltage Reduction (CVR)....56

Key Result: System Efficiency Improvements and Fuel Savings....58

Key Result: Reduced Peak Demand....59

3.3 Automated Power Factor Correction....59

Key Result: Improved Power Factors and Better Power Quality....60
Key Result: Deferred Capacity Additions....60
Case Study: Southern Company....61
Case Study: Wisconsin Power and Light Company (WPL)....63
Case Study: Avista Utilities....65
Case Study: Sacramento Municipal Utility District (SMUD)....67
Case Study: Central Lincoln People's Utility District....69

4 Major Findings: Equipment Health Monitoring....71

Key Result: Improved Failure Prediction and Proactive Maintenance Reduce Failure-Related Outages....73
Key Result: Fewer Physical Inspections and Reduced Labor for Maintenance and Repairs....73
Case Study: Florida Power & Light Company (FPL)....74

5 Major Findings: Integration of Distributed Energy Resources....76

5.1 Automated DER Dispatch and Management....77
5.2 Operation of Thermal Energy Storage....78
Case Study: Burbank Water and Power (BWP)....79
Case Study: Glendale Water and Power (GWP)....81

6 Key Lessons and Conclusions....83

6.1 DA Applications Produce Large Volumes of New Data for Processing and Analysis....83
6.2 Standard Protocols for Data Interfaces Were Limited....83
6.3 Extensive Equipment Testing and Customization May Be Required....84
6.4 DA Requires Increased Workforce Training and Expertise....85
6.5 Communications Systems Need Comprehensive Planning for Multiple Smart Grid Functions....85
6.6 Systems Integration is a Critical Element of DA Deployment....87
6.7 Utilities Approached Automation in Distinct Ways....89
6.8 Cybersecurity and Interoperability Are Integral to Smart Grid....91

7 Future Directions and Next Steps....94

7.1 SGIG Utilities Largely Plan to Expand Smart Grid Investments in DA....94
7.2 DA Projects Highlighted Continuing R&D Challenges....95

APPENDIX A. Where to Find Additional Information....98
APPENDIX B. Approach to Data Collection and Analysis....100
APPENDIX C. Supporting Build Metrics Data....105
APPENDIX D. Supporting Impact Metrics Data....108
APPENDIX E. Acronyms and Abbreviations....112

Executive Summary

Across the United States, more than 6 million miles of distribution lines and more than 200,000 distribution circuits provide the critical link between the bulk power grid and 160 million electricity customers.[1] Distribution automation (DA) uses digital sensors and switches with advanced control and communication technologies to automate feeder switching; voltage and equipment health monitoring; and outage, voltage, and reactive power management. Automation can improve the speed, cost, and accuracy of these key distribution functions to deliver reliability improvements and cost savings to customers.

Prior to ARRA, the widespread adoption of DA technology was hampered by a lack of data on performance, cost, and benefits in real-world applications. This report shares key results from the 62 SGIG projects implementing DA technologies and also documents lessons learned on technology installation and implementation strategies. With this report, the U.S. Department of Energy (DOE) aims to further accelerate grid modernization by helping decision makers better assess the benefits and costs of DA investments and learn from leading-edge utilities.

The Smart Grid Investment Grant (SGIG) Program

The American Recovery and Reinvestment Act (ARRA) of 2009 provided DOE with $3.4 billion to invest in 99 SGIG projects to modernize the electric grid, strengthen cybersecurity, improve interoperability, and collect smart grid impact data. Electricity industry recipients matched or exceeded this investment dollar-for-dollar.

Deployment of DA accounted for more than a quarter of the $7.9 billion total SGIG investment. SGIG utilities installed nearly 82,000 smart digital devices to upgrade 6,500 U.S. distribution circuits, including:

DA Asset	Total Installed
Remote Fault Indicators	13,423
Smart Relays	11,033
Automated Feeder Switches	9,107
Automated Capacitors	13,037
Automated Voltage Regulators	10,665
Transformer Monitors	20,263
Automated Feeder Monitors	4,447

Utilities also invested in the high-bandwidth, low-latency communications systems and information management and control systems that form the backbone of DA operations.

Major Findings

SGIG projects demonstrated that DA technologies and systems can achieve substantial grid impacts and benefits that met and often exceeded pre-project expectations, including:

- → **Improved fault location, isolation, and service restoration capabilities** that result in fewer and shorter outages, lower outage costs, reduced equipment failure, and fewer inconveniences for consumers.
- → **Improved distribution system resilience to extreme weather** events by automatically limiting the extent of major outages and improving operator ability to diagnose and repair damaged equipment.

[1] U.S. Energy Information Administration, "Electric power sales, revenue, and energy efficiency: Form EIA-861 detailed data files," Final 2014 data, October 21, 2015.

- → **More effective equipment monitoring and preventative maintenance** that reduces operating costs, enables more efficient use of capital assets, reduces the likelihood of equipment failures, and leads to fewer outages.
- → **More efficient use of repair crews and truck rolls** that reduces operating costs, enables faster service restoration, and lowers environmental emissions.
- → **Improved grid integration of selected distributed energy resources (DER)** such as thermal storage for commercial and municipal buildings.

Each SGIG DA utility installed a distinct set of DA assets, tested different capabilities, and deployed assets at a different scale—enabling each utility to test technology integration and explore costs and performance based on their individual objectives, systems, and experience levels. As a result, utility costs and performance were not directly comparable across all projects. Nonetheless, the SGIG projects produced important findings on DA technology performance and benefits in four key areas: reliability and outage management; voltage and reactive power management; equipment health monitoring, and integration of DER. This report also highlights select projects that exemplify the wide range of DA results and lessons learned.

Reliability and Outage Management

DA reduced the frequency, impact, duration, and cost of major storms and outage events, which significantly improved reliability indices for several utilities.

DA technologies provided advanced capabilities for operators to detect, locate, and diagnose faults. In particular, fault location, isolation, and service restoration (FLISR) technologies can automate power restoration in seconds by automatically isolating faults and switching some customers to adjacent feeders. FLISR can reduce the number of affected customers and customer minutes of interruption *by half* during a feeder outage for certain feeders. Fully automated switching and validation typically resulted in greater reliability improvements than operator-initiated remote switching with manual validation.

Precise fault location enabled operators to dispatch repair crews accurately and notify customers of outage status, which reduced outage length and repair costs, reduced the burden on customers to report outages, and increased customer satisfaction.

Per outage event, FLISR operations:[2]

Reduced number of customers interrupted by 55%

Reduced customer minutes of interruption by 53%

In 2013, 3 utilities reported System Average Interruption Frequency Index (**SAIFI) improvements of 17%-58%** from pre-deployment baselines

DA operations **avoided >197,000 truck rolls**[3] and **3.4 million vehicle miles traveled** from 2011 to 2015[4]

Savings reduced an estimated **2,350 metric tons of CO_2 equivalent**—the same amount produced to power 214 homes for a year[5]

[2] Average per event for FLISR operations reported by five utilities over one year.
[3] Data from 16 reporting SGIG DA utilities from April 2011 to March 2015.
[4] Data from 18 reporting DA utilities from April 2011 to March 2015.
[5] Based on analysis of truck roll data from 18 SGIG DA utilities between April 2011 and March 2015, using U.S. Environmental Protection Agency, "Greenhouse Gas Equivalencies Calculator," last updated April 2014.

DA helped customers avoid outage costs and created operations and maintenance (O&M) efficiencies that led to savings for utilities.

For customers, DA operations during major storms saved one utility's customers on a 14-feeder segment $1.2 million in one year. For utilities, automating functions that previously required field crews to conduct on-site monitoring, maintenance, and repair reduced labor costs, truck rolls, vehicle-miles traveled, and replacement part costs.

FLISR and smart meters at the Electric Power Board of Chattanooga, TN helped operators **restore system-wide power about 17 hours earlier than without DA** after a July 2012 derecho. After another storm in February 2014, EPB was able to **restore power 36 hours faster and reduce affected customers from 70,000 down to 33,000**.

SGIG utilities in total **avoided $6.2 million in distribution operations costs** in about 1 year[6] and **avoided $1.46 million in switching costs** over 3 years[7]

Voltage and Reactive Power Management

Automated voltage regulation and power factor correction enabled utilities to reduce peak demands, more efficiently utilize existing assets, defer capital investments, and improve power quality for the growing digital economy.

Utilities used CVR to reduce feeder voltage levels, improve the efficiency of distribution systems, and reduce energy consumption, especially during peak demand periods.

Automated power factor correction provides grid operators with new capabilities for managing reactive power flows and boosting power quality. Several utilities improved power factors to near unity through integrated volt/volt-ampere reactive controls (IVVC), and one utility reduced reactive power requirements by about 10%-13% over one year.

Several utilities found that **CVR can result in energy savings of 2-4 percent on affected feeders**—a change that when applied system-wide could save hundreds of thousands of dollars in yearly energy costs and reduced environmental emissions

ConEdison **increased its 4kV substation capacity by 2.8 percent** under peak conditions using CVR, resulting in a net **savings of $15.7 million**.

O&M savings from CVR formed the largest portion by far of Duke Energy's 20-year smart grid business case, with a **net-present value of more than $155 million**

Southern Company realized about **$3.4 million in net present-value from deferred distribution capacity investments** by using automated capacitor banks to reduce reactive power loss.

[6] Data from Nine SGIG DA utilities that reported savings from April 2013 to September 2014.
[7] Data from eight SGIG DA utilities that reported savings from April 2011 to March 2014.

Equipment Health Monitoring

Installing sensors on key components (e.g., power lines and transformer banks) to measure equipment health parameters can provide real-time alerts for abnormal equipment conditions as well as analytics that help utility engineers plan preventative equipment maintenance, repair, and replacement.

These technologies and systems also equip grid operators with new capabilities to better dispatch repair crews based on diagnostics data.

Florida Power and Light prevented an outage for 15,000 customers and avoided $1 million in restoration costs by identifying and repairing a transformer before it failed

Several utilities automated monitoring to reduce physical inspections, enable proactive maintenance, and better diagnose equipment failures

Integration of Distributed Energy Resources (DER)

Grid integration of DERs requires advanced tools to monitor and dispatch DERs, and to address new power flow and control issues, such as low-voltage ride through, harmonic injection, voltage fluctuations, and reactive power management. Some SGIG utilities evaluated distributed energy resource management systems (DERMS) and integrated automated dispatch systems (IADS) on small DER installments. A small number also tested thermal energy storage for commercial and government buildings.

Burbank Water and Power in California used DER management systems to control ice storage systems that made ice overnight to power daytime air conditioning loads, which reduced the buildings' cooling requirements by about 5%

Key Lessons and Conclusions

Many DA utilities faced a learning curve that required new business practices, custom solutions, and extensive training and testing. Tackling new technical challenges revealed valuable lessons learned that can help other electric utilities embarking on DA projects:

- **Return on Investment for a Specific Technology or Function is Utility-Specific:** Cost-effectiveness depends on a number of factors, including project scale, the functionality of individual devices, the utility's learning curve, and the need for wholly new software and systems or the ability to retrofit. Larger scale projects saw the most significant results and could better leverage foundational investments in communications infrastructure and information systems integration.
- **DA Applications Produce Large Volumes of New Data for Processing and Analysis**: Installing thousands of smart monitoring devices gave operators unprecedented levels of data to process, store, analyze, error-check, and turn into actionable information. Operators recommended establishing policies for data storage, retention, access, and security from the start.
- **Standard Protocols for Data Interfaces Were Limited**: Ensuring uniform data standards among a wide range of technologies and systems was a challenge. Many utilities used standard protocols to build data interfaces among software applications.

- **Extensive Equipment Testing and Customization May Be Required**: Automated devices typically need more frequent firmware and software upgrades than traditional utility equipment, requiring more frequent field tests and evaluations. Standard templates from vendors also typically require customization to meet each utility's unique distribution system configurations. Many found that lab conditions for testing field device communications did not always accurately represent field conditions.
- **DA Requires Increased Workforce Training and Expertise**: DA brings changes in grid operations that require increased training and expertise for field technicians, engineers, and grid operators, particularly in database management, data analytics, information systems, and cybersecurity.
- **Communications Systems Need Comprehensive Planning for Multiple Smart Grid Functions**: Many utilities attempted to realize synergies in their communications strategies by leveraging new systems for DA, AMI, and other smart grid applications. This requires comprehensive evaluation of communications requirements from the start of project planning.
- **Systems Integration is a Critical Element of DA Deployment**: Multiple information management and control systems all need access to new data streams to effectively accomplish DA functions. Systems integration proved to be one the most significant challenges during DA implementation under SGIG, particularly for those utilities deploying DA equipment for the first time. Integration often required developing customized software for data processing, error checking, and coding.
- **Cybersecurity and Interoperability Are Integral to Smart Grid**: Cybersecurity was a cornerstone of the SGIG program from its onset. Sound cybersecurity policies, plans, and practices were integrated throughout each project lifecycle, including design, procurement, installation, commissioning, and ongoing maintenance and support.

Future Directions and Next Steps

With the SGIG projects complete, the vast majority of SGIG DA utilities are expanding their smaller-scale DA deployments in a phased approach to upgrade more feeders and substations, focusing on poor performers or those that serve critical business needs for reliability. Several also plan to extract more value from existing deployments by upgrading communications capacity, activating unused DA functions embedded in existing devices and management systems, and installing new devices and systems on already automated feeders and substations.

DOE continues to support grid modernization through research, development, demonstration, analysis, and technology transfer activities. While the SGIG program is now complete, grid modernization remains an important national priority. DOE through the Grid Modernization Initiative (GMI) recently released a Grid Modernization Multi-Year Program Plan (MYPP) that describes the challenges and opportunities for achieving a modern, secure, sustainable, and reliable grid and how DOE will help achieve this through programs and activities. The Grid Modernization Lab Consortium, a multi-year collaboration among 14 DOE National Laboratories and regional networks, will enable DOE in developing and implementing the activities in the MYPP. [8]

[8] DOE, Grid Modernization Initiative, *Grid Modernization Multi-Year Program Plan*, November 2015.

DA deployments highlighted several continuing challenges for grid modernization:

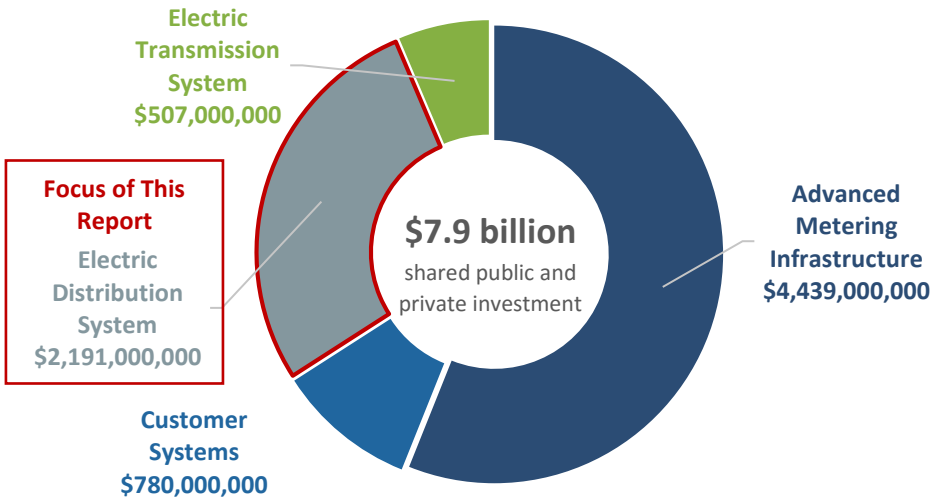
- Improved cybersecurity and interoperability standards, protocols, tools, and techniques for safe, rapid, and cost-effective DA implementation.
- Faster simulation methods and more robust control approaches to operate modern grid systems with large amounts of variable generation.
- High-resolution, low-cost sensors that report real-time conditions along feeders to enhance distribution system operator visibility beyond substation assets.
- Advanced DERMS for integrating distributed and demand-response resources in a coordinated and cost-effective way.
- Advanced grid devices and power electronics, such as solid-state distribution transformers, offer enhanced functionality and flexibility to increase total system efficiency and manage microgrids.
- Lower cost and safer energy storage systems for improved DER integration and distribution system management.

1 Distribution Automation Deployment in the Smart Grid Investment Grants

In 2009, the U.S. Department of Energy (DOE) launched the Smart Grid Investment Grant (SGIG) program—funded with $3.4 billion dollars from the American Recovery and Reinvestment Act (ARRA) of 2009—to jumpstart modernization of the nation's electricity system, strengthen cybersecurity, improve interoperability, and collect an unprecedented level of data on smart grid and customer operations. When matched with an additional $4.5 billion in industry investment, the 99 SGIG projects invested a total of $7.9 billion in new smart grid technology and equipment for transmission, distribution, metering, and customer systems (see Figure 1).

The large public and private investments made under ARRA have accelerated smart grid technology deployments, providing real-world data on technology costs and benefits along with valuable lessons learned and best practices. This report informs electric utilities, policymakers, and other key stakeholders of the qualitative and quantitative impacts, benefits, costs, and lessons learned from SGIG projects that implemented distribution automation (DA). Most SGIG projects began in 2009 and concluded in 2015, making this the final report on DA results from the SGIG program.

Figure 1. Breakdown of $7.9 Billion SGIG Investment



DA investments in the electric distribution system totaled about $2.19 billion—including Recovery Act funds from DOE and cost share from the utilities—accounting for 27 percent of the total SGIG investment. Of the 99 total SGIG recipients, 62 utilities installed and evaluated one or more DA technologies and systems, and reported key results to DOE. (Many of these 62 DA projects also installed new advanced metering infrastructure [AMI] or customer-based technologies and systems. Project results specific to those technologies are reported separately in *Advanced Metering Infrastructure and Customer Systems: Results from the SGIG Program*. Separate SGIG projects that tested transmission system technologies reported results in *Advancement of Synchrophasor Technology in Projects Funded by the American Recovery and Reinvestment Act of 2009*.)

SGIG project funds were used for several purposes: the purchase, testing, and installation of hardware and software; conducting training; implementing cybersecurity protections; systems integration activities; data collection and analysis; and other technical and administrative tasks needed for successful completion of project objectives.

Full descriptions and results of all projects can be found on SmartGrid.gov. This report highlights select projects that exemplify the wide range of results and lessons learned from the SGIG DA projects.

1.1 DA Technologies and Functions Deployed in SGIG

DA applies advanced control and communication technologies and integrates digital controls, switches, and sensors to improve or automate electricity delivery functions that were previously either not possible or were performed using electro-mechanical or manual processes. DA can improve the speed, cost, and accuracy of several key distribution system processes, including fault detection, feeder switching, and outage management; voltage monitoring and control; reactive power management; preventative equipment maintenance for critical substation and feeder line equipment; and grid integration of distributed energy resources (DER). Table 1 describes the four key DA applications and the specific smart grid functions that SGIG utilities tested during the projects.

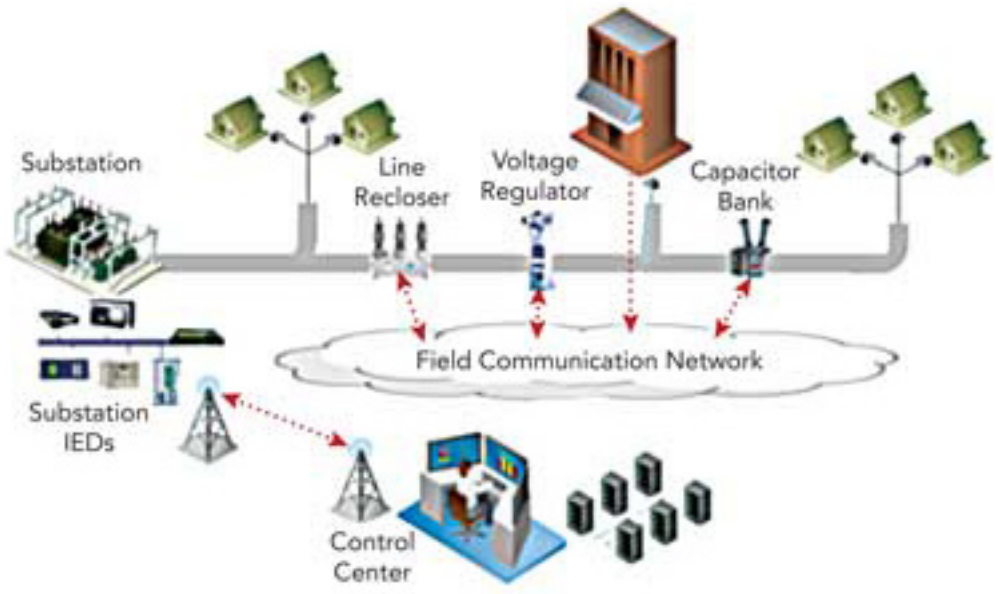
Table 1. SGIG Smart Grid Applications and Functions under DA Projects

DA Application	Specific Smart Grid Functions
Reliability and Outage Management	• Remote fault location and diagnostics • Automated feeder switching • Outage status monitoring and notification • Optimized restoration dispatch
Voltage and Reactive Power Management	• Integrated voltage and volt–ampere reactive (VAR) controls (IVVC) • Automated voltage regulation • Conservation voltage reduction (CVR) • Real-time load balancing • Automated power factor corrections
Asset Health Management	• Real-time or near real-time equipment health monitoring
Distributed Energy Resources (DER) Integration	• Integrated and automated DER dispatching and management • Operation of customer-sited thermal energy storage systems

Achieving these functions required the deployment of advanced field devices, including remote fault indicators, smart relays, automated feeder switches, feeder and transformer monitors, automated capacitors, and automated voltage regulators. These devices can work autonomously or be monitored and controlled via communications networks linked to back-office information management and control

systems (Figure 2[9]). Optimizing the control and performance of DA operations relies heavily on robust communication systems to transmit large volumes of data, and effective systems integration to analyze data and provide actionable information for grid operators.

Figure 2. Illustration of a Distribution Automation System



To implement DA, advanced field devices are typically equipped with radio, wireless, or cellular communication to transmit data to collection points and ultimately back to utility control centers using backhaul communications networks. At the control center, the data is typically integrated into the supervisory control and data acquisition (SCADA) system, distribution management system (DMS), and outage management system (OMS) for processing, analysis, and action, either automatically or by operators. Table 2 outlines the nearly 82,000 DA field devices installed under SGIG.

Table 2. DA Asset Deployments under SGIG Projects

DA Asset	Total # Devices Installed	# of SGIG Utilities Deploying	Range of Installments by SGIG Utilities (Least to Most)
Remote Fault Indicators	13,423	17	3 – 4,755
Smart Relays	11,033	27	4 – 4,755
Automated Feeder Switches	9,107	39	2 – 2,193
Automated Capacitors	13,037	30	2 – 2,098
Automated Voltage Regulators	10,665	21	2 – 3,339
Transformer Monitors	20,263	8	2 – 17,401
Automated Feeder Monitors	4,447	19	2 – 1,583

[9] Robert Uluski, "Developing a Business Case for Distribution Automation," *Electric Light & Power*, June 10, 2013.

Investor-owned utilities, municipal and public power utilities, and electric cooperatives all conducted and reported on SGIG DA projects. Most of the projects focused on testing only select applications, and thus each project installed a different combination of assets and conducted systems integration in different ways. Table 3 shows which devices and systems support each DA applications.

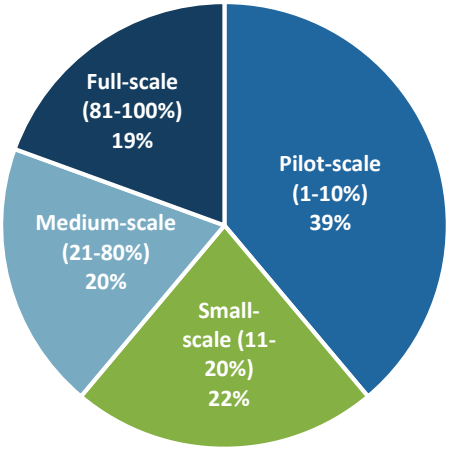
Table 3. Devices and Systems that Support DA Applications

DA Technologies and Systems		DA Applications			
		Reliability and Outage Management	Voltage and Reactive Power Management	Equipment Health Condition Monitoring	DER Integration
Devices	Remote Fault Indicators	•	•		
	Smart Relays	•			
	Automated Feeder Switches (or Reclosers)	•	•		
	Automated Capacitors		•		•
	Automated Voltage Regulators		•		•
	Automated Feeder Monitors	•	•	•	•
	Transformer Monitors			•	
Systems Integration	Communications and Backhaul Systems	•	•	•	•
	SCADA Systems	•	•		
	DMS	•	•	•	•
	Integration with AMI/Smart Meters	•	•	•	•
	OMS, GIS, CIS, Workforce Management Integration	•			

The majority of SGIG DA utilities were primarily interested in integration tests, technology performance evaluation, and cost-benefit analysis before committing to expanded DA deployments. Each utility deployed DA assets at a different scale to achieve distinct evaluation objectives. For example, one project deployed just 2 transformer monitors, while another deployed more than 17,000 (or about 86 percent of total installed by all SGIG projects). About 61 percent of the reporting utilities implemented DA at either a small scale (covering less than 20 percent of feeders) or pilot scale (covering less than 10 percent of feeders).

Just under 20 percent of reporting utilities implemented system-wide deployment of DA assets (covering more than 80 percent of feeders). For the most part, these utilities had previous experience with DA technologies and systems. Figure 3 shows the percentage of SGIG DA utilities that deployed DA assets at each scale.

Figure 3. Extent of SGIG DA Asset Deployments by Percent of Utility System (36 Projects Reporting)



Distribution Automation Field Devices[10]

Remote Fault Indicators

Remote fault indicators are sensors that detect when voltage and current levels on feeders are outside normal operating boundaries. Operators can use this information to rapidly determine the location of a fault (such as an equipment failure or tree contacting a power line), or distinguish between a fault and temporary high loads, such as high motor starting current. Fault indicators can be equipped with visual displays to assist field crews, and connected to communications networks that are integrated with SCADA, OMS or DMS to provide greater accuracy in locating and identifying faults.

Smart Relays

Smart relays apply sophisticated software to accurately detect, isolate, and diagnose the cause of faults. They may be installed in utility substations for feeder protection or on devices in automated switching schemes. Device controls are activated according to equipment settings and algorithms. The relays also store and process data to send back to grid operators and back office systems for further analysis. Recent advances in sensor and relay technologies have improved the detection of high-impedance faults—difficult to detect with conventional relays—that occur when energized power lines contact a foreign object, but such contact only produces a low-fault current.

Automated Feeder Switches and Reclosers

Automated feeder switches open and close to isolate faults and reconfigure faulted segments of the distribution feeder to restore power to customers on line segments without a fault. They are typically configured to work with smart relays to operate in response to control commands from autonomous control packages, distribution management systems, or signals from grid operators.

Switches can also be configured to open and close at predetermined sequences and intervals when fault currents are detected. This action, known as reclosing, is used to interrupt power flow to a feeder that has been impacted by an obstruction and reenergize after the obstruction has cleared itself from the line. Reclosing reduces the likelihood of sustained outages when trees and other objects temporarily contact power lines during storms and high winds.

[10] For additional descriptions of devices, communications networks, and information management systems, see DOE, *Reliability Improvements from the Application of Distribution Automation Technologies – Initial Results*, November 2012.

Automated Capacitors

Utilities use capacitors to compensate for reactive power requirements caused by inductive loads from customer equipment, transformers, or overhead lines. Compensating for reactive power reduces the total amount of power that need to be provided by power plants, resulting in a flatter voltage profile along the feeder, and less energy wasted from electrical losses in the feeder. A distribution capacitor bank consists of a group of capacitors connected together. The capacity of the banks installed on distribution feeders depends on the number of capacitors, and typically ranges from 300 to 1,800 kilovolt-ampere reactive (kVAR). Capacitor banks are mounted on substation structures, distribution poles, or "pad-mounted" in enclosures.

Automated Voltage Regulators and Load Tap Changers

Voltage regulators are types of transformers that make small adjustments to voltage levels in response to changes in load. They are installed in substations (where they are called load tap changers) and along distribution feeders to regulate downstream voltage. Voltage regulators have multiple "raise" and "lower" positions and can automatically adjust according to feeder configurations, loads, and device settings. For example, as load on distribution feeders increases, the amount of voltage drop along those feeders also increases. A voltage regulator on the feeder detects when voltages are above or below target levels and then automatically adjust voltages to stay within the desired range.

Automated Feeder Monitors

Feeder monitors measure load on distribution lines and equipment and can trigger alarms when equipment or line loadings reach potentially damaging levels. Monitors deliver data in near-real time to back office systems and analysis tools so that grid operators can effectively assess loading trends and take corrective switching actions, such as taking equipment offline, transferring load, or repairing equipment when necessary. These field devices are used in coordination with information and control systems to prevent outages from occurring due to equipment failure or overload conditions.

Transformer Monitors

Transformer monitors are equipment health sensors for measuring parameters, such as power transformer insulation oil temperatures, that can reveal possibilities for abnormal operating conditions and premature failures. These devices can be configured to measure different parameters on many types of devices. Typically, these devices are applied on substation transformers and other equipment whose failure would result in significant reliability and cost impacts for utilities and customers.

Communications Networks

Many SGIG utilities expanded the communications networks for distribution systems to acquire large volumes of new data from sensors, process the data, and send control signals with low-latency to operate equipment. Communications networks allow utilities to connect devices to each other and to SCADA, DMS, and other information and control systems, which greatly expands the capabilities of grid operators to manage power flows and address reliability issues.

SGIG utilities leveraged a variety of wired and wireless communications technologies to support their smart grid application. Choosing the most suitable communication technologies and configurations

required utilities to examine multiple requirements, considering all current and future smart technologies that may use the networks:

- Bandwidth
- Latency
- Cost
- Reliability and coverage
- Spectrum availability[11]
- Backup power needs
- Cybersecurity considerations

Most utilities use at least two-layer communication systems to communicate between field devices and information and control systems. Typically, the first layer of the network connects substations and distribution management systems at headquarter locations. Some utilities use existing SCADA communications systems for this layer. Many SGIG utilities chose high-speed, fiber optic or microwave communications systems, while some chose to contract third-party telecommunication vendors for their high speed cellular network.

The second layer of the network typically connects substations with field devices, where most SGIG utilities did not have a legacy system to leverage. Many SGIG utilities chose some form of wireless network for this layer, including radio frequency mesh or Wi-Fi.

Information Management and Control Systems

DMS, OMS, SCADA, and AMI can all play critical roles in automating distribution system functions. Their effective integration is often key to successful DA efforts. For example, OMS and DMS are typically used to integrate various sources of fault information—from line sensors, reclosers, AMI, and customer calls—and display this data on geographic information system (GIS) and SCADA screens for both control room operators and field crews. With low-latency communications networks, this information can be updated in near real time.

DA projects ideally include field device integration with the DMS, which is typically used to monitor the system for feeder and equipment conditions that may contribute to faults and outages, identify faults, and determine optimal switching schemes to restore power to the greatest amount of load or number of customers. DMS deployments can involve varying degrees of sophistication, from data collection and monitoring to highly complex, automated systems capable of independently managing the operation of the distribution system. Greater levels of sophistication and centralized controls are typically associated with producing greater levels of smart grid capabilities.

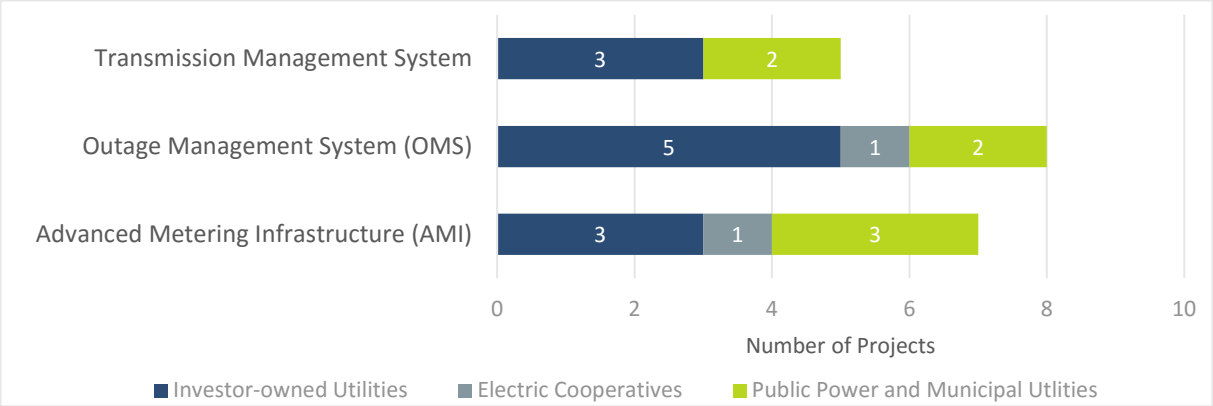
DMS integrate data from sensors, monitors, and other field devices to assess conditions and control the grid. They act as visualization and decision support systems to assist grid operators with monitoring and controlling distribution systems, components, and power flows. DMS can be used to automate or support voltage and volt-ampere reactive (VAR) controls, as well as other activities that increase the

[11] The Federal Communications Commission (FCC) manages and licenses the electromagnetic spectrum for the communications of commercial users and state, county, and local governments, including commercial and non-commercial fixed and mobile wireless services, broadcast television and radio, satellite, and other services. Frequency bands are reserved for different uses. There is a finite amount of spectrum and a growing demand for it. See FCC, "About the Spectrum Dashboard."

efficiency of distribution operations and maintenance. A DMS continuously updates models of the distribution system in near real time so grid operators can better understand distribution system conditions at all times. Changes in system loads, outages, and maintenance issues are typically presented to operators through dashboards and visualization tools.

Fifteen of the SGIG DA utilities reported that they integrated their DMS with one or more additional information management or control systems (see Figure 4).

Figure 4. Number of SGIG DA Utilities that Integrated DMS with Other Types of Information Management and Control Systems (15 utilities reporting)



OMS are information management and visualization tools that analyze outage data and status of protective devices to determine the scope of outages and the likely location of problems. An OMS compiles information on the times and locations of customer calls, smart meter outage notifications, and fault data from monitoring and protective devices in substations and on feeder lines. Advanced OMS integrates smart meter data from AMI networks to improve detection of outage location and number of customer impacted. Currently, most OMS incorporate GIS to help repair crews get to outage locations more quickly, often with a better idea of the problem.[12] By filtering and analyzing outage information from multiple sources, modern OMS can provide grid operators and repair crews with more specific and actionable information to manage outages and restorations more precisely and cost-effectively.

Figure 5. A Visual Display from an Outage Management System



[12] Typically, distribution system operators use information provided by the OMS to direct field crews to outage locations. Crews do not typically do this on their own unless they have mobile devices with links to the OMS. Several of the SGIG DA utilities found advantages from equipping field crews in this way and decentralizing aspects of service restoration activities.

1.2 Project Build and Impact Metrics

Each SGIG project collected and reported two types of metrics: 1) **build metrics**, including the number of installed devices, device functions, and their costs; and 2) **impact metrics** (e.g., fewer outages, reliability index improvements, reduced line losses, reduced electric demand) that assessed the effects of the new technologies and systems on grid operations and business practices. Appendix B includes a detailed review of the data collection and analysis process.

At the outset of the SGIG program, DOE collaborated with each of the project teams to develop a Metrics and Benefits Reporting Plan (MBRP) outlining how the utility would collect and report metrics over the course of the project. DOE analysis[13] of the DA projects involved the assessment of four key components (see Figure 6), along with lessons learned.

Figure 6. SGIG Analysis Process



- ***Assets*** (e.g., automated feeder switches)
- ***Functions*** (e.g., switches automatically open/close to reconfigure power flows)
- ***Impacts*** (e.g., fewer and shorter power outages)
- ***Benefits*** (e.g., lower economic losses from outages)

Because DA involves not only new technologies but also new business practices and procedures, DOE analysis also included assessment of lessons learned and best practices from the SGIG projects.

1.3 Key Data Limitations and Considerations

This report is designed to present a comprehensive review of DA technology impacts and benefits reported under the SGIG program. **Results on DA technology cost, performance, and savings were not directly comparable across *all* 62 DA projects for a number of reasons, including utility size and project scale, differences in the specific devices and functions deployed, pre-project technology maturity, and baseline data availability.** Several factors are important to consider when evaluating project data and results in this report:

- **SGIG DA utilities did not deploy every technology or function**, and therefore did not all report results for every data point. As a result, select charts and graphs are marked with notations such as "36 projects reported this data point." In some cases, the most significant benefits represent experiences from a small number of projects. While several DA utilities deployed more than one DA asset or tested more than one application, almost all of the DA assets were deployed by 30 or fewer utilities. Similarly, a large percentage of certain DA devices were deployed by only a

[13] The DOE analysis approach is further outlined in: Electric Power Research Institute (EPRI), *Guidebook for Cost/Benefit Analysis of Smart Grid Demonstration Projects*, Revision 1, December 2012.

handful of SGIG utilities**.** For exampl**e,** 78 percent of SGIG remote fault indicators were deployed by just 3 utilities.

- **As expected, large-scale technology deployments produced the most significant and meaningful impacts and benefits. The DA projects had a wide range of scale,** and directly comparing technology results across all projects at different scales was not meaningful; instead, the report includes aggregated results where possible and individual project results as examples. Some results were reported by only a small subset of utilities.
- **The SGIG DA utilities had differing levels of experience and expertise with DA** technologies and systems. Utilities that had steeper learning curves yielded limited impact data during time periods when they were first installing and operating the new technologies.
- **Individual project case studies are highlighted in this report, including certain project costs and benefits, to present a range of examples on the DA technology cost-benefit ratio**. Though all projects reported DA implementation costs, [14] costs varied greatly among projects and average DA implementation costs were not reliable metrics for several reasons:
    - Utilities did not uniformly measure and report total equipment costs. In reporting the total cost per device, many utilities included several different non-hardware costs—including software and licensing fees, hardware installation labor, IT testing and requirements gathering, project management, software integration, and staff training. These costs can vary greatly based on the utility's prior DA experience and existing technology platforms.
    - Small-scale deployments are not able to achieve the same economy of scale as large-scale deployments, given the fixed cost of new system implementation.
    - Costs may vary based on different capabilities or functionalities of individual devices.
    - Some utilities deployed wholly new equipment, whereas others may have been able to retrofit existing devices to operate in an automated fashion.
    - DA hardware and software was largely purchased by 2010, making it likely that cost data is not indicative of current or future equipment costs.
- **Some utilities had trouble establishing reliable historical baselines from which to measure improved performance.** Accurately measuring the impact of DA technologies required consistent measurement of historical performance—before the technologies were implemented. Several utilities underestimated the time, effort, and engineering expertise required to accurately measure smart grid impacts and historical baselines. Some utilities had difficulty measuring year-to-year performance changes attributable to SGIG deployments versus those resulting from routine feeder maintenance, storm damages, and changing customer demographics.

[14] Information on how individual projects deployed funds and evaluated impacts can be found on the Project Information page at SmartGrid.gov.

2 Major Findings: Reliability and Outage Management

Improving grid reliability can reduce economic losses and customer inconveniences from sustained power interruptions, which are estimated to cost the economy almost $80 billion annually.[15] Table 4 summarizes select results from the 46 SGIG DA utilities that applied DA for reliability and outage management.

Table 4. Reliability and Outage Management Results from DA Investments

Primary Aim	• Fewer and shorter power disruptions for customers • Improved reliability performance, as measured by standard reliability indices (such as SAIFI and SAIDI)—which may be tied to utility performance standards			
Smart Grid Function	Remote fault location and diagnostics	Fault location, isolation, and service restoration (FLISR) and automated feeder switching	Outage status monitoring and customers notifications	Optimized restoration dispatch
Description	Without DA, utilities rely primarily on customer calls to identify outages. With DA, operators receive field telemetry from fault indicators, line monitors, and smart meters to rapidly pinpoint and diagnose issues.	FLISR operations quickly reconfigure the flow of electricity and can restore power to many customers who would otherwise have experienced sustained outages.	DA provides operators with comprehensive and real-time outage information, and alerts customers with more timely and accurate information about restoration.	By integrating distribution, outage management, and geographic information systems, utilities can precisely dispatch repair crews and accelerate restoration.
Key Impacts and Benefits	• Overall reduced customer minutes of interruption (CMI) • Shorter outage events with fewer affected customers • Lower or avoided restoration costs • Faster response, dispatch of repair crews, and prioritization of repairs	16 utilities reported reductions of about **146 million customer minutes of interruption** over three years For an outage event, FLISR operations showed: • Up to **45% reduction in number of customers interrupted** • Up to **51% reduction in customer minutes of interruption** About **270,000 fewer customers experienced sustained interruptions** (of >5 minutes) compared to estimated outcomes without FLISR One utility reported repair crews spent approximately 560 fewer hours annually assessing outages		

[15] Lawrence Berkeley National Laboratory, Cost of Power Interruptions to Electricity Consumers in the United States, LBNL-58164, (LBNL, 2006).

2.1 Remote Fault Location, Isolation, and Service Restoration using Automated Feeder Switching

DA technologies provided advanced capabilities for operators to detect, locate, and diagnose faults. Remote fault indicators, relays, and reclosers provide access to real-time data on key feeders, which when delivered to a fully functional DMS, can help operators accurately determine causes and locations of faults and the extent of outages when they occur.

In addition, utilities with AMI can configure smart meters to generate "last gasp" signals when they lose power. Control room operators can also "ping" smart meters to confirm power outages or restoration status. Integrating AMI data with DMS, OMS, and GIS can thus help operators pinpoint and visualize outages, and deploy repair crews to precise fault locations. Several DA utilities also implemented AMI as part of their SGIG projects.[16]

Many SGIG utilities deployed DA technologies for more than simple fault indication. Fault location, isolation, and service restoration (FLISR) technologies and systems involve automated feeder switches and reclosers, line monitors, communication networks, DMS, OMS, SCADA systems, grid analytics, models, and data processing tools. These technologies work in tandem to automate power restoration by automatically isolating faults and restoring service to remaining customers by transferring them to adjacent feeders via tie lines. This can reduce the number of customers impacted by a fault and the length of an interruption.

FLISR systems can operate autonomously through a distributed or central control system (e.g., DMS), or can be set up to require manual validation by control room operators. Implementing autonomous, fully automated FLISR systems typically requires extensive validation and calibration processes to ensure effective and reliable operations. Automated FLISR actions typically take less than one minute, while manually validated FLISR actions can take five minutes or more.

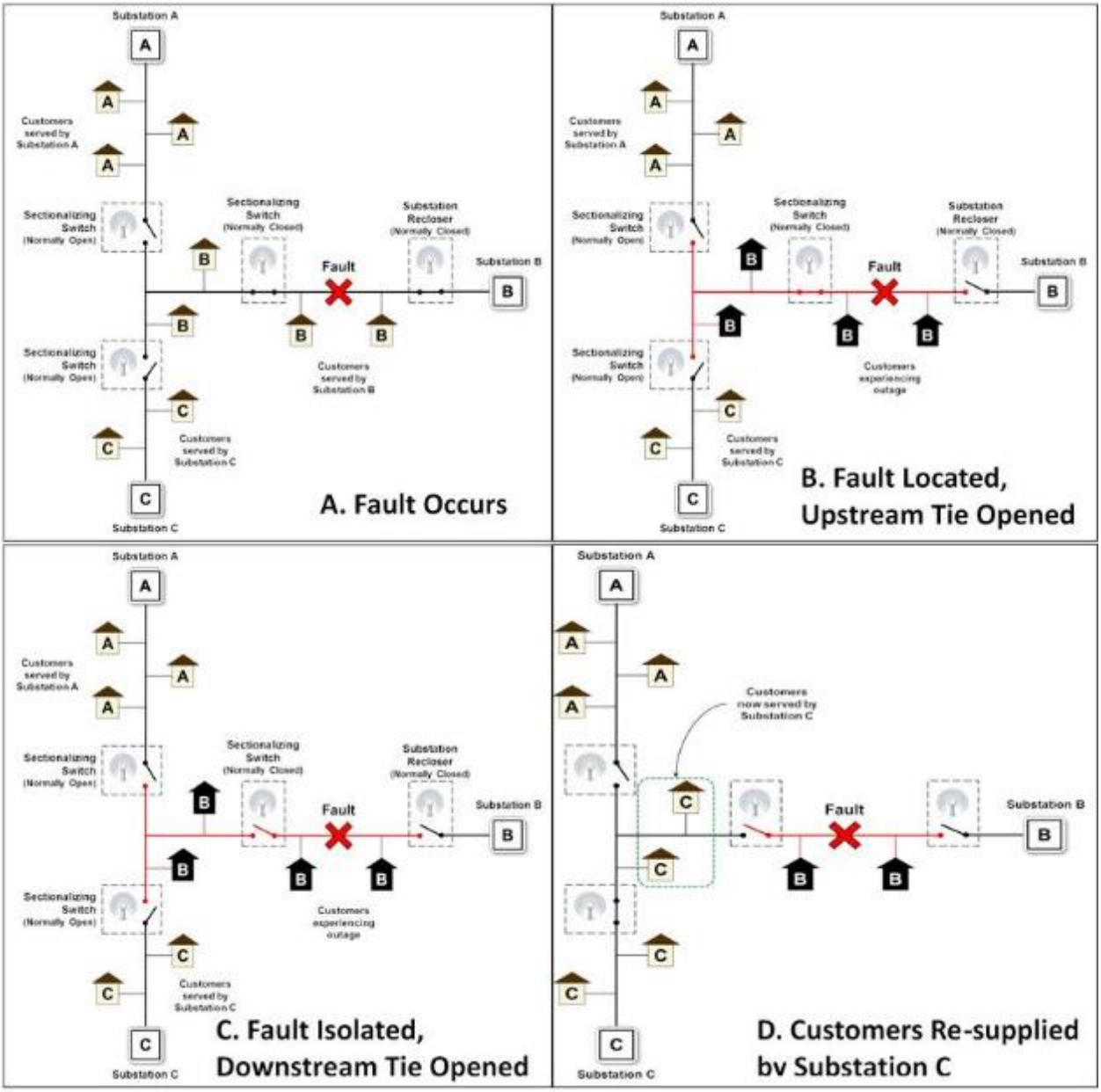
Figure 7 presents simplified examples (A-D) to show how FLISR operations typically work. In Figure 7-A, the FLISR system locates the fault, typically using line sensors that monitor the flow of electricity and measures the magnitudes of fault currents, and communicates conditions to other devices and grid operators.

Once located, FLISR opens switches on both sides of the fault: one immediately upstream and closer to the source of power supply (Figure 7-B), and one downstream and further away (Figure 7-C). The fault is now successfully isolated from the rest of the feeder.

With the faulted portion of the feeder isolated, FLISR next closes the normally-open tie switches to neighboring feeder(s). This re-energizes portion(s) of the feeder without a fault and restores services to all customers served by these feeder sections from another substation/feeder (Figure 7-D). The fault isolation feature of the technology can help crews locate the trouble spots more quickly, resulting in shorter outage durations for the customers impacted by the faulted section.

[16] SGIG results from AMI applications are presented separately in: DOE, *Advanced Metering Infrastructure and Customer Systems: Results from the Smart Grid Investment Grant Program*, 2016.

Figure 7. Illustration of FLISR Operations



Several SGIG utilities implemented FLISR in distinct ways. For example, Pepco's Automatic Sectionalizing & Restoration (ASR) schemes segment feeders into two, three, or four sections using closed remote-controlled switches or automatic circuit reclosers in the field. Duke Energy also installed "Self-Healing Teams" of field devices, which connect electronic reclosers and circuit breakers from two or three neighboring feeders and enable them to operate together in an integrated manner. See the case studies for detailed descriptions of how each utility designed and operated their FLISR functions.

→ See **Case Study:** Pepco (page 50)

→ See **Case Study:** Duke Energy (page 40)

Table 5 also summarizes some of the key FLISR activities within the SGIG program.[17]

Table 5. Overview of Five SGIG FLISR Utility Activities

	CenterPoint Energy	Duke Energy	Eversource	Pepco	Southern Company
Name of FLISR System	Self-Healing Grid	Self-Healing Teams	Auto Restoration Loops	Automatic Sectionalizing & Restoration	Self-Healing Networks
Field Devices Involved	Intelligent Grid Switching Devices act as switching devices and monitoring equipment	Electronic reclosers, circuit breakers, and line sensors	Telemetry communications, line sensors, and "smart" switches	Substation breakers, field switches, reclosers, and "smart" relays	Automated switches/ reclosers, and fault indicators
Mode of FLISR Operation	Manual validation required	Fully automated	Transitioned to full automation during the project	Fully automated	Fully automated
Location of FLISR Operations	Dedicated server; to be transitioned to DMS	Dedicated self-healing application	DMS	Dedicated server in the substation	Dedicated server or DMS

Key Result: Measurable Improvements in Reliability

DA implementation resulted in significant improvements in reliability indices for several SGIG utilities. Most utilities use reliability indices developed by the Institute of Electrical and Electronic Engineers (IEEE) to track performance and evaluate improvement needs. Table 6 provides a summary of the four primary reliability indices used by the electric power industry.

Table 6. IEEE Reliability Indices [18]

Reliability Index	Description	Equation
System Average Interruption Frequency Index (SAIFI)	The sum of the number of interrupted customers (N_i) for each power outage greater than five minutes during a given period, or **customers interrupted (CI)**, divided by the total number of customers served (N_T). This metric is expressed in the average number of outages per year. Major events are excluded.	$SAIFI = \frac{\sum N_i}{N_T} = \frac{CI}{N_T}$
System Average Interruption Duration Index (SAIDI)	The sum of the restoration time for each sustained interruption (r_i) multiplied by the number of customers interrupted (N_i), or **customer minutes interrupted (CMI)**, divided by the total number of customers served for the area (N_T). This metric is expressed in average minutes per year. Major events are excluded.	$SAIDI = \frac{\sum r_i N_i}{N_T} = \frac{CMI}{N_T}$

[17] For more information, see: DOE, *Fault Location, Isolation, and Service Restoration Technologies Reduce Outage Impact and Duration*, (DOE, November 2014).
[18] IEEE, *Guide for Electric Power Distribution Reliability Indices*, IEEE Standard 1366-2012, (IEEE, 2012).

Reliability Index	Description	Equation
Customer Average Interruption Duration Index (CAIDI)	The sum of the restoration time for each sustained interruption (r_i) multiplied by the number of customers interrupted (N_i), or CMI, divided by the sum of the number of customers interrupted (N_i). This metric is commonly expressed in minutes per outage. Major events are excluded.	$CAIDI = \frac{\sum r_i N_i}{\sum N_i} = \frac{CMI}{\sum N_i}$
Momentary Average Interruption Frequency Index (MAIFI)	The sum of the number of momentary interruptions (IM_i) multiplied by the number of customers interrupted for each momentary interruption (N_{mi}) divided by the total number of customers served (N_T). This metric is expressed in momentary interruptions per year.	$MAIFI = \frac{\sum IM_i N_{mi}}{N_T}$

The best way to evaluate the impact of DA technologies on system reliability is to compare reliability indices before and after deployment using a well-established pre-deployment baseline. Unfortunately, many SGIG utilities had trouble establishing accurate, reliable pre-deployment baselines from which to measure performance improvements. It is recognized that the process of developing a baseline is complex and time consuming for utilities. Simply comparing reliability indices from year to year—rather than against a baseline—cannot effectively measure the full impact of DA investments.[19]

Utilities that **did** compare results against pre-deployment baselines reported significant reliability improvements with DA. In 2013 alone, three utilities reported SAIFI improvements of 17 percent to 58 percent compared to pre-deployment baselines (see Figure 8). [20] SAIFI is the primary metric used to track the frequency of outages.

The impact of DA on reliability depends on the system design and its potential for improvement. Utilities that applied DA technologies to the worst feeders first saw a larger relative impact than utilities who applied DA to feeders with less room for improvement.

PPL Electric Utilities Corporation estimated a 58 percent decrease in the average number of interruptions experienced by customers in 2013, and a 55 percent drop in the average number of customer minutes interrupted. Based on these results, PPL estimates a 25 percent improvement in reliability over the subsequent five years through the continued deployment of DA.

Duke Energy also reported experiencing a 17 percent improvement in SAIFI 2013 from DA operations in Ohio, while the Northern Virginia Electric Cooperative (NOVEC) compared 2011-2013 data from 41 feeders with pre-deployment five-year benchmarks and showed improvements across all major reliability indices.

→ See **Case Study:** PPL Electric Utilities Corporation (page 48)

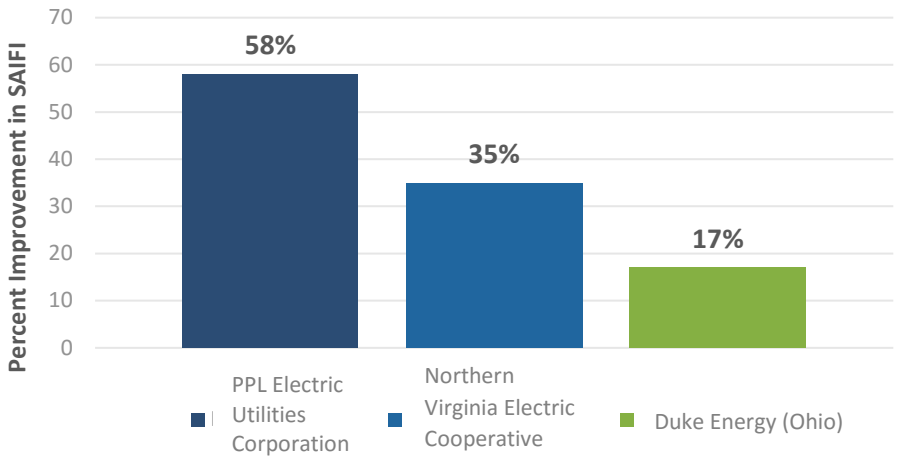
→ See **Case Study:** Northern Virginia Electric Cooperative (page 34)

→ See **Case Study**: Duke Energy (page 40)

[19] For example, Appendix D shows SAIFI, SAIDI, CAIDI, and MAIFI comparisons from summer 2013 to summer 2014 for several utilities implementing DA. The data demonstrates that many utilities experienced reliability improvements year over year with DA, while others saw *decreased* reliability after DA deployments. Without well-documented pre-deployment baselines for comparison, changing weather from year to year (e.g., more/fewer storms) or changing system configurations can obscure the true reliability impact of DA technologies.

[20] Baselines are not always explicitly stated.

Figure 8. Percentage Improvements in SAIFI in 2013 Compared to Pre-Deployment Baselines



Several other utilities also reported improvements in their major reliability indices:

- The Electric Power Board (EPB) of Chattanooga, TN reported a 30 percent reduction in SAIFI and a 20 percent reduction in SAIDI from 2011 to 2014.
- Between April 2013 and September 2014, the Sacramento Municipal Utility District (SMUD) achieved reductions of 28 percent in SAIDI and 19 percent in SAIFI.

→ See **Case Study:** Electric Power Board (page 36)

→ See **Case Study:** Sacramento Municipal Utility District (page 67)

Key Result: Reduced Impact, Duration, and Cost of Major Storms and Outage Events

CMI is the restoration time for each sustained interruption multiplied by the number of customers interrupted during that outage, making it a valuable metric for assessing customer impacts from DA operations (see Table 6 in previous section for a detailed definition).

Over one year, FLISR operations during certain feeder outages *reduced by half* the number of affected customers and total customer minutes of interruption, according to data from five utilities. Five utilities (representing 10 operating companies) applied similar FLISR operations during 266 events between April 2013 and March 2014.[21] FLISR operations applied to either: (1) full-feeder outages where the fault is upstream of a sectionalizing switch (and thus interrupts service to all customers on a feeder), or (2) partial-feeder outages where the fault is downstream of a sectionalizing switch (and thus interrupts service to a portion of customers on a feeder). Figure 9 shows substantial reductions in the number of CI and CMI for both types of outages. Table 7 provides supporting data.

[21] U.S. Department of Energy, *Fault Location, Isolation, and Service Restoration Technologies Reduce Outage Impact and Duration*, November 2014.

Figure 9. FLISR Effects on the Number of Customers Interrupted (CI) and Customer Minutes of Interruption (CMI) by Type of Outage

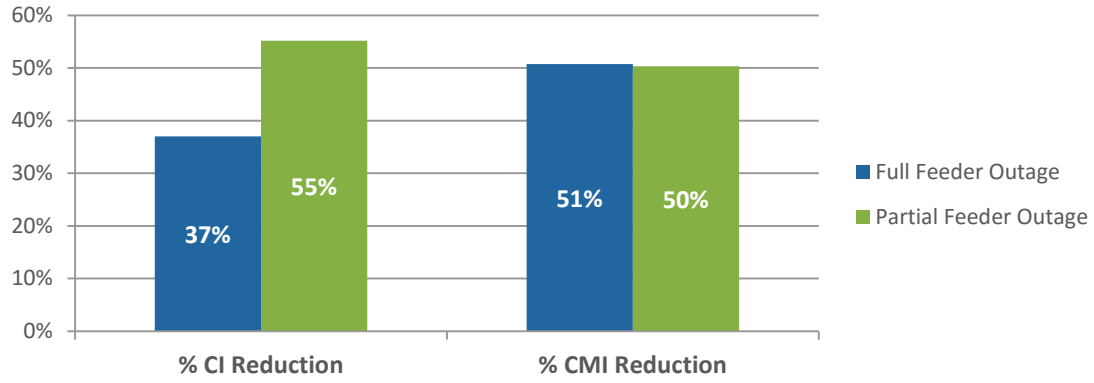


Table 7. Effects of FLISR Operations on CI and CMI by Type of Outage

Type of Outage	Total Estimated CI *without* SGIG technologies	Total Actual CI *with* SGIG technologies	**% Reduction of CI**	Total Estimated CMI ***without*** SGIG technologies	Total Actual CMI ***with*** SGIG technologies	**% Reduction of CMI**
Full Feeder Outage	255,424	160,972	**37%**	18,301,994	9,016,784	**51%**
Partial Feeder Outage	206,763	92,726	**55%**	17,470,615	8,676,751	**50%**

The same SGIG utilities found that fully automated switching and validation typically resulted in greater CI and CMI reductions than operator-initiated remote switching with manual validation. Figure 10 shows the percent reduction in CI and CMI by type of FLISR operating scheme for the same 266 FLISR events as above. Table 8 provides supporting data.

Figure 10. FLISR Effects on the Number of Customers Interrupted (CI) and Customer Minutes of Interruption (CMI) by Type of FLISR Operating Scheme

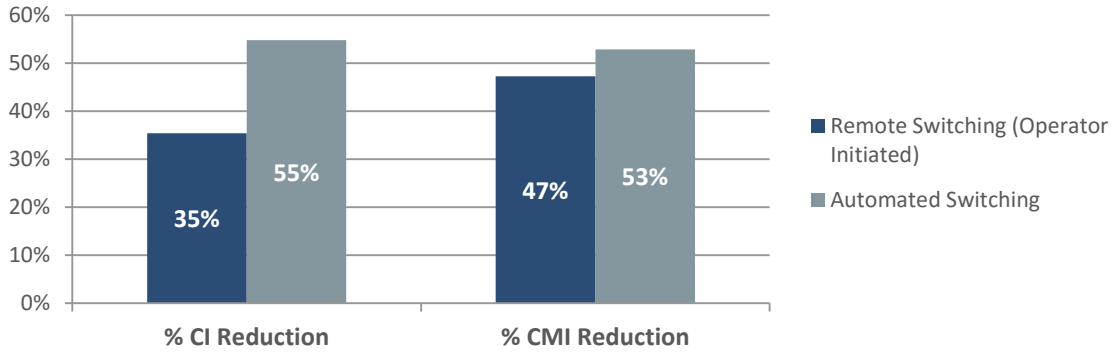


Table 8. Effects of FLISR Operations on CI and CMI by Type of FLISR Operating Scheme

Type of Switching	Total Estimated CI ***without*** SGIG technologies	Total Actual CI ***with*** SGIG technologies	**% Reduction of CI**	Total Estimated CMI ***without*** SGIG technologies	Total Actual CMI ***with*** SGIG technologies	**% Reduction of CMI**
Operator-Initiated	230,388	148,917	**35%**	15,037,440	7,926,425	**47%**
Fully Automated	231,799	104,781	**55%**	20,735,169	9,767,110	**53%**

Table 9 shows the potential magnitude of CMI impacts from DA operations over several months or years for 15 SGIG DA utilities. Due to data constraints, the period of data collection and reporting is not identical for all utilities; some reported data for only one month or one year, while others collected data for multiple years. The benefits of the technology likely continued well beyond these reporting periods.

Table 9. CMI Avoided by DA Operations

Seq. #	Utility	CMI Avoided	Period of Data Collection
1	Indianapolis Power & Light (IPL)	1,541,049	10/2013 – 09/2014
2	Eversource (formerly NSTAR)	18,831,841	10/2012 – 03/2015
3	Pepco—Washington, DC	1,813,656	04/2013 – 03/2015
4	Pepco—MD	4,914,654	04/2013 – 03/2015
5	Southern Company	17,194,770	04/2013 – 09/2014
6	Duke Energy Business Services	8,971,792	04/2013 – 03/2015
7	CenterPoint Energy	14,488,820	04/2013 – 09/2014
8	Electric Power Board (EPB)	42,848,905	10/2013 – 03/2014
9	Avista Utilities	35,609	08/2013
10	Atlantic City Electric	50,011	10/2013 – 03/2014
11	Duke Energy (formerly Progress Energy)	28,688,810	01/2012 – 08/2013
12	Sacramento Municipal Utility District (SMUD)	705,510	04/2013 – 09/2014
13	City of Leesburg	125,694	09/2014
14	PPL Electric Utilities Corporation	2,400,000	10/2012 – 09/2013
15	Burbank Water and Power (BWP)	4,411,791	07/2010 – 08/2014
	Total	**147,962,153**	

Several SGIG utilities experienced major storms or events during their project period and used DA technologies to significantly reduce restoration time and limit the number of customers affected. Fewer and shorter outages help customers avoid economic losses, inconveniences, and public health and safety risks. Individual case studies contain detailed descriptions of the following examples:

- FLISR and smart meters at EPB resulted in 36 million fewer CMI during a July 2012 derecho and helped operators restore system-wide power about 17 hours earlier than without DA. After another storm in February 2014, EPB was able to restore power 36 hours faster and reduce affected customers from 70,000 down to 33,000.
- When a garbage truck hit a power pole and caused almost 900 customers to lose power at Avista Utilities, FLISR restored more than 800 customers instantaneously, and the remainder within minutes.
- Florida Power and Light (FPL) saw about 9,000 fewer customer interruptions due to FLISR operations during Tropical Storm Isaac in 2012.

Many utilities use value-of-service studies, which involve statistical analyses of economic damages and willingness-to-pay by customers for more reliable electric service in order to estimate the monetary value of the benefits from reliability improvements. DOE developed the Interruption Cost Estimate (ICE)

calculator, which is based on meta-analysis of utility value-of-service studies, as a tool for utilities to estimate economic benefits from investments in reliability improvements.[22] **At least three utilities were able to estimate their customers' savings as a result of DA operations during a major storm**:

- Consolidated Edison used the ICE calculator to estimate more than $1.2 million in avoided interruption costs—largely benefitting industrial and commercial customers—for a 14-feeder system for a single year.

→ See **Case Study:** Consolidated Edison (page 44)

→ See **Case Study:** Glendale Water and Power (page 81)

- Central Maine Power used the ICE calculator to estimate that SGIG DA investments in substation and line reclosers saved customers an average of $18,000 per outage involving line reclosers, and $29,000 per outage when the outage took out a substation. This utility estimated total customer savings of more than $935,000 in 2014, and expects avoided economic losses to total more than $20.7 million through 2020.[23]
- Glendale Water and Power (GWP) estimated the net present value of DA investments would increase by 42 percent if customer savings were included in the analysis.

A lack of standard metrics across utilities to measure storm response makes it difficult to compare benefits from investments in FLISR and automated feeder switching in a consistent manner across utilities. Outages occur in different seasons, at different times of day, or on different days of the week—all of which can affect how much an outage will cost utilities and customers, along with the estimated savings. Utilities that experience increased storm events in one year may realize greater overall benefits from DA technologies than other utilities that do not.

In addition, because weather events are random, predicting future storm impacts and benefits for inclusion in forward-looking business cases can be difficult. For example, the February 2014 snowstorm that affected the Electric Power Board (EPB) occurred on a weekend. Had the storm arrived on a weekday, there would have been lower overtime costs and the savings from fewer truck rolls would have been lower. Thus, the savings for improvements in outage management can be hard to estimate before the investments take place, as assumptions about weather events and other factors can turn out to be inaccurate. As a result, business cases need to contain contingencies that reflect uncertainties in the weather, timing, and other factors. To build a business case, it is important for utilities to collect data, no matter what metrics are used, to document impacts and benefits and provide information decision makers can use for business case analysis.

Key Result: Operations and Maintenance Efficiency and Savings

SGIG utilities reduced O&M costs by automating functions that previously required field crews to conduct on-site monitoring, maintenance, and repair functions. Reductions in labor costs, truck rolls, vehicle-miles traveled, and replacement parts can accrue to significant savings for operators. The SGIG DA utilities reported four major sources of labor cost savings in outage management:

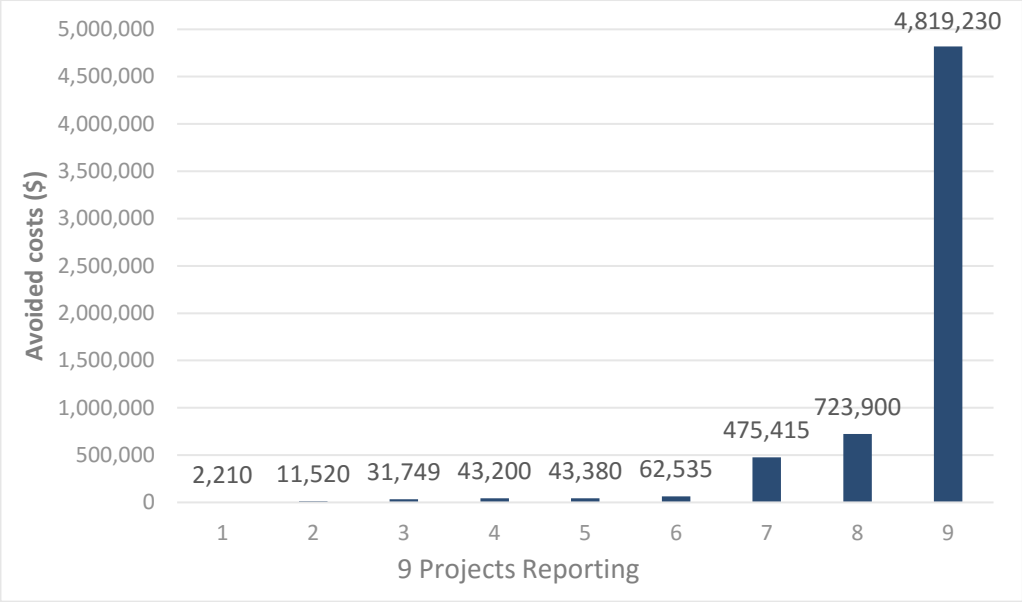
[22] Lawrence Berkeley National Laboratory, "Interruption Cost Estimate Calculator," 2015.
[23] Based on an estimate that the value of an average outage hour for an average customer (covering residential, commercial, and industrial customer classes) to be about $97 for 2014-2019.

- Pre-empting and avoiding outages before they occur
- Proactively identifying outages during work hours, rather than waiting for customer calls (which typically come during nights and weekends)
- Optimizing truck rolls during an outage
- Correcting nested outages along with primary outages instead of coming back to them later

Utilities generally do not apply consistent metrics and tools to measure and compare the benefits from investments in reliability and outage management.

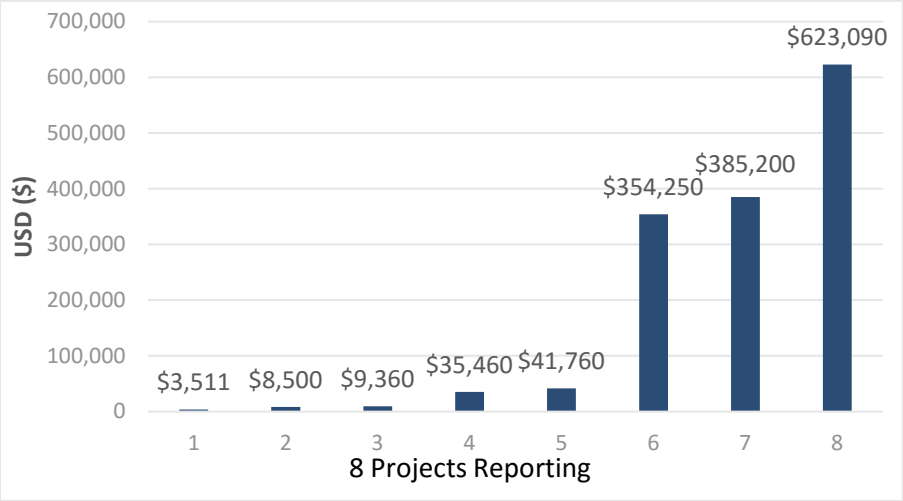
Nine SGIG DA utilities saved more than $6.2 million in total avoided distribution operations costs from April 2013 to September 2014 (see Figure 11). The utility that produced most of the benefits is one that implemented system-wide DA deployment.

Figure 11. Avoided Distribution Operations Costs for SGIG DA Utilities, April 2011 to September 2014 (9 Projects Reporting)



Savings from avoided switching costs totaled more than $1.46 million for eight SGIG DA utilities that reported savings from April 2011 to March 2014 (see Figure 12). Automated feeder switching reduces O&M costs by requiring fewer truck rolls and fewer instances where repairs crews are sent to accomplish feeder switching functions manually.

Figure 12. Avoided Switching Costs for SGIG DA Utilities, April 2011 – March 2014 (8 Projects Reporting)



There are several examples of SGIG DA utilities reducing labor resource requirements and service restoration costs, including the following:

- NOVEC's savings from DA operations were about $1,500 in avoided fuel and about $133,000 in labor savings from summer 2011-summer 2014.
- EPB reported saving about $1.4 million in avoided overtime costs following DA operations after a snowstorm in February 2014.
- Duke Energy (formerly Progress Energy) reduced its annual outage assessment activities by 20% (more than 500 hours).

Using an automated or remote-controlled approach to fault restoration and equipment health monitoring can resolve or prevent outages, ultimately reducing the labor hours of field crew and truck fleet vehicle miles. By identifying where on the grid a fault has occurred, DA also enables repair crews to be dispatched to precise locations for repair and restoration service activities. Reduced customer service labor hours also result from improvements in outage monitoring and notification. A more reliable estimated time of restoration (ETR) and more proactive customer outage notifications reduces call volume during outage events, thereby reducing labor hours for call center staff.[24]

In total, from April 2011 to March 2015, 16 reporting SGIG DA utilities avoided more than 197,000 truck rolls and 18 reporting DA utilities avoided more than 3.4 million vehicle-miles traveled as a result of various types of DA operations (see Figure 13 and Figure 14). The utilities in the two figures with the highest levels of O&M savings were the ones that pursued full-scale implementation of DA (i.e., #16 for truck rolls, and #17 and #18 for vehicle-miles traveled). The lowest savings per utility was 52 truck rolls and the highest per utility was 123,070. The lowest savings per utility was 86 avoided vehicle-miles and the highest was 1,705,601.

[24] Because these types of savings cross-cut all four DA applications discussed in this report, it is not possible to attribute the savings to reliability and outage management alone. The SGIG utilities were not required to report O&M impacts specific to these categories, as doing so would have been cost prohibitive.

Figure 13. Total Avoided Truck Rolls by 16 SGIG DA Utilities, April 2011 – March 2015

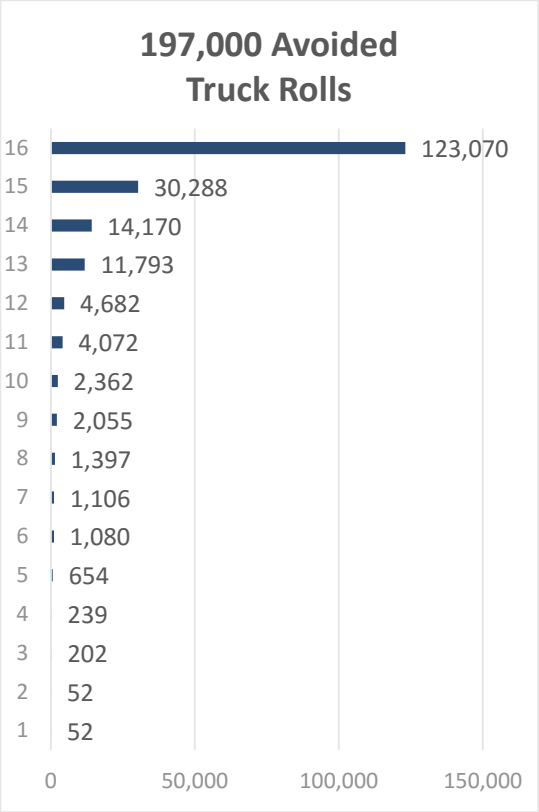
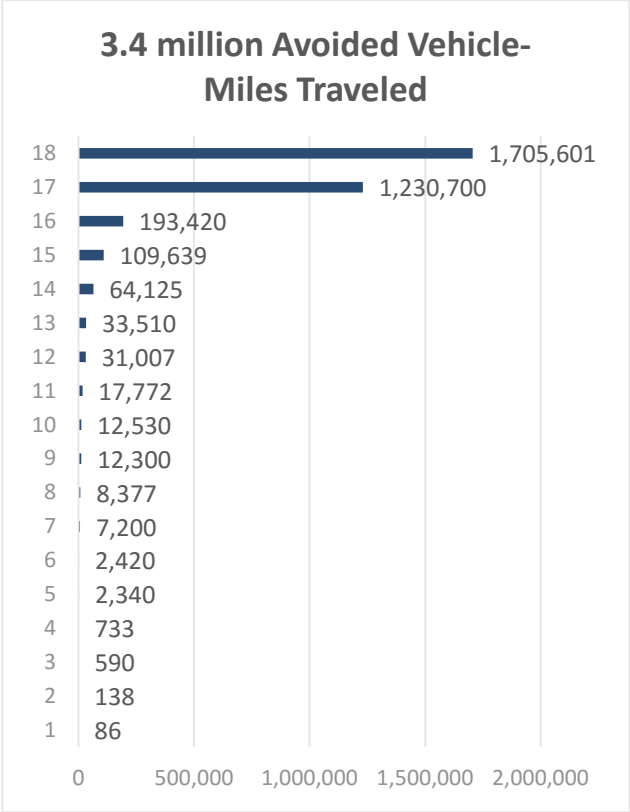


Figure 14. Total Avoided Vehicle-Miles Traveled by 18 SGIG DA Utilities, April 2011 – March 2015



Based on analysis of truck roll data from 18 SGIG DA utilities between April 2011 and March 2015, **it is estimated that DA operations resulted in reductions of about 2,350 metric tons of carbon dioxide-equivalent**, which equals the amount of carbon dioxide released from consuming about 264,000 gallons of gasoline.[25]

2.2 Outage Status Monitoring and Notification

Integrating information from monitoring devices and AMI with OMS and GIS enables utilities to provide customers with more accurate and timely information about the status of outages and restoration services. Automated features lower utility costs and customers benefit from better information about when services will be restored following outages.

Many utilities leverage smart meters and AMI to implement this functionality. Utilities set up automated processes for pinging meters over large areas when large outages are reported, and then target affected feeders and neighborhoods as service restoration activities progress. This saves valuable time in the minutes following an outage so operators do not have to undertake manual meter pings. Some utilities turn off the automated last gasp notifications in the initial phase of storm response, when emphasis is on restoring substations and transformers and a barrage of meter notifications can overwhelm OMS

[25] U.S. Environmental Protection Agency, "Greenhouse Gas Equivalencies Calculator," last updated April 2014; Argonne National Laboratory (ANL), *GREET Model*, (ANL Systems Assessment Laboratory, 2015).

screens if the system is configured in that fashion. In these cases, meter notifications get turned back on once outages have been located and restoration activities are underway.

Utilities with other monitoring devices such as line monitors, fault indicators, and relays integrate information from these with smart meter data and OMS operations. The next task involves communicating with customers about the status of outage restoration activities. Notifications involve multiple channels including phone and text messages, email alerts, and website posts, sometimes including the estimated time to restoration of services. Glendale Water and Power's interactive voice response (IVR) software and Burbank Water and Power's OMS system that supports customer call-backs and notifications are two examples. Additional examples of customer notification are reported in *Advanced Metering Infrastructure and Customer Systems: Results from the SGIG Program*.

Key Result: Improved Customer Satisfaction and Public Awareness

Customer notifications and estimated restoration times help improve public awareness and planning, reduce the burden on customers to report outages, and increased customer satisfaction. CenterPoint Energy's Power Alert Service updated customers on restoration progress, and earned an 85 percent overall satisfaction rating.

When Hurricane Isaac hit Mississippi in 2012, Magnolia Electric Power Association (MEPA), a member of South Mississippi Electric Power Association (SMEPA), was required to give the Mississippi Emergency Management Agency updates three times a day on the status of outages and restoration efforts by county. With 5-second updates on SCADA data from system relays and monitors, and 15-second smart meter updates, MEPA was able to provide the requested outage reports relatively easily. Previously, during Hurricane Katrina in 2005, it took MEPA several hours to provide this information.

2.3 Optimized Restoration Dispatch

The availability of timely, accurate, and more comprehensive information about outages and the ability to process that data and deliver it to grid operators and repair crews accelerates restoration times and lowers costs, which benefits both utilities and customers. A key tool for supporting this smart grid-enabled function involves integration of OMS operations with workforce management systems (WMS). WMS is used to help field crews with software tools for automated scheduling, resource optimization, dynamic routing, and workflow management. WMS can set priorities for restoration tasks based on multiple criteria for level of importance and supports crew management, by tracking crew sizes, locations, and performance in restoring services.

Another way DA enables optimized crew dispatch is by enabling hot line tags to be placed remotely on distribution equipment. Hot line tags are placed on equipment during field activities to ensure worker safety. Traditionally, utilities typically sent repair crews to manually place physical tags on distribution equipment before crews could conduct operations and maintenance activities. These tags would carry warnings not to operate certain switches/relays because another team was at work elsewhere on the feeder. With smart systems in place, utilities can "tag" DA equipment remotely through SCADA, allowing restoration efforts to proceed faster and more safely.

Key Result: Faster, More Targeted, and Safer Restoration

The SGIG DA utilities implemented a variety of approaches to optimizing restoration dispatch activities. Individual case studies provide more detailed explanations of the following examples:

- Following a February 2014 storm, PECO was able to dispatch repair crews and restore services three days faster than they would have otherwise using AMI data (when smart meter roll out was 50 percent complete).
- The Sacramento Municipal Utility District (SMUD) used software for correlating, analyzing, and visualizing data from field devices, DMS, OMS, GIS, and weather forecasts. The new system quickly synthesizes numerous streams of disparate data and provides on-the-fly assessments of grid, asset health, weather, power supply, and electricity demand conditions.
- Consolidated Edison's OMS has been merged with electric distribution and service mapping information, customer billing information, customer service call data, workforce and repair crew availability, and SCADA telemetry into one screen for control center operators.
- CenterPoint Energy's OMS enables operators to visualize outages the moment they occur and often times, trucks are rolled before customer calls are received.

CASE STUDY: **NORTHERN VIRGINIA ELECTRIC COOPERATIVE (NOVEC)**



Electric Cooperative



Virginia



143,196 Customers

Distribution Circuits Impacted:	105 (of 235)	Distribution Substations Impacted:	37 (of 53)

DA Communication Network: IP-based communication links

Total Cost of DA Implementation under SGIG

$10,000,000

Distribution Automation Devices Deployed					
Automated Feeder Switches	✓	14	Remote Fault Indicators	✗	
Automated Capacitors	✓	164	Transformer Monitors	✓	56
Automated Regulators	✓	340	Smart Relays	✓	25
Feeder Monitors	✗		Fault Limiters	✗	
Automated Reclosers	✓	117	Smart Reclosers	✓	19
Substation Battery Bank Monitors	✓	33			

DA Improved Reliability from Five-Year Benchmarks: NOVEC reported reliability improvements on the 41 feeders installed with electronic vacuum reclosers and motor-operated air break switches. NOVEC analysis compared 2011-2013 data from 41 feeders for the major reliability indices with pre-deployment, five-year benchmarks and showed improvements across the board, as shown in Table 10.

Table 10. NOVEC Reliability Analysis, 2011-2013.

Analysis Period	SAIFI	SAIDI	CAIDI	MAIFI
Summer Benchmark	0.62	54.49	88.50	0.39
Summer 2011	0.66	38.32	57.93	0.21
Summer 2012	0.37	27.71	74.20	0.20
Summer 2013	0.40	22.53	70.63	0.15
Winter Benchmark	0.48	36.08	74.93	0.39
Winter 2011	0.27	21.63	68.55	0.40
Winter 2012	0.28	16.03	71.09	0.13

Improved Efficiencies Reduce Truck Rolls and Fleet Miles: NOVEC reduced truck rolls and fleet vehicle miles from improved efficiencies from a variety of automated field activities. Table 11 provides a summary of the savings.

Table 11. Summary of NOVEC Savings from DA Operations from 2011 to 2013.

Activity	Truck Rolls Avoided	Vehicle Miles Saved
Substation Inspection Reductions	150	1,200
Fault Response/Forensic Data Retrieval	300	18,000
Remote Hot Line Tagging	3600	57,600
Remote Equipment Setting Changes	300	2,400
Remote Inspection	100	6,000

Efficiencies Reduce Labor Costs and Produce Fuel Savings: NOVEC, which serves 155,000 customers, avoided 59 truck rolls and 831 vehicle-miles traveled covering the summer of 2011 through the summer of 2014. Assuming average costs per mile to fuel and maintain typical repair trucks (diesel-light truck Class 5) are about $1.88 per mile, and average labor costs per truck roll are about $160 (excluding overheads), then NOVEC's savings from these DA operations were about $1,500 in avoided fuel, and about $133,000 in labor savings.

Power Quality Monitors Reduce Voltage Variations: NOVEC used power quality monitors on meters and transformers to help reduce voltage variations such as sags and surges and power harmonics. NOVEC received daily reports from these monitors and was able to check the number of regulator operations per device, tap positions of regulators, and feeder voltage levels. Based on the operational information from the power quality monitors, NOVEC ensured service voltage levels to customers remained within the acceptable level (114 volts to 127 volts) by remotely controlling, or making timely repairs to, voltage regulators.

READ MORE ABOUT NOVEC'S PROJECT ON SMARTGRID.GOV:

Northern Virginia Electric Cooperative Project Page

Northern Virginia Electric Cooperative Project Description – *July 2014*

CASE STUDY: **ELECTRIC POWER BOARD OF CHATTANOOGA (EPB)**



Municipal/Public Utility



Tennessee, Georgia



172,079 Customers

Distribution Circuits Impacted:	**232 (of 370)**

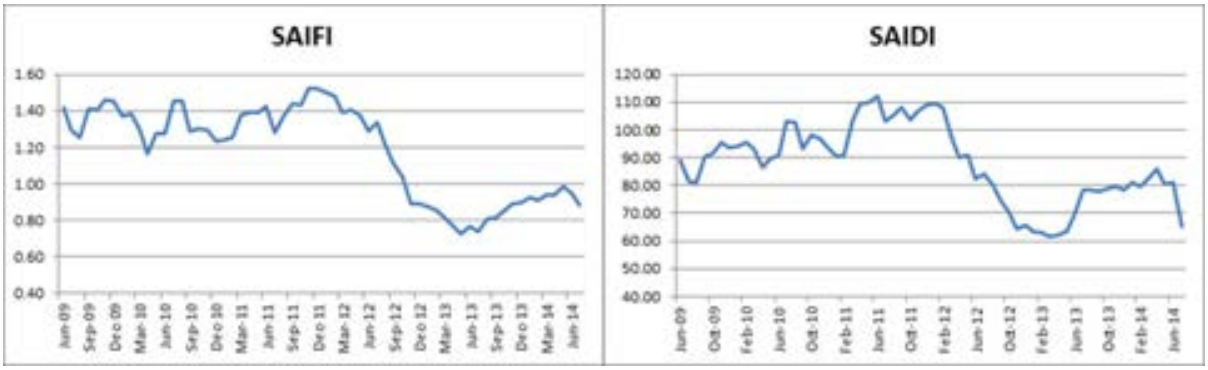
Communication Network: Fiber optic network

Total Cost of DA Implementation under SGIG	Distribution Automation Devices Deployed				
	Automated Feeder Switches	✓	**1,294**	Remote Fault Indicators	✗
	Automated Capacitors	✗		Transformer Monitors	✗
$49,878,568	Automated Regulators	✗		Smart Relays	✗
	Feeder Monitors	✗			

Communication Upgrades Support Smart Grid and More: EPB installed an ultra-speed, high-bandwidth, fiber optic network that provides services beyond those for electric grid applications.

Sustained Outage Frequency Reductions Improve Reliability: EPB also reported a 30 percent reduction in SAIFI from 2011 to 2014. As shown in Figure 15, SAIDI also showed a 20 percent reduction over the same time period.

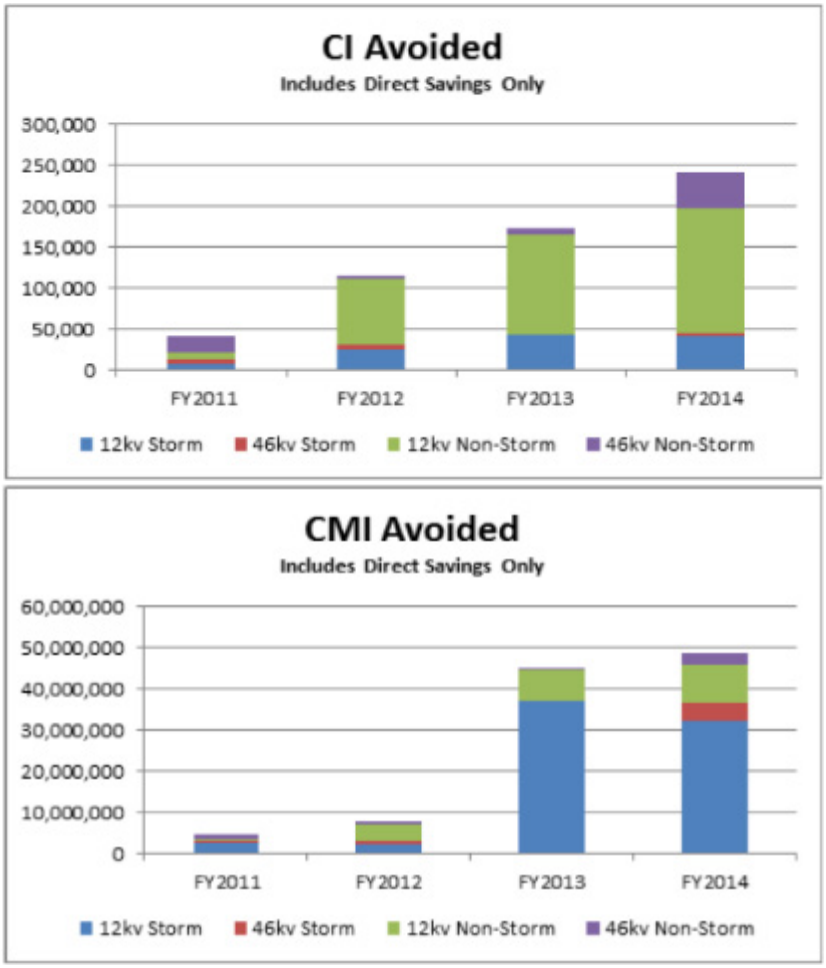
Figure 15. SAIFI and SAIDI Performance for EPB, 2009 – 2014



DA Operations Produce Customer Minutes of Interruption (CMI) Savings: Figure 16 shows improvement in CI avoided during the time period in which automated feeder switching (AFS), FLISR, and AMI technologies and systems were deployed and operated by EPB. The upper chart in the figure shows increases in avoided CI, and that in 2011-2013, the amount of avoided CI increased particularly

for customers "upstream" of faults, an indicator that AFS and FLISR operations were effective. The lower chart in the figure shows improvements in the number of CMI experienced by customers.

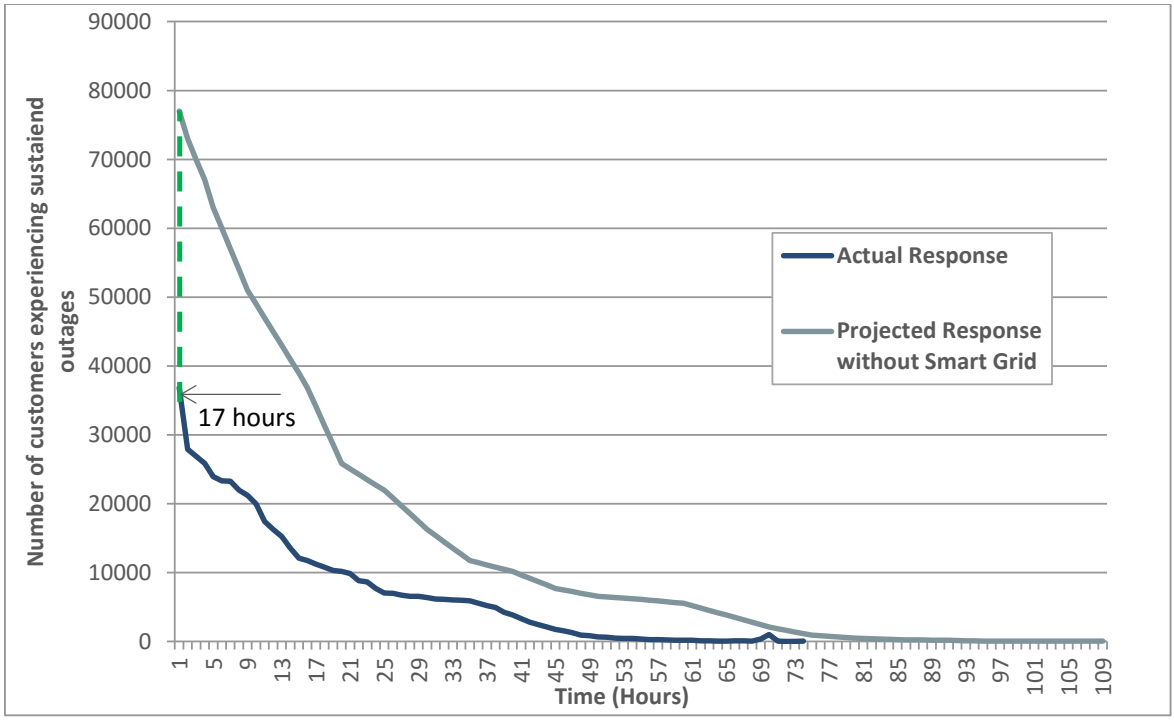
Figure 16. CI and CMI Improvements for EPB, 2010 – 2014



Instant Restoration Reduces the Extent of Major Outages: The July 2012 derecho that impacted much of the Midwest also struck Chattanooga, affecting about half of EPB's customers. Because of EPB investments in smart switches and smart meters, the outage duration for all affected customers decreased by about half. This resulted in about 36 million fewer CMI than would have occurred without the new technologies.

AFS Enables System-Wide Restoration Days Faster Following Major Storms: Figure 17 shows the results of using smart switches and smart meters for storm restoration at EPB. The blue line shows the time it would have taken EPB to restore power to affected customers in this storm without application of AFS and AMI. The green line shows the improvement in restoration time due to these practices. Overall, EPB's response was up to 17 hours faster due to the automated feeder switches, which restored power to 40,000 customers instantly and allowed crews to focus on a more limited number of issues. Smart meter data also helped operators verify outages, enabling EPB field crews to locate and fix downed lines faster and more efficiently.

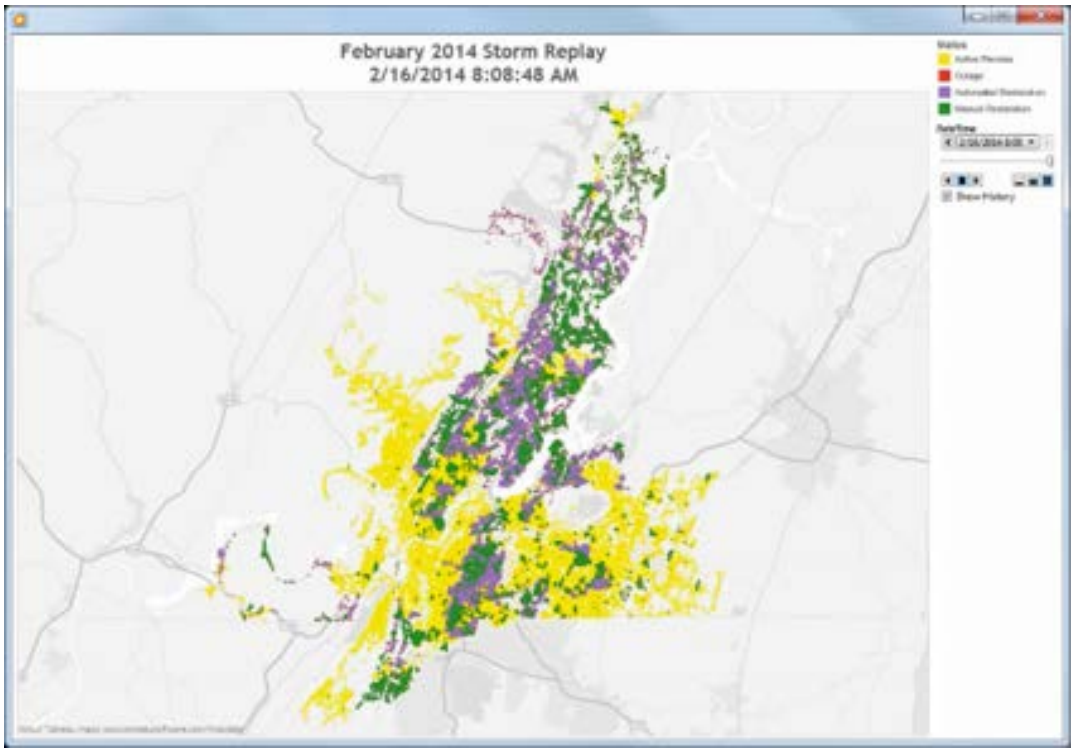
Figure 17. Improvement in Service Restoration by EPB Following a Storm in July 2012



EPB also experienced a snowstorm in February 2014 that affected more than 50 feeders and almost 33,000 customers. During the storm, EPB kept all of its smart switches active and did not deactivate FLISR capabilities. EPB reports that without the fault isolating capabilities of the smart switches, about 70,000 customers would have experienced sustained outages. EPB estimates that it was able to restore power about 36 hours earlier than would have been possible without smart grid deployments. Of those 36 hours avoided outage hours, EPB estimates about 16 were due to the self-healing actions of the smart switches, and about 20 were due to EPB's ability to "ping" smart meters, verify outage status, and redirect repair crews accordingly. EPB estimates it saved about $1.4 million in overtime costs for field crews during this storm.

Figure 18 shows a map of outage and restoration patterns from the snowstorm. The map shows the areas that were restored automatically (purple) and manually (green). Customers that were not interrupted are shown in yellow.

Figure 18: EPB Map of Outage and Restoration Patterns during a Snowstorm in February 2014



Business Case Analysis Considers Multiple Factors: The February 2014 snowstorm that affected the EPB occurred on a weekend. Had the storm arrived on a weekday, there would have been lower overtime costs and the savings from fewer truck rolls would have been lower. Thus, the savings for improvements in outage management can be hard to estimate before the investments take place, as assumptions about weather events and other factors can turn out to be inaccurate. As a result, business cases need to contain contingencies that reflect uncertainties in the weather, timing, and other factors. To build a business case, it is important for utilities to collect data, no matter what metrics are used, to document impacts and benefits and provide information decision makers can use for business case analysis.

Fiber Optic Network Extends Services: EPB installed an ultra-speed, high-bandwidth, fiber optic network which provides services beyond those for electric grid applications.

Future Deployment Will Provide Real-Time Information: EPB reports that the deployment of DA equipment is part of EPB's plan to more fully automate its distribution system. Moving forward, EPB expects data from the smart switches to provide information on real-time loadings on all of EPB's transformers so that demand can be better calculated and planned for, thus utilizing existing capital assets more effectively.

READ MORE ABOUT ELECTRIC POWER BOARD OF CHATTANOOGA'S PROJECT ON SMARTGRID.GOV:

Electric Power Board of Chattanooga Project Page

Electric Power Board of Chattanooga Project Description – *September 2014*

Electric Power Board of Chattanooga Case Study – *May 2011*

CASE STUDY: **DUKE ENERGY**



Investor-Owned Utility



Ohio, Indiana, Kentucky, North Carolina, South Carolina



4,514,000 Customers

Communication Network: Cellular DA and SCADA network

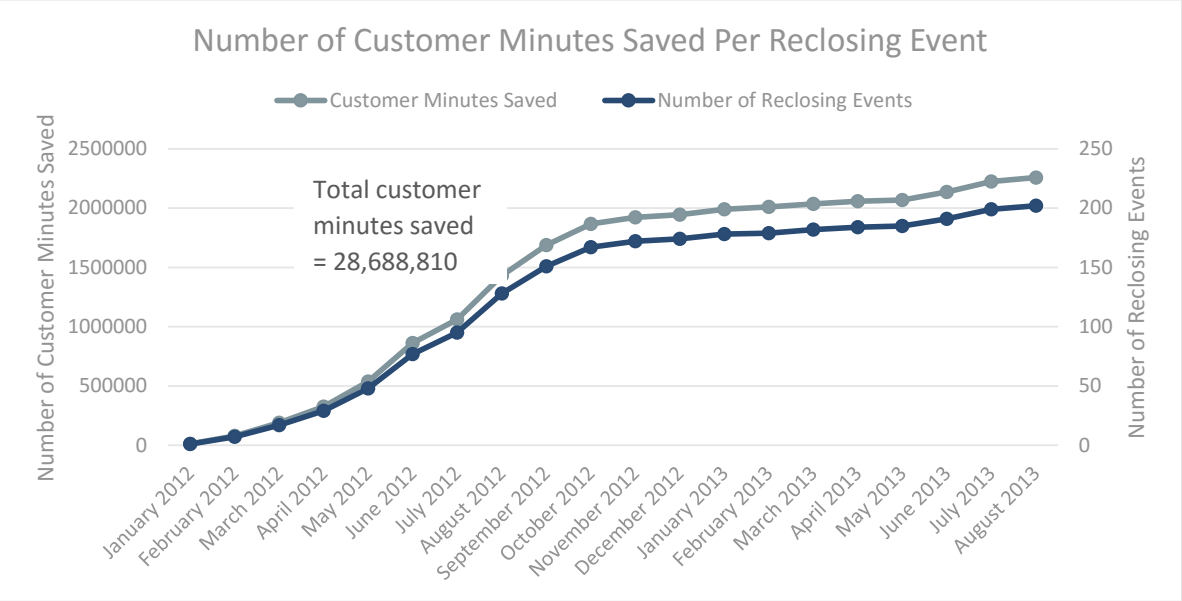
Total Cost of DA Implementation under SGIG	Distribution Automation Devices Deployed					
	Automated Feeder Switches	✓	914	Remote Fault Indicators	✓	4,755
	Automated Capacitors	✓	2,098	Transformer Monitors	✗	
$189,471,768	Automated Regulators	✓	914	Smart Relays	✓	4,755
	Feeder Monitors	✓	83			

DA Technologies Better Equip Field Crews: Duke Energy's approach emphasizes equipping field crews with key data and information tools. Instead of deploying field crews based on customer outage reports, line sensors and analysis software identify precise locations for repair, reducing costs and accelerating restoration of services.

Self-Healing Teams Enable Integrated FLISR Operations: Duke Energy installed "Self-Healing Teams" of field devices for FLISR operations. The teams of devices include centrally located control software and field installed electronic reclosers and switches that use digital-cell or radio communications. The device teams connect electronic reclosers and circuit breakers from two or three neighboring feeders and enable them to operate together in an integrated manner. These devices measure and digitally communicate information regarding distribution line loadings, voltage levels, and fault data to a central application that remotely locates and isolates faulted distribution line sections and automatically restores service to non-faulted line sections. Duke Energy used the following criteria to select the most advantageous feeders to implement Self- Healing Teams: feeder outage histories, availability of communications installations, and the number and type of customers on the feeder. Line sensors are placed at strategic locations along the feeder lines to help identify long-lasting faults and outages and to enhance the utility's response for accelerating restoration of services. Data from the line sensors are communicated to the utility's control room.

Re-Closure Activations Result in Avoided CMI: From January 2012 to August 2013, Duke Energy estimated avoiding about 28,688,810 CMI, due to re-closure activations, as shown in Figure 19. In 2014, after an additional 200 re-closers were installed, an estimated 111,200 additional CMI were avoided (75,400 CMI if major storms are excluded).

Figure 19. Number of Customer Minutes Saved Per Reclosing Event at Duke Energy



Smart Meter Data Improves Outage Diagnostics: As a part of its AMI system deployment, Duke Energy installed 966,000 smart meters with outage diagnostics features that allow the utility to "ping" meters and determine fault location. Its AMI system helped resolve 1,393 cases of single-call outages with remote diagnostics between 2010 and 2014.

Annual Outage Assessment Time Reduced: Duke Energy reports reductions in the amount of time spent annually assessing outages (including fault location) by more than 560 hours[26]. This impact results from applications of both fault location technologies and systems and AMI for pinging meters and confirming the status of power outages and restoration activities. Table 15 shows the results of Duke's estimates.

Table 12. Duke Energy Estimates of Reductions in Outage Assessment Activities

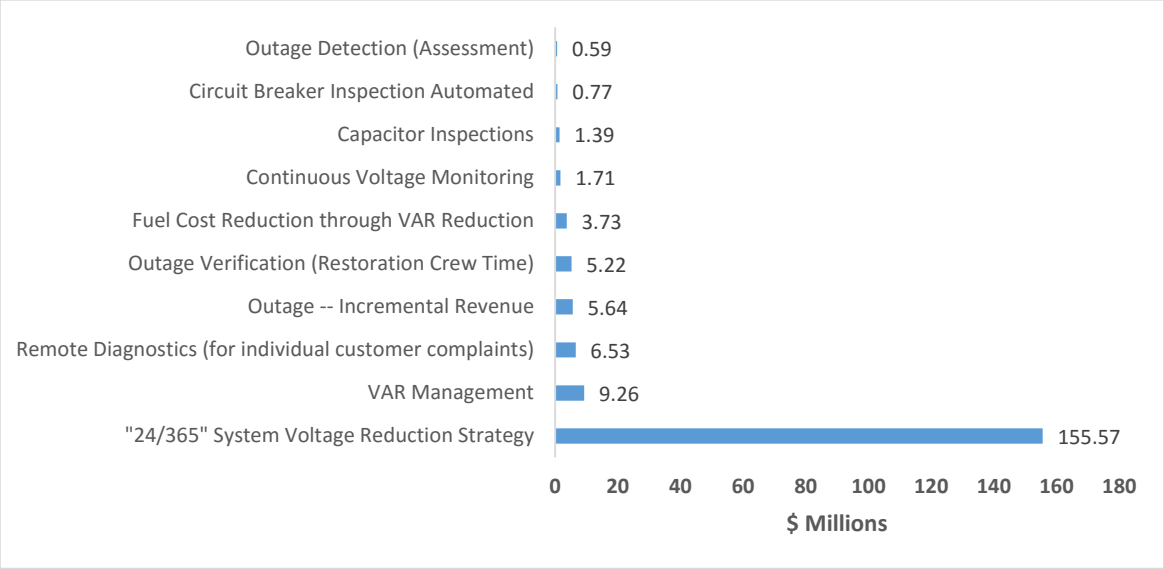
Duke Energy Estimates of Reductions in Outage Assessment Activities	
Outage Assessment Time Before SGIG (hours)	2,838
Outage Assessment Time After SGIG (hours)	2,270
Reduction in Outage Assessment Time (hours)	**568**
Percent Reduction in Outage Assessment Time (%)	**20%**

Service Voltage Level Reductions Lower Electricity Consumption: Management of peak demands through service voltage level reductions can reduce electricity consumption of end-use appliances and equipment and reduce customer bills. Reduction in electricity consumption is on the order of 1–3 percent. When implemented during peak hours, conservation voltage reductions (CVR) actions can supplement traditional demand-side management programs such as direct load controls, time-based rates, and incentive based programs. Duke Energy refers to its CVR actions as "Distribution System Demand Response" for this reason.

[26] Duke collected this data from work order management systems, service outage management systems, and labor timekeeping systems.

Continuous Voltage Optimization Vastly Improves Smart Grid Business Case: Duke Energy was among the first utilities to rigorously assess and establish the business case for its smart grid deployment. In 2011, Duke supported a third-party evaluation from the Public Utilities Commission of Ohio that validated 26 benefit areas.[27] Duke estimated the value of the revenue and benefit streams it can expect over 20 years, and discounted them to today's dollar to account for the changing value of money. Duke's deployment as of 2014 was tracking ahead of the 2011 estimated benefits in aggregate. Figure 20 shows that continuous voltage monitoring forms a large portion of the business case. Continuous voltage optimization can also reduce generation to avoid fuel costs and defer distribution capital investments. Other DA investments have smaller paybacks for Duke.

Figure 20. Estimated Net Present Value of Duke Energy's Smart Grid Program (2011 Dollars)



Integrated Volt/Volt-Ampere Reactive (VAR) Controls Achieve Voltage Reduction: Duke Energy used integrated volt/VAR controls to achieve consistent 2 percent voltage reduction on more than 200 circuits in Ohio. These reductions saved fuel and lowered customer bills, with no detrimental effects on service quality.

Remote Capabilities Reduce Physical Inspections: The remote capabilities of Duke Energy's new capacitor bank controllers reduced physical inspections by 1,085 units in 2013. Continuous monitoring instead of a once-a-year physical inspection reduces manual inspection costs and better optimizes voltage.

New DMS Integration Requires Change Management Practices: Under SGIG funding, Duke Energy installed a new DMS to enable new capabilities from device deployments, including FLISR, IVVC, and automated switching plans. The DMS now provides a data historian, Distribution Operations Training Simulator, and DMS/OMS interface capabilities across Duke's service territory. A key success for Duke Energy's smart grid project was the early implementation of business process management and change

[27] MetaVu for the Staff of the Public Utilities Commission of Ohio, *Duke Energy Ohio Smart Grid Audit and Assessment*, (MetaVu, June 2011).

management best practices. Implementing a DMS and deploying distribution automation were large-scale efforts that required leadership and coordination across multiple business units. Duke Energy facilitated business process management and change management through its newly formed Grid Modernization Organization, which is responsible for industry trend identification, business case development, business and regulatory approval, and upon project approval, project management and business readiness activities.

Change management prepares people and processes for business changes, particularly those with project benefits that depend on employee adoption, usage, and commitment to project timelines. Effective organizational change was particularly critical for the implementation of a DMS and integration of distribution automation devices, which required staff, technology, and process integration across business units. For example, DMS changes the roles of the GIS and IT support from traditional back-office staff to operational partners within the business. Adequate communication was a must. DMS required equal IT and business support, so joint business and IT leadership was required for its success. For any large-scale smart grid effort, communications, business process management, and change management structures should be built into the project plan, and relevant business units should be engaged early and often.

Deployment Expansions Planned: Duke Energy plans to complete its 10-year plan for grid modernization and expand deployments of fault location, isolation, and system restoration technologies and systems ("Self-Healing Teams") to additional substations and feeders with focus on service territories in Indiana, Kentucky, Florida, and the Carolinas.

READ MORE ABOUT DUKE ENERGY'S PROJECT ON SMARTGRID.GOV:

Duke Energy Project Page

Duke Energy Project Description – *September 2015*

CASE STUDY: **CONSOLIDATED EDISON (CON EDISON)**



Investor-Owned Utility



New York, New Jersey



3,578,188 Customers

Distribution Circuits Impacted:	**840 (of 2,297)**

DA Communication Network: Master radio sites to upgrade SCADA and wireless

Total Cost of DA Implementation under SGIG

$272,341,798

Distribution Automation Devices Deployed					
Automated Feeder Switches	✓	**797**	Remote Fault Indicators	✓	**1,851**
Automated Capacitors	✓	**449**	Transformer Monitors	✓	**17,401**
Automated Regulators	✓	**111**	Smart Relays	✓	**205**
Feeder Monitors	✓	**617**	Recloser Controls		307
Remote Battery Monitors	✓	**17**			

OMS, DMS, SCADA, and GIS Integration: Con Edison OMS has been merged with electric distribution and service mapping information, customer billing information, customer service call data, workforce and repair crew availability, and SCADA telemetry into one screen for control center operators. During outages, embedded models and analysis tools provides operators with predictions of field operations, actual data streams on grid conditions from SCADA, number of customers affected or restored, damage assessment information, and tracking of outage and restoration activities for managing and dispatching service and restoration crews and resources. This system also provides customer call center staff with maps of the grid showing the location of meters without power. This information is updated in near real time, is used to direct and manage field crews to restore power, and enables communications with customers on outage locations and estimated return to service times.

DA Greatly Reduces Customer Costs from Fewer and Shorter Outages: Con Edison used the ICE calculator to estimate the reduction in cost to customers for power interruptions occurring on its Orange & Rockland feeders. The calculator (which includes savings realized when adding distribution automation to circuits) estimates over $1.2 million reduction in interruption costs for the 14-feeder feeder system for a single year. These benefits were largely estimated to occur in the commercial and industrial customer classes, with the residential customers saving about $27,000. The impact of interruptions on industrial and commercial customers varies widely according to the type of business and the processes interrupted. The customer-average savings was about $650 per customer for larger customers and about $230 per customer for smaller customers.

Voltage Management Improves Substation Capacity under Peak Conditions: Through the use of overhead medium voltage distribution circuits and improved voltage management, Con Edison was able

to improve voltage management capabilities; enhance power system measurement; reduce reactive power consumption; and improve asset utilization, capacity management, and energy efficiency. Deployments included installation of pole mounted distribution capacitors, load tap changer (LTC) controllers at 4 kilovolt (kV) unit substation transformers, power quality and battery monitoring systems, and development of 4kV grid models for enhanced load flow analysis. Table 21 summarizes the key results based on data through the end of 2013.

Table 13. Summary of Con Edison Voltage Control Results

Summary of Con Edison Voltage Control Results		
Asset Utilization and Capacity Management	i.	Increased 4kV unit substation capability by 31.1 megavolt-ampere (MVA) or 2.8% under peak conditions, resulting in a net savings of $15.7 million.
	ii.	Reduced 4kV system primary losses by 2.3% under peak conditions.
Voltage Controls for Reactive Power Management and Energy Efficiency	iii.	Reduced reactive power requirements at the aggregate level of 33 substations in Queens by about 12.3% and 9.9% over a one-year test period through the application of advanced LTC controls.
	iv.	Increased power factor at these same substations by about 2% and 1% over the same one-year test period.
	v.	Reduced annual system energy losses by 4,500 megawatt-hours (MWh), resulting in estimated annual energy savings of about $340,000.

DERMs Improves Control of Demand Resources: Con Edison's distributed energy resource management system (DERMS) was used to monitor and control a variety of supply and demand resources including distributed generation and storage, building management systems, and demand response customers.

Data Historian Improves Data Access and Management: Con Edison's data historian project implements a centralized data repository for all electric distribution SCADA data. The system is integrated with existing corporate data systems and provides a single point of access for all users of the company's electric distribution data. BWP's data historian is responsible for capturing and storing operational measurements for the electric distribution network and for providing analytical tools for assessing distribution performance.

READ MORE ABOUT CON EDISON'S PROJECT ON SMARTGRID.GOV:

Consolidated Edison Company Project Page

Consolidated Edison Company Project Description – *August 2014*

Consolidated Edison Company Case Study – *May 2011*

CASE STUDY: **CENTERPOINT ENERGY**



Investor-Owned Utility



Houston, TX



2,320,156 Customers

Distribution Circuits Impacted:	**188 (of 1,516)**	**Distribution Substations Impacted:**	**31 (of 240)**

DA Communication Network: RF, WiMAX, and cellular technologies

Total Cost of DA Implementation under SGIG	Distribution Automation Devices Deployed					
	Automated Feeder Switches	✓	567	Remote Fault Indicators	✗	
	Automated Capacitors	✗		Transformer Monitors	✗	
	Automated Regulators	✗		Smart Relays	✓	171
$120,604,288	Feeder Monitors	✗				

DA Technology Package Enables FLISR Functions: CenterPoint Energy implemented its Intelligent Grid Switching Devices—a comprehensive package of DA technologies that perform a number of integrated grid functions. For example, Intelligent Grid Switching Devices use enclosures similar to line reclosers to provide reliable switching operations across thousands of operations without maintenance. Intelligent Grid Switching Devices also include monitoring equipment to measure load and voltage accurately and enable power quality analysis at the device. The system uses data storage and communications control packages that perform analytics and securely communicate rapidly with processors at both the substation and at the utility's central computing location.

OMS Integration Enables Outage Visualization and Efficient Dispatch of Repair Crews: CenterPoint Energy's OMS enables operators to visualize outages the moment they occur and trucks are often rolled before customer calls are received. In several cases, outages have been restored before customers were even aware that they had lost power. During large events, CenterPoint's OMS system can display results from thousands of last gasp smart meter signals, as well as data from SCADA and customer calls all on one screen, which enables operators to dispatch field crews more efficiently. Before this system was used, once a fault had been repaired, operators assumed all customers on the feeders had their power restored, which is not an accurate assumption during large scale outages. In some cases, customers involved in nested outages would still be without power and field crews would have to be dispatched a second time.

Improved Outage Alerts Increase Customer Satisfaction: CenterPoint Energy implemented a Power Alert Service (PAS) for customers using its OMS and AMI outage alerts to keep customers up-to-date with accurate information about the progress of restoration activities. Based on survey analysis, CenterPoint found customers highly satisfied with the service (see Figure 21).

Figure 21. Results of CenterPoint Energy Survey of Customer Satisfaction for Outage Information

Satisfaction Measures	
Overall Satisfaction with PAS: Combined responses for all delivery methods (email, text, and phone. 4 or 5 on a 5-point scale).	**85%**
Message Timeliness – "Power Out": Time to receive power out message met or exceeded expectations (4 or 5 on a 5-point scale).	**88%**
Message Timeliness – "Power On": Time to receive power on message met or exceeded expectations (4 or 5 on a 5-point scale).	**96%**
Usefulness of Information Provided: 4 or 5 on a 5-point scale.	**86%**
Estimated Restoration Time Accuracy: Power restored within +/- 30m of estimate.	**73%**

Advanced Distribution System Management Improves Planning: CenterPoint Energy's Advanced Distribution Management System (ADMS), which manages its FLISR operations, replaced the utility's legacy DMS, OMS, and distribution SCADA systems and allows the utility to use real-time smart meter and Intelligent Grid Switching Device data to better plan, engineer, and operate the grid. ADMS also integrates with the company's GIS, CIS, transmission management system, and many other back-office applications. ADMS capabilities include near-real time distribution load flow data capture and a platform for controlling FLISR operations. Figure 22 shows CenterPoint's distribution management system in 1993 and in 2014, illustrating how new technologies have made system operations increasingly digital.

Figure 22. CenterPoint Energy's DMS – 1993 and 2014



Post-SGIG DA Activities Planned: The utility plans to continue activities with its DMS vendor and user community to develop and deploy additional advanced capabilities and applications. CenterPoint plans to expand the capabilities of its Intelligent Grid Switching Devices from requiring manual validations to full automation, which will be tested on a limited number of substations and feeders before larger-scale deployments are implemented.

READ MORE ABOUT CENTERPOINT ENERGY'S PROJECT ON SMARTGRID.GOV:

CenterPoint Energy Project Page

CenterPoint Energy Project Description – *September 2014*

CenterPoint Energy Case Study – *February 2012*

CASE STUDY: **PPL ELECTRIC UTILITIES CORPORATION**



Investor-Owned Utility



Pennsylvania



1,396,751
Customers

Distribution Circuits Impacted:	**50 (of 1153)**	**Distribution Substations Impacted:**	**10 (of 376)**

DA Communication Network: WiMAX, cellular, and fiber optic cable

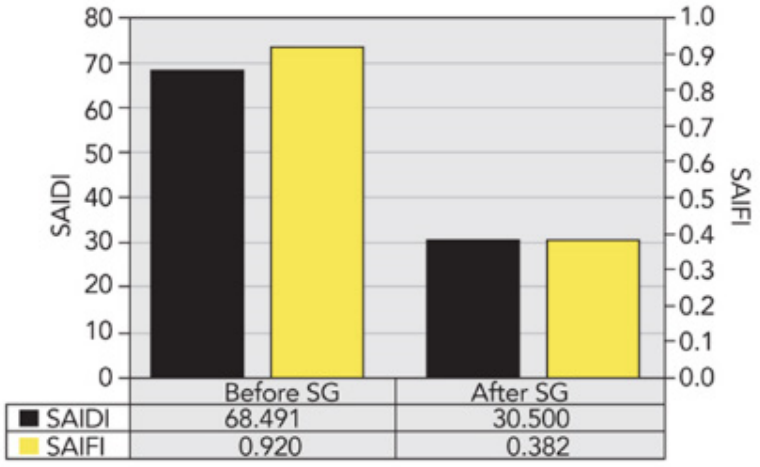
Total Cost of DA Implementation under SGIG

$38,108,290

Distribution Automation Devices Deployed					
Automated Feeder Switches	✓	214	Remote Fault Indicators	✗	
Automated Capacitors	✓	195	Transformer Monitors	✗	
Automated Regulators	✗		Smart Relays	✗	
Feeder Monitors	✗		Automated Reclosers	✓	77

DA Results in Sustained Reliability Improvements: PPL Electric Utilities Corporation estimated a 58 percent decrease in the average number of interruptions experienced by customers in 2013 (compared against a pre-deployment baseline), which also involved a 55 percent drop in the average number of customer minutes interrupted. PPL also estimated improvements in SAIDI over that same time period (see Figure 23).

Figure 23. SAIDI and SAIFI Improvements before and after Smart Grid (SG) Deployment, Estimated by PPL in 2013



Based on these results, PPL estimates a 25 percent improvement in reliability over the subsequent five years through the deployment of distribution automation. This estimate is based on analysis of PPL's

three-phase distribution circuits only, and excluded major events. Because 2013 was a good year weather-wise, PPL expects long-term effects to be somewhat lower than the effects shown in Figure 23.

Remote Switching Improves CMI: In January 2012, PPL accomplished remote switching and restored 300 customers approximately 30 minutes earlier than if done manually, resulting in a CMI improvement of 9,000. Following an overload condition on two main lines in March 2012, PPL rerouted power in five minutes to prevent a sustained outage of 2,600 customers. In September, 2012 interference by a squirrel caused circuit breaker damage which affected more than 3,000 customers. PPL estimates that about 330,000 CMI were saved using remote detection and restoration procedures.

Future DA Investments Plan to Upgrade All Feeders: PPL Electric Utilities Corporation plans to continue DA investments through 2018 until all feeders (about 1,140 total) are upgraded. This involves installation or replacement of approximately 3,400 devices in addition to the 1,500 devices installed as of 2014 that will receive new communications devices. Plans call for completing DA upgrades on remaining feeders within five years, and to install sensors on all three-phase capacitors within three years. Future DA investments are estimated to cost about $118 million. Future projects include about 3,000 automated feeder switches and 4,000 automated capacitor banks.[28]

READ MORE ABOUT PPL ELECTRIC UTILITIES CORPORATION'S PROJECT ON SMARTGRID.GOV:

PPL Electric Utilities Corporation Project Page

PPL Electric Utilities Corporation Project Description – *September 2014*

PPL Electric Utilities Corporation Case Study – *December 2011*

[28] DOE, *PPL Electric Utilities Corporation (PPL Smart Grid Project)*, 2014.

CASE STUDY: **PEPCO - DC**



Investor-Owned Utility



Washington, DC



249,059 Customers

Distribution Circuits Impacted:	**19 (of 779)**
DA Communication Network:	Wireless mesh

Total Cost of DA Implementation under SGIG

$8,308,800

Distribution Automation Devices Deployed

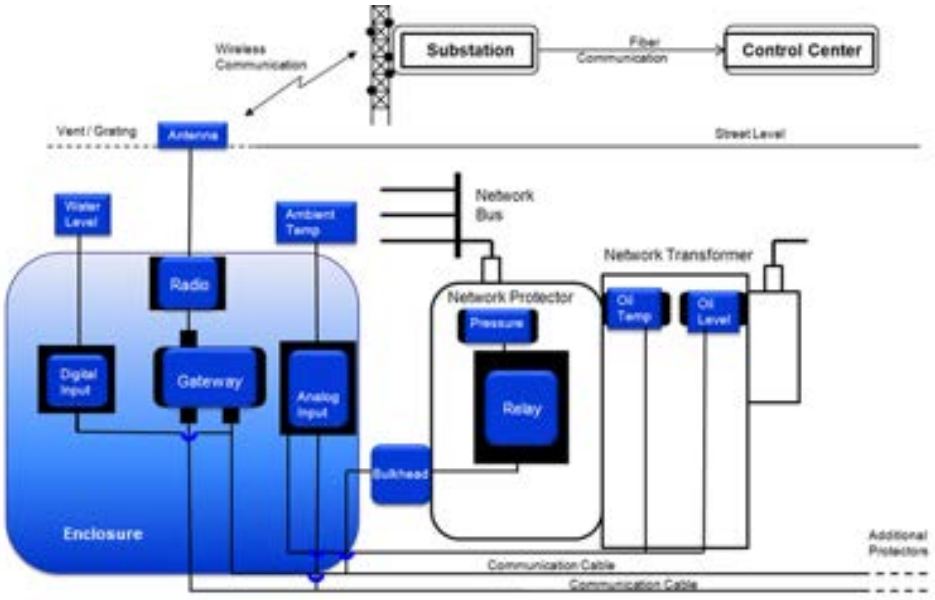
Automated Feeder Switches	✓	**42**	Remote Fault Indicators	✗	
Automated Capacitors	✗		Transformer Monitors	✓	**41**
Automated Regulators	✗		Smart Relays	✓	**306**
Feeder Monitors	✗		Substation DRTUs	✓	6
Transformer Health Sensors	✓	14	Automated Circuit Reclosers/Switches	✓	64

OMS and GIS Integration Improves Outage Management: In addition to OMS integration with AMI, Pepco's OMS has GIS mapping capabilities that display feeder and switch locations. The system shows operators and field crews the number of customers without power during outage events and the number of customer calls for each event. The system also allows operators to manually ping meters.

RMS and EMS Integration Improves Equipment Health Condition Monitoring: Pepco's remote monitoring system (RMS) is also integrated with the company's overall Energy Management System (EMS), enabling real-time and continuous data flows for operators and maintenance and repair crews to identify and address potential issues that can cause system disturbances. Pepco is also leveraging data from its remote monitoring system to improve its system planning process. It is using loads and voltages telemetry at peak time to verify the accuracy of the network computer model and the sizing of existing network transformers.

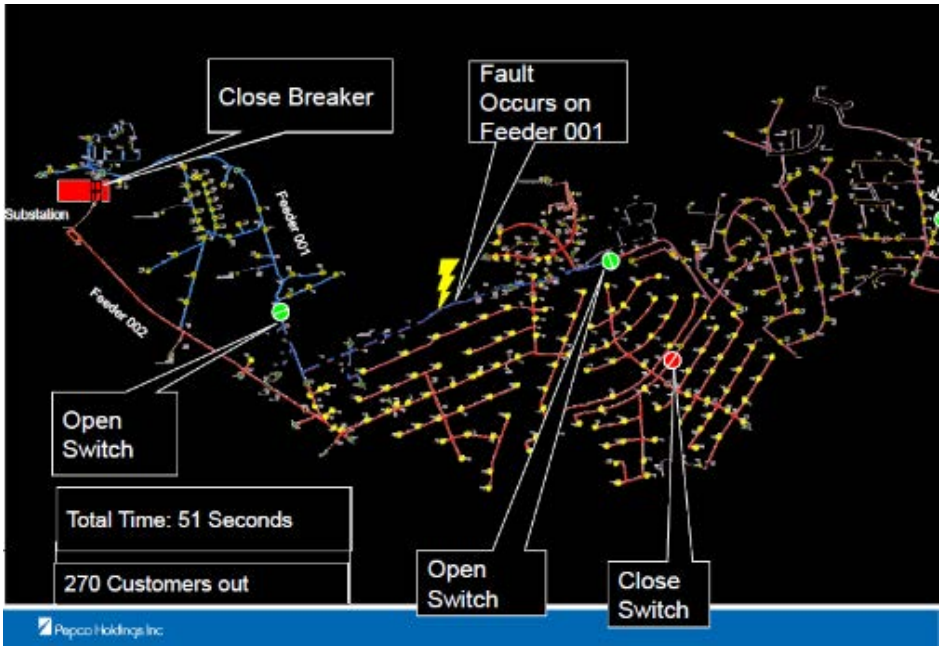
Figure 24 shows an example of how equipment health condition monitoring technologies and systems work together to implement actions. Pepco's approach focuses on transformers, and collects data such as oil level, oil temperature, and protector pressure (text in blue boxes without round corners), which is transmitted using radio communication to substations, and then is transmitted back to control centers using fiber-optic communications backhaul.

Figure 24. Illustration of Pepco's System for Equipment Health Condition Monitoring



Automatic Sectionalizing & Restoration Schemes Enable FLISR Operations: Pepco implements FLISR operations through its Automatic Sectionalizing & Restoration (ASR) schemes, which segment feeders into two, three, or four sections using closed remote-controlled switches or automatic circuit reclosers in the field. For any fault in one section, ASR first opens closed switches to isolate the faulted section. Then, it restores the non-faulted sections by reclosing feeder breakers and/or closing open tie switches to other feeders. Figure 25 shows a screen shot of Pepco's ASR operations.

Figure 25. Screenshot of Pepco's Demonstration of FLISR Operations



PEPCO CASE STUDY

Remote Software/Firmware Upgrades Reduce Time in Field: Pepco is moving toward remote, "over-the-air" upgrade capabilities to reduce the amount of time needed to implement changes in the field when new software versions become available.

DERMS Enabled Testing of Solar Systems Integration Revealed Challenges: Pepco developed a DERMS and measured voltage fluctuations from an 18 megawatt photovoltaic array connected to the distribution grid. The system simulated voltage levels that ranged from about 124 volts when the system was off to about 126 volts when system was set with a 0.97 leading power factor, and about 127 volts when the system was set with a 0.97 lagging power factor. With voltage level requirements set at 115.2 – 124.8 volts (+/- 4 percent of 120 volts), inverters were able to provide voltage management that reduced voltage fluctuations, and helped prevent voltage sags or collapses if large amounts of solar were to trip off line at one time. Pepco's photovoltaic system caused reverse flows on a few low load days, resulting in high voltage on the feeder and some damage to some customer equipment.

Future FLISR Deployments Planned: Pepco plans to continue its automatic sectionalizing and restoration deployments with the goal of reaching 15 percent of its systems, including expansion into areas covered by Delmarva Power, which was not part of its SGIG project.

READ MORE ABOUT PEPCO'S PROJECT ON SMARTGRID.GOV:

Note: Pepco Holdings, Inc. had three utilities with SGIG projects. Links to all three projects are included here.

Pepco Project Page

Pepco Holdings, Inc.—DC Project Description – *September 2015*

Pepco-MD Smart Grid Project Interim Report – *August 2013*

Atlantic City Electric Project Page

Atlantic City Electric Project Description – *September 2015*

3 Major Findings: Voltage and Reactive Power Management

Voltage monitoring and control and automated power factor correction enabled 38 SGIG utilities to reduce peak demands, efficiently utilize existing assets, and improve power quality.

Table 14. Voltage and Reactive Power Management Results from DA Investments

Primary Aim	• Reduced wear and tear on capital assets • Lower capital and operating costs to keep rates affordable for consumers • Protect sensitive electronic equipment—in utility and customer systems—from voltage and other power quality issues that can damage or limit equipment performance			
Smart Grid Function	Integrated volt/volt-ampere reactive controls (IVVC)	Automated voltage regulation	Conservation voltage reduction (CVR)	Automated power factor correction
Description	IVVC enables automated and greater control of voltages and reactive power levels to improve feeder power factors and reduce line losses.	Enables utilities to monitor voltages, determine optimal control signals, and use manual or automated controls to regulate voltage levels on particular feeders	Monitoring and automated controls enable utilities to reduce feeder voltage levels to reduce electricity use, primarily during peak periods.	By monitoring voltages and using automated capacitor banks, utilities accomplish power factor corrections to improve energy efficiency and reduce energy requirements for electricity delivery
Key Impacts & Benefits	• Reduced line losses to improve energy efficiency and capacity management • Reduced peak demand • Improved reliability and reduced outage costs • Energy savings to reduce emissions and customer bills • Improved voltage management capabilities and power system measurement • Reduced reactive power consumption • Generation fuel supply and cost savings • Reduced damage to customer-side electronic equipment		38 utilities employed conservation voltage reduction to **reduce peak demands by 1%–3%** on average per event. One utility reduced annual system energy losses by an estimated 4,500 MWh, resulting in: • $0.34 million in **annual energy savings** • **Reduced CO_2 emissions** by about 340 metric tons Several utilities **improved power factors to near unity** (where power factors equal 1). One utility in particular: • **Reduced reactive power requirements by about 10%–13%** over a one-year test period • **Increased power factors by 1%–2%**	

Historically, the size and placement of LTCs, voltage regulators, and capacitors were typically based on off-line modeling of peak- and light-load conditions, as well as operating experience. Most utilities did not monitor loads and voltages on the distribution system. For the last several decades, SCADA systems have been used by many utilities for distribution system monitoring, but these reach only substations and do not monitor feeder conditions from substations to customers. The lack of operating visibility on distribution feeders has historically required utilities to design and operate their systems in a relatively conservative manner to accommodate worst case scenarios. There has been little opportunity to optimize voltage and reactive power levels for constantly changing load conditions.

With the introduction of smart sensors, communications, and controls, utilities are now able to implement automated approaches to monitor and regulate voltage levels and reactive power levels, and to perform conservation voltage reduction and power factor correction to improve power quality. Many of the SGIG utilities pursued pilot-scale implementation of DA technologies for voltage monitoring and control to test the ability to improve efficiency and/or peak demand management.

As weather and climate conditions influence electricity demands, electricity generation and delivery assets are sized to serve demand when it reaches its highest levels, even though peak levels only occur less than 10 percent of the year. Because peak demand is one the most significant drivers of electricity costs, utilities attempt to reduce peak demands to improve asset utilization. This can result in lower capital requirements and operations and maintenance costs. Through rate cases and other proceedings, reduced peak demand can ultimately translate into lower electricity rates for consumers.

In addition, the use of digital electronics and computer controls in homes, offices, and factories is on the rise, enabling the nation's electricity consumers to operate more efficiently and expand capabilities for improving productivity, economic performance, and quality of life for consumers at home. However, changes from purely electro-mechanical to power-electronic-based components affect power quality requirements and other aspects of grid operations. For example, growing use of electronic, variable-speed-drive industrial motors can affect the inertial balance of the grid, which would impact the stability of local power systems. The changes in power quality requirements boost the need for addressing power quality issues on distribution systems.

Table 15 shows the impacts that result from the application of automated voltage controls.

Table 15. Utility and Customer Impacts from Voltage Management for Asset Utilization

Impacts	How Impacts are Accomplished
Utility Impacts	
Improved energy efficiency through reduced line losses and improved power factors	Feeder and substation sensors provide voltage and phase data to grid operators and/or DMS. Automated controls trigger voltage regulators and capacitor bank switching to optimize performance through conservation voltage reduction.
Reductions in peak demand	Smart meters and feeder sensors provide voltage data to grid operators and/or DMS. Automated controls implement conservation voltage reduction during peak periods which lower peak demands.

Impacts	How Impacts are Accomplished
Reductions in labor requirements	If automated volt/VAR control devices are replacing manually switched legacy equipment, this could result in avoided field visits for operations and maintenance of the devices without degrading the performance of the distribution system.
Improved reliability	Applications of conservation voltage reduction and real-time load balancing during peak periods reduces peak demands, risks for equipment overloads and the frequency of power disruptions.
Customer Impacts	
Energy savings and bill reductions	Applications of conservation voltage reduction reduce power consumption for affected customers and produces energy savings and lower bills.
Outage cost reductions	Reductions in the number of power disruptions reduce economic losses from outages for customers.

3.1 Integrated Volt/VAR Controls (IVVC) and Automated Voltage Regulation

Integrated volt/VAR technologies and systems provide new capabilities for grid operations to automate voltage controls and reactive power management. The SGIG DA utilities that implemented integrated volt/VAR controls employed a variety of techniques but all involved a common set of functions that began with data collection and telemetry for feeder voltage levels, feeder loads (real power in watts), and feeder reactive power (in VARs). Automated volt/VAR control devices (e.g., capacitor banks and voltage regulators) also report on their operational status (e.g., tap position of voltage regulators) to the utility's SCADA system.

The SCADA system collects the data and delivers it to utility back office systems and also typically to the DMS. In these cases, the DMS uses inputs from other grid assets and monitoring devices to continuously update models of electric distribution system operations. DMS models are used to estimate the effects of various grid elements on power flows and voltage profiles, including interconnected distributed generators such as rooftop photovoltaic or fossil-fuel fired gen sets. Given the available inputs and modeling capabilities, the DMS is used to determine optimal, coordinated volt/VAR control actions that are appropriate for given operational needs.

Once the optimal control actions are determined, the DMS sends switching commands to each volt/VAR control device through the SCADA system, which passes the commands to individual devices, such as switching capacitor banks and adjusting load tap changer and voltage regulator set points. If desired, grid operators can choose to manually override control actions determined by the DMS.

Grid operators can monitor, control, and optimize voltage from substations, along feeders, and all the way to customer premises using DA. Voltage level data at the customer from smart meters is sent to grid operators and DMS for use in optimizing grid performance. Voltage regulation down to the customer level is an important complementary objective for utilities implementing more comprehensive volt/VAR controls, like CVR (see more below).

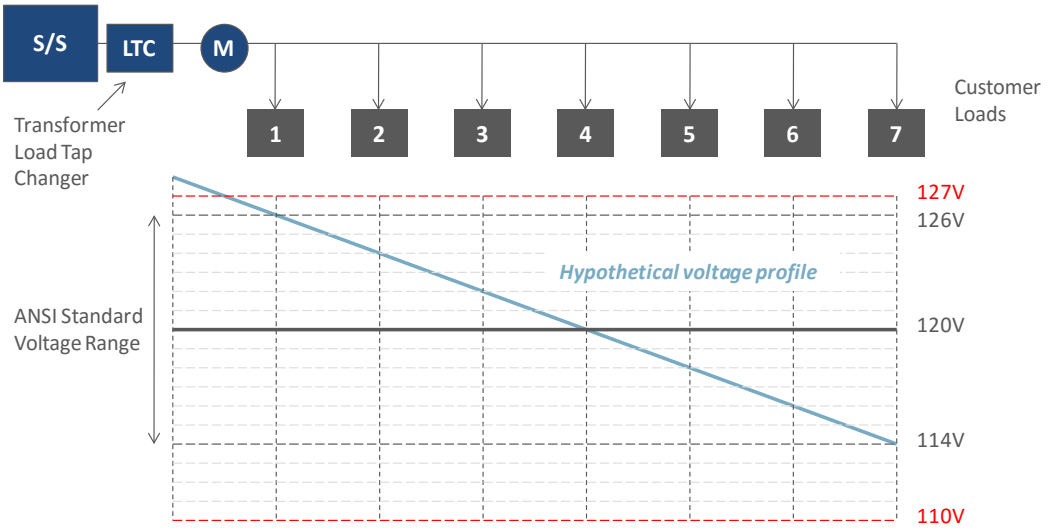
3.2 Conservation Voltage Reduction (CVR)

CVR optimizes distribution asset utilization by using monitoring and automated controls to reduce feeder voltage levels, improve the efficiency of distribution systems, and reduce energy consumption during peak periods or for longer-duration operations. Typical objectives of CVR include:

- Management of peak demands through service voltage level reductions, which can reduce electricity consumption of end-use appliances and equipment and reduce customer bills. Reduction in electricity consumption is on the order of 1–3 percent. When implemented during peak hours, CVR actions can supplement traditional demand-side management programs such as direct load controls, time-based rates, and incentive based programs. Duke Energy refers to its CVR actions as "Distribution System Demand Response" for this reason.
- Line loss reductions through feeder voltage level reductions and reactive power management results in lower electric resistance, which improves system energy efficiency and saves energy.

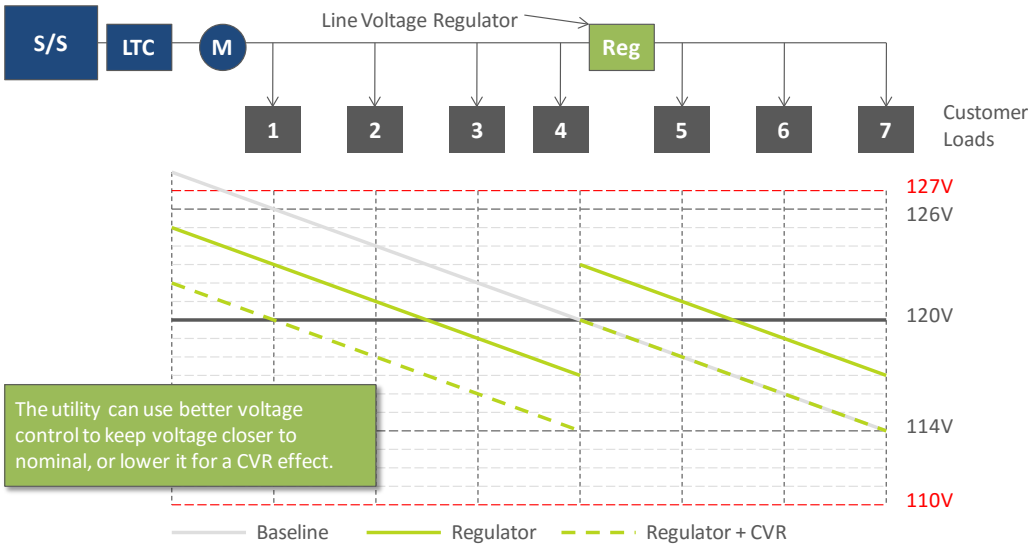
Operators use LTCs and voltage regulators to make small adjustments to voltage as load changes. Figure 26 and Figure 27 show the effects of LTCs and voltage regulators on a hypothetical distribution feeder voltage profile.

Figure 26. Hypothetical Feeder Voltage Profile with a Load Tap Changer



In Figure 27, the LTC can adjust the voltage at the head of the feeder to keep the profile within the acceptable voltage range, while voltage regulators placed mid-way along the feeder add a control point to raise or lower the downstream voltage levels.

Figure 27. Hypothetical Feeder Voltage Profile with a Load Tap Changer and Voltage Regulator



Operators can also use capacitors to compensate for reactive power caused by inductive loads. Figure 28 shows how capacitor banks placed along a feeder supports voltage profiles both downstream and upstream. The combined effect of the three types of equipment is to help utilities to keep overall profiles closer to desired levels under a variety of load conditions.

Figure 28. Hypothetical Feeder Voltage Profile with a Load Tap Changer, Voltage Regulator, and Capacitor Bank

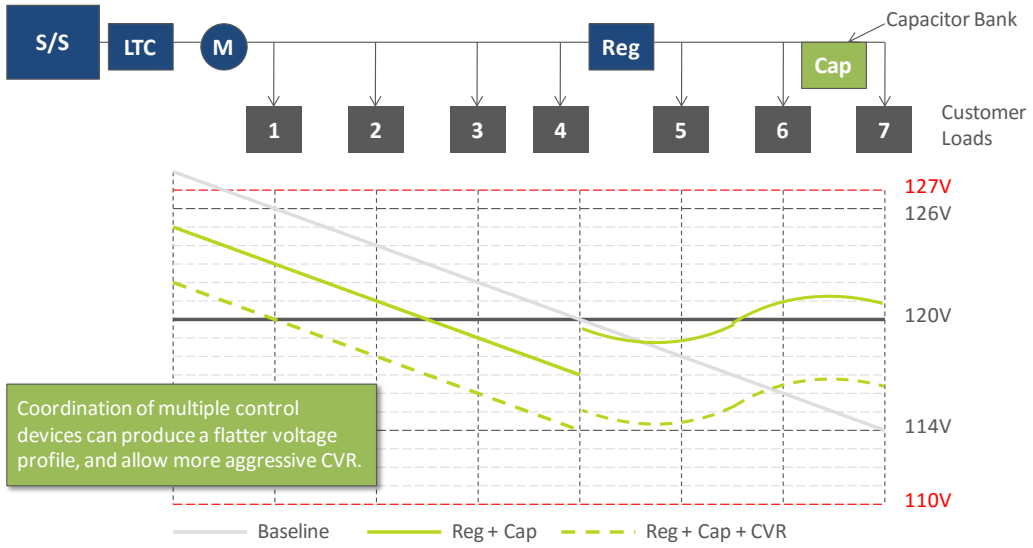


Table 16 provides a summary of the equipment for voltage support and reactive power control.

Table 16. Summary of Voltage Control Equipment, Functions, and Location

Equipment	Function	Area Impacted
Load tap changer	Raise or lower voltage	Entire feeders
Voltage regulator	Raise or lower voltage	Downstream of connection point
Capacitor banks	Compensate reactive load	Entire feeder with greatest effect closer to the load
	Support voltage	Upstream and downstream of connection point with greatest effect closer to the connection point

Historically, CVR often faced competing operational objectives. For instance, many utilities are subject to obligations and penalties with transmission operators for not maintaining reactive power levels within certain ranges (although CVR can also improve power factor to help meet transmission system objectives). In addition, reactive power management can also be operated for voltage support rather than line loss reductions, and in these instances, overcompensation is possible, in which voltages can increase.

DA can now provide operators with access to real-time voltage information to help reduce voltage while ensuring that voltage levels do not fall below acceptable levels. Remote, automated control of grid devices enables utilities to maintain reactive power level without overcompensating power factors. Smart meter data on voltages down to the customer level can be an important aspect of CVR to monitor voltage conditions and verify the performance of CVR operations.

Several DA utilities leveraged smart grid technologies in a selection of feeders to implement automated volt/VAR control. Central Lincoln Public Utilities District's case study provides an example of an innovative CVR system design combining distribution planning analytics, real-time management and control, and AMI.

Key Result: System Efficiency Improvements and Fuel Savings

SGIG DA utilities used conservation voltage reductions during peak and off-peak periods to improve system efficiencies. **Several utilities found that CVR could result in savings of 2-4 percent on affected feeders—a change that seems minor, but when applied system-wide, could result in comparable energy savings** and hundreds of thousands of dollars in energy costs.

Central Lincoln Public Utilities District, Wisconsin Power and Light (WPL), Duke Energy, and Glendale Water and Power (GWP) each saw improved feeder efficiencies on that scale due to CVR. Based on GWP's CVR pilot, it estimates a full-scale, five-year program could net power costs savings **of $470,000 to $1.2 million per year.**

→ See **Case Study:** Glendale Water and Power (page 81)

→ See **Case Study**: Wisconsin Power and Light (page 63)

The utilities used different analysis approaches to estimate energy savings and efficiency improvements due to CVR and volt/VAR controls, and applied pilots at different scales:

- Duke Energy estimates saving about 39,000 MWh over more than a year. The utility's rigorous business case assessment found that O&M savings from CVR formed the largest portion of the 20-year business case by far, with a net-present value of more than $155 million.
- Avista used model-based analysis of historical and current feeder loads to estimate an energy savings of about 42,000 MWh in 2014.
- Con Edison estimated annual energy loss reductions of about 4,500 MWh with estimated annual energy savings of about $340,000.

→ See **Case Study:** Duke Energy (page 40)

→ See Case Study: **Avista Utilities** (page 65)

→ See **Case Study:** Consolidated Edison (page 44)

Key Result: Reduced Peak Demand

CVR was also used by several of the SGIG DA utilities to achieve reductions in peak demands.

- Oklahoma Gas and Electric estimated peak demand reductions of about 2.3 percent on 22 circuits in 2012.
- Sacramento Municipal Utility District estimated a 2.5 percent reduction of peak demand in one pilot substation in summer 2011, and estimated a 1 percent average load reduction across 14 substations throughout the program.
- Southern Company used CVR to shave peak load during extreme weather, reducing the voltage level by 5 percent for approximately 5 hours, resulting in 300 MW of peak reduction.

→ See **Case Study:** Sacramento Municipal Utility District (page 67)

→ See **Case Study**: Southern Company (page 61)

3.3 Automated Power Factor Correction

Automated power factor correction provides grid operators with new capabilities for managing reactive power flows. Measurement devices provide grid operators and DMS with data on voltages and reactive power levels. Using this information, operators and DMS determine optimal control signals which trigger the switching of capacitor banks. When necessary, distribution operators can manually override commands generated by DMS.

Utility objectives for reactive power compensation include improving power factors and reducing line losses. Accomplishing these objectives potentially leads to significant cost savings due to lower energy and fuel requirements. Electric distribution systems operate most efficiently when power factors are equal to 1.

Key Result: Improved Power Factors and Better Power Quality

The SGIG DA utilities observed utility and customer impacts from actions to boost power quality. For example, Wisconsin Power and Light achieved overall power factor improvements from about 0.95 to about 0.97 between 2011 and 2013. Northern Virginia Electric Cooperative used power quality monitors on meters and transformers to help reduce voltage variations such as sags and surges, and power harmonics.

→ See **Case Study**: Wisconsin Power and Light (page 63)

→ See **Case Study**: Northern Virginia Electric Cooperative (page 34)

Key Result: Deferred Capacity Additions

There are several capacity deferral benefits from voltage control, CVR, and reactive power management. Two examples of this come from Con Edison and Southern Company. Con Edison used its voltage control and reactive power management technologies to increase its 4kV unit substation capability by 2.8 percent, resulting in a net savings of $15.7 million. Southern Company realized about $3.4 million in net present-value from deferred distribution capacity investments from reactive power loss reduction using automated capacitor banks, leading to power factor improvements to near unity.

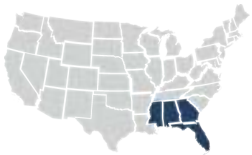
→ See **Case Study**: Consolidated Edison (page 44)

→ See **Case Study**: Southern Company (page 61)

CASE STUDY: **SOUTHERN COMPANY**



Investor-Owned Utility



Alabama, Florida, Georgia, and Mississippi



4,395,000
Customers

Distribution Circuits Impacted:	**2,081 (of 4,706)**	**Distribution Substations Impacted:**	**359 (of 3,325)**

DA Communication Network: Radio communications via SCADA platform

Total Cost of DA Implementation under SGIG

$207,274,827

Distribution Automation Devices Deployed					
Automated Feeder Switches	✓	**2,193**	Remote Fault Indicators	✓	**263**
Automated Capacitors	✓	**1,869**	Transformer Monitors	✗	
Automated Regulators	✓	**3,339**	Smart Relays	✓	**848**
Feeder Monitors	✗		Capacitor Monitors	✓	7,876

Reducing Reactive Power Loss Defers Capacity Investments: Southern Company realized about $3.4 million in net present value from deferred distribution capacity investments from reactive power loss reduction using automated capacitor banks, leading to power factor improvements to near unity.

DSCADA Reduces Truck Rolls & Vehicle Miles: Southern Company avoided over 94,000 truck rolls and almost 1 million vehicle miles traveled from October 2011 to September 2014 by using SCADA to remotely place and remove hot line tags, or to perform remote switching.

CVR Lowers Peak Load during Extreme Weather Event: Southern Company used CVR to shave the peak load during an extreme weather event in January 2014 (see Figure 29). With abnormally low temperatures, the system load was over 20 percent higher than the forecasted peak load for that day. Southern Company implemented CVR to reduce the voltage level by 5 percent for approximately 5 hours, resulting in 300 MW of peak reduction. This reduction helped Southern avoid the need for manual load shedding.

Figure 29. Southern Company CVR Results for the Polar Vortex in January, 2014

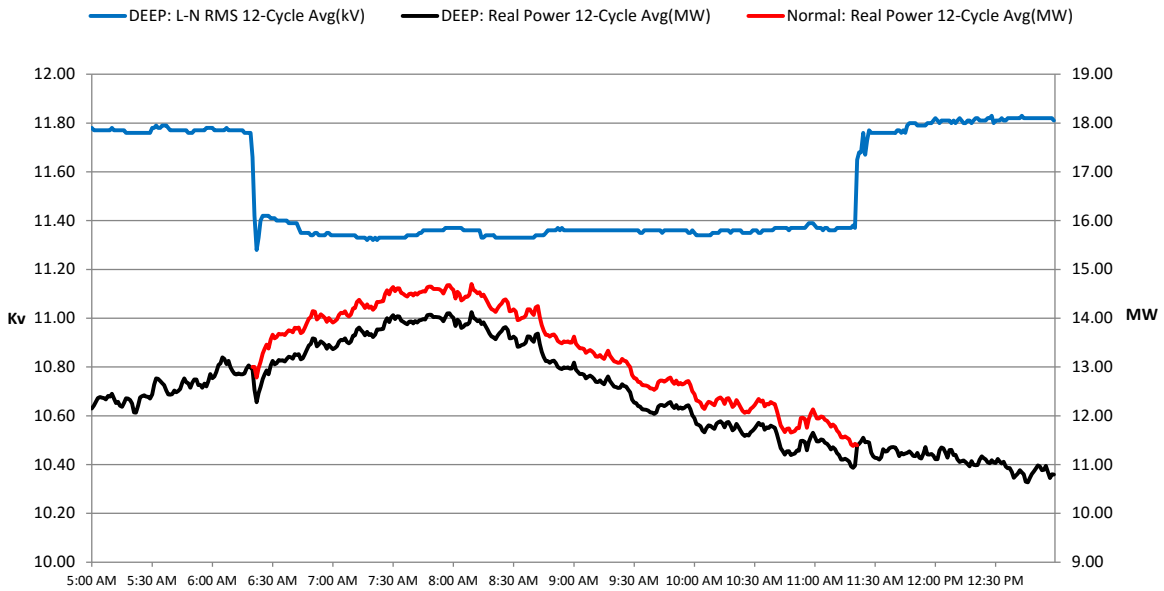


Figure 29 shows the voltage and load profile of a substation where CVR was implemented (blue line showing actual voltage; red line showing predicted higher load without CVR; and black line showing actual load, respectively).

Continued Integration of DMS and OMS Planned: Southern Company plans on moving forward with the integration of its distribution management and outage management systems, and will create a single user interfaces for grid operators. Plans also include expanding coverage of self-healing networks within its operating utilities to further reduce service interruptions for customers.

READ MORE ABOUT SOUTHERN COMPANY'S PROJECT ON SMARTGRID.GOV:

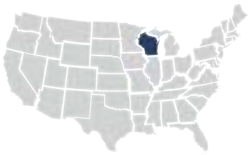
Southern Company's Project Page

Southern Company Project Description – *September 2014*

CASE STUDY: **WISCONSIN POWER AND LIGHT COMPANY (WPL)**



Investor-Owned Utility



Wisconsin



453,573
Customers

Distribution Circuits Impacted:	**298 (of 906)**

Communication Network: Capacitor control radios, take out radios, routers, hopper radios

Total Cost of DA Implementation under SGIG

$6,306,738

Distribution Automation Devices Deployed				
Automated Feeder Switches	✗		Remote Fault Indicators	✗
Automated Capacitors	✓	**576**	Transformer Monitors	✗
Automated Regulators	✗		Smart Relays	✗
Feeder Monitors	✗			

DA Operations Improve Power Factors: WPL achieved overall power factor improvements from about 0.95 to about 0.97 between 2011 and 2013 as a result of DA operations for power quality. This result is based on data collected from four representative distribution substations.

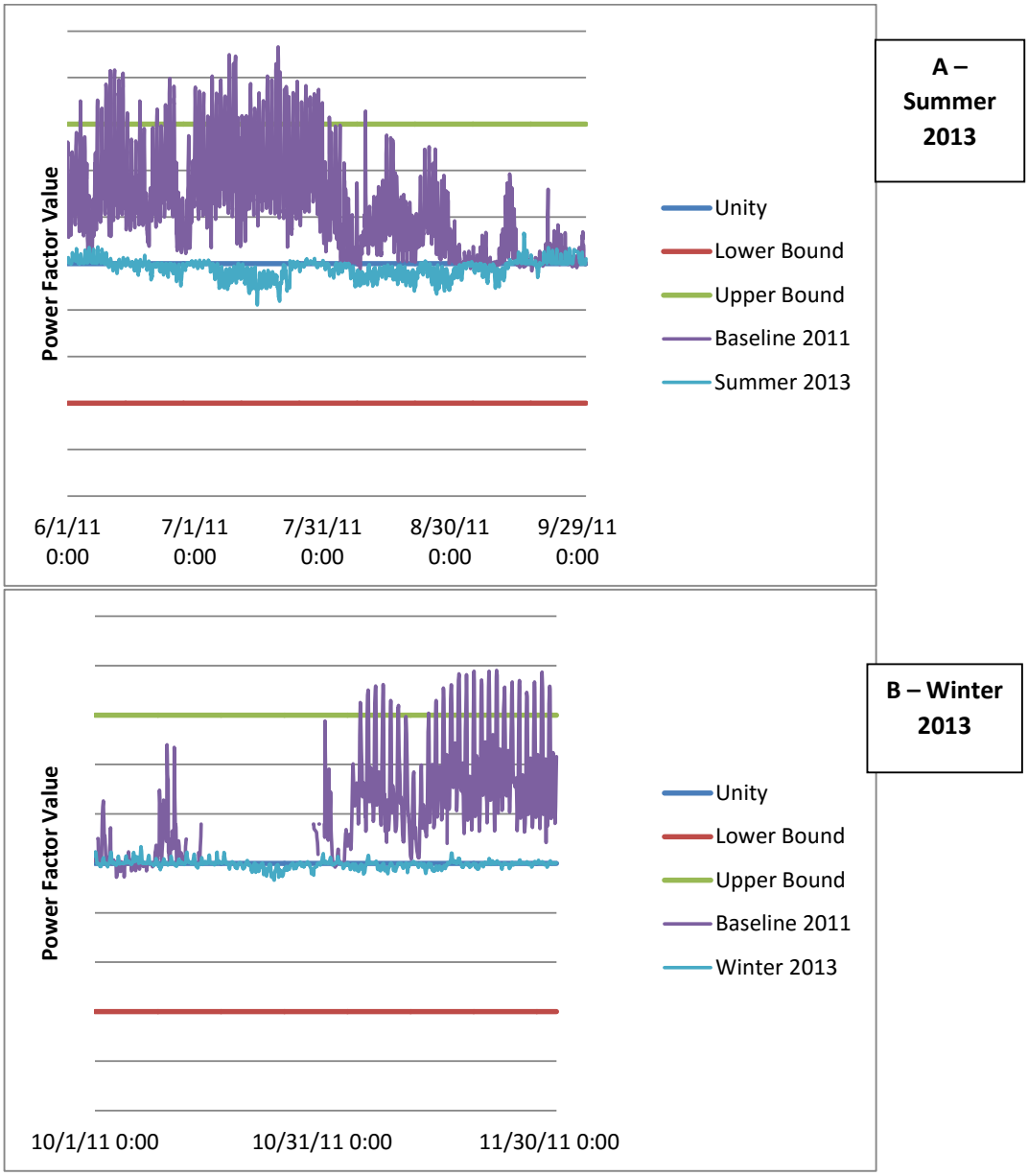
Table 17 shows that three out of the four substations realized power factor improvements, with two almost reaching a power factor of 1.0. While one of the four showed a decrease, the amount was small and within the range of error.

Table 17. Power Factor Data from Four WPL Substations, 2011 to 2013

Substation	Power Factor in 2011	Power Factor in 2013
Substation 1	0.97	0.96
Substation 2	0.96	0.99
Substation 3	0.95	0.99
Substation 4	0.93	0.96
Overall	**0.95**	**0.97**

Power Factors Less Variable after DA Operations: Figure 30 A and B compares power factor data at a fifth WPL substation for the summer and winter of 2013. The figures show power factor improvements in 2013 compared to baseline data before DA operations from 2011. In both cases, power factors were less variable and significantly closer to unity after DA operations were implemented than before.

Figure 30 A and B. Power Factors for a WPL Substation Before and After DA Operations, 2011 to 2013



READ MORE ABOUT WPL's PROJECT ON SMARTGRID.GOV:

Wisconsin Power and Light Company Project Page

Wisconsin Power and Light Company Project Description – *June 2015*

CASE STUDY: **AVISTA UTILITIES**



Investor-Owned Utility



Washington



354,554
Customers

Distribution Circuits Impacted:	**59 (of 330)**	**Distribution Substations Impacted:**	**13 (of 206)**

DA Communication Network: Radio frequency mesh and fiber optic cable

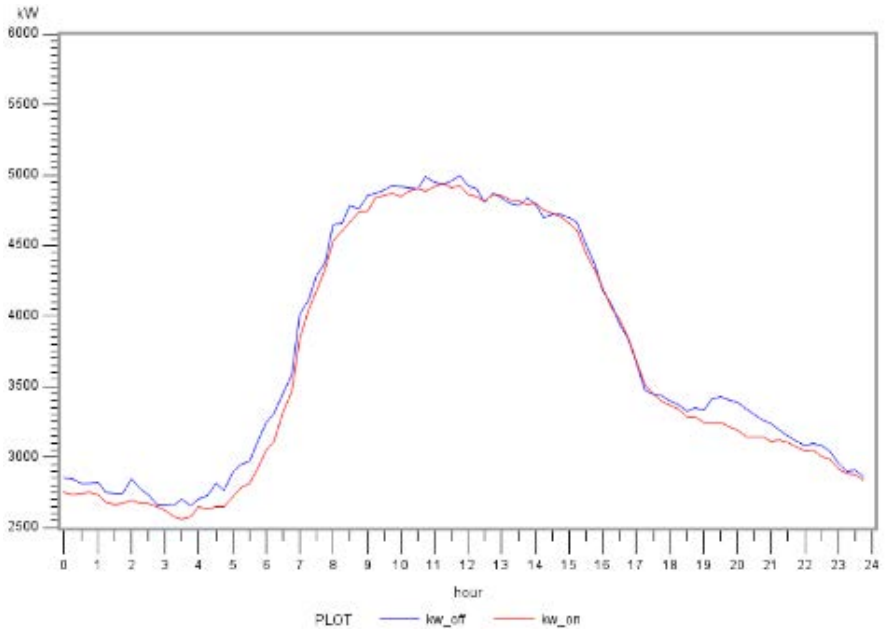
Total Cost of DA Implementation under SGIG	Distribution Automation Devices Deployed					
	Automated Feeder Switches	✓	263	Remote Fault Indicators	✗	
	Automated Capacitors	✓	123	Transformer Monitors	✗	
	Automated Regulators	✓	177	Smart Relays	✓	102
$41,657,885	Feeder Monitors	✓	102			

Automated Restoration Reduces CMI: A garbage truck hit an Avista Utilities power pole in August 2013, causing almost 900 customers to lose power. Avista Utilities' DMS automatically isolated the fault and restored more than 800 upstream customers instantaneously, saving an estimated total of 40 minutes of outage time per customer. The remaining downstream customers were restored several minutes later, saving 32 outage minutes. In total, 35,600 CMI were avoided as a result of DA operations.

CVR Results in Energy Savings: Avista Utilities estimates achieving energy savings of approximately 42,000 MWh during 2014 on feeders that serve a mix of residential, commercial, industrial, and agricultural customers in Spokane and Pullman, WA.

The SGIG DA utilities used different analysis approaches to estimate energy savings and efficiency improvements due to CVR. The Avista estimates are based on model-based analysis of historical and current feeder loads throughout the measurement period, normalized for weather, load characteristics, and customer behavior. Figure 31 shows two hourly load curves for one of the 25 feeders evaluated by Avista.

Figure 31. CVR Impacts on Hourly Load Curves for a Feeder



Note: The red line is with CVR, and the blue line is without CVR.

READ MORE ABOUT AVISTA UTILITIES' PROJECT ON SMARTGRID.GOV:

Avista Utilities Project Page

Avista Utilities Project Description –*July 2014*

CASE STUDY: **SACRAMENTO MUNICIPAL UTILITY DISTRICT (SMUD)**



Municipal/Public Utility



Sacramento, CA



672,860
Customers

Distribution Circuits Impacted:	**171 (of 644)**

DA Communication Network: RF mesh and fiber

Total Cost of DA Implementation under SGIG	Distribution Automation Devices Deployed					
	Automated Feeder Switches	✓	156	Remote Fault Indicators	✓	26
	Automated Capacitors	✓	177	Transformer Monitors	✗	
$62,172,480	Automated Regulators	✗		Smart Relays	✓	155
	Feeder Monitors	✗				

New Software Supports Rapid Outage Response, Switching, and Restoration Operations: SMUD used software for correlating, analyzing, and visualizing data from field devices, DMS, OMS, GIS, and weather forecasts, and displayed the information for grid operators in the distribution control center. The geospatial and visual analytics displays merged and correlated data from a variety of sources including smart meters, line sensors, substation monitors, and weather reports, making the information easier for SMUD operators to act on and to understand. The system displays historical and real-time data side-by-side, and users have the flexibility to dynamically zoom in to specific parts of the grid or assets of interest for more detailed visualizations. The data displays can be viewed on an 8-by-30 foot video wall in SMUD's control center, and is also available to supervisors and field crews on desktop computers and mobile computing devices.

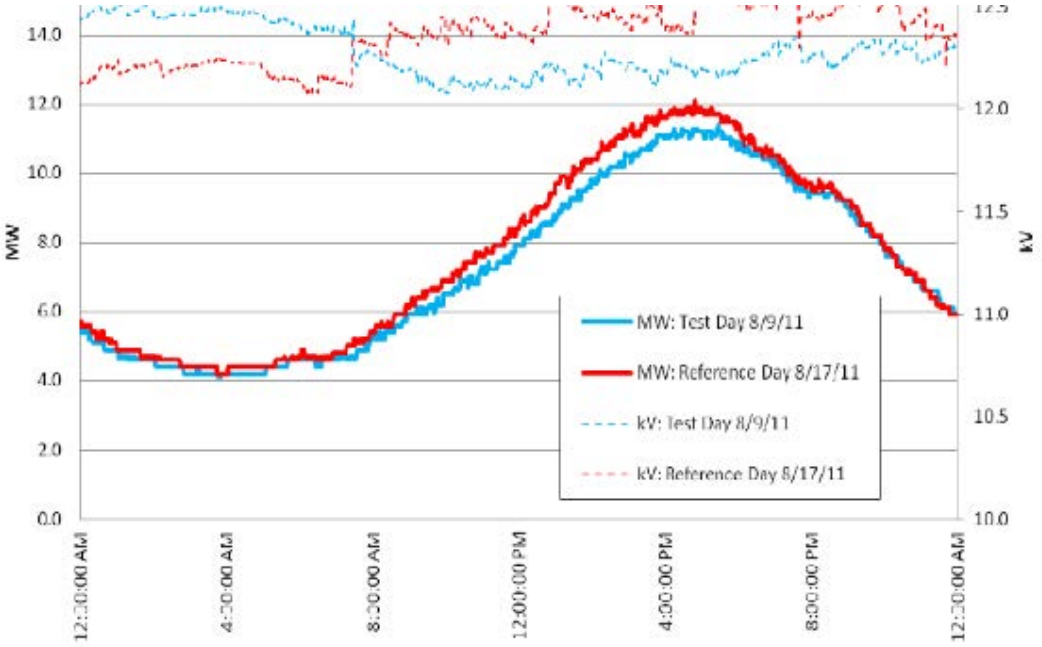
At SMUD, this system supplements the hands-on knowledge and experience of operators and field crews. The new system boosts capabilities, efficiency, and performance; quickly synthesizes numerous streams of disparate data; and provides on-the-fly assessments of grid, asset health, weather, power supply, and electricity demand conditions. The system helps managers and operators respond more quickly to outages, rapidly develop switching plans, and communicate outage restoration priorities to field crews.

Automatic Sectionalizing and Restoration System Improves Reliability: SMUD analyzed the effects of its automatic sectionalizing and restoration system on outages that result in feeder lock-out. Between April 2013 and September 2014, SMUD achieved 28 percent savings in SAIDI and 19 percent savings in SAIFI.

From April 2013 to September 2014, the SMUD experienced 46 unplanned, feeder-locking outages. SMUD was able to complete DA operations in 30 instances and saved about 705,500 CMI. Approximately 10,260 customers were affected in these 30 outages, 19 percent less than the number of customers who would have been affected otherwise.

CVR Program Reduced Peak Demand. In summer 2011, SMUD conducted a pilot test of its CVR program, which resulted in an estimated 2.5 percent reduction of peak demand on one of the pilot substations. Figure 31 shows peak demand reductions from CVR for a test day in August 2011. SMUD continued to deploy volt-VAR optimization technologies throughout the SGIG program, and estimates a 1 percent average load reduction across 14 substations and approximately 1.5 MWh of energy savings per day.

Figure 32. Reference versus Test Day CVR Impacts for a SMUD Substation



The figure compares two load curves: the red line is for a reference day; the blue line is for a test day involving CVR operations.

READ MORE ABOUT SMUD'S PROJECT ON SMARTGRID.GOV:

SMUD Project Page

SMUD Project Description – *November 2014*

SMUD 2013 PowerStat Study – *March 2014*

CASE STUDY: **CENTRAL LINCOLN PEOPLE'S UTILITY DISTRICT**



Municipal/Public Utility



Oregon



38,465
Customers

Communication Network: Fiber optic cable and high-speed wireless

Total Cost of DA Implementation under SGIG	Distribution Automation Devices Deployed				
	Automated Feeder Switches	✓	17	Remote Fault Indicators	✗
	Automated Capacitors	✗		Transformer Monitors	✗
$2,561,406	Automated Regulators	✓	2	Smart Relays	✗
	Feeder Monitors	✓	14		

Innovative CVR Design: Central Lincoln implemented an innovative CVR system design that combines distribution planning analytics, real-time management and control, and an approved measurement and verification methodology by integrating its AMI system with adaptive control algorithms (see Figure 33). The CVR project was implemented in three phases:

1. **Distribution planning analytics:** During the initial planning phase, Central Lincoln resolved existing voltage outliers using collected load profile data, including average voltage over 15-minute intervals, from nearly 1,500 smart meters on a project substation.
2. **Real-time management and control:** The CVR control system was integrated with SCADA and AMI systems. Every 15 minutes, the system analyzes near-real-time AMI data for a small subset of meters. If AMI voltages are outside the target range, the affected smart meters send an alert to notify the control system, which then sends a SCADA command to adjust the source voltage at the appropriate substation. This adaptive process allows the utility to automatically adjust voltage for seasonal, monthly, weekly, and daily variations in load. Figure 33 is a screenshot from the Manager UI covering approximately 12 hours of data.
3. **Measurement and verification:** After sufficient data was collected for both summer and winter seasons, Central Lincoln analyzed the data for measurement and verification of its CVR program.

CVR Reduces Total Energy Consumption: Central Lincoln estimates saving approximately 360 MWh (about 2.4 percent of electricity consumption of the affected feeders) due to CVR in 2013 (compared to 2012). Going forward, Central Lincoln plans to implement conservation voltage regulation territory-wide and install additional DA devices on its system.[29]

[29] DOE, *Fault Location, Isolation, and Service Restoration Technologies Reduce Outage Impact and Duration*, (DOE, November 2014).

Figure 33. User Interface Screenshot of Central Lincoln's CVR Management System



Equipment Upgrades Lower Voltages across Entire Feeders: Central Lincoln identified upgrades to correct abnormal voltage sags, which provided additional headroom to lower voltages across entire feeders. These improvements included:

- Replacing undersized meter bases for a group of large seasonal loads (an RV park);
- Replacing a missing transformer that had been removed from the field, but was still mapped in GIS; and
- Rectifying feeder configuration design issues based on low voltages identified on the customers' meters.

READ MORE ABOUT CENTRAL LINCOLN PEOPLE'S UTILITY DISTRICT'S PROJECT ON SMARTGRID.GOV:

Central Lincoln People's Utility District Project Page

Central Lincoln People's Utility District Project Description – *August 2014*

4 Major Findings: Equipment Health Monitoring

Equipment health condition monitoring provides utilities with new tools and capabilities to improve operational efficiency and reduce the frequency and duration of outages. It involves installing sensors on key components (e.g., power lines and transformer banks) to measure equipment health parameters.

Table 18. Equipment Health Condition Monitoring Results from DA Investments

Primary Aim	• Provide grid operators with actionable equipment health information to conduct preventative maintenance and dispatch repair crews more efficiently
Smart Grid Function	Equipment monitoring, data analysis, and preventative maintenance
Description	Identified equipment problems in advance of failure. Implemented remedies, extended equipment life, and prevented outages.
Key Impacts & Benefits	• Improved operational efficiency—by extending equipment life or removing equipment before it fails • Fewer and shorter power disruptions reduce customer outage cost and inconvenience Several utilities **avoided transformer outages through preventative maintenance** activities using equipment sensors. One utility reported **fixing a transformer before it failed** and saved several thousand customers from losing power.

Transformer sensors are used to provide data to grid operators and equipment diagnostics software on the status of operations. Real-time telemetry for transformer sensors includes:

- Ambient temperatures: transformers can require cooling to dissipate heat. Excess heat can reduce efficiency, damage equipment, increase maintenance needs, and shorten lifespans.
- Oil levels: oil is used to insulate and suppress electrical discharges. Low oil level can lead to equipment failures.
- Oil temperatures: oil also serves as coolant to help dissipate resistance heat. Abnormal oil temperatures can interfere with proper heat dissipation.
- Water levels: rainwater can penetrate transformer vessels, which can cause equipment failures if critical levels are reached.
- Pressure levels: electric arcing (electrical breakdown of gas caused by current traveling through air) can cause sudden pressure increases inside transformer vessels, which can lead to equipment failures if critical levels are reached.

Grid sensors are used to provide data to grid operators on equipment status and including the potential risks of overloads. Real time telemetry for grid sensors includes: phase currents, phasing voltages, transformer loadings, and power factors.

Once the sensor data is received by utility back office systems, diagnostics software determines if there is an equipment failure. The diagnostics software, which is typically integrated with back office systems, retrieves sensor data for analysis. The data flows through the system continuously, and is available to the diagnostics software on an on-demand/as-needed basis.

Preventative maintenance scheduling is another new capability from equipment health monitoring. Utility personnel can assess equipment data histories and set priorities for maintenance and inspection activities. Data analysis can pre-diagnose equipment that are suspected of failures by reviewing operational parameters (e.g., pressure, temperature, and oil levels) before inspections to determine the best approach for proactive repair and/or replacement. Data analytics software can evaluate failure risks for specific devices and set priorities for maintenance and inspection activities accordingly.

Table 19 shows the types of utility impacts from equipment health monitoring and how they are accomplished by new smart grid functions and capabilities.

Table 19. Utility Impacts from Equipment Health Monitoring

Impacts	How Impacts are Accomplished
1. Reduced duration of equipment maintenance activities	• Shorter and more targeted field inspections from remote identification of actual/potential equipment issues. • More targeted and timely inspections from greater operator visibility and alerts when automated assets don't respond to controls properly. • Fewer field visits when operators can remotely adjust equipment setting to resolve simple equipment issues without the need to dispatch repair crews.
2. Reduced frequency of equipment failures	• Data analytics enables operators to implement preventative maintenance, which allows repair or replacement of critical equipment before failure. • Control room alerts warn operators of abnormal operating conditions and potential overloads.
3. Deferred cost of equipment replacement	• Operator can override equipment operations (e.g., transformers) based on sensor data from other local assets (e.g., feeder loads). Manual overrides can prevent unnecessary operations and prolong the life of the equipment by avoiding excessive wear and tear.
4. Reduced number or duration of sustained outages	• Monitoring systems can reduce outage durations caused by equipment failures and by expediting corrective maintenance.
5. Reduced frequency of sustained outages	• Outage frequencies reduced by: (1) reducing the frequency of equipment failures, and (2) by expediting resolution of equipment failures through remote operation by control room staff.
6. Reduced resource requirements associated with equipment maintenance activities	• Reduced duration of maintenance activities enables resource reallocation to other maintenance activities. • Reduced frequency of equipment failures, reduced frequency of outages, lead to reduced needs for physical field inspections, labor hours, truck rolls, and/or fleet vehicle miles.
7. Improved worker safety	• Control room operators can pinpoint feeder segment to de-energize and reduce the risk of safety incidents.

Key Result: Improved Failure Prediction and Proactive Maintenance Reduce Failure-Related Outages

Equipment health monitoring provides grid operators and maintenance crew with up-to-date feedback on the operational status of the network and identifies network components that require on-site inspection and maintenance. It can provide real-time alerts for abnormal equipment conditions, based on potential violations of equipment operational parameters. It can also provide analytics that help utility engineers plan preventative and proactive equipment maintenance, repair, and replacement activities, as well as the cause of equipment failures through post-mortem forensic analysis. The Pepco case study in this report provides an example of how the equipment health monitoring system was designed.

→ See **Case Study:** Pepco (page 50)

These technologies and systems equip grid operators with new capabilities to dispatch repair crews based on diagnostics data from equipment health monitoring. When systems alert control rooms of abnormal diagnostics data, operators can notify appropriate personnel (e.g., engineers, technicians, or field crews) to investigate the equipment in question. Monitoring systems can be designed for operators to remotely operate monitored equipment to correct the cause of abnormal diagnostics data, or control the equipment to prevent further damages or failures.

- Equipment health monitors at Florida Power and Light helped identify and prevent a potential transformer failure, preventing an outage for about 15,000 customers and avoiding at least $1 million in restoration costs. The utility's case study in this report provides information about additional cost savings and improvements in proactive equipment maintenance.

→ See **Case Study**: Florida Power & Light Company (page 74)

- Marblehead Municipal Lighting Department avoids 10-15 distribution line transformer outages annually during summer heat waves through transformer monitoring using 15-minute readings.

Key Result: Fewer Physical Inspections and Reduced Labor for Maintenance and Repairs

Several SGIG utilities reduced physical inspections of capacitor banks, reducing the labor needed for inspections. For example, Duke Energy's new capacitor bank controllers reduced physical inspections by 1,085 units in 2013. Preventative maintenance also reduced the labor hours and overtime associated with restoration and repairs following major equipment failures.

→ See **Case Study**: Duke Energy (page 40)

CASE STUDY: **FLORIDA POWER & LIGHT COMPANY (FPL)**



Investor-Owned Utility



Florida



4,524,000 Customers

Distribution Circuits Impacted:	**476 (of 3,124)**

DA Communication Network: Wireless mesh network

Total Cost of DA Implementation under SGIG	Distribution Automation Devices Deployed					
	Automated Feeder Switches	✓	**285**	Remote Fault Indicators	✓	**3,879**
	Automated Capacitors	✓	**1,403**	Transformer Monitors	✓	**2,716**
$84,667,288	Automated Regulators	✓	**1,806**	Smart Relays	✓	**1,084**
	Feeder Monitors	✓	**1,014**	Throw-over Sensors	✓	745

Equipment Health Monitoring Pre-Empts Transformer Failure: FPL installed remote monitors on power transformers in about 500 substations. FPL's Transmission Performance and Diagnostic Center (TPDC) and its System Control Center remotely monitor critical transformers and feeders for faults. Equipment health monitors evaluate conditions on high- and low-voltage transformer bushings, including capacitance, power factor, and the extent of current imbalance. Bushing failures can damage transformers, which may require costly repairs and create extended service interruptions. In 2012, the TPDC detected an out-of-tolerance high-voltage bushing using a newly installed monitor, indicating a potential transformer fault. FPL tested and replaced the unit, preventing an outage for about 15,000 customers and avoiding at least $1 million in restoration costs. Through the third quarter of 2014, FPL had proactively replaced more than 1,000 distribution transformers, preventing potential unplanned outages for an estimated 10,000 customers.

Monitoring Quickly Identifies Issues, Prevents Larger Problems: FPL monitors capacitance voltage transformers (CVTs) by measuring voltage magnitudes and calculating phase angles. To prevent further complications, engineers implemented an algorithm that used data on voltage magnitudes and phase angles to detect early CVT degradation. In September 2011, the control room received an alert indicating a potential problem with a degraded phase on a CVT. Local field engineers were able to locate and replace the defective CVT, thus preventing a failure that could have resulted in an extended outage for several thousand customers.

FLISR Operations Reduced Outages and Momentary Disturbances during Major Storms: FPL is using AFS and Automated Lateral Switches (ALS) as a key part of an unprecedented program to reduce the number of momentary outages—those lasting less than one minute. Tropical Storm Isaac, which struck Florida in August 2012, caused significant power outages in FPL service territory. Automated feeder switching and FLISR operations contributed to reductions in CI and momentary disturbances. The

company reports that 9 operations serving almost 16,000 customers led to more than 9,000 fewer customer interruptions and approximately 2,500 fewer upstream momentary disturbances.

FPL also markedly increased the average annual customer minutes of interruption avoided by 5.1 million minutes from 2012 through the third quarter of 2014. This was achieved, in part, due to the absence of major storms, as well as AFS and FLISR operations. The company used technologies that led to reductions in the frequency of outages.

AFS Expansions Planned: FPL is increasing its AFS deployment beyond the 1,000 already installed to 10,000 ALS or more in ensuing years.

READ MORE ABOUT FPL's PROJECT ON SMARTGRID.GOV:

Florida Power & Light Company Project Page

Florida Power & Light Company Project Description – *April 2015*

Florida Power & Light Company Case Study – *July 2012*

5 Major Findings: Integration of Distributed Energy Resources

DERs include a variety of technologies such as rooftop photovoltaics, wind generators, high efficiency reciprocating engines, combined heat and power systems, micro-turbines, energy storage systems,[30] fuel cells, plug-in electric vehicles, and demand response programs. As DER costs come down, DER installations are growing—increasing the need for more effective and lower cost technologies, tools, and techniques for grid integration that also maintain safety and reliability.

Table 20. DER Integration Results from DA Investments

Primary Aim	• Reduce the costs and difficulties of interconnecting the growing numbers of DERs with local utility distribution systems	
Smart Grid Function	Automated DER dispatch and management	Operation of Thermal Energy Storage for Demand Management
Description	Analysis tools and DERMS are helping utilities to integrate DERs into grid operations while maintaining reliability and safety objectives.	Utilities and commercial and municipal customers collaborated in operating ice storage systems to shift building air conditioning from peak to off-peak periods.
Key Impacts & Benefits	• Lower electricity bills for consumers who act as both electricity producers and consumers • Reduced emissions from displaced traditional thermal generation • Increased resilience by reducing reliance on central power generation	Two utilities used DERMS to integrate ice storage to shift air conditioning load from peak to off-peak periods in commercial and municipal buildings—which in one case **reduced the buildings' cooling requirements by 5%**. DERMS provide **near real-time status reports on DERs** and help visualize their impact on the grid.

Grid integration requires tools to monitor and dispatch DERs, and to address electric power flow and control issues such as low-voltage ride through, harmonic injection, voltage fluctuations, and reactive power management. Solutions are needed to ensure that new DERs do not jeopardize the safety or reliability of electric distribution systems. Also needed are standards and protocols for DER interconnections, computer simulations, distribution management systems, and the addition of new hardware and protective devices.

[30] DOE's Smart Grid Demonstration Program included 16 energy storage projects that evaluated technologies and systems. Interim and final Technology Performance Reports can be downloaded from www.smartgrid.gov.

SGIG DA utilities evaluated DER-enabling technologies such as DERMS, and DERs including thermal energy storage for commercial and government buildings. The SGIG role focused not on DER evaluations, but on the tools and techniques for DER grid integration.[31] Several SGIG DA utilities did evaluate specific DERs, but not as part of their SGIG projects.

IADS are real-time control systems that integrate demand- and supply-side resources into day-ahead and real-time utility operations. These systems can be configured to optimize and automate dispatch of distributed and renewable resources, demand response and direct load control programs, and energy storage systems.

DERMS offer more capabilities than IADS, including network awareness, asset monitoring and control, scheduling and dispatch, active and reactive power import and export control, voltage control, constraint management, forecasting, resource valuation, and optimal demand response dispatch.

5.1 Automated DER Dispatch and Management

IADS help utilities to develop efficient operations and balance multiple objectives including system reliability, security, safety, and integration with wholesale markets. IADS are used to implement flexible monitoring and control of the distribution system to enable integration of distributed energy resources without degrading safety or reliability, or causing damages to the grid.

DERMS provide near real-time status reports on DERs and associated utility communications and control equipment to provide visualization or representation of DER impacts on the distribution grid; data for modeling and verification; and mitigation of both DER backfeeding and cold load pick-up. These capabilities support DA planning and operations.

Several of the SGIG DA utilities used IADS and DERMS (full case studies in this report provide more complete descriptions):

- Burbank Water and Power's IADS is used to manage all types of supply and demand resources, including the thermal storage operations the utility tested. It enables grid operators to turn units on and off remotely without disrupting cooling service to the host building.
- Consolidated Edison's DERMS was used to monitor and control a variety of supply and demand resources including distributed generation and storage, building management systems, and demand response customers.
- Pepco developed a DERMS and measured voltage fluctuations from an 18 MW photovoltaic array connected to the distribution grid, which caused reverse flows on a few low load days, resulting in high voltage on the feeder and some damage to some customer equipment.

→ See **Case Study**: Burbank Water and Power (page 79)

→ See **Case Study**: Consolidated Edison (page 44)

→ See **Case Study:** Pepco (page 50)

[31] Idaho Power Company implemented a SGIG project involving the grid integration of wind energy resources through the development of a wind forecasting model. This activity involved wholesale power markets at the transmission level and is not included in this report on distribution system operations. For further details see *New Forecasting Tools Enhance Wind Energy Integration in Idaho and Oregon*, August 2014.

5.2 Operation of Thermal Energy Storage

Thermal storage systems can be used by utilities and customers to improve asset utilization by shifting demand to off-peak periods. These were implemented by two California municipal utilities: Burbank Water & Power and Glendale Water & Power. Demand response aspects of these deployments are discussed further in two SGIG reports: DOE, *Municipal Utilities' Investment in Smart Grid Technologies Improves Services and Lowers Costs* and *Advanced Metering Infrastructure and Customer Systems: Results from the SGIG Program*.

→ See **Case Study**: Burbank Water and Power (page 79)

→ See **Case Study:** Glendale Water and Power (page 81)

CASE STUDY: **BURBANK WATER AND POWER (BWP)**



Municipal/Public Utility



California



51,858 Customers

94%



of distribution system with DA

Distribution Circuits Impacted:	**130 (of 138)**

DA Communication Network: Fiber optic Ethernet

Total Cost of DA Implementation under SGIG	Distribution Automation Devices Deployed					
	Automated Feeder Switches	✗		Remote Fault Indicators	✗	
	Automated Capacitors	✗		Transformer Monitors	✗	
$10,932,246	Automated Regulators	✓	130	Smart Relays	✗	
	Feeder Monitors	✗				

OMS Integration Expands DA Capabilities: BWP's OMS not only records outage causes and locations, but also estimates restoration times, adjusts predictions based on field reports, and supports customer call-backs and notifications.

Smart Grid Investments Deliver Exceptional Reliability: An independent auditor's report found that BWP investments in smart grid technologies have helped them deliver "exceptional system reliability," noting that in fiscal year 2012 "the system experienced approximately 15 minutes of service outage once every 5.4 years compared to the typical industry system of approximately 96 minutes of service outage once every 1.2 years."[32]

BWP reported avoiding over 4.4 million CMI between 2010 and 2014. This was nearly a 50 percent reduction in estimated CMI of 8.4 million without SGIG upgrades. SGIG upgrades included relays with microprocessors with auto-reclosing capabilities.

Thermal Storage Load Management Reduces Peak Demand: BWP integrated the operation of 34 ice storage units installed on commercial and municipal buildings to reduce peak demands. The systems use electric chillers operated overnight to make ice, which can be used during the day to cool the buildings, thereby lowering air conditioning loads and reducing peak demand. BWP's 34 units reduced peak demand by at least 230 kilowatts and shifted about 1,400 kilowatt hours from peak to off-peak periods, which reduced the buildings' cooling requirements by about 5 percent, resulting in energy savings and emissions reductions for the municipality.

[32] Audited Financial Statements, Fiscal Year 2013-1013, Burbank Water and Power, Independent Auditor's Report by White, Nelson, Diehl, and Evans LLP, June 30, 2013.

BWP included ice storage operations in their Integrated Automatic Dispatch System (IADS) to dispatch and account for demand response operations. BWP's IADS is a comprehensive system that manages all types of supply and demand resources and integrates dispatch with wholesale operations and the California Independent System Operator. The system provided a dashboard that reports operating statistics and provides controls for remote operation of the units, enabling grid operators to turn units on and off remotely without disrupting cooling service to the host building. Building operators have the ability to override pre-determined or utility-directed controls for operation of the ice storage systems.

READ MORE ABOUT BURBANK WATER AND POWER's PROJECT ON SMARTGRID.GOV:

Burbank Water and Power Project Page

Burbank Water and Power Project Description – *August 2014*

CASE STUDY: **GLENDALE WATER AND POWER (GWP)**



Municipal/Public Utility



California



84,343
Customers

Distribution Circuits Impacted:	**4 (of 110)**
DA Communication Network:	Wireless RF and Ethernet/IP backhaul

Total Cost of DA Implementation under SGIG	Distribution Automation Devices Deployed					
	Automated Feeder Switches	✓	18	Remote Fault Indicators	✗	
	Automated Capacitors	✓	4	Transformer Monitors	✗	
$7,645,153	Automated Regulators	✗		Smart Relays	✓	22
	Feeder Monitors	✗				

Conservation Voltage Reduction Could Significantly Lower Power Costs: GWP is also piloting a CVR program that uses smart meter voltage data to improve feeder efficiency and to provide significant energy efficiency benefits to customers. GWP estimates that a full-scale CVR project can achieve energy savings of between 2 percent and 4 percent on 65 percent of GWP feeders, or between 14,000 and 28,000 MWh per year. At full scale, the program will include 68,000 GWP meters. Assuming GWP's current value of saved energy of $50 per MWh, a full-scale, five-year program could net GWP power cost savings of $470,000 to $1.2 million per year.

Customer Savings Increase Net Present Value of Investments: GWP used value-of-service estimates for business case analysis of DA investments. They estimated the net present value of investments in DA technologies and systems would increase by 42 percent if customer savings from fewer and shorter outages are included in the analysis. The value-of-service estimates used were $0.12 per minute avoided for residential customers, $73.11 per minute avoided for commercial customers, and $247.89 per minute avoided for industrial customers.

Customer Notification Improves: One customer notification approach involves use of telephone messaging and IVR software. GWP's IVR system gives customers the ability to report outages, listen to known outage details, request follow-up status reports and automated call backs. GWP also uses its IVR system to send bulk messages about outages and other matters to customers.

Thermal Energy Storage Offers Potential Demand Reduction:[33] GWP integrated 214 ice storage system units at more than 50 commercial and municipal locations (13 city buildings and 40 commercial

[33] Demand response aspects of these deployments are discussed further in DOE, *Municipal Utilities' Investment in Smart Grid Technologies Improves Services and Lowers Costs*, (DOE, September 2014).

customers), totaling about 1.3 megawatts (MW) of thermal energy storage capacity—and therefore potential peak demand reduction—under GWP's control (see Figure 34 for a photo).

Figure 34. Examples of Thermal Energy Storage Units under Control by GWP



Two Phases of Deployment Expansion Planned: GWP's distribution system consists of 42 12kV and 69 4kV feeders. GWP's SGIG project included a DA pilot program involving two feeders. GWP is planning to expand deployments in two phases, to be completed by 2026. The initial phase automates existing 12kV feeders at a rate of about six feeders a year with an estimated average cost of about $1.0 million per feeder. The second phase is to upgrade/automate existing 4kV feeders at an average rate of about seven feeders a year and an estimated average cost of about $1.6 million per feeder. [34]

READ MORE ABOUT GLENDALE WATER AND POWER'S PROJECT ON SMARTGRID.GOV:

Glendale Water and Power Project Page

Glendale Water and Power Project Description – *July 2015*

Glendale Water and Power Case Study – *March 2012*

[34] DOE, *City of Glendale Smart Grid Initiative - FINAL REPORT*, (DOE, 2015).

6 Key Lessons and Conclusions

Implementation of DA involves the installation of thousands of devices with two-way data communications capabilities supported by high-bandwidth and/or low-latency communications networks. With sensors monitoring electricity consumption, voltages, loads, and other variables, grid operators face unprecedented levels of data to process, analyze, store, and turn into actionable information for optimizing DA operations and implementing automated controls.

Multiple information management and control systems all need access to these new data streams to effectively accomplish DA functions. Systems integration proved to be one the most significant challenges during DA implementation under SGIG, particularly for those utilities deploying DA equipment for the first time. Many DA utilities faced a learning curve that required new business practices and extensive training and testing, and revealed valuable lessons learned and recommendations that can help other utilities embarking on DA projects.

6.1 DA Applications Produce Large Volumes of New Data for Processing and Analysis

One of the major technical challenges of DA implementation involves processing and analyzing vast quantities of new data from sensors, automated devices, and smart meters. Data management challenges are inevitable. With low-latency communications systems, incoming data streams can be quite large and spotting data inconsistencies and error checking becomes a major challenge. SGIG utilities reported the need for new analytical tools and more refined algorithms to flag suspect data components or conditions to prevent interpretation errors.

To prevent errors and keep DA/DMS systems from becoming outdated, data needs to be managed on an ongoing basis. Operators found they needed to build data management requirements into system designs from the start. They made use of data warehouses (for enterprise data) and data historians (for operation data), and established policies for data storage, retention, access, and security.

6.2 Standard Protocols for Data Interfaces Were Limited

Many DA utilities found it challenging to ensure data standards were uniform between different technologies, systems, and applications. Intelligent devices need to be configured and tested to comply with National Institute of Standards and Technology (NIST) standards. Compliance with standards helps ensure interoperability between DA technologies.

Software and firmware upgrades were often needed. For example, many SGIG DA utilities used the MultiSpeak protocol to build data interfaces among software applications. MultiSpeak was obtained from the National Rural Electric Cooperative Association (NRECA) and selected by NIST as a standard that supports the Smart Grid Standards Framework vision. Others used enterprise service buses to simplify the integration process and provide platforms for data distribution and enterprise application integration.

Many of the utilities used data historian software to support integration efforts and enable engineers and technicians to view distribution system information in real time. Data historians function as both

data warehouses and analysis platforms for time series data generated from SCADA and distribution management systems.

For example, Con Edison's data historian project implements a centralized data repository for all electric distribution SCADA data. The system is integrated with existing corporate data systems and provides a single point of access for all users of the company's electric distribution data. BWP's data historian is responsible for capturing and storing operational measurements for the electric distribution network and providing analytical tools for assessing distribution performance.

6.3 Extensive Equipment Testing and Customization May Be Required

Automated devices typically need more frequent firmware and software upgrades than traditional utility equipment, requiring more frequent field tests and evaluations. Standard templates from vendors also typically require customization to meet each utility's unique distribution system configurations and integrate effectively with existing SCADA systems, OMS, and DMS. To address the need for frequent testing, Pepco is moving toward remote "over-the-air" upgrade capabilities to reduce the amount of time needed to implement changes in the field when new software versions become available.

Turn-key solutions were not generally available for the SGIG DA utilities, created new learning curves for implementation. Most of the SGIG DA utilities functioned as test beds and in many cases assisted vendors in identifying fixes for subsequent equipment upgrades. In general, these experiences reflected the ongoing evolution of the industry at the time. Some issues were unknown before SGIG deployments and became evident only when large-scale deployments occurred. For example, Indianapolis Power & Light and the Town of Danvers, Massachusetts learned to specify to vendors that all necessary functionality be built-in and to allow sufficient time for application development and integration, or risk schedule and cost issues.

While almost all of the utilities recommend testing DA equipment for communications and interoperability before field deployment, many also reported that lab conditions for testing field device communications may not accurately represent field conditions:

- Snohomish PUD found that the radio network implemented in the lab did not simulate field conditions so that time delays, latencies, and packet losses could not be tested.
- Atlantic City Electric in New Jersey found that modeling and testing in the lab to validate interoperability of devices is essential to reduce implementation errors, but that it is also necessary to account for environmental factors such as tree foliage and radio coverage for adjusting radio mesh networks in the field.

Some utilities were able to leverage technology to avoid the need for extensive field testing. For example, Georgia Power developed a distributed network protocol (DNP) simulator that was independent of either SCADA or the FLISR systems. The simulator eliminated the need for field trials. The DNP simulator was used for operator training as well as scenario testing of the vendors' SCADA and FLISR software.

6.4 DA Requires Increased Workforce Training and Expertise

SGIG DA utilities conducted extensive training programs to familiarize control room and field staff with the new technologies and systems and provide engineers and technicians with stronger IT-related skill sets, including information management, computer systems and cybersecurity. The training programs typically involved new business practices and processes for both control room operators and field crews and involved various levels of expertise from operations to maintenance and oversight of hardware and software applications.

Training courses among the SGIG utilities varied in length from short application orientations to comprehensive DA application training sessions. In general, the training programs started as soon as the DA projects were launched, and involved training for engineering staff so they could train others and involvement from vendors to customize sessions and provide live support.

Some of the SGIG utilities used vendors for equipment installation, while others performed these functions in-house. Advantages of the in-house approach include better knowledge of field conditions and easier staff transition into new roles. A typical example of in-house installation involves Burbank Water and Power's auto-reclosing project, which was designed and implemented by BWP engineers and electrical construction crews. The field crews were given flexibility to conform the design to field conditions and measurements.

→ See **Case Study**: Burbank Water and Power (page 79)

FLISR operations in particular bring changes in grid operations that require increased training and expertise for field technicians, engineers, and grid operators, particularly in database management, data analytics, and information systems. Cross-functional teams of technical experts in these areas better enable effective implementation. Field staff typically require the most training to learn new equipment capabilities and gain confidence in their proper operation. In many cases, meter reading personnel found new opportunities through training to serve new roles supporting DA deployments and operations.

6.5 Communications Systems Need Comprehensive Planning for Multiple Smart Grid Functions

Many utilities attempted to realize synergies in their communications strategies. For example, FPL installed single networks to communicate with all end-point devices including smart meters, smart switches, and reclosers. The aim is to leverage resources and minimize training requirements, vendor interactions, IT interfaces, software solutions, and systems integration requirements. EPB installed an ultra-speed, high-bandwidth, fiber optic network, which provides internet services and communications for other city utilities beyond those services used for its AMI and DA electric grid applications.

→ See **Case Study**: Florida Power & Light Company (page 74)

→ See **Case Study:** Electric Power Board (page 36**)**

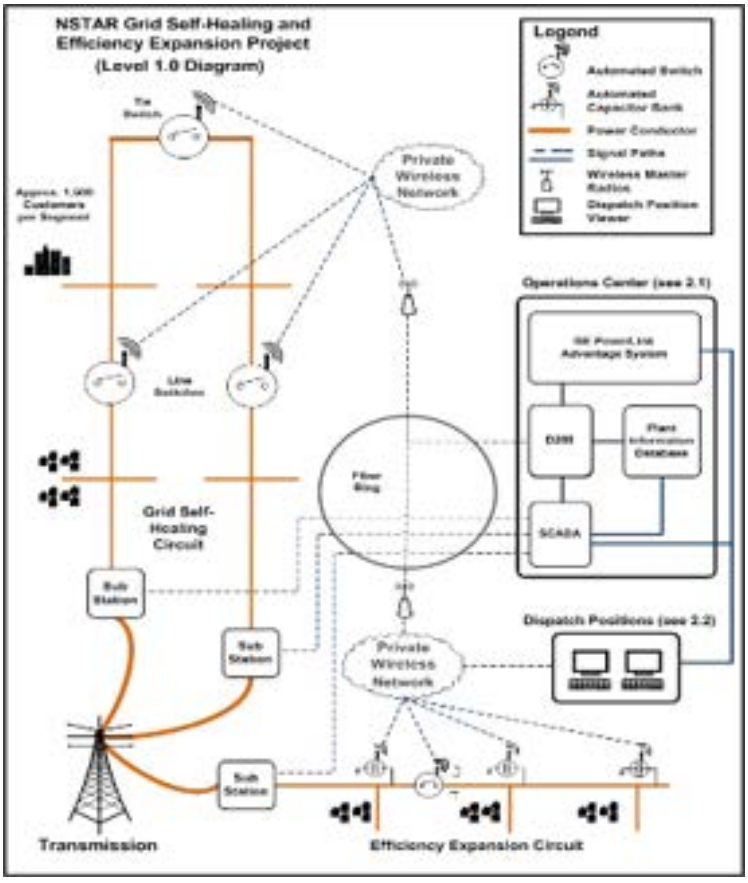
The SGIG utilities learned that there is value in leveraging communications capacity to serve multiple smart grid applications, but that detailed planning is need to ensure that implementation proceeds smoothly and the devices and software operate as intended. In leveraging resources, the utilities were

able to use the same networks for backhauling load data from smart meters to meter data management systems and for pinging meters during outages to determine which customers were without power.

Utilities found that FLISR communication networks in particular require increased resilience because they must operate under conditions where the grid itself is damaged or not functioning properly. The networks also need wide bandwidth and low latency to support near real-time operations. These factors can drive costs, constrain technology choices, and limit automation capabilities. The two-way communications network must have sufficient coverage, capacity, and latency characteristics to interface and interoperate with a wide variety of technologies and systems, including various field devices and DMS, OMS, and SCADA systems.

Some utilities found that implementation of FLISR would benefit from comprehensive evaluations for communications requirements from the start of project planning. For example, Eversource (formerly NSTAR) learned that less-than-robust radio communications can interfere with DA operations. Eversource's communications network for DA was in place when automated switches, reclosers, and line monitors for FLISR operations were being installed; in several instances, the network lacked radio coverage to accomplish required tasks. Figure 35 shows a schematic of FLISR communications architecture deployed by Eversource.

Figure 35. Schematic Communications Architecture at Eversource (formerly NSTAR)



6.6 Systems Integration is a Critical Element of DA Deployment

Information management and control systems such as DMS, SCADA, OMS, Meter Data Management System (MDMS), CIS, RMS, and GIS all need access to new data streams from sensors and controls to optimize DA functions and maximize the value of new technologies. In some cases, multiple systems need to access the same data stream and interoperate, such as when OMS use data from line sensors to identify faults along with data from smart meters to assess service restoration progress. Integration of new and legacy systems such as SCADA was a consistent challenge for virtually all of the SGIG DA utilities. While it is difficult to propose a one-size-fits-all solution for this challenge, several utilities favored making enhancements to existing systems when possible, or making incremental upgrades rather than substituting new systems.

Integration activities often involved development of customized software for data processing, error checking, and coding so that field information could be accepted and used by control room operators and management systems. The SGIG DA utilities all took on the task of systems integration to varying degrees, based on the extent of their deployment of smart grid technologies, resources, and functionality needs. The following sections describe how systems integration was generally conducted.

DMS Integration

The DMS is considered the brain of the smart distribution system. DMS establishes the load flow conditions of the distribution network and recommends (or, when fully automated, issues control commands to SCADA) switching scenarios to improve performance or resolve issues on the distribution system. The DMS also facilitates the modeling and dispatch of distributed generation, energy storage, and generators connected into the network.

Integration of DMS and AMI provides advantages for implementing automated controls for voltages and reactive power management. Premise-level voltage and VAR information allows utilities to confirm in near real-time whether the minimum service voltage level is met for all of their customers. This near real-time confirmation enables utilities to significantly improve performance and the quality of input data for DMS to determine set points for voltage and reactive power control devices. This is particularly important for CVR operations. If the voltage set point is too low, utilities risk not meeting the minimum service voltage level at the end of a feeder. With near real-time AMI data, DMS is able to achieve maximum voltage reduction while ensuring compliance with the service voltage requirements.

DMS integration typically includes accessing and using information for one of more of the following sources:

- Real-time sensory information from SCADA
- Energy consumption information from MDMS, data warehouses, and distribution models
- Switching commands to SCADA
- Circuit models from GIS
- Operating measurements from SCADA and MDMS
- Load forecasts

Under SGIG funding, Duke Energy installed a new DMS to enable new capabilities from device deployments, including FLISR, IVVC, and automated switching plans. CenterPoint Energy's Advanced Distribution Management Software (ADMS), which manages their FLISR operations, replaced the utility's legacy DMS, OMS, and distribution SCADA systems.

→ See **Case Study:** Duke Energy (page 40)

→ See **Case Study**: CenterPoint Energy (page 46)

SCADA Integration

SCADA, a legacy system for many utilities, is responsible for monitoring and control of substation relays, distribution switches, and other equipment and sensor points from throughout the electric distribution system to ensure that voltages and currents are managed within operational and financial requirements. When integrated with other DA systems, it provides a platform for a range of distribution management functions.

SCADA systems process operational data from the field and displays status on control center operator screens. Abnormal conditions trigger display alarms, which are then acted on by grid operators that can issue operator commands. DMS can also automatically issue SCADA commands. Locating faults using SCADA allows utilities to isolate and repair faults and restore service quickly, thereby increasing system resilience. SCADA equipment at the transmission and substation levels is also used when system conditions require load curtailments in ways that balance system protections with consumer needs.

SCADA technologies can also be used to facilitate monitoring of customer-owned generation to enhance safety and improve energy management. SCADA software and master stations, with proper switching and reclosers, can identify access points for customer loads and allow for real-time monitoring of all types of distributed generation assets, including back-up generators.

SCADA integration typically involves interfaces with a variety of systems and sources of grid information, including:

- GIS for distribution network models
- Real-time operating and switching information from DMS
- Measurements and data to DMS and data historians
- Measurements and data from MDMS, or data warehouses

When interoperable with other systems (i.e., DMS, MDMS, OMS, CIS, GIS, and DERMS), SCADA provides:

- Distribution control for substations, feeders, inter-tie points, and distribution equipment
- Sequencing of events, time-stamped data, trending, and diagnostic data for load management, outage analysis, and demand response
- Web-based access for operators, engineers, and managers for accomplishing system operations, outage management, and operations and maintenance activities every hour of every day throughout the year.

OMS and AMI Integration

Outage management involves integrating data streams from a variety of disparate information sources and coordinating the activities of both headquarters staff and field crews. AMI is the primary source of

information about the outage status of customers and can provide data to field crews, thereby accelerating restoration times and lowering outage costs to customers.

Specifically, integration of OMS and AMI enables use of last gasp messages and "power on" notifications from smart meters, and provides outage status reports to control room operators, who can also "ping" meters to validate power delivery status. With this information and capabilities, field crews can determine outage locations and nested outages, improve outage restoration times, reduce truck rolls, and determine the best course of action to restore service to customers. Customer information systems (CIS) can also be engaged for messaging customers with status reports on restoration activities and estimates on when service will be restored. AMI-enabled outage indication functionality results in faster identification of service outage locations, improved labor productivity, and better customer service and satisfaction.

OMS integration typically involves interfaces with a variety of systems and sources of grid information, including:

- Outage events and restorations from MDMS, SCADA, DMS, and CIS
- Distribution network models from GIS
- Outage information and alerts to CIS, web portals, and interactive voice response stems
- Work orders to field crews using workforce management systems

RMS Integration

RMS integrates real-time monitoring capabilities for phase currents, phasing voltages, transformer loadings, power factors, and other key metrics. RMS also provides condition assessment information such as ambient temperatures, oil temperatures, oil levels, water levels, and protector housing pressure. RMS sensors send data to control centers indicating how the network is running and what systems need attention.

RMS is often augmented with transformer information and load management software which integrates smart meter data and distribution transformer data. This software evaluates transformer loadings, predicts potential overload conditions, and identifies transformers that are underutilized. See Pepco case study in this report for an example of RMS integration.

→ See **Case Study:** Pepco (page 50)

6.7 Utilities Approached Automation in Distinct Ways

Each utility used an individual approach to implementing and automating control packages for feeder switching and for voltage control and reactive power management.

Automation for FLISR and Feeder Switching

Automated feeder switching is accomplished through automatic isolation and reconfiguration of segments of distribution feeders using sensors, controls, switches, and communications systems. Automated feeder switches can open or close in response to a fault condition identified locally or to a control signal sent from another location. When combined with communications and controls, the

operation of multiple switches can be coordinated to clear faulted portions of feeders and reroute power to and from portions that have not experienced faults.

The performance of FLISR systems depends on several factors, including (1) the topology of the feeders (i.e., radial, looped, and networked), (2) loading conditions, (3) the number of feeder segments affected, and (4) the control approaches implemented. In general, there are two main types of automation approaches: centralized and decentralized. Centralized switching involves distribution management systems or SCADA to coordinate automated equipment operations among multiple feeders. Decentralized switching (also sometimes called distributed or autonomous switching) uses local control packages to operate automated equipment on specific feeders according to pre-established switching logics. Many projects are using a combination of centralized and decentralized approaches.

The amount of time it takes to accomplish FLISR actions depends on the sequence of events, field devices, and the extent of latency in the communications systems. Centralized systems take more factors into account when determining switching strategies and take longer to perform FLISR, but they include more switching options if there are loading issues or other complications. Decentralized systems typically switch between a few predetermined feeders and are able to perform FLISR more quickly.

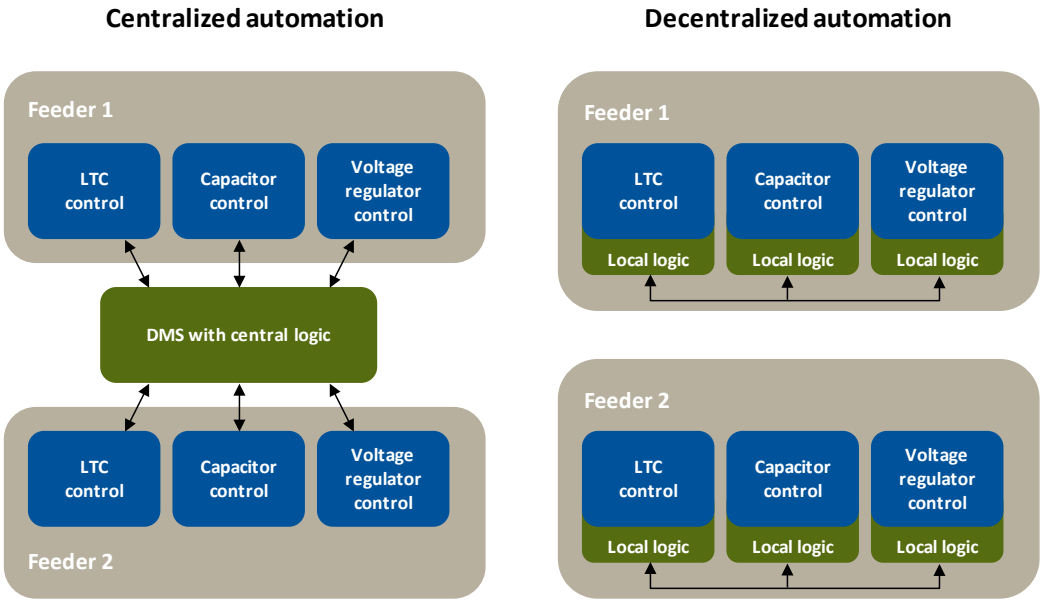
The different feeder switching devices, systems, and approaches depend on the project's objectives, legacy equipment and systems, long-term grid modernization goals, and investment timetables. Projects that seek to address a small group of feeders that are highly vulnerable to outages may favor a distributed approach, while projects that seek to improve reliability for large portions of their service territories may choose a centralized approach. Other aspects of distribution system modernization, such as voltage controls, reactive power management, and asset management also affect investment decisions in feeder switching approaches.

Control packages can also be operated remotely by operators or distribution management systems. Depending on the specific needs, control packages can have more complex algorithms that can respond to changing system conditions or operational objectives. For example, with severe storms approaching, switches can be programmed not to reclose based on the expectation that most faults could not be cleared with reclosing. This capability can avoid problems that arise from unnecessary reclosing and from fault currents on portions of the system that would ultimately go out of service because of storm damage.

Automation for Voltage Regulation and Reactive Power Management

Utilities also implemented both centralized and decentralized control for voltage regulation and reactive power management. In general, centralized controls involve a centrally located computer and SCADA or other communication network to coordinate automated equipment operations among multiple feeders. In contrast, decentralized controls use local control packages to operate automated equipment on a single feeder, or on relatively small numbers of feeders, according to pre-established logic. Many projects use a combination of centralized and decentralized approaches, depending on feeder characteristics and volt/VAR optimization (VVO) objectives. Figure 36 provides a schematic that summarizes some of the differences between these two approaches.

Figure 36. Centralized and Decentralized Control Approaches



The two types of approaches can vary on the amount of time it takes to accomplish VVO actions. For example, centralized systems can account for more factors when determining control strategies but may take longer to execute the strategies than do decentralized systems. However, centralized systems can deal with a broader spectrum of system conditions and thus can be more flexible than decentralized systems.

6.8 Cybersecurity and Interoperability Are Integral to Smart Grid

A key objective of the SGIG program was to accelerate the development and deployment of effective cybersecurity protections for smart grid technologies and systems. A cradle-to-grave approach ensures cybersecurity protections are built into smart grid technologies and systems. This approach offers stronger and longer-lasting protection than security measures that are "bolted on" after systems are fully developed and deployed. Cybersecurity was a cornerstone of the SGIG program from its onset. DOE required all grant proposals to show how cybersecurity would be addressed in every phase of the project lifecycle and how security could be upgraded in response to changes to the threat or technological environment.

Prior to starting work, DOE required each awardee to develop and submit a Cybersecurity Plan (CSP) for approval. Plans identified cybersecurity risks and how they would be mitigated, cybersecurity criteria used for vendor and device selection, relevant cybersecurity standards and/or best practices that would be followed, corporate accountability to ensure successful implementation, and how the project would support emerging smart grid cybersecurity standards. Throughout the SGIG program, the Cybersecurity Plans and corresponding on-site reviews were DOE's primary tools for confirming adherence to good cybersecurity practices, monitoring progress, building lessons learned, sharing best practices, and continuously improving cybersecurity protections.

The DOE cybersecurity team participated in 311 annual site visits and more than 100 conference calls from 2011 to 2015 to monitor progress on cybersecurity implementation. During annual project site visits, SGIG cybersecurity team members rigorously reviewed all CSPs and their implementation against 13 cybersecurity criteria and, as needed, made recommendations. Year-to-year results showed improvements in nearly all projects and areas, reflecting a maturation of cybersecurity practices and management.

DOE developed a dedicated, secure website of cybersecurity resources, which served as a central repository of tools, guides, presentations, and resources specifically tailored to the needs of SGIG project teams. DOE also conducted cybersecurity webinars for SGIG grant recipients and hosted two Smart Grid Cybersecurity Information Exchanges, which promoted peer-to-peer discussions of lessons learned and best practices.

SGIG project participants improved their understanding of cybersecurity issues and specific needs in deploying smart grid technologies and systems. This was most readily apparent in smaller, utilities that saw a dramatic increase in the staff's sophistication in cybersecurity processes. Although not an SGIG program requirement, many utilities intend to continue to modify and use their SGIG CSPs as foundations of their organizations' ongoing cybersecurity programs.

Interoperability is also critical in a modern grid because it enables two or more networks, systems, devices, applications, or components to share and readily use information securely and efficiently with little or no inconvenience to the user.[35] Since 2009, the industry has made substantial progress in tackling key interoperability issues, and the SGIG projects were important for evaluating deployments, assessing needs, and accomplishing key activities in accelerating interoperability development.

Lessons Learned and Best Practices from the 2012 Smart Grid Cybersecurity Information Exchange

SGIG utilities shared valuable lessons learned from implementing their CSPs and shared them with peers during the 2012 Cybersecurity Information Exchange. [36] Insights from the SGIG utilities include:

- **Early cybersecurity planning with product vendors is key**. Develop cybersecurity specific procurement contract language and consider early engagement of 3rd-party software suppliers when planning smart grid investments. Demand that products meet cybersecurity standards and define those standards early. Provide strong contractual language in proposal requests. Request that vendors take responsibility for security and vulnerability mitigation over the full product lifecycle.
- **Ensure interoperability through robust testing with manufacturers and industry partners**. Collaborate with manufacturers to develop robust test environments that are fully representative of all factors in the field. Become active in national partnerships and support emerging smart grid cybersecurity standards. Create interoperability with legacy systems through gateway proxies and service buses.
- **Obtain strong cybersecurity support from executives and managers**. A CSP should behave like a business plan that includes a budget, defined risk, metrics and evidence, and is written so that

[35] GridWise Architecture Council, "Introduction to Interoperability and Decision Maker's Interoperability Checklist, v1.0."
[36] DOE, 2012 DOE Smart Grid Cybersecurity Information Exchange, June 2013.

senior management can understand it. Obtain upfront management support and resources, tie security needs to the business strategy, and communicate the business implications of cybersecurity investments. Keep executives informed throughout a project.

- **Eliminate company silos and define clear cybersecurity roles and responsibilities**. Undefined personnel roles and responsibilities are major obstacles and must be established at the beginning of any cybersecurity program. Company "silos" must be crossed so that the cybersecurity program is well understood by multiple stakeholders. Employees must work to narrow the gulf between operations and IT staff to fully address cybersecurity.
- **Conduct workforce training to build cybersecurity expertise and literacy**. There is often a lack of common vocabulary on cybersecurity issues and enterprise-wide cultural change is often needed. Utilities should conduct training to build deep cyber expertise for key staff, but also support cybersecurity training for all technical staff to promote awareness and familiarity across the organization.

7 Future Directions and Next Steps

The SGIG DA projects invested more than $2 billion in new technologies, tools, and techniques for the modernization of electric distribution systems. While substantial, these investments represent a relatively small portion of the total level of investment that the electric power industry is expected to contribute toward grid modernization over the next several decades.[37] The SGIG projects were specifically designed as learning opportunities, providing the electricity industry with additional data on smart grid performance and lessons learned that can catalyze continued investment in smart grid technologies and systems in the coming years.

This section discusses the future smart grid investment plans of several SGIG participants. It also identifies some of the key technical challenges that remain to be addressed to reduce the risks and improve the cost-effectiveness of investments in DA technologies, tools, and techniques.

7.1 SGIG Utilities Largely Plan to Expand Smart Grid Investments in DA

Most SGIG DA utilities implemented small-scale projects; only a few completed system-wide deployments. The vast majority are planning to build on their SGIG DA experiences and expand grid modernization investments. The pace of grid modernization expansions beyond SGIG are governed by distinct local conditions and needs.

Several of the participating SGIG DA utilities that invested in partial deployments plan to further invest in the phased upgrade of additional substations and feeders. Many utilities are upgrading the worst performing substations and feeders first, or those serving customers with critical business needs for shorter and fewer outages. For example:

- Glendale Water and Power plans a system-wide upgrade to be completed by 2026.
- PPL Electric Utilities Corporation plans to upgrade all feeders by continuing DA investments through 2018.
- Florida Power and Light is rapidly expanding its deployment of additional automated feeder switches based on project success.
- Duke Energy's SGIG project was part of a 10-year plan for grid modernization and FLISR deployment.
- Pepco plans to deploy its FLISR technologies to 15 percent of its systems.
- Central Lincoln Public Utility District plans to implement CVR territory-wide.

Several utilities also plan to add or expand DA capabilities in existing deployments by upgrading communications capacity, making greater use of unused DA functions embedded in existing devices and management systems, and installing new devices and systems on already automated feeders and substations. Examples include:

- CenterPoint Energy plans to expand FLISR capabilities to include full automation.
- Westar Energy in Kansas plans to implement an enterprise smart grid data analytics platform to integrate and leverage data from field devices with new asset and work management systems.

[37] Electric Power Research Institute, *Estimating the Costs and Benefits of the Smart Grid*, 2011.

- Southern Company plans to create single-user interfaces for grid operators by integrating its DMS and OMS.
- Georgia Power plans to have all of its automated normal open points controlled by a centralized FLISR system.
- Florida Power and Light is exploring how to tie new fault location capabilities to substations to minimize customer interruptions and improve power quality by addressing voltage flicker issues.
- PECO Energy Company plans to use DA and AMI to improve its ability to respond to "nested" outages, which can occur within major events and can often go unnoticed.

Additional SGIG utilities (beyond the 62 included in this report) that were not part of the DA program also plan to leverage their SGIG-funded deployments toward future DA deployments. For example, NV Energy's new statewide communications network now links a variety of smart grid components. NV Energy plans to deploy DA devices and applications, upgrade the DMS, integrate AMI meter power failure messages with the DMS, enhance outage communications, and pilot VVO.

7.2 DA Projects Highlighted Continuing R&D Challenges

The transition from traditional to modern electric distribution systems using smart grid technologies is under way, but efforts are in the very earliest stages of development and deployment. The SGIG DA utilities have shown the potential to enable fewer and shorter outages and reduce energy requirements by using automated controls. Continued modernization of distribution management systems will require the electricity industry to continually address R&D challenges as new technologies emerge. Several of these challenges are summarized below.

Cybersecurity and Interoperability

Cybersecurity and interoperability remain important technical challenges for modernizing electric distribution systems. Standards, protocols, tools, and techniques are needed for ensuring secure and interoperable technologies and systems. Success in these areas involves ongoing activities for government and industry, including changes in regulations, business practices, and consumer data privacy protections.

Modeling, Visualization, and Data Analytics

Evolving system-level challenges underscore the need for a new class of monitoring, control, and analytic capabilities. These challenges include the integration of large amounts of variable generation; increased susceptibility of the system to destabilizing events; and rapidly developing security issues. In the last few years, parallel computing techniques, lower cost high-speed communications, advanced modeling frameworks, and wide-area coordination mechanisms have become available, and together hold the promise for faster simulation methods and more robust control approaches necessary for operating modern grid systems.

Currently, most distribution system operators have limited visibility into the conditions and state of the system, except for distribution substations. As more distributed energy resources are deployed, greater visibility (e.g., along feeders to utility meters and possibly into buildings) is needed to ensure reliability, power quality, and enable advanced applications. The installation of approximately 50 million smart meters, covering about 43 percent of U.S. homes, has been a valuable step in improving distribution

visibility.[38] However, phenomena associated with system dynamics and protections require much better sensors that can inform operations on the order of milliseconds.

Because of the large number of feeders and substations, high-resolution sensors will need to be lower in cost for wide-scale deployment. Micro-synchrophasors, or distribution phasor measurement units, are one technology that can provide the enhanced visibility needed for the future grid. Other technologies include advanced sensors that provide configuration and/or real-time condition information on field assets. Communications and data management requirements must link to the type of decisions that will be made. Advanced applications using the sensor data can help map and update the topology of distribution systems, determine asset health, enable "real-time" distribution operations, and accelerate post-event recovery.

Recent experiences with the aggregation of demand response resources into electricity market structures presents a potential framework for coordination of distributed energy resources. Advanced DERMS can be valuable contributors for improving utility integration of distributed resources.

Advanced Grid Devices and Power Electronics

Solid state distribution transformers involve design concepts that combine power electronics and high-frequency magnetics for more compact transformers and new control capabilities. In these early stages of development, it is envisioned that solid state transformers will not be drop-in replacements for existing transformers but will be deployed, once market-ready, in strategic locations that can fully utilize their enhanced functionality and flexibility.

Solid state transformers can perform a variety of functions now played by a variety of devices, including voltage regulation and reactive power supplies, and can be used to form hybrid AC and DC systems that can increase total system efficiency. They can also be used to manage the interaction between microgrids and utility systems. Solid state transformers can regulate the process of disconnecting and reconnecting with the main grid, quickly and precisely change the direction of power flows, and limit fault currents.

Microgrid Management and Energy Storage

Microgrids involve groups of interconnected loads and distributed energy resources within clearly defined electrical boundaries that acts as a single controllable entity with respect to the grid. It can connect and disconnect from the grid to enable it to operate in both grid-connected or island mode and can be nested one within another. Single-customer microgrids are generally facilities with a need for generation, such as large university campuses, hospital complexes, military bases, and industrial parks. Advanced tools and techniques are needed for integration with electric distributions systems to occur safely and reliably.

One of the major challenges common across the various energy storage technologies is cost. The total cost of electric storage system include all subsystem components, installation, and integration costs. While there is a strong focus on reducing the cost of the "energy storage" component, such as battery chemistries or the spinning mass in flywheels, this component only constitutes approximately 30 to 40

[38] The Edison Foundation Institute for Electric Innovation (IEI), *Utility-Scale Smart Meter Deployments*, (IEI, September 2014). The SGIG program installed more than 16 million smart meters.

percent of the total system cost. A total systems approach is needed to reduce balance-of-system costs and achieve the desired cost and performance targets. Other technical challenges include improving the safety of these technologies and assessing the appropriate value streams for the multiple services electricity storage can provide.

Advanced Demand-Side Solutions

There are many opportunities to make a variety of end-use loads more "grid-friendly," which may blur the lines between the utility and customer sides of the meter blur. For example, automated responsive customer equipment can be designed to detect voltage and frequency levels from the grid or respond to signals from control systems. However, manufacturers must ensure that these loads will be capable of providing grid services without jeopardizing the quality and reliability of their primary function.

Smart loads may include building control systems that are optimized for individual services—such as lighting, heating, cooling, ventilation, and pumping—but that can also interact with utility or operator signals. Communications-enabled thermal energy storage systems (hot and cold) have been used in demand response programs. Electric water heaters are emerging as another form of thermal energy storage that can be used to provide greater grid flexibility. Advancing these technologies will require consideration of how efficiency improvements will need to be optimized with greater system flexibility.

DOE expects to continue supporting grid modernization through research, development, demonstration, analysis, and technology transfer activities, especially in areas where there is a demonstrated federal role such as cybersecurity, interoperability, and advanced concepts and technologies based on new discoveries in science, engineering, and mathematics.

While the SGIG program is now complete, grid modernization remains an important national priority. DOE through the Grid Modernization Initiative (GMI) recently released a Grid Modernization Multi-Year Program Plan (MYPP) that describes the challenges and opportunities for achieving a modern, secure, sustainable, and reliable grid and how DOE will help achieve this through programs and activities. The Grid Modernization Lab Consortium, a multi-year collaboration among 14 DOE National Laboratories and regional networks, will assist DOE in developing and implementing the activities in the MYPP. [39]

[39] DOE, Grid Modernization Initiative, *Grid Modernization Multi-Year Program Plan*, November 2015.

APPENDIX A.
Where to Find Additional Information

To learn more about national efforts to modernize the electric grid, visit the Office of Electricity Delivery and Energy Reliability's website and the SmartGrid.gov website. DOE has also published several reports that contain findings on topics similar to those addressed in the projects featured in this report.

A.1. Final SGIG Technology Analysis Reports



Advancement of Synchrophasor Technology in Projects Funded by the American Recovery and Reinvestment Act of 2009
2016



Advanced Metering Infrastructure and Customer Systems: Results from the Smart Grid Investment Grant Program
2016

A.2. SGIG Program-Level Interim Progress Reports



Smart Grid Investment Grant Progress Report 2013
September 2013



Economic Impact of Recovery Act Investments in Smart Grid
March 2013



Smart Grid Investment Grant Progress Report 2012
July 2012

A.3. Key SGIG Technology Analysis Interim Reports

Demand Reductions from the Application of Advanced Metering Infrastructure, Pricing Programs, and Customer-Based Systems - Initial Results	Dec 2012
Operations and Maintenance Savings from Advanced Metering Infrastructure - Initial Results	Dec 2012
Reliability Improvements from the Application of Distribution Automation Technologies - Initial Results	Dec 2012
Application of Automated Controls for Voltage and Reactive Power Management - Initial Results	Dec 2012

Synchrophasor Technologies and their Deployment in the Recovery Act Smart Grid Programs	Aug 2013
Municipal Utilities' Investment In Smart Grid Technologies Improves Services and Lowers Costs	Oct 2014
Smart Grid Investments Improve Grid Reliability, Resilience, and Storm Response	Nov 2014
Evaluating Electric Vehicle Charging Impacts and Customer Charging Behaviors - Experiences from Six Smart Grid Investment Grant Projects	Dec 2014
Fault Location, Isolation, and Service Restoration Technologies Reduce Outage Impact and Duration	Dec 2014

A.4. DA Project Case Studies

Case Studies	Project Performer	Date
A Smarter Electric Circuit: Electric Power Board of Chattanooga Makes the Switch	EPB	May-11
Bright Lights, Big City: A Smarter Grid in New York	Con Edison	May-11
At the Forefront of the Smart Grid: Empowering Consumers in Naperville, Illinois	City of Naperville	Sep-11
Vermont Pursues a Statewide Smart Grid Strategy	eEnergy Vermont	Nov-11
Building a Smarter Distribution System in Pennsylvania	PPL	Dec-11
A "Model-Centric" Approach to Smarter Electric Distribution Systems	ORU	Dec-11
Glendale, California Municipal Invests in Smart Grid to Enhance Customer Services and Improve Operational Efficiencies	GWP	Feb-12
CenterPoint Energy's Smart Grid Solutions Improve Operating Efficiency and Customer Participation	CenterPoint	Feb-12
Smart Grid Solutions Strengthen Electric Reliability and Customer Services in Florida	FPL	Jun-12
Using Smart Grid Technologies to Modernize Distribution Infrastructure in New York	Con Edison	Jul-14
Integrated Smart Grid Provides Wide Range of Benefits in Ohio and the Carolinas	Duke Energy	Aug-14
Smart Grid Technologies Cut Emissions and Costs in Ohio	AEP Ohio	Oct-15
Renovating the Grid and Revitalizing a Neighborhood	KCP&L	Oct-15

APPENDIX B.
Approach to Data Collection and Analysis

The 62 SGIG DA projects collected and analyzed data about the deployed technologies and systems, resulting grid impacts, benefits, and lessons learned.

DOE compiled this information for analysis of DA operations, and for sharing with the electric power industry through DOE's **Smart Grid Investment Grant (SGIG) website**.

The primary purpose of SGIG's data collection and analysis is to provide electric power industry stakeholders and decision makers – public and private – with information on grid impacts, benefits, costs, and lessons-learned to help assess the cost-effectiveness of investments in DA technologies and systems. The goal is to help accelerate modernization of the nation's electric distribution systems.

B.1. Analysis Approach

Figure B-1 shows the overall DOE approach for analysis of SGIG DA projects.[40] The analysis begins with assessments of the deployed ***smart grid assets***. The assessments include the technologies and systems, such as automated capacitor banks or distribution management systems, and how these are being installed and operated by the SGIG DA utilities. The next step involves assessments of the new ***smart grid functions*** that the new assets enable. This includes assessments of the new functions and capabilities, such as automated feeder switching or conservation voltage reductions, and how to make them operational to achieve certain grid impacts and benefits.

Figure B-1. SGIG Analysis Approach



The third step involves assessments of the ***smart grid impacts***, which generally includes analysis of specific physical metrics that measure changes resulting from deployment of assets and implementation of functions, such as improvements in reliability indices or reductions in the numbers of truck rolls. The last step involves the determination of ***smart grid benefits***, which generally includes monetization of the impacts for use in business case analysis, such as the value of reductions in customer losses from fewer/shorter outages, or financial savings from deferral of capital investments.

Benefits analysis can include utility, customer, and societal perspectives and covers two general types of benefits: those that can be monetized, such as cost savings; and those that are difficult to monetize,

[40] See DOE, "Analytical Approach" on SmartGrid.gov; Electric Power Research Institute (EPRI), *Guidebook for Cost/Benefit Analysis of Smart Grid Demonstration Projects*, Revision 1, (DOE, December 2012); and DOE and EPRI, *Methodological Approach for Estimating the Benefits and Costs of Smart Grid Demonstration Projects*, December 2009.

such as reductions in carbon dioxide emissions or increases in customer choices, services, and satisfaction.

B.2. Data Collection Approach

To conduct effective analysis of the SGIG DA projects, accurate data is needed from the utilities on the performance of the deployed assets, functions, impacts, and benefits. At the outset of the SGIG program in 2009-2010, DOE collaborated with each of the SGIG project teams to develop Metrics and Benefits Reporting Plans (MBRP). Each SGIG project was required to have an approved MBRP before equipment installations could begin. The MBRPs were customized to reflect each project's unique scope and objectives.

A series of meetings between DOE and SGIG project teams developed these plans, outlined specific data to collect, and identified when and how it would be reported to DOE. Each plan discussed two separate sets of data collection efforts: Build Metrics and Impact Metrics.

- **Build Metrics** comprise the set of devices and systems and related costs to buy and install; this information was posted and updated on the SGIG website every three months to inform stakeholders about the pace of progress with SGIG project implementation. DA build metric data includes information on the numbers and costs of installed devices and systems.
- **Impact Metrics** comprise the set of information developed by the project teams to assess the effects of the new technologies and systems on grid operations and business practices. Impact Metrics submissions to DOE occurred twice a year and required the project teams to collect and analyze information to show how the installed technologies and systems operated to achieve grid modernization objectives in several key areas: reliability and outage management, asset utilization, power quality, integration of distributed energy resources (DER), and asset health condition monitoring.

The Impact Metric data submissions typically involved the utilities calculating quantitative values that show the effects before and after, or with and without, deployment and operation of DA technologies and systems. One of the challenges in estimating DA impacts involves the need to develop accurate baselines (before DA or without DA) against which impacts can be measured.

B.3. Scope of Data Collection

Table B-1 lists the assets, technologies, and systems that were collected for build metrics reporting from the SGIG DA projects. Build metric data collection compiles information on the installation of electric distribution smart grid assets deployed under SGIG. Because each of the projects had its own unique scope and objectives, not all of the SGIG DA projects provided information on all of the build metrics.

Table B-1. List of Key DA Build Metrics for SGIG Projects

List of Key SGIG DA Build Metrics – Assets, Technologies, and Systems
• Advanced metering infrastructure and smart meters   ○ Smart meters with outage notification feature enabled   ○ Smart meters with power quality monitoring feature enabled • Automated feeder switches

List of Key SGIG DA Build Metrics – Assets, Technologies, and Systems
• Automated capacitors • Automated voltage regulators • Distribution automation/substation communications networks • Distribution management systems (DMS)   ○ Integration of DMS with AMI   ○ Integration of DMS with OMS • Feeder monitors • Remote fault indicators • Smart relays • Substation/transformer monitors

Table B-2 lists the impact metrics that were collected for the SGIG DA projects. Because each of the projects had its own unique scope and objectives, not all of the SGIG DA projects contributed to all of the impact metrics. In addition, the usefulness of the data on impact metrics varies across the projects so it was necessary for DOE to screen the information and report on selected projects and impacts.

Table B-2. List of DA Impact Metrics for SGIG Projects

List of SGIG DA Impact Metrics.	
Impact Areas	**Impact Metrics**
Reliability and outage management	• Reduced truck rolls and vehicle miles • Improved reliability indices • Reduced outage duration
Asset utilization	• Reduced line losses (kWh) • Reduced demand (kW) • Avoid occasional truck rolls and vehicle miles • Improved power factors • Reduced electricity usage
Power quality	• Reduced line losses (kWh) • Reduced demand (kW) • Avoid occasional truck rolls and vehicle miles
Integration of DER	• Reduced peak demands (kW) • Reduced truck rolls and vehicle miles • Reduced electricity usage (kWh)
Asset health conditions	• Reduced truck rolls and vehicle miles • Reduced the instances of equipment failures

While there are 62 utilities that deployed DA assets, technologies, and systems under SGIG, 47 of them contributed impact metrics to this report. As shown in Table B-3, the number of utilities contributing DA impact metrics varies.

Table B-3. Number of SGIG DA Utilities Contributing Impact Metrics Data for DA

DA Impact Metrics	Number of DA Utilities Reporting	Percentage of 62 Total DA Utilities
System Average Interruption frequency Index	36	58%
System Average Interruption Duration Index	37	60%
Customer Average Interruption Duration Index	36	58%
Momentary Average Interruption Frequency Index	12	19%
Avoided Distribution Operations Vehicle Miles	18	29%
Avoided Distribution Operations Costs	9	15%
Avoided Distribution Operations Truck Rolls	16	28%
Distribution Feeder Switching Operations Count	12	19%
Avoided Distribution Feeder Switching Operations Costs	8	13%

B.4. Data Collection Challenges and Limitations

DOE's data collection and analysis activities produced a variety of reports and case studies on the results and lessons learned from the SGIG DA projects.[41] The extent of the DOE analysis is limited in various ways due to challenges that were faced by the SGIG DA utilities in the data collection and analysis process.

One of the most significant challenges concerned the development of accurate baselines for assessing grid impacts. Most of the SGIG utilities encountered challenges in collecting and analyzing appropriate data for the development of accurate baselines. Other utilities underestimated the amount of time, effort, and engineering expertise needed for accurate impact metric estimation and reporting.

One difficulty in assessing grid impacts stemmed from the use of historical data from affected feeders in order to assess smart grid impacts before and after data collection and analysis. However, this technique was complicated in most cases by the need to make weather adjustments so that smart grid impacts on key metrics such as reliability indices could be separated from other factors that could affect reliability such as the weather. For many utilities weather adjustments were not exact and raised questions about the accuracy and validity of the before-and-after impact estimates. However, some utilities were successful in accomplishing weather adjustments for estimating DA impacts and DOE's DA analysis focused on the experiences and reported results from these utilities.

In addition to weather adjustment issues, many of the utilities also experienced other difficulties including changes to feeders from one year to the next due to routine maintenance, storm damages, and the types and numbers of customers served by the upgraded feeders. DOE was able to identify the utilities with these problems and during the metrics realignment process made adjustments in the types

[41] See Appendix A for a list of documents and web links.

of impact metrics to be submitted to DOE. In some cases, the utilities offered to substitute technical reports that they produced in lieu of impact data to send to DOE. DOE was often able to use the reports as sources of data for analysis. Selected reports provided by the utilities on DA impact analysis results are posted on the DOE website.

Another challenge with DA data collection and analysis concerned the lack of commonality among the projects in their respective goals and objectives. While some of the utilities deployed and operated DA on large numbers of feeders, most utilities conducted small- and pilot-scale tests on relatively small numbers of feeders. Because of these differences, aggregating data for analysis by utilities with such starkly different objectives is not generally useful.

A final challenge concerned differences in the level of experience and know-how among the SGIG utilities with DA technologies and systems. In many cases, the technologies and systems deployed by the SGIG DA utilities involved learning curves to determine how to install and operate new assets and functions properly. In many cases impact analysis was not worthwhile during periods when the utilities were primarily trying to figure out the best ways to install and operate the DA technologies and systems. This limited the number of useful impact metric reports from these types of utilities. However, the experiences from the DA utilities facing these circumstances produced valuable information on lessons-learned for DA deployments and operations.

There are also several caveats associated with the analysis of the cost data. One is that the utilities did not use uniform cost categories. As a result, cost data from some of the utilities could not be used in the analysis because cost categories included combinations of different cost items, in unknown proportions, that could not be separated. In addition, much of the hardware and software used in the SGIG DA projects were purchased up to five years ago, and equipment functionality and costs for certain devices have changed substantially since then. As a result, the cost information reflects the wide range of experiences of the SGIG DA utilities but are may not be indicative of the costs of the equipment today or in the future.

To address these challenges and issues, in 2013—about midway through the SGIG program—DOE conducted a re- assessment of the MBRPs and contacted each of the project teams to determine how to improve the quality and usefulness of the impact metrics submissions. For most of the SGIG DA utilities, this reassessment effort for impact metrics reporting resulted in a greater focus on a smaller number of the most valuable impact metrics. In many cases, it also resulted in the utilities agreeing to prepare separate reports on grid impacts in lieu of submitting data sets on grid impacts.

APPENDIX C.
Supporting Build Metrics Data

A total of 62 utilities deployed DA assets, technologies, and systems under the SGIG program. Of those projects, 52 projects reported at least one DA-related build metric to DOE; the remaining 10 projects only installed DA technologies at a very small scale (as part of projects that were focused more on AMI technologies) and were not required to report DA-related build metrics. (Build metrics for these 10 projects specific to AMI and customer technologies are reported separately in *Advanced Metering Infrastructure and Customer Systems: Results from the SGIG Program*). These 10 recipients that did not report DA build metrics include:

1. Black Hills Corporation/Colorado Electric
2. Cobb Electric Membership Corporation
3. Connecticut Municipal Electric Energy Cooperative
4. Guam Power Authority
5. Idaho Power Authority
6. Madison Gas and Electric Company
7. Marblehead Municipal Light Department
8. New Hampshire Electric Cooperative
9. San Diego Gas and Electric Company
10. South Kentucky Rural Electric Cooperative Corporation

Build metrics for the 52 reporting DA utilities are reported in this appendix.

C.1. DA Device and System Deployments (by Project)

ID	Utility Name	% of System with SCADA	% of System with DA	Automated Feeder Switches (#)	Automated Capacitors (#)	Automated Regulators (#)	Feeder Monitors (#)	Remote Fault Indicators (#)	Transformer Monitors (#)	Smart Relays (#)
1	Atlantic City Electric Company		9	164	27					55
2	Avista Utilities	75	21	263	123	177	102			102
3	Burbank Water and Power	100	94			130				
4	CenterPoint Energy Houston Electric	100	11.7	567						171
5	Central Lincoln People's Utility District	100	9	17		2	14			
6	City of Anaheim Public Utilities Department			101	26			272		
7	City of Auburn, IN	100	20	5	10					22
8	City of Fort Collins Utilities, CO	8	0.45	2						

ID	Utility Name	% of System with SCADA	% of System with DA	Automated Feeder Switches (#)	Automated Capacitors (#)	Automated Regulators (#)	Feeder Monitors (#)	Remote Fault Indicators (#)	Transformer Monitors (#)	Smart Relays (#)
9	City of Glendale Water & Power, CA	100		8						4
10	City of Leesburg, FL	100	16.3	6	20					
11	City of Naperville, IL		3.9	7						12
12	City of Ruston, LA			6	10		28			28
13	City of Tallahassee, FL	11.2	11.2	93						
14	City of Wadsworth, OH			31	13					
15	Consolidated Edison Company of New York	39	37	797	449	111	617	1,851	17,401	205
16	Cuming County Public Power District	100				76	67			
17	Denton County Electric Cooperative			2	2	2	2	6		
18	Detroit Edison Company	1.54	1.56	9	40	16			2	75
19	Duke Energy Business Services	100	98	914	2,098	914	83	4,755		4,755
20	El Paso Electric	1	2.6	13			6	8		8
21	Electric Power Board of Chattanooga, TN	100	100	1,294						
22	First Energy Service Corporation	5.9	2.3	30	187	4	236			
23	Florida Power & Light Company			285	1,403	1,806	1,014	3,879	2,716	1,084
24	Golden Spread Electric Cooperative	48.25	37.9	97	23	16	114	34		138
25	Hawaiian Electric Company	7	7	29						
26	Indianapolis Power & Light Company		27	184	1,308	76		3	17	618
27	Knoxville Utilities Board	6.8	6.4					117		
28	Lafayette Consolidated Government, LA	9.8	35		47					
29	Memphis Light, Gas and Water Division	100	95							489
30	Minnesota Power	0.3	0.3	5			5			
31	Modesto Irrigation District		2.8		5					

ID	Utility Name	% of System with SCADA	% of System with DA	Automated Feeder Switches (#)	Automated Capacitors (#)	Automated Regulators (#)	Feeder Monitors (#)	Remote Fault Indicators (#)	Transformer Monitors (#)	Smart Relays (#)
32	Municipal Electric Authority of Georgia	92.7	80			813				284
33	Northern Virginia Electric Cooperative		100	14	164	340			56	25
34	Eversource (formerly NSTAR)	81.62		360	109		360	360		
35	Oklahoma Gas and Electric Company		11.62		456					14
36	PECO Energy Company			100	63					221
37	Pepco of Washington, DC		2.4	42					41	306
38	Pepco of Maryland		9.6	103				186		466
39	Powder River Energy Corporation	100				30				
40	PPL Electric Utilities Corporation		4	214	195					
41	Duke Energy (formerly Progress Energy)	98.5	48.5	829	589	2,320	1,583			
42	Public Utility District No. 1 of Snohomish County	100	2.3	6		13	45	45		382
43	Rappahannock Electric Cooperative	90.91	23.6			300	64			
44	Sacramento Municipal Utility District	17.1	18.84	156	177			26		155
45	South Mississippi Electric Power Association	83.3					65		18	118
46	Southern Company Services	95	44.2	2,193	1,869	3,339		263		848
47	Southwest Transmission Cooperative	67	39	22	10	78		54		154
48	Talquin Electric Cooperative	15	15		62					
49	Town of Danvers, MA	94	94	50	14		12			
50	Vermont Transco	33.11	13.87	42		102	30	9	12	276
51	Westar Energy	100	1	31	6			27		
52	Wisconsin Power and Light Company		32		576					

APPENDIX D.
Supporting Impact Metrics Data

Individual utilities reported impact metrics for key data points, which are anonymized and included in the following tables. Utility names are replaced with a generic ID number in each table; however, one utility ID number does not refer to the same utility across tables (e.g., the utility represented by ID 1 in the first table is not the same utility represented by ID 1 in the second table).

D.1. Avoided Vehicle Miles, Truck Rolls, Switching Operations, and Associated Costs (By Project)

ID	Avoided Distribution Operations Vehicle Miles	Avoided Distribution Operations Cost ($)	Avoided Distribution Truck Rolls (#)	Distribution Feeder Switching Operations Count (#)	Avoided Distribution Feeder Switching Operations Cost ($)
1	2,340	$43,380	239	291	$41,760
2	109,639		1,397	478	
3				597	
4	7,200		1,080		
5				37	
6	64,125		2,055	2,055	$7,500
7	138				
8				20	$8,500
9	1,705,601				
10	17,772		14,170	14,170	$354,250
11	12,530	$62,535	4,072	44	
12	193,420	$723,900	11,793		$385,200
13				9	$3,511
14	86	$475,415			
15	733		52	60	
16	8,377	$2,210	2,362		
17	590	$11,520	52		$9,360
18	2,420	$43,200	202	280	$35,460
19	31,007	$31,749	654		
20	33,510		4,682		
21			30,288		
22	1,230,700	$4,819,230	123,070	9,586	$623,090
23	12,300		1,106		
24	2,340	$43,380	239	291	$41,760
25	109,639		1,397	478	

D.2. Year over Year Comparison of Key Reliability Indices (By Project)

The following four tables show changes in SAIFI, SAIDI, CAIDI, and MAIFI between the summers of 2013 and 2014 for those SGIG DA utilities that contributed these metrics.

Changes shown are year over year, not against a baseline. The table data highlight the importance of pre-deployment baselines to effectively evaluating the reliability impacts and benefits of smart grid technologies. As the data demonstrate, several utilities experienced reliability improvements year over year on affected feeders, while others saw decreased reliability. This could be due to changes in weather patterns or system configurations, or due to the fact that DA deployments were not at a sufficient scale to create significant system impacts. Simply comparing reliability indices from year to year—rather than against a pre-deployment baseline—cannot effectively measure the full impact of DA investments. However, the following tables offer insight into potential year-over-year changes to reliability indices when implementing DA.

Table D-1. SAIFI Comparisons, Summer 2013 and Summer 2014

ID	Summer 2013	Summer 2014	% Change
1	0.190	0.220	-15.8%
2	0.507	0.640	-26.4%
3	0.494	0.645	-30.6%
4	0.183	0.030	83.8%
5	0.326	0.309	5.1%
6	0.319	0.436	-36.7%
7	0.730	0.630	13.7%
8	1.140	0.630	44.7%
9	0.390	0.341	12.5%
10	1.310	1.850	-41.2%
11	1.780	1.150	35.4%
12	0.063	0.302	-379.4%
13	0.240	0.370	-54.2%
14	0.520	0.427	17.9%
15	0.403	0.530	-31.6%
16	0.134	0.101	24.9%
17	0.710	0.800	-12.7%
18	1.744	1.800	-3.2%
19	0.710	0.920	-29.6%
20	0.388	0.053	86.4%
21	1.588	1.027	35.3%
22	0.440	0.538	-22.3%
23	0.690	0.842	-22.0%

Note: 36 utilities contributed SAIFI values to this report; 23 utilities provided data for both summer 2013 and summer 2014.

Table D-2. SAIDI Comparisons, Summer 2013 and Summer 2014

ID	Summer 2013	Summer 2014	% Change
1	6.88	8.87	-28.9%
2	48.66	51.40	-5.6%
3	42.12	68.43	-62.5%
4	10.40	0.06	99.4%
5	21.22	13.65	35.7%
6	31.16	37.40	-20.0%
7	102.63	54.11	47.3%
8	82.87	59.00	28.8%
9	20.85	20.66	0.9%
10	175.80	218.40	-24.2%
11	134.16	36.00	73.2%
12	157.00	108.00	31.2%
13	2.52	19.97	-692.5%
14	0.08	0.50	-559.2%
15	25.10	44.04	-75.5%
16	50.34	37.09	26.3%
17	22.53	28.84	-28.0%
18	11.28	1.49	86.8%
19	63.00	79.78	-26.6%
20	134.88	131.69	2.4%
21	85.20	104.88	-23.1%
22	55.36	4.18	92.4%
23	212.08	162.09	23.6%
24	0.29	0.37	-28.6%
25	62.27	73.34	-17.8%

Note: 37 projects contributed SAIDI values to this report; 25 utilities provided data for both summer 2013 and summer 2014.

Table D-3. CAIDI Comparisons, Summer 2013 and Summer 2014

Number	Summer 2013	Summer 2014	% Change
1	36.00	39.00	-8.3%
2	96.09	80.37	16.4%
3	85.26	105.28	-23.5%
4	65.09	44.12	32.2%
5	97.55	85.70	12.1%
6	140.92	86.54	38.6%
7	72.70	94.00	-29.3%
8	53.71	60.52	-12.7%
9	134.40	117.60	12.5%
10	1.32	1.38	-4.5%
11	88.00	94.00	-6.8%
12	12.26	34.75	-183.4%
13	1.20	1.66	-38.2%
14	105.00	120.00	-14.3%
15	97.23	86.92	10.6%
16	70.63	73.49	-4.0%
17	84.06	14.76	82.4%
18	88.71	118.55	-33.6%
19	63.31	64.83	-2.4%
20	120.00	114.00	5.0%
21	142.77	79.11	44.6%
22	133.58	157.80	-18.1%
23	1.53	1.43	6.5%
24	90.23	87.10	3.5%

Note: 36 projects contributed CAIDI values to this report; 24 utilities provided data for both summer 2013 and summer 2014.

Table D-4. MAIFI Comparisons, Summer 2013 and Summer 2014

Number	Summer 2013	Summer 2014	% Change
1	2.84	3.36	-18.3%
2	0.57	0.43	25.4%
3	3.31	5.84	-76.5%
4	1.88	2.20	-17.0%
5	1.83	1.17	36.1%
6	0.40	1.67	-316.3%
7	0.15	0.11	26.7%
8	0.23	0.12	46.8%
9	0.58	2.80	-382.8%

Note: 12 utilities contributed MAIFI values to this report; 9 utilities provided data for both summer 2013 and summer 2014.

APPENDIX E.
Acronyms and Abbreviations

Acronym	Definition
AC	alternating current
ADMS	Advanced Distribution Management System
AFS	automated feeder switching
ALS	automated lateral switch
AMI	advanced metering infrastructure
ANSI	American National Standards Institute
ARRA	American Recovery and Reinvestment Act
ASR	Pepco's Automatic Sectionalizing and Restoration
BHCOE	Black Hills/Colorado Electric
BPM	business process management
BWP	Burbank Water & Power
CAIDI	Customer Average Interruption Duration Index
CI	customers interrupted
CIS	customer information systems
CM	change management
CMEEC	Connecticut Municipal Electric Energy Cooperative
CMI	customer minutes of interruption
CMP	Central Maine Power
CSP	Cybersecurity Plan
CVR	conservation voltage reductions
CVT	capacitance voltage transformers
DA	distribution automation
DC	direct current
DER	distributed energy resources
DERMS	distributed energy resources management system
DMS	distribution management system
DNP	distributed network protocol
DOE	U.S. Department of Energy

Acronym	Definition
DSCADA	distribution supervisory control and data acquisition
EMS	Energy Management System
EPB	Electric Power Board of Chattanooga
ETR	estimated time of restoration
FCC	Federal Communications Commission
FLISR	fault location, isolation, and service restoration
FPL	Florida Power and Light
GIS	geographic information systems
GWP	Glendale Water and Power
HES	head end systems
IADS	Integrated Automated Dispatch Systems
ICE	Interruption Cost Estimate
ICP	Integrated Control Platform
IED	intelligent electronic device
IEEE	Institute of Electrical and Electronic Engineers
IOU	investor-owned utility
IP	Internet Protocol
IPL	Indianapolis Power & Light Company
IT	information technology
IVR	interactive voice response
IVVC	integrated volt/volt-ampere reactive controls
KUB	Knoxville Utilities Board
kV	kilovolt
kVAR	kilovolt-ampere reactive
kW	kilowatt
kWh	kilowatt hour
LAN	local area network
LBNL	Lawrence Berkeley National Laboratory
LTC	load tap changer
MAIFI	Momentary Average Interruption Frequency Index
MBRP	Metrics and Benefits Reporting Plan

Acronym	Definition
MDMS	meter data management systems
MEAG	Municipal Electric Authority of Georgia
MEPA	Magnolia Electric Power Association
MGE	Madison Gas and Electric
MHz	megahertz
MMLD	Marblehead Municipal Lighting Department
MVA	megavolt-ampere
MW	megawatt
MWh	megawatt hour
NIST	National Institute of Standards and Technology
NOVEC	Northern Virginia Electric Cooperative
O&M	operations and maintenance
OG&E	Oklahoma Gas and Electric
OMS	outage management system
PAS	Power Alert Service
PLC	Power Line Carrier
R&D	research and development
RF	Radio Frequency
RMS	remote monitoring systems
RMS	remote monitoring systems
RV	recreational vehicles
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SCADA	supervisory control and data acquisition
SDG&E	San Diego Gas and Electric
SGDP	Smart Grid Demonstration Program
SGIG	Smart Grid Investment Grant
SMEPA	South Mississippi Electric Power Association
SMUD	Sacramento Municipal Utility District
TPDC	Transmission Performance and Diagnostic Center
VAR	volt-ampere reactive

Acronym	Definition
VSAT	very small aperture terminal
VVO	volt/VAR optimization
WiMAX	Worldwide Interoperability for Microwave Access
WMS	workforce management systems
WPL	Wisconsin Power and Light

MPSC Case No: U-21534

Requester: MNSC

Question No.: MNSCDE-18.17

Respondent: S. Hartwick

Page: 1 of 1

Question: 17. Refer to the rebuttal testimony of Witness Hartwick, Q&A 13. Has the Company documented the number of energized wire downs avoided as a result of historic Distribution Automation investment in reclosers on the 4.8kV system? If so, produce the data and analysis.

Answer: We have not performed this analysis.

Attachment: None

MPSC Case No: U-21534

Requester: MNSC

Question No.: MNSCDE-18.20a

Respondent: S. Hartwick

Page: 1 of 1

Question: 20. Refer to the rebuttal testimony of Witness Hartwick, Q&A 18. Related to the G&W Viper reclosers:

a. When did DTE initiate the installation of these reclosers?

Answer: DTE Electric installed the first G&W Viper reclosers in 2022 as a test case. The Distribution Automation program began routinely installing G&W Viper reclosers in 2023.

Attachment: None

MPSC Case No: U-21534

Requester: MNSC

Question No.: MNSCDE-18.20b

Respondent: S. Hartwick

Page: 1 of 1

Question: 20. Refer to the rebuttal testimony of Witness Hartwick, Q&A 18. Related to the G&W Viper reclosers:

b. Does this recloser result in added costs to DTE, compared to other reclosers? If so, produce the Company's cost-benefit evaluation of G&W Viper reclosers versus other reclosers.

Answer: DTE Electric did not perform a cost-benefit evaluation of the G&W Viper recloser versus other reclosers. An engineering evaluation was performed including several reclosers across multiple factors. The G&W Viper was the device identified as meeting DTE Electric's requirements for Distribution Automation. One major benefit of the G&W Viper was the capability to implement new logic algorithms like ground detection. The ground detection algorithm mitigates safety hazards due to its ability to reduce the risk from potentially energized downed wires on the 4.8 kV system.

Attachment: None

MPSC Case No: U-21534

Requester: MNSC

Question No.: MNSCDE-18.20c

Respondent: S. Hartwick

Page: 1 of 1

Question: 20. Refer to the rebuttal testimony of Witness Hartwick, Q&A 18. Related to the G&W Viper reclosers:

c. Produce any request for bids or proposals related to DTE's evaluation and assessment of G&W Viper and other types of reclosers for the 4.8kV system.

Answer: The Company objects to this request because the information requested consists of confidential, proprietary or commercial information the disclosure of which would cause the Company, its ratepayers and its customers competitive harm and because it is contrary to contractual rights of third parties. Without waiving these objections, but subject to them, the Company responds as follows:

The Company obtains quotes on cost and specifications as part of the engineering evaluation. While costs are a component of the evaluation, the engineering considerations are needed to determine if the devices meet our specifications for planned use cases on our grid. Based on the Company's evaluation, the G&W Viper was determined as the optimal solution.

Attachment: None

Co-respondent: Legal

MPSC Case No: U-21534

Requester: MNSC

Question No.: MNSCDE-18.21

Respondent: S. Hartwick

Page: 1 of 1

Question: 21. Refer to the rebuttal testimony of Witness Hartwick, Q&A 22. For reclosers installed by DTE in 2022, 2023, and 2024, produce the Company's review to determine the optimal number of devices to install for each 4.8kV circuit where DTE installed reclosers.

Answer: DTE Electric objects to the request for the reasons that the request is overly broad, seeks excessive detail, seeks confidential, proprietary research, or commercial information belonging to DTE Electric, the disclosure of which would cause DTE Electric and its customers competitive or commercial harm, seeks information involving Cyber Security, CEII (either critical energy infrastructure information or critical electric infrastructure information), North American Electric Reliability Corporation (NERC) NERC-CIP (including but not limited to BES Cyber Asset information subject to protection under the Information Protection Program pursuant to NERC Reliability Standards CIP-003-6 and CIP-011-2), Supervisory Control and Data Acquisition (SCADA), confidential Midcontinent Independent System Operation (MISO) and ITC Holdings Corp and/or its affiliate companies' information in the possession of DTE Electric. Subject to this objection and without waiver thereof, the Company would answer as follows:

Each circuit is unique and requires an engineering review. This review is conducted by an engineer to analyze the circuit (i.e., circuit configuration, customer counts, etc.) and running load studies to determine the optimal number or reclosers. This process of analyzing the circuit is not something which can easily be produced on a piece of paper. Attached is an example output of the analysis.

Attachment: CEII U-21534 MNSCDE-18.21-01 Example Review - Viper Count.pdf

Co-respondent: Legal

MPSC Case No: U-21534

Requester: MNSC

Question No.: MNSCDE-18.23

Respondent: S. Hartwick

Page: 1 of 1

Question: 23. Refer to the rebuttal testimony of Witness Hartwick, Q&As 27 and 34. Identify or produce the workpaper or analysis supporting the Company's expectations of reducing SAIDI on the particular circuits to be automated in 2024 and 2025.

Answer: The estimated benefits were determined using the reliability model, Exhibit A-43, Schedule HH2. Outputs from the reliability model were captured in the attached file to detail the origins of the estimates.

Attachment: U-21534 MNSCDE-18.23-01 2024-2025 Automation Benefits.xlsx

U-21534 MNSCDE-18.23-01 2024-2025 Automation Benefits

	A	B	C	D	E	F	G	H	I	J	K
1											
2			Baseline	2023	2024	2025	2026	2027	2028	2029	2030
3											
4	Everything But	Automation	563	491	504	490	470	443	412	381	348
5	Everything And	Automation	563	491	504	482	416	350	251	173	158
6		2024 benefit				9					
7		2025 benefit					45				
8											
9	2024										
10	Only Automation Ckts	Automation On	15	13	12	6	6	6	6	5	5
11		Automation Off	15	13	12	11	10	10	10	9	8
12						5					
13						45%					
14	2025										
15	Only Automation Ckts	Automation On	69	60	61	59	30	28	26	25	23
16		Automation Off	69	60	61	59	56	53	49	47	44
17							27				
18							47%				

MPSC Case No: U-21534

Requester: MNSC

Question No.: MNSCDE-18.24

Respondent: S. Hartwick

Page: 1 of 1

Question: 24. For 4.8kV circuits automated in 2022 and 2023 as part of Company's Distribution Automation program to install reclosers, identify the SAIDI minutes for each circuit for the 5 years preceding the recloser installation and the years since the recloser installation.

Answer: Please see the attached Excel file.

Attachment: U-21534 MNSCDE-18.24-01 2022-2023 DA Circuits_ExMED SAIDI 2017-2023.xlsx

U-21534 MNSCDE-18.24-01 2022-2023 DA Circuits_ExMED SAIDI 2017-2023

	A	B	C	D	E	F	G	H	I
1			ExMED SAIDI (min)						
2	**Circuit**	**Install Year (IY)**	**IY-5**	**IY-4**	**IY-3**	**IY-2**	**IY-1**	**IY**	**IY+1**
3	REDFD1064	2022	346	447	141	69	120	48	173
4	ARNLD1912	2023	426	14	91	14	16	27	-
5	ANNCH1342	2023	10	2122	72	2	52	14	-
6	ANNCH1520	2023	192	54	18	1	41	84	-
7	APPOL1383	2023	70	94	87	13	25	18	-
8	ARNLD0581	2023	87	68	151	3	0	0	-
9	ARNLD1653	2023	72	13	123	0	89	164	-
10	ARNLD1695	2023	227	14	300	3	6	11	-
11	ATLAS2068	2023	0	38	3	0	62	4	-
12	BAKER2522	2023	149	7	3	12	49	9	-
13	BALFR1203	2023	75	27	32	36	282	180	-
14	BALFR1212	2023	750	128	23	6	40	16	-
15	BALFR2038	2023	244	47	25	154	276	239	-
16	BALFR2039	2023	48	110	54	45	131	74	-
17	BALFR2097	2023	175	47	108	306	9	73	-
18	BALFR2162	2023	53	33	188	46	15	30	-
19	BERKY1991	2023	243	20	0	3	6	191	-
20	BERKY2681	2023	60	240	18	171	688	24	-
21	BERND0342	2023	139	147	43	4	40	82	-
22	BISHP1945	2023	2	21	16	8	28	39	-
23	BLAIR1849	2023	63	206	68	70	37	30	-
24	BUNRT1658	2023	76	1040	96	13	21	20	-
25	BUNRT1779	2023	44	280	69	176	27	3	-
26	BURTN0381	2023	212	168	40	253	55	20	-
27	BVRLY2662	2023	233	33	4	43	24	30	-
28	CEDAR2610	2023	21	3	14	4	10	33	-
29	CENTR0348	2023	12	33	56	61	9	44	-
30	CENTR1818	2023	114	54	76	5	23	69	-
31	CENTR2420	2023	5	6	8	42	6	4	-
32	CHAND1021	2023	1498	762	818	270	42	131	-
33	CHIGO1448	2023	57	41	47	14	113	20	-
34	CHIGO1463	2023	198	425	55	33	17	59	-
35	CONAT2235	2023	210	99	64	27	52	98	-
36	COOLG1209	2023	177	63	325	29	302	151	-
37	CORNL2006	2023	227	15	8	5	109	284	-
38	CORNL2007	2023	130	312	63	2	120	38	-
39	CORNL2928	2023	29	16	79	15	65	16	-
40	CRTIS2031	2023	263	96	13	21	14	73	-
41	CULVR0313	2023	272	163	3	228	4	6	-
42	CULVR0315	2023	59	393	12	127	46	27	-
43	CULVR0316	2023	280	312	25	67	108	136	-
44	DALY1737	2023	42	10	212	133	33	17	-
45	DCATR0057	2023	166	1	84	207	5	77	-
46	DCATR2140	2023	361	69	36	64	25	46	-
47	DENVR2067	2023	1607	927	195	223	218	22	-
48	DERBN1316	2023	337	41	56	22	41	109	-
49	DIX1498	2023	5	1	8	7	12	63	-
50	DUDLY2714	2023	57	239	27	10	192	56	-
51	ECORS1095	2023	51	17	81	2	23	132	-
52	ECORS1345	2023	30	23	13	27	792	528	-
53	ECORS1382	2023	47	14	11	12	10	28	-

U-21534 MNSCDE-18.24-01 2022-2023 DA Circuits_ExMED SAIDI 2017-2023

	A	B	C	D	E	F	G	H	I
54	ECORS1414	2023	192	143	112	269	702	121	-
55	ECORS1956	2023	535	34	531	12	460	14	-
56	ECORS2077	2023	299	2	6	8	3	256	-
57	ECORS2103	2023	23	23	6	11	16	29	-
58	ECORS2106	2023	318	9	25	105	38	15	-
59	EIGMI2040	2023	52	314	206	83	33	76	-
60	ELGIN1686	2023	1	72	1	45	32	4	-
61	ELGIN1690	2023	44	24	14	11	129	39	-
62	EMPIR1378	2023	186	321	78	4	76	116	-
63	EMPIR2232	2023	941	28	28	86	350	100	-
64	EMRCK2921	2023	5	5	108	5	2	321	-
65	EMRCK2925	2023	137	38	112	12	4	383	-
66	EMRCK2929	2023	323	13	180	15	4	368	-
67	ERIN2422	2023	17	31	5	25	4	26	-
68	ERIN2441	2023	21	246	42	11	8	170	-
69	ERIN2453	2023	15	36	13	17	2	40	-
70	ESTLD2241	2023	60	149	336	193	19	17	-
71	EVRGN1282	2023	297	29	34	17	135	61	-
72	EVRGN1892	2023	320	91	22	132	148	44	-
73	FERND2698	2023	1455	420	23	298	109	73	-
74	FRANK1749	2023	267	187	136	247	583	37	-
75	FRANK1764	2023	861	83	250	17	607	28	-
76	FRASR0848	2023	95	186	97	116	12	4	-
77	FRASR1873	2023	92	5	64	31	392	103	-
78	FRASR2436	2023	8	105	47	11	46	37	-
79	FRMNT1250	2023	5	63	9	8	405	20	-
80	FRMTN1712	2023	94	339	65	167	36	72	-
81	GDRIV1182	2023	46	254	139	25	194	66	-
82	GDRIV2220	2023	51	297	209	41	185	34	-
83	GLEND1408	2023	4	23	54	35	78	507	-
84	GNSTN1287	2023	98	66	16	135	19	733	-
85	GRANT2233	2023	51	183	7	24	827	9	-
86	GRPTE1205	2023	19	267	21	43	17	52	-
87	HARPR2402	2023	5	79	52	21	59	192	-
88	HARPR2409	2023	124	70	43	7	15	1	-
89	HARPR2431	2023	27	54	31	81	119	117	-
90	HARPR2515	2023	43	85	10232	66	90	43	-
91	HARPR2526	2023	44	5	21	13	17	29	-
92	HARVY1706	2023	421	19	24	623	76	916	-
93	HAWTH1176	2023	512	468	13	213	494	123	-
94	HAWTH2020	2023	39	112	179	539	27	31	-
95	HAYES1141	2023	95	232	4	20	33	139	-
96	HAYES1385	2023	833	839	282	147	144	132	-
97	HAYES2109	2023	58	214	167	20	24	28	-
98	HAZPK1265	2023	69	36	8	95	11	43	-
99	HIKRY1495	2023	14	41	8	61	119	28	-
100	HILL0364	2023	7	21	10	26	41	15	-
101	HILL2590	2023	14	37	3	4	5	18	-
102	HILL2596	2023	47	32	25	37	4	5	-
103	HOBRT0315	2023	454	409	218	92	141	456	-
104	HOOVR0304	2023	40	16	14	13	0	3	-
105	INDIN1406	2023	183	16	367	60	8	48	-
106	INDIN1423	2023	126	0	17	2	1	5	-

U-21534 MNSCDE-18.24-01 2022-2023 DA Circuits_ExMED SAIDI 2017-2023

	A	B	C	D	E	F	G	H	I
107	IVNHO2679	2023	5	340	672	137	595	47	-
108	IVNHO2728	2023	30	116	37	16	194	66	-
109	IVNHO2732	2023	116	322	274	203	137	6	-
110	KEEGO0311	2023	10	85	154	11	27	17	-
111	KEEGO0312	2023	53	124	24	11	21	107	-
112	KENEY2708	2023	26	142	48	1	57	33	-
113	LAKSD2544	2023	30	41	18	117	3	33	-
114	LAPER2312	2023	11	41	11	75	359	132	-
115	LIBER1815	2023	46	18	20	1321	30	335	-
116	LIBER2401	2023	487	896	153	67	19	287	-
117	LINCN0356	2023	124	34	49	24	7	6	-
118	MANDY0302	2023	80	7	14	73	261	5	-
119	MARIN0301	2023	10	11	45	1	597	69	-
120	MELRO0491	2023	0	250	54	306	18	28	-
121	MELRO2412	2023	71	152	122	345	232	327	-
122	MELRO2439	2023	23	152	190	1	70	177	-
123	MERRD1879	2023	455	897	189	212	268	450	-
124	MLVDL1192	2023	58	124	9	35	59	231	-
125	MOHAK1924	2023	11	15	6	4	5	37	-
126	NANKN1693	2023	83	180	105	314	323	19	-
127	NAVAR1241	2023	207	205	356	38	7	28	-
128	NELSN0003	2023	121	71	171	236	223	357	-
129	NELSN0309	2023	91	3	109	26	39	378	-
130	NRLND1548	2023	4	7	282	674	11	8	-
131	NUNLY0365	2023	19	10	36	93	45	106	-
132	NUNLY0367	2023	139	431	117	267	150	26	-
133	NUNLY1923	2023	13	4	3	55	37	13	-
134	NUNLY1936	2023	2	11	0	6	4	11	-
135	NUNLY2566	2023	41	72	144	55	270	29	-
136	OUTDR2087	2023	325	12	19	21	10	325	-
137	PINGR0403	2023	494	63	101	32	29	249	-
138	PURTN1173	2023	440	33	20	41	15	130	-
139	PURTN1246	2023	1170	43	39	102	335	268	-
140	QTNRD0324	2023	576	67	37	713	612	55	-
141	QTNRD1409	2023	115	4	19	53	27	53	-
142	RAVIN1665	2023	47	8	113	877	4	13	-
143	RAVIN1787	2023	302	11	172	121	121	27	-
144	REDFD1113	2023	72	28	120	325	258	45	-
145	STARK1821	2023	167	115	4	12	4	21	-
146	ROCHR0579	2023	0	0	5	0	11	0	-
147	ROCHR1814	2023	42	6	22	26	5	36	-
148	ROCHR1823	2023	99	6	126	10	21	7	-
149	ROCHR1838	2023	35	232	5	23	12	139	-
150	ROMEO0300	2023	15	56	599	314	124	3	-
151	ROMEO0306	2023	50	19	32	279	128	26	-
152	ROSVL0803	2023	0	0	0	0	0	0	-
153	ROSVL1756	2023	147	22	445	1	3	4	-
154	ROSVL1884	2023	0	167	470	0	95	9	-
155	ROSVL2416	2023	8	8	378	7	8	12	-
156	ROSVL2484	2023	145	66	296	50	85	286	-
157	RVRVW2820	2023	1	4	21	1	36	165	-
158	SAVAN1086	2023	138	31	868	17	26	54	-
159	SAVAN2123	2023	81	116	186	257	47	32	-

U-21534 MNSCDE-18.24-01 2022-2023 DA Circuits_ExMED SAIDI 2017-2023

	A	B	C	D	E	F	G	H	I
160	SAVAN2244	2023	151	74	57	96	34	19	-
161	SCOTN1068	2023	32	65	53	74	17	92	-
162	SHADK1093	2023	1	53	213	37	4	134	-
163	FRMNT2096	2023	338	443	63	550	40	59	-
164	HOWEL2931	2023	118	383	3	22	22	41	-
165	SHORS2507	2023	4	38	24	43	27	103	-
166	SHORS2511	2023	0	1	292	21	2	29	-
167	SHORS2513	2023	2	54	41	6	14	9	-
168	SIXMI1200	2023	91	173	55	66	93	81	-
169	SIXMI1236	2023	356	17	58	3	9	106	-
170	SIXMI2011	2023	392	66	149	4	8	56	-
171	TWEMI1939	2023	7	191	26	11	1469	270	-
172	STEPH0812	2023	0	4	0	4	108	0	-
173	STEPH0912	2023	0	0	0	171	103	0	-
174	STLUS1206	2023	45	85	45	22	78	79	-
175	SUTTN0383	2023	6	17	63	53	11	109	-
176	TIRMN1541	2023	385	294	65	11	128	37	-
177	TRNTN0308	2023	3	153	14	4	2	23	-
178	TURNR1114	2023	109	58	28	601	10	215	-
179	TURNR1148	2023	75	49	684	53	16	30	-
180	UNLAK1688	2023	58	4	22357	162	4	59	-
181	UTICA0357	2023	33	189	237	0	15	116	-
182	VENIC2013	2023	93	573	133	1	68	95	-
183	VERNR1489	2023	60	233	155	150	73	23	-
184	VERNR1592	2023	127	125	271	469	139	137	-
185	VERNR2051	2023	79	20	29	9	300	5	-
186	VILLA1553	2023	28	36	33	8	285	107	-
187	VILLA2161	2023	338	18	286	41	61	22	-
188	WALLK1655	2023	90	4	3	89	15	187	-
189	WALTN2680	2023	187	175	33	22	6	103	-
190	WATFD0314	2023	375	97	8	28	42	316	-
191	WATFD2684	2023	204	121	2	32	87	32	-
192	WATFD2701	2023	548	66	19	26	130	27	-
193	WCHTR1618	2023	154	295	506	302	98	340	-
194	WCHTR2666	2023	219	163	24	248	311	443	-
195	WEBST1965	2023	35	8	17	74	361	35	-
196	WHITR2809	2023	34	45	20	77	58	50	-
197	WRNSI2668	2023	9	10	113	158	18	4	-
198	YORK0302	2023	2	0	81	92	957	0	-
199	YORK0303	2023	22	49	125	16	158	73	-

MPSC Case No: U-21534

Requester: MNSC

Question No.: MNSCDE-18.25

Respondent: S. Hartwick

Page: 1 of 1

Question: 25. Refer to the rebuttal testimony of Witness Hartwick, Q&A 67. What is the Company's estimated completion date or timeframe for the BCA for Grid Automation Telecommunications?

Answer: The Company will complete the tool prior to planning routes for the next tier of locations targeted for deployment in 2026.

Attachment: None

MPSC Case No: U-21534

Requester: MNSC

Question No.: MNSCDE-12.9

Respondent: J. Kryscynski

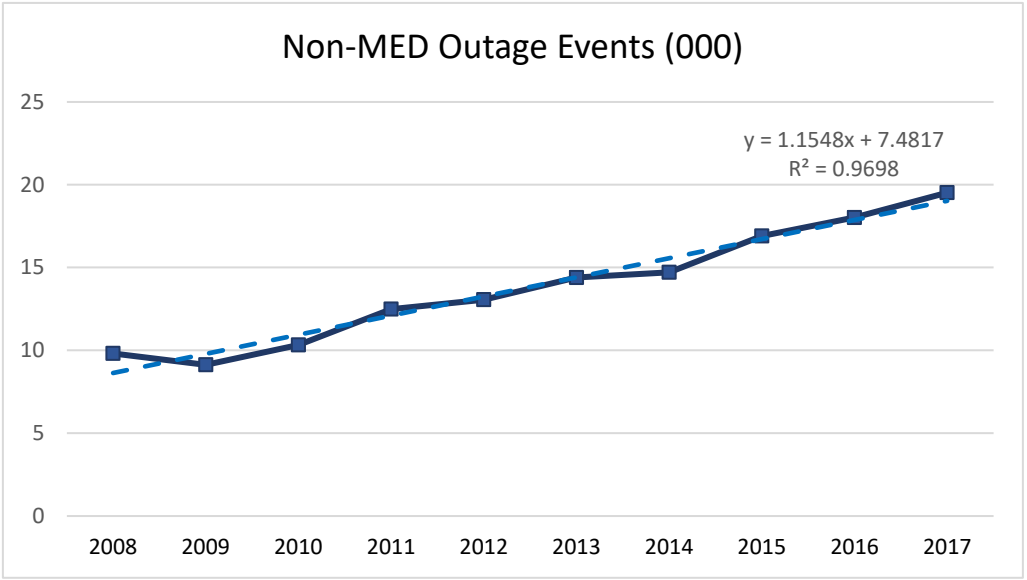
Page: 1 of 1

Question: 9. Refer to Mr. Kryscynski's testimony at AJK-70:11, which identifies "Estimate impact of system degradation" as a step employed by the Company's reliability improvement estimation model. Provide all workpapers, assumptions, calculations, estimates, and other materials employed to estimate the impact of system degradation. Cite the sources for all source data employed by the model.

Answer: Please see the attached document.

Attachment: U-21534 MNSCDE-12.9-01 Degradation Analysis

Year	Non-MED (000)	Non-MED (000)
2008	10	
2009	9	-7.0%
2010	10	13.1%
2011	12	21.0%
2012	13	4.6%
2013	14	10.2%
2014	15	2.2%
2015	17	14.9%
2016	18	6.6%
2017	20	8.4%
		8.4%
		8.2%
		8%



Multiple Outages

MPSC Case No: U-21534

Requester: MNSC

Question No.: MNSCDE-15.47h

Respondent: M. Elliott Andahazy

Page: 1 of 1

Question: 47. Refer to the Company's response to MNSCDE-8.21b which states "The Company budgets and manages the Breaker Replacement Program at the program level."

h. Refer to "U-21534 MNSCDE-3.1-01 Outages 2017-2023." Identify the outages that resulted from breaker failure.

Answer: The Company has not performed the requested analysis.

The Company has performed an analysis on all breaker failures by circuit from 2019-2023 in the attached file.

Attachment: U-21534 MNSCDE-15.47h-01 Breaker Failures 2019-2023

	A	B	C	D	E	F	G	H
1		U-21534 MNSCDE-15.47h-01 Breaker Failures 2019-2023						
2		Failure Date	Substation	Position	Circuit	Mfg	Model	Installation Decade
3		1/6/2019	ANGLA	N3	TB12A-13	IT	15HKV500	1980
4		1/7/2019	BEACH	F3	Trf 3	BB	15VHK500	1980
5		1/7/2019	BROCK	RY	TRK 8424T	IT	46KS-2500-12D	1970
6		1/7/2019	PTAUS	RB	TIE 3205	WE	460G1500	1960
7		1/14/2019	PROUD	RK	TIE 8623	AB	48PM31-20	1990
8		1/18/2019	MADSN	AF	TB 11	WE	B-13	1930
9		1/22/2019	ARIZA	C1	DC 9823	IT	15HK500	1970
10		1/22/2019	ARIZA	G1	TB 11-12	IT	15HK500	1970
11		1/22/2019	CROWN	K	DC 9780T	GE	AM13.8-500-6H	1960
12		1/22/2019	HIKRY	G3	TB 13-14	IT	15HK500	1970
13		1/22/2019	SRGNT	G1	TB 11-12	IT	15HK500	1970
14		1/24/2019	HOWRD	AW	PL 313T	WE	B-26	1950
15		1/30/2019	DEWEY	A	DC 8244	GE	AM13.8-500-6H	1960
16		1/30/2019	GAY	B	DC 2829	WE	R-4	1970
17		2/1/2019	OUTDR	N	DC 2087	WE	R-4	1970
18		2/2/2019	BNSTN	I	Dc 9347	WE	ESM 560	1970
19		2/7/2019	MALTA	M3	DC8723T	EA	150VCP-W25	2010
20		2/7/2019	SOFLD	J1	DC 8912	GE	AM13.8-500-6H	1960
21		2/8/2019	PAGE	D	DC 8828	WE	ESM 560	1970
22		2/8/2019	TRNTN	L	DC 2835	WE	B-20	1950
23		2/9/2019	WALKR	CX	TRK 545	AB	R-4	1990
24		2/14/2019	TURNR	H	Trf 2	WE	B-13	1930
25		2/15/2019	WMSTN	C2	DC 9856	BB	15VHK500	1980
26		2/19/2019	NRLND	N5A	DC 9037T	GE	AM13.8-500-6H	1960
27		2/21/2019	FLAG	J2	Trf 2	GE	FK255-150	1950
28		2/21/2019	WMSTN	E2	DC 8021	BB	15VHK500	1980
29		2/22/2019	CORNL	C	DC 2928	GE	AM13.8-500-6H	1960
30		2/22/2019	KEEGO	C1	Trf 2	AC	DZ-60B	1950
31		2/24/2019	CHIGO	L	DC 1420	WE	B-20	1950
32		2/25/2019	ANGLA	S3	DC 9112	BB	15VHKX500	1990
33		2/26/2019	OAKWD	G	TB 1	WE	ESM 560	1970
34		2/26/2019	PULFD	Y	DC 1134	WE	B-26	1950
35		2/26/2019	WTRMN	SCD	TRK 724	PO	PV38-1200-40	2000
36		2/28/2019	PATON	F1	Trf 1	IT	15HKV500	1980
37		3/1/2019	ALFRD	G	TB 11-12	IT	15HK500	1970
38		3/5/2019	STANT	I	PL 8369	IT	15HK500	1970
39		3/8/2019	ANGLA	L2	DC 9060	IT	15HKV500	1980
40		3/9/2019	SANDU	E	DC 8238	MI	17DV25-12	2010
41		3/10/2019	Fox	H	TB 11	GE	FK255-150	1950
42		3/10/2019	OAKWD	G	TB 1	WE	ESM 560A	1990
43		3/11/2019	ANGLA	O3	Trf 3	IT	15HK500	1970
44		3/15/2019	PULFD	V	PL 286T	WE	B-26	1950
45		3/26/2019	GIBSN	M	DC 1017	WE	B-20B	1950
46		3/26/2019	MADSN	AF	TB 11-12	WE	B-13	1930
47		4/3/2019	DIX	N	DC 1339	IT	15HK500	1970
48		4/4/2019	CHTNT	I	DC 8287T	GE	AM13.8-500	1960
49		4/15/2019	CAMDN	J	DC 8282	IT	15HK500	1970
50		4/15/2019	HAWTH	F	Tie 11-12	WE	F-100	1940
51		4/22/2019	IMLAY	RB	TIE 3241	WE	O221	1940
52		4/23/2019	CREWD	I	DC 8326	GE	AM13.8-500	1960
53		4/25/2019	GDRIV	BL	DC 1297	WE	B-20	1950
54		4/25/2019	WTRMN	NM	Reg Tie Trans 3	WE	34.5G2500	1950
55		4/26/2019	PHENX	SB	Trans 102	SI	SP 48.3	1990
56		4/27/2019	GRPTE	D	DC 1004	GE	FK255-250	1950
57		5/1/2019	WTRMN	NM	Reg Tie Trans 3	WE	34.5G2500	1950
58		5/2/2019	ERIN	F	TRANS 1	GE	VB13.8-500-3	2000
59		5/8/2019	NVILL	D	DC 9368	GE	AM13.8-500	1960
60		5/9/2019	DIMND	G	CTB1	WE	ESM	1980
61		5/12/2019	BECK	J	DC 8685	GE	AM13.8-500-7H	1960
62		5/15/2019	ROTUN	N	PL 8341	AB	15VHK500	1980
63		5/16/2019	LAPER	E	DC 2312	AB	ESVA	2000
64		5/16/2019	WAREN	SB	Cap 12	GE	FK26-42000-3R	1950
65		5/22/2019	COLNS	D	DC9868 S.E.	GE	VB13.8-500-3	2000
66		5/23/2019	DAYTN	RR	TIE 1473	AB	48PM31-20	1990
67		5/26/2019	CHAND	G	Cable PL 500	WE	B-26	1950
68		5/27/2019	DAYTN	RR	TIE 1473	AB	48PM31-20	1990
69		5/29/2019	JAKSN	C	DC 312	AC	DZ-60B	1950
70		5/29/2019	TRNTN	H	SECT BKR 11-12	WE	B-20	1950
71		5/31/2019	DREXL	M	TRANS 2	BB	15VHKX500	1990
72		6/4/2019	PLYMO	K	PL 4	WE	R-4	1970
73		6/8/2019	MOTT	D	DC 8124	IT	15HK500	1970
74		6/13/2019	CATLI	A	DC 9128	GE	VB13.8-500-3	2000
75		6/13/2019	RICHM	C	Trans 1	WE	B-20R	1950
76		6/19/2019	TROY	SD	TRK 3511A-3512A-ST	IT	46KS-2500-12D	1970
77		6/24/2019	WTRMN	NP	EQ Bus 111	GE	FH209C	1930
78		6/27/2019	CESNA	C	DC 9876	BB	15VHK500	1980
79		6/30/2019	NOVI	E	DC1662	AC	MC-250	1970
80		7/6/2019	SCOTN	Y	DC 2012	GE	FK55Y20	1950
81		7/7/2019	HIKRY	I	DC 1861AT-1821AT S.E.	GE	AM13.8-500-5H	1960
82		7/9/2019	VENIC	D	DC 1452T	AB	R4	2010
83		7/20/2019	ADAMS	B	DC8429	BB	15VHK500	1980
84		7/21/2019	OUTDR	N	DC 2032	WE	R-4	1970
85		7/21/2019	REMER	RI	TRK 7065 S.E.	IT	46KS-2500-12D	1970
86		7/24/2019	HAWTH	L	TB 11-13	GE	FK255-250	1950
87		7/26/2019	SCOTN	AL	PL 655T	WE	B-20	1950
88		7/26/2019	SPOOL		PL 9481T	PO	VB15.0-20-4	2010
89		8/1/2019	BUNCE	RP	TRK 833	AB	48PM31-20	1990

	A	B	C	D	E	F	G	H
90		8/1/2019	DIMND	C	DC9875	AB	ESVA 800	2000
91		8/1/2019	GULLY	A1	PL 647	IT	15HK500	1970
92		8/12/2019	HANCK	B	DC8142	IT	15HK500	1970
93		8/20/2019	BIHAM	N	DC2720	BB	15VHKX500	1990
94		8/21/2019	HANCK	J2A	DC9023	BB	15VHKX500	1990
95		8/22/2019	BNSTN	QP	TRK 1346	AB	48PM31-20	1990
96		8/23/2019	COMLK	E	DC9020T	CH	150-VCP-W500	2000
97		8/23/2019	TIRMN	L2L3	DC1196	IT	15HK500	1970
98		8/24/2019	MAUME	I	Trf 2	GE	AM13.8-250-3	1950
99		8/27/2019	FOUTN	B	DC9468	CH	150-VCP-W500	2000
100		8/28/2019	GDRIV	BL	DC 1297	WE	B-20	1950
101		8/29/2019	IVNHO	C2	DC2679	GE	VB13.8-500-3	2000
102		9/4/2019	AKRON	Q	DC 9015	AB	15VHKX500	2010
103		9/6/2019	FLMRE	D2	PL 8361T	BB	15VHK500	1980
104		9/6/2019	HOWEL	AI	Trans 1	GE	FK255-150	1950
105		9/9/2019	COLRD	A	DC 9100	BB	15VHKX500	1990
106		9/9/2019	FLINT	A	DC 9837T	GE	VB 13.8-500-3	2000
107		9/12/2019	NAVAR	SC	TRK 328T S.E.	WE	O441	1950
108		9/12/2019	NEAST	I	DC 8500	WE	ESM500	1970
109		9/13/2019	NAVAR	SI	TRK 346T S.E.	GE	FK34.5-1500Y	1950
110		9/14/2019	BNSTN	K	DC 9380	WE	ESM500	1970
111		9/16/2019	BUNRT	V	TB 13-14	GE	AM13.8-500-5H	1960
112		9/16/2019	SALIN	RK	TIE 1568	AB	48PM31-20	1990
113		9/21/2019	NBURG	SF	TRK 2087 S.E.	AB	48PM31-20	1990
114		9/27/2019	BIHAM	L2	DC 2696	IT	15HK500	1970
115		9/30/2019	STEPH	I	PL 812	IT	15HK500	1970
116		10/2/2019	NAVAR	RJ	Cap 3-1	AB	48PM31-20	1990
117		10/3/2019	FAWN	C	DC8799	WE	ESM 560	1970
118		10/4/2019	LINCN	H	DC2694	AB	R-4	1990
119		10/4/2019	STERL	N3	TB12A-13	BB	15VHKX500	1990
120		10/6/2019	ORCHD	BN	LPL 321L	AB	AMVAC	2010
121		10/8/2019	EMPIR	F1	Trans1 Bus 11	GE	AM13.8-500-5H	1960
122		10/10/2019	HOWRD	CR	Trans 4A/4B	AB	R-4	1990
123		10/15/2019	STOPL	E	TRK1719	WE	F-100	1940
124		10/18/2019	JSLYN	J	DC9151	BB	15HK500	1970
125		10/21/2019	BNSTN	JQ	BNSTN MAZDA 1 Line	ME	AHJ-60	1970
126		10/22/2019	MOHAK	F	DC1941	GE	FK255-150	1950
127		10/22/2019	TAYLR	K	DC9483	BB	15VHKX500	1990
128		10/24/2019	MLVDL	L	DC2259	GE	FK255-150	1950
129		10/25/2019	WAYNE	C	DC9413	GE	VB13.8-500	1990
130		10/28/2019	AKRON	L	DC8964	GE	AM13.8-500-7H	1960
131		10/28/2019	TURNR	BB	TB11A-14A	WE	B-13	1930
132		10/29/2019	VERNR	G	DC2043	GE	FK255-150	1950
133		11/1/2019	ARGO	RI	TRK 3150	WE	O441	1950
134		11/1/2019	FRANK	E	TRANS 1	WE	B-22B	1950
135		11/8/2019	DIX	I	TIE BKR 11-12	IT	15HK500	1970
136		11/8/2019	HOWEL	AL	DC 2931	GE	FK255-150	1950
137		11/10/2019	GOLF	C	DC 8697	BB	15VHKX500	1990
138		11/13/2019	SNSET	B	DC 8237-T	IT	15HK500	1970
139		11/15/2019	WRNSI	D	DC 336	WE	150-DH-250A	1960
140		11/19/2019	MAUME	C	DC 8224	GE	AM13.8-250-3	1950
141		11/21/2019	GARY	D	DC1864T	GE	AM13.8-500-5H	1960
142		11/27/2019	BEACH	A	DC 8601 S.E.	BB	15VHK500	1980
143		11/28/2019	MILFD	I	DC 9247	GE	VB13.8-500-3	2000
144		11/30/2019	APACE	M2A	TRANS 2	BB	15VHKX500	1990
145		12/3/2019	WICK	C	DC 9453	BB	15VHKX500	1990
146		12/5/2019	BECK	K	DC 8685	GE	AM13.8-500-7H	1960
147		12/5/2019	GARFD	CH	Transfer Bus Feed 2	WE	CO-111	1940
148		12/6/2019	CLKSN	B	DC 9113	BB	15VHKX500	1990
149		12/12/2019	CATO	B6A	PL 8306	BB	15VHKX500	1990
150		12/16/2019	BELVL	E	DC 1701	GE	AM13.8-250-2	1950
151		12/16/2019	BELVL	C	DC 1699	GE	AM13.8-250-2	1950
152		12/16/2019	PIGON	G	Tie bkr 1	ME	VWE 280	1990
153		12/16/2019	SOFLD	P	DC 9094	BB	15VHK500	1980
154		12/17/2019	TAMRK	J	DC 9067	GE	VB13.8-500	2000
155		12/17/2019	TAMRK	E	DC 9055T	GE	VB13.8-500	2000
156		12/19/2019	MTCLM	S	Tie Breaker 11A-12A	GE	VB13.8-500-3	2000
157		12/29/2019	CHIGO	Q	PL 456	GE	FK255-250	1950
158		1/8/2020	MILFD	RC	Tie 2819	AB	48PM31-20	1990
159		1/9/2020	COLRD	C	DC8987	BB	15VHK500	1980
160		1/9/2020	DIX	G1	TB11-12	IT	15HK500	1970
161		1/13/2020	TCOLA	E	DC9201	AB	ESVA	2000
162		1/14/2020	STLUS	M	TB12-13	GE	AM13.8-500-5H	1960
163		1/15/2020	PTAUS	RB	TIE3205	WE	460G1500	1960
164		1/17/2020	MADSN	AF	TB11	WE	B-13	1930
165		1/20/2020	MILFD	RC	Tie 2819	AB	48PM31-20	1990
166		1/21/2020	BIHAM	Q3	TB12A-13	BB	15VHKX500	1990
167		1/21/2020	HINES	G1	Tie Bkr 11-12	GE	AM13.8-500-6H	1960
168		1/23/2020	SHELD	D	DC8190	BB	15VHK500	1980
169		1/27/2020	SNSET			AB	48PM31-20	1990
170		2/3/2020	ANGLA	N	TB 13A-13	IT	15HKV500	1980
171		2/4/2020	CAMDN	D	DC8230	IT	15HK500	1970
172		2/5/2020	LOCDL	J	PL9011	GE	AM13.8-500-6H	1960
173		2/6/2020	MENLO	E	DC 8789	BB	ESVA 800	2000
174		2/7/2020	MONSA	C	Trans 1	AC	DZ-60B	1950
175		2/9/2020	ZEBRA	E	DC9479T	AB	15VHK500	1980
176		2/10/2020	BAKER	I	TB 11	GE	FK255-150	1950
177		2/12/2020	BNSTN	RC	TRK 1322	AB	48PM31-20	1990
178		2/13/2020	ERIN	RV	TRK4266-ST	IT	46KS-2500-12D	1970

	A	B	C	D	E	F	G	H
179		2/14/2020	MILFD	RC	Tie 2819	AB	48PM31-20	1990
180		2/14/2020	OTSGO	RC	TIE9303	AB	48PM31-20	1990
181		2/17/2020	GULLY	C	DC1994T	IT	15HK500	1970
182		2/19/2020	SNSET	RO	TRK5906	AB	48PM31-20	1990
183		2/20/2020	MILFD	RC	Tie 2819	AB	48PM31-20	1990
184		2/23/2020	RUSH	RC	Tie 9111	AB	48PM31-20	1990
185		2/26/2020	PULFD	CN	Linkage Bus 3	WE	CO-111	1940
186		2/27/2020	LOMRD	B	DC8189	GE	AM13.8-500-5H	1960
187		2/28/2020	NBURG	RI	DC8044T	GE	AM13.8-500-5H	1960
188		3/6/2020	GARY	B	DC 1431	GE	AM13.8-500-5H	1960
189		3/6/2020	SOFLD	J	DC 8912	GE	AM13.8-500-7H	1960
190		3/8/2020	LAUDR	A	DC 1400	WE	B-22B	1950
191		3/9/2020	GAY	D	DC 1762	GE	FK255-150	1950
192		3/12/2020	DAVIS	Q	DC 8231	BB	15VHKX500	1990
193		3/16/2020	OTSGO	RD	TRF 101	AB	48PM31-20	1990
194		3/19/2020	NBURG	D	DC 8060	GE	AM13.8-500-5H	1960
195		3/20/2020	AMSTR	AE	PL 270T	GE	FKR-55Y-28	1950
196		3/21/2020	NEFF	RF	SEC BKR 1-1	WE	460G1500	1960
197		3/27/2020	BENSN	Q	DC 8431	BB	15VHKX500	1990
198		3/29/2020	LIBER	K	Trans 2	AB	R-4	1990
199		4/4/2020	BLMFD	RH	Tie 1268	AB	48PM31-20	1990
200		4/8/2020	NEFF	RJ	TIE 5611	WE	460G1500	1960
201		4/9/2020	MACMB	F	DC 8506	WE	ESM 560	1970
202		4/25/2020	LINCN	RN	SB 3-4	WE	O441	1950
203		5/2/2020	RVRVW	L	DC 1521A-B S.E.	GE	AM13.8-250-3	1950
204		5/5/2020	RUSH	RI	TIE 9111	AB	48PM31-20	1990
205		5/7/2020	CHTNT	A	DC 8961	GE	AM13.8-500-7H	1960
206		5/12/2020	ROMLS	RE	TRK 7717	AB	48PM31-20	1990
207		5/13/2020	MEDNA	RI	TRK 6722	AB	48PM31-20	1990
208		5/25/2020	PDMNT	LSB1577		AB	48PM31-20	1990
209		5/27/2020	VILLA	B	DC 2161	GE	FK255-250	1950
210		6/1/2020	BOYNE	D	DC 8450T S.E.	BB	15VHK500	1980
211		6/1/2020	GARCY	K		WE	WE B-22B	1950
212		6/2/2020	NEFF	RF	SB1-2	WE	460G1500	1960
213		6/3/2020	APACE	J	DC 8996 S.E. and Cable and Cap 12 S.E.	GE	AM13.8-500-6H	1960
214		6/3/2020	CHIGO	L	Cable DC 1420	WE	B-20B	1950
215		6/3/2020	VENIC	P	TRANS 3 S.E. AND CABLE OF TRK 361-ST	WE	R-4	1970
216		6/5/2020	OAKWD	J	Oakwood Tap, Trans 2 S.E, DC 8984 S.E. and Line	WE	ESM560A	1980
217		6/10/2020	MLVDL	I	PL 437T S.E. AND CABLE	GE	FK255-250	1950
218		6/10/2020	STOPL	Q	Section Breaker 11-13 S.E.	AB	R-4	1990
219		6/10/2020	TWEMI	K	TRANS 2	WE	F-100	1940
220		6/12/2020	DENVR	W	DC 2222 S.E. and CABLE	WE	B-22B	1950
221		6/12/2020	ESTLD	J	DC 2238 S.E.	GE	FK255-150	1950
222		6/18/2020	BREWR	J	DC 8840 S.E.	AB	ESVA	2000
223		6/20/2020	UTICA	D	TRANS 1 S.E.	AB	R-4	1990
224		6/22/2020	GARCY	K	PL 580	WE	B-22B	1950
225		6/23/2020	ALNPK	H	TRANS 3	IT	15HK500	1970
226		6/24/2020	FOX	H	TIE BKR 11	AB	R-4	1990
227		6/27/2020	YALE	RI	TIE 3220	WE	460G1500	1960
228		6/29/2020	MADRID	RK	TIE 8014 AB-AC S.E.	IT	46KS-2500-12D	1970
229		7/11/2020	DIX	I	DC 2058 S.E.	IT	15HK500	1970
230		7/11/2020	WAYBN	I	DC 1161 S.E. and Cable	WE	B-20	1950
231		7/15/2020	GDRIV	BO	DC 1182	WE	B-20	1950
232		7/20/2020	INDIN	H	TRANS 2 S.E.	AB	R-4	1990
233		7/20/2020	REDFD	H	DC 1325 S.E.	WE	B-20	1950
234		7/21/2020	HOMER	G	TB 11-12 S.E.	GE	AM13.8-500-6H	1960
235		7/24/2020	LOCDL	D	DC 8909-S S.E.	GE	AM13.8-500-6H	1960
236		7/29/2020	HARVY	B	DC1531	WE	B-22B	1950
237		8/6/2020	GULLY	F	TRANS 1	IT	15HK500	1970
238		8/6/2020	SPOOL	F	Trans 1	PO	VB15.0-20-4	2010
239		8/8/2020	WAREN	SE	TRK 648	AB	72PM31-20	2010
240		8/11/2020	MONSA	A	Trans 2 S.E., Trans 1 S.E. & PL 3	AC	DZ-60B	1950
241		8/12/2020	INKST	I	DC 315	AC	DZ-60B	1950
242		8/14/2020	RUSH	RI	TIE 9111	AB	48PM31-20	1990
243		8/16/2020	NAVAR	G	DC 1241 S.E.	GE	FK255-150	1950
244		8/23/2020	CULVR	K	TRANS 2	WE	R-4	1970
245		8/28/2020	BROCK	RE	TRK8412	IT	46KS-2500-12D	1970
246		8/29/2020	BRAZL	I	DC 8402	GE	AM13.8-500-6H	1960
247		8/29/2020	CARPT	RA	TIE 5208 S.E.	WE	GO-2A	1960
248		8/31/2020	IRNTN	SH	TRK 3031 S.E.	SI	BZO-145-63-6	1980
249		9/1/2020	CHIGO	Q	PL 456A-B	GE	FK255-250	1950
250		9/2/2020	OTTWA	F	TRANS 1 S.E. & BUS 11	GE	VB13.8-500-3	2000
251		9/7/2020	PTHUR	E	DC 304 S.E. AND TRANS 1 S.E.	WE	B-20	1950
252		9/12/2020	VERNR	T	DC 2037 VERNIER	GE	FK255-250	1950
253		9/21/2020	WAREN	F	CTB 1	MI	17DV25-12	2010
254		9/23/2020	DAVIS	F	TRANS 1 S.E.	IT	15HK500	1970
255		9/24/2020	HAWTH	S	Tie Breaker 11-12 S.E.		Need to check paper files	
256		9/25/2020	WATFD	RA	TRK 6172	AB	48PM31-20	1990
257		10/2/2020	NEAST	G	CTB # 1	CP	VWE 560A	1990
258		10/3/2020	ALNPK	H	TRANS 3	IT	15HK500	1970
259		10/3/2020	SNSET	RO	TRK 5906	AB	48PM31-20	1990
260		10/4/2020	FRMTN	K	Trans 2	GE	FK255-150	1950
261		10/13/2020	WILEY	K	DC 2614	BB	ESVA 800	2000
262		10/14/2020	YOST	C	PL 8096T	GE	AM13.8-500-6H	1960
263		10/16/2020	LAKSD	E	DC 1895T	WE	B-22B	1950
264		10/16/2020	RUSH	RI	TIE 9111	AB	48PM31-20	1990
265		10/19/2020	DAVIS	D	DC 8214T	IT	15HK500	1970
266		10/19/2020	IRNTN	RC	Trk 3077	SI	BZO-145-63-6	1980
267		10/19/2020	STEPH	S	DC8522	WE	ESM560	1980

	A	B	C	D	E	F	G	H
268		10/23/2020	BIRCH	T2-L	TRANS 2	AC	DZ-60B	1950
269		10/29/2020	STANT	M	PL 8393	IT	15HK500	1970
270		11/5/2020	NSCEN	LSB 1555	LSB 1555	WE	GO-4B	1950
271		11/6/2020	COOLG	K	Trf 3	WE	R-4	1970
272		11/6/2020	TEMPL	I4	NF 235T	PO	VB15.0-20-4	2010
273		11/8/2020	RUSH	HD	Trf 101	AB	145PM	2000
274		11/9/2020	CARTR	G	TB 11	GE	AM13.8-250H-4	1950
275		11/9/2020	LAKSD	D	DC 2540	WE	B-22B	1950
276		11/11/2020	ORCHD	BO	LPL321W	GE	FK255-150	1950
277		11/12/2020	TEMPL	B	FSS 1303	PO	VB15.0-20-4	2010
278		11/14/2020	MADSN	W	PL 268AT	GE	FK255-150	1950
279		11/16/2020	ECORS	D	DC 1345	GE	FK255-150	1950
280		11/17/2020	TWEMI	A	DC 355	AB	R-4	1990
281		11/18/2020	STERL	J2A	PL 8289T	IT	15HK500	1970
282		12/1/2020	KORTE	G	DC 1393	WE	B-22B	1950
283		12/2/2020	SNSET	RO	TRK 5906	AB	48PM31-20	1990
284		12/3/2020	HAYES	P2	DC 2109	GE	AM13.8-500-6H	1960
285		12/10/2020	CORNL	E	Trf 1	IT	15HV250	1960
286		12/12/2020	CHTNT	N1A	TB 11A-12	BB	15VHKX500	1990
287		12/13/2020	STEPH	SH	TRK 2516	WE	GO-4B	1950
288		12/15/2020	FRFAX	N	TB 11-12	MI	17DV25-12	2010
289		12/16/2020	FRLDG	AI	DC 303	AC	DZ-60B	1950
290		12/16/2020	NAVAR	SE	Bus 6	WE	O441	1950
291		12/17/2020	PTAUS	RB	Tie 3205	WE	460G1500	1960
292		12/18/2020	HANCK	CTG12-2	CTG 12-2	IT	15HK1000	1970
293		12/21/2020	NAVAR	SC	TRK 328T S.E.	WE	O441	1950
294		12/21/2020	WTRMN	SN	Tie 189A-B	PO	38PV40CDR	1990
295		12/22/2020	SPRUC	E	DC 9817T	IT	15HKV500	1980
296		12/29/2020	FRISB	RY	Trf 102	PO	PV38	1990
297		12/29/2020	SLOAN	E3	DC 8529	BB	15VHKX500	1990
298		12/30/2020	BECK	D	DC 8687	GE	AM13.8-500-7H	1960
299		1/4/2021	HANCK	F	Trans 1	IT	15HK500	1970
300		1/4/2021	LINCN	G	DC 1566-S	AC	DZ-100B	1960
301		1/5/2021	HAGER	H	Trans 2	BB	15VHKX500	1990
302		1/5/2021	ROSVL	AG	Trans 1	GE	FK255-150	1950
303		1/6/2021	FRISB	RZ	TRK 1820	PO	PV38-1200-40	2000
304		1/12/2021	GLEND	H	TB 11-12A	AB	AMVAC	2010
305		1/22/2021	COMLK	G	TB 11-12	CH	150-VCP-W500	2000
306		1/22/2021	LILY	G	TB 11-12	AB	15VHK500	1980
307		1/24/2021	WMSTN	F	Trans 1	BB	15VHK500	1980
308		1/26/2021	LILY	F	TRANS 1	BB	15VHK500	1980
309		1/27/2021	DEWEY	G	TB 11-12	GE	AM13.8-500-5H	1960
310		1/28/2021	FRISB	RY	TRF 102	PO	38PV40	1990
311		1/28/2021	HANCK	RD	Trk 4405	AB	48PM31-20	1990
312		1/28/2021	MALRD	G	TB 11-12	IT	15HK500	1970
313		1/29/2021	HANCK	RD	TRK 4405	AB	48PM31-20	1990
314		2/1/2021	TINKN	K2	DC8914	IT	15HK500	1970
315		2/6/2021	JAKSN	T1-L	Trans 1	AC	DZ-60B	1950
316		2/8/2021	PLACD	RH	TRK 6125	IT	46KS-2500-12D	1970
317		2/9/2021	CEDAR	H	TB 11	GE	AM13.8-250-3	1950
318		2/9/2021	LYNCH	V	DC2260	WE	B-20B	1950
319		2/9/2021	STEPH	K1	DC1919	IT	15HK500	1970
320		2/10/2021	MACK	SB	Trf 104	WE	34.5G2500	1950
321		2/12/2021	KENT	F	Trans 1	WE	F-100	1940
322		2/15/2021	FLMRE	E1	PL8346	BB	15VHK500	1980
323		2/16/2021	FLMRE	E1	PL8346	BB	15VHK500	1980
324		2/16/2021	WICK	F1	Trans 1	IT	15HK500	1970
325		2/16/2021	WICK	C1	DC9453	IT	15VHKX500	1990
326		2/17/2021	AUBRN	E2	DC8864	IT	15HK500	1970
327		2/17/2021	IVNHO	D1	DC2717T	GE	VB13.8-500-3	2000
328		2/17/2021	IVNHO	G1	TB11-12	GE	VB13.8-500-3	2000
329		2/17/2021	TINKN	D1	DC8884	IT	15HK500	1970
330		2/18/2021	GULLY	G1	TB11-12	IT	15HK500	1970
331		2/18/2021	NAVAR	RY	TRK 362	WE	O441	1950
332		2/19/2021	WLVRN	F1	Trans 1	IT	15HK500	1970
333		2/20/2021	CODY	RR	TRK2824	AB	48PM31-20	1990
334		2/22/2021	CONAT	P	DC2064	GE	FK255-250	1950
335		3/1/2021	BIDLE	G	PL 10	WE	B-22B	1950
336		3/1/2021	BNSTN	RC	Trk 1322	AB	48PM31-20	1990
337		3/1/2021	LINCN	AF	TB 13-14A	WE	R-4	1970
338		3/8/2021	AKRON	K	DC8971	GE	AM13.8-500-7H	1960
339		3/9/2021	NBURG	E	PL 8075	GE	AM13.8-500-6H	1960
340		3/9/2021	NBURG	F	DC 8044	GE	AM13.8-500-5H	1960
341		3/11/2021	FLAG	J	DC 1680	GE	FK255-150	1950
342		3/12/2021	FRASR	M	PL 848	WE	B-20B	1950
343		3/18/2021	RGENT	D	DC 352	WE	B-20B	1950
344		3/18/2021	STERL	RG	TRK 2713	AB	48PM31-20	1990
345		3/19/2021	PADOK	C	DC 4018	GE	FK255-150	1950
346		3/22/2021	BVRLY	D	DC 1865	AB	AMVAC	2010
347		3/22/2021	STERL	RN	Trans 102	WE	460G2500	1960
348		3/23/2021	AKRON	P	DC 9047	BB	15VHKX500	1990
349		3/23/2021	GULLY	C	DC 1994	IT	15HK500	1970
350		3/23/2021	IRNTN	RJ	SB 1-2 S.E.	SI	BZO-145-63-6	1980
351		3/28/2021	ZEBRA	A	DC 9472	AB	15VHK500	1980
352		3/29/2021	NRLND	G	DC 1428	GE	FK255-150	1950
353		4/9/2021	GARFD	G	DC 1035	WE	B-26	1950
354		4/14/2021	BIHAM	J	DC 1885-ST	IT	15HK500	1970
355		5/3/2021	RSVLT	I	TB 13 S.E.	WE	B-13	1930
356		5/4/2021	BECK	F	TRANS 1 S.E.	GE	VVB13.8-500-OH	2000

	A	B	C	D	E	F	G	H
357		5/25/2021	STANT	G5	TB 15-16A	IT	15HK500	1970
358		6/8/2021	RAVIN	D1	TRF 01	GE	FK255-150	1950
359		6/24/2021	SPKNE	B2	DC 9056	GE	VVC13.8-500	1990
360		6/27/2021	MCGRW	F	DC 1201	AB	R-4	2010
361		6/27/2021	MCGRW	S	DC 1164	AB	R-4	2010
362		6/27/2021	MCGRW	L	DC 1321	AB	R-4	2010
363		6/27/2021	MCGRW	AK	DC 2030	AB	R-4	2010
364		6/27/2021	MCGRW	I	DC1366	AB	R-4`	2010
365		6/27/2021	MCGRW	AG	PL96	AB	R-4	2010
366		6/27/2021	MCGRW	AH		GE	FK255-150	1950
367		6/27/2021	MCGRW	AI	PL395	AB	R-4	2010
368		6/27/2021	MCGRW	AJ	RES PL	AB	R-4	2010
369		6/27/2021	MCGRW	AK	DC2030	AB	R-4	2010
370		6/27/2021	MCGRW	AM	PL79	AB	R-4	2010
371		6/27/2021	MCGRW	AN	PL552T	AB	R-4	2010
372		6/27/2021	MCGRW	AQ	PL612	AB	R-4	2010
373		6/27/2021	MCGRW	AR	PL132	AB	R-4	2010
374		6/27/2021	MCGRW	AS		WE	B-20	1950
375		6/27/2021	MCGRW	AW	PL461	AB	R-4	2010
376		6/27/2021	MCGRW	AX		GE	FK255-150	1950
377		6/27/2021	MCGRW	B	DC1280	AB	R-4	2010
378		6/27/2021	MCGRW	CF	Linkage Bus Feed 1	WE	B-32	1950
379		6/27/2021	MCGRW	CK	Linkage Bus Feed 3	WE	B-32	1950
380		6/27/2021	MCGRW	CP	Transfer Bus Feed	WE	B-32	1950
381		6/27/2021	MCGRW	E	DC1048	AB	R-4	2010
382		6/27/2021	MCGRW	F	DC1201	AB	R-4	2010
383		6/27/2021	MCGRW	H	RES PL	AB	R-4	2010
384		6/27/2021	MCGRW	I	DC1366	AB	R-4	2010
385		6/27/2021	MCGRW	K	DC1167	AB	R-4	2010
386		6/27/2021	MCGRW	L	DC1321	AB	R-4	2010
387		6/27/2021	MCGRW	N	PL128	AB	R-4	2010
388		6/27/2021	MCGRW	O		AB	R-4	2010
389		6/27/2021	MCGRW	Q	PL134T	AB	R-4	2010
390		6/27/2021	MCGRW	R	DC1111	AB	R-4	2010
391		6/27/2021	MCGRW	S	DC1164	AB	R-4	2010
392		7/1/2021	ROSVL	AM	DC 1525	GE	FK255-150	1950
393		7/6/2021	SCOTN	AP	TB 16	AB	AMVAC	2010
394		7/6/2021	SCOTN	AR	DC 1300	AB	R-4	1990
395		7/6/2021	SCOTN	AZ	TB 14	WE	B-13	1930
396		7/6/2021	SCOTN	BF	Boiler Feed	AB	R-4	1990
397		7/6/2021	SCOTN	I	TB 15	AB	R-4	1990
398		7/6/2021	SCOTN	R	TB 12	WE	B-13	1930
399		7/6/2021	SCOTN	BI	DC 2042	WE	B-20	1950
400		7/6/2021	SCOTN	AO	DC 1069	WE	B-20	1950
401		7/6/2021	SCOTN	AS	PL 492	AB	AMVAC	2010
402		7/6/2021	SCOTN	C	PL219AT-22AT	WE	B-20	1950
403		7/6/2021	SCOTN	AK	DC 1283	WE	B-20	1950
404		7/6/2021	SCOTN	AL	PL 655T	WE	B-20	1950
405		7/6/2021	SCOTN	AG	PL 108	WE	B-20	1950
406		7/6/2021	SCOTN	Q	CABLE OF DC 1018	WE	B-20	1950
407		7/6/2021	SCOTN	Y	CABLE OF DC 2012	GE	FK55Y20	1950
408		7/7/2021	SAVAN	B	DC 1088	WE	B-20	1950
409		7/8/2021	WCHTR	N	DC 2666	GE	FK255-150	1950
410		7/12/2021	PULFD		LINKAGE BUS FEED 3 BREAKER S.E.	WE	CO-111	1940
411		7/13/2021	LAUDR	C	DC 1554	WE	B-22B	1950
412		7/14/2021	RUSH	RI	TIE 9111	AB	48PM31-20	1990
413		7/15/2021	APACE	R	DC9046	BB	15VHKX500	1990
414		7/19/2021	CORTL	V	PL 543T	GE	VB13.8-500	1990
415		7/19/2021	LOMRD	B		GE	AM13.8-500-5H	1960
416		7/20/2021	WTRMN	NW	TRK 709T	PO	PV38-1200-40	2000
417		7/23/2021	MOUND	P	Tie bkr 11-13	AB	R-4	1990
418		7/24/2021	MOHAK	F	DC 1941T	GE	FK255-150	1950
419		7/25/2021	STERL	I	DC 8624	IT	15HK500	1970
420		8/12/2021	BENSN	N3	TB 12A-13	BB	15VHKX500	1990
421		9/2/2021	MCGRW	AN	PL 552T SE	AB	R-4	2010
422		9/22/2021	BENSN	R3	DC 8532	BB	15VHKX500	1990
423		10/8/2021	OAKWD	J	DC 8984	MI	17DV25-12	2010
424		11/1/2021	WAGNR	J	DC 1374	GE	FK255-150	1950
425		11/4/2021	ANGLA	S2S3	PL 9112	BB	15VHKX500	1990
426		11/18/2021	HINES	RP	TRK 2918	AB	48PM31-20	1990
427		11/22/2021	ALFRD	I2	PL 8165	IT	15HK500	1970
428		11/30/2021	DREXL	O3	TRF 3	BB	15VHKX500	1990
429		1/5/2022	ARIZA	A1	DC9812T	IT	15HK500	1970
430		1/6/2022	ARGO	RI	TRK 3150	GE	O441	1950
431		1/6/2022	ARIZA	I	DC 9854T	IT	15HKV500	1980
432		1/6/2022	BOYNE	I	DC 8566 S.E.	BB	15VHK500	1980
433		1/7/2022	GOLF	E	DC 8400T	BB	15VHKX500	1990
434		1/11/2022	FRONT	F	PL 61 A-B	GE	FK255-150	1950
435		1/11/2022	LOMRD	S3	DC 8173 S.E.	BB	15VHKX500	1990
436		1/14/2022	HANCK	F	Trans 1	IT	15HK500	1970
437		1/14/2022	HOOVR	E	Trans 1 S.E.	WE	B-22B	1950
438		1/14/2022	STANT	Q7	PL 8357-ST	IT	15HK500	1970
439		1/20/2022	STERL	RG	Trk 2713 A-B	AB	48PM31-20	1990
440		1/24/2022	WLNUT	F	Trans 1 SE	IT	15HK500	1970
441		1/27/2022	ALFRD	E1	PL 8212T	IT	15HK500	1970
442		2/1/2022	ARIZA	B2	DC 9816 S.E.	IT	15HK500	1970
443		2/8/2022	CODY	RP	TRK 2840	AB	48PM31-20	1990
444		2/16/2022	HURST	RC	TRANS 101 S.E.	AB	48PM31-20	1990
445		2/18/2022	DENVR	U	DC 2139	AB	R-4	1990

	A	B	C	D	E	F	G	H
446		2/19/2022	LAMBT	G	DC 2082	WE	B-22B	1950
447		2/25/2022	FRONT	A	PL 63	GE	FK255-150	1950
448		2/25/2022	WLVRN	D2	DC 8266	IT	15HK500	1970
449		2/28/2022	HIKRY	H2	Trans 2	GE	AM13.8-500-6H	1960
450		3/1/2022	ARGO	RI	TRK 3150	WE	O441	1950
451		3/2/2022	WTRMN	NJC	Cable TRK 764T	PO	PV38-1200-40	2000
452		3/7/2022	VILLA	J	DC 1556	AB	R-4	1990
453		3/13/2022	BROCK	RD	TRK 8407T	IT	46KS-2500-12D	1970
454		3/14/2022	CREWD	G	TIE BKR 11-12 S.E.	GE	AM13.8-500-6H	1960
455		3/22/2022	NAVAR	SC	TRK 328T	WE	O441	1950
456		3/23/2022	VICTR	RJ	TRK 4911 S.E.	AB	48PM31-20	1990
457		3/25/2022	HOWRD	CR	Trans 4 S.E.	AB	R-4	1990
458		3/27/2022	BUNRT	X4	DC 8110	GE	AM13.8-500-5H	1960
459		3/27/2022	MARLT	T1-L, B	TRF 01, SB 11-12	AC	DZ-60B	1950
460		3/28/2022	KOPNK	D1	DC 9482	BB	15VHK500	1980
461		3/28/2022	MAUME	F	DC 8000	GE	AM13.8-250-3	1950
462		3/30/2022	PHENX	C	DC 9821	WE	ESM 560	1970
463		3/31/2022	CARTR	C	DC 8855T S.E.	GE	AM13.8-250-6S	1950
464		3/31/2022	IMLAY	RB	TIE 3241 S.E.	WE	O221	1940
465		3/31/2022	NRLND	Q	DC 1567T	GE	FK255-250	1950
466		3/31/2022	SEVLE	B	DC 9364	IT	15HK500	1970
467		3/31/2022	UTICA	Q	DC 2558	AB	R-4	1990
468		4/4/2022	HANCK	M1A	TRF 01	BB	15VHKX500	1990
469		4/4/2022	INKST	B	DC326	AC	DZ-60B	1950
470		4/5/2022	BUNCE	SU	TRK 824	WE	GO-4B	1950
471		4/5/2022	SCOTN	AG	PL 108T	WE	B-20	1950
472		4/7/2022	ESTLD	O	DC 1303	WE	138B250	1950
473		4/8/2022	SIXMI	J	TRF 02	WE	F-100	1940
474		4/11/2022	KENEY	C	DC 2697	WE	B-22B	1950
475		4/11/2022	LILY	E1	N/A	AB	15VHK500	1980
476		4/12/2022	BOYNE	RC	Trans 101	AB	48PM31-20	1990
477		4/14/2022	ESSEX	S4Q	SB 121-123	PO	38PV40CDSX-1	2010
478		4/17/2022	REDRN	RL	SB 1-2	WE	460G1500	1960
479		4/18/2022	ROTUN	L1	PL 8356	BB	15VHKX500	1990
480		4/18/2022	ROTUN	L1	PL8356	BB	15VHKX500	1990
481		4/19/2022	CYPRS	D	S.E. DC 8767	AB	ESVA 800	2000
482		4/19/2022	LOMRD	N3	TB 12A-13	BB	15VHKX500	1990
483		4/20/2022	PTAUS	RA	TIE 3208	WE	460G1500	1960
484		4/21/2022	JSLYN	A1	DC 9140-ST	BB	15VHKX500	1990
485		4/27/2022	CONAT	E	DC 1450	AB	R-4	1990
486		5/1/2022	LCSTR	B2	DC 8823	GE	AM13.8-500-6H	1960
487		5/3/2022	ORCHD	O	TB 15	WE	B-13	1930
488		5/6/2022	CLKSN	G1	TB 11-12	IT	15HK500	1970
489		5/9/2022	MEDNA	RI	TRK6722	AB	48PM31-20	1990
490		5/12/2022	OTSGO	RC	TIE 9303	AB	48PM31-20	1990
491		5/17/2022	CENTR	F	DC 1824	GE	FK255-150	1950
492		5/17/2022	NUNLY	H2	TRF 02	IT	15HK500	1970
493		5/18/2022	STEPH	RC	TRK 2559	WE	460G1500	1960
494		5/24/2022	FRISB	E	PL 651-S	WE	B-20	1950
495		5/24/2022	NEAST	H	CB2	WE	ESM 560	1970
496		5/25/2022	OUTDR	F	SB 11A-12A	AB	R-4	1990
497		5/26/2022	ROBIN	D	DC 8750, TRF 01	WE	ESM 560	1970
498		6/8/2022	CONAT	P	DC2064	GE	FK255-250	1950
499		6/20/2022	HOWEL	AI	TRF 01	GE	FK255-150	1950
500		6/25/2022	CONAT	B	DC 1293	AC	DZ-60B	1950
501		6/25/2022	CONAT	B	DC 1293	AC	DZ-60B	1950
502		6/25/2022	QUEEN	J	TRF 02	GE	AM13.8-250-3	1950
503		6/30/2022	MOUND	p	TB 11-13	AB	R-4	1990
504		7/2/2022	CHIGO	F	PL 434	GE	FK255-150	1950
505		7/4/2022	UNLAK	H	SB 11-12	GE	AM13.8-250	1950
506		7/5/2022	AMSTR	BP	PL 374T	GE	FKR-55Y-28	1950
507		7/6/2022	DALY	B	DC 1711T	AB	R-4	1990
508		7/6/2022	FLMNG	RR	TRK 7702	WE	O221	1940
509		7/6/2022	INKST	B	DC 326	AC	DZ-60B	1950
510		7/7/2022	GRFIN	LSB 1515	LSB 1515	AB	48PM31-20	1990
511		7/16/2022	AMSTR	AZ	PL619T	GE	FKR-55Y-28	1950
512		7/18/2022	BENSN	K2	DC 8661	IT	15HK500	1970
513		7/20/2022	MELRO	E	DC 2412	AB	R-4	1990
514		7/28/2022	WSEND	Q	DC 1038	WE	B-26	1950
515		7/29/2022	PIONR	RM	SB 1-2	AB	48PM31-20	1990
516		8/3/2022	NIXON	R3	TRF 03	GE	VB13.8-500-3	2000
517		8/8/2022	ABBOT	H	DC 1740	WE	B-20B	1950
518		8/8/2022	FRISB	AG	PL42T	WE	B-20	1950
519		8/8/2022	VERNR	F	DC 1575	GE	FK255-150	1950
520		8/10/2022	TWEMI	L	DC 1551	WE	B-22B	1950
521		8/10/2022	TWEMI	C	PL1	WE	B-22B	1950
522		8/10/2022	TWEMI	E	PL10	WE	B-22B	1950
523		8/10/2022	TWEMI	D	TRF 01	WE	F-100	1940
524		8/15/2022	DAVIS	D2	DC 8214T	IT	15HK500	1970
525		8/18/2022	MEYRS	F1	TRF 01	GE	AM13.8-500-6H	1960
526		8/20/2022	SAXON	F4	DC 8046	GE	VIB	1970
527		8/23/2022	OUTDR	F	SB 11A-12A	AB	R-4	1990
528		8/24/2022	TCOLA	RJ	TRK 3304	IT	46KS-2500-12D	1970
529		8/28/2022	CORTL	SI	TRK 1728	PO	38PV40CDR	1990
530		8/30/2022	FERND	E	DC 2698	WE	B-20B	1950
531		8/30/2022	WSEND	Q	DC 1038	WE	B-26	1950
532		8/31/2022	AMSTR	Q	DC 2035	AB	R-4	1990
533		8/31/2022	HOBRT	G	TRF 01	WE	B-20B	1950
534		9/1/2022	SYRAC	M2A	DC 2063	GE	VB13.8-500-3	2000

	A	B	C	D	E	F	G	H
535		9/3/2022	CHIGO	G	DC 2072	GE	FK255-150	1950
536		9/3/2022	FRISB	G	PL 114T	WE	B-20	1950
537		9/3/2022	FRISB	G	PL 114	WE	B-20	1950
538		9/7/2022	WAREN	SE	TRK 648	AB	72PM44-20	2000
539		9/7/2022	YOST	J1A	DC 8144	GE	AM13.8-500-5H	1960
540		9/15/2022	HAZPK	K1	DC 1934	IT	15HK500	1970
541		9/15/2022	YOST	P1A	DC 9371	GE	VVC13.8-500	1990
542		9/16/2022	COLRD	K2	DC 8989	BB	15VHKX500	1990
543		9/19/2022	MEYRS	F1	TRF 01	GE	AM13.8-500-6H	1960
544		9/20/2022	GLBRT	E2	DC 9381	GE	AM13.8-500-7H	1960
545		9/22/2022	CROWN	I	DC 9850	GE	AM13.8-500-6H	1960
546		9/24/2022	BLTMR	G3	TB 13-14, DC 8340	GE	AM13.8-500-6H	1960
547		9/27/2022	SHELD	F1	TRF 01	BB	15VHK500	1980
548		9/29/2022	FERND	P	TRF 03	WE	R-4	1970
549		10/5/2022	IRNTN	SAD	SEC 3-4	SI	BZO-145-63-6	1980
550		10/10/2022	ESSEX	N2Q	TRK 523	PO	38PV40CDR	1990
551		10/14/2022	ROTUN	A1	PL 8377T	BB	15VHKX500	1990
552		10/17/2022	CAMDN	F4	TRF 04	IT	15HK500	1970
553		10/18/2022	CAMDN	I4	DC 8230	IT	15HK500	1970
554		10/20/2022	BIDLE	E	DC 1616	WE	B-22B	1950
555		10/22/2022	NOLAN	H2	TRF 02	GE	VB13.8-500-3	2000
556		10/22/2022	SPRUC	G1	TB 11-12	IT	15HKV500	1980
557		10/24/2022	FRISB	RV	TRK 1834	PO	PV38-1200-40	2000
558		10/24/2022	SRGNT	E2	Cable DC 8268 S.E.	IT	15HK500	1970
559		10/25/2022	BRONC	H4	TRF 04	GE	VB13.8-500-3	2000
560		10/26/2022	FOX	H	TB 11	AB	R-4	1990
561		10/31/2022	IRNTN	SE	TRK 3028	WE	34.5G2500	1950
562		11/1/2022	MALRD	L2	DC 9384	IT	15HK500	1970
563		11/3/2022	GRANT	C	PL 369	GE	FK255-250	1950
564		11/4/2022	DIX	E	DC 1323T	GE	FK255-250	1950
565		11/5/2022	VERNR	R	DC 1545	GE	FK255-250	1950
566		11/10/2022	BALFR	O	DC 2181	GE	FK255-250	1950
567		11/11/2022	CONRD	G	CTB 1	BB	ESVA 800	2000
568		11/15/2022	ESTLD	P	DC 1384	WE	138B250	1950
569		11/21/2022	FLMNG	RR	TIE 7702	WE	O221	1940
570		11/21/2022	PULFD	AJ	DC 2111T	WE	B-26	1950
571		11/22/2022	TCOLA	RJ	TRK 3304	IT	46KS-2500-12D	1970
572		11/28/2022	WICK	S2A	TB 12A-13	GE	VB13.8-500-3	2000
573		11/29/2022	NSCEN	LSB 1555	LSB 1555	WE	GO-4B	1950
574		11/30/2022	KENEY	F	DC 2695	WE	B-22B	1950
575		12/1/2022	INKST	I	DC 315	AC	DZ-60B	1950
576		12/4/2022	BALFR	H	DC 1207	WE	B-26	1950
577		12/5/2022	STANT	R6	PL 8327	IT	15HK500	1970
578		12/9/2022	BROCK	RI	SB 1-2	IT	46KS-2500-12D	1970
579		12/9/2022	SNSET	B	DC 8237-T	IT	15HK500	1970
580		12/15/2022	ALFRD	G1	TB 11-12	IT	15HK500	1970
581		12/15/2022	IMLAY	RB	Tie 3241	WE	O221	1940
582		12/18/2022	YOST	N2A	TRF 02	GE	AM13.8-500-7H	1960
583		12/22/2022	DEWEY	G	Tie 11-12	GE	AM13.8-500-5H	1960
584		12/22/2022	VILLA	H	DC 1552	AB	R-4	1990
585		12/23/2022	GRANT	I	DC 2233	GE	FK255-150	1950
586		12/23/2022	IMLAY	RB	TIE 3241	WE	O221	1940
587		12/27/2022	INKST	I	DC 315	AC	DZ-60B	1950
588		12/28/2022	ESSEX	N2W	Trunk 539-S	WE	U-DEION	1940
589		1/10/2023	NOLAN	F	Trf 01	GE	VB13.8-500	2000
590		1/12/2023	HOWEL	AJ	DC 2932	AC	DZ-60B	1950
591		1/12/2023	MARLT	D	DC 8281	BB	ESVA 800	2000
592		1/17/2023	LILY	K2	DC 9253	BB	15VHK500	1980
593		1/18/2023	ROMLS	C	DC 9464 S.E.	AB	ESVA 800	2020
594		1/18/2023	OTSGO	RD	TRF 101	AB	48PM31-20	2000
595		1/24/2023	WHITR	C2	DC 2814 WHITTIER S.E.	AB	15VHK750	1980
596		1/24/2023	ARWHD	RO	TIE 7520 S.E.	ME	CH-60-46-2500	1980
597		1/24/2023	CODY	RP	TRK 2840	AB	48PM31-20	1990
598		1/26/2023	MANDY	I	PL903	WE	B-20	1950
599		1/29/2023	TURNR	D	DC 1220 S.E.	IT	15HK500	1950
600		1/30/2023	NINMI	D	PL 825AT-826A	AB	R-4	2010
601		2/1/2023	SRGNT	E2	DC 8268 SE	IT	15HK500	1970
602		2/1/2023	BUNCE	RB	Trans 103 S.E.	AB	48PM31-20	2000
603		2/3/2023	MILFD	E1	DC 9248	GE	VB13.8-500-2	2000
604		2/9/2023	SUTTN	M	DC 1636	WE	150-DH-250A	1960
605		2/13/2023	QUAKR	I2	DC 9230T S.E.	AB	15VHK500	1980
606		2/13/2023	ECORS	A	DC 2077	GE	FK255-150	1950
607		2/15/2023	CONAT	P	DC 2064	GE	FK255-250	1950
608		2/20/2023	WAYNE	K2	DC 9397T S.E.	GE	VB13.8-1000-3	2000
609		2/21/2023	CLKSN	C1	DC9009 Bus 11 S.E.	BB	15VHKX500	1990
610		2/22/2023	LAMBT	H	DC 1449	WE	B-22B	1950
611		2/22/2023	MALTA	D1	DC 8814 S.E.	EA	150VCP W25	2010
612		2/23/2023	BECK	I2	DC 8466	GE	PV-VL13.8-500-3	2010
613		2/23/2023	GRPTE	D	DC 1004	GE	FK255-250	1950
614		2/23/2023	WSTLD	G	TB 11-12 S.E.	IT	15HK500	1970
615		2/23/2023	OMEGA	D	DC 8444	AB	ESVA 800	2000
616		2/24/2023	SANDU	SC	Tie 4104 S.E.	WE	GO-4B	1950
617		2/24/2023	DENVR	B	DC 1260 SE	GE	FK255-150	1950
618		2/24/2023	LILY	B2	DC 9126	BB	15VHK500	1980
619		2/25/2023	CODY	RR	TRK 2824	AB	48PM31-20	1990
620		2/25/2023	HILL	B	DC 2596 HILL	WE	R-4	1990
621		2/25/2023	HILL	F	DC 2590 HILL	GE	FK255-150	1950
622		2/25/2023	YORK	LSB 1591	LSB 1591	WE	GO-4B	1950
623		2/26/2023	WSTLD	D2	DC 8170	IT	15HK500	1970

	A	B	C	D	E	F	G	H
624		2/26/2023	ALNPK	B3	DC 2197 SE	IT	15HK500	1970
625		2/27/2023	BNSTN	RQ	SB 2-3	AB	48PM31-20	1990
626		2/28/2023	BALFR	H	DC 1207 BALFR	WE	B-26	1950
627		3/1/2023	ECORS	I	DC 2091	GE	FK255-150	1950
628		3/1/2023	AMSTR	BU	PL13A-B	WE	R-4	1990
629		3/3/2023	LILY	J1	DC 9120 S.E.	BB	15VHK500	1980
630		3/4/2023	ROMLS	RK	TRK 7745	AB	48PM31-20	2000
631		3/4/2023	WEBST	S	DC 1932 WEBST	AB	R-4	2010
632		3/4/2023	LAMBT	N	DC 1524	AB	R-4	2010
633		3/5/2023	FOX	G	DC 1657 FOX	AB	R-4	2010
634		3/5/2023	RGENT	C	DC357	WE	B-20B	1950
635		3/6/2023	NBURG	E1	DC 8075 NEWBURGH	GE	AM13.8-500-6H	1960
636		3/6/2023	LIBER	H	DC 1820	WE	B-22B	1950
637		3/7/2023	PDMNT	LSB 1577	LSB 1577	AB	48PM31-20	2010
638		3/22/2023	CHAND	G	PL 500	WE	B-26	1950
639		3/23/2023	HARVY	F	DC 1706 HARVEY	GE	FK255-150	1950
640		3/25/2023	NIXON	C2	DC 9061	IT	15HK500	1970
641		3/25/2023	BENSN	G1	TB 11-12	IT	15HK500	1970
642		3/26/2023	MENLO	K	DC 8768	BB	ESVA 800	2000
643		3/26/2023	OAKPK	E	DC 1707	WE	B-20B	1950
644		4/2/2023	HAYES	M3	DC 1385 S.E.	GE	AM13.8-500-6H	1960
645		4/7/2023	NAVAR	SB	TRK315	AB	48PM31-20	2000
646		4/19/2023	BNSTN	RQ	SB 2-3	AB	48PM31-20	1990
647		4/25/2023	CHAND	BF	TRANS 1	WE	R-4	1990
648		4/27/2023	BRITN	L	DC 334 S.E.	GE	AM13.8-250-2	1950
649		4/27/2023	BRITN	K	DC332 S.E.	GE	AM13.8-250-2	1950
650		5/3/2023	BEACH	C4	DC8673	BB	15VHK500	1980
651		5/5/2023	GENOA	RU	TRF 102	AB	48PM31-20	2010
652		5/8/2023	SAVAN	K2	DC 1083 S.E.	IT	15HK500	1970
653		5/9/2023	SAVAN	I	TRF 02	WE	B-13	1930
654		5/11/2023	REDRN	I	SPARE	SI	15FSV500	1980
655		5/12/2023	HANCK	F1	TRF 01	IT	15HK500	1970
656		5/15/2023	WHITR	H2	TRF 02	AB	15VHK750	1980
657		5/19/2023	CAMDN	F4	TRANS 4 S.E.	AB	RMVAC	1970
658		5/24/2023	PULFD	CF	LINKAGE BUS FEED 1 S.E.	WE	CO-111	1940
659		5/25/2023	BENSN	O2A	TRF 02	BB	15VHKX500	1990
660		5/26/2023	EMRCK	G	TB 11	WE	B-22B	1950
661		5/26/2023	FRFAX	N	Sec bkr 11A-12A	MI	17DV25-12	2010
662		5/30/2023	PAGE	C	DC9495 T.O.	MI	17DV25-12	2010
663		5/30/2023	FRLDG	RG	TB 7745	AB	48PM31-20	2000
664		6/1/2023	STLUS	O2O3	PL 67 S.E	GE	AM13.8-500-6H	1960
665		6/1/2023	CRTIS	B	DC1330	GE	FK255-150	1950
666		6/14/2023	VICTR	RJ	TRK 4911	AB	48PM31-20	2010
667		6/14/2023	VERNR	L	DC 1503	GE	FK255-150	1950
668		6/16/2023	CORTL	SD	TRK 1761A-1762A S.E.	PO	38PV40CDR	1999
669		6/21/2023	BERKY	A	DC2664 A-B	WE	B-20B	1950
670		6/22/2023	LINCN	A	DC 1572-ST	GE	FK255-250	1950
671		6/25/2023	INKST	I	DC 315	AC	DZ-60B	1950
672		6/25/2023	INKST	B	DC 326	AC	DZ-60B	1950
673		6/27/2023	BURTN	D	DC 385A-ST-386A	GE	AM13.8-500-6H	1960
674		6/27/2023	INKST	A	DC 318	AC	DZ-60B	1950
675		6/27/2023	BUNCE	RD	TRK 829 S.E.	WE	GO-4B	1950
676		6/27/2023	PHENX	K	DC 9804	WE	ESM 560	1970
677		6/28/2023	YALE	J	DC 2633 S.E.	AB	ESVA 800	2000
678		7/2/2023	SNSET	I	DC 9048	IT	15HK500	1970
679		7/12/2023	CODY	RP	TRK 2840 S.E.	AB	48PM31-20	1990
680		7/13/2023	NEAST	H	CTB 2	BB	ESM 560	1980
681		7/16/2023	CUSTR	F	TB 11-12	GE	FK255-250	1950
682		7/18/2023	RUSH	RI	TIE 9111	AB	48PM31-20	2000
683		7/21/2023	GRPTE	AO	PL 36T	GE	FK255-250	1950
684		7/21/2023	GLEND	G	DC 2212A-2213A	WE	R-4	1990
685		7/22/2023	NAVAR	RW	TRK 359	AB	72PM44-20	2010
686		7/26/2023	ANNCH	Q	PL 408	AB	AMVAC	2010
687		7/27/2023	LINCN	AC	DC 2726	GE	FK255-150	1950
688		7/27/2023	DENVR	M	DC 1353T	WE	B-22B	1950
689		7/29/2023	SPRUC	J1J2	DC9843	IT	15HKV500	1980
690		7/30/2023	GAY	L	DC1773	GE	FK255-150	1950
691		7/30/2023	WALKR	D	PL 75	WE	B-20	1950
692		7/31/2023	INKST	A	DC 318	AC	DZ-60B	1950
693		8/2/2023	TEGER	E2	DC 8872 S.E.	IT	15HK500	1970
694		8/4/2023	CODY	RP	TRK 2840	AB	48PM31-20	1990
695		8/11/2023	WHITR	F1	TRF 01	AB	15VHK750	1980
696		8/12/2023	APACE	M2A	TRF 02	BB	15VHKX500	1990
697		8/16/2023	ERIN	RB	TRK 4210T	AB	72PM44-20	2000
698		8/22/2023	LOMRD	H2	TRF 02	GE	AM13.8-500-5H	1960
699		8/25/2023	INKST	A	DC 318	AC	DZ-60B	1950
700		8/25/2023	CONAT	M	DC 1269 S.E.	AC	DZ-60B	1950
701		8/26/2023	OUTDR	K	TRF 01	WE	R-4	1990
702		8/27/2023	BNSTN	RE	TRK 1340	AB	48PM31-20	1990
703		8/27/2023	STOPL	Q	SB 11-13 S.E	AB	R-4	2010
704		8/30/2023	SCOTN	CS	LINKAGE BUS FEED 5 BKR	AB	R-4	2010
705		9/5/2023	VICTR	RK	CAP1-1 S.E.	AB	48PM31-20	2000
706		9/5/2023	SHADK	D	DC 1093 S.E.	GE	FK255-150	1950
707		9/6/2023	CODY	RP	TRK 2840	AB	48PM31-20	1990
708		9/6/2023	PHENX	RO	TRK 5548	AB	48PM31-20	2000
709		9/27/2023	HAZPK	L2	DC 1951	IT	15HK500	1970
710		10/1/2023	NEFF	RC	TB 4104 S.E.	WE	460G1500	1960
711		10/5/2023	SIXMI	E	DC 1200	GE	FK255-150	1950
712		10/9/2023	GAY	D	DC1762	GE	FK255-150	1950

	A	B	C	D	E	F	G	H
713		10/10/2023	LINCN	AF	TIE BREAKER 13-14A	WE	R4	1990
714		10/11/2023	ROTUN	F1	TRF 01	BB	15VHKX500	1990
715		10/11/2023	INKST	I	DC 315	AC	DZ-60B	1950
716		10/13/2023	ORION	G1	TB 11-12	BB	15VHK500	1980
717		10/13/2023	CHTNT	M1A	TRF 01	BB	15VHKX500	1990
718		10/13/2023	CHTNT	M1A	TRF 01	BB	15VHKX500	1990
719		10/14/2023	BIHAM	P3	TRF 03	BB	15VHKX500	1990
720		10/23/2023	CHARL	I	NET FDR 65T	AB	R-4	2010
721		10/27/2023	ERIN	RV	TRK 4266-ST	IT	46KS-2500-12D	1970
722		10/27/2023	IRNTN	SE	TRK 3028	WE	34.5G2500	1950
723		10/31/2023	FRISB	RV	TRK 1834 S.E.	PO	PV38-1200-40	2000
724		11/9/2023	CEDAR	G	DC 383T	GE	AM13.8-250-3	1950
725		11/10/2023	GRFIN	D	DC 9799	MI	17DV25-12	2010
726		11/12/2023	LAPER	I	TRF 02	AB	ESVA 800	2000
727		11/15/2023	LAPER	J4	DC 8774	GE	AM13.8-500-6H	1960
728		11/16/2023	KORTE	F	DC 1511	WE	B-22B	1950
729		11/17/2023	CONAT	M	DC 1269	AC	DZ-60B	1950
730		11/20/2023	COLNS	A1A2	DC9870	GE	VB13.8-500-3	2000
731		11/22/2023	SOFLD	E2	DC 9054	GE	VVC13.8-500-0H	1990
732		11/26/2023	KORTE	F	DC 1511	WE	B-22B	1950
733		12/1/2023	RSVLT	D	TRF 03	AB	R-4	2010
734		12/1/2023	KOPNK	K2	DC 9541	BB	15VHK500	1980
735		12/3/2023	KOPNK	D1	DC 9482-S	BB	15VHK500	1980
736		12/4/2023	PERU	F1	TRF 01	GE	AM13.8-500-OH	2000
737		12/8/2023	STANT	G5	TB 15-16A	IT	15HK500	1970
738		12/9/2023	CHTNT	Q1A	DC 9042	BB	15VHKX500	1990
739		12/9/2023	SEVLE	B2	DC 9364 S.E.	IT	15HK500	1970
740		12/9/2023	OUTDR	K	TRF 01	WE	R-4	1990
741		12/9/2023	KOPNK	K1	DC 9541	BB	15VHK500	1980
742		12/9/2023	NEAST	RT	TRK 422	WE	O441	1950
743		12/9/2023	WHELR	C4	PL 8941	BB	15VHK500	1980
744		12/10/2023	STANT	M6	PL 8393-ST	IT	15HK500	1970
745		12/12/2023	RICHM	LSB 1523	LSB 1523	WE	O221	1940
746		12/15/2023	MACMB	RH	Trf 101	WE	460G2500	1960
747		12/20/2023	FRLDG	J	DC 8042 S.E.	AB	ESVA 800	2000
748		12/28/2023	LOCDL	M2	TRF 02	BB	15VHKX500	1990
749		12/28/2023	WEBST	G	TB 11-12A	AB	R-4	2010

MPSC Case No: U-21534

Requester: MNSC

Question No.: MNSCDE-20.12

Respondent: R. Steudle

Page: 1 of 1

Question: Refer to the rebuttal testimony of witness Steudle, Q&A 66. Has the Company evaluated, sought bids for, benchmarked, or otherwise considered or explored the cost to purchase from a third-party alternative tree trim prioritization model tools? If so, identify the tools evaluated and produce the supporting documentation.

Answer: The Company has not performed this analysis.

Attachment: *None*

MPSC Case No: U-21534

Requester: MNSC

Question No.: MNSCDE-20.13

Respondent: R. Steudle

Page: 1 of 1

Question: Refer to the rebuttal testimony of witness Steudle, Q&A 66. Has the Company evaluated potential benefits or advantages to comparing a third-party alternative tree trim prioritization model tool versus the tool DTE is developing internally? If so, produce the evaluation and identify the potential benefits or advantages.

Answer: The Company has not performed this analysis.

Attachment: *None*

MPSC Case No: U-21534

Requester: MNSC

Question No.: MNSCDE-20.14

Respondent: R. Steudle

Page: 1 of 1

Question: Refer to the rebuttal testimony of witness Steudle, Q&A 66. What are the assumed costs of considering third-party or alternative tools? Produce all documentation supporting the assumed cost(s).

Answer: The Company has not performed this analysis.

However, the intent of Question 66 of Witness Steudle' s rebuttal was to note that the Company has already invested in a risk-prioritization model, investing in a an additional one would be incremental cost and redundant to the tool we already have.

Attachment: *None*

DTE Electric Company
One Energy Plaza, 1635 WCB
Detroit, MI 48226-1279



Paula Johnson-Bacon
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March 1, 2023

Ms. Lisa Felice
Executive Secretary
Michigan Public Service Commission
7109 West Saginaw Highway
Lansing, Michigan 48917

Re: In the matter of the Application of DTE Electric Company for authority to increase its rates, amend its rate schedules and rules governing the distribution and supply of electric energy, and for miscellaneous accounting authority.
MPSC Case No. U-20162

Dear Ms. Felice:

Pursuant to the Commission's final Order in MPSC Case No. U-20162, please find attached DTE Electric Company's March 1, 2023 Tree Trim Annual Report. If you have any questions, please feel free to contact me.

Very truly yours,

Paula Johnson-Bacon

PJB/cdm
Encl.

March 1, 2023 Tree Trim Annual Report

In Case U-20162, the Commission directed DTE Electric (DTEE) to file an annual report to detail the progress of the Surge program and Enhanced Tree Trim Program (ETTP) performance. From the U-20162 Order on May 2, 2019:

> Thus, the annual report shall also break out all activity, costs, and miles trimmed under any and all tree trimming programs (including hardening) in the city of Detroit, to provide information on the progress made in the city of Detroit with each program. The reporting shall include measurable data for the efforts, including miles completed by service center, performance of ETTP circuits compared to non-ETTP circuits, the costs of the efforts, number of employees directly involved in the efforts, tree-related outage reductions, SAIDI reductions, and whether the funding for the efforts is a capital expense or O&M cost. Further, the report shall track ETTP circuit performance, comparing average outages for the three years prior to the enhanced trimming with outages in the years after the trimming has been performed. The first report is due in this docket March 1, 2020, and an annual report is due on March 1 of each year thereafter.

Per Case U-20162 order and Case U-20561 order this report covers the requested information. The report is split into five sections:

1) Miles Completed to ETTP Standard – Annual ETTP maintenance miles are reported by Service Center over the 2015-2022 time period. City of Detroit miles are broken out separately.
2) O&M and Capital Spend on Tree Trimming Activities – Annual tree trim spend are reported by Service Center over the 2016-2022 time period. City of Detroit spend are broken out separately. Costs from 2015 are not included because the ETTP specification makes up a relatively small portion of the overall tree trim spend in that year.
3) ETTP Circuit Performance – ETTP circuit performance comparing average outage events, customer interruptions, outage minutes, and wire downs before and after ETTP work. The performance will cover ETTP circuits trimmed in 2015 through 2021 with reliability data that ranges from 2012 to 2022. Performance of ETTP circuits trimmed in 2022 will be measured starting in 2023.
4) Spot Tree Trimming – Description of spot-trimming work done on the 10 worst performing circuits.
5) Tree Trim Workforce – A 2022 summary of the tree trim workforce is broken down by DTEE employee and contractor.

6) Incremental Funding for Tree Trim Program – Description of the additional work completed in 2022 from the increased funding from Case no. U-21128, in which the Company committed an incremental $90M to the tree trim program.

Section 1 – Miles Completed to ETTP Standard

Since the inception of the ETTP standard, the Company has trimmed 33,251 miles. 6,714 ETTP miles were trimmed in 2022 as part of the Surge program. Below, **Table 1** breaks out ETTP miles trimmed by distribution and subtransmission, **Table 2** details miles trimmed by service center and year. **Table 3** shows total miles trimmed to ETTP, which may include second and third cycle ETTP trimming, it has a breakdown of only unique miles trimmed to ETTP, which do not count second or third cycle of ETTP trimming. It also shows miles in backlog, average density and work location by service center. Previous filings from the Company had also included manual/climbing trimming data by service center, which was from a onetime study performed by a third-party consultant. The Company does not collect climbing data for each circuit trimmed, however backlot work is strongly correlated with manual/climbing trimming. **Table 4** shows ETTP miles trimmed in the City of Detroit, and **Table 5** covers miles trimmed as part of the 4.8kV Hardening Program.

Table 1 – ETTP Miles Trimmed by Circuit Type

Circuit Type	2015	2016	2017	2018	2019	2020	2021	2022	Total	% of System
Distribution[1]	257	2,270	2,733	3,128	3,181	4,583	5,021	5,991	27,164	75%
Subtransmission[2]	188	1,030	868	540	1,006	1,006	726	723	6,087	100%
Total Miles	**445**	**3,300**	**3,601**	**3,668**	**4,187**	**5,589**	**5,747**	**6,714**	**33,251**	**79%[3,4]**

Table 2 – ETTP Miles Trimmed by Service Center

Service Center	2015	2016	2017	2018	2019	2020	2021	2022	Total
ANN	5	143	566	309	246	537	285	585	2,676
CAN	40	60	62	271	307	335	360	375	1,810
HWL	192	272	445	262	264	603	659	719	3,416
LAP	13	341	390	423	378	653	584	555	3,337
MAR	70	351	419	432	303	334	395	776	3,080

[1] Some of these distribution miles are on their second-cycle of ETTP trimming and show up in the numbers more than once.
[2] Some of these subtransmission miles are on their second- or third-cycle of ETTP trimming and show up in the numbers more than once.
[3] Numerator only includes unique miles – it only counts the miles once even if the miles are on their second- or third-cycle of ETTP trimming.
[4] The system % trimmed to ETTP by end of 2022 was misstated in S. Hartwick's testimony in U-21297. On page SMH9 – line 7, the system total was stated as 77%. As part of this report, the Company audited the final 2022 metrics and identified several circuits that had been missing from the preliminary analysis include in the rate case

MTC	23	250	259	115	321	430	274	335	2,007
NAE	42	693	470	533	557	463	826	793	4,377
NPT	5	159	263	342	254	536	561	196	2,316
PON	6	426	230	237	424	567	618	551	3,059
RFD	24	219	112	381	670	444	300	922	3,072
SBY	8	111	102	207	129	114	181	377	1,229
WWS	17	275	283	156	334	573	704	531	2,873
Total Miles	**445**	**3,300**	**3,601**	**3,668**	**4,187**	**5,589**	**5,747**	**6,714**	**33,251**

Table 3 – ETTP Miles Trimmed, Miles of Backlog, Average Tree Density and Mix of Work by Service Center

Service Center	Cumulative Miles Trimmed ETTP[5]	Total System Miles		For the 2022 Plan Only			
		Unique Miles Trimmed to ETTP[6]	Remaining Miles of Backlog to ETTP[7]	2022 Unique Miles Trimmed to ETTP[5]	Total 2022 Miles Trimmed	Avg. Tree Density[8] (trees/mile)	Work Location[7] (% Backlot)
ANN	2,676	1,906	330	184	585	274	76%
CAN	1,810	1,386	41	37	375	244	91%
HWL	3,416	2,366	62	73	719	221	70%
LAP	3,337	2,530	139	119	555	199	68%
MAR	3,080	2,079	904	256	776	175	64%
MTC	2,007	1,365	1,206	47	335	137	64%
NAE	4,377	2,747	1,034	159	793	151	94%
NPT	2,316	1,897	55	60	196	160	76%
PON	3,059	2,320	532	451	551	399	76%
RFD	3,072	2,768	649	808	922	325	85%
SBY	1,229	979	331	295	377	298	81%
WWS	2,873	2,248	1,100	454	531	343	79%
Total Miles	**33,251**	**24,591**	**6,383**	**2,943**	**6,714**	**248**	**78%**

[5] Includes second or third cycle ETTP trim.
[6] Does not include second or third cycle ETTP trim.
[7] Remaining miles in backlog after 2022 trimming.
[8] Density and work location are calculated based on task points identified by the planners during planning – includes brush.

Table 4 – ETTP Miles Trimmed in the City of Detroit by Service Center

Service Center	2015	2016	2017	2018	2019	2020	2021	2022	Total	% of City
CAN	40	42	60	234	293	291	326	246	**1,532**	
MTC	-	-	6	-	-	6	-	-	**12**	
RFD	5	87	27	251	464	90	129	259	**1,312**	
Total Detroit Miles[9]	**45**	**129**	**93**	**485**	**757**	**386**	**455**	**505**	**2,856**	**96%**[10]

Table 5 – ETTP Miles Trimmed as Part of the 4.8kV Hardening Program[11]

Service Center	2015	2016	2017	2018	2019	2020	2021	2022	Total
CAN				20	0	106	198	199	**523**
RFD				127	158	161	129	325	**900**
Total 4.8kV Miles				**146**	**158**	**267**	**327**	**524**	**1,423**

Section 2 – O&M and Capital Spend on Tree Trimming Activities

The Company spent $239,570,162 in O&M for its tree trim program in 2022 as detailed in **Table 6**; years 2016 through 2021 are also included for reference. **Table 6** groups costs into five categories:

1) Line Clearance Maintenance – Comprises costs needed for maintenance activities such as contractor labor and equipment, general foreman cost, per diems, and overtime premiums.
2) Trouble – Spend on non-storm unplanned reactive tree trim work related to outage or non-outage problems on the electric system.
3) Tree Trim Program/Other – Includes customer request work, auditing, software maintenance, the herbicide program, training, safety, and other cost miscellaneous costs associated with Tree Trim.
4) DTE Staff Cost – DTE staff costs related to the tree trim program.

[9] Some of these miles are on their second cycle of ETTP trimming and show up in the number more than once.
[10] Numerator only includes unique miles trimmed to ETTP, therefore does not double count miles on second- cycle or beyond.
[11] Program began in 2018 and miles in Table 5 are a subset of miles in Tables 1-3.

Table 6 – Annual O&M Tree Trim Spend by Category[12]

O&M Spend	2016	2017	2018	2019	2020	2021	2022
Line Clearance Maintenance	$59,155,543	$69,344,451	$71,757,936	$116,748,952	$151,021,453	$140,202,546	$209,270,442
Trouble	$10,738,172	$11,395,011	$12,966,909	$16,556,969	$12,237,821	$10,667,520	$12,682,979
Tree Trim Program/Other	$2,771,660	$1,812,622	$2,500,756	$10,229,182	$6,839,979	$15,670,339	$13,013,567
DTE Staff Cost	$1,496,789	$1,704,325	$1,883,630	$2,667,190	$3,722,732	$4,372,897	$4,603,174
COVID-19[13]					$1,340,624	$746,118	
O&M Total	**$74,162,165**	**$84,256,409**	**$89,109,232**	**$146,202,293**	**$175,162,609**	**$171,659,420**	**$239,570,162**

Table 7 further breaks down the "Line Clearance Maintenance" costs in **Table 6** by service center.

Table 7 – Annual Maintenance Tree Trim Spend by Service Center (O&M Only)

Service Center	2016	2017	2018	2019	2020	2021	2022
ANN	$4,081,462	$12,103,989	$9,489,387	$6,699,698	$18,811,275	$11,077,345	$19,663,782
CAN	$3,312,191	$1,200,014	$8,851,085	$18,827,931	$11,253,759	$6,701,520	$14,189,914
HWL	$4,838,162	$12,561,698	$6,269,100	$6,523,040	$19,744,784	$23,573,175	$20,366,427
LAP	$5,145,835	$5,820,146	$4,385,310	$5,306,986	$12,866,142	$8,215,356	$6,297,393
MAR	$3,679,637	$4,450,068	$5,021,951	$2,757,355	$5,087,650	$3,444,947	$8,968,144
MTC	$3,868,638	$4,093,991	$1,961,451	$3,770,923	$9,913,687	$3,727,800	$4,874,212
NAE	$3,100,279	$2,242,086	$2,615,529	$3,137,335	$5,336,176	$3,858,290	$5,567,071
NPT	$1,990,418	$4,844,204	$5,288,021	$3,400,257	$9,634,726	$12,826,082	$6,520,390
PON	$12,293,540	$8,619,875	$8,167,988	$24,883,843	$27,768,967	$29,346,468	$31,445,874
RFD	$5,929,162	$3,762,082	$11,025,927	$28,999,125	$12,309,855	$6,816,756	$42,187,521
SBY	$3,351,803	$3,078,400	$4,338,480	$2,656,440	$3,982,452	$2,863,698	$15,143,984
WWS	$7,564,417	$6,567,898	$4,343,707	$9,786,018	$14,311,980	$27,751,110	$34,045,729
Total	**$59,155,544**	**$69,344,451**	**$71,757,936**	**$116,748,951**	**$151,021,453**	**$140,202,546**	**$209,270,442**

[12] Table does not include any spot trimming expenses from other programs because they are not part of the tree trim maintenance costs. This table does not include tree trimming cost related to storm, those costs are charged outside the tree trim budget.

[13]These expenses were mainly for the one-person per vehicle policy, and PPE for DTEE employees and contractors.

Table 8 details the 4.8kV Hardening capital spend in 2018-2022.

Table 8 – Annual 4.8kV Hardening Tree Trim Capital Spend by Service Center

Service Center	2018	2019	2020	2021	2022
CAN	$ 2,136,156	-	$5,878,864	$11,757,474	$10,675,606
RFD	$ 7,858,107	$ 10,081,771	$12,025,855	$10,274,963	$25,313,553
Total	**$ 9,994,263**	**$ 10,081,771**	**$17,904,719**	**$22,032,437**	**$35,989,159**

Table 9 highlights the $37,334,046 tree trim spend in the City of Detroit for the year 2022, which includes $28,865,840 of Capital spend. City spend in 2016 through 2021 is included for reference.

Table 9 – Annual Detroit O&M and 4.8kV Hardening Capital Tree Trim Spend

	2016	2017	2018	2019	2020	2021	2022
Detroit - O&M	$6,217,231	$2,345,651	$14,071,122	$40,513,330	$7,333,594	$3,875,167	$8,468,206
Detroit – 4.8kV Hardening Capital	-	-	$9,326,363	$10,081,771	$11,888,408	$21,408,206	$28,865,840
Detroit Total	**$6,217,231**	**$2,345,651**	**$23,397,485**	**$50,595,101**	**$19,222,002**	**$25,283,373**	**$37,334,046**

Section 3 – ETTP Circuit Performance

Methodology Used to Calculate ETTP Performance

The methodology used to calculate ETTP Performance for all distribution circuits uses the average of three years of Pre-trim ETTP tree-outage events and compares it to each year post trimming. All post-trim year results of the same year were then summed to increase the sample size (as an example, all post-trim year 1 results are summed). The difference between the before trimming performance and the post trimming performance was used to create the "% Change in Outage Event Reduction for ETTP circuits". To create a control group for comparison, the same methodology was used for the remainder of circuits not trimmed ETTP[14] (Non-ETTP circuits), which is identified as "% Change in Outage Event Reduction for Non-ETTP circuits". To account for natural weather variation, the performance of the control group is subtracted from the ETTP circuit performance to provide an accurate representation of the true impact of the ETTP. This is the same methodology outlined in Case U-20561, U-20836 and U-21297.

[14] This group consists of circuits that have not been trimmed to the ETTP specification and are considered off-cycle

Table 10 – Methodology for ETTP Performance Analysis

2012	2103	2014	2015	2016	2017	2018	2019	# of ETTP Circuits
			Three Year Average Pre-ETTP Performace			Year of Trim	Post Trim Year 1	321
		Three Year Average Pre-ETTP Performace			Year of Trim	Post Trim Year 1	Post Trim Year 2	128
	Three Year Average Pre-ETTP Performace			Year of Trim	Post Trim Year 1	Post Trim Year 2	Post Trim Year 3	171
Three Year Average Pre-ETTP Performace			Year of Trim	Post Trim Year 1	Post Trim Year 2	Post Trim Year 3	Post Trim Year 4	20

Table 11 – Methodology for Control Group Non-ETTP Performance Analysis

2012	2103	2014	2015	2016	2017	2018	2019	# of ETTP Circuits
			Three Year Average Pre-Non-ETTP Performace			Year of Trim	Post Trim Year 1	N/A
		Three Year Average Pre-Non-ETTP Performace			Year of Trim	Post Trim Year 1	Post Trim Year 2	N/A
	Three Year Average Pre-Non-ETTP Performace			Year of Trim	Post Trim Year 1	Post Trim Year 2	Post Trim Year 3	N/A
Three Year Average Pre-Non-ETTP Performace			Year of Trim	Post Trim Year 1	Post Trim Year 2	Post Trim Year 3	Post Trim Year 4	N/A

The control group of non-ETTP circuits and the ETTP circuits are compared against each other to account for non-tree trim related variations. This methodology normalizes reliability performance from variations that occur year-to-year, such as weather and storms. This approach provides a more accurate measure of the ETTP effectiveness since we are comparing circuits over the course of years.

ETTP Outage Event Performance

The actual difference of outage events on ETTP circuits compared to the balance of the system not trimmed ETTP is 62.1% in post-trim year 1, 68.6% in the second year, 51.1% in the third year, and 40.6% in the fourth year. The actual reduction for Years 1-4 post ETTP trim are depicted in **Table 12**.

Table 12 – ETTP Tree-Related Outage Event Difference Compared to Non ETTP Circuits

	Number of Dist. Circuits ETTP Trimmed	% Change in Outage Event Reduction for ETTP circuits	% Change in Outage Event Reduction for Non-ETTP circuits	**Difference in % Change in Event Reduction ETTP vs Non-ETTP circuits**	U-20162 Surge Model Projected Reduction
1 Year Post Trim	1,549	-27.3%	34.8%	**-62.1%**	-57.0%
2 Years Post Trim	1,228	-15.2%	53.4%	**-68.6%**	-57.0%
3 Years Post Trim	754	9.4%	60.5%	**-51.1%**	-50.0%
4 Years Post Trim	298	36.7%	77.3%	**-40.6%**	-37.0%

ETTP Customer Interruptions Performance

Using the same methodology discussed above, the Company has determined that actual customer interruptions on ETTP circuits vs. Non-ETTP circuits show a 66.3% difference in Year 1, 76.6% difference in Year 2, 64.6% difference in Year 3, and 52.4% difference in Year 4. These results are shown in Table 13.

Table 13 – ETTP Tree-Related Customer Interruption Difference Compared to Non ETTP Circuits

	Number of Dist. Circuits ETTP Trimmed	% Change in Outage Interruption Reduction for ETTP circuits	% Change in Outage Interruption Reduction for Non-ETTP circuits	**Difference in % Change in Event Reduction ETTP vs Non-ETTP circuits**	U-20162 Surge Model Projected Reduction
1 Year Post Trim	1,549	-46.7%	19.6%	**-66.3%**	-57.0%
2 Years Post Trim	1,228	-44.8%	31.8%	**-76.6%**	-57.0%
3 Years Post Trim	754	-38.9%	25.7%	**-64.6%**	-50.0%
4 Years Post Trim	298	-24.6%	27.8%	**-52.4%**	-37.0%

ETTP Customer Outage Minute Performance

Customer minutes of interruption, shown in **Table 14**, also shows significant improvements from the ETTP program. Actual minutes of customer interruption on ETTP circuits vs. Non-ETTP

circuits show a 59.1% difference in Year 1, 62.3% difference in Year 2, 13.6% difference in Year 3, and 26.4% difference in Year

Table 14 – ETTP Tree-Related Customer Outage Minutes of Interruption Difference Compared to Non ETTP Circuits

	Number of Dist. Circuits ETTP Trimmed	% Change in Outage Minutes Reduction for ETTP circuits	% Change in Outage Minutes Reduction for Non-ETTP circuits	**Difference in % Change in Event Reduction ETTP vs Non-ETTP circuits**	U-20162 Surge Model Projected Reduction
1 Year Post Trim	1,543	-51.8%	7.3%	**-59.1%**	-57.0%
2 Years Post Trim	1,228	-37.3%	25.0%	**-62.3%**	-57.0%
3 Years Post Trim	754	-25.9%	-12.3%	**-13.6%**	-50.0%
4 Years Post Trim	298	-32.8%	-6.4%	**-26.4%**	-37.0%

Table 15 shows the 2022 outage minutes saved and avoided due to ETTP trimming and the impact to overall system SAIDI, a net reduction of 104 SAIDI minutes. If only ETTP circuits are considered, the SAIDI minute reduction is 175 minutes.

Table 15 – 2022 ETTP Outage Minute Reduction and SAIDI Impact

	ETTP Outage Minutes
3 Years Before Trim Avg. Outage Minutes	529,746,395
2022 Outage Minutes	406,138,378
Minutes Saved	123,608,016
Minutes Avoided – Non ETTP System Deterioration	107,578,860
Total Minute Reduction	231,186,876
ETTP Overall System SAIDI Minute Reduction	**104**
SAIDI Minute Reduction for ETTP Circuits ONLY	**175**

Table 17 – Tree Trimming on 2022 Ten Worst Performing Circuits

Circuit	sysSAIFI[15]	sysSAIFI ex MED[16]	Spot Trimming		Last Maintenance Trimming Year
			Performed in 2022?	Number of Poles Trimmed	
FISHR8188	0.0074	0.0074	Yes	28	2018
SWANC9408	0.0058	0.0047	No		2020
DUBLN8205	0.0058	0.0039	Yes	21	2020
BUNRT8426	0.0057	0.0056	No		2014
MACMB8521	0.0055	0.0044	No		2022
MOTT9789	0.0054	0.0053	No		2020
KENSL9858	0.0052	0.0051	No		2022
JSLYN9140	0.0050	0.0050	Yes	142	2015
BECK8727	0.0048	0.0037	Yes	36	2010
NRBRN8808	0.0047	0.0047	No		2022

Section 5 – Tree Trim Workforce

The internal employees directly involved in Tree Trimming are detailed in **Table 18**. In 2022, the average number for contractors on property were 1,639. Contractor headcount fluctuation over the course of 2022 is seen in **Chart 1**.

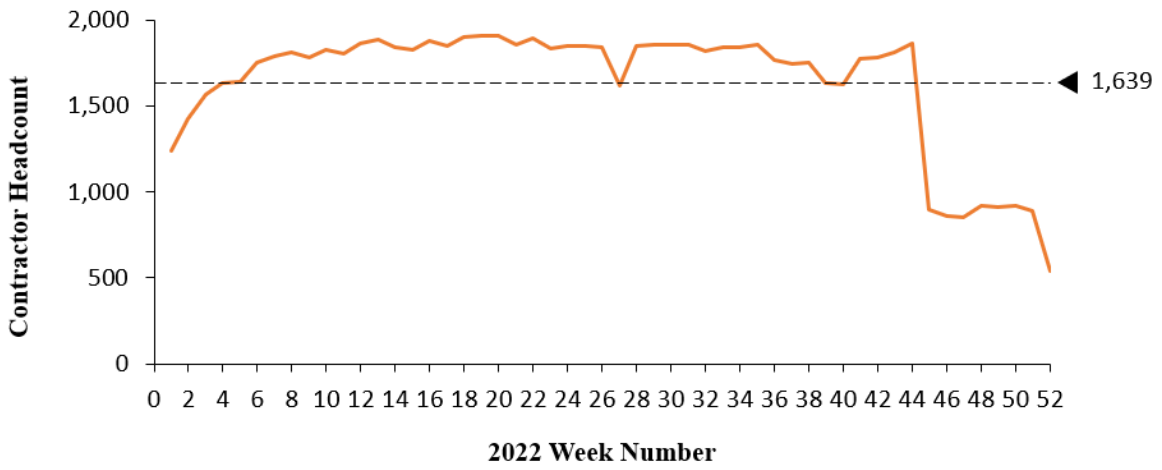
Table 18 – 2022 DTE and Contractor Tree Trim Headcount

Facilitator - Arborists	14
Supervision	11
Regional Foresters	7
Strategy and Planning	9
Internal Employees involved with ETTP	**41**

2022 Average # of Contractors	**1,639**

[15] sysSAFI is the number of customer interruptions on a specific circuit divided by the number of system customer interruptions
[16] MED stands for Major Event Days

Chart 1 – 2022 Contract Tree Trim Headcount by Week



The 2022 average local journeymen trimmers were 722, and the number of local apprentices were 267. Outsourced journeymen trimmers averaged 650 for 2022. It is typical for the workforce numbers to fluctuate over the year, especially in the late fall when many outsource trimmers return to their home states for the holidays. The outsource trimmers then slowly return through the first quarter of the year based on the Company's capacity needs.

The Company is participating in three programs in an effort to increase the number of local trimmers. The three programs are the Parnall Correctional Facility Vocational Village Training Program, the City of Detroit Tree Trim Academy, and the IBEW Local 17 Traditional Boot Camp. Below is an update on each of the programs:

1. Parnall Correctional Facility- The Parnall Tree Trimming program is designed to provide returning citizens the skills needed to start as an apprentice tree trimmer. DTE has partnered with the Michigan Department of Corrections to provide qualified instructors and the required training facilities. The company has paired 23 graduates with jobs.

2. Tree Trim Academy – The Company has partnered with the City of Detroit, IBEW Local 17, and its tree-trimming contractors to develop and implement a pre-woodsman training pilot program to satisfy the demand for qualified tree trimmers. The pilot tree trimming academy is located within the City of Detroit and facilitates training that is aimed at preparing local resident candidates to work as woodsmen. Once candidates complete the pre-woodsman program, graduates enter the nine-day boot camp that was previously designed in partnership with the Company, IBEW Local 17, and the Company's tree-trimming contractors.

The first cohort completed the tree trimming academy in the spring of 2021, and as of December 2022, 148 individuals have graduated from the program, with 100% of them being offered a job upon graduation.

3. Traditional Boot Camp – IBEW continues to hold regular scheduled boot camp training for apprentices. Current camps are conducted at their training facility in Wales, MI.

Section 6 – Incremental Funding for Tree Trim Program

August 31, 2021, the Company proposed additional funding for the Tree Trim program in Case no. U-21128. Per the application, the Company would invest incremental funding into the Tree Trim Surge during the remainder of 2021 through 2023, beyond the authorized regulatory asset amounts, and would not seek recovery of the additional expenditures. This has the effect of advancing the Company's tree trimming efforts while avoiding future customer expense for those investments, thus providing an affordability benefit to customers. The Company's application was approved on November 4th, 2021, and the Company committed to $90 million of incremental funding for the Tree Trimming program.

In 2022, the Company spent $85.8 million of the incremental $90 million investment. The annual maintenance plan was developed based on the total budget, including the incremental $85.8 million. The Company did not distinguish specific circuits trimmed as part of the base budget compared to the incremental funding. However, the Company can calculate the incremental work the additional funding enabled us to complete. The additional $85.8 million allowed the Company to complete an extra 1,700 off-cycle miles in 2022 and lead the system to be 79% on-cycle at year end. These miles were focused in poor reliability areas and trimming was completed prior to the 2022 storm season.

Reliability results for circuits trimmed in 2022 will be evaluated at the end of 2023. The Company measures reliability improvement from the calendar year after the circuit has been trimmed, more details on the methodology are included in Section 3 – ETTP Circuit Performance.

The remaining $4.2 million of the incremental funding will be spent in 2023 and is earmarked for the Company's spot trimming program to address high-risk areas that are not on the 2023 maintenance plan.

ETTP Wire-Down Performance

Using the same methodology discussed above, the Company has determined that actual wire-down events for ETTP circuits vs. Non-ETTP circuits show a 53.0% difference in Year 1, 60.0% difference in Year 2, 38.8% difference in Year 3, and 8.7% difference in Year 4. These results are shown in **Table 16**.

Table 16 – Post-ETTP Wire-Down Difference Compared to Non-ETTP Circuits

	Number of Dist. Circuits ETTP Trimmed	% Change Wire-Down Events for ETTP circuits	% Change for Wire-Down Events for Non-ETTP circuits	**Difference in % Change in Wire-Down Events ETTP vs. Non-ETTP circuits**
1 Year Post Trim	1,549	-61.2%	-8.2%	**-53.0%**
2 Years Post Trim	1,228	-63.7%	-3.7%	**-60.0%**
3 Years Post Trim	754	-56.2%	-17.3%	**-38.8%**
4 Years Post Trim	298	-38.2%	-29.5%	**-8.7%**

Section 4 – Spot Trimming on Worst Performing Circuits

DTE Electric provides an annual power quality investigation report which contains data on all primary customer power quality investigations conducted in the past year for end-use customers, derived from their power quality meters, and the outcome of each investigation. This report contains the DTE Electric January 1, 2022 through December 31, 2022 results and identifies a list of 10 worst performing circuits based on SAIFI outages compared to the rest of the system. Table 17 lists these circuits and the spot trimming that took place in 2022, or planned maintenance trimming.

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March 1, 2022

Ms. Lisa Felice
Executive Secretary
Michigan Public Service Commission
7109 West Saginaw Highway
Lansing, MI 48917

Re: In the matter of the Application of DTE Electric Company for authority to increase its rates, amend its rate schedules and rules governing the distribution and supply of electric energy, and for miscellaneous accounting authority.
MPSC Case No. U-20162

Dear Ms. Felice:

Pursuant to the Commission's final Order in MPSC Case No. U-20162, attached is DTE Electric Company's March 1, 2022 Tree Trim Annual Report for electronic filing in the above-captioned matter.

If you have any questions, please feel free to contact me.

Very truly yours,

Paula Johnson-Bacon

PJB/cdm
Attachment

March 1, 2022 Tree Trim Annual Report

In Case U-20162, the Commission directed DTE Electric (DTEE) to file an annual report to detail the progress of the Surge program and Enhanced Tree Trim Program (ETTP) performance. From the U-20162 Order on May 2, 2019:

> Thus, the annual report shall also break out all activity, costs, and miles trimmed under any and all tree trimming programs (including hardening) in the city of Detroit, to provide information on the progress made in the city of Detroit with each program. The reporting shall include measurable data for the efforts, including miles completed by service center, performance of ETTP circuits compared to non-ETTP circuits, the costs of the efforts, number of employees directly involved in the efforts, tree-related outage reductions, SAIDI reductions, and whether the funding for the efforts is a capital expense or O&M cost. Further, the report shall track ETTP circuit performance, comparing average outages for the three years prior to the enhanced trimming with outages in the years after the trimming has been performed. The first report is due in this docket March 1, 2020, and an annual report is due on March 1 of each year thereafter.

Per Case U-20162 order and Case U-20561 order this report covers the requested information. The report is split into six sections:

1) Miles Completed to ETTP Standard – Annual ETTP maintenance miles are reported by Service Center over the 2015-2021 time period. City of Detroit miles are broken out separately.
2) O&M and Capital Spend on Tree Trimming Activities – Annual tree trim spend are reported by Service Center over the 2016-2021 time period. City of Detroit spend are broken out separately. Costs from 2015 are not included because the ETTP specification makes up a relatively small portion of the overall tree trim spend in that year.
3) ETTP Circuit Performance – ETTP circuit performance comparing average outage events, customer interruptions, outage minutes, and wire downs before and after ETTP work. The performance will cover ETTP circuits trimmed in 2015 through 2020 with reliability data that ranges from 2012 to 2021. Performance of ETTP circuits trimmed in 2021 will be measured starting in 2022.
4) Spot Tree Trimming – Description of spot-trimming work done on the 10 worst performing circuits.
5) Tree Trim Workforce – A 2021 summary of the tree trim workforce is broken down by DTEE employee and contractor.

6) COVID Response – Summary of safety measures taken to keep the workforce and public safe during the COIVD-19 pandemic.

Section 1 – Miles Completed to ETTP Standard

Since the inception of the ETTP standard, the Company has trimmed 26,537 miles. 5,747 ETTP miles were trimmed in 2021 as part of the Surge program. Below, **Table 1** breaks out ETTP miles trimmed by distribution and subtransmission, **Table 2** details miles trimmed by service center and year. **Table 3** shows total miles trimmed to ETTP, which may include second and third cycle ETTP trimming, it has a breakdown of only unique miles trimmed to ETTP, which do not count second or third cycle of ETTP trimming. It also shows miles in backlog, average density and work location by service center. Previous filings from the Company had also included climbing data by service center, which was from a onetime study performed by a third-party consultant. The Company does not collect climbing data for each circuit trimmed, however backlot work is strongly correlated with climbing. **Table 4** shows ETTP miles trimmed in the City of Detroit, and **Table 5** covers miles trimmed as part of the 4.8kV Hardening Program.

Table 1 – ETTP Miles Trimmed by Circuit Type

Circuit Type	2015	2016	2017	2018	2019	2020	2021	Total	% of System
Distribution[1]	257	2,270	2,733	3,128	3,181	4,583	5,021	21,173	67%
Subtransmission[2]	188	1,030	868	540	1,006	1,006	726	5,364	100%
Total Miles	**445**	**3,300**	**3,601**	**3,668**	**4,187**	**5,589**	**5,747**	**26,537**	**70%[3]**

Table 2 – ETTP Miles Trimmed by Service Center

Service Center	2015	2016	2017	2018	2019	2020	2021	Total
ANN	5	143	566	309	246	537	285	**2,091**
CAN	40	60	62	271	307	335	360	**1,435**
HWL	192	272	445	262	264	603	659	**2,697**
LAP	13	341	390	423	378	653	584	**2,782**
MAR	70	351	419	432	303	334	395	**2,304**
MTC	23	250	259	115	321	430	274	**1,672**
NAE	42	693	470	533	557	463	826	**3,584**
NPT	5	159	263	342	254	536	561	**2,120**
PON	6	426	230	237	424	567	618	**2,508**
RFD	24	219	112	381	670	444	300	**2,150**
SBY	8	111	102	207	129	114	181	**852**
WWS	17	275	283	156	334	573	704	**2,342**
Total Miles	**445**	**3,300**	**3,601**	**3,668**	**4,187**	**5,589**	**5,747**	**26,537**

[1] Some of these distribution miles are on their second-cycle of ETTP trimming and show up in the numbers more than once.
[2] Some of these subtransmission miles are on their second- or third-cycle of ETTP trimming and show up in the numbers more than once.
[3] Numerator only includes unique miles – it only counts the miles once even if the miles are on their second- or third-cycle of ETTP trimming.

Table 3 – ETTP Miles Trimmed, Miles of Backlog, Average Tree Density and Mix of Work by Service Center

Service Center	Cumulative Miles Trimmed ETTP[4]	Total System Miles		For the 2021 Plan Only			
		Unique Miles Trimmed to ETTP[5]	Remaining Miles of Backlog to ETTP[6]	2021 Unique Miles Trimmed to ETTP[5]	Total 2021 Miles Trimmed	Avg. Tree Density[7] (trees/mile)	Work Location[7] (% Backlot)
ANN	2,091	1,722	514	205	285	337	68%
CAN	1,435	1,349	78	294	360	296	87%
HWL	2,697	2,293	135	455	659	327	72%
LAP	2,782	2,411	258	321	584	212	82%
MAR	2,304	1,823	1,160	122	395	104	62%
MTC	1,672	1,318	1,253	81	274	104	86%
NAE	3,584	2,588	1,193	205	826	99	88%
NPT	2,120	1,837	115	485	561	121	74%
PON	2,508	1,869	983	199	618	462	73%
RFD	2,150	1,960	1,457	201	300	332	88%
SBY	852	684	626	54	181	146	79%
WWS	2,342	1,794	1,554	409	704	231	81%
Total Miles	**26,537**	**21,648**	**9,327**	**3,031**	**5,747**	**232**	**78%**

Table 4 – ETTP Miles Trimmed in the City of Detroit by Service Center

Service Center	2015	2016	2017	2018	2019	2020	2021	Total	% of City
CAN	40	42	60	234	293	291	326	**1,286**	
MTC	-	-	6	-	-	6	0	**12**	
RFD	5	87	27	251	464	90	129	**1,053**	
Total Detroit Miles[8]	**45**	**129**	**93**	**485**	**757**	**386**	**455**	**2,351**	**80%[9]**

[4] Includes second or third cycle ETTP trim.
[5] Does not include second or third cycle ETTP trim.
[6] Remaining miles in backlog after 2021 trimming.
[7] Density and work location are calculated based on task points identified by the planners during planning – includes brush.
[8] Some of these miles are on their second cycle of ETTP trimming and show up in the number more than once.
[9] Numerator only includes unique miles trimmed to ETTP, therefore does not double count miles on second- cycle or beyond.

Table 5 – ETTP Miles Trimmed as Part of the 4.8kV Hardening Program[10]

Service Center	2015	2016	2017	2018	2019	2020	2021	Total
CAN				20	0	106	198	**324**
RFD				127	158	161	129	**575**
Total 4.8kV Miles				**146**	**158**	**267**	**327**	**898**

Section 2 – O&M and Capital Spend on Tree Trimming Activities

The Company spent $171,659,420 in O&M for its tree trim program in 2021 as detailed in **Table 6**; years 2016 through 2020 are also included for reference. **Table 6** groups costs into five categories:

1) Line Clearance Maintenance – Comprises costs needed for maintenance activities such as contractor labor and equipment, general foreman cost, per diems, and overtime premiums.
2) Trouble – Spend on non-storm unplanned reactive tree trim work related to outage or non-outage problems on the electric system.
3) Tree Trim Program/Other – Includes customer request work, auditing, software maintenance, the herbicide program, training, safety, and other cost miscellaneous costs associated with Tree Trim.
4) DTE Staff Cost – DTE staff costs related to the tree trim program.
5) COVID Expenses – Includes costs associated with the additional safety measures that were taken due to the COVID-19 Pandemic. Further details are included at the end of this report.

Table 6 – Annual O&M Tree Trim Spend by Category[11]

O&M Spend	2016	2017	2018	2019	2020	2021
Line Clearance Maintenance	$59,155,543	$69,344,451	$71,757,936	$116,748,952	$151,021,453	$140,202,546
Trouble	$10,738,172	$11,395,011	$12,966,909	$16,556,969	$12,237,821	$10,667,520
Tree Trim Program/Other	$2,771,660	$1,812,622	$2,500,756	$10,229,182	$6,839,979	$15,670,339
DTE Staff Cost	$1,496,789	$1,704,325	$1,883,630	$2,667,190	$3,722,732	$4,372,897
COVID-19					$1,340,624	$746,118
O&M Total	**$74,162,165**	**$84,256,409**	**$89,109,232**	**$146,202,293**	**$175,162,609**	**$171,659,420**

Table 7 further breaks down the "Line Clearance Maintenance" costs in **Table 6** by service center.

[10] Program began in 2018 and miles in Table 4 are a subset of miles in Tables 1-3.
[11] Table does not include any spot trimming expenses from other programs because they are not part of the tree trim maintenance costs. This table does not include tree trimming cost related to storm, those costs are charged outside the tree trim budget.

Table 7 – Annual Maintenance Tree Trim Spend by Service Center

Service Center	2016	2017	2018	2019	2020	2021
ANN	$4,081,462	$12,103,989	$9,489,387	$6,699,698	$18,811,275	$11,077,345
CAN	$3,312,191	$1,200,014	$8,851,085	$18,827,931	$11,253,759	$6,701,520
HWL	$4,838,162	$12,561,698	$6,269,100	$6,523,040	$19,744,784	$23,573,175
LAP	$5,145,835	$5,820,146	$4,385,310	$5,306,986	$12,866,142	$8,215,356
MAR	$3,679,637	$4,450,068	$5,021,951	$2,757,355	$5,087,650	$3,444,947
MTC	$3,868,638	$4,093,991	$1,961,451	$3,770,923	$9,913,687	$3,727,800
NAE	$3,100,279	$2,242,086	$2,615,529	$3,137,335	$5,336,176	$3,858,290
NPT	$1,990,418	$4,844,204	$5,288,021	$3,400,257	$9,634,726	$12,826,082
PON	$12,293,540	$8,619,875	$8,167,988	$24,883,843	$27,768,967	$29,346,468
RFD	$5,929,162	$3,762,082	$11,025,927	$28,999,125	$12,309,855	$6,816,756
SBY	$3,351,803	$3,078,400	$4,338,480	$2,656,440	$3,982,452	$2,863,698
WWS	$7,564,417	$6,567,898	$4,343,707	$9,786,018	$14,311,980	$27,751,110
Total	**$59,155,544**	**$69,344,451**	**$71,757,936**	**$116,748,951**	**$151,021,453**	**$140,202,546**

Table 8 details the 4.8kV Hardening capital spend in 2018-2021.

Table 8 – Annual 4.8kV Hardening Tree Trim Capital Spend by Service Center

Service Center	2018	2019	2020	2021
CAN	$ 2,136,156	-	$5,878,864	$11,757,474
RFD	$ 7,858,107	$ 10,081,771	$12,025,855	$10,274,963
Total	**$ 9,994,263**	**$ 10,081,771**	**$17,904,719**	**$22,032,437**

Table 9 highlights the $25,283,373 tree trim spend in the City of Detroit for the year 2021, which includes $21,408,206 of Capital spend. City spend in 2016 through 2020 is included for reference.

Table 9 – Annual Detroit O&M and Capital Tree Trim Spend

	2016	2017	2018	2019	2020	2021
Detroit - O&M	$6,217,231	$2,345,651	$14,071,122	$40,513,330	$7,333,594	$3,875,167
Detroit - Capital	-	-	$9,326,363	$10,081,771	$11,888,408	$21,408,206
Detroit Total	**$6,217,231**	**$2,345,651**	**$23,397,485**	**$50,595,101**	**$19,222,002**	**$25,283,373**

Section 3 – ETTP Circuit Performance

Methodology Used to Calculate ETTP Performance

The methodology used to calculate ETTP Performance for all distribution circuits uses the average of three years of Pre-trim ETTP tree-outage events and compares it to each year post trimming.

All post-trim year results of the same year were then summed to increase the sample size (as an example, all post-trim year 1 results are summed). The difference between the before trimming performance and the post trimming performance was used to create the "% Change in Outage Event Reduction for ETTP circuits". To create a control group for comparison, the same methodology was used for the remainder of circuits not trimmed ETTP, which is identified as "% Change in Outage Event Reduction for Non-ETTP circuits". To account for natural weather variation, the performance of the control group is subtracted from the ETTP circuit performance to provide an accurate representation of the true impact of the ETTP. This is the same methodology outlined in Case U-20561.

Table 10 – Methodology for ETTP Performance Analysis

2012	2103	2014	2015	2016	2017	2018	2019	# of ETTP Circuits
			Three Year Average Pre-ETTP Performace			Year of Trim	Post Trim Year 1	321
		Three Year Average Pre-ETTP Performace			Year of Trim	Post Trim Year 1	Post Trim Year 2	128
	Three Year Average Pre-ETTP Performace			Year of Trim	Post Trim Year 1	Post Trim Year 2	Post Trim Year 3	171
Three Year Average Pre-ETTP Performace			Year of Trim	Post Trim Year 1	Post Trim Year 2	Post Trim Year 3	Post Trim Year 4	20

Table 11 – Methodology for Control Group Non-ETTP Performance Analysis

2012	2103	2014	2015	2016	2017	2018	2019	# of ETTP Circuits
			Three Year Average Pre-Non ETTP Performace			Year of Trim	Post Trim Year 1	N/A
		Three Year Average Pre-Non ETTP Performace			Year of Trim	Post Trim Year 1	Post Trim Year 2	N/A
	Three Year Average Pre-Non ETTP Performace			Year of Trim	Post Trim Year 1	Post Trim Year 2	Post Trim Year 3	N/A
Three Year Average Pre-Non ETTP Performace			Year of Trim	Post Trim Year 1	Post Trim Year 2	Post Trim Year 3	Post Trim Year 4	N/A

The control group of circuits and the ETTP group of circuits must be compared to account for non-ETTP related variations. If the Company only looks at the performance of ETTP circuits, it does

not account for natural weather variation or general deterioration/improvements on our system. Assume that a group of ETTP circuits were trimmed in 2018 and that 2019 turns out to be a particularly favorable storm year compared to the before trim average (2015-2017). When the ETTP performance is measured, it is possible that the Year 1 improvement is 90%, which looks like an incredible improvement but, when compared against the control group, which may also have seen a significant improvement of 70%, the value of ETTP does not seem as significant. In this example the delta between the control group and ETTP is only 20%. Because the methodology discussed helps weather normalize reliability across multiple years for data, it is a much more accurate way to gauge true ETTP effectiveness.

ETTP Outage Event Performance

The actual difference of outage events on ETTP circuits compared to the balance of the system not trimmed ETTP is 69.1% in post-trim year 1, 65.2% in the second year, 73.5% in the third year, and 63.1% in the fourth year. The actual reduction for Years 1-4 post ETTP trim are depicted in **Table 12**.

Table 12 – ETTP Tree-Related Outage Event Difference Compared to Non ETTP Circuits

	Number of Dist. Circuits ETTP Trimmed	% Change in Outage Event Reduction for ETTP circuits	% Change in Outage Event Reduction for Non-ETTP circuits	**Difference in % Change in Event Reduction ETTP vs Non-ETTP circuits**	U-20162 Surge Model Projected Reduction
1 Year Post Trim	1,389	-29.3%	39.8%	**-69.1%**	-57.0%
2 Years Post Trim	972	-1.0%	64.1%	**-65.2%**	-57.0%
3 Years Post Trim	509	2.4%	75.9%	**-73.5%**	-50.0%
4 Years Post Trim	180	33.6%	96.7%	**-63.1%**	-37.0%

ETTP Customer Interruptions Performance

Using the same methodology discussed above, the Company has determined that actual customer interruptions on ETTP circuits vs. Non-ETTP circuits show a 73.9% difference in Year 1, 66.8% difference in Year 2, 78.9% difference in Year 3, and 52.7% difference in Year 4. These results are shown in Table 13.

Table 13 – ETTP Tree-Related Customer Interruption Difference Compared to Non ETTP Circuits

	Number of Dist. Circuits ETTP Trimmed	% Change in Outage Event Reduction for ETTP circuits	% Change in Outage Event Reduction for Non-ETTP circuits	**Difference in % Change in Event Reduction ETTP vs Non-ETTP circuits**	U-20162 Surge Model Projected Reduction
1 Year Post Trim	1,389	-45.8%	28.1%	**-73.9%**	-57.0%
2 Years Post Trim	972	-22.4%	44.3%	**-66.8%**	-57.0%
3 Years Post Trim	509	-37.4%	41.5%	**-78.9%**	-50.0%
4 Years Post Trim	180	-7.1%	45.5%	**-52.7%**	-37.0%

ETTP Customer Outage Minute Performance

Customer minutes of interruption, shown in **Table 14**, also show significant improvements. Actual minutes of customer interruption on ETTP circuits vs. Non-ETTP circuits show a 66.7% difference in Year 1, 56.9% difference in Year 2, 46.3% difference in Year 3, and 40.8% difference in Year 4.

Table 14 – ETTP Tree-Related Customer Outage Minutes of Interruption Difference Compared to Non ETTP Circuits

	Number of Dist. Circuits ETTP Trimmed	% Change in Outage Event Reduction for ETTP circuits	% Change in Outage Event Reduction for Non-ETTP circuits	**Difference in % Change in Event Reduction ETTP vs Non-ETTP circuits**	U-20162 Surge Model Projected Reduction
1 Year Post Trim	1,389	-54.7%	12.0%	**-66.7%**	-57.0%
2 Years Post Trim	972	-20.9%	35.9%	**-56.9%**	-57.0%
3 Years Post Trim	509	-52.1%	-5.9%	**-46.3%**	-50.0%
4 Years Post Trim	180	-39.1%	1.7%	**-40.8%**	-37.0%

Table 15 shows the 2021 outage minutes saved and avoided due to ETTP trimming and the impact to overall system SAIDI, a net reduction of 171 SAIDI minutes. If only ETTP circuits are considered, the SAIDI minute reduction is 295 minutes.

Table 15 – 2021 ETTP Outage Minute Reduction and SAIDI Impact

	ETTP Outage Minutes
3 Years Before Trim Avg. Outage Minutes	568,927,084
2021 Outage Minutes	344,743,553
Minutes Saved	224,183,531
Minutes Avoided – Non ETTP System Deterioration	155,476,155
Total Minute Reduction	379,659,686
ETTP Overall System SAIDI Minute Reduction	**171**
SAIDI Minute Reduction for ETTP Circuits ONLY	**295**

ETTP Wire-Down Performance

Using the same methodology discussed above, the Company has determined that actual wire-down events for ETTP circuits vs. Non-ETTP circuits show a 35.2% difference in Year 1, 37.1% difference in Year 2, 26.9% difference in Year 3, and 12.7% difference in Year 4. These results are shown in **Table 16**.

Table 16 – Post-ETTP Wire-Down Difference Compared to Non-ETTP Circuits

	Number of Dist. Circuits ETTP Trimmed	% Change Wire-Down Events for ETTP circuits	% Change for Wire-Down Events for Non-ETTP circuits	**Difference in % Change in Wire-Down Events ETTP vs. Non-ETTP circuits**
1 Year Post Trim	1,389	-25.6%	9.6%	**-35.2%**
2 Years Post Trim	972	-15.4%	21.7%	**-37.1%**
3 Years Post Trim	509	-13.0%	13.9%	**-26.9%**
4 Years Post Trim	180	-7.8%	4.9%	**-12.7%**

Section 4 – Spot Trimming on Worst Performing Circuits

DTE Electric provides an annual power quality investigation report which contains data on all primary customer power quality investigations conducted in the past year for end-use customers, derived from their power quality meters, and the outcome of each investigation. This report contains the DTE Electric January 1, 2021 through December 31, 2021 results and identifies a list of 10 worst performing circuits based on SAIFI outages compared to the rest of the system. **Table 17** lists these circuits and the spot trimming that took place in 2021, or planned maintenance trimming.

Table 17 – Tree Trimming on 2021 Ten Worst Performing Circuits

Circuit	sysSAIFI[10]	sysSAIFI ex MED[11]	Spot Trimming		ETTP Maintenance Trimming Year
			Performed in 2021?	Number of Poles Trimmed	
CLYDE9079	0.0102	0.0059	No		2021
DRAKE8969	0.0085	0.0045	Yes	102	2021
WDLOW8255	0.0077	0.006	No		2021
COLRD9100	0.0076	0.0074	Yes	71	2022 Planned
BLCRK9344	0.0075	0.004	Yes	62	2021/2022
ZACRY9502	0.0068	0.0068	No		2020
WDLOW9064	0.0067	0.0041	No		2020/2021
PERU 9432	0.0066	0.0049	No		2022 Planned
SALIN9788	0.0063	0.0033	No		2021/2022
MALRD9393	0.0057	0.0034	No		2022 Planned

Section 5 – Tree Trim Workforce

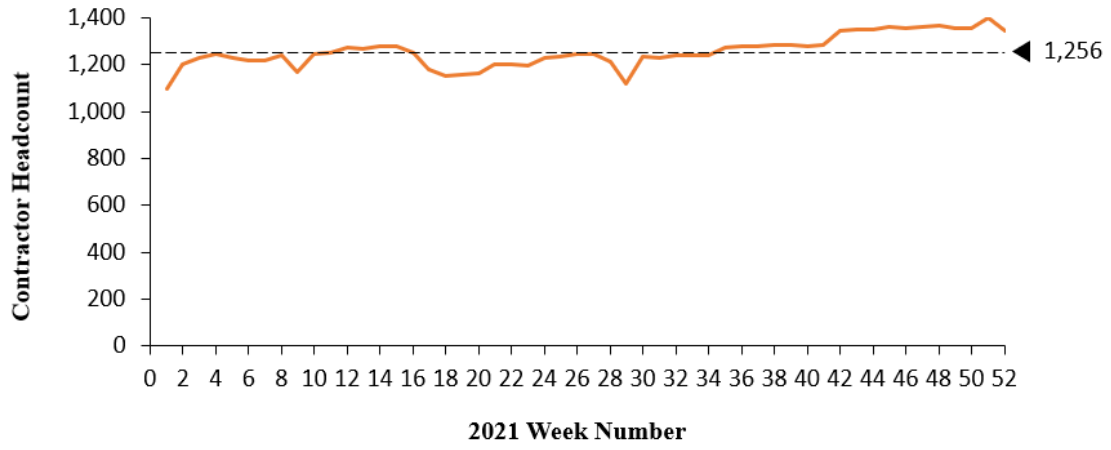
The internal employees directly involved in Tree Trimming are detailed in **Table 18**. In 2021, the average number for contractors on property were 1,256. Contractor headcount fluctuation over the course of 2021 is seen in **Chart 1**.

Table 18 – 2021 DTE and Contractor Tree Trim Headcount

Facilitator - Arborists	14
Supervision	8
Regional Foresters	6
Strategy and Planning	5
Internal Employees involved with ETTP	**33**

2021 Average # of Contractors	**1,256**

Chart 1 – 2021 Contract Tree Trim Headcount by Week



The 2021 average local journeymen trimmers were 614, and the number of local apprentices were 230. Outsourced journeymen trimmers averaged 412 for 2021. The Company is participating in three programs in an effort to increase the number of local trimmers. The three programs are the Parnall Correctional Facility Vocational Village Training Program, the City of Detroit Tree Trim Academy, and the IBEW Local 17 Traditional Boot Camp. Below is an update on each of the programs:

1. Parnall - The Parnall Tree Trimming program is designed to provide returning citizens the skills needed to start as an apprentice tree trimmer. DTE has partnered with the Michigan Department of Corrections to provide qualified instructors and the required training facilities. The company has paired 23 graduates with jobs.

2. Tree Trim Academy – The Company has partnered with the City of Detroit, IBEW Local 17, and its tree-trimming contractors to develop and implement a pre-woodsman training pilot program to satisfy the demand for qualified tree trimmers. The pilot tree trimming academy is located within the City of Detroit and facilitates training that is aimed at preparing local resident candidates to work as woodsmen. Once candidates complete the pre-woodsman program, graduates enter the nine-day boot camp that was previously designed in partnership with the Company, IBEW Local 17, and the Company's tree-trimming contractors.

   The first cohort completed the tree trimming academy this past spring, and as of November 2021, 36 individuals have graduated from the program, with 100% of them receiving job offers upon graduation. Due to the collaborative outreach effort and positive reception the academy has received thus far, there is already a waitlist for 2022's cohort.

3. Traditional Boot Camp – IBEW continues to hold regular scheduled boot camp training for apprentices. Current camps are conducted at their training facility in Wales, MI.

Section 6 – COVID Response (Added for 2020 & 2021 only)

In 2021, DTE continued to follow to federal and state health and safety guidelines around COVID-19. As the vaccine became available, the Company loosened policies around one-person per vehicle and PPE requirements to align with the evolving recommendations of health officials.

To support the necessary safety measures in Tree Trimming, DTEE spent $0.7M in 2021. These expenses were mainly for the one-person per vehicle policy, and PPE for DTEE employees and contractors.

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May 6, 2021

Ms. Lisa Felice
Executive Secretary
Michigan Public Service Commission
7109 West Saginaw Highway
Lansing, MI 48917

Re: In the matter of the Application of DTE Electric Company for authority to increase its rates, amend its rate schedules and rules governing the distribution and supply of electric energy, and for miscellaneous accounting authority. MPSC Case No. U-20162

Dear Ms. Felice:

Pursuant to the Commission's final Order in MPSC Case No. U-20162, attached is DTE Electric Company's Amended March 1, 2021 Tree Trim Annual Report for electronic filing in the above-captioned matter.

If you have any questions, please feel free to contact me.

Very truly yours,

Paula Johnson-Bacon

PJB/kbk
Attachment

Amended March 1, 2021 Tree Trim Annual Report

In Case U-20162, the Commission directed DTE Electric (DTEE) to file an annual report to detail the progress of the Surge program and Enhanced Tree Trim Program (ETTP) performance. From the U-20162 Order on May 2, 2019:

> Thus, the annual report shall also break out all activity, costs, and miles trimmed under any and all tree trimming programs (including hardening) in the city of Detroit, to provide information on the progress made in the city of Detroit with each program. The reporting shall include measurable data for the efforts, including miles completed by service center, performance of ETTP circuits compared to non-ETTP circuits, the costs of the efforts, number of employees directly involved in the efforts, tree-related outage reductions, SAIDI reductions, and whether the funding for the efforts is a capital expense or O&M cost. Further, the report shall track ETTP circuit performance, comparing average outages for the three years prior to the enhanced trimming with outages in the years after the trimming has been performed. The first report is due in this docket March 1, 2020, and an annual report is due on March 1 of each year thereafter.

Per Case U-20162 order and Case U-20561 order this report covers the requested information. The report is split into six sections:

1) Miles Completed to ETTP Standard – Annual ETTP maintenance miles are reported by Service Center over the 2015-2020 time period. City of Detroit miles are broken out separately.
2) O&M and Capital Spend on Tree Trimming Activities – Annual tree trim spend are reported by Service Center over the 2016-2020 time period. City of Detroit spend are broken out separately. Costs from 2015 are not included because the ETTP specification makes up a relatively small portion of the overall tree trim spend in that year.
3) ETTP Circuit Performance – ETTP circuit performance comparing average outage events, customer interruptions, outage minutes, and wire downs before and after ETTP work. The performance will cover ETTP circuits trimmed in 2015 through 2019 with reliability data that ranges from 2012 to 2020. Performance of ETTP circuits trimmed in 2020 will be measured starting in 2021.
4) Spot Tree Trimming – Description of spot-trimming work done on the 10 worst performing circuits.
5) Tree Trim Workforce – A 2020 summary of the tree trim workforce is broken down by DTEE employee and contractor.

6) COVID Response – Summary of safety measures taken to keep the workforce and public safe during the COIVD-19 pandemic.

Section 1 – Miles Completed to ETTP Standard

Since the inception of the ETTP standard, the Company has trimmed 20,790 miles. 5,589 ETTP miles where trimmed in 2020 as part of the Surge program. Below, **Table 1** breaks out ETTP miles trimmed by distribution and subtransmission, **Table 2** details miles trimmed by service center and year. **Table 3** shows miles trimmed, miles in backlog, average density and work location by service center. Previous filings from the Company had also included climbing data by service center, which was from a onetime study performed by a third-party consultant. The Company does not collect climbing data for each circuit trimmed, however backlot work is strongly correlated with climbing. **Table 4** shows ETTP miles trimmed in the City of Detroit, and **Table 5** covers miles trimmed as part of the 4.8kV Hardening Program.

Table 1 – ETTP Miles Trimmed by Circuit Type

Circuit Type	2015	2016	2017	2018	2019	2020	Total	% of System
Distribution	257	2,270	2,733	3,128	3,181	4,583	**16,152**	56%
Subtransmission[1]	188	1,030	868	540	1,006	1,006	**4,638**	100%
Total Miles	**445**	**3,300**	**3,601**	**3,668**	**4,187**	**5,589**	**20,790**	**60%**[2]

Table 2 – ETTP Miles Trimmed by Service Center

Service Center	2015	2016	2017	2018	2019	2020	Total
MAR	70	351	419	432	303	334	**1,909**
ANN	5	143	566	309	246	537	**1,806**
CAN	40	60	62	271	307	335	**1,075**
HWL	192	272	445	262	264	603	**2,038**
LAP	13	341	390	423	378	653	**2,198**
MTC	23	250	259	115	321	430	**1,398**
NAE	42	693	470	533	557	463	**2,758**
NPT	5	159	263	342	254	536	**1,559**
PON	6	426	230	237	424	567	**1,890**
RFD	24	219	112	381	670	444	**1,850**
SBY	8	111	102	207	129	114	**671**
WWS	17	275	283	156	334	573	**1,638**
Total Miles	**445**	**3,300**	**3,601**	**3,668**	**4,187**	**5,589**	**20,790**

[1] 2,098 of these miles are subtransmission that are on their second cycle and show up in the numbers twice
[2] Numerator only includes unique miles – it does not double count subtransmission on second cycle

Table 3 – ETTP Miles Trimmed, Miles of Backlog, Average Tree Density and Mix of Work by Service Center

Service Center	Total System Miles Trimmed to ETTP[3]	Miles of Backlog to ETTP[4]	For the 2020 Plan Only		
			2020 Miles Trimmed to ETTP	Avg. Tree Density[5] (trees/mile)	Work Location[5] (% Backlot)
MAR	1,909	1,281	334	291	71%
ANN	1,806	719	537	277	66%
CAN	1,075	373	335	206	76%
HWL	2,038	590	603	127	79%
LAP	2,198	579	653	88	58%
MTC	1,398	1,334	430	117	76%
NAE	2,758	1,399	463	138	88%
NPT	1,559	600	536	80	67%
PON	1,890	1,182	567	360	75%
RFD	1,850	1,657	444	262	85%
SBY	671	680	114	130	82%
WWS	1,638	1,963	573	165	77%
Total Miles	**20,790**	**12,358**	**5,589**	**192**	**77%**

Table 4 – ETTP Miles Trimmed in the City of Detroit by Service Center

Service Center	2015	2016	2017	2018	2019	2020	Total	% of City
CAN	40	42	60	234	293	291	**960**	
MTC	-	-	6	-	-	6	**12**	
RFD	5	87	27	251	464	90	**924**	
Total Detroit Miles[6]	**45**	**129**	**93**	**485**	**757**	**386**	**1,896**	**74%[7]**

Table 5 – ETTP Miles Trimmed as Part of the 4.8kV Hardening Program[8]

Service Center	2015	2016	2017	2018	2019	2020	Total
CAN				20	0	**106**	**126**
RFD				127	158	**161**	**446**
Total 4.8kV Miles				**146**	**158**	**267**	**572**

[3] 2,098 of these miles are subtransmission that are on their second cycle and show up in the numbers twice
[4] Remaining miles in backlog after 2020 trimming
[5] Density and work location are calculated based on task points identified by the planners during planning – includes brush
[6] The total unique miles complete in the City of Detroit are 1,860. 36 Subtransmission miles are on their second cycle and are counted twice in the Table 3
[7] Numerator only includes unique miles – it does not double count subtransmission on second cycle
[8] Program began in 2018 and miles in Table 4 are a subset of miles in Tables 1-3.

Section 2 – O&M and Capital Spend on Tree Trimming Activities

The Company spent $175,062,609 in O&M for its tree trim program in 2020 as detailed in **Table 6**; years 2016 through 2019 are also included for reference. **Table 6** groups costs into five categories:

1) Line Clearance Maintenance – Comprises costs needed for maintenance activities such as contractor labor and equipment, general foreman cost, per diems, and overtime premiums.
2) Trouble – Spend on non-storm unplanned reactive tree trim work related to outage or non-outage problems on the electric system.
3) Tree Trim Program/Other – Includes customer request work, auditing, software maintenance, the herbicide program, training, safety, and other cost miscellaneous costs associated with Tree Trim.
4) DTE Staff Cost – DTE staff costs related to the tree trim program.
5) COVID Expenses – Includes costs associated with the additional safety measures that were taken due to the COVID-19 Pandemic. Further details are included at the end of this report.

Table 6 – Annual O&M Tree Trim Spend by Category[9]

O&M Spend	2016	2017	2018	2019	2020
Line Clearance Maintenance	$59,155,543	$69,344,451	$71,757,936	$116,748,952	$151,021,453
Trouble	$10,738,172	$11,395,011	$12,966,909	$16,556,969	$12,237,821
Tree Trim Program/Other	$2,771,660	$1,812,622	$2,500,756	$10,229,182	$6,839,979
DTE Staff Cost	$1,496,789	$1,704,325	$1,883,630	$2,667,190	$3,722,732
COVID-19					$1,340,624
O&M Total	**$74,162,165**	**$84,256,409**	**$89,109,232**	**$146,202,293**	**$175,162,609**

Table 7 further breaks down the "Line Clearance Maintenance" costs in **Table 6** by service center.

Table 7 – Annual Maintenance Tree Trim Spend by Service Center

Service Center	2016	2017	2018	2019	2020
MAR	$3,679,637	$4,450,068	$5,021,951	$2,757,355	$5,087,650
ANN	$4,081,462	$12,103,989	$9,489,387	$6,699,698	$18,811,275
CAN	$3,312,191	$1,200,014	$8,851,085	$18,827,931	$11,253,759
HWL	$4,838,162	$12,561,698	$6,269,100	$6,523,040	$19,744,784
LAP	$5,145,835	$5,820,146	$4,385,310	$5,306,986	$12,866,142
MTC	$3,868,638	$4,093,991	$1,961,451	$3,770,923	$9,913,687
NAE	$3,100,279	$2,242,086	$2,615,529	$3,137,335	$5,336,176
NPT	$1,990,418	$4,844,204	$5,288,021	$3,400,257	$9,634,726
PON	$12,293,540	$8,619,875	$8,167,988	$24,883,843	$27,768,967

[9] Table does not include any spot trimming expenses from other programs because they are not part of the tree trim maintenance costs.

RFD	$5,929,162	$3,762,082	$11,025,927	$28,999,125	$12,309,855
SBY	$3,351,803	$3,078,400	$4,338,480	$2,656,440	$3,982,452
WWS	$7,564,417	$6,567,898	$4,343,707	$9,786,018	$14,311,980
Total	**$59,155,543**	**$69,344,451**	**$71,757,936**	**$116,748,952**	**$151,021,453**

Table 8 details the 4.8kV Hardening capital spend in 2018-2020.

Table 8 – Annual 4.8kV Hardening Tree Trim Capital Spend by Service Center

Service Center	2018	2019	2020
CAN	$ 2,136,156	-	$5,878,864
RFD	$ 7,858,107	$ 10,081,771	$12,025,855
Total	**$ 9,994,263**	**$ 10,081,771**	**$17,904,719**

Table 9 highlights the $19,222,002 tree trim spend in the City of Detroit for the year 2020, which includes $11,888,408 of Capital spend. City spend in 2016 through 2019 is included for reference.

Table 9 – Annual Detroit O&M and Capital Tree Trim Spend

	2016	2017	2018	2019	2020
Detroit - O&M	$6,217,231	$2,345,651	$14,071,122	$40,513,330	$7,333,594
Detroit - Capital	-	-	$9,326,363	$10,081,771	$11,888,408
Detroit Total	**$6,217,231**	**$2,345,651**	**$23,397,485**	**$50,595,101**	**$19,222,002**

Section 3 – ETTP Circuit Performance

Methodology Used to Calculate ETTP Performance

The methodology used to calculate ETTP Performance for all distribution circuits uses the average of three years of Pre-trim ETTP tree-outage events and compares it to each year post trimming. All post-trim year results of the same year were then summed to increase the sample size (as an example, all post-trim year 1 results are summed). The difference between the before trimming performance and the post trimming performance was used to create the "% Change in Outage Event Reduction for ETTP circuits". To create a control group for comparison, the same methodology was used for the remainder of circuits not trimmed ETTP, which is identified as "% Change in Outage Event Reduction for Non-ETTP circuits". To account for natural weather variation, the performance of the control group is subtracted from the ETTP circuit performance to provide an accurate representation of the true impact of the ETTP. This is the same methodology outlined in Case U-20561.

Table 10 – Methodology for ETTP Performance Analysis

2012	2103	2014	2015	2016	2017	2018	2019	# of ETTP Circuits
			Three Year Average Pre-ETTP Performace			Year of Trim	Post Trim Year 1	321
		Three Year Average Pre-ETTP Performace			Year of Trim	Post Trim Year 1	Post Trim Year 2	128
	Three Year Average Pre-ETTP Performace			Year of Trim	Post Trim Year 1	Post Trim Year 2	Post Trim Year 3	171
Three Year Average Pre-ETTP Performace			Year of Trim	Post Trim Year 1	Post Trim Year 2	Post Trim Year 3	Post Trim Year 4	20

Table 11 – Methodology for Control Group Non-ETTP Performance Analysis

2012	2103	2014	2015	2016	2017	2018	2019	# of ETTP Circuits
			Three Year Average Pre-Non ETTP Performace			Year of Trim	Post Trim Year 1	N/A
		Three Year Average Pre-Non ETTP Performace			Year of Trim	Post Trim Year 1	Post Trim Year 2	N/A
	Three Year Average Pre-Non ETTP Performace			Year of Trim	Post Trim Year 1	Post Trim Year 2	Post Trim Year 3	N/A
Three Year Average Pre-Non ETTP Performace			Year of Trim	Post Trim Year 1	Post Trim Year 2	Post Trim Year 3	Post Trim Year 4	N/A

The control group of circuits and the ETTP group of circuits must be compared to account for non-ETTP related variations. If the Company only looks at the performance of ETTP circuits, it does not account for natural weather variation or general deterioration/improvements on our system. Assume that a group of ETTP circuits were trimmed in 2018 and that 2019 turns out to be a particularly favorable storm year compared to the before trim average (2015-2017). When the ETTP performance is measured, it is possible that the Year 1 improvement is 90%, which looks like an incredible improvement but, when compared against the control group, which may also have seen a significant improvement of 70%, the value of ETTP does not seem as significant. In this example the delta between the control group and ETTP is only 20%. Because the methodology discussed helps weather normalize reliability across multiple years for data, it is a much more accurate way to gauge true ETTP effectiveness.

ETTP Outage Event Performance

The actual difference of outage events on ETTP circuits compared to the balance of the system not trimmed ETTP is 76.1% in post-trim year 1, 93.5% in the second year, 87.0% in the third year, and 91.2% in the fourth year. The actual reduction for Years 1-4 post ETTP trim are depicted in **Table 12**.

Table 12 – ETTP Tree-Related Outage Event Difference Compared to Non ETTP Circuits

	Number of Dist. Circuits ETTP Trimmed	% Change in Outage Event Reduction for ETTP circuits	% Change in Outage Event Reduction for Non-ETTP circuits	**Difference in % Change in Event Reduction ETTP vs Non-ETTP circuits**	U-20162 Surge Model Projected Reduction
1 Year Post Trim	1,071	-34.0%	42.1%	**-76.1%**	-57.0%
2 Years Post Trim	642	-25.7%	67.8%	**-93.5%**	-57.0%
3 Years Post Trim	321	-13.8%	73.2%	**-87.0%**	-50.0%
4 Years Post Trim	193	-6.3%	84.9%	**-91.2%**	-37.0%

ETTP Customer Interruptions Performance

Using the same methodology discussed above, the Company has determined that actual customer interruptions on ETTP circuits vs. Non-ETTP circuits show a 62.9% difference in Year 1, 76.4% difference in Year 2, 71.7% difference in Year 3, and 75.0% difference in Year 4. These results are shown in Table 13.

Table 13 – ETTP Tree-Related Customer Interruption Difference Compared to Non ETTP Circuits

	Number of Dist. Circuits ETTP Trimmed	% Change in Customers Interrupted for ETTP circuits	% Change in Customers Interrupted for Non-ETTP circuits	**Difference in % Change in Customers Interrupted ETTP vs. Non-ETTP circuits**	U-20162 Surge Model Projected Reduction
1 Year Post Trim	1,071	-34.4%	34.8%	**-62.9%**	-57.0%
2 Years Post Trim	642	-19.7%	56.6%	**-76.4%**	-57.0%
3 Years Post Trim	321	-22.1%	49.7%	**-71.7%**	-50.0%
4 Years Post Trim	193	-23.3%	51.7%	**-75.0%**	-37.0%

ETTP Customer Outage Minute Performance

Customer minutes of interruption, shown in **Table 14**, also show significant improvements. Actual minutes of customer interruption on ETTP circuits vs. Non-ETTP circuits show a 57.3% difference in Year 1, 84.9% difference in Year 2, 42.2% difference in Year 3, and 47.9% difference in Year 4. **Table 15** shows the 2020 outage minutes saved and avoided due to ETTP trimming and the impact to overall system SAIDI, a net reduction of 94 SAIDI minutes. If only ETTP circuits are considered, the SAIDI minute reduction is 258 minutes.

Table 14 – ETTP Tree-Related Customer Outage Minutes of Interruption Difference Compared to Non ETTP Circuits

	Number of Dist. Circuits ETTP Trimmed	% Change in Customer Minutes Interrupted for ETTP circuits	% Change in Customer Minutes Interrupted for Non-ETTP circuits	**Difference in % Change in Customer Minutes Interrupted ETTP vs. Non-ETTP circuits**	U-20162 Surge Model Projected Reduction
1 Year Post Trim	1,071	-44.6%	12.7%	**-57.3%**	-57.0%
2 Years Post Trim	642	-44.4%	40.4%	**-84.9%**	-57.0%
3 Years Post Trim	321	-53.7%	-11.6%	**-42.2%**	-50.0%
4 Years Post Trim	193	-59.9%	-12.0%	**-47.9%**	-37.0%

Table 15 – 2020 ETTP Outage Minute Reduction and SAIDI Impact

	ETTP Outage Minutes
3 Years Before Trim Avg. Outage Minutes	425,794,780
2020 Outage Minutes	152,199,382
Minutes Saved	273,595,397
Minutes Avoided – Non ETTP System Deterioration	65,921,445
Total Minute Reduction	207,673,953
ETTP Overall System SAIDI Minute Reduction	**94**
SAIDI Minute Reduction for ETTP Circuits ONLY	**258**

ETTP Wire-Down Performance

Using the same methodology discussed above, the Company has determined that actual wire-down events for ETTP circuits vs. Non-ETTP circuits show a 24.9% difference in Year 1, 39.6% difference in Year 2, 38.9% difference in Year 3, and 62.2% difference in Year 4. These results are shown in **Table 16**.

Table 16 – Post-ETTP Wire-Down Difference Compared to Non-ETTP Circuits

	Number of Dist. Circuits ETTP Trimmed	% Change Wire-Down Events for ETTP circuits	% Change for Wire-Down Events for Non-ETTP circuits	**Difference in % Change in Wire-Down Events ETTP vs. Non-ETTP circuits**
1 Year Post Trim	1,071	-17.6%	14.6%	**-32.2%**
2 Years Post Trim	642	-13.1%	28.8%	**-42.0%**
3 Years Post Trim	321	-13.2%	24.1%	**-37.3%**
4 Years Post Trim	193	-23.3%	20.1%	**-43.4%**

Section 4 – Spot Trimming on Worst Performing Circuits

DTE Electric provides an annual power quality investigation report which contains data on all primary customer power quality investigations conducted in the past year for end-use customers, derived from their power quality meters, and the outcome of each investigation. This report contains the DTE Electric January 1, 2020 through December 31, 2020 results and identifies a list of 10 worst performing circuits based on SAIFI outages compared to the rest of the system. **Table 17** lists these circuits and the spot trimming or maintenance trimming that took place on these circuits in 2020.

Table 17 – Tree Trimming on 2020 Ten Worst Performing Circuits

Circuit	sysSAIFI[10]	sysSAIFI ex MED[11]	Spot Trimming Performed in 2020?	Number of Poles Trimmed	Maintenance Trimming in 2020?
BELVL9356	0.0119	0.0097	Yes	145	
MTMRA8035	0.0081	0.0067			Trimmed 2020 Q4 – 2021 Q1
MAUME8241	0.0073	0.0051	Yes	75	
TAMRK9545	0.0071	0.0071	Yes	49	
STEPH8522	0.0068	0.0065			Trimmed Q4 2020
MACMB8521	0.0061	0.0061	Yes	10	
MACMB8510	0.0060	0.0060	Yes	73	
KENSL9858	0.0059	0.0059	Yes	180	
ZACRY9502	0.0059	0.0046			Trimmed Q4 2020
STEPH8707	0.0056	0.0049			Trimmed Q4 2020

Section 5 – Tree Trim Workforce

The internal employees directly involved in Tree Trimming are detailed in **Table 18**. In 2020, the average number for contractors on property were 1,164. Contractor headcount fluctuation over the course of 2020 is seen in **Chart 1**.

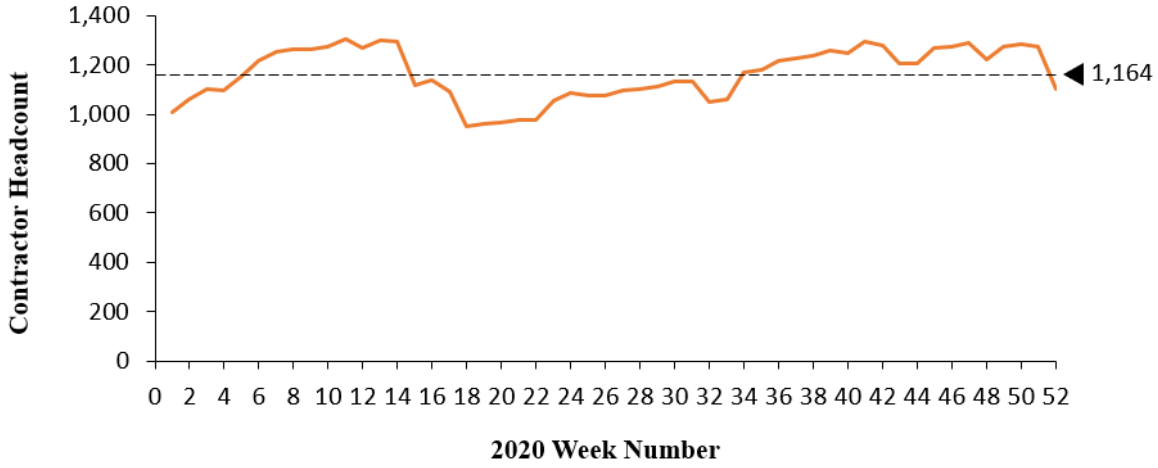
Table 18 – 2020 DTE and Contractor Tree Trim Headcount

Facilitator - Arborists	14
Supervision	9
Regional Foresters	5
Strategy and Planning	5
Internal Employees involved with ETTP	**33**

2020Average # of Contractors	**1,164**

[10] sysSAFI is the number of customer interruptions on a specific circuit divided by the number of system customer interruptions
[11] MED stands for Major Event Days

Chart 1 – 2020 Contract Tree Trim Headcount by Week



The 2020 average local journeymen trimmers were 617, and the number of local apprentices were 301. Outsourced journeymen trimmers averaged 246 for 2020. The Company is participating in three programs in an effort to increase the number of local trimmers. The three programs are the Parnall Correctional Facility Vocational Village Training Program, the City of Detroit Tree Trim Academy, and the IBEW Local 17 Traditional Boot Camp. Below is an update on each of the programs:

1) Parnall – The Parnall Tree Trimming program is designed to provide returning citizens the skills needed to start as an apprentice tree trimmer. DTE has partnered with the Michigan Department of Corrections to provide qualified instructors and the required training facilities. There have been eighteen graduates released as of January 2021, since the program begun in June of 2019. All eighteen graduates have been placed with employers and fourteen of them remain employed as of January 2021. The Vocational Village has significantly reduced training operations in response to COVID-19 and it is not certain as to how many graduates to expect in the immediate future.
2) Tree Trim Academy – The Company is working to set up a training facility in the City of Detroit. DTEE has worked with the City of Detroit and has acquired a property for the Tree Trimming Academy. Currently, the training facility is nearing the end of construction and the training curriculum has been developed. The Company has partnered with Focus: HOPE to identify and recruit local candidates for the training. If everything remains on schedule, classes are expected to begin in March of 2021.
3) Traditional Boot Camp – IBEW continues to hold regular scheduled boot camp training for apprentices. Current camps are conducted at their training facility in Wales, MI. Once the Tree Trim Academy is operational, boot camps will be conducted both at the Tree Trim Academy and in Wales, MI. DTE and IBEW implemented a number of

COVID responsive protocols to ensure the safety of the trainers and trainee's safety remain the priority.

Section 6 – COVID Response (Added for 2020 only)

In March of 2020, DTEE and its contractors adjusted all aspects our daily processes and procedures in light of the emerging COIVD-19 pandemic. With safety being DTEE's first priority, the company suspended all in-person operations, except for those deemed essential. Tree Trimming is considered an essential service by the Department of Homeland Security in order to maintain the integrity of our electrical grid and the safety of communities.

DTEE worked with its contractors to continue trimming while adhering to strict safety measures to keep our customers and workforce safe from COVID-19. These measures included:

- All DTEE Employees and contractors wear masks at all times, and maintain social distance, except for when the task requires people to be closer for safety reasons
- Daily health screenings are completed by all employees and contractors
- If a person tests positive or has known exposure to COVID-19, contact-tracing and quarantining is done in accordance with the CDC guidelines
- Minimize in-person interactions with customers – planners used emails, text and phone calls to communicate with customers and obtain removal permits
- Maintain one person per vehicle policy – exceptions are made for trimmers who live together or do not have a driver's licenses

To support these safety measures in Tree Trimming, DTEE spent $1.3M in 2020. These expenses were mainly for the one person per vehicle policy and PPE for DTEE employees and contractors.

DTE Electric
U-20169
2020 Report Appendix A

Step 1) Calculate ETTP Minutes Saved	
Sum of Average Minutes Interrupted Prior to Circuit Trimmed	425,794,780
Sum of 2020 Minutes Interrupted for ETTP Circuits	152,199,382
ETTP Minutes Saved	*273,595,397*

Step 2) Calculate Minutes Avoided (balance of system degradation)	
Sum of Average Minutes Interrupted for Balance of System (circuits not trimmed each year)	1,793,904,263
Sum of 2020 Minutes Interrupted for Balance of System	1,516,172,438
System Degradation %	15%
Minutes Avoided	*65,921,445*

Step 3) Calculate Total Minute Reduction	
ETTP Minutes Saved	273,595,397
Minutes Avoided	65,921,445
Total Minute Reduction	*207,673,953*

Step 4) Calculate SAIDI Reduction	
ETTP Customers (2015-2019)	805,104
Total Customers	2,204,114
Overall System SAIDI Minute Reduction	*94*
SAIDI Minute Reduction for ETTP Customers Only	*258*

DTE Electric
U-20169
2020 Report Appendix A

2015 ETTP Population	3-year Average Prior to Trimming	2020 Minutes Interrupted (Five Years After Trimming)
ETTP	13,866,826	2,398,943
Balance of System	404,271,637	303,234,488

2016 ETTP Population	3-year Average Prior to Trimming	2020 Minutes Interrupted (Four Years After Trimming)
ETTP	82,268,777	31,125,786
Balance of System	363,607,379	303,234,488

2017 ETTP Population	3-year Average Prior to Trimming	2020 Minutes Interrupted (Three Years After Trimming)
ETTP	49,148,401	17,413,560
Balance of System	288,858,825	303,234,488

2018 ETTP Population	3-year Average Prior to Trimming	2020 Minutes Interrupted (Two Years After Trimming)
ETTP	103,378,673	45,751,670
Balance of System	352,185,951	303,234,488

2019 ETTP Population	3-year Average Prior to Trimming	2020 Minutes Interrupted (One Year After Trimming)
ETTP	177,132,103	55,509,423
Balance of System	384,980,471	303,234,488

DTE Electric Company
One Energy Plaza, 1635 WCB
Detroit, MI 48226-1279



Paula Johnson-Bacon
(313) 235-7052
paula.bacon@dteenergy.com

March 2, 2020

Ms. Lisa Felice
Executive Secretary
Michigan Public Service Commission
7109 West Saginaw Highway
Lansing, Michigan 48917

Re: In the matter of the Application of DTE Electric Company for authority to increase its rates, amend its rate schedules and rules governing the distribution and supply of electric energy, and for miscellaneous accounting authority.
MPSC Case No. U-20162

Dear Ms. Felice:

Pursuant to the Commission's final order in case number U-20162, please find attached DTE Electric Company's March 2, 2020 Tree Trim Annual Report. If you have any questions, please feel free to contact me.

Very truly yours,

Paula Johnson-Bacon

PJB/erb
Encl.

March 2, 2020 Tree Trim Annual Report

In Case U-20162, the Commission directed DTE Electric (DTEE) to file an annual report to detail the progress of the Surge program and Enhanced Tree Trim Program (ETTP) performance. From the U-20162 Order on May 2, 2019:

> Thus, the annual report shall also break out all activity, costs, and miles trimmed under any and all tree trimming programs (including hardening) in the city of Detroit, to provide information on the progress made in the city of Detroit with each program. The reporting shall include measurable data for the efforts, including miles completed by service center, performance of ETTP circuits compared to non-ETTP circuits, the costs of the efforts, number of employees directly involved in the efforts, tree-related outage reductions, SAIDI reductions, and whether the funding for the efforts is a capital expense or O&M cost. Further, the report shall track ETTP circuit performance, comparing average outages for the three years prior to the enhanced trimming with outages in the years after the trimming has been performed. The first report is due in this docket March 1, 2020, and an annual report is due on March 1 of each year thereafter.

Per the Case U-20162 order this report covers the requested information and is split into four sections:

1) Miles Completed to ETTP Standard – Annual ETTP maintenance miles are reported by Service Center over the 2015-2019 time period. City of Detroit miles are broken out separately.
2) O&M and Capital Spend on Tree Trimming Activities – Annual tree trim spend are reported by Service Center over the 2016-2019 time period. City of Detroit spend are broken out separately. Costs from 2015 are not included because the ETTP specification makes up a relatively small portion of the overall tree trim spend in that year.
3) ETTP Circuit Performance – ETTP circuit performance comparing average outage events, customer interruptions, outage minutes, and wire downs before and after ETTP work. The performance will cover ETTP circuits trimmed in 2015 through 2018 with reliability data that ranges from 2012 to 2019. Performance of ETTP circuits trimmed in 2019 will be measured starting in 2020.
4) Tree Trim Workforce – A 2019 summary of the tree trim workforce is broken down by DTEE employee and contractor.

Section 1 – Miles Completed to ETTP Standard

Since the inception of the ETTP standard, the Company has trimmed 15,201 miles. 4,187 ETTP miles where trimmed in 2019 as part of the surge program. Below, **Table 1** breaks out ETTP miles trimmed by distribution and subtransmission, **Table 2** details miles trimmed by service center, **Table 3** shows ETTP miles trimmed in the City of Detroit, and **Table 4** covers miles trimmed as part of the 4.8kV Hardening Program.

Table 1 – ETTP Miles Trimmed by Circuit Type

Circuit Type	2015	2016	2017	2018	2019	Total	% of System
Distribution	257	2,270	2,733	3,128	3,181	11,569	41%
Subtransmission[1]	188	1,030	868	540	1,006	3,632	100%
Total Miles	**445**	**3,300**	**3,601**	**3,668**	**4,187**	**15,201**	**46%[2]**

Table 2 – ETTP Miles Trimmed by Service Center

Service Center	2015	2016	2017	2018	2019	Total
MAR	70	351	419	432	303	1,576
ANN	5	143	566	309	246	1,269
CAN	40	60	62	271	307	740
HWL	192	272	445	262	264	1,437
LAP	13	341	390	423	378	1,546
MTC	23	250	259	115	321	967
NAE	42	693	470	533	557	2,294
NPT	5	159	263	342	254	1,022
PON	6	426	230	237	424	1,323
RFD	24	219	112	381	670	1,406
SBY	8	111	102	207	129	557
WWS	17	275	283	156	334	1,064
Total Miles	**445**	**3,300**	**3,601**	**3,668**	**4,187**	**15,201**

[1] 1093 of these miles are subtransmission that are on their second cycle and show up in the numbers twice. Only unique miles are included in percentage complete calculation.
[2] Numerator only includes unique miles – it does not double count subtransmission on second cycle.

Table 3 – ETTP Miles Trimmed in the City of Detroit by Service Center[3]

Service Center	2015	2016	2017	2018	2019	Total	% of City
CAN	40	42	60	234	293	**668**	
MTC	-	-	6	-	-	**6**	
RFD	5	87	27	251	464	**834**	
Total Detroit Miles[4]	**45**	**129**	**93**	**485**	**757**	**1,509**	**59%**

Table 4 – ETTP Miles Trimmed as Part of the 4.8kV Hardening Program

Service Center	2015	2016	2017	2018	2019	Total
CAN				20	0	**20**
RFD				127	158	**285**
Total 4.8kV Miles				**146**	**158**	**305**

Section 2 – O&M and Capital Spend on Tree Trimming Activities

The Company spent $146,202,293 in O&M for its tree trim program in 2019 as detailed in **Table 5**; years 2016 through 2018 are also included for reference. **Table 5** groups costs into five categories:

1) Line Clearance Maintenance – Comprises costs needed for maintenance activities such as contractor labor and equipment, general foreman cost, per diems, and overtime premiums.
2) Trouble – Spend on non-storm unplanned reactive tree trim work related to outage or non-outage problems on the electric system.
3) Tree Trim Program/Other – Includes customer request work, auditing, software maintenance, the herbicide program, training, safety, and other cost miscellaneous costs associated with Tree Trim.
4) DTE Staff Cost – DTE staff costs related to the tree trim program.
5) Customer Excellence – Spot trimming work to address our worst performing circuits

Table 5 – Annual O&M Tree Trim Spend by Category[5]

O&M Spend	2016	2017	2018	2019
Line Clearance Maintenance	$59,155,543	$69,344,451	$71,757,936	$116,748,952
Trouble	$10,738,172	$11,395,011	$12,966,909	$16,556,969
Tree Trim Program/Other	$2,771,660	$1,812,622	$2,500,756	$10,229,182
DTE Staff Cost	$1,496,789	$1,704,325	$1,883,630	$2,667,190
O&M Total	**$74,162,165**	**$84,256,409**	**$89,109,232**	**$146,202,293**

[3] Program began in 2018 and miles in Table 4 are a subset of miles in Tables 1-3.
[4] The total unique miles complete in the City of Detroit are 1,478. 31 Subtransmission miles are on their second cycle and are counted twice in the Table 3. Only unique miles are included in percentage complete calculation.
[5] Table does not include any spot trimming expenses from other programs because they are not part of the tree trim program costs.

Table 6 further breaks down the "Line Clearance Maintenance" costs in **Table 5** by service center.

Table 6 – Annual Maintenance Tree Trim Spend by Service Center

Service Center	2016	2017	2018	2019
MAR	$3,679,637	$4,450,068	$5,021,951	$2,757,355
ANN	$4,081,462	$12,103,989	$9,489,387	$6,699,698
CAN	$3,312,191	$1,200,014	$8,851,085	$18,827,931
HWL	$4,838,162	$12,561,698	$6,269,100	$6,523,040
LAP	$5,145,835	$5,820,146	$4,385,310	$5,306,986
MTC	$3,868,638	$4,093,991	$1,961,451	$3,770,923
NAE	$3,100,279	$2,242,086	$2,615,529	$3,137,335
NPT	$1,990,418	$4,844,204	$5,288,021	$3,400,257
PON	$12,293,540	$8,619,875	$8,167,988	$24,883,843
RFD	$5,929,162	$3,762,082	$11,025,927	$28,999,125
SBY	$3,351,803	$3,078,400	$4,338,480	$2,656,440
WWS	$7,564,417	$6,567,898	$4,343,707	$9,786,018
Total	**$59,155,543**	**$69,344,451**	**$71,757,936**	**$116,748,952**

Table 7 details the 4.8kV Hardening capital spend in 2018 and 2019.

Table 7 – Annual 4.8kV Hardening Tree Trim Capital Spend by Service Center

Service Center	2018	2019
CAN	$ 2,136,156	-
RFD	$ 7,858,107	$ 10,081,771
Total	**$ 9,994,263**	**$ 10,081,771**

Table 8 highlights the $50,595,101 tree trim spend in the City of Detroit for the year 2019, which includes $10,081,771 of Capital spend. City spend in 2016 through 2018 is included for reference

Table 8 – Annual Detroit O&M and Capital Tree Trim Spend

	2016	2017	2018	2019
Detroit - O&M	$6,217,231	$2,345,651	$14,071,122	$40,513,330
Detroit - Capital	-	-	$9,326,363	$10,081,771
Detroit Total	**$6,217,231**	**$2,345,651**	**$23,397,485**	**$50,595,101**

Section 3 – ETTP Circuit Performance

Methodology Used to Calculate ETTP Performance

The methodology used to calculate ETTP Performance for all distribution circuits uses the average of three years of Pre-trim ETTP tree-outage events and compares it to each year post trimming. All post-trim year results of the same year were then summed to increase the sample size (as an example, all post-trim year 1 results are summed). The difference between the before trimming performance and the post trimming performance was used to create the "% Change in Outage Event Reduction for ETTP circuits". To create a control group for comparison, the same methodology was used for the remainder of circuits not trimmed ETTP, which is identified as "% Change in Outage Event Reduction for Non-ETTP circuits". To account for natural weather variation, the performance of the control group is subtracted from the ETTP circuit performance to provide an accurate representation of the true impact of the ETTP. This is the same methodology outlined in Case U-20561.

Table 9 – Methodology for ETTP Performance Analysis

2012	2103	2014	2015	2016	2017	2018	2019	# of ETTP Circuits
			Three Year Average Pre-ETTP Performace			Year of Trim	Post Trim Year 1	321
			Three Year Average Pre-ETTP Performace			Year of Trim	Post Trim Year 1	Post Trim Year 2	128
		Three Year Average Pre-ETTP Performace			Year of Trim	Post Trim Year 1	Post Trim Year 2	Post Trim Year 3	171
	Three Year Average Pre-ETTP Performace			Year of Trim	Post Trim Year 1	Post Trim Year 2	Post Trim Year 3	Post Trim Year 4	20

Table 10 – Methodology for Control Group Non-ETTP Performance Analysis

2012	2103	2014	2015	2016	2017	2018	2019	# of ETTP Circuits
			Three Year Average Pre-Non ETTP Performace			Year of Trim	Post Trim Year 1	N/A
			Three Year Average Pre-Non ETTP Performace			Year of Trim	Post Trim Year 1	Post Trim Year 2	N/A
		Three Year Average Pre-Non ETTP Performace			Year of Trim	Post Trim Year 1	Post Trim Year 2	Post Trim Year 3	N/A
	Three Year Average Pre-Non ETTP Performace			Year of Trim	Post Trim Year 1	Post Trim Year 2	Post Trim Year 3	Post Trim Year 4	N/A

The control group of circuits and the ETTP group of circuits must be compared to account for non-ETTP related variations. If the Company only looks at the performance of ETTP circuits, it does not account for natural weather variation or general deterioration/improvements on our system. Assume that a group of ETTP circuits were trimmed in 2018 and that 2019 turns out to be a particularly favorable storm year compared to the before trim average (2015-2017). When the ETTP performance is measured, it is possible that the Year 1 improvement is 90%, which looks like an incredible improvement but, when compared against the control group, which may also have seen a significant improvement of 70%, the value of ETTP does not seem as significant. In this example the delta between the control group and ETTP is only 20%. Because the methodology discussed above is capable of accounting for these types of variations, it is a much more accurate way to gauge true ETTP effectiveness.

ETTP Outage Event Performance

The actual difference of outage events on ETTP circuits compared to the balance of the system not trimmed ETTP is 72.5% in post-trim year 1, 90.6% in the second year, 82.5% in the third year, and 115.2% in the fourth year. The actual reduction for Years 1-4 post ETTP trim are depicted in **Table 11**.

Table 11 – ETTP Tree-Related Outage Event Difference Compared to Non ETTP Circuits

	Number of Dist. Circuits ETTP Trimmed	% Change in Outage Event Reduction for ETTP circuits	% Change in Outage Event Reduction for Non-ETTP circuits	**Difference in % Change in Event Reduction ETTP vs Non-ETTP circuits**	U-20162 Surge Model Projected Reduction
1 Year Post Trim	642	-23.0%	49.4%	**-72.4%**	-57.0%
2 Years Post Trim	321	-12.3%	78.3%	**-90.6%**	-57.0%
3 Years Post Trim	193	1.6%	84.1%	**-82.5%**	-50.0%
4 Years Post Trim	20	6.2%	121.4%	**-115.2%**	-37.0%

ETTP Customer Interruptions Performance

Using the same methodology discussed above, the Company has determined that actual customer interruptions on ETTP circuits vs. Non-ETTP circuits show a 65.7% difference in Year 1, 80.4% difference in Year 2, 69.2% difference in Year 3, and 72.8% difference in Year 4. These results are shown in Table 12.

Table 12 – ETTP Tree-Related Customer Interruption Difference Compared to Non ETTP Circuits

	Number of Dist. Circuits ETTP Trimmed	% Change in Customers Interrupted for ETTP circuits	% Change in Customers Interrupted for Non-ETTP circuits	**Difference in % Change in Customers Interrupted ETTP vs. Non-ETTP circuits**	U-20162 Surge Model Projected Reduction
1 Year Post Trim	642	-29.4%	36.3%	**-65.7%**	-57.0%
2 Years Post Trim	321	-21.2%	59.2%	**-80.4%**	-57.0%
3 Years Post Trim	193	-24.3%	44.8%	**-69.2%**	-50.0%
4 Years Post Trim	20	-25.3%	47.4%	**-72.7%**	-37.0%

ETTP Customer Outage Minute Performance

Customer minutes of interruption, shown in **Table 13**, also show significant improvements. Actual minutes of customer interruption on ETTP circuits vs. Non-ETTP circuits show a 44.9% difference in Year 1, 88.3% difference in Year 2, 31.9% difference in Year 3, and 34.7% difference in Year 4. **Table 14** shows the 2019 outage minutes saved and avoided due to ETTP trimming and the impact to overall system SAIDI, a net reduction of 42 SAIDI minutes. If only ETTP circuits are considered, the SAIDI minute reduction is 175 minutes.

Table 13 – ETTP Tree-Related Customer Outage Minutes of Interruption Difference Compared to Non ETTP Circuits

	Number of Dist. Circuits ETTP Trimmed	% Change in Customer Minutes Interrupted for ETTP circuits	% Change in Customer Minutes Interrupted for Non-ETTP circuits	**Difference in % Change in Customer Minutes Interrupted ETTP vs. Non-ETTP circuits**	U-20162 Surge Model Projected Reduction
1 Year Post Trim	642	-27.5%	17.4%	**-44.9%**	-57.0%
2 Years Post Trim	321	-37.6%	50.7%	**-88.3%**	-57.0%
3 Years Post Trim	193	-49.1%	-17.2%	**-31.9%**	-50.0%
4 Years Post Trim	20	-46.4%	-11.7%	**-34.7%**	-37.0%

Table 14 – 2019 ETTP Outage Minute Reduction and SAIDI Impact

	ETTP Outage Minutes
3 Years Before Trim Avg. Outage Minutes	248,662,677
2019 Outage Minutes	156,905,685
Minutes Saved	91,756,993
Minutes Avoided – Non ETTP System Deterioration	1,561,556
Total Minute Reduction	93,318,548
ETTP Overall System SAIDI Minute Reduction	**42**
SAIDI Minute Reduction for ETTP Circuits ONLY	**175**

ETTP Wire-Down Performance

Using the same methodology discussed above, the Company has determined that actual wire-down events for ETTP circuits vs. Non-ETTP circuits show a 24.9% difference in Year 1, 39.6% difference in Year 2, 38.9% difference in Year 3, and 62.2% difference in Year 4. These results are shown in **Table 15**.

Table 15 – Post-ETTP Wire-Down Difference Compared to Non-ETTP Circuits

	Number of Dist. Circuits ETTP Trimmed	% Change Wire-Down Events for ETTP circuits	% Change for Wire-Down Events for Non-ETTP circuits	**Difference in % Change in Wire-Down Events ETTP vs. Non-ETTP circuits**
1 Year After Trimming	642	-8.8%	16.0%	**-24.8%**
2 Years After Trimming	321	-8.9%	30.7%	**-39.6%**
3 Years After Trimming	193	-13.9%	24.9%	**-38.8%**
4 Years After Trimming	20	-33.1%	29.0%	**-62.1%**

Section 4 – Tree Trim Workforce

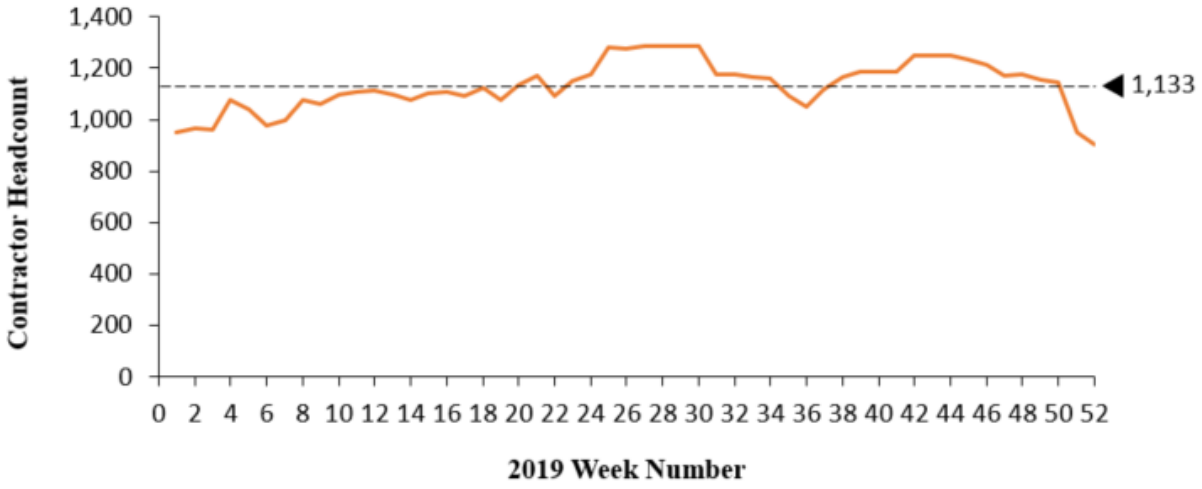
The internal employees directly involved in Tree Trimming are detailed in **Table 16**. In 2019, the average number for contractors on property were 1,133. Contractor headcount fluctuation over the course of 2019 is seen in **Chart 1**.

Table 16 – 2019 DTE and Contractor Tree Trim Headcount

Facilitator - Arborists	14
Supervision	6
Regional Foresters	5
Strategy and Planning	6
Internal Employees involved with ETTP	**31**

2019 Average # of Contractors	**1,133**

Chart 1 – 2019 Contract Tree Trim Headcount by Week



The 2019 average local journeymen trimmers were 601, and the number of local apprentices were 293. Outsourced journeymen trimmers averaged 239 for 2019. The Company is participating in three programs in an effort to increase the number of local trimmers. The three programs are the Parnall Correctional Facility Training Program, the City of Detroit Tree Trim Academy, and the IBEW Local 17 Traditional Boot Camp. Below is an update on each of the programs:

1) Parnall – The Parnall Tree Trimming program is designed to provide returning citizens the skills needed to start as an apprentice tree trimmer. DTE has partnered with the Michigan Department of Corrections to provide qualified instructors and the required training facilities. There have been four graduates released as of February 2020, since the program begun in June of 2019. All four graduates have been placed with employers. We expect two to three graduates per month through 2020.
2) Tree Trim Academy – The Company is working to set up a training facility in the City of Detroit. DTEE has worked with the City of Detroit and has acquired a property for the Tree Trimming Academy. Currently training facilities are being set up and the training curriculum is being developed. The Company has partnered with Focus: HOPE to identify and recruit local candidates for the training. If everything remains on schedule, classes are expected to begin in June of 2020.
3) Traditional Boot Camp – IBEW continues to hold regular scheduled boot camp training for apprentices. Current camps are conducted at their training facility in Wales, MI. Once the Tree Trim Academy is operational, boot camps will be conducted both at the Tree Trim Academy and in Wales, MI.

EXHIBIT MEC-71 IS AN EXCEL FILE

You can find MEC-71 at the below link:

MEC-71. WP AJK U-21534 GPM.xlsx

(link expires October 13th)

EXHIBIT MEC-72 IS AN EXCEL FILE

You can find MEC-72 at the below link:

MEC-72. WP AJK U-21534 Reliability Model.xlsb

(link expires October 13th)

MPSC Case No: U-21534

Requester: MNSC

Question No.: MNSCDE-19.28

Respondent: M. Elliott Andahazy

Page: 1 of 1

Question: Refer to the rebuttal testimony of Witness Elliott Andahazy, Q&A 56. Identify the annual number of outages and customer minutes interrupted caused by aged URD cable, URD cable malfunction, imminent failure of a URD cable, or otherwise associated with aged URD cable and the age of the URD cable that caused the outage for each year 2019 through 2023.

Answer: The Company has not performed the requested analyses. The URD interruption related information the Company has available is as follows:

Year	Customers Interrupted	Minutes Interrupted	Avg. Age of URD Cable
2019	23,024	5,814,107	36
2020	29,758	6,298,638	37
2021	34,765	9,393,896	37
2022	30,837	7,759,427	38
2023	34,640	14,024,332	38

Attachment: *N/A*

MPSC Case No: U-21534

Requester: MNSC

Question No.: MNSCDE-19.29

Respondent: M. Elliott Andahazy

Page: 1 of 1

Question: Refer to the rebuttal testimony of Witness Elliott Andahazy, Q&A 12, and her referenced direct testimony at page 26, Figure 5. Does DTE track whether wire downs are DPLD arc wire or 4.8kV circuit wire? If so, please provide the breakdown of each, for before and after, for both the Hardened and Control Group Circuits included in the analysis supporting Figure 5.

Answer: No. The Company tracks wire down events but not does capture data differentiating between DTEE wire downs or DPLD arc wire downs.

Attachment: *N/A*

MPSC Case No: U-21534

Requester: MNSC

Question No.: MNSCDE-19.30

Respondent: M. Elliott Andahazy

Page: 1 of 1

Question: Refer to the rebuttal testimony of Witness Elliott Andahazy, Q&As 19 and 20. Does DTE track wire downs on 4.8kV circuits collocated with DPLD arc wire, and on 4.8kV circuits without DPLD are wire? If so, please provide the breakdown of each with and without DPLD, for before and after, for the Hardened and Control Group Circuits included in the analysis supporting Figure 5 on page 25 of Witness Elliot Andahazy's direct testimony.

Answer: The Company tracks wire down events on all its circuits regardless of circuit voltage or the presence of DPLD arc wire. The Company has not performed the requested analysis.

Attachment: *N/A*

MPSC Case No: U-21534

Requester: MNSC

Question No.: MNSCDE-19.33

Respondent: M. Elliott Andahazy

Page: 1 of 1

Question: Refer to the rebuttal testimony of Witness Elliott Andahazy, Q&A 20. If DTE implemented DPLD arc wire removal only, those circuits would remain eligible for pole and pole top inspections and tree trimming according to the Company's program schedules, correct? In other words, if DTE removed DPLD arc wire on a circuit in 2025, would that work modify the pole and pole top inspection cycle or the vegetation clearing (tree trimming) cycle for that circuit? Please explain.

Answer: DPLD arc wire removal only would not modify the PTMM or Tree Trim schedules.

Attachment: *N/A*

MPSC Case No: U-21534

Requester: MNSC

Question No.: MNSCDE-19.34

Respondent: M. Elliott Andahazy

Page: 1 of 1

Question: Refer to the rebuttal testimony of Witness Elliott Andahazy, Q&A 19, and Table 4. Refer also to Exhibit A-23 Schedule M12. Has DTE evaluated the cost per mile and wire down, SAIFI, and SAIDI reductions, of combining Tree Trimming and Arc Wire Removal? If so, please provide the analysis.

Answer: Table 4 assumes that the Company trims trees and inspects poles and pole-top equipment only at locations where DPLD arc wire is collocated with DTEE equipment. The Company has not performed other analyses with regards to DPLD arc wire removal.

Attachment: *N/A*

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of DTE Electric Company for authority to increase its rates, amend its rate schedules and rules governing the distribution and supply of electric energy, and for miscellaneous accounting authority.
_____/

Case No. U-20162

Volume No. 4

PUBLIC RECORD

CROSS-EXAMINATION

Proceedings held in the above-entitled matter before Sally L. Wallace, J.D., Administrative Law Judge with MAHS, at the Michigan Public Service Commission, 7109 West Saginaw Highway, Lake Michigan Room, Lansing, Michigan, on Thursday, December 13, 2018, at 9:01 a.m.

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- - -

REPORTED BY: Marie T. Schroeder, CSR-2183
Lori Anne Penn, CSR-1315

I N D E X

WITNESS: PAGE

IRENE M. DIMITRY

Cross-Examination (Continuing) by Mr. Bzdok 431

MATTHEW T. PAUL

Direct Examination by Mr. Christinidis 506
Cross-Examination by Mr. King 609
Cross-Examination by Mr. Fisk 617
Cross-Examination by Mr. Keskey 667

MARCO A. BRUZZANO

Direct Examination by Ms. Donofrio 685
Cross-Examination by Mr. King 901

redirect for Mr. Paul?

MR. CHRISTINIDIS: No redirect, your Honor.

JUDGE WALLACE: Thank you very much, Mr. Paul. You are excused.

THE WITNESS: Thank you, your Honor.

(The witness was excused.)

- - -

(A pause was had in the proceedings.)

JUDGE WALLACE: We are going to end today at 5:00 o'clock; if that's mid question, it's fine, we're ending at 5:00 today. And then tomorrow we're throwing everybody into a hat, everybody's remaining name, and then we're going to pick like six names, and those people are waived, because we got to figure this out, people, we are not making progress here, not like we have to. Santa Claus is putting you all on the naughty list.

So Ms. Donofrio, why don't you go.

(Documents marked for identification by the Court Reporter as Exhibit Nos. A-23 and A-31.)

- - -

M A R C O A. B R U Z Z A N O

was called as a witness on behalf of DTE Electric Company and, having been duly sworn to testify the truth, was examined and testified as follows:

DIRECT EXAMINATION

BY MS. DONOFRIO:

Q Please state your name and business address for the record.

A My name is Marco A. Bruzzano, and my address is One Energy Plaza, Detroit, Michigan 48226.

Q Can you move the microphone a little bit closer to you.

A Can you hear me O.K.?

JUDGE WALLACE: You have to push the --

THE WITNESS: I think it's on now.

Q (By Ms. Donofrio): There you go. O.K. Mr. Bruzzano, did you file with the Commission a document entitled the Qualifications and Direct Testimony of Marco A. Bruzzano, consisting of a cover sheet and 122 pages of questions and answers?

A I did.

Q Do you have any changes you wish to make to your direct testimony?

A I do.

Q Could you take us through those changes, please?

A On page 29, about line 5, there's a Table 10, Customer Savings due to Avoided Outages, and the first column under Customer Type, all three rows read "Non-Summer", the words "Non-Summer" should be taken out.

Q In each of the three rows?

A In each of the three rows, that's correct.
Q Are there any further changes to your direct testimony?
A One additional change. It's on page 39, right below line 1 there's a Table 12, 4.8 kV System Alternatives, sixth row down, which reads Includes PLD and Arc Wire Removal, if you move over three columns below the column called Secondary Program, the word "No" should be taken out and the word "Yes" should be put in its place.
Q With those changes made, is that, then, the direct testimony that you're adopting today?
A It is.
Q Are you sponsoring any exhibits associated with your direct testimony in the case?
A I am.
Q For purposes of identification, are these nine exhibits, direct exhibits designated as Exhibit A-12 Schedule B5.4, consisting of 10 pages; Exhibit A-13 Schedule C5.6, consisting of 3 pages; Exhibit A-23 Schedule M1, consisting of 16 pages; Exhibit A-23 Schedule M2, consisting of 32 pages; Exhibit A-23 Schedule M3, consisting of 29 pages; Exhibit A-23 Schedule M4, which though it is a 28-page exhibit, you are only sponsoring pages 1 through 10; Exhibit A-23 Schedule M5, consisting of 231 pages; and Exhibit A-30 Schedule T-2, consisting of seven pages; and Exhibit A-30 Schedule T2.1,

consisting of 103 pages?
A That is correct.
Q Were these exhibits prepared by you or at your direction?
A They were.
Q Do you have any changes to make to any of these nine direct exhibits?
A I do not.
Q Did you also file with the Commission a document entitled the Rebuttal Testimony of Marco A. Bruzzano, consisting of a cover sheet and 86 pages of questions and answers?
A Yes.
Q Do you have any changes you wish to make to your rebuttal testimony?
A I do.
Q Could you take me through those changes, please?
A Yes. They are both on page 30. On line 10, towards the end of the sentence where it currently reads "and will in a significant", the word "result" should be inserted so that it will read "and will result in a significant".

The next change on that same page, on line 17, the first three words, between the words "reasonable" and "prudent", there are two letters, "un", the "un" should be stricken and the word "and" should be added.

Q With those changes made, is that, then, the rebuttal

testimony that you're adopting today?
A Yes, it is.
Q Are you sponsoring any exhibits associated with your rebuttal testimony in this case?
A I am.
Q For purposes of identification, are these 11 rebuttal exhibits designated as Exhibit A-31 Scheduled U1, consisting of 14 pages; Exhibit A-31 Schedule U2, consisting of one page; and Exhibit A-31 Schedule U3, consisting of 432 pages; Exhibit A-31 Schedule U4, consisting of one page; Exhibit A-31 Schedule U5, consisting of 9 pages; Exhibit A-31 Schedule U6, consisting of 40 pages; Exhibit A-31 Schedule U7, consisting of 3 pages; Exhibit A-31 Schedule U8, consisting of 6 pages; Exhibit A-31 Schedule U9, consisting of 2 pages; Exhibit A-31 Schedule U10, consisting of 51 pages; and Exhibit A-31 Schedule U11, consisting 67 pages?
A Yes, that is correct.
Q Were these rebuttal exhibits prepared by you or at your direction?
A Schedules U2, U3, U7, U8, U9, and U11 were prepared under my direction; others are previously admitted exhibits from cases included in their titles or my responses to discovery or audit requests or are responses by the Staff

to the Company's discovery requests.

Q Do you have any changes to make to these 11 rebuttal exhibits?

A I do not.

MS. DONOFRIO: DTE electric moves to bind into the record the Qualification, Direct Testimony, and Rebuttal Testimony of Marco A. Bruzzano, and for the admission at the end of cross-examination of direct Exhibits A-12 Schedule B5.4; Exhibit A-13 Schedule 5 -- C5.6; Exhibit A-23 Schedules M1, M2, M3, M4, and M5; Exhibit A-30 Schedules T2 and T2.1; rebuttal Exhibit A-31 Schedules U1, U2, U3, U4, U5, U6, U7, U8, U9, U10, and U11, and tenders Mr. Bruzzano for cross-examination.

JUDGE WALLACE: Thank you. Is there any objection to binding in the revised direct testimony and revised rebuttal testimony of Mr. Bruzzano? (No response).

And as I noted earlier, can we, unless some of these exhibits are complete, can we wait until the end to make sure we admit all the exhibits since we can't really admit them piecemeal, we admit them as a whole exhibit? We're trying to keep track of that.

MS. DONOFRIO: That's fine.

JUDGE WALLACE: O.K. So hearing no objection, the revised direct testimony and revised

rebuttal testimony of Mr. Bruzzano are bound into the record.

(Testimony bound in.)

- - -

691

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of	)	
DTE ELECTRIC COMPANY	)	
for authority to increase its rates, amend	)	Case No. U-20162
its rate schedules and rules governing the	)	
distribution and supply of electric energy, and	)	
for miscellaneous accounting authority.	)	

QUALIFICATIONS

AND

REVISED DIRECT TESTIMONY

OF

MARCO A. BRUZZANO

DTE ELECTRIC COMPANY
QUALIFICATIONS OF MARCO A. BRUZZANO

Line No.

Q. What is your name, business address and by whom are you employed?

A. My name is Marco Bruzzano. My business address is: One Energy Plaza, Detroit, Michigan 48226. I am employed by DTE Energy Corporate Services, LLC, a subsidiary of DTE Energy.

Q. On whose behalf are you testifying?

A. I am testifying on behalf of DTE Electric Company (DTE Electric or Company).

Q. Please state your educational background.

A. I earned a bachelor of science degree, with honors, and a master's degree in Mechanical Engineering from the Georgia Institute of Technology. During my master's program, I received a full fellowship, working as a research assistant on a project sponsored by the Electric Power Research Institute (EPRI). I also earned an MBA, with distinction, from Duke University.

Q. Please describe your work experience.

A. Immediately prior to joining the Company, I was a principal with Booz Allen Hamilton's Energy & Utilities practice. I also worked as an engagement manager with McKinsey & Company, primarily in the Electric Power & Natural Gas and Petroleum practices. During my consulting career, I led projects for utilities, major international oil companies, and independent power producers on a broad range of strategic, operational, and organizational engagements. I was directly involved in or led the development of multiple capital investment strategies. During my tenure at McKinsey, I was also a leader of firm's Capital Productivity initiative.

Line No.

Prior to consulting, I worked for Chevron USA's refining division, where I was a design engineer in the Richmond, CA refinery. In that role, I managed multiple capital upgrade and maintenance projects. I also worked as a planning analyst, with responsibility for evaluating major capital investments and coordinating the refinery's capital budget.

I joined DTE Electric in 2008 as a director in the Corporate Strategy group. In this role, I led the Company's operational benchmarking program, managed the development of long-term commodity price forecasts, and led a number of strategic projects. In 2013, I was appointed vice president, Corporate Strategy, and assumed overall responsibility for supporting DTE Energy's business units on priority strategic initiatives, including the development of an updated investment strategy for electric distribution. In 2016, I was appointed to my current position, vice president, Distribution Operations, where I built on the work I had led in Corporate Strategy to develop the Distribution Operations Five-Year Investment and Maintenance Plan.

Q. Please describe your current position and duties.

A. My current responsibilities include two primary focus areas: 1) Electrical Engineering & Planning; and 2) Scheduling & Coordination. These organizations are briefly described below:

Electrical Engineering & Planning (EE&P): This organization is responsible for determining the health of the Company's electric distribution assets and developing programs to maintain and improve their safe, reliable, and cost-effective operation. EE&P is also responsible for defining technical standards for the equipment to be

Line No.

utilized on the distribution network and for developing projects needed for customer connections, relocations, increasing loads, infrastructure improvements, and technology improvements.

Scheduling & Coordination (S&C): This organization schedules and dispatches planned work, facilitates and oversees contractor field resources, manages capital projects and programs, and performs contract management.

Line No.

economically advantageous for customers. The 4.8kV Hardening Program supports the deferral of conversion projects by improving the condition of the system and reducing costs.

Pole and Pole Top Hardware (Pole Top Maintenance)

Q. What is included in the Pole and Pole Top Hardware program?

A. Poles and pole top hardware are exposed to harsh conditions (e.g., ice, extreme heat, wind), causing them to degrade and weaken over time. High cost and long duration customer outages can result when this equipment fails unexpectedly. This program proactively identifies and replaces damaged equipment before unexpected failures occur.

Q. How does the Company determine what poles and pole top hardware need to be replaced?

A. Annually, patrols are performed on a portion of the system to test and inspect poles and pole top hardware. The Company inspects poles on a 10-12 year cycle. Results from these patrols have typically shown that approximately five to seven percent of the total poles inspected have reduced strength and need to be remediated. These poles are either replaced or reinforced based on specific criteria. During the patrols, pole top hardware that has failed is also identified. Examples include cracked or broken insulators, which can lead to pole fires; broken guy wires, which can lead to excessive leaning and potentially to broken poles; and obsolete equipment that is prone to failures (such as cutouts and arrestors with known defects).

Line No.

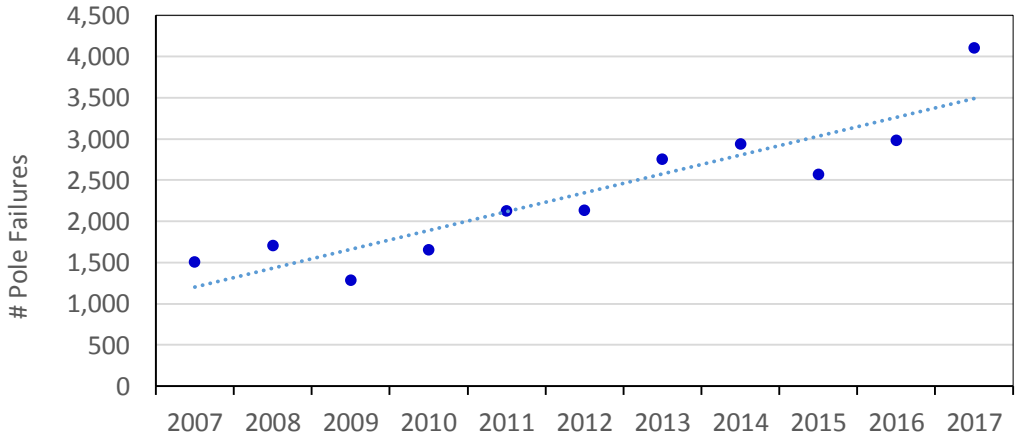
Q. Does the Company replace failed equipment with identical equipment for the pole and pole top hardware program?

A. No. When the Company replaces these items, it uses equipment that complies with current standards. For example, the minimum pole class for poles with primary voltage wire (4.8kV and 13.2kV) is stronger than previous standards. Also, DTE Electric replaces wood crossarms with fiberglass crossarms, porcelain cutouts with polymer cutouts, and porcelain insulators with polymer clamp-top insulators. Fiberglass crossarms have five times the mechanical strength of their wood counterparts, and polymer equipment has six times the mechanical strength of its porcelain counterparts.

Q. What trends is the Company experiencing with poles and pole top hardware?

A. In recent years, the number of poles that are failing in service has increased, which is consistent with the increasing age of the system and the ongoing damage from tree interference. The increasing trend in pole failures is shown in Figure 6.

Figure 6: In Service Pole Failures from 2007 to 2017



Q. What is the Company doing to address the trend in pole failures?

A. The Company is increasing the annual Pole and Pole Top Hardware program by

Line No.

approximately $20 million to respond to this trend and prevent costly and unexpected outages for its customers.

Q. Can the Company breakdown the increase in funding and the benefits customers can expect?

A. Yes. Table 14 describes the increased scope, funding, and benefits of the program compared to the 2017 level.

Table 14: Pole and Pole Top Hardware Increased Scope

Scope Increase Category	Additional Funding Required (2017 to Test Year)	Driving Force	Benefits
Inspections	$4.7 million	Increase the inspection scope and rate of pole inspections to prevent emergent failures: 2017: 63,000 through PTM and 39,000 through Joint Use visual inspection process Test Year: 110,000 through an enhanced PTM inspection program (per industry best practices) and a similar amount as in the past through Joint Use visual inspection process	Increased inspections will reduce the risk of pole and equipment failures, improving reliability and reducing reactive maintenance costs by allowing work to be performed on a planned basis.
Pole Top Hardware	$2.2 million	Increase the components of pole top hardware inspected and repaired to prevent emergent failures: 2017: 16 components Test Year: 48 components	It is more efficient and safer to perform work on a planned basis and outages can be avoided with proactive work.
Reinforce and Replace Poles Identified through Inspections	$13.3 million	Enhanced and increased inspections per industry best practices will identify additional volume of work: 2017: Poles addressed 2,700 Test Year: Poles addressed 10,600	Addressing poles in a proactive and planned way will reduce the time customers spend without power, reduce reactive costs, and enhance safety.
Total	$20.2 million 2017: $19.2 million + $20.2 million Test Year: $39.4 million		

EXHIBIT MEC-76

RESERVED

MPSC Case No: U-21534

Requester: MNSC

Question No.: MNSCDE-19.2a.

Respondent: S. Deol

Page: 1 of 2

Question: Refer to Deol rebuttal Testimony, Q&A10 and discovery response U-21297 MNSCDE- 3.3ai-01.

Provide a current list of circuits the proposes to convert from a lower voltage to 13.2kV during the projected test year and the IRM plan years.

Answer: The Company objects to this request because it is vague. It is unclear how the cited discovery response from U-21297 is related to Q&A 10 of Witness Deol's rebuttal and how it otherwise relates to the list of circuits requested. Without waiving these objections, but subject to them, the Company responds as follows:

Please see below for the list of whole circuits to be converted during the projected test year and the IRM plan years.

DUDLY0141
ARGO 0334
WALKR0075
WALKR0248
PULFD0416
PULFD0419
PULFD0694
PULFD2175
PULFD2224
PULFD2111
PULFD2155
PULFD0103
PULFD0237
GLEND1974
KENT0046
KENT1235
KENT1023
KENT1334
KENT0563
KENT0565
HOWRD1247
HOWRD1248

Co-Respondent: Legal

MPSC Case No: U-21534

Requester: MNSC

Question No.: MNSCDE-19.2a.

Respondent: S. Deol

Page: 2 of 2

HOWRD1122
PINGV0325
PINGV0322
PINGV0328
PINGV2650
PTHOP0301
PTHOP0302
RICHM2415
RICHM2496

Please also see discovery response MNSCDE-15.28a regarding the 2026 and 2027 proposed IRM extension.

Attachment: None.

Co-Respondent: Legal

MPSC Case No: U-21534

Requester: MNSC

Question No.: MNSCDE-19.2b.

Respondent: S. Deol

Page: 1 of 1

Question: Refer to Deol rebuttal Testimony, Q&A10 and discovery response U-21297 MNSCDE- 3.3ai-01.

For each circuit listed in response to sub-part a, identify which of the circuits the company has determined will be overloaded in the next 10 years.

Answer: The Company objects to this request because it is vague. It is unclear how the cited discovery response from U-21297 is related to Q&A 10 of Witness Deol's rebuttal and how it otherwise relates to the list of circuits requested. Without waiving these objections, but subject to them, the Company responds as follows:

Please see discovery response MNSCDE-17.5a for 2025 circuit load projections and ratings. Currently KENT 1334 and HOWRD 1247 are over day to day rating. Additionally, GLEND1974, PINGV0328, RICHM2415, and RICHM2496 are over DDO.

All the circuits listed in MNSCDE-19.2a are planned to be converted in 2025. Assuming conversions are completed as planned, these circuits will go to 0 MVA loading and thus no other circuits are projected to be overloaded.

Attachment: None.

Co-respondent: Legal

MPSC Case No: U-21534

Requester: MNSC

Question No.: MNSCDE-19.2c.

Respondent: S. Deol

Page: 1 of 1

Question: Refer to Deol rebuttal Testimony, Q&A10 and discovery response U-21297 MNSCDE- 3.3ai-01.

For each circuit listed in sub-part b, provide the capacity and forecasted loading, as shown in U-21297 MNSCDE-3.3ai-01, for the next 10 years.

Answer: The Company objects to this request because it is vague. It is unclear how the cited discovery response from U-21297 is related to Q&A 10 of Witness Deol's rebuttal and how it otherwise relates to the list of circuits requested. Without waiving these objections, but subject to them, the Company responds as follows:

Please see discovery response MNSCDE-19.2b.

Attachment: None.

Co-respondent: Legal

MPSC Case No: U-21534

Requester: MNSC

Question No.: MNSCDE-19.2d.

Respondent: S. Deol

Page: 1 of 1

Question: Refer to Deol rebuttal Testimony, Q&A10 and discovery response U-21297 MNSCDE- 3.3ai-01.

For each circuit listed in sub-part a, identify the system performance issues, other than “outages” (as shown in U-21297 MNSCDE-2.3-01) that the circuit experienced in each of the past 7 years.

Answer: The Company objects to this request because it is vague. It is unclear how the cited discovery response from U-21297 is related to Q&A 10 of Witness Deol’s rebuttal and how it otherwise relates to the list of circuits referenced. In addition, it is unclear what is meant by “system performance issues”.

Attachment: None.

Co-respondent: Legal

MPSC Case No: U-21534

Requester: MNSC

Question No.: MNSCDE-19.2e.

Respondent: S. Deol

Page: 1 of 1

Question: Refer to Deol rebuttal Testimony, Q&A10 and discovery response U-21297 MNSCDE- 3.3ai-01.

For each of the circuits listed in response to sub-part d, provide a list customer complaints the company received associated with system performance for each of the past 5 years.

Answer: Please see discovery response MNSCDE-19.2d.

Attachment: None.

MPSC Case No: U-21534

Requester: MNSC

Question No.: MNSCDE-19.2f.

Respondent: S. Deol

Page: 1 of 1

Question: Refer to Deol rebuttal Testimony, Q&A10 and discovery response U-21297 MNSCDE- 3.3ai-01.

For each of the circuits listed in response to subpart d, provide a list of the OSHA reportable incidents that have occurred associated with the 4.8kv delta system in each of the past 7 years.

Answer: The Company objects to this request because it is vague. It is unclear how the cited discovery response from U-21297 is related to Q&A 10 of Witness Deol's rebuttal and how it otherwise relates to the list of circuits referenced. DTE Electric also objects for the reasons that the request is over broad, unduly burdensome and the information requested is not relevant, nor is it reasonably calculated to lead to the discovery of relevant evidence. The Company also objects as a portion of the information requested may consist of confidential and privileged attorney-client information prepared in anticipation of litigation, or attorney work product. Without waiving these objections, but subject to them, the Company responds as follows:

The Company does not have data in the format requested. In addition, the number of events is not relevant because they include, for example, injury resulting from automobiles or structures making contact with poles and/or lines, and other incidents that do not bear on the relative safety of the system, or whether fault was found to lay with the Company.

The Company records injury incident data in the format required by the Michigan Occupational Safety and Health Administration, specifically Part 11 Recording and Reporting of Occupational Injuries and Illnesses.

Attachment: None.

Co-respondent: Legal

MPSC Case No: U-21534

Requester: MNSC

Question No.: MNSCDE-17.1

Respondent: S. Deol

Page: 1 of 1

Question: 1. Refer to Deol rebuttal, Q&A13 and Deol direct, p. 14. Produce the source of the 90% reliability improvement estimate for the conversions included in the instant case, including any workpapers in electronic Excel format with formulas intact and any documents relied on for inputs.

Answer: Please see discovery response MNSCDE-13.11.

Attachment: None.

MPSC Case No: U-21534

Requester: MNSC

Question No.: MNSCDE-13.11

Respondent: S. Deol

Page: 1 of 1

Question: 11. Refer to Deol p. SSD-14. Witness Deol states that through 4.8kv conversions, the company expects to see a reduction of up to 90% in customer minutes of interruption, wire down, and trouble events. Please provide the source analysis of this estimate, including native format workpapers.

Answer: The 90% is an estimate based on full rebuild of most components on circuit, eliminating equipment challenges that cause outages. The estimate is consistent with results that do partial equipment rebuilds. As an example, as detailed in Company witness Elliott Andahazy's testimony on page MEA-24 in Figure 3, the 4.8kV hardening program has demonstrated a 65% reduction in customer minutes of interruption (CMI) excluding MED's. The scope of the Hardening program is limited to replacing failed poles, replacing pole top hardware as needed, and trimming trees as needed. Conversion program work includes all the work associated with Hardening but also involves replacing most aged existing poles with new larger and stronger poles and replacing smaller aged wires with new larger higher strength wire. In addition to the reliability impact of replacing aged equipment with new equipment, in many cases the replacement equipment is an enhanced standard, not a like for like replacement. The rebuilt Conversion program circuits adhere to National Electrical Safety Code (NESC) Grade B construction, which results in hardened circuits with larger loading safety factors to better withstand higher wind conditions as compared to the current aged 4.8 kV Grade C construction.

In addition to replacement of equipment, the updated circuit design includes the installation of modern protection and automation devices, the net percentage reduction in customer minutes of interruptions is expected to reach up to 90%. For these same reasons, the number of wire downs and trouble events are also expected to show similar significant benefits. As the Company completes additional circuit conversions and develops a larger sample size, it will directly calculate the benefits of the Conversion program.

Attachment: *None*

Co-respondent: J. Kryscynski; M. Elliott Andahazy

MPSC Case No: U-21534

Requester: MNSC

Question No.: MNSCDE-17.2

Respondent: S. Deol

Page: 1 of 1

Question: 2. Refer to Deol rebuttal, Q&A13 and Table 1. Produce the source of the figures in the table for all-weather SAIDI average 2018-2022, including any workpapers in electronic Excel format with formulas intact and any documents relied on for inputs.

Answer: Please see the attachment labelled “U-21534 MNSCDE-17.2 2018-2022 All-Weather SAIDI.”

Attachment: U-21534 MNSCDE-17.2 2018-2022 All-Weather SAIDI

	A	B	C	D	E	F	G	H	I	J	K	L
2	**DTE Electric Company**									Requestor:	MNSC	
3	**2018 - 2022 All-Weather SAIDI Data**									Question No.:	MNSCDE-17.2	
4	**Summarized in Deol Rebuttal Testimony**									Respondent:	S. Deol	
5	**Table 1**											
6												
7												
8			All-Weather Outage minutes		All-Weather SAIDI minutes				Average			
9		Year	4.8KV	13.2KV	4.8KV	13.2KV		Circuit Voltage	4.8KV	13.2KV		
10		2018	590,365,522	452,090,168	646	356		SAIDI Minutes	623.2	514.8		
11		2019	469,240,702	544,745,911	508	426						
12		2020	343,558,493	428,687,114	372	337						
13		2021	854,949,791	1,202,750,118	936	922						
14		2022	601,418,170	700,522,182	654	533						
15												
16												

MPSC Case No: U-21534

Requester: MNSC

Question No.: MNSCDE-17.4

Respondent: S. Deol

Page: 1 of 1

Question: 4. Refer to Deol rebuttal, Q&A15: Produce any estimates or other information you have regarding the relative safety risk of 4.8kV circuits compared to 13.2kV circuits.

Answer: Please see the discovery response MNSCDE-15.34e.

Attachment: None.

MPSC Case No: U-21534

Requester: MNSC

Question No.: MNSCDE-15.34e

Respondent: S. Deol

Page: 1 of 1

Question: 34. Refer to the Company's response to MNSCDE-8.13a, which states "The 4.8kV Conversion and 4.8kV Hardening Programs are tracked separately and there is no overlap between the programs. The Company does not perform 4.8kV Hardening on circuits identified as likely to be converted in the near-term."

e. Provide all analyses that DTE has completed, including workpapers, calculations, data employed, and identifying the sources of the data employed, indicating that hardening 4.8kV circuits in advance of conversion to 13.2kV delivers benefits to customers in excess of costs to customers. If the Company has not completed.

Answer: The Company has not performed the analysis requested but has assessed alternatives to 4.8kV Hardening and presented this analysis in the March 22, 2023 Technical Conference (please see attached file for the presentation which includes the historical context of why the 4.8kV Hardening Program was created and assesses alternatives).

The 4.8kV Hardening and 4.8kV Conversion programs were created for different purposes and are not direct replacements for each other.

The Company was ordered on December 7, 2017 (Order in Case No. U-18484) to work with the Detroit Public Lighting Department (DPLD) to remove unused DPLD arc and distribution wire. The 4.8kV Hardening Program was created in 2018 in response as a way to remove DPLD arc and distribution wire while also providing reliability benefits and is currently anticipated to conclude in 2026.

The 4.8kV Conversion Program is a long-term program designed to convert the Company's 4.8kV electrical system to a higher capacity 13.2kV electrical system.

Attachment: U-21534 MNSCDE-15.34e-01 4.8kV Hardening Technical Conference

Co-Respondent(s): M. Elliott Andahazy

Technical Conference

March 22, 2023

Today's Agenda

- **Conference kickoff (15 min)**
- Context and background
  - Overview of DTE's 4.8kV distribution system (45 min)
  - 4.8/13.2kV distribution systems and the integration of EVs and DERs (15 min)
  - The Detroit 4.8kV System and PLD arc wire (15 min with Hardening)
- 4.8kV Hardening Program (45 min)
- 4.8kV Hardening program and alternative solutions (1 hr)
- Open table discussion/conference feedback (30 min)

Conference Kickoff

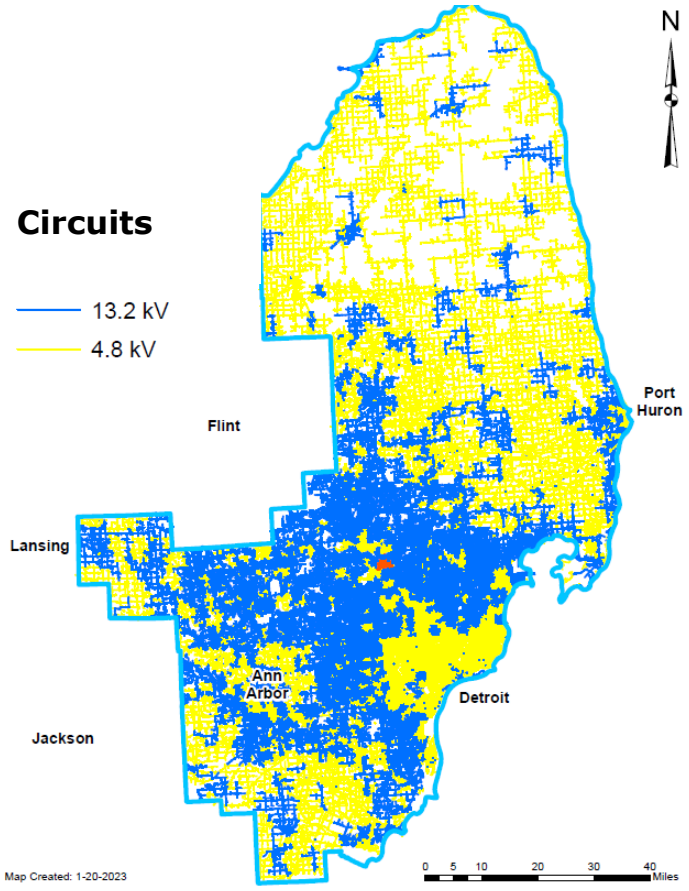
- DTE kickoff and welcome

Today's Agenda

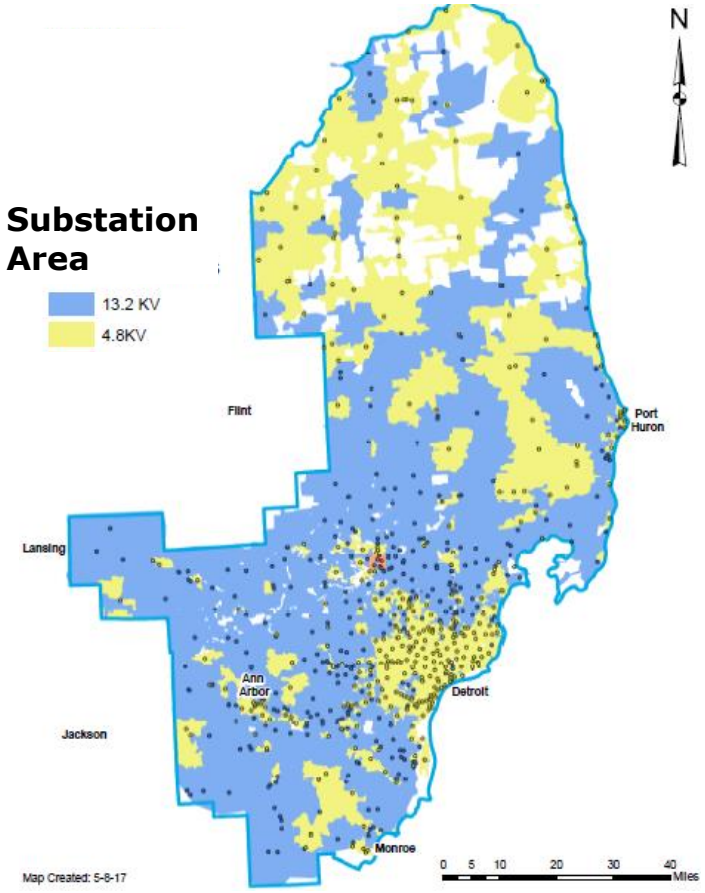
- Conference kickoff (15 min)
- **Context and background**
  - **Overview of DTE's 4.8kV distribution system (45 min)**
  - 4.8/13.2kV distribution systems and the integration of EVs and DERs (15 min)
  - The Detroit 4.8kV System and PLD arc wire (15 min with Hardening)
- 4.8kV Hardening Program (45 min)
- 4.8kV Hardening program and alternative solutions (1 hr)
- Open table discussion/conference feedback (30 min)

DTE's distribution system consists primarily of two voltages – 13.2kV and 4.8kV

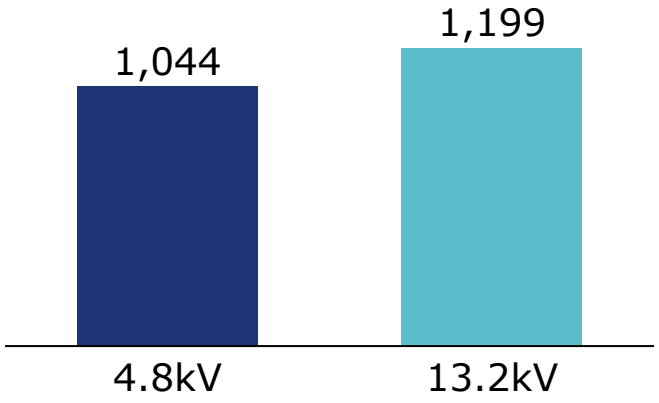
System Map (Circuit voltage)



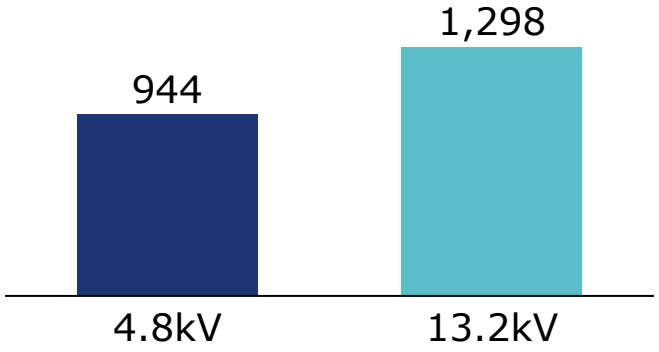
System Map (Substation Voltage)



Customer Count
(Circuit Voltage, 000's)



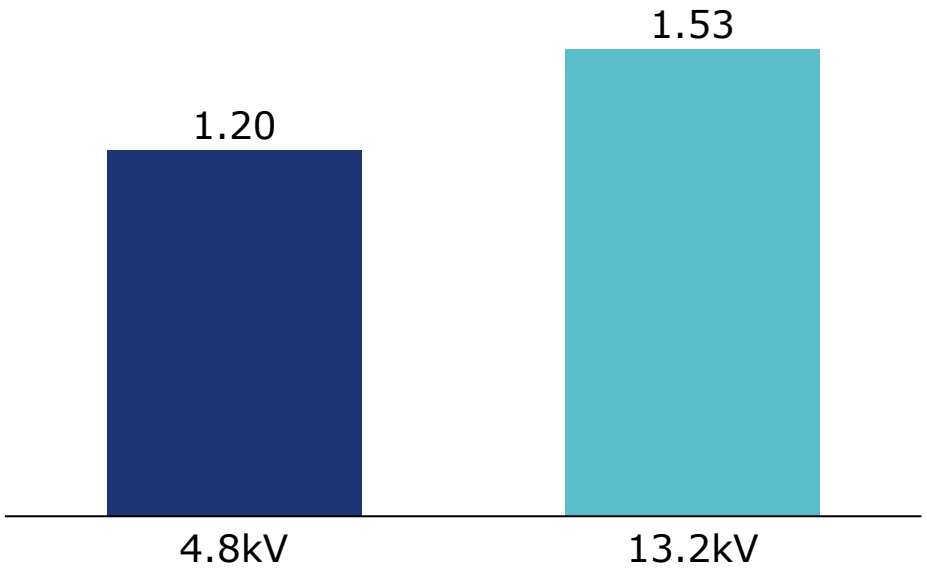
Customer Count
(Substation Voltage, 000's)



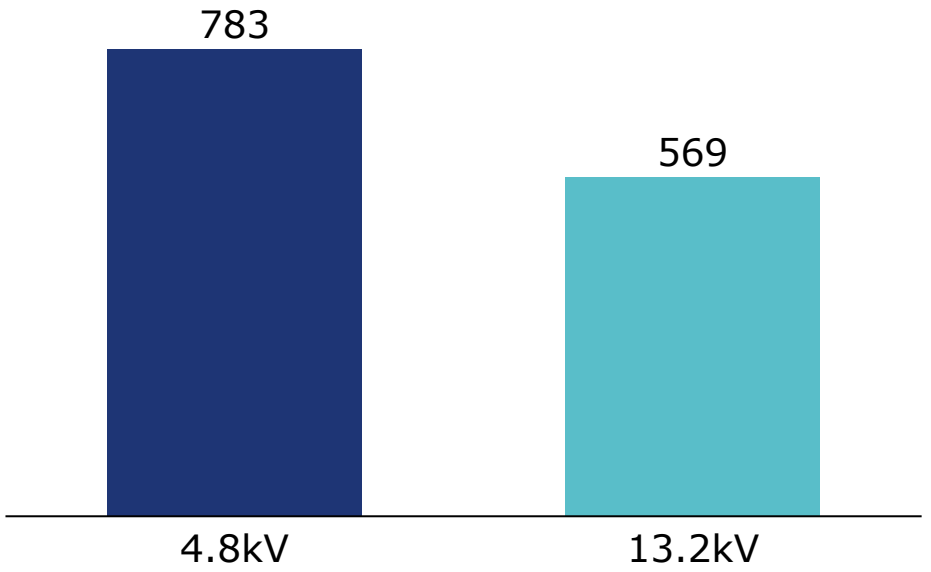
Some circuits on the system contain ISO down areas, which begin at a 13.2kV substation but voltage is stepped down to 4.8kV through isolation transformers serving ~100k customers across 5,500 line miles

Customers served by our 4.8kV systems, on average, experience fewer outages (SAIFI), but longer total duration (SAIDI)

All-weather SAIFI[1]
by substation voltage



All-weather SAIDI[1]
by substation voltage



DTE invests in reliability improvements on both 4.8kV and 13.2kV systems to improve safety and reliability

1. 5-year average 2017-21

While our 4.8kV and 13.2kV systems have some unique differences, the basic components of the circuit remain the same

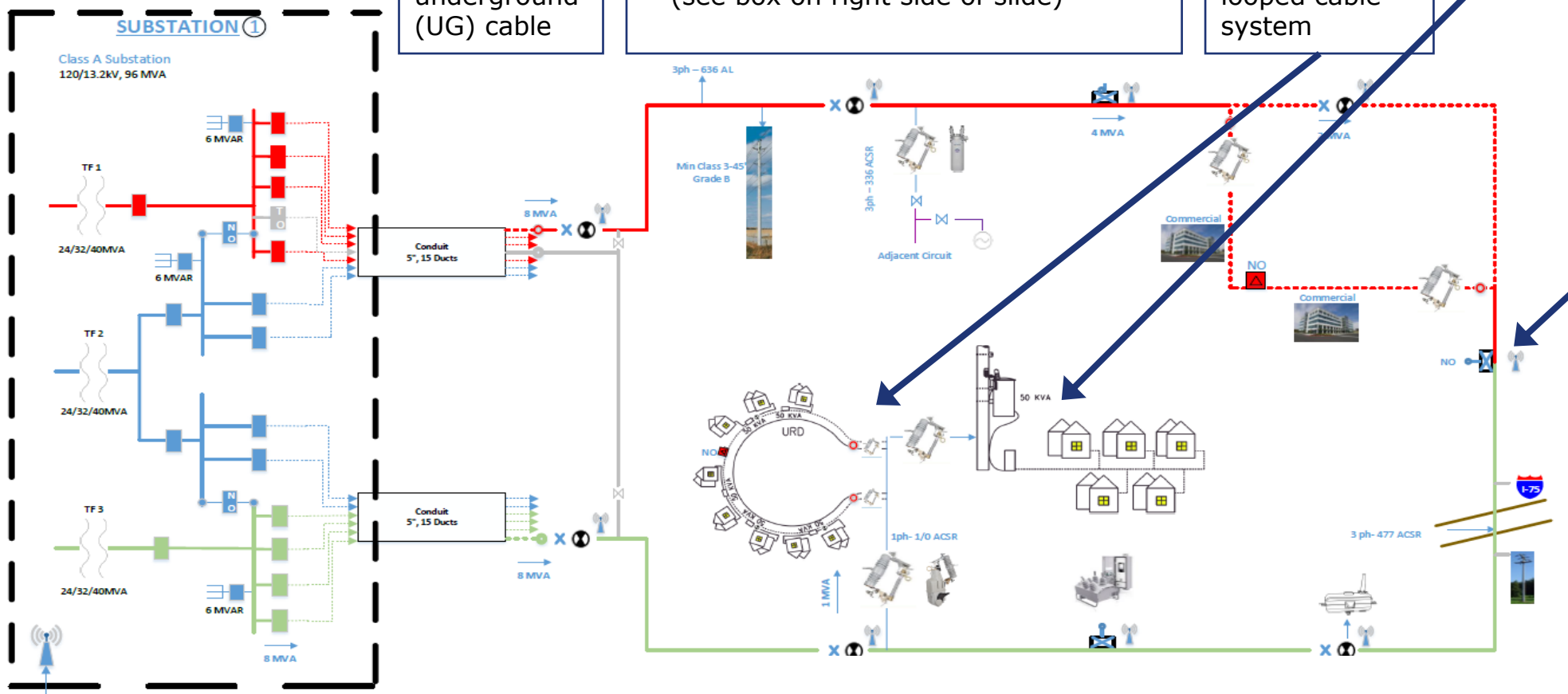
Substation
Step down from transmission or subtransmission voltage to primary voltage (4.8kV, 13.2kV)

Cable
Circuits leave substation through conduit and underground (UG) cable

Circuits
- Often come overhead at a pole
- 3-phase backbone, and laterals (primary voltage)
- May be tied together for loop schemes (see box on right side of slide)

URD
Underground residential distribution (URD) – buried looped cable system

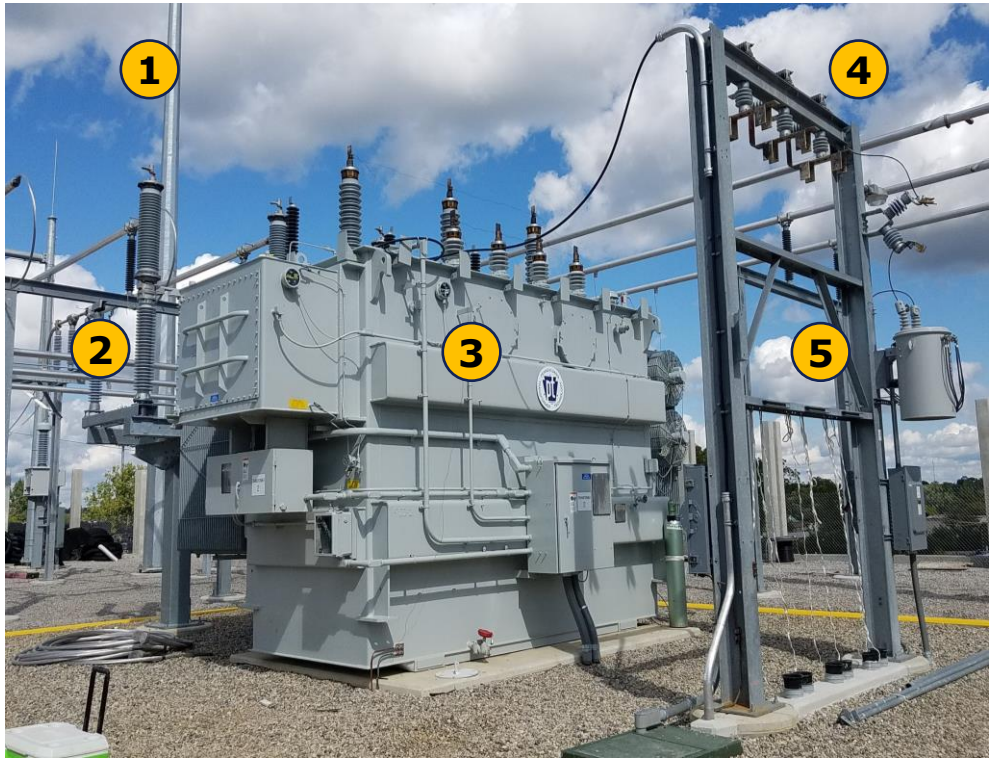
Secondary
Lower voltage system on low side of distribution transformers



Loop scheme
The two circuits (red and green) have a point of connection here creating a 'loop'

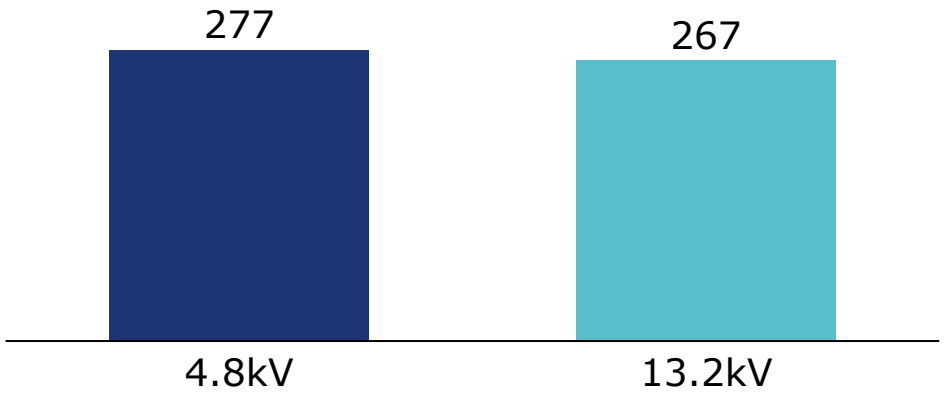
The purpose of a substation is to step down transmission or subtransmisison voltages to distribution voltages to serve residential, commercial or industrial loads

Typical Substation Configuration

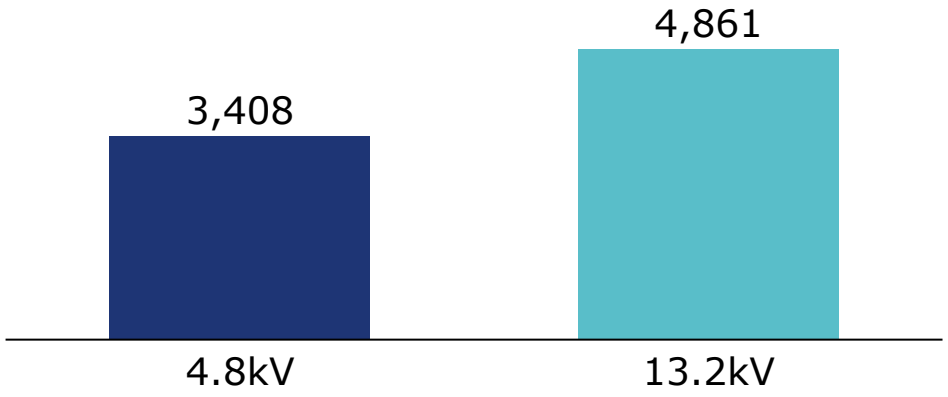


1. 120kV Input
2. Circuit Switcher
3. Power Transformer
4. 13.2kV Output
5. Secondary Tower

Number of substations

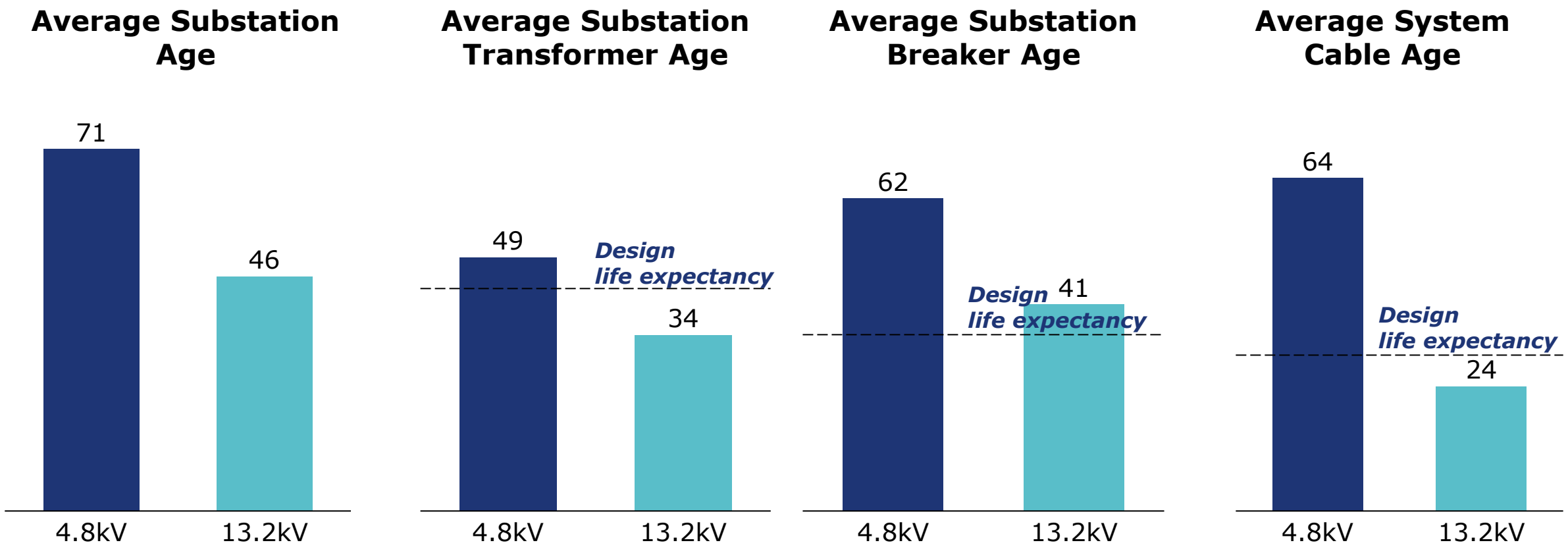


Customers per substation



DTE

While age is only one factor influencing system performance, our 4.8kV equipment is significantly older on average than equipment on the 13.2kV system

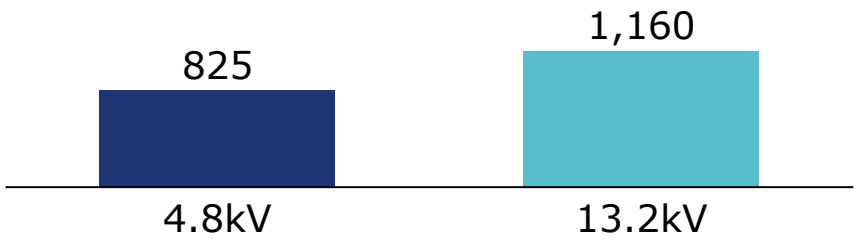


Note: Life expectancy uses median of expected age range

About 35% of our system is underground and primarily uses two main types of cable – System Cable and Underground Residential Distribution (URD) cable



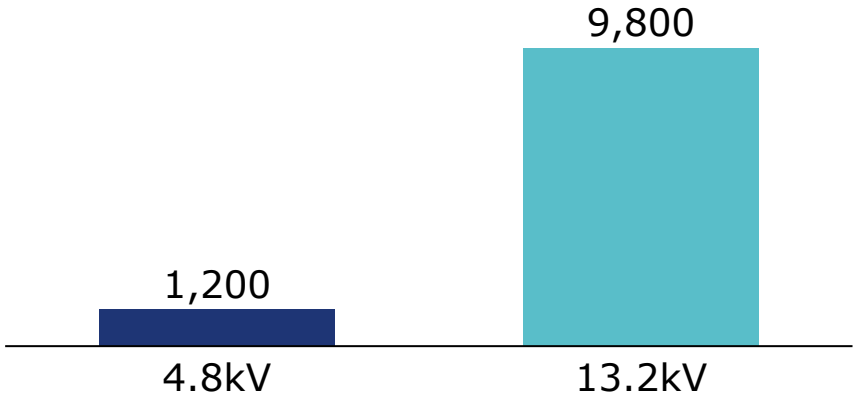
System Cable miles by voltage class



- Most frequently used leaving substation underground regardless of voltage
- Pulled through conduit (duct banks)



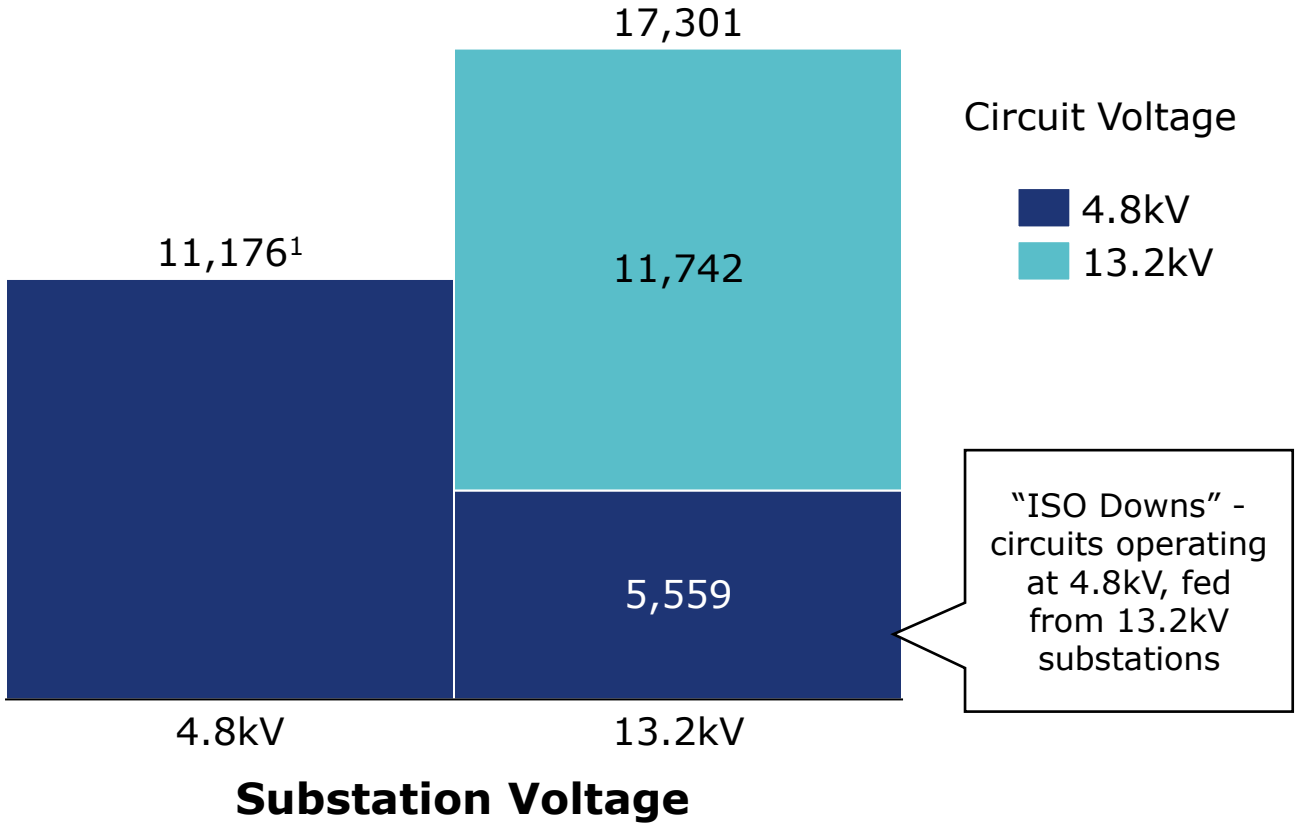
URD miles by voltage class



- Direct buried cable in residential subdivisions between transformers
- All new subdivisions since 1970s are fed by URD
- Even when served from a URD, often part of the circuit is fed from the overhead

The most visible part of the distribution system has ~28,500 miles of overhead circuits with, 16,700 miles operating at 4.8kV





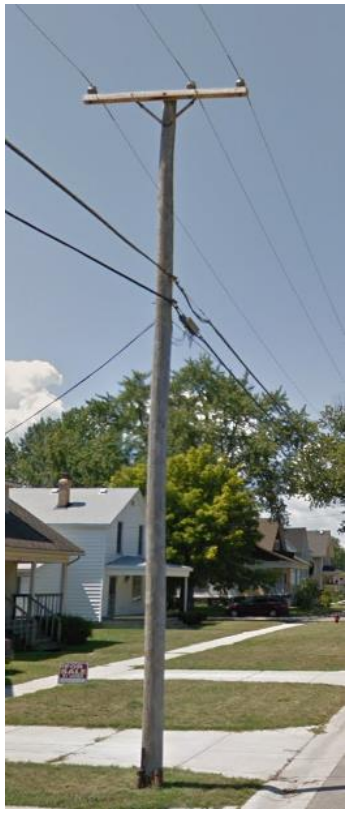
1. 32 miles of 13.2kV standard overhead is being operated at 4.8kV

Construction of the three phase leads are similar across voltage type, and may be either in the rear lot or near road right of way; 4.8kV poles are often shorter and require less clearance

4.8kV System



Rear Lot



Road
right-of-way

13.2kV System



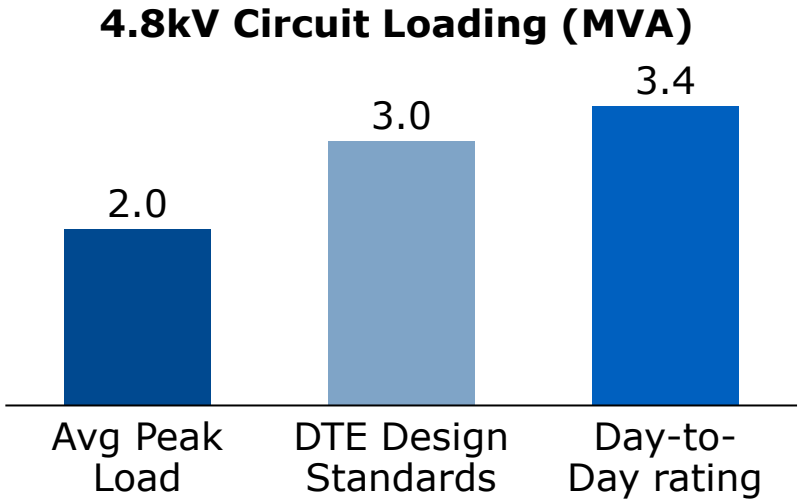
Rear Lot

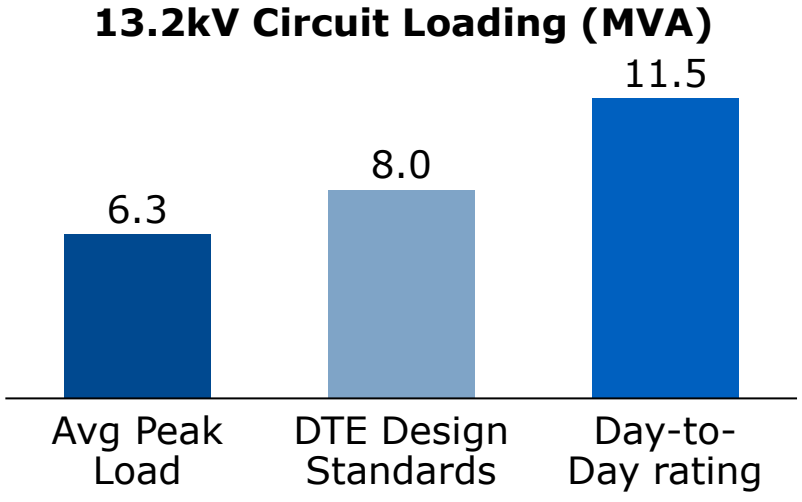


Road
right-of-way

13.2kV circuits can serve up to three times the load of a comparable 4.8kV circuit; DTE Design Standards limit load on a circuit to maintain system capacity and operational flexibility







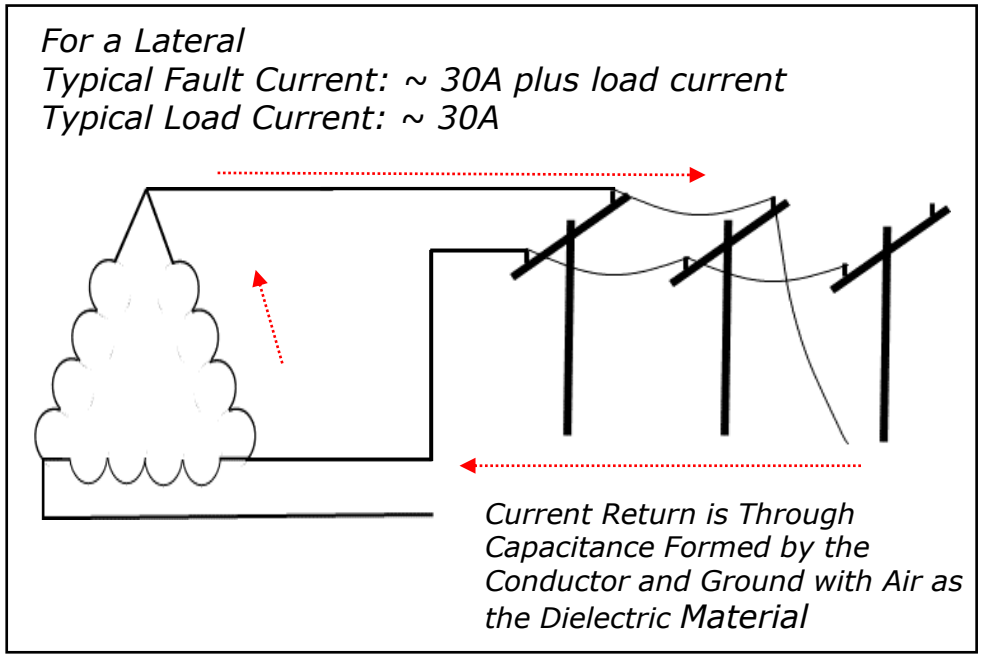
- The day-to-day rating is the load that equipment can operate at without impacting lifespan
- The DTE Design standards limit of 8 MVA is intended to provide capacity to support ~1/2 of an adjacent circuit and remain within the day-to-day rating of the equipment
- Approximately 20% of 4.8kV circuits and 30% of 13.2kV circuits operate above the DTE Design Standards limit

Despite the 4.8kV's superior SAIFI performance, the nature of our 4.8kV system introduces challenges impacting Safety, Reliability, Capacity, Outage Duration, and the ability to add Automation

Safety	**The 4.8kV system is an ungrounded delta configuration, making detection of wire downs challenging**
Reliability	**Has most of the conductor which is weaker in strength compared to current wire standards**
Capacity	**Inherent to the design, the 4.8kV substations and circuits have lower capacity**
Outage Duration	**Ringed circuit & banked secondary make maintenance & fault locating more difficult**
Automation	**The 4.8kV system has limited remote monitoring & control capabilities**

The 4.8kV ungrounded delta configuration leads to low fault currents from wiredowns that don't result in a protective device operating and makes wiredown detection challenging

Ground Fault on 4.8kV Ungrounded Delta

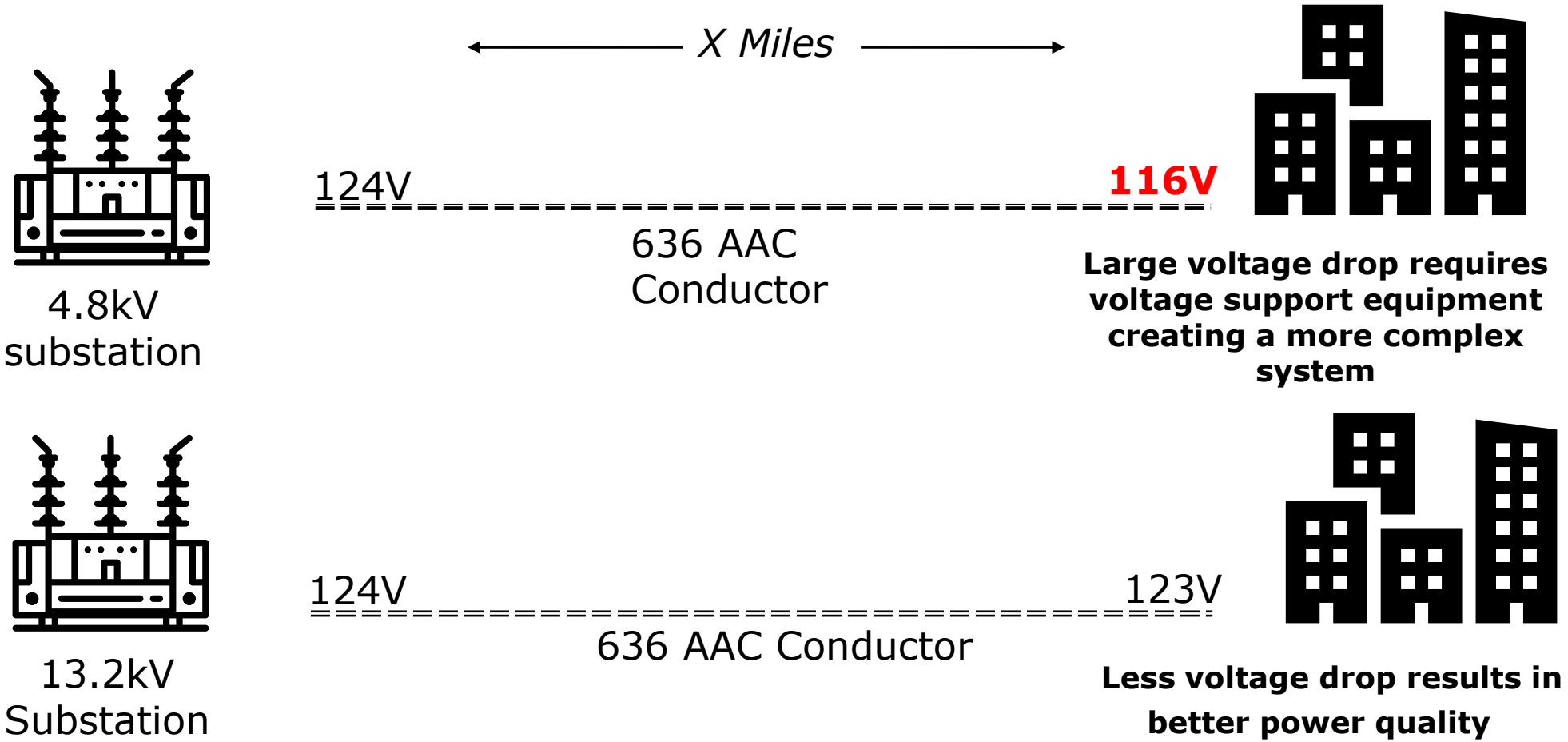


- There is no direct ground path on a delta configuration – and downed wires may only create a fault current that is not much larger than typical loads
- Due to lower fault currents, down wires are typically live
- 80% of the faults are phase-to-ground, which include wire downs
- The remaining 20% are phase-to-phase faults, which create significantly more fault current and trip protective devices typically
- Because protective devices don't operate as frequently, SAIFI performance is superior to a grounded system (13.2kV)

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- 4.8kV Hardening Program (45 min)
- 4.8kV Hardening program and alternative solutions (1 hr)
- Open table discussion/conference feedback (30 min)

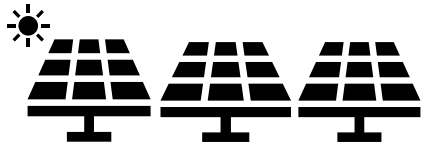
4.8kV is more susceptible to voltage fluctuations from large electric loads coming on and off the system; future EV and DER additions are expected to exacerbate this issue



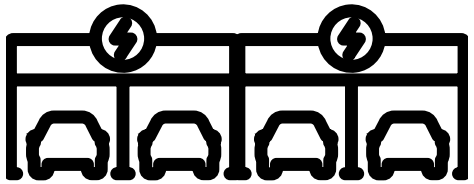
In addition to the voltage concerns, the 4.8kV system will be more challenged to serve future commercial DER and EV's due to limited capacity



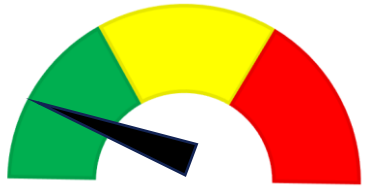
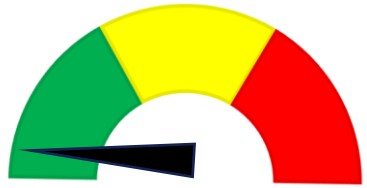
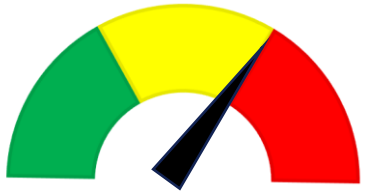
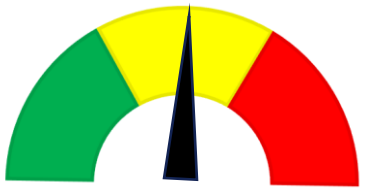
100 EV's
~0.6 MVA



Small Commercial Solar
~0.5 – ~2 MVA



EV Charging Station
~1.5 MVA

	4.8kV Circuit 3.0MVA	**13.2kV Circuit 8 MVA**
100 EV's ~0.6 MVA	 20%	 8%
Small Commercial Solar ~0.5 – ~2 MVA	 66%	 25%
EV Charging Station ~1.5 MVA	 50%	 19%

EV and DER on their own can require a majority of circuit capacity on a 4.8kV circuit making it a challenge to serve

Today's Agenda

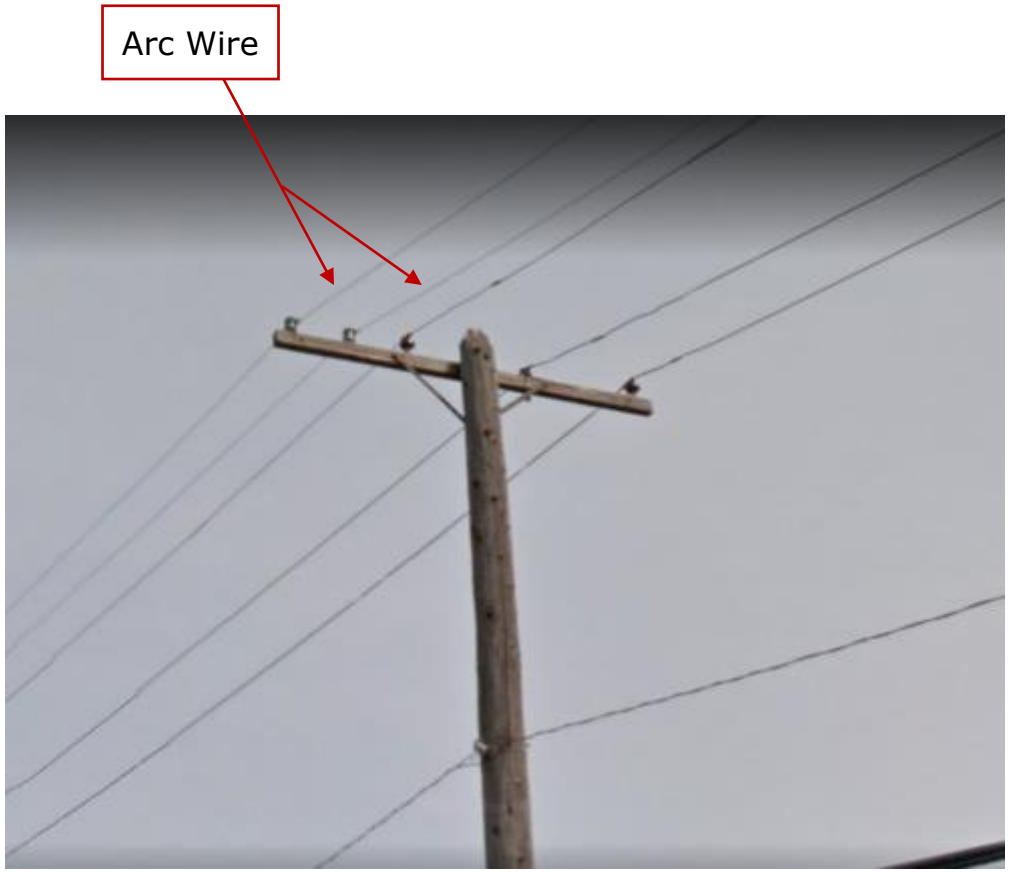
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The age of and access to the 4.8kV infrastructure in the City of Detroit provides significant challenges to maintenance and reliability programs

- The 4.8kV system in the City of Detroit has approximately 2,400 primary overhead line miles
- The electrical system in much of Detroit is the original distribution built and many sections were constructed in the early 1900s
- When installed, back lot construction was prudent
  - Access for DTE construction, maintenance, and tree trimming was through the city-maintained alleyway
  - Over time, the city abandoned alleys and their maintenance which became inaccessible by truck as trees were overgrown or property owners relocated their fence lines
- While much of this construction provided safe and reliable service for decades, the age of the infrastructure, as well as the construction type (size and strength of wire and poles, etc.), no longer provides the level of service the community needs



The Public Lighting Department (PLD) Arc Wire System was used to supply electricity to arc-type streetlamps and share utility poles with DTE Electric distribution



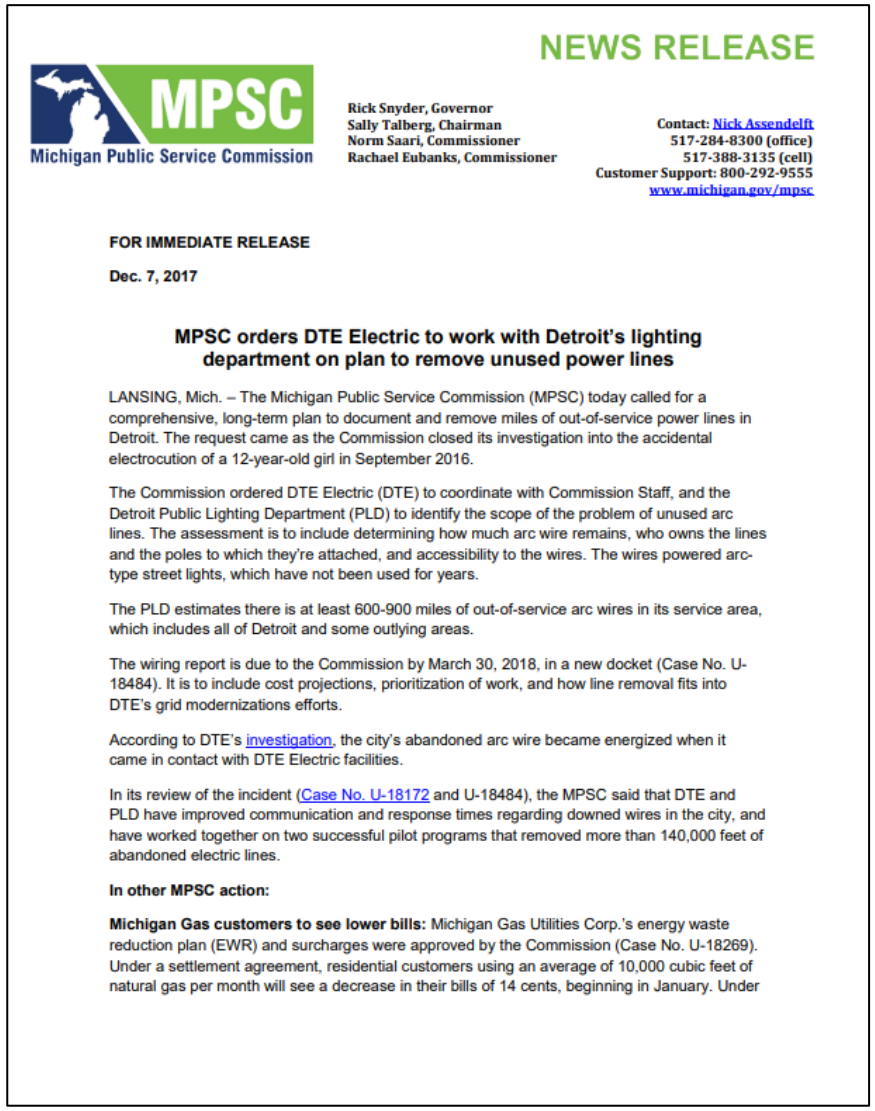
- Those streetlamps are no longer used, but large amounts of arc wires are still attached to utility poles
- The abandoned wire poses a risk if it becomes energized by making contact with DTE facilities
- In 2017, we estimated that there were approximately 1,300 miles of DPLD arc wire that was intermittently co-located among DTE Electric's 2,400 miles
- An average DTE Electric circuit in the City of Detroit is expected to have arc wire co-located on about 50% of the poles

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In December 2017, the Commission issued an order for DTE to work with Detroit Public Lighting to remove unused arc wire co-located on its infrastructure

- The Order in Case No. U-18484, required DTE to work with relevant entities to accomplish a long-term comprehensive plan to address out-of-service Detroit Public Lighting Department owned arc wire
- The Company closely examined the options to best address the issue and concluded that addressing the DPLD arc wire as a standalone program was not the option that best addressed the safety and reliability needs of the grid
- In response, the 4.8kV Hardening program was developed that balanced safety, cost, and reliability improvements



NEWS RELEASE

MPSC
Michigan Public Service Commission

Rick Snyder, Governor
Sally Talberg, Chairman
Norm Saari, Commissioner
Rachael Eubanks, Commissioner

Contact: Nick Assendelft
517-284-8300 (office)
517-388-3135 (cell)
Customer Support: 800-292-9555
www.michigan.gov/mpsc

FOR IMMEDIATE RELEASE

Dec. 7, 2017

MPSC orders DTE Electric to work with Detroit's lighting department on plan to remove unused power lines

LANSING, Mich. – The Michigan Public Service Commission (MPSC) today called for a comprehensive, long-term plan to document and remove miles of out-of-service power lines in Detroit. The request came as the Commission closed its investigation into the accidental electrocution of a 12-year-old girl in September 2016.

The Commission ordered DTE Electric (DTE) to coordinate with Commission Staff, and the Detroit Public Lighting Department (PLD) to identify the scope of the problem of unused arc lines. The assessment is to include determining how much arc wire remains, who owns the lines and the poles to which they're attached, and accessibility to the wires. The wires powered arc-type street lights, which have not been used for years.

The PLD estimates there is at least 600-900 miles of out-of-service arc wires in its service area, which includes all of Detroit and some outlying areas.

The wiring report is due to the Commission by March 30, 2018, in a new docket (Case No. U-18484). It is to include cost projections, prioritization of work, and how line removal fits into DTE's grid modernizations efforts.

According to DTE's investigation, the city's abandoned arc wire became energized when it came in contact with DTE Electric facilities.

In its review of the incident (Case No. U-18172 and U-18484), the MPSC said that DTE and PLD have improved communication and response times regarding downed wires in the city, and have worked together on two successful pilot programs that removed more than 140,000 feet of abandoned electric lines.

In other MPSC action:

Michigan Gas customers to see lower bills: Michigan Gas Utilities Corp.'s energy waste reduction plan (EWR) and surcharges were approved by the Commission (Case No. U-18269). Under a settlement agreement, residential customers using an average of 10,000 cubic feet of natural gas per month will see a decrease in their bills of 14 cents, beginning in January. Under

The 4.8kV Hardening Program was created to complete a long-term comprehensive plan to address the removal of arc wire while at the same time providing additional safety and reliability benefits

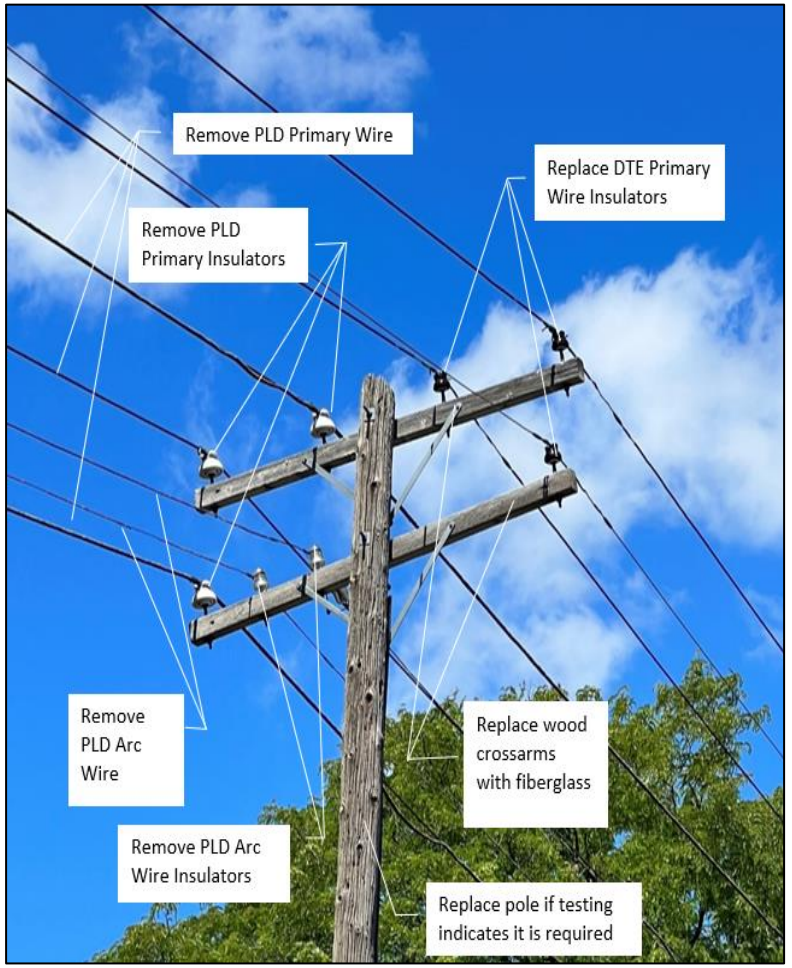
Objectives

- Remove Detroit Public Lighting Department (PLD) arc wire and distribution wire
- Harden and stabilize the 4.8 kV distribution circuits to improve safety, reliability, and storm resiliency
- Extend the life of the 4.8 kV circuits until DTE completes conversion

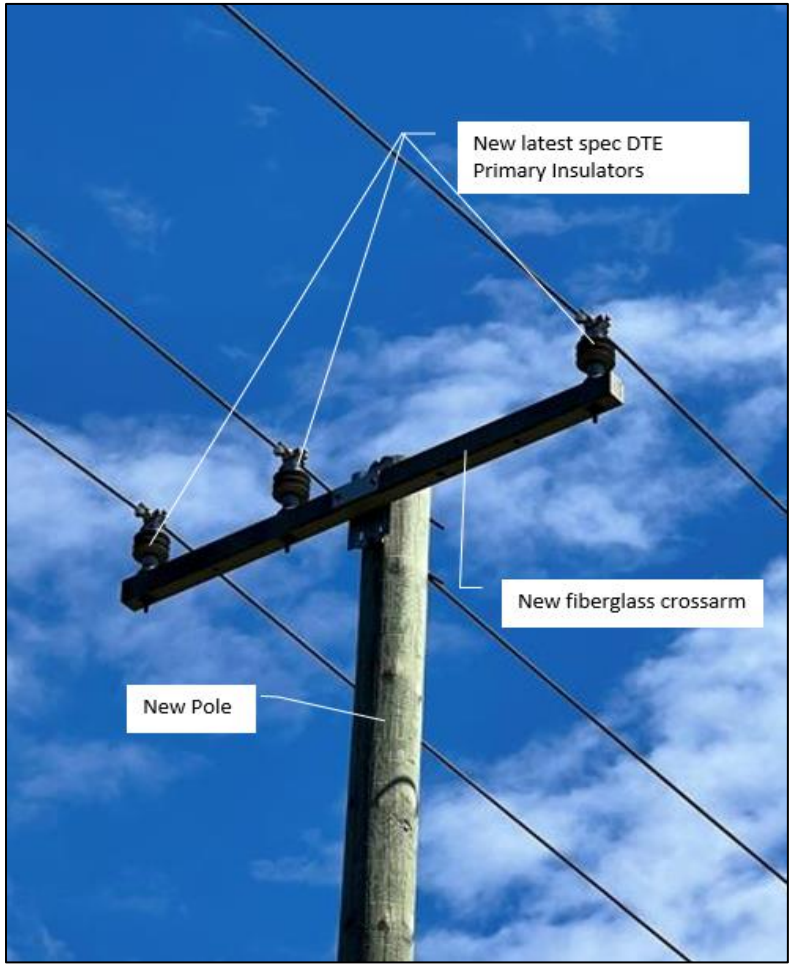
Scope of Work

- Replace or reinforce condemned poles
- Replace wood crossarms with fiber glass
- Remove Detroit PLD arc wires and distribution wires that are co-located with DTE assets
- Remove service lines to abandoned properties
- Trim the trees to construction specifications

Before Hardening



After Hardening



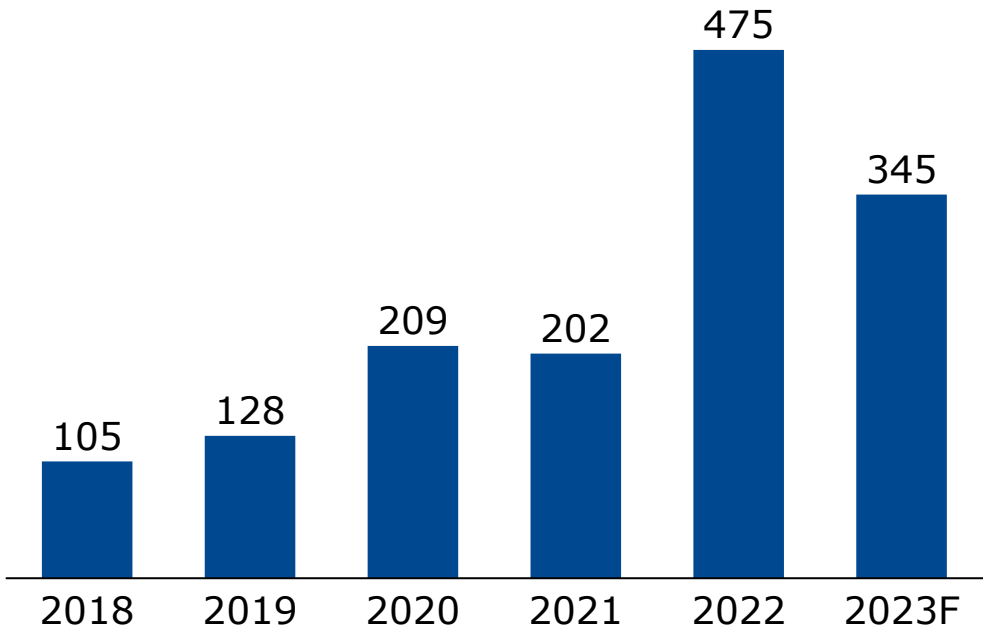
Before and after photos are from different pole locations

4.8kV Hardening Program Overview - Video

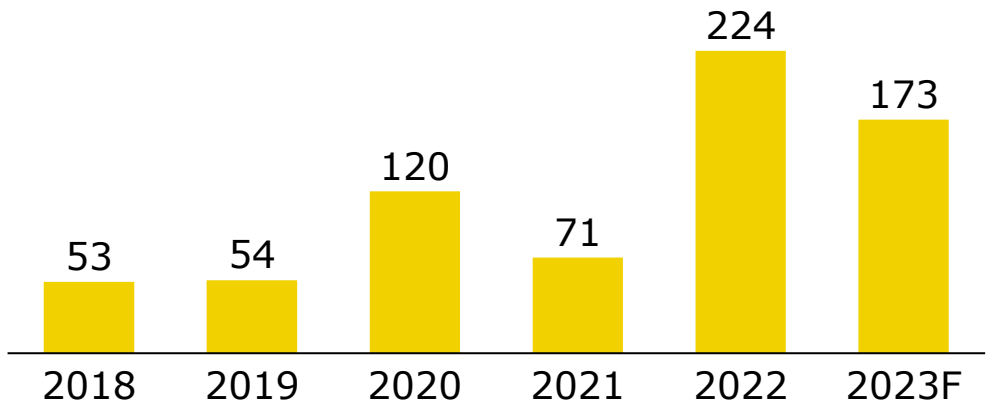


Since 2018, the 4.8kV Hardening Program had addressed ~185 circuits impacting over 144K customers in the City of Detroit and surrounding areas and, by the end of 2023, will have removed over 700 miles of arc wire

4.8kV Miles Hardened
~1,465 miles total

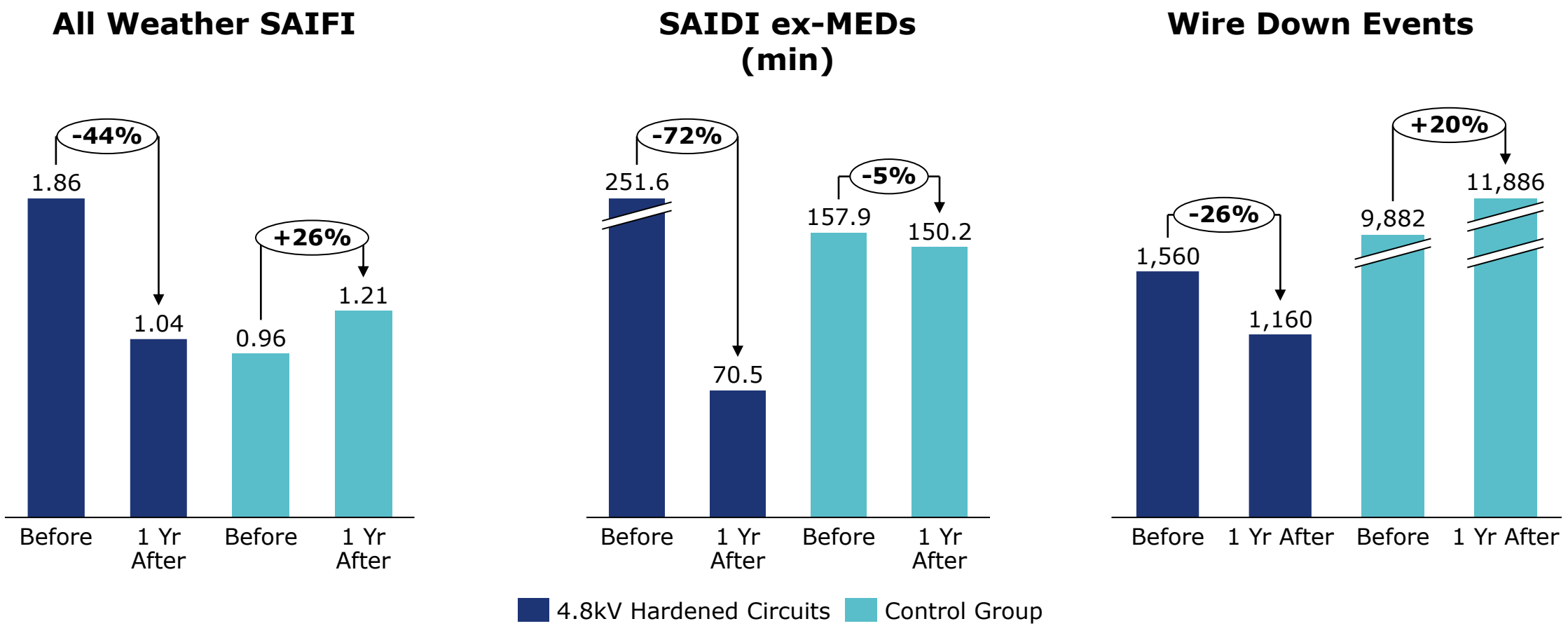


Miles of Arc Wire Removed
~700 miles total



Through 2023 we estimate that we will have removed over half of the arc wire that is co-located with DTE owned assets, and estimates that 400-600 miles of arc wire remain

Performance of circuits addressed by the 4.8kV Hardening program have seen significant improvements in SAIFI, SAIDI ex-MEDs, and wire down events



Note 1: Analysis based on aggregate numbers of 82 circuits hardened - 10 in 2018, 35 in 2019, and 37 in 2020 using three-year historic average (2015/16/17 – 2017/18/19) compared to one year after (2019/20/21)
Note 2: Performance deterioration for control group is largely driven by weather
Note 3: SAIDI during MEDs is heavily influenced by circuit restoration prioritization; hence SAIDI ex-MEDs is considered a better metric to reflect the program improvements

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As directed by the Commission in case U-20836, DTE has considered several alternatives to the 4.8kV Hardening program

Tree Trimming	• Trees trimmed to enhanced specification, no arc wire removal
PTMM	• Replace failed poles and pole top equipment, no arc wire removal
Arc Wire Removal	• Arc wire removal only, reduced scope tree trimming and equipment replacement
4.8kV Hardening	• Arc wire removed, crossarms replaced, tree trimming
Pre-conversion	• Arc wire removed, rebuild wires, poles, and pole tops to 13.2kV standards
Conversion	• Fully convert circuit and substation to 13.2kV, includes automation
Microgrids	• Arc wire removed with pre-conversion and microgrid for reliability
DERs	• Utility-scale or distributed solar and storage to improve capacity
Energy Efficiency	• Target residential, commercial, and industrial customers for waste reduction
Storage	• Utility-scale battery storage to improve capacity by shifting/decreasing peak

When comparing the effectiveness of the various alternatives, five approaches were appropriate for addressing the removal of the PLD arc wire

	Arc Wire Removal	Improved Reliability	Improved Safety/ Wire down	Improved Capacity	Cost Level	Execution Complexity
Tree Trimming	○	◒	◔	○	Low	Low
PTMM	○	◒	◔	○	Low	Low
1 Arc Wire Removal	●	◔	◔	○	Medium	Low
2 4.8kV Hardening	●	◔	◒	○	Medium	Low
3 Pre-conversion	●	●	●	◔	High	Medium
4 Conversion	●	●	●	●	High	High
5 Microgrids	●	●	●	◒	Very High	Very High
DERs	○	○	○	◔	Medium	Medium
Energy Efficiency	○	○	○	◔	Low	Medium
Storage	○	◔	○	◒	High	Medium

Selected for Consideration

Increasing difficulty

1 **Arc Wire Removal Only:** While there are benefits to only removing the arc wire, this option overlooks the opportunity to significantly improve the safety and reliability for the entire circuits that contain arc wire

Execution Speed: High

Scope – Arc Wire removal only
Cost per mile: $175K - $207K

- Remove Detroit Public Lighting Department (PLD) arc wire
- Trim the trees as needed to identify/remove the arc wire
- Balance the cross arms to make safe (for poles with arc wire, vast majority of cross arms will need to be replaced)
- Replace/reinforce pole if necessary
- Replace pole top if necessary

Benefits

- Remove Detroit Public Lighting Department (PLD) arc wire
- Improved reliability:
  - Wire down – 13% improvement
  - SAIFI – 22% improvement
  - SAIDI – 36% improvement
- Arc wire removal only is ~55% of the cost of Hardening per mile and best-case scenario results in half the reliability benefits

~50% of 4.8kV circuit miles will not receive reliability benefits under this program

② **4.8kV Hardening:** By conducting 4.8 kV Hardening on circuits that contain arc wire, customers experience significantly improved reliability and safety across the entirety of the circuit

Execution Speed: Medium-High

Scope – 4.8kV Hardening
Cost per mile: $333K - $373K

- Remove Detroit PLD arc wires and distribution wires that are co-located with DTE assets
- Trim the trees to construction specifications
- Perform pole testing and replace or reinforce condemned poles
- Replace wood crossarms with fiber glass crossarms
- Remove service lines to abandoned properties

Benefits

- Remove Detroit Public Lighting Department (PLD) arc wire
- Harden and stabilize the 4.8kV distribution circuits
- Extend the life of the 4.8kV circuits
- Improved reliability:
  - Wire down – 26% improvement
  - SAIFI – 44% improvement
  - SAIDI – 72% improvement

③ **Pre-conversion:** Brings the OH portion of the circuit up to new 13.2kV standards while leaving the UG and substation unchanged; this delivers tremendous reliability and safety benefits but does not add the additional capacity of full conversion

Execution Speed: Medium-Low

Scope – Pre-conversion
Cost per mile: $1.4M - $2.0M

- Remove Detroit PLD arc wires and distribution wires that are co-located with DTE assets
- Trim the trees to construction specifications
- Rebuild pole tops using fiberglass cross arms
- Replace poles and transformers as needed
- Reconductor overhead lines as needed, install neutral wire
- Rebuild underground infrastructure as needed

Benefits

- Replaced equipment meets latest upgraded standards
- Prepares the overhead infrastructure for conversion to 13.2kV
- Improved reliability
  - Wire down – 90% improvement
  - SAIFI – 85% improvement
  - SAIDI – 85% improvement

4 **Conversion:** Complete rebuild of the all parts of the substation and circuit yielding safety, reliability, and capacity benefits

Execution Speed: Low

Scope – Conversion
Cost per mile: $2.4M - $3.0M

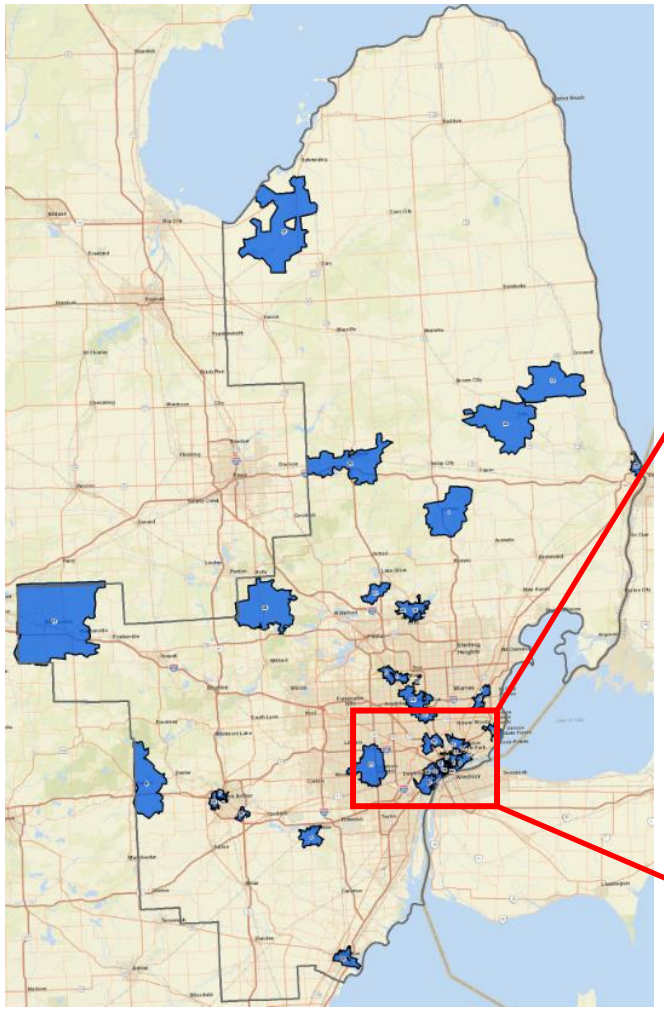
- All pre-conversion activities
- Build new 13.2kV sub/expand existing 13.2kV sub and install controls & automation in the substations/circuits to latest design standards
- Establish new DCs from new/upgraded 13.2kV substation
- Reconfigure circuits & establish jumpering points
- Convert and transfer load off the 4.8kV system to the 13.2kV system

Benefits

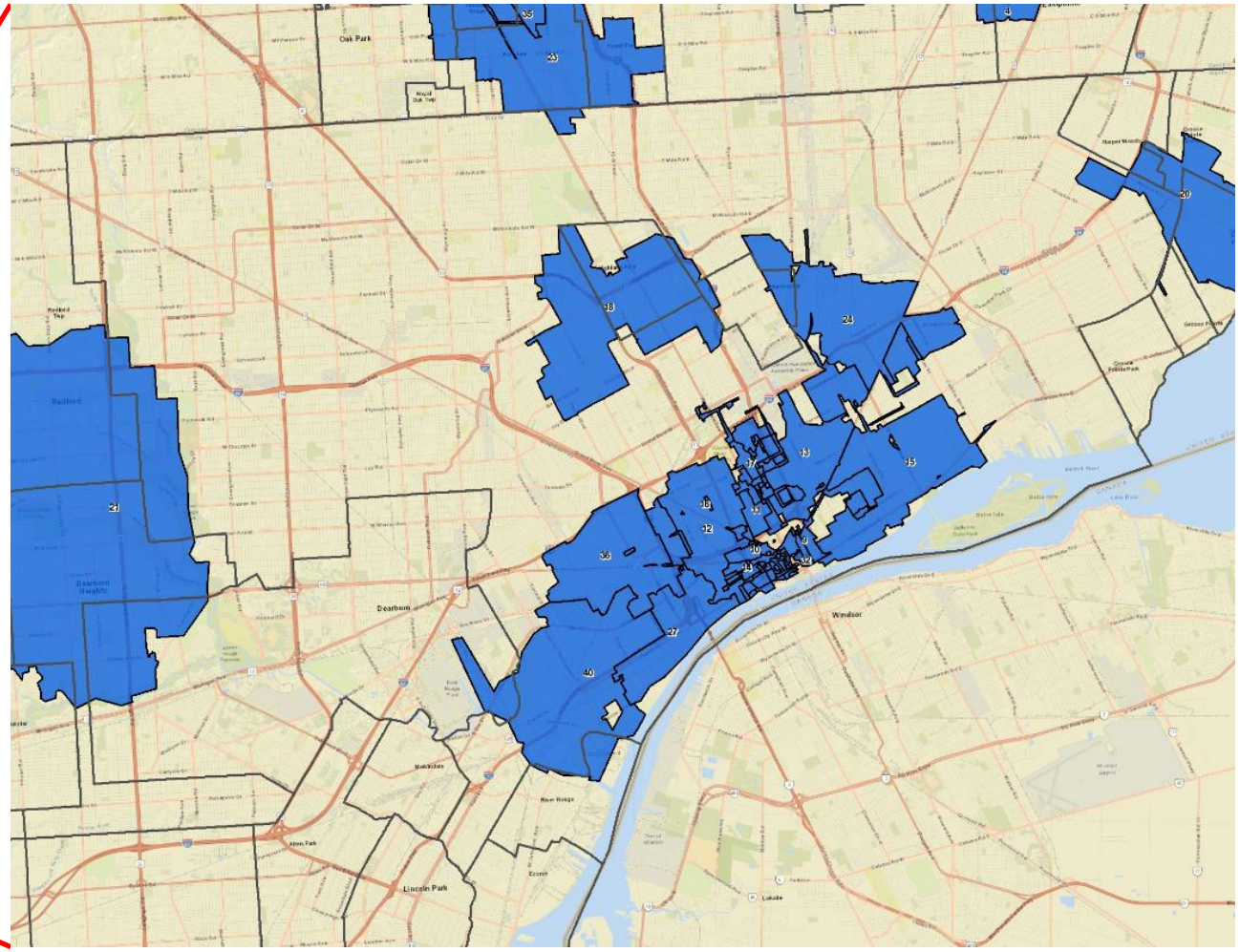
- Decommissioning of aging equipment
- Increased area capacity
- Reduced overload situations
- Improved jumpering capability
- Automated restoration
- Wye configuration is safer as wire downs are generally de-energized

DTE has several 4.8kV conversion projects underway throughout our service territory, many of which are concentrated in the City of Detroit

DTE Conversion Projects



City of Detroit Conversion Projects



In addition to all the construction work that conversion entails, there are a significant number of challenging activities that must occur to complete the rebuild and voltage conversion of a circuit



1. **Property acquisition** can be a long process to identify and purchase the location
2. **Permitting and approvals** for easements and environmental clearances for new circuits often have long time horizons
3. **Interconnection with ITC** can be lengthy requiring studies and approvals through MISO
4. **Customer Communication and Outreach** efforts can be extensive when new construction differs from existing facilities
5. **Establishing new circuits** requires significant underground work from the substation impacting adjacent public roads and property
6. **Weather constraints** impact the timing of customer shutdowns as they are typically performed in weather above 40 degrees
7. **Large scale coordination and overhead resources** are required to change each distribution transformer to the higher voltage simultaneously

5 **Microgrids:** Microgrid customers are likely to experience higher levels of reliability, but installation costs and execution complexity are very high

Execution Speed: Low

Scope –Microgrids
Cost per mile: $12.1M - $17.0M[1]

- All pre-conversion
- Install solar and battery storage as dictated by project along with associated equipment (inverters, switchboards, communication gateways, reclosers, etc.)
- Site prep as needed for battery storage (fence, driveway, below grade conduit etc.)

Benefits

- Islanding capability when main grid is not on-line
- Increased reliability from redundant source
- Improved jumpering capability
- Automated restoration
- Improved reliability within the Microgrid[2]
  - Wire down – 90% improvement
  - SAIFI – 90% improvement
  - SAIDI – 90% improvement

Microgrids can vary significantly based on use case; a key component to microgrids is energy storage[3] which is high cost and has a long lead time

1 Based on Port Austin example using 500kW solar and 1MW x 4MWh battery trailer
2 Based on expectations
3. DTE did not consider fossil generation as an energy source for microgrids

5 **Microgrids:** One microgrid project is currently in progress in Port Austin; the Company is pursuing additional microgrid projects at Port Austin and O'Shea as part of an IIJA grant

Port Austin Project (Pilot/IIJA Grant)

Current Project:
- Install (1) 500kW solar array
- Install (1) 1MW x 2-4MWh battery storage systems at two separate locations
- Install reclosers, communication and controls to create microgrid

Future Proposals:
- Install two additional microgrids
- All three microgrids will work together to provide optimized reliability for customers

O'Shea Project (Pilot/IIJA Grant)

Current Project:
- Install (1) 1MW x 2-4MWh battery storage system (already owned)

Future proposals:
- Install one more battery storage and other equipment to create two microgrids
- Install reclosers, communication and controls
- The two microgrids will work together to provide optimized reliability for customers

Expected outcomes from these pilots

- Influence the industry's development of the electrical system and advance the deployment of sophisticated and simpler microgrids
- Develop internal DTE Electric expertise with microgrids
- Enhance partnerships with other organizations such as EPRI and DOE National Laboratories
- Progress technology outside the NWA and microgrid space (i.e., fault locating, load forecasting, DER anomaly detection)

When comparing the alternative approaches, the 4.8kV Hardening program was selected originally because it strikes a balance between cost, reliability, and the timely removal of the arc wire from the DTE Electric system

	Cost per mile[1]	Wire down Reduction	SAIFI Reduction[2]	CAIDI Reduction[3]	Capacity Increase	Increase DER Usage	Execution Complexity	Potential Use Case
Arc Wire Removal	$191K	13%	22%	36%	No	No	Low	Lowest overall cost to remove arc wire
4.8kV Hardening	$353K	26%	44%	72%	No	No	Low	Highest benefit/cost for reliability improvement
Pre-conversion	$1.7M	90%	85%	85%	No	Yes	Medium	Provides step change in reliability performance
Conversion	$2.7M	90%	85%	85%	Yes	Yes	High	Best benefit/cost for significant capacity needs
Microgrids	$14.6M	90%	95%	95%	Yes	Yes	Very High	Potentially application for grid areas with critical reliability needs

1. Median of cost range
2. SAIFI measures the frequency of customer interruptions
3. CAIFI measures the duration of customer interruptions

Today's Agenda

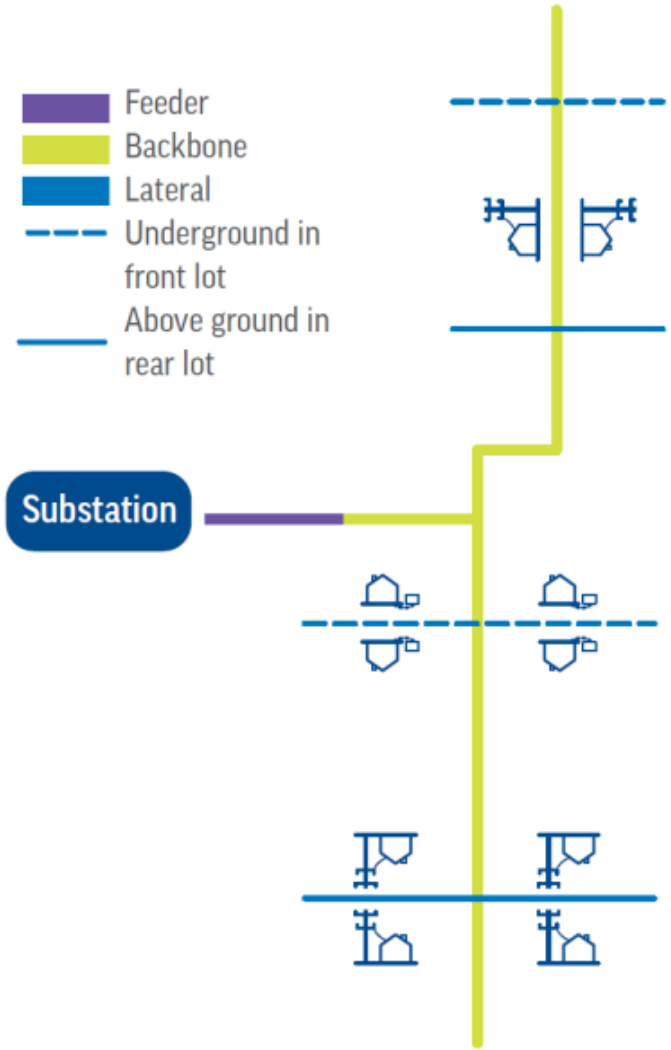
- Conference kickoff (15 min)
- Context and background
  - Overview of DTE's 4.8kV distribution system (45 min)
  - 4.8/13.2kV distribution systems and the integration of EVs and DERs (15 min)
  - The Detroit 4.8kV System and PLD arc wire (15 min with Hardening)
- 4.8kV Hardening Program (45 min)
- 4.8kV Hardening program and alternative solutions (1 hr)
- **Open table discussion/conference feedback (30 min)**

Discussion / feedback

- Open table discussion
- Conference feedback

Appendix

A circuit's primary construction in design can be divided into four main components: the feeder, the backbone, laterals, and the secondary



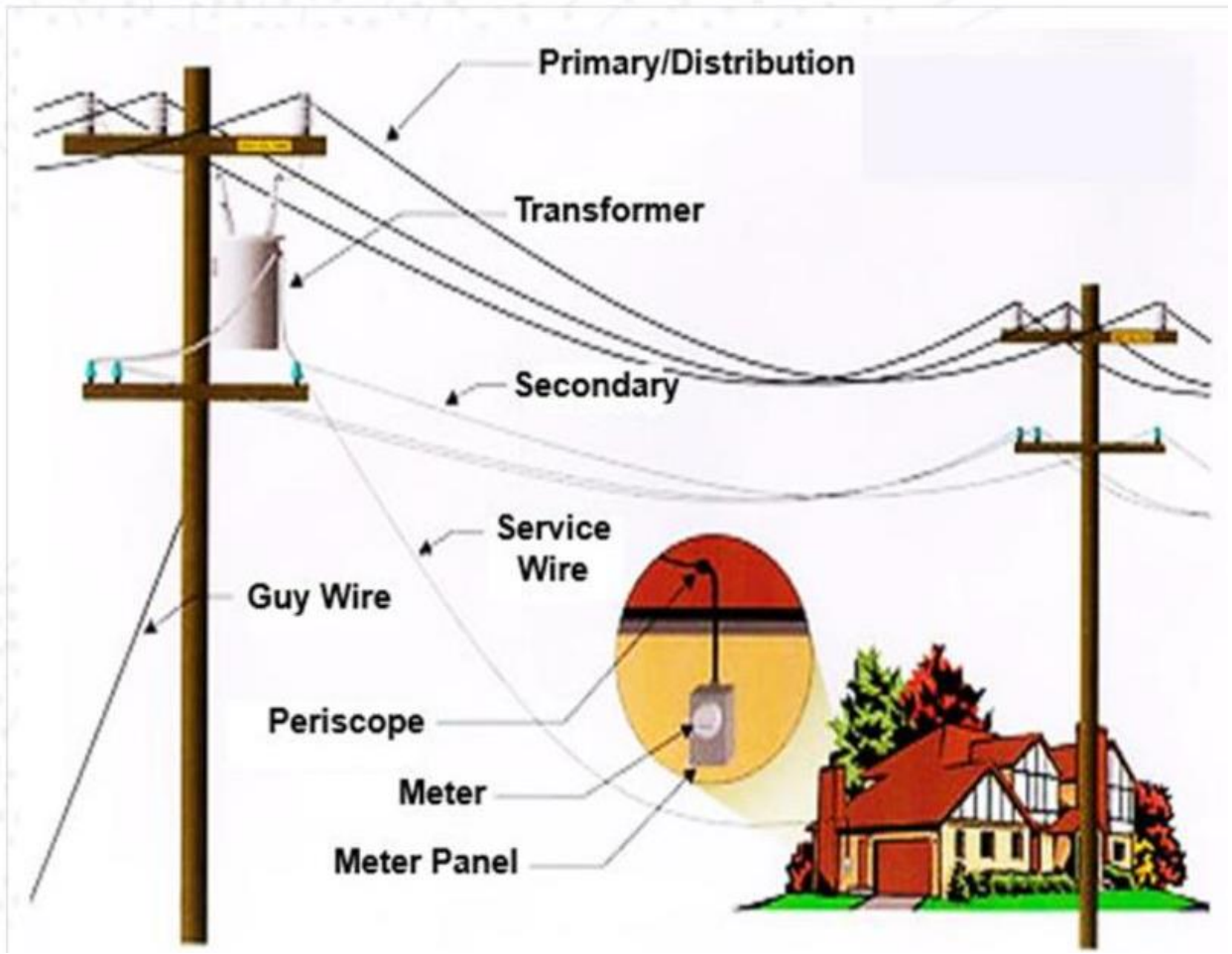
Feeder – portion of the circuit which exits the substation to get to load/customers. Often underground but can be overhead

Backbone – carries the major portions of the load, may connect to alternate sources during contingency, sectionalizing reduces the impact of customer to the area and can aid in expediting restoration

Laterals – section of circuit that branches from backbone of circuit, can be three phase or single phase serving any combination of customer types; residential, commercial, and/or industrial

Secondary - Secondary refers to set of lines where the primary voltage is stepped down to a lower voltage to support services to customer businesses and/or homes (Discussed in more detail later)

The Secondary refers to set of lines where the primary voltage is stepped down to a lower voltage to support services to customer businesses and/or homes

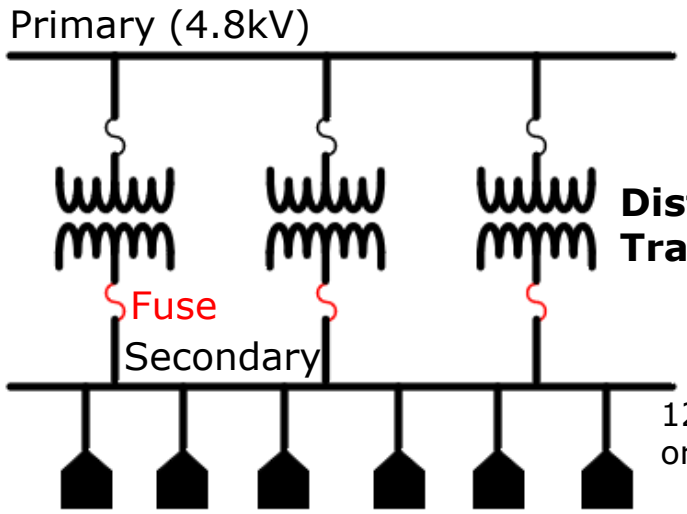


- The **Secondary** is the lead between poles that sits lower on the pole than the primary conductor
  - Can be 3-phase or 1-phase
- The lead that branches from the pole to the meter is the **Service Wire**

4.8 kV circuits can have any of the below secondary configurations; however, 13.2 kV circuits have only a radial fed secondary configuration

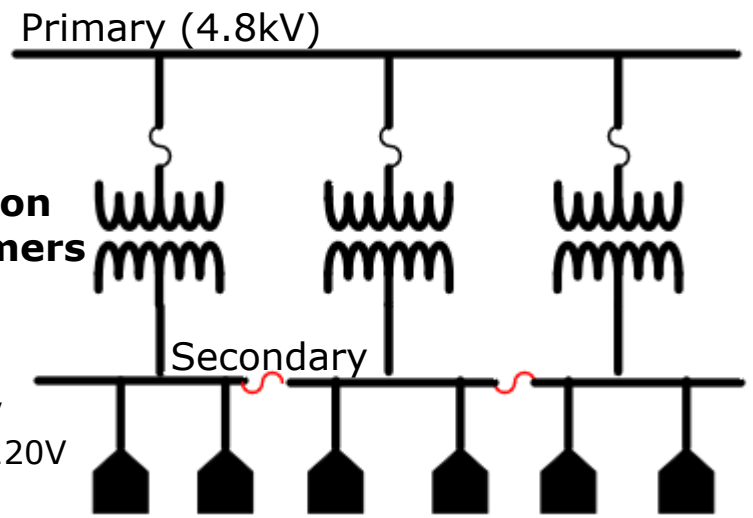
Common Secondary Configurations

Solid Bank Fusing



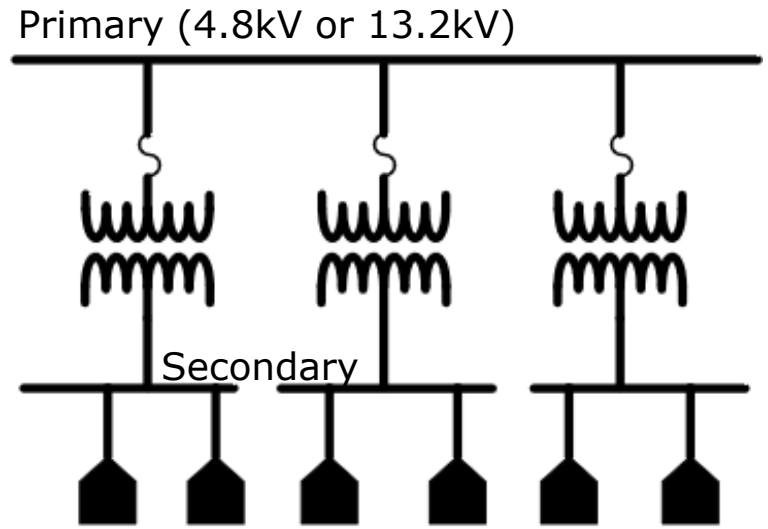
- 4.8 kV Only
- Adjacent transformers pick up load for loss of one transformer
- Reliable, difficult to restore
- This configuration is no longer installed

Loose Bank Fusing



- 4.8 kV Only
- Can help support voltage
- Outage to only customers affected by loss of that transformer

Radial



- 4.8 kV or 13.2kV
- Outage to only customers affected by loss of that transformer

MPSC Case No: U-21534

Requester: MNSC

Question No.: MNSCDE-17.5a

Respondent: S. Deol

Page: 1 of 1

Question: 5. Refer to Deol rebuttal, Q&A16-17:

a. What percentage of 4.8kV circuits do you believe will exceed their day-to-day rating during the projected test year? Produce any documents you rely on for your answer.

Answer: DTE Electric objects to the request for the reasons that the request is overly broad, seeks excessive detail, seeks confidential, proprietary research, or commercial information belonging to DTE Electric, the disclosure of which would cause DTE Electric and its customers competitive or commercial harm, seeks information involving Cyber Security, CEII (either critical energy infrastructure information or critical electric infrastructure information), North American Electric Reliability Corporation (NERC) NERC-CIP (including but not limited to BES Cyber Asset information subject to protection under the Information Protection Program pursuant to NERC Reliability Standards CIP003-6 and CIP-011-2), Supervisory Control and Data Acquisition (SCADA), confidential Midcontinent Independent System Operation (MISO) and ITC Holdings Corp and/or its affiliate companies' information in the possession of DTE Electric.

Subject to this objection, and without waiving this objection, DTE Electric would answer as follows:

Please see the attachment labelled "NDA CEII U-21534 MNSCDE-17.5a 4.8kV Circuits." Circuits are operated under a Distribution Design Order (DDO) limit, a specific form of a distribution standard intended to maintain system capacity and operational flexibility. Distribution circuits are designed to adhere to the Company's DDO. Based on the most recent Area Load Analysis, approximately 21.8% of load-carrying 4.8kV circuits will exceed their DDO limit in 2025 and 7.6% of load-carrying 4.8kV circuits will exceed their day-to-day rating.

Attachment: NDA CEII U-21534 MNSCDE-17.5a 4.8kV Circuits

Co-Respondent: Legal

MPSC Case No: U-21534

Requester: MNSC

Question No.: MNSCDE-17.6

Respondent: S. Deol

Page: 1 of 1

Question: 6. Refer to Deol rebuttal, p. 25, lines 8-11: Produce all documents you rely on for the claim that redundancy in the Subtransmission system is an industry best practice to allow for continued customer service during a single contingency situation.

Answer: Designing redundancy in the electrical system is considered necessary and part of good engineering practice when it comes to feeding substations that serve a large number of customers. To meet the level of service expected by customers, it is necessary to design and have available redundancy on subtransmission and transmission circuits that feed substations and potentially serve more than 10,000 customers. Except for extreme conditions, it is unreasonable to expect this number of customers to be without power for multiple days to complete work on restoring an unplanned outage or any planned outages to complete maintenance and replacement work.

Attachment: None.

MPSC Case No: U-21534

Requester: MNSC

Question No.: MNSCDE-19.5a.

Respondent: S. Deol

Page: 1 of 1

Question: Refer to Deol rebuttal, p. 24:

Identify all incidents in which customers were out of service during intentional interruptions (equipment shutdowns) in the past 5 years. For each provide the date, the number of customers interrupted (CI), and customer minutes interrupted (CMI).

Answer: The Company objects to this request because it is based on an inaccurate premise. My rebuttal testimony does not state customers' service is intentionally interrupted. On page 24 of my rebuttal testimony in the instant case, I state the following:

"Redundancy is also required to provide operational flexibility by allowing intentional interruptions (equipment shutdowns) to safely perform proactive maintenance activities and equipment upgrades, without impacting customer service. In several instances, intentional interruptions are limited to a short window of time during the year due to an existing thermal and/or voltage planning criteria violation."

Attachment: None.

MPSC Case No: U-21534

Requester: MNSC

Question No.: MNSCDE-19.5b.

Respondent: S. Deol

Page: 1 of 1

Question: Refer to Deol rebuttal, p. 24:

For the list of incidents provided in response to subpart a, identify which incidents were “limited to a short window of time during a year due to an existing thermal and/or voltage planning criteria violation” and provide a count of customer complaints recorded as a result.

Answer: Please see discovery response MNSCDE-19.5a.

Attachment: None.

MPSC Case No: U-21534

Requester: MNSC

Question No.: MNSCDE-19.6

Respondent: S. Deol

Page: 1 of 1

Question: Refer to Deol rebuttal, p. 25, lines 8-11: Identify all incidents in the past five years in which a subtransmission equipment outage resulted in 10,000 or more customer interruptions. For each, provide the date, CI, and CMI.

Answer: The Company objects to this request because it is based on an inaccurate premise. Page 25, lines 8-11 of my rebuttal testimony states the following:

"Given that subtransmission outages **can** impact multiple substations that **can** result in more than 10,000 customers impacted, redundancy in the Subtransmission system is an industry best practice to allow for continued customer service during a single contingency situation." (emphasis added)

My rebuttal testimony highlights the extent to which subtransmission outages **can** impact service to customers. Please also see discovery response MNSCDE-5.3a which provides subtransmission equipment outages including events where over 7,800 customers were impacted.

Attachment: None.

MPSC Case No: U-21534

Requester: MNSC

Question No.: MNSCDE-17.8

Respondent: S. Deol

Page: 1 of 1

Question: 8. Refer to Deol rebuttal, p. 27 lines 12-22: Identify all instances of subtransmission equipment that are experiencing loadings above 100% of their normal rating.

Answer: Please see the column labelled “% Loading N-0 violation” on pages 1 and 2 of Exhibit A-50, Schedule OO2 filed in the instant case.

Attachment: None.

MPSC Case No: U-21534

Requester: MNSC

Question No.: MNSCDE-17.9

Respondent: S. Deol

Page: 1 of 1

Question: 9. Refer to Deol rebuttal, Q&A36. Identify all Subtransmission Redesign and Rebuild projects that address equipment that has caused customer outages due to thermal violations like that described in the Trunk 359 example.

Answer: DTE Electric objects for the reasons that the request is overly broad, unduly burdensome and seeks excessive detail. In addition, the information requested consists of confidential, proprietary, research and development of trade secrets, or commercial information, the disclosure of which would cause DTE Electric, its ratepayers, and its customers competitive harm and is otherwise not reasonably calculated to lead to the discovery of admissible evidence. Subject to these objections, and without waiving these objections, DTE Electric would answer as follows:

The example provided was intended to highlight a situation in which the unavailable redundancy of the system directly resulted in customer outages. All planning criteria violations on the subtransmission system have the exposure to result in a similar outage to customers. A previous customer outage, as the result of a planning criteria violation, is not an exclusive criteria or driver for the need to address these existing issues with projects.

Attachment: None.

Co-Respondent: Legal

EXHIBIT MEC-87

RESERVED

MPSC Case No: U-21534

Requester: MNSC

Question No.: MNSCDE-17.10

Respondent: S. Deol

Page: 1 of 1

Question: 10. Refer to Deol rebuttal, Q&A37-38. Identify all Subtransmission Redesign and Rebuild projects that address equipment that has experienced voltage violations like that described in the Northeast Area Transformer example.

Answer: Please see the column labelled “N-1 Volt (% of nominal voltage)” on pages 3 and 4 of Exhibit A-50, Schedule OO2 filed in the instant case for the circuits and stations with a voltage violation. Please also see Exhibit A-23, Schedule M6 for project details on the associated circuits and stations.

Attachment: None.

EXHIBIT MEC-89

RESERVED

Michigan Public Service Commission
DTE Electric Company
Projected Capital Expenditures
Distribution Plant
($000)

Case No.: U-21297
Exhibit: A-12
Schedule: B5.4
Witness: B. L. Hill 1/
M. Elliott Andahazy 3/ 6/
P. Smith 7/
S. S. Deol 4/
S. M. Hartwick 8/
Page: 1 of 21

Line No.	(a) Description		(b) Historical 12 mos. ended 12/31/2021	(c) Projected Bridge Period 12 mos. ending 12/31/2022	(d) Projected Bridge Period 11 mos. ending 11/30/2023	(e) Projected Bridge Period 23 mos. ending 11/30/2023	(f) Projected Test Year 12 mos. ending 11/30/2024
				Capital Expenditures			
1	**Base Capital Programs**						
2	Emergent Replacements						
3	Storm	1/	395,286	176,904	202,195	379,099	226,440
4	Non - Storm	1/	209,236	265,214	167,818	433,033	187,941
5	Substation Reactive	1/	46,008	45,422	42,139	87,561	47,191
6	Emergent Replacement Reduction Based on Strategic Spend		-	-	(13,094)	(13,094)	(37,159)
7	Subtotal Emergent Replacements		650,531	487,541	399,057	886,598	424,413
8	Customer Connections, Relocations & Other						
9	Connections and New Load	2/	184,832	217,753	181,146	398,899	202,867
10	Relocations	2/	24,595	26,124	23,626	49,750	26,459
11	Electric System Equipment	2/	30,471	31,984	26,848	58,832	30,068
12	NRUC and Improvement Blankets	2/	22,905	36,629	20,534	57,163	22,996
13	General Plant, Tools & Equipment and Miscellaneous	2/	7,445	7,528	6,070	13,597	6,292
14	Public Lighting Department Project	2/	19,353	13,600	2,200	15,800	200
15	Subtotal Customer Connections, Relocations & Other		289,602	333,617	260,424	594,041	288,882
16	Customer Advances for Construction	2/	(25,397)	(26,755)	(24,890)	(51,646)	(27,875)
17	**Total Base Capital Programs**		**914,736**	**794,403**	**634,591**	**1,428,994**	**685,420**
18	**Strategic Capital Programs**						
19	Infrastructure Resilience and Hardening	3/	184,765	384,109	308,234	692,343	244,470
20	Infrastructure Redesign and Modernization	4/	94,275	162,735	312,669	475,404	526,398
21	Technology and Automation	5/ 6/ 7/ 8/	80,068	98,276	126,557	224,833	99,540
22	**Subtotal Strategic Capital Programs**		**359,108**	**645,120**	**747,460**	**1,392,580**	**870,409**
23	**Total Capital**		**1,273,843**	**1,439,523**	**1,382,051**	**2,821,574**	**1,555,829**
24	**Regulatory Asset**						
25	Advanced Distribution Management System (ADMS)	9/	**2,692**	**7,501**	**772**	**8,273**	**-**

1/ Exhibit A-12, Schedule B5.4 - page 3
2/ Exhibit A-12, Schedule B5.4 - pages 4-5, lines 9, 19, 26, 33, 38, 39 & 41
3/ Exhibit A-12, Schedule B5.4 - page 8, line 31
4/ Exhibit A-12, Schedule B5.4 - page 11, line111
5/ Exhibit A-12, Schedule B5.4 - page 12, line 41
6/ SOC projects sponsored by Company Witness M. Elliott Andahazy
7/ ADMS/AMI projects sponsored by Company Witness P. Smith
8/ Tree Trim project sponsored by Company Witness S.M. Hartwick
9/ Regulatory Asset treatment per Case No. U-20162

Michigan Public Service Commission
DTE Electric Company
Projected Capital Expenditures
Distribution Plant
($000)

Case No.: U-21297
Exhibit: A-12
Schedule: B5.4
Witness: B. L. Hill 1/
M. Elliott Andahazy 3/ 6/
P. Smith 7/
S. S. Deol 4/
S. M. Hartwick 8/
Page: 2 of 21

Line No.	(a) Description		(b) Historical 12 mos. ended 12/31/2021	(c) Normalization Adjustment 10/	(d) Adjusted Historical Test Period sum (b) thru (c)	(e) Projected Calendar Year 12 mos. ending 12/31/2022	(f) Projected Calendar Year 12 mos. ending 12/31/2023	(g) Projected Calendar Year 12 mos. ending 12/31/2024
					Capital Expenditures			
1	**Base Capital Programs**							
2	Emergent Replacements							
3	Storm	1/	395,286	(188,977)	206,310	176,904	220,576	226,973
4	Non - Storm	1/	209,236	(38,003)	171,233	265,214	183,074	188,384
5	Substation Reactive	1/	46,008	(3,012)	42,996	45,422	45,969	47,302
6	Emergent Replacement Reduction Based on Strategic Spend		-	-	-	-	(14,285)	(39,239)
7	Subtotal Emergent Replacements		650,531	(229,992)	420,539	487,541	435,335	423,420
8	Customer Connections, Relocations & Other							
9	Connections and New Load	2/	184,832			217,753	197,614	203,345
10	Relocations	2/	24,595			26,124	25,773	26,521
11	Electric System Equipment	2/	30,471			31,984	29,289	30,138
12	NRUC and Improvement Blankets	2/	22,905			36,629	22,401	23,051
13	General Plant, Tools & Equipment and Miscellaneous	2/	7,445			7,528	6,622	6,262
14	Public Lighting Department Project	2/	19,353			13,600	2,400	-
15	Subtotal Customer Connections, Relocations & Other		289,602			333,617	284,099	289,317
16	Customer Advances for Construction	2/	(25,397)			(26,755)	(27,153)	(27,940)
17	**Total Base Capital Programs**		**914,736**			**794,403**	**692,281**	**684,797**
18	**Strategic Capital Programs**							
19	Infrastructure Resilience and Hardening	3/	184,765			384,109	333,807	238,796
20	Infrastructure Redesign and Modernization	4/	94,275			162,735	341,094	543,244
21	Technology and Automation	5/ 6/ 7/ 8/	80,068			98,276	136,604	97,538
22	**Subtotal Strategic Capital Programs**		**359,108**			**645,120**	**811,505**	**879,579**
23	**Total Capital**		**1,273,843**			**1,439,523**	**1,503,786**	**1,564,376**
24	**Regulatory Asset**							
25	Advanced Distribution Management System (ADMS)	9/	**2,692**	**2,692**		**7,501**	**772**	**-**

1/ Exhibit A-12, Schedule B5.4 - page 3
2/ Exhibit A-12, Schedule B5.4 - pages 4-5, lines 9, 19, 26, 33, 38, 39 & 41
3/ Exhibit A-12, Schedule B5.4 - page 8, line 31
4/ Exhibit A-12, Schedule B5.4 - page 11, line111
5/ Exhibit A-12, Schedule B5.4 - page 12, line 41
6/ SOC projects sponsored by Company Witness M. Elliott Andahazy
7/ ADMS/AMI projects sponsored by Company Witness P. Smith
8/ Tree Trim project sponsored by Company Witness S.M. Hartwick
9/ Regulatory Asset treatment per Case No. U-20162
10/ Normalization Adjustment:

	Amount
Emergent Replacements (Exh. B5.4, p.3, Line 24, col. (j)	(229,992)

Michigan Public Service Commission
DTE Electric Company
Projected Capital Expenditures
Distribution Plant - Emergent Replacements
($000)

Case No.: U-21297
Exhibit: A-12
Schedule: B5.4
Witness: B. L. Hill
Page: 3 of 21

	(a)		(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
			Capital Expenditures								
Line No.	Description		Historical 12 mos. ended 12/31/2017	Historical 12 mos. ended 12/31/2018	Historical 12 mos. ended 12/31/2019	Historical 12 mos. ended 12/31/2020	Historical 12 mos. ended 12/31/2021	Historical 5-year average 1/	12/1/2023 - 11/30/2024 Test Year	1/1/2021 - 12/31/2021 Historical	Emergent Replacements Adjustment (h) - (i)
1	**Base Capital Programs**										
2	**Emergent Replacements**										
3	**Storm**		122,588	142,108	178,931	150,897	395,286	197,962			
4	Inflation Adjustment		12,813	11,175	10,658	7,092	-	8,348			
5	Inflation Adjusted Historical Capital		135,401	153,283	189,589	157,989	395,286	206,310	206,310	395,286	(188,977)
6	Inflation 1/1/22 -12/31/22	3.60%							7,427	14,230	(6,803)
7	Inflation 1/1/23 -12/31/23	3.20%							6,840	13,105	(6,265)
8	Inflation 1/1/24-11/30/24	2.66%							5,864	11,235	(5,371)
9	Projected Storm Replacements								226,440	433,856	(207,416)
10	**Non-Storm**		126,187	159,555	163,112	155,324	209,236	162,683			
11	Inflation Adjustment		13,190	12,547	9,716	7,300	-	8,550			
12	Inflation Adjusted Historical Capital		139,377	172,102	172,827	162,624	209,236	171,233	171,233	209,236	(38,003)
13	Inflation 1/1/22 -12/31/22	3.60%							6,164	7,533	(1,368)
14	Inflation 1/1/23 -12/31/23	3.20%							5,677	6,937	(1,260)
15	Inflation 1/1/24-11/30/24	2.66%							4,867	5,947	(1,080)
16	Projected Non-Storm Replacements								187,941	229,652	(41,711)
17	**Substation Reactive**		34,857	44,275	40,386	38,131	46,008	40,732			
18	Inflation Adjustment		3,643	3,482	2,406	1,792	-	2,265			
19	Inflation Adjusted Historical Capital		38,500	47,756	42,792	39,924	46,008	42,996	42,996	46,008	(3,012)
20	Inflation 1/1/22 -12/31/22	3.60%							1,548	1,656	(108)
21	Inflation 1/1/23 -12/31/23	3.20%							1,425	1,525	(100)
22	Inflation 1/1/24-11/30/24	2.66%							1,222	1,308	(86)
23	Projected Substation Reactive Replacements								47,191	50,497	(3,306)
24	**Total Emergent Replacements Normalization Adjustment (Line 5 + Line 12 + Line 19) Pre-inflation**								**420,539**	**650,531**	**(229,992)** 2/
25	Inflation 1/1/22 -12/31/22	3.60%							15,139	23,419	(8,280)
26	Inflation 1/1/23 -12/31/23	3.20%							13,942	21,566	(7,625)
27	Inflation 1/1/24-11/30/24	2.66%							11,952	18,489	(6,537)
28	Total Projected Emergent Replacements Expense (Line 11 + Line 18 + Line 25)								**461,573**	**714,005**	**(252,433)**
								Savings	**(37,159)**		

1/ Five year average of actual expenditures adjusted for inflation is included in this request
2/ Historical normalization adjustment carried to Base Capital Programs - see Exhibit A-12, B5.4, page 2, line 7, col. (c)

Michigan Public Service Commission
DTE Electric Company
Projected Capital Expenditures
Distribution Plant - Connections, Relocations and Other
($000)

Case No.: U-21297
Exhibit: A-12
Schedule: B5.4
Witness: B. L. Hill
Page: 4 of 21

Line No.	Description		(a)	(b) Historical	(c) Projected Calendar Year	(d) Projected Calendar Year	(e) Projected Calendar Year	(f) Bridge Period	(g) Test Year
				Capital Expenditures					
				12 mos. ended 12/31/2021	12 mos. ending 12/31/2022	12 mos. ending 12/31/2023	12 mos. ending 12/31/2024	23 mos. ending 11/30/2023	12 mos. ending 11/30/2024
1	**Connections and New Load**								
2	Small Load Growth Projects (Blanket)			21,661	14,981	23,159	23,831	36,210	23,775
3	Customer Connections			108,810	129,249	116,335	119,708	235,889	119,427
4	Customer Connections CIAC			(15,524)	(22,338)	(16,598)	(17,079)	(37,553)	(17,039)
5	Customer Connections (Net of CIAC)			93,286	106,912	99,737	102,629	198,337	102,388
6	New Business Projects	1/		54,361	73,523	58,120	59,806	126,800	59,665
7	New Business Projects CIAC			(9,390)	(2,758)	(10,039)	(10,330)	(11,960)	(10,306)
8	Subtotal New Business Projects (net of CIAC)			44,971	70,765	48,081	49,475	114,840	49,359
9	**Total Connections and New Load**			**184,832**	**217,753**	**197,614**	**203,345**	**398,899**	**202,867**
10	**Total Connections and New Load CIAC**			(24,914)	(25,096)	(26,637)	(27,410)	(49,513)	(27,345)
11	**Total Connections and New Load (Net of CIAC)**			159,918	192,657	170,977	175,935	349,386	175,522
12	**Relocations**								
13	Small Relocation Projects (Blanket)			7,018	9,521	7,503	7,721	16,399	7,703
14	Major Infrastructure Relocation Project								
15	Gordie Howe International Bridge			489	484	-	-	484	-
16	Relocation Projects (excl.Major Infrastructure Projects)	2/		17,089	16,119	18,270	18,800	32,867	18,756
17	Relocation Projects CIAC			(483)	(1,660)	(516)	(531)	(2,133)	(530)
18	Subtotal Relocation Projects (Net of CIAC)			16,606	14,459	17,754	18,269	30,734	18,226
19	**Total Relocations**			**24,595**	**26,124**	**25,773**	**26,521**	**49,750**	**26,459**
20	**Total Relocations CIAC**			(483)	(1,660)	(516)	(531)	(2,133)	(530)
21	**Total Relocations (Net of CIAC)**			24,113	24,464	25,257	25,990	47,617	25,929
22	**Electric System Equipment**								
23	Distribution Transformers & Regulators			3,076	8,991	-	-	8,991	-
24	Major Equipment			13,594	7,166	14,534	14,956	20,489	14,921
25	Meters			13,800	15,827	14,755	15,183	29,352	15,147
26	**Total Electric System Equipment**			**30,471**	**31,984**	**29,289**	**30,138**	**58,832**	**30,068**

Michigan Public Service Commission
DTE Electric Company
Projected Capital Expenditures
Distribution Plant - Connections, Relocations and Other
($000)

Case No.: U-21297
Exhibit: A-12
Schedule: B5.4
Witness: B. L. Hill
Page: 5 of 21

(a)	(b)	(c)	(d)	(e)	(f)	(g)
			Capital Expenditures			
	Historical	**Projected Calendar Year**			**Bridge Period**	**Test Year**
Line No. **Description**	**12 mos. ended 12/31/2021**	**12 mos. ending 12/31/2022**	**12 mos. ending 12/31/2023**	**12 mos. ending 12/31/2024**	**23 mos. ending 11/30/2023**	**12 mos. ending 11/30/2024**
27 **NRUC and Improvement Blankets**						
28 System Improvements	9,715	23,187	10,387	10,688	32,708	10,663
29 Normal Retirement Unit Changeouts (NRUC)	5,702	5,490	6,096	6,273	11,078	6,258
30 Operational Technologies	5,535	5,692	5,918	6,089	11,117	6,075
31 Batteries and Chargers	1,918	2,254	-	-	2,254	-
32 Animal Mitigation	35	5	-	-	5	-
33 **Total NRUC and Improvement Blankets**	**22,905**	**36,629**	**22,401**	**23,051**	**57,163**	**22,996**
34 **General Plant, Tools & Equipment and Miscellaneous**						
35 Substation Physical Security	1,753	724	536	-	1,215	45
36 Warren SC Transformer Yard Reorganizaton	-	-	-	-	-	-
37 General Plant, Tools & Equipment and Miscellaneous	5,692	6,803	6,086	6,262	12,382	6,248
38 **Total General Plant, Tools & Equipment and Miscellaneous**	**7,445**	**7,528**	**6,622**	**6,262**	**13,597**	**6,292**
39 **Public Lighting Department Project**	19,353	13,600	2,400	-	15,800	200
40 **Total Customer Connections, Relocations & Other**	289,602	333,617	284,099	289,317	594,041	288,882
41 **Total Cust Connections, Relocations & Other CIAC**	(25,397)	(26,755)	(27,153)	(27,940)	(51,646)	(27,875)
42 **Total Cust Connections, Relocations & Other Net of CIAC**	264,205	306,862	256,946	261,376	542,396	261,007

1/ Exhibit A-12, Schedule B5.4 - page 6, line 65
2/ Exhibit A-12, Schedule B5.4 - page 7, line 26

Michigan Public Service Commission Case No.: U-21297
DTE Electric Company Exhibit: A-12
Projected Capital Expenditures Schedule: B5.4
Distribution Plant - Prior Year's Projects Witness: B. L. Hill
($000) Page: 6 of 21

Line No.	(a) Description	(b) Historical 12 mos. ended 12/31/2021
1	**Prior Year's New Business Projects:**	
2	New Business: CORKT New Circuits	7,359
3	New Business fed from Saturn	4,304
4	New Business fed from GRAYL	4,098
5	New Business fed from WHITR2699	3,938
6	New Business fed from AKRON	2,849
7	New Business fed from SAVAN/HLTRD Sub	2,617
8	New Business alley vacate	2,409
9	New Substation (Nitro) to support new load	2,363
10	New Substation (Globe) to support new load	2,319
11	Support Load OMEGA/ Boyne	2,307
12	New Business for downtown complex	2,127
13	Load Growth: Morton	1,972
14	New Substation (Morton) to support new load	1,691
15	New Business fed from Erin-Stephens 120kV	1,370
16	New Business fed from PHENX DC 9821	1,167
17	New Business fed from Lombard	994
18	New Business fed from TEMPL, STANT, MADSN	941
19	New Business - MCGRW96	871
20	Support Load Armada DC8550	767
21	New Skid Mount Substation Orion Township	717
22	Quaker Transformer Upgrade	663
23	New Business fed from CATO STANT	607
24	Misc. New Business Specific Projects	600
25	New Business fed from 120kV Waterman Zug	574
26	New Business fed from CODY	450
27	New Business fed from Seaside	446
28	New Business NINMI	434
29	New Business fed from BURTN	433
30	New Business fed from Sheldon	420
31	New Business fed from MIDTN SPOOL	404
32	New Business fed from KERN Substation	337
33	New Business fed from CORTL	329
34	New Business CATLI	306
35	Load growth- SLATR 2652 Voltage violations	273
36	New Business fed from Alamo Substation	252
37	New Business fed from INKST	217
38	New Business fed from Midtown	122
39	New Business -Lenox-Stephens 120kV line	106
40	Expand Explorer Substation for New Business	93
41	New Business fed from Hood Substation	73
42	Add PL 9178 Giddings for New Business	72
43	New Substation (Kings Point Gratiot) to support new load	67
44	System Loading: Grayling	60
45	New Business Fed from CORTL/ 1089 & 0673	50
46	New Business: SRGNT8268, ANGLA8862, ANGLA9258	50
47	New Business fed from OTTWA 9530	43
48	New Business -TRK 2439	31
49	New Substation (AIRPT) to support new load	26
50	New Business Henry St	18
51	New Business fed from TIE1544	16
52	Support Load - SWANC	14
53	New Business CYPRS-FALCN	3
54	New Class I Farmington Hills	3
55	New Business: Feed from SNOVR- DC0301	2
56	New Business fed from POLRS & LIVON	2
57	New Business fed from PRICE	2
58	New Business fed from Fleming Substation	2
59	New Business: Feed from NAVAR1172	1
60	New Business fed from Whittier	1
61	New Business Compressor Station	1
62	New Business fed from TRK5817	0
63	New Business fed from APACE	(3)
64	New Business fed from Boyne Substation	(413)
65	**Total Prior Year's New Business Projects**	**54,361**

Michigan Public Service Commission Case No.: U-21297
DTE Electric Company Exhibit: A-12
Projected Capital Expenditures Schedule: B5.4
Distribution Plant - Prior Year's Projects Witness: B. L. Hill
($000) Page: 7 of 21

Line No.	(a) Description	(b) Historical 12 mos. ended 12/31/2021
1	**Prior Year's Relocation Projects:**	
2	Relocate for Manhole -Midtown, Stone Pool and Garfield	6,774
3	Relocate - Trk 629A-B, Trk 635S-A	1,613
4	Mound Rd Relocation	1,507
5	Cass I-94 Bridge	1,446
6	Relocate for BNSTN9700 & TRK1346	1,443
7	Relocate for Trk 682, Trk 675, Trk 663A-S	1,176
8	Relocate for Trk 2107A-B Relocation	892
9	Relocate -ACSR LW Palms 1PN to 2PS Gratiot Ave	838
10	ZEBRA Relocation	529
11	Grand River I-94 Bridge	302
12	Maple Rd Relocation	211
13	Park Rd Relocation	93
14	OH Crossing at I-75	74
15	Relocate for ITC	72
16	Bates & Monroe Alley	51
17	Relocate for rail right of way	30
18	Relocate for Trk 359/ 306 /318A-B & DC209	26
19	Mt. Elliot I-94 Bridge Relocation	11
20	New Boston Twp Relocation	6
21	Pipeline Relocation	4
22	Dearborn Relocation	3
23	Temple West block Relocation	3
24	23 Mile Rd Relocation Phase 2	(2)
25	Wahington Rd Relocation	(12)
26	**Total Prior Year's Relocation Projects**	**17,089**

Michigan Public Service Commission
DTE Electric Company
Projected Capital Expenditures
Distribution Plant - Infrastructure Resilience and Hardening
($000)

Case No.: U-21297
Exhibit: A-12
Schedule: B5.4
Witness: M. Elliott Andahazy
Page: 8 of 21

Line No.	(a) Description		(b) Historical 12 mos. ended 12/31/2021	(c) Projected Calendar Year 12 mos. ending 12/31/2022	(d) Projected Calendar Year 12 mos. ending 12/31/2023	(e) Projected Calendar Year 12 mos. ending 12/31/2024	(f) Bridge Period 23 mos. ending 11/30/2023	(g) Test Year 12 mos. ending 11/30/2024
			Capital Expenditures					
1	**Infrastructure Resilience and Hardening**							
2	Mobile Fleet Program		5,984	13,566	5,305	4,500	18,429	4,567
3	Substation Risk: Drexel		1,663	1,915	268	-	2,160	22
4	Substation Risk: Chestnut		534	161	3,715	7,245	3,566	6,951
5	Substation Risk: Savage		211	562	2	-	564	0
6	Substation Risk: Apache		1,908	3,381	11,628	2,638	14,040	3,387
7	Substation Risk: Port Huron		2,969	184	-	-	184	-
8	Substation Risk: Belleville Switchgear Decommission		298	1,206	1,006	-	2,128	84
9	Substation Risk: McGraw		518	10,740	29,714	9	37,978	2,485
10	Substation Risk: Voyager		-	200	-	-	200	-
11	Substation Risk: Flood Defense Program		-	74	5,800	-	5,391	483
12	4.8 kV Hardening		65,362	151,314	80,000	-	224,647	6,667
13	Pole and Pole Top Maintenance and Modernization (PTMM)		31,647	70,224	63,445	120,587	128,383	115,825
14	Cable Replacement Program		14,984	27,452	24,870	25,000	50,250	24,989
15	Frequent Outage Program (CEMI)		23,251	55,597	55,252	47,625	106,245	48,261
16	Breaker Replacement Program	1/	17,365	13,576	13,177	-	26,753	-
17	Pontiac Vaults		3,044	1,355	58	-	1,408	5
18	URD Replacement Program	1/	4,705	6,336	13,750	-	20,086	-
19	URD Replacement Program: Detroit URD 1-1		1,595	1,061	-	-	1,061	-
20	40 kV: Automatic Pole Top Switch		1,301	3,419	6,325	6,338	9,217	6,337
21	Disconnect and Switcher Replacement		3,863	2,970	4,900	4,900	7,462	4,900
22	SCADA Pole Top Device Replacement		999	584	1,611	1,808	2,061	1,792
23	Substation Regulator Replacement		-	422	894	904	1,242	904
24	Steel Pole Highway Crossings		18	1,935	3,000	5,000	4,685	4,833
25	Station Upgrade: Warren (Relay Replacement)		115	3,183	-	-	3,183	-
26	Station Upgrade: Northeast (Relay Replacement)		2,431	12,494	2,417	-	14,709	201
27	Station Upgrade: Lincoln		-	-	330	5,300	303	4,886
28	Station Upgrade: Navarre		-	-	-	330	-	303
29	Station Upgrade: 120kV Relays Upgrade for ITC Projects		-	198	3,839	4,112	3,717	4,089
30	Batteries and Chargers Replacement Program		-	-	2,500	2,500	2,292	2,500
31	**Total Infrastructure Resilience and Hardening Projects and Programs**		**184,765**	**384,109**	**333,807**	**238,796**	**692,343**	**244,470**

1/ Projected test year capital expenditures for Breaker Replacement and URD Replacement Programs are included in the IRM request (see Exhibit A-33, Schedule X3).

Michigan Public Service Commission
DTE Electric Company
Projected Capital Expenditures
Distribution Plant - Infrastructure Redesign and Modernization
($000)

Case No.: U-21297
Exhibit: A-12
Schedule: B5.4
Witness: S. S. Deol
Page: 9 of 21

(a)		(b)	(c)	(d)	(e)	(f)	(g)
		Capital Expenditures					
		Historical	Projected Calendar Year			Bridge Period	Test Year
Line No.	Description	12 mos. ended 12/31/2021	12 mos. ending 12/31/2022	12 mos. ending 12/31/2023	12 mos. ending 12/31/2024	23 mos. ending 11/30/2023	12 mos. ending 11/30/2024
1	**Infrastructure Redesign and Modernization**						
2	Ann Arbor System Improvements: State Substation	8,259	6,004	1,608	-	7,477	134
3	Ann Arbor System Improvements: Apex (Blue) Substation	-	3,489	1,933	-	5,260	161
4	Ann Arbor System Improvements: Argo 40kV Reconfiguration	-	788	7,920	7,400	8,048	7,443
5	Subtransmission Redesign & Rebuild: Transformer High Side Protection Program	1,500	887	5,500	5,500	5,929	5,500
6	Subtransmission Redesign & Rebuild: Tie 4104	-	106	1,004	11,697	1,027	10,806
7	Subtransmission Redesign & Rebuild: Maxwell Amherst	22	192	-	-	192	-
8	Subtransmission Redesign & Rebuild: Tie 810	1,630	9,100	20,000	20,890	27,433	20,816
9	Subtransmission Redesign & Rebuild: Trunk 7106	2,395	206	-	-	206	-
10	Subtransmission Redesign & Rebuild: Trunk 2255	190	2,339	34	-	2,370	3
11	Subtransmission Redesign & Rebuild: Trunk 2237-ST	143	1,051	-	-	1,051	-
12	Subtransmission Redesign & Rebuild: Trunk 7333	2,918	1,229	-	-	1,229	-
13	Subtransmission Redesign & Rebuild: Sandusky Transformer 101 Breaker	-	-	4,283	-	3,926	357
14	Subtransmission Redesign & Rebuild: Boyne	3,675	14,185	7,037	-	20,636	586
15	Subtransmission Redesign & Rebuild: Tie 6907	-	-	426	1,790	391	1,677
16	Subtransmission Redesign & Rebuild: Tie 7504	2	14	1,628	6,430	1,506	6,030
17	Subtransmission Redesign & Rebuild: Tie 4105	6,659	12,971	19,949	10,629	31,258	11,406
18	Subtransmission Redesign & Rebuild: Trunk 2308	-	51	7,244	2,030	6,692	2,465
19	Subtransmission Redesign & Rebuild: Tie 1568	3	47	688	-	678	57
20	Subtransmission Redesign & Rebuild: Trunk 4217	316	300	4,865	-	4,760	405
21	Subtransmission Redesign & Rebuild: Trunk 3509	-	159	1,184	1,217	1,245	1,214
22	Subtransmission Redesign & Rebuild: Trunk 4266	-	17	270	5,096	265	4,694
23	Subtransmission Redesign & Rebuild: Badax Transformer 102 Addition	-	611	7,820	1,503	7,779	2,030
24	Subtransmission Redesign & Rebuild: Trunk 4245	7	8	3,059	1,000	2,812	1,172
25	Subtransmission Redesign & Rebuild: Tie 6602	-	-	660	3,689	605	3,436
26	Subtransmission Redesign & Rebuild: Trunk 4911	-	44	894	8,209	864	7,599
27	Subtransmission Redesign & Rebuild: Custer Republic	-	-	159	1,658	146	1,533
28	Subtransmission Redesign & Rebuild: Trunk 2419	-	-	169	785	155	734
29	Subtransmission Redesign & Rebuild: Tie 3205	-	17	500	4,793	475	4,435
30	Subtransmission Redesign & Rebuild: Praxair	-	18	2,767	-	2,554	231
31	Subtransmission Redesign & Rebuild : Small Projects & Reserve	-	4	34	415	36	383
32	Subtransmission Breaker Short Circuit Violations	13	1,594	1,414	95	2,890	205
33	Subtransmission Redesign & Rebuild: Slocum	-	698	737	-	1,374	61
34	Subtransmission Redesign & Rebuild: Kennett	-	-	437	315	401	326
35	Subtransmission Redesign & Rebuild: Trunk 4601	-	-	214	1,711	197	1,586
36	Subtransmission Redesign & Rebuild: Tempest Phase II	-	-	970	8,353	889	7,737
37	Subtransmission Redesign & Rebuild: Waterman	-	-	103	2,207	94	2,031
38	Subtransmission Redesign & Rebuild: Trunk 7105	-	-	61	270	55	253
39	Subtransmission Redesign & Rebuild: Tie 5208	-	-	50	500	46	463
40	Subtransmission Redesign & Rebuild: Cortland Station Expansion	1,083	908	343	2,379	1,222	2,209
41	Subtransmission Redesign & Rebuild: 40kV Capacitor Banks at Armada and Adair	970	1,725	950	-	2,596	79

Michigan Public Service Commission
DTE Electric Company
Projected Capital Expenditures
Distribution Plant - Infrastructure Redesign and Modernization
($000)

Case No.: U-21297
Exhibit: A-12
Schedule: B5.4
Witness: S. S. Deol
Page: 10 of 21

(a)		(b)	(c)	(d)	(e)	(f)	(g)
		Capital Expenditures					
		Historical	Projected Calendar Year			Bridge Period	Test Year
Line No.	Description	12 mos. ended 12/31/2021	12 mos. ending 12/31/2022	12 mos. ending 12/31/2023	12 mos. ending 12/31/2024	23 mos. ending 11/30/2023	12 mos. ending 11/30/2024
42	CODI: Charlotte Network Upgrade	8,100	8,286	6,658	11,673	14,389	11,255
43	CODI: Targeted Network Secondary Cable Replacement	869	1,789	3,800	3,800	5,272	3,800
44	CODI: Corktown Substation	13,301	1,360	-	-	1,360	-
45	CODI: Islandview Substation	3,264	12,912	35,745	46,424	45,679	45,534
46	CODI: CATO Substation Expansion	-	319	10,795	13,300	10,214	13,091
47	CODI: Howard Conversion	-	2	700	15,000	644	13,808
48	CODI: Midtown Substation Expansion	6,510	2,234	1,803	-	3,887	150
49	CODI: Alfred Substation Expansion	417	53	4,137	11,782	3,846	11,145
50	CODI: Garfield Network Upgrade	11,177	18,193	30,000	36,220	45,693	35,701
51	CODI: Kent/Gibson Conversion	211	2,051	19,810	39,751	20,209	38,089
52	4.8 kV CC: Hilton Substation and Circuit Conversion	93	-	-	-	-	-
53	4.8 kV CC: Zenon Substation and Circuit Conversion	29	1	-	-	1	-
54	4.8 kV CC: Cortland / Oakman / Linwood Consolidation	1,579	387	-	-	387	-
55	4.8 kV CC: Ariel Substation and Circuit Conversion	597	1,032	600	-	1,582	50
56	4.8 kV CC: I-94 Substation and Circuit Conversion (Promenade)	502	14,509	9,959	33,139	23,638	31,207
57	4.8 kV CC: Almont Relief and Circuit Conversion (Midas)	5,585	12,643	3,565	-	15,911	297
58	4.8 kV CC: Buckler Circuit Conversion	2,169	8,136	2,865	2,648	10,762	2,666
59	4.8 kV CC: Calla Circuit Conversion and Phase 2	327	65	17	3,926	80	3,601
60	4.8 kV CC: Lapeer - Elba Expansion and Circuit Conversion (Apollo)	988	2,710	8,682	16,982	10,668	16,290
61	4.8 kV CC: McKinstry Sub Decommission	114	68	4,628	-	4,311	386
62	4.8 kV CC: Quincy Conversion	888	1,021	2,338	-	3,164	195
63	4.8 kV CC: Pinegrove Substation Relocation and Conversion	1,455	2,520	43,760	24,780	42,633	26,362
64	4.8 kV CC: Pinegrove Substation Relocation and Conversion CIAC	-	-	(15,300)	(8,700)	(14,025)	(9,250)
65	4.8 kV CC: Hawthorne Relief and Circuit Conversion	-	402	6,000	13,000	5,902	12,417
66	4.8 kV CC: Hawthorne Trf #2 and Secondary Cable Replacement	-	59	1,790	-	1,700	149
67	4.8 kV CC: Birmingham Decommissioning and Circuit Conversion	-	1	1,501	4,540	1,376	4,287
68	4.8 kV CC: Crestwood Substation	-	23	-	-	23	-
69	4.8 kV CC: MAUME 8241 Downtown Clawson Conversion	-	2,638	3	-	2,642	0
70	4.8 kV CC: Power line Conversion of MADSN 175L-W	-	123	238	-	341	20
71	4.8 kV CC: GRFIN & WMSTN Conversions	-	508	4,145	8,019	4,307	7,696
72	4.8 kV CC: ISO Conversion Program	-	33	7,000	40,000	6,449	37,250
73	4.8kV CC: SCOTN	1	49	2,710	1,087	2,534	1,222
74	4.8kV CC: Rochester Decommissioning and Tienken Relief	-	-	104	711	95	661
75	4.8 kV CC: Ann Arbor AC Network Conversion	-	-	135	711	124	663
76	4.8kV CC: Pittsfield Substation and Circuit Conversion	-	-	178	2,423	163	2,236
77	4.8kV CC: Hemlock Decommissioning and Circuit Conversion	-	-	158	1,371	144	1,270
78	4.8kV CC: Yale-Slater Decommissioning and Circuit Conversion	-	-	269	4,319	247	3,982
79	4.8 kV CC: Slater	-	1,930	-	-	1,930	-
80	4.8 kV CC: Grosse Pointe Substation and Circuit Conversion	-	-	2,000	15,100	1,833	14,008
81	4.8 kV CC: Royal Oak Substation and Circuit Conversion	-	-	2,000	15,100	1,833	14,008
82	8.3 kV CC: Pontiac Overhead Conversion	872	3,016	12,420	23,582	14,402	22,652
83	8.3 kV CC: Pontiac Underground Conversion	43	702	1,208	3,428	1,809	3,243

Michigan Public Service Commission
DTE Electric Company
Projected Capital Expenditures
Distribution Plant - Infrastructure Redesign and Modernization
($000)

Case No.: U-21297
Exhibit: A-12
Schedule: B5.4
Witness: S. S. Deol
Page: 11 of 21

(a)		(b)	(c)	(d)	(e)	(f)	(g)
		Capital Expenditures					
		Historical	Projected Calendar Year			Bridge Period	Test Year
Line No.	Description	12 mos. ended 12/31/2021	12 mos. ending 12/31/2022	12 mos. ending 12/31/2023	12 mos. ending 12/31/2024	23 mos. ending 11/30/2023	12 mos. ending 11/30/2024
84	System Loading: Brest Substation	58	-	-	-	-	-
85	System Loading: Carleton	2,304	376	28	-	401	2
86	System Loading: Grayling	0	-	-	-	-	-
87	System Loading: Prospect	2	-	-	-	-	-
88	System Loading: Mandy 307 Load Transfer	720	24	-	-	24	-
89	System Loading: Brown City	125	44	4,685	8,392	4,339	8,083
90	System Loading: Mack Transformer 102	252	54	8	-	61	1
91	System Loading: Port Sanilac	-	35	303	6,034	312	5,557
92	System Loading: Richmond/Armada	1,217	1,164	6,351	7,050	6,986	6,992
93	System Loading: Cody	-	-	461	1,584	423	1,491
94	System Loading: Otsego/Capac/Shaw	-	-	396	1,688	363	1,580
95	System Loading: Macomb/Golf	-	-	-	126	-	116
96	System Loading: Grenada	32	185	2,105	7,535	2,114	7,083
97	System Loading: Malta Circuits	1	-	-	-	-	-
98	System Loading: Lark/Spruce	-	12	44	607	52	560
99	System Loading: Globe	-	-	500	2,358	458	2,203
100	System Loading: Jewell	-	-	-	500	-	458
101	System Loading: Mayville	-	-	-	150	-	138
102	System Loading: Goodison	-	-	-	79	-	72
103	System Loading: Wixom	-	-	500	3,033	458	2,822
104	System Loading: Diamond	-	-	-	21	-	19
105	System Loading: Spokane/Seneca	-	-	116	5,984	106	5,495
106	System Loading: Sterling	-	-	95	756	87	701
107	System Loading: Disco	-	-	43	417	39	386
108	System Loading: Tahoe	-	-	25	354	23	327
109	Pilot: Strategic and Service Undergrounding	256	454	2,100	1,900	2,379	1,917
110	Pilot: Primary Deconductoring	432	1,848	-	-	1,848	-
111	**Total Infrastructure Redesign and Modernization Projects and Programs**	**94,275**	**162,735**	**341,094**	**543,244**	**475,404**	**526,398**
112	**Category Summary**						
113	Ann Arbor System Improvements (Sum lines 2 thru 4)	8,259	10,281	11,460	7,400	20,786	7,738
114	Subtransmission Redesign and Rebuild (Sum lines 5 thru 41) 1/	21,527	48,483	95,454	103,161	135,982	102,519
115	Conversions (Sum lines 42 thru 83) 1/	59,092	99,774	216,421	384,115	298,161	370,141
116	System Loading (Sum lines 84 thru 108)	4,710	1,894	15,659	46,668	16,248	44,084
117	Pilots (Sum lines 109 thru 110)	688	2,303	2,100	1,900	4,228	1,917
118	**Total Infrastructure Redesign and Modernization Projects and Programs**	**94,275**	**162,735**	**341,094**	**543,244**	**475,404**	**526,398**

1/ Capital expenditures for new projects starting in the projected test year within Subtransmission Redesign/Rebuild and Conversions/Consolidation are included in the IRM request (see Exhibit A-33, Schedule X3).

Michigan Public Service Commission
DTE Electric Company
Projected Capital Expenditures
Distribution Plant - Technology and Automation
($000)

Case No.: U-21297
Exhibit: A-12
Schedule: B5.4
Witness: B. L. Hill
M. Elliott Andahazy 1/
P. Smith 2/
S. M. Hartwick 3/
Page: 12 of 21

Line No.	(a) Description		(b) Historical 12 mos. ended 12/31/2021	(c) Projected Calendar Year 12 mos. ending 12/31/2022	(d) Projected Calendar Year 12 mos. ending 12/31/2023	(e) Projected Calendar Year 12 mos. ending 12/31/2024	(f) Bridge Period 23 mos. ending 11/30/2023	(g) Test Year 12 mos. ending 11/30/2024
				Capital Expenditures				
1	**Technology and Automation**							
2	ADMS: DMS/OMS	2/	22,390	28,165	10,840	-	38,102	903
3	ADMS: Network Management System	2/	1,292	1,328	2,900	2,900	3,986	2,900
4	SOC: ESOC	1/	14,859	1,420	200	-	1,604	17
5	SOC: ASOC	1/	463	7,046	27,100	1,000	31,888	3,258
6	Grid Automation Telecommunications (13.2kV Telecommunications)		10,239	14,206	19,100	16,861	31,714	17,047
7	Distribution Sensing and Monitoring (incldg Line Sensors)		2,466	1,523	-	-	1,523	-
8	Tree Trim Risk Prioritization Model	3/	-	-	1,440	-	1,320	120
9	Automation: Substation		111	490	5,000	25,000	5,073	23,333
10	Automation: 13.2kV Circuit Distribution		-	-	2,000	4,000	1,833	3,833
11	CVR/VVO		4,603	4,912	-	5,000	4,912	4,583
12	NWA: O'Shea Energy Storage		1,096	1,067	350	-	1,388	29
13	NWA: Battery Trailer		-	949	750	2,250	1,637	2,125
14	NWA: Omega Load Relief		5,545	2,197	700	-	2,839	58
15	NWA: Fisher Load Relief		11	77	1,350	4,650	1,315	4,375
16	NWA: Port Austin Load Relief		-	598	4,282	775	4,523	1,068
17	NWA: Veridian		-	387	3,308	4,625	3,420	4,516
18	NWA: Small Solar and Storage Testbed		446	337	500	500	796	500
19	NWA: EV Charging Demonstration at ACM		600	1,231	1,300	2,628	2,423	2,518
20	Technology Programs & NWA		4	0	-	-	0	-
21	DERMS		-	-	4,640	2,540	4,253	2,715
22	DER Control		-	-	290	290	266	290
23	Mobile Technology		-	990	4,575	725	5,184	1,046
24	Work Management & Scheduling Upgrades		-	6,160	7,350	3,025	12,898	3,385
25	Substation Design Tool Upgrades		1,120	262	2,653	1,866	2,693	1,932
26	Asset Management Upgrades		-	668	1,725	1,500	2,249	1,519
27	Load Forecasting & Analytics		1,951	2,536	5,506	4,275	7,583	4,378
28	Interconnection Process Enablement		-	1,950	3,991	5,607	5,608	5,472
29	Hosting Capacity Enablement		-	49	250	150	278	158
30	AMI: Meter Communications Upgrades	2/	1,530	626	-	-	626	-
31	Microwave End of Life		-	259	500	500	718	500
32	SCADA Remote Access and Configuration Platform		1,051	453	500	-	912	42
33	Automation Configuration and Test Record Database		319	(43)	2,250	2,250	2,020	2,250
34	Grid Edge Insights & New Technology		759	1,801	1,960	2,191	3,598	2,171
35	Sensor, Network and Algorithm Development (Solar Deployment)		-	96	1,178	204	1,176	285
36	Other Modernize Grid Management		-	4,772	375	2,225	5,116	2,071
37	Substation Cybersecurity		14	787	1,700	-	2,346	142
38	Operational Technology and Error Free Communication		6,014	5,898	-	-	5,898	-
39	4.8 kV Circuit Automation	4/	3,186	4,627	16,042	-	20,668	-
40	SCADA / AMI Enhancements		-	450	-	-	450	-
41	**Total Technology and Automation Projects and Programs**		**80,068**	**98,276**	**136,604**	**97,538**	**224,833**	**99,540**

1/ SOC projects sponsored by Company Witness M. Elliott Andahazy
2/ ADMS/AMI projects sponsored by Company Witness P. Smith
3/ Tree Trim project sponsored by Company Witness S. M. Hartwick
4/ Projected test year capital expenditures for 4.8 kV Circuit Automation are included in the IRM request (see Exhibit A-33, Schedule X3).

Michigan Public Service Commission
DTE Electric Company
Projected Capital Expenditures
Allowance for Funds Used During Construction (AFUDC)
Distribution Operations
($000)

Case No.: U-21297
Exhibit: A-12
Schedule: B5.4
Witness: B. L. Hill 1/
M. Elliott Andahazy 2/
S. S. Deol 3/
P. Smith 4/
Page: 13 of 21

Line No.	(a) Description		(b) Adjusted Historical 12 mos. ended 12/31/2021	(c) Projected 12 mos. ending 11/30/2024	
1	**Base Capital Programs:**				
2	Gordie Howe International Bridge	**1/**	811	-	
3	Other Routine Base Capital Programs	**1/**	1,544	1,148	**5/**
4	**Subtotal Base Capital Programs**		**2,355**	**1,148**	
5	**Strategic Capital Programs:**				
6	Infrastructure Resilience and Hardening	**2/**	2,168	2,844	**5/**
7	Infrastructure Redesign:				
8	Ann Arbor System Improvements	**3/**	1,459	148	
9	Other Infrastructure Redesign	**3/**	2,602	15,556	**5/**
10	Technology and Automation:				
11	SOC Modernization	**2/**	2,628	-	
12	ADMS Projects	**4/**	1,613	264	
13	Other Technology and Automation	**1/**	271	605	**5/**
14	**Subtotal Strategic Capital Programs**		**10,741**	**19,418**	
15	**Total AFUDC - Distribution Operations**		**13,096**	**20,565**	**6/**

1/ Sponsored by Company Witness B. L. Hill: Base Capital Programs, Other Technology and Automation
2/ Sponsored by Company Witness M. Elliott Andahazy: Infrastructure Resilience and Hardening, SOC Modernization
3/ Sponsored by Company Witness S. S. Deol: Infrastructure Redesign
4/ Sponsored by Company Witness P. Smith: ADMS projects
5/ AFUDC estimates for platform are developed at a high level based on historical trend
6/ The projected AFUDC amounts are based on the authorized U-20836 of 5.417%

Michigan Public Service Commission
DTE Electric Company
Projected Capital Expenditures
Removal Costs, Plant in Service and CWIP
Distribution Plant
($000)

Case: U-21297
Exhibit: A-12
Schedule: B5.4
Witnesses: B. L. Hill 1/, M. Elliott Andahazy 2/,
S. S. Deol 3/, P. Smith 4/, S. M. Hartwick 5/

Line No.	(a) Description		(b) In-Service Assumption	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)
				Capital Expenditures (including Removal Costs)				Est. % Removal	Activity Accum. Depr. - Removal Costs			Activity Plant in Service			Activity CWIP - Net Additions/(Unitization)		
				12 mos. ended 12/31/2021	12 mos. ending 12/31/2022	11 mos. ending 11/30/2023	12 mos. ending 11/30/2024		12 mos. ending 12/31/2022 col (d)x(g)	11 mos. ending 11/30/2023 col (e)x(g)	12 mos. ending 11/30/2024 col (f)x(g)	12 mos. ending 12/31/2022	11 mos. ending 11/30/2023	12 mos. ending 11/30/2024	12 mos. ending 12/31/2022 col (d)-(h)-(k)	11 mos. ending 11/30/2023 col (e)-(i)-(l)	12 mos. ending 11/30/2024 col (f)-(j)-(m)
	Base Capital Programs																
1	Emergent Replacements	**1/**	Annual	650,531	487,541	399,057	424,413	15%	73,131	59,859	63,662	414,410	339,199	360,751	-	-	-
2	Connections & New Load:																
3	Gordie Howe International Bridge	**1/**	12/31/2022	489	484	-	-	15%	73	-	-	827	-	-	(415)	-	-
4	Other Connections and New Load	**1/**	Annual	263,716	306,377	235,534	261,007	15%	45,957	35,330	39,151	260,421	200,204	221,856	-	-	-
5	Connections Sub-Total			264,205	306,862	235,534	261,007		46,029	35,330	39,151	261,248	200,204	221,856	(415)	-	-
6																	
7	**Infrastructure Resilience and Hardening**																
8	Mobile Fleet Program	**2/**	Annual	5,984	13,566	4,863	4,567	15%	2,035	729	685	11,531	4,133	3,882	-	-	-
9	Substation Risk: Drexel	**2/**	12/31/2023	1,663	1,915	245	22	15%	287	37	3	-	-	3,269	1,628	208	(3,250)
10	Substation Risk: Chestnut	**2/**	12/31/2024	534	161	3,405	6,951	15%	24	511	1,043	-	-	-	137	2,894	5,908
11	Substation Risk: Savage	**2/**	12/31/2023	211	562	2	0	15%	84	0	0	-	-	659	478	2	(659)
12	Substation Risk: Apache	**2/**	12/31/2024	1,908	3,381	10,659	3,387	15%	507	1,599	508	-	-	-	2,874	9,060	2,879
13	Substation Risk: Port Huron	**2/**	12/31/2022	2,969	184	-	-	15%	28	-	-	2,679	-	-	(2,523)	-	-
14	Substation Risk: Belleville Switchgear Decomm	**2/**	12/31/2023	298	1,206	922	84	15%	181	138	13	-	-	2,133	1,025	784	(2,062)
15	Substation Risk: McGraw	**2/**	12/31/2025	518	10,740	27,238	2,485	15%	1,611	4,086	373	-	-	-	9,129	23,152	2,112
16	Substation Risk: Voyager	**2/**	12/31/2022	-	200	-	-	15%	30	-	-	170	-	-	-	-	-
17	Substation Risk: Flood Defense Program	**2/**	12/31/2023	-	74	5,317	483	15%	11	798	73	-	-	4,993	63	4,519	(4,582)
18	4.8 kV Hardening	**2/**	Annual	65,362	151,314	73,333	6,667	15%	22,697	11,000	1,000	128,617	62,333	5,667	-	-	-
19	Pole and Pole Top Maintenance and Moderniz	**2/**	Annual	31,647	70,224	58,158	115,825	15%	10,534	8,724	17,374	59,691	49,435	98,452	-	-	-
20	Cable Replacement Program	**2/**	Annual	14,984	27,452	22,798	24,989	15%	4,118	3,420	3,748	23,334	19,378	21,241	-	-	-
21	Frequent Outage Program (CEMI)	**2/**	Annual	23,251	55,597	50,648	48,261	15%	8,340	7,597	7,239	47,258	43,051	41,022	-	-	-
22	Breaker Replacement Program	**2/**	Annual	17,365	13,576	13,177	-	15%	2,036	1,977	-	11,540	11,201	-	-	-	-
23	Pontiac Vaults	**2/**	12/31/2023	3,044	1,355	53	5	15%	203	8	1	-	-	3,788	1,152	45	(3,784)
24	URD Replacement Program	**2/**	Annual	4,705	6,336	13,750	-	15%	950	2,063	-	5,385	11,688	-	-	-	-
25	URD Replacement Program: Detroit URD 1-1	**2/**	12/31/2022	1,595	1,061	-	-	15%	159	-	-	2,257	-	-	(1,356)	-	-
26	40 kV: Automatic Pole Top Switch	**2/**	Annual	1,301	3,419	5,798	6,337	15%	513	870	951	2,906	4,928	5,386	-	-	-
27	Disconnect and Switcher Replacement	**2/**	Annual	3,863	2,970	4,492	4,900	15%	446	674	735	2,525	3,818	4,165	-	-	-
28	SCADA Pole Top Device Replacement	**2/**	12/31/2035	999	584	1,477	1,792	15%	88	222	269	-	-	-	496	1,256	1,523

Michigan Public Service Commission
DTE Electric Company
Projected Capital Expenditures
Removal Costs, Plant in Service and CWIP
Distribution Plant
($000)

Case: U-21297
Exhibit: A-12
Schedule: B5.4
Witnesses: B. L. Hill 1/, M. Elliott Andahazy 2/, S. S. Deol 3/, P. Smith 4/, S. M. Hartwick 5/

Line No.	(a) Description		(b) In-Service Assumption	(c)	(d)	(e)	(f)	(g) Est. % Removal	(h)	(i) Activity Accum. Depr. - Removal Costs	(j)	(k)	(l) Activity Plant in Service	(m)	(n)	(o) Activity CWIP - Net Additions/(Unitization)	(p)
					Capital Expenditures (including Removal Costs)												
29	Substation Regulator Replacement	**2/**	12/31/2027	-	422	820	904	15%	63	123	136	-	-	-	359	697	768
30	Steel Pole Highway Crossings	**2/**	12/31/2024	18	1,935	2,750	4,833	15%	290	413	725	-	-	-	1,644	2,338	4,108
31	Station Upgrade: Warren (Relay Replacement)	**2/**	12/31/2022	115	3,183	-	-	15%	477	-	-	2,803	-	-	(98)	-	-
32	Station Upgrade: Northeast (Relay Replacemer	**2/**	12/31/2023	2,431	12,494	2,216	201	15%	1,874	332	30	-	-	14,741	10,620	1,883	(14,570)
33	Station Upgrade: Lincoln	**2/**	12/31/2025	-	-	303	4,886	15%	-	45	733	-	-	-	-	257	4,153
34	Station Upgrade: Navarre	**2/**	12/31/2026	-	-	-	303	15%	-	-	45	-	-	-	-	-	257
35	Station Upgrade: 120kV Relays Upgrade for IT	**2/**	12/31/2035	-	198	3,519	4,089	15%	30	528	613	-	-	-	168	2,991	3,476
36	Batteries and Chargers Replacement Program	**2/**	12/31/2035	-	-	2,292	2,500	15%	-	344	375	-	-	-	-	1,948	2,125
37	Resilience Sub-Total			184,765	384,109	308,234	244,470		57,616	46,235	36,671	300,697	209,964	209,397	25,796	52,034	(1,598)
38	**Infrastructure Redesign**																
39	Ann Arbor System Improvements: State Substation	**3/**	12/31/2023	8,259	6,004	1,474	134	15%	901	221	20	-	-	13,489	5,103	1,253	(13,376)
40	Ann Arbor System Improvements: Apex (Blue) Substation	**3/**	12/31/2023	-	3,489	1,772	161	15%	523	266	24	-	-	4,608	2,965	1,506	(4,471)
41	Ann Arbor System Improvements: Argo 40kV Reconfiguration	**3/**	12/31/2024	-	788	7,260	7,443	15%	118	1,089	1,116	-	-	-	670	6,171	6,327
42	Subtransmission Redesign & Rebuild: Transformer High Side Protection Program	**3/**	Annual	1,500	887	5,042	5,500	15%	133	756	825	754	4,285	4,675	-	-	-
43	Subtransmission Redesign & Rebuild: Tie 4104	**3/**	12/31/2025	-	106	921	10,806	15%	16	138	1,621	-	-	-	90	782	9,185
44	Subtransmission Redesign & Rebuild: Maxwell Amherst	**3/**	12/31/2022	22	192	-	-	15%	29	-	-	182	-	-	(19)	-	-
45	Subtransmission Redesign & Rebuild: Tie 810	**3/**	12/31/2025	1,630	9,100	18,333	20,816	15%	1,365	2,750	3,122	-	-	-	7,735	15,583	17,693
46	Subtransmission Redesign & Rebuild: Trunk 7106	**3/**	12/31/2022	2,395	206	-	-	15%	31	-	-	2,211	-	-	(2,035)	-	-
47	Subtransmission Redesign & Rebuild: Trunk 2255	**3/**	12/31/2023	190	2,339	31	3	15%	351	5	0	-	-	2,178	1,988	26	(2,176)
48	Subtransmission Redesign & Rebuild: Trunk 2237-ST	**3/**	12/31/2022	143	1,051	-	-	15%	158	-	-	1,015	-	-	(121)	-	-
49	Subtransmission Redesign & Rebuild: Trunk 7333	**3/**	12/31/2022	2,918	1,229	-	-	15%	184	-	-	3,525	-	-	(2,481)	-	-
50	Subtransmission Redesign & Rebuild: Sandusky Transformer 101 Breaker	**3/**	12/31/2023	-	-	3,926	357	15%	-	589	54	-	-	3,641	-	3,337	(3,337)
51	Subtransmission Redesign & Rebuild: Boyne	**3/**	12/31/2023	3,675	14,185	6,450	586	15%	2,128	968	88	-	-	21,163	12,058	5,483	(20,664)
52	Subtransmission Redesign & Rebuild: Tie 6907	**3/**	12/31/2024	-	-	391	1,677	15%	-	59	252	-	-	-	-	332	1,425
53	Subtransmission Redesign & Rebuild: Tie 7504	**3/**	12/31/2025	2	14	1,492	6,030	15%	2	224	904	-	-	-	12	1,268	5,125
54	Subtransmission Redesign & Rebuild: Tie 4105	**3/**	12/31/2025	6,659	12,971	18,286	11,406	15%	1,946	2,743	1,711	-	-	-	11,026	15,543	9,695

Michigan Public Service Commission
DTE Electric Company
Projected Capital Expenditures
Removal Costs, Plant in Service and CWIP
Distribution Plant
($000)

Case: U-21297
Exhibit: A-12
Schedule: B5.4
Witnesses: B. L. Hill 1/, M. Elliott Andahazy 2/,
S. S. Deol 3/, P. Smith 4/, S. M. Hartwick 5/

Line No.	(a) Description		(b) In-Service Assumption	(c)	(d)	(e)	(f)	(g) Est. % Removal	(h)	(i) Activity Accum. Depr. - Removal Costs	(j)	(k)	(l) Activity Plant in Service	(m)	(n)	(o) Activity CWIP - Net Additions/(Unitization)	(p)
				Capital Expenditures (including Removal Costs)													
55	Subtransmission Redesign & Rebuild: Trunk 2308	3/	12/31/2024	-	51	6,641	2,465	15%	8	996	370	-	-	-	43	5,645	2,095
56	Subtransmission Redesign & Rebuild: Tie 1568	3/	12/31/2023	3	47	631	57	15%	7	95	9	-	-	628	40	536	(579)
57	Subtransmission Redesign & Rebuild: Trunk 4217	3/	12/31/2023	316	300	4,460	405	15%	45	669	61	-	-	4,659	255	3,791	(4,315)
58	Subtransmission Redesign & Rebuild: Trunk 3509	3/	12/31/2024	-	159	1,086	1,214	15%	24	163	182	-	-	-	136	923	1,032
59	Subtransmission Redesign & Rebuild: Trunk 4266	3/	12/31/2024	-	17	248	4,694	15%	2	37	704	-	-	-	14	211	3,990
60	Subtransmission Redesign & Rebuild: Badax Transformer 102 Addition	3/	12/31/2024	-	611	7,168	2,030	15%	92	1,075	304	-	-	-	519	6,093	1,725
61	Subtransmission Redesign & Rebuild: Trunk 4245	3/	12/31/2024	7	8	2,804	1,172	15%	1	421	176	-	-	-	6	2,384	996
62	Subtransmission Redesign & Rebuild: Tie 6602	3/	12/31/2025	-	-	605	3,436	15%	-	91	515	-	-	-	-	514	2,921
63	Subtransmission Redesign & Rebuild: Trunk 4911	3/	12/31/2026	-	44	820	7,599	15%	7	123	1,140	-	-	-	38	697	6,459
64	Subtransmission Redesign & Rebuild: Custer Republic	3/	12/31/2024	-	-	146	1,533	15%	-	22	230	-	-	-	-	124	1,303
65	Subtransmission Redesign & Rebuild: Trunk 2419	3/	12/31/2025	-	-	155	734	15%	-	23	110	-	-	-	-	132	624
66	Subtransmission Redesign & Rebuild: Tie 3205	3/	12/31/2026	-	17	458	4,435	15%	3	69	665	-	-	-	14	390	3,770
67	Subtransmission Redesign & Rebuild: Praxair	3/	12/31/2023	-	18	2,536	231	15%	3	380	35	-	-	2,367	15	2,156	(2,171)
68	Subtransmission Redesign & Rebuild : Small Projects & Reserve	3/	12/31/2024	-	4	31	383	15%	1	5	58	-	-	-	4	27	326
69	Subtransmission Breaker Short Circuit Violations	3/	12/31/2024	13	1,594	1,296	205	15%	239	194	31	-	-	-	1,355	1,102	174
70	Subtransmission Redesign & Rebuild: Slocum	3/	12/31/2023	-	698	676	61	15%	105	101	9	-	-	1,220	593	574	(1,168)
71	Subtransmission Redesign & Rebuild: Kennett	3/	12/31/2024	-	-	401	326	15%	-	60	49	-	-	-	-	341	277
72	Subtransmission Redesign & Rebuild: Trunk 4601	3/	12/31/2025	-	-	197	1,586	15%	-	29	238	-	-	-	-	167	1,348
73	Subtransmission Redesign & Rebuild: Tempest Phase II	3/	12/31/2024	-	-	889	7,737	15%	-	133	1,161	-	-	-	-	756	6,577
74	Subtransmission Redesign & Rebuild: Waterman	3/	12/31/2024	-	-	94	2,031	15%	-	14	305	-	-	-	-	80	1,727
75	Subtransmission Redesign & Rebuild: Trunk 7105	3/	12/31/2025	-	-	55	253	15%	-	8	38	-	-	-	-	47	215
76	Subtransmission Redesign & Rebuild: Tie 5208	3/	12/31/2025	-	-	46	463	15%	-	7	69	-	-	-	-	39	393
77	Subtransmission Redesign & Rebuild: Cortland Station Expansion	3/	12/31/2025	1,083	908	315	2,209	15%	136	47	331	-	-	-	772	267	1,878
78	Subtransmission Redesign & Rebuild: 40kV Capacitor Banks at Armada and Adair	3/	12/31/2023	970	1,725	871	79	15%	259	131	12	-	-	3,098	1,466	740	(3,031)
79	CODI: Charlotte Network Upgrade	3/	12/31/2025	8,100	8,286	6,103	11,255	15%	1,243	915	1,688	-	-	-	7,043	5,188	9,567
80	CODI: Targeted Network Secondary Cable Replacement	3/	12/31/2025	869	1,789	3,483	3,800	15%	268	523	570	-	-	-	1,521	2,961	3,230
81	CODI: Corktown Substation	3/	12/31/2022	13,301	1,360	-	-	15%	204	-	-	12,462	-	-	(11,306)	-	-

Michigan Public Service Commission
DTE Electric Company
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Page: 17 of 21

Line No.	(a) Description		(b) In-Service Assumption	(c)	(d)	(e)	(f)	(g) Est. % Removal	(h)	(i) Activity Accum. Depr. - Removal Costs	(j)	(k)	(l) Activity Plant in Service	(m)	(n)	(o) Activity CWIP - Net Additions/(Unitization)	(p)
					Capital Expenditures (including Removal Costs)												
82	CODI: Islandview Substation	3/	12/31/2028	3,264	12,912	32,767	45,534	15%	1,937	4,915	6,830	-	-	-	10,975	27,852	38,704
83	CODI: CATO Substation Expansion	3/	12/31/2027	-	319	9,895	13,091	15%	48	1,484	1,964	-	-	-	271	8,411	11,128
84	CODI: Howard Conversion	3/	12/31/2030	-	2	642	13,808	15%	0	96	2,071	-	-	-	2	545	11,737
85	CODI: Midtown Substation Expansion	3/	12/31/2023	6,510	2,234	1,653	150	15%	335	248	23	-	-	8,965	1,899	1,405	(8,837)
86	CODI: Alfred Substation Expansion	3/	12/31/2024	417	53	3,793	11,145	15%	8	569	1,672	-	-	-	45	3,224	9,474
87	CODI: Garfield Network Upgrade	3/	12/31/2028	11,177	18,193	27,500	35,701	15%	2,729	4,125	5,355	-	-	-	15,464	23,375	30,346
88	CODI: Kent/Gibson Conversion	3/	12/31/2027	211	2,051	18,159	38,089	15%	308	2,724	5,713	-	-	-	1,743	15,435	32,376
89	4.8 kV CC: Hilton Substation and Circuit Conversion	3/	Annual	93	-	-	-	15%	-	-	-	-	-	-	-	-	-
90	4.8 kV CC: Zenon Substation and Circuit Conversion	3/	12/31/2022	29	1	-	-	15%	0	-	-	25	-	-	(25)	-	-
91	4.8 kV CC: Cortland / Oakman / Linwood Consolidation	3/	12/31/2022	1,579	387	-	-	15%	58	-	-	1,670	-	-	(1,342)	-	-
92	4.8 kV CC: Ariel Substation and Circuit Conversion	3/	12/31/2023	597	1,032	550	50	15%	155	83	8	-	-	1,895	877	468	(1,852)
93	4.8 kV CC: I-94 Substation and Circuit Conversion (Promenade)	3/	12/31/2030	502	14,509	9,129	31,207	15%	2,176	1,369	4,681	-	-	-	12,333	7,760	26,526
94	4.8 kV CC: Almont Relief and Circuit Conversion (Midas)	3/	12/31/2023	5,585	12,643	3,268	297	15%	1,897	490	45	-	-	18,525	10,747	2,778	(18,272)
95	4.8 kV CC: Buckler Circuit Conversion	3/	12/31/2024	2,169	8,136	2,626	2,666	15%	1,220	394	400	-	-	-	6,915	2,232	2,266
96	4.8 kV CC: Calla Circuit Conversion and Phase 2	3/	12/31/2025	327	65	15	3,601	15%	10	2	540	-	-	-	55	13	3,060
97	4.8 kV CC: Lapeer - Elba Expansion and Circuit Conversion (Apollo)	3/	12/31/2024	988	2,710	7,958	16,290	15%	406	1,194	2,444	-	-	-	2,303	6,765	13,847
98	4.8 kV CC: McKinstry Sub Decommission	3/	12/31/2023	114	68	4,242	386	15%	10	636	58	-	-	4,089	58	3,606	(3,761)
99	4.8 kV CC: Quincy Conversion	3/	12/31/2023	888	1,021	2,143	195	15%	153	321	29	-	-	3,610	868	1,821	(3,444)
100	4.8 kV CC: Pinegrove Substation Relocation and Conversion	3/	12/31/2025	1,455	2,520	40,113	26,362	15%	378	6,017	3,954	-	-	-	2,142	34,096	22,407
101	4.8 kV CC: Pinegrove Substation Relocation and Conversion CIAC	3/	12/31/2025	-	-	(14,025)	(9,250)	15%	-	(2,104)	(1,388)	-	-	-	-	(11,921)	(7,863)
102	4.8 kV CC: Hawthorne Relief and Circuit Conversion	3/	12/31/2028	-	402	5,500	12,417	15%	60	825	1,863	-	-	-	341	4,675	10,554
103	4.8 kV CC: Hawthorne Trf #2 and Secondary Cable Replacement	3/	12/31/2023	-	59	1,641	149	15%	9	246	22	-	-	1,572	50	1,395	(1,445)
104	4.8 kV CC: Birmingham Decommissioning and Circuit Conversion	3/	12/31/2031	-	1	1,376	4,287	15%	0	206	643	-	-	-	0	1,170	3,644
105	4.8 kV CC: Crestwood Substation	3/	12/31/2022	-	23	-	-	15%	4	-	-	20	-	-	-	-	-
106	4.8 kV CC: MAUME 8241 Downtown Clawson Conversion	3/	12/31/2023	-	2,638	3	0	15%	396	0	0	-	-	2,246	2,243	3	(2,245)
107	4.8 kV CC: Power line Conversion of MADSN 175L-W	3/	12/31/2023	-	123	218	20	15%	18	33	3	-	-	307	104	185	(290)
108	4.8 kV CC: GRFIN & WMSTN Conversions	3/	12/31/2024	-	508	3,799	7,696	15%	76	570	1,154	-	-	-	432	3,229	6,542

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Line No.	(a) Description		(b) In-Service Assumption	(c)	(d)	(e)	(f)	(g) Est. % Removal	(h)	(i) Activity Accum. Depr. - Removal Costs	(j)	(k)	(l) Activity Plant in Service	(m)	(n)	(o) Activity CWIP - Net Additions/(Unitization)	(p)
					Capital Expenditures (including Removal Costs)												
109	4.8 kV CC: ISO Conversion Program	**3/**	12/31/2027	-	33	6,417	37,250	15%	5	963	5,588	-	-	-	28	5,454	31,663
110	4.8kV CC: SCOTN	**3/**	12/31/2024	1	49	2,484	1,222	15%	7	373	183	-	-	-	42	2,112	1,039
111	4.8kV CC: Rochester Decommissioning and Tienken Relief	**3/**	12/31/2028	-	-	95	661	15%	-	14	99	-	-	-	-	81	562
112	4.8 kV CC: Ann Arbor AC Network Conversion	**3/**	12/31/2028	-	-	124	663	15%	-	19	99	-	-	-	-	106	563
113	4.8kV CC: Pittsfield Substation and Circuit Conversion	**3/**	12/31/2028	-	-	163	2,236	15%	-	25	335	-	-	-	-	139	1,900
114	4.8kV CC: Hemlock Decommissioning and Circuit Conversion	**3/**	12/31/2028	-	-	144	1,270	15%	-	22	191	-	-	-	-	123	1,080
115	4.8kV CC: Yale-Slater Decommissioning and Circuit Conversion	**3/**	12/31/2028	-	-	247	3,982	15%	-	37	597	-	-	-	-	210	3,385
116	4.8 kV CC: Slater	**3/**	12/31/2022	-	1,930	-	-	15%	290	-	-	1,641	-	-	-	-	-
117	4.8 kV CC: Grosse Pointe Substation and Circuit Conversion	**3/**	12/31/2031	-	-	1,833	14,008	15%	-	275	2,101	-	-	-	-	1,558	11,907
118	4.8 kV CC: Royal Oak Substation and Circuit Conversion	**3/**	12/31/2031	-	-	1,833	14,008	15%	-	275	2,101	-	-	-	-	1,558	11,907
119	8.3 kV CC: Pontiac Overhead Conversion	**3/**	12/31/2028	872	3,016	11,385	22,652	15%	452	1,708	3,398	-	-	-	2,564	9,678	19,254
120	8.3 kV CC: Pontiac Underground Conversion	**3/**	12/31/2026	43	702	1,107	3,243	15%	105	166	486	-	-	-	597	941	2,757
121	System Loading: Brest Substation	**3/**	Annual	58	-	-	-	15%	-	-	-	-	-	-	-	-	-
122	System Loading: Carleton	**3/**	12/31/2023	2,304	376	25	2	15%	56	4	0	-	-	2,302	320	22	(2,300)
123	System Loading: Grayling	**3/**	Annual	0	-	-	-	15%	-	-	-	-	-	-	-	-	-
124	System Loading: Prospect	**3/**	Annual	2	-	-	-	15%	-	-	-	-	-	-	-	-	-
125	System Loading: Mandy 307 Load Transfer	**3/**	12/31/2022	720	24	-	-	15%	4	-	-	632	-	-	(612)	-	-
126	System Loading: Brown City	**3/**	12/31/2026	125	44	4,294	8,083	15%	7	644	1,212	-	-	-	38	3,650	6,870
127	System Loading: Mack Transformer 102	**3/**	12/31/2023	252	54	7	1	15%	8	1	0	-	-	267	46	6	(266)
128	System Loading: Port Sanilac	**3/**	12/31/2026	-	35	278	5,557	15%	5	42	833	-	-	-	30	236	4,723
129	System Loading: Richmond/Armada	**3/**	12/31/2026	1,217	1,164	5,822	6,992	15%	175	873	1,049	-	-	-	990	4,949	5,943
130	System Loading: Cody	**3/**	12/31/2027	-	-	423	1,491	15%	-	63	224	-	-	-	-	359	1,267
131	System Loading: Otsego/Capac/Shaw	**3/**	12/31/2027	-	-	363	1,580	15%	-	54	237	-	-	-	-	309	1,343
132	System Loading: Macomb/Golf	**3/**	12/31/2028	-	-	-	116	15%	-	-	17	-	-	-	-	-	98
133	System Loading: Grenada	**3/**	12/31/2028	32	185	1,930	7,083	15%	28	289	1,062	-	-	-	157	1,640	6,020
134	System Loading: Malta Circuits	**3/**	Annual	1	-	-	-	15%	-	-	-	-	-	-	-	-	-
135	System Loading: Lark/Spruce	**3/**	12/31/2028	-	12	40	560	15%	2	6	84	-	-	-	10	34	476

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				Capital Expenditures (including Removal Costs)					Activity Accum. Depr. - Removal Costs			Activity Plant in Service			Activity CWIP - Net Additions/(Unitization)		
136	System Loading: Globe	3/	12/31/2028	-	-	458	2,203	15%	-	69	330	-	-	-	-	390	1,873
137	System Loading: Jewell	3/	12/31/2029	-	-	-	458	15%	-	-	69	-	-	-	-	-	390
138	System Loading: Mayville	3/	12/31/2028	-	-	-	138	15%	-	-	21	-	-	-	-	-	117
139	System Loading: Goodison	3/	12/31/2027	-	-	-	72	15%	-	-	11	-	-	-	-	-	61
140	System Loading: Wixom	3/	12/31/2027	-	-	458	2,822	15%	-	69	423	-	-	-	-	390	2,399
141	System Loading: Diamond	3/	12/31/2027	-	-	-	19	15%	-	-	3	-	-	-	-	-	16
142	System Loading: Spokane/Seneca	3/	12/31/2027	-	-	106	5,495	15%	-	16	824	-	-	-	-	90	4,671
143	System Loading: Sterling	3/	12/31/2028	-	-	87	701	15%	-	13	105	-	-	-	-	74	596
144	System Loading: Disco	3/	12/31/2026	-	-	39	386	15%	-	6	58	-	-	-	-	33	328
145	System Loading: Tahoe	3/	12/31/2028	-	-	23	327	15%	-	3	49	-	-	-	-	20	278
146	Pilot: Strategic and Service Undergrounding	3/	Annual	256	454	1,925	1,917	15%	68	289	288	386	1,636	1,629	-	-	-
147	Pilot: Primary Deconductoring	3/	12/31/2022	432	1,848	-	-	15%	277	-	-	1,938	-	-	(367)	-	-
148	Redesign Sub-Total	3/		94,275	162,735	312,669	526,398		24,410	46,900	78,960	26,462	5,922	107,131	111,863	259,847	340,308
149																	
150	**Technology and Automation**																
151	ADMS: DMS/OMS	4/	1/31/2023	22,390	28,165	9,937	903	0%	-	-	-	-	60,492	903	28,165	(50,555)	(0)
152	ADMS: Network Management System	4/	12/31/2035	1,292	1,328	2,658	2,900	0%	-	-	-	-	-	-	1,328	2,658	2,900
153	SOC: ESOC	2/	12/31/2023	14,859	1,420	183	17	0%	-	-	-	-	-	16,479	1,420	183	(16,463)
154	SOC: ASOC	2/	5/31/2024	463	7,046	24,842	3,258	0%	-	-	-	-	-	35,609	7,046	24,842	(32,351)
155	Grid Automation Telecommunications (13.2kV Telecommunications)	1/	Annual	10,239	14,206	17,508	17,047	0%	-	-	-	14,206	17,508	17,047	-	-	-
156	Distribution Sensing and Monitoring (incldg Line Sensors)	1/	Annual	2,466	1,523	-	-	0%	-	-	-	1,523	-	-	-	-	-
157	Tree Trim Risk Prioritization Model	5/	12/31/2023	-	-	1,320	120	0%	-	-	-	-	-	1,440	-	1,320	(1,320)
158	Automation: Substation	1/	Annual	111	490	4,583	23,333	0%	-	-	-	490	4,583	23,333	-	-	-
159	Automation: 13.2kV Circuit Distribution	1/	Annual	-	-	1,833	3,833	0%	-	-	-	-	1,833	3,833	-	-	-
160	CVR/VVO	1/	Annual	4,603	4,912	-	4,583	0%	-	-	-	4,912	-	4,583	-	-	-
161	NWA: O'Shea Energy Storage	1/	12/31/2023	1,096	1,067	321	29	0%	-	-	-	-	-	2,513	1,067	321	(2,483)
162	NWA: Battery Trailer	1/	12/31/2035	-	949	688	2,125	0%	-	-	-	-	-	-	949	688	2,125

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					Capital Expenditures (including Removal Costs)												
163	NWA: Omega Load Relief	**1/**	12/31/2023	5,545	2,197	642	58	0%	-	-	-	-	-	8,443	2,197	642	(8,384)
164	NWA: Fisher Load Relief	**1/**	12/31/2024	11	77	1,238	4,375	0%	-	-	-	-	-	-	77	1,238	4,375
165	NWA: Port Austin Load Relief	**1/**	12/31/2024	-	598	3,925	1,068	0%	-	-	-	-	-	-	598	3,925	1,068
166	NWA: Veridian	**1/**	12/31/2026	-	387	3,032	4,516	0%	-	-	-	-	-	-	387	3,032	4,516
167	NWA: Small Solar and Storage Testbed	**1/**	12/31/2025	446	337	458	500	0%	-	-	-	-	-	-	337	458	500
168	NWA: EV Charging Demonstration at ACM	**1/**	12/31/2025	600	1,231	1,192	2,518	0%	-	-	-	-	-	-	1,231	1,192	2,518
169	Technology Programs & NWA	**1/**	12/31/2022	4	0	-	-	0%	-	-	-	4	-	-	(4)	-	-
170	DERMS	**1/**	12/31/2035	-	-	4,253	2,715	0%	-	-	-	-	-	-	-	4,253	2,715
171	DER Control	**1/**	12/31/2027	-	-	266	290	0%	-	-	-	-	-	-	-	266	290
172	Mobile Technology	**1/**	12/31/2035	-	990	4,194	1,046	0%	-	-	-	-	-	-	990	4,194	1,046
173	Work Management & Scheduling Upgrades	**1/**	12/31/2035	-	6,160	6,738	3,385	0%	-	-	-	-	-	-	6,160	6,738	3,385
174	Substation Design Tool Upgrades	**1/**	12/31/2027	1,120	262	2,432	1,932	0%	-	-	-	-	-	-	262	2,432	1,932
175	Asset Management Upgrades	**1/**	12/31/2026	-	668	1,581	1,519	0%	-	-	-	-	-	-	668	1,581	1,519
176	Load Forecasting & Analytics	**1/**	12/31/2027	1,951	2,536	5,047	4,378	0%	-	-	-	-	-	-	2,536	5,047	4,378
177	Interconnection Process Enablement	**1/**	12/31/2026	-	1,950	3,658	5,472	0%	-	-	-	-	-	-	1,950	3,658	5,472
178	Hosting Capacity Enablement	**1/**	12/31/2026	-	49	229	158	0%	-	-	-	-	-	-	49	229	158
179	AMI: Meter Communications Upgrades	**4/**	Annual	1,530	626	-	-	0%	-	-	-	626	-	-	-	-	-
180	Microwave End of Life	**1/**	12/31/2025	-	259	458	500	0%	-	-	-	-	-	-	259	458	500
181	SCADA Remote Access and Configuration Platform	**1/**	12/31/2023	1,051	453	458	42	0%	-	-	-	-	-	2,005	453	458	(1,963)
182	Automation Configuration and Test Record Database	**1/**	12/31/2024	319	(43)	2,063	2,250	0%	-	-	-	-	-	-	(43)	2,063	2,250
183	Grid Edge Insights & New Technology	**1/**	12/31/2035	759	1,801	1,796	2,171	0%	-	-	-	-	-	-	1,801	1,796	2,171
184	Sensor, Network and Algorithm Development (Solar Deployment)	**1/**	12/31/2024	-	96	1,080	285	0%	-	-	-	-	-	-	96	1,080	285
185	Other Modernize Grid Management	**1/**	12/31/2026	-	4,772	344	2,071	0%	-	-	-	-	-	-	4,772	344	2,071
186	Substation Cybersecurity	**1/**	12/31/2023	14	787	1,558	142	0%	-	-	-	-	-	2,502	787	1,558	(2,360)
187	Operational Technology and Error Free Communication	**1/**	12/31/2022	6,014	5,898	-	-	0%	-	-	-	11,912	-	-	(6,014)	-	-
188	4.8 kV Circuit Automation	**1/**	Annual	3,186	4,627	16,042	-	0%	-	-	-	4,627	16,042	-	-	-	-
189	SCADA / AMI Enhancements	**1/**	12/31/2022	-	450	-	-	0%	-	-	-	450	-	-	-	-	-
190	Technology Sub-Total			80,068	98,276	126,557	99,540		-	-	-	38,749	100,458	118,691	59,527	26,099	(19,151)

Michigan Public Service Commission
DTE Electric Company
Projected Capital Expenditures
Removal Costs, Plant in Service and CWIP
Distribution Plant
($000)

Case: U-21297
Exhibit: A-12
Schedule: B5.4
Witnesses: B. L. Hill 1/, M. Elliott Andahazy 2/,
S. S. Deol 3/, P. Smith 4/, S. M. Hartwick 5/
Page: 21 of 21

Line No.	(a) Description	(b) In-Service Assumption	(c)	(d)	(e)	(f) Capital Expenditures (including Removal Costs)	(g) Est. % Removal	(h)	(i)	(j) Activity Accum. Depr. - Removal Costs	(k)	(l)	(m) Activity Plant in Service	(n)	(o)	(p) Activity CWIP - Net Additions/(Unitization)
191	Total Distribution Plant		1,273,843	1,439,523	1,382,051	1,555,829		201,187	188,324	218,443	1,041,565	855,746	1,017,826	196,771	337,981	319,559

1/ Sponsored by Company Witness B. L. Hill: Base Capital Programs, Technology and Automation
2/ Sponsored by Company Witness M. Elliott Andahazy: Infrastructure Resilience and Hardening, SOC projects
3/ Sponsored by Company Witness S. S. Deol: Infrastructure Redesign
4/ Sponsored by Company Witness P. Smith: ADMS/AMI projects
5/ Sponsored by Company Witness S.M. Hartwick: Tree Trim project

EXHIBIT MEC-91

RESERVED

MPSC Case No: U-21297

Requester: MNSC

Question No.: MNSCDE-2.11 (Supplemental)

Respondent: S. Deol

Page: 1 of 1

Question: Refer to discovery response MNCDE-1.8 and the direct testimony of Satvir Deol quoted in the response: Has DTE identified a set of areas where the 4.8kV system is near load capacity such that adding electric vehicles and/or DERs is likely to quickly exceed system capability? If yes, provide a list of these areas.

Answer: The Company objects for the reason that the request is unduly burdensome, overly broad, oppressive and calculated to cause unreasonable expense to DTE Electric and its ratepayers. The Company also objects because the information requested may constitute CEII and/or is not relevant or is not reasonably calculated to lead to the discovery of admissible evidence. Without waiving these objections, but subject to them, based upon currently available information the Company responds as follows:

Yes, the Company has an annual planning process that evaluates total circuit loading and identifies circuits that are approaching or at capacity and creates projects to add capacity where needed.

These projects and their associated circuits are shared in the Company Exhibits M4-M6 which include detailed project scope that explains voltages involved. Projects labeled 4.8kV CC and CODI specifically address the 4.8kV system. Additionally, projects labeled System Loading may be performed on the 4.8kV system.

DERs are handled on a case-by-case basis and any system upgrades needed to add capacity are addressed through the interconnection process.

Load growth is dynamic and driven by multiple factors beyond EV and DER adoption. The Company must plan for all sources of load growth. However, the Company is not always made aware of all sources of marginal load growth and makes the planning process more challenging.

See attachment U-21297 MNSCDE-2.11-01 4.8kV Circuits Above Daily Rating or Within 10% of Daily Rating.

Attachment: *U-21297 MNSCDE-2.11-01 4.8kV Circuits Above Daily Rating or Within 10% of Daily Rating*

Co-Respondent(s): Legal

U-21297 MNSCDE-2.11-01 4.8kV Circuits Above Daily Rating or Within 10% of Daily Rating

Circuit Name
Circuit2972
Circuit1201
Circuit517
Circuit3328
Circuit34
Circuit3308
Circuit3153
Circuit2804
Circuit1236
Circuit242
Circuit3339
Circuit1395

EXHIBIT MEC-93

RESERVED

EXHIBIT MEC-94

RESERVED

EXHIBIT MEC-95

RESERVED

EXHIBIT MEC-96

RESERVED

MPSC Case No: U-21297

Requester: MNSC

Question No.: MNSCDE-3.8d

Respondent: S. Deol

Page: 1 of 1

Question: Refer to Witness Deol's testimony, Page SSD-7 at 24, which states "Through the conversion projects, the Company expects to see an 85% reduction in customer minutes interruptions and customer interruptions, a 90% reduction in wire downs, and an 85% reduction in trouble events from the overhead (OH) lines conversion. Additionally, the higher voltage will provide load relief and increased capacity to serve customers' needs."

d. Provide any analyses the Company has completed which indicates the benefits of the conversions to customers exceed the costs of the conversions to customers (revenue requirements). If the Company has not completed any such analyses, please explain why not.

Answer: The Company calculates expected benefits to customers in terms of reliability improvements, but does not attempt to calculate a specific monetary benefit from those reliability improvements. There is an industry tool called the Department of Energy's Interruption Cost Estimator that has a general estimate of customer cost impacts for some types of outages. The Company has not used that tool in the instant case but is exploring the potential use of that tool in the future. Additionally, benefits such as safety improvements, capacity, and system operability are difficult to monetize, therefore the Company has not performed such an analysis.

Attachment: N/A

MPSC Case No: U-21297

Requester: MNSC

Question No.: MNSCDE-3.9c

Respondent: S. Deol

Page: 1 of 1

Question: Refer to Witness Deol's testimony, page SSD-8 at 5, which states "The Company performed an analysis on its subtransmission system, detailed later in my testimony, that revealed that approximately one-third of the circuits on the subtransmission system violated the Company's planning criteria. Additionally, the analysis showed that the Company's aging subtransmission system is not currently adequate to serve the Company's customers' long-term needs given its limited capacity and reliability performance."

c. Refer to the Company's response to subpart (b) above. For any circuit/substation project for which rated capacities will not be exceeded by 2026, please provide any analyses the Company has completed which indicates the economic benefits of the projects to customers will exceed the costs of the projects to customers (revenue requirements). If the Company has not completed any such analyses for projects not required due to load growth/forecasts relative to capacity ratings, please explain why not.

Answer: The Company calculates expected benefits to customers in terms of reliability improvements, but does not attempt to calculate a specific monetary benefit from those reliability improvements. There is an industry tool called the Department of Energy's Interruption Cost Estimator that has a general estimate of customer cost impacts for some types of outages. The Company has not used that tool in the instant case but is exploring the potential use of that tool in the future. Additionally, benefits such as safety improvements, capacity, and system operability are difficult to monetize, therefore the Company has not performed such an analysis.

Attachment: N/A

MPSC Case No: U-21297

Requester: MNSC

Question No.: MNSCDE-3.16c

Respondent: S. Deol

Page: 1 of 1

Question: Refer to Witness Deol's testimony regarding the City of Detroit Infrastructure improvement program described on pages SSD-23 to SSD-28, as well as to the Company's Five-Year Grid Plan filed September 30, 2021, pages 325-332.

c. Provide any analyses which indicate the benefits of the completed CODI program to customers exceed the costs of the completed CODI program (revenue requirements) to customers. If the Company has not completed such analyses, please explain why not.

Answer: The Company calculates expected benefits to customers in terms of reliability improvements, but does not attempt to calculate a specific monetary benefit from those reliability improvements. There is an industry tool called the Department of Energy's Interruption Cost Estimator that has a general estimate of customer cost impacts for some types of outages. The Company has not used that tool in the instant case but is exploring the potential use of that tool in the future. Additionally, benefits such as safety improvements, capacity, and system operability are difficult to monetize, therefore the Company has not performed such an analysis.

Attachment: N/A

MPSC Case No: U-21297

Requester: MNSC

Question No.: MNSCDE-3.23b

Respondent: S. Deol

Page: 1 of 1

Question: Refer to Exhibit A-23 Schedule M10, page 6, and the statement regarding the Strategic Undergrounding pilot, “Data will be available in the first quarter of 2023, and the benefit- cost analysis will take place at that time. The Company’s benefit analysis consists of two parts. First the Company looks at the improvements in the area of construction, and second those improvements are compared to a control group.”

b. Confirm that the “improvements” referred to will be converted to the value to customers of reliability improvements in dollars, such as by using the U.S. Department of Energy’s Interruption Cost Estimator tool. If the Company will not be converting reliability improvements into customer value denominated in dollars, please explain why not.

Answer: The Company calculates expected benefits to customers in terms of reliability improvements, but does not attempt to calculate a specific monetary benefit from those reliability improvements. There is an industry tool called the Department of Energy’s Interruption Cost Estimator that has a general estimate of customer cost impacts for some types of outages. The Company has not used that tool in the instant case but is exploring the potential use of that tool in the future. Additionally, benefits such as safety improvements, capacity, and system operability are difficult to monetize, therefore the Company has not performed such an analysis.

Attachment: N/A

MPSC Case No: U-21297

Requester: MNSC

Question No.: MNSCDE-3.24b

Respondent: S. Deol

Page: 1 of 1

Question: Refer to Exhibit A-12 Schedule B5.4, page 10, which lists 10 City of Detroit Infrastructure (CODI) projects.

b. For each of these projects, provide all analyses, calculations, workpapers, data, and other materials the Company has completed/has available which indicate that the benefits of each project to customers exceeds the costs of each project to customers. If the Company has not completed such analyses, please explain why not.

Answer: The Company calculates expected benefits to customers in terms of reliability improvements, but does not attempt to calculate a specific monetary benefit from those reliability improvements. There is an industry tool called the Department of Energy's Interruption Cost Estimator that has a general estimate of customer cost impacts for some types of outages. The Company has not used that tool in the instant case but is exploring the potential use of that tool in the future. Additionally, benefits such as safety improvements, capacity, and system operability are difficult to monetize, therefore the Company has not performed such an analysis.

Attachment: N/A

MPSC Case No: U-21297

Requester: MNSC

Question No.: MNSCDE-3.13a

Respondent: S. Deol

Page: 1 of 1

Question: Refer to Witness Deol's testimony, page SSD-14 at 7, which states "Both 4.8kV and higher voltage systems are capable of handling additional load from electric vehicles (EVs) and DERs. However, areas where the 4.8kV system is near load capacity, adding these new technologies can quickly exceed system capability."

a. Provide the number of instances on 4.8kv circuits in which the company was unable to accommodate new DER from 2018 to 2022.

Answer: In the time from 2018 and 2022, no DER was unable to be accommodated on the 4.8KV system.

Attachment: *N/A*

MPSC Case No: U-21297

Requester: MNSC

Question No.: MNSCDE-3.13b

Respondent: S. Deol

Page: 1 of 1

Question: Refer to Witness Deol's testimony, page SSD-14 at 7, which states "Both 4.8kV and higher voltage systems are capable of handling additional load from electric vehicles (EVs) and DERs. However, areas where the 4.8kV system is near load capacity, adding these new technologies can quickly exceed system capability."

b. Provide the number of instances on 4.8kv circuits in which the company was unable to accommodate new EV load from 2018 to 2022.

Answer: The Company does not track service requests specific to EV charging, but is not aware of any specific circumstances where new single EV charger has not been able to be accommodated.

Attachment: *N/A*

EXHIBIT MEC-99

RESERVED

EXHIBIT MEC-100

RESERVED

EXHIBIT MEC-101

RESERVED

EXHIBIT MEC-102

RESERVED

MPSC Case No: U-21297

Requester: Staff

Question No.: STDE-6.4a

Respondent: S. Deol

Page: 1 of 1

Question: Refer to Mr. Deol's testimony, page 7, line 24 to page 8, line 2, where he states that through the conversion projects, the Company expects to see reductions in customer minutes interruptions, customer interruptions, wire downs, and trouble events. Please provide the supporting calculations and assumptions for the following:

a. The 85% reduction in customer minutes interruptions

Answer: The Company believes that these reductions are achievable based on the results for the 4.8kV Hardening program. Results from the 4.8kV Hardening program show a 44% reduction in All-Weather SAIFI, a 72% reduction in SAIDI ex-MEDs, and a 26% reduction in wire downs. With the additional scope of work for conversion including reconductoring, installing controls and automation, replacing transformers, providing jumpering points, etc.; the Company expects to see better reliability improvements above those experienced in the 4.8kV Hardening program. Reconductoring will replace aged smaller wire with new larger wire that will be better able to withstand damage from falling branches and ice. Automation and jumpering will allow the Company to isolate outages to smaller pockets and transfer load to adjacent circuits which will reduce outage size and duration. As the Company completes conversion projects it will review and analyze the data and update these projections.

Attachment: N/A

MPSC Case No: U-21297

Requester: Staff

Question No.: STDE-6.4b

Respondent: S. Deol

Page: 1 of 1

Question: Refer to Mr. Deol's testimony, page 7, line 24 to page 8, line 2, where he states that through the conversion projects, the Company expects to see reductions in customer minutes interruptions, customer interruptions, wire downs, and trouble events. Please provide the supporting calculations and assumptions for the following:

b. The 85% reduction in customer interruptions

Answer: See response to STDE-6.4a.

Attachment: N/A

MPSC Case No: U-21297

Requester: Staff

Question No.: STDE-6.4c

Respondent: S. Deol

Page: 1 of 1

Question: Refer to Mr. Deol's testimony, page 7, line 24 to page 8, line 2, where he states that through the conversion projects, the Company expects to see reductions in customer minutes interruptions, customer interruptions, wire downs, and trouble events. Please provide the supporting calculations and assumptions for the following:

c. The 90% reduction in wire downs

Answer: See response to STDE-6.4a.

Attachment: N/A

MPSC Case No: U-21297

Requester: Staff

Question No.: STDE-6.4d

Respondent: S. Deol

Page: 1 of 1

Question: Refer to Mr. Deol's testimony, page 7, line 24 to page 8, line 2, where he states that through the conversion projects, the Company expects to see reductions in customer minutes interruptions, customer interruptions, wire downs, and trouble events. Please provide the supporting calculations and assumptions for the following:

d. The 85% reduction in trouble events from the overhead lines conversion.

Answer: See response to STDE-6.4a.

Attachment: N/A

Disclaimer: The contents of this guidance document does not have the force and effect of law and is not meant to bind the public in any way. This document is intended only to provide clarity to the public regarding existing requirements under the law or agency policies.

UNITED STATES DEPARTMENT OF AGRICULTURE
Rural Utilities Service

BULLETIN 1724D-101A
RD-GD-2017-85

SUBJECT: **Electric System Long-Range Planning Guide**

TO: All Electric Borrowers

EFFECTIVE DATE: Date of Approval

OFFICE OF PRIMARY INTEREST: Engineering Standards Branch, Office of Policy, Outreach, and Standards

INSTRUCTIONS: This Bulletin replaces Bulletin 1724D-101A, Electric System Long-Range Planning Guide, dated May 10, 1995.

AVAILABILITY: This bulletin can be accessed via Internet at:

http://www.rurdev.usda.gov/RDU_Bulletins_Electric.html

PURPOSE: The purpose of this guide is to highlight the key engineering principles and methods used in the preparation of long-range plans that will assure sound, long-range economic conclusions for owners, engineers, and consultants.

Assistant Administrator
Electric Program

2/16/17
Date

TABLE OF CONTENTS

1 Purpose 8
2 The Long-Range Planning Process 8
3 Phase 1—Collect and Evaluate System Data 10
4 Phase 2—Define Engineering and Economic Criteria 14
5 Phase 3—Develop Design Options and Cost Allocations 17
6 Phase 4—Select and Validate Preferred Plan 19
7 Phase 5—Develop Plan for Implementing Long-Range Plan 22
8 Phase 6—Complete Report and System Circuit Diagrams 23
9 Phase 7—Present Final Report for Board Approval 24
10 Special Considerations 25
11 Use of the Long-Range Plan to Guide System Changes 30
12 Power Supply Studies 31
13 Periodic Determination of Plan Validity 31
14 Conclusion 32

Exhibits
Exhibit A: Summary of Data Required
Exhibit B: Sample Engineering and Economic Criteria
Exhibit C: RUS Fixed Charge Rate Calculation Guide
Exhibit D: Radial Transmission Line Reliability and Operational Assessment
Exhibit E: Sample Economic Conductor Life System Analysis
Exhibit F: Sample Substation Loading Sheet for Specific Plan
Exhibit G: Sample Plan Economic Analysis Spreadsheet
Exhibit H: Sample Sensitivity Analyses
Exhibit I: Suggested Table of Contents for Long-Range Engineering Plan
Exhibit J: Suggested Table of Contents of Supporting Data
Exhibit K: Checklist of Long-Range Planning Report (RUS Form 260)
Exhibit L: Summary of Long-Range Planning Report (RUS Form 261)

Appendices
Appendix 1: Economic Conductor Life Cycle Analysis
Appendix 2: Radial Transmission Line Reliability and Operational Assessment
Appendix 3: Aging Considerations for Long-Range Capital Expenditures
Appendix 4: Distributed Generation in Long-Range Planning
Appendix 5: Bibliography and References

INDEX:
Distribution System Design and Construction Budget
Long-Range Plan
System Configuration and Operation

ABBREVIATIONS

$D	Distribution Costs (Plan PW for OOS)
$DP	Delivery Point Surcharge Costs (PW for OOS)
$LD	Primary Line Losses (Plan PW at Distributor/Cooperative Costs for OOS)
$LPS	Primary Line Losses (Plan PW at Power Supplier Costs for OOS)
$S	Substation Costs (Plan PW for OOS)
$TL	Transmission Line Costs (Plan PW for OOS)
AAC	All-Aluminum Conductor
AAAC	All-Aluminum Alloy Conductor
ACAR	Aluminum Conductor, Alloy-Reinforced
ACSR	Aluminum Conductor, Steel-Reinforced
AFC	Annual Fixed Charges
AMR	Automated Meter Reading
APP	Alternate Preferred Plan
CFR	Code of Federal Regulations
CPR	Continuing Plant Records
CRN	Cooperative Research Network
CU	Copper
CWP	Construction Work Plan
DA	Distribution Automation
DG	Distributed Generation
EEC	Engineering and Economic (Design) Criteria
FERC	Federal Energy Regulatory Commission
G&T	Generation and Transmission Cooperative
GFR	General Field Representative
GIS	Geographical Information System
HMW	High Molecular Weight (Underground Power Cable Type)
IEEE	Institute of Electrical and Electronics Engineers
kcmil	Thousand Circular Mil
KWh	Kilowatt-hours
LDSF	Load Distance Service Factor
LF	Load Forecast
LL	Long Level (of LRP)
LR	Long-Range
LRP	Long-Range Plan
LRPG	Long-Range Planning Guide
MW	Megawatts
NERC	North American Energy Reliability Council
NESC	National Electric Safety Code
NRECA	National Rural Electric Cooperative Association
OOS	One-Ownership Study
O&M	Operations and Maintenance
PCB	Polychlorinated Biphenyl
PP	Preferred Plan
PSS	Power Supply Study

PV	Photovoltaic
PW	Present Worth
REA	Rural Electrification Administration
ROW	Right-of-Way for Distribution and Transmission Lines
RTL	Radial Transmission Line
RUS	Rural Utilities Service
SAIDI	System Average Interruption Duration Index
SCADA	Supervisory Control and Data Acquisition
TIER	Times Interest Earnings Ratio
T/L	Transmission Line
UL	Underwriters Laboratories
URD	Underground Residential Distribution
VAR	Volt-Ampere Reactive
XLPE	Cross-Linked Polyethylene

DEFINITIONS

Alternate Preferred Plan (APP). The APP is the long-range plan determined by the planning engineer and support team to be the best system approach to serve the future long-range loads *if* certain parameters assumed in the study significantly change. Such parameters include, but are not limited to, large increase in power costs; large increase in wheeling costs; significant changes in wholesale rate structure, such as transmission lines; new transmission lines become available for use; significant changes in load growth, etc.

Annual Fixed Charges (AFC). The AFC or fixed charge rate is used to annualize capital cost expenditures in economic analyses. The rate is calculated by adding up all annual system expenses and dividing them by the total number of utility plants installed. Often the rate is calculated for a period (e.g., five years) and then averaged. The expense accounts typically used are capital interest costs, operations, maintenance, depreciation, and taxes (if applicable). To illustrate, a project is estimated to have a total cost of $2,000,000. If the AFC has been calculated at 15%, then the annualized costs would be $300,000 (15% × $2,000,000). This implies that if the project is constructed and $2,000,000 is added to the electric plant capital costs, it is going to take $300,000 per year to fully pay for all the operating expenses. See Exhibit C of this *Guide* for an example of the calculations.

Board. The Board is the Board of Directors and trustees of the Owner. The Board is responsible for setting policy, including final approval of the LRP.

Borrower. A Borrower is an organization which seeks a loan from, or to arrange financing through, the RUS for the purpose of constructing facilities or making improvements to its electric system.

Distribution Automation (DA). DA enables an electric utility to monitor, coordinate, and operate electric system and consumer components in real-time from remote locations.

Distributed Generation (DG). DG—also called on-site generation, dispersed generation, decentralized generation, or distributed energy—generates electricity from many small, localized energy sources. Most industrial electric generation is from large, centralized facilities, such as fossil fuel plants (coal- and gas-powered), nuclear power plants, large solar or wind power farms, or hydropower plants. These large plants have excellent economies of scale, but usually transmit electricity for long distances through transmission lines and substations that sometimes negatively impact the environment.

Economic Conductor Life Analysis. The most economical type of lines can be determined by comparing the life costs of various distribution line conductors. The costs are based on the AFC rate, the cost of capital to build the line, and the estimated line losses based on projected loading and power costs. See Exhibit E of this *Guide* for an example of the calculations.

One-Ownership Study (OOS). OOS refers to the economic analysis of an electrical system where all owners of the various parts of the system (e.g., transmission lines, substations, distribution lines, etc.) are considered together as one entity. The study includes the costs for all owners and considers each alternate plan in order to identify the most economical approach, while taking into account all organizations and their costs.

Owner. The party (or parties) that operate and control the electric system. An electric system typically has many components which include, but are not limited to, the distribution lines, substations, subtransmission lines, and transmission lines. Typically, in the United States, ownership of such components is by one or more parties. The responsibilities of the Owner are generally carried out by the general manager, executive, or person of similar title, who is principally accountable for overseeing the property.

Planning Engineer. The planning engineer is the individual responsible for conducting all necessary studies associated with the LRP, including the preparation of the final report. It is desirable that this individual be a duly-registered professional engineer under the state laws of the electric system and recognized by RUS as being qualified in preparing LRPs. Although the planning engineer is usually an outside consultant, he or she may be a member of the owner's staff or combination of the two. Although many owners' staff engineers compile CWPs, each owner should evaluate the advantage of additional perspectives, skills, and availability of time provided by an outside consultant when involved in the LRP.

Power Supplier. The Power Supplier is an organization from which the Owner purchases wholesale power and energy. The role of the power supplier may be filled by a private investor-owned power company, a governmental agency, or a generation and transmission (G&T) cooperative of which the Owner is a member. In many cases, the owner purchases energy from more than one power supplier. In cases where all purchases are coordinated through one organization, that organization is the power supplier even if it has no generating capacity of its own.

Power Supply Study (PSS). PSS refers to studies completed separately from the LRP. The LRP is completed using, generally, average facility costs and assumptions for substation and delivery point locations. When CWPs are being prepared, PSS are generally completed for certain

portions of the system to formally justify the construction of certain projects, such as transmission lines, substations, etc. The PSS is completed in conjunction with the power supplier and transmission line/substation owners using precise budgetary estimates. Typically, the PSS validates the LRP and allows the projects to be budgeted for construction.

Preferred Plan (PP). The PP is the LRP determined by the planning engineer and support team to be the best system approach to serve long-range future loads. The PP is the option that should be followed for all planned future construction in CWPs.

Radial Transmission Lines (RTL). RTL refers to transmission lines that feed one or more delivery points that are electrically fed from only one source. No alternate loop feed is available for an RTL.

Sensitivity Analysis. After determining the costs for each plan evaluated and the Preferred Plan appears to have been identified, it is important to compare the plans if certain economic parameters varied from what was projected. This process is called the Sensitivity Analysis and is usually carried out for the plans with the closest lowest costs. Parameters typically covered in the analysis include construction inflation rate, load growth, energy inflation rate, present worth rate, and wheeling costs. See Exhibit H of this *Guide* for an example of such analysis.

Smart Grid Technology. This term refers to the new technology available to the electric distribution system for improved operation, protection, and efficiency. The technology is a big step in Distributed Automation, allowing system equipment to record events—and appropriately respond—for improved system performance. Equipment that supports the Smart Grid Technology includes automatic meter information systems, protective relays of substation feeder breakers, line controlled switches and reclosers allowing for fault isolation and load transfers, etc.

Substation Firm Capacity. *Substation* Firm Capacity is a term that refers to an electric distribution system that has a spare substation transformer or mobile substation or transformer available for each of the transformer sizes, voltages, etc., on the system. The spare transformer may be stored at a substation or in the equipment storage yard. *System* firm capacity implies that spare transformers are stored at *some* location on the system. *Site* firm capacity implies that the spare transformer is stored at the substation for which it is intended, the result of which improves reliability and aids in system O&M. This is often the practice of some systems where there are loads that have paid for such capacity or where loads are critical and high-priority in nature.

System Circuit Diagram. The System Circuit Diagram is typically an electric system map showing only electric plant components, such as distribution lines, substations, transmission lines, and some key, land-based information. The map is clear of a lot of details so that planned construction can be shown plainly. The diagram should include line voltage, loading, and voltage drops. The map is used to show planned construction for each LRP, including the load level to which they are to be built. The maps can be paper or digital in form.

System Planning. System Planning is the careful evaluation of an electric power system, the consideration of alternative methods of meeting the electric power needs of the consumers, and

the selection of the most promising of the viable alternatives for providing economical, reliable, environmentally acceptable service at a reasonable cost. System Planning by RUS borrowers is manifested in the long-range plan (LRP) and the construction work plan (CWP).

CONTRIBUTORS

The United States Department of Agriculture Rural Utilities Service acknowledges the dedication and technical expertise of all the organizations and individuals who participated in the development of this guide. This guide is designed to help borrowers develop and implement long-range options and plans effectively. This document is based on inputs from members of the NRECA Transmission and Distribution System Planning Subcommittee. Committee members and associates who provided invaluable assistance in preparing this document were:

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1 PURPOSE

This document is intended to provide guidance in the preparation of long-range plans for electric borrowers. It addresses the minimum requirements and responsibilities of system owners, engineers and consultants, and it identifies key engineering principles and methods for reaching sound long-range economic decisions. This guide supports the RUS regulations found in 7CFR1710.250 and replaces existing RUS Bulletin 1724D-101A.

2 THE LONG-RANGE PLANNING PROCESS

Every electric distribution borrower has a responsibility to develop plans for serving existing and future system loads while maintaining customer satisfaction and meeting environmental requirements. Therefore, it is prudent practice for borrowers and their key stakeholders to engage in a structured planning process to develop a long-range plan for achieving those goals. This resulting plan is an engineering and management tool that provides guidelines for operating and expanding the electric distribution system. At a minimum, the long-range plan should:

- Determine the most practical and economical means of serving existing and future system loads while maintaining reliable service;
- Identify changes, such as additions, upgrades or retirements of facilities and delivery points, as they are needed in order to meet system requirements; and
- Estimate capital requirements for implementing the recommended plan.

In most cases, the borrower's planning engineer is responsible for managing the planning process, including conducting all necessary studies and preparing the long-range plan for review and approval by the borrower's senior management and board of directors and others as necessary. The planning engineer may be a member of the borrower's staff or a consultant, or these responsibilities may be shared between staff and consultants.

The planning process utilized and long-range plan produced, including all load forecasts, should comply with all applicable state or other regulatory requirements.

a Study Phases

This guide outlines a seven-phase process for developing the long-range plan. It identifies the primary steps in each phase and highlights critical coordination issues. The process includes:

- Phase 1—Collect and evaluate system data,
- Phase 2—Define engineering and economic criteria or parameters to be used in the study,
- Phase 3—Evaluate design options and cost allocations,
- Phase 4—Select and validate preferred plan,
- Phase 5—Develop transition plans and maps,

- Phase 6—Complete report and system circuit diagrams and
- Phase 7—Present report and obtain final approval.

It may be desirable to undertake some individual tasks from different phases of the process concurrently, but it is prudent to consider the impact this may have on the overall results. The information collected and decisions made in each phase provide the basis for analysis in subsequent phases. That makes it important to complete the phases in the order suggested. Otherwise, revisions in one phase could result in the need for revisions to work already undertaken in subsequent phases. This could delay project completion and potentially increase costs.

b Consultation with Key Stakeholders

It is important for the borrower to coordinate planning activities with other key stakeholders, including the borrower's power supplier, RUS and other lender if necessary. In most cases, the power supplier is also the transmission service provider. If there is a separate transmission service provider, both the power supplier and the transmission service provider should be included in planning process. For convenience, references to power suppliers in this bulletin are understood to include transmission providers.

It is prudent to provide essential information to stakeholders in printed or electronic form. In addition, the borrower should conduct at least four stakeholder meetings to ensure that each organization's interests are adequately considered and addressed:

- Meeting 1—Preliminary conference for discussion of distribution system data;
- Meeting 2—Engineering and economic criteria conference for review, discussion, and comment on design criteria;
- Meeting 3—Preferred plan review to present preferred plan, economic analysis and sensitivity studies to key stakeholders; and
- Meeting 4—Final report presentation for action by the system's board of directors.

Members of the borrower's management and staff, including key responsible personnel from the operations and maintenance department, and, if appropriate, consultants should participate in each meeting. Representatives of other stakeholder groups should participate as needed. For example, if changes to the transmission system are needed, power supplier participation in Meetings 2 and 3 is essential. If not, it may not be necessary. Since the availability of capital may depend on completion of the long range plan, representatives of RUS and other lenders if necessary should be invited to attend the meetings and kept informed of developments.

While it is often advantageous to conduct the meeting to review the preferred plan (Meeting 3) in person due to the complexity of the data, maps, and other

information to be discussed, it may be acceptable to conduct the meetings by telephone or web conferences and email exchanges. The increased use of these technologies can reduce the cost of the planning process and may enable more people to participate.

3 PHASE 1—COLLECT AND EVALUATE SYSTEM DATA

The primary task in Phase 1 is to identify the basic data needed to support the planning process and computer model development. It is essential to collect the best available data in this process. Steps include identifying data requirements, assigning data collection responsibilities and presenting results for discussion at Meeting 1.

Basic system data include, but are not limited to, the following general categories:

- System configuration and operational data;
- Economic parameters and cost estimates;
- Wholesale rates, including any wheeling costs; and
- Anticipated load growth patterns.

A detailed list of data needed to complete a long-range plan is shown in Exhibit A of this *Guide*.

a System Configuration and Operational Data

Required system configuration and operational data includes:

- Transmission line diagrams, distribution circuit diagrams, and/or computer model data reflecting the most current peak-loading conditions experienced;
- Proper feeder wire sizes and number of phases, the location and sizes of capacitor and voltage regulator banks, and the correct location of normal line opens;
- Accurate peak consumer and substation load data;
- Feeder voltage and current readings at substations and along the electric lines;
- System reliability data; and
- Historical cost data for system improvements and line construction.

Required information about key components of the electric delivery system, including transmission and substations, includes:

- Voltages, capacities, and ownership of transmission lines and substations;
- The loading of each substation and available capacity;
- Substation capacity, both firm and spare , if any; and
- The load growth rate for each substation over the last 10 years, if available.

The borrower and its power supplier should discuss their respective plans to

determine whether the power supplier has bulk electric plans that could be beneficial to the borrower's distribution system and to avoid duplication of efforts. If the power supplier is a generation and transmission cooperative (G&T), it is important to determine whether the load is being served on-system directly from the G&T's facilities or off-system through another borrower's facilities. Off-system loads sometimes involve wheeling charges, which should be included in the economic analysis. Ownership interests and shared costs of any jointly-owned substations should be identified.

b Economic Parameters

It is necessary to estimate the following economic parameters:

- System annual fixed costs and inflation rates for both energy and construction expenses;
- Construction costs for system components, such as transmission lines and taps, substations, distribution lines and voltage conversion equipment; and
- Present worth and inflation rates, which should be acceptable to the stakeholders.

Costs that are common to all alternate plans under consideration, such as consumer distribution transformers, service drops, sectionalizing equipment, meters and capacitors, are often ignored in economic comparisons, as they typically do not affect the results of the comparison.

c Wholesale Rates

Information about the wholesale energy rate structure of the power supplier and any wheeling costs paid by the power supplier for off-system loads should also be collected. While this information is sometimes ignored, it can make a significant difference in the economic comparison of alternate plans. It is important to identify any delivery point costs paid by the distribution system. Such costs are not necessarily included in a one-ownership[1] economic analysis, but they impact costs indirectly and should be evaluated.

It is important to determine if there are any anticipated wholesale rate increases or changes in wholesale rate philosophy that might transfer direct costs from the power supplier to the distribution system. For example, a power supplier may wish to stop providing subtransmission lines and substations and to transfer the ownership and associated costs of these facilities to its wholesale customers. While this does not happen often, the borrower should be aware of any potential actions that could significantly impact long-range costs.

For example, a power supplier may plan to change from an allocation method of

[1] See Section 10a for more discussion of one-ownership economic analysis.

assigning the cost of substation changes to all customers to a method that directly assigns the costs of such changes to customers served by the substation. This could significantly affect long-range costs and system upgrade decisions.

It is also important to consider territorial laws for the service area being studied. Potential annexation of borrower territory by other utilities requires special consideration and evaluation.

d Load Forecast

It is essential to begin the long-range planning process with a reasonable and supportable load forecast approved by the system's management, board of directors and RUS. Borrowers are typically required to develop a new load forecast every two to three years. Borrowers are required to follow the load forecast regulations in 7 CFR 1710 subpart E. The forecast should include projections of annual kilowatt-hour sales, level and season of annual peak demand and losses for a range of assumptions for each district in the borrower's service territory. Many distribution system load forecasts deal with a 10-year period. It may be necessary to extend the forecast to cover the planning period, typically 20 years (see Section 4c and Section 5a of this *Guide*). Construction projects included in the long-range plan should correspond to forecast requirements.

Stakeholders should review the load forecast for reasonableness and to identify anomalies or flaws. Any adjustments to the approved forecast should be documented and agreed to by the power supplier, borrower and RUS general field representative before proceeding. Borrowers should also comply with applicable federal and state requirements regarding load forecasts.

The long-range plan should identify three to five key load levels (LLs) to serve as benchmarks for construction work plans. Load Level 1 (LL1) is typically the actual load level at the beginning of the study, and the final load level is that projected for the last year of the study. Interim load levels determine the need to construct specific projects. For example, LL1 may correspond to projects schedule for the first three years of the long-range plan. LL2 would be the load level projected for Year 4, corresponding to projects needed in Years 4, 5, and 6. LL3 would be the load level projected for Year 7, corresponding to projects needed in Years 7, 8, and 9, and so on. The load levels, not the date, serve as a trigger for the construction work plan. If, for example, loads fall short of Load Level 2 as predicted for Year 4, construction of projects corresponding to that demand may be delayed. If Load Level 3 is reached in Year 5 instead of Year 7, certain projects may be constructed earlier. There may be different load levels for different parts of the system, and they may trigger construction at different times.

e System Reliability Data

Reliability is a key issue for all electric suppliers. A thorough review of system reliability data is needed to identify weaknesses that can be addressed in the long-range plan and formulate ways to improve system reliability. In general, the components most likely to significantly affect system reliability are transmission lines, substations and distribution feeders. Distribution feeders with smaller conductors or feeders that do not serve as ties for substations are likely to experience more outage time than larger conductors, looped lines, or ties between substations.

The borrower should consider providing on-site backup power for substations that serve high-priority loads, such as large towns, hospitals, commercial and industrial loads. Designs for distribution feeders should provide strong ties between sources for improved reliability. Reliability needs, such as larger conductor sizes and overhead versus underground construction, should be addressed in the design criteria for the long-range plan.

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f Operation and Maintenance Survey

RUS requires its field representatives to conduct a periodic review of the operations and maintenance practices of each borrower. This review will normally be done at least once every three years. The review collects data, such as outage information, losses, power factor, capacity factor and other operational factors. The results of the review are provided to the borrower on RUS Form 300. The review provides a useful overview of the system's operation and maintenance characteristics and identifies areas that need to be addressed. It also includes suggestions for system improvements.

Projects to be included in the long-range plan will be determined by a number of factors, such as costs, including all fixed costs, and the needs identified by the operations and maintenance review.

g Conductor Options

Until recently, conductor selection was driven by load current and voltage drop, but as energy costs increase, line losses are becoming an increasingly significant economic factor. Choosing the correct conductor sizes can help the borrower minimize costs. An economic conductor life analysis is a useful tool for determining the most economical conductor voltages and sizes for different construction options, considering losses, line load levels and voltage drops.

The analysis estimates the total ownership cost of conductors of different sizes over their expected life. The information allows the system to weigh the higher initial cost of larger conductor sizes against long-term cost savings due to lower line losses and lower voltage drops. Other factors considered in selecting a

conductor include:

- Conductor Availability. The borrower should discuss the availability of different conductors under consideration with its wire vendors. Suppliers should be able to provide the selected conductor during emergencies as well as for routine construction.
- Storm Situations. Other systems that could be expected to help restore power in storm and other emergency situations should have the ability to work on the conductor sizes utilized.
- Tooling and Connectors. The borrower should review the cost of the tooling and connectors required for the conductors under consideration to determine whether any would add significant costs.
- Switching Capability. An economic conductor life analysis provides a recommended minimum conductor size, based on the initial load and expected load growth for a line. However, if main tie lines will be used as backup for other feeders, it may be prudent to select a larger conductor size in order to improve system reliability.

Conductor options should not be limited to those currently in use on the borrower's system. While ACSR conductors have been utilized extensively by electric distribution systems over many years, other available conductors—such as AAC, AAAC, and ACAR—should be included in the evaluation. It is important to note that the different characteristics of different conductors may require different modeling techniques.

Borrowers may find it helpful to find out which conductors other electric systems in their area are using and why.

There is typically little cost difference in the pole, pole-top assembly, guying and anchoring for conductors of similar strength and size. The primary differences among conductor options are the cost of the conductor in dollars per 1,000 feet and the cost of losses.

Exhibit E of this *Guide* provides an economic conductor life system analysis. Additional discussion of the factors involved in such an analysis is included in Appendix 1 of this *Guide*.

4 PHASE 2—DEFINE ENGINEERING AND ECONOMIC CRITERIA

The tasks identified in Phase 1 should be completed before proceeding to Phase 2. The information collected is used to establish the basic engineering and economic criteria (EEC), or assumptions, for the economic models developed to compare alternate plans for meeting future needs.

Exhibit B of this *Guide* provides an example of engineering and economic criteria. Additional details and discussion items identified below are included later in this guide.

a Basic Cost Estimates and Parameters

The following basic cost estimates and parameters are needed as input to the economic models of alternate plans:

- Cost estimates for construction of various distribution lines;
- Cost estimates for 25-kV line reinsulation and conversion, such as step banks and consumer transformers;
- Cost estimates for uprating existing substations by voltage class and MVA capacity;
- Cost estimates for new substation alternatives by voltage class and MVA capacity;
- Cost estimates for transmission lines and taps by voltage class;
- Economic parameters for borrower and power supplier, including cost of losses, annual fixed charge rate, transmission O&M costs, distribution O&M costs, substation O&M costs, avoided energy cost, distribution energy cost, inflation rate for energy costs, inflation rate for construction costs, present worth rate, delivery point costs and total value of distribution plant;
- Reliability criteria for transmission line looping and substation firm capacity, if available;
- Projected system peak loads by load levels from actual load level at the beginning of the study to the projected requirements for the final year of the study; and
- General criteria for the overall plan, such as distribution system design and operating criteria, line and equipment loading limits, and multiphase conversion limits.

b Transformer Criteria

It is useful to establish a criteria for replacement of substation transformers, based on capacity and age. For example, it is prudent to replace any that have significant maintenance problems, have suspect levels of combustible gases or show signs of failure. Transformers that have been in service more than 35 years are likely to experience major maintenance costs during the planning period. The cost of maintaining versus replacing this equipment should be compared in the economic analysis.

Several factors should be considered in establishing criteria for sizing transformers for substations to ensure that equipment remains in service over its useful life, including the initial load and growth rate at the substation location, potential load shifts due to new substations and load shifts during emergency situations. Areas of the system with low growth rates may require different criteria for sizing transformers than areas of the system with higher growth rates. However, it may be more economical to establish a standard transformer size for the entire system to accommodate changes in load growth patterns during the

planning period. There may also be cost benefits to purchasing the same size transformer for multiple locations. This provides the flexibility to move units as load patterns evolve. Single versus two three-phase transformer configurations should be evaluated from a reliability and maintenance perspective.

c Planning Period

Load forecasts normally project loads for a 10-year period. For long-range planning purposes, it is usually desirable to predict loads for a longer period. The planning period should be at least long enough for the system to need enough upgrades and/or new construction to permit the exploration of several alternate plans and system configurations. In general, this is the amount of time it takes for the system load to double, about 20 years at an annual demand growth rate of about 3.5 percent and 25 years or more for a system with a 3.0 percent growth rate. Planning parameters for systems with growth levels of less than 2 percent should be considered on an individual basis.

It is important to choose a period that will stress the electric system to force change so that options can be evaluated.

d Design Options

The engineering and economic criteria should establish several design options for evaluation. Options for adding capacity, assuming the existing system is operating at 12.5 kV or less, include:

- Add no new delivery points, increase the capacity of existing lines and substations and maintain the same distribution voltage levels;
- Add no new delivery points, increase the capacity of existing substations and convert the distribution voltage to 25-kV operation;
- Add new delivery points and/or increase the capacity of existing substations and maintain the same distribution voltage levels; or
- Add new delivery points and convert the distribution voltage to 25 kV.
- Consider a hybrid system with both 12.5kV and 25kV distribution.

The borrower should study the options that best fit system conditions and evaluate the economic and operational benefits for each.

e Stakeholder Agreement on Engineering and Economic Criteria

Key stakeholders should have the opportunity to review, discuss, offer comments on and agree to the engineering and economic criteria. Meeting 2 provides an opportunity for the parties to confer and reach agreement on these issues. Agreement on the criteria between the borrower and power supplier is critical to the validity of the study.

5 PHASE 3—DEVELOP DESIGN OPTIONS AND COST ALLOCATIONS

Key stakeholders should agree to the engineering and economic criteria established in Phase 2 before proceeding with Phase 3. The next task in the planning process is to develop the design options identified in Phase 3 and estimate costs for each option.

a Load Forecast Issues

It is often necessary to extrapolate the system's approved load forecast to match the long-range planning period. One way to do this is to identify different growth areas on the system, based on current experience, large loads and expected changes. The basic process for this is:

- Identify areas of higher, average and lower growth on the system circuit diagram.
- Allocate load and estimate the growth rate in each area based on the total system peak demands in the load forecast.
- Use this information to extrapolate the load forecast to match the planning period.

It is also important to determine whether all areas of the system peak during the same season. For example, a system that peaks in the summer overall, may serve an all-electric subdivision, creating an area within the system that peaks in the winter.

Other acceptable methods of load allocation include projecting from individual feeders for small systems or using the square mile grid analysis approach. In addition, actual individual consumer demand data may be available to systems that have deployed advanced metering infrastructure (AMI) or a smart meter system.

Large power and residential loads are usually forecast separately. One way to project large power loads in the 150 to 1,000 kW is to double demand over the life of the study. This approach assumes that existing loads will grow and/or new loads will be added in the vicinity of existing large power loads.

Large power loads greater 1,000 kW are usually forecast individually, based on information provided by the customer. These loads usually do not add significant capital requirements, as large commercial customers typically make a contribution in aid to construction to pay for any changes to the system needed to service their load.

To simplify the system design process, loads are typically assumed to have a 95 to 98 percent power factor so that designs for alternate system configurations can omit line capacitors. This reduces design time and costs, and does not significantly affect the final economic comparisons. Likewise, sectionalizing and

system protection costs are typically omitted as well. However, the costs for capacitors and sectionalizing devices usually are included in the total plant projections.

b Distribution System Design and Construction Budget

The next step is to develop a distribution system design and construction budget for each alternative under consideration. Appropriate conductors were identified in the economic conductor life evaluation (see Section 3g of this *Guide*). The same kVA load capacity should be used for each option so that end-of-line accumulated voltage drops are approximately equivalent. For example, if the 25-kV option has a total drop of approximately 10 volts, then the drop on the 12.5-kV option should also be approximately 10 volts. This approach provides comparable service levels for each option, which is necessary for a true economic comparison.

The costs associated with each alternative should be calculated for the power supplier and borrower using the one-ownership approach (see Exhibit G of this *Guide*). That is, the economic analysis is conducted as if all parts of the delivery system, both transmission and distribution, were owned by one entity. This helps identify the alternative that will deliver power to the consumer at the most economical overall cost, even though different options might require different levels of investment by the borrower.

For comparison purposes, line costs are usually levelized over the study period. If a borrower has delayed maintaining the system and increasing capacity to the point that it is experiencing high voltage drops, the borrower will need to initiate a significant construction program as soon as possible to correct the problem. Consequently, more capital costs will be incurred in the early years of the study, and the levelized cost will be higher than if the same construction program were spread evenly over the planning period.

Substation and transmission line capital costs are generally allocated to the year in which new capacity is needed. Annual losses, both in primary lines and transmission lines, if appropriate, are forecast using an appropriate, calculated compound growth rate.

A substation loading chart showing substation capacities and required improvements for each alternative under consideration is needed in order to properly allocate substation and transmission line costs.

Exhibit F of this *Guide* provides a sample substation loading chart.

c Reliability Issues

Reliability of service should be evaluated for each alternative. Normally,

installing new substations to establish new load centers shortens the distribution lines, which should improve reliability. Converting existing distribution lines to a higher voltage instead may decrease reliability. The expected reliability of the conversion option can be improved by:

- Installing two separate substation power transformers or making provision for a mobile substation to increase reliability,
- Establishing main substation tie feeders for transferring load from one substation to another,
- Establishing loop-feed transmission to a substation, or
- Employing a more sophisticated distribution line sectionalizing scheme.

Using one or more of these options can help establish comparable reliability for options under consideration.

It is important for the economic analysis that the alternatives under consideration be based on comparable assumptions. This means that projected load levels should be the same for each year, changes in existing substation capacity should be scheduled in approximately the same years and voltage drops on circuit extremities should be comparable for all alternatives. Close coordination between all parties involved in designing the system alternatives and allocating costs is essential to ensure that these conditions are met. If alternatives are based on different criteria, such as different load levels or different schedules for substation capacity increases, the resulting economic analysis will not be sound or valid.

6 PHASE 4—SELECT AND VALIDATE PREFERRED PLAN

The analysis outlined in Phase 3 should be completed before proceeding to Phase 4.

The principal task of Phase 4 is to select and validate the preferred long-range plan based on a comparison of the alternative system designs and cost allocations completed in Phase 3. The plan selected should not be limited by the existing system. Although there are inherent benefits in continuing to use installed facilities, a proposal that requires early retirement of those facilities should be adopted if it results in significant cost savings.

a Compare Costs to Determine Preferred Plan

The primary factor in choosing a plan is usually full life-cycle cost. It may be necessary to compare a plan with high initial capital costs but low annual costs to a plan with lower capital costs but high annual costs. A plan chosen just for low capital costs or just for low annual costs may not be the plan that provides the best service at the most reasonable overall cost to the consumer. There are numerous methods of performing this type of economic comparison. Regardless of the method used, the following factors should be included in the economic evaluation:

- Time Value of Money, or Present Worth Analysis. Dollars spent this year are worth more than dollars spent next year.
- Inflation in Both Energy and Construction Costs. Energy, labor, and material costs are likely to increase significantly during the planning period.
- Line Losses. The cost of losses on the distribution system and transmission lines, if appropriate, should be included in the cost of service.
- Operation and Maintenance Costs. This is usually estimated as a percentage of added plant.
- Annual Fixed Charges. This is usually estimated as a percentage of added plant.

The present worth method of economic evaluation is preferred in most situations, but there should be an additional comparison to annual costs to help validate the economic results and aid in the selection of the preferred plan.

The preferred plan is usually the option with the lowest one-ownership costs of all the alternatives being considered. If two plans have comparable one-ownership costs, then the plan that more equitably spreads the capital costs between power supplier and distribution system or provides the highest reliability should be chosen.

Exhibit G of this *Guide* provides a sample economic analysis workbook, including a summary list of all plans considered. RUS Bulletin 1724D-104 provides another example of an engineering economics workbook that could be used.

b Perform Sensitivity Analysis to Confirm Preferred Plan

It is important to conduct sensitivity studies for any plans that appear to be reasonable in order to verify the results of the economic analysis and selection of the preferred plan. This analysis should include variations in key economic parameters, including:

- Present worth rate,
- Energy inflation rate,
- Construction inflation rate,
- Fixed charge rate,
- Load growth and
- Wheeling costs, if applicable.

The basic assumptions for these factors should be increased and decreased to determine if the preferred plan is still the best choice under different economic conditions. It is helpful to present the results of the sensitivity analysis in both tabular and graphic form to aid in interpretation and communications.

Exhibit H of this *Guide* shows an example of a sensitivity analysis.

If the results of the sensitivity analysis are close, other factors that may be considered include:

- Energy Conservation. If one plan results in higher long-term energy savings, that plan should be given higher priority.
- Excess Capacity. While each plan must provide the minimum capacity required to serve the projected system load, a plan that provides more excess capacity at the end of the planning period should be given higher priority.
- Service Reliability. While each plan must provide a minimum level of service reliability, a plan that provides better service reliability should be given higher priority.
- System Manpower and Labor Costs. The advantage depends on conditions in the borrower's service territory. If there are manpower shortages and labor costs are above the national average, the most labor-intensive alternative may be less desirable. If labor is readily available in the community, the alternative with the larger construction program may be more desirable.
- Flexibility. One plan may provide a greater capability for expansion at the end of the planning period while another plan may require radical changes in basic design parameters to expand at that point. The plan with the longest useful life should be given higher priority. A plan that defers major expenditures and provides more flexibility to take advantage of future developments in technology should be given higher priority.
- Solution to Chronic Problems. The plan that best addresses a chronic system problem should be given higher priority.

A cost-benefit analysis may be helpful in evaluating alternatives based on these factors.

While economic comparison is the primary basis for selecting the preferred plan, the final decision should be based on good engineering judgment and the best available information. If there is significant uncertainty about a key assumption, such as load growth in a specific area, it may be desirable to designate an alternate preferred plan. The alternate preferred plan can be included in the planning documents and ready for implementation. The final decision on which plan to implement can be made once the parameters for the assumption in question have been firmly established. All work sheets, sketches, maps, and other backup used in developing and selecting the preferred plan and the alternate should be included in the long-range plan supporting documents and retained for future reference.

c Present Preferred Plan for Review and Acceptance

The final step in Phase 4 is to present the preferred plan and any alternate preferred plans to the stakeholders at Meeting 3 for review and acceptance (as appropriate). All economic analyses, including any sensitivity analyses, should

be presented and fully discussed. The borrower should send summaries of preliminary results to stakeholders for their review prior to the meeting.

At the meeting, participants should review and discuss the reasonableness and feasibility of the preferred plan and any alternates. If the review reveals any serious problems with the analysis or plans, it will be necessary to propose a solution, revise the economic analyses and, depending on the extent of the revisions, conduct another review. Once the preferred plan is agreeable to all, it should be approved by the borrower and power supplier.

The power supplier should provide written validation of three aspects of the study:

- The transmission provider and power supplier were included in the long-range planning process.
- The power supplier considers the preferred plan and any alternate preferred plan to be reasonable guides for the borrower's long-term needs in light of the power supplier's system configuration and long-range plans.
- The transmission provider and power supplier will consider the distributor's preferred plan and alternate preferred plan recommendations in their own long-range plans.

This letter should be included in the long-range plan report as supporting data.

7 PHASE 5—DEVELOP PLAN FOR IMPLEMENTING LONG-RANGE PLAN

The preferred plan and alternates, if any, provide a vision of the borrower's system, including expected system upgrades, additions and retirements, at a future date. This vision is achieved through the construction work plan, which is synchronized with the preferred plan through the load levels identified in Phase 1 (see Section 3d of this *Guide*).

The preferred plan clearly states what needs to be accomplished at each load level in the construction work plan and identifies the major components for upgrades and new construction. In practice, the construction work plan will likely need to specify additional work to complete the configuration in the preferred plan and maintain adequate system capacity and acceptable voltage drops.

Ideally, the long-range plan should be completed before the construction work plan. As a practical matter, a borrower may need to, with the agreement of the RUS general field representative, complete its next construction work plan after completing the long-range plan through Phase 4. This allows the borrower to apply for loan funds in a timely manner. For example, the construction work plan to meet Load Level 2 would be based on the design criteria established by the preferred plan, but the remaining phases of the long-range plan would be completed after the construction work plan.

8 PHASE 6—COMPLETE REPORT AND SYSTEM CIRCUIT DIAGRAMS

It is important to document the long-range planning activities, including analysis and results, in a complete written report. Information to be presented in the report includes:

- The engineering analysis of the existing system and the preferred plan;
- Information about alternate preferred plans, if any;
- The strategy for the implementing the preferred plan;
- Summaries of the analysis of options no longer under consideration;
- A discussion of the economic analysis, including methodology and a cost comparison of the results for each alternative;
- An explanation of the reasons for recommending the preferred plan;
- Suggestions for standardizing items such as conductor sizes, line reinsulation design levels, and substation power transformer sizes and voltages
- Summaries of findings and assumptions to aid the periodic review of the continued validity of the plan and support the formulation of revisions or amendments if necessary; and
- A bibliography identifying all data, external documents and judgment sources.

It is useful to include small sketches of the system or sections of the system to illustrate or replace written descriptions and to present summaries of basic data, statistics, economic comparisons, costs data, and engineering analysis in the form of tables or graphs whenever possible.

In addition, the report should include the following tables and diagrams:

- A table showing new construction and major system improvements for substations and related transmission line improvements along with the estimated costs and expected in-service dates. The table should also include equipment to increase the capacity of services, transformers, meters, sectionalizing, regulators, capacitors, etc., as well as annual projections of costs for connecting new services.
- A table showing annual cost estimates for ordinary replacements, or new equipment that does not result in an increase in capacity or quality of service, that result from factors such as normal wear and tear, rot, corrosion and damage.
- A table showing electric plant costs broken down by the categories of new services and system improvements. This will enable management to relate investment in facilities to the time of installation for use in the preparation of long-range financial forecasts.
- A table summarizing key information about the borrower’s electric plant, including actual data for the most recent 10 years and projected data for the long-range study period. Information to be tabulated includes number of new services, system improvements, system retirements, and peak demands. The data should be used to generate accompanying graphs showing total electric plant and total plant per peak kilowatt.
- Substation loading charts for each load level, including the percent loading.

- A circuit diagram for the base, or existing system.
- A circuit diagram for the system as planned at the end of the planning period. This diagram should show projected loads along with new construction and system improvements colored coded for the load level at which the improvements are anticipated. The supporting data should include a primary analysis for each load level to allow for easy evaluation of system voltage drops and losses. Typically, only unregulated voltage drops are included; however, regulated drops may be indicated as well if desired or required.
- A transmission line diagram showing all transmission lines crossing the borrower's system, including those owned by the power supplier and other transmission providers. The diagram should include all existing substation delivery points as well as any new delivery points in the preferred plan and alternate plans, if appropriate.

It is not necessary to include the detailed calculations for the engineering analyses and other planning investigations in the report. However, this information should be retained as reference material. The borrower should retain calculations and work sheets as long as the plan is valid and in effect.

The draft report should be presented to appropriate stakeholders for review and comment. Any issues raised by the review should be resolved before the report is finalized. The final report should be certified by a registered professional engineer licensed to practice in the state where the borrower is headquartered.

Exhibit I of this *Guide* provides a suggested table of contents for a long-range engineering plan that can be used as a guide in organizing report contents.

Form 260 provides a checklist for the long-range plan document. Form 261 provides a summary of the long-range plan results, including general data, line miles, substations and metering points, and plant investment projects.

A long-range plan is expected to remain valid for seven to 12 years. The final report and supporting data should be retained in a manner suitable for long-term use.

9 PHASE 7—PRESENT FINAL REPORT FOR BOARD APPROVAL

The final long-range plan report should be presented to the borrower's board of directors for their review and approval. The presentation should include a discussion of the issues associated with electric distribution system planning, the options considered, the results of the analysis, and the recommendations for the preferred plan and alternate plans if any. It is often helpful to schedule a special meeting for this purpose. Once the review is complete and any issues raised resolved, the board of directors should pass a resolution approving the plan. The borrower may also need to obtain formal acceptance of the plan by their lenders.

Copies of the approved report should be provided to the borrower's power supplier, and

other lenders, if necessary, and state public service commission, if required. If requested, supporting documents should also be provided. The borrower should consider providing these materials in an electronic rather than printed format.

10 SPECIAL CONSIDERATIONS

a One-Ownership Studies

Most distribution borrowers in the United States do not own transmission lines and substations, but the costs for these facilities should be considered in the planning process. The one-ownership approach to economic analysis evaluates various alternatives as if all transmission and distribution facilities used to deliver power to the consumer were owned by one entity. It identifies the plan that has the lowest present worth regardless of which entity owns transmission and distribution facilities. Only costs paid to outside parties are included in the study. Money exchanged between owners of the facilities involved is excluded. It should be noted that generation costs are typically evaluated separately from transmission and distribution costs and are not included in the one-ownership study.

The following example shows a sample analysis of present worth costs of an option using the one-ownership concept.

Electric System Cost Summary	Power Supplier Costs	Distribution System Costs	One Ownership Costs
Transmission Line Costs ($TL)	$TLPS	–	$TLPS
Substation Cost ($S)	$SPS	$SD	$SPS+$SD
Distribution Costs ($D)	–	$DD	$DD
Wheeling Charges ($WC)	$WC	–	$WC
Transmission Line Losses ($TLL)	$TLL	–	$TLL
Primary Line Losses @ Distribution Costs	($PLD)	$PLD	–
Primary Line Losses @ Pwr. Supplier	$PLPS	–	$PLPS
Total Costs ($TOT)	$TOTPS	$TOTD	$TOT

In this example, transmission line costs, substation costs, distribution costs and the cost of primary power supplier losses are costs incurred by either the power supplier or the distribution system and thus qualify as one-ownership costs. The cost of primary distribution losses and delivery point costs are included wholesale rates paid to the power supplier by the distribution system. Therefore, the same costs are expenses for the distribution system and a source of revenue for the power supplier. To avoid duplication, these costs are subtracted from power supplier costs. The economic comparison in Exhibit G also includes one-ownership costs.

There are a number of acceptable ways to calculate the costs inputs to a one-

ownership analysis. It is important for the borrower to work with its power supplier to reach agreement on how losses are handled.

b Conversion to a Higher Distribution Voltage

One option for meeting future needs is to convert the distribution system's existing operating voltage to a higher voltage, for example, 4.16 kV to 12.47 kV, 12.47 kV to 24.9 kV, 12.47 kV or 24.9 kV to 35 kV. Today, most electric distribution systems operate at the 12.47 kV level, and conversion to 24.9 kV is the most common option considered. It is rare to find distributors operating at 4.16 kV level or 35 kV. However, the economic and operational parameters of all options should be considered in evaluating future system needs.

An economical approach to adding system capacity is to raise the primary voltage level from 7.2/12.47 kV grounded-wye to 14.4/24.94 kV grounded-wye. This reduces the line current by 50 percent, reduces both the total voltage drop on the circuit extremities and primary line losses to 25 percent of the 12.47 kV levels, and may add to costs.

Conversion to a primary distribution voltage of 25 kV can be the most economical approach when transmission lines are not readily available in service areas needing additional capacity. This is a good option when it would be necessary to construct more than five miles of additional transmission line to support new substation and delivery point taps. The higher distribution voltage allows for twice the 12.47 kV load and usually supports the use of smaller primary line conductors, generally less than 477 kcmil ACSR. The main difference in line construction between the two voltage levels is the pin and insulator. However, the 125 kV BIL at 14.4 kV distribution transformer costs may be more than the 95 kV BIL at 7.2 kV units.

Two methods are used in the field for 25-kV conversion. One is conversion by phases, using single-voltage consumer transformers. The other is by circuit, using dual-voltage, 7.2-kV × 14.4-kV consumer transformers. The first method may be less expensive, but the second method may be preferred due to safety and reliability considerations. The second method can be accomplished more systematically with two- or three-person crews.

Single-phase, platform-mounted autotransformers are no longer recommended for use in the primary voltage conversion process as the devices are unreliable for high-level through-faults. The best approach to stepping primary voltages—considering all installation costs—is the use of three-phase pad-mounted transformers. The underground residential distribution (URD) method eliminates platform mounting costs of units, especially if large two-winding units are used. The pad-mounted step transformers are typically two-winding transformer banks of 5 MVA or less. Lower weight 7.5 MVA and 10 MVA pads are available in the autotransformer configuration at a reasonable price.

The system design for voltage conversions should also be practical and reliable for operations. A plan that uses many permanently installed step-down transformers is unreliable because system protection and sectionalizing is difficult. At 25 kV, it is preferable to convert major services areas, such as substations and long feeders, and eliminate the use of step transformers for long taps with many distribution transformers.

The use of step transformers for long periods of time should be avoided if possible. They can be useful during the conversion process but generally should not be used in permanent installations. An exception is the installation of step transformers at key tie points where the distribution voltage changes. In this case, they are in place for use in emergencies and load transfers, and typically do not carry load. Step transformers may also be needed in underground distribution systems.

With this approach, losses from step transformers can be ignored and the number of step banks for the conversion process can be greatly reduced.

Operating at the higher distribution level of 25 kV has advantages and disadvantages. Advantages cited include:

- Reinsulating and converting the distribution system can revitalize an old system and eliminate old equipment that has caused problems;
- The amount of overloaded lines may be reduced;
- Excessive voltage drops may be eliminated;
- It may reduce the need for line voltage regulators, a high-maintenance and high failure rate device; and
- It can reduce system losses by two to three percent.

Disadvantages cited include:

- The system may experience more feeder outages than at the lower voltage, because the higher voltage will fault to ground through tree branches, whereas the lower voltage system will burn the branches and trees;
- More consumers are served on a given feeder, so outages have a greater impact on system reliability; and
- Operating expenses are higher for systems using both 12.5-kV and 25-kV equipment.

Operating a 25-kV system requires more aggressive right-of-way maintenance than a lower voltage system to reduce and avoid outages caused by vegetation. Since a 25-kV system serves more consumers per substation, per feeder and per tap, it may require additional consideration to sectionalizing capabilities and reliability issues.

Converting to 25 kV does not provide an economic advantage for every system. Systems with extensive transmission lines in their service areas and reasonable substation construction costs may find it difficult to justify the conversion. Systems experiencing growth of less than two percent per year will also find it difficult to justify the conversion on an economic basis. In some cases, it may be desirable to insulate for 25 kV at an early date in preparation for full conversion at a later date, such as when an older system needs to be essentially rebuilt or when part of a system is already operating at 25 kV. The added costs for the higher insulation level are low and may provide significant benefits in the future.

RUS Bulletin 1724D-105, "Rural Distribution System Conversion Considerations," provides additional information on system conversions.

c Transmission Line Losses

Transmission losses can be a factor when considering conversion from one transmission line voltage to another, but in most cases transmission losses are common between plans and can be ignored. The power supplier can provide guidance as to whether or not to evaluate transmission losses in the long-range system study.

When an alternate plan transfers load from one transmission line to another, it may be necessary to consider transmission losses. Moving load served on a heavily loaded transmission line to a lightly loaded transmission line or from a high-impedance transmission line to a low-impedance transmission line may reduce transmission losses enough to make one alternative more attractive than another. Shifting load in the opposite direction may reduce an alternative's feasibility, particularly if the load being moved is a significant portion of the rating of the line.

When plans involve conversion or elimination of subtransmission lines with voltages $\leq$ 69 kV, it is prudent to calculate the transmission line losses at the one-ownership level. Subtransmission line losses can be significant, especially when lines are close to overload and carry load factor loads greater than 45 percent for distances of more than 20 miles.

d Radial Transmission Line Reliability Assessment

The long-range plan should address the reliability of delivery points, especially those served by long, highly loaded radial transmission lines. While this is often considered the power supplier's responsibility, from a reliability standpoint it is desirable to view the electric system as a total unit. The power supplier and distribution system should jointly plan for delivery points in order to improve system operations and reliability.

Appendix 2 of this *Guide* outlines a procedure for assessing radial transmission

lines.

e Long-Range Capital Expenditures for Slow-Growing and Aging Systems

While long-range planning typically focuses on meeting needs resulting from system growth, other issues must sometimes be addressed. For example, borrowers with older systems may need to replace aging plant before system reliability falls to unacceptable levels. Systems experiencing slow or declining growth may need to plan for retirement of existing plant.

Such conditions and their capital needs should be addressed in the long-range plan. A systematic evaluation will help determine which replacement alternatives provide the most benefits based on system operating conditions, capital costs, electric rates, reliability and the ability to get the work accomplished in a timely manner.

Appendix 3 of this *Guide* provides additional information about this process.

f Use of Distributed Generation and Smart-Grid Technology

Borrowers should be aware of the potential impact of emerging energy policies and initiatives on the planning process. Distributed generation (DG) has the potential to impact long-range planning in the electric utility industry. Significant growth in the use of distributed resources was predicted in the 1990s in anticipation of deregulation and new opportunities for competition. Deregulation has not been adopted as then expected. There were, however, some successful deployments, which provided practical experience and successful proofs of concept.

Today, global environmental concerns and the expectation of significantly increased energy costs in the future are creating pressure to adopt energy policies that will significantly impact the electric utility industry. Initiatives that support increased deployment of distributed generation, the development of renewable energy sources, both centralized and distributed, higher energy-efficiency standards, demand-side management, and similar smart grid applications have the potential to radically change the way electricity is provided to the consumer.

The goals of current energy policy include increasing efficiency, reducing demand or, at a minimum, reducing the rate of growth, and increasing reliance on domestic resources. If these goals are achieved, there will be new design criteria and a shift in emphasis from system performance to system maintenance and the sustainability of existing infrastructure. Although the impact is hard to quantify at this point, new policies will ultimately affect planning and operations for all aspects of the electric system—generation, transmission, and distribution.

Proponents of smart grid technology envision an array of active demand-side

management methods that depend upon both programs with predictable energy savings, such as active load management systems and appliances, and applications with unpredictable results, such as real-time pricing and inclining block rate structures. It remains to be seen how much these systems will influence long-range load forecasts and the planning process. Although there is increasing pressure to reduce both capital expenditures and energy consumption, borrowers must ensure that the electrical network operates to certain standards under all conditions.

If there is a proliferation of distributed generation, future planning activities may have to address issues such as automation and control, communications, computing systems, and electronic security. While these concepts are likely several years from materially affecting distribution system long-range planning practices, it is important to be aware of the potential impact and monitor developments.

Appendix 4 of this *Guide* provides detailed information about distributed generation applications in four categories—large-scale, medium-scale, small-scale, and residential/commercial solar photovoltaics (PV)—and discusses ways to include them in a system's long-range plan.

g Special Equipment Considerations

Electric distribution systems should evolve as new technology to improve system operations, reliability and efficiency becomes available. However, the long-range study is not the appropriate tool for analyzing new technology. Separate studies are needed to evaluate the capabilities of new equipment to improve system operations, reliability and efficiency, such as:

- Automated metering reading (AMR),
- Electronic and/or microprocessor relays and metering,
- Geographical information systems (GIS),
- Supervisory control and data acquisition (SCADA),
- Concrete and steel poles,
- Communication systems,
- Special sectionalizing equipment,
- Outage management systems,
- Computer software,
- Operational tools and
- Other smart grid technologies.

11 USE OF THE LONG-RANGE PLAN TO GUIDE SYSTEM CHANGES

When complete, the long-range plan provides a picture of the future electric system. It specifies line conductor sizes, primary voltages, and new delivery point locations;

addresses transmission needs; and provides a basis for the distribution system and power supplier to make sound decisions to satisfy long-range system needs.

The plan allows the borrower to evaluate proposed sites for future substations and transmission lines and to purchase right-of-way in advance if state statutes and corporate by-laws allow. This can result in significant cost savings, especially in high-growth areas.

It is important to review the plan any time major changes in the electric system are under consideration, particularly when developing construction work plans or acquiring new large loads.

The benefits gained from the planning process and implementation of the long-range plan will offset the costs of developing the plan and reduce the likelihood of the need for costly rebuilds.

12 POWER SUPPLY STUDIES

The economic analysis in the long-range plan and the selection of the preferred plan are based on estimated parameters for component costs and system fixed charges. It is necessary to conduct a power supply study (PSS) to develop specific, accurate cost estimates and to determine availability of land, including right-of-way, before a particular project can be included in the budget and construction can begin. Most power suppliers, including generation and transmission cooperatives, provide guidelines for conducting such studies before capital is committed for construction. The studies follow most of the same procedures and guidelines used in the long-range system study but are based on more accurate costs determined from actual design options and field reviews. In addition, a power supply study is limited to a small part of the overall electric system.

Sometimes the power supply study results in a conclusion and system approach that is different from the long-range plan. In this case, the power supply study should be adopted as an amendment to the long-range plan. If the results of power supply studies are frequently different from the long-range plan, it may indicate that it is time to develop a new plan.

13 PERIODIC DETERMINATION OF PLAN VALIDITY

A borrower should review its long-range plan on a regular basis by comparing basic data, design criteria, and assumptions with actual system experience in order to verify the plan’s continued validity. At a minimum, a system should review its plan prior to preparing a new construction work plan, and a faster-growing system should conduct an annual review. If actual experience deviates significantly from assumptions, it is time to devise a new plan.

The average life span of a long-range plan for a fast-growing system is five to seven years, seven to 10 years for a moderate-growth system, and 10 to 15 years for slow-

growth systems. Regular review will ensure the plan remains valid and will also assist the borrower in determining the need for a new plan when revisions are no longer adequate. Events that necessitate revision or replacement of the long range plan include:

- Loads develop faster or slower than projected.
- Power suppliers change their plans and service policies.
- Transmission or substation additions which are not in the long-range plan are needed.
- Significant large loads are added to the system.
- Necessary rights-of-way cannot be obtained.
- Laws and/or ordinances, such as requirements for underground line construction, change.
- Changes in technology offer new benefits.

Even if no major changes are needed, numerous minor revisions may necessitate a new plan.

14 CONCLUSION

Every borrower should develop and periodically review a long-range plan for meeting the system's future needs. The borrower should create the plan through a structured process that includes consultation and coordination with key stakeholders, including its power supplier, and its lenders if appropriate.

The long-range plan estimates the systems future needs based on its approved load forecast, evaluates alternate plans for meeting those needs, identifies the preferred plan and alternate plans if needed based on cost and other considerations, and proposes a schedule for system upgrades, new construction and retirements to implement the plan.

Users of this guide are encouraged to look at additional supplemental documents which are Excel® 2010 Workbooks. They can be useful tools in the completion of a Long-Range System Study. A summary of those documents is given below:

1. LRPG Exhibit C, Fixed Charges Calculations;
2. LRPG Exhibit D, Radial Transmission Line Assessment;
3. LRPG Exhibit E, Conductor Life Analysis;
4. LRPG Exhibit G, Economic Plan Analyses;
5. LRPG Exhibit H, Sensitivity Analyses;
6. LRPG Exhibit K, RUS Long Range Plan Report Checklist (Form 260); and
7. LRPG Exhibit L, RUS Long Range Plan Report Summary (Form 261).

Documents 1–5 each have a "Use Narrative" explaining the use of the workbook and how the spreadsheet can be applied. Copies of the documents are included on the RUS website.

EXHIBIT A
SUMMARY OF DATA REQUIRED

The information listed below is considered to be the typical data needed by the distribution planner to complete a Long-Range Plan (LRP).

1. 10 years of year-end RUS Financial and Operating Report Electric Distribution (Formerly known as the Form 7).
2. System computer model data and system maps for base system conditions that are available.
3. GIS mapping system for peak load conditions, if available.
4. A copy of the most recently completed Operations and Maintenance Survey (RUS Form 300).
5. Loading conditions by line section for the most recent peak month conditions.
6. Historical growth factors for consumers, kWh usage, and kW demand.
7. Other peak system load data, including measured monthly peak substation loading and feeder peak currents from field ammeters or SCADA system datum.
8. Historical annual fixed rate charge for the past five years, at a minimum, using the fixed charge spreadsheet of this LRPG.
9. Annual fixed rate charges of the power supplier.
10. A current copy of Load Forecast, formerly called the Power Requirements Study.
11. System Engineering and Economic Criteria (update as required).
12. Current substation configurations, voltages, capacities, ownership, age, conditions, power transformer losses, expansion capabilities and limitations, etc.
13. The current system policy for primary conductor size use and why they were chosen.
14. The average costs of building the various size distribution lines on a dollar-per-mile basis in today's dollars.
15. The average costs of building the various size and voltage class transmission lines.†
16. The average costs of building various size and voltage class substations.†
17. The average costs of building various size low-side switching structures on a per-bay basis.
18. A list of special, on-system, large power and growth loads, getting input from district managers (be sure to document those loads that are in the current LF and those that are not).
19. Current electric state territorial laws and the possibility for system annexation by a neighboring distributor.
20. Wholesale rate structures and special conditions, including any anticipated changes. Also identify inflation rate for wholesale power costs and determine current avoided costs in dollars per kilowatt-hour.†
21. Transmission line locations within the electric distributor's service area, their conductor size and voltage class. Also identify potential substation sites by locating industrial parks and potential large power and residential growth areas.†
22. Employment and income sources, growth potentials, land terrain and uses, saturation areas, inflation rates, etc.
23. Determine how many copies of the LRP report will be needed, including a bound copy of the supporting data.

† May have to be provided by power supplier.

EXHIBIT B
SAMPLE ENGINEERING AND ECONOMIC CRITERIA

ABC ELECTRIC COOPERATIVE
City, State
2008 LONG-RANGE PLAN
ECONOMIC CRITERIA
(2007 DOLLARS)

DISTRIBUTION COST
ESTIMATES (Distributor)

			Cost/Mile	
1ø	1/0 ACSR	=	$20,000	per mile
2ø	1/0 ACSR	=	$35,000	per mile
3ø	1/0 ACSR	=	$42,000	per mile
3ø	3/0 ACSR	=	$54,000	per mile
3ø	336 ACSR	=	$65,000	per mile
3ø	336 ACSR Double Circuit	=	$92,000	per mile
3ø	477 ACSR	=	$70,000	per mile
3ø	477 ACSR Double Circuit	=	$105,000	per mile
3ø	795 ACSR	=	$121,000	per mile
1ø	1/0 AL URD	=	$80,000	per mile
1ø	4/0 AL URD	=	$85,000	per mile
3ø	1/0 AL URD	=	$150,000	per mile
3ø	4/0 AL URD	=	$175,000	per mile
3ø	350 AL URD	=	$180,000	per mile
3ø	500 AL URD	=	$185,000	per mile
3ø	1000 AL URD	=	$190,000	per mile
3ø	1500 AL URD	=	$200,000	per mile
1ø	25kV Reinsulation	=	$5,100	per mile
2ø	25kV Reinsulation	=	$5,900	per mile
3ø	25kV Reinsulation	=	$8,200	per mile
1ø	500 kVA Step Transformers (Pad)	=	$15,000	each
3ø	3000 kVA Step Transformers (Pad)	=	$86,000	each
3ø	5000 kVA Step Transformers (Pad)	=	$120,000	each
14.4-kV Transformer Replacement Cost		=	$750	each
Transformer Change-Out Labor Costs		=	$300	each

SUBSTATION COST ESTIMATES

3ø	Circuit Breaker or Recloser for Substation	=	$22,000	per feeder

ABC ELECTRIC COOPERATIVE
City, State
2008 LONG-RANGE PLAN
ECONOMIC CRITERIA
(2007 DOLLARS)

SUBSTATION COST ESTIMATES[*1]

CURRENT PROJECTS[*2]

Description	Transformer Size	# Feeder Bays	Cost	Comments
Uprate existing 46kV/12.5kV Substation A to 115kV/12.5kV	12/16/20 MVA	4	$1,200,000	TBC in 2008
Abandon existing 46kV/12.5kV Substation B and build new 115kV/12.5kV sub	12/16/20 MVA	4	$1,200,000	TBC in 2008
Build new 115kV/25kV Substation C	12/16/20 MVA	4	$1,200,000	TBC in 2008

EXISTING SUBSTATIONS

Power Transformers

Description	Existing Transformer Size	Proposed Transformer Size	Cost	Comments
Uprate existing transformer at Substation D	10/12.5 MVA	12/16/20 MVA	$700,000	
Uprate existing transformer at Substation E	10 MVA	12/16/20 MVA	$1,400,000	
Uprate existing transformer at Substation F	10/12.5 MVA	12/16/20 MVA	$700,000	
Uprate existing Substation C	1-10/16/20 MVA	2-12/16/20 MVA	$1,000,000	
Uprate existing Substation E	1-10/16/20 MVA	2-12/16/20 MVA	$1,200,000	

25 kV Conversion

Description	Cost	Comments
Uprate existing Substation D from 115kV/12.5kV to 115kV/25kV	$650,000	
Uprate existing Substation E from 115kV/12.5kV to 115kV/25kV[*3]	$650,000	
Uprate new Substation H from 115kV/12.5kV to 115kV/25kV	$700,000	

NEW SUBSTATIONS

Description	Transformer Size	# Feeder Bays	Cost	Comments
Build new 115kV/12.5kV sub	10/12.5 MVA	4	$1,400,000	
Build new 115kV/12.5kV sub	10/12.5 MVA	6	$1,472,000	
Build new 115kV/25kV sub	10/12.5 MVA	4	$1,425,000	
Build new 115kV/25kV sub	10/12.5 MVA	6	$1,497,000	
Build new 115kV/12.5kV sub	12/16/20 MVA	4	$1,450,000	
Build new 115kV/12.5kV sub	12/16/20 MVA	6	$1,522,000	
Build new 115kV/25kV sub	12/16/20 MVA	4	$1,475,000	
Build new 115kV/25kV sub	12/16/20 MVA	6	$1,547,000	

*[*1] Data provided by G&T*
*[*2] 2007 Dollars*
*[*3] Credit of $169, 289 (per G&T) for existing power transformer at Substation E not included in cost estimate*
TBC=To Be Completed
NOTE: G&T would install a 2nd 20 MVA transformer in lieu of a 15/20/25 MVA unit.

ABC ELECTRIC COOPERATIVE
City, State
2008 LONG-RANGE PLAN
ECONOMIC CRITERIA
(2007 DOLLARS)

TRANSMISSION COST ESTIMATES[*1]

115 kV Tap Point	=	$250,000
115 kV Transmission Line Cost per Mile	=	$350,000
115 kV Transmission Line (For Substation E)—0.7 mi.	=	$245,000
115 kV Transmission Line (Substation C to Substation F)—5 mi.	=	$1,750,000
115 kV Transmission Line (Substation D to Substation H)—3.75 mi.	=	$1,312,500

[*1] *Per G&T estimates*

ECONOMIC and BASE ASSUMPTIONS
(2007 BASIS)

	Power Distributor Elec. Coop. Name Distribution	**Power Supplier[*] G&T Name Sub. / Trans.**
Losses/kWh ($)	$0.0600	$0.0400
Present Worth Interest Rate (%)	6.00%	6.00%
Annual Fixed Charge (%)[**]	9.83%	10.50%
T&D O&M Costs (%)	6.23%	0.00%
Substation O&M Costs (%)	0.00%	0.00%
Inflation Rate (%)	3.50%	3.50%
Energy Inflation Rate (%)	6.00%	2.88%
Annual Delivery Point Charge ($)	–	–
Total Value of Distribution Plant (12/31/xx)	$70,123,456	

[*] *Data provided by G&T*
[**] *Interest, depreciation, taxes, and insurance only.*

SYSTEM DESIGN CRITERIA

Each alternative being evaluated will be designed utilizing the Engineering and Economic Criteria (EEC) from the most current Construction Work Plan. Each long-range plan will be designed to have approximately the same capacity by requiring that line regulators will not be required in the long-range load level, but will allow for one bank of line regulators when and if needed on interim load levels.

ABC ELECTRIC COOPERATIVE
City, State
2008 LONG-RANGE PLAN
ECONOMIC CRITERIA
LOADING AND OPTIONS

LOADING LEVELS[*1]

Load Levels	Years	Most Probable Summer Peak kW Demand	Most Probable Winter Peak kW Demand	Most Probable Total Consumers
1	2006 (05/06) System (actual) =	97,848	113,139	27,263
2	2011 (10/11) System =	127,552	144,271	30,227
3	2015 (14/15) System =	137,846	155,914	32,360
4	2026 (25/26) System =	163,370	184,785	37,819
	2006 to 2026 Average Compound Growth Rate =	**2.60%**	**2.48%**	**1.65% per year**

Load Levels	Years	Extreme Weather Summer Peak kW Demand[*2]	Extreme Weather Winter Peak kW Demand	Extreme Weather Total Consumers
1	2006 (05/06) System (actual) =	97,848	113,139	27,263
2	2011 (10/11) System =	144,797	175,874	30,227
3	2015 (14/15) System =	157,398	191,519	32,360
4	2026 (25/26) System =	188,647	230,314	37,819
	2006 to 2026 Average Compound Growth Rate =	**3.34%**	**3.62%**	**1.65% per year**

[*1] *From 2007 Load Forecast*
[*2] *Recommended load levels for Long-Range System Study*

PLAN OPTIONS CONSIDERED[*3]

Plan A	No New Delivery Points Added and Distribution Lines to Remain at Current Voltage Levels
Plan B	No New Delivery Points Added and All Distribution Voltage Converted to 25 kV
Plan C	New Delivery Points Added and Distribution Lines Remain at Current Voltage Levels
Plan D	New Delivery Points Added and Distribution Voltage Converted to 25 kV
Plan D1	Like D, but Substation B added instead of Substation A
Plan D1A	Like D1, but Substation C served from G&T 115-kV transmission line.

[*3] *As decided by the cooperative, the power supplier, and/or RUS, as the case may be*

EXHIBIT C
RUS FIXED CHARGE RATE CALCULATION GUIDE

ABC ELECTRIC COOPERATIVE
City, State
LONG-RANGE PLAN

Following is some data to assist in the calculation of a Fixed Charge Rate. A fixed charge rate is composed of several factors: the costs of capital, operation and maintenance, taxes, insurance, and depreciation. Calculating the cost of insurance as a percentage of investment is difficult and the result makes little difference; therefore, it can be ignored for most applications. The fixed charge rate is not an exact figure, but an estimate which is dependent on the quality of the assumptions involved in its calculation.
Note: References to annual Financial and Operating Report Electric Distribution are based on the 2014 Revision of the report.

I. Cost of Capital

A. It is important to recognize the cost of capital, which is greater than the cost of debt. This is because there is a cost of member equity. The return on equity portion of this calculation can be figured in at least three ways. The Goodwin method includes the cycle of capital credits in calculating the return on equity. Or, one may adopt a return on equity that a state regulatory authority has declared to be adequate for electric utilities. Or a TIER-based calculation, such as that illustrated below, may be used.

B. Net TIER (Times Interest Earnings Ratio)
   1. For future projects, TIER should be selected in accordance with the owner's Equity Management Plan.
   2. For comparison, TIER for a past year could be calculated from data on the annual Form 7:

$$\text{TIER} = \frac{\text{Interest [Part A, line 15(b)]} + \text{Margins [Part A, line 28(b)]}}{\text{Interest [Part A, line 15(b)]}} = \frac{\$1{,}892{,}504 + \$1{,}625{,}723}{\$1{,}892{,}504} = \mathbf{1.859}$$

C. CAPITAL STRUCTURE
   1. For future projects, the debt ratio should be in accordance with the owner's Equity Management Plan. Line of credit or short-term borrowing should be taken into consideration in long-term financial decisions.
   2. For comparison, the debt and equity ratios for a past year could be calculated from data on the annual Form 7:

$$\text{Debt Ratio} = \frac{\text{LTD (Part C,line 41)}}{\text{LTD (Part C,line 41)} + \text{Tot. Marg. \& Eq. (Part C,line 36)}} = \frac{\$36{,}131{,}862}{\$36{,}131{,}862 + \$35{,}001{,}345} \times 100 = \mathbf{50.79\%}$$

$$\text{Equity Ratio} = \frac{\text{Tot. Marg. \& Eq. (Part C,line36)}}{\text{LTD (Part C,line 41)} + \text{Tot. Marg. \& Eq. (Part C,line 36)}} = \frac{\$35{,}001{,}345}{\$36{,}131{,}862 + \$35{,}001{,}345} \times 100 = \mathbf{49.21\%}$$

D. COST OF CAPITAL

1. For future projects the cost of debt should be estimated carefully, taking long-term trends into account. A suggested form would be:

	Proportion of Debt		Long Range Est. of Interest Rate		
RUS	70%	×	4.60%	=	3.22% (a)
Supplemental Lender	30%	×	6.00%	=	1.80% (b)
Cost of Debt = (a) + (b)				=	**5.02%**

2. In case one needs to calculate the embedded cost of debt for a past year, it can be calculated from the annual Form 7:

[Embedded cost of debt] $\frac{\text{Interest [Part A, line 15(b)]}}{\text{LTD [Part C, line 41]}} \times 100 = \frac{\$1,892,504}{\$36,131,862} \times 100 =$ **5.24%**

3. Weighted cost rate of debt:

Debt Ratio (from 1.C above)		Cost of Debt (from 1.D above)		
50.79	×	5.02	=	**2.55%** (CD)

4. Weighted cost of equity:

Equity Ratio (from 1.C above)		Cost of Debt (from 1.D above)		
49.21	×	5.02	=	**2.47 %** (CE)

5. Cost of capital:

Wtd. cost rate of Debt (from 1.D.3 above)		TIER (from 1.B above)		
2.55	×	1.86	=	**4.74 %** (CC)

II. Operation and Maintenance

A. For future projects, O&M should be selected to agree with the various plan alternatives. If a more costly alternative promises lower O&M, it should be reflected here.

B. For comparison, a historic distribution-plant O&M could be calculated by this form, with figures from the annual form 7:

	Part E line 15(e)		Part F line 7(a)			
Net Distribution Plant, annual Form 7, last year	$66,382,036	–	$	=	$66,382,036	
Net Distribution Plant, annual Form 7, 2 years ago	$63,359,785	–	$	=	$63,359,785	
Average Net Distribution Plant last year				=	$64,870,911 (a)	
Distribution Operations: Part A, line 5(b):				=	$ 2,636,701 (b)	
Distribution Maintenance: Part A, line 6(b):				=	$ 2,072,182 (c)	
O&M as % of Avg. Net Dist. Plant [(b) + (c)] / (a) × 100; or estimated from II.A., above					$4,708,883	**7.26%** (O&M)

III. Taxes

Property tax: annual Form 7, last year, Part A, line 13(b)	$ —	
Other tax: annual Form7, last year, Part A, line 14(b)	$ 4,653	
Total taxes paid on plant	$ 4,653 (a)	
Plant the taxes were paid on: Net Utility Plant, annual Form 7, 2 years ago, Part C, line 5	$ 54,849,072	
+ Materials and Supplies, annual Form 7, 2 years ago, Part C, line 22	$ 847,091	
	$ 55,696,163 (b)	**0.0084 %** (Tx)

Tax Rate: [(a)/(b)] x 100, or estimated future tax rate

IV. Depreciation

Use an appropriate depreciation figure for the projected alternative(s) being studied. Most owners use straight-line depreciation where the depreciation rate is the reciprocal of the asset's life.

Annual rate for the coop, for plant or for classes of plant **3.24%** (Dep)

V. Total Annual Fixed Charge Rate

= Cost of Capital (CC) + Oper. & Main. (O&M) + Taxes (Tx) + Depreciation (Dep) = **15.25%**

VI. Modified Tier (Net TIER less G&T Capital Credits)

$$\text{Modifed TIER} = \frac{\text{Interest [Part A, line 15(b)]} + \text{Margins [Part A, line 28(b)]} - \text{G\&T CC [Part A, line 25(b)]}}{\text{Interest [Part A, line 15(b)]}}$$

$$= \frac{\$1{,}892{,}504 + \$1{,}625{,}723 - \$833{,}883}{\$1{,}892{,}504} = \mathbf{1.4184}$$

VII. Debt Service Coverage (DSC) Ratio

$$\text{DSC} = \frac{\text{Interest [Part A, line 15(b)]} + \text{Margins [Part A, line 28(b)]} + \text{Dep. [Part A, line12 (b)]}}{\text{Total Debt Service} = \text{Principal [Part O, line 13(c)]} + \text{Interest [Part A, line 15(b)]}}$$

$$= \frac{\$1{,}892{,}504 + \$1{,}625{,}723 + \$2{,}387{,}846}{\$1{,}307{,}936 + \$1{,}892{,}504} = \mathbf{1.85}$$

VIII. Modified Debt Service Coverage (DSC) Ratio

Modified DSC =

$$\frac{\text{Interest [Part A, line 15(b)]} + \text{Margins [Part A, line 28(b)]} + \text{Dep. [Part A, line 12(b)]} - \text{G\&T CC [Part A, line 25(b)]}}{\text{Debt Service [Part O, line 13(c)]} + \text{[Part A, line 15(b)]}}$$

$$= \frac{\$1{,}892{,}504 + \$1{,}625{,}723 + \$2{,}387{,}846 - \$833{,}883}{\$1{,}307{,}936 + \$1{,}892{,}504} = \mathbf{1.58}$$

IX. Plant Revenue Ratio (PRR)

$$\text{PRR} = \frac{\text{Total Utility Plant [Part C, line 3]}}{\text{Elec. Revenue [Part R, line 12+13]} - \text{Power Cost [Part L, line 5(d)]}} = \frac{\$79{,}937{,}007}{\$43{,}400{,}629 - \$28{,}742{,}748} = \mathbf{5.45}$$

ABC ELECTRIC COOPERATIVE
City, State
SUMMARY RUS FIXED CHARGE RATE PROJECTIONS

TOTAL ANNUAL FIXED CHARGE RATE

Year	Cost Debt (CD)		TIER		Cost Capital (CC)	Operation Maintenance (O&M)	Taxes (Tx)	Depreciation (Dep)	(TFCR)
2002	2.24%	×	2.6218	=	5.87%	6.39%	0.00%	3.24%	15.50%
2003	2.49%	×	2.2376	=	5.57%	6.08%	0.00%	3.24%	14.88%
2004	2.59%	×	1.6704	=	4.32%	6.21%	0.00%	3.24%	13.77%
2005	2.58%	×	2.0150	=	5.20%	6.44%	0.00%	3.24%	14.87%
2006	2.55%	×	1.8590	=	4.74%	7.26%	0.01%	3.24%	15.25%
Projected	2.49%		2.0808		5.14%	6.48%	0.00%	3.24%	14.86%

TFCR = Cost of Capital (CC) + Oper. & Main. (O&M) + Taxes (Tx) + Depreciation (Dep)

KEY RATIOS

Year	TIER	Modified TIER	Debt Ratio	Equity Ratio	DSC	Modified DSC	Plant Revenue Ratio
2002	2.62	2.43	44.57%	55.43%	2.48	2.36	5.22
2003	2.24	1.94	49.57%	50.43%	2.10	1.93	5.25
2004	1.67	1.50	51.53%	48.47%	1.75	1.65	5.66
2005	2.02	1.72	51.40%	48.60%	1.94	1.76	5.39
2006	1.86	1.42	50.79%	49.21%	1.85	1.58	5.45
Projected	2.08	1.80	49.57%	50.43%	2.02	1.86	5.40

EXHIBIT D
RADIAL TRANSMISSION LINE RELIABILITY AND OPERATIONAL ASSESSMENT

Radial Transmission Line (RTL) Characteristics:		RTL #:	ABC25
Name and Description:	Southport to Wewa 115 kV		
Operating Voltage (kV):	*115*	*Conductor Size & Type:*	*397ACSR (Ibis)*
Right-of-Way Width (feet):	*100*	*Radial Distance (miles):*	*33.5*
Last Peak Load (MW):	*18.7*	*Peak Time (month, year):*	*Jul-09*
Load Distance Service Factor (MW-Miles):[A]	*626*	*Year Built:*	*1985*
With loss of the RTL, what % of load can existing distribution ties support?			*None*
Major Line Maintenance Cycle Years:	*15*		
Year of Last Major Line Maintenance:	*2002*		
Right-of-Way Location (cross-country, roadside, etc.):	*Cross Country; Swamp; Water*		
Right-of-Way Maintenance Cycles (years):	*5*		
Frequency of Right-of-Way (years):			
Inspections	*Annually*	*Mowing/Spraying*	*5*
Danger Tree Removal	*As Required*	*Side Trimming*	*10*
Transmission Line Provider:	ABC G&T		
Impacted Distributors or Cooperatives:	XYZ Cooperative Only		

RTL Reliability and Operational Questions[B]	**No**	**Yes**
1. *Does the RTL have a high Load Distance Service Factor (LDSF) greater than 150 megawatt-miles?*		X
2. *Is the RTL poorly accessible as determined by the Owner during all or part of the year?*		X
3. Does the RTL serve a delivery point that provides power to high priority loads (e.g., hospitals, manufacturing parks, airports, commercial loads, etc.)?	X	
4. *Is the conductor in deteriorated condition based on recent sample testing?*	X	
5. *Is the RTL condition contributed to more than three sustained outages over the last two years?*		X
6. *Has there been an outage over four hours in the past five years attributed to the RTL (excluding those during a major storm)?*		X
7. *Is the RTL in the power supplier's top 5% of most unreliable lines?*		X
8. *Does the RTL owner have any major improvement plans in the near future or in the general area of the distributor/cooperative substation?*		X
9. *Is the RTL operating at 69 kV or less and have a >50% of the conductor published full load amperes for the projected long-range peak loading conditions?*	X	
Number "Yes" Responses[C] **=**		6

RTL PLANNING COMMITMENT

Based on the above assessment, the electric system distribution engineer has decided that the referenced RTL X ***is*** or _____ ***is not*** to be included in the new electric system long-range plan. A copy of this assessment and commitment is to be supplied to the RTL provider indicated above.

Signature: Alfred E. Newman

Distributor's Planning Engineer Name: Alfred E. Newman, P.E.

Distributor's Planning Engineer Title: Manager of E&O, XYZ Cooperative

[A] Load Distance Service Factor = (Latest Peak Demand Load Served) × (Radial Line Distance)

[B] Categories shown in italics are to be answered by the RTL Owner and Provider, if applicable.

[C] RTLs that have a number of "affirmative" responses to the reliability and operational questions above should be included in the long-range planning process.

EXHIBIT E
SAMPLE ECONOMIC CONDUCTOR LIFE SYSTEM ANALYSIS

ABC ELECTRIC COOPERATIVE
CITY, STATE
2008 LONG-RANGE PLAN

CONDUCTOR LIFE CYCLE ANALYSIS
(NEW CONSTRUCTION LEGEND AND INPUT VALUES)

0.00%	TOTAL	Total fixed cost. This is an optional replacement for O&M + TAX + DEP + INS.
6.23%	O&M	Operations and Maintenance Expense as a percentage of Average Net Distribution Plant calculated using RUS Bulletin 1724D-101A, ***Electric System Long-Range Planning Guide***, based on RUS Fixed Charge Calculation Guide
0.00%	TAX	Property tax: annual Form 7, last year Part A, line 13(b) *Plant the taxes were paid on: annual Form 7, 2 years ago, Part C, line 5 + line 22* *Tax Rate: (Property tax / Plant) x 100, or estimated future tax rate*
3.24%	DEP	Most Owners use straight-line depreciation where the depreciation rate is the reciprocal of the asset's life. Use annual rate for Co-op, for classes of plant Depreciation rate on RUS Form 7 Part E Lines 5(f) and line 6(f)
0.00%	INS	Insurance as a percentage of Net Distribution Plant. *Calculating the cost of insurance as a percentage of investment is difficult, and the result makes little difference, therefore, it can be ignored for most applications.*
3.50%	INF	The annual inflation rate
30	m	The loan amortization period in years
7.2&14.4	KV	Line-to-ground voltage in kV
99.00%	PF	Peak month power factor
6.59%	INT	Cost of Capital (Calculated using *RUS Fixed Charge Guide*) used for Present Worth Calculation
2.60%	LGR	The annual rate of growth projected for the peak demand (use latest PRS)
30	ULC	Useful Life of Conductor
$0.00	$/kW	Monthly demand charge in dollars per kW per month. If $/kW is zero, the following dependent inputs will also be zero:
0.00%	kWI	Demand charge inflation rate
0.00%	CF	Coincidence factor (this factor represents the coincidence between the non-coincident peak for the line and billing demand)
0.000	RMO	The number of months the metered demand exceeds the minimum billing demand
0.000	RAT	The annual demand ratchet expressed as a decimal
0.000	N	The ratio of the average of the squares of the monthly kW demands for the months when the metered demand exceeds the minimum billing demand to the square of the peak month demand
$0.0689	$/kWh	Energy charge in dollars per kWh per month
6.00%	kWhI	Energy charge inflation rate
43.70%	LF	Annual load factor

ABC ELECTRIC COOPERATIVE
CONDUCTOR LIFE CYCLE ANALYSIS

7.2 kV
Summary

	Initial Loading			**Future Loading Based on a 2.60% LGR for 30 Years**	
For loads below	1,378 kW	use	1/0 ACSR	2,976	kW
For loads between	1,378 kW and 1,423 kW	use	3/0 ACSR	2,976	kW
For loads between	1,423 kW and 1,779 kW	use	336 ACSR	3,073	kW
For loads between	1,779 kW use 5,823 kW	use	477 ACSR	3,842	kW
For loads above	5,823 kW	use	795 ACSR	12,577	kW

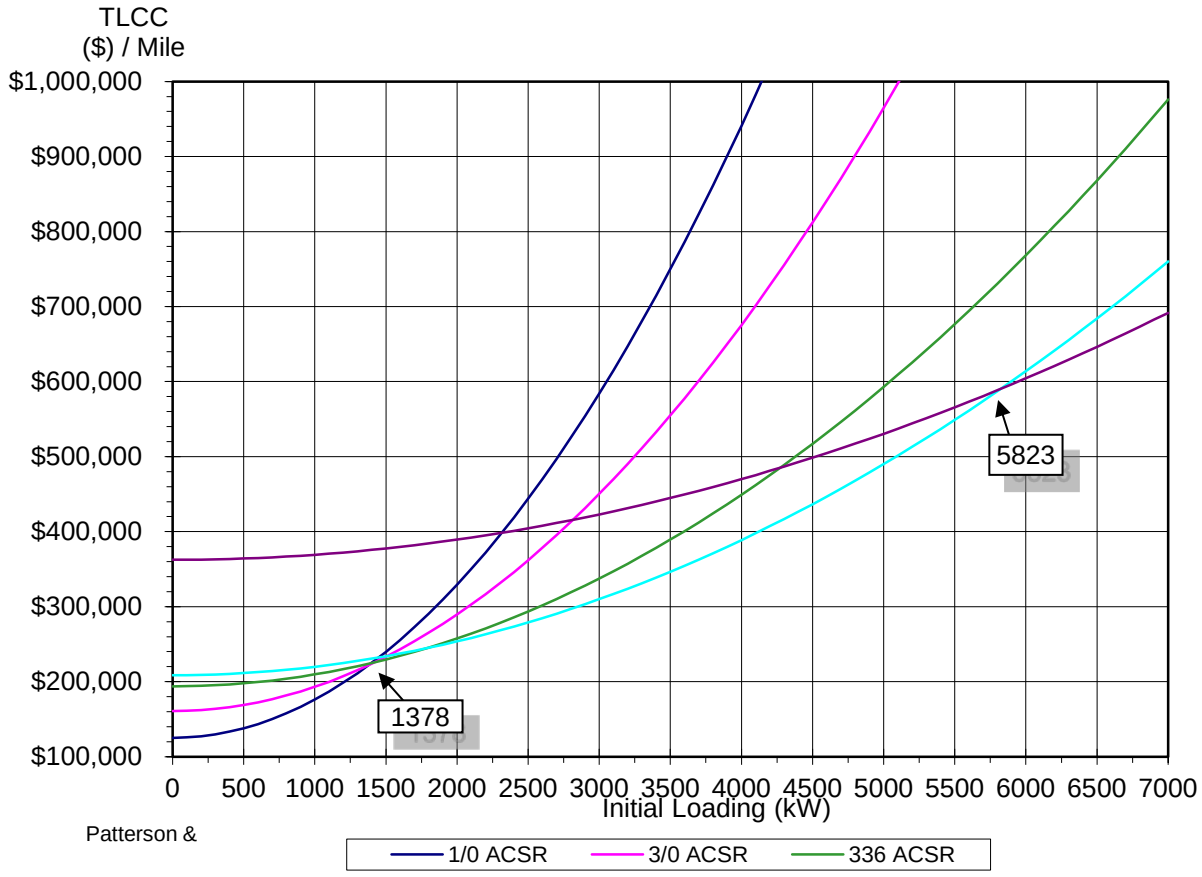
Construction Costs

Conductor	Cost Per Mile	Ohms Per Mile†	Conductor Operating Capacity* 100%	50%	
3 Ø 1/0 ACSR	$42,000	0.888	4,918	2,459	kW
3 Ø 3/0 ACSR	$54,000	0.560	7,271	3,635	kW
3 Ø 336 ACSR	$65,000	0.278	11,334	5,667	kW
3 Ø 477 ACSR	$70,000	0.196	14,327	7,164	kW
3 Ø 795 ACSR	$121,600	0.117	19,246	9,623	kW

† Resistance based on conductor operating temperature of 25°C (77°F) for Winter Loading.

* 100% Conductor Operating Capacity based on conductor temperature of 75°C (167°F), with a 25°C (77°F) ambient, with a and a 2 ft./sec wind, frequency = 60 Hz. Per *Westinghouse T&D Reference Book*, East Pittsburgh, Pa. (4th Edition: 11th Printing), 1950.

ABC ELECTRIC COOPERATIVE PLAN
CONDUCTOR LIFE CYCLE ANALYSIS
Total Life Cycle Cost — Three-Phase 7.2 kV



ABC ELECTRIC COOPERATIVE
CONDUCTOR LIFE CYCLE ANALYSIS

14.4 kV
Summary

	Initial Loading			**Future Loading based on a 2.60% LGR for 30 Years**	
For loads below	2,756 kW	use	1/0 ACSR	5,953	kW
For loads between	2,756 kW and 2,846 kW	use	3/0 ACSR	5,953	kW
For loads between	2,846 kW and 3,559 kW	use	336 ACSR	6,147	kW
For loads between	3,559 kW use 11,647 kW	use	477 ACSR	7,687	kW
For loads above	11,647 kW	use	795 ACSR	25,156	kW

Construction Costs

			Conductor Operating Capacity*		
Conductor	Cost Per Mile	Ohms Per Mile	100%	50%	
3 Ø 1/0 ACSR	$42,000	0.888	9,837	4,918	kW
3 Ø 3/0 ACSR	$54,000	0.560	14,541	7,271	kW
3 Ø 336 ACSR	$65,000	0.278	22,667	11,334	kW
3 Ø 477 ACSR	$70,000	0.196	28,655	14,327	kW
3 Ø 795 ACSR	$121,600	0.117	38,491	19,246	kW

† Resistance based on conductor operating temperature of 25°C (77°F) for Winter Loading.

* 100% Conductor Operating Capacity based on conductor temperature of 75°C (167°F), with a 25°C (77°F) ambient, with a and a 2 ft./sec wind, frequency = 60 Hz. Per *Westinghouse T&D Reference Book*, East Pittsburgh, Pa. (4th Edition: 11th Printing), 1950.

ABC ELECTRIC COOPERATIVE
CONDUCTOR LIFE CYCLE ANALYSIS
Total Life Cycle Cost — Three-Phase 14.4 kV

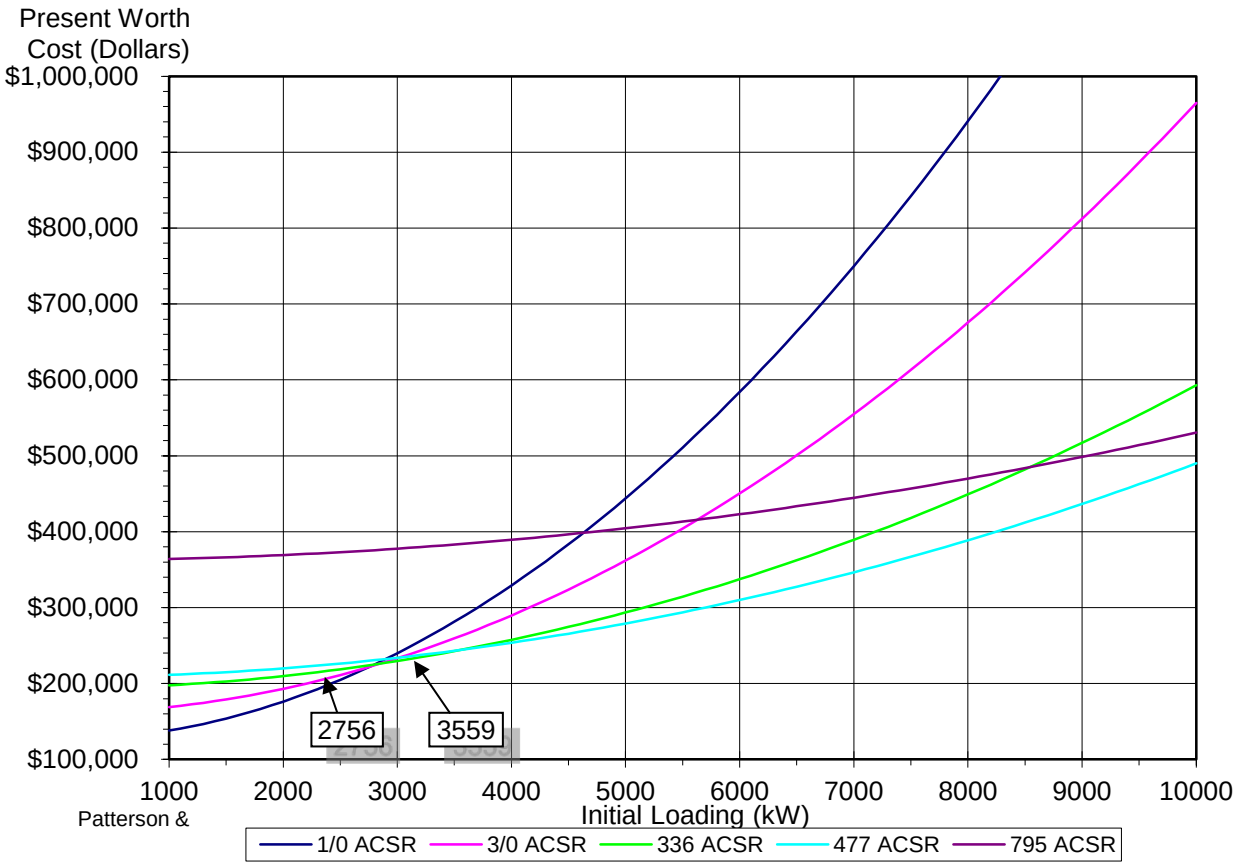


EXHIBIT F
SAMPLE SUBSTATION LOADING SHEET FOR SPECIFIC PLAN

ABC Electric Cooperative
City, State
2008 LONG-RANGE PLAN
SUBSTATION LOAD DATA
Plan D1 (Preferred Plan)

No.	Substation Name	Voltage kV	Xfmr Qty. Size MVA	Existing Capacity	Proposed Capacity	% Loaded 2006	Summer 2006 kW	SUBSTATION DEMANDS 2007 kW	2008 kW	2009 kW	2010 kW	LL2 2011 kW	2012 kW	2013 kW	LL3 2014 kW	2015 kW	2016 kW	2017 kW	2018 kW	2019 kW	2020 kW	2021 kW	2022 kW	2023 kW	2024 kW	2025 kW	LL4 2026 kW
1	Substation A	115-25	1-10/12.5				8,073	8,501	8,951	9,426	9,925	10,451	11,005	11,236	11,472	11,713	11,877	12,044	12,212	12,383	12,557	12,732	12,911	13,091	13,275	13,461	13,649
	(- Substation O)											- 3,799	- 4,000	- 4,084	- 4,170	- 4,257	- 4,317	- 4,377	- 4,439	- 4,501	- 4,564	- 4,628	- 4,692	- 4,758	- 4,825	- 4,892	- 4,961
	Total	115-25	1-10/12.5	12,500	12,500	65%	8,073	8,501	8,951	9,426	9,925	6,652	7,005	7,152	7,302	7,456	7,560	7,667	7,773	7,882	7,993	8,104	8,219	8,333	8,450	8,569	8,688
2	Substation B	115-12.5	1-10/12.5				4,441	4,676	4,924	5,185	5,460	5,749	6,054	6,181	6,311	6,444	6,534	6,625	6,718	6,812	6,907	7,004	7,102	7,202	7,302	7,405	7,508
	Substation J												- 750														
	Total	115-12.5	1-10/12.5	12,500	12,500	36%	4,441	4,676	4,924	5,185	5,460	5,749	5,304	6,181	6,311	6,444	6,534	6,625	6,718	6,812	6,907	7,004	7,102	7,202	7,302	7,405	7,508
3	Substation C	115-25	1-10/12.5				9,533	10,038	10,570	11,131	11,720	12,342	12,996	13,269	13,547	13,832	14,025	14,222	14,421	14,623	14,827	15,035	15,246	15,459	15,675	15,895	16,117
	(-switching w/ Substation F)							- 150	- 158	- 166	- 175	- 184	- 194	- 198	- 202	- 207	- 210	- 213	- 215	- 219	- 222	- 225	- 228	- 231	- 234	- 238	- 241
	Substation F												- 1,800														
	Substation D												- 250														
	(- Substation O)											- 3,514	- 3,700	- 3,778	- 3,857	- 3,938	- 3,993	- 4,049	- 4,106	- 4,163	- 4,222	- 4,281	- 4,341	- 4,401	- 4,463	- 4,525	- 4,589
	Total	115-25	1-10/12.5	12,500	12,500	76%	9,533	9,888	10,412	10,965	11,545	8,644	7,052	9,293	9,488	9,687	9,822	9,960	10,100	10,241	10,383	10,529	10,677	10,827	10,978	11,132	11,287
4	Substation D	115-25	1-12/16/20				12,079	12,673	13,444	14,262	15,130	16,053	17,032	17,458	17,894	18,342	18,635	18,933	19,236	19,544	19,857	20,174	20,497	20,825	21,158	21,497	21,841
	(- Substation N)									- 1,970	- 2,074	- 2,184	- 2,300	- 2,348	- 2,398	- 2,448	- 2,482	- 2,517	- 2,552	- 2,588	- 2,624	- 2,661	- 2,698	- 2,736	- 2,774	- 2,813	- 2,852
	(- Substation N)																							- 1,023	- 1,041	- 1,059	- 1,078
	(- Substation P)																							- 5,582	- 5,679	- 5,779	- 5,880
	Substation C												250														
	Total	115-25	1-12/16/20	20,000	20,000	60%	12,079	12,673	13,444	12,292	13,056	13,869	14,942	15,110	15,496	15,894	16,153	16,416	16,684	16,956	17,233	17,513	17,799	11,484	11,664	11,846	12,031
5	Substation E (old)	46-12.5	3-1.917				4,604	4,848	5,105	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	(-load to Substation E (new)) *1								- 5,105	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Total	46-12.5	3-1.917	5,750	5,750	80%	4,604	4,848	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5	Substation E (new)	46-12.5	1-12/16/20					0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	+load from Substation E (old) *1								5,105	5,376	5,660	5,960	6,050	6,177	6,307	6,439	6,529	6,621	6,713	6,807	6,903	6,999	7,097	7,197	7,298	7,400	7,503
	+load from Substation K *1								2,943	3,099	3,263	3,436	3,500	3,574	3,649	3,725	3,777	3,830	3,884	3,938	3,993	4,049	4,106	4,163	4,222	4,281	4,341
	(-load to Substation M) *1								- 825	- 869	- 915	- 963	- 1,500	- 1,532	- 1,564	- 1,596	- 1,619	- 1,642	- 1,664	- 1,688	- 1,711	- 1,735	- 1,760	- 1,784	- 1,809	- 1,835	- 1,860
	Total	46-12.5	1-12/16/20	0	20,000	0%		0	7,223	7,606	8,008	8,433	8,050	8,219	8,392	8,568	8,687	8,809	8,933	9,057	9,185	9,313	9,443	9,576	9,711	9,846	9,984
6	Substation F	46-25	3-1.250				2,662	2,803	2,952	3,108	3,273	3,446	3,629	3,705	3,783	3,862	3,916	3,971	4,027	4,083	4,140	4,198	4,257	4,317	4,377	4,438	4,501
	+switching w/ Substation F							150	158	166	175	184	250	255	261	266	270	274	277	281	285	289	293	297	302	306	310
	LP18 - existing prison *2						0	1,000	1,500	2,000	2,000	2,000	2,100	2,205	2,315	2,431	2,563	2,680	2,814	2,955	3,103	3,258	3,421	3,592	3,771	3,960	4,158
	LP23 - new prison *2						0	0	0	0	1,500	1,500	1,575	1,654	1,736	1,823	1,914	2,010	2,111	2,216	2,327	2,443	2,566	2,694	2,828	2,970	3,118
	Total	46-25	3-1.250	3,750	20,000	71%	2,662	3,953	4,610	5,274	6,948	7,130	7,554	7,819	8,095	8,382	8,653	8,935	9,229	9,535	9,855	10,188	10,537	10,900	11,278	11,674	12,087
7	Substation G	115-12.5	1-10				7,407	7,898	8,422	8,980	9,575	10,210	10,200	10,468	10,744	11,026	11,219	11,415	11,615	11,818	12,025	12,236	12,450	12,668	12,889	13,115	13,344
	uprate in 2011																										
	Total	115-12.5	1-10	10,000	20,000	74%	7,407	7,898	8,422	8,980	9,575	10,210	10,200	10,468	10,744	11,026	11,219	11,415	11,615	11,818	12,025	12,236	12,450	12,668	12,889	13,115	13,344
8	Substation H	115-25	1-10/12.5				10,946	11,672	12,446	13,271	14,151	15,089	15,100	15,497	15,905	16,323	16,609	16,899	17,195	17,496	17,802	18,114	18,431	18,753	19,081	19,415	19,755
	(- Substation Q)																				- 3,563	- 3,625	- 3,689	- 3,753	- 3,819	- 3,886	- 3,954
	Total	115-25	1-10/12.5	12,500	20,000	88%	10,946	11,672	12,446	13,271	14,151	15,089	15,100	15,497	15,905	16,323	16,609	16,899	17,195	17,496	14,239	14,489	14,742	15,000	15,262	15,529	15,801
9	Substation I	115-25	1-10/12.5				9,451	10,078	10,746	11,458	12,218	13,028	13,892	14,257	14,632	15,017	15,280	15,547	15,819	16,096	16,378	16,664	16,956	17,253	17,554	17,862	18,174
	(- Substation N)									- 5,650	- 6,025	- 6,424	- 6,850	- 7,030	- 7,215	- 7,405	- 7,534	- 7,666	- 7,800	- 7,937	- 8,076	- 8,217	- 8,361	- 8,507	- 8,656	- 8,808	- 8,962
	(- Substation P)																							- 4,770	- 4,854	- 4,939	- 5,025
	Total	115-25	1-10/12.5	12,500	12,500	76%	9,451	10,078	10,746	5,808	6,193	6,604	7,042	7,227	7,417	7,612	7,746	7,881	8,019	8,159	8,302	8,447	8,595	3,976	4,044	4,115	4,187
10	Substation J	115-25	1-12/16/20				12,349	13,051	13,833	14,661	15,541	16,473	17,462	17,899	18,346	18,805	19,106	19,411	19,722	20,037	20,358	20,684	21,015	21,351	21,692	22,040	22,392
	(- Substation O)											- 4,274	- 4,500	- 4,595	- 4,691	- 4,789	- 4,857	- 4,925	- 4,993	- 5,063	- 5,134	- 5,206	- 5,279	- 5,353	- 5,428	- 5,504	- 5,581
	Total	115-25	1-12/16/20	20,000	20,000	62%	12,349	13,051	13,833	14,661	15,541	12,199	12,962	13,304	13,695	14,016	14,249	14,486	14,729	14,974	15,224	15,478	15,736	15,998	16,264	16,536	16,811
11	Substation K	46-12.5	3-2.5				3,606	3,797	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	(-Substation K Abandoned)								- 3,797																		
	Total	46-12.5	3-2.5	7,500	7,500	48%	3,606	3,797	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
12	Substation L	115-12.5	1-12/16/20				11,667	12,441	13,265	14,145	15,083	16,083	16,800	17,242	17,695	18,161	18,478	18,802	19,131	19,466	19,806	20,153	20,506	20,864	21,230	21,601	21,979
	+load from Substation K *1									0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	(- Substation L 25kV 25kV)										- 12,543	- 13,374	- 14,261	- 14,636	- 15,021	- 15,416	- 15,686	- 15,960	- 16,240	- 16,524	- 16,813	- 17,107	- 17,407	- 17,711	- 18,021	- 18,337	- 18,657
	Total	115-12.5	1-12/16/20	12,500	20,000	93%	11,667	12,441	13,265	14,145	2,540	2,709	2,539	2,606	2,674	2,745	2,792	2,842	2,891	2,942	2,993	3,046	3,099	3,153	3,209	3,264	3,322
12	Substation L 25kV 25kV	115-25	1-12/16/20				0				12,543	13,374	14,261	14,636	15,021	15,416	15,686	15,960	16,240	16,524	16,813	17,107	17,407	17,711	18,021	18,337	18,657
	(-Substation Q)																				- 1,247	- 1,269	- 1,291	- 1,314	- 1,337	- 1,360	- 1,384
	Total	115-25	1-12/16/20	0	20,000	0%	0	0	0	0	12,543	13,374	14,261	14,636	15,021	15,416	15,686	15,960	16,240	16,524	15,566	15,838	16,116	16,397	16,684	16,977	17,273
13	Substation M	46-12.5	3- 833				2,354	2,479	2,610	2,748	2,894	3,048	3,209	3,276	3,345	3,415	3,463	3,512	3,561	3,611	3,661	3,713	3,765	3,817	3,871	3,925	3,980
	+load from Substation E (old) *1								825	869	915	963	850	868	886	905	917	930	943	956	970	983	997	1,011	1,025	1,040	1,054
	Total	46-12.5	3- 833	2,500	20,000	94%	2,354	2,479	3,435	3,617	3,809	4,011	4,059	4,144	4,231	4,320	4,380	4,442	4,504	4,567	4,631	4,696	4,762	4,828	4,896	4,965	5,034
14	Substation N	115-25	1-12/16/20				0	0	16,100	16,100	16,100	16,100	16,100	16,100	16,100	16,100	16,100	16,100	16,100	16,100	16,100	16,100	16,100	16,100	16,100	16,100	16,100
	Total	115-25	1-12/16/20	0	20,000	0%	0	0	16,100	16,100	16,100	16,100	16,100	16,100	16,100	16,100	16,100	16,100	16,100	16,100	16,100	16,100	16,100	16,100	16,100	16,100	16,100
14	Substation N - 2nd Transformer	115-25	1-12/16/20				0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	+load from Substation I									5,050	5,384	5,741	5,800	5,953	6,109	6,270	6,379	6,491	6,605	6,720	6,838	6,958	7,079	7,203	7,329	7,458	7,588
	+load from Substation D									1,970	2,074	2,184	2,000	2,042	2,085	2,129	2,158	2,189	2,219	2,250	2,282	2,314	2,346	2,379	2,412	2,446	2,480
	+load from Substation D																							1,023	1,041	1,059	1,078
	(-load to Substation P)																							- 2,106	- 2,143	- 2,181	- 2,219
	Total	115-25	1-12/16/20	0	20,000	0%	0	0	0	7,020	7,458	7,925	7,800	7,995	8,194	8,398	8,537	8,680	8,824	8,970	9,120	9,272	9,425	8,499	8,639	8,782	8,927
15	Substation O	115-25	1-12/16/20				0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	+load from Substation A											3,086	3,200	3,267	3,336	3,406	3,454	3,502	3,551	3,601	3,651	3,702	3,754	3,807	3,860	3,914	3,969
	+load from Substation C											3,514	3,200	3,267	3,336	3,406	3,454	3,502	3,551	3,601	3,651	3,702	3,754	3,807	3,860	3,914	3,969
	+load from Substation J											3,751	3,600	3,676	3,753	3,832	3,885	3,940	3,995	4,051	4,107	4,165	4,223	4,282	4,342	4,403	4,465
	Total	115-25	1-12/16/20	0	20,000	0%	0	0	0	0	0	10,351	10,000	10,210	10,425	10,644	10,793	10,944	11,097	11,253	11,409	11,569	11,731	11,896	12,062	12,231	12,403
16	Substation P	115-25	1-12/16/20				0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	+load from Substation D																							5,582	5,679	5,779	5,880
	+load from Substation I																							4,770	4,854	4,939	5,025
	+load from Substation N																							2,106	2,143	2,181	2,219
	Total	115-25	1-12/16/20	0	20,000	0%	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	12,458	12,676	12,899	13,124
17	Substation Q	115-25	1-12/16/20				0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	+load from Substation L 25kV 25kV																							1,247	1,269	1,291	1,314
	+load from Substation H																							3,563	3,625	3,689	3,753
	Total	115-25	1-12/16/20	0	20,000	0%	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	4,810	4,894	4,980	5,067
	System Total			144,500	343,250	69%	99,172	105,955	127,811	134,350	142,852	149,049	149,970	155,961	159,450	163,031	165,520	168,061	170,651	173,286	175,975	178,716	181,513	184,362	187,264	190,231	193,249

EXHIBIT G
SAMPLE PLAN ECONOMIC ANALYSIS SPREADSHEET

Client Name: ABC ELECTRIC COOPERATIVE
Plan Number: PLANS A, B, C, D, D1, D1A
Assumptions: See Detail Plan Analysis

Number of Years for This Comparison: 18

FIRST YEAR OF STUDY 2008

	Power Distributor	Power Supplier
1. Energy Cost/kWh ($)	$0.0689	$0.04300
2. Present Worth Interest Rate (%)	6.00%	6.00%
3. Annual Fixed Charge (%)	9.83%	10.50%
4. T&D O&M Costs (%)	6.23%	0.00%
5. Substation O&M Costs (%)	0.00%	0.00%
6. Inflation Rate (%)	3.50%	3.50%
7. Energy Inflation Rate (%)	6.00%	2.88%
8. Additional Delivery Point Charge ($)		—
9. Percent of Dist. Line Insulated for 25kV	0%	

Note: Annual Fixed Charge only includes interest, depreciation, taxes, and insurance rates.
O&M costs inflate with Inflation Rate.
Energy costs inflate with Energy Inflation Rate.

ABC ELECTRIC COOPERATIVE

City, State

2008 LONG-RANGE PLAN

ECONOMIC COMPARISONS

(2008 DOLLARS)

PLAN SUMMARY

Plan A	No New Delivery Points Added and Distribution Lines to Remain at Current Voltage Levels
Plan B	No New Delivery Points Added and All Distribution Voltage Converted to 25 kV
Plan C	New Delivery Points Added and Distribution Lines Remain at Current Voltage Levels
Plan D	New Delivery Points Added and Distribution Voltage Converted to 25 kV
Plan D1	Like D, but Substation B Added Instead of Substation A
Plan D1A	Like D1, but Substation C Served from G&T 115-kV Transmission Line

PRESENT WORTH ECONOMIC ANALYSIS

	G&T Power Supplier	Wheeling Costs	ABC EC Power Distributor	Distributor Losses at Distributor Cost	Distributor Losses at Supplier Cost	One Ownership	Preferred Plan Cost Difference
Plan A	$16,548,914	$11,448,005	$18,372,961	*$10,862,380*	$5,167,561	$51,537,441	$1,494,069
Plan B	$17,455,913	$11,448,005	$23,150,650	*$9,775,706*	$4,684,871	$56,739,439	$6,696,067
Plan C	$17,777,867	$12,095,507	$16,677,014	*$10,486,111*	$5,000,427	$51,550,815	$1,507,443
Plan D[*1]	$18,959,550	$11,646,030	$14,680,545	*$9,858,514*	$4,721,654	$50,007,779	($35,593)
Plan D1	$20,207,558	$9,922,383	$15,267,278	*$9,688,539*	$4,646,153	$50,043,372	$0
Plan D1A	$22,301,687	$8,374,892	$15,267,278	$9,688,539	$4,646,153	$50,590,010	$546,638

CONSTRUCTION COSTS AND LOSSES SUMMARY

	G&T Power Supplier Costs	Wheeling Costs	ABC EC Power Distributor Costs	Total Costs	ABC EC Power Distributor Losses	Total Cost of Construction and Losses	Preferred Plan Cost Difference
Plan A	$14,648,138	$19,381,592	$18,217,063	$52,246,793	$10,862,380	$63,109,173	$180,212
Plan B	$16,128,849	$19,381,592	$22,958,945	$58,469,386	$9,775,706	$68,245,092	$5,316,131
Plan C	$15,268,138	$20,863,794	$16,501,473	$52,633,405	$10,486,111	$63,119,516	$190,555
Plan D	$17,248,849	$19,957,572	$16,263,577	$53,469,998	$9,858,514	$63,328,512	$399,551
Plan D1	$19,811,349	$16,545,686	$16,883,387	$53,240,422	$9,688,539	$62,928,961	$0
Plan D1A	$21,811,349	$13,835,086	$16,883,387	$52,529,822	$9,688,539	$62,218,361	($710,600)

Note: Highlight indicates the Preferred Plan. The Preferred Alternate Plan is Plan D1A.

[*1] Due to operational reasons, this plan is not considered a viable option.

ABC CONSULTANT—ECONOMIC COMPARISON PROGRAM

Client Name: ABC ELECTRIC COOPERATIVE
Plan Number: PLAN D1

Number of years for this comparison: 18
MAXIMUM YEARS = 30

	Power Distributor	Energy Supplier
1. Energy Cost/kWh ($)	$0.0689	$0.0430
2. Present Worth Interest Rate (%)	6.00%	6.00%
3. Annual Fixed Charge (%)	9.83%	10.50%
4. T&D O&M Costs (%)	6.23%	0.00%
5. Substation O&M Costs (%)	0.00%	0.00%
6. Inflation Rate (%)	3.50%	3.50%
7. Energy Inflation Rate (%)	6.00%	2.88%
8. Annual Delivery Point Charge ($)	—	

Note: Annual Fixed Charge only includes interest, depreciation, taxes, and insurance rates.
O&M costs inflate with Inflation Rate.
Energy costs inflate with Energy Inflation Rate.

Cost Summary—Present Worth Dollars

	Power Supplier	Power Distributor	One Ownership
Transmission & Substation	$20,207,558	—	$20,207,558
Substation & Distribution	—	$15,267,278	15,267,278
Subtotal	20,207,558	15,267,278	35,474,836
Delivery Point (Rev./Costs)	0	0	0
Wheeling Charges	9,922,383	—	9,922,383
Transmission Losses	0	—	0
Distribution Losses (Rev./Costs)	(9,688,539)	9,688,539	0
Distribution Losses at Supplier Cost	4,646,153	—	4,646,153
Totals	$25,087,555	$24,955,817	$50,043,372

ABC CONSULTANT—ECONOMIC COMPARISON PROGRAM

Client Name: ABC ELECTRIC COOPERATIVE
Plan Number: PLAN D1

Distributor Costs

Year	Distribution Construction Costs	Sub&Trans Construction Costs	Total Construction Costs	Inflated Distribution Costs	Inflated Substation Costs	Inflated Construction Costs	Annual O&M Costs	Annual Fixed Costs	Total Annual Costs	Present Worth of Distributor Annual Costs	Annual Distribution Losses	Present Worth of Inflated Annual Distribution Losses	Number of Delivery Points	Present Worth of Delivery Point Charges
2008	757,388	100,000	857,388	757,388	100,000	857,388	47,185	84,281	131,467	131,467	$469,322	469,322	2	0
2009	757,388	50,000	807,388	783,897	51,750	835,647	96,022	166,425	262,447	247,592	$473,833	473,833	2	0
2010	757,388	50,000	807,388	811,333	53,561	864,894	146,568	251,444	398,012	354,230	$478,344	478,344	2	0
2011	757,388	75,000	832,388	839,730	83,154	922,883	198,883	342,164	541,047	454,274	$482,856	482,856	2	0
2012	757,388	0	757,388	869,120	0	869,120	253,029	427,598	680,628	539,121	$487,367	487,367	2	0
2013	757,388	0	757,388	899,539	0	899,539	309,071	516,023	825,094	616,558	$491,878	491,878	2	0
2014	757,388	0	757,388	931,023	0	931,023	367,073	607,543	974,616	687,066	$496,389	496,389	2	0
2015	757,388	0	757,388	963,609	0	963,609	427,106	702,265	1,129,372	751,097	$500,901	500,901	2	0
2016	757,388	0	757,388	997,335	0	997,335	489,240	800,303	1,289,544	809,076	$505,412	505,412	2	0
2017	757,388	0	757,388	1,032,242	0	1,032,242	553,549	901,773	1,455,322	861,403	$509,923	509,923	2	0
2018	757,388	0	757,388	1,068,371	0	1,068,371	620,108	1,006,794	1,626,902	908,454	$514,434	514,434	2	0
2019	757,388	0	757,388	1,105,764	0	1,105,764	688,998	1,115,490	1,804,488	950,582	$518,946	518,946	2	0
2020	757,388	0	757,388	1,144,465	0	1,144,465	760,298	1,227,991	1,988,289	988,119	$523,457	523,457	2	0
2021	757,388	50,000	807,388	1,184,522	78,198	1,262,719	834,093	1,352,117	2,186,210	1,024,981	$527,968	527,968	2	0
2022	757,388	0	757,388	1,225,980	0	1,225,980	910,472	1,472,630	2,383,102	1,054,048	$532,479	532,479	2	0
2023	757,388	50,000	807,388	1,268,889	83,767	1,352,657	989,524	1,605,596	2,595,120	1,082,853	$536,991	536,991	2	0
2024	1,463,393	0	1,463,393	2,537,503	0	2,537,503	1,147,610	1,855,033	3,002,643	1,181,979	$541,502	541,502	2	0
2025	1,463,393	0	1,463,393	2,626,316	0	2,626,316	1,311,230	2,113,200	3,424,430	1,271,711	$546,013	546,013	2	0
2026	1,463,393	0	1,463,393	2,718,237	0	2,718,237	1,480,576	2,380,403	3,860,978	1,352,670	$550,524	550,524	2	0
Totals	16,508,387	375,000	16,883,387	23,765,262	450,430	24,215,692	11,630,636	18,929,075	30,559,711	15,267,278	9,688,539	9,688,539		0

Supplier Costs

Year	Transmission Construction Costs	Substation Construction Costs	Total Construction Costs	Inflated Transmission Costs	Inflated Substation Costs	Inflated Construction Costs	Annual O&M Costs	Annual Fixed Costs	Total Annual Costs	Present Worth of Supplier Annual Cost	Annual Transmission Losses	Present Worth of Inflated Annual Transmission Losses	Inflated Distribution Losses at Supplier Cost	Present Worth Inflated Distribution Losses at Supplier Cost
2008	2,973,138	4,800,000	7,773,138	2,973,138	4,800,000	7,773,138	0	816,179	816,179	816,179	0	0	292,900	292,900
2009	0	3,100,000	3,100,000	0	3,208,500	3,208,500	0	1,153,072	1,153,072	1,087,804	0	0	304,233	287,012
2010	0	1,475,000	1,475,000	0	1,580,057	1,580,057	0	1,318,978	1,318,978	1,173,886	0	0	315,974	281,216
2011	2,057,500	1,475,000	3,532,500	2,281,187	1,635,359	3,916,546	0	1,730,215	1,730,215	1,452,722	0	0	328,140	275,513
2012	0	0	0	0	0	0	0	1,730,215	1,730,215	1,370,493	0	0	340,745	269,902
2013	0	0	0	0	0	0	0	1,730,215	1,730,215	1,292,918	0	0	353,803	264,382
2014	0	480,711	480,711	0	590,917	590,917	0	1,792,262	1,792,262	1,263,474	0	0	367,331	258,954
2015	0	0	0	0	0	0	0	1,792,262	1,792,262	1,191,956	0	0	381,345	253,616
2016	0	0	0	0	0	0	0	1,792,262	1,792,262	1,124,487	0	0	395,861	248,368
2017	0	0	0	0	0	0	0	1,792,262	1,792,262	1,060,837	0	0	410,897	243,209
2018	0	0	0	0	0	0	0	1,792,262	1,792,262	1,000,789	0	0	426,470	238,139
2019	0	0	0	0	0	0	0	1,792,262	1,792,262	944,141	0	0	442,600	233,156
2020	0	0	0	0	0	0	0	1,792,262	1,792,262	890,699	0	0	459,305	228,261
2021	250,000	1,475,000	1,725,000	390,989	2,306,835	2,697,824	0	2,075,533	2,075,533	973,091	0	0	476,606	223,451
2022	0	0	0	0	0	0	0	2,075,533	2,075,533	918,010	0	0	494,522	218,727
2023	250,000	1,475,000	1,725,000	418,837	2,471,140	2,889,977	0	2,378,981	2,378,981	992,665	0	0	513,074	214,088
2024	0	0	0	0	0	0	0	2,378,981	2,378,981	936,477	0	0	532,285	209,532
2025	0	0	0	0	0	0	0	2,378,981	2,378,981	883,469	0	0	552,177	205,059
2026	0	0	0	0	0	0	0	2,378,981	2,378,981	833,461	0	0	572,774	200,668
Totals	5,530,638	14,280,711	19,811,349	6,064,151	16,592,807	22,656,958	0	34,691,695	34,691,695	20,207,558	0	0	7,961,042	4,646,153

ABC CONSULTANT—ECONOMIC COMPARISON PROGRAM

Client Name: ABC ELECTRIC COOPERATIVE
Plan Number: PLAN D1

One-Ownership Costs

Year	Total Annual Costs	Present Worth of Total Annual Costs
2008	947,646	947,646
2009	1,415,519	1,335,396
2010	1,716,990	1,528,115
2011	2,271,262	1,906,996
2012	2,410,843	1,909,614
2013	2,555,309	1,909,476
2014	2,766,878	1,950,540
2015	2,921,633	1,943,053
2016	3,081,805	1,933,563
2017	3,247,583	1,922,240
2018	3,419,164	1,909,243
2019	3,596,749	1,894,723
2020	3,780,550	1,878,818
2021	4,261,743	1,998,071
2022	4,458,635	1,972,059
2023	4,974,101	2,075,518
2024	5,381,624	2,118,456
2025	5,803,410	2,155,180
2026	6,239,959	2,186,131
Total	65,251,405	35,474,836

EXHIBIT H
SAMPLE SENSITIVITY ANALYSES

ABC ELECTRIC COOPERATIVE
City, State
2008 LONG-RANGE PLAN
One-Ownership Present Worth Sensitivity Analysis*

% Inflation Rate	Plan D	Plan D1	Plan D1A
1.0%	$47,431,239	$47,149,289	$47,547,814
1.5%	$47,907,257	$47,683,278	$48,110,847
2.0%	$48,401,963	$48,238,569	$48,695,471
2.5%	$48,916,286	$48,816,245	$49,302,769
3.0%	$49,451,214	$49,417,445	$49,933,880
3.5%	$50,007,779	$50,043,372	$50,590,010
4.0%	$50,587,073	$50,695,289	$51,272,423
4.5%	$51,190,240	$51,374,529	$51,982,454
5.0%	$51,818,489	$52,082,495	$52,721,508

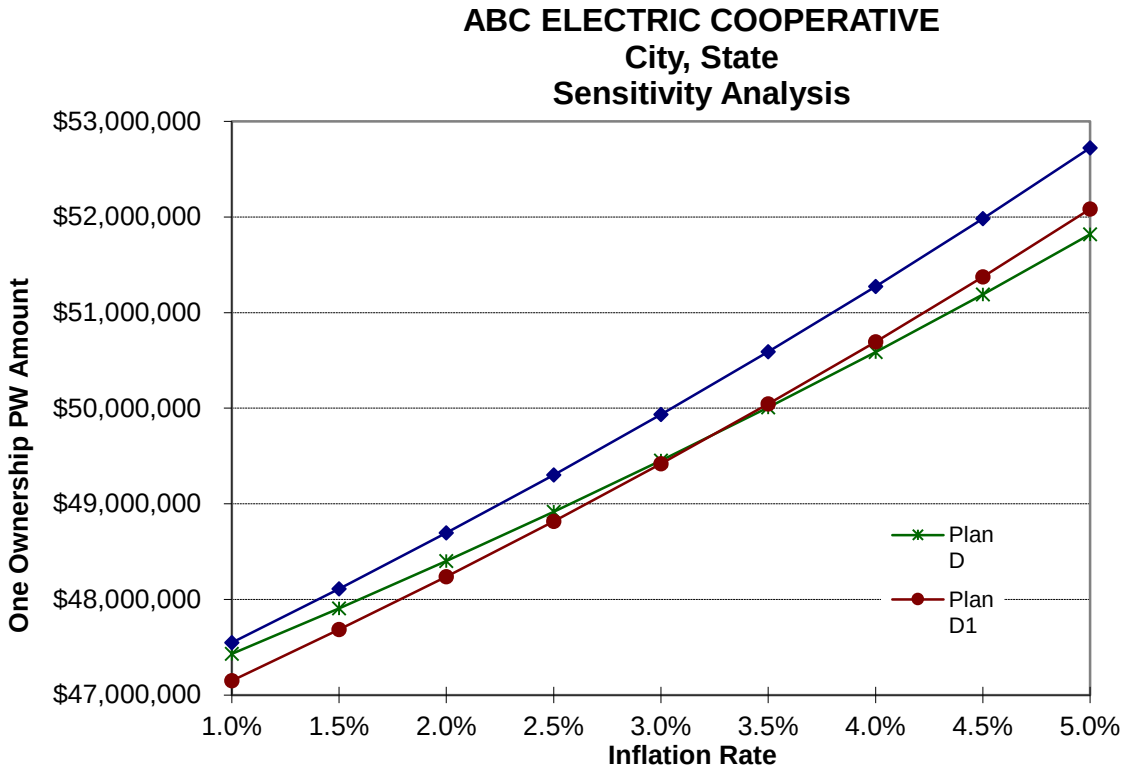
% Load Growth	Plan D	Plan D1	Plan D1A
2.71%	$56,200,499	$56,038,290	$56,526,398
3.40%	$50,007,779	$50,043,372	$50,590,010
4.56%	$41,131,306	$41,422,929	$42,091,843

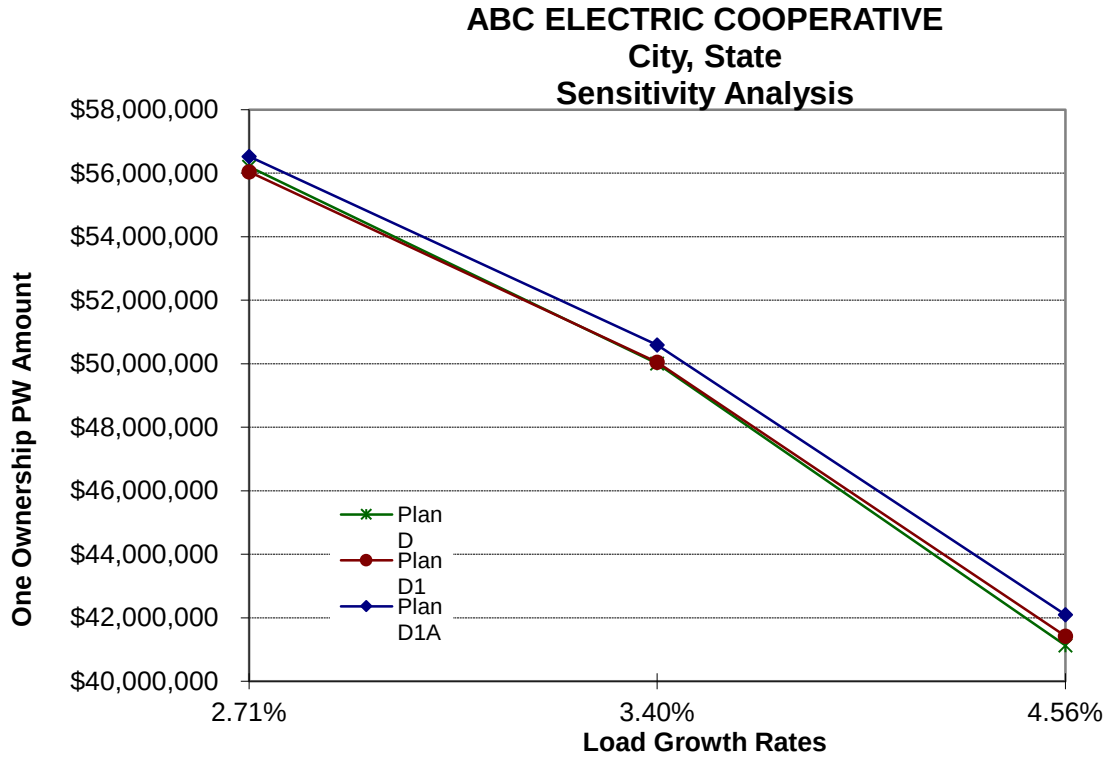
Energy Inflation Rate	Plan D	Plan D1	Plan D1A
1.0%	$49,349,487	$49,398,720	$49,945,358
2.0%	$49,683,345	$49,725,701	$50,272,339
3.0%	$50,054,417	$50,089,032	$50,635,670
4.0%	$50,467,206	$50,493,103	$51,039,741
5.0%	$50,926,763	$50,942,841	$51,489,479
6.0%	$51,438,753	$51,443,768	$51,990,406
7.0%	$52,009,526	$52,002,075	$52,548,713

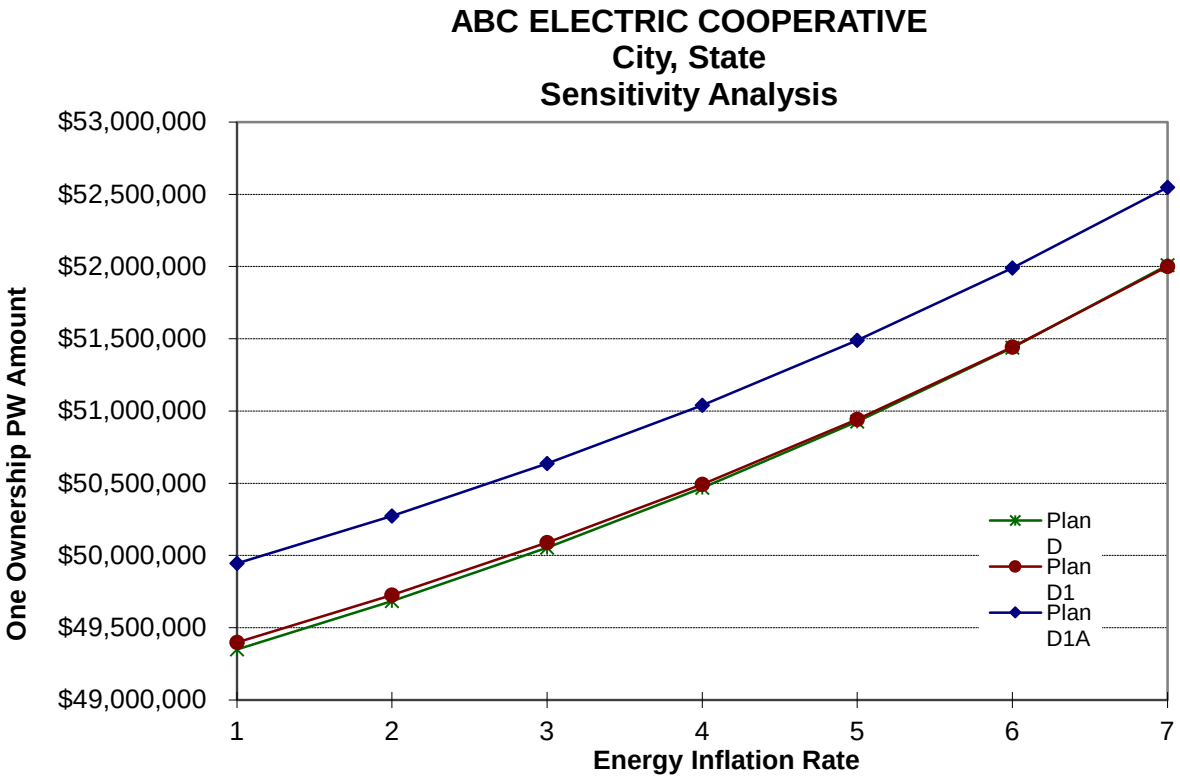
Present Worth Rate	Plan D	Plan D1	Plan D1A
4.0%	$59,834,287	$59,930,497	$60,592,357
5.0%	$54,605,925	$54,668,875	$55,269,305
6.0%	$50,007,779	$50,043,372	$50,590,010
7.0%	$45,952,166	$45,965,294	$46,464,672
8.0%	$42,364,821	$42,359,541	$42,817,259
9.0%	$39,182,695	$39,162,372	$39,583,243

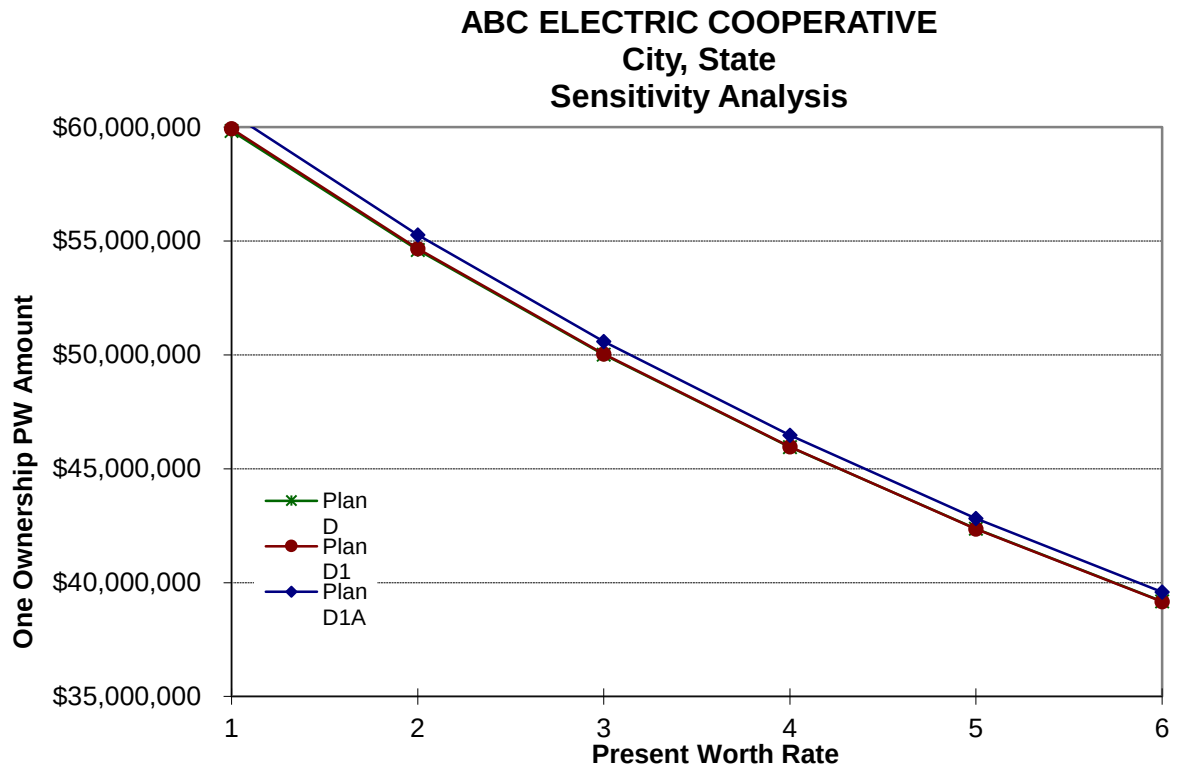
Wheeling Cost	Plan D	Plan D1	Plan D1A
$2.00	$49,449,552	$49,616,093	$50,229,369
$2.50	$52,221,503	$51,989,868	$52,232,932
$3.00	$54,993,453	$54,363,644	$54,236,495
$3.50	$57,765,404	$56,737,420	$56,240,057
$4.00	$60,537,355	$59,111,196	$58,243,620
$4.50	$63,309,305	$61,484,972	$60,247,183
$5.00	$66,081,256	$63,858,748	$62,250,746
$5.50	$68,853,207	$66,232,524	$64,254,309
$6.00	$71,625,158	$68,606,300	$66,257,871

** For the three closest plans with different design approaches.*


ABC ELECTRIC COOPERATIVE
City, State
Sensitivity Analysis
$53,000,000
$52,000,000
$51,000,000
$50,000,000
$49,000,000
$48,000,000
$47,000,000
One Ownership PW Amount
1.0%
1.5%
2.0%
2.5%
3.0%
3.5%
4.0%
4.5%
5.0%
Inflation Rate
Plan D
Plan D1


ABC ELECTRIC COOPERATIVE
City, State
Sensitivity Analysis
$58,000,000
$56,000,000
$54,000,000
$52,000,000
$50,000,000
$48,000,000
$46,000,000
$44,000,000
$42,000,000
$40,000,000
One Ownership PW Amount
2.71%
3.40%
4.56%
Load Growth Rates
Plan D
Plan D1
Plan D1A


ABC ELECTRIC COOPERATIVE
City, State
Sensitivity Analysis
$53,000,000
$52,500,000
$52,000,000
$51,500,000
$51,000,000
$50,500,000
$50,000,000
$49,500,000
$49,000,000
One Ownership PW Amount
1
2
3
4
5
6
7
Energy Inflation Rate
Plan D
Plan D1
Plan D1A


ABC ELECTRIC COOPERATIVE
City, State
Sensitivity Analysis
$60,000,000
$55,000,000
$50,000,000
$45,000,000
$40,000,000
$35,000,000
One Ownership PW Amount
1
2
3
4
5
6
Present Worth Rate
Plan D
Plan D1
Plan D1A

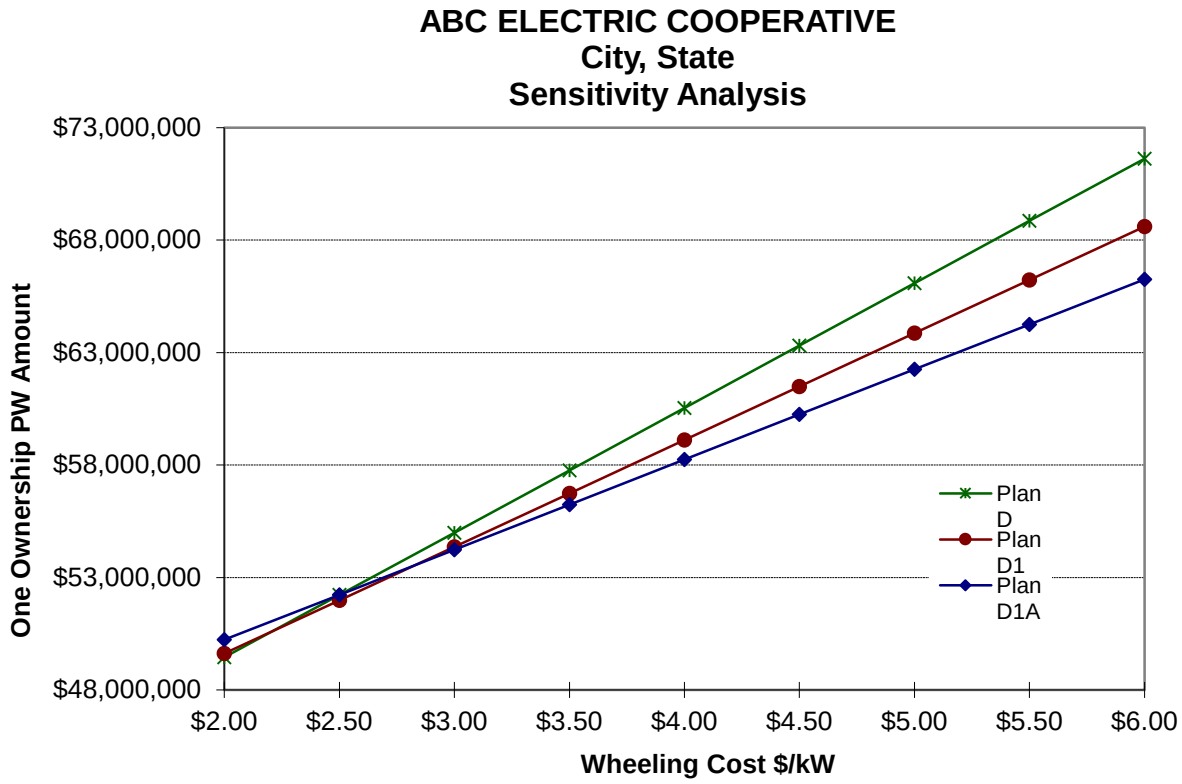

ABC ELECTRIC COOPERATIVE
City, State
Sensitivity Analysis
$73,000,000
$68,000,000
$63,000,000
$58,000,000
$53,000,000
$48,000,000
One Ownership PW Amount
$2.00
$2.50
$3.00
$3.50
$4.00
$4.50
$5.00
$5.50
$6.00
Wheeling Cost $/kW
Plan D
Plan D1
Plan D1A

EXHIBIT I
SUGGESTED TABLE OF CONTENTS FOR LONG-RANGE ENGINEERING PLAN

ABC ELECTRIC COOPERATIVE
2008 LONG-RANGE PLAN
TABLE OF CONTENTS

LETTER OF TRANSMITTAL AND ENGINEERING CERTIFICATION i
CHECKLIST OF SYSTEM PLANNING REPORT (RUS Form 260) ii
SUMMARY OF SYSTEM PLANNING REPORT (RUS Form 261) iv
GENERAL COOPERATIVE LOCATION MAP v
I. INTRODUCTION 1
II. PURPOSE OF REPORT 3
III. SUMMARY OF REPORT AND RECOMMENDATIONS 4
IV. ANALYSIS OF EXISTING SYSTEM AND BASIC DATA 5
A. Introduction 5
B. Purpose of Analysis 5
C. Summary, Conclusion, and Recommendations 5
D. System Growth Patterns 5
E. Capacity of Existing System 5
F. Environmentally Sensitive Areas 6
G. Adequacy of Basic Data 6
V. PLANNING CRITERIA 7
A. Long-Range Demand Level 7
B. Area Load Density and Growth Potential 7
C. Special Loads 7
D. Service Reliability 8
E. Engineering and Economic Criteria (Eec) 8
F. Financial Criteria 8
G. Other Criteria 9
H. Assumptions 9
I. Facilities and EQUIPMENT 9
VI. LONG-RANGE PLAN 10
A. Exploratory Plans 10
B. Plan Selection 11
C. The Recommended Plan 12
D. Alternate Plans Reviewed 13
1. Plan D1a—Alternate Preferred Plan 13
VII. CONCLUSION 14

EXHIBITS

EXHIBIT 1 System Statistical Data
EXHIBIT 2 Substation Load Data

EXHIBIT 3 Engineering and Economic Criteria
EXHIBIT 4 Consumer Outage Summary
EXHIBIT 5 RUS Fixed Charge Summary
EXHIBIT 6 Economic Parameters and Cost Estimates
EXHIBIT 7 Summary of Total Plant Investment
EXHIBIT 8 Summary of Estimated Capital Additions to Distribution Plant
EXHIBIT 9 Summary of Estimated System Distribution Improvement Costs
EXHIBIT 10 Cost Estimates, New Services
EXHIBIT 11 Cost Estimates, Distribution Line Construction
EXHIBIT 12 Cost Estimates, Transmission Facilities
EXHIBIT 13 Cost Estimates, Substations
EXHIBIT 14 Cost Estimates, Uprating Existing Services
EXHIBIT 15 Cost Estimates, Miscellaneous Distribution Equipment
EXHIBIT 16 Cost Estimates, Ordinary Replacements
EXHIBIT 17 Estimated Distribution Plant Investment Charts
EXHIBIT 18 Economic Comparisons of Plans Reviewed
EXHIBIT 19 Sensitivity Analysis
EXHIBIT 20 Conductor Life Cycle Analysis
EXHIBIT 21 Transmission System (Existing System with LL4 Improvements)

MAPS*

Map 1 Existing Summer 2006 Base System, Load Level 1
Map 2 Proposed Summer 2026 System, Load Level 4

**Maps for Preferred Plan D1 only. Alternate plans are available upon request. See supporting data for primary analyses of system conditions.*

SUPPORTING DATA

Other appropriate information and data that substantiate the conclusions made in this report have been bound under separate cover and are available from Patterson & Dewar Engineers and ABC Electric Cooperative upon request.

EXHIBIT J
SUGGESTED TABLE OF CONTENTS OF SUPPORTING DATA

ABC ELECTRIC COOPERATIVE
2008 LONG-RANGE PLAN

SUPPORTING DATA
TABLE OF CONTENTS

TAB A Summary of Plans

TAB B Large Power Loads (Summer 2006)

TAB C Economic Parameters and Cost Estimates

TAB D Growth Projections

TAB E Generation and Transmission Correspondence and Cost Estimates

TAB F RUS Fixed Charge Summary

TAB G Summary of Economic Comparisons with Plan Calculation Tabs

TAB H Sensitivity Analysis (Details)
- Inflation
- Load Growth
- Energy Inflation
- Present Worth Rate

PLAN D1 (Preferred Plan) **

TAB I Add 3 new delivery points (DPs). Convert the rest of Substations C, E, and F to 25kV.
- Transmission System
- Substation Loading
- Losses Allocations
- Cost Allocations

TAB J Primary Analysis, Load Level 1—Existing System Summer 2006

TAB K Primary Analysis, Load Level 2—Proposed System Summer 2012
(2008 Construction Work Plan)

TAB L Primary Analysis, Load Level 3—Proposed System Summer 2016

** *See main long-range study report for further details of the Preferred Plan results.*

EXHIBIT K
CHECKLIST OF LONG-RANGE PLANNING REPORT (RUS FORM 260)

U. S. DEPARTMENT OF AGRICULTURE RURAL UTILITIES SERVICE **CHECK OF SYSTEM PLANNING REPORT** Reference Bulletin 1724D-101A	BORROWER DESIGNATION XX-XXX-XXXXXXX	
	DATE REPORT COMPLETED	NAME OF PLANNING ENGINEER

CHECK		**PART I - THE SYSTEM PLANNING REPORT** *(If "No" column is checked, explain under "Remarks")*
YES	NO	
		1. Does the report present an analysis of the existing system and basic data?
		2. Does the report present a transition from the existing system to the long-range system?
		3. Does the report contain a summary of the exploratory plans which the engineer considered?
		4. Did the borrower have a service reliability standard for the engineer to use as a means of evaluating continuity and reliability of service to consumers?
		5. Was each exploratory plan developed in sufficient detail to clearly establish the basis for selection of the recommended plan?
		6. Have all reasonable exploratory plans been considered?
		7. Have the transitional steps been formed by grouping together various system improvements requiring approximately the same load level?
		8. Are graphs presented relating estimated total plant investment to load levels?
		9. Is a table presented listing the fixed cost elements and the associated percentage of plant investment used for the economic comparisons?
		10. Are economic comparisons of exploratory plans presented on an annual cost basis?
		11. Are summaries of cost data tabulated and identified as called for in Bulletin 1724D-101A (6.5.4)?
		12. Does the report contain a circuit diagram of the complete system for each major step in the transition and for the long-range system as called for in Bulletin 1724D-101A(6.5.6)?
		13. Are the system's transmission lines, if any, and those of the power supplier or other utilities in or near the system's service area shown on the circuit diagrams or other diagrams?
		14. Is the report, including the analysis of the existing system, concise and well-organized so that management can easily work with the report without further engineering interpretation?
		15. Has a copy of a resolution signifying the board of directors' action concerning acceptance of the report been received?

DATE	SIGNATURE

RUS FORM 260 — CAB (7/96) 5-68

CHECK		PART II—DEVELOPMENT OF THE LONG-RANGE PLAN
YES	NO	
		1. Does the analysis of the existing system give a good understanding of the system's performance?
		2. Is the load level for the long-range system within the range of three to six times the average kwh/consumer/month for the highest peak month experienced to date?
		3. Does each exploratory plan presented, including the long-range plan, make use of existing facilities as long as it is economical to do so?
		4. Does each exploratory plan presented, including the long-range plan, provide a system which is designed to meet the required voltage standards?
		5. Does the transition from the existing system to the long-range system demonstrate a practical and economical development of the system?
		6. Are proposed voltage regulator installations in the long-range plan in accordance with the recommendations in RUS Bulletin 1724D-101A?
		7. Are the cost estimates used by the engineer reasonable?
		8. Are the design criteria established by management reasonable so that they do not rule out logical exploratory plans?
		9. In addition to the economic comparisons, are sufficient comparisons and considerations made to show the superiority of the selected long-range plan over the other exploratory plans?
		10. If indeterminate factors or uncertain conditions exist, is an alternate transition from the existing system to the long-range system proposed?
		11. Is the proposed long-range plan based on power sources that the engineer and the system's management are reasonably sure will be available?

REMARKS

DATE	COMPLETED BY — SIGNATURE

EXHIBIT L
SUMMARY OF LONG-RANGE PLANNING REPORT (RUS FORM 261)

SUMMARY OF SYSTEM PLANNING REPORT	SYSTEM DESIGNATION PLANNING ENGINEER	DATE PLANNING REPORT COMPLETED

PART I—GENERAL DATA

ITEMS 1.	2. LINE MILES TRANS. a.	 DISTR. b.	3. NO. OF CONSUMERS ALL TYPES *(Including special loads)* c.	 SPECIAL LOADS d.	TOTAL SYSTEM LOADS *(kW)* 4.	TOTAL SPECIAL LOADS *(kW)* 5.	TOTAL YEARLY SALES *(kWh)* 6.	7. PAST PEAK LOAD kWh/CONS. /MO. a.	 DATE b.	DESIGN LOAD kWh/CONS. /MO. PEAK MO. 8.
PRESENT SYSTEM AS OF_____										
LONG-RANGE PLAN										

PART II—LINE MILES

ITEMS 1.	2. DISTRIBUTION 12.5/7.2 kV a.	 24.9/14.4 kV b.	_____ kV c.	_____ kV d.	3. TRANSMISSION _____ kV a.	_____ kV b.	_____ kV c.	_____ kV d.
PRESENT SYSTEM AS OF _____								
LONG-RANGE PLAN								

PART III—SUBSTATIONS AND METERING POINTS

NAME OR LOCATION* 1.	POWER SUPPLIER 2.	3. PRESENT SYSTEM MVA a.	 kV PRIMARY b.	 kV SECONDARY c.	4. LONG-RANGE PLAN MVA a.	 kV PRIMARY b.	 kV SECONDARY c.

PART IV—INVESTMENT IN PLANT *(Thousands of Dollars)*

ITEMS 1.	TRANSMISSION LINES 2.	ALL SUBSTATIONS 3.	DISTR. TRANSFORMERS METERS & SERVICES 4.	ALL OTHER DISTR. FACILITIES 5.	TOTAL T&D PLANT 6.	GENERAL & PROD. PLANT 7.
PRESENT SYSTEM AS OF _____					$0	
LONG-RANGE PLAN					$0	

RUS FORM 261 REV. 1-95 (CAB 5/96) ** Include those furnished by Power Supplier and designate with asterisk.*

REMARKS:

INSTRUCTIONS

A copy of this form is needed for each system planning report. *(See RUS Bulletin 1724-101A).*

Part I List data as indicated by column headings.
Column 7 *(present system)* actual experienced peak.
Column 8 *(present system)*. Engineer's best judgment as to system's capability in terms kWh/mo/cons. as determined from his "Analysis of Present System and Basic Data."

Part II List the mileage breakdown of all distribution and transmission lines in the present system and similar data for the long-range plan.

Part III List data for each substation or metering point as indicated in the column headings.

Part IV List investment in plant *(dollars)* as indicated by the column headings for the present system and for 2 - 3 - 4 - 5 - 6 for the long-range plan. Investment *(dollars)* for the several columns are included under the following accounts:

Column 2—350 + 351 + 352 + 354 + 355 + 356 + 357 + 358 + 359
Column 3—353 + 362
Column 4—368 + 369 + 370
Column 5—360 + 361 + 364 + 365 + 366 + 367 + 371 + 372 + 373
Column 7—Sum of 389 thru 398 + Sum of 310 thru 345 as applicable.

APPENDIX 1
ECONOMIC CONDUCTOR LIFE CYCLE ANALYSIS

1 BACKGROUND

An Economic Conductor Life Cycle Cost Analysis is a long-term comparison of the costs of alternatives available in the construction of distribution lines. As is the case with many economic decisions, more initial investment will result in more savings in the long term. The goal of this analysis is to identify the best possible combination of initial investment and long-term losses reduction. The end product of Economic Conductor Life Cycle Analysis is, typically, a graph generated by a spreadsheet showing the Total Life Cycle Cost as the Y axis and the Initial Loading as the X axis. See Exhibit E of this *Guide* for an example of such a graph. The graph demonstrates that there are crossover points where it is more economical to choose a larger conductor for higher initial loading.

2 COSTS AND ECONOMIC BREAKDOWN

There are many costs incurred due to the construction and operation of a distribution line. The goal is to identify the *relevant* costs that should be compared for an accurate evaluation. For example, it is obvious that, for a higher-cost line, there will be more annual taxes because taxes are based on value. However, does a larger or smaller wire size really result in a measurable difference in annual operation and maintenance expense? One of the largest maintenance expenses, right-of-way trimming, would be the same for a smaller wire size as it would be for a larger wire size. It is up to the cooperative planning engineer to identify and quantify real annual differences for the purposes of this evaluation.

Estimated plant life should be based on the best historical information available. In some climates, conductor may last more than 30 years. Where growth is a major concern, it is possible that—due to reasons such as road widening—conductors may not be expected to be in service for more than 20 years. The various components of the analysis will have an impact on the outcome and should be reviewed thoroughly.

The value of losses is sometimes a difficult number to derive. It is important to remember that you are considering the *future* value of losses and that historical demand and energy charges are usually blended costs of embedded investments. What you are considering is the reduction of losses that otherwise would have to be generated from tomorrow's generation plants at much higher rates than embedded, historical costs. This will result in the increased value of losses and a trend toward larger conductors.

The key to conducting a successful comparison of life cycle costs is to begin with accurate base data. The most important figure is the construction costs of a mile of line for a wire size. Very detailed reviews must be conducted to determine the best cost. Outliers—conductors evaluated with very high or low costs—that are on the extreme ends should be reviewed in detail and possibly removed from the cost development. Estimates of construction costs for wire sizes with no history should be carefully

estimated. Some determination of additional costs due to larger wire, shorter spans, increased pole class, possibly heavier hardware, etc., must be made. Conversations with neighboring cooperatives that are using different size conductors would aid in the estimation process.

An important item to consider in the evaluation process is that there are two components to selecting feeder conductors. Initially, conductor selection is accomplished at a high level to pick the few major wire sizes and types to be used for the next 10 to 20 years. Once that macro analysis is done, a comparison on a more micro level is possible. It is important, after the long-range plan (LRP) is completed, that appropriate segments of line are analyzed prior to design and construction. For example, a very long feeder is probably not uniformly loaded for its entire length. If the feeder splits after the first mile or so into several significantly loaded directions, the first segment should be considered separately from the remainder of the feeder or other significant, identifiable segments. Due to the ease of use of modern Economic Conductor Life Cycle Cost Analysis spreadsheets, this would be a very prudent exercise.

There are a number of Economic Conductor Life Cycle Cost Analysis spreadsheets or programs available. Generally, the differences lie in respect to the level of detail they offer. For the purposes of this *Guide*, a standard Economic Conductor Life Cycle Cost Analysis spreadsheet will be reviewed.

3 VARIOUS CONDUCTOR TYPES

A brief review of common aluminum conductor options is presented below. When accomplishing an LRP and a conductor alternative study, a more detailed consideration of the available types of conductor should be considered. There are distinct advantages and disadvantages to using certain conductor types and sizes under different local conditions. For some areas of the country, conductors with high tensile strength or reduced vibration are more advantageous because of longer spans or terrain. Some situations may require conductors with increased conductivity and thermal ratings. Some areas may require higher corrosion resistance. These localized and specific requirements must be considered and weighed during the selection process.

Key conductor types being manufactured today are:

All-Aluminum Conductor (AAC). AAC conductor is a high conductivity cable that consists of aluminum wires concentrically stranded. Generally this conductor is preferred in heavily loaded urban areas where short spans and high current levels exist. The aluminum used is a compound known as 1350-H19, which has a good combination of conductivity and corrosion resistance.

Aluminum Conductor, Steel Reinforced (ACSR). ACSR has been the standard for overhead distribution and transmission conductor for years. It has a good combination of strength and ampacity. The conductor consists of a steel core surrounded by layers of

aluminum (1350-H19). Higher strength is achieved by increasing the number of steel support core wires for use in transmission systems or particular distribution applications of extremely long spans. An advantage that ACSR has over AAC is that the steel core decreases the sag of the conductor and allows a higher thermal rating to be achieved for a particular span length. The steel also increases the strength of the line providing greater resistance to ice and breaking problems.

All-Aluminum Alloy Conductor (AAAC). AAAC was designed to compare favorably to ACSR in strength to weight and in ampacity. The wires within the conductor are an aluminum alloy (6201-T81) developed to be stronger than the 1350-H19. The biggest advantage that AAAC has over ACSR is that it is much more corrosion-resistant and abrasion-resistant. Because of this, it is particularly beneficial along coasts or corrosion-prone areas.

Aluminum Conductor, Aluminum-Alloy Reinforced (ACAR). ACAR is a conductor that consists of separate strands of the aluminum alloy (6201-T81) found in AAAC along with 1350-H19 aluminum strands. There are a number of different configurations for the same wire size to optimize ampacity or strength for a given application.

Specialized Conductors. There are a number of other special configurations and materials available to address specific problems, such as vibration, increased tensions, or other concerns. These are typically very specialized products and outside the scope of this manual. However, it is worthwhile to research and evaluate these conductors to address certain needs.

4 CONCLUSION

Selecting and standardizing on a selected few conductor types is a key responsibility of the distribution planning engineer. Typically, two or three types of conductors are chosen: one for lightly loaded single-phase and three-phase lines, one for medium-loaded three-phase lines, and one for heavily loaded and main substation tie lines. The key factor in making the decision is economics. However, the operational control function of conductor availability is also another key factor. Each conductor evaluated for economics must be evaluated for availability. Each electric system experiences environmental conditions and land attributes that have to be considered for rebuilding and conductor availability. These conditions vary but can be summarized as follows:

- Coastal atmospheres with high corrosive attributes,
- Ice storms,
- Tornadoes,
- Hurricanes,
- Earthquakes,
- Flooding, or
- Mountainous terrains.

The above list is in no way complete and inclusive, but does highlight the factors the electric planning engineer needs to consider when selecting conductors for line construction.

APPENDIX 2
RADIAL TRANSMISSION LINE RELIABILITY AND OPERATIONAL ASSESSMENT

1 BACKGROUND

A radial transmission line serving distribution substations is defined as distribution delivery point(s) served by a transmission line system that does not have any other means of transmission service. If there is a failure of the transmission line, there is a resulting power outage to the substation (or substations) until the line is repaired. A service reliability study will indicate areas of the system which need special attention and may even indicate the general type of work which will be most cost-effective in correcting such service deficiencies. If the transmission supplier is responsible for an excessive amount of the outage time (typically, more than one consumer-hour per consumer/year averaged or trended over five years), this should be noted. The transmission supplier should be requested to provide comparable outage analyses for all similar delivery points.

Reliability should be based on standards or criteria established by the cooperative or other national organizations. A service reliability standard provides a basis on which management can evaluate system performance. Please see RUS Bulletin 1730A-119 entitled “Interruption Reporting and Service Continuity Objectives for Electric Distribution Systems” for further details regarding RUS service reliability polices. Also, the system planner should be fully aware of the transmission line reliability policies and indices as required by the Federal Energy Regulatory Commission (FERC) as administered by the North American Energy Reliability Council (NERC). Most FERC/NERC guidelines deal with the bulk transmission grid; however, they do have an impact on the reporting that each power supplier is required to file.

The importance of service reliability should be reflected in the long-range system plan. Because of wide differences in operating conditions and local requirements, RUS does not attempt to specify a service reliability standard for all systems. However, each borrower should adopt a standard, which will serve as a goal in the development of its system. The five consumer-hours per consumer per year interruption rate used for loan applications should not be considered as a goal. Rather, system goals should be nearer one hour for suburban and two hours for rural consumers. Furthermore, it should be recognized that, except during truly unusual major storms, consumers are not concerned with the source of an interruption. Whether the power is off only for their individual transformer or because of a power supplier’s interruption makes little difference to the consumer. Thus, all sources of interruption should be considered for possible improvement in service reliability.

The need for improvements to radial transmission lines can be separated into two different categories: performance and exposure. Addressing a radial transmission line’s performance can involve significantly different factors than addressing a similar line’s exposure. For example, improving ROW or adding lightning arrestors are good approaches to improving performance; however, they do nothing to reduce exposure. By

the same token, providing an alternate transmission source may improve SAIDI metrics but momentary outages and frequency of outages will remain unchanged unless the alternate transmission source becomes the primary source.

Whether the transmission lines are owned by the distribution system or the transmission supplier, planning should be approached on a "one system" concept. Excessive costs for transmission facilities cannot be justified by minor savings on one part of the system. The converse is also true that excessive distribution plant should not be constructed simply to avoid transmission construction. The economy of radial-feed substations should be weighed against the reliability of loop-feed substations. The applicability of each design, as it pertains to the basic system design and established operating practices, should be carefully considered.

To aid in such an assessment, the following procedures and the attached form have been created. With the planning engineer and all associated parties working together to complete the factual data required, all pertinent conditions can then be assessed. By answering the questions listed with a clear yes or no, needs can be established and all parties can agree that long-range plans should attempt to satisfy those needs. If many of the questions are answered in the affirmative, clear reliability concerns are present and system improvement options should be reviewed under the "one-ownership" concept to identify the economics for improved reliability of each option.

2 PROCEDURE

The general process for accomplishing the assessment is as follows:

1. The transmission line provider and cooperative/distributor are to review the current radial electric power delivery system and identify any weak links that involve significant load requirements. (Note: The transmission and substation provider and cooperative/distributor may be the same entity). A weak link is identified as a system configuration that has recently contributed to an extensive unplanned outage and/or a condition that would require a lengthy outage in order to accomplish extensive maintenance. Radial transmission lines without backup or looping options are prime components that need to be reviewed. It is not the intent of this assessment to review and evaluate every radial transmission line in the cooperative/distributor's service area, only those lines that have recently presented a problem or have significant current or future high load conditions.

2. After identifying the weak links, factual data is to be accumulated by the transmission line provider and cooperative/distributor, and tabulated on the attached form. After tabulating the factual data and answering the questions, the number of affirmative answers can be counted.

3. If there are a number of affirmative answers tabulated, long-range planning should include the review of economical ways to improve and/or eliminate the weak links.

4. After a thorough review of possible solutions using the "One Ownership" method, the cooperative/distributor can decide which options, if any, should be included in its long-range plan. The attached form can be used as a general tool for documenting what is to be included in the new LRP and why. It is *not* to be considered an official commitment document for system improvements. It is only a tool for communicating with the various electric system owners. It is further understood that agreement to include the weak link in the planning process in no way commits any party to construct the system improvement required to resolve the weak link.

5. After an economic review of the options has identified that the weak link can be eliminated or improved in the long range, all system parties/owners should commit to planning those system improvements. If they cannot, all parties agree to live with the weak link and work around it as conditions dictate.

3 MEANING OF TERMS (Listed in Form Order)

The terms used in the Radial Transmission Line Reliability and Operational Assessment form are defined as follows:

T/L #. The designation given by the long-range system study for the Transmission Line (T/L) under consideration.

Transmission Line Description. A short phrase that defines clearly the T/L under review.

Operating Voltage. The phase-to-phase nominal operation voltage of the line.

Conductor Size and Type. Denotes the wire size and type. Including the "word code" would be very helpful. An example is "336 kcmil ACSR (Linnet)."

Right-of-Way Width. Denotes the available width of ROW in feet.

Radial Distance. The length of the T/L from the bulk feed or looped line to the cooperative/distributor's delivery point, recorded in miles. If more than one delivery point is associated with the radial line, the line distances between each delivery point are to be determined and recorded.

Peak Load. The maximum non-coincident peak electric load is the highest ever experienced on the system or, at least, over the last 12 months, expressed in megawatts (MW). If there is more than one delivery point associated with the radial line, the peak loads are to be tabulated for each delivery point.

Last Peak Time. The month and year of the last peak load is identified.

Load Distance Service Factor (LDSF). This is the arithmetical product of the radial T/L distance (in miles) times the last peak load experienced on the line (in MW). The LDSF

is recorded in MW-miles and is a numerical value for the planning engineer to assess the criticalness of electric load to a distance of T/L. The factor really has no real meaning and is to be used only as a guide for assessing the need for system improvements and T/L looping. If there are multiple substations or delivery points served by the T/L, an LDSF is to be calculated for each point, including the total load being served from and through that delivery point.

Transmission Line Provider. The organization that has responsibility for planning, maintaining, and operating the T/L under review.

Cooperative/Distributor or Cooperative. Refers to the organization that distributes power from the delivery point that is served by the radial T/L.

Significance of MW-Miles. Planning engineers in the T/L and distribution business have generally agreed that, when radial transmission line loading reaches an LDSF greater than 100 to 150 MW-miles, efforts should be included in system long-range planning to look for ways to reduce the radial exposure. This should be considered only a guide and not a mandate in system long-range planning.

Poorly Accessible T/Ls. Refers to T/Ls that have rights-of-way (ROW) that, for whatever reason, are not readily accessible during a significant part of a given year. Reasons for inaccessibility could be, but are not limited to, the following: ROWs that are very swampy and subject to rainy seasons; ROWs that are mountainous and subject to snow or icy conditions during parts of the year; and ROWs over waterways with T/Ls built off pilings or piers.

High-Priority Loads. Distribution loads served by the cooperative/distributor that would experience severe uneconomical or life-and-death conditions if an extensive outage occurred. Typical loads that would experience such could be hospitals, industrial/manufacturing plants, airports, commercial loads, large oil and gas pumping loads, etc. Service areas where consumers rely heavily on electricity for heating could, likewise, be considered a high-priority load.

Conductor Condition. Occasionally, T/L providers perform sample testing on very old (i.e., more than 30 years) conductors to see if their condition is suitable for further long-term use. If conductors are found to be in reasonably good condition (e.g., they are not brittle or prone to breaking, the steel core is not rusty or missing, etc.), then they can continue in use. If, however, such is not the case, replacement or repair of the Radial Transmission Line (RTL) needs to be included in the long-range planning process.

Three Outages Over Last Two Years. T/Ls that have experienced more than one outage per year over the last two years due to poor line hardware indicates poor and depreciated equipment conditions and are in need of replacement and/or improvement that should be included in long-range planning.

Four-Hour Outage Within 12 Months. A four-hour outage can be critical for many distribution loads and must be considered when long-range planning takes place. T/Ls having such operational conditions with a high LDSF should be reviewed in the system long-range planning process.

Unreliable Line Percentage. FERC requires that T/L providers identify the reliability of all their lines and rate them in order from least to most reliable. With such information, the power supplier or transmission line provider can quickly tell if the radial T/L under review is within the top 5% of most unreliable lines on their system. If it is, it is important that system improvements be reviewed in long-range planning.

Loaded >50% Capacity. Radial T/Ls projected to be peak loaded over 50% of published full load capacity should be evaluated for long-range system improvements, especially for lines operating at ≤ 69 kV. Published capacity denotes the manufacturer's rating, typically with conductor at 75ºC, ambient temperature at 25ºC, emissivity at 0.5%, wind at 2 feet per second, and the conductor in direct sunlight.

Operating Voltage ≤ 69 kV. Radial T/Ls operating at subtransmission voltage levels can have high line losses and voltage drops when heavily loaded and are not good for bulk feed looping. Such voltage levels do not directly impact system reliability but do impact system operations and economics. Also, such voltage lines are weak for transformation to 25 kV distribution. As a result, such lines are a good place for possible system improvements or changes within the surrounding service area.

4 RADIAL TRANSMISSION LINE ASSESSMENT FORM

The form below is for assessing the reliability of radial transmission lines. It can be duplicated for as many radial T/Ls as the power supplier, transmission line provider, and/or cooperative/distributor identify as needing review. Electronic or Excel® versions can be acquired from the NRECA T&D System Planning Chair and the Staff Director of the RUS Electrical Engineering Branch.

Radial Transmission Line Reliability and Operational Assessment

Radial Transmission Line (RTL) Characteristics: RTL #:_____

Name and Description: _____
Operating Voltage (kV): _____ Conductor Size & Type: _____
Right-of-Way Width (feet):_____ Radial Distance (miles): _____
Last Peak Load (MW):_____ Peak Time (month, year): _____
Load Distance Service Factor (MW-Miles):[A] _____ Year Built: _____
With loss of the RTL, what % of load can existing distribution ties support? _____
Major Line Maintenance Cycle Years: _____
Year of Last Major Line Maintenance: _____
Right-of-Way Location (cross-country, roadside, etc.): _____
Right-of-Way Maintenance Cycles (years): _____
Frequency of Right-of-Way (years):

Inspections	_____	Mowing/Spraying	_____
Danger Tree Removal	_____	Side Trimming	_____

Transmission Line Provider:_____
Impacted Distributors or Cooperatives: _____

RTL Reliability and Operational Questions[B]	No	Yes
1. *Does the RTL have a high Load Distance Service Factor (LDSF) greater than 150 megawatt-miles?*	___	___
2. *Is the RTL poorly accessible as determined by the Owner during all or part of the year?*	___	___
3. Does the RTL serve a delivery point that provides power to high priority loads (e.g., hospitals, manufacturing parks, airports, commercial loads, etc.)?	___	___
4. *Is the conductor in deteriorated condition based on recent sample testing?*	___	___
5. *Is the RTL condition contributed to more than three sustained outages over the last two years?*	___	___
6. *Has there been an outage over four hours in the past five years attributed to the RTL (excluding those during a major storm)?*	___	___
7. *Is the RTL in the power supplier's top 5% of most unreliable lines?*	___	___
8. *Does the RTL owner have any major improvement plans in the near future or in the general area of the distributor/cooperative substation?*	___	___
9. *Is the RTL operating at 69 kV or less and have a >50% of the conductor published full load amperes for the projected long-range peak loading conditions?*	___	___

Number "Yes" Responses[C] = ___

RTL PLANNING COMMITMENT

Based on the above assessment, the electric system distribution engineer has decided that the referenced RTL _____ ***is*** or _____ ***is not*** to be included in the new electric system long-range plan. A copy of this assessment and commitment is to be supplied to the RTL provider indicated above.

Signature: _____
Distributor's Planning Engineer Name: _____
Distributor's Planning Engineer Title: _____

[A] Load Distance Service Factor = (Latest Peak Demand Load Served) × (Radial Line Distance)
[B] Categories shown in italics are to be answered by the RTL Owner and Provider, if applicable.
[C] RTLs that have a number of "affirmative" responses to the reliability and operational questions above should be included in the long-range planning process.

APPENDIX 3
AGING CONSIDERATIONS FOR LONG-RANGE CAPITAL EXPENDITURES

A cooperative needs to balance capital expenditures across all parts of its system to maintain an acceptable level of service for all consumers. This appendix addresses the challenges that arise when all or part of the system is experiencing stagnant growth or declining loads, including the issue of allocating available funds between growth and non-growth areas.

The problems commonly encountered in aging, low-growth distribution systems can be described as follows:

- Deteriorated poles, crossarms, etc. > 35-50 years old
- Deteriorated and obsolete conductors (copper-clad and aluminum) > 40 years old, especially those with excessively long spans and aging conductors
- Deteriorated and obsolete substations (wooden structures)
- Deteriorated and obsolete substation transformers
- Deteriorated transmission lines (34.5 kV, 46 kV)
- Deteriorated reclosers and switches
- Deteriorated voltage regulators and regulator controls
- Excessive electrical losses (primary, secondary, and transformer)
- High levels or unknown levels of PCBs in power and distribution transformers
- Deteriorated concentric neutral underground cable where the neutral is corroded away
- Inadequate or ineffective lightning protection
- Inadequate or ineffective grounding, causing excessive stray voltages
- Inadequate sectionalizing and overcurrent protection
- Deteriorated knife blade switches
- Deteriorated and improperly maintained reclosers
- Deteriorated insulators causing excessive radio noise
- Deteriorated Air Break Switches out of adjustment or inoperable due to corrosion
- Insufficient grounding and insufficient lightning arrestors
- Rusting equipment enclosures (especially pad-mounted equipment)
- Obsolete SCADA system (no spare parts or support)
- Obsolete two-way radios (no parts available)
- Obsolete microwave systems (no spare parts available)

<u>Outage Criteria</u>
Cooperatives are expected to provide improved outage reliability and power quality to their members. Sectionalizing schemes and equipment used 20 or 30 years ago will usually not be acceptable to today's electric consumer. Reliability suffers even further when the distribution system begins to deteriorate. The cooperative's management and engineer must determine the reliability requirements that their membership expects and plan accordingly.

<u>System Losses</u>
System losses are a substantial financial drain on any system, and the average cooperative has losses in the hundreds of thousands of dollars every year. The cooperative should track losses by

substation on a monthly and yearly basis in order to identify problems in different parts of the system. While losses are a costly part of system operation, they also present an opportunity. Reducing losses reduces overall costs.

The continued use of small, aging conductors can contribute substantially to losses.

Underground Cable is one of the many troublesome spots on an aging system.

- High Molecular Weight (HMW) cable has proved to be very unreliable and should be replaced as soon as possible
- Bare concentric neutral cables are often found to have neutral conductors that are badly corroded or completely gone, which causes numerous operating problems.
- Non tree-retardant cross-linked polyethylene cables (XLPE) begins to have a high rate of failure as it ages.

The location and quantities of these types of underground cables should be recorded and evaluated for failure rate and plans made for their possible replacement.

Old and Depreciated Transformers

- Does the cooperative have any old 1.5 kVA, 3 kVA, 5 kVA, or possibly any 7.5 kVA transformers still in service? Check the continuing plant records (CPR) or mapping records.
- Are there any PCB transformers or capacitors or substation PCB transformers left? These may need to be replaced after checking the kWh/kW usage, etc.

Rights-of-Way

Right-of-way (ROW) problems can be a significantly costly item as well.

- How many miles of right-of-way that need to be cleared periodically?
- Are the ROWs in worse condition in the slow-growth areas?
- How many miles were cleared, cut, or mowed last year?
- How many years will it take, based upon past performance, to clear ROWs on the entire system?
  - Determine the optimum clearing cycle based on the differing growth rates of vegetation in the area.

Recloser Maintenance

- Are the operations counters on all reclosers regularly recorded?
- Is a formalized maintenance plan in place? Old, poorly maintained reclosers will seriously reduce system reliability.
- Are sectionalizing studies up to date?

Electronic Recloser/Breaker Maintenance

- Electronic recloser controls and breaker relay should be regularly tested.

- Old, obsolete units should be replaced. These controls are usually used in substations and main feeders, and have the largest impact on the proper operation of the system sectionalizing scheme.

Voltage Regulators

- Are operations counters read regularly?
- Has the number of operations exceeded manufacturers' recommendations, typically 20 years or 1,000,000 operations (see manufacturers' recommendations)?
- Can the regulator stand the available fault current if a fault occurs? In general, this is 40 times the nameplate ampere rating of the regulator for a time period of 0.8 seconds.

Pad-Mounted Equipment

Maintenance issues with transformers, switchgear and other pad-mounted equipment can be a big expense to the cooperative.

- Structural problems are the predominant failure mode.
- Rust and corrosion are a major concern.
- Oil leaks can also occur.
- Routine visual inspection is required (see CRN Report #98-11, entitled *Motor Problem Resolution and Avoidance*, for further details).

Aging Conductors

Given the fact that overhead electrical conductors have an average life expectancy of approximately 50 years, it is clear that many original distribution lines are approaching the end of their useful life span. (See CRN Report #00-31, entitled *Guide to When to Replace Distribution Line Conductors*, for additional details.) Conductor replacement should be strongly considered with a pole replacement program, to avoid the wasteful expense of setting new poles in a line with old conductors.

Some of the commonly used original conductors are as follows:

Size	Type	App. Ampere Capacity	Rated Breaking Load (lb.) NEW Conductor	Weight (lb./mile)
2A	Copperweld-Copper	240	5,876	1,356
4A	Copperweld-Copper	180	3,398	853
6A	Copperweld-Cooper	140	2,585	536
8A	Copperweld-Copper	100	2,233	392
9-1/2 D	Copperweld-Copper	65	1,743	298
3 #12	Copperweld	90	2,236	289

Some of the more common reasons why conductors fail include:

- Ice loading that exceeds maximum conductor tension;

- Long spans with ice loading, resulting in elastic stretch;
- Arcing damage from trees, lightning, wind, etc.;
- Surface corrosion on copper-clad conductors that leads to steel corrosion;
- Electrolytic corrosion due to galvanic action;
- Surface corrosion and inner corrosion of the steel strand on aluminum conductors;
- Loss of zinc coating on steel core wires (ACSR conductors);
- Fatigue failure due to wind-induced vibration; and
- Annealing due to excessive electrical current (hard-drawn copper wire).

Record Keeping on Conductors

It is very helpful to keep detailed records when conductors fail, including the reason for the failure, , size of conductor, condition of conductor, approximate age, span lengths, etc. A database should be created and maintained detailing conductor failure by substation, by circuit, and by geographic area.

Inspection Provisions

The inspection provisions are contained in the *2012 National Electric Safety Code* (NESC), Section 214. A good inspection program is intended to identify areas or equipment that need maintenance or replacement. Maintenance must be done a regular basis to keep up with the inspection process, otherwise the process breaks down and system reliability suffers. Maintenance and inspection programs should be part of the planning and budget process to insure that adequate funds are available to maintain the programs.

RUS Bulletin 1730-1, *Electric System Operation and Maintenance* (O&M), includes more detailed directions on the inspection process. It is important to keep in mind that line patrol is usually carried out while walking, riding or flying a line to look for obvious right-of-way or pole-line condition problems. Line patrol does not usually involve a detailed pole-by-pole inspection to find loose hardware, cracked insulators, etc. While a detailed line inspection program would be the ideal, it generally proves too slow and costly to allow for regular, economical maintenance and upkeep of the distribution system. However, the use of radio frequency interference (RFI) and/or infra-red detection equipment during line patrol may detect conditions such as loose connectors and cracked insulators that may otherwise be missed.

Voltage Drop

One of the classic problems associated with small conductors used with older lines is excessive voltage drop. All distribution systems should have their engineer regularly perform a distribution voltage drop study (usually done as part of a construction work plan) to insure that parts of the system are not experiencing excessive voltage drop. The results of the voltage drop study will identify overloaded conductors and areas with low voltage that may require reconductoring or the addition of voltage regulators.

Distribution System Model Discrepancies

In order to effectively perform a distribution voltage drop study, the system model must be reasonably accurate. Older low-growth systems often find that errors have crept into their models over the years, such as:

- Line sections are of wrong length.
- Mixed conductor spans are entered into the database as the largest conductor (i.e., 1 #6, 1 #8, 1 #4, with an 8A neutral is listed in the model as 3-phase, 4 CU).
- Regulators and capacitors are missing or listed in wrong locations.

Process for Formulating an Engineering Solution

1. Quantify the problem by making a list of all known system deficiencies in the slow-growth areas.
2. Quantify the number of consumers that would be affected by an outage on a particular section of line.
3. Estimate costs to repair/replace each item based on current costs.
4. Prioritize the list of problem areas based upon one or more of the following subjective criteria using good engineering judgment:
   (a) Cost/benefit ratio
   (b) Outage reduction
   (c) Improved losses
   (d) Reduced liability
   (e) Improved operational flexibility
   (f) Improved safety
   (g) Fewer consumers affected by an outage
5. Examine the current work plan in the following areas:
   (a) Quantify proposed investment in slow-growth areas.
   (b) Review RUS Form 7 (year-end) of completed work orders and determine how much investment in slow-growth areas was added to plant over last year.
   (c) Compare these two numbers to determine the extent of the problem. If the work order amount spent in low-growth areas last year is relatively low compared to the proposed improvements in that area, then the capital budget will have to be substantially increased to pay for the needed improvements.
6. Determine the number of poles and amount of line that needs to be replaced.
   (a) Approximately 20 poles/mile × miles of line = number of poles on the system.
   (b) Review CPR records of poles. How do they compare?
   (c) Estimate the average age of the poles on the system. It is best if the average age can be broken down by substation area.
   (d) How many were inspected and treated with a ground line treatment, if needed?
   (e) How many years will it take to completely inspect the system at last year's inspection rate, and is that time frame acceptable considering the average decay rate in the region. How many poles were replaced last year?
   (f) Determine cost/benefit or payback period on treating poles.
   (g) A plan should be put into place to have poles replaced by the end of a reasonable life expectancy.

(h) Quantify how many miles of copper/copper-clad line are still in service. Check the CPR records, the engineering model, and the system maps. Most copper lines are *at least* 50 years old.

(i) It is good practice to remove all steel lines as soon as practicable.

(j) Is there a current plan to replace copper/copper-clad line? Copper replacement programs should be budgeted and approved in a construction work plan.

(k) It is usually most practical to replace portions of the copper lines each year according to a prioritized list. It is recommended that systems replace all small 1-phase or V-phase copper distribution lines within the next 10 years or less, depending upon their condition and the outage experience on the specific line.

Balancing Capital Needs

1. Examine the current construction work plan to see what percentage of the total dollars in the work plan is budgeted for replacing aging plant (usually classified in the work plan as ordinary replacement).
2. After quantifying the extent of the aging problem, determine the timeframe in which remedies have to be made and, therefore, how much capital needs to be budgeted to ordinary replacement on a yearly basis.
3. Compare new investment dollars per consumer in the various areas of the system or by substation.
4. Depending upon the age and condition of the system, 10 percent to 30 percent of the total annual work plan budget may be earmarked for aging plant problems. Experience has shown that older, low-growth, high-equity systems are often not in very good condition either physically or electrically.
5. An electric utility business requires continuing capital investment supported by carefully managed depreciation and capital addition programs. Judicious use of borrowed funds for physical plant that will last at least 35 years is a prudent financial practice.

Summary

The cooperative should:

1. Develop a detailed list of all known system operation and maintenance problems. All systems are not the same, and the problems will vary according to terrain, climate, and electrical load patterns.
2. Quantify the remedies in dollars, man-hours, capital expenses, etc.
3. Prioritize the remedies based upon the criteria outlined above.
4. Budget funds for the highest priority items.
5. Construct the facilities as planned through construction work plans.
6. Update the aging plant area list, and re-prioritize and re-budget yearly or during work plan cycles.
7. Follow through with the plan, and complete the needed replacement. Failure to address these issues in a timely manner is likely to have grave financial consequences.

APPENDIX 4
DISTRIBUTED GENERATION IN LONG-RANGE PLANNING

1 BACKGROUND

In 1936, when the Rural Electrification Administration was created by the U.S. Congress, Distributed Generation (DG) was not even on the radar screen. In fact, for most rural areas, electricity was only a wish and a hope for the future. Of approximately 6.3 million farms at that time, only about 205,000 were receiving centralized electric service. By the early 1970s, about 98% of all farms in the United States had electric service—quite a success story for the REA program. Where there is vision and economic technology, lives change for the better. Such is thought of DG. Technology is changing very fast in this area and DG is expected to have significant impacts on electric power distribution.

Since technology, operating standards, and economics are not quite ready for broad applications of DG systems, why then include such a topic in a Long-Range Planning Guide? It has been included to challenge electric distribution planners for what is to come and for them to acknowledge that the technology and economics are there for some applications today.

With the high costs of large generating plants, transmission lines, substations, and distribution lines, we all need to be looking for alternative methods to providing electric power to our customers in the most economical method available. DG may fit that situation in some circumstances even today and the planning engineer needs to consider all resources that are available.

There are several different types and applications of distributed generation and they are listed as follows:

- Large-Scale,
- Medium-Scale,
- Small-Scale, and
- Residential/Commercial Solar PV.

Each category is summarized below to aid the system planner in identifying how and when DG could be applied.

2 LARGE-SCALE (500 kW–10 MW) DG (*Industrial*)

In general, application of large-scale DG systems will require some level of detailed engineering. These relatively large distributed generators will likely have a significant impact on long-range planning, particularly the larger applications. Many large-scale distributed generation applications have been implemented over the last several years, and many were cost-justified through the application of rate incentives, such as peak shaving, reserve or dispatchable capacity, and real-time or market-based pricing.

Recent, significant increases in fuel costs have brought into question the economic feasibility of many of these generators as long-range solutions. Volatility in both natural gas and diesel fuels, common fuels for this scale DG, has significantly reduced the cost-effectiveness of these applications. However, there are still significant potential savings with this size DG project in certain applications, particularly where load growth or short-term peak loading conditions require significant capital investments. Additionally, overall reliability of a feeder or transmission segment can be improved, when normally served by a radial source, if the generator is located near the load. Other considerations —such as tariffs, rate restrictions, all-requirement contracts, fuel costs, environmental impact, and O&M requirements—should also factor into the decision-making process. Generators of this size should at least be considered in some of these special cases as alternatives to capital-intensive projects, particularly reliability-based ones.

Similar considerations will have to be given to the ever-popular renewable resources, particularly wind power. Wind farms will likely be the quickest large DG applications to impact system planners. Today, most wind farms are larger than 10 MW; however, as popularity rises and costs decrease, there will be increased pressure to move to small wind farm applications. The biggest design factor of this size system will be its "back-feed" capability. In renewable-rich areas, and with proper incentives, there is the distinct possibility that these renewable sources may exceed local demand. In this case, the system planner must also consider line and equipment capacities and ability to manage bi-directional load flow on a day-to-day or hour-to-hour basis.

From strictly a planning perspective, the system planner will have to seriously consider the availability and predictability of renewable DG energy sources. Although renewable resources—such as wind and solar—are great at off-setting energy produced by burning fossil fuels, the variability in the "fuel" availability will be a challenge, particularly the farther out on the distribution system these medium DG sources are located. It is very likely that renewable resources can only be used to off-set or delay capacity improvements when they are combined with near real-time smart grid applications, such as load shedding.

3 MEDIUM-SCALE (50 kW–500 kW) DG (*Commercial*)

This DG size is probably the most commonly available engine-generator set today. They are quite common in many commercial and some industrial applications. Industries highly dependent on electrical power, and often required by law or economics to have generator backup, make up a considerable aggregated DG capacity base. Hospitals, prisons, fire protection, casinos, and even hotels often have full or near-full capacity generation on-site. In the late 1990s, there was a significant effort by the industry to utilize this unused capacity. Although there are successful projects utilizing medium-scale DG, deployment has not reached projections because of several hurdles, including the following:

- Limited rate support;
- Increasing fuel costs;
- Limited G&T price signaling;
- Limited communications and system control functions between the DG owner and the utility for large-scale assimilation with the distribution system;
- Equipment costs, especially for paralleling switchgear;
- Service interruption on lower cost, break-before-make transition switchgear; and
- Operation and Maintenance cost and expertise.

As in large-scale systems, medium-scale DG may be able to delay capital-intensive improvements, but more likely on a distribution system level, provided that the DG source is very reliable. If a DG system is going to be included as a solution for a distribution system limitation, the system planner may need to require that the DG be directly assigned to interruptible loads. Otherwise, system performance may fall outside of acceptable ranges.

Application of medium-sized renewable DG sources will likely lag behind large-scale DG sources by a few years. However, if economies of scale apply to the manufacturing of renewable products, then medium-sized applications will become more commonplace. In renewable-rich areas, the aggregate of medium-sized DG projects on a feeder, in effect, may become similar to a large-scale DG source. In this case, many of the large-scale DG issues apply. If only one or two medium-sized renewable DG sources are located along a distribution feeder, then the traditional DG considerations above will apply, with one likely caveat. Most renewable DG applications require grid power for excitation of the generator, and they will most likely require parallel operation. Parallel operations with the grid—even in medium-scale applications—creates a host of new design considerations, particularly with respect to bi-directional load flow, voltage regulation, and sectionalizing.

4 SMALL-SCALE (1 kW–50 kW) DG (*Residential*)

Small-scale DG is currently very limited. Most DG of this size will be either residential or small commercial applications. In general, these applications operate more as a load off-set or reduction rather than as a generation source. Renewable energy applications such as solar are the most likely candidates in this category. To date, there has been more debate than deployment on these DGs, although popularity continues to rise. Most current solar applications interface via an inverter, which monitors the distribution system for outages and turns off in the event of a grid outage.

With the adoption of IEEE and UL standards, there is less and less operational and sectionalizing concern over these small DG applications, although the debate is not over. It will take a significant penetration of these DG applications to have a significant impact from a system-planning perspective. If anything, there will be more of a financial impact from small-scale DG applications since they are effectively reducing load. As with other recently set goals—such as energy efficiency and inclining block rates—small-scale DG

will have more of an impact on the load projection aspect of system planning. Again, the biggest factor of concern is the predictability of the impact of the small DG or other load-reducing smart grid application.

As an example, an area may exist on a feeder where solar panels are installed on all new houses. On a normal, warm, sunny day, solar panels would likely offset a considerable amount of air conditioning load. However, an event as simple as a cloudy weather front moving through would immediately reduce solar output, producing an aggregate affect equivalent to cold-load pickup since there would be considerable lag in the thermal response of the homes cooling down from the cloud cover. Given that battery storage is considerably more expensive and maintenance intensive, it is less likely that energy storage will be implemented with early residential inverter systems.

Again, the system designer must take into consideration the impact of even small DG effects on the distribution system when they are adopted on a large scale. Incentive programs pushed by federal mandates may accelerate the deployment of such systems. Federal mandates such as renewable portfolio standards appear to have little to do with economics and may, in fact, impact even distribution planning sooner than expected.

5 RESIDENTIAL AND COMMERCIAL SOLAR GENERATION

One of the greatest potentials for distribution system and power supply is the development of small solar generators less than one megawatt in size. In most of the United States, there is very good availability of solar energy during peak summer times. Extensive addition of solar generators by residential and commercial consumers would reduce the requirement for new large generator construction, as well as reduce major improvements on distribution systems (e.g., major three-phase circuit rebuilds, substation upratings, etc.). Currently, power suppliers are realizing such potential and are developing generation purchasing policies that will pay solar generator installers from 12 to 20 cents per kilowatt-hour with contracts lasting up to ten years. As more and more power suppliers realize this potential, the addition of solar generators will greatly impact distribution system planning and will need to be considered when evaluating future capital requirements for long-term electric system needs.

The key to the situation is the quality, reliability, and costs of the equipment being manufactured. If quality and reliability can be assured by industry and governmental long-term warranties, and if costs continue to decline as the demand for such generation occurs, the solar generation option will play a very important role in future planning of electric distribution systems.

6 CONCLUSION

As technology expands and economics drives the market, DG is sure to have an impact on electric power distribution in the very near future. As constraints continue in the

building of more large generating plants, transmission lines, substations, and distribution lines, DG is sure to become more and more economical.

Power suppliers and distribution cooperatives are encouraged to work closely together to develop policies that will encourage this renewable resource, one which will contribute significantly to the reduction of capital funds to increase system capacity as the demand for electric energy grows.

APPENDIX 5
BIBLIOGRAPHY AND REFERENCES

1 RURAL UTILITIES SERVICE DOCUMENTS

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1724D-101B "System Planning Guide: Construction Work Plans," 10/31/2000

1724D-103 "System Planning Guide: System Mapping," 4/12/2011

1724D-104 "Engineering Economics Computer Workbook Procedure," 2/3/1998

1724D-105 "Rural Distribution System Conversion Considerations," 5/22/2009

1724E-202 "An Overview of Transmission Line Studies," 2/10/1993

1724E-203 "Guide for Upgrading Transmission Lines," 12/28/1994

1724E-300 "Design Guide for Rural Substations," 6/7/2001

1730-1 "Electric System Operation and Maintenance," 4/12/2011

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RUS Bulletin 45-4 "Distribution System Energy Losses," 4/28/1975 (Expired)

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2 REFERENCES

CRN Report 00-31 "Guide to When to Replace Distribution Line Conductors," 2000

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"Engineering Economy," Thuesen, Fabruycky, and Thuesen, Latest Edition, Prentice-Hall, Inc.

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"Electric Distribution Manual," R. A. Dewberry, Raytheon Engineers and Constructors, Ebasco Division, Electric Power Systems, 1985, Electric World/McGraw-Hill Publications Company

"Overhead Conductor Manual," Southwire Company, Carrollton, Georgia, 1994

EXHIBIT MEC-105

RESERVED

MPSC Case No: U-21534

Requester: MNSC

Question No.: MNSCDE-17.7

Respondent: S. Deol

Page: 1 of 2

Question: 7. Refer to Exhibits A-50, Schedule OO1 and A-50, Schedule OO2. Explain in detail what the values in each column of these two exhibits represent and how each was determined.

Answer: Please see the definitions below for each heading in Exhibit A-50, Schedule OO2 (NDA CEII Discovery Response MNSCDE-5.5a(S1) – Subtransmission Load Data).

Thermal Violations (Pages 1 & 2 of Exh. A-50, Sch. OO2)

Year Analysis Completed: The year DTE Electric performed the loading analysis on the Subtransmission system

Forecast Year: The year of the forecasted system loads used for the analysis

Tie or Trunk: The subtransmission circuit number, tie line or trunkline

Normal Rating (N-0) (MVA): The circuit's normal rating in MVA (Mega-volt amperes) under system normal conditions (no contingency) during the peak loading season.

Emergency Rating (N-1) (MVA): The circuit's emergency rating in MVA (Mega-volt amperes) under a single contingency condition during the peak loading season.

Normal Flow (N-0) (MVA): The load flow on the circuit in MVA (Mega-volt amperes) under system normal conditions (no contingency) during the peak loading season.

Emergency Flow (N-1) (MVA): The load flow on the circuit in MVA (Mega-volt amperes) under a single contingency condition during the peak loading season.

%Loading N-0 violation: The percent of normal flow divided by the normal rating

%Loading N-1 violation: The percent of emergency flow divided by the emergency rating

Voltage Violations (Pages 3 & 4 of Exh. A-50, Sch. OO2)

U-21534 | Question: MNSCDE-17.7
MNSC Hearing Exhibits
Ex MEC-106 | Source: MNSCDE-17.7
Page 2 of 2

Year Analysis Completed: The year DTE Electric performed the loading analysis on the Subtransmission system
Forecast Year: The year of the forecasted system loads used for the analysis
Tie, Trunk, or Station: The subtransmission circuit number (tie line or trunkline) or Subtransmission station
N-1 Min Volt Limit (% of nominal voltage): The allowable low voltage limit for Subtransmission voltage under a single contingency condition (N-1)
N-1 Max Volt Limit (% of nominal voltage): The allowable high limit for Subtransmission voltage under a single contingency condition (N-1)
N-1 Volt (% of nominal voltage): The low voltage violation resulting on the Subtransmission tie line trunk line or station resulting from a single contingency occurring during peak system loads.

Attachment: None.

MPSC Case No: U-21534

Requester: MNSC

Question No.: MNSCDE-8.5c (S1)

Respondent: J. Kryscynski

Page: 1 of 4

Question: 5. Refer to Mr. Kryscynski's testimony at page 56, which states "The engineering team evaluates alternatives to meet the system needs and selects the best project or program to move forward. If necessary, a BCA takes place as part of the engineering process to select the best option. The solution which is selected to move forward is scored in the GPM for prioritization." Refer also to NDA U-21534 MNSCDE-1.8a GPM CONFIDENTIAL, which provides GPM scores for 138 different projects in tab "GPM Results".

c. Provide the approved capital project authorizations on every one of these 138 projects with an expected total capital cost exceeding $10 million. Include all supporting documentation presented to management with each capital project authorization.

Answer: Duplicative capital authorizations were requested in MNSCDE-8.5c, MNSCDE-8.6, MNSCDE-8.9d, MNSCDE-8.14a, MNSCDE-8.15a, MNSCDE-8.16a, MNSCDE-8.17a, MNSCDE-8.18a, MNSCDE-8.19a, MNSCDE-8.20a, MNSCDE-8.21a, MNSCDE-8.22b, MNSCDE-9.3b, MNSCDE-12.2j, MNSCDE-12.11, and MNSCDE-12.12. To the extent available, the requested authorizations are attached.

The Distribution Grid Plans (DGP), filed with the Commission, include a 5-year investment plan which constitutes the initial capital investment plan that is reviewed and approved by management. For the 2023 DGP which includes the 5-year investments for capital projects and programs, please see Exhibit A-23 Schedule M8.

The DGP 5-year investment plan is a key input to the annual management review. For 2023 capital investments, the 2021 DGP was the supportive grid planning reference. For 2024 to 2027 investments, the 2023 DGP is the grid planning reference. Below is an example from section 11 of the 2023 DGP, showing planned future investments that were reviewed by management.

MPSC Case No: U-21534

Requester: MNSC

Question No.: MNSCDE-8.5c (S1)

Respondent: J. Kryscynski

Page: 2 of 4

Programs	$ Millions					
	2024	2025	2026	2027	2028	5-Year Total
Infrastructure Resilience & Hardening						
Pole and Pole Top Maintenance and Modernization	$121	$121	$151	$192	$188	$773

The Company considers this annual management review, which includes the President of DTE Electric and which subsequently leads to the request contained in the rate case, to be the authorization for projects under $10 million and for programs that are composed of many individual projects that are below that threshold (e.g. PTMM, 4.8kV Hardening).

Supporting this discovery request, in addition to the 2023 DGP and the rate case budget submitted in Exhibit A-12, Schedule B5.4, the Company is providing two types of capital project authorizations, depending on whether they are authorizations for projects above $10MM, such as a converison, or for programs, such as PTMM.

First, in addition to the management reviews and approvals as noted, individual projects greater than $10 million require specific management approval and must be authorized by a Capital Appropriations Request Form (CARF). Approved CARFs for projects associated with projects in tab “GPM Results” have been collected and attached. Some large projects in the engineering and design phase may not have yet reached the threshold to require a CARF.

Second, capital programs (e.g., PTMM) and projects smaller than $10MM that are authorized during the annual management review process receive futher confirmed immediatley prior to the year in which they are to be executed. The relavant forms for 2022, 2023, and 2024 are attached.

Attachment: U-21534 MNSCDE-8.5c(S1)-01 2022 Budget Appropriation
U-21534 MNSCDE-8.5c(S1)-02 2023 Budget Appropriation

MPSC Case No: U-21534

Requester: MNSC

Question No.: MNSCDE-8.5c (S1)

Respondent: J. Kryscynski

Page: 3 of 4

U-21534 MNSCDE-8.5c(S1)-03 2024 Budget Appropriation
U-21534 MNSCDE-8.5c(S1)-04 4.8 kV CC Almont Relief and Circuit Conversion (Midas)
U-21534 MNSCDE-8.5c(S1)-05 4.8 kV CC Ariel Substation and Circuit Conversion
U-21534 MNSCDE-8.5c(S1)-06 4.8 kV CC Buckler Circuit Conversion
U-21534 MNSCDE-8.5c(S1)-07 4.8 kV CC Cortland - Oakman - Linwood Consolidation
U-21534 MNSCDE-8.5c(S1)-08 4.8 kV CC Cortland - Oakman - Linwood Consolidation

U-21534 MNSCDE-8.5c(S1)-09 4.8 kV CC GRFIN & WMSTN Conversions
U-21534 MNSCDE-8.5c(S1)-10 4.8 kV CC Hilton Substation and Circuit Conversion
U-21534 MNSCDE-8.5c(S1)-11 4.8 kV CC I-94 Substation and Circuit Conversion (Promenade) - Below Grade
U-21534 MNSCDE-8.5c(S1)-12 4.8 kV CC Pinegrove Substation Relocation and Conversion
U-21534 MNSCDE-8.5c(S1)-13 4.8 kV CC Pinegrove Substation Relocation and Conversion
U-21534 MNSCDE-8.5c(S1)-14 4.8 kV CC Zenon Substation and Circuit Conversion
U-21534 MNSCDE-8.5c(S1)-15 4.8 kV CC Zenon Substation and Circuit Conversion
U-21534 MNSCDE-8.5c(S1)-16 8.3 kV CC Pontiac Overhead Conversion
U-21534 MNSCDE-8.5c(S1)-17 ADMS DMS-OMS
U-21534 MNSCDE-8.5c(S1)-18 ADMS DMS-OMS
U-21534 MNSCDE-8.5c(S1)-19 Ann Arbor System Improvements
U-21534 MNSCDE-8.5c(S1)-20 Ann Arbor System Improvements
U-21534 MNSCDE-8.5c(S1)-21 Buffalo-Charles OH to UG pilot
U-21534 MNSCDE-8.5c(S1)-22 CODI Alfred Substation Expansion
U-21534 MNSCDE-8.5c(S1)-23 CODI CATO Substation Expansion
U-21534 MNSCDE-8.5c(S1)-24 CODI Charlotte Network Upgrade
U-21534 MNSCDE-8.5c(S1)-25 CODI Charlotte Network Upgrade
U-21534 MNSCDE-8.5c(S1)-26 CODI Corktown Substation

MPSC Case No: U-21534

Requester: MNSC

Question No.: MNSCDE-8.5c (S1)

Respondent: J. Kryscynski

Page: 4 of 4

U-21534 MNSCDE-8.5c(S1)-27 CODI Garfield Network Upgrade
U-21534 MNSCDE-8.5c(S1)-28 CODI Garfield Network Upgrade
U-21534 MNSCDE-8.5c(S1)-29 CODI Garfield Radial (Midtown Circuits)
U-21534 MNSCDE-8.5c(S1)-30 CODI Garfield Radial (Midtown Circuits)
U-21534 MNSCDE-8.5c(S1)-31 CODI Howard Conversion
U-21534 MNSCDE-8.5c(S1)-32 CODI Howard Conversion
U-21534 MNSCDE-8.5c(S1)-33 CODI Islandview Substation - Phase 1
U-21534 MNSCDE-8.5c(S1)-34 CODI Islandview Substation - Phase 2
U-21534 MNSCDE-8.5c(S1)-35 CODI Islandview Substation - Phase 2
U-21534 MNSCDE-8.5c(S1)-36 CODI Kent-Gibson Conversion - Phase 1
U-21534 MNSCDE-8.5c(S1)-37 CODI Kent-Gibson Conversion - Phase 1
U-21534 MNSCDE-8.5c(S1)-38 CODI Midtown Substation Expansion
U-21534 MNSCDE-8.5c(S1)-39 Station Upgrade Northeast (Relay Replacement)
U-21534 MNSCDE-8.5c(S1)-40 Station Upgrade Warren (Relay Replacement)
U-21534 MNSCDE-8.5c(S1)-41 Substation Risk Apache
U-21534 MNSCDE-8.5c(S1)-42 Substation Risk Apache
U-21534 MNSCDE-8.5c(S1)-43 Substation Risk Chestnut
U-21534 MNSCDE-8.5c(S1)-44 Substation Risk Chestnut
U-21534 MNSCDE-8.5c(S1)-45 Substation Risk McGraw
U-21534 MNSCDE-8.5c(S1)-46 Subtransmission Redesign & Rebuild Boyne
U-21534 MNSCDE-8.5c(S1)-47 Subtransmission Redesign & Rebuild Tie 4105 Phase 1
U-21534 MNSCDE-8.5c(S1)-48 Subtransmission Redesign & Rebuild Tie 4105 Phase 3
U-21534 MNSCDE-8.5c(S1)-49 Subtransmission Redesign & Rebuild Tie 4105 Phase 3
U-21534 MNSCDE-8.5c(S1)-50 Subtransmission Redesign & Rebuild Tie 810
U-21534 MNSCDE-8.5c(S1)-51 Subtransmission Redesign & Rebuild Tie 810
U-21534 MNSCDE-8.5c(S1)-52 Subtransmission Redesign & Rebuild Trunk 2308
U-21534 MNSCDE-8.5c(S1)-53 Subtransmission Redesign & Rebuild Trunk 4911
U-21534 MNSCDE-8.5c(S1)-54 System Loading Richmond-Armada
U-21534 MNSCDE-8.5c(S1)-55 System Loading Richmond-Armada
U-21534 MNSCDE-8.5c(S1)-56 Clerical Corrections

DTE Energy

Appropriation Request

Summary Sheet

Project Name:	**RELI0368-01 Islandview Substation and Conduit Exits**	Capital Budget / Project #:	**I-000829-0001-0099**
Utility/Non-Utility:	**Utility**	Project Type:	**Infrastructure Redesign**
Business Segment:	**Electric Utility**	Business unit within budget?:	**Yes**
Business Unit:	**Distribution Operations**	Project Start Date:	**11/2020**
Project Sponsor:	**Sharon Pfeuffer / Heather Rivard**	In-Service Date:	**12/2023**
		Post Investment Evaluation Date:	**5/24/2025**

Current Approval Request ($Millions):	**$32.3**
Previous Request(s) ($Millions):	**$0.0**
Total Project ($Millions):	**$32.3**

Financial Summary ($Millions)

	Prior Years	2021	2022	2023	2024	2025	Beyond	Total
Current Capital Approval Request	$0.1	$1.3	$30.0	$0.8	$0.0	$0.0	$0.0	**$32.3**
Previous Request(s)	-	-	-	-	-	-	-	**$0.0**
Total Project Request	0.1	1.3	30.0	0.8	-	-	-	**$32.3**
Operating After-Tax Cash Flow	(134)	(1,245)	(28,036)	2,303	3,014	2,907	50,006	**28,815**
Net Income	3	39	789	1,495	1,452	1,392	18,397	**23,567**

Hurdle Rate	IRR	NPV	Payback(years)	First 5 Yrs Avg. Net Income	Customer cost (savings)*
6.1%	**6.1%**	**$394.8**	**15**	**$ 756**	**$41,374**

Project Description and Approval

The Islandview Initiative is part of the City of Detroit Infrastructure (CODI) plan, which was implemented to align strategies between serving new load demand and addressing aging infrastructure. The Islandview Initiative converts and consolidates thirty-three 4.8kV circuits into eight 13.2kV circuits fed from a new 120-13.2kV Class 'A' substation. The Initiative includes 7 distinct, independent projects executed over the next ten years.

The scope for this project includes building a 120-13.2kV Class 'A' substation along with conduit exits and manholes surrounding the site.

Major Risk and Risk Mitigants

Existing energized lines, ITC/DTE coordination during design phase and construction. Long lead material delays

Approval Level (per FC20)	Finance Committee	Required yes	Required no
Business Unit President		**yes**	
Corporate Staff Review		**yes**	
Chris Allen	6/23/2021		
Corporate Development *	**Date**	**yes**	
DTE Controller Review	**Date**		**no**
Growth & Value Creation Committee Review		**yes**	
Chief Financial Officer		**yes**	
Chief Operating Officer		**yes**	
Chief Executive Officer			**no**
Finance Committee			**no**
Board of Directors			**no**

Final Approval Signatures

Heather Rivard	6/22/2021
Project Sponsor	**Date**
Trevor Lauer	**6/23/2021**
Business Unit President	**Date**
David Ruud	6/29/2021
Chief Financial Officer	**Date**
Jerry Norcia	6/28/2021
Chief Executive Officer / Chief Operating Officer	**Date**

* Corporate Development indicates that Corporate Staff Review is complete. See page 2 for any comments from Corporate Staff

DTE Energy

Appropriation Request
Corporate Staff Review

Project Name:	**RELI0368-01 Islandview Substation and Conduit Exits**	Capital Budget / Project #:	**I-000829-0001-0099**
Executive Sponsor:	**Sharon Pfeuffer / Heather Rivard**		

Corporate Staff Review				**Comments and Issues**
Chad Detrich **Corporate Finance and Development**	6/15/2021 **Date**	X **Support**	 **Do Not Support**	
Case Lancaster **Business Unit Controllers**	6/21/2021 **Date**	X **Support**	 **Do Not Support**	
Jill Farris **Corporate Accounting**	6/15/2021 **Date**	x **Support**	 **Do Not Support**	
John Miller **Corporate Tax**	6/17/2021 **Date**	X **Support**	 **Do Not Support**	
Todd Baker **Environmental**	6/14/2021 **Date**	X **Support**	 **Do Not Support**	
Matthew Misiak **Legal**	6/17/2021 **Date**	X **Support**	 **Do Not Support**	
Lori Taylor-Wallace **Purchasing**	6/15/2021 **Date**	X **Support**	 **Do Not Support**	
Habeeb Maroun **Regulatory Affairs**	16-Jun **Date**	X **Support**	 **Do Not Support**	Most Recent Regulatory Capital Info by Year *To be completed by project team 2020 2021 2022 2023 Beyond $- $- $- $- $- Team should be prepared to support timing of actual 2020 – 2021 spend of $1.4M versus $500k projected capital in U-20561. $6.0M risk-based capital at risk of delay in recovery until money is spent and prudency demonstrated in the subsequent case.
Mark Johnson **Risk Management**	21-Jun-21 **Date**	X **Support**	 **Do Not Support**	
Roger Olson **Corporate Insurance**	6/21/2021 **Date**	X **Support**	 **Do Not Support**	

Islandview Distribution Circuits

WHEREAS, the officers of this Company and DTE Electric Company (DTE Electric) have advised that upgrading the electric infrastructure in the Islandview area with new equipment and a new substation (Project) will improve reliability, reduce wire downs and provide a modernized electric distribution system to area customers, all as detailed in the attached Exhibit A; and

WHEREAS, the officers of this Company and DTE Electric are requesting approval to invest up to $87.2 million to execute the Project, as detailed in Exhibit A.

NOW, THEREFORE, BE IT

RESOLVED, that the Company's capital expenditures for the Project be, and hereby are, approved up to a total amount not exceeding $87.2 million, as detailed in Exhibit A; and further

RESOLVED, that the Chairman, President and Chief Executive Officer of this Company and the President and Chief Operating Officer-DTE Electric (Named Officers) be, and each hereby is, authorized to cause DTE Electric to expend up to $87.2 million to execute the Project; and further

RESOLVED, that the Named Officers be, and each hereby is, authorized to do all acts and deeds and execute and deliver all such documents as any one of each such Named Officers deems necessary, advisable or appropriate to carry into effect the purpose and intent of these resolutions; and further

RESOLVED, that the Vice President, Corporate Secretary and Chief of Staff is hereby requested and directed to file a copy of these resolutions, including Exhibit A hereto, in the Company's corporate minute book.

DTE Energy

Appropriation Request
Summary Sheet

Project Name:	RELI0368-02 Island View IVIEW Circuit DC9645	Capital Budget / Project #:	I-000829-0001-0103
Utility/Non-Utility:	Utility	Project Type:	Infrastructure Redesign
Business Segment:	Electric Utility	Business unit within budget?:	Yes
Business Unit:	Distribution Operations	Project Start Date:	1/1/2022
Project Sponsor:	Sharon G. Pfeuffer, Ryan Stowe/ Matthew T. Paul	In-Service Date:	12/31/2024
		Post Investment Evaluation Date:	12/21/2026

Current Approval Request ($000s):	$87.2
Previous Request(s) ($000s):	$0
Total Project ($000s):	$87.2

Financial Summary ($000s)

	Prior Years	2022	2023	2024	2025	2026	Beyond	Total
Current Capital Approval Request	$0	$4.1	$45.5	$37.6	$0	$0	$0	**$87.2**
Previous Request(s)	0	$0	$0	$0	$0	$0	$0	**$0**
Total Project Request	0	$4.1	$45.5	$37.6	$0	$0	$0	**$87.2**
Operating After-Tax Cash Flow	(29)	(3,837)	(42,145)	(30,065)	8,670	8,324	127,888	**$ 68,806**
Net Income	1	99	1,279	3,202	3,948	3,761	43,981	**$ 56,271**

Hurdle Rate	IRR	NPV	Payback(years)	First 5 Yrs Avg. Net Income	Customer cost (savings)*
6.1%	6.1%	$1,027	14	$ 1,706	$108,284

Project Description and Approval

Convert existing 4.8kV infrastructure such that Walker and Pulford loads can be absorbed and decommission aging assets. This work is being driven by increased commercial/ industrial load along the downtown riverfront area, future PLD conversions, and limitations of throwover between Walker and Pulford. The scope of work is convert portions of 16 existing WALKR/PULF 4.8kV circuits to 2-13.2kV circuits fed from IVIEW substation. DC9645 - 22.8 miles of OH conductor, 5,475 ft. UG cable, 137 ft. UG conduit, 4 primary service customers. DC9682 - 9.3 miles of OH conductor, 12,627 ft. UG cable, 205 ft. UG conduit, and 7 primary service customers.

Major Risk and Risk Mitigants

An analysis was performed on the estimate for the project consistent with DTE Energy Risk Management Guidelines. The risk model indicates that $13.4M risk-based capital in additional to the $67M base cost estimate results in a 95% probability of achievement. Reference Monte Carlo analysis for further details.

Approval Level (per FC20) Finance Committee

	Date	Required yes	Required no
Business Unit President		yes	
Corporate Staff Review		yes	
Timothy Lepczyk	11/7/2022		
Corporate Development *	**Date**	yes	
DTE Controller Review	**Date**		no
Growth & Value Creation Committee Review		yes	
Chief Financial Officer		yes	
Chief Operating Officer		yes	
Chief Executive Officer		yes	
Finance Committee		yes	
Board of Directors			no

Final Approval Signatures

Matthew Paul	11/2/2022
Project Sponsor	**Date**
Trevor Lauer	**11/2/2022**
Business Unit President	**Date**
David Ruud	12/5/2022
Chief Financial Officer	**Date**
Jerry Norcia	12/8/2022
Chief Executive Officer / Chief Operating Officer	**Date**

* Corporate Development indicates that Corporate Staff Review is complete. See page 2 for any comments from Corporate Staff

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DTE Energy

Appropriation Request
Corporate Staff Review

Project Name:	RELI0368-02 Island View IVIEW Circuit DC9645	Capital Budget / Project #:	I-000829-0001-0103
Executive Sponsor:	Sharon G. Pfeuffer, Ryan Stowe/ Matthew T. Paul		

Corporate Staff Review	Date	Support	Do Not Support	Comments and Issues
Chad Detrich **Corporate Finance and Development**	10/31/2022	X		
Case Lancaster **Business Unit Controllers**	11/1/2022	X		
Matt Przybysz **Corporate Accounting**	10/27/2022	X		
John Miller **Corporate Tax**	10/31/2022	X		
Amanda Kosch **Environmental**	11/1/2022	X		An environmental change checklist will need to be completed and an associated action plan created and maintained for this project. Permitting will likely be required. Environmental will need to be involved with decommissioning of assets.
Matthew Misiak **Legal**	10/31/2022	X		
Lori Wallace **Purchasing**	10/26.2022	X		
Habeeb Maroun **Regulatory Affairs**	10/26/2022	X		Most Recent Regulatory Capital Info by Year *To be completed by project team 2022 2023 2024 2025 2.9 14.5 24.3 25.6 To ensure full cost recovery, project team should be prepared to demonstrate prudency of incremental project spend in the next electric rate case. If any contingency is included in the next case, there is a risk of delay in recovery until the funds are spent and prudency demonstrated in the subsequent case.
Jonathan Schmidt **IT Cybersecurity**	11/7/2022	X		*Note if the project is an acquisition, physical security must also approve
Daniel Northey **Risk Management**	11/1/2022	X		ERM has evaluated this project and noted no risk category above a rating of low
Mick Darin **Corporate Insurance**	10/27/2022	X		

MPSC Case No: U-21534

Requester: MNSC

Question No.: MNSCDE-15.33a

Respondent: S. Deol

Page: 1 of 1

Question: 33. Refer to the Company's response to MNSCDE-8.12a, which provides lists of 4.8kV circuits that will be converted to 13.2kV due to the construction of two new substations.

a. Provide an estimate of the costs remaining to convert the 4.8kV circuits listed.

Answer: Please see Exhibit A-23 Schedule M6 for the Islandview and Midas projects for an estimate of the remaining cost to convert the 4.8kV circuits. The new 13.2kV substations were completed in 2023. The majority of the work remaining on these projects is circuit conversions.

Attachment: *None*

MPSC Case No: U-21534

Requester: MNSC

Question No.: MNSCDE-15.33b

Respondent: S. Deol

Page: 1 of 1

Question: 33. Refer to the Company's response to MNSCDE-8.12a, which provides lists of 4.8kV circuits that will be converted to 13.2kV due to the construction of two new substations.

b. Provide a schedule of the timing of the conversion of the 4.8kV circuits listed.

Answer: For approximate construction schedules please see Exhibit A-23 Schedule M6 for the Islandview and Midas projects.

Attachment: *None*

MPSC Case No: U-21534

Requester: MNSC

Question No.: MNSCDE-8.12a

Respondent: S. Deol

Page: 1 of 1

Question: 12. Refer to the Company's response to MNSCDE 3.4(b), which states "Conversion projects sequence portions of 4.8kV circuits until the full circuit is converted. Taking this approach the Company has completed 13.7 miles of conversion in 2023." Refer also to Mr. Deol's testimony at 14:13 to 14:25 which describes four types of work completed on 13.2kV substations and on 4kV circuits to be completed in advance of actual 4.kV conversion to 13.2 kV operations.

a. Provide a list of 13.2 kV substations for which 4.8kV conversion work has been completed since the last rate case. Provide the amounts spent on this work, and placed into service, since the last rate case, by 13.2kV substation. Please also provide, for each such 13.2kV substation, the list of 4.8kV circuits which the 13.2kV substation will serve upon 4.8kV circuit conversion.

Answer: The Company objects for the reason that the request is vague and incapable of answer in its present form because it is unclear what is meant by "since the last rate case". Subject to this objection, and without waiving this objection, DTE Electric would answer as follows:

Assuming this request seeks information relating to 13.2 kV substations for which 4.8kV conversion work was completed in 2023, The company completed two new 13.2kV substations, Islandview and Midas. The 4.8kV circuits that these substations will serve are listed below.

Islandview substation - WALKR1016, WALKR264, WALKR283, WALKR398, WALKR404, WALKR460, WALKR1199, WALKR279, WALKR296, WALKR438, WALKR54, WALKR192, WALKR207, WALKR645, WALKR160, WALKR663, WALKR708, WALKR248, WALKR55, WALKR63, WALKR75, PULFD0103, PULFD0237, PULFD0285, PULFD0286, PULFD0416, PULFD0419, PULFD0694, PULFD1134, PULFD2111, PULFD2155, PULFD2175, PULFD2224

Midas Substation – ALMOT303, ALMOT304

Attachment: *N/A*

Michigan Public Service Commission
DTE Electric Company
Distribution Plant Capital Project Detail - Infrastructure Redesign & Modernization

Case No.: U-21297
Exhibit: A-23
Schedule: M5
Witness: S. S. Deol
Page: 1 of 509

(a)	(b)
Category	**Distribution Plant Capital Project Detail - Infrastructure Redesign & Modernization**
	Capital Exhibit:
pages: 6-9 of 509	Exhibit A-12, Schedule B5.4, Page 9 of 21, Line 2 Ann Arbor System Improvements: State Substation
pages: 10-13 of 509	Exhibit A-12, Schedule B5.4, Page 9 of 21, Line 3 Ann Arbor System Improvements: Apex (Blue) Substation
pages: 14-17 of 509	Exhibit A-12, Schedule B5.4, Page 9 of 21, Line 4 Ann Arbor System Improvements: Argo 40kV Reconfiguration
pages: 18-21 of 509	Exhibit A-12, Schedule B5.4, Page 9 of 21, Line 5 Subtransmission Redesign & Rebuild: Transformer High Side Protection Program
pages: 22-25 of 509	Exhibit A-12, Schedule B5.4, Page 9 of 21, Line 6 Subtransmission Redesign & Rebuild: Tie 4104
pages: 26-29 of 509	Exhibit A-12, Schedule B5.4, Page 9 of 21, Line 7 Subtransmission Redesign & Rebuild: Maxwell Amherst
pages: 30-33 of 509	Exhibit A-12, Schedule B5.4, Page 9 of 21, Line 8 Subtransmission Redesign & Rebuild: Tie 810
pages: 34-37 of 509	Exhibit A-12, Schedule B5.4, Page 9 of 21, Line 9 Subtransmission Redesign & Rebuild: Trunk 7106
pages: 38-41 of 509	Exhibit A-12, Schedule B5.4, Page 9 of 21, Line 10 Subtransmission Redesign & Rebuild: Trunk 2255
pages: 42-45 of 509	Exhibit A-12, Schedule B5.4, Page 9 of 21, Line 11 Subtransmission Redesign & Rebuild: Trunk 2237-ST
pages: 46-49 of 509	Exhibit A-12, Schedule B5.4, Page 9 of 21, Line 12 Subtransmission Redesign & Rebuild: Trunk 7333
pages: 50-53 of 509	Exhibit A-12, Schedule B5.4, Page 9 of 21, Line 13 Subtransmission Redesign & Rebuild: Sandusky Transformer 101 Breaker
pages: 54-57 of 509	Exhibit A-12, Schedule B5.4, Page 9 of 21, Line 14 Subtransmission Redesign & Rebuild: Boyne
pages: 58-61 of 509	Exhibit A-12, Schedule B5.4, Page 9 of 21, Line 15 Subtransmission Redesign & Rebuild: Tie 6907
pages: 62-65 of 509	Exhibit A-12, Schedule B5.4, Page 9 of 21, Line 16 Subtransmission Redesign & Rebuild: Tie 7504
pages: 66-69 of 509	Exhibit A-12, Schedule B5.4, Page 9 of 21, Line 17 Subtransmission Redesign & Rebuild: Tie 4105
pages: 70-73 of 509	Exhibit A-12, Schedule B5.4, Page 9 of 21, Line 18 Subtransmission Redesign & Rebuild: Trunk 2308
pages: 74-77 of 509	Exhibit A-12, Schedule B5.4, Page 9 of 21, Line 19 Subtransmission Redesign & Rebuild: Tie 1568
pages: 78-81 of 509	Exhibit A-12, Schedule B5.4, Page 9 of 21, Line 20 Subtransmission Redesign & Rebuild: Trunk 4217
pages: 82-85 of 509	Exhibit A-12, Schedule B5.4, Page 9 of 21, Line 21 Subtransmission Redesign & Rebuild: Trunk 3509
pages: 86-89 of 509	Exhibit A-12, Schedule B5.4, Page 9 of 21, Line 22 Subtransmission Redesign & Rebuild: Trunk 4266
pages: 90-93 of 509	Exhibit A-12, Schedule B5.4, Page 9 of 21, Line 23 Subtransmission Redesign & Rebuild: Badax Transformer 102 Addition
pages: 94-97 of 509	Exhibit A-12, Schedule B5.4, Page 9 of 21, Line 24 Subtransmission Redesign & Rebuild: Trunk 4245
pages: 98-101 of 509	Exhibit A-12, Schedule B5.4, Page 9 of 21, Line 25 Subtransmission Redesign & Rebuild: Tie 6602
pages: 102-105 of 509	Exhibit A-12, Schedule B5.4, Page 9 of 21, Line 26 Subtransmission Redesign & Rebuild: Trunk 4911
pages: 106-109 of 509	Exhibit A-12, Schedule B5.4, Page 9 of 21, Line 27 Subtransmission Redesign & Rebuild: Custer Republic
pages: 110-113 of 509	Exhibit A-12, Schedule B5.4, Page 9 of 21, Line 28 Subtransmission Redesign & Rebuild: Trunk 2419
pages: 114-117 of 509	Exhibit A-12, Schedule B5.4, Page 9 of 21, Line 29 Subtransmission Redesign & Rebuild: Tie 3205
pages: 118-121 of 509	Exhibit A-12, Schedule B5.4, Page 9 of 21, Line 30 Subtransmission Redesign & Rebuild: Praxair
pages: 122-125 of 509	Exhibit A-12, Schedule B5.4, Page 9 of 21, Line 31 Subtransmission Redesign & Rebuild : Small Projects & Reserve

Michigan Public Service Commission
DTE Electric Company
Distribution Plant Capital Project Detail - Infrastructure Redesign & Modernization

Case No.: U-21297
Exhibit: A-23
Schedule: M5
Witness: S. S. Deol
Page: 2 of 509

(a)	(b)
Category	**Distribution Plant Capital Project Detail - Infrastructure Redesign & Modernization**
	Capital Exhibit:
pages: 126-129 of 509	Exhibit A-12, Schedule B5.4, Page 9 of 21, Line 32 Subtransmission Breaker Short Circuit Violations
pages: 130-133 of 509	Exhibit A-12, Schedule B5.4, Page 9 of 21, Line 33 Subtransmission Redesign & Rebuild: Slocum
pages: 134-137 of 509	Exhibit A-12, Schedule B5.4, Page 9 of 21, Line 34 Subtransmission Redesign & Rebuild: Kennett
pages: 138-141 of 509	Exhibit A-12, Schedule B5.4, Page 9 of 21, Line 35 Subtransmission Redesign & Rebuild: Trunk 4601
pages: 142-145 of 509	Exhibit A-12, Schedule B5.4, Page 9 of 21, Line 36 Subtransmission Redesign & Rebuild: Tempest Phase II
pages: 146-149 of 509	Exhibit A-12, Schedule B5.4, Page 9 of 21, Line 37 Subtransmission Redesign & Rebuild: Waterman
pages: 150-153 of 509	Exhibit A-12, Schedule B5.4, Page 9 of 21, Line 38 Subtransmission Redesign & Rebuild: Trunk 7105
pages: 154-157 of 509	Exhibit A-12, Schedule B5.4, Page 9 of 21, Line 39 Subtransmission Redesign & Rebuild: Tie 5208
pages: 158-161 of 509	Exhibit A-12, Schedule B5.4, Page 9 of 21, Line 40 Subtransmission Redesign & Rebuild: Cortland Station Expansion
pages: 162-165 of 509	Exhibit A-12, Schedule B5.4, Page 9 of 21, Line 41 Subtransmission Redesign & Rebuild: 40kV Capacitor Banks at Armada and Adair
pages: 166-169 of 509	Exhibit A-33, Schedule X3, Page 1 of 1, Line 10 Subtransmission Redesign & Rebuild: Tie 3416 Reconductoring
pages: 170-173 of 509	Exhibit A-33, Schedule X3, Page 1 of 1, Line 11 Subtransmission Redesign & Rebuild: Pigeon Area Improvement
pages: 174-177 of 509	Exhibit A-33, Schedule X3, Page 1 of 1, Line 12 Subtransmission Redesign & Rebuild: Trunk 2443
pages: 178-181 of 509	Exhibit A-33, Schedule X3, Page 1 of 1, Line 13 Subtransmission Redesign & Rebuild: Trunk 5838
pages: 182-185 of 509	Exhibit A-33, Schedule X3, Page 1 of 1, Line 14 Subtransmission Redesign & Rebuild: Trunk 3508
pages: 186-189 of 509	Exhibit A-33, Schedule X3, Page 1 of 1, Line 15 Subtransmission Redesign & Rebuild: Thumb Electric Fault Isolation
pages: 190-193 of 509	Exhibit A-33, Schedule X3, Page 1 of 1, Line 16 Subtransmission Redesign & Rebuild: Derby
pages: 194-197 of 509	Exhibit A-33, Schedule X3, Page 1 of 1, Line 17 Subtransmission Redesign & Rebuild: Trunk 3546
pages: 198-201 of 509	Exhibit A-33, Schedule X3, Page 1 of 1, Line 18 Subtransmission Redesign & Rebuild: Mohican
pages: 202-205 of 509	Exhibit A-33, Schedule X3, Page 1 of 1, Line 19 Subtransmission Redesign & Rebuild: Bernard
pages: 206-209 of 509	Exhibit A-33, Schedule X3, Page 1 of 1, Line 20 Subtransmission Redesign & Rebuild: STPS6
pages: 210-213 of 509	Exhibit A-33, Schedule X3, Page 1 of 1, Line 21 Subtransmission Redesign & Rebuild: Trunk 2455
pages: 214-217 of 509	Exhibit A-33, Schedule X3, Page 1 of 1, Line 22 Subtransmission Redesign & Rebuild: Oak Beach Capacitor
pages: 218-221 of 509	Exhibit A-33, Schedule X3, Page 1 of 1, Line 23 Subtransmission Redesign & Rebuild: Trunk 7386
pages: 222-225 of 509	Exhibit A-33, Schedule X3, Page 1 of 1, Line 24 Subtransmission Redesign & Rebuild: Reverse Power Relay Scheme Program
pages: 226-229 of 509	Exhibit A-33, Schedule X3, Page 1 of 1, Line 25 Subtransmission Redesign & Rebuild: Tie 3705
pages: 230-233 of 509	Exhibit A-33, Schedule X3, Page 1 of 1, Line 26 Subtransmission Redesign & Rebuild: Hurst
pages: 234-237 of 509	Exhibit A-12, Schedule B5.4, Page 9 of 21, Line 27 Subtransmission Redesign & Rebuild: Trunk 7130 A-B - Angola
pages: 238-241 of 509	Exhibit A-12, Schedule B5.4, Page 10 of 21, Line 42 CODI: Charlotte Network Upgrade
pages: 242-245 of 509	Exhibit A-12, Schedule B5.4, Page 10 of 21, Line 43 CODI: Targeted Network Secondary Cable Replacement
pages: 246-249 of 509	Exhibit A-12, Schedule B5.4, Page 10 of 21, Line 44 CODI: Corktown Substation

Michigan Public Service Commission
DTE Electric Company
Distribution Plant Capital Project Detail - Infrastructure Redesign & Modernization

Case No.: U-21297
Exhibit: A-23
Schedule: M5
Witness: S. S. Deol
Page: 3 of 509

(a)	(b)
Category	**Distribution Plant Capital Project Detail - Infrastructure Redesign & Modernization**
	Capital Exhibit:
pages: 250-253 of 509	Exhibit A-12, Schedule B5.4, Page 10 of 21, Line 45 CODI: Islandview Substation
pages: 254-257 of 509	Exhibit A-12, Schedule B5.4, Page 10 of 21, Line 46 CODI: CATO Substation Expansion
pages: 258-261 of 509	Exhibit A-12, Schedule B5.4, Page 10 of 21, Line 47 CODI: Howard Conversion
pages: 262-265 of 509	Exhibit A-12, Schedule B5.4, Page 10 of 21, Line 48 CODI: Midtown Substation Expansion
pages: 266-269 of 509	Exhibit A-12, Schedule B5.4, Page 10 of 21, Line 49 CODI: Alfred Substation Expansion
pages: 270-273 of 509	Exhibit A-12, Schedule B5.4, Page 10 of 21, Line 50 CODI: Garfield Network Upgrade
pages: 274-277 of 509	Exhibit A-12, Schedule B5.4, Page 10 of 21, Line 51 CODI: Kent/Gibson Conversion
pages: 278-281 of 509	Exhibit A-12, Schedule B5.4, Page 10 of 21, Line 53 4.8 kV CC: Zenon Substation and Circuit Conversion
pages: 282-285 of 509	Exhibit A-12, Schedule B5.4, Page 10 of 21, Line 54 4.8 kV CC: Cortland / Oakman / Linwood Consolidation
pages: 286-289 of 509	Exhibit A-12, Schedule B5.4, Page 10 of 21, Line 55 4.8 kV CC: Ariel Substation and Circuit Conversion
pages: 290-293 of 509	Exhibit A-12, Schedule B5.4, Page 10 of 21, Line 56 4.8 kV CC: I-94 Substation and Circuit Conversion (Promenade)
pages: 294-297 of 509	Exhibit A-12, Schedule B5.4, Page 10 of 21, Line 57 4.8 kV CC: Almont Relief and Circuit Conversion (Midas)
pages: 298-301 of 509	Exhibit A-12, Schedule B5.4, Page 10 of 21, Line 58 4.8 kV CC: Buckler Circuit Conversion
pages: 302-305 of 509	Exhibit A-12, Schedule B5.4, Page 10 of 21, Line 59 4.8 kV CC: Calla Circuit Conversion and Phase 2
pages: 306-309 of 509	Exhibit A-12, Schedule B5.4, Page 10 of 21, Line 60 4.8 kV CC: Lapeer - Elba Expansion and Circuit Conversion (Apollo)
pages: 310-313 of 509	Exhibit A-12, Schedule B5.4, Page 10 of 21, Line 61 4.8 kV CC: McKinstry Sub Decommission
pages: 314-317 of 509	Exhibit A-12, Schedule B5.4, Page 10 of 21, Line 62 4.8 kV CC: Quincy Conversion
pages: 318-321 of 509	Exhibit A-12, Schedule B5.4, Page 10 of 21, Line 63 and Line 64 4.8 kV CC: Pinegrove Substation Relocation and Conversion
pages: 322-325 of 509	Exhibit A-12, Schedule B5.4, Page 10 of 21, Line 65 4.8 kV CC: Hawthorne Relief and Circuit Conversion
pages: 326-329 of 509	Exhibit A-12, Schedule B5.4, Page 10 of 21, Line 66 4.8 kV CC: Hawthorne Trf #2 and Secondary Cable Replacement
pages: 330-333 of 509	Exhibit A-12, Schedule B5.4, Page 10 of 21, Line 67 4.8 kV CC: Birmingham Decommissioning and Circuit Conversion
pages: 334-337 of 509	Exhibit A-12, Schedule B5.4, Page 10 of 21, Line 68 4.8 kV CC: Crestwood Substation
pages: 338-341 of 509	Exhibit A-12, Schedule B5.4, Page 10 of 21, Line 69 4.8 kV CC: MAUME 8241 Downtown Clawson Conversion
pages: 342-345 of 509	Exhibit A-12, Schedule B5.4, Page 10 of 21, Line 70 4.8 kV CC: Power line Conversion of MADSN 175L-W
pages: 346-349 of 509	Exhibit A-12, Schedule B5.4, Page 10 of 21, Line 71 4.8 kV CC: GRFIN & WMSTN Conversions
pages: 350-353 of 509	Exhibit A-12, Schedule B5.4, Page 10 of 21, Line 72 4.8 kV CC: ISO Conversion Program
pages: 354-357 of 509	Exhibit A-12, Schedule B5.4, Page 10 of 21, Line 73 4.8kV CC: SCOTN
pages: 358-361 of 509	Exhibit A-12, Schedule B5.4, Page 10 of 21, Line 74 4.8kV CC: Rochester Decommissioning and Tienken Relief
pages: 362-365 of 509	Exhibit A-12, Schedule B5.4, Page 10 of 21, Line 75 4.8 kV CC: Ann Arbor AC Network Conversion
pages: 366-369 of 509	Exhibit A-12, Schedule B5.4, Page 10 of 21, Line 76 4.8kV CC: Pittsfield Substation and Circuit Conversion
pages: 370-373 of 509	Exhibit A-12, Schedule B5.4, Page 10 of 21, Line 77 4.8kV CC: Hemlock Decommissioning and Circuit Conversion

Michigan Public Service Commission
DTE Electric Company
Distribution Plant Capital Project Detail - Infrastructure Redesign & Modernization

Case No.: U-21297
Exhibit: A-23
Schedule: M5
Witness: S. S. Deol
Page: 4 of 509

(a)	(b)
Category	**Distribution Plant Capital Project Detail - Infrastructure Redesign & Modernization**
	Capital Exhibit:
pages: 374-377 of 509	Exhibit A-12, Schedule B5.4, Page 10 of 21, Line 78 4.8kV CC: Yale-Slater Decommissioning and Circuit Conversion
pages: 378-381 of 509	Exhibit A-12, Schedule B5.4, Page 10 of 21, Line 79 4.8 kV CC: Slater
pages: 382-385 of 509	Exhibit A-12, Schedule B5.4, Page 10 of 21, Line 80 4.8 kV CC: Grosse Pointe Substation and Circuit Conversion
pages: 386-389 of 509	Exhibit A-12, Schedule B5.4, Page 10 of 21, Line 81 4.8 kV CC: Royal Oak Substation and Circuit Conversion
pages: 390-393 of 509	Exhibit A-12, Schedule B5.4, Page 10 of 21, Line 82 8.3 kV CC: Pontiac Overhead Conversion
pages: 394-397 of 509	Exhibit A-12, Schedule B5.4, Page 10 of 21, Line 83 8.3 kV CC: Pontiac Underground Conversion
pages: 398-401 of 509	Exhibit A-33, Schedule X3, Page 1 of 1, Line 3 4.8 kV CC: White Lake Decommissioning and Circuit Conversion
pages: 402-405 of 509	Exhibit A-33, Schedule X3, Page 1 of 1, Line 4 4.8 kV CC: Unionville Decommissioning and Circuit Conversion
pages: 406-409 of 509	Exhibit A-33, Schedule X3, Page 1 of 1, Line 5 4.8 kV CC: Belleville Substation and Circuit Conversion
pages: 410-413 of 509	Exhibit A-33, Schedule X3, Page 1 of 1, Line 6 4.8 kV CC: Barber Substation and Circuit Conversion
pages: 414-417 of 509	Exhibit A-33, Schedule X3, Page 1 of 1, Line 7 4.8 kV CC: Zenon Circuit Conversion Phase 2
pages: 418-421 of 509	Exhibit A-12, Schedule B5.4, Page 11 of 21, Line 85 System Loading: Carleton
pages: 422-425 of 509	Exhibit A-12, Schedule B5.4, Page 11 of 21, Line 88 System Loading: Mandy 307 Load Transfer
pages: 426-429 of 509	Exhibit A-12, Schedule B5.4, Page 11 of 21, Line 89 System Loading: Brown City
pages: 430-433 of 509	Exhibit A-12, Schedule B5.4, Page 11 of 21, Line 90 System Loading: Mack Transformer 102
pages: 434-437 of 509	Exhibit A-12, Schedule B5.4, Page 11 of 21, Line 91 System Loading: Port Sanilac
pages: 438-441 of 509	Exhibit A-12, Schedule B5.4, Page 11 of 21, Line 92 System Loading: Richmond/Armada
pages: 442-445 of 509	Exhibit A-12, Schedule B5.4, Page 11 of 21, Line 93 System Loading: Cody
pages: 446-449 of 509	Exhibit A-12, Schedule B5.4, Page 11 of 21, Line 94 System Loading: Otsego/Capac/Shaw
pages: 450-453 of 509	Exhibit A-12, Schedule B5.4, Page 11 of 21, Line 95 System Loading: Macomb/Golf
pages: 454-457 of 509	Exhibit A-12, Schedule B5.4, Page 11 of 21, Line 96 System Loading: Grenada
pages: 458-461 of 509	Exhibit A-12, Schedule B5.4, Page 11 of 21, Line 98 System Loading: Lark/Spruce
pages: 462-465 of 509	Exhibit A-12, Schedule B5.4, Page 11 of 21, Line 99 System Loading: Globe
pages: 466-469 of 509	Exhibit A-12, Schedule B5.4, Page 11 of 21, Line 100 System Loading: Jewell
pages: 470-473 of 509	Exhibit A-12, Schedule B5.4, Page 11 of 21, Line 101 System Loading: Mayville
pages: 474-477 of 509	Exhibit A-12, Schedule B5.4, Page 11 of 21, Line 102 System Loading: Goodison
pages: 478-481 of 509	Exhibit A-12, Schedule B5.4, Page 11 of 21, Line 103 System Loading: Wixom
pages: 482-485 of 509	Exhibit A-12, Schedule B5.4, Page 11 of 21, Line 104 System Loading: Diamond
pages: 486-489 of 509	Exhibit A-12, Schedule B5.4, Page 11 of 21, Line 105 System Loading: Spokane/Seneca
pages: 490-493 of 509	Exhibit A-12, Schedule B5.4, Page 11 of 21, Line 106 System Loading: Sterling
pages: 494-497 of 509	Exhibit A-12, Schedule B5.4, Page 11 of 21, Line 107 System Loading: Disco

Michigan Public Service Commission
DTE Electric Company
Distribution Plant Capital Project Detail - Infrastructure Redesign & Modernization

Case No.: U-21297
Exhibit: A-23
Schedule: M5
Witness: S. S. Deol
Page: 5 of 509

(a)	(b)
Category	**Distribution Plant Capital Project Detail - Infrastructure Redesign & Modernization**
	Capital Exhibit:
pages: 498-501 of 509	Exhibit A-12, Schedule B5.4, Page 11 of 21, Line 108 System Loading: Tahoe
pages: 502-505 of 509	Exhibit A-12, Schedule B5.4, Page 11 of 21, Line 109 Pilot: Strategic and Service Undergrounding
pages: 506-509 of 509	Exhibit A-12, Schedule B5.4, Page 11 of 21, Line 110 Pilot: Primary Deconductoring

Michigan Public Service Commission
DTE Electric Company
Distribution Plant Capital Project Detail - Infrastructure Redesign & Modernization

Case No.: U-21297
Exhibit: A-23
Schedule: M5
Witness: S. S. Deol
Page: 294 of 509

(a)	(b)
Program:	4.8 kV CC: Almont Relief and Circuit Conversion (Midas) (Pg. 1 of 4)
Purpose and Necessity:	Almont substation is over its substation firm rating of 6.8 MVA. Almont 304 is over its day-to-day rating of 5.5 MVA. Multiple Method of Service (MOS) requests have been received with no capacity available to serve them. Limited jumpering options are available because Almont is a 4.8 kV substation surrounded by 13.2 kV substations. A cable failure occurred in 2019 which caused the breaker to fail and led to an extensive outage for the Almont area due to no jumpering available. Due to the high loads, the substation is blocked from automatic throwover. In addition, the breakers are from 1956 and spare parts are not available.
Category:	Infrastructure Redesign & Modernization

Michigan Public Service Commission
DTE Electric Company
Distribution Plant Capital Project Detail - Infrastructure Redesign & Modernization

Case No.: U-21297
Exhibit: A-23
Schedule: M5
Witness: S. S. Deol
Page: 295 of 509

(a)	(b)
Program:	4.8 kV CC: Almont Relief and Circuit Conversion (Midas) (Pg. 2 of 4)
Line Number:	Exhibit A-12, Schedule B5.4, Page 10, Line 57
Scope:	• Build a new Class 'R' 13.2 kV substation with 4 circuits • Reconductor ~4-5 miles of overhead primary • Convert 21 miles of overhead primary • Establish new jumpering points • Reconfigure Almont circuits • Transfer Almont load to the new substation • Convert and transfer remaining Almont load to the new substation • Decommission Almont substation

Michigan Public Service Commission
DTE Electric Company
Distribution Plant Capital Project Detail - Infrastructure Redesign & Modernization

Case No.: U-21297
Exhibit: A-23
Schedule: M5
Witness: S. S. Deol
Page: 296 of 509

(a) (b)

Program:	4.8 kV CC: Almont Relief and Circuit Conversion (Midas) (Pg. 3 of 4)						
Customer benefit / Effect on cost of operation and reliability:	• Alleviates the loading issue on Almont substation, leading to: - Elimination of loading related safety risks - Improved reliability - Reduction of long duration outage risks - Reduced O&M and Capital expenses • Elimination of aging OH infrastructure, leading to: - Improved reliability- reduction in customer outage time - Reduced Capital expenses - Reduced O&M expenses • Provide additional capacity to allow for load growth						
Impact Dimension:	Safety	Load Relief	Regulatory Compliance	Major Event Risk	Reliability	O&M Avoidance	Reactive Capital Avoidance
Targeted:	x	x		x	x	x	x

Michigan Public Service Commission
DTE Electric Company
Distribution Plant Capital Project Detail - Infrastructure Redesign & Modernization

Case No.: U-21297
Exhibit: A-23
Schedule: M5
Witness: S. S. Deol
Page: 297 of 509

(a) (b)

Program:	4.8 kV CC: Almont Relief and Circuit Conversion (Midas) (Pg. 4 of 4)					
Approximate Construction Schedule::	2021- 2022: Substation Construction 2022: OH Pre-conversion construction 2023: Pre-conversion and conversion construction and Almont decommission					
Budget Basis:	• Future cost are developed using past similar completed projects adjusted for the latest labor rates and material cost while incorporating the lesson learned and input from the experienced execution teams					
Cost:	Estimated project spend in 2022-2024: $16.2 M					
Projected ($000's):		**12 mos. 1/1/22 12/31/22**	**12 mos. 1/1/23 12/31/23**	**12 mos. 1/1/24 12/31/24**		**Test Year 12 mos. Ending 11/30/2024**
	Total Labor (DTE Electric & Contractors)	8,214	1,910	-		159
	Material	3,445	1,270	-		106
	Other	984	386	-		32
	Total	**12,643**	**3,565**	**-**		**297**

Michigan Public Service Commission
DTE Electric Company
Distribution Plant Capital Project Detail - Infrastructure Redesign & Modernization

Case No.: U-21297
Exhibit: A-23
Schedule: M5
Witness: S. S. Deol
Page: 250 of 509

(a)	(b)
Program:	CODI: Islandview Substation (Pg. 1 of 4)
Purpose and Necessity:	New customer load has been added along the Detroit riverfront and additional development is anticipated in the future. The new substation is to be sited east of downtown Detroit near the riverfront and allow for the decommissioning of Walker substation and half of Pulford substation. Both Pulford and Walker substations have been in service since the 1920's and cannot reliably serve new load. The new substation will also provide capacity to serve customers being transitioned from the Detroit Public Lighting Department system to the DTE Electric system.
Category:	Infrastructure Redesign & Modernization

Michigan Public Service Commission
DTE Electric Company
Distribution Plant Capital Project Detail - Infrastructure Redesign & Modernization

Case No.: U-21297
Exhibit: A-23
Schedule: M5
Witness: S. S. Deol
Page: 251 of 509

(a)	(b)
Program:	CODI: Islandview Substation (Pg. 2 of 4)
Line Number:	Exhibit A-12, Schedule B5.4, Page 10, Line 45
Scope:	• Construct a new Class 'A' 13.2kV substation with two transformers and a setup for a future third transformer position • Pre-convert existing 4.8kV circuits from Walker Substation - 22 circuits • Pre-convert existing 4.8kV circuits from Pulford Substation - 10 circuits • Convert and transfer WALKR and PULFD circuits to new substation • Decommission cable for four trunk lines (24kV) • Decommission WALKR Substation

Michigan Public Service Commission
DTE Electric Company
Distribution Plant Capital Project Detail - Infrastructure Redesign & Modernization

Case No.: U-21297
Exhibit: A-23
Schedule: M5
Witness: S. S. Deol
Page: 252 of 509

(a) (b)

Program:	CODI: Islandview Substation (Pg. 3 of 4)						
Customer benefit / Effect on cost of operation and reliability:	• Provide sufficient capacity to serve growing areas • Decommission aging infrastructure and reduce major event risk • Enhance safety, reliability and power quality for upgraded circuits by reducing 85% of circuit wire down events, customer interruptions, and customer minutes • Reduce trouble events and reactive costs for upgraded circuits by 85% for both circuit tree related and non-tree related reactive capital • Increase protection for the distribution system • Enhance grid technology and automation • Reduce new customer connection timeframe and cost						
Impact Dimension:	Safety	Load Relief	Regulatory Compliance	Major Event Risk	Reliability	O&M Avoidance	Reactive Capital Avoidance
Targeted:	x	x		x	x	x	x

Michigan Public Service Commission
DTE Electric Company
Distribution Plant Capital Project Detail - Infrastructure Redesign & Modernization

Case No.: U-21297
Exhibit: A-23
Schedule: M5
Witness: S. S. Deol
Page: 253 of 509

(a) (b)

Program:	CODI: Islandview Substation (Pg. 4 of 4)					
Approximate Construction Schedule::	2022: Substation construction, Engineering and Design 2023: Substation construction, Overhead pre-conversion, Engineering and Design of underground conduit 2024: Overhead pre-conversion/conversion, underground conduit construction, Engineering and Design for pre-conversion/conversion					
Budget Basis:	• Future cost are developed using past similar completed projects adjusted for the latest labor rates and material cost while incorporating the lesson learned and input from the experienced execution teams					
Cost:	Estimated project spend in 2022-2024: $95.1 M This project is expected to continue beyond 2024					
Projected ($000's):		**12 mos. 1/1/22 12/31/22**	**12 mos. 1/1/23 12/31/23**	**12 mos. 1/1/24 12/31/24**		**Test Year 12 mos. Ending 11/30/2024**
	Total Labor (DTE Electric & Contractors)	10,259	28,282	29,567		29,460
	Material	1,619	3,077	10,976		10,318
	Other	1,034	4,386	5,881		5,756
	Total	**12,912**	**35,745**	**46,424**		**45,534**

Michigan Public Service Commission
DTE Electric Company
Distribution Plant Capital Project Detail - Infrastructure Redesign & Modernization

Case No.: U-20836
Exhibit: A-23
Schedule: M5 Revised
Witness: S. G. Pfeuffer
Page: 1 of 347

(a)	(b)
Category	**Distribution Plant Capital Project Detail - Infrastructure Redesign & Modernization**
	Capital Exhibit:
pages: 4-7 of 347	Exhibit A-12, Schedule B5.4, Page 9 of 12, Line 2 Ann Arbor System Improvements: State Substation
pages: 8-11 of 347	Exhibit A-12, Schedule B5.4, Page 9 of 12, Line 3 Ann Arbor System Improvements: Apex (Blue) Substation
pages: 12-15 of 347	Exhibit A-12, Schedule B5.4, Page 9 of 12, Line 4 Ann Arbor System Improvements: Argo 40kV Reconfiguration
pages: 16-19 of 347	Exhibit A-12, Schedule B5.4, Page 9 of 12, Line 5 Transformer High Side Protection Program
pages: 20-23 of 347	Exhibit A-12, Schedule B5.4, Page 9 of 12, Line 6 PQ Meter Fault Locating
pages: 24-27 of 355	Exhibit A-12, Schedule B5.4, Page 9 of 12, Line 7 Subtransmission Redesign & Rebuild: Prior Year's
pages: 28-31 of 347	Exhibit A-12, Schedule B5.4, Page 9 of 12, Line 8 Subtransmission Redesign & Rebuild: Tie 4104
pages: 32-35 of 347	Exhibit A-12, Schedule B5.4, Page 9 of 12, Line 9 Subtransmission Redesign & Rebuild: Tie 3416
pages: 36-39 of 347	Exhibit A-12, Schedule B5.4, Page 9 of 12, Line 10 Subtransmission Redesign & Rebuild: Maxwell Amherst
pages: 40-43 of 347	Exhibit A-12, Schedule B5.4, Page 9 of 12, Line 11 Subtransmission Redesign & Rebuild: Tie 810
pages: 44-47 of 347	Exhibit A-12, Schedule B5.4, Page 9 of 12, Line 12 Subtransmission Redesign & Rebuild: Trunk 7106
pages: 48-51 of 347	Exhibit A-12, Schedule B5.4, Page 9 of 12, Line 13 Subtransmission Redesign & Rebuild: Trunk 2255
pages: 52-55 of 347	Exhibit A-12, Schedule B5.4, Page 9 of 12, Line 14 Subtransmission Redesign & Rebuild: Trunk 2237-ST
pages: 56-59 of 347	Exhibit A-12, Schedule B5.4, Page 9 of 12, Line 15 Subtransmission Redesign & Rebuild: Trunk 7333
pages: 60-63 of 347	Exhibit A-12, Schedule B5.4, Page 9 of 12, Line 16 Subtransmission Redesign & Rebuild: Sandusky Transformer 101 Breaker
pages: 64-67 of 347	Exhibit A-12, Schedule B5.4, Page 9 of 12, Line 17 Subtransmission Redesign & Rebuild: Sandusky Transformer 102 Addition
pages: 68-71 of 347	Exhibit A-12, Schedule B5.4, Page 9 of 12, Line 18 Subtransmission Redesign & Rebuild: Boyne
pages: 72-75 of 347	Exhibit A-12, Schedule B5.4, Page 9 of 12, Line 19 Subtransmission Redesign & Rebuild: Tie 6907
pages: 76-79 of 347	Exhibit A-12, Schedule B5.4, Page 9 of 12, Line 20 Subtransmission Redesign & Rebuild: Tie 7504
pages: 80-83 of 347	Exhibit A-12, Schedule B5.4, Page 9 of 12, Line 21 Subtransmission Redesign & Rebuild: Tie 4105
pages: 84-87 of 347	Exhibit A-12, Schedule B5.4, Page 9 of 12, Line 22 Subtransmission Redesign & Rebuild: Trunk 2308
pages: 88-91 of 347	Exhibit A-12, Schedule B5.4, Page 9 of 12, Line 23 Subtransmission Redesign & Rebuild: Tie 1568
pages: 92-95 of 347	Exhibit A-12, Schedule B5.4, Page 9 of 12, Line 24 Subtransmission Redesign & Rebuild: Trunk 4217
pages: 96-99 of 347	Exhibit A-12, Schedule B5.4, Page 9 of 12, Line 25 Subtransmission Redesign & Rebuild: Trunk 3509
pages: 100-103 of 347	Exhibit A-12, Schedule B5.4, Page 9 of 12, Line 26 Subtransmission Redesign & Rebuild: Trunk 4266
pages: 104-107 of 347	Exhibit A-12, Schedule B5.4, Page 9 of 12, Line 27 Subtransmission Redesign & Rebuild: Badax Transformer 102 Addition
pages: 108-111 of 347	Exhibit A-12, Schedule B5.4, Page 9 of 12, Line 28 Subtransmission Redesign & Rebuild: Trunk 4245
pages: 112-115 of 347	Exhibit A-12, Schedule B5.4, Page 9 of 12, Line 29 Subtransmission Redesign & Rebuild: Tie 6602
pages: 116-119 of 347	Exhibit A-12, Schedule B5.4, Page 9 of 12, Line 30 Subtransmission Redesign & Rebuild: Trunk 4911
pages: 120-123 of 347	Exhibit A-12, Schedule B5.4, Page 9 of 12, Line 31 Subtransmission Redesign & Rebuild: Custer Republic

Michigan Public Service Commission
DTE Electric Company
Distribution Plant Capital Project Detail - Infrastructure Redesign

Case No.: U-20836
Exhibit: A-23
Schedule: M5 Revised
Witness: S. G. Pfeuffer
Page: 2 of 347

(a)	(b)
Category	**Distribution Plant Capital Project Detail - Infrastructure Redesign**
	Capital Exhibit:
pages: 124-127 of 347	Exhibit A-12, Schedule B5.4, Page 9 of 12, Line 32 Subtransmission Redesign & Rebuild: Pigeon Area Improvement
pages: 128-131 of 347	Exhibit A-12, Schedule B5.4, Page 9 of 12, Line 33 Subtransmission Redesign & Rebuild: Trunk 2443
pages: 132-135 of 347	Exhibit A-12, Schedule B5.4, Page 9 of 12, Line 34 Subtransmission Redesign & Rebuild: Trunk 5838
pages: 136-139 of 347	Exhibit A-12, Schedule B5.4, Page 9 of 12, Line 35 Subtransmission Redesign & Rebuild: Trunk 2419
pages: 140-143 of 347	Exhibit A-12, Schedule B5.4, Page 9 of 12, Line 36 Subtransmission Redesign & Rebuild : Small Projects & Reserve
pages: 144-147 of 347	Exhibit A-12, Schedule B5.4, Page 9 of 12, Line 37 Subtransmission Breaker Short Circuit Violations
pages: 148-151 of 347	Exhibit A-12, Schedule B5.4, Page 9 of 12, Line 38 Subtransmission Redesign & Rebuild: Slocum
pages: 152-155 of 347	Exhibit A-12, Schedule B5.4, Page 9 of 12, Line 39 Station Upgrade: Cortland Station Expansion
pages: 156-159 of 347	Exhibit A-12, Schedule B5.4, Page 9 of 12, Line 40 Subtransmission Redesign & Rebuild: 40kV Capacitor Banks at Armada and Adair
pages: 160-163 of 347	Exhibit A-12, Schedule B5.4, Page 9 of 12, Line 41 CODI: Charlotte Network Upgrade
pages: 164-167 of 347	Exhibit A-12, Schedule B5.4, Page 9 of 12, Line 42 CODI: Targeted Network Secondary Cable Replacement
pages: 168-171 of 347	Exhibit A-12, Schedule B5.4, Page 9 of 12, Line 43 CODI: Corktown Substation
pages: 172-175 of 347	Exhibit A-12, Schedule B5.4, Page 9 of 12, Line 44 CODI: Islandview Substation
pages: 176-179 of 347	Exhibit A-12, Schedule B5.4, Page 9 of 12, Line 45 CODI: CATO Substation Expansion
pages: 180-183 of 347	Exhibit A-12, Schedule B5.4, Page 9 of 12, Line 46 CODI: Howard Conversion
pages: 184-187 of 347	Exhibit A-12, Schedule B5.4, Page 9 of 12, Line 47 CODI: Midtown Substation Expansion
pages: 188-191 of 347	Exhibit A-12, Schedule B5.4, Page 10 of 12, Line 48 CODI: Alfred Substation Expansion
pages: 192-195 of 347	Exhibit A-12, Schedule B5.4, Page 10 of 12, Line 49 CODI: Garfield Network Upgrade
pages: 196-199 of 347	Exhibit A-12, Schedule B5.4, Page 10 of 12, Line 50 CODI: Kent/Gibson Conversion
pages: 200-203 of 347	Exhibit A-12, Schedule B5.4, Page 10 of 12, Line 51 4.8 kV CC: Hilton Substation and Circuit Conversion
pages: 204-207 of 347	Exhibit A-12, Schedule B5.4, Page 10 of 12, Line 52 4.8 kV CC: Zenon Substation and Circuit Conversion
pages: 208-211 of 347	Exhibit A-12, Schedule B5.4, Page 10 of 12, Line 53 4.8 kV CC: Cortland / Oakman / Linwood Consolidation
pages: 212-215 of 347	Exhibit A-12, Schedule B5.4, Page 10 of 12, Line 54 4.8 kV CC: Ariel Substation and Circuit Conversion
pages: 216-219 of 347	Exhibit A-12, Schedule B5.4, Page 10 of 12, Line 55 4.8 kV CC: I-94 Substation and Circuit Conversion
pages: 220-223 of 347	Exhibit A-12, Schedule B5.4, Page 10 of 12, Line 56 4.8 kV CC: Almont Relief and Circuit Conversion (Midas)
pages: 224-227 of 347	Exhibit A-12, Schedule B5.4, Page 10 of 12, Line 57 4.8 kV CC: Buckler Circuit Conversion
pages: 228-231 of 347	Exhibit A-12, Schedule B5.4, Page 10 of 12, Line 58 4.8 kV CC: Calla Circuit Conversion
pages: 232-235 of 347	Exhibit A-12, Schedule B5.4, Page 10 of 12, Line 59 4.8 kV CC: Northville Decommissioning and Circuit Conversion
pages: 236-239 of 347	Exhibit A-12, Schedule B5.4, Page 10 of 12, Line 60 4.8 kV CC: Lapeer - Elba Expansion and Circuit Conversion (Apollo)
pages: 240-243 of 347	Exhibit A-12, Schedule B5.4, Page 10 of 12, Line 61 4.8 kV CC: McKinstry Sub Decommission
pages: 244-247 of 347	Exhibit A-12, Schedule B5.4, Page 10 of 12, Line 62 4.8 kV CC: White Lake Decommissioning and Circuit Conversion

Michigan Public Service Commission
DTE Electric Company
Distribution Plant Capital Project Detail - Infrastructure Redesign

Case No.: U-20836
Exhibit: A-23
Schedule: M5
Witness: S. G. Pfeuffer
Page: 3 of 347

(a)	(b)
Category	**Distribution Plant Capital Project Detail - Infrastructure Redesign**
	Capital Exhibit:
pages: 248-251 of 347	Exhibit A-12, Schedule B5.4, Page 10 of 12, Line 63 4.8 kV CC: Quincy Conversion
pages: 252-255 of 347	Exhibit A-12, Schedule B5.4, Page 10 of 12, Line 64 & 65 4.8 kV CC: Pinegrove Substation Relocation and Conversion
pages: 256-259 of 347	Exhibit A-12, Schedule B5.4, Page 10 of 12, Line 66 4.8 kV CC: Promenade Site Prep and Below Grade
pages: 260-263 of 347	Exhibit A-12, Schedule B5.4, Page 10 of 12, Line 67 4.8 kV CC: Hawthorne Relief and Circuit Conversion
pages: 264-267 of 347	Exhibit A-12, Schedule B5.4, Page 10 of 12, Line 68 4.8 kV CC: Birmingham Decommissioning and Circuit Conversion
pages: 268-271 of 347	Exhibit A-12, Schedule B5.4, Page 10 of 12, Line 69 4.8kV CC: ISO Camden
pages: 272-275 of 347	Exhibit A-12, Schedule B5.4, Page 10 of 12, Line 70 4.8kV CC: ISO Gilbert
pages: 276-279 of 347	Exhibit A-12, Schedule B5.4, Page 10 of 12, Line 71 8.3 kV CC: Pontiac Overhead Conversion
pages: 280-283 of 347	Exhibit A-12, Schedule B5.4, Page 10 of 12, Line 72 8.3 kV CC: Pontiac Underground Conversion
pages: 284-287 of 347	Exhibit A-12, Schedule B5.4, Page 10 of 12, Line 73 System Loading: Prior Year
pages: 288-291 of 347	Exhibit A-12, Schedule B5.4, Page 10 of 12, Line 74 System Loading: Brest Substation
pages: 292-295 of 347	Exhibit A-12, Schedule B5.4, Page 10 of 12, Line 75 System Loading: Carleton
pages: 296-299 of 347	Exhibit A-12, Schedule B5.4, Page 10 of 12, Line 76 System Loading: Grayling
pages: 300-303 of 347	Exhibit A-12, Schedule B5.4, Page 10 of 12, Line 77 System Loading: Prospect
pages: 304-307 of 347	Exhibit A-12, Schedule B5.4, Page 10 of 12, Line 78 System Loading: Mandy 307 Load Transfer
pages: 308-311 of 347	Exhibit A-12, Schedule B5.4, Page 10 of 12, Line 79 System Loading: Brown City
pages: 312-315 of 347	Exhibit A-12, Schedule B5.4, Page 10 of 12, Line 80 System Loading: Mack Transformer 102
pages: 316-319 of 347	Exhibit A-12, Schedule B5.4, Page 10 of 12, Line 81 System Loading: Port Sanilac
pages: 320-323 of 347	Exhibit A-12, Schedule B5.4, Page 10 of 12, Line 82 System Loading: Richmond/Armada
pages: 324-327 of 347	Exhibit A-12, Schedule B5.4, Page 10 of 12, Line 83 System Loading: Cody
pages: 328-331 of 347	Exhibit A-12, Schedule B5.4, Page 10 of 12, Line 84 System Loading: Otsego/Capac/Shaw
pages: 332-335 of 347	Exhibit A-12, Schedule B5.4, Page 10 of 12, Line 85 System Loading: Macomb/Golf
pages: 336-339 of 347	Exhibit A-12, Schedule B5.4, Page 10 of 12, Line 86 System Loading: Grenada
pages: 340-343 of 347	Exhibit A-12, Schedule B5.4, Page 10 of 12, Line 87 Pilot: Strategic and Service Undergrounding
pages: 344-347 of 347	Exhibit A-12, Schedule B5.4, Page 10 of 12, Line 88 Pilot: Primary Deconductoring

Michigan Public Service Commission
DTE Electric Company
Distribution Plant Capital Project Detail - Infrastructure Redesign & Modernization

Case No.: U-20836
Exhibit: A-23
Schedule: M5 Revised
Witness: S. G. Pfeuffer
Page: 220 of 347

(a)	(b)
Program:	4.8 kV CC: Almont Relief and Circuit Conversion (Midas) (Pg. 1 of 4)
Purpose and Necessity:	Almont substation is 3.4 MVA over its substation firm rating. Both of its circuits are at or above their day-to-day ratings during summer peak hours. Limited/No jumpering options are available because Almont is a 4.8 kV substation surrounded by 13.2 kV substations. Five new Method of Service requests (MOS) have been received for new sub divisions and grow houses, with no capacity to feed them. Commitments to the community have been made to improve reliability. Breakers are 1956 and spare parts are not available. Each circuit is over 55 overhead miles. A cable failure occurred in 2019 caused breaker to fail and extensive outage for the Almont area due to no jumpering available and, due to high loads, the substation was being blocked from automatic throwover
Category:	Infrastructure Redesign & Modernization

Michigan Public Service Commission
DTE Electric Company
Distribution Plant Capital Project Detail - Infrastructure Redesign & Modernization

Case No.: U-20836
Exhibit: A-23
Schedule: M5 Revised
Witness: S. G. Pfeuffer
Page: 221 of 347

(a)	(b)
Program:	4.8 kV CC: Almont Relief and Circuit Conversion (Midas) (Pg. 2 of 4)
Line Number:	Exhibit A-12, Schedule B5.4, Page 10, Line 56
DGP Section:	11.3
Scope:	• Build a new Class 'R' 13.2 kV substation with 4 circuits • Reconductor 2.7 miles of overhead primary • Convert 21 miles of overhead primary • Establish new jumpering points • Reconfigure Almont circuits • Transfer Almont load to the new substation • Convert and transfer remaining Almont load to the new substation • Decommission Almont substation

Michigan Public Service Commission
DTE Electric Company
Distribution Plant Capital Project Detail - Infrastructure Redesign & Modernization

Case No.: U-20836
Exhibit: A-23
Schedule: M5 Revised
Witness: S. G. Pfeuffer
Page: 222 of 347

(a) (b)

Program:	4.8 kV CC: Almont Relief and Circuit Conversion (Midas) (Pg. 3 of 4)						
Customer benefit / Effect on cost of operation and reliability:	• Alleviates the loading issue on Almont substation, leading to: - Elimination of loading related safety risks - Improved reliability - Reduction of long duration outage risks - Reduced O&M and Capital expenses • Elimination of aging OH infrastructure, leading to: - Improved reliability - Fewer truck roles - Reduced Capital expenses - Reduced O&M expenses • Reduce new customer connection timeframe and cost						
Impact Dimension:	Safety	Load Relief	Regulatory Compliance	Major Event Risk	Reliability	O&M Avoidance	Reactive Capital Avoidance
Targeted:	x	x		x	x	x	x

Michigan Public Service Commission
DTE Electric Company
Distribution Plant Capital Project Detail - Infrastructure Redesign & Modernization

Case No.: U-20836
Exhibit: A-23
Schedule: M5 Revised
Witness: S. G. Pfeuffer
Page: 223 of 347

(a) (b)

Program:	4.8 kV CC: Almont Relief and Circuit Conversion (Midas) (Pg. 4 of 4)
Current Projects:	4.8 kV CC: Almont Relief and Circuit Conversion (Midas Sub) - MEP 4.8 kV CC: Almont Relief and Circuit Conversion (Midas OH) - DO
Budget Basis:	• Engineering Estimate
Cost:	Estimated project spend in 2021-2023: $21.4 M

~~**Test Year ($000's):**~~

	~~**2 mos. 11/01/22 12/31/22**~~	~~**10 mos. 01/01/23 10/31/23**~~	~~**Test Year 12 mos. ending 10/31/23**~~
~~Total Labor (DTE Electric & Contractors)~~	~~1,701~~	~~664~~	~~2,365~~
~~Material~~	~~340~~	~~133~~	~~473~~
~~Other~~	~~227~~	~~88~~	~~315~~
~~**Total**~~	~~**2,268**~~	~~**885**~~	~~**3,153**~~

Test Year ($000's):

	2 mos. 11/01/22 12/31/22	**10 mos. 01/01/23 10/31/23**	**Test Year 12 mos. ending 10/31/23**
Total Labor (DTE Electric &	1,481	796	2,277
Material	560	-	560
Other	227	88	315
Total	**2,268**	**885**	**3,153**

Michigan Public Service Commission
DTE Electric Company
Projected Capital Expenditures
Distribution Plant
($000)

Case No.: U-20836
Exhibit: A-12
Schedule: B5.4
Witness: S. G. Pfeuffer
M. Elliott-Andahazy 6/
P. Smith 7/
Page: 1 of 12

Line No.	(a) Description		(b) Historical 12 mos. ended 12/31/2020	(c) Projected Bridge Period 12 mos. ended 12/31/2021	(d) Projected Bridge Period 10 mos. ending 10/31/2022	(e) Projected Bridge Period 22 mos. ending 10/31/2022	(f) Projected Test Year 12 mos. ended 10/31/2023
				Capital Expenditures			
1	**Base Capital Programs**						
2	Emergent Replacements						
3	Storm	1/	150,897	380,618	141,803	522,421	174,276
4	Non - Storm	1/	155,324	190,816	143,721	334,537	176,634
5	Substation Reactive	1/	38,131	40,621	36,954	77,575	45,417
6	Emergent Replacement Reduction Based on Strategic Spend		-	-	(12,684)	(12,684)	(24,615)
7	Subtotal Emergent Replacements		344,352	612,055	309,794	921,849	371,711
8	Customer Connections, Relocations & Other						
9	Connections and New Load	2/	137,221	187,535	140,230	327,765	172,342
10	Relocations	2/	24,128	31,917	22,936	54,853	27,332
11	Electric System Equipment	2/	56,182	25,650	33,883	59,533	41,642
12	NRUC and Improvement Blankets	2/	27,168	22,135	25,412	47,547	31,232
13	General Plant, Tools & Equipment and Miscellaneous	2/	8,569	9,031	10,306	19,337	9,665
14	Public Lighting Department Project	2/	21,051	21,282	7,700	28,982	-
15	Subtotal Customer Connections, Relocations & Other		274,320	297,550	240,467	538,017	282,214
16	Customer Advances for Construction	2/	(21,395)	(31,423)	(22,044)	(53,468)	(27,092)
17	**Total Base Capital Programs**		**597,277**	**878,181**	**528,217**	**1,406,399**	**626,833**
18	**Strategic Capital Programs**						
19	Infrastructure Resilience and Hardening	3/	167,035	189,706	265,694	455,400	346,091
20	Infrastructure Redesign and Modernization	4/	49,311	92,399	215,146	307,545	314,334
21	Technology and Automation	5/ 6/ 7/	91,293	73,421	99,551	172,972	137,342
22	**Subtotal Strategic Capital Programs**		**307,640**	**355,525**	**580,391**	**935,917**	**797,767**
23	**Total Capital**		**904,916**	**1,233,707**	**1,108,609**	**2,342,315**	**1,424,600**
24	**Regulatory Asset**						
25	Advanced Distribution Management System (ADMS)	8/	**3,989**	**2,837**	**6,405**	**9,242**	**2,978**

1/ Exhibit A-12, Schedule B5.4 - page 3
2/ Exhibit A-12, Schedule B5.4 - pages 4-5, lines 9, 19, 26, 33, 38, 39 & 41
3/ Exhibit A-12, Schedule B5.4 - page 8, line 29
4/ Exhibit A-12, Schedule B5.4 - page 10, line 89
5/ Exhibit A-12, Schedule B5.4 - page 11, line 41

Michigan Public Service Commission
DTE Electric Company
Projected Capital Expenditures
Distribution Plant
($000)

Case No.: U-20836
Exhibit: A-12
Schedule: B5.4
Witness: S. G. Pfeuffer
M. Elliott-Andahazy 6/
P. Smith 7/
Page: 2 of 12

Line No.	(a) Description		(b) Historical 12 mos. ended 12/31/2020	(c) Normalization Adjustment 9/	(d) Adjusted Historical Test Period sum (b) thru (c)	(e) Projected Calendar Year 12 mos. ended 12/31/2021	(f) 12 mos. ended 12/31/2022	(g) 12 mos. ended 12/31/2023
			Capital Expenditures					
1	**Base Capital Programs**							
2	Emergent Replacements							
3	Storm	1/	150,897	9,499	160,396	380,618	170,164	175,098
4	Non - Storm	1/	155,324	7,242	162,566	190,816	172,466	177,467
5	Substation Reactive	1/	38,131	3,668	41,799	40,621	44,345	45,631
6	Emergent Replacement Reduction Based on Strategic Spend		-	-	-	-	(15,221)	(26,494)
7	Subtotal Emergent Replacements		344,352	20,408	364,761	612,055	371,753	371,702
8	Customer Connections, Relocations & Other							
9	Connections and New Load	2/	137,221			187,535	168,276	173,156
10	Relocations	2/	24,128			31,917	27,523	27,294
11	Electric System Equipment	2/	56,182			25,650	40,660	41,839
12	NRUC and Improvement Blankets	2/	27,168			22,135	30,495	31,379
13	General Plant, Tools & Equipment and Miscellaneous	2/	8,569			9,031	12,367	9,125
14	Public Lighting Department Project	2/	21,051			21,282	7,700	-
15	Subtotal Customer Connections, Relocations & Other		274,320			297,550	287,021	282,793
16	Customer Advances for Construction	2/	(21,395)			(31,423)	(26,453)	(27,220)
17	**Total Base Capital Programs**		**597,277**			**878,181**	**632,321**	**627,275**
18	**Strategic Capital Programs**							
19	Infrastructure Resilience and Hardening	3/	167,035			189,706	318,833	351,543
20	Infrastructure Redesign and Modernization	4/	49,311			92,399	258,176	325,566
21	Technology and Automation	5/ 6/ 7/	91,293			73,421	119,461	140,918
22	**Subtotal Strategic Capital Programs**		**307,640**			**355,525**	**696,469**	**818,027**
23	**Total Capital**		**904,916**			**1,233,707**	**1,328,790**	**1,445,302**
24	**Regulatory Asset**							
25	Advanced Distribution Management System (ADMS)	8/	**3,989**		**3,989**	**2,837**	**8,409**	**974**

1/ Exhibit A-12, Schedule B5.4 - page 3
2/ Exhibit A-12, Schedule B5.4 - pages 4-5, lines 9, 19, 26, 33, 38, 39 & 41
3/ Exhibit A-12, Schedule B5.4 - page 8, line 29
4/ Exhibit A-12, Schedule B5.4 - page 10, line 89
5/ Exhibit A-12, Schedule B5.4 - page 11, line 41
6/ ADMS/SOC projects sponsored by Company Witness M. Elliott-Andahazy
7/ AMI projects sponsored by Company Witness P. Smith
8/ Regulatory Asset treatment per Case No. U-20162
9/ Normalization Adjustment:

	Amount
Emergent Replacements (Exh. B5.4, p.3, Line 24, col. (h)	20,408

Michigan Public Service Commission
DTE Electric Company
Projected Capital Expenditures
Distribution Plant - Emergent Replacements
($000)

Case No.: U-20836
Exhibit: A-12
Schedule: B5.4
Witness: S. G. Pfeuffer
Page: 3 of 12

Line No.	(a) Description		(b) Historical 12 mos. ended 12/31/2018	(c) Historical 12 mos. ended 12/31/2019	(d) Historical 12 mos. ended 12/31/2020	(e) Historical 3-year average 1/	(f) 11/1/2022 - 10/31/2023 Test Year	(g) 1/1/2020 - 12/31/2020 Historical	(h) Emergent Replacements Adjustment (f) - (g)
1	**Base Capital Programs**								
2	**Emergent Replacements**								
3	**Storm**		142,108	178,931	150,897	157,312			
4	Inflation Adjustment		6,030	3,221	-	3,084			
5	Inflation Adjusted Historical Capital		148,138	182,152	150,897	160,396	160,396	150,897	9,499
6	Inflation 1/1/21 -12/31/21	3.10%					4,972	4,678	294
7	Inflation 1/1/22 -12/31/22	2.90%					4,796	4,512	284
8	Inflation 1/1/23-10/31/23	2.42%					4,112	3,869	244
9	Projected Storm Replacements						174,276	163,955	10,320
10	**Non-Storm**		159,555	163,112	155,324	159,330			
11	Inflation Adjustment		6,770	2,936	-	3,235			
12	Inflation Adjusted Historical Capital		166,326	166,048	155,324	162,566	162,566	155,324	7,242
13	Inflation 1/1/21 -12/31/21	3.10%					5,040	4,815	225
14	Inflation 1/1/22 -12/31/22	2.90%					4,861	4,644	217
15	Inflation 1/1/23-10/31/23	2.42%					4,168	3,982	186
16	Projected Non-Storm Replacements						176,634	168,765	7,869
17	**Substation Reactive**		44,275	40,386	38,131	40,931			
18	Inflation Adjustment		1,879	727	-	869			
19	Inflation Adjusted Historical Capital		46,153	41,113	38,131	41,799	41,799	38,131	3,668
20	Inflation 1/1/21 -12/31/21	3.10%					1,296	1,182	114
21	Inflation 1/1/22 -12/31/22	2.90%					1,250	1,140	110
22	Inflation 1/1/23-10/31/23	2.42%					1,072	978	94
23	Projected Substation Reactive Replacements						45,417	41,431	3,985
24	**Total Emergent Replacements Normalization Adjustment (Line 5 + Line 12 + Line 19) Pre-inflation**						**364,761**	**344,352**	**20,408**
25	Inflation 1/1/21 -12/31/21	3.10%					11,308	10,675	633
26	Inflation 1/1/22 -12/31/22	2.90%					10,906	10,296	610
27	Inflation 1/1/23-10/31/23	2.42%					9,352	8,829	523
28	Total Projected Emergent Replacements Expense (Line 11 + Line 18 + Line 25)						**396,326**	**374,152**	**22,175**
						Savings	**(24,615)**		

1/ Five year average of actual expenditures adjusted for inflation is included in this request
2/ Historical normalization adjustment carried to Base Capital Programs - see Exhibit A-12, B5.4, page 2, line 7, col. (c)

Michigan Public Service Commission
DTE Electric Company
Projected Capital Expenditures
Distribution Plant - Connections, Relocations and Other
($000)

Case No.: U-20836
Exhibit: A-12
Schedule: B5.4
Witness: S. G. Pfeuffer
Page: 4 of 12

Line No.	Description		(b) Historical 12 mos. ended 12/31/2020	(c) Projected Calendar Year 12 mos. ended 12/31/2021	(d) Projected Calendar Year 12 mos. ended 12/31/2022	(e) Projected Calendar Year 12 mos. ended 12/31/2023	(f) Bridge Period 22 mos. ending 10/31/2022	(g) Test Year 12 mos. ended 10/31/2023
				Capital Expenditures				
1	**Connections and New Load**							
2	Small Load Growth Projects (Blanket)		18,053	19,872	19,152	19,707	35,832	19,615
3	Customer Connections		89,211	113,632	117,342	120,745	211,418	120,178
4	Customer Connections CIAC		(14,756)	(18,796)	(19,410)	(19,972)	(34,971)	(19,879)
5	Customer Connections (Net of CIAC)		74,455	94,836	97,933	100,773	176,447	100,300
6	New Business Projects	1/	29,957	54,031	31,781	32,703	80,515	32,549
7	New Business Projects CIAC		(4,709)	(8,494)	(4,996)	(5,141)	(12,657)	(5,117)
8	Subtotal New Business Projects (net of CIAC)		25,248	45,537	26,785	27,562	67,858	27,433
9	**Total Connections and New Load**		**137,221**	**187,535**	**168,276**	**173,156**	**327,765**	**172,342**
10	**Total Connections and New Load CIAC**		(19,466)	(27,290)	(24,406)	(25,113)	(47,628)	(24,995)
11	**Total Connections and New Load (Net of CIAC)**		117,755	160,246	143,870	148,042	280,138	147,347
12	**Relocations**							
13	Small Relocation Projects (Blanket)		14,943	7,208	15,853	16,313	20,419	16,236
14	Major Infrastructure Relocation Project							
15	Gordie Howe International Bridge		(874)	3,161	998	-	3,993	166
16	Relocation Projects (excl.Major Infrastructure Projects)	2/	10,059	21,548	10,671	10,981	30,441	10,929
17	Relocation Projects CIAC		(1,930)	(4,134)	(2,047)	(2,107)	(5,840)	(2,097)
18	Subtotal Relocation Projects (Net of CIAC)		8,129	17,414	8,624	8,874	24,601	8,833
19	**Total Relocations**		**24,128**	**31,917**	**27,523**	**27,294**	**54,853**	**27,332**
20	**Total Relocations CIAC**		(1,930)	(4,134)	(2,047)	(2,107)	(5,840)	(2,097)
21	**Total Relocations (Net of CIAC)**		22,199	27,783	25,476	25,187	49,013	25,235
22	**Electric System Equipment**							
23	Distribution Transformers & Regulators		17,856	151	-	-	151	-
24	Major Equipment		21,435	12,550	22,740	23,400	31,500	23,290
25	Meters		16,891	12,949	17,920	18,439	27,882	18,353
26	**Total Electric System Equipment**		**56,182**	**25,650**	**40,660**	**41,839**	**59,533**	**41,642**

Michigan Public Service Commission
DTE Electric Company
Projected Capital Expenditures
Distribution Plant - Connections, Relocations and Other
($000)

Case No.: U-20836
Exhibit: A-12
Schedule: B5.4
Witness: S. G. Pfeuffer
Page: 5 of 12

Line No.	(a) Description	(b) Historical 12 mos. ended 12/31/2020	(c) Projected Calendar Year 12 mos. ended 12/31/2021	(d) Projected Calendar Year 12 mos. ended 12/31/2022	(e) Projected Calendar Year 12 mos. ended 12/31/2023	(f) Bridge Period 22 mos. ending 10/31/2022	(g) Test Year 12 mos. ended 10/31/2023
				Capital Expenditures			
27	**NRUC and Improvement Blankets**						
28	System Improvements	12,117	8,607	14,527	14,949	20,713	14,878
29	Normal Retirement Unit Changeouts (NRUC)	7,398	5,319	7,849	8,076	11,859	8,038
30	Operational Technologies	5,401	5,546	5,730	5,897	10,322	5,869
31	Batteries and Chargers	2,058	2,628	2,183	2,246	4,447	2,236
32	Animal Mitigation	194	35	206	212	206	211
33	**Total NRUC and Improvement Blankets**	**27,168**	**22,135**	**30,495**	**31,379**	**47,547**	**31,232**
34	**General Plant, Tools & Equipment and Miscellaneous**						
35	Substation Physical Security	562	1,644	2,000	-	3,310	333
36	Warren SC Transformer Yard Reorganizaton		-	1,873	384	1,561	632
37	General Plant, Tools & Equipment and Miscellaneous	8,007	7,387	8,494	8,741	14,466	8,700
38	**Total General Plant, Tools & Equipment and Miscellaneous**	**8,569**	**9,031**	**12,367**	**9,125**	**19,337**	**9,665**
39	**Public Lighting Department Project**	21,051	21,282	7,700	-	28,982	-
40	**Total Customer Connections, Relocations & Other**	274,320	297,550	287,021	282,793	538,017	282,214
41	**Total Cust Connections, Relocations & Other CIAC**	(21,395)	(31,423)	(26,453)	(27,220)	(53,468)	(27,092)
42	**Total Cust Connections, Relocations & Other Net of CIAC**	252,924	266,126	260,568	255,572	484,549	255,122

1/ Exhibit A-12, Schedule B5.4 - page 6, line 59
2/ Exhibit A-12, Schedule B5.4 - page 7, line 30

Michigan Public Service Commission Case No.: U-20836
DTE Electric Company Exhibit: A-12
Projected Capital Expenditures Schedule: B5.4
Distribution Plant - Prior Year's Projects Witness: S. G. Pfeuffer
($000) Page: 6 of 12

Line No.	(a) Description	(b) Historical 12 mos. ended 12/31/2020
1	**Prior Year's New Business Projects:**	
2	New Business for downtown complex	2,683
3	New Business fed from 120kV Waterman Zug	2,504
4	New Business fed from TEMPL, STANT, MADSN	2,480
5	New Business fed from CORTL	2,222
6	New Business fed from KERN Substation	2,188
7	New Business fed from MIDTN SPOOL	2,013
8	New Business fed from Seaside	1,848
9	New Business fed from Cato, St Antoine	1,841
10	Quaker Transformer Upgrade	1,405
11	Misc. New Business Specific Projects	1,395
12	New Substation (Nitro) to support new load	1,283
13	New Skid Mount Substation Orion Township	1,068
14	New Business fed from Midtown	955
15	New Business fed from CODY	691
16	New Substation (Morton) to support new load	574
17	New Business fed from APACE	484
18	New Business fed from PRICE	442
19	New Business fed from Hood Substation	352
20	New Business Health Co Campus	332
21	Load Growth: Morton	314
22	New Business fed from CATO STANT	292
23	New Business fed from INKST	285
24	New Business Compressor Station	268
25	New Business fed from AKRON	192
26	New Business fed from Sheldon	175
27	New Business fed from GRAYL	170
28	New Class I Farmington Hills	168
29	New Business fed from Saturn	159
30	New Business fed from BURTN	146
31	New Business fed from Alamo Substation	146
32	New Business fed from Stone Pool, Midtown	119
33	New Business fed from Lombard	113
34	New Business fed from WHITR2699	106
35	New Business alley vacate	101
36	New Business Henry St	91
37	Load Growth: Globe	89
38	Expand Explorer Substation for New Business	42
39	New Business for Development in Detroit Park	42
40	Duvall DC9644 & DC9460T	41
41	New Business Willis & Woodward	41
42	New Business: CORKT New Circuits	41
43	New Substation (Globe) to support new load	19
44	New Business Data Center	15
45	New Business fed from Jupiter Navarre	7
46	New Class I for Research Facility	6
47	New Business fed from Atlanta	3
48	New STDF for Hospital Expansion in Pt. Huron	3
49	New Business Auto Data Center	1
50	New Business for Apartments	1
51	New Class I on Trunk 2032	1
52	Mercury-MOS GLBRT8095	1
53	New Business fed from Fleming Substation	0
54	New STDF for Hospital Expansion	0
55	New Class I on the Bismarck-Lenox 120 kV line	0
56	New Business fed from ANGLA	0
57	Prior Year's New Business Projects	0
58	New Business for M1 Rail	0
59	**Total Prior Year's New Business Projects**	**29,957**

Michigan Public Service Commission Case No.: U-20836
DTE Electric Company Exhibit: A-12
Projected Capital Expenditures Schedule: B5.4
Distribution Plant - Prior Year's Projects Witness: S. G. Pfeuffer
($000) Page: 7 of 12

Line No.	(a) Description	(b) Historical 12 mos. ended 12/31/2020
1	**Prior Year's Relocation Projects:**	
2	Relocate for Trk 359/ 306 /318A-B & DC209	2,993
3	Cass I-94 Bridge	1,245
4	Bates & Monroe Alley	1,217
5	Milwaukee Bridge Relocation	921
6	23 Mile Rd Relocation Phase 2	675
7	Pipeline Relocation	603
8	Dearborn Relocation	559
9	Park Rd Relocation	537
10	Mt. Elliot I-94 Bridge Relocation	488
11	Grand River I-94 Bridge	264
12	Maple Rd Relocation	359
13	New Boston Twp Relocation	57
14	Temple West block Relocation	27
15	Relocate for Manhole -Midtown, Stone Pool and Garfield	27
16	Relocate for Trk 682, Trk 675, Trk 663A-S	20
17	Relocate for rail right of way	17
18	ZEBRA Relocation	14
19	Relocate for Trk 2107A-B Relocation	14
20	Wahington Rd Relocation	13
21	Mound Rd Relocation	13
22	Relocate for ITC	5
23	Prior Year's Relocation Projects	1
24	Vining Rd Relocation	1
25	TRK1418 Relocation	1
26	23 Mile Rd Relocation	0
27	Armstrong Rd. Relocation	0
28	Baldwin Rd. Relocation, Orion	(4)
29	Telegraph Rd. Widening	(8)
30	**Total Prior Year's Relocation Projects**	**10,059**

Michigan Public Service Commission
DTE Electric Company
Projected Capital Expenditures
Distribution Plant - Infrastructure Resilience and Hardening
($000)

Case No.: U-20836
Exhibit: A-12
Schedule: B5.4
Witness: S. G. Pfeuffer
Page: 8 of 12

(a)	(b)	(c)	(d)	(e)	(f)	(g)
			Capital Expenditures			
	Historical	**Projected Calendar Year**			**Bridge Period**	**Test Year**
Line No. **Description**	**12 mos. ended 12/31/2020**	**12 mos. ended 12/31/2021**	**12 mos. ended 12/31/2022**	**12 mos. ended 12/31/2023**	**22 mos. ending 10/31/2022**	**12 mos. ended 10/31/2023**
1 **Infrastructure Resilience and Hardening**						
2 Mobile Fleet Program	2,386	3,700	4,480	3,305	7,433	3,501
3 Substation Risk: Drexel	1,378	1,010	847	-	1,716	141
4 Substation Risk: Chestnut	-	1,109	500	2,932	1,526	2,527
5 Substation Risk: Savage	1,161	150	41	-	184	7
6 Substation Risk: Apache	172	1,230	8,496	9,225	8,310	9,104
7 Substation Risk: Port Huron	3,775	2,912	8	-	2,919	1
8 Substation Risk: Belleville Switchgear Decommission	5	447	1,132	-	1,391	189
9 4.8 kV Hardening	55,165	68,246	115,857	114,000	164,793	114,310
10 Pole and Pole Top Hardware (PTMM)	36,364	33,444	58,912	93,500	82,537	87,735
11 Cable Replacement Program	12,139	13,430	35,126	44,200	42,701	42,688
12 Cable Replacement: Harsen's Island	353	-	-	-	-	-
13 Frequent Outage Program (CEMI) including Circuit Renewal	26,374	30,058	46,039	22,074	68,424	26,068
14 System Resiliency - Efficient Frontier	1,795	-	-	-	-	-
15 Breaker Replacement Program	10,931	11,672	15,438	18,000	24,536	17,573
16 Pontiac Vaults	4,880	3,676	615	-	4,189	103
17 URD Replacement Program	964	5,190	6,027	10,000	10,212	9,338
18 URD Replacement Program: Detroit URD 1-1	59	1,581	2	-	1,583	0
19 4.8 kV Relay Improvements (Delta Ground Detection Program)	2,052	2,721	3,075	8,500	5,283	7,596
20 40 kV: Automatic Pole Top Switch	819	1,500	5,300	6,300	5,917	6,133
21 Disconnect and Switcher Replacement	2,093	3,323	3,525	3,551	6,261	3,547
22 SCADA Pole Top Device Replacement	1,446	918	1,425	1,900	2,106	1,821
23 Substation Regulator Replacement	-	-	425	425	354	425
24 Steel Pole Highway Crossings	-	113	3,000	8,000	2,613	7,167
25 Station Upgrade: Warren (Relay Replacement)	2,260	1,031	-	-	1,031	-
26 Station Upgrade: Northeast (Relay Replacement)	464	2,245	8,234	-	9,106	1,372
27 Station Upgrade: Lincoln	-	-	330	5,300	275	4,472
28 Station Upgrade: Navarre	-	-	-	330	-	275
29 **Total Infrastructure Resilience and Hardening Projects and Programs**	**167,035**	**189,706**	**318,833**	**351,543**	**455,400**	**346,091**

Michigan Public Service Commission
DTE Electric Company
Projected Capital Expenditures
Distribution Plant - Infrastructure Redesign and Modernization
($000)

Case No.: U-20836
Exhibit: A-12
Schedule: B5.4
Witness: S. G. Pfeuffer
Page: 9 of 12

Line No.	(a) Description	(b) Historical 12 mos. ended 12/31/2020	(c) Projected Calendar Year 12 mos. ended 12/31/2021	(d) Projected Calendar Year 12 mos. ended 12/31/2022	(e) Projected Calendar Year 12 mos. ended 12/31/2023	(f) Bridge Period 22 mos. ending 10/31/2022	(g) Test Year 12 mos. ended 10/31/2023
			Capital Expenditures				
1	**Infrastructure Redesign and Modernization**						
2	Ann Arbor System Improvements: State Substation	3,788	4,610	13,466	-	15,832	2,244
3	Ann Arbor System Improvements: Apex (Blue) Substation	3,343	2,534	4,052	-	5,910	675
4	Ann Arbor System Improvements: Argo 40kV Reconfiguration	-	-	6,649	16,677	5,541	15,006
5	Transformer High Side Protection Program	215	1,925	3,000	3,000	4,425	3,000
6	PQ Meter Fault Locating	-	-	50	1,739	42	1,457
7	Subtransmission Redesign & Rebuild: Prior Year's	926	-	-	-	-	-
8	Subtransmission Redesign & Rebuild: Tie 4104	-	15	300	5,327	265	4,489
9	Subtransmission Redesign & Rebuild: Tie 3416	6,035	-	-	-	-	-
10	Subtransmission Redesign & Rebuild: Maxwell Amherst	2,568	270	-	-	270	-
11	Subtransmission Redesign & Rebuild: Tie 810	1,172	1,469	18,167	16,178	16,608	16,509
12	Subtransmission Redesign & Rebuild: Trunk 7106	188	3,160	11	-	3,169	2
13	Subtransmission Redesign & Rebuild: Trunk 2255	6	352	3,956	35	3,648	689
14	Subtransmission Redesign & Rebuild: Trunk 2237-ST	11	141	2,238	-	2,006	373
15	Subtransmission Redesign & Rebuild: Trunk 7333	-	3,047	18	-	3,062	3
16	Subtransmission Redesign & Rebuild: Sandusky Transformer 101 Breaker	-	50	1,500	-	1,300	250
17	Subtransmission Redesign & Rebuild: Sandusky Transformer 102 Addition	-	-	-	116	-	97
18	Subtransmission Redesign & Rebuild: Boyne	111	4,740	18,044	2,906	19,777	5,429
19	Subtransmission Redesign & Rebuild: Tie 6907	-	-	-	71	-	59
20	Subtransmission Redesign & Rebuild: Tie 7504	13	2	-	1,074	2	895
21	Subtransmission Redesign & Rebuild: Tie 4105	141	5,752	10,000	19,948	14,085	18,290
22	Subtransmission Redesign & Rebuild: Trunk 2308	-	-	-	1,898	-	1,582
23	Subtransmission Redesign & Rebuild: Tie 1568	-	7	46	862	45	726
24	Subtransmission Redesign & Rebuild: Trunk 4217	-	277	55	5,001	322	4,176
25	Subtransmission Redesign & Rebuild: Trunk 3509	-	15	61	1,504	66	1,263
26	Subtransmission Redesign & Rebuild: Trunk 4266	-	-	300	3,548	250	3,007
27	Subtransmission Redesign & Rebuild: Badax Transformer 102 Addition	-	15	2,223	1,370	1,867	1,512
28	Subtransmission Redesign & Rebuild: Trunk 4245	-	13	300	4,288	263	3,623
29	Subtransmission Redesign & Rebuild: Tie 6602	-	-	-	660	-	550
30	Subtransmission Redesign & Rebuild: Trunk 4911	-	-	-	447	-	373
31	Subtransmission Redesign & Rebuild: Custer Republic	-	-	-	89	-	74
32	Subtransmission Redesign & Rebuild: Pigeon Area Improvement	-	-	465	3,087	388	2,650
33	Subtransmission Redesign & Rebuild: Trunk 2443	-	-	-	124	-	103
34	Subtransmission Redesign & Rebuild: Trunk 5838	-	-	-	178	-	148
35	Subtransmission Redesign & Rebuild: Trunk 2419	-	-	-	169	-	141
36	Subtransmission Redesign & Rebuild : Small Projects & Reserve	-	-	-	3,500	-	2,917
37	Subtransmission Breaker Short Circuit Violations	-	780	2,915	2,400	3,209	2,486
38	Subtransmission Redesign & Rebuild: Slocum	-	-	500	1,740	417	1,533
39	Station Upgrade: Cortland Station Expansion	1	1,194	1,886	6,355	2,766	5,610
40	Subtransmission Redesign & Rebuild: 40kV Capacitor Banks at Armada and Adair	-	1,052	2,270	-	2,943	378
41	CODI: Charlotte Network Upgrade	10,336	8,283	11,636	12,872	17,979	12,666
42	CODI: Targeted Network Secondary Cable Replacement	2,868	1,202	1,850	3,800	2,743	3,475
43	CODI: Corktown Substation	1,071	12,762	1,298	-	13,844	216
44	CODI: Islandview Substation	139	1,284	16,000	25,145	14,617	23,621
45	CODI: CATO Substation Expansion	-	-	650	10,408	542	8,782
46	CODI: Howard Conversion	-	-	-	700	-	583
47	CODI: Midtown Substation Expansion	3,355	6,530	3,010	-	9,038	502

Michigan Public Service Commission
DTE Electric Company
Projected Capital Expenditures
Distribution Plant - Infrastructure Redesign and Modernization
($000)

Case No.: U-20836
Exhibit: A-12
Schedule: B5.4
Witness: S. G. Pfeuffer
Page: 10 of 12

Line No.	(a) Description	(b) Historical 12 mos. ended 12/31/2020	(c) Projected Calendar Year 12 mos. ended 12/31/2021	(d) Projected Calendar Year 12 mos. ended 12/31/2022	(e) Projected Calendar Year 12 mos. ended 12/31/2023	(f) Bridge Period 22 mos. ending 10/31/2022	(g) Test Year 12 mos. ended 10/31/2023
		Capital Expenditures					
48	CODI: Alfred Substation Expansion	-	446	7,608	1,413	6,786	2,446
49	CODI: Garfield Network Upgrade	1,058	9,977	15,000	30,000	22,477	27,500
50	CODI: Kent/Gibson Conversion	58	210	7,000	8,875	6,043	8,563
51	4.8 kV CC: Hilton Substation and Circuit Conversion	434	144	-	-	144	-
52	4.8 kV CC: Zenon Substation and Circuit Conversion	980	29	-	-	29	-
53	4.8 kV CC: Cortland / Oakman / Linwood Consolidation	2,009	1,411	2,851	-	3,787	475
54	4.8 kV CC: Ariel Substation and Circuit Conversion	59	853	-	-	853	-
55	4.8 kV CC: I-94 Substation and Circuit Conversion	-	-	-	4,971	-	4,142
56	4.8 kV CC: Almont Relief and Circuit Conversion (Midas)	516	6,726	13,609	1,062	18,067	3,153
57	4.8 kV CC: Buckler Circuit Conversion	442	2,308	11,550	6,131	11,933	7,034
58	4.8 kV CC: Calla Circuit Conversion	1,018	255	-	-	255	-
59	4.8 kV CC: Northville Decommissioning and Circuit Conversion	0	-	-	-	-	-
60	4.8 kV CC: Lapeer - Elba Expansion and Circuit Conversion (Apollo)	169	461	6,536	20,881	5,908	18,490
61	4.8 kV CC: McKinstry Sub Decommission	-	100	4,591	471	3,926	1,158
62	4.8 kV CC: White Lake Decommissioning and Circuit Conversion	2	0	-	-	0	-
63	4.8 kV CC: Quincy Conversion	5	913	3,549	-	3,871	592
64	4.8 kV CC: Pinegrove Substation Relocation and Conversion	-	256	24,500	31,530	20,673	30,358
65	4.8 kV CC: Pinegrove Substation Relocation and Conversion CIAC	-	-	(15,000)	(18,000)	(12,500)	(17,500)
66	4.8 kV CC: Promenade Site Prep and Below Grade	-	1,024	12,032	29	11,050	2,030
67	4.8 kV CC: Hawthorne Relief and Circuit Conversion	-	-	360	6,000	300	5,060
68	4.8 kV CC: Birmingham Decommissioning and Circuit Conversion	44	-	227	1,853	189	1,582
69	4.8kV CC: ISO Camden	-	-	-	500	-	417
70	4.8kV CC: ISO Gilbert	-	-	-	500	-	417
71	8.3 kV CC: Pontiac Overhead Conversion	460	816	3,409	10,950	3,656	9,693
72	8.3 kV CC: Pontiac Underground Conversion	3	58	800	1,208	725	1,140
73	System Loading: Prior Year	1	-	-	-	-	-
74	System Loading: Brest Substation	133	55	-	-	55	-
75	System Loading: Carleton	1,255	2,135	2	-	2,137	0
76	System Loading: Grayling	167	0	-	-	0	-
77	System Loading: Prospect	73	2	539	-	451	90
78	System Loading: Mandy 307 Load Transfer	100	944	-	-	944	-
79	System Loading: Brown City	61	69	2,736	7,481	2,349	6,690
80	System Loading: Mack Transformer 102	3,801	230	-	-	230	-
81	System Loading: Port Sanilac	-	-	448	3,238	373	2,773
82	System Loading: Richmond/Armada	176	520	5,011	3,850	4,695	4,043
83	System Loading: Cody	-	-	50	164	42	145
84	System Loading: Otsego/Capac/Shaw	-	-	325	1,143	271	1,007
85	System Loading: Macomb/Golf	-	-	717	2,102	598	1,871
86	System Loading: Grenada	-	8	747	2,000	630	1,791
87	Pilot: Strategic and Service Undergrounding	-	306	20,698	40,000	17,554	36,783
88	Pilot: Primary Deconductoring	-	664	1,368	-	1,804	228
89	**Total Infrastructure Redesign and Modernization Projects and Programs**	**49,311**	**92,399**	**258,176**	**325,566**	**307,545**	**314,334**

Michigan Public Service Commission
DTE Electric Company
Projected Capital Expenditures
Distribution Plant - Technology and Automation
($000)

Case No.: U-20836
Exhibit: A-12
Schedule: B5.4
Witness: S. G. Pfeuffer
M. Elliott-Andahazy 1/ 3/
P. Smith 2/
Page: 11 of 12

Line No.	(a) Description		(b) Historical 12 mos. ended 12/31/2020	(c) Projected Calendar Year 12 mos. ended 12/31/2021	(d) Projected Calendar Year 12 mos. ended 12/31/2022	(e) Projected Calendar Year 12 mos. ended 12/31/2023	(f) Bridge Period 22 mos. ending 10/31/2022	(g) Test Year 12 mos. ended 10/31/2023
				Capital Expenditures				
1	**Technology and Automation**							
2	ADMS: DMS/OMS	1/ 3/	19,393	21,928	34,138	8,089	50,377	12,430
3	ADMS: Network Management System	1/	5,506	637	2,800	2,900	2,971	2,883
4	SOC: ESOC	1/	51,463	14,062	369	-	14,369	62
5	SOC: ASOC	1/	-	577	9,982	23,967	8,895	21,636
6	Grid Automation Telecommunications (13.2kV Telecommunications)		761	9,129	14,800	19,100	21,462	18,383
7	Distribution Sensing and Monitoring (incldg Line Sensors)		2,495	2,000	4,866	10,500	6,055	9,561
8	SCADA / AMI Enhancements		-	-	750	1,500	625	1,375
9	Automation: Substation		10	126	2,040	3,000	1,826	2,840
10	Automation: Distribution		-	-	2,022	5,000	1,685	4,504
11	CVR/VVO		960	4,507	7,000	17,402	10,340	15,668
12	NWA: O'Shea Energy Storage		493	1,268	125	-	1,373	21
13	NWA: Battery Trailer		-	-	500	1,500	417	1,333
14	NWA: Omega Load Relief		-	3,747	4,021	-	7,098	670
15	NWA: Fisher Load Relief		-	46	839	3,382	745	2,958
16	NWA: Port Austin Load Relief		-	100	1,899	2,501	1,682	2,401
17	NWA: Veridian		-	-	1,841	5,574	1,534	4,952
18	NWA: Small Solar and Storage Testbed		166	365	375	275	678	292
19	NWA: EV Charging Demonstration at ACM		-	473	800	1,300	1,140	1,217
20	Technology Programs & NWA		1,676	2	-	-	2	-
21	DERMS		-	-	2,540	2,540	2,117	2,540
22	DER Control		-	-	290	290	242	290
23	Mobile Technology		-	-	450	4,575	375	3,888
24	Work Management & Scheduling Upgrades		-	-	1,500	10,900	1,250	9,333
25	Substation Design Tool Upgrades		-	143	1,423	1,088	1,328	1,144
26	Asset Management Upgrades		-	-	1,300	2,075	1,083	1,946
27	Load Forecasting & Analytics		-	674	3,150	3,125	3,299	3,129
28	Interconnection Process Enablement		-	-	3,768	3,616	3,140	3,641
29	Hosting Capacity Enablement		-	-	250	250	208	250
30	AMI: Installations	2/	215	-	-	-	-	-
31	AMI: Meter Communications Upgrades	2/	7,975	1,310	500	500	1,727	500
32	Microwave End of Life		-	-	500	500	417	500
33	SCADA Remote Access and Configuration Platform		177	645	1,271	-	1,704	212
34	Automation Configuration and Test Record Database		-	168	2,250	1,742	2,043	1,827
35	Grid Edge Insights & New Technology		-	572	1,700	1,800	1,989	1,783
36	Sensor, Network and Algorithm Development (Solar Deployment)		-	-	437	1,178	364	1,055
37	Other Modernize Grid Management		-	-	4,663	750	3,886	1,402
38	Substation Cybersecurity		-	-	2,300	-	1,917	383
39	Operational Technology and Error Free Communication		-	10,941	2,000	-	12,608	333
40	Analog Lines Elimination		4	-	-	-	-	-
41	**Total Technology and Automation Projects and Programs**		**91,293**	**73,421**	**119,461**	**140,918**	**172,972**	**137,342**

1/ ADMS/SOC projects sponsored by Company Witness M. Elliott-Andahazy
2/ AMI projects sponsored by Company Witness P. Smith
3/ Investment also includes ADMS Reporting and ClickSoft OH/UG projects as supported by Company Witness M. Elliott Andahazy

Michigan Public Service Commission
DTE Electric Company
Projected Capital Expenditures
Allowance for Funds Used During Construction (AFUDC)
Distribution Operations
($000)

Case No.: U-20836
Exhibit: A-12
Schedule: B5.4
Witness: S. G. Pfeuffer
Page: 12 of 12

Line No.	(a) Description		(b) Adjusted Historical 12 mos. ended 12/31/2020	(c) Projected 12 mos. ended 10/31/2023
1	**Base Capital Programs:**			
2	Gordie Howe International Bridge		811	-
3	Other Routine Base Capital Programs	**1/**	803	841
4	**Subtotal Base Capital Programs**		**1,614**	**841**
5	**Strategic Capital Programs:**			
6	Infrastructure Resilience and Hardening	**1/**	1,490	3,085
7	Infrastructure Redesign:			
	Ann Arbor System Improvements		1,459	299
	Other Infrastructure Redesign	**1/**	2,070	14,532
8	Technology and Automation:			
9	SOC Modernization		2,628	-
10	ADMS Projects		1,613	531
11	Other Technology and Automation	**1/**	48	322
12	**Subtotal Strategic Capital Programs**		**9,309**	**18,769**
13	**Total AFUDC - Distribution Operations**	**2/**	**10,923**	**19,609**

1/ AFUDC estimates for platform are developed at a high level based on historical trend
2/ The projected AFUDC amounts are based on the authorized U-20561 rate of 5.463%

Michigan Public Service Commission
DTE Electric Company
Distribution Plant Capital Project Detail - Infrastructure Redesign & Modernization

Case No.: U-20836
Exhibit: A-23
Schedule: M5 Revised
Witness: S. G. Pfeuffer
Page: 172 of 347

(a)	(b)
Program:	CODI: Islandview Substation (Pg. 1 of 4)
Purpose and Necessity:	New customer load has been added along the Detroit riverfront and additional development is anticipated in the future. The new substation is to be sited east of downtown Detroit near the riverfront and allow for the decommissioning of Walker substation and half of Pulford substation. Both Pulford and Walker substations have been in service since the 1920's and cannot reliably serve new load. The new substation will also provide capacity to serve customers being transitioned from the Detroit Public Lighting Department system to the DTE Electric system.
Category:	Infrastructure Redesign & Modernization

Michigan Public Service Commission
DTE Electric Company
Distribution Plant Capital Project Detail - Infrastructure Redesign & Modernization

Case No.: U-20836
Exhibit: A-23
Schedule: M5 Revised
Witness: S. G. Pfeuffer
Page: 173 of 347

(a)	(b)
Program:	CODI: Islandview Substation (Pg. 2 of 4)
Line Number:	Exhibit A-12, Schedule B5.4, Page 9, Line 44
DGP Section:	11.4
Scope:	• Construct a new Class 'A' 13.2 kV substation with two transformers and a setup for a future third transformer position • Pre-Convert existing 4.8 kV circuits from Walker Substation - 22 circuits • Pre-Convert existing 4.8 kV circuits from Pulford Substation - 10 circuits • Convert and transfer WALKR and PULFD circuits to new substation • Decommission cable for four trunk lines (24 kV) • Decommission WALKR Substation

Michigan Public Service Commission
DTE Electric Company
Distribution Plant Capital Project Detail - Infrastructure Redesign & Modernization

Case No.: U-20836
Exhibit: A-23
Schedule: M5 Revised
Witness: S. G. Pfeuffer
Page: 174 of 347

(a) (b)

Program:	CODI: Islandview Substation (Pg. 3 of 4)						
Customer benefit / Effect on cost of operation and reliability:	• Provide sufficient capacity to serve growing areas • Decommission aging infrastructure and reduce major event risk • Enhance safety, reliability and power quality for upgraded circuits by reducing 85% of circuit wire down events, customer interruptions, and customer minutes • Reduce trouble events and reactive costs for upgraded circuits by 85% for both circuit tree related and non-tree related reactive capital • Increase protection for the distribution system • Enhance grid technology and automation • Reduce new customer connection timeframe and cost						
Impact Dimension:	Safety	Load Relief	Regulatory Compliance	Major Event Risk	Reliability	O&M Avoidance	Reactive Capital Avoidance
Targeted:	x	x		x	x	x	x

Michigan Public Service Commission
DTE Electric Company
Distribution Plant Capital Project Detail - Infrastructure Redesign & Modernization

Case No.: U-20836
Exhibit: A-23
Schedule: M5 Revised
Witness: S. G. Pfeuffer
Page: 175 of 347

(a) (b)

Program:	CODI: Islandview Substation (Pg. 4 of 4)
Current Projects:	CODI: Islandview Substation
Budget Basis:	• Project Management Estimate
Cost:	Estimated project spend in 2021-2023: $42.4 M This project is expected to continue beyond 2023

~~**Test Year ($000's):**~~

	~~**2 mos. 11/01/22 12/31/22**~~	~~**10 mos. 01/01/23 10/31/23**~~	~~**Test Year 12 mos. ending 10/31/23**~~
~~Total Labor (DTE Electric & Contractors)~~	~~2,000~~	~~15,715~~	~~17,715~~
~~Material~~	~~400~~	~~3,143~~	~~3,543~~
~~Other~~	~~267~~	~~2,095~~	~~2,362~~
~~**Total**~~	~~**2,667**~~	~~**20,954**~~	~~**23,621**~~

Test Year ($000's):

	2 mos. 11/01/22 12/31/22	**10 mos. 01/01/23 10/31/23**	**Test Year 12 mos. ending 10/31/23**
Total Labor (DTE Electric &	1,787	14,458	16,245
Material	613	4,400	5,014
Other	267	2,095	2,362
Total	**2,667**	**20,954**	**23,621**

Michigan Public Service Commission
DTE Electric Company
Projected Capital Expenditures
Distribution Plant
($000)

Case No.: U-20561
Exhibit: A-12
Schedule: B5.4
Witness: M. A. Bruzzano
J. L. Robinson 6/
Page: 1 of 10

Line No.	(a) Description		(b) Historical 12 mos. ended 12/31/2018	(c) Projected Bridge Period 12 mos. ending 12/31/2019	(d) Projected Bridge Period 4 mos. ending 4/30/2020	(e) Projected Bridge Period 16 mos. ending 4/30/2020	(f) Projected Test Year 12 mos. ending 4/30/2021
				Capital Expenditures			
1	**Base Capital Programs**						
2	Emergent Replacements						
3	Storm	1/	142,108	106,256	36,446	142,702	110,394
4	Non - Storm	1/	159,555	107,056	36,720	143,776	111,225
5	Substation Reactive	1/	44,275	33,579	11,518	45,096	34,887
6	Emergent Replacement Reduction Based on Strategic Spend		-	(1,239)	(2,081)	(3,320)	(9,118)
7	Subtotal Emergent Replacements		345,938	245,651	82,603	328,254	247,388
8	Customer Connections, Relocations & Other						
9	Connections and New Load	2/	135,232	139,018	47,683	186,702	144,433
10	Relocations	2/	26,183	27,995	7,250	35,245	20,039
11	Electric System Equipment	2/	51,967	53,422	18,324	71,745	55,502
12	NRUC and Improvement Blankets	2/	17,879	18,379	6,304	24,684	19,095
13	General Plant, Tools & Equipment and Miscellaneous	2/	5,887	6,052	2,076	8,128	6,288
14	Subtotal Customer Connections, Relocations & Other		237,147	244,866	81,637	326,503	245,358
15	Customer Advances for Construction	2/	(30,623)	(31,480)	(10,798)	(42,278)	(32,706)
16	**Total Base Capital Programs**		**552,463**	**459,037**	**153,442**	**612,479**	**460,039**
17	**Strategic Capital Programs**						
18	Infrastructure Resilience and Hardening	3/	171,761	177,524	59,810	237,334	197,520
19	Infrastructure Redesign	4/	69,393	86,389	31,237	117,626	110,983
20	Technology and Automation	5/ 6/	38,803	127,802	35,460	163,262	85,130
21	**Subtotal Strategic Capital Programs**		**279,957**	**391,715**	**126,507**	**518,222**	**393,633**
22	**Total Capital**		**832,419**	**850,752**	**279,949**	**1,130,701**	**853,673**
23	**Regulatory Asset**						
24	Advanced Distribution Management System (ADMS)	7/		**520**	**5,410**	**5,930**	**11,697**

1/ Exhibit A-12, Schedule B5.4 - page 3
2/ Exhibit A-12, Schedule B5.4 - page 4, line 9, 19, 26, 33, 34 & 36
3/ Exhibit A-12, Schedule B5.4 - page 7, line 26
4/ Exhibit A-12, Schedule B5.4 - page 8, line 56
5/ Exhibit A-12, Schedule B5.4 - page 9, line 17
6/ AMI projects sponsored by Company Witness Robinson
7/ Regulatory Asset treatment per Case No. U-20162

Michigan Public Service Commission
DTE Electric Company
Projected Capital Expenditures
Distribution Plant
($000)

Case No.: U-20561
Exhibit: A-12
Schedule: B5.4
Witness: M. A. Bruzzano
J. L. Robinson 6/
Page: 2 of 10

Line No.	(a) Description		(b) Historical 12 mos. ended 12/31/2018	(c) Normalization Adjustment 8/	(d) Adjusted Historical Test Period sum (b) thru (c)	(e) Projected Calendar Year 12 mos. ending 12/31/2019	(f) 12 mos. ending 12/31/2020	(g) 12 mos. ending 12/31/2021
					Capital Expenditures			
1	**Base Capital Programs**							
2	Emergent Replacements							
3	Storm	1/	142,108	(38,746)	103,362	106,256	109,337	112,508
4	Non - Storm	1/	159,555	(55,415)	104,140	107,056	110,160	113,355
5	Substation Reactive	1/	44,275	(11,611)	32,664	33,579	34,553	35,555
6	Emergent Replacement Reduction Based on Strategic Spend		-	-	-	(1,239)	(6,242)	(14,869)
7	Subtotal Emergent Replacements		345,938	(105,772)	240,166	245,651	247,808	246,548
8	Customer Connections, Relocations & Other							
9	Connections and New Load	2/	135,232			139,018	143,050	147,198
10	Relocations	2/	26,183			27,995	21,750	16,618
11	Electric System Equipment	2/	51,967			53,422	54,971	56,565
12	NRUC and Improvement Blankets	2/	17,879			18,379	18,912	19,461
13	General Plant, Tools & Equipment and Miscellaneous	2/	5,887			6,052	6,227	6,408
14	Subtotal Customer Connections, Relocations & Other		237,147			244,866	244,911	246,251
15	Customer Advances for Construction	2/	(30,623)			(31,480)	(32,393)	(33,333)
16	**Total Base Capital Programs**		**552,463**			**459,037**	**460,326**	**459,467**
17	**Strategic Capital Programs**							
18	Infrastructure Resilience and Hardening	3/	171,761			177,524	179,430	233,700
19	Infrastructure Redesign	4/	69,393			86,389	93,710	145,530
20	Technology and Automation	5/ 6/	38,803			127,802	106,380	42,630
21	**Subtotal Strategic Capital Programs**		**279,957**			**391,715**	**379,520**	**421,860**
22	**Total Capital**		**832,419**			**850,752**	**839,846**	**881,326**
23	**Regulatory Asset**							
24	Advanced Distribution Management System (ADMS)	7/				**520**	**16,230**	**2,630**

1/ Exhibit A-12, Schedule B5.4 - page 3
2/ Exhibit A-12, Schedule B5.4 - page 4, line 9, 19, 26, 33, 34 & 36
3/ Exhibit A-12, Schedule B5.4 - page 7, line 26
4/ Exhibit A-12, Schedule B5.4 - page 8, line 56
5/ Exhibit A-12, Schedule B5.4 - page 9, line 17
6/ AMI projects sponsored by Company Witness Robinson
7/ Regulatory Asset treatment per Case No. U-20162
8/ Normalization Adjustment:

	Amount
Emergent Replacements (Exh. B5.4, p.3, Line 24, col. (j)	(105,772)

Michigan Public Service Commission
DTE Electric Company
Projected Capital Expenditures
Distribution Plant - Emergent Replacements
($000)

Case No.: U-20561
Exhibit: A-12
Schedule: B5.4
Witness: M. A. Bruzzano
Page: 3 of 10

Line No.	Description		(b) Historical 12 mos. ended 12/31/14	(c) Historical 12 mos. ended 12/31/15	(d) Historical 12 mos. ended 12/31/2016	(e) Historical 12 mos. ended 12/31/2017	(f) Historical 12 mos. ended 12/31/2018	(g) Historical 5-year average 1/	(h) 5/1/2020 - 4/30/2021 Test Year	(i) 1/1/2018 - 12/31/2018 Historical	(j) Emergent Replacements Adjustment (h) - (i)
			Capital Expenditures								
1	**Base Capital Programs**										
2	**Emergent Replacements**										
3	**Storm**		100,230	72,046	63,709	122,588	142,108	100,136			
4	Inflation Adjustment		6,029	4,258	2,899	2,942	-	3,226			
5	Inflation Adjusted Historical O&M		106,259	76,304	66,608	125,530	142,108	103,362	103,362	142,108	(38,746)
6	Inflation 1/1/19 -12/31/19	2.80%							2,894	3,979	(1,085)
7	Inflation 1/1/20 -12/31/20	2.90%							3,081	4,237	(1,155)
8	Inflation 1/1/21 -4/30/21	0.97%							1,057	1,453	(396)
9	Projected Storm Replacements								110,394	151,777	(41,382)
10	**Non-Storm**		62,665	76,258	81,042	126,187	159,555	101,141			
11	Inflation Adjustment		3,770	4,507	3,688	3,028	-	2,998			
12	Inflation Adjusted Historical O&M		66,435	80,765	84,730	129,216	159,555	104,140	104,140	159,555	(55,415)
13	Inflation 1/1/19 -12/31/19	2.80%							2,916	4,468	(1,552)
14	Inflation 1/1/20 -12/31/20	2.90%							3,105	4,757	(1,652)
15	Inflation 1/1/21 -4/30/21	0.97%							1,065	1,632	(567)
16	Projected Non-Storm Replacements								111,225	170,411	(59,186)
17	**Substation Reactive**		18,255	25,402	34,857	35,495	44,275	31,657			
18	Inflation Adjustment		1,098	1,501	1,586	852	-	1,007			
19	Inflation Adjusted Historical O&M		19,353	26,903	36,443	36,346	44,275	32,664	32,664	44,275	(11,611)
20	Inflation 1/1/19 -12/31/19	2.80%							915	1,240	(325)
21	Inflation 1/1/20 -12/31/20	2.90%							974	1,320	(346)
22	Inflation 1/1/21 -4/30/21	0.97%							334	453	(119)
23	Projected Substation Reactive Replacements								34,887	47,287	(12,401)
24	**Total Emergent Replacements Normalization Adjustment (Line 5 + Line 12 + Line 19) Pre-inflation**								**240,166**	**345,938**	**(105,772)**
25	Inflation 1/1/19 -12/31/19	2.80%							6,725	9,686	(2,962)
26	Inflation 1/1/20 -12/31/20	2.90%							7,160	10,313	(3,153)
27	Inflation 1/1/21 -4/30/21	0.97%							2,456	3,537	(1,082)
28	Total Projected Emergent Replacements Expense (Line 11 + Line 18 + Line 25)								**256,506**	**369,475**	**(112,969)**
								Savings	**(9,118)**		

1/ Five year average of actual expenditures adjusted for inflation is included in this request

2/ Historical normalization adjustment carried to Base Capital Programs - see Exhibit A-12, B5.4, page 2, line 7, col. (c)

Michigan Public Service Commission
DTE Electric Company
Projected Capital Expenditures
Distribution Plant - Connections, Relocations and Other
($000)

Case No.: U-20561
Exhibit: A-12
Schedule: B5.4
Witness: M. A. Bruzzano
Page: 4 of 10

Line No.	(a) Description		(b) Historical 12 mos. ended 12/31/2018	(c) Projected Calendar Year 12 mos. ending 12/31/2019	(d) Projected Calendar Year 12 mos. ending 12/31/2020	(e) Projected Calendar Year 12 mos. ending 12/31/2021	(f) Bridge Period 16 mos. ending 4/30/2020	(g) Test Year 12 mos. ending 4/30/2021
			Capital Expenditures					
1	**Connections and New Load**							
2	Small Load Growth Projects (Blanket)		12,613	12,967	13,343	13,729	17,414	13,472
3	Customer Connections		84,777	87,151	89,678	92,279	117,043	90,545
4	Customer Connections CIAC		(14,161)	(14,558)	(14,980)	(15,414)	(19,551)	(15,125)
5	Customer Connections (Net of CIAC)		70,616	72,593	74,698	76,864	97,492	75,420
6	New Business Projects	1/	37,842	38,901	40,030	41,190	52,245	40,416
7	New Business Projects CIAC		(12,814)	(13,173)	(13,555)	(13,948)	(17,691)	(13,686)
8	Subtotal New Business Projects (net of CIAC)		25,028	25,729	26,475	27,243	34,554	26,731
9	**Total Connections and New Load**		**135,232**	**139,018**	**143,050**	**147,198**	**186,702**	**144,433**
10	**Total Connections and New Load CIAC**		(26,975)	(27,730)	(28,534)	(29,362)	(37,242)	(28,810)
11	**Total Connections and New Load (Net of CIAC)**		108,257	111,288	114,516	117,836	149,460	115,622
12	**Relocations**							
13	Small Relocation Projects (Blanket)		7,607	7,819	8,046	8,280	10,502	8,124
14	Major Infrastructure Relocation Project							
15	Gordie Howe International Bridge		10,915	12,300	5,600	-	14,167	3,733
16	Relocation Projects (excl.Major Infrastructure Projects)	2/	7,661	7,875	8,104	8,339	10,577	8,182
17	Relocation Projects CIAC		(3,648)	(3,750)	(3,859)	(3,971)	(5,036)	(3,896)
18	Subtotal Relocation Projects (Net of CIAC)		4,013	4,125	4,245	4,368	5,540	4,286
19	**Total Relocations**		**26,183**	**27,995**	**21,750**	**16,618**	**35,245**	**20,039**
20	**Total Relocations CIAC**		(3,648)	(3,750)	(3,859)	(3,971)	(5,036)	(3,896)
21	**Total Relocations (Net of CIAC)**		22,535	24,245	17,891	12,648	30,209	16,143
22	**Electric System Equipment**							
23	Distribution Transformers & Regulators		25,827	26,550	27,320	28,112	35,656	27,584
24	Major Equipment		14,945	15,363	15,808	16,267	20,632	15,961
25	Meters		11,196	11,509	11,843	12,186	15,457	11,957
26	**Total Electric System Equipment**		**51,967**	**53,422**	**54,971**	**56,565**	**71,745**	**55,502**
27	**NRUC and Improvement Blankets**							
28	System Improvements		8,887	9,136	9,401	9,673	12,269	9,491
29	Normal Retirement Unit Changeouts (NRUC)		3,782	3,887	4,000	4,116	5,221	4,039
30	Operational Technologies		2,955	3,038	3,126	3,217	4,080	3,156
31	Batteries and Chargers		2,221	2,283	2,349	2,417	3,066	2,372
32	Animal Mitigation		35	36	37	38	48	37
33	**Total NRUC and Improvement Blankets**		**17,879**	**18,379**	**18,912**	**19,461**	**24,684**	**19,095**
34	**General Plant, Tools & Equipment and Miscellaneous**		5,887	6,052	6,227	6,408	8,128	6,288
35	**Total Customer Connections, Relocations & Other**		237,147	244,866	244,911	246,251	326,503	245,358
36	**Total Cust Connections, Relocations & Other CIAC**		(30,623)	(31,480)	(32,393)	(33,333)	(42,278)	(32,706)
37	**Total Cust Connections, Relocations & Other Net of CIAC**		206,525	213,386	212,518	212,918	284,225	212,651

1/ Exhibit A-12, Schedule B5.4 - page 5, line 42
2/ Exhibit A-12, Schedule B5.4 - page 6, line 9

Michigan Public Service Commission Case No.: U-20561
DTE Electric Company Exhibit: A-12
Projected Capital Expenditures Schedule: B5.4
Distribution Plant - Prior Year's Projects Witness: M. A. Bruzzano
($000) Page: 5 of 10

Line No.	(a) Description	(b) Historical 12 mos. ended 12/31/2018
1	**Prior Year's New Business Projects:**	
2	New Business Auto Data Center	4,537
3	New Class I for Research Facility	3,456
4	New Business fed from Hood Substation	2,254
5	New Business fed from Fleming Substation	2,246
6	New Class I from Warren Evergreen	2,234
7	New Business for generation facility	2,189
8	New Class I on Trunk 2032	2,100
9	Quaker Transformer Upgrade	2,050
10	New Business Compressor Station	1,790
11	New Business Data Center	1,769
12	New Class I on the Bismarck-Lenox 120 kV line	1,419
13	Expand Explorer Substation for New Business	1,343
14	New Business fed from Cato, St Antoine	1,128
15	Duvall DC9644 & DC9460T	830
16	New Business Henry St	818
17	New STDF for Hospital Expansion in Pt. Huron	784
18	New Business Health Co Campus	765
19	New Business for M1 Rail	733
20	New Business fed from Alamo Substation	671
21	New Business for Apartments	667
22	New Substation (Nitro) to support new load	611
23	New Business for Headquarters in Dearborn	596
24	Add 3rd TRF at Skylark Substation for New Business	569
25	New Business fed from Boyne Substation	343
26	Add PL 9178 Giddings for New Business	315
27	New Class I Farmington Hills	212
28	New Business for Development in Detroit Park	208
29	New Business fed from JSLYN 9182	201
30	New Business Willis & Woodward	200
31	Mercury-MOS GLBRT8095	153
32	New Class I in Detroit fed from 120kV Tap	145
33	New Business for Headquarters in Detroit	139
34	New Business fed from SE Industrial Substation	96
35	New Class I on Trunk 2907	79
36	New STDF for Hospital Expansion	69
37	Misc. New Business Specific Projects	45
38	New Business fed from Stone Pool, Midtown	29
39	New Business fed from Midtown	27
40	New Business fed from Willow Run Substation	21
41	New Business alley vacate	2
42	**Total Prior Year's New Business Projects**	**37,842**

Michigan Public Service Commission
DTE Electric Company
Projected Capital Expenditures
Distribution Plant - Prior Year's Projects
($000)

Case No.: U-20561
Exhibit: A-12
Schedule: B5.4
Witness: M. A. Bruzzano
Page: 6 of 10

Line No.	(a) Description	(b) Historical 12 mos. ended 12/31/2018
1	**Prior Year's Relocation Projects:**	
2	Prior Year's Relocation Projects	2,544
3	Dearborn Relocation	2,463
4	23 Mile Rd Relocation	1,202
5	Temple West block Relocation	886
6	Relocate for rail right of way	276
7	Mt. Elliot I-94 Bridge Relocation	253
8	Relocate for ITC	37
9	**Total Prior Year's Relocation Projects**	**7,661**

Michigan Public Service Commission
DTE Electric Company
Projected Capital Expenditures
Distribution Plant - Infrastructure Resilience and Hardening
($000)

Case No.: U-20561
Exhibit: A-12
Schedule: B5.4
Witness: M. A. Bruzzano
Page: 7 of 10

(a)	(b)	(c)	(d)	(e)	(f)	(g)
			Capital Expenditures			
	Historical	Projected Calendar Year			Bridge Period	Test Year
Line No. Description	12 mos. ended 12/31/2018	12 mos. ending 12/31/2019	12 mos. ending 12/31/2020	12 mos. ending 12/31/2021	16 mos. ending 4/30/2020	12 mos. ending 4/30/2021
1 **Infrastructure Resilience and Hardening**						
2 Mobile Fleet Program	4,310	2,150	1,000	1,000	2,483	1,000
3 Substation Risk: Malta	4,539	2,278	-	-	2,278	-
4 Substation Risk: Drexel	1,808	3,292	-	-	3,292	-
5 Substation Risk: Chestnut	564	-	600	9,000	200	3,400
6 Substation Risk: Nunneley	352	54	-	-	54	-
7 Substation Risk: Savage	252	892	-	900	892	300
8 Substation Risk: Tiffany	5	-	-	-	-	-
9 Substation Risk: Apache	-	500	9,800	3,600	3,767	7,733
10 Substation Risk: Port Huron	-	420	2,796	-	1,351	1,864
11 4.8 kV Hardening	40,325	58,444	64,000	70,000	79,777	66,000
12 Pole and Pole Top Hardware	35,683	28,441	28,500	40,000	37,941	32,333
13 Pole and Pole Top Hardware: Stockbridge Substation	1,301	-	-	-	-	-
14 Cable Replacement Program	9,213	13,992	20,000	45,000	20,659	28,333
15 Cable Replacement: Harsen's Island	1,603	6,100	-	-	6,100	-
16 Frequent Outage Program (CEMI) including Circuit Rene	21,632	18,145	18,000	25,000	24,145	20,333
17 System Resiliency - Efficient Frontier	10,877	5,510	-	-	5,510	-
18 Breaker Replacement Program	9,919	11,147	12,000	13,000	15,147	12,333
19 Pontiac Vaults	6,518	9,486	7,034	-	11,831	4,690
20 URD Replacement Program	10,915	4,000	4,000	10,000	5,333	6,000
21 URD Replacement Program: Detroit URD 1-1	-	3,498	-	-	3,498	-
22 Porcelain Cutout Replacement Program	6,367	4,000	5,000	5,000	5,667	5,000
23 4.8 kV Relay Improvements (Delta Ground Detection Program)	2,583	1,400	2,500	5,000	2,233	3,333
24 40 kV: Automatic Pole Top Switch	898	1,576	2,000	4,000	2,243	2,667
25 Disconnect and Switcher Replacement	2,098	2,200	2,200	2,200	2,933	2,200
26 **Total Infrastructure Resilience and Hardening Projects and Programs**	**171,761**	**177,524**	**179,430**	**233,700**	**237,334**	**197,520**

Michigan Public Service Commission
DTE Electric Company
Projected Capital Expenditures
Distribution Plant - Infrastructure Redesign
($000)

Case No.: U-20561
Exhibit: A-12
Schedule: B5.4
Witness: M. A. Bruzzano
Page: 8 of 10

Line No.	(a) Description	(b) Historical 12 mos. ended 12/31/2018	(c) Projected Calendar Year 12 mos. ending 12/31/2019	(d) Projected Calendar Year 12 mos. ending 12/31/2020	(e) Projected Calendar Year 12 mos. ending 12/31/2021	(f) Bridge Period 16 mos. ending 4/30/2020	(g) Test Year 12 mos. ending 4/30/2021
			Capital Expenditures				
1	**Infrastructure Redesign**						
2	Ann Arbor System Improvements: State Substation	21,024	21,612	26,351	5,171	30,396	19,291
3	Ann Arbor System Improvements: Apex (Blue) Substation	9,050	6,888	1,230	-	7,298	820
4	Ann Arbor System Improvements: Argo 40kV Reconfiguration	-	-	3,069	6,519	1,023	4,219
5	PQ Meter Fault Locating	-	-	1,000	1,000	333	1,000
6	Subtransmission Redesign: Prior Year's	446	-	-	-	-	-
7	Subtransmission Redesign: Tie 4104	3,987	4,422	-	-	4,422	-
8	Subtransmission Redesign: Tie 3416	1,553	3,670	9,100	-	6,703	6,067
9	Subtransmission Redesign: Tie 810	141	-	500	11,000	167	4,000
10	Subtransmission Redesign: Trunk 7106	-	-	200	3,800	67	1,400
11	Subtransmission Redesign: Trunk 2255	-	-	100	1,830	33	677
12	Subtransmission Redesign: Trunk 2237-ST	-	-	100	1,810	33	670
13	Subtransmission Redesign: Trunk 7333	-	-	-	3,000	-	1,000
14	Subtransmission Redesign: Sandusky Transformer	-	-	-	450	-	150
15	Subtransmission Redesign: Boyne Station	-	-	-	500	-	167
16	Subtransmission Redesign: Trunk 6854	-	-	-	150	-	50
17	Subtransmission Redesign: Tie 6907	-	-	-	100	-	33
18	Subtransmission Redesign: Tie 7504	-	-	-	500	-	167
19	Station Upgrade: Warren (Relay Replacement)	5,288	3,152	-	-	3,152	-
20	Station Upgrade: Northeast (Relay Replacement)	62	1,500	5,000	4,500	3,167	4,833
21	Station Upgrade: Lincoln	-	-	500	4,000	167	1,667
22	Station Upgrade: Navarre	-	-	-	500	-	167
23	CODI: Charlotte Network Upgrade	5,694	15,700	15,700	17,300	20,933	16,233
24	CODI: Targeted Network Secondary Cable Replacement	2,860	1,850	1,850	1,850	2,467	1,850
25	CODI: Corktown Substation	2,131	800	10,200	1,600	4,200	7,333
26	CODI: Temple Cascades	580	-	-	-	-	-
27	CODI: Stone Pool Exit Conduit	22	-	-	-	-	-
28	CODI: Midtown Substation Expansion	-	2,700	7,100	1,100	5,067	5,100
29	CODI: Alfred Substation Expansion	-	-	500	9,500	167	3,500
30	CODI: Garfield Network Upgrade	-	-	-	8,350	-	2,783
31	CODI: Howard Conversion	-	-	-	1,700	-	567
32	4.8 kV CC: Hilton Substation and Circuit Conversion	6,586	7,920	-	-	7,920	-
33	4.8 kV CC: Zenon Substation and Circuit Conversion	3,218	950	-	-	950	-
34	4.8 kV CC: Cortland / Oakman / Linwood Consolidation	1,201	8,731	4,460	-	10,218	2,973
35	4.8 kV CC: Ariel Substation and Circuit Conversion	1,188	3,400	-	-	3,400	-
36	4.8 kV CC: I-94 Substation and Circuit Conversion	653	-	-	500	-	167
37	4.8 kV CC: Belle Isle Substation and Circuit Conversion	502	-	-	500	-	167
38	4.8 kV CC: Almont Relief and Circuit Conversion	269	-	500	12,700	167	4,567
39	4.8 kV CC: Argo / Buckler Load Transfer	254	1,091	1,100	2,300	1,457	1,500
40	4.8 kV CC: Calla Circuit Conversion	173	1,385	-	-	1,385	-
41	4.8 kV CC: Northville Decommisioning and Circuit Conversion	58	-	-	-	-	-
42	4.8 kV CC: Lapeer - Elba Expansion and Circuit Conversion	11	-	500	11,000	167	4,000
43	4.8 kV CC: McKinstry Sub Decommission	-	-	500	2,000	167	1,000
44	4.8 kV CC: Birmingham Decommissioning and Circuit Conversion	-	-	-	1,000	-	333
45	8.3 kV CC: Pontiac Overhead Conversion	31	-	500	13,500	167	4,833
46	System Loading: Prior Year	2,380	-	-	-	-	-
47	System Loading: Carleton	15	190	3,000	-	1,190	2,000
48	System Loading: Grayling	17	-	-	1,000	-	333
49	System Loading: Prospect	-	430	-	-	430	-
50	System Loading: Cody	-	-	300	5,500	100	2,033
51	System Loading: Diamond	-	-	200	3,750	67	1,383
52	System Loading: Mandy 307 Load Transfer	-	-	150	2,550	50	950
53	System Loading: Brown City	-	-	-	1,000	-	333
54	System Loading: Wixom	-	-	-	1,000	-	333
55	System Loading: Sterling	-	-	-	1,000	-	333
56	**Total Infrastructure Redesign Projects and Programs**	**69,393**	**86,389**	**93,710**	**145,530**	**117,626**	**110,983**

Michigan Public Service Commission
DTE Electric Company
Projected Capital Expenditures
Distribution Plant - Technology and Automation
($000)

Case No.: U-20561
Exhibit: A-12
Schedule: B5.4
Witness: M. A. Bruzzano
J. L. Robinson 1/
Page: 9 of 10

Line No.	(a) Description		(b) Historical 12 mos. ended 12/31/2018	(c) Projected Calendar Year 12 mos. ending 12/31/2019	(d) Projected Calendar Year 12 mos. ending 12/31/2020	(e) Projected Calendar Year 12 mos. ending 12/31/2021	(f) Bridge Period 16 mos. ending 4/30/2020	(g) Test Year 12 mos. ending 4/30/2021
				Capital Expenditures				
1	**Technology and Automation**							
2	SOC Modernization		4,460	36,100	63,300	5,600	57,200	44,067
3	ADMS: EMS/GMS		16,600	6,790	-	-	6,790	-
4	ADMS: DMS/OMS		835	25,980	28,000	9,900	35,313	21,967
5	ADMS: Network Management System		5,173	10,760	2,700	-	11,660	1,800
6	AMI: 3G to 4G Communication Upgrade	1/	1,738	27,800	2,500	-	28,633	1,667
7	AMI: 3G to 4G Industrial Communication Upgrade	1/	591	10,000	2,400	-	10,800	1,600
8	AMI: Installations	1/	1,633	2,026	-	-	2,026	-
9	AMI Leverage (PI, Analytics)	1/	106	-	-	-	-	-
10	Line Sensors		5,340	3,532	1,000	4,000	3,865	2,000
11	13.2 kV Telecommunications		180	1,313	2,000	10,000	1,980	4,667
12	Distribution Automation		-	-	1,000	10,000	333	4,000
13	Analog Lines Elimination		738	-	-	-	-	-
14	Pilot: Non-Wire Alternatives		10	2,520	2,500	2,500	3,354	2,500
15	Pilot: CVR/VVO		-	350	350	-	467	233
16	Pilot: Technology Programs		1,398	630	630	630	840	630
17	**Total Technology and Automation Projects and Programs**		**38,803**	**127,802**	**106,380**	**42,630**	**163,262**	**85,130**

1/ AMI projects sponsored by Company Witness Robinson

Michigan Public Service Commission
DTE Electric Company
Projected Capital Expenditures
Allowance for Funds Used During Construction (AFUDC)
Distribution Operations
($000)

Case No.: U-20561
Exhibit: A-12
Schedule: B5.4
Witness: M. A. Bruzzano
Page: 10 of 10

Line No.	(a) Description		(b) Adjusted Historical 12 mos. ended 12/31/2018	(c) Projected 12 mos. ending 4/30/2021
1	**Base Capital Programs:**			
2	Gordie Howe International Bridge		727	903
3	Other Routine Base Capital Programs	**1/**	1,233	1,066
4	**Subtotal Base Capital Programs**		**1,960**	**1,969**
5	**Strategic Capital Programs:**			
6	Infrastructure Resilience and Hardening	**1/**	2,148	2,534
7	Infrastructure Redesign:			
	Ann Arbor System Improvements		798	3,107
	Other Infrastructure Redesign	**1/**	1,848	4,180
8	Technology and Automation:			
9	SOC Modernization		293	2,740
10	ADMS Projects		573	2,016
11	Other Technology and Automation	**1/**	-	-
12	**Subtotal Strategic Capital Programs**		**5,660**	**14,577**
13	**Total AFUDC - Distribution Operations**	**2/**	**7,620**	**16,546**

1/ AFUDC estimates for platform are developed at a high level based on historical trend
2/ The projected AFUDC amounts are based on the authorized U-20162 rate of 5.48%

Michigan Public Service Commission
DTE Electric Company
Distribution Plant Capital Project Detail - Infrastructure Redesign

Case No.: U-20561
Exhibit: A-23 Revised
Schedule: M5
Witness: M. A. Bruzzano
Page: 1 of 104

(a) (b)

Category	Distribution Plant Capital Project Detail - Infrastructure Redesign
	Capital Exhibit:
pages: 3-4 of 104	Exhibit A-12, Schedule B5.4, Page 8 of 9, Line 2 Ann Arbor System Improvements: State Substation
pages: 5-6 of 104	Exhibit A-12, Schedule B5.4, Page 8 of 9, Line 3 Ann Arbor System Improvements: Apex (Blue) Substation
pages: 7-8 of 104	Exhibit A-12, Schedule B5.4, Page 8 of 9, Line 4 Ann Arbor System Improvements: Argo 40kV Reconfiguration
pages: 9-10 of 104	Exhibit A-12, Schedule B5.4, Page 8 of 9, Line 5 PQ Meter Fault Locating
pages: 11-12 of 104	Exhibit A-12, Schedule B5.4, Page 8 of 9, Line 6 Subtransmission Hardening: Prior Year's
pages: 13-14 of 104	Exhibit A-12, Schedule B5.4, Page 8 of 9, Line 7 Subtransmission Hardening: Tie 4104
pages: 15-16 of 104	Exhibit A-12, Schedule B5.4, Page 8 of 9, Line 8 Subtransmission Hardening: Tie 3416
pages: 17-18 of 104	Exhibit A-12, Schedule B5.4, Page 8 of 9, Line 9 Subtransmission Hardening: Tie 810
pages: 19-20 of 104	Exhibit A-12, Schedule B5.4, Page 8 of 9, Line 10 Subtransmission Hardening: Trunk 7106
pages: 21-22 of 104	Exhibit A-12, Schedule B5.4, Page 8 of 9, Line 11 Subtransmission Hardening: Trunk 2255
pages: 23-24 of 104	Exhibit A-12, Schedule B5.4, Page 8 of 9, Line 12 Subtransmission Hardening: Trunk 2237-ST
pages: 25-26 of 104	Exhibit A-12, Schedule B5.4, Page 8 of 9, Line 13 Subtransmission Hardening: Trunk 7333
pages: 27-28 of 104	Exhibit A-12, Schedule B5.4, Page 8 of 9, Line 14 Subtransmission Hardening: Sandusky Transformer
pages: 29-30 of 104	Exhibit A-12, Schedule B5.4, Page 8 of 9, Line 15 Subtransmission Hardening: Boyne Station
pages: 31-32 of 104	Exhibit A-12, Schedule B5.4, Page 8 of 9, Line 16 Subtransmission Hardening: Trunk 6854
pages: 33-34 of 104	Exhibit A-12, Schedule B5.4, Page 8 of 9, Line 17 Subtransmission Hardening: Tie 6907
pages: 35-36 of 104	Exhibit A-12, Schedule B5.4, Page 8 of 9, Line 18 Subtransmission Hardening: Tie 7504
pages: 37-38 of 104	Exhibit A-12, Schedule B5.4, Page 8 of 9, Line 19 Station Upgrade: Warren (Relay Replacement)
pages: 39-40 of 104	Exhibit A-12, Schedule B5.4, Page 8 of 9, Line 20 Station Upgrade: Northeast (Relay Replacement)
pages: 41-42 of 104	Exhibit A-12, Schedule B5.4, Page 8 of 9, Line 21 Station Upgrade: Lincoln
pages: 43-44 of 104	Exhibit A-12, Schedule B5.4, Page 8 of 9, Line 22 Station Upgrade: Navarre
pages: 45-46 of 104	Exhibit A-12, Schedule B5.4, Page 8 of 9, Line 23 CODI: Charlotte Network Upgrade
pages: 47-48 of 104	Exhibit A-12, Schedule B5.4, Page 8 of 9, Line 24 CODI: Targeted Network Secondary Cable Replacement
pages: 49-50 of 104	Exhibit A-12, Schedule B5.4, Page 8 of 9, Line 25 CODI: Corktown Substation
pages: 51-52 of 104	Exhibit A-12, Schedule B5.4, Page 8 of 9, Line 26 CODI: Temple Cascades
pages: 53-54 of 104	Exhibit A-12, Schedule B5.4, Page 8 of 9, Line 27 CODI: Stone Pool Exit Conduit
pages: 55-56 of 104	Exhibit A-12, Schedule B5.4, Page 8 of 9, Line 28 CODI: Midtown Substation Expansion

Michigan Public Service Commission
DTE Electric Company
Distribution Plant Capital Project Detail - Infrastructure Redesign

Case No.: U-20561
Exhibit: A-23 Revised
Schedule: M5
Witness: M. A. Bruzzano
Page: 2 of 104

(a) (b)

Category	Distribution Plant Capital Project Detail - Infrastructure Redesign
	Capital Exhibit:
pages: 57-58 of 104	Exhibit A-12, Schedule B5.4, Page 8 of 9, Line 29 CODI: Alfred Substation Expansion
pages: 59-60 of 104	Exhibit A-12, Schedule B5.4, Page 8 of 9, Line 30 CODI: Garfield Network Upgrade
pages: 61-62 of 104	Exhibit A-12, Schedule B5.4, Page 8 of 9, Line 31 CODI: Howard Conversion
pages: 63-65 of 104	Exhibit A-12, Schedule B5.4, Page 8 of 9, Lines 32-35 & 40-41 4.8 kV Conversion & Consolidation Projects
pages: 66-67 of 104	Exhibit A-12, Schedule B5.4, Page 8 of 9, Line 36 4.8 kV CC: I-94 Substation and Circuit Conversion
pages: 68-69 of 104	Exhibit A-12, Schedule B5.4, Page 8 of 9, Line 37 4.8 kV CC: Belle Isle Substation and Circuit Conversion
pages: 70-71 of 104	Exhibit A-12, Schedule B5.4, Page 8 of 9, Line 38 4.8 kV CC: Almont Relief and Circuit Conversion
pages: 72-73 of 104	Exhibit A-12, Schedule B5.4, Page 8 of 9, Line 39 4.8 kV CC: Argo / Buckler Load Transfer
pages: 74-76 of 104	Exhibit A-12, Schedule B5.4, Page 8 of 9, Line 42 4.8 kV CC: Lapeer - Elba Expansion and Circuit Conversion
pages: 77-78 of 104	Exhibit A-12, Schedule B5.4, Page 8 of 9, Line 43 4.8 kV CC: McKinstry Sub Decommission
pages: 79-81 of 104	Exhibit A-12, Schedule B5.4, Page 8 of 9, Line 44 4.8 kV CC: Birmingham Decommissioning and Circuit Conversion
pages: 82-84 of 104	Exhibit A-12, Schedule B5.4, Page 8 of 9, Line 45 8.3 kV CC: Pontiac Overhead Conversion
pages: 85-86 of 104	Exhibit A-12, Schedule B5.4, Page 8 of 9, Line 46 System Loading: Prior Year
pages: 87-88 of 104	Exhibit A-12, Schedule B5.4, Page 8 of 9, Line 47 System Loading: Carleton
pages: 89-90 of 104	Exhibit A-12, Schedule B5.4, Page 8 of 9, Line 48 System Loading: Grayling
pages: 91-92 of 104	Exhibit A-12, Schedule B5.4, Page 8 of 9, Line 49 System Loading: Prospect
pages: 93-94 of 104	Exhibit A-12, Schedule B5.4, Page 8 of 9, Line 50 System Loading: Cody
pages: 95-96 of 104	Exhibit A-12, Schedule B5.4, Page 8 of 9, Line 51 System Loading: Diamond
pages: 97-98 of 104	Exhibit A-12, Schedule B5.4, Page 8 of 9, Line 52 System Loading: Mandy 307 Load Transfer
pages: 99-100 of 104	Exhibit A-12, Schedule B5.4, Page 8 of 9, Line 53 System Loading: Brown City
pages: 101-102 of 104	Exhibit A-12, Schedule B5.4, Page 8 of 9, Line 54 System Loading: Wixom
pages: 103-104 of 104	Exhibit A-12, Schedule B5.4, Page 8 of 9, Line 55 System Loading: Sterling

Michigan Public Service Commission
DTE Electric Company
Distribution Plant Capital Project Detail - Infrastructure Redesign

Case No.: U-20561
Exhibit: A-23 Revised
Schedule: M5
Witness: M. A. Bruzzano
Page: 70 of 104

(a)	(b)
Program:	4.8 kV CC: Almont Relief and Circuit Conversion (Pg. 1 of 2)
Purpose and Necessity:	Almont substation is 153% of the firm rating. Both of its circuits are nearing their day-to-day ratings during summer peak hours. Limited jumpering options are available because Almont is a 4.8 kV substation surrounded by 13.2 kV substations.
Category:	Infrastructure Redesign
Line Number:	Exhibit A-12, Schedule B5.4, Page 8, Line 38
Scope:	• Build a new 13.2 kV substation • Convert and transfer approximately 50% of Almont load to the new substation • Convert 20 miles of overhead primary, including 7 miles of subtransmission • Reconfigure Almont circuits • Establish new jumpering points
Customer benefit / Effect on cost of operation and reliability:	• Provide sufficient capacity to serve fast growing areas • Decommission aging infrastructure and reduce major event risk • Enhance safety, reliability and power quality for upgraded circuits by reducing 85% of circuit wire down events, customer interruptions, and customer minutes • Reduce trouble events and reactive costs for upgraded circuits by 85% for both circuit tree related and non-tree related reactive capital • Increase protection for the distribution system • Enhance grid technology and automaton • Reduce new customer connection timeframe and cost

Michigan Public Service Commission
DTE Electric Company
Distribution Plant Capital Project Detail - Infrastructure Redesign

Case No.: U-20561
Exhibit: A-23 Revised
Schedule: M5
Witness: M. A. Bruzzano
Page: 71 of 104

(a) (b)

Program:	4.8 kV CC: Almont Relief and Circuit Conversion (Pg. 2 of 2)						
Impact Dimension:	Safety	Load Relief	Regulatory Compliance	Substation Outage Risk	Reliability	O&M Avoidance	Reactive Capital Avoidance
Targeted:	x	x		x	x	x	x
Current Projects:	• 4.8 kV CC: Almont Relief and Circuit Conversion						
Cost:	Estimated project spend in 2019-2021: $13.2 M This project is expected to continue beyond 2021						

Test Year ($000's):

	8 mos. 05/01/20 12/31/20	**4 mos. 01/01/21 04/30/21**	**Test Year 12 mos. ending 04/30/21**
Total Labor (DTE Electric &	250	3,175	3,425
Material	50	635	685
Other	33	423	457
Total	**333**	**4,233**	**4,567**

Michigan Public Service Commission
DTE Electric Company
Distribution Plant Capital Project Detail - Infrastructure Redesign

Case No.: U-20561
Exhibit: A-23 Revised
Schedule: M5
Witness: M. A. Bruzzano
Page: 68 of 104

(a)	(b)
Program:	4.8 kV CC: Belle Isle (Island View) (Pg. 1 of 2)
Purpose and Necessity:	New customer load has been added along the Detroit riverfront and additional development is anticipated in the future. The new substation is to be sited east of downtown Detroit near the riverfront and allow for the decommissioning of Pulford and Walker substations. Both Pulford and Walker substations have been in service since the 1920's and cannot reliably serve new load. The new substation will also provide capacity to serve customers being transitioned from the Detroit Public Lighting Department system to the DTE Electric system.
Category:	Infrastructure Redesign
Line Number:	Exhibit A-12, Schedule B5.4, Page 8, Line 37
Scope:	• Construct a new Class A 13.2 kV substation with two transformers and a setup for a future third transformer position • Convert existing 4.8 kV circuits from Walker Substation - 22 circuits • Convert existing 4.8 kV circuits from Pulford Substation - 10 circuits • Decommission cable for four trunk lines (24 kV) and decommission two trunk lines (24 kV) • Decommission Walker substation
Customer benefit / Effect on cost of operation and reliability:	• Provide sufficient capacity to serve fast growing areas • Decommission aging infrastructure and reduce major event risk • Enhance safety, reliability and power quality for upgraded circuits by reducing 85% of circuit wire down events, customer interruptions, and customer minutes • Reduce trouble events and reactive costs for upgraded circuits by 85% for both circuit tree related and non-tree related reactive capital • Increase protection for the distribution system • Enhance grid technology and automaton • Reduce new customer connection timeframe and cost

Michigan Public Service Commission
DTE Electric Company
Distribution Plant Capital Project Detail - Infrastructure Redesign

Case No.: U-20561
Exhibit: A-23 Revised
Schedule: M5
Witness: M. A. Bruzzano
Page: 69 of 104

(a) (b)

Program:	4.8 kV CC: Belle Isle (Island View) (Pg. 2 of 2)						
Impact Dimension:	Safety	Load Relief	Regulatory Compliance	Substation Outage Risk	Reliability	O&M Avoidance	Reactive Capital Avoidance
Targeted:	x	x		x	x	x	x
Current Projects:	• 4.8 kV CC: Belle Isle (Island View)						
Cost:	Estimated project spend in 2019-2021: $0.5 M The project is expected to continue beyond 2021						

Test Year ($000's):

	8 mos. 05/01/20 12/31/20	**4 mos. 01/01/21 04/30/21**	**Test Year 12 mos. ending 04/30/21**
Total Labor (DTE Electric &	-	125	125
Material	-	25	25
Other	-	17	17
Total	**-**	**167**	**167**

Company's next witness?

MR. WATSON: No, your Honor. That will be Ms. Johnson-Bacon I believe.

JUDGE FELDMAN: Okay. Let's go off the record.

(At 1:31 p.m. until 1:42 p.m., off-record discussion and addressing technical issues.)

JUDGE FELDMAN: Back on the record. Ms. Johnson-Bacon.

MS. JOHNSON-BACON: At this time the Company would call Satvir Deol.

JUDGE FELDMAN: We'll have Mr. Deol sworn in.

- - -

S A T V I R S. D E O L

was called as a witness on behalf of DTE Electric Company and, having been duly sworn to testify the truth, was examined and testified as follows:

DIRECT EXAMINATION

BY MS. JOHNSON-BACON:

Q Mr. Deol, please state your name and business address for the record.

A Satvir Deol, and my business address is One Energy Plaza, Detroit, Michigan 48226.

Q Did you file with the Commission a document entitled the

Qualifications and Revised Direct Testimony of Satvir Deol, consisting of a cover sheet and 47 pages of questions and answers?

A Yes.

Q Do you have any changes you wish to make to your revised direct testimony?

A No.

Q Is that then the revised direct testimony that you're adopting today?

A Yes.

Q Are you sponsoring any exhibits associated with your revised direct testimony this in case?

A Yes.

Q For the purposes of identification, are these five direct exhibits designated as Exhibit A-12 Schedule B5.4, consisting of 21 pages; Exhibit A-23 Schedule M5, consisting of 509 pages; Exhibit A-23 Schedule M10, consisting of 12 pages; Exhibit A-33 Schedule X2, consisting of one page; and Exhibit A-33 Schedule X3, consisting of one page?

A Yes.

Q Are these the exhibits prepared by you or at your direction?

A Yes.

Q Do you have any changes to make to any of these five

direct exhibits?
A No.
Q Did you also file with the Commission a document entitled the Rebuttal Testimony of Satvir Deol, consisting of a cover sheet and 52 pages of questions and answers?
A Yes.
Q Do you have any changes you wish to make to your rebuttal testimony?
A Yes.
Q Is that change the word "capacity" on page 7, line 5, should instead of "capacity" read "emergency rating"?
A Correct, yeah.
Q Is that then, with that change, the rebuttal testimony that you're adopting today?
A With that change, yes.
Q Are you sponsoring any exhibits associated with your rebuttal testimony in this case?
A Yes.
Q For purposes of identification, are these seven rebuttal exhibits designated as Exhibit A-41 Schedule FF1, consisting of four pages; Exhibit A-41 Schedule FF2, consisting of two pages; Exhibit A-41 Schedule FF3, consisting of 17 pages; Exhibit A-41 Schedule FF4, consisting of 15 pages; Exhibit A-41 Schedule FF5, consisting of four pages; Exhibit A-41 Schedule FF6,

consisting of two pages; and Exhibit A-41 Schedule FF7, consisting of two pages?

A Yes.

Q Were these exhibits prepared by you or at your direction?

A Yes.

Q Do you have any changes to make to any of these seven rebuttal exhibits?

A No.

MS. JOHNSON-BACON: Your Honor, DTE Electric moves to bind into the record the Qualifications, Revised Direct Testimony, and Rebuttal Testimony of Satvir Deol, and for the admission at the end of cross-examination of the exhibits identified, those being direct Exhibit A-12 Schedule B5.4, direct Exhibit A-23 Schedule M5, direct Exhibit A-23 Schedule M10; direct exhibit A-33 Schedule X1, direct Exhibit A-33 Schedule X2; and rebuttal Exhibit A-41 Schedules FF1 through FF7, and tenders Mr. Deol for cross-examination in this case.

JUDGE FELDMAN: All right. I believe this witness is sponsoring Schedules X2 and X3 in Exhibit A-33? You're nodding. Let me ask for the record if there are any objections to binding in this witness's prefiled revised direct or his prefiled rebuttal with the changes that he's made -- change, the single change that

he's made on the stand this afternoon? (No response.)

Hearing no objections, the prefiled revised direct and rebuttal testimony as revised of Satvir S. Deol will be bound into the record.

(Testimony bound in.)

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185

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of	)	
DTE ELECTRIC COMPANY	)	
for authority to increase its rates, amend	)	Case No. U-21297
its rate schedules and rules governing the	)	
distribution and supply of electric energy, and	)	
for miscellaneous accounting authority.	)	

QUALIFICATIONS

AND

REVISED DIRECT TESTIMONY

OF

SATVIR S. DEOL

DTE ELECTRIC COMPANY
QUALIFICATIONS AND REVISED DIRECT TESTIMONY OF SATVIR S. DEOL

Line No.

Q1. What is your name, business address and by whom are you employed?

A1. My name is Satvir S. Deol (he/him/his), and my business address is One Energy Plaza, Detroit, Michigan, 48226 and I am employed by DTE Electric Company (DTE Electric or Company).

Q2. On whose behalf are you testifying?

A2. I am testifying on behalf of DTE Electric.

Q3. What is your educational background?

A3. I received a Bachelor of Science Degree in Electrical Engineering specializing in Power Distribution from Michigan Technological University. I graduated from University of Minnesota with a Master of Science in Electrical Engineering specializing in Power System Control. I also have a Master of Business Administration specializing in Finance from University of Michigan – Dearborn. Furthermore, I have attended professional development courses in power system design & protection and circuit modeling & power flow analysis. I was also trained in the Toyota Production System (TPS) continuous improvement methodologies.

Q4. Please summarize your professional experience.

A4. I worked for Shell Western Exploration & Production, Inc. (SWEPI) as a facilities engineer from 1990 to 1992. I was responsible for coordinating & performing maintenance on substations, co-generation facilities, and the power distribution network for all oil production fields and offshore platforms in California. I also supported the field electrical teams for emergent issues and was the project manager for several major electrical projects.

S. S. DEOL
U-21297

Line No.

I worked for Ford Motor Company (Ford) from 1995 to 2007. Through my twelve year career at Ford, I had numerous assignments with increasing responsibility. As a product design engineer, I designed electrical motors and received two patents. I have experience in the production and assembly of electrical components as a manufacturing engineer. I have worked internationally, launching an alternator rectifier assembly line in India, and upgrading a plant in Brazil. As a product planning analyst, I worked with hybrid, electrical & fuel cell vehicle architectures and gained experience working within industry consortiums. I obtained leadership experience as a powertrain capacity planning supervisor and then as an ignition system supervisor, where I had design & release responsibility of all current and future ignition systems for all North America produced V-engines. Also, I achieved my six-sigma black belt certification and led numerous continuous improvement projects.

I joined DTE Energy in 2007 as a program manager to implement continuous improvement programs within the Materials & Logistics organization. After a series of roles with increasing responsibility, in 2010 I was promoted to senior supply chain manager supporting Fossil Generation Operations.

In 2013, I moved to Distribution Operations as a program leader for a continuous improvement project focusing on the oil distribution breaker inspection process. In 2014, I assumed the role as a service center manager leading the Southwest region for Substation Operations. In this role, I was responsible for the operation, planned & corrective maintenance, and executing capital projects for substations in my

Line
No.

region. I was given the additional responsibility of the Southeast region in 2016. In 2018, I was promoted to my current role as director of Substation Operations.

Q5. Do you hold any certifications or are you a member of any professional organizations?

A5. I am a Lean Six Sigma Blackbelt.

Q6. What are your current duties and responsibilities?

A6. As director of Substation Operations, I am responsible to ensure safe and reliable operation of all the substations within the DTE Energy service territory. The major areas of focus are: 1) safety; 2) planned maintenance; 3) emergent & corrective maintenance; 4) capital replacement programs; and 5) continuous improvement.

Q7. Have you previously sponsored testimony before the Michigan Public Service Commission (MPSC or Commission)?

A7. I have not testified before the Michigan Public Service Commission.

S. S. DEOL
U-21297

Line No.

Purpose of Testimony

Q8. What is the purpose of your testimony?

A8. As referenced in witness Robinson's description of the distribution witnesses, the purpose of my testimony is to support, as reasonable and prudent, the historical capital expenditures for 2021 and projected capital expenditures for 2022 thru November 30, 2024, in the distribution strategic investment category of Infrastructure Redesign and Modernization and discuss metrics and programs associated with the Company's proposed Infrastructure Recovery Mechanism (IRM).

Q9. Are you sponsoring any exhibits in this proceeding?

A9. Yes. I am sponsoring the following exhibits:

Exhibit	Schedule	Description
A-12	B5.4	Projected Capital Expenditures – Distribution Plan (Pages 1, 2, 9-11, and 13-21)
A-23	M5	Distribution Plant Capital Project Detail – Infrastructure Redesign and Modernization
A-23	M10	Appoline Report
A-33	X2	Distribution – Base Rate Investments + Infrastructure Recovery Mechanism
A-33	X3	Distribution - Infrastructure Recovery Mechanism

Q10. Were these exhibits prepared by you or under your direction?

A10. Yes, they were.

Line No.

Q11. How is your testimony organized?

A11. My testimony consists of the following parts:

Part I Infrastructure Recovery Mechanism (IRM) Support

Part II Infrastructure Redesign and Modernization

Part I Infrastructure Recovery Mechanism (IRM) Support

Q12. Is the Company proposing that any of the capital programs discussed in your testimony and exhibits be associated with the Company's proposed Distribution Infrastructure Recovery Mechanism (IRM)?

A12. Yes. As part of the IRM proposal put forth by Company witness Foley, the Company is proposing that a portion of Conversions program investment and a portion of Subtransmission Redesign & Rebuild program investment be authorized for IRM treatment.

Q13. Why does the Company believe that it is appropriate for these programs to be authorized for IRM treatment?

A13. These programs are appropriate for the Distribution IRM because they are a key focus of and requirement for the Company's future grid plan. Inclusion will provide support for the incorporation of new technologies such as electric vehicle (EV) charging stations and Distributed Energy Resources (DERs), as well as operational technologies. As described below in more detail, these programs are designed to improve reliability, operability, and safety, as well as add capacity to the Company's system. In previous rate cases the Commission has expressed concern as to the Company's ability to achieve projected investment levels in these programs. As further described by Company witness Foley, inclusion of these

Line No.

programs in the Distribution IRM will help ensure that the Company invests in programs that are a priority for customers while also ensuring that customers do not fund investments that do not occur.

Q14. What level of investment is the Company proposing that the Commission authorize under the Distribution IRM for these programs?

A14. As discussed by Company witness Foley, the Company is proposing a roughly 3-year IRM beginning concurrent with the projected test year in the instant case (i.e., December 1, 2023). The Company is proposing that IRM Plan Year 1 be 13 months such that subsequent IRM plan years are aligned to calendar years. As captured in witness Foley's Exhibit A-33, Schedule X1, I am proposing the following investment level shown in Table 1 for the programs I am supporting in the instant case.

Table 1 Distribution IRM Investments ($millions)

Capital Program	Projected Test Year *(12 mos. end 11/30/24)*	Plan Year 1 *13 mos. ending 12/31/2024*	Plan Year 2 *12 mos. ending 12/31/2025*	Plan Year 3 *12 mos. ending 12/31/2026*
Conversions	$371.6	$1.6	$185.8	$371.6
Subtransmission Redesign & Rebuild	$107.6	$5.5	$53.8	$107.6

As described by Company witness Foley, if the Company were to invest less than these levels, the associated over-recovery of costs would be refunded to customers.

The level of Distribution IRM Investments for the projected test year (12 months ending 11/30/24) is supported on Exhibit A-33, Schedules X2 and X3, sponsored

Line No.

by Company Witnesses Hill, Elliott Andahazy, and myself. Schedule X2 distinguishes expenditures included in the base rate request from the amounts included in the IRM request, while Schedule X3 details the IRM investments in detail by project.

For the Conversions and Subtransmission Redesign & Rebuild programs, I am sponsoring an investment level of $1.5 million and $5.1 million, respectively, for 12 months ending 11/30/2024 on Exhibit A-33, Schedule X3, Lines 8 and 28.

These amounts are also shown on Exhibit A-33, Schedule X2, lines 4 and 5, column (c), as part of the IRM expenditures and relate only to new projects starting in the projected test period. Capital expenditures related to projects already underway prior to the projected test period remain in the base rate request on line 4 and 5, column (b). All other Infrastructure Redesign and Modernization expenditures remain in the base rate request as shown on line 6, column (b). The grand total in column (d) for the Conversions program on line 5 in the amount of $371.6 million as well as the Subtransmission Redesign & Rebuild program on line 6 in the amount of $107.6 million is used by witness Foley to increase the level of IRM investment in IRM Year 2 (50% of the total spend) and IRM Year 3 (100% of the total spend) as shown in Table 1 above.

Q15. What does the Company intend to accomplish for these programs during the IRM timeframe?

A15. These programs are a key focus for the Company's grid of the future. Through the conversion projects, the Company expects to see an 85% reduction in customer

Line No.

minutes interruptions and customer interruptions, a 90% reduction in wire downs, and an 85% reduction in trouble events from the overhead (OH) lines conversion. Additionally, the higher voltage will provide load relief and increased capacity to serve customers' needs.

The Company performed an analysis on its subtransmission system, detailed later in my testimony, that revealed that approximately one-third of the circuits on the subtransmission system violated the Company's planning criteria. Additionally, the analysis showed that the Company's aging subtransmission system is not currently adequate to serve the Company's customers' long-term needs given its limited capacity and reliability performance. The comprehensive subtransmission program detailed later in my testimony will resolve these issues.

More detail on these programs and why they are beneficial to customers is provided later in my testimony and in Exhibit A-23 Schedule M5.

Q16. How will the Company select specific projects to execute during the IRM timeframe?

A16. The Company will continue to select projects based on customer needs (safety, reliability, and capacity) and ranking in the Global Prioritization Method (GPM) model as discussed by Company Witness Kryscynski.

Q17. Is the Company proposing to begin reporting any program execution metrics associated with these programs?

A17. Yes. As part of the IRM Reconciliation Process described by Company witness Foley, the Company is proposing to begin reporting the metrics shown in Table 2.

Line No.

Table 2 IRM Program Execution Metrics

Programs	*Program Execution Metric**
Conversions	OH line miles converted Average cost per OH line mile converted UG line miles converted Average cost per UG line mile converted Higher Voltage substations constructed Average Cost per substation constructed 4.8kV substations decommissioned Average cost per 4.8kV substation decommissioned
Subtransmission Redesign & Rebuild	OH line miles Average cost per OH line mile UG line miles Average cost per UG line miles Stations constructed/rebuilt Average cost per stations constructed/rebuilt

* measured vs. target

Q18. What are the benefits of IRM treatment for the proposed capital programs?

A18. As further discussed by Company witness Foley, there are four key benefits of a Distribution IRM:

- Certainty of investment. The approval of an IRM effectively establishes a dedicated funding source for capital programs critical to customer safety, reliability, and/or resiliency. The Company would not be able to shift investment authorized for IRM treatment to programs outside the IRM, or between programs within it. Importantly, any underinvestment in the programs associated with IRM would be returned to customers.
- Greater transparency. As part of the Distribution IRM, new planning and reconciliation process would be established that would provide Staff with

Line No.

greater transparency into the Company's investment plans and its execution of those plans.

- Opportunities for feedback. As part of the IRM Planning Process, Staff would have the opportunity to review and provide feedback on the Company's planned IRM investments for the upcoming year. Likewise, the Company would then have the opportunity to address that feedback and respond to any questions or concerns raised by Staff before execution of its plans.
- Increased accountability. As part of the IRM Reconciliation process, the Company would begin reporting new program execution metrics to help assess its execution of its investment plans.

Part II Infrastructure Redesign and Modernization

Q19. What is included in Infrastructure Redesign and Modernization?

A19. As discussed by company witness Miller, projects and programs in the Infrastructure Redesign and Modernization pillar fundamentally upgrade the electrical system. Projects fall into three primary areas, Subtransmission Redesign & Rebuild, Conversion to higher voltage (City of Detroit Infrastructure (CODI) and Conversions), and System Loading. Voltage and purpose distinguish the difference between the Company's subtransmission system and distribution system. The Company operates subtransmission voltages of 24kV, 40kV, and 120kV and this infrastructure is designed to feed substations that convert the voltage to distribution levels. The Company currently operates distribution voltages of 4.8kV, 8.3kV, and 13.2kV and this infrastructure is designed to feed customers. Subtransmission projects focus on the subtransmission system, whereas conversion and load relief projects focus on the distribution system. Capital investment details for

Line No.

Infrastructure Redesign and Modernization projects are included in Exhibit A-12, Schedule B5.4, pages 910 and Exhibit A-23, Schedule M5. Also included on Exhibit A-12, Schedule B5.4 for this category is AFUDC on page 13 and plant activity on pages 15-19, described in more detail by Company Witness Miller

Q20. Why are Infrastructure Redesign and Modernization Projects needed?

A20. Infrastructure Redesign and Modernization projects are a key part of the Company's plan for the grid of the future. These projects add capacity by converting to a higher voltage for growing customer load, reduces outages and outage restoration time using modern equipment, improves redundancy and resiliency of the system, and increases safety. Projects in this pillar fundamentally change the way the grid operates. For these reasons, detailed in more depth later in my testimony, the Company is increasing focus on these projects and accelerating the rate at which it implements conversions, subtransmission rebuilds, and load relief projects.

Q21. Are there specific Infrastructure Redesign and Modernization programs you would like to discuss in more detail?

A21. Yes. I would like to highlight the following programs because I believe that discussion beyond what is contained in the exhibits will be helpful in establishing a deeper understanding of their scope, the rationale for making the investments, and the benefits customers will receive:

- 4.8kV Conversion
    - 4.8kV ISO Conversion Program
- City of Detroit Infrastructure (CODI)

Line No.

- 8.3kV CC: Pontiac Conversion
- Subtransmission Redesign & Rebuild
- Strategic Undergrounding Projects
- Primary Deconductoring
- System Loading

4.8kV Conversion

Q22. Can you describe the Company's 4.8kV distribution system?

A22. The Company's original distribution system voltage is 4.8kV. The system was designed to an ungrounded delta configuration and banked secondary standard, which has both benefits and drawbacks. Delta configuration is a design from the early 1900's, which for many years provided very low number of outages. In most neighborhoods, the 4.8kV system was constructed as OH rear-lot poles and wires, which customers find aesthetically preferable to front-lot construction. Initially, right-of-way truck access was readily available through municipally maintained alleys in many areas, including much of Detroit. Starting in the mid-1950's, many municipalities began to abandon alleys and allowed property owners to extend their fence lines, inhibiting Company truck access to the poles and wires. Consequently, the limited access resulted in a significant increase in the time to locate and repair trouble on the 4.8kV system, as well as increases in time to perform tree trimming and other maintenance work.

Q23. What are the challenges and issues associated with the 4.8kV system?

A23. Beside accessibility, other key issues impacting the reliability and operability of the Company's 4.8kV system are summarized below:

Line No.

- The 4.8kV system uses the small #6 and #4 conductors, which are weaker in strength compared to current higher standard wires.
- Inherent in the design, the 4.8kV substations and circuits have lower capacity than the higher voltage systems.
- The 4.8kV system can experience more significant voltage drops than higher voltage systems.
- The 4.8kV system is an ungrounded delta configuration, making detection, location, and protection of single-phase downed wires challenging.
- Ringed circuit and banked secondary designs make maintenance, fault identification, troubleshooting, and restoration more difficult and can result in outages that are longer in duration. Opening the rings on 4.8kV circuits may result in low voltage and/or more outage events for customers.
- The 4.8kV system is less compatible with today's automated technology
- The 4.8kV system has a limited amount of remote monitoring and control capability. Due to equipment age, the retrofits on 4.8kV substations and circuits to enhance remote monitoring and control capability are costly and challenging. The original 4.8kV substation design included individual relays for individual functions, usually on a 3-foot-by-7-foot panel. When a new breaker is installed, the entire relay panel and all associated control wiring must be replaced to accommodate the new technology.

Q24. Why does the Company need to convert its 4.8kV system?

A24. The conversion program has several customer benefits: it will allow the decommissioning of aging equipment, which will lead to improved reliability and lower emergent maintenance costs; restoration times and costs will be reduced, as

Line No.

modern distribution equipment can, in the event of an outage, transfer loads automatically, while substation and distribution equipment can be remotely operated from the System Operation Center (SOC), eliminating the need to dispatch operators or line crews to perform switching activities. The Company expects to see an 85% reduction in customer minutes interruptions and customer interruptions, a 90% reduction in wire downs, and an 85% reduction in trouble events.

Both 4.8kV and higher voltage systems are capable of handling additional load from electric vehicles (EVs) and DERs. However, areas where the 4.8kV system is near load capacity, adding these new technologies can quickly exceed system capability. Conversion to higher voltages introduces more system capacity to handle future electrification by increasing conductor size and reducing voltage drop. Conversion will also allow for the adoption of modern automated technology, to reduce outages and improve restoration time.

Q25. What impact will the 4.8kV Hardening program have on the pace of conversion of the 4.8kV system?

A25. The 4.8kV Hardening program will not delay the pace of conversion. The 4.8kV Hardening program is described in detail by witness Elliott Andahazy.

Q26. What is the scope of the 4.8kV Conversion program?

A26. The program is aimed at upgrading the 4.8kV system to a higher voltage by building new substations and upgrading circuits to add capacity to serve growing load. The 4.8 kV Conversion program also addresses deteriorating reliability performance due to aging electric infrastructure. The work performed as part of a 4.8kV Conversion includes:

Line No.

- Remove arc wire from the Company's system,
- Building new higher voltage substations or expanding and upgrading existing 13.2kV substations.
- Installing controls and automation in the substations and circuits to our latest design standards.
- Completing overhead (OH) conversion work including rebuilding pole top equipment, replacing poles and transformers as needed, and installing neutral wire.
- Rebuilding underground infrastructure as needed.
- Reconductoring OH lines as needed based on new circuit configurations and existing wire size.
- Establishing new distribution circuits from new, upgraded, or existing 13.2kV substations.
- Reconfiguring circuits and establishing new jumpering points (jumpering is the act of feeding a circuit that has become deenergized with an adjacent circuit, restoring power to the customers on the deenergized circuit).
- Converting and transferring the load off of the 4.8kV substations to the higher voltage substations.
- Decommissioning of aging 4.8kV substations and associated subtransmission infrastructure

Q27. Will customers benefit from overhead (OH) conversion work prior to building a new higher voltage substation or in parallel with substation construction?

A27. Yes. Projects where OH conversion work is performed early or in parallel with the substation construction, the customers will see the reliability benefits sooner and a

Line No.

reduction in wire downs. Once the substation is built, the added benefits of capacity will be achieved as the circuits are energized to the higher voltage.

Q28. How are conversion projects prioritized?

A28. The near term (five-year) projects reflect investments that address current loading constraints and safety considerations on the system. The Company's engineers consider substation firm rating, circuit overloads, wire downs per OH mile, and substation risk, to define these investment projects.

Prioritization and sequencing of a long-term conversion plan will be an iterative process. Future iterations will include integrated forecasting tools that will enhance planning capabilities and incorporate additional data, such as propensity studies and hourly load shapes, into the current substation loading profiles. In addition, the pace at which the electrification scenario develops, and the signposts of that scenario materialize, will further impact results. More detail is provided in Exhibit A-23 Schedule M7 DGP, section 11.3.2 4.8kV Conversion prioritization.

Q29. Are there specific 4.8kV Conversion projects you would like to discuss in more detail?

A29. Yes. I would like to highlight the following projects because I believe that discussion beyond what is contained in the exhibits will be helpful in establishing a deeper understanding of their scope, of the rationale for making the investments, and of the benefits customers will receive, as well as provide for a better understanding of the drivers and benefits of 4.8kV conversion in general:

- I-94 Substation and Circuit Conversion (Promenade)

Line No.

- Lapeer – Elba Expansion and Circuit Conversion (Apollo)

Q30. What are the benefits of the I-94 Substation and Circuit Conversion (Promenade) project?

A30. The I-94 Substation and Circuit Conversion (Promenade) project provides eliminates existing overloads and provides additional capacity to serve residential, commercial, and industrial customers in the city of Detroit, southwest of Detroit City Airport. The new 13.2kV Promenade substation will allow for the decommissioning of existing 4.8kV substations Lambert, Lynch, and Pulford; all of which are 70 years old or older. Decommissioning these substations will remove at risk equipment, including 10 transformers, over 20 regulators, over 20 oil circuit breakers and disconnects, over 20 miles of 4.8kV underground cable, and over 30 miles of 24kV underground cable. Conversion of the circuits will improve safety and reliability for the customers in this area.

Q31. What are the drivers, and scope of the I-94 Substation and Circuit Conversion (Promenade)?

A31. The Promenade project is driven by transmission system violations, future loading conditions, and aging infrastructure. Currently ITC has several MISO loading violations in the east downtown portion of their transmission system. The proposed future Saturn Promenade Islandview Alfred transmission system pathway will alleviate these violations.

An I-94 industrial park is expected to add new commercial and industrial customers to the area resulting in increased loads that the current system will not be able to adequately support. The Promenade project will also provide support for the

Line No.

increased capacity demands that will result from the Detroit Public Lighting Department (PLD) conversions. As customers are transferred from the old PLD system to the Company's system, load on the Company's system has increased causing overloads, creating planning criteria violations.

This project involves construction of the new 120kV to 13.2kV Promenade substation and the conversion and transfer of 4.8kV circuits out of Lambert, Lynch, and Pulford to the new Promenade substation. In total 23 4.8kV (10 Pulford circuits, 8 Lambert circuits, and 5 Lynch circuits) circuits will be converted to six 13.2kV circuits. This will help allow for the decommissioning of Lambert, Lynch, and Pulford substations. Additionally, the construction of the new 120kV transmission feed will allow for the decommissioning of four 24kV trunk lines with an average weighted age of 90 years.

Q32. What are the benefits of the Lapeer – Elba Expansion and Circuit Conversion project?

A32. The Lapeer – Elba project provides load relief and capacity for new growth in Lapeer County. The decommissioning of Elba and Lapeer 4.8kV substations will reduce outage risk by removing aging infrastructure from the system. New jumpering capability will be established with the elimination of the 4.8kV islanded system (an islanded system is an area where the 4.8kV system is surrounded by 13.2kV system). Additionally, reliability and power quality will be enhanced with the upgraded distribution circuits and elimination of the 40kV OH infrastructure feeding Elba.

Line No.

Q33. What are the drivers and scope of the Lapeer – Elba Expansion and Circuit Conversion project?

A33. Lapeer and Elba substations are both located in Lapeer County. The Lapeer substation property has two substations, one operating at 4.8kV and the other at 13.2kV, while Elba is a 4.8kV substation. The Lapeer 4.8kV substation is approaching its firm rating at summer peak, and the Elba substation exceeds its firm rating, with its transformer over day-to-day rating at summer peak. The Lapeer 13.2kV substation is over firm rating, and one of its circuits is over day-to-day rating, with the other approaching its day-to-day rating. Thus, the substation capacity in the Lapeer-Elba area cannot accommodate any load growth. In addition to the loading concerns, there are a number of reliability and operability issues in the area. Elba substation is almost 70 years old and is fed from a 6-mile 40kV dedicated OH line from Tie 9111 that has experienced poor reliability performance due to its location in a heavily treed right-of-way with limited shutdown capability for operation and maintenance. The 40kV problems have caused power quality issues to customers served out of Elba. There is limited jumpering capability for Elba, as it is an islanded 4.8kV area surrounded by 13.2kV substations.

The project involves construction of the new 120kV to 13.2kV Apollo substation and the conversion and transfer of the 4.8kV circuits out of Lapeer and Elba to the new Apollo substation. Following the transfer of all load, Elba Substation, the 40kV OH line feeding Elba, and the 4.8kV substation at Lapeer will be decommissioned.

Line No.

This project will reduce wire downs, improve reliability, and provide additional capacity to serve new load and eliminate existing overloads.

4.8kV ISO Conversion Program

Q34. What is an ISO down?

A34. The Company operates some circuits at 4.8kV that are fed from a 13.2kV substation; these are known as isolation down areas (ISO down). The reason for this grid configuration is that in some instances, there is a need to address immediate overloading on a circuit or circuits fed from a substation at which other circuits are not overloaded. This issue can be addressed by building a higher voltage substation, typically 13.2kV, and converting only the overloaded circuits, or portions of the circuit, to the higher voltage while operating the remaining circuits at the current voltage, typically 4.8kV. Whereas all the circuits out of the new substation are fed at 13.2kV, only the circuits that were overloaded operate at 13.2kV. Circuits that were not overloaded and rebuilt have the voltage dropped to 4.8kV by a transformer and operate unconverted as 4.8kV circuits, thus isolating them from the 13.2kV circuits. Ultimately all the circuits will require conversion to 13.2kV as creating ISO downs is not a permanent solution because 4.8kV ISO downed areas of the circuits have not been upgraded or modernized and have the same characteristics of 4.8kV circuits fed from a 4.8kV substation: they have the same reliability issues, safety concerns, and operational concerns, and face the same challenges when it comes to incorporating increasing EVs and DERs. Table 1 ~~16~~ provides the number of circuits with ISO downs, number of customers served, and the 4.8kV OH and underground line miles.

Line No.

Table 3 Number of Circuits with ISO Downs

	Number of Circuits	Number of Customers	Miles Overhead Wire	Miles Underground Wire
4.8kV ISO Downs	433	143,504	5,559	398

Q35. What are the benefits of the 4.8kV ISO Conversion program?

A35. The ISO conversion projects are expected to bring multiple benefits including safety improvements by reducing wire downs; improving reliability; providing for technology modernization; providing additional capacity; and avoiding costs associated with aging infrastructure.

Q36. What is the scope of work for converting ISO down areas?

A36. The program is aimed at upgrading the 4.8kV portions of the circuits to a higher voltage, thus adding capacity to serve growing load, improve safety by reducing wire downs, improve jumpering capability to adjacent 13.2kV circuits, and to address deteriorating reliability performance due to aging electric infrastructure. The scope of work for the 4.8kV ISO down conversions includes:

- Installing controls and automation in the substations and circuits to our latest design standards
- Completing OH conversion work including rebuilding pole tops, replacing poles and transformers as needed, and installing neutral wire.
- Rebuilding underground infrastructure as needed.

Line No.

- Reconductoring OH lines as needed based on new circuit configurations and existing wire size.
- Reconfiguring circuits and establishing new jumpering points.
- Removing ISO down transformers.

Q37. How will circuits in the 4.8kV ISO Conversion program be prioritized?

A37. The Company prioritizes the order in which it addresses the different ISO down locations based on specific criteria, with safety being the primary driver in the prioritization efforts. Work is prioritized at the substation level, as it is more efficient to plan and perform the work for the group of circuits tied to the same substation. Each ISO down is scored based on the following factors:

1) Recorded wire downs;

2) Total substation SAIDI;

3) Total outage and non-outage events requiring the dispatch of a line crew.

Ranking of the substations follows the Company's overall goals of reducing risk, improving reliability, and managing costs. The Company calculates a three-year historic average for wire downs, customer minutes interruption (SAIDI), outage/non-outage events and estimates the amount of reduction ISO down conversion is expected to bring in each metric like the calculations for the impact dimensions in the GPM model as discussed by witness Kryscynski. The amount of reduction in wire downs, SAIDI, and outage/non-outage events is divided by the estimated cost to perform the work to provide a benefit-cost for each impact dimension. To aggregate the benefit-cost ratios across all the impact dimensions, safety, reliability, and cost avoidance, benefit-cost ratios are indexed to scores of

Line No.

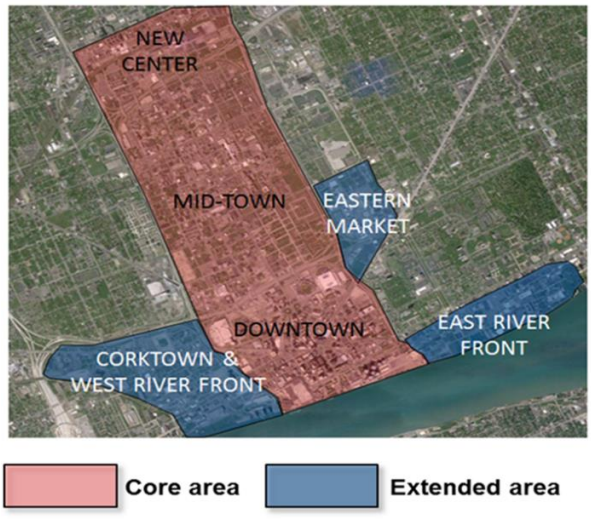
0-100. In similar manner to the GPM, each impact dimension is multiplied by a weighting factor of 10 for safety, 3 for reliability, and 3 for cost avoidance. The Company recognizes that other priorities could impact the execution order of ISO down conversion. Other priorities that are considered include, but is not limited to, load growth and jumpering creation.

City of Detroit Infrastructure (CODI) Upgrades

Q38. What areas of Detroit will be addressed by the CODI program?

A38. Figure 1 below shows the areas of Detroit that will be addressed by the CODI program which includes a core area from Downtown to the Midtown and New Center areas and an extended area including Eastern Market, Corktown, and the West and East River Fronts. There are 31,800 customers served in this area including 27,486 residential, 4,299 commercial, and 15 industrial customers. In addition to residential, commercial, and industrial customers including healthcare facilities and universities, this area of Detroit is also vital to tourism and recreation in the region, with an abundance of shopping, sports venues, and parks.

Figure 1 CODI Scope Area



Line No.

Q39. Why is the CODI program needed?

A39. The earliest electrical grid in southeast Michigan was developed in the downtown area in the city of Detroit. Significant portions of the electrical infrastructure in Detroit were placed in service in the early part of the 20th century, and much of that earlier infrastructure remains. Additionally, certain sections of Detroit have seen significant economic growth. Redevelopment in the City of Detroit is stressing this aging infrastructure, and new customer load cannot be served with existing capacity. The downtown CODI area has been experiencing load growth since 2012, with potential for up to 20% of additional load growth by the end of 2023. Due to significant cable network configuration in the CODI area, substation and circuit upgrades must be sequenced and conducted in a robust, multi-year program as opposed to individual episodic projects to address the interdependency of the system. These projects require system shutdowns that will need to be managed carefully due to the critical customer loads that will be impacted, including hospitals. The Company has developed the CODI program for that purpose. It is important to note that the load growth that has been realized over the last 10 years is not the only driver of this program. The electrical infrastructure (substations, underground cable, manholes, network equipment, and other assets) in this area has served the customers well over many decades. However, this infrastructure is experiencing higher failure rates, increasing the risk of long-duration outages impacting customers, and which can lead to high reactive maintenance costs. The continued implementation of the CODI program is necessary to address this aging infrastructure to serve the customers safely and reliably in this area.

Line
No.

Q40. What is the scope of the CODI Upgrades program?

A40. The downtown CODI program is different from other conversions projects due to the presence of large amounts of system cable and secondary network cable. This adds to the complexity of operating, maintaining, and upgrading this part of the system. Due to significant cable network configuration in the CODI area, substation and circuit upgrades must be sequenced and conducted in a robust, multi-year program as opposed to individual projects to address the interdependency of the system. Between 2021 and 2024, investments have and will be made into ten CODI projects including the targeted network secondary cable replacement program. Table ~~5~~ **4** highlights these projects with additional detail provided in Exhibit A-23 Schedule M5.

Line
No.

Table 4 City of Detroit Infrastructure Projects

Project	Key Scope of Work	Estimated Timeline
CODI: Charlotte Network Upgrade	* Rebuild 30 miles of network feeder cable * Rebuild 7 miles of system cable * Replace or remove 83 netbank transformers *Convert 8 primary customers * Convert the circuits to 13.2kV * Decommission Charlotte substation	2018-2025
CODI: Targeted Network Secondary Cable Replacement	Replace targeted sections of the secondary network cable system that have a higher probability of failure	2019-2025
CODI: Corktown Substation	Build a new general purpose substation	2019-2022
CODI: Islandview Substation	*Construct a new 13.2kV substation * Convert 32 existing 4.8kV circuits from Walker and Pulford *Decommission Waler substation * Decommission aging 24kV cables and infrastructure	2020-2028
CODI: CATO Substation Expansion	Expand 13.2kV Cato substation by installing a 3rd transformer and a 12-position switchgear	2022-2027
CODI: Howard Conversion	* Rebuild 6 miles of network feeder cable * Rebuild 12 miles of system cable * Replace or remove 89 netbank transformers * Convert 26 primary customers * Convert 3 miles of overhead * Convert and consolidate the circuits to 13.2kV fed by Corktwon, St. Antoine, Cato, and Temple substations * Decommission Howard substation	2023-2030

Line
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Project	Key Scope of Work	Estimated Timeline
CODI: Midtown Substation Expansion	Expand 13.2kV Midtown substation by installing a 3rd transformer and a 12-position switchgear	2019-2023
CODI: Alfred Substation Expansion	Expand 13.2kV Alfred substation by installing a 3rd transformer and a 12-position switchgear	2021-2024
CODI: Garfield Network Upgrade	* Rebuild 36 miles of network feeder cable * Replace or remove 78 netbank transformers * Convert 24 miles of overhead * Convert and consolidate the circuits to 13.2kV fed by Stone Pool substation * Remove 4.8kV and 24kV cable and decommission Garfield substation	2020-2028
CODI: Kent/Gibson Conversion	Kent Substation * Rebuild 6 miles of system cable * Convert 1 primary customer * Convert 7 miles of overhead * Convert and consolidate the circuits to 13.2kV fed by Corktown substation * Decommission and remove 2 miles of 4.8kV cable * Remove 24kV cable and equipment * Remove 6 breakers and decommission Kent substation Gibson Substation * Rebuild 10 miles of system cable * Convert 22 miles of overhead * Convert and consolidate the circuits to 13.2kV fed by Corktown substation * Decommission and remove 4 miles of 4.8kV cable * Remove 24kV cable and equipment * Remove 8 breakers and decommission Kent substation	2021-2027

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Q41. How are conversion and CODI projects benefiting customers in the City of Detroit?

A41. While approximately 14% of the Company's customers are in the city of Detroit, the Company is investing over 30% of its 2022-2024 strategic capital in the city (Table 3). These projects address aging infrastructure, improve safety and reliability of the distribution system. The CODI and conversion projects in the instant case will convert the system that serves more than 50,000 residential Detroit customers to 13.2kV from 4.8kV.

Table 5 Key Investments in the City of Detroit

Project/Program	Exhibit /Schedule	Page No. /Line No.	2022 - 2024 Capital Investment in City of Detroit ($thousands)	2022 - 2024 Percent of Startegic Capital in City of Detroit vs Total Strategic Capital
Substation Risk: McGraw	A-12 B5.4	Pg. 8/Ln. 9	40,463	1.7%
Substation Risk: Voyager	A-12 B5.4	Pg. 8/Ln. 10	200	0.0%
4.8 kV Hardening	A-12 B5.4	Pg. 8/Ln. 12	231,314	9.8%
Cable Replacement: Detroit URD 1-1	A-12 B5.4	Pg. 8/Ln. 19	1,061	0.0%
Station Upgrade: Navarre	A-12 B5.4	Pg. 8/Ln. 28	330	0.0%
Subtransmission Redesign & Rebuild: Trunk 2255	A-12 B5.4	Pg. 9/Ln. 11	2,373	0.1%
Subtransmission Redesign & Rebuild: Trunk 2419	A-12 B5.4	Pg. 9/Ln. 32	954	0.0%
Subtransmission Redesign & Rebuild: Trunk 2455	A-33 X3	Pg. 1/Ln. 21	1,995	0.1%
Subtransmission Redesign & Rebuild - Waterman	A-12 B5.4	Pg. 10/Ln. 55	2,310	0.1%
Subtransmission Redesign & Rebuild: Cortland Station Expansio	A-12 B5.4	Pg. 10/Ln. 60	3,630	0.2%
CODI: Charlotte Network Upgrade	A-12 B5.4	Pg. 10/Ln. 60	26,617	1.1%
CODI: Targeted Network Secondary Cable Replacement	A-12 B5.4	Pg. 10/Ln. 61	9,389	0.4%
CODI: Corktown Substation	A-12 B5.4	Pg. 10/Ln. 62	1,360	0.1%
CODI: Islandview Substation	A-12 B5.4	Pg. 10/Ln. 63	95,082	4.0%
CODI: CATO Substation Expansion	A-12 B5.4	Pg. 10/Ln. 64	24,414	1.0%
CODI: Howard Conversion	A-12 B5.4	Pg. 10/Ln. 65	15,702	0.7%
CODI: Midtown Substation Expansion	A-12 B5.4	Pg. 10/Ln. 66	4,037	0.2%
CODI: Alfred Substation Expansion	A-12 B5.4	Pg. 10/Ln. 67	15,973	0.7%
CODI: Garfield Network Upgrade	A-12 B5.4	Pg. 10/Ln. 68	84,413	3.6%
CODI: Kent/Gibson Conversion	A-12 B5.4	Pg. 10/Ln. 69	61,611	2.6%
4.8 kV CC: Cortland / Oakman / Linwood Consolidation	A-12 B5.4	Pg. 10/Ln. 72	387	0.0%
4.8 kV CC: I-94 Substation and Circuit Conversion (Promenade)	A-12 B5.4	Pg. 10/Ln. 74	57,607	2.4%
4.8 kV CC: McKinstry Sub Decommission	A-12 B5.4	Pg. 10/Ln. 79	4,696	0.2%
4.8 kV CC: Power line Conversion of MADSN 175L-W	A-12 B5.4	Pg. 10/Ln. 91	361	0.0%
4.8kV CC: SCOTN	A-12 B5.4	Pg. 11/Ln. 94	3,846	0.2%
4.8 kV CC: Zenon Circuit Conversion Phase 2	A-33 X3	Pg. 1/Ln. 7	800	0.0%
Pilot: Strategic and Service Undergrounding	A-12 B5.4	Pg. 11/Ln. 132	4,454	0.2%
Pilot: Primary Deconductoring	A-12 B5.4	Pg. 11/Ln. 133	1,848	0.1%
4.8 kV Relay Improvement (Delta Ground Detection Program)	A-12 B5.4	Pg. 12/Ln. 39	47,127	2.0%
Total			744,354	31.5%

Line No.

8.3 kV Pontiac Conversion

Q42. Why does the Company operate at a different grid voltage, 8.3kV, in the Pontiac area?

A42. The 8.3kV system that serves the city of Pontiac was acquired from CMS Energy in the 1980s. More detail on the 8.3kV system can be found in Exhibit A-23 Schedule M7 DGP beginning on page 341.

Q43. What are the drivers of the 8.3 kV Pontiac Conversion?

A43. The Pontiac area is the only 8.3kV in the Company's distribution system. Unlike the 4.8kV and 13.2kV systems, contingency options through jumpering are limited for the 8.3kV system, because the 8.3kV system is an island surrounded by the 13.2kV system, it is challenging to transfer load from 13.2kV to 8.3kV and from 8.3kV to 13.2kV to transfer load from 8.3kV circuits to neighboring facilities. This results in a high risk for stranded load in the event of a substation outage event.

Adding to the operational challenges, the 8.3kV system is aged, and replacement parts are no longer available. Due to the design configuration and timeframe when these substations were built, they now have non-standard clearances. For Company employees to maintain safe working conditions, to prevent arc flashes, substation shutdowns are required versus isolating a single piece of equipment. This leads to extended customer interruptions during outage events and leaves the system in an abnormal state for extended periods of time if any 8.3kV equipment fails.

Line No.

For reasons listed above and to increase capacity, improve reliability, safety, and operability, the Company has developed plans to upgrade and convert the Pontiac system to 13.2kV as part of grid modernization.

Q44. What are the benefits of the 8.3kV Pontiac Conversion?

A44. Expanding and upgrading the 13.2kV Wheeler substation will allow for conversion of the 8.3kV Pontiac system. Converting the Pontiac system to 13.2kV will provide jumpering points from nearby 13.2kV substations and shorten outage times by allowing the Company to restore customers prior to repairing all the damaged infrastructure (restore before repair). The expanded 13.2kV Wheeler substation will also provide for capacity needs in the future and better prepare the area for adoption of DERs. Additionally, this project will decommission all four 8.3kV substations and the 13.2kV Bloomfield substation that has been identified to have at-risk switchgear. Removing at-risk, outdated, and obsolete 8.3kV equipment from the system will reduce emergent cost and improve response time for customer restoration.

Q45. What is the scope of the 8.3kV Pontiac Conversion?

A45. The 8.3kV system is served by four substations: Bartlett, Paddock, Rapid Street, and Stockwell, and their combined eighteen distribution circuits. The plan to address the 8.3kV system has been developed, starting with upgrading the system vaults as outlined in previous rate cases and in Section 8.19 of the DGP. The remaining scope of work for the 8.3kV system includes upgrading the existing 13.2kV Wheeler substation and transferring the feed to all remaining OH and underground infrastructure from Bartlett, Paddock, Rapid Street, and Stockwell to

Line No.

the upgraded substation. This will require replacement of customer-owned switchgear, fuses, transformers, and cables rated at less than 15kV class.

Subtransmission Redesign & Rebuild

Q46. Can you describe the Company's Subtransmission system?

A46. The Company's subtransmission system is an interconnected web that transmits higher voltage across the service territory to stations that step down the voltage to distribution levels to serve customers. The subtransmission system is operated at the voltages of 24kV, 40kV, or 120kV. The design of the system is intended to provide redundancy to the feed points of the distribution substations which directly serve customers. This redundancy provides continued service to the customers during a single contingency situation. This situation is caused by an outage of equipment in the OH, UG, or station system that is necessary to allow power flow to customers. The Company's subtransmission system differs from that of most other utilities because it includes both radial and network designs. The radial configuration, called a trunk line, has one source station and can feed one or multiple substations. The network configuration, called a tie line, has multiple source stations and feeds multiple substations. The Company utilizes a coordinated system of automatic pole top switches (APTS) and line section breakers on the networked tie lines to isolate faults and maintain service to customers in single contingency failure situations.

Q47. What are the challenges and issues associated with the subtransmission system?

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Line No.

A47. Similar to the distribution system, the subtransmission system is experiencing aging, beyond 80 years old in some areas, and storm related reliability challenges, as well as increased loading and a loss of contingencies. Areas of the subtransmission OH system are in difficult-to-access, deeply wooded areas and along railroads, increasing the time and difficulty for restoring service or maintaining equipment. These factors are leading to an increased number of failures on both the OH and underground subtransmission systems and delaying restorations. These failures result in large sustained outage and the loss of redundancy, depending on the system configuration.

The Company performed an analysis on the subtransmission system that revealed approximately one-third of the circuits on the subtransmission system violated the Company's planning criteria and need to be addressed, described in Table 6.

Line
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1 **Table 6 Subtransmission Priority Criteria**

Subtransmission Dimensions	Definition
Load Loss for Single Contingency	Total load that will be shed when a subtransmission line can no longer support the substation and does not have a back-up or the back-up cannot support the load
Load over allowable Emergency Rating for Single Contingency	Total load when a subtransmission line exceeds its emergency rating of its alternative route during an event (i.e., outage)
Load over Day to Day Rating, Normal Conditions	Total load that exceeds the rating of a subtransmission line during normal conditions
Strong Load Growth Prospect	Consideration given to subtransmission lines that are predicted to experience load growth
Voltage Violation	Consideration given to subtransmission lines that experience low voltage conditions when they are not in their normal configuration (i.e., due to an outage)
Reliability Impact	Consideration given for the reliability of the subtransmission lines based on total sustained outages, miles of circuit exposure, construction standards & equipment, total customers and total load served and ability to serve the load from an alternate source

2 Additionally, the analysis showed that the Company's aging subtransmission
3 system is not currently adequate to serve the Company's customers' long-term
4 needs given its limited capacity and reliability performance. System loading and
5 the impact of outages on customer operations have increased over time and reduced
6 the redundancy. Existing overloads and the aging equipment place loading
7 constraints on the system. These constraints limit the Company's ability to get
8 shutdowns required for system upgrade projects and routine maintenance can only
9 be completed during periods of low load or through the deployment of portable
10 equipment. These periods of low load are typically only during a few weeks in the

Line No.

spring and the fall. The loading constraints also make it challenging to add new customers or provide capacity for existing customers with increased load.

Q48. What analysis was performed to determine that circuits on the subtransmission system violate planning criteria?

A48. Subtransmission Planning Engineers analyze the condition of the system on a yearly basis to determine existing and projected limitations to serving customers in a single contingency situation. This analysis is conducted by utilizing industry-standard modeling software (PSSE & TARA) with individual substation loads submitted by Company SMEs and the models used by the Midcontinent Independent System Operator (MISO). The models provided by MISO include multiple electric system scenarios, including current and future peak loading conditions. Using these models, a study is run on each individual subtransmission line with all possible contingency situations assessed to identify all violations of subtransmission planning criteria. The planning criteria focuses on both thermal overloads and voltage violations under normal system conditions and during a single contingency configuration. A thermal overload indicates that equipment on the circuit or station exceeds its rating, and a voltage violation indicates that the voltage on at least part of the circuit is no longer within an acceptable range.

Q49. Why does the Company need to redesign and rebuild its subtransmission system?

A49. This rebuilt hardened resilient subtransmission system will dramatically improve safety, reliability, operability, and increase capacity. The resiliency of the OH subtransmission system will be achieved by rebuilding to the Company's grade B

Line No.

standard which will harden against weather impacts such as high winds and lighting. Company's grade B standard is described in more detail below. The rebuilt OH subtransmission system will have larger conductor to provide additional capacity and reduce voltage drop over long distances. The underground subtransmission reliability will improve due to the removal of at-risk or overloaded cables. Additionally, rebuilding the subtransmission system will also remove aging equipment reducing the probability of equipment failures.

An outage event on the distribution system could impact up to 1,000+ customers, based on the size of the circuit. By comparison, an outage on the subtransmission system could impact multiple substations resulting in up to 10,000+ customers impacted. Furthermore, subtransmission outages typically require the deployment of costly mobile generation or portable substations to restore customers quickly because permanent solution take extended periods of time to implement. The rebuilt subtransmission system by design will provide redundancy to reduce/eliminate multiple substation outages.

This rebuilt and redesigned subtransmission system will support area load growth for existing and new customers. Along with the ability to support DER interconnections, such as large-scale solar arrays. As the generation profile is expected to change with the integration of more DERs and the retirement of fossil generation plants, improvements to the subtransmission system will support the changing power flows on the system.

Q50. What is the scope of the Subtransmission Redesign & Rebuild program?

A50. The subtransmission redesign and rebuild program is focused on installing new station equipment, as well as rebuilding both the OH and underground portions of

Line No.

the subtransmission system. The station work involves the installation of large transformers, capacitor banks and associated equipment, and will provide significant improvements to the system with additional redundancy and voltage support. The OH work will be completed to our updated, more resilient grade B standards which include the replacement of old wooden poles with new steel poles, porcelain insulators with polymer clamp top insulators, and smaller wire aging conductors – which can be damaged by lightning strikes – with larger wire, stronger conductors able to withstand winds up to 90 mph resulting in a much more storm resilient system. The larger wire standard conductor will provide significantly more capacity on each circuit, while also reducing the magnitude of voltage drop over long distances on the system and providing approximately twice the strength of existing conductors to withstand contact with a tree limb if one happens to fall on it. The underground work consists of replacing at-risk or overloaded cable with new sections and rebuilding cable poles to new specifications.

Q51. How did the Company develop the Subtransmission Redesign & Rebuild Plan?

A51. In order to determine the subtransmission projects that would have the greatest impact on reliability and resiliency of the system, the Company reviewed:

1) current system planning criteria violations, related to loading and voltage challenges;

2) future distribution system plans and loading projections;

3) and customer outages caused by subtransmission failures.

The Company then ranked the planning criteria violations based on severity, and projects were identified that could address the limiting elements on the system. The

Line No.

scope of the projects and future subtransmission system configuration is also influenced by distribution system plans to construct new and retire old substations. These plans provide the necessary input to ensure the scope of the subtransmission projects will meet the requirements of our customers for decades to come. In addition to planning criteria violations and future distribution system plans, the Subtransmission Planning Engineering group also closely monitors the reliability of the system and identifies circuits with multiple reliability issues. These circuits are identified, and the outages are analyzed to determine the most effective project to improve reliability performance. The Planning Engineers consider both existing routes of the lines that may need rebuilding in place, and sections where wire down events have occurred, which might merit relocation. Based on their analysis, the Planning Engineer identifies which sections to focus on for redesign and rebuild of the lines. The projects that address these sections include rebuilding to the current more resilient construction standards and relocating the lines to road accessibility wherever possible.

Q52. How does the Company determine priorities when selecting circuits for Subtransmission Redesign & Rebuild?

A52. The order in which the circuits and stations will be addressed is determined by working with the distribution Planning Engineers to collaborate on conversion/consolidation projects and the priority criteria, which is evaluated over the whole system on an annual basis.

The Company considers multiple criteria when evaluating the priority of the subtransmission redesign and rebuild projects. Consistent with the rest of the strategic investment portfolio, the load relief prioritization scores for

Line No.

subtransmission feed into the GPM model, supported by Company witness Kryscynski, to help formulate the future capital plan. The Load Relief model was updated to incorporate the subtransmission planning criteria for subtransmission redesign & rebuild projects. Subtransmission load relief prioritization scores are determined based on load loss for single contingency, load over allowable emergency rating for single contingency, load over day to day ratings, strong load growth prospect, and whether there is a voltage violation. Please see Table 6 for further description of the criteria. Once subtransmission projects are prioritized they are evaluated through the GPM model to be compared with the rest of the Company's portfolio.

Q53. Are all the subtransmission redesign projects listed separately in this case?

A53. No. There are times when the Company experiences issues on the subtransmission system that are not overly complex, that can be executed without extensive engineering and planning like the other subtransmission projects. These projects are generally small in nature, requiring $500,000 or less in capital. The scope of work for these projects addresses thermal and voltage violations under either normal or single contingency situations. Projects of this nature are identified during the Annual System Review process, which is the same methodology used to identify all the subtransmission projects under the Subtransmission Redesign & Rebuild program. Because the Company experiences these situations every year and they can be solved quickly without extensive engineering and planning, the Company has created a Small Projects and Reserve program. This program will allow the Company to address smaller issues on the subtransmission system in real time without the delay of a more extensive project.

Line No.

Q54. How will customers benefit from the Small Projects and Reserve program?

A54. The Small Projects and Reverse program will provide multiple customer benefits including safety, improved reliability and operability, and increased capacity within a shorter period of time due to the much more limited scope required to address identified system issues. With the ability to address the system conditions and provide more immediate benefits to the customers with a relatively quick solution, the projects are executed shortly after identification instead of following a more formal ranking and scheduling potentially years out.

Strategic Undergrounding Program

Q55. Has the Company piloted undergrounding existing OH lines?

A55. Yes. The Company initiated a pilot on Appoline DC 1346 in Detroit to move rear-lot OH assets to rear-lot underground infrastructure.

Q56. What were the objectives of the pilot?

A56. As described in the Company's 2021 Distribution Grid Plan (Exhibit A-23 Schedule M7), the goals of the Appoline pilot were to determine actual installation costs, understand customer acceptance, and determine opportunities to improve cost and construction efficiency.

Q57. What was the timing of the Appoline undergrounding pilot?

A57. The Company began engineering for the pilot in 2018 and construction started in 2019. Of the 61 customers targeted for undergrounding, 21 still remain on OH service. The Company performs undergrounding of services as part of its regular

Line No.

business practice, typically at the customer's request, and there is nothing additional to learn by undergrounding the remaining customers. This pilot has achieved its primary objective, and therefore, the Company considers it complete. Through this pilot the Company was able to gather the needed lessons learned on undergrounding rear lot OH infrastructure. The Company has completed an initial report, pursuant to the Order in Case No. U-20836, on the Appoline pilot and is included in the instant case as Exhibit A-23 Schedule M10. That report provides additional details on the timing and status of the pilot.

Q58. Is the Company considering other strategic undergrounding projects?

A58. Yes. In the instant case, the Company is proposing an additional undergrounding project for Fairmount DC 1593, which will allow us to continue to develop our understanding of this technology aimed at resilience.

Q59. What is the scope of the Fairmount DC 1593 underground project?

A59. The scope of this undergrounding project differs from Appoline, in that it is to relocate OH rear-lot assets to front-lot URD in a two-block area served by Fairmount DC 1593 in the City of Detroit. It includes installing two cable poles, conduit, and primary conductor to establish the URD loop around the two-blocks. This project will install 14 pad-mounted transformers, 43 secondary pedestals and other necessary equipment to serve approximately 98 customers in the area. All the equipment and the system design will be completed in preparation for conversion to 13.2kV at some point in the future. Once the URD loop is established, and the new services have been completed; the existing OH assets will be removed from the rear-lot.

Line No.

Q60. Why was Fairmount DC 1593 selected?

A60. Customers on this circuit have continued to experience a higher-than-average number of downed wires per mile, despite the fact that tree trimming has been completed. Furthermore, in 2021 and 2022 some of the customers on this circuit experienced 5 or more sustained outages and dozens of momentary outages. During the August 9, 2021 catastrophic storm approximately half the customers fed by Farimount DC 1593 were without power for over 50 hours. There were many downed wires in backyards with limited truck access that led to this delayed restoration time. Because of these issues, it was determined that this circuit was a good candidate for undergrounding and would allow the Company to continue its knowledge gathering for undergrounding existing OH infrastructure.

Q61. What is the timing of the Fairmount underground project?

A61. Engineering is being completed and design is expected to start late in the first quarter or early in the second quarter with the intent of starting construction in late fall of 2023. Construction completion is scheduled for the end of 2024. The Company is also employing lessons learned from the Appoline project by beginning to actively engage customers to gain support for the project with the goal to get significant customer approval prior to beginning construction.

Q62. What does the Company expect to accomplish with the Fairmount DC 1593 underground project?

A62. As described earlier in this testimony and Exhibit A-23 Schedule M10, the Company learned a great deal about the installation costs, customer acceptance and

Line No.

construction efficiency when addressing rear-lot construction by completing the Appoline pilot and benchmarking work. The Fairmount project will leverage these lessons learned by removing OH infrastructure to improve safety and reliability for the customers. The Company has an opportunity to expand its knowledge of designing and implementing front lot underground infrastructure to replace existing rear lot OH infrastructure. When this project is completed, the Company will have additional data to support a more statistically significant benefit cost analysis for undergrounding projects.

Primary Deconductoring

Q63. What are the benefits of the Primary Deconductoring?

A63. The driving benefit is that by removing OH lines that are not fully utilized, and any associated arc wire, the Company is eliminating wire downs. Removing unnecessary OH lines also eliminates the potential for power outages caused by those lines failing or being damaged. As the Company installs new secondary lines where needed they are installed at the new standard, larger size, meaning they are stronger and are rated for higher voltages. Any transformers installed are also to the new standards, dual voltage, and are rated for 13.2kV.

Q64. What is the scope of work for Primary Deconductoring?

A64. The scope of work for Primary Deconductoring includes the removal of underutilized infrastructure such as small-sized primary wire, arc wire, OH transformers, and other pole top equipment. In addition, where necessary the Company will reconductor secondary wires and upgrade transformers and other

Line No.

pole top equipment, and where possible install equipment in truck accessible locations.

Q65. Has the Company completed the Primary Deconductoring pilot?

A65. Yes. The Company has completed projects on two circuits.

Q66. What are the lessons learned from the Primary Deconductoring pilot?

A66. In the initial phases of the pilot the Company assumed a flat KVA usage per home, this assumption proved to be incorrect and lead to low voltage issues. The Company has moved to a more dynamic assumption for KVA usage per home. This dynamic approach considers the type of housing in the area of work, i.e. number of duplexes, single family homes, etc. Since using this approach, the Company has not experienced any low voltage issues.

Q67. How will Primary Deconductoring be used in the future?

A67. The Company is currently performing deconductoring in the 4.8kV Hardening program, for further detail see the testimony of witness Elliott Andahazy. In the short term the Company will consider deconductoring where appropriate in the 4.8kV Conversion program, as well. As results are reviewed and analyzed, the Company will consider if a standalone Primary Deconductoring program is needed.

System Loading

Q68. Can you describe a system overload?

A68. System overloads occur when there is not enough capacity to meet customer demands and still maintain equipment operating ratings. Capacity needs are

Line No.

considered for two conditions: normal state and contingency states. The normal state exists when all equipment and components are in services and operating as designed. The contingency states exist when there is either a temporary planned equipment shutdown or the loss/failure of a component of the electric power system (e.g., transformer, cable or breaker). Under contingency conditions, equipment in the rest of the system may see an increase in loading to compensate for the out-of-service equipment, therefore requiring additional capacity above normal state.

To meet the two capacity requirements, most components and equipment have two ratings: day-to-day and emergency. These ratings are calculated to maintain the viability of an asset throughout its expected useful life. Operating equipment above its designated ratings can cause immediate failure or accelerate end-of-life and is considered an overload.

- The day-to-day rating (for normal state conditions) is the load level that the equipment can be operated at for its expected life span.
- The emergency rating (for contingency state conditions) is typically higher than the day-to-day rating and indicates the load level that the equipment can operate for short periods of time only. Operating at the emergency rating adds stress to the equipment and shortens its lifespan. If a piece of equipment exceeds its emergency rating, the Company's ESOC takes immediate steps to transfer load or shed load if necessary.
- Substations also have a firm rating, which is the maximum load the substation can carry under a single contingency condition and is based on the lowest emergency rating of all the substation equipment that is required to serve the load.

Line No.

Q69. What are the challenges and issues with system overloads?

A69. System overloads make it challenging for the Company to serve new customers and provide additional capacity for existing customer. System overloads stress equipment reducing useful life and impacts system operability by limiting jumpering. Without jumpering capabilities to adjacent circuits, outages can be sustained for longer periods of time because the equipment must be replaced to restore customers. Furthermore, stressed equipment can also increase the probability of emergent failures leading to customer outages.

The Company conducts annual Area Load Analysis (ALA) to determine if there are any overloads on the system. Based on the 2021 ALA study, over 30% of distribution substations have loading constraints. This includes substations operating over its firm ratings and substation equipment and/or circuit equipment working near or over its day-to-day rating during peak hours. In areas that have seen and continue to see steady load growth, capital investments are required to prevent overloads.

Q70. What are the benefits of System Loading projects?

A70. System Loading alleviate the stress on the system caused by overloads and reduces potential failures. Capital investment to address these system overloads will improve reliability and provide capacity for new customer and increased demand form existing customers. Additionally, the system load projects help maintain/improve system operability by restoring jumpering capabilities and removes aged equipment from the system.

Q71. What is the scope of work for System Loading projects?

Line No.

A71. System Loading projects include scope to add capacity to the distribution system, and typically include:

- construction of new substations
- expansion of current substations by installing additional transformers
- replacing existing transformers
- installing new switchgear lineups
- creating new distribution circuits
- reconductoring circuits
- converting circuits to higher voltage and transferring load once additional capacity has been created

Many areas identified in the priority ranking for system load relief are addressed as part of CODI, 4.8kV Conversion, or 8.3kV Pontiac Conversion programs. Load relief needs that are not included in those programs are part of the System Loading projects category.

Q72. How are system loading projects prioritized?

A72. Distribution engineers assess the load on the system and its impact on individual pieces of equipment under two conditions: normal state and contingency state. This analysis is done to determine if adequate distribution system capacity exists to serve both current and projected future demands.

System loading information from this analysis is updated and evaluated annually. Projects are evaluated for load relief on how they address four factors: substation equipment overload, substation over firm, circuit equipment overload, or strong load growth. Based on these variables a priority ranking of the load relief projects is developed. More information about Load Relief criteria and prioritization can be

S. S. DEOL
U-21297

Line No.

found in Section 11.1 of the DGP (Exhibit A-23 Schedule M7 sponsored by Witness Robinson).

Q73. Does this complete your direct testimony?

A73. Yes, it does.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of	)	
DTE ELECTRIC COMPANY	)	
for authority to increase its rates, amend	)	Case No. U-21297
its rate schedules and rules governing the	)	
distribution and supply of electric energy, and	)	
for miscellaneous accounting authority.	)	

REBUTTAL TESTIMONY

OF

SATVIR S. DEOL

DTE ELECTRIC COMPANY
REBUTTAL TESTIMONY OF SATVIR S. DEOL

Line No.

Q1. Please state your full name, title, business address and by whom you are employed?

A1. My name is Satvir S. Deol (he/him/his), and my business address is One Energy Plaza, Detroit, Michigan, 48226 and I am employed by DTE Electric Company (DTE Electric or Company).

Q2. Did you file direct testimony in this proceeding on behalf of DTE Electric Company (DTE Electric or Company)?

A2. Yes.

Purpose of Testimony

Q3. What is the purpose of your rebuttal testimony?

A3. The purpose of this testimony is to rebut certain positions of Staff Witness Shi, Staff Witness Evans, Michigan Attorney General (AG), Michigan Environmental Council (MEC), Natural Resources Defense Council (NRDC), Sierra Club (SC), and Citizens Utility Board of Michigan (CUB), collectively referred to as "AG-MNSC" Witness Stephens, and Attorney General Witness Coppola. The absence of a discussion of other matters in my rebuttal testimony should not be taken as an indication of agreement with other aspects of any intervenor's testimony.

Q4. Are you sponsoring any exhibits in this proceeding?

A4. Yes. I am sponsoring the following exhibits:

Exhibit	Schedule	Description
A-41	FF1	Subtransmission System Violations
A-41	FF2	MNSCDE-3.3ai

Line No.

1	A-41	FF3	MNSCDE-3.8a-c
2	A-41	FF4	MNSCDE-3.18
3	A-41	FF5	MNSCDE-3.9b
4	A-41	FF6	STDE-6.7a
5	A-41	FF7	MNSCDE-7.37

6

7 **Q5. Were these exhibits prepared by you or under your direction?**

8 A5. Yes, they were.

9

10 **Q6. How is your testimony organized?**

11 A6. There are 11 specific points I will rebut in my testimony, as listed below. A detailed
12 discussion of why the intervenor's recommendations should not be accepted by the
13 Commission follows.

14

15 ## Rebuttal Contents

16 Purpose of Testimony 1
17 Interpretation of the Directionally Plausible Forecast 3
18 Rebuttal Issue 1: AG-MNSC Witness Stephen's misuse and misunderstanding of the
19 Electric Vehicle (EV) forecast used in the DGP as the Directionally Plausible Forecast
20 3
21 Proposed disallowance of 50% for conversion projects, CODI, system loading,
22 subtransmission redesign and rebuild programs 11
23 Rebuttal Issue 2: AG-MNSC Witness Stephens' use of 50% as a suggested
24 disallowance. 11
25 Subtransmission Redesign & Rebuild (Subtransmission) 14
26 Rebuttal Issue 3: AG-MNSC Witness Stephens' recommendation to disallow 50% of
27 strategic capital associated with Subtransmission projects. 14
28 4.8kV/8.3kV Conversion Projects 23
29 Rebuttal Issue 4: AG-MNSC Witness Stephens's recommendation to disallow 50% of
30 strategic capital associated with 4.8kV/8.3kV conversion projects. 23

Line No.

Table 1 4.8kV and 13.2kV All-Weather Reliability 32
City of Detroit Infrastructure Projects (CODI) 33
Rebuttal Issue 5: AG-MNSC Witness Stephens' recommendation to disallow 50% of strategic capital associated CODI projects. 33
Rebuttal Issue 6: Staff Witness Shi recommendation to disallow strategic capital associated CODI projects. 38
Table 2 CODI Investments 2021 – 2024 40
Table 3 Monthly Average OH Contractors 41
System Loading Projects 43
Rebuttal Issue 7: AG-MNSC Witness Stephens' recommendation to disallow 50% of strategic capital associated System Loading projects. 43
Strategic Undergrounding (SUG) 46
Rebuttal Issue 8: Staff Witness Evan's recommendation to disallow strategic capital in the SUG projects. 46
Table 4 All Weather SAIDI Results 48
Table 5 SAIDI ex-MED Results 48
Rebuttal Issue 9: AG Witness Coppola's recommendation to disallow strategic capital associated SUG. 49
Rebuttal Issue 10: Staff Witness Evan's recommendation to perform a cost/benefit analysis for undergrounding services. 50

Interpretation of the Directionally Plausible Forecast

Rebuttal Issue 1: AG-MNSC Witness Stephen's misuse and misunderstanding of the Electric Vehicle (EV) forecast used in the DGP as the Directionally Plausible Forecast

Q7. What is AG-MNSC Witness Stephens's assessment of the directionally plausible EV growth forecast from the Distribution Grid Plan (DGP)?

A7. On page 13 lines 2 and 3, Witness Stephens claims: "DTE appears to be basing its need to convert all its circuits to 13.2kV within 15 years on EV growth." In this quote he makes reference to the Company's 2021 Distribution Grid Plan (DGP) (Exhibit A-23, Schedule M7 supported by Company witness Robinson) and the Company's directionally plausible forecast for electric vehicle (EV) growth. He

Line No.

further states, based on the directionally EV loading workpapers, provided as Ex MEC-25, on page 15, lines 6-7 of his direct testimony: "It appears to me that the Company's Area Load Analysis, completed in 2020, artificially de-rated the capacities of circuits and substations." And on page 21, lines 1-3: "It wasn't until I reviewed the EV loading workpapers late in discovery that I realized the capacities the Company was assigning to its substations were subjectively determined rather than based on manufactures' nameplate capacity ratings." AG-MNSC Witness Stephens refers to the directionally plausible forecast as the EV loading workpapers.

Q8. What is the Company's directionally plausible forecast, referred to as the EV loading workpapers by AG-MNSC Witness Stephens?

A8. The Company contracted a third party to create a directionally plausible forecast as part of its 2021 DGP, Exhibit A-23, Schedule M7, supported by Company witness Robinson. As noted in the DGP on page 36, the purpose of the plausible forecast was not to predict with specificity the numerical value of that scenario; rather, as the directionally plausible forecast plays out, the teams can identify stresses that are seen on the system. This directionally plausible forecast included a projection of electric vehicle adoption across the Company's service territory as part of an effort to study the impacts on the distribution systems from aggressive load growth caused by the adoption of EVs. The Company performed this analysis to understand how increased load from EV adoption may stress the distribution system as the assumed aggressive growth in loading moves along the trajectory of this forecast, the intent of this directionally plausible forecast was explicitly not intended to predict the

Line No.

specific impact on peak load, as noted in footnote 6 on page 45 of Exhibit A-23, Schedule M7.

Q9. How was the directionally plausible forecast used in the DGP?

A9. The directionally plausible forecast was developed as part of the DGP's Electrification scenario planning analysis, section 3.3.1 in Exhibit A-23, Schedule M7, to assess how load growth from EV adoption could impact the distribution system. Scenario-based planning is an established methodology for making informed decisions when the future is highly uncertain. To better understand the uncertainties surrounding the fundamental changes to the grid, three future scenarios were developed to assess the potential changes that could impact the electric grid as well as their implications over the next 15 years. The directionally plausible forecast was used as a supporting analysis for the Electrification scenario planning analysis.

Q10. Was directionally plausible forecast used to support any investments in the instant case or the Infrastructure Recovery Mechanism (IRM)?

A10. No. As noted above, the Directionally Plausible Forecast was not intended to predict the specific impact on peak load that would be required for project creation. Additionally, in discovery response MNSCDE-7.21c, attached as Exhibit A-41 Schedule FF1; the Company clearly states: "This directionally plausible forecast served the purpose to highlight needs of a particular plausible future and was not used to determine specific capital investments."

Line No.

Q11. Are the Company's substation ratings subjectively determined and de-rated as claimed by AG-MNSC Witness Stephens?

A11. No. As provided in Witness Stephens's exhibit Ex MEC-25, column iii has a header that says "Capacity / Firm Rating (MVA)." Firm rating means, as stated in my direct testimony on page SSD-44 lines 21-24: "Substations also have a firm rating, which is the maximum load the substation can carry under a single contingency condition and is based on the lowest emergency rating of all the substation equipment that is required to serve the load." This definition clearly shows that the Company is basing its substation ratings on defined equipment ratings as opposed to being subjectively determined or de-rated. In fact, witness Stephens, on page 20, lines 16-20 states: "[i]n my experience, substation capacities are determined by the capacity of equipment as assigned by each item's manufacturer, called 'nameplate' capacity. Almost every piece of equipment in a substation is assigned a nameplate capacity rating by its manufacturer. To determine the capacity ratings for a substation, one need only know the nameplate capacity ratings of the piece of equipment in that substation with the lowest rating." Witness Stephens definition of substation capacity is similar to the definition stated in my direct testimony, both definitions reference substation equipment ratings as the defining element of the substation capacity. The only difference in the substation rating definitions is that the Company includes single contingency consideration in its planning.

Q12. Why does the Company factor in a single contingency condition when calculating the substation capacity, as opposed to the equipment-rating only approach used by Witness Stephens?

Line No.

A12. A single contingency condition is one in which a piece of equipment fails, and an adjacent piece of equipment is required to pick up the load normally handled by that failed component in order to maintain power for customers without an interruption. An example would be a two-transformer substation with each transform having a capacity of 15 MVA. The Company would designate a Firm Rating for the substation at 15 MVA even though both transformers could be serving 12 MVA. In the event that one transformer failed, the other would pick up the load and temporarily it would serve the combined 24 MVA. This situation would mean that the operating transformer would now be 60% overloaded (24 MVA/15 MVA). Witness Stephens even points out in his testimony, on page 21, lines 3-5: "[a]s indicated earlier, it is impossible for a piece of equipment to operate at 50% or more past its nameplate capacity for long before it fails." If the Company did not rate substations based on single contingency the Company would experience additional failures as adjacent equipment would quickly become overloaded causing what is known as cascading failures, as acknowledged by Witness Stephens.

Q13. Is it standard in industry to develop substation ratings in grid planning based on single contingency?

A13. Yes. While there is no universally adopted set of planning criteria across all utilities, one example of a planning standard is the 2017 – USDA Rural Utilities Service Electric System Long-Range Planning, RUS Bulletin 1724D-101A Section 4.b[1] on transformer criteria provides the follow guidance "Several factors should be considered in establishing criteria for sizing transformers for substations

[1] 2017 USDA Rural Utilities Service Electric System Long Range Planning UEP_Bulletin_1724D-101A.pdf (usda.gov)

Line No.

to ensure that equipment remains in service over its useful life, including the initial load and growth rate at the substation location, potential load shifts due to new substations and *load shifts during emergency situations*." Emphasis added. Compliance with these criteria is required to receive federal funding for rural electric development programs and projects.

Q14. How is AG-MNSC witness Stephens' interpretation of the directionally plausible forecast in the DGP incorrect?

A14. First, the full quote in Exhibit A-23, Schedule M7, page 319 states: "While this may take decades, DTEE's aspiration is to convert it in the next 15 years, particularly as the grid needs from the electrification and increased DG/DS adoption scenarios materialize. Looking beyond the no-regrets investments of the next five years, DTEE will create longer term plans through the use of more advanced tools and analytics discussed in the DGP, such as the Integrated Forecasting Solution described in Section 4.2." This quote acknowledges that conversion of the 4.8kV system is likely to take decades, and the goal to convert that system in 15 years was stated as the Company's *aspiration*. The quote also clarifies that investments made over the next five years, 2021-2025 at the time of the DGP filing, are considered no-regrets investments under various scenarios and are not dependent on only the electrification scenario as described in the DGP. In the instant case, Case No. U-21297, the Company is looking for funding through 2024 the projected test year, which is within the 2021-2025 plan no-regrets timeframe. The Company has requested approval of investments for the periods extending into and through 2025 and 2026 as part of its proposed Infrastructure Recovery Mechanism (IRM), which is just one year beyond the no-regrets timeframe identified in the 2021 DGP.

Line No.

Witness Stephens uses the existence of the EV loading forecast (EV loading workpapers) to criticize the Company's capital planning process, and by extension DTEE's proposed distribution investments. However, Witness Stephens does not identify any specific projects where the Company relies on the EV loading workpapers to support associated capital expenditures, because that was not and is not the purpose of EV loading forecast.

Q15. Does AG-MNSC Witness Stephens use other Company provided EV forecasts in his testimony?

A15. Yes. Witness Stephens uses an EV forecast from the Company's 2022 Integrated Resource Plan (IRP), Case No. U-21193.

Q16. Does witness Stephens correctly interpret the Company's IRP EV forecast and how it relates to the DGP and the conversion programs?

A16. No. On pages 14 and 15 of witness Stephens' testimony states that the EV charging load at peak forecast from the IRP is only "one quarter (26.8%) of what the Company's justification for 15-year 4.8kV circuit conversion claims the EV charging load impact will be (5,405 MW)." The Company is not sure where witness Stephens quoted EV load impact of 5,405 MW comes from, as the value in the Exhibit A-23, Schedule M7 page 45, Exhibit 3.3.1.1 is 5,286 MW.

The EV forecast in the IRP was created and used as an input to the overall load forecast. Since the forecast was created at a system level, it was not used for specific planning distribution projects or programs.

Line No.

As stated in footnote 6 in the DGP, Exhibit A-23 Schedule M7 page 45, the directionally plausible forecast is not intended to predict the specific impact on peak load, but rather to understand how the increased load stresses the system as it moves along the trajectory of this forecast. Exhibit 3.3.1.1 of the DGP on page 45 was not to justify any projects in the instant case or the IRM.

Neither of these forecasts were used in the development of any distribution projects or programs in the instant case or IRM period. Conversion projects, and the CODI program, in the instant case and the IRM period are supported with project specific evidence. See Exhibit A-23, Schedule M5, pages 238-417, my direct testimony, and Exhibit A-23, Exhibit M7 Section 11.3 4.8kV Conversion, Section 11.4 CODI Program, and Section 11.5 8.3kV system conversion and consolidation.

Q17. What should the Commission make of AG-MNSC witness Stephens' interpretation of the impacts of the 2021 DGP's directionally plausible forecast?

A17. The Commission should be aware that in my direct testimony the Company introduced the definition of firm rating, and that definition includes the use of lowest rated piece of equipment to determine substation capacity. It is prudent for the Company to build in single contingency considerations when planning substations capacity to avoid cascading failures of overloaded equipment, as witness Stephens notes that equipment 50% over its rating will fail before too long.

S. S. DEOL
U-21297

Line No.

The Commission should also note that the EV loading workpapers (as referenced by witness Stephens) were not used as justification for any projects or programs in the instant case or IRM.

The Commission should reject witness Stephens' interpretation of the EV loading workpapers and any recommendations he makes that rely on his interpretation.

Proposed disallowance of 50% for conversion projects, CODI, system loading, subtransmission redesign and rebuild programs

Rebuttal Issue 2: AG-MNSC Witness Stephens' use of 50% as a suggested disallowance.

Q18. Does AG-Witness Stephens recommend a significant disallowance for four Strategic Capital Programs?

A18. Yes. As shown in Table 2 on page 25 of witness Stephens' testimony he shows a recommended disallowance of 50% of the proposed capital for Circuit Conversions, City of Detroit Infrastructure, System Loading, and Subtransmission Redesign and Rebuild.

Q19. Why does AG-MNSC Witness Stephens make this recommendation?

A19. Witness Stephens seems to rely on an unsupported conclusion that a 50% reduction in investment will not have a significant impact upon the safety and reliability goals driving these investments.

On page 23, lings 19-21, continued page 24, lines 1-4, Witness Stephens states: "However, even with my recommended disallowance and reductions in planned

Line No.

spending for these programs (50%), the remaining capital spending budgets still represent significant increases over historical (2021) capacity expansion spending levels. As a result, even the reduced level of capital spending I recommend for the capacity expansion programs will be much more than adequate until a new and improved distribution planning process can be installed." Witness Stephens does not discuss how the proposed investments or his proposed disallowance will impact the safety and reliability goals of those investments.

Q20. Does AG-MNSC witness Stephens justify his 50% disallowance and claim that level of funding "will be much more than adequate?"

A20. No. Witness Stephens does not offer any evidence, calculations, analysis, or workpapers supporting his claim that his recommended level of capital "will be much more than adequate."

Furthermore, witness Stephens does not assess the impacts of any one project in these programs that he believes could be directly delayed due to his proposed investment levels. In witness Stephens' testimony he does not directly dispute the purpose or necessity, reasonableness or prudency, or the Company's ability to execute any of the Company's projects.

Q21. Does the Company provide justification for the requested levels of investments?

A21. Yes. The Company has filed direct testimony, along with exhibits (Exhibit A-23 Schedule M3-M6). These documents detail the purpose, necessity, scope of work, schedule, investment profile of each of its capital projects.

S. S. DEOL
U-21297

Line No.

Q22. How were these projects developed?

A22. As described in Company Witness Miller's Direct Testimony, pages 5-9, Company subject matter experts (SMEs) review grid and customer needs and develop projects and programs to address those needs. Needs can include safety, reliability, risk, system operability, new customer, relocations, cost considerations (such as cost avoidance), or load growth. Proposed projects are reviewed and analyzed by a group of SMEs, peers, and leaders within the Company. This process helps ensure that the projects and programs the Company is working on are best suited for the needs of the gird and the customers it serves. Once these projects and programs have been vetted, they are ranked in the Company's Global Prioritization Method (GPM) model, as discussed by Company witness Kryscynski in his direct testimony Part I: Global Prioritization Model, beginning on page AJK-4. The timing of the investments is well thought out and designed to accomplish the goals set forth by the Company SMEs.

Q23. Should the Commission adopt AG-MNSC Witness Stephens recommended disallowance amount of 50%?

A23. No. The Commission should reject Witness Stephens' recommendation to disallow 50% of the capital associated with these programs.

Witness Stephens is not offering any support as to why a 50% disallowance is correct or how this recommendation was derived. Whereas, the Company has provided detailed analysis on each and every one of its capital projects and programs.

Line No.

Furthermore, Witness Stephens is not challenging any specific project within these programs or the Company's ability to execute these projects, and he has not provided any evidence as to which projects are not needed at this time or should be delayed due to his proposed level of capital investments.

Subtransmission Redesign & Rebuild (Subtransmission)

Rebuttal Issue 3: AG-MNSC Witness Stephens' recommendation to disallow 50% of strategic capital associated with Subtransmission projects.

Q24. What is AG-MNSC Witness Stephens' recommendation regarding the Subtransmission Redesign and Rebuild program?

A24. On page 24, lines 10-15, Witness Stephens is recommending a 50% reduction in Subtransmission Redesign and Rebuild (Subtrans or Subtransmission) projects.

Q25. Why does AG-MNSC Witness Stephens make this recommendation?

A25. Similar to his arguments against conversion projects, most of Witness Stephens' testimony between pages 19 and 25 related to Subtransmission projects includes his assessment of the EV loading workpapers. On page 18, lines 6-7, Witness Stephens claims, with regard to System Loading and Subtransmission: "The justification for both programs is related to the same concept: loads and load growth relative to equipment capacity ratings." Additionally, on page 21, lines 1-3 Witness Stephens states: "It wasn't until I reviewed the EV loading workpapers late in discovery that I realized the capacities the Company was assigning to its substations were subjectively determined rather than based on manufacturers' nameplate capacity ratings." Therefore, the Company can only assume Witness Stephens is

Line No.

relying on his assessment of the EV loading workpapers to support his proposed disallowance.

Witness Stephens also claims that support for planning criteria violations was not provided, page 21, lines 13-15, and that support for reliability and safety benefits to this program were not provided, page 22, lines 8-11.

Q26. Does the Company agree with AG-MNSC Witness Stephens' recommendation and rationale?

A26. No. Witness Stephens once again relies on his own misinterpretation of the EV loading workpapers, as described earlier in my rebuttal testimony, as the reason for his proposed disallowance of subtransmission investments.

Additionally, Witness Stephens' claim that support for planning criteria violations was not provided is incorrect as discussed immediately above. The Company also disagrees with Witness Stephens' use of OSHA recordable as a measure of safety benefits.

Q27. What is the Subtransmission system?

A27. In simple terms, as stated in my direct testimony page SSD-31, lines 6-7, "The Company's subtransmission system is an interconnected web that transmits higher voltage across the service territory to stations that step down the voltage to distribution levels to serve customers."

On page 293, Exhibit A-23, Schedule M7, further detail is provided: "subtransmission system is operated at a voltage of either 24kV, 40kV, or 120kV

Line No.

and is used to step down transmission voltage to serve distribution and industrial substations. The design of the system is intended to introduce redundancy to the feed points of the distribution and industrial substations, resulting in continued service to customers during a single contingency situation."

The most critical aspect of the subtransmission system is the redundancy provided to limit customer impacts when resolving emergent situations and during maintenance activities (preventative [PM] or corrective [CM]).

Q28. Why are the Subtransmission projects necessary?

A28. As stated in my direct testimony, pages SSD-31 – SSD-32, similar to the distribution system, the subtransmission system is experiencing aging (beyond eighty years old in some areas) has experienced storm related reliability challenges, increased load, and loss of contingencies. The Company performed an analysis on the subtransmission system that revealed approximately one-third of the circuits on the subtransmission system violated Company planning criteria, as described in Table 6 on page SSD-33 of my direct testimony. As noted in my direct testimony page SSD-33, lines 2-3: "the analysis showed that the Company's aging subtransmission system is not currently adequate to serve the Company's customers' long-term needs given its limited capacity and reliability performance."

Q29. Can you briefly summarize the analysis that was performed on the subtransmission system?

A29. Yes, page SSD-34 and Exhibit A-23, Schedule M7 DGP pages 294-295 detail this analysis. To summarize, Company subtransmission planning engineers analyze the

Line No.

subtransmission system by modeling multiple electric system scenarios across each individual subtransmission line with all possible contingency situations assessed. These analyses are conducted utilizing industry-standard modeling software with individual substation load submitted by Company SMEs and the models used by the Midcontinent Independent System Operator (MISO).

Q30. What benefits do the Subtransmission projects provide?

A30. As stated in my direct testimony on pages SSD-34 – SSD-35, Subtransmission projects will improve safety, reliability, operability, and increase capacity. As noted above, the most critical aspect of these projects is to provide redundancy, having multiple feeds to a substation. By having redundancy for each substation limits customer impacts when resolving emergent situations and during maintenance activities (preventative [PM] or corrective [CM]).

As noted in my direct testimony, page SSD-35 lines 8-13: "An outage event on the distribution system could impact up to 1,000+ customers, based on the size of the circuit. By comparison, an outage on the subtransmission system could impact multiple substations resulting in up to 10,000+ customers impacted. Furthermore, subtransmission outages typically require the deployment of costly mobile generation or portable substations to restore customers quickly because permanent solution take extended periods of time to implement."

Q31. Does the Company have additional concerns with AG-MNSC Witness Stephens' use of the EV loading workpapers as justification for a disallowance associated with Subtransmission projects?

Line No.

A31. Yes. In addition to the evidence provided earlier in my rebuttal testimony regarding Witness Stephens' misinterpretation of the EV loading workpapers, he makes another incorrect assumption when applying the EV loading workpapers to Subtransmission projects. Witness Stephens states: "the Subtransmission Redesign and Rebuild projects are intended to relieve capacity constraints under contingency configurations (when one substation is temporarily serving as back-up to another substation)" page 19, lines 9-12. Additionally witness Stephens states: "(Substations are part of the subtransmission system)." page 21, lines 16-17. Substations are not considered part of the subtransmission system, they are a separate part of the grid infrastructure. Applying the EV loading workpapers for substations, to the subtransmission system is not an appropriate assumption.

Q32. What is considered part of the subtransmission system?

A32. The subtransmission system consists of the circuits that operate at 24kV, 40kV, and 120kV and stations that transform the transmission voltages (120kV and higher) to the 24kV and 40kV that feed the distribution substations. This does not include the substations that transform both transmission and subtransmission voltages to the distribution level voltages (4.8kV, 8.3kV and 13.2kV), which are part of the distribution system that serve primary and secondary customers. The capacity needs described, and detailed in Exhibit A-23, Schedule M5, are part of the Subtransmission Redesign and Rebuild program are only on the subtransmission system and not the distribution substations. The subtransmission system provides redundancy to the distribution substations with multiple feeds, and it is these subtransmission feeds that the program is focused on. Redundancy is a critical facet of the subtransmission system.

S. S. DEOL
U-21297

Line No.

Q33. How does AG-MNSC Witness Stephens' measure safety on the Subtransmission system?

A33. Witness Stephens, on page 22, lines 8-11, states: "Yet in discovery, the Company could not provide historical safety and reliability data on the subtransmission system, and it was clear the Company is not even tracking the baseline data required to measure safety or reliability improvements on the subtransmission system.[32]" In footnote 32 he references DTE's responses to MNSCDE-7.37(b) (safety); however, that discovery response refers to reliability, and the Company assumes Witness Stephens meant MNSCDE-7.37(a), Exhibit A-41, Schedule FF7. The question in MNSCDE-7.37(a) asks: "Provide the number of OSHA recordable incidents that have occurred with respect to the subtransmission system by year from 2018-2022." This question and its reference in testimony leads the Company to believe that Witness Stephens is relying on OSHA recordables as a measure of safety on the subtransmission system.

Q34. Does the Company agree with AG-MNSC Witness Stephens' use of OSHA recordable incidents as a measure of safety on the Subtransmission system?

A34. No. As discussed in detail in Company Witness Elliott Andahazy's rebuttal testimony, pages MEA-3-Rebuttal through MEA-6-Rebuttal, the Company does not agree with witness Stephens' use of OSHA recordables as an appropriate measure of safety.

Q35. What concerns does the Company have with AG-MNSC Witness Stephens' statements about reliability on the subtransmission system?

Line No.

A35. Witness Stephens, as noted above, states that the Company did not provide reliability data associated with the subtransmission system. However, in the rebuttal response Witness Stephens incorrectly alleges the Company did provide a definition of how it measures reliability on the subtransmission system: "The Company determines the reliability on the subtransmission system by analyzing criteria violations, which directly impacts the availability of the redundancy of the system.", Ex MEC-31 page 1 of witness Stephens' testimony.

Witness Stephens does not address this discovery response, nor does he argue that planning criteria violations are not a measurement of reliability.

Q36. Are planning criteria violations a measure of reliability?

A36. Yes. The planning criteria directly relate to the availability of the subtransmission system to serve our customers, both during normal configuration and the redundancy needed for a contingency scenario.

Planning criteria violations are areas of the system that are not in specification, they have low voltage or thermal overloads during normal or contingency system conditions. Thermal overloads can lead to reduced life of our electrical equipment and potentially catastrophic failure, while low voltage could damage customer equipment and ultimately lead to an intentional outage for parts of or entire substations.

Mitigating these planning criteria violations through subtransmission investment projects is required to continue to serve our customers growing loads during normal

Line No.

system configurations, as well as providing the necessary system redundancy to avoid the risk of large customer outages when contingency scenarios take place.

Additionally, these areas of the system become significantly more difficult to replace, upgrade and maintain without having the necessary redundancy to plan and complete a scheduled system shutdown, that doesn't require customers to lose service. Completing regular system maintenance and equipment replacement work is also critical to improving customer reliability. This is discussed in detail in Exhibit A-23, Schedule M7 DGP, beginning on page 295.

Q37. Did the Company provide the output of the subtransmission analysis?

A37. Yes. In discovery the Company provided a list of circuits that show over one-third of the system violates planning criteria along with the planning criteria violated. Witness Stephens states: "Further, I note that the Company refused to provide the analysis which indicated that one-third of the circuits on the subtransmission system violated the Company's planning criteria." Page 21, lines 13-15. This is not correct, as noted in Witness Stephens' Exhibit MEC-30, DTE's response to MNSCDE-3.20(a), the Company objected to providing the full report including analysis because of critical energy infrastructure information (CEII) reasons. This is different than not providing the data, and the Company did provide the output, Exhibit-41 Schedule FF1, which shows ~39% of the subtransmission system has planning criteria violations.

Did AG-MNSC witness Stephens argue that violations of system planning criteria do not have a reliability impact or effect operability? No. Witness Stephens does

Line No.

not argue that planning criteria violations do not have a reliability impact or effect on operability. Instead witness Stephen's again relies on his misinterpretation of the substation ratings; on page 22, lines 3-5 witness Stephens states: "But the 'violations of system planning criteria' identified by the Company in its DGP appear to be based on the subjective capacity ratings, not manufacturer nameplate capacity ratings, as indicated by the detail obtained in discovery on EV projections."

Q38. Should the Commission adopt AG-MNSC witness Stephens' recommendation to reduce Subtransmission capital by 50%?

A38. No. The Commission should not adopt witness Stephens proposed 50% reduction in subtransmission investments, because his arguments are not supported. Subtransmission strategic investments should be approved because they are necessary to improving reliability for customers, and they are reasonable and prudent.

Witness Stephens relies heavily on his misinterpretation of the EV loading workpapers, which in this instance are more concerning considering substations are not part of the subtransmission system. The Company's substation capacity ratings are based on equipment rating as is the method Witness Stephens proposes as appropriate; however, the Company must consider contingency when planning. The EV loading workpapers were not used to support a any project proposed in the instant case nor the IRM period, instead the Company relied on project specific loading as detailed in Exhibit A-23, Schedule M5.

Line No.

Secondly, Witness Stephens relies on the incorrect assumption that OSHA recordable incidents are an appropriate measure of safety improvements, which the Company shows is not a correct assumption, in Company Witness Elliott Andahazy's rebuttal testimony, pages MEA-3-Rebuttal through MEA-6-Rebuttal.

Third, Witness Stephens does not argue the merits of using planning criteria violations as a measure of reliability, instead he uses the EV loading workpapers to attempt to disprove the validity of criteria themselves. This too was a misinterpretation of the EV loading workpapers.

Finally, Witness Stephens did not refute the evidence presented by the Company for these subtransmission projects nor did he address the specific purpose and necessity of any project. Witness Stephens did not question the reasonableness or prudency of any specific project, or the investments associated with them nor the Company's ability to execute the associated work.

4.8kV/8.3kV Conversion Projects

Rebuttal Issue 4: AG-MNSC Witness Stephens's recommendation to disallow 50% of strategic capital associated with 4.8kV/8.3kV conversion projects.

Q39. What is AG-MNSC Witness Stephens' recommendation regarding 4.8kV/8.3kV conversion projects?

A39. On page 16, lines 7-12, AG-MNSC Witness Stephens recommends capital investments in 4.8kV/8.3kV conversion be cut by 50%.

Q40. Why does AG-MNSC Witness Stephens make this recommendation?

Line No.

A40. On page 16, lines 7-12 AG-MNSC Witness Stephens states: "I recommend that, going forward, 4.8kV and 8.2kV capital spending be cut by ½, at least until a more complete and rigorous forecast of EV adoption and its impacts on circuit- and substation-specific loads at circuit- and substation-specific peaks can be completed, and until accurate substation-specific capacity ratings can be developed."

Witness Stephens does provide testimony about reliability but does not explain how the reliability numbers in Table 1 on page 16 are calculated, thus the Company cannot confirm those numbers. Witness Stephens claims based on this table that: "the reliability of DTE's 4.8 and 8.2kV circuits is significantly better than the Company's 13.2kV circuits, as Table 1 below indicates.", page 16 lines 2-3. As witness Stephens does not use this data to support a disallowance, the Company assumes that it is irrelevant to his arguments.

Witness Stephens' only stated reason for his proposed 4.8kV/8.3kV disallowance is based on the EV loading workpapers and a presumed inaccuracy of the data therein.

Q41. Is Witness Stephens' use of the EV loading workpapers appropriate?

A41. No, as described earlier in this rebuttal testimony Witness Stephens' characterization of the EV loading workpapers is inaccurate. Witness Stephens' mistaken reliance on that inaccurate characterization to support his proposed 4.8kV/8.3kV disallowance is intrinsically without merit. Witness Stephens has offered no criticism of the support the Company actually provided for those proposed investments and the provided support demonstrates that these projects are

Line No.

reasonable and prudent. Based on that demonstration the Commission should approve the 4.8kV/8.3kV projects as proposed by the Company.

Q42. What are 4.8kV CC or 8.3kV CC projects?

A42. The Company uses the title 4.8kV CC: to indicate that a project is a conversion/consolidation project on the 4.8kV system. This means that the project could convert an area to higher voltage or consolidate underutilized assets, and in some cases simply decommission 4.8kV equipment no longer carrying load. Similarly, 8.3kV CC: means the same type of work for the 8.3kV system.

Q43. Why are the 4.8kV/8.3kV conversion projects necessary?

A43. As stated in my direct testimony, on pages SSD-12 – SSD-13, the 4.8kV system is the Company's original distribution system, which was designed in the early 1900's. In addition to aging infrastructure the 4.8kV system has several challenges and issues such as small conductors, lower capacity, significant voltage drops, and more.

As stated in my direct testimony, on pages SSD-29 – SSD-30, the 8.3kV system serves the city of Pontiac and was acquired from CMS Energy in the 1980s. The system is surrounded by the 13.2kV system and it is challenging to transfer load from 13.2kV to 8.3kV and from 8.3kV to 13.2kV; this results in a high risk for stranded load in the event of a substation outage. Adding to the operational challenges, the 8.3kV system is aged, and replacement parts are no longer readily available.

Line No.

Q44. What benefits do the 4.8kV/8.3kV conversion projects provide?

A44. As stated in my direct testimony, pages SSD-13 – SSD-14, conversion projects will improve safety and reliability, allow for the decommissioning of aging equipment, which will lead to reduced emergent maintenance costs, provide better system operability, increase capacity, amongst other benefits. These benefits align with Witness Stephens' objectives stated on page 11, lines 3-4: "The 'desired future state' should be defined through numerical targets (objectives) for each of the three remaining metrics I listed above (safety, reliability, and capacity), with time frames."

Q45. Does the Company agree with Witness Stephens' recommendation and rationale to reduce 4.8kV/8.3kV conversion by 50%?

A45. No. As noted above the Company has not developed the 4.8kV/8.3kV conversion projects using the data in the EV loading workpapers as justification.

As far as the substation-specific capacity, the Company has provided as evidenced by the definition of firm rating provided by the Company that is very similar to the standard witness Stephens uses to determine substation-specific capacity ratings.

Q46. Does AG-MNSC Witness Stephens agree that loading and aging infrastructure are reasons to support system upgrades and conversions?

A46. Yes. On page 10, lines 2-4, Witness Stephens states: "All infrastructure must be replaced over time, and capacity must be upgraded over time as load grows on a circuit-by-circuit, substation-by-substation basis." Followed by, "[l]oad growth, that is, circuit overloading, is indeed a good reason to convert a 4.8kV or 8.2kV

Line No.

circuit to 13.2kV; in fact, in my opinion, it is one of the only reasons to convert." (page 13, lines 3 -5)

In the first quote Witness Stephens acknowledges that "All infrastructure must be replaced over time," showing that he understands equipment does not last forever. The second quote shows witness Stephens understands that conversions need to take place when there is load growth, note he did not specifically say EV load growth. Witness Stephens went as far as to state, load growth "is one of the only reasons to convert." The Company has demonstrated that based on the age of both the 4.8kV/8.3kV systems that at this time it is reasonable that they be replaced.

Q47. Has the Company provided evidence in this instant case and IRM period to support each 4.8kV/8.3kV conversion project?

A47. Yes. The Company has provided what it calls a "capital summary" (Exhibit A-23, Schedule M5 pages 278-414) for each project included in this instant case and the proposed IRM period. These capital summaries provide the purpose and necessity for each program, scope of work, expected benefits, approximate construction schedule, and investment breakdown.

Q48. Did the Company provide circuit capacities and loading forecast for current conversion and CODI projects?

A48. Yes. On page 21 lines 15-16 Witness Stephens states: "Nor did the Company provide substation capacity ratings or loads when requested in discovery." When asked in discovery the Company did provide loading data if it did not violate CEII. Examples of loading data provided in discovery, Exhibit A-41, Schedule FF2

Line No.

MNSCDE-3.3ai, Exhibit A-41, Schedule FF3 MNSCDE-3.8ci, Exhibit A-41, Schedule FF4 MNSCDE-3.18, Exhibit A-41, Schedule FF5 MNSCDE-3.9b

Q49. Are there other drivers, aside from loading, for the 4.8kv CC: projects?

A49. Yes. Examples taken from Exhibit A-23, Schedule M5, include 4.8kV CC: Cortland/Oakman/Linwood Consolidation (Ex. A-23, Sch. M5 page 282) and 4.8kV CC: Zenon Substation and Circuit Conversion (Ex. A-23, Sch. M5 page 278).

The Cortland/Oakman/Linwood Consolidation project is required to remove load from the underutilized substations Linwood and Oakman and transfer it to the Cortland substation. This will enable the Company to decommission the two underutilized substations and remove old equipment from the system, thus reducing maintenance on this equipment.

The 4.8kV CC: Zenon Substation and Circuit Conversion project was to build a 13.2kV substation and transfer the load off of the antiquated McKinstry substation. Much of the equipment at McKinstry was beyond normal service life with unavailable replacements or spare parts (which one might think would fall in to witness Stephens' idea that all infrastructure needs to be replaced over time). This project is in close out with only trialing expenditures remaining for 2022.

These are examples of projects in the 4.8kV/8.3kV CC list that are not driven by load growth. The Company has provided the purpose and benefits for all its proposed projects in Exhibit A-23, Schedule M5.

Line No.

Q50. Does AG-MNSC Witness Stephens directly address 4.8kV/8.3kV CC projects that the Company proposed for drivers other than load growth?

A50. No. In fact, Witness Stephens does not address any specific project or challenge, nor the purpose and necessity, scope of work, or reasonableness or prudence of any specific 4.8kV CC or 8.3kV CC project. Witness Stephens simply relies on the misinterpretation of the EV loading workpapers described early in my rebuttal testimony to arrive at his 50% investment reduction.

Q51. For 4.8kV CC and 8.3kV CC projects that have load growth as one of the factors for conversion, does the Company provide evidence of an existing overloads or expected overload?

A51. Yes. Examples of projects where load growth is a factor include 4.8kV CC: I-94 Substation and Circuit Conversion (Promenade) (Ex. A-23, Sch. M5 page 290) and 4.8kV CC: Almont Relief and Circuit Conversion (Midas) (Ex. A-23, Sch. M5 page 294).

The Promenade project has been developed to address current load growth in the area. As stated on page 290 of the DGP the Company cites the development of the I-94 Industrial Park site. The existing substations Lynch and Lambert (both 4.8kV) have limited capacity for additional load, with limited throw-over and jumpering options (the ability to transfer or shift load to adjacent circuits) which means they cannot reliably serve the new load coming from the I-94 Industrial Park. All of this is detailed in Exhibit A-23, Schedule M5.

Line No.

The Midas project has been developed because the 4.8kV Almont substation is currently over its firming rating and Almont transformer 304 is over its day-to-day rating. The area has also experienced multiple Method of Service (MOS) requests for new load. All of this is detailed in Exhibit A-23, Schedule M5.

In addition to load growth, conversion projects provide additional benefits such as reliability improvements, removal of aging assets which reduces maintenance costs, and safety improvement in wire down reductions. Other conversion projects that have load growth as a contributing factor also provide that load detail in Exhibit A-23, Schedule M5.

Q52. Does AG-MNSC Witness Stephens directly address the projects in which load growth was a driver for conversion?

A52. No. Witness Stephens does not address anyone specific project or challenge the purpose and necessity, scope of work, or reasonableness or prudence of any specific 4.8kV CC or 8.3kV CC project. However, as noted above Witness Stephens has indicated his support for conversion projects based on load growth.

Q53. Does the Company have any other concerns about AG-MNSC witness Stephens' testimony on 4.8kV/8.3kV conversions?

A53. Yes. There are three additional areas I would like to address.

First, the Company consistently identifies the reduction in wire downs as a key safety benefit. While Witness Stephens has flawed arguments about OSHA

Line No.

incidents as a metric in other categories of investment, he does not address the subject of safety as it relates to conversion projects.

Second, Witness Stephens does not address the subject of operability of the grid as it relates to conversion projects. The Company has spoken extensively on this topic as well and the benefits that conversion projects bring with improved automation and remote operability provide for the customers as well as the improved operability associated with increased circuit to circuit connection or jumpering capabilities (the ability to transfer or shift load to adjacent circuits).

Third, whereas Witness Stephens does not use it as a reason for his proposed disallowance, he does provide Table 1 on page 15 that is intended to show the reliability of the 4.8kV system versus the 13.2kV system. The Company is not sure how Witness Stephens derived the values in his table, but the Company has served discovery on the topic in an attempt to better under his calculations. Witness Stephens claims based on this table that: “the reliability of DTE’s 4.8 and 8.2kV circuits is significantly better than the Company’s 13.2kV circuits, as Table 1 below indicates.”, page 16 lines 2-3.

The Company notes that in the Technical Conference on March 22, 2023, it provided All-weather SAIFI and All-weather SAIDI metrics for the 4.8kV and 13.2kV systems by bus voltage and believes these numbers are more accurate than the ones provided by Witness Stephens. These numbers show that the reliability on the 4.8kV system is not significantly better than the Company’s 13.2kV system. See Table 1 below.

Line No.

Table 1 4.8kV and 13.2kV All-Weather Reliability

Voltage	All-weather SAIFI	All-weather SAIDi
4.8kV	1.20	783
13.2kV	1.53	569

Q54. Is the conversion to 13.2kV from 4.8kV the primary driver for reliability improvements these projects?

A54. The change in voltage to 13.2kV from 4.8kV does allow the Company to install more technologies for remote operability, which will improve reliability. However, significant reliability improvements will come from the reconstructing of the existing circuits using higher grade material, increasing jumpering options (the ability to transfer or shift load to adjacent circuits), and removing aging infrastructure. Things like replacing wood cross arms with fiberglass and reconductoring (removing small, aged wire and replacing it with new stronger bigger wire) are the things that will drive reliability improvements, as well as decommissioning 4.8kV substations with obsolete equipment.

Q55. Should the Commission adopt AG-MNSC Witness Stephens' recommendation to reduce 4.8kV/8.3kV conversion capital by 50%?

A55. No. The Commission should not adopt Witness Stephens proposed 50% reduction in 4.8kV/8.3kV conversion investments, because his arguments are not supported. The 4.8kV/8.3kV conversion strategic investments should be approved because they are necessary to improving reliability and safety for customers, and they are reasonable and prudent.

Line No.

Witness Stephens' primary explicit reason for his proposed disallowance of 50% of the capital associated with 4.8kV/8.3kV conversion projects is his misinterpretation of the EV loading workpapers. The Company's substation capacity ratings are in line with the method witness Stephens proposes; however, the Company must consider contingency when planning. The EV loading workpapers was not used to support a single project in this instant case or the IRM period as noted in discovery, instead the Company relied on project specific loading as detailed in Exhibit A-23, Schedule M5.

Additionally, Witness Stephens did not refute the evidence in my direct testimony and exhibits for these 4.8kV/8.3kV conversion projects nor did he address the specific purpose and necessity of anyone given project. Witness Stephens did not question the reasonableness or prudency of anyone specific project or the investments associated with them or the Company's ability to execute the work.

City of Detroit Infrastructure Projects (CODI)

Rebuttal Issue 5: AG-MNSC Witness Stephens' recommendation to disallow 50% of strategic capital associated CODI projects.

Q56. What is AG-MNSC Witness Stephens' recommendation regarding the CODI projects?

A56. On page 18, lines 15-18, of Witness Stephens' direct testimony, he recommends: "As with the 4.8kV and 8.2kV [sic] conversion programs, I recommend spending going forward be cut by 50%, thus spreading the program out over a longer time period, at least until improvements to distribution planning in Michigan such as

Line No.

those recommended by AG-MNSC Witness Alvarez can be developed and put to work."

Q57. Why does AG-MNSC Witness Stephens make this recommendation?

A57. Witness Stephens on page 17, lines 8-13, states: "As with 4.8kV conversions generally, load growth, that is overloading, is a reason to convert, though I do not recommend simply buying into the Company's claims that loads are growing wholesale, or that capacity ratings are accurately stated. Circuit- and substation-specific load growth forecasts relative to nameplate (not assessed or subjectively-determined) substation capacity ratings should be required before any specific projects are authorized by the Commission."

Q58. Does the Company agree with AG-MNSC Witness Stephens' recommendations and rationale?

A58. No. First, as discussed earlier in my rebuttal on Witness Stephens' arguments on the EV loading workpapers, the Company does not subjectively determine substation capacity ratings and instead uses manufacture ratings in line with what Witness Stephens recommends.

Second, Witness Stephens makes an unsupported argument that the Company "claims that loads are growing wholesale." There is no evidence to support this comment, and the Company has provided a purpose and necessity for each of the CODI projects in Exhibit A-23 Schedule M5, none of which include claims of wholesale load growth.

Line No.

Q59. What is the CODI program?

A59. As described in my direct testimony on page SSD-23 the City of Detroit Infrastructure (CODI) program includes a core area of Detroit from Downtown to the Midtown areas and an extended area including Eastern Market, Corktown, and the West and East River Fronts, and includes hospitals, universities, government offices, and sports venues in addition to residential and commercial customers. The scope of the program, described in my direct testimony on pages SSD-25 – SSD-27, is to convert the existing 4.8kV system, some of the oldest sections of the Company's grid, to 13.2kV.

Q60. What benefits does the CODI program provide?

A60. As described in my direct testimony on page SSD-28, the CODI program addresses aging infrastructure, improved safety, and reliability of the distribution system. Furthermore, conversions provide an opportunity to reduce infrastructure, serving customers at 13.2kV requires fewer substations, cable, and other assets than it does at 4.8kV. Fewer assets in the field provide fewer points for the system to fail, leading to reduced emergent expenditures.

Q61. Did the Company base CODI projects based on the idea that "loads are growing wholesale" as is claimed by witness Stephens?

A61. No. The Company provided the purpose and necessity for each of the CODI projects in Exhibit A-23 Schedule M5. Additionally, the Company provided the circuit capacity, historic loading, and forecasting loading for each CODI circuit through discovery, Exhibit A-41, Schedule FF4 MNSCDE-3.18, with additional load growth information provided in STDE-6.7a, Exhibit A-41, Schedule FF6.

Line No.

Q62. Can you provide examples of other reasons to convert the CODI area of Detroit besides loading?

A62. Yes. Witness Stephens is correct that loading assessments are a driver for conversion, but conversion analyses must also consider the need to address aging infrastructure. The CODI work is addressing cable replacements, breaker replacements, and other work to address aging infrastructure. These substations are built in multi-level buildings constructed in the 1920's and do not have room to accommodate upgraded or larger size equipment due to the small floorplate space. Much of the existing equipment (induction regulators, network feeder stab switches, etc.) is not commercially available for replacements, and has been refurbished in house by the Company for years to keep these systems running. This is not a sustainable method to operate the distribution system and these substations must be addressed, including the severely aging 24kV subtransmission components that serve them.

As noted earlier, on page 10, lines 2-4, witness Stephens states: "All infrastructure must be replaced over time, and capacity must be upgraded over time as load grows on a circuit-by-circuit, substation-by-substation basis." The Company believes, as evidenced by the above statement, the equipment targeted by the CODI project, due to its advanced age, fits witness Stephens' idea that all infrastructure must be replaced over time. Now is the time to replace the existing CODI assets.

Q63. Does AG-MNSC Witness Stephens' address the aging infrastructure in the CODI area?

Line No.

A63. No. Witness Stephens does not address the aging infrastructure in the CODI area. In Exhibit A-23, Schedule M5 under the purpose and necessity the Company lists the age of several of the substations that will be decommissioned as a result of the CODI projects. Based on his stated recognition of the need to replace assets, the age of the CODI assets, the Company expects that Witness Stephens would support the CODI projects. However, Witness Stephens does not provide an analysis of any CODI project on their own merits, for loading or otherwise.

Q64. Does it make sense to address the aging infrastructure in the city of Detroit through a coordinated set of projects such as CODI?

A64. Yes. As stated on page SSD-25 lines 2-8 in my direct testimony: "The downtown CODI program is different from other conversions projects due to the presence of large amounts of system cable and secondary network cable. This adds to the complexity of operating, maintaining, and upgrading this part of the system. Due to significant cable network configuration in the CODI area, substation and circuit upgrades must be sequenced and conducted in a robust, multi-year program as opposed to individual projects to address the interdependency of the system." The CODI projects are a long-term, well-defined set of conversion designed to target specific needs within the city of Detroit.

Q65. Should the Commission adopt AG-MNSC Witness Stephens' recommendation to reduce CODI capital by 50%?

A65. No. The Commission should not adopt witness Stephens proposed 50% reduction in CODI investments, because his arguments are not supported. The CODI strategic

Line No.

investments should be approved because they are necessary to improving reliability and safety for customers, and they are reasonable and prudent.

Witness Stephens' testimony is an incomplete assessment of the benefits and drivers of the CODI work. Witness Stephens appears to make his recommendation by mistakenly claiming that the Company based these projects on "wholesale" load growth combined with his misinterpretation of the Company's substation capacity ratings.

The Company's substation capacity ratings are in line with the method witness Stephens proposes; however, the Company must consider contingency when planning. Instead of "wholesale" load growth, the Company relied on project specific loading as detailed in Exhibit A-23, Schedule M5 and in discovery. Additionally, witness Stephens did not refute the evidence put in the record for these CODI projects nor did he address the specific purpose and necessity of anyone given project. Witness Stephens did not question the reasonableness or prudency of anyone specific project or the investments associated with them.

Rebuttal Issue 6: Staff Witness Shi recommendation to disallow strategic capital associated CODI projects.

Q66. What is Staff Witness Shi's recommendation regarding CODI projects?

A66. On page 7 lines 20-23 Staff Witness Shi recommends a disallowance of $56.4 million for the Bridge Period (11 months ending 11/30/2023) and $115.9 million for the Test Year ending 11/30/2024.

Line No.

Q67. Why does Staff Witness Shi make this recommendation?

A67. On pages 4-7 Witness Shi performs calculations based on historic investment levels in the CODI projects and supports her disallowance based on the amount of investment the Company has successfully performed in recent years. Witness Shi notes on page 6 lines 8-9 that the Company had an increase of 8% in CODI investments between 2021 and 2022. Witness Shi also states: "Staff found no evidence through Company witness Mr. Doel's testimony, nor from the discovery response, that DTE will substantially increase manpower, nor accelerate the CODI program spending from 2022 to 2023 and further into 2024."

Based on this information, Witness Shi believes the Company is not able to achieve greater than a 10% year over year increase in CODI work. Witness Shi applies the 10% increase to 2022 investments to get the projected 2023 investments and then applies 10% increase to the 2023 projection to get the 2024 projection. All investments above those dollars witness Shi is recommending be disallowed.

Q68. Does the Company agree with Staff Witness Shi's recommendation?

A68. No. Whereas the Company understands Witness Shi's concerns regarding historic investment levels, those CODI investments were primarily for substations, examples include the Temple and Stone Pool substations, and some work for the AC network upgrades. Those work streams require different resources, are typically more complex to construct, as well as have a comparably lower capital expenditure relative to the circuit conversion work. The work for CODI projects in 2023 and 2024, and beyond, will focus more on the overhead (OH) conversions. These OH conversion will require more capital than the construction of the substations did,

S. S. DEOL
U-21297

Line No.

and require a different resource, namely overhead linemen. Table 2 below provides the information shared in Witness Shi's direct testimony on page 5.

Table 2 CODI Investments 2021 – 2024

Line No.	(a) Description	(b) Historical 12 mos. ended 12/31/2021	(c) Actual 12 mos. ending 12/31/2022	(d) Total 12 mos. ending 12/31/2023	(e) Projected 12 mos. ending 12/31/2024	(f) Bridge Period 23 mos. ending 11/30/2023	(g) Test Year 12 mos. ending 11/30/2024
($000)		Capital Expenditures					
	Infrastructure Redesign and Modernization						
42	CODI: Charlotte Network Upgrade	8,100	8,286	6,658	11,673	14,389	11,255
43	CODI: Targeted Network Secondary Cable Replacement	869	1,789	3,800	3,800	5,272	3,800
44	CODI: Corktown Substation	13,301	1,360	2	-	1,362	-
45	CODI: Islandview Substation	3,264	12,912	35,745	46,424	45,679	45,534
46	CODI: CATO Substation Expansion	-	319	10,795	13,300	10,214	13,091
47	CODI: Howard Conversion	-	2	700	15,000	644	13,808
48	CODI: Midtown Substation Expansion	6,510	2,234	1,803	-	3,887	150
49	CODI: Alfred Substation Expansion	417	53	4,137	11,782	3,846	11,145
50	CODI: Garfield Network Upgrade	11,177	18,193	30,000	36,220	45,693	35,701
51	CODI: Kent/Gibson Conversion	211	2,051	19,810	39,751	20,209	38,089
	Total amount	**43,849**	**47,199**	**113,451**	**177,951**	**151,196**	**172,575**

Capital investments in 2021 and 2022 shown in columns (b) and (c) mainly consist of building or upgrading substations (Midtown Substation Expansion, Corktown Substation and Islandview Substation). Now that this work is complete. Capital investments for 2023 and 2024 focus on the more capital-intensive work of overhead (OH) and underground conversions, including the AC network conversion. These projects include Garfield Network Upgrade (36 miles of network feeder cable and 24 miles of OH), Kent/Gibson Conversion (16 miles of system cable and 29 miles of OH), and Islandview (32 OH circuit conversions). More detailed scope of work is provided in Exhibit A-23, Schedule M5 for each project. Exhibit A-23, Schedule M5 pages 238-277 provides approximately construction schedules for each project to show what stage they are in during the rate case period.

Line No.

Q69. Does the Company have the resources and organization to complete this level of work?

A69. Yes. As stated in witness Miller's direct testimony, pages BFM-16 – BFM-18, the Company has increased labor force (employees and contractors, engineering and planning staff), leveraged partnerships, and in early 2022 created a standalone Project Management Organization (PMO). These actions were taken to provide increased focus on strategic capital investments to improve project execution (on time and budget). In particular to overhead conversion work, the Company has increased its overhead workforce from 293 to 659 average monthly contractors as shown in Table 3 below. The Company has taken these measures to ensure it has a suitable workforce to perform the work and a qualified organization to manage the work.

Table 3 Monthly Average OH Contractors

Month/Year	Monthly Ave OH Contractors
April 2020	293
December 2020	255
January 2021	267
January 2022	401
January 2023	582
June 2023	659

Q70. Should the Commission adopt Staff Witness Shi's recommendation to disallow capital for CODI projects?

S. S. DEOL
U-21297

Line No.

A70. No. The Commission should not adopt Witness Shi's proposed reduction in CODI investments, these investment should be approved because they are necessary; they are planned in a reasonable and prudent manner; and they will benefit the Company's customers.

Witness Shi has understandable concerns reviewing historic investments in the CODI projects. However, these projects are moving into the next phase of work, namely circuit conversion. These circuit conversions are going to require more construction work than the previous phase of building substations. As an example, CODI: Corktown Substation was constructed for approximately $20 million. The Company will now be investing in the OH conversion work to transfer load from Kent and Gibson substations. This work includes almost 30 miles of overhead conversion. The Company estimates expenditures between $2.4-$3.0 million per mile of overhead conversion. Just the overhead conversion work associated with the project will be between $72-$90 million. In addition to the OH conversion, the Kent/Gibson project includes radial powerline system cable rebuild, decommissioning existing substations, and more, Exhibit, Schedule M5 page 275. The Company has provided construction schedules in Exhibit A-23, Schedule M5 for each project, and these show the move to more circuit conversion away from substation builds. As the work type is transitioning, the Company is going to require the additional capital to complete the work.

Additionally, the Company has provided evidence that it has the resources required to complete this level of work, in the Table 3 and in Company witness Miller's direct testimony.

S. S. DEOL
U-21297

Line No.

System Loading Projects

Rebuttal Issue 7: AG-MNSC Witness Stephens' recommendation to disallow 50% of strategic capital associated System Loading projects.

Q71. What is AG-MNSC Witness Stephens' recommendation regarding System Loading projects?

A71. On page 24, lines 10-15, Witness Stephens is recommending a 50% reduction in System Loading projects.

Q72. Why does AG-MNSC witness Stephens make this recommendation?

A72. In Witness Stephens' testimony, he talks about System Loading and Subtransmission Redesign and Rebuild Programs (Subtransmission) together in pages 19 to 25. In this discussion, Witness Stephens focuses primarily on Subtransmission and does not specifically talk about System Loading as a program or any system loading projects.

Most of Witness Stephens' testimony between pages 19 and 25 is with regard to Subtransmission projects, and his assessment of the EV loading workpapers. On page 18, lines 6-7 Witness Stephens claims, with regard to System Loading and Subtransmission: "The justification for both programs is related to the same concept: loads and load growth relative to equipment capacity ratings." Additionally, on page 21, lines 1-3 Witness Stephens states: "It wasn't until I reviewed the EV loading workpapers late in discovery that I realized the capacities the Company was assigning to its substations were subjectively determined rather than based on manufacturers' nameplate capacity ratings." Therefore, the Company

Line No.

can only assume Witness Stephens is relying on his assessment of the EV loading workpapers to support his proposed disallowance.

Q73. Does the Company agree with AG-MNSC Witness Stephens's recommendation and rationale?

A73. No. As discussed in earlier, the Company understands that Witness Stephens appears to misconstrue the purpose of the EV loading workpapers. The Company did not rely on those workpapers to support any of its loading related projects. Additionally, the Company does in fact use nameplate capacities when rating its substations as noted earlier in my rebuttal testimony.

Furthermore, the Company provides the overloads being addressed for each project in Exhibit A-23, Schedule M5 pages 418-501. The Company also identified the meaning of firm rating as well as day-to-day rating and emergency rating of its substations, on page SSD-44 of my direct testimony. These definitions are not arbitrary as witness Stephens suggests. Instead of calling out or debating these ratings directly, with evidence of a better system, Witness Stephens simply says the Company's rating of all its substations is arbitrary. The only support Witness Stephens offers is the suggestion that the Company use nameplate capacity. As discussed earlier in my rebuttal testimony the Company does use nameplate capacity and a single contingency scenario.

Q74. What are System Loading projects?

A74. Similar to the loading constraints that can be one of several drivers for 4.8kV/8.3kV conversion projects, system loading projects are developed to support

Line No.

improvements to the 13.2kV system where insufficient capacity impacts reliability, load growth, and system operability.

Q75. Why are the System Loading projects necessary?

A75. As stated in my direct testimony, pages SSD-45, system overloads make it challenging for the Company to serve new customers and stress equipment reducing the useful life and impact system operability by limiting jumpering. Without jumpering capabilities to adjacent circuits, outages can be sustained for longer periods of time because the equipment must be repaired or replaced in order to restore customers.

Q76. What benefits do the System Loading projects provide?

A76. As stated in my direct testimony, pages SSD-45, System Loading projects alleviate the stress on the system caused by overloads and reduces potential failures. Capital investment to address these system overloads will improve reliability and provide capacity for new customer and increased demand form existing customers. Additionally, the system load projects help maintain/improve system operability by restoring jumpering capabilities (the ability to transfer or shift load to adjacent circuits) and removes aged equipment from the system.

Q77. Should the Commission adopt AG-MNSC witness Stephens' recommendation to reduce System Loading capital by 50%?

A77. No. The Commission should not adopt witness Stephens proposed 50% reduction in System Loading investments, because his arguments are not supported. The System Loading strategic investments should be approved because they are

Line No.

necessary to improving reliability and safety for customers, and they are reasonable and prudent.

Witness Stephens does not directly discuss the merits of any one project in the System Loading portfolio. Witness Stephens's sole reason for his proposed disallowance of 50% of the capital associated with System Loading projects is his misinterpretation of the EV loading workpapers. The Company's substation capacity ratings are similar the method Witness Stephens proposes; however, the Company must consider contingency when planning. The EV loading workpapers were not used to support a single project in this instant case or the IRM period as noted in discovery, instead the Company relied on project specific loading calculations as detailed in Exhibit A-23, Schedule M5.

Additionally, Witness Stephens did not refute the evidence put in the record for these System Loading projects nor did he address the specific purpose and necessity of anyone given project. Witness Stephens did not question the reasonableness or prudency of anyone specific project or the investments associated with them.

Strategic Undergrounding (SUG)

Rebuttal Issue 8: Staff Witness Evan's recommendation to disallow strategic capital in the SUG projects.

Q78. What is Staff witness Evans's recommendation regarding SUG projects?

A78. On page 11, lines 1-3 of witness Evan's testimony he states: "For that reason, I am recommending a full disallowance of the $1,925,000 projected for the 11 months ending 11/30/2023 and $1,917,000 projected for the test year."

Line No.

Q79. Why does Staff Witness Evans make this recommendation?

A79. On page 10, lines 24-28, Witness Evans states that the reason for disallowance is that the Company has not complied with the Commission's order: "However, neither Mr. Deol's testimony nor any exhibits provided a benefit/cost analysis of the proposed Fairmount pilot, so the Company cannot and does not compare it to the benefit/cost analysis of other solutions, such as grid hardening, grid conversion, or tree trimming."

Q80. Why was the Company unable to complete a benefit/cost analysis?

A80. As stated in Exhibit A-23, Schedule M10, page 6, the Company required a full year of reliability data from 2022 in order to conduct an analysis. This data was not available at the time of this filing.

Q81. Has the Company performed an effectiveness analysis since the time of the rate case filing?

A81. Yes. Once the full data set from 2022 was available the Company performed an effectiveness analysis using the same method used for analyzing the 4.8kV Hardening program and the Tree Trim program. As described in Exhibit A-23, Schedule M10. The Company reviewed data in four groups: Customers undergrounded (Completed), Customers on the block not undergrounded (Not-Competed), and one block on either side of the project Control Group 1 and Control Group 2.

Q82. What were the results of the effectiveness analysis?

Line No.

A82. The results of the effectiveness analysis were indeterminate due to the small sample size, driven by the short amount of time post-construction. As shown by Table 4 below, all groups had a significant reduction in All Weather SAIDI.

Table 4 All Weather SAIDI Results

All Weather SAIDI	2018	3-yr Prior 2019	2020	Construction Year 2021	1-yr After 2022	% Change Decrease/(Increase)
Completed	5,351	47	29	495	8	100%
Not-Completed	4,301	26	23	683	10	99%
Control Group 1	3,299	8	51	2,660	29	97%
Control Group 2	3,202	145	35	580	9	99%

The results of SAIDI ex-MEDs are more varied with results from Control Group 2 showing the most improvement as shown in Table 5 below.

Table 5 SAIDI ex-MED Results

SAIDI Ex-MEDs	2018	3-yr Prior 2019	2020	Construction Year 2021	1-yr After 2022	% Change Decrease/(Increase)
Completed	37	47	29	20	8	79%
Not-Completed	23	26	23	46	10	58%
Control Group 1	26	8	51	1	29	(2%)
Control Group 2	50	145	33	1	9	88%

These results are not sufficient for the Company to draw any conclusions from and indicate that a larger sample size and more time is required to adequately determine the effectiveness of strategic undergrounding.

Q83. Should the Commission adopt Staff Witness Evans's proposed disallowance for capital associated with SUG?

Line No.

A83. No. The Commission should not adopt Witness Evans's proposed disallowance.

The Company requires the funding to complete its next pilot in order to obtain more data. It is only through the collection of more data that the Company will be able to truly determine if SUG is a viable option.

Rebuttal Issue 9: AG Witness Coppola's recommendation to disallow strategic capital associated SUG.

Q84. What is AG Witness Coppola's recommendation regarding SUG projects?

A84. On page 68, lines 15-18 Witness Coppola recommends a disallowance "of $16,000 for 2021, $409,000 for 2022, $1,681,000 for the 11 months ending November 2023, and $1,917,000 from the 12 months ending November for a total amount of $4,023,000." These investments are for the Fairmount project as acknowledged by Witness Coppola on page 65, lines 11-13 of his testimony.

Q85. Why does AG Witness Coppola make this recommendation?

A85. On page 68, lines 13-15 of Witness Coppola's testimony he states: "In summary, the Company has not made a compelling and convincing case that another strategic undergrounding pilot project is needed at this time to prepare a cost/benefit analysis of comparable solutions."

Q86. Does the Company agree with AG Witness Coppola's recommendation and rationale?

A86. No. As stated earlier in my rebuttal, the results of the Company's current pilot are inconclusive due to the small sample size. The Company needs to continue trying

Line No.

new pilots until it has sufficient data to draw a proper conclusion, and to support the use of undergrounding as a viable alternative to overhead construction in improving reliability and resilience for our customers.

Q87. Should the Commission adopt AG Witness Coppola's proposed disallowance for capital associated with SUG?

A87. No. The Commission should not adopt Witness Coppola's proposed disallowance.

The Company requires the funding to complete its next pilot in order to obtain more data in developing a sound business case for an undergrounding construction alternative as a post-pilot program. It is only through the collection of more data that the Company will be able to truly make the case SUG is a viable option for areas of the grid.

Rebuttal Issue 10: Staff Witness Evan's recommendation to perform a cost/benefit analysis for undergrounding services.

Q88. What is Staff Witness Evans's recommendation regarding undergrounding service drops?

A88. On page 11, lines 5-9 Witness Evans's recommends: "Due to the number of down service drops that occurred in the late February and early March 2023 storms, Staff recommends that the Company provide a cost-benefit analysis of undergrounding residential service drops in its next rate case. Reliability improvements should be one of the benefits discussed, and the methodology for calculating, estimating, or measuring such benefits should be described in the analysis."

Line No.

Q89. Has the Company proposed underground services in prior rate cases?

A89. Yes. In U-20836, the Company proposed a pilot to underground which was detailed in Company witness Pfeuffer, T4 pages 341-342.

Q90. How did the Commission respond to the proposed pilot to underground services?

A90. The Commission disallowed the pilot to underground services. The reason for disallowance is stated in the Order dated November 18, 2022, page 111-112: "Therefore, until the Appoline pilot is complete and a full report is available, and until a more robust analysis of the benefit/cost of strategic underground is available, the Commission finds it reasonable and prudent to approve a $15.1 million disallowance for the 10 months ending October 2022 and a $36.8 million disallowance for the projected test year."

Q91. Can the Company perform a cost-benefit analysis of servicing undergrounds without a pilot?

A91. Not effectively. The Company could potentially perform benchmarking and other activities to acquire some knowledge, but until the Company attempts to execute this work at scale and in different field conditions, it cannot provide a robust cost-benefit analysis.

Q92. Should the Commission adopt Witness Evans's proposal for a cost-benefit analysis for underground service drops?

A92. The Company is willing to have discussion on the potential for proposing another overhead service undergrounding pilot with the Staff to be included in future cases.

S. S. DEOL
U-21297

Line
No.

Q93. Does this conclude your rebuttal testimony?

A93. Yes, it does.

JUDGE FELDMAN: Mr. Bzdok, I believe you have cross-examination for this witness.

MR. BZDOK: Your Honor, may we -- go ahead, Lori.

COURT REPORTER: Can we -- sorry. Can we check if anyone can hear Marie?

JUDGE FELDMAN: Let's go off the record.

(At 1:48 p.m., off-record discussion.)

JUDGE FELDMAN: Back on the record. Mr. Bzdok, you may proceed when you are ready.

MR. BZDOK: Thank you, your Honor.

CROSS-EXAMINATION

BY MR. BZDOK:

Q Good afternoon, Mr. Deol.

A (No response.)

Q You're all muted.

THE WITNESS: Oh, you want me to go back on or do you want --? O.K.

JUDGE FELDMAN: I think probably if we have a choice of microphones, maybe it would be better for the court reporter if we have Mr. Deol's microphone on.

THE WITNESS: O.K. We could -- I think we're good. We situated it out.

JUDGE FELDMAN: Great. Mr. Bzdok, I

believe we're ready --

MR. BZDOK: Thank you.

JUDGE FELDMAN: -- whenever you are.

Q Mr. Deol, one of the topics that I want to talk to you about today is converting the 4.8 kV circuits to 13.2 kV circuits. You, in your direct testimony, present -- and I'm just sort of paraphrasing or generally speaking right now, you present the conversion of -- you present testimony related to the conversion of 4.8 kV circuits to 13.2 circuits in two contexts. One is as one of the IRM programs, capital programs, and then second is as one of the rate case projected test year capital programs. Is that fair?

A Yes, that's fair.

Q Do you know the total capital costs of the conversions of 4.8 kV circuits to 13.2 kV circuits in the projected test year?

A Just to clarify, when you say projected test year -- I'm trying to get acclimated to the regulatory lingo here -- Is it just that particular year or for the overall test case?

Q Let's do both.

A O.K. As far as the test case itself, let me do a quick calculation here, that approximates 727 million-ish for the test case.

Q Thank you. How about the test year, the projected test year?
A Would that be 2023, correct?
Q No. Bear with me a second. That would be December 1, 2023, to November 30, 2024.
A That would be 384 approximate.
Q And just so the transcript is clear, because we can't talk like normal people, $384 million?
A Correct, yes. 384, approximately 384 million.
Q And then looking at Table 1 on page 6 of your direct testimony for the distribution IRM investments?
A Yes.
Q There are investments for the IRM years of 1.6 million in plan year one, 185.8 in plan year two, and 371.6 million in plan year three; is that correct?
A Correct.
Q Do you know, are those cumulative totals or are those per year totals?
A Those are per year totals.
Q So the total, the total kind of conversion capital expenditures that you're supporting for the purposes of approval requests, let's call them in this case, would be the 727 in the test case plus the 1.6 in plan year one, the 185.8 in plan year two, and the 371.6 million in plan year three. Is that right?

A As far as the IRM aspect, right, Mr. Foley is I guess the Company expert or the witness on the way the IRM would work and is allocated. From my perspective I provide what the capital spend would be for these programs and what the capital allocation would be there. I would refer you to Witness Foley to be able to get it down to a year by year perspective there for the IRM.

Q So part one of your testimony is titled Infrastructure Recovery Mechanism or IRM Support, correct?

A Correct.

Q And you are supporting for the IRM years the reasonableness and prudence of capital, two capital programs, one is conversions and one is subtransmission redesign and rebuild, correct?

A Correct.

Q So in the context of being the witness who is supporting the reasonableness and prudence of the IRM amounts for those or for those IRM programs, that's all I'm asking you for. I'm not asking you for, you know, details on the IRM surcharges or something like that, but just trying to get a sense of the total capital that you're supporting for conversions in this case.

A I would refer you to Exhibit A-12 B5.4, line -- well, actually that's the infrastructure and modernization. Sorry. A-12 B5.4, page 11, line 115, as far as the

conversions. As far as I understand the test case would be till twelve months ending 11-30-2024. Also I'm supporting the 727 as far as the overall cost for these projects.

As far as the IRM mechanism, I am not the expert in there. I would defer to Witness Foley to explain those from year one, year two, year three.

Q O.K. Give me just a second. So I think the exhibit reference you gave me was A-12 B5.4, page 11 line 115?

A Yes.

Q And so if the -- the total conversion, capital spending which you're supporting in this case, would be the capital spends on that line plus the conversion program spends for the IRM years in your Table 1. Is that a fair way to kind of put those together?

A No. The total I am supporting -- I guess the conversion mechanism as I stated, right, you would want to -- I would refer back to Witness Foley to explain the appropriations for plan year two and three. So I believe the test case here that we are supporting would go to 2024. So it would be the second line there, right. So it would be the 1.6 and the 5.5 in addition to the two lines there in Exhibit 12 B5.4.

Q O.K. I'm sorry if I'm maybe being a little dense. You said the 1.6 and then the 1 something point 5?

A Just if I looked at Table 1 on page 6.
Q Yes?
A So if I look at plan year one.
Q Yes?
A Right. So it would be those totals, that 1.6 for conversions and the 5.5 for the subtrans and redesign in addition to those totals here.
Q All right.
A Or actually I believe those are a subset of those totals defined here.
Q So if we were looking at -- if we were trying to assess how much total conversions investment you are supporting in this case, would you agree that would be comprised of test year amounts on A-12 B5.4 line 115, and IRM year conversion amounts in Table 1 of page 6 of your direct?
A Let me verify. I believe if I refer back to Schedule A-12 B5.4, the total amount would be, as we had discussed, approximately the 727 million for this test case, and I believe the IRM -- well, the IRM is a portion of that. So the overall that I am supporting is the 727 million for conversions.
Q I'm not trying to be difficult, just trying to make sure that I understand exactly the scale of the numbers. When I look at your A-12 B5.4 page 11, that has spending amounts stated for various time periods, correct?

A Correct.
Q And those time periods run through -- the farthest future time period that those spends run to is November 30, 2024, correct?
A Correct.
Q And then if I look at Table 1 on page 6 of your direct, that also then includes spends for three periods beyond November 30, 2024, one being simply one month, the month of December 2024, that's where the 1.6 is, and then calendar year 2025 and then calendar year 2026. Would you agree?
A Yes.
Q So would you agree with me that the total conversions capital spending that you are supporting in this case, including not only the test year case but also these IRM out year periods, would be the sum of those?
A I believe the test period is up till November 30, 2024. I believe that table is providing as an example of if we were to go to the IRM structure that this is how these program totals would fall into the IRM.
Q So are these amounts additive to the A-12 B5.4 amounts?
A No, they're not.
JUDGE FELDMAN: But they would be for those future years?
A Assuming that the spend is similar, yes.

MR. BZDOK: O.K. A light bulb went on. I understand now.

Q (Continuing): Do you have access to the SharePoint site for this case?

A Yes.

Q It timed me out again. If you're not signed in, please sign in. I'm going to have to sign in again.

A No, I'm signed in.

Q So let me just catch up to you. The first one we're going to look at is Exhibit MEC-74, but I'll have to get there.

A I'll get that.

Q So we're in, right, the DTE folder and a folder with your name on it. And within that there's an MNSC hearing exhibits folder.

A Yes.

Q And then within that -- O.K.

A Which one did you want me to take a look at?

Q So it should be MEC-74 proposed. Are you able to -- If you right click on that do you get a column of options which include Open at the top and then Open in Browser?

A No. Because when I right click on that it says download.

Q O.K. That's what I use so I can see more than one of these at the same time, but.

JUDGE FELDMAN: Excuse me. I think --

excuse me. I think if you go with that download and then you open it from a download it will put it, keep it open and allow you to go back and forth between the SharePoint and the document.

Q So this is, for the record this is -- Thank you, Judge. This for the record is discovery response MNSCDE-2.11 supplemental. Correct?

A Yes.

Q And this was asking if DTE had identified a set of areas where the 4.8 kV system is near load capacity such that adding electric vehicles and/or DERs is likely to quickly exceed system capability? And if yes, to provide a list of those areas, correct?

A Yes.

Q Would you agree DERs are Distributed Energy Resources?

A Correct.

Q And then as an attachment to that, the Company provided in this supplemental response a list of circuits that are above their daily rating or within ten percent of their daily rating, correct?

A Yes, I do see that.

Q And in this context, within ten percent of their daily rating would mean within ten percent of reaching their daily rating, right? So sort of 90 percent of their daily rating up to a hundred percent of their daily

rating?
A Yes, I would interpret it that way.
Q And that list comprises 12 circuits, correct?
A Yes.
MR. BZDOK: I'm going to move to admit, your Honor, at this time MEC-74.
MS. JOHNSON-BACON: No objection.
JUDGE FELDMAN: Thank you very much. Anybody else have any objections? Hearing no objections, Exhibit MEC-74 is admitted.
Q (Continuing): Do you know how many total 4.8 kV circuits that's out of? And I can navigate you some more to refresh your memory if not.
A I'm sorry, I didn't hear the question. It came in partial.
Q Oh, I'm sorry. The 12 circuits that are at or within ten percent of capacity, 4.8 kV circuits, that's out of how many total 4.8 kV circuits on the DTE system?
A I don't have the total number of 4.8 circuits readily available here with me.
Q Take a look in that SharePoint at -- There's an excel in there that is U21297 MNSCDE-2.2-01, non AC network circuits. Do you see that?
A Actually I'm having a hard time navigating back. I had the file open. Now I'm not sure how to get back to the

file itself.

O.K. All right. I'm back. Which one did you want me to take a look?

Q It was -- sorry, I'm checking one other thing. Bear with me a second.

2.2-01 non AC network circuits. If it's helpful, there's as an associated discovery question, a supplemental discovery response in the SharePoint folder which is marked MEC-75, MNSCDE-2.2 Supplemental. We did not produce the spreadsheet as an attachment because of its size.

A So can you state that question again?

Q Sure.

A Which question was it?

Q So the discovery, so the proposed exhibit in the SharePoint is MEC-75.

A MEC-75.

JUDGE FELDMAN: Let's go off the record. Let's go off the record and make sure we're all on the same page. Off the record.

(Briefly off the record.)

JUDGE FELDMAN: Back on the record. Mr. Bzdok.

MR. BZDOK: Thank you.

Q (By Mr. Bzdok): Mr. Deol, proposed Exhibit MEC-75 is a

discovery -- is a supplemental discovery response from you; is that correct?

A Correct.

Q And in that supplemental discovery response you provided a spreadsheet attachment entitled U21297 MNSCDE-2.2-01 non AC network circuits. Correct?

A Correct.

Q And in the SharePoint folder are you able to locate a spreadsheet with that title?

A Yes.

Q And subject to my representation that I have not modified this spreadsheet in any way, does it appear to you to be the one that was provided with this discovery response?

A I don't have this one readily available with me. I should have, but I didn't print this out because this was an extensive file. But I would assume that you wouldn't modify it.

Q Yes. I am affirming to you on the record I have not modified it. So you know, and you can rely on that. But does it appear to you to be the sheet that was provided with this response?

A It appears the to be the listing that we provided with this response, correct.

Q Column (b) contains the voltage for all of these circuits, correct?

A Column (b), yes. That would be the distribution voltage. It represents the 4.8 and the 13.2 circuits.
Q And some 8.2s, correct?
A I didn't get to the 8.2s yet. But yes, we do have 8.3 kV as part of our system.
Q 8.3, thank you. If I sort the voltage cells lowest to highest --
A O.K. Hold on.
Q Go ahead.

MR. BZDOK: Can I share for a second, Judge?

JUDGE FELDMAN: Yes.

(Sharing screen.)

Q (By Mr. Bzdok): Mr. Deol, can you see on my screen -- again subject to this representation I have not modified anything -- the same spreadsheet that we were looking at in the SharePoint?
A Yes, I can see the screen. I can see the spreadsheet.
Q If I go to column (b) for voltage and I sorted lowest to -- smallest to largest, I put all the 4.8s together, correct?
A Understanding Excel, yes, that should give you all the voltage levels together.
Q And again that's subject to all my representations. I can sort, I can copy down to the end of the 4.8s, and

that tells me down here, that gives a count down here of 1,945, 4.8 kV circuits. Would you agree?

A Yes. I would agree that Excel wouldn't lie so if the file is saying that's how many circuits are down there, that's what it would be.

Q Do you have knowledge that is inconsistent with that, like Oh, no, that's totally wrong, it's way more or way less than that?

A Let me just verify real quick.

Q I did enjoy "Excel wouldn't lie."

A Sometimes it does lie. If you make a mistake in your formula, then you can blame Excel.

I am referring to Witness Robinson's testimony, page 11, Table 4. It says: List the overall circuits by voltage. So if I look at the 4.8, based on this data there's 1,945 4.8 kV circuits.

Q All right. Same number?

A O.K. Excel didn't lie.

Q So 12 out of 1,945 4.8 kV circuits are at or within ten percent or at their daily rating, agreed?

A I'd have to go back to -- there is a timeframe for those. Was there a timeframe in that question?

Q So by "that question", I think you're referring to --

A The initial one that we started out with.

Q 2.1 Supplemental which was MEC-74. The question, if it's

useful, read: Refer to discovery response MNSCDE-1.8 and the direct testimony of Satvir Deol quoted in the response, has DTE identified a set of areas where the 4.8 kV system is near load capacity such that adding electric vehicles and/or DERs is likely to quickly exceed system capability? If yes, provide a list of these areas.

A So based on that question though, I'm just going to rephrase that, right. So would that mean, the way I'm looking at it is, provide that data that addition of DERs would take them to that capacity if we do it now, today, 2023.

Q So my understanding of what DTE provided in response to that question was a list of 12 circuits, correct?

A Correct. Yes, we provided 12 circuits.

Q And DTE characterized that list as circuits that are at -- above their daily rating or within ten percent of their daily rating, correct?

A Correct.

Q So --

A There is no time bound here in the question, right? So maybe we -- yes. We should have expanded on the time frame. The way -- yes, O.K.

Q I didn't take your list to be a list of anything other than these are the circuits we're aware of today that meet those criteria, fair? I was not trying to place

more a larger timeframe or an expectation about the future on that. I took that: Here's the list.

A Yes. So my understanding of that question would be these would be the circuits that if we added additional DERs, that we would put them to that limit, like now, currently, in the state of the system.

JUDGE FELDMAN: So just looking at the question -- excuse me. Just looking at the question in Exhibit MEC-74, this list is a set of areas where the 4.8 kV system is near load capacity such that adding electric vehicles and/or DERs is likely to quickly exceed system capability?

A Right.

MR. BZDOK: Did that complete your questions, Judge, for the moment?

JUDGE FELDMAN: Yes.

MR. BZDOK: I didn't want to jump in on your --

JUDGE FELDMAN: Thanks. Sorry for the interruption.

Q (By Mr. Bzdok): Setting aside DERs and setting aside EVs, that data represents the 4.8 kV circuits that are at or within ten percent of their daily rating, agreed?

A I would rephrase that, that they are at 90 percent or to their daily rating in 2023 at this moment or this

analysis.

Q And literally based on the response, it would actually be within ten percent of their daily rating or above their daily rating, right?

A Correct. Re-reading the response, yes, they're within ten percent or exceed the daily rate.

Q Thank you. One of your rebuttal exhibits is Exhibit A-41 Schedule FF3.

MS. JOHNSON-BACON: Is this on the SharePoint, Chris?

MR. BZDOK: It is also on the SharePoint site. I marked it as an exhibit before I found out, before I reconnected that he also had filed it. So it is on the SharePoint site marked as a proposed MEC exhibit, proposed MEC-76, and the spreadsheet associated with that attachment is also loaded there, MNSC 3.8a-01, list of circuits for conversion.

JUDGE FELDMAN: And that's the spread -- one of those three spreadsheets that does not have an exhibit designation.

MR. BZDOK: Correct. So --

THE WITNESS: Is --

Q (By Mr. Bzdok): Go ahead.

A Sorry. Just so I can follow along, I'm more of a binder type of person, makes it a little easier for me to follow

along that way, so is that question MNSCDE-3.8a?
Q Yes.
A O.K. Thank you. So I have those available with me.
Q O.K. So in your Exhibit A-41 Schedule FF3, which is that MNSCDE-3.8a and then an attachment, 21297 MNSCDE-3.8aa-01, list of circuits for conversion, which also appears in the SharePoint as MEC-76. That provides a list of circuits planned for conversion in the years 2023, 2024, 2025, and 2026, correct?
A I would have to verify the timeframe on these, but that's just providing, the top column is just providing the load rating or the expected load rating for those circuits in those years.
Q O.K.
A I would have to look at each individual one here in Exhibit 23 M5 to go verify the timing for each of these.
Q They are planned conversion projects, would you agree with that, based on the question asking to provide a list of conversion projects by circuit --
A Yes.
Q -- for which capital --
A Yes. These are circuits that would be planned to be converted.
Q And for which capital costs will be recovered in this rate case or through the proposed IRM, correct?

A Correct.
Q In the -- Do you know how many of them, do you know how many circuit conversions are on that list?
A I would have to go count them all to tell you that. I can do that if you want me to. It will take a little bit here to count all of these.

MR. BZDOK: May I share, Judge?

JUDGE FELDMAN: Yes.

(Sharing screen.)

Q (By Mr. Bzdok): So if I go to the spreadsheet version, and on the same representation that I have not modified anything, and so I look at that MNSCDE-3.8a-01, list of circuits before conversion, and I, on the precept that Excel wouldn't lie to me -- I scroll down through them, I get count of 334 circuits, 4.8 kV circuits planned for conversion during the rate case and IRM years. Would you agree?
A I would agree that the Excel counted 334, yes.

MR. BZDOK: Your Honor, I'm going to move to admit some of those exhibits at this time. I'm going to move to admit MEC-75. And I'm going to move to admit MEC-76 even though that information is also in his rebuttal exhibit just because I think we have been talking about MEC-76.

JUDGE FELDMAN: All right. Let me ask

for the record if there are any objections to the admission into evidence of proposed Exhibits MEC-75 or -76.

MS. JOHNSON-BACON: No objections, your Honor.

JUDGE FELDMAN: Thank you. Hearing no objections, those exhibits MEC-75 and MEC-76 are admitted.

MR. BZDOK: Thank you. Give me just a second.

JUDGE FELDMAN: Certainly.

Q (By Mr. Bzdok): O.K. DTE is planning to convert all of its 4.8 kV overhead circuits to 13.2 kV circuits. Would you agree?

A The Company plans to convert all of our 4.8 kV circuits to a higher voltage.

Q To -- So should I interpret your answer to mean that a higher voltage could be 13.2 kV or could be some other higher voltage?

A 13.2 at the moment. But as future trends come across, there is potential.

Q O.K. Potential that it could go to a higher voltage, is that what I understand you to say, higher than 13.2?

A If you want to, you know, right now the 13.2 is the system coming across. But as other peer utilities were

looking to investigate further as things change, maybe additional future load growth, and you would consider higher voltage. But at the moment the plan is 13.2.

Q O.K. Do you know what the cost of converting all of DTE's, the capital cost of converting all of DTE's 4.8 kV to 13.2 kV will be, or the range of costs?

A No, I don't. I don't have enough data here to calculate that out.

Q Mr. -- Your rebuttal testimony in this case, one of the witnesses that you rebutted was MNSC Dennis Stephens. Is that correct?

A Correct.

Q He had an estimate for this on pages, in his direct testimony which you rebutted, you rebutted his direct testimony I should say, and it was on pages 13 to 15.

A I actually don't have that, those pages with me.

Q O.K. Give me a second to navigate to them.

JUDGE FELDMAN: They should be in the SharePoint.

MR. BZDOK: Oh, that's a good point.

Q (By Mr. Bzdok): So they'll be in the MNSC folder.

A Which ones would they be?

Q So I'm kicked out again, but I will get back in. So in the -- when you open the folder, there are folders corresponding to all the parties in this case.

A O.K.
Q And then one of the folders then is marked MNSC.
A Let me go find it.
Q O.K.
MS. JOHNSON-BACON: If it's helpful, the folder is titled MECNRDCSC.
A I'm not seeing that in there. Maybe I didn't go far or I went too far out.
JUDGE FELDMAN: Let's go off the record.
(Off the record briefly.)
JUDGE FELDMAN: Back on the record.
MR. BZDOK: Thank you.
Q (By Mr. Bzdok): So page 12 of Mr. Stephens' testimony?
A Sorry, apologize. Can you tell me which of the exhibits is it?
Q So not an exhibit. In his testimony on page 12.
A Is it MEC? Which number is it?
Q It does not have an exhibit number. It's in the SharePoint. It's just the name of the document.
JUDGE FELDMAN: Let's go off the record again. Off the record, please.
(Briefly off the record.)
JUDGE FELDMAN: Back on the record. Mr. Bzdok.
Q (By Mr. Bzdok): So page -- so the Revised Direct

Testimony of Dennis Stephens, page 12, under a heading 4.8 kV and 8.3 kV Substation and Circuit Conversion Programs, there is a question and answer. Do you see that?

A Is it page 12, line 3?

Q That's where the heading is, and then the answer that follows. He estimates based on the average cost to converting one mile overhead 4.8 and 8.2 kV circuits to 13.2 kV -- an average cost per mile of 2.4 to 3 million, the cost of the entire conversions of 4.8 kV and 8.2 kV to 13.2 kV will be in the range of 27.4 to $33.4 billion. Do you see that?

A Yes, I see that.

Q At a high level -- Well, I guess, are you aware of any estimate that differs from that? That will be my first question.

A The costs specified here, the 2.4 to 3.0?

Q My first question is: Are you aware of any estimate for the total cost of these conversions that is different than the range of 27.4 billion to 33.4 billion that Mr. Stephens offers?

A I have not looked at or done any calculations that would define what the cost would be for the overall conversion of 4.8 circuits that the Company has.

Q O.K. Take a look at your rebuttal testimony, page 3,

line 28.
A O.K. I'm there.
Q Here you quote a statement from Mr. Stephens on the next page of his direct testimony, DTE appears to be basing its need to convert all its circuits to 13.2 kV within 15 years on EV growth. Do you see that statement?
A Yes, I do.
Q And then you go on, on pages 4 and 5, to talk at some length about EV load growth forecasts, correct?
A Correct.
Q And you make a statement in your rebuttal, page 9 lines 4 to 7 -- Well, you start on line 2 with Mr. Stephens uses the existence of the EV loading forecasts, EV loading work papers, to criticize the Company's capital planning process and by extension DTE's proposed distribution investments. However, Witness Stephens does not identify any specific projects where the Company relies on the EV loading work papers to support associated capital expenditures because that was not and is not the purpose of the EV loading forecasts. Correct?
A Correct.
Q Witness Stephens, in his testimony, did not talk about the EV loading forecast or EVs generally as supporting or not supporting specific capital projects. Correct?
A I would have to refer back to his testimony.

MS. JOHNSON-BACON: Chris, can you direct the witness to a specific portion of Mr. Stephens' testimony?

MR. BZDOK: That's a fair question.

Q Let's try it maybe a different way. Let's look back at, Mr. Deol, at specifically on Mr. Stephens testimony, page 13. Would you generally agree that Mr. Stephens' testimony with respect to the EV forecast is in relation to the DTE plan to convert all 4.8 kV and 8.2 kV circuits to 13.2 kV?

A Is there a line number that you can refer me to?

Q Lines 2 and 3, page 13.

A Is it the lines that DTE appears to be basing its need to convert all of its 13.2 kV circuits within 15 years on EV growth?

Q Yes.

A O.K. I'm there.

Q Mr. Stephens is not criticizing specific capital projects, he's criticizing an overall plan. Would you agree with that characterization?

A I would state that Mr. Stephens is stating that the Company's converting all of its 4.8 kV 8.3 kV circuits within the 15 year plan based on EV growth.

Q Would you disagree that DTE has throughout its materials in this case cited EV growth and electrification in

general as one of the reasons why it's seeking to convert its entire 4.8 kV system to 13.2 kV?

MS. JOHNSON-BACON: I'm going to object based on foundation, Chris. I don't know what you're referring to.

Q (By Mr. Bzdok): Mr. Deol, you testify in your direct and in your rebuttal about the Company's Distribution Grid Plan; is that correct?

A Sorry, I didn't catch the last part of your question.

Q You testify in your direct and rebuttal at various points about DTE's Distribution Grid Plan; is that right?

A Actually I don't recall me referencing that.

Q You don't recall referencing the DGP in your rebuttal testimony?

A Not off the top of my head. I'd have to look through it.

Q O.K. Page 4 line 14, page 4 line 15, page 5 Line 5, page 8 line 14.

A Yes.

Q Line 20.

A Yes, I do see it. Yes.

Q Page 10 line 1, line 5.

A Thank you for that. I do see it. It's been a while since I did the rebuttal.

Q O.K. Would you agree that--. In your rebuttal, page 10 line 8, lines 8 to 13 --

A What page was that?
Q Your rebuttal, page 10, lines 8 to 13.
A 8 to 13, I'm there.
Q You state on page 9 -- sorry, on line 9 you state: Conversion projects, and the CODI program, in the instant case and the IRM period are supported with project specific evidence. Correct?
A Correct.
Q And then among the materials that you cite in support of statement is Exhibit A-23 Schedule M7, Section 11.3, 4.8 kV conversion. Do you see that?
A Reading line 11 on that page it says: See Exhibit A-23 Schedule M5, pages 238 to 417 in my direct testimony, and Exhibit A-23 or -- yes, Exhibit M7, Section 11.3, 4.8 conversions. Is that what you're referring to?
Q Yes. So the Exhibit A-23 Schedule M7 is the DGP, right?
A Per Witness Robinson's testimony page 4, correct, Exhibit A-23 M7 is the Distribution Grid Plan.
Q Would you agree with me that that Section 11.3 that you cite there in the DGP talks repeatedly about EV load growth and electrification as the justification for the conversion projects?
A I don't have that section with me right now. I would have to go get it to answer that.
JUDGE FELDMAN: Mr. Bzdok, I am in no way

rushing you but I think we're getting close to the point where we're going to have to take an afternoon break, so I leave it to you within the next few questions to decide when that is. Or if you want the witness to locate this exhibit in the SharePoint, you know, we could also do that over a break, if you want.

MR. BZDOK: So I think this is a fine time to take a break. And you're welcome, Mr. Deol, to locate Section 11.3 of the DGP on the break if you want to, but I also feel like I can mostly take that up in briefing, so I can also move to another topic. But I mean it's fine to take a break now.

JUDGE FELDMAN: All right. Off the record.

(At 3:05 p.m., a 15-minute recess was taken.)

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JUDGE FELDMAN: Back on the record. Mr. Bzdok, when you're ready.

MR. BZDOK: Thank you, your Honor.

Q (By Mr. Bzdok): Mr. Deol, let's pull up another discovery exhibit, which is going to be in that DTE Electric folder with your name on it, and then in the MNSC Hearing Exhibits, and it's going to be proposed Exhibit MNSC -- sorry -- MEC-72.

A Hold on, you got to stick with me here, I'm trying to

navigate through. Can we go off the record? I've just got to ask Paula a question to figure out how to navigate through this file again.

JUDGE FELDMAN: Off the record.

(Brief pause.)

JUDGE FELDMAN: Back on the record.

Q (By Mr. Bzdok): So just for the record, proposed Exhibit MEC-72 is a compilation of discovery responses from Mr. Deol, MNSCDE-3.8d as in dog, 3.9c as in Charley, 3.16c as in Charley, 3.23b as in boy, and 3.24b as in boy. Mr. Deol, just to try to streamline this a little bit, each of these questions, generally speaking, asks about cost and benefit analyses; would you agree with that as sort of a high-level paraphrase?

A Just repeating them roughly, the -- the questions do refer to benefits and in there multiple times.

Q And the answers to these questions are very similar, each response is very similar to the other, correct?

A I believe the Company made an attempt to respond to the question that was asked for each of those scenarios.

Q 3.8d deals with conversions, correct?

A 3.8d. I would state that question 3.8d is asking to provide, or asking the Company to provide an analysis of the benefits of conversion to the customer, that's what it's asking is my interpretation of it.

Q And 3.9c similarly, is asking a similar question relative to a portion of the subtransmission projects, correct?
A Yes. Yes, 3.9c references subtransmission system.
Q And 3.16c references the CODI program, City of Detroit Infrastructure program; is that right?
A Yes, it references the COD -- the CODI program.
Q And 3.23b references the Strategic Undergrounding pilot; is that correct?
A Correct, it references Strategic Undergrounding.
Q And 3.24b, finally, references a list of ten specific CODI projects, correct?
A Correct.
Q And in each of the responses relative to those programs, the Company indicates that it has not calculated expected monetary benefits to customers arising from those programs, correct?
A Well, in each of the responses, they state that the Company's looking at the reliability based on these projects.
Q And has not calculated a financial cost-benefit, agreed?
A I mean I can go refer -- if you go to 3.8d, the response says, "The Company calculates expected benefits to customers in terms of reliability improvements."
Q Each response says the Company has not calculated a specific monetary benefit for customers for the given

program, and each response says the Company is aware of a tool and is exploring the potential use of that tool in the future; is that a fair characterization to sort of sum it up?

A So 3.8d does say that, as there is an industry tool called the Department of Energy Interruption Cost Estimator that has a general estimate of customer cost impacts for some types of the outages. The Company has not used that tool in the instant case but is exploring the potential use as a tool in the future.

MR. BZDOK: I want to move to admit proposed MEC-72.

JUDGE FELDMAN: Let me ask for the record if there are any objections to the admission of that exhibit?

MS. JOHNSON-BACON: No objection.

JUDGE FELDMAN: Hearing no objection, Exhibit MEC-72 is admitted.

MR. BZDOK: Thank you.

Q (By Mr. Bzdok): Take a look at 73, MEC-73, which is proposed -- sorry -- it is proposed Exhibit MEC-73, and it is Discovery Response STDE-6.4a-d like dog.

JUDGE FELDMAN: Are you sure that's not (b) as in boy?

MS. JOHNSON-BACON: Yeah, I'm seeing 6.4a

and 6.4b here, Chris.

MR. BZDOK: I'm seeing that, too. My intent with this exhibit was to make it 6.4a-d, which is what I'm holding in my hands, but I'm seeing that on the SharePoint it's 6.4a-b.

MS. JOHNSON-BACON: We can probably help, I think the witness has his discovery responses with him.

MR. BZDOK: That would be great.

MS. JOHNSON-BACON: So if you have that and he has them, I'll trust you to update that on SharePoint later.

MR. BZDOK: Yes, we will. Thank you.

JUDGE FELDMAN: Thank you. And let's go off the record to let Mr. Deol locate that.

(Brief pause.)

JUDGE FELDMAN: Back on the record. Mr. Bzdok.

MR. BZDOK: Thank you.

Q (By Mr. Bzdok): So in what I guess has been marked so far as 6.4a and b, and will be marked as 6.4a, b, c, and d, you're responding to some questions from Staff regarding projections or assumptions related to outcomes from the conversion projects; is that fair?

A Can you repeat your question again?

Q Yes. These questions and answers in (a) through (d) ask

for supporting calculations and assumptions for certain, for certain improvements that the Company has stated that it expects to see in page 7, line 24, to page 8, line 2, of your direct testimony, right?

A Can you share the page with me again so I can refer to it real quick?

Q Sure. It's at the top of the discovery questions that we're looking at --

A Oh, O.K.

Q -- page 7 --

A Gotcha. Yes. Yes, I agree that's on page, bottom of page 7, continuing to page 8 on my direct testimony, it does state those projections for the conversion program.

Q There are, on response -- so responses (b) through (d) simply refer to the response to (a), correct?

A Correct.

Q And the expectations that were stated in your testimony were an 85-percent reduction in customer minutes interruptions, a 85-percent reduction in customer interruptions, a 90-percent reduction in wire downs, and an 85-percent reduction in trouble events from the overhead lines conversion, correct?

A Correct.

Q And for supporting calculations for those expectations, the answer indicates some results from the 4.8 kV

hardening program that show a 44-percent reduction in all weather S-A-I-F-I, or SAIFI, a 72-percent reduction in S-A-I-D-I, ex-MEDs, and a 26-percent reduction in wire downs, correct?

A Correct, those are the benefits listed from the 4.8 kV hardening program.

Q And just so the record is clear, the SAIFI is System Average Interruption Frequency Index; is that right?

A Correct.

Q SAIDI is System Average Interruption Duration Index, correct?

A Correct.

Q And ex-MEDs is Excluding Major Event Days, correct?

A Correct.

Q Where are the calculations that are translating those figures from the 4.8 kV hardening program to the 85-percent reduction in customer minutes operation, 85-percent reduction in customer interruptions, the 90-percent reduction in wire downs, and 85-percent reduction in trouble events that are stated as expectations?

A Well, those are projections based on what we've seen on the hardening program that where we have, say, data there, we're projecting based on subject matter experts in these areas, and those projections are based on as we

convert (inaudible) --

COURT REPORTER: I'm sorry. As we convert, we're? Repeat what you said.

A As we convert, we're reconductoring, so we're, on the 4.8, it's the typical 4., No. 4 and No. 6 copper, so we're replacing that with stronger conductors, we're upgrading the poles and the pole-top hardware based on their expertise, and what we've realized for the 4.8 kV hardening, that's where the numbers and projections are coming from.

Q (By Mr. Bzdok): Are the 85 percent and 90 percent numbers the result of a calculation or are they the result of a, someone expressing an opinion, or something else?

A Those are numbers based on the SME's expert experience and their training from what we're seeing, realization that the 4.8 kV hardening, we're not reconductoring in that program and we're only replacing poles where necessary, and the pole-top hardware where necessary, whereas we're taking those, what we have achieved and project those out to where we're reconductoring with a stronger conductor, adding additional new pole-top hardware, and replacing the poles; those, from their experience and their expertise, are projections to get to 85-percent reduction for customer events, 85-percent for

customer interruption, 90-percent for wire downs, and 85-percent reduction in trouble events.

Q O.K. Thank you.

MR. BZDOK: I'm going to move to admit MEC-73 at this time.

JUDGE FELDMAN: Subject to your providing the complete copy for the SharePoint and the parties?

MR. BZDOK: Yes, subject to my providing subparts (c) and (d) so that the completed exhibit will be MEC-73 Discovery Responses STDE-6.4a, b, c, and d.

JUDGE FELDMAN: All right. Let me ask if there are any objections to admitting this exhibit with the stipulation that Mr. Bzdok will prepare it as described and get it circulated? You are muted, Ms. Johnson-Bacon, but I believe you said no objection. Still muted.

MS. JOHNSON-BACON: No objection.

JUDGE FELDMAN: All right. Thank you. And having heard no other objection, Exhibit MEC-73 is admitted with Mr. Bzdok's promise to get that circulated.

MR. BZDOK: Thank you. And Breanna Thomas has already indicated in the chat that she has revised that exhibit, so she has already delivered on my promise.

JUDGE FELDMAN: Excellent. Thank you.

MR. BZDOK: Thanks, Breanna.

Q (By Mr. Bzdok): Take look at proposed Exhibit MEC-77, which is MNSCDE-3.13a and b.

A Was it MEC-77?

Q Yes.

A Thank you. Yes, I'm there.

Q These responses indicate that between 2018 and 2022, the Company's not aware of any circumstance where a 4.8 kV circuit could not accommodate EV charging or distributed energy resource additions. Agreed?

A Are you referring to MNSCDE-3.13a?

Q I was summarizing the response together in an attempt to streamline a little bit.

A I would agree that for 3.13a, that's what the Company has stated, between 2018 and 2022, no DER was unable to be able to -- to be accommodated on the 4.8 kV system. But (b) is a different answer, though, it's a different question.

Q O.K.

MR. BZDOK: Your Honor, I'm going to move to admit MEC-77. I'm also I think for streamlining purposes to try to move this, jump ahead a little on our timeline, I'm going to move to admit MEC-78, I mean once everyone has a chance to look at them, MEC-78, 3.5 -- MNSCDE-3.5a through 3.6b, and MEC-79, which is

MNSCDE-3.7, I'm moving for admission of those without questioning, if the Company's agreeable to that.

JUDGE FELDMAN: All right. Let's give Ms. Johnson-Bacon a minute to take a look at those, and then let me also ask anybody else to let me know if they have any objections to admitting any of those three exhibits.

MS. JOHNSON-BACON: No objection.

JUDGE FELDMAN: Thank you. Anybody else?

(No response.)

Hearing no objections, Exhibits MEC-77, 78, and 79 are admitted into evidence.

MR. BZDOK: Thank you.

Q (By Mr. Bzdok): Let's talk about single contingency. I'm in your rebuttal, page 6.

A O.K.

Q Generally speaking, as a jumping-off point -- we're going to talk about this for a while. Generally speaking, as a jumping-off point, on page 6 you are describing that the Company in doing distribution capital planning uses a certain method for the firm ratings, the firm capacity ratings of its substations; is that right?

A I would interpret that as that the Company when it does it's planning of renewed substations, it uses or plans using a single contingency criteria.

Q And then on page 7 of your rebuttal, you describe a single contingency condition; is that right?
A Yes. Trying to -- the goal is to provide an example.
Q So in the example you give of a two-transformer substation with each transformer having an emergency rating, as corrected, of 15 MVA, correct?
A Correct.
Q And just for the record, MVA stands for what?
A Voltage amps, I forget the M here, sorry. Mega, yeah, sorry. Megawatt -- megavolt amps. Didn't know that I was getting a quiz on the electrical terminology here, sorry.
Q No, I don't mean it as a quiz, I mean when we're going through the transcript, right, and there are abbreviations and such, we like to try to make sure that we're just stating what those are. Didn't mean any surprise by it.

And in the example you give, the substation has two transformers, each with an emergency rating of 15 MVA, correct?
A Correct.
Q And you indicate that even though both transformers could be serving 12 MVA, the designated firm rating is 15 MVA, representing the emergency rating of one of the transformers, correct?

A Correct.
Q You further indicate that -- so when you say -- here's a question. So when you say even though each transformer, both transformers could be serving 12 MVA, what is that based on. Is that a nameplate capacity of 12 MVA or something else?
A In this scenario, it's just listed, the scenario was more based trying to explain how to get the firm rating, how do you define firm.
Q Sure. And I'm just -- and this is by contrast with some other alternatives, and so I'm just trying to understand, when you say both transformers could be serving 12 MVA, what does that 12 MVA represent in the --
A In this example, it could have been a load that the transformers were serving.
Q O.K.
A The important part of the example was the defining the emergency rating and how to look at it from firm as the Company calculates in single contingency situations.
Q The single contingency rating would be the 15 MVA, right?
A Yes. It usually is the lowest of the piece of equipment for that particular substation, and in this case, since they're both equal, it would be 15.
Q In your example, the substation with both transformers you indicate could serve 24 MVA, correct?

A I would summarize that in this particular example, that the two transformers are serving 12. You know, I didn't go in and put in what other, what's the day-to-day here. So there's -- you know, if you look at the way the Company looks at its ratings, there's three ratings that we go with. And I can refer you to my direct testimony, I believe it's page 44, yeah, and starting with line 13 through 25, it defines the ratings that the Company uses for, in this particular case it would be for substations here, but we would use that same approach for all equipment.

Q So in this example, what's the day-to-day rating of the sub, is it 12 or is it 24, or is it something else?

A In this example, the day-to-day isn't defined. The example was suited to define how do we, how the Company defines firm rating.

Q Sure. And so in understanding how that contrasts with -- I'm trying to understand how that contrasts with the day-to-day rating in the example that you've given.

A Again, the example is to provide how to define firm or to further explain how the Company defines firm rating. Day-to-day isn't stated in here. I have to look at, you know, I have to go back and redefine the scenario to say day-to-day, it would have been X, Y, and Z; and this scenario or this example is trying to define how the

Company determines firm rating.
Q O.K. You indicate in the example that in a single contingency condition where one of those transformers failed, the other one would operate at 24 MVA and therefore be 60-percent overloaded, correct?
A Correct, yeah. If one of the transformer fails, the other transformer would have to carry the load per the design that the Company has for reliability, have to be able to carry the entire load of that substation, which would be 24 MVA in this example.
Q How long could that condition persist, generally speaking?
A The contingency condition or --
Q Yeah. Yep.
A It depends on the scenario. It could be days, weeks, depends on what failed.
Q O.K. Look at page 7 of your rebuttal.
A O.K.
Q Next question and answer. Question is, question 13 is, "Is it standard in industry to develop substation ratings in grid planning based on single contingency?" And then you answer, "Yes." And then you elaborate, "While there is no universally adopted set of planning criteria across all utilities, one example of a planning standard is the 2017 - USDA Rural Utilities Service Electric System

Long-Range Planning, RUS Bulletin. 1724D-101A Section 4.b on transformer criteria", and then you quote some guidance there, correct?

A Yes.

Q O.K. And then you cite that document in a Footnote 1, and I think you provide a link to it both in your testimony and in the footnote, correct?

A Correct.

Q If you look in your folder in the MNSC or MEC NRDC --

A I have a printed copy.

Q O.K. Just because we have to sometimes do these sort of artificial things for creating a record, can you also look at MEC-80 for the purpose of identifying it as the document that you were citing there?

A Yes, this is the document that I have reviewed.

Q When did you obtain this document?

A While we were doing research for rebuttal.

Q It's not a document that DTE had been relying on in the system planning but rather a document that you found in doing research for the rebuttal?

A When we, like we stated, when we define or plan our substations, we base on N-1 contingency to protect, to make sure that we have reliability in case there are failures that the other piece of equipment in the substation can take the load for the entire substation to

be able to not have the customers take outages in those N-1 contingency situations. That was the design that we do. The question we had gotten, I believe, or we were trying to look to see if there was a standard. We didn't find the standard, but there is references to this in there.

And also, in talking to other utilities, it's not uncommon that the other utilities use an N-1 scenario while they're designing their substations.

MR. BZDOK: Your Honor, I'm going to object to and move to strike the last portion of that answer on hearsay, in talking to other utilities. There's just -- that is impossible to deal with on a record. So I would move to strike the last part of that answer which -- And it was also unresponsive to the question which was, if we wound it back, was about this document.

JUDGE FELDMAN: Ms. Johnson-Bacon.

MS. JOHNSON-BACON: I don't mind if it's stricken.

JUDGE FELDMAN: Thank you. It will be stricken. The answer was nonresponsive. I agree with Mr. Bzdok on that point.

MR. BZDOK: Thank you.

Q (By Mr. Bzdok): Would you agree with me that the

document which you cite on page 7, and which has now been marked proposed Exhibit MEC-80, is a document that USDA and some stakeholders generate for the use of rural electric cooperatives?

A Based on the title I would. The title states United States Department of Agriculture, Rural Utility Services.

Q So are you agreeing with me

A That's what the title says.

Q So are you agreeing with me?

A Sure.

MS. JOHNSON-BACON: I'd object. He's arguing with the witness. The document speaks for itself.

MR. BZDOK: Just trying to get an answer, which I think I've gotten.

JUDGE FELDMAN: All right. I think the record is clear enough and we can move on.

Q (By Mr. Bzdok): The section you cite in your rebuttal testimony on page 7, Section 4. or Section 4b, appears on page 15 of the document. Correct?

A Yes.

Q Under transformer criteria, correct?

A Correct.

Q And the section that you quote in the document refers to several factors that should be considered in establishing

criteria for sizing transformers for substations, correct?

A Correct.

Q It includes initial load at the substation, correct? Let me try and say them all at once sort of for -- It includes initial load at the substation, it includes growth rate at the substation, it includes potential load shifts due to new substations, and it includes load shifts during emergency situations, correct?

A I found the planning periods. I found the design options to consider. I guess I don't see the emergency situation in here. Unless you can point me to it.

Q Sure. So it's the text that you, in your rebuttal testimony, quote and then emphasize on page 8 line 3.

A Again I'm looking at the document itself. I just am not quickly getting to it, if you wanted me to verify the document.

Q O.K. So in the document on page 15.

A O.K.

Q Sorry, I misunderstood. Page 15, there's a Section B toward the lower third of the document.

A Uh-huh.

Q Transformer criteria.

A Yes.

Q And then in the second paragraph under that document, in

the second paragraph under transformer criteria is the quote that you set forth in your rebuttal testimony on pages 7 and 8, right?

A Yes. Sorry. I apologize, it took me a while then to refer both ways. But yes, it is in that last paragraph on page 15 of the document.

Q So is it fair to say that this USDA document is not recommending the use -- well, let me back up.

The language you emphasize from that document and the quote in your rebuttal testimony are the words "load shifts during emergency situations", correct?

A Correct.

Q And a load shift during an emergency situation, my understanding what you're saying there is that that represents, that could represent an example of a single contingency event where a substation with two transformers is relying on one when the other is out. Am I interpreting your testimony correctly?

A That was my interpretation of that.

Q So according to this USDA guidance for rural electric cooperatives, single contingency is one of several factors that should be considered and not the sole factor. Agree?

A Well, no. If you read it again, this is a criteria when you are designing it, right. So you would want to design

for the current load. You want to make sure that you're taking into account future projected load. And the way I interpret it is, in case there is an emergency, you should size your transformer to be able to accommodate it that way. I don't -- Sorry. I don't want to go over --

Q Go ahead.

A No, that's fine. That's the way I interpret it.

Q I can take it. I can take it.

A No, no. That's fine.

Paula will kick me over here if I say, you know, something. I got to keep it to that point, so.

Q The very next sentence is, and I quote: Areas of the system with slow growth rates may require different criteria for sizing transformers in areas of the system with higher growth rates, correct?

A In that paragraph?

Q Yes.

A Yes, it does say that.

Q So that would support an interpretation that USDA is not saying use one method, it's saying figure out the method based on a number of criteria for specific situations. Would you agree with that?

A If you go further down and read the next line, it says: However, it may be more economic to establish the standard transformer size for the entire system to

accommodate changes for a load growth environment. I think the document itself is providing you guidance.

Q The document also notes on the next page under Paragraph E, stakeholder agreement on engineering and economic criteria, makes the statement "Key stakeholders should have the opportunity to review, discuss, offer comments on and agree to the engineering and economic criteria." Do you see that?

A Yes, I do see that.

MR. BZDOK: Your Honor, I'm going to move to admit MEC-80.

JUDGE FELDMAN: Let me ask for the record if there are any objections to the admission into evidence of proposed Exhibit MEC-80.

MS. JOHNSON-BACON: There is not.

JUDGE FELDMAN: Hearing no objections, that Exhibit MEC-80 is admitted.

Q (By Mr. Bzdok): Let's take a look at your rebuttal testimony now, new topic. Loading data, substation loading data. Your rebuttal testimony, page 27.

A O.K. I'm there.

Q Here you state a Question and Answer 48, you have a quote from Witness Stephens: Nor did the Company provide substation capacity ratings or loads when requested in discovery. And then you have a response. And you go on

to say: When asked in discovery, the Company did provide loading data if it did not violate CEII. Correct?

A Yes.

Q And just so the record is clear, CEII there is Critical Electric Infrastructure Information; is that right?

A Yes. Thank you. I would have struggled.

Q I'm here to help. And then you provide some examples of loading data provided in discovery with some discovery responses to MNSC that then are included as exhibits and schedules in your rebuttal testimony, agree?

A Correct.

Q Do you have those exhibits available?

A I do.

Q Let's take a look at them. So these are all Exhibits A-41 and then they're different FF schedules, right?

A Right.

Q So Exhibit A-41 Schedule FF2 is discovery response MNSCDE-3.3ai. Correct?

A I got it under MNSCDE-3.aa. Could be an error on my part.

Q O.K. Do you have the actual exhibit available to you?

A Which, if we just go back, which schedule are you referring to? I guess maybe I'm looking at the wrong schedule than you are.

Q FF2.

A FF2. Yes. So I was looking at the wrong one. All right. I'm at FF2.
Q So no --
A What's that?
Q No surprises, I'm just going to go through each one of them as you list them.
A O.K.

JUDGE FELDMAN: I'm sorry, I hate to make things worse but everybody really is getting tired at the end of the day, and you have re-double your efforts not to speak over each other, please.

MR. BZDOK: Thank you. I think as we get familiar with each other we become a little more conversational, and that plays into it too. We speak like normal human beings.

Q (By Mr. Bzdok): So Schedule FF2 I have from your exhibits is a response to MNSCDE-3.3ai, and then an attachment, MNSCDE-3.3ai-01 circuits worked on in 2022. Do you have the same?
A The attachment lists all of the 4.8 and the 8.3 conversion circuits that were worked on in 2020.
Q That exhibit provides capacity and then it also provides MVA, correct?
A Yes, the exhibit provides the capacity of that circuit and the loading on that circuit by year from 2015 to

2026, based on projections there going out in the future.
Q Thank you. You anticipate my question. The MVA is the loading data, the MVA in those years, that's the loading data, correct?
A That is the load on that circuit in forecasted load.
Q So that's capacity and loading for the circuit, correct?
A Yes, that's the capacity and the indicated load by year with projections out into '24, '25 and '26.
Q For circuit not substation, agreed?
A Yes, that's by circuit.
Q My question, so take a look at FF3, and my question will be the same.
A O.K.
Q That's providing loading data by circuit and not by substation, correct?
A Correct, it's by circuit.
Q There are additional pages, there is an additional attachment, I think we've solved this mystery about 3.8. There is an additional attachment that's part of FF3 that starts on page 10 of that exhibit. 3.8ci-01 capacity?
A Yes, on page 10, yes, provides capacity for the circuit.
Q By circuit and not by substation, correct?
A Correct, it's by circuit.
Q FF4 is MNSCDE-3.18, and an attachment list of CODI circuits starting on page 4 of that schedule?

A Yes. It lists circuits.
Q And that's providing data by circuit and not by substation, correct?
A Correct.
Q And finally FF5, which is an attachment 3.9bi-01, interruption dates, ratings, loads. Are you there?
A Yes, I'm there.
Q That finally is also providing data by circuit and not by substation, correct?
A This one is a little different than the other ones. This is providing data for the subtrans circuits.
Q Let's talk about reliability. So now I'm on your rebuttal testimony pages 31 and 32.
A O.K.
Q Here you are discussing -- So I'm starting on line 11 on page 31.
A O.K.
Q Here you are discussing a Table 1 that Witness Stephens included in his direct testimony on page 15 that is intended to show the reliability of the 4.8 kV system versus the 13.2 kV system, correct?
A Yes. The Table 1 in Witness Stephens' testimony, yes. Yes, it makes assumptions based on, I guess, his interpretation.
Q And then you note that in a technical conference on

March 22, 2023, the Company provided SAIFI and SAIDI data for 4.8 kV and 13.2 kV systems, correct?

A Correct.

Q And then you state that these numbers show that the reliability on the 4.8 kV system is not significantly better than the Company's 13.2 kV system. And you say to see Table 1 below, correct?

A Correct.

Q Sorry. I'm logging into the SharePoint again. It does not like me today. And just to complete that question, then the data you're providing is Table 1 on page 32, correct?

A It's taking the table that was shared in the technical conference, that the Company had shared.

Q O.K. So in the SharePoint I'm actually going to -- it's still in DTE Electric Company but I'm going to send you into the folder for Elliot Andahazy, Ms. Elliot Andahazy.

A O.K. I'm there.

Q In there there is a proposed Exhibit MEC-81.

A O.K.

Q And that's a response, MNSCDE-7.30a. Correct?

A It's MNSCDE-7.30a.

Q And that indicates there are two attachments, correct, a presentation and a Q and A?

A It does indicate that.

Q If you go to the next page, the first page of the first attachment, it indicates that it's for a technical conference on March 22, 2023, correct?
A Yes.
Q That's the date of the technical conference that you mention on line 20 of page 31 of your rebuttal, right?
A Correct.
Q And page 7 of the exhibit, which is page 6 of the presentation, contains in bar chart format the same data you are presenting in Table 1 of your rebuttal. Is that right?
A That is correct.
Q And that bar chart in the exhibit states, and I quote, "Customers served by our 4.8 kV systems on average experience fewer outages SAIFI but longer total duration SAIFI, correct?
A Correct.

MR. BZDOK: Your Honor, I'm going to move to admit Exhibit MEC-81.

JUDGE FELDMAN: Let me ask for the record if there are any objections to the admission of this exhibit.

MS. JOHNSON-BACON: No objection from the Company.

JUDGE FELDMAN: Thank you. Hearing no

objections, Exhibit MEC-81 is admitted.

MR. BZDOK: Your Honor, may I have -- Can we go off the record?

JUDGE FELDMAN: Off the record.

(Discussion held off the record.)

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(At 4:44 p.m., the hearing was adjourned to Wednesday, July 20, 2023, at 10:00 a.m.)

- - -

Thursday, July 20, 2023

At 10:07 a.m.

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(Hearing resumes following adjournment of Wednesday, July 19, 2023.)

JUDGE FELDMAN: All right. On the record. Good morning, all. Can I ask the counsel present to place their appearances on the record, please. Ms. Johnson-Bacon.

MS. JOHNSON-BACON: Good morning, your Honor. Paula Johnson-Bacon appearing on behalf of DTE Electric Company. Also with me this morning is Mr. Christinidis on behalf of the Company.

JUDGE FELDMAN: Thank you. Ms. Stirling.

MS. STIRLING: Good morning, your Honor. Anna Stirling on behalf of the Michigan Public Service Commission Staff. I would also like to enter the appearances of Monica Stephens and Daniel Sonneveldt. We anticipate Mr. Sonneveldt will be joining us shortly.

JUDGE FELDMAN: Thank you. Mr. King.

MR. KING: Good morning, your Honor. Joel King appearing on behalf of Attorney General Dana Nessel.

JUDGE FELDMAN: Thank you. Mr. Bzdok.

MR. BZDOK: Good morning, your Honor.

Christopher Bzdok and Tracy J. Andrews on behalf of the Michigan (inaudible) --

COURT REPORTER: Oh, you're really bad, you're breaking up.

JUDGE FELDMAN: Could you try that again, Mr. Bzdok, slowly.

MR. BZDOK: Good morning, your Honor.

JUDGE FELDMAN: Good morning.

MR. BZDOK: Christopher Bzdok on behalf of the Michigan Environmental Council, Natural Resources Defense Council, Sierra Club, and Citizens Utility Board of Michigan, along with Tracy J. Andrews.

JUDGE FELDMAN: Thank you. Mr. Campbell.

MR. CAMPBELL: Good morning, your Honor. Steve Campbell, Clark Hill, PLC, on behalf of the Association of Businesses Advocating Tariff Equity.

JUDGE FELDMAN: Thank you. Mr. Abrams.

MR. ABRAMS: Good morning, your Honor. Daniel Abrams appearing on behalf of the Ecology Center, the Environmental Law & Policy Center, the Union of Concerned Scientists, and Vote Solar, collectively referred to as the Clean Energy Organizations.

JUDGE FELDMAN: Thank you. Ms. Horne.

MS. HORNE: Good morning, your Honor. Melissa Horne on behalf of Wal-Mart, Inc.

JUDGE FELDMAN: Thank you. Ms. Flower.

MS. FLOWER: Good morning, your Honor. Olivia Flower on behalf of International Transmission Company. Also entering appearances this morning for Hannah Buzolits and Rick Aaron.

JUDGE FELDMAN: Thank you. Mr. Boehm.

MR. BOEHM: Good morning, your Honor. Kurt Boehm appearing on behalf of The Kroger Company.

JUDGE FELDMAN: Thank you. Let me just ask if there's anybody that I've missed who wants to put in an appearance who might have joined after we got started this morning? (No response.)

All right. When we left off yesterday, Mr. Deol was on the witness stand and we paused his cross-examination to allow counsel to review some additional documents. Mr. Bzdok, would you be ready to proceed with the conclusion of your cross-examination at this point?

MR. BZDOK: Yes, I would.

JUDGE FELDMAN: All right. Mr. Deol, let me just remind you that you're still under oath, and Mr. Bzdok, you may proceed when you're ready.

MR. BZDOK: Thank you, your Honor.

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S A T V I R S. D E O L

resumed the stand, and having been previously sworn, testified further as follows:

CROSS-EXAMINATION (Continuing)

BY MR. BZDOK:

Q Good morning, Mr. Deol.

A Good morning, Mr. Bzdok.

Q I don't think we need a lot of time today. I will note that there are three new exhibits in the SharePoint folder which we're going to discuss today. If you have a chance to navigate to the DTE Electric folder and then to your folder within that and the MNSC exhibits folder.

A Yes, sir.

Q O.K. So today we're going to talk about proposed Exhibits MEC-83 --

A O.K.

Q -- Discovery Response 17.6a, along with a page we attached to it from Exhibit A-23 Schedule M5; Exhibit MEC-84, MNSCDE-17.7e, again along with a page we attached to that from Exhibit A-23 Schedule M5; and then Exhibit MEC-85, which is Discovery Response MNSCDE-3.8bii with an excerpt of the Attachment 1 that was attached to that response, and we have also loaded the full Excel version of that attachment wire downs and trouble events into the SharePoint. We have excerpted it because it's 40 some

thousand lines.

So let's start with 83.

A O.K.

Q So I want to talk -- I want to sort of continue the thread of our discussion yesterday about single contingency, using a single contingency method for determining the firm rating of substations for determining substation loading and distribution capital planning. Do you recall generally that we had a discussion about that yesterday?

A Regarding the contingency situations, the N-1?

Q Yep.

A Yes, we did have a discussion regarding that.

Q O.K. In proposed MEC-83, that Discovery Response 17.6a, we asked you about substation loading at Unionville. Do you see that there?

A Yes.

Q And we attached to that a page from Exhibit A-23 Schedule M5, page 402. Do you see that on the second page?

A Yep, I do see that.

Q O.K. So this, high level, is a portion of the project support documents for the Unionville decommissioning and circuit conversion; would you agree?

A This is a document that was submitted through my exhibit.

Q Yes. And it indicates at the top that Unionville

Substation is 111 percent of firm rating and 91 percent of emergency rating, correct?

A Correct.

Q It indicates further that the substation is equipped with three single-phase 500 kVA transformers and they are the limiting element, correct?

A Correct.

Q So the 111 percent of firm rating, based on the discussion we had (inaudible) --

COURT REPORTER: I'm sorry, Mr. Bzdok, you're breaking up.

JUDGE FELDMAN: Would you repeat that question?

MR. BZDOK: Yeah, let me log off and log back on and see if that helps.

JUDGE FELDMAN: Off the record.

(Brief off-record discussion.)

JUDGE FELDMAN: O.K. Back on the record.

Q (By Mr. Bzdok): I'm going to try to pick up where I think I left off. The purpose and necessity for the project on this page 402 of Exhibit A-23 Schedule M5 indicates Unionville Substation is 111 percent of firm rating, 91 percent of emergency rating, and the substation is equipped with three single-phase 500 kVA transformers which are the limiting element, correct?

A Correct.
Q That 111 percent of firm rating refers to the single contingency, that's the rating developed under the single contingency methodology that we were discussing yesterday, correct?
A I'll refer back just to relate to it. It says a firm rating, which is the maximum load the substation can carry under a single contingency condition, it's based on the lowest emergency rating of all of the substation equipment that is required to serve that load.
Q So I'm just trying to explore this as an example of an actual project in the same way that you explored it as a hypothetical project in your testimony which we discussed yesterday. The transformers are the limiting element of the substation, correct?
A Correct.
Q And there are three of them, correct?
A There's three single-phase transformers, correct, not three three-phase.
Q O.K. Explain the -- so you made a point to note that; can you explain the significance of it?
A So this is one of our older substations, so typically we have a three-phase transformer. Due to the time era of the substation, each individual phase, X, Y, and Z, has its own unique transformer rather than a three-phase

transformer.
Q O.K. Operationally, then, what is the -- in a single contingency event in which one of those transformers is down or is out, what is the backup, is it another one of the transformers or is it the adjacent Fairgrove Substation, or something else?
A In this situation here, as stated, there is no jumping capability, so we would be rolling a portable, portable device here to either pick up the phase or pick up the entire station here.
Q O.K. So how, then, in this example is that firm rating determined as a function of the single contingency method?
A So in this particular case, the three single-phase would be equivalent to a three-phase, so you would add up the 500 kVA, come up to be 1.5 MVA rating there, so the contingency here would be a portable, and then we would follow the same method, so we would -- the maximum load that the substation can carry under a single contingency is based on the lowest emergency rating of all the substation equipment. When we go through that process, the substation, the three single-phase transformers themselves are the limiting factor.
Q So does that mean the -- go ahead --
A That would establish the firm rating for this substation.

Q So does that mean the firm rating is 500 kVA?
A No. The firm rating in this particular one -- I don't recall what exactly the firm rating is, but it would be the calculation, you would assume the 500, like I try to equate earlier, the individual phases would sum up to 1.5 MVA equivalent to a 1.5 MVA three-phase transformer.
Q So then is the firm rating 500 or 1.5 or something else?
A That is -- it's a number that's actually higher than 1.5, but I can't recollect right now.
Q O.K. In the discovery request we asked you to confirm that the Unionville Substation loading exceeds the firm rating but not the emergency rating -- or sorry -- that loading for that substation which exceeds the firm rating but not the emergency rating only occurs for a very small percentage of the hours in any year.
A Yes.
Q And you indicated that the Company cannot confirm or not confirm as it does not know what constitutes a very small percentage of the hours in any year, correct?
A Correct.
Q How would you characterize it then? If I were to ask you how often does that happen or what amount of the year does that happen (inaudible) --
COURT REPORTER: I'm sorry, you're breaking up again.

JUDGE FELDMAN: Just toward the tail end of the last part of that question was all static.

Q (By Mr. Bzdok): If I was to ask you how does -- how often or how much of the year or what portion of the hours of the year does that generally happen, how would you answer that question?

A I don't have the data to answer it either way.

Q So you don't know how, even within a range or an approximation, how often that condition occurs?

A I don't have the data here with me to tell you that.

Q Would you agree that a substation -- well, no, let's talk about 84.

A O.K. Let me go get that one. O.K. I have it up.

Q This one says, for the, this is Purpose and Necessity for the (inaudible) --

COURT REPORTER: We lost you again.

JUDGE FELDMAN: Purpose and necessity, that was the last part I heard.

Q (By Mr. Bzdok): For the Carleton project, correct?

A Correct.

Q It indicates the Carleton Substation is approximately 190 percent of the maximum loadability; is that right?

A Correct.

Q And then it says, "Transformer 2 is at 106% of its day to day rating," correct?

A Correct.
Q And then it says, "DC 312 CARLT is at 117% of its day to day rating," correct?
A Correct.
Q So day-to-day rating is the rating for an amount of load as you've defined it in your testimony that a piece of equipment can carry essentially every day for a long period of time, right?
A Right. As we've discussed, the day-to-day rating is defined for a normal state condition, it's the load level that the equipment can be operated at for its expected lifespan.
Q What is the maximum loadability in this context?
A For this situation or this design, it would be the firm rating here.
Q And what is the DC 312 CARLT?
A It's a particular circuit that is served from this substation.
Q So both of the elements mentioned are slightly above their day-to-day rating, but almost twice their firm rating; is that right?
A Can you repeat that question again, please, or restate it?
Q Sure. So each of the elements cited here are modestly above their day-to-day rating, but the substation as a

whole is above its firm rating by a much larger amount; would you agree?

A I would restate it that transformer 2 is above its day-to-day and Carleton 312 is above its day-to-day rating; and yes, the firm rating of the substation is higher than what's listed for trans 2 overage and DC 13 Carleton's overage of the day-to-day rating.

Q And just so the record is clear, when you say Carleton's subrating or Carleton's subfirm rating, did you mean the exceedance of the firm rating is much above?

A Yes. I was referring to the 190 percent.

Q O.K. Why is that? So in other words, can you explain how the -- those exceedances of the day-to-day ratings for the two cited elements are then determined to exceed the firm rating of the sub by a much larger amount?

A Going back to my testimony, page 44 there, the firm rating, which is the maximum load that the substation can carry under a single contingency and it's based on the lowest emergency rating of all of substation equipment that is required to serve that load, per that definition, that's how the 190 was calculated.

Q O.K. Same question I asked you about the other one, we asked the Company to confirm that the amount of time that these loadings exceed equipment day-to-day rating is a very small percentage of the hours in a year, and the

answer was, "The Company cannot confirm or not confirm as it does not know what constitutes a very small percentage of the hours in any year," correct?

MS. JOHNSON-BACON: I'm sorry, Chris, are you referring to proposed Exhibit 83?

MR. BZDOK: 84.

MS. JOHNSON-BACON: 84. O.K.

MR. BZDOK: Yep. I'm asking the same question about it as I asked about 83.

MS. JOHNSON-BACON: O.K. Understand. Thank you.

A Because I'm a bit confused, you just looked at the document, I don't -- the exhibit that you were asking me to take a look at, I don't see that response in there, unless I didn't go all the way down, but I don't see that question associated in there.

Q (By Mr. Bzdok): Give me just a second. So you're looking at MEC-84?

A Yes.

Q 17.7e?

A Oop. O.K. Going back up. Yes, I see the last paragraph. O.K. Yes, I do see that.

Q O.K. So my question then is, how would you characterize the amount or percentage of hours in the year in which the loadings for those elements exceed the equipment's

day-to-day rating?

MS. JOHNSON-BACON: I'll object. I believe the witness has already answered this question.

MR. BZDOK: He answered it as to 83, but I'm asking him as to the equipment in 84.

JUDGE FELDMAN: O.K.

MS. JOHNSON-BACON: You can go ahead and answer.

A As far as the previous one, I do not have the data here to be able to respond to that.

Q (By Mr. Bzdok): Do you have any general intuition about whether it's a small or a large portion of the year?

A Without not having the information here, I can't.

Q If single contingency is used to designate firm ratings for substations, as long as there's even one hour of the year that the load cannot be carried by whatever the backup is, that means the substation loading exceeds the firm rating; would you agree?

A You're going to have to slow down and ask that question again, I did not see the association there.

Q O.K. If single contingency is used to designate the firm ratings for substations, that would mean that a substation could exceed its firm rating even if there's only one hour per year that the loading exceeds what the backup could carry in the single contingency event; would

you agree?
A I'm still not associating your question there, I'm fully not understanding what you're asking me.
Q O.K. Let's look at your rebuttal testimony, page 7.
A O.K. I am there.
Q So in answer 12, you're providing the example of how single con -- how firm rating would be determined using single contingency for a hypothetical two-transformer substation, correct?
A Correct.
Q And you indicate there that, in your example, each transformer in that substation has an emergency rating of 15 MVA, correct?
A Correct.
Q You indicate further that, for that substation, both transformers could be serving 12 MVA, correct?
A Correct.
Q In that example, is 12 MVA their day-to-day rating?
A No. As we discussed yesterday, it's just what they're carrying on there. I didn't specify any rating from a day-to-day perspective. We were trying to just get a point across of how under a single contingency the firm rating is defined.
Q O.K. And then you indicate that, "The Company would designate a Firm rating for the substation at 15 MVA,"

correct?

A For the definition, right. So going back referring to the definition is the maximum of what the substation can carry under a single contingency condition that is based on the lowest emergency rating of all the substation equipment that is required to serve the load. So the assumption here is the transformer is the lowest, so the firm rating would be established for this substation at 15 MVA.

Q And that would be true -- so let me say it a different way. If the load carried by that substation exceeds 15 MVA even only one hour of the year, under this methodology, that sub would be determined to be in exceedance of its firm rating, correct?

A When the single contingency happens for this substation, right, if both of the transformers are carrying 12 MVA at that time, we lose one transformer, the other transformer would be carrying 24 MVA, then it would be 160-percent overloaded of its firm rating. That's what the example says.

Q And it would be designated as over, it's loaded over its rating even if that event only happens one hour of the year, correct?

A It would be overloaded every time the single contingency happens.

Q And it would be classified as an over, as loaded beyond its rating even if that loading level only is seen one hour per year, agreed?

A No. As stated, every time that single contingency happens, the substation would be over its firm rating.

JUDGE FELDMAN: O.K. So what's the firm rating for that substation that it would be over?

THE WITNESS: As identified in the example, the firm rating for this two-transformer substation would be 15 MVA.

JUDGE FELDMAN: So I hate to wade into this, but if one of those transformers experienced a load above that 15 level, would that -- at any point without regard to whether the, whether the emergency condition giving rise to that rating materialized, would that be considered violating that firm rating?

THE WITNESS: I think that's what I'm trying to answer is that every time that single contingency happens, right, so if we lose that transformer, whatever, upfeed, that the load has to be shifted on that other transformer, you would be above your firm rating.

JUDGE FELDMAN: Are there any other circumstances in which that firm rating could be exceeded?

THE WITNESS: I'm not sure what -- I mean there could be multiple conditions that you'd lose, right, you have an incoming feed, you'd lose that, the other transformer has to serve; there's downstream, the cables fail on the other transformer, so the single transformer has to serve the load. So there's many situations that either one of those transformers or other equipment upstream or downstream of it that's serving the load could fail and that could result in the single contingency situation where one of them has to carry the load for the entire substation.

JUDGE FELDMAN: But an exogenous increase in the load on its own couldn't result in a violation of that firm rating, exogenous increase in the load to the substation?

THE WITNESS: I guess I'm not understanding that question.

JUDGE FELDMAN: All right. Well, I think I've taken up enough of Mr. Bzdok's time, so I apologize. Excuse the interruption, Mr. Bzdok.

MR. BZDOK: No apology needed, Judge.

Q (By Mr. Bzdok): Taking a look at MEC-83 again, that Discovery Response 17.6a and then the attachment, and really what I want to look at is that Exhibit A-23 Schedule M5, page 402, which is attached to that

response, or if you'd rather look in your exhibit. So Unionville Substation.

A O.K. I do have that up.

Q The statement, "Unionville Substation is 111% of Firm Rating", that means that it experiences loading of 111 percent of the firm rating as determined by the methodology that you've described, correct?

A Correct.

Q And it only needs to exceed that firm rating, it only needs to hit 111 percent of that firm rating even one hour a year to get -- for that statement to be true, correct?

A Every time it's in that single contingency situation, it will exceed it.

Q And how often is it in that single -- and if it's in that single contingency situation only one hour a year, that statement will be true, correct?

A All I can tell you is every time we are in that single contingency, it's in that situation.

MR. BZDOK: O.K. I'm going to move to admit 83 and 84.

MS. JOHNSON-BACON: No objection.

JUDGE FELDMAN: Thank you very much. Does anybody else have an objection? (No response.)

Hearing no objection, Exhibits MEC-83 and

MEC-84 are admitted.

Q (By Mr. Bzdok): Mr. Deol, I have one last topic for you, and I promise not to argue with you anymore, I just have some questions about one of your discovery attachments. I'm just trying to, trying to get a better understanding of it. So if you would look at MEC-85.

A O.K., looking at it.

Q This Discovery Response MNSCDE-3.8bii asks for wire down events for circuits that have been listed in a prior discovery response along with certain information about those wire down events, fair?

A Yes, this asked for -- sorry. Can you repeat your question again?

Q This discovery response asked for some, a list of certain wire down and trouble events and certain information about them, fair?

A Fair.

Q And there's an attachment listed that provides this information as U-21297 MNSCDE-3.8bii-01 Wire Downs and Trouble Events, correct?

A Correct.

Q And there is, on the following pages I will tell you, I will represent to you that we made an excerpt consisting of the first 240 rows of that attachment, and I will further represent to you that we did not modify any of

the values or information in the Excel, and then I will let you know that in the SharePoint we have loaded that original attachment as well, so maybe take a look at that first, or next.

A The Excel file?

Q Yeah. Or I can share it. If it's easier for you to toggle one document, I can share the other one.

A Sure.

JUDGE FELDMAN: Are you just asking him to be able to confirm that those pages look like they're properly extracted from the entire document?

MR. BZDOK: I am, but then I'm going to ask him some questions about the document as well. It does look like someone name Bryant Miller at DTE Energy is doing something in the version that's on SharePoint, so I guess I would ask that that not happen.

JUDGE FELDMAN: Let's go off the record.

(At 10:47 a.m., brief pause.)

JUDGE FELDMAN: Back on the record.

Q (By Mr. Bzdok): So does the spreadsheet generally look familiar to you as the attachment that was provided?

A Are you sharing, or do you want me to bring up the spreadsheet?

Q I can share.

MR. BZDOK: Is it O.K. with you, Judge,

if I share briefly?

JUDGE FELDMAN: Yes, you can, but just if you can also direct him to that actual document again because you can't really page through the pages of a shared screen, as you know.

MR. BZDOK: Fair enough.

Q (By Mr. Bzdok): So the original spreadsheet is in that same location in the SharePoint, I am going to share it at this moment, and then --

A Well, that's --

Q I can see that you have located it in the SharePoint as well, correct?

A Yes.

Q You're right over here, "S"?

A Yes, sir.

Q O.K. So great. So this is generally familiar to you as the document that was provided?

A Yes, this is the document that was provided.

Q O.K. And it includes a listing of circuits, a year, a date within the year, a job type, and then has these numbers for trouble events and wire down counts, correct?

A Correct.

Q And using the magic of Excel, right, we can ascertain that it contains 49,000 -- this takes longer in SharePoint than it does on -- does not work as well as it

does on my -- let's just say, so subject to check, it contains -- oh, that's why -- 43,934 rows of data, agreed?

A Subject to check, yes.

Q O.K. I think I can stop sharing this now, you're welcome to stay in it. What I'm hoping to do is just to do an eyeball check of the document included as the excerpt of that to see if it appears, again subject to check, consistent with an excerpt of the first 240 rows of that spreadsheet, again on a representation I have not modified anything.

A Subject to check, yes.

Q O.K. So I just have some questions for you seeking information about some of what's in this document, and I would welcome you to refer to whatever, the original spreadsheet or this excerpt or whatever information is useful to you to answer my questions. There is a list in column B of job type, correct?

A Correct.

Q What do the different job types mean? So I'm looking for like what does it mean to have a police/fire event, what dozen hazards mean, what is single customer problem, what is safety concern, and what is critical infrastructure customer?

A Those would be the classifications that we'd use to

identify the event that had come in.
Q Is a police/fire event an event where there's some type of emergency response from a police or fire individuals or both?
A Correct.
Q What's the difference between a hazard and a public safety concern?
A I don't have the exact definitions there with me right now to be able to answer that.
Q O.K. What's a critical infrastructure customer?
A Be a hospital.
Q O.K. Any other?
A Well, there's many that, classifications, could be a pumping stations, something that's very critical to the infrastructure.
Q O.K. There are in the -- and then there are these numbers about trouble events and wire down count, correct?
A Correct.
Q And in some rows it's one or the other, and in some rows it's both, correct?
A Correct.
Q What would it mean for an event to be both a trouble event and a wire down count?
A So the trouble event would be that the event was noted,

right, so there's a call-in for an event so that (inaudible) --

COURT REPORTER: I'm sorry, I lost you, I think.

THE WITNESS: Was that for me or was that for Chris?

COURT REPORTER: I believe that was you, Mr. Deol. I'm not sure, but I kind of lost you there, breaking up a little.

THE WITNESS: O.K. Is it better now or --

COURT REPORTER: Yes.

A O.K. So the trouble event is that an event was called in based on those types, so that was something that the Company would have to respond to, and then the wire down would be was there a wire down associated with it based on investigation, so.

Q (By Mr. Bzdok): O.K. Are there ever wire downs without trouble events?

A There could be.

Q O.K. Take a look at -- I want to look at a couple specific examples of things and ask you what they mean, so we're in the early, in the early rows here.

A O.K.

Q So let's look at May 4, 2018.

A May 4.
Q So I'm in lines, I'm in lines 8, row 8 to row 11.
A O.K.
Q There, under the same date of May 4, 2018, there's a row for hazards with a trouble event and a wire down row for a police/fire event with a trouble event and a wire down, a row for public safety concern with a wire -- a trouble event and a wire down, and a single customer problem with a trouble event but no wire down, and they're all in the same circuit on the same date. Does that mean -- does that suggest there was one incident that had all these different types of classifications associated with it, or does it mean something else?
A I'd have to go look at that incident. Like it could mean that there were multiple wire downs or multiple incidents off of the circuit, circuits can be big.
Q O.K. Could be the same, could be different events on the same circuit?
A Yeah. I mean circuits can be multiple customers, vast distances.
Q O.K.
A But in order to fully answer your question, I would have to go back and look at this date, 5/4, on this particular circuit.
Q O.K. That won't be necessary, we've taken plenty of your

time already.

Take a look at July 22, 2019, which -- well, hold on. Take a look at, take a look at row 52, Circuit 1115, 2019, 7/20/2019, public safety concern.

A O.K.

Q Six trouble events and six wire downs. And then jump down to row 54, same circuit next day, public safety concern, and then jump down to row 56, next day, July 22, public safety concern; does that represent like an event that persisted for more than one day or something else?

A Again, I would have to go back and take a look at these events, but you could have, again, the circuits are big, lots of customers off of the circuit, so you could have multiple events.

Q O.K. Are wire downs -- so I'm not finding anywhere in here a column, the trouble events column ever being zero; would you agree with that, subject to check?

A Correct, subject to check.

Q O.K. Does that mean that wire downs are a subset of trouble events?

A There are multitudes of trouble events that could happen in the system, and you associate wire downs with that.

Q Could you just repeat that last part, you said something about wire, and something about wire downs?

A As you confirm them, right, you would associate if the

wire was down for that event.

Q O.K.

MR. BZDOK: I'm going to move to admit proposed Exhibit MEC-85 at this time.

JUDGE FELDMAN: Let me ask if there are --

MS. JOHNSON-BACON: No objection.

JUDGE FELDMAN: Thank you very much, Ms. Johnson-Bacon. Anybody else? (No response.)

Hearing no objections, Exhibit MEC-85 is admitted.

Q (By Mr. Bzdok): Mr. Deol, it's been a long road, I appreciate your time, and I have no further questions for you at this time.

A O.K. Thank you.

JUDGE FELDMAN: Thank you, Mr. Bzdok.

Let me just ask for the record if anybody else has any cross-examination for this witness? (No response.)

All right. Ms. Johnson-Bacon, do you need a few minutes with this witness before deciding on your redirect?

MS. JOHNSON-BACON: Yes, please. Thank you.

JUDGE FELDMAN: All right. Let's go off

the record.

(Recess from 11:03 a.m. until 11:16 a.m.)

JUDGE FELDMAN: All right. Back on the record. Ms. Johnson-Bacon, do you have any redirect for this witness?

MS. JOHNSON-BACON: The Company does not have redirect for Mr. Deol. Thank you.

JUDGE FELDMAN: All right. Thank you. Thank you for your testimony, Mr. Deol, thank you for your patience and coming yesterday, and as well as returning this morning. You are excused from our virtual witness stand, but of course you may stay for the remainder of our proceedings.

(The witness was excused.)

- - -

JUDGE FELDMAN: Let me ask for the record if there are any objections to any of the schedules that Mr. Deol sponsors within Exhibit A-12, that would be Schedule B5.4; within Exhibit A-23, that would be Schedules M5 and M10; or within Exhibit A-33, that would be Schedules X2 and X3; or if there are any objections to the admission into evidence of Exhibit A-41 in its entirety since Mr. Deol sponsors that entire exhibit?

(No response.)

Hearing no objections, Exhibit A-41 is

admitted into evidence, and we will deem the schedules that I identified within Mr. Deol's exhibits or those portions of his Exhibits A-12, A-23, and A-33 admissible when we take up those exhibits in their entirety.

Let's go off the record.

(Recess from 11:17 a.m. until 11:31 a.m.)

JUDGE FELDMAN: Back on the record. Ms. Johnson-Bacon, are you ready to call the Company's next witness?

MS. JOHNSON-BACON: Yes, your Honor. The Company calls Allen J. Krysinski to the record.

JUDGE FELDMAN: Thank you. The court reporter will swear in Mr. Krysinski.

A L L E N J. K R Y S C Y N S K I

was called as a witness on behalf of DTE Electric Company and, having been duly sworn to testify the truth, was examined and testified as follows:

COURT REPORTER: Thank you.

DIRECT EXAMINATION

BY MS. JOHNSON-BACON:

Q Please state your name and business address for the record.

A Sure. Allen James Kryscynski, Jr., business address is One Energy Plaza, Detroit, Michigan.

Q Did you file with the Commission a document entitled the

MPSC Case No: U-21534

Requester: MNSC

Question No.: MNSCDE-17.5c

Respondent: S. Deol

Page: 1 of 1

Question: 5. Refer to Deol rebuttal, Q&A16-17:

c. Produce the source of your claim that 20% of the company's 4.8kV substations operate over firm rating.

Answer: Please see Exhibit A-23, Schedule M8 filed in the instant case. On page 9 of this exhibit is "Exhibit 1.2.1 DTEE Substations by Type and Voltage" showing 244 general purpose 4.8kV substations. Additionally, page 122 of this exhibit is "Exhibit 9.3.6.2 – Conversion Projects to Address 25 4.8kV Substations with Highest Loading Constraints" showing 49 total 4.8kV substations over firm.

Attachment: None.

CONFIDENTIAL ATTACHMENT NOT INCLUDED

IN PUBLIC VERSION OF EXHIBIT MEC-121C

MPSC Case No: U-21534

Requester: MNSC

Question No.: MNSCDE-20.3

Respondent: B. Villadsen

Page: 1 of 1

Question: Refer to the rebuttal testimony of witness Villadsen, Q&A24, page 24 lines 11-14. Explain the assertion that "the normalized MRP is derived using historic data," including what historic data, the period of historic data, and the way the MRP uses historic data.

Answer: The referenced sentence is based on Kroll's description of their derivation of the recommended MRP. Please see the attachment labelled:

U-21534 MNSCE-20.3 Attachment 01_Kroll webcast at p. 47.

Attachment: *U-21534 MNSCDE-20.3 Attachment 01_Kroll webcast*

KROLL

Cost of Capital in the Current Environment

Presented by:

Carla S. Nunes, CFA James P. Harrington

28 September 2022

U.S. Equity Risk Premium

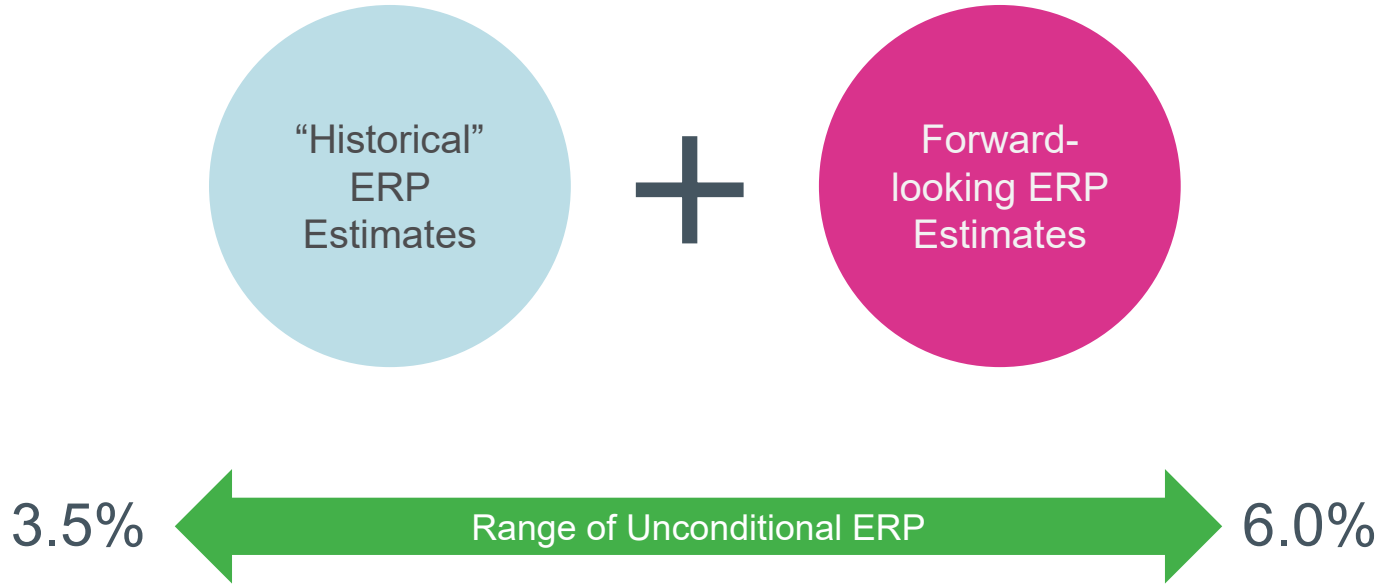
KROLL

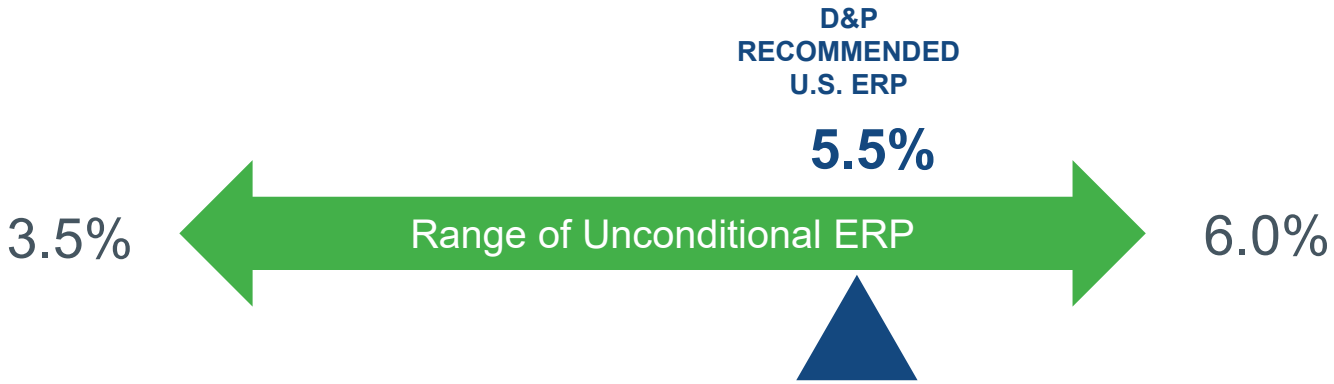
STEP 1: What is a reasonable range of unconditional ERP that can be expected over an entire business cycle?

"What is the range?"

STEP 2: Research has shown that ERP is cyclical during the business cycle. We use the term conditional ERP to mean the ERP that reflects current market conditions.

"Where are we in the range?"

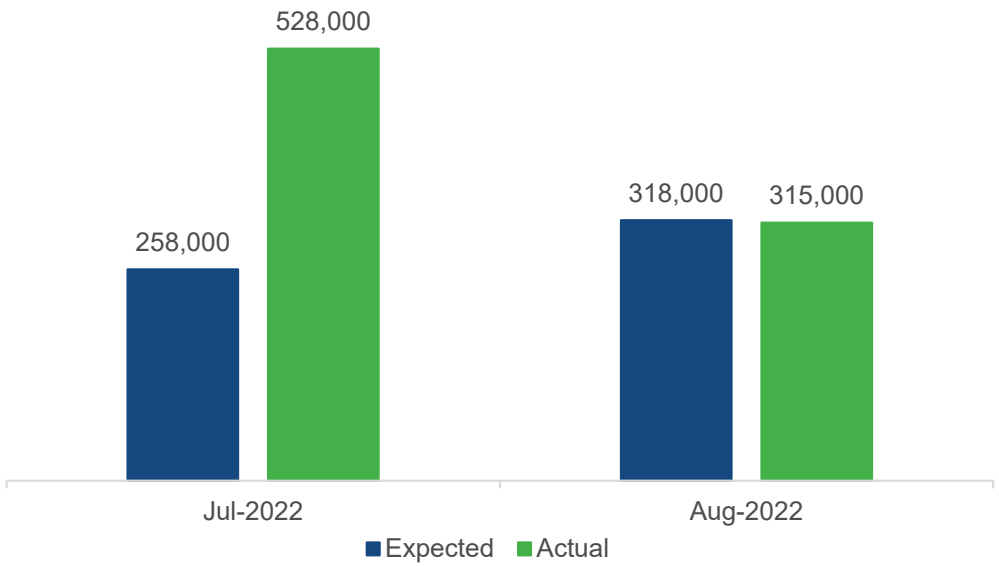

"Historical" ERP Estimates
+
Forward-looking ERP Estimates
3.5%
Range of Unconditional ERP
6.0%


D&P
RECOMMENDED
U.S. ERP
5.5%
3.5%
Range of Unconditional ERP
6.0%

Factors Considered in ERP Recommendation – Summary Table

	Factor	Change	Effect on ERP
Financial Markets	U.S. Equity Markets	▲	▼
	Implied Equity Market Volatility	▼	▼
	Corporate Credit Spreads	▲	▲
	Damodaran Implied ERP Model	▲	▲
	Default Spread Model	▲	▲
	U.S. Equity Market Uncertainty Index	▲	▲
Economic Indicators	Historical & Projected Real GDP Growth	▲	▼
	Unemployment	▼	▼
	Consumer Sentiment	▼	▲
	Business Confidence	◀▶	▲
	Sovereign Credit Ratings	◀▶	◀▶
	Economic Policy Uncertainty (EPU) Index	▼	▼

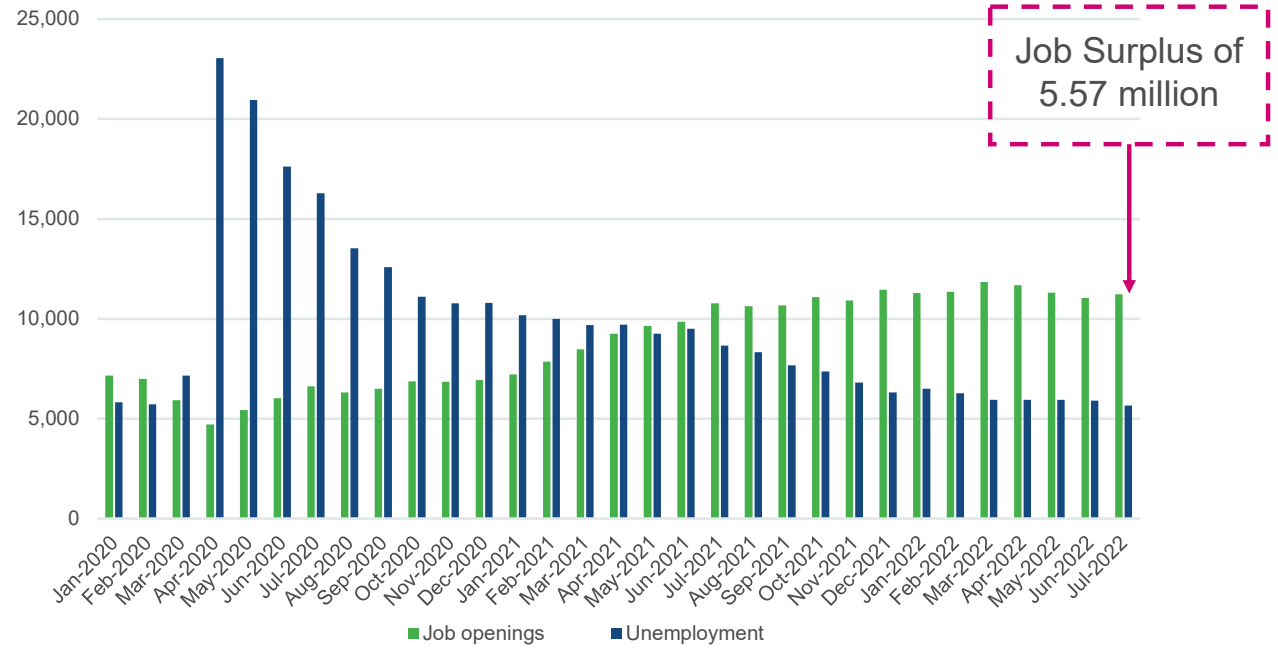
.... but still near pre-COVID lows



	July	August
Unemployment Rate	3.5%	3.7%
Change from Prior Month	-0.1%	0.2%

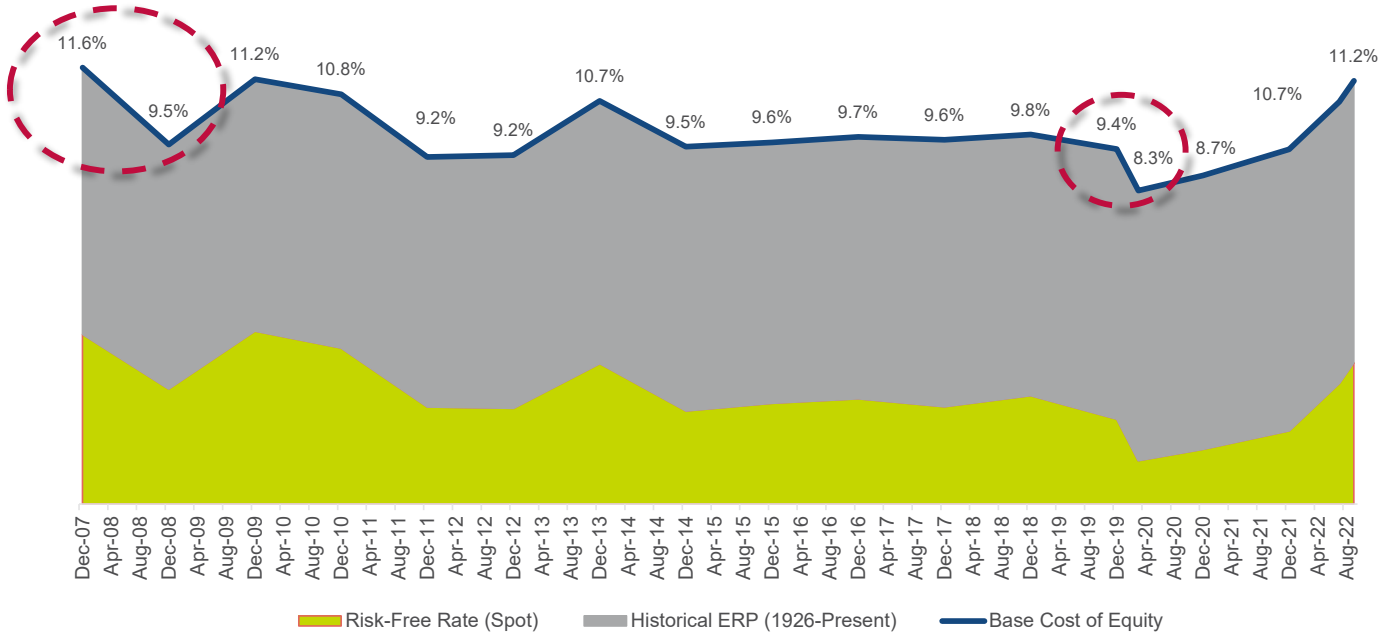
Sources: Non-farm payrolls by Bureau of Labor Statistics; CNBC "Payrolls increased 528,000 in July, much better than expected in a sign of strength for jobs market" August 5, 2022; CNBC "Payrolls rose 315,000 in August as companies keep hiring", September 2, 2022.

U.S. Job Openings vs Number of Employed (thousands)



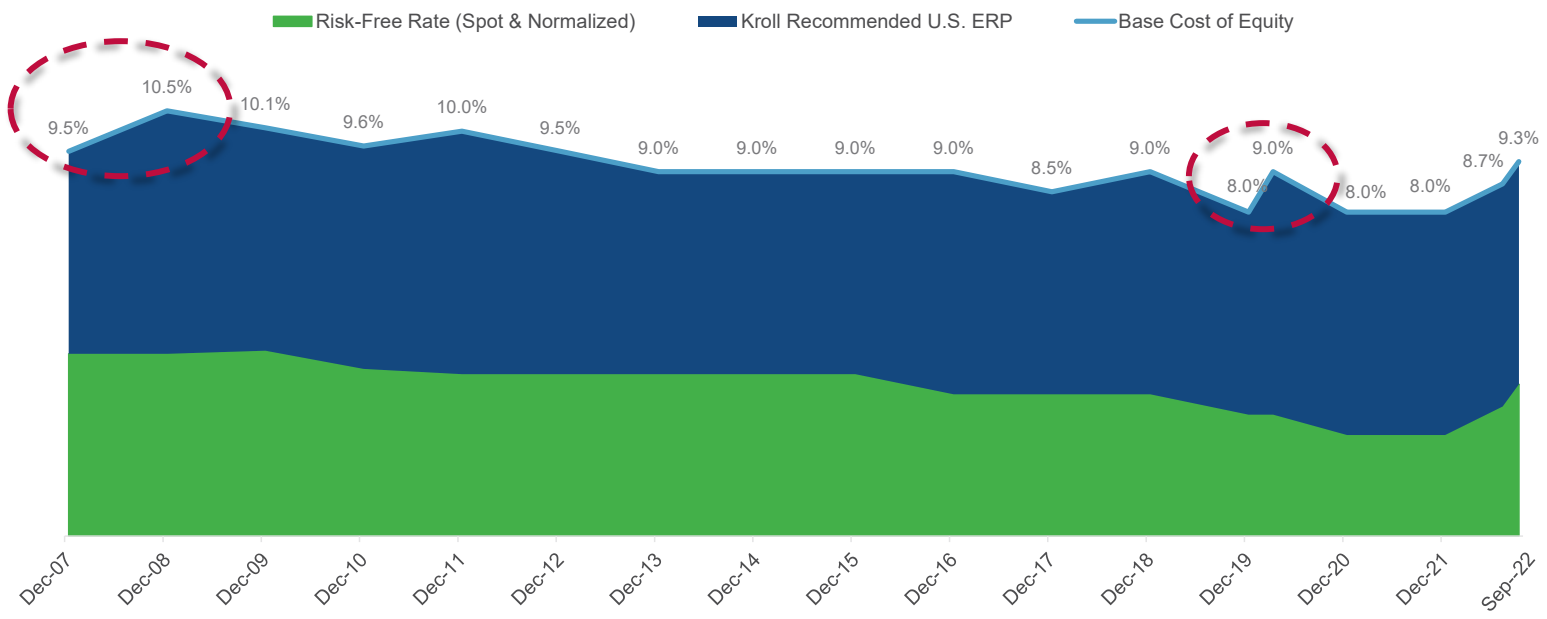
Job Surplus peaked at 5.90 million in March 2022

Spot 20-Year U.S. Government Yield in Conjunction with Unadjusted "Historical" Equity Risk Premium *



* The Historical Equity Risk Premium is defined as the ERP over the years 1926–Present as of the date of the analysis. For example, the Historical Equity Risk Premium for December 2019 spans the years 1926–2019 while the Historical ERP for 2020 spans the years 1926–2020.

Current U.S. Normalized Risk-free Rate and ERP Recommendations



MPSC Case No: U-21534

Requester: MNSC

Question No.: MNSCDE-20.4

Respondent: B. Villadsen

Page: 1 of 1

Question: Refer to the rebuttal testimony of witness Villadsen, Q&A24, page 25. Produce a copy of the cited study by Professor Ibbotson.

Answer: Please see the attachment labelled:

U-21534 MNSCDE-20.4 Attachment 01_Ibbotson

Attachment: *U-21534 MNSCDE-20.4 Attachment 01_Ibbotson*

The Equity Risk Premium

Roger G. Ibbotson
Professor in Practice, Yale School of Management
Chairman, Zebra Capital Management

The equity risk premium (ERP) is a concept that seems to mean different things to different people. Some people treat it as the equilibrium long-run return, whereas others treat it as their own personal estimate of the long-run return. Some discuss it as a future return, whereas others discuss it as a realized return. Some compare equity returns with long-term bond returns or yields, whereas others compare equity returns with short-term bond returns or yields. There are various ways to estimate the ERP, whether we are talking about equilibrium or personal estimates and whether we are making forecasts or measuring past realizations. In this paper, I will clarify the terminology, compare the various ways of estimating and measuring the equity risk premium, and discuss some of the other premiums that exist in both equity and other capital markets.

What is the equity risk premium? I consider it a long-run equilibrium concept that gives an estimate of the future excess return of the stock market over and above the bond market. There are several advantages to thinking of the ERP as an equilibrium concept. It provides the *market's* estimate of the excess return on stocks relative to bonds. It is neutral in the sense that it does not take advantage of any particular investor's expertise but, rather, tries to determine what the market thinks. In this way, it can be used as a benchmark for more active or dynamic forecasts of the stock market. It can also be used for long-term planning purposes in setting a long-term asset allocation or in estimating the returns that a portfolio can provide to meet various future obligations.

I have already established that from an investor's perspective, the ERP is the expected return that investors can earn on stocks in excess of bonds. From a corporation's perspective, however, the ERP is part of the cost of equity capital. When looking at a company's entire weighted average cost of capital, the ERP is usually the most important ingredient. From a valuation perspective, the ERP is used as part of the discount rate when estimating the present value of a set of future cash flows. The expected return of equity is used in all three of these contexts, and they are all equivalent to each other after taking into account certain market imperfections, such as taxes and transaction costs.

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Methods of Estimating the Equity Risk Premium

How should we estimate the equity risk premium in equilibrium over the long run? There are four primary ways. The first is to look at the historical ERPs that we get from comparing past stock returns with past bond returns. These realizations give us an idea as to the magnitude of payoffs that investors have received for taking on the extra risk of being in the stock market rather than the various bond markets. A second way is to use a consensus estimate of the opinions of all the participants in the marketplace. Because these market participants are setting the price, they must also be the investors who are buying or selling stocks to reflect their long-term outlook. A third method is to look at the demand side of the equation. In this case, we are trying to determine how much extra return an investor would demand for taking on the extra risk of buying stocks rather than bonds. The last way is to look at the supply side of the equation. Here we consider what the economy and corporations supply to the market in the form of earnings or cash flow.

Historical. Let us start with the historical perspective. **Table 1** lists the returns over the period 1926 through 2010 for the following Ibbotson indices: Large Company Stocks, Small Company Stocks, Long-Term Corporate Bonds, Long-Term Government Bonds, Intermediate-Term Government Bonds, U.S. Treasury Bills, and Inflation. The geometric mean annualized return from Large Company Stocks was 9.9 percent, and the arithmetic mean return was 11.9 percent. The Long-Term Government Bond geometric mean return was 5.5 percent, and the arithmetic mean return was 5.9 percent. The U.S. Treasury Bill geometric mean return was 3.6 percent, and the arithmetic mean return was 3.7 percent. The table demonstrates that there can be many

Table 1. Ibbotson Index Series: Summary Statistics of Annual Total Return, 1926–2010

Series	Geometric Mean	Arithmetic Mean	Standard Deviation
Large Company Stocks	9.9%	11.9%	20.4%
Small Company Stocks	12.1	16.7	32.6
Long-Term Corporate Bonds	5.9	6.2	8.3
Long-Term Government Bonds	5.5	5.9	9.5
Intermediate-Term Government Bonds	5.4	5.5	5.7
U.S. Treasury Bills	3.6	3.7	3.1
Inflation	3.0	3.1	4.2

Source: Ibbotson® SBBI®, *2011 Classic Yearbook: Market Results for Stocks, Bonds, Bills, and Inflation, 1926–2010* (Chicago: Morningstar, 2011).

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ERPs even when using a single historical data period. At the high extreme, the arithmetic mean ERP of Large Company Stocks compared with U.S. Treasury Bills was 8.2 percent (11.9 percent − 3.7 percent). At the low extreme, the geometric mean ERP of Large Company Stocks compared with Long-Term Government Bonds was 4.4 percent (9.9 percent − 5.5 percent). Thus, researchers and investors often have confusing conversations with each other. Even when they might agree on the *same* historical time interval and dataset, the ERP historical measure can be anywhere in the range of 4.4–8.2 percent, depending on which definition of ERP is used.

Investors typically use the Large Company Stock geometric mean return minus the Long-Term Government Bond return as their characterization of the historical ERP, which for 1926–2010 is 4.4 percent. In corporate finance and in valuation discounting, arithmetic means are more often used. Even if a characterization of the ERP is agreed upon, however, a debate over what historical period is most representative of the future long-run return can occur. Some might want to use even longer historical periods to reduce the estimation error, which falls in proportion to the square root of time. Some might want to use shorter and more recent periods, which better reflect the current and future environment. Those who think the historical method should be used still have plenty to debate about. The historical method, however, has the great advantage that it measures what really happened. It reveals how much stocks have actually outperformed bonds over whatever interval is under investigation.

Consensus. The consensus method might appear to be a very good approach; when using this method, one attempts to obtain the estimates from the market participants themselves (i.e., the very investors who are setting the market prices). But there are a number of problems with this approach. Most of these investors have no clear opinion about the long-run outlook. Many of them have only very short-term horizons. Individual investors often exhibit extreme optimism or pessimism and make procyclical forecasts, and so following a boom, they can have ERP estimates that exceed 20 percent or 30 percent. Following a recession or a decline in stock market prices, their estimates of the ERP might even be negative. Academics and institutional investors may be more thoughtful, but any survey of their opinions would have to be very carefully designed. I have seen surveys, however, that do not seem to even clarify whether the questionnaire refers to arithmetic mean returns or geometric mean returns. Many surveys also do not make clear whether the ERP to which they refer is the excess return of stocks over government bonds or Treasury bills or some other type of bond. This lack of clarity makes the surveys very difficult to interpret. The most extensive surveys have been done by Pablo Fernández (see, for example, Fernández, Aguirreamalloa, and Corres 2011).

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Demand. The demand approach to estimating the ERP stems from the idea that investors demand an extra return for investing in stocks rather than bonds. In the capital asset pricing model (CAPM), the ERP is the central feature. The CAPM is derived from utility curves that characterize the risk–return trade-off. In the CAPM, all assets are held in the market portfolio, and the expected return of the market portfolio is sufficient to satisfy the investors' demand for stocks relative to their risk. Attempts to measure the ERP using the demand approach focus on analyzing utility functions. Mehra and Prescott (1985) first attempted to come up with reasonable measures of the ERP in this way. The ERP was very low and did not reasonably match any of the historical data. This mismatch came to be known as the "equity premium puzzle." Subsequently, many researchers have attempted to resolve the puzzle using behavioral finance, different types of utility curves, different distributional assumptions about stock returns, and risk aversion measures that are conditional on the state of the economy. In the end, the puzzle can be resolved in many ways, but the demand approach is not likely to provide a good estimate of the equity risk premium.

Supply. The supply approach attempts to estimate what the economy or the companies in the economy can supply to the market in the form of cash flows. This approach can be applied to the economy, using per capita or total GDP growth, net capital investment, and output provided to both capital and labor. It can also be applied at the corporate level, using company cash flows, earnings, dividends, payout ratios, stock share repurchases, and cash flow receipts from mergers and acquisitions. My co-authors and I used this approach in Diermeier, Ibbotson, and Siegel (1984) and in Ibbotson and Chen (2003), as did several of the authors in *The Equity Risk Premium: Essays and Explorations* (Goetzmann and Ibbotson 2006). The supply approach is a promising alternative for estimating the ERP.

Many Different Risk Premiums

Table 1 shows that the equity risk premium is not the only premium in the market. The following are some of the potential premiums:

- Long-horizon ERP (stocks – long-term government bonds)
- Short-horizon ERP (stocks – U.S. Treasury bills)
- Small-stock premium (large stocks – small stocks)
- Default premium (long-term corporate bonds – long-term government bonds)
- Horizon premium (long-term government bonds – U.S. Treasury bills)
- Real interest rate (U.S. Treasury bills – inflation)

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The equity risk premium is the largest of these premiums, but all are important. We can forecast stock and bond returns of various types by restacking the various premiums. This approach is known as the "build-up method" and was first proposed in Ibbotson and Siegel (1988). **Exhibit 1** provides an example of the build-up method.

Exhibit 1. Components of Assets' Expected Returns

				Small Stocks	Foreign Stocks	
				Small-stock premium	Foreign stock premium	Foreign Bonds
Stocks						
Equity risk premium	Bonds			Equity risk premium	Equity risk premium	Foreign bond premium
Bond horizon premium	Bond horizon premium	Cash	Real Estate	Bond horizon premium	Bond horizon premium	Bond horizon premium
Real riskless rate	Real riskless rate	Real riskless rate	Real return on real estate	Real riskless rate	Real riskless rate	Real riskless rate
Inflation	Inflation	Inflation	Inflation	Inflation	Inflation	Inflation

Source: Ibbotson and Siegel (1988).

As Exhibit 1 shows, a small-stock return can be estimated from the following components: expected inflation, the expected real rate of interest, the bond horizon premium, the long-horizon ERP, and the small-stock premium. A corporate bond return can be estimated from the expected inflation rate, the expected real rate of interest, the horizon risk bond horizon premium, and the default risk premium. Often the first three terms (inflation, interest rate, and bond horizon premium) are combined into the long-term yield of a riskless bond because this yield is typically observed directly in the marketplace.

One reason that the ERP is so important is that it is often the largest number in the stack. The ERP is also the most important source of estimation error because it is not directly observable in the future. Instead, we have a historical record of past realizations and various other forecast methods. In this framework, the expected stock return is the sum of two components: the long-term riskless rate, which is the yield on bonds and is directly observable, and the long-horizon ERP, which can only be estimated.

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Other Premiums in the Market

The stock market is frequently characterized by investment styles. I have discussed the small-stock premium, and investing in small- versus large-capitalization stocks is considered an investment style. Fama and French (1993), among others, proposed the other prevalent style in the marketplace. They showed that value stocks outperform growth stocks over long periods of time. They defined value stocks as those of companies that have high book-to-market ratios. Others define value stocks as having high earnings-to-price ratios (or low price-to-earnings ratios). The premiums of value over growth stocks and small over large stocks are often characterized as risk premiums because they are long term in nature, have a positive payoff, and can be earned through passive rather than active management.

Another premium in the market that has been empirically observed is the momentum premium (see, for example, Jegadeesh and Titman 1993). Stocks that did well in the previous year tend to do well in the next year, whereas stocks that did poorly in the previous year tend to do poorly again. The momentum premium is not typically characterized as an investment style because momentum investing usually involves some form of active management to realize the excess returns. There is some evidence that momentum premiums are becoming more erratic and less predictable, perhaps because momentum is becoming so well known in the market. With so many investors taking advantage of the momentum premium, it may tend to disappear over time.

The liquidity premium is perhaps as important as any of the risk premiums. Ibbotson, Diermeier, and Siegel (1984) proposed that the three security characteristics that investors most wish to avoid and, therefore, need to be most compensated for in the long run are (1) risk, (2) lack of liquidity, and (3) taxation. This observation forms part of the demand approach to expected returns because investors demand a premium to take on risk, to give up liquidity, or to invest in a security that is heavily taxed. The liquidity premium is very well known and has been applied primarily in bond and alternative asset markets. Because a bond yield is observable, a less liquid bond can easily be seen to have a higher yield than a more liquid bond that is otherwise similar. This spread is the liquidity premium, and it can be used as another stack in the build-up method described previously. Real estate and private equity are examples of alternative investments for which investors would demand a higher return in order to compensate for the fact that they cannot easily liquidate their positions. These liquidity premiums are not observable, but it is generally accepted that a substantial portion of the return that investors receive from these types of investments must be a reward for taking on this lack of liquidity.

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Ibbotson, Chen, and Hu (2011) proposed a new equity investment style based on the concept of the liquidity premium. We restricted the investment universe to publicly traded stocks and found that cross-sectional differences in liquidity have a large impact on returns, even though almost every one of these stocks trades every day. Thus, the liquidity premium is important not only across asset classes but also in the continuum of liquidity within an asset class. In the case of stocks, there is a substantial difference between the returns of the most popular stocks, which are the most heavily traded, and the returns of the least popular stocks. These premiums are larger than small-stock premiums and are comparable in magnitude to value premiums. When compared with size, value, and momentum, liquidity premiums have a different but at least as powerful effect. **Table 2** provides a comparison of liquidity and size premiums.

Table 2. U.S. Equity Annual Return Quartiles, 1972–2010

	Liquidity			
Size	1 (lowest)	2	3	4 (highest)
1 (smallest)	18.17%	17.46%	13.51%	6.16%
2	16.87	15.15	11.68	6.52
3	15.15	14.36	12.87	9.56
4 (largest)	12.49	11.48	11.55	9.87

Source: Ibbotson, Chen, and Hu (2011).

Dynamic and Tactical ERP Forecasts

Most forecasts of the equity risk premium are not equilibrium forecasts. They are not attempts at estimating an ERP that can be used for long-term investment-planning purposes, the equity cost of capital in corporate finance, or the discount rate used in valuation. Rather, they are attempts to outperform the market by applying special expertise in determining whether the stock market is over- or undervalued today. Forecasts of high returns for the stock market are accompanied by recommendations to buy stocks instead of bonds, whereas low-return forecasts are accompanied by recommendations to reduce stock investments.

Of course, knowing when to buy stocks and when to sell them is very difficult, particularly at the macro level. At the individual stock level, thousands of stocks might be over- or underpriced. But at the market level, any mispricing must be systematic. For the stock market to be overpriced in aggregate, most of the individual stocks have to be overpriced, which means that the investors in aggregate must be systematically overconfident because the market price

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reflects their collective judgment. Most stock market forecasts implicitly say that the market is wrong in some way. The forecasters believe that their particular judgment is superior to the judgment of the marketplace.

In many cases, whether the forecaster is making an equilibrium forecast or a beat-the-market forecast is not very clear. The four approaches to the equity risk premium discussed in this paper are not always clearly classified as to whether they are being applied in an equilibrium context or for the purpose of beating the market. The historical approach is based on return realizations, but one can argue over whether they are representative of the future or are too high or low. The consensus approach is subject to incorrect measurement to such an extent that it may be difficult to apply in either context. The demand approach is usually more theoretical and is mostly useful in determining the broad direction—so that one can say that the ERP is a positive number and in equilibrium stocks should always be expected to outperform bonds in the long run. The supply approach has the most flexibility; investors can attempt to use it in an equilibrium context, or they can apply their special expertise in an attempt to outperform the market. For example, one might say that an aging population argues for lower returns in the future or that the increasing speed of technological change argues for higher returns in the future. Each expert places relative importance on a particular factor, which causes the experts to end up with a wide diversity of opinions.

Summary

I have defined what the equity risk premium is and how it can be used in equilibrium and beat-the-market contexts. The terminology is confusing to many investors and financial writers: They tend to mix up a future concept with a past realization, they assign a number to the ERP without clarifying which measurement of the ERP is being used, and they rarely clarify whether they are talking about the ERP in an equilibrium or a beat-the-market context.

I have also discussed various other premiums in the market. These premiums represent the differential returns of the many different asset classes and investment styles in the market. To make sound investment decisions, it is important to have good estimates of these premiums.

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MPSC Case No: U-21534

Requester: MNSC

Question No.: MNSCDE-20.5

Respondent: B. Villadsen

Page: 1 of 1

Question: Refer to the rebuttal testimony of witness Villadsen, Q&A26, footnotes 82 and 83. Produce a copy of the cited pages from the cited texts.

Answer: Please see the attachments labelled:

U-21534 MNSCDE-20.5_01 Brealey Myers Allen
U-21534 MNSCDE-20.5_02 Ross Westerfield Jaffe

Attachment: *U-21534 MNSCDE-20.5_01 Brealey Myers Allen*
U-21534 MNSCDE-20.5_02 Ross Westerfield Jaffe

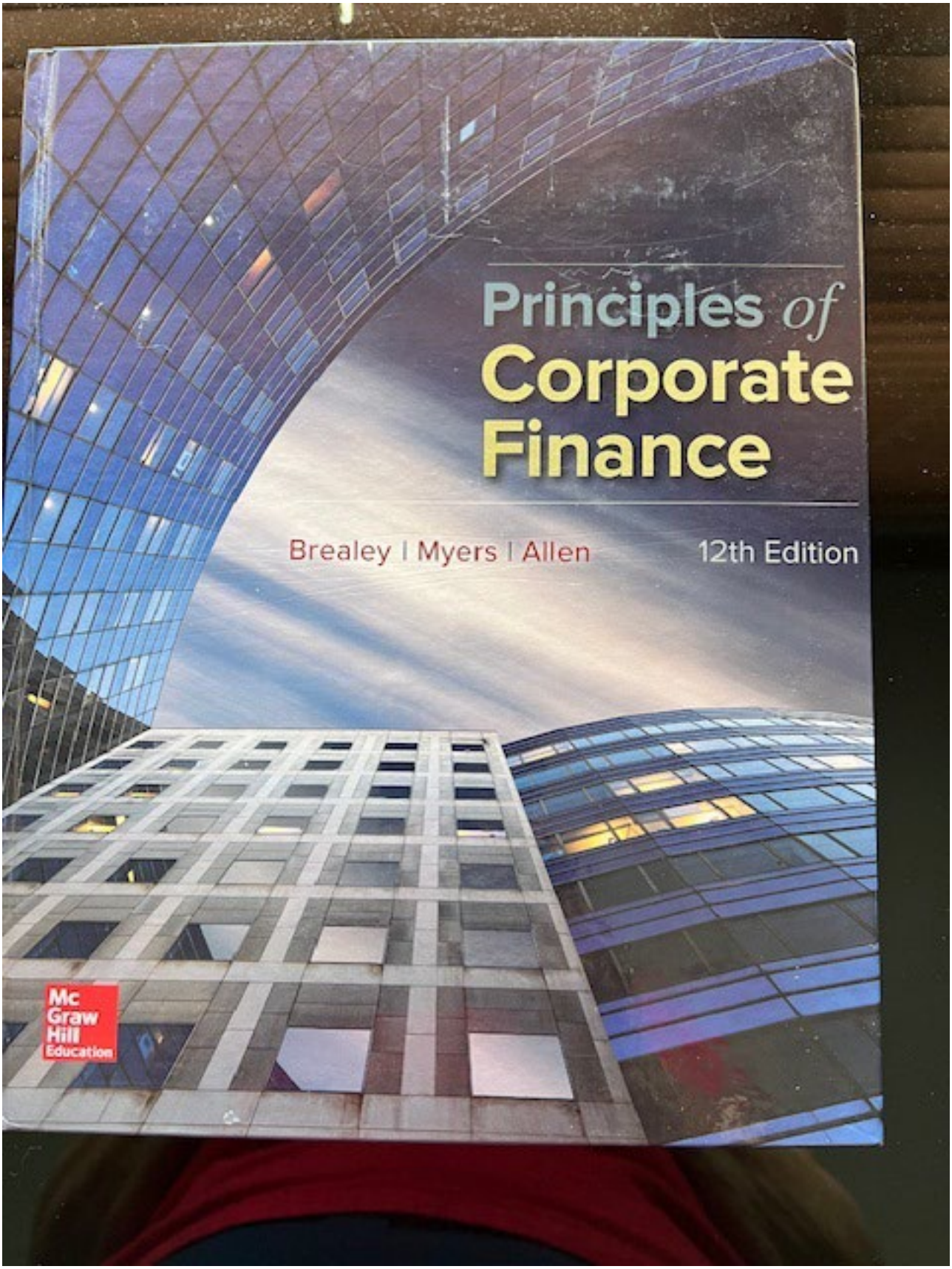

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TABLE 7.1 Average rates of return on U.S. Treasury bills, government bonds, and common stocks, 1900–2014 (figures in % per year).

Source: E. Dimson, P. R. Marsh, and M. Staunton, *Triumph of the Optimists: 101 Years of Investment Returns*, (Princeton, NJ: Princeton University Press, 2002), with updates provided by the authors.

	Average Annual Rate of Return		
	Nominal	Real	Average Risk Premium (Extra Return versus Treasury Bills)
Treasury bills	3.8	1.0	0
Government bonds	5.4	2.4	1.5
Common stocks	11.5	8.4	7.7

to keep up with inflation. An investment in long-term Treasury bonds would have produced $278. Common stocks were in a class by themselves. An investor who placed a dollar in the stocks of large U.S. firms would have received $38,255.

We can also calculate the rate of return from these portfolios for each year from 1900 to 2014. This rate of return reflects both cash receipts—dividends or interest—and the capital gains or losses realized during the year. Averages of the 115 annual rates of return for each portfolio are shown in Table 7.1.

Over this period, Treasury bills have provided the lowest average return—3.8% per year in *nominal* terms and 1.0% in *real* terms. In other words, the average rate of inflation over this period was about 3% per year. Common stocks were again the winners. Stocks of major corporations provided an average nominal return of 11.5%. By taking on the risk of common stocks, investors earned a *risk premium* of 11.5 − 3.8 = 7.7% over the return on Treasury bills.[4]

You may ask why we look back over such a long period to measure average rates of return. The reason is that annual rates of return for common stocks fluctuate so much that averages taken over short periods are meaningless. Our only hope of gaining insights from historical rates of return is to look at a very long period.[5]

Arithmetic Averages and Compound Annual Returns

Notice that the average returns shown in Table 7.1 are arithmetic averages. In other words, we simply added the 115 annual returns and divided by 115. The arithmetic average is higher than the compound annual return over the period. The 115-year compound annual return for common stocks was 9.6%.[6]

The proper uses of arithmetic and compound rates of return from past investments are often misunderstood. Therefore, we call a brief time-out for a clarifying example.

Suppose that the price of Big Oil's common stock is $100. There is an equal chance that at the end of the year the stock will be worth $90, $110, or $130. Therefore, the return could be −10%, +10%, or +30% (we assume that Big Oil does not pay a dividend). The *expected* return is ⅓(−10 + 10 + 30) = +10%.

---

[4]The risk premium for bonds doesn't "add up" because of rounding.

[5]We cannot be sure that this period is truly representative and that the average is not distorted by a few unusually high or low returns. The reliability of an estimate of the average is usually measured by its *standard error*. For example, the standard error of our estimate of the average risk premium on common stocks is 1.9%. There is a 95% chance that the *true* average is within plus or minus 2 standard errors of the 7.7% estimate. In other words, if you said that the true average was between 3.9% and 11.5%, you would have a 95% chance of being right. *Technical note:* The standard error of the average is equal to the standard deviation divided by the square root of the number of observations. In our case the standard deviation of the risk premium is 20.2%, and therefore the standard error is $20.2/\sqrt{115} = 1.9\%$.

[6]This was calculated from $(1 + r)^{115} = 38{,}255$, which implies $r = .096$. *Technical note:* For log normally distributed returns the annual compound return is equal to the arithmetic average return minus half the variance. For example, the annual standard deviation of returns on the U.S. market was about .20, or 20%. Variance was therefore $.20^2$, or .04. The compound annual return is about .04/2 = .02, or 2 percentage points less than the arithmetic average.

If we run the process in reverse and discount the expected cash flow by the expected rate of return, we obtain the value of Big Oil's stock:

$$PV = \frac{110}{1.10} = \$100$$

The expected return of 10% is therefore the correct rate at which to discount the expected cash flow from Big Oil's stock. It is also the opportunity cost of capital for investments that have the same degree of risk as Big Oil.

Now suppose that we observe the returns on Big Oil stock over a large number of years. If the odds are unchanged, the return will be −10% in a third of the years, +10% in a further third, and +30% in the remaining years. The arithmetic average of these yearly returns is

$$\frac{-10 + 10 + 30}{3} = +10\%$$

Thus the arithmetic average of the returns correctly measures the opportunity cost of capital for investments of similar risk to Big Oil stock.[7]

The average compound annual return[8] on Big Oil stock would be

$$(.9 \times 1.1 \times 1.3)^{1/3} - 1 = .088, \text{ or } 8.8\%$$

which is *less* than the opportunity cost of capital. Investors would not be willing to invest in a project that offered an 8.8% expected return if they could get an expected return of 10% in the capital markets. The net present value of such a project would be

$$NPV = -100 + \frac{108.8}{1.1} = -1.1$$

Moral: If the cost of capital is estimated from historical returns or risk premiums, use arithmetic averages, not compound annual rates of return.[9]

Using Historical Evidence to Evaluate Today's Cost of Capital

Suppose there is an investment project that you *know*—don't ask how—has the same risk as Standard and Poor's Composite Index. We will say that it has the same degree of risk as the *market portfolio*, although this is speaking somewhat loosely, because the index does not include all risky securities. What rate should you use to discount this project's forecasted cash flows?

Clearly you should use the currently expected rate of return on the market portfolio; that is the return investors would forgo by investing in the proposed project. Let us call this market return r_m. One way to estimate r_m is to assume that the future will be like the past and that today's investors expect to receive the same "normal" rates of return revealed by the averages shown in Table 7.1. In this case, you would set r_m at 11.5%, the average of past market returns.

---

[7] You sometimes hear that the arithmetic average correctly measures the opportunity cost of capital for one-year cash flows, but not for more distant ones. Let us check. Suppose that you expect to receive a cash flow of $121 in year 2. We know that one year hence investors will value that cash flow by discounting at 10% (the arithmetic average of possible returns). In other words, at the end of the year they will be willing to pay $PV_1 = 121/1.10 = \$110$ for the expected cash flow. But we already know how to value an asset that pays off $110 in year 1—just discount at the 10% opportunity cost of capital. Thus $PV_0 = PV_1/1.10 = 110/1.1 = \$100$. Our example demonstrates that the arithmetic average (10% in our example) provides a correct measure of the opportunity cost of capital regardless of the timing of the cash flow.

[8] The compound annual return is often referred to as the *geometric average* return.

[9] Our discussion assumed that we *knew* that the returns of −10, +10, and +30% were equally likely. For an analysis of the effect of uncertainty about the expected return see I. A. Cooper, "Arithmetic Versus Geometric Mean Estimators: Setting Discount Rates for Capital Budgeting," *European Financial Management* 2 (July 1996), pp. 157–167; and E. Jacquier, A. Kane, and A. J. Marcus, "Optimal Estimation of the Risk Premium for the Long Run and Asset Allocation: A Case of Compounded Estimation Risk," *Journal of Financial Econometrics* 3 (2005), pp. 37–55. When future returns are forecasted to distant horizons, the historical arithmetic means are upward-biased. This bias would be small in most corporate-finance applications, however.

Investors track Sharpe ratios to measure the risk-adjusted performance of investment managers. (Take a look at the mini-case at the end of this chapter.)

We can now separate the investor's job into two stages. First, the best portfolio of common stocks must be selected—S in our example. Second, this portfolio must be blended with borrowing or lending to obtain an exposure to risk that suits the particular investor's taste. Each investor, therefore, should put money into just two benchmark investments—a risky portfolio S and a risk-free loan (borrowing or lending).

What does portfolio S look like? If you have better information than your rivals, you will want the portfolio to include relatively large investments in the stocks you think are undervalued. But in a competitive market you are unlikely to have a monopoly of good ideas. In that case there is no reason to hold a different portfolio of common stocks from anybody else. In other words, you might just as well hold the market portfolio. That is why many professional investors invest in a market-index portfolio and why most others hold well-diversified portfolios.

8-2 The Relationship Between Risk and Return

In Chapter 7 we looked at the returns on selected investments. The least risky investment was U.S. Treasury bills. Since the return on Treasury bills is fixed, it is unaffected by what happens to the market. In other words, Treasury bills have a beta of 0. We also considered a much riskier investment, the market portfolio of common stocks. This has average market risk: its beta is 1.0.

Wise investors don't take risks just for fun. They are playing with real money. Therefore, they require a higher return from the market portfolio than from Treasury bills. The difference between the return on the market and the interest rate is termed the *market risk premium*. Since 1900 the market risk premium ($r_m - r_f$) has averaged 7.7% a year.

In Figure 8.6 we have plotted the risk and expected return from Treasury bills and the market portfolio. You can see that Treasury bills have a beta of 0 and a risk premium of 0.[7] The market portfolio has a beta of 1 and a risk premium of $r_m - r_f$. This gives us two benchmarks for an investment's expected risk premium. But what is the expected risk premium when beta is not 0 or 1?

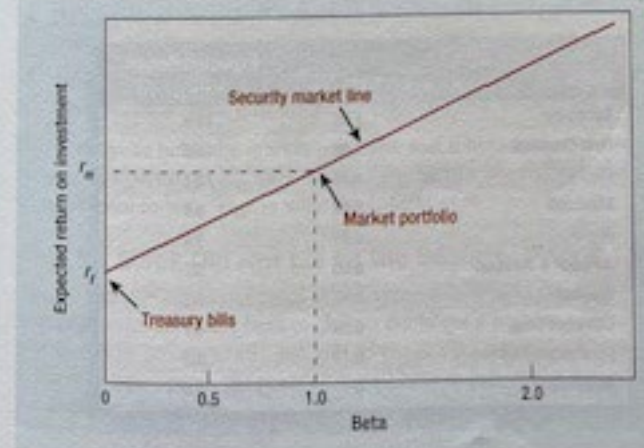
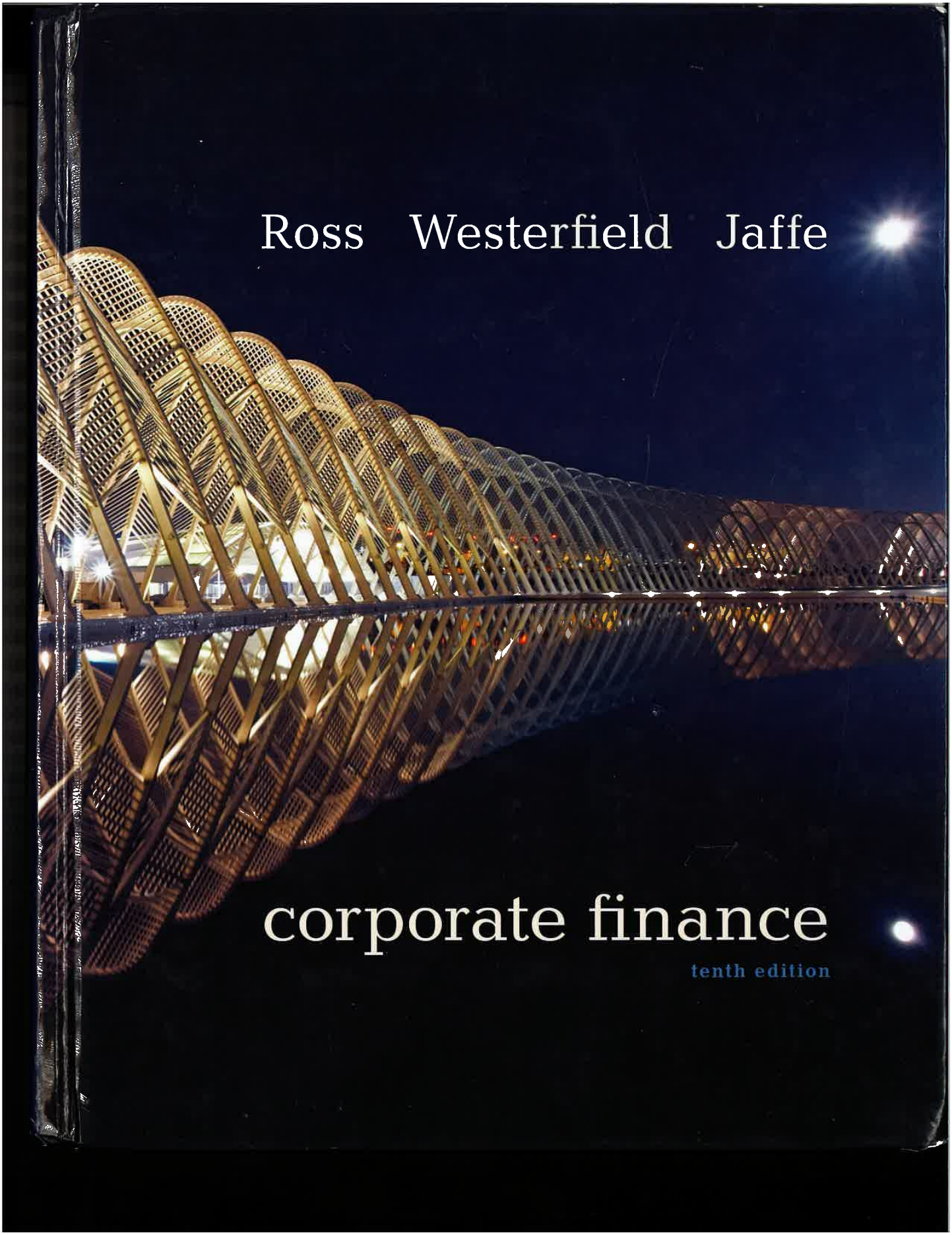


FIGURE 8.6
The capital asset pricing model states that the expected risk premium on each investment is proportional to its beta. This means that each investment should lie on the sloping security market line connecting Treasury bills and the market portfolio.

[7] Remember that the risk premium is the difference between the investment's expected return and the risk-free rate. For Treasury bills, the difference is zero.


Ross Westerfield Jaffe
corporate finance
tenth edition

10.7 The U.S. Equity Risk Premium: Historical and International Perspectives

So far, in this chapter, we have studied the United States in the period from 1926 to 2011. As we have discussed, the historical U.S. stock market risk premium has been substantial. Of course, anytime we use the past to predict the future, there is a danger that the past period isn't representative of what the future will hold. Perhaps U.S. investors got lucky over this period and earned particularly large returns. Data from earlier years for the United States is available, though it is not of the same quality. With that caveat in mind, researchers have tracked returns back to 1802, and the U.S. equity risk premium in the pre-1926 era was smaller. Using the U.S. return data from 1802, the historical equity risk premium was 5.4 percent.[3]

Also, we have not looked at other major countries. Actually, more than half of the value of tradable stock is not in the United States. From Table 10.4, we can see that while the total world stock market capitalization was $22.3 trillion in 2011, only about 53 percent was in the United States. Thanks to Dimson, Marsh, and Staunton, data from earlier periods and other countries are now available to help us take a closer look at equity risk premiums. Table 10.5 and Figure 10.11 show the historical stock market risk premiums for 17 countries around the world in the period from 1900 to 2010. Looking at the numbers, the U.S. historical equity risk premium is the 7th highest at 7.2 percent (which differs from our earlier estimate because of the different time periods examined). The overall world average risk premium is 6.9 percent. It seems clear that U.S. investors did well, but not exceptionally so relative to many other countries. The top-performing countries according to the Sharpe ratio were the United States, Australia, South Africa, and France, while the worst performers were

Table 10.4
World Stock Market Capitalization, 2011

Country	$ in Trillions	Percent
United States	$11.9	53%
Europe (excluding U.K.)	3.8	17
Japan	2.2	10
United Kingdom	2.0	9
Pacific (excluding Japan)	1.3	6
Canada	1.1	5
	$22.3	100%

SOURCE: *Ibbotson SBBI 2012 Classic Yearbook*, Morningstar, p. 216.

[3]Jeremy J. Siegel has estimated the U.S. equity risk premium with data from 1802. As can be seen in the following table, from 1802 to 2011 the historical equity risk premium was 5.4 percent.

	Average Returns 1802–2011 (%)
Common stock	9.6
Treasury bills	4.2
Equity risk premium	5.4

Adopted and updated from J. Siegel, *Stocks for the Long Run*, 4th ed. (New York: McGraw-Hill, 2008).

Table 10.5
Annualized Equity Risk Premiums and Sharpe Ratios for 17 Countries, 1900–2010

Country	Historical Equity Risk Premiums (%) (1)	Standard Deviation (%) (2)	The Sharpe Ratio (1)/(2)
Australia	8.3%	17.6%	0.47
Belgium	5.5	24.7	0.22
Canada	5.6	17.2	0.33
Denmark	4.6	20.5	0.22
France	8.7	24.5	0.36
Germany*	9.8	31.8	0.31
Ireland	5.3	21.5	0.25
Italy	9.8	32.0	0.31
Japan	9.0	27.7	0.32
Netherlands	6.5	22.8	0.29
Norway	5.9	26.5	0.22
South Africa	8.3	22.1	0.37
Spain	5.4	21.9	0.25
Sweden	6.6	22.1	0.30
Switzerland	5.1	18.9	0.27
United Kingdom	6.0	19.9	0.30
United States	7.2	19.8	0.36
Average	**6.9**	**23.0**	**0.30**

*Germany omits 1922–1923.

SOURCE: Elroy Dimson, Paul Marsh, and Michael Staunton, Credit Suisse Global Investment Returns Sourcebook, 2011, published by Credit Suisse Research Institute 2011. The Dimson-Marsh-Staunton data set is distributed by Morningstar, Inc.

Belgium, Norway, and Denmark. Germany, Japan, and Italy might make an interesting case study because they have the highest stock returns over this period (despite World Wars I and II), but also the highest risk.

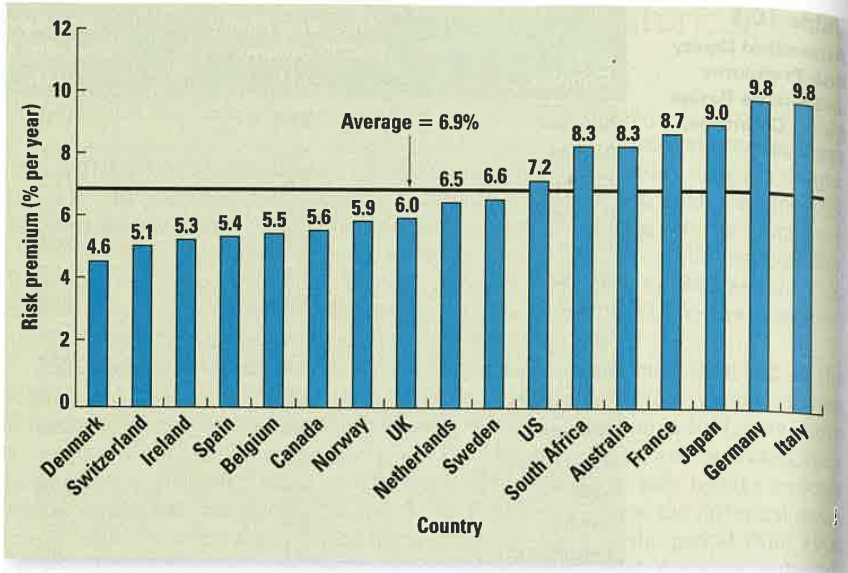
So what is a good estimate of the U.S. equity risk premium going forward? Unfortunately, nobody can know for sure what investors expect in the future. If history is a guide, the expected U.S. equity risk premium could be 7.2 percent based upon estimates from 1900–2010. We should also be mindful that the average world equity risk premium was 6.9 percent over this same period. On the other hand, the more recent periods (1926–2011) suggest higher estimates of the U.S. equity risk premium, and earlier periods going back to 1802 suggest lower estimates.

The standard error (SE) helps with the issue of how much confidence we can have in our historical average of 7.2 percent. The SE is the standard deviation of the historical risk premium and is given by the following formula:

$$\text{SE} = \text{SD}(\overline{R}) = \frac{\text{SD}(R)}{\sqrt{\text{The number of observations}}}$$

If we assume that the distribution of returns is normal and that each year's return is independent of all the others, we know there is a 95.4 percent probability that the true mean return is within two standard errors of the historical average.

Figure 10.11
Stock Market Risk Premiums for 17 Countries: 1900–2010



SOURCE: Elroy Dimson, Paul Marsh, and Michael Staunton, "The Worldwide Equity Premium: A Smaller Puzzle," in *Handbook of the Equity Risk Premium*, Rajnish Mehra, ed. (Elsevier, 2007). Updates by the authors.

More specifically, the 95.4 percent confidence interval for the true equity risk premium is the historical average return ± (2 × standard error). As we have seen from 1900 to 2010, the historical equity risk premium of U.S. stocks was 7.2 percent and the standard deviation was 19.8 percent. Therefore 95.4 percent of the time the true equity risk premium should be within 3.43 and 10.97 percent:

$$7.2 \pm 2\left(\frac{19.8}{\sqrt{111}}\right) = 7.2 \pm 2\left(\frac{19.8}{10.5}\right) = 7.2 \pm 3.77$$

In other words, we can be 95.4 percent confident that our estimate of the U.S. equity risk premium from historical data is in the range from 3.43 percent to 10.97 percent.

Taking a slightly different approach, Ivo Welch asked the opinions of 226 financial economists regarding the future U.S. equity risk premium, and the median response was 7 percent.[4]

We are comfortable with an estimate based on the historical U.S. equity risk premium of about 7 percent, but estimates of the future U.S. equity risk premium that are somewhat higher or lower could be reasonable if we have good reason to believe the past is not representative of the future.[5] The bottom line is that any estimate of

[4]For example, see I. Welch, "Views of Financial Economists on the Equity Risk Premium and Other Issues," *Journal of Business*, 73 (2000), pp. 501–537. Shannon P. Pratt and Roger J. Grabowski ("Cost of Capital: Applications and Examples," John Wiley, 2010) conclude, after reviewing a variety of evidence, that the equity risk premium is in the 3.5 to 6 percent range.

[5]In Elroy Dimson, Paul Marsh, and Mike Staunton, "The Worldwide Equity Premium: A Smaller Puzzle," from *Handbook of the Equity Risk Premium*, R. Mehra, ed., the authors argue that a good estimate of the world equity risk premium going forward should be about 5 percent, largely because of nonrecurring factors that positively affected worldwide historical returns. However, it could be argued that the global financial crisis of 2008–2009 was a negative shock to the stock market that has increased the equity risk premium from its historical levels.

U-21534 | September 9, 2024
MNSC Hearing Exhibits
Ex MEC -124 | Source U-21534 MNSCDE -20.5 with Atts 1,2
Page 11 of 11

the future equity risk premium will involve assumptions about the future risk environment as well as the amount of risk aversion of future investors.

10.8 2008: A Year of Financial Crisis

2008 entered the record books as one of the worst years for stock market investors in U.S. history. How bad was it? The widely followed S&P 500 Index, which tracks the total market value of 500 of the largest U.S. corporations, decreased 37 percent for the year. Of the 500 stocks in the index, 485 were down for the year.

Over the period 1926–2008, only the year 1931 had a lower return than 2008 (−43 percent versus −37 percent). Making matters worse, the downdraft continued with a further decline of 8.43 percent in January 2009. In all, from November 2007 (when the decline began) through January 2009, the S&P 500 lost 45 percent of its value.

Figure 10.12 shows the month-by-month performance of the S&P 500 decline during 2008. As indicated, returns were negative in eight of the twelve months. Most of the decline occurred in the fall, with investors losing almost 17 percent in October alone. Small stocks fared no better. They also fell 37 percent for the year (with a 21 percent drop in October), their worst performance since losing 58 percent in 1937.

As Figure 10.12 suggests, stock prices were highly volatile at the end the year—more than has been generally true historically. Oddly, the S&P had 126 up days and 126 down days (remember the markets are closed weekends and holidays). Of course, the down days were much worse on average.

The drop in stock prices was a global phenomenon, and many of the world's major markets declined by much more than the S&P. China, India, and Russia, for example, all experienced declines of more than 50 percent. Tiny Iceland saw share prices drop by more than 90 percent for the year. Trading on the Icelandic exchange was temporarily suspended on October 9. In what has to be a modern record for a single day, stocks fell by 76 percent when trading resumed on October 14.

Did any types of securities perform well in 2008? The answer is yes, because, as stock values declined, bond values increased, particularly U.S. Treasury bonds. In fact, long-term Treasury bonds *gained* 20 percent, while shorter-term Treasury bonds were up 13 percent. Higher quality long-term corporate bonds did less well, but still managed

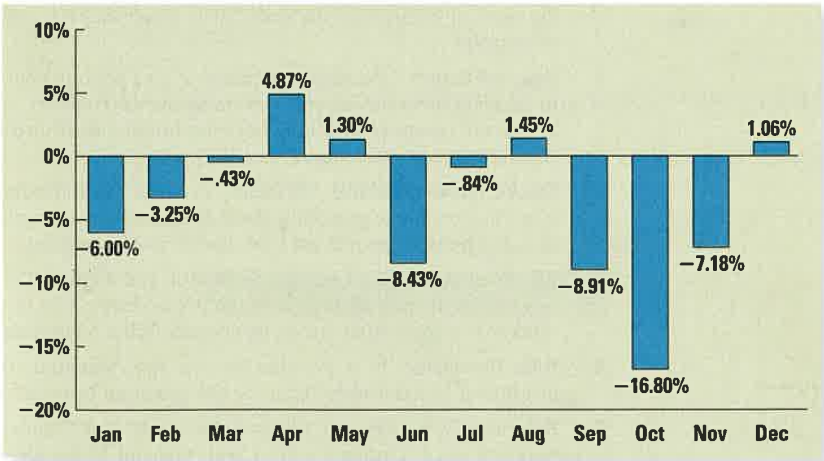


Figure 10.12
S&P 500 Monthly Returns, 2008

MPSC Case No: U-21534

Requester: MNSC

Question No.: MNSCDE-19.1a.

Respondent: A. Willis

Page: 1 of 1

Question: Refer to Willis rebuttal:

Explain in detail what you believe Table 1 demonstrates regarding MNSC witness Gard's analysis.

Answer: As described in the rebuttal testimony of Company Witness Willis (Pg 6, Ln 14) the purpose of Table 1 is "to underscore that there is no specific significance to single v. multifamily or electric space heating as it concerns which usage drivers ought to be considered for their own cost of service class. As is evident from the table, the peak behavior characteristics are not homogenous across different usage levels (as usage goes up, the apparent load factor improves), but that does not mean it is appropriate to use usage as the basis for different residential cost of service classes or rate schedules"

Attachment:

MPSC Case No: U-21534

Requester: MNSC

Question No.: MNSCDE-19.1b.

Respondent: A. Willis

Page: 1 of 1

Question: Refer to Willis rebuttal:

Based on Table 1, do you believe there is no meaningful difference in the cost to serve single-family and multi-family households? If yes, please explain your rationale.

Answer: The Table supports no position on whether or not there is a “meaningful difference in the cost to serve” single v multifamily households. See also the response to MNSCDE-19.1a.

Attachment: *None*

MPSC Case No: U-21534

Requester: MNSC

Question No.: MNSCDE-19.1c.

Respondent: A. Willis

Page: 1 of 1

Question: Refer to Willis rebuttal:

Based on Table 1, do you believe there is no meaningful difference in the cost to serve households with and without electric space heating? If yes, please explain your rationale.

Answer: The Table supports no position on whether or not there is a “meaningful difference in the cost to serve” households with and without electric space heating. See also the response to MNSCDE-19.1a.

Attachment: *None*

MPSC Case No: U-21534

Requester: MNSC

Question No.: MNSCDE-20.16

Respondent: T. Uzenski

Page: 1 of 1

Question: Refer to the rebuttal testimony of witness Uzenski, Q&As 32 to 40, related to capitalization of tree trim expense. Does DTE maintain a written policy, guidance, standards, or otherwise to guide whether tree trim expense is capitalized or expensed? If so, please produce it.

Answer: The Company does not have a comprehensive written policy, but it does apply these standards:

Capital

- Tree trimming to ensure the safety of employees and contractors doing work related to the replacement of a retirement unit is capital.
- Tree trimming that is required for the first installation of a retirement unit is capital.

O&M

- Extended tree trimming beyond what is needed to complete a capital project is expensed.
- Tree trimming to maintain clearances and not tied to a capital project is expensed.
- Spot trimming related to non-capital repairs are expensed.
- Make-safe trimming for customer needs is expensed.

Regulatory Asset

- Tree trim surge costs as approved by the Commission are deferred to the regulatory asset.

Attachment: *none*

MPSC Staff's Answer to the Michigan Environmental Council, Natural Resources Defense Council, Sierra Club and Citizens Utility Board of Michigan First Discovery Request
MPSC Case No. U-21534
August 27, 2024

Question:

1. Refer to Braunschweig rebuttal, p. 6 lines 7-19:

a. Produce a copy of the agendas and minutes of all meetings of the AAA to date.

Answer:

1a. The AAA subcommittee did not always produce agendas ahead of its meetings. I have attached the agendas that were produced. Additionally, the AAA did not produce minutes from its meetings, rather meetings were recorded in place of minutes for all but the first two meetings. See below for all meeting presentations and recordings copied from the AAA website.

A. October 3, 2023

B. Presentation | Recording

C. September 2023

D. No Meeting

E. August 1, 2023

F. Presentation | Recording

G. July 11, 2023

H. Presentation | Recording

I. June 27, 2023

MPSC Staff's Answer to the Michigan Environmental Council, Natural Resources Defense Council, Sierra Club and Citizens Utility Board of Michigan First Discovery Request
MPSC Case No. U-21534
August 27, 2024

J. **Presentation | Recording**

K. May 23, 2023

L. **Presentation | Recording**

M. April 18, 2023

N. **Presentation | Recording**

O. November 10, 2022

P. **Presentation | Recording**

Q. October 10, 2022

R. **Presentation | Recording**

S. September 8, 2022

T. **Presentation | Recording**

U. August 11, 2022

V. **Presentation | Recording**

W. July 14, 2022

X. **Presentation | Recording**

Y. June 9, 2022

Z. **Presentation | Recording**

AA. May 12, 2022

BB. **Presentation | Recording**

CC. April 14, 2022

DD. **Presentation | Recording**

MPSC Staff's Answer to the Michigan Environmental Council, Natural Resources Defense Council, Sierra Club and Citizens Utility Board of Michigan First Discovery Request
MPSC Case No. U-21534
August 27, 2024

EE. **March 10, 2022**

FF. **Presentation | Recording**

GG. **February 10, 2022**

HH. **Presentation | Recording**

II. **January 13, 2022**

JJ. **Presentation**

KK. **December 09, 2021**

LL. **Presentation | Recording**

MM. **November 10, 2021**

NN. **Presentation | Recording**

OO. **October 14, 2021**

PP. **Presentation | Recording**

QQ. **September 09, 2021**

RR. **Presentation**

SS. **August 12, 2021**

TT. **Presentation**

Respondent: Elaina Braunschweig

MPSC Staff's Answer to the Michigan Environmental Council, Natural Resources Defense Council, Sierra Club and Citizens Utility Board of Michigan First Discovery Request
MPSC Case No. U-21534
August 27, 2024

Question:

1b. Produce a copy of the presentations from all meetings of the AAA to date that are not already available at https://www.michigan.gov/mpsc/commission/workgroups/energy-affordability-and-accessibility-collaborative/affordability-alignment-assistance-subcommittee, including presentations from all meetings after October 3, 2023

Answer:

1b. Please see Exhibit No. S-17.2 in the instant case.

Respondent: Elaina Braunschweig

MPSC Staff's Answer to the Michigan Environmental Council, Natural Resources Defense Council, Sierra Club and Citizens Utility Board of Michigan First Discovery Request
MPSC Case No. U-21534
August 27, 2024

Question:

1c. Produce a copy of any governance-related documents for the AAA.

Answer:

1c. The AAA does not have a governance-related document per se, rather a guiding statement, guiding principles, and commission directives. Please see slides 4-5 in the link to the September 9, 2021 presentation listed above for the statement and principles and slide 4 of the August 12, 2021 presentation and slides 5-11 of the April 18, 2023 presentation to view subcommittee charges to date, which have been assigned to the AAA by either the Commission directly or to the EAAC as a whole (and then assigned to the AAA by EAAC leadership) through various cases. See the attached document titled "Commission orders relating to EAAC 2021 2022" that Staff created to collect a list of cases that assigned work to the EAAC, which Staff then used to propose the current AAA (and other EAAC subcommittees') charge in its 3/16/23 report to the Commission and the Commission approved the current AAA charge in its 12/21/23 order.

Respondent: Elaina Braunschweig

MPSC Staff's Answer to the Michigan Environmental Council, Natural Resources Defense Council, Sierra Club and Citizens Utility Board of Michigan First Discovery Request
MPSC Case No. U-21534
August 27, 2024

Question:

1d. Identify any and all proposals, reforms, or changes discussed at AAA meetings that have subsequently become included in DTE Electric tariffs or rates. For each such proposal, reform, or change, identify the AAA meetings where it was discussed.

Answer:

1d. Staff is unaware of any AAA reform proposals or AAA recommendations to the Commission that have led to tariff or rate revisions. However, it's possible the work that the AAA has done and discussions that have taken place could have influenced subsequent testimonies of the parties involved.

Respondent: Elaina Braunschweig

Affordability, Alignment, and Assistance Subcommittee

Elaina Braunschweig (MPSC—Rates and Tariff) Braunschweige@michigan.gov
Jamie Curtis (MPSC—MEAP administrator) CurtisJ14@michigan.gov
Kasey Grieco (SWP MEAP Grantee—Asst. Program Manager) kgrieco@superiorwatersheds.org

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*Meeting presentations, recordings, and materials are shared on the EAAC website in the AAA section

Agenda

1. Goals Background and 2023 Preview
2. Background on LIA issue
3. Presentation and Discussion on DTE LIA report
4. Next Steps

AAA Meeting Scheduling

Survey



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AAA in Review



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Original Subcommittee Charge

The charge of the Affordability, Alignment and Assistance Subcommittee (AAA) is:

- Looking at all aspects of energy affordability including streamlining and making more accessible existing energy assistance programs,
- Researching next generation affordable payment plans,
- Analyzing collections processes,
- Integrating programming with EWR and weatherization, as well as rate design.

Guiding Statement

End the crisis-assistance-crisis cycle by centering energy *affordability* and facilitating customers sustainably affording their energy bills by providing all households with uninterrupted *access* to *affordable*, *sufficient* energy in an *efficient*, *healthy*, and *sustainable* manner.

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*Established by AAA members in September 2021

Guiding Principles

The ideal system/program design should achieve this while also:

- **Ensuring equitable distribution** in the access to, use of, and outcomes from energy affordability and assistance policies/programs
- **Centering impacted community priorities** and participation in policy/program development, accountability, and assessment
- **Treating customers with dignity**, enabling them to live comfortably, and not penalizing customers for an inability to pay their bills
- **Coordinating and communicating clearly** with relevant state agencies to integrate state policy goals, including those related to healthy homes and climate change



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*Established by AAA members in September 2021

Recap of AAA work

- 2021-2022 topics covered
  - → Educated on the customer assistance enrollment journey and details of each assistance program
    - Developed recommendations for improvement in the U-20757 report
    - Developed a customer journey excel file (on our website) to store all relevant information.
  - → Convened EWR ad-hoc group to improve assistance recipient referrals to EWR
- Learn more about how customers move through the energy assistance landscape by reviewing our posted meeting materials from October 2021-February 2022

2022 U-20757 Report

*Glossary of terms on pp. 76-77



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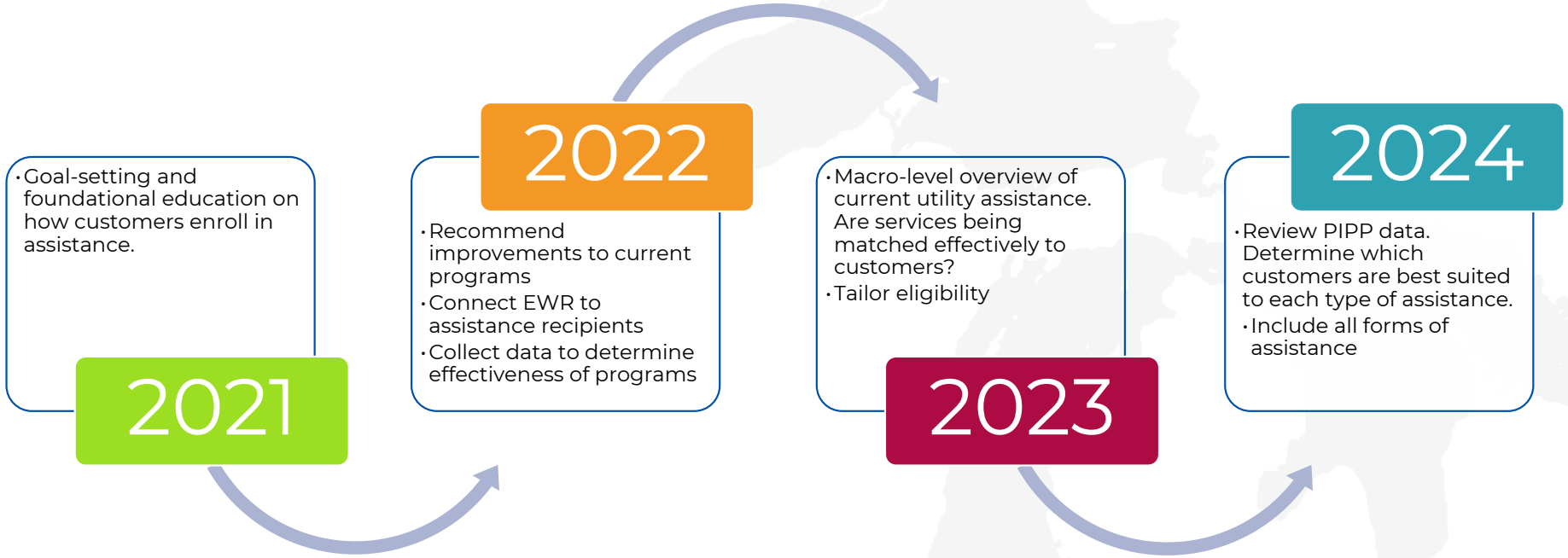
Recap of 2022 U-20757 Report

- Our recommendations (pp.16-25) hope to achieve change by collaborating with other organizations and agencies. However, some issues require legislative change, which is not within the MPSC's authority.
- We requested clarification in the U-20757 report (pp. 16-17) on outstanding AAA Commission directives and in the meantime are focusing on order compliance this year. The Commission has assigned the EAAC many tasks that we invite you to collaborate with us on.
- If issues in the current customer journey come up in future, we can address them in our annual 20757 report.

Proposed 2023-2024 AAA Charge p. 58— Awaiting Commission Approval

- Initiate a stakeholder discussion of DTE's report on the enrollment of customers in the LIA credit program and submit a report and recommendations to the Commission.
- Discuss the LIA/RIA enrollment assignment, enrollment cap, and best use/program pairings.
- Evaluate the feasibility of a low-income customer subclass in the Cost-of-Service-Study (COSS)
- Develop a proposal for an energy affordability standard and how the standard can be integrated into the regulatory environment.
  - → Look at all aspects of energy affordability including rate design.
  - → Look at all aspects of affordability utilizing the definition of energy affordability.
  - → Map where assistance and affordability tools intersect with aspects of affordability.
- Evaluate and make recommendations regarding PIPPs. (2024)

The AAA Timeline



Overarching Charge of the LIEPB

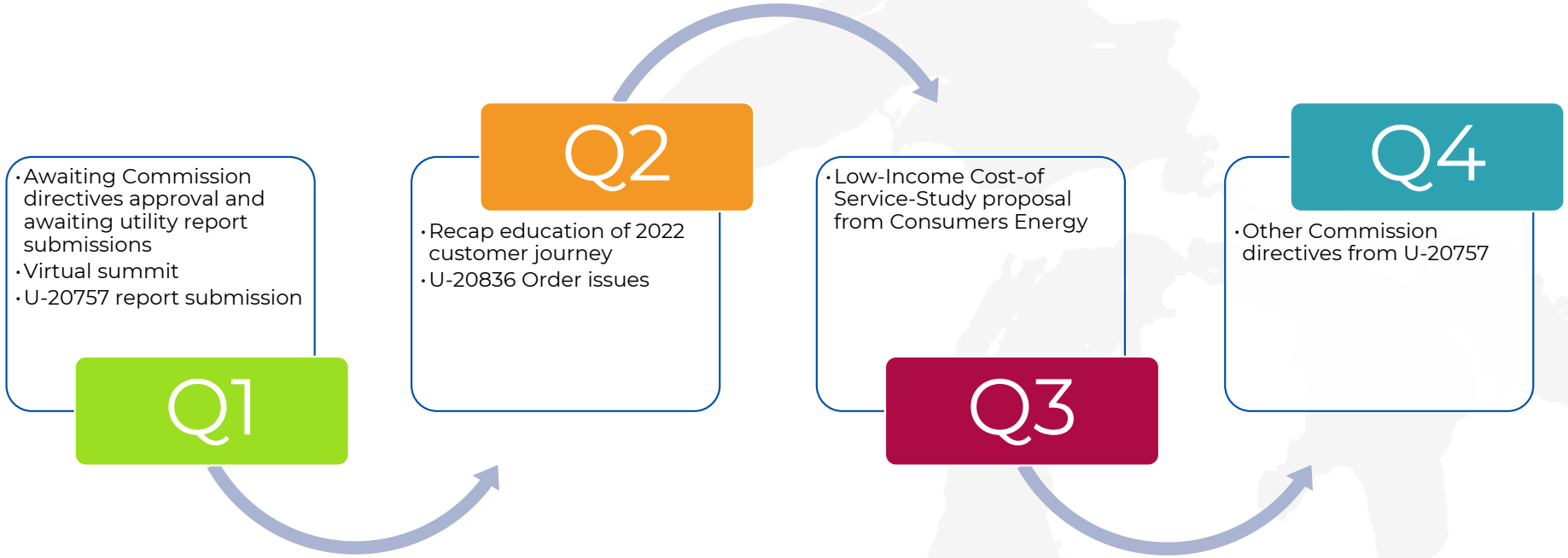
- The overall goal of the work of the EAAC is to define and ensure energy affordability, accessibility, and security/self-sufficiency in collaboration with the EWR-LI and the LIEPB (its advisory organization) as stated by the Commission through Case No. U20757.
- To build on these directives, the LIEPB set their primary purpose as "guiding the process of assessing energy affordability and accessibility holistically, especially through linking EWR services and energy assistance programs."
- They set as their overarching goal "to reduce the number of households with unsustainable energy burdens." All work of the Board, EAAC, and EWR-LI Workgroup flowed from this purpose and goal.

Accomplishing Goals in 2023-2024



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Potential Timeline for 2023



*This timeline is tentative and subject to change based on the priorities of the AAA members

Goals Structure

1
- **Choose a goal**
- Solicit input on changes members would like to see in said program or goal using the guiding question/subcommittee charge parameters

2
- **Research the goal**
- Have organization who runs that program (utilities/Staff/DHHS) provide background knowledge/limitations of that program

3
- **Identify solutions**
- Bring to Low-Income Energy Policy Board for greater review

4
- If appropriate, collaborate with the responsible organization
- **Propose to the Commission**

Progress

Goal: customer journey
- Recommendations in 2022 U-20757 report

Goal: Do our assistance programs work?
- Data collected
- Analyzing utility systems in 2023

Adding new sub-goals in 2023

Objective 1

Initiate a stakeholder discussion of DTE's report on the enrollment of customers in the LIA credit program and submit a report and recommendations to the Commission.

Discuss the LIA/RIA enrollment assignment, enrollment cap, and best use/program pairings.

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Low Income Assistance Credit (LIA) Pilot History

- **What**: $40 monthly credit
- **Why**: DTE proposed the LIA in 2015 to mitigate payment crises and manage DTE uncollectible expense and improve the collection process.
  - The Residential Income Assistance (RIA) credit was chosen to be equal to the monthly customer charge as a way to fulfill MCL-460.11 because it credits the monthly amount a customer cannot control.
- **Who**: Confirm with DTE
- **How**: the tariff does not distinguish enrollment methods—rather states "customers who select this pilot"
  - Case No. U-17767 (2015) originally assigned qualified customers randomly
  - Mentioned in DTE testimony in Case No. U-18255 (2018) that they applied LIA LSP customers

*Low Income Self Sufficiency Plan (LSP) is DTE's Affordable Payment Plan (APP)

12/11/15 U-17767

- DTE proposed, and was approved, to start a pilot called the Residential **Service Special Low Income Pilot tariff** on rate D1.6, which was the standard residential rate (D1) with **a $40 monthly credit to 32,000 qualifying customers**. To qualify, customers had to have **12-month historical usage levels less than $1,700 and an income at or below 150% of the federal poverty level**. No metrics were established to evaluate the effectiveness of the credit, nor was the purpose of the credit stated/approved by the Commission. (12/11/15 Order, pp. 130-132).

- Tariff found in Appendix 1

DTE's Intent for LIA in U-17767

- "The D1.6 tariff that DTE Electric proposes to pilot will **provide proactive assistance** to eligible low-income customers that will make their utility bill more affordable. As experienced through past and current low-income programs, proactive solutions provide vulnerable customers assistance that **mitigates the occurrence of a crisis situation**. As a result, **efficiencies in the collection cycle** are gained, thereby enabling DTE Electric to **manage its arrears and uncollectible expense**." (Direct Testimony of Company witness Tomina, pp.15-16)

4/18/18 U-18255

- DTE is approved to remove the billing cap of $1,700 and to average out the enrollment of 32,000 over the year (4/18/18 Order, pp.82-83).

  - → Tariff found in Appendix 1
  - → No other orders changed the D1.6 LIA rate. U-20561 ordered the exploration of what became the Payment Stability Plan pilot (a form of PIPP) and U-20836 ordered the EAAC to discuss the LIA and produce a report.

11/18/22 U-20836 Commission Order, p. 407

- Finding the ALJ's recommendations to be well-reasoned and supported by the record, **the Commission adopts the ALJ's recommendations regarding the RIA/LIA programs**. While the Commission understands the calls for urgency expressed by the DAAOs and recognizes that energy affordability is a critical issue for many DTE Electric ratepayers, the Commission agrees with the ALJ that **the EAAC is in the best position to assess the issues of the enrollment assignment and caps as well as potential revisions to the LIA credit**. The Commission further finds that a report detailing DTE Electric's current enrollment practices would be informative and beneficial to the EAAC's discussion of the issue. Therefore, the Commission directs DTE Electric to file, within 120 days from the date of this order, **a report detailing the company's current approach to enrolling customers in the LIA credit program with current enrollment data from 2021 and 2022 (through the end of 2022).** The report shall be filed in Case No. U-20757. Following the submission of DTE Electric's report, the Commission directs the EAAC to initiate, according to a format and schedule set by the collaborative, **a stakeholder discussion of the company's report on the enrollment of customers in the LIA credit program and submit a report and recommendations to the Commission**.

*The ALJ's (administrative law judge) PFD (proposal for decision) is Appendix 2

Order Compliance Objectives

1. Analyze the use and effectiveness of the LIA credit
2. Decide on the best use of the credit
   - We could maintain the current approach
   - We could consider ways of using the credit to further equity or focus on impacted communities
   - We could propose reformatting RIA and LIA
   - Consider MEAP's broader goal of matching service with customer cohorts
3. Determine a clear and consistent approach across utilities
   - Consider utilities with vastly different revenues
   - Consider if an enrollment cap is appropriate
4. Determine what success looks like/if success is appropriate
5. Determine end-date or approval necessities of this pilot
6. Survey to determine support based on types of AAA members
7. File report to the Commission

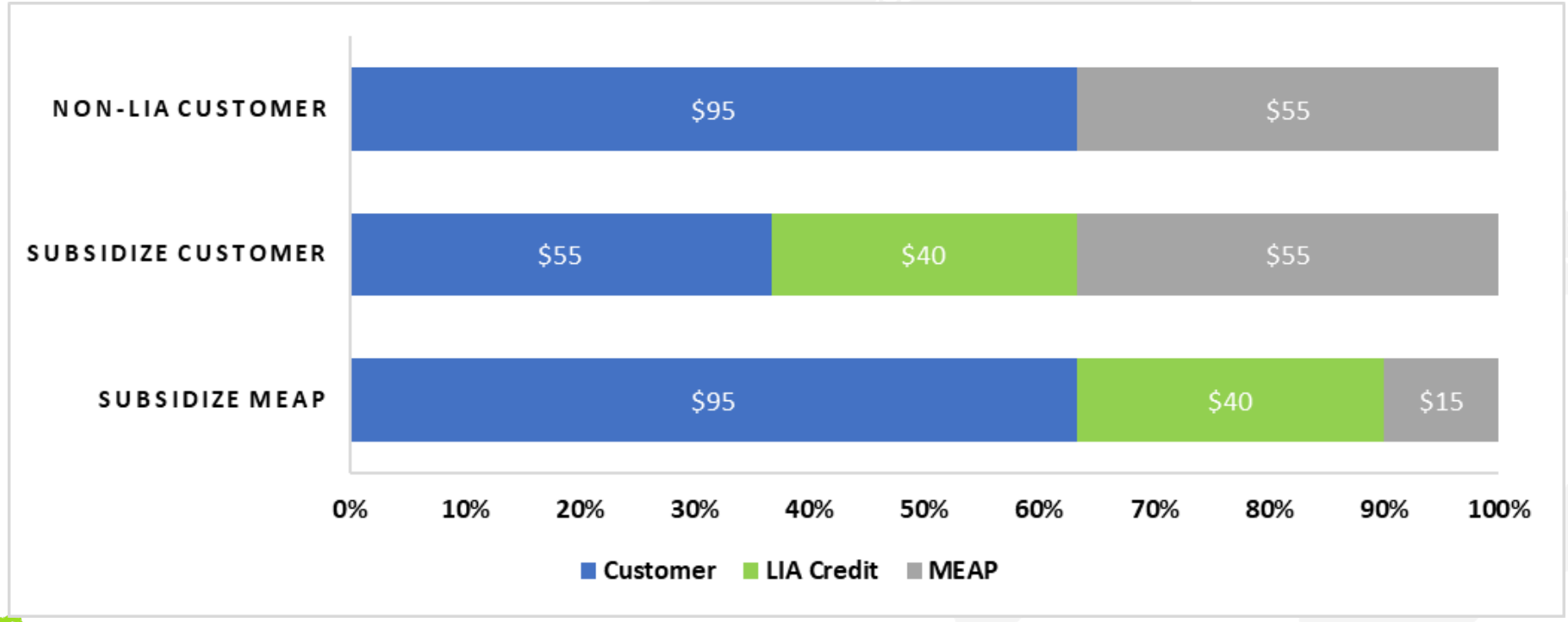
DTE Report Presentation



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Clarity Questions

- Are all LIA recipients LSP (APP) recipients?
- Which best demonstrates how LIA-LSP customers' bills are broken down, based on a sample bill size of $150?



Brainstorm: Goal of Credit

- Today's intent is not to debate past Commission decisions or testimonies, rather consider the future of this type of assistance.
  - First, will DTE briefly outline the current goal of the credit?
  - Then, the group can share thoughts on what they believe the goal of the credit could/should be going forward.
    - This discussion could include the RIA too

Please raise your hand before speaking and do not interrupt anyone or debate their ideas. Vetting proposals will come later. Thank you.

Next Steps

Next Meeting:

Continue discussion on LIA credit
Lay out options for the credit

Data:

Data and education materials are on our website and will be used for reference as we analyze affordability and assistance on a macro level this year.

Goals:

Notify us if you have any goals for the group in 2023 or issues that concern you.
We are currently working on directives that have been directed to the EAAC through Commission orders.

Leadership:

Come to us with any concerns or ideas!

Appendix 1: DTE LIA Tariff

❑ 12/11/15 U-17767 LIA Tariff

LIA Rate D1.6 Tariff Language Sheet No. D-12.01 from Canceled Rate Sheets from MPSC#1:

Customers who select this pilot rate must qualify for the Residential Service rate D1 and must have been billed by the Company $1,700 or less over the last 12 months. To qualify for this pilot rate a customer must also provide annual evidence of receiving a Home Heating Credit (HHC) energy draft or warrant, or must provide confirmation by an authorized State or Federal agency verifying that the customer's total household income does not exceed 150% of the poverty level as published by the United States department of health and human services or if the customer receives any of the following: i) Assistance from a state emergency relief program; ii) Food stamps or iii) Medicaid. Service under this rate shall be limited to 32,000 customers.

❑ 4/18/18 U-18255 LIA Tariff (currently still in effect)

LIA Rate D1.6 Tariff Language Sheet No. D-12.01 from Canceled Rate Sheets from MPSC#1:

Customers who select this pilot rate must qualify for the Residential Service rate D1. To qualify for this pilot rate a customer must also provide annual evidence of receiving a Home Heating Credit (HHC) energy draft or warrant, or must provide confirmation by an authorized State or Federal agency verifying that the customer's total household income does not exceed 150% of the poverty level as published by the United States department of health and human services or if the customer receives any of the following: i) Assistance from a state emergency relief program; ii) Food stamps or iii) Medicaid. Service under this rate shall be limited to an average of 32,000 customers.

Appendix 2: U-20836 Proposal for Decision pp. 662-663

- This PFD recommends that the company file a report detailing its current approach to enrolling customers in the LIA credit program, as well as current (2021 and 2022 to date) enrollment data. Once DTE's report is filed, this PFD recommends that the parties engage in discussions through the Energy Affordability and Accessibility Collaborative (EAAC). Among the topics to consider is Staff's recommendation that LIA credits be randomly assigned monthly. In conjunction with that discussion, to provide some continuity for customers, it would be appropriate for the parties to discuss raising the enrollment cap. While a random selection may be best, it is unclear on this record whether that selection must be made monthly as Staff argues, or if there could be an agreed upon time period for enrollment, which would provide opportunity for DTE to coordinate with its LSP program. The other "clarifying" changes DTE and Staff propose appear to be unnecessary to address at this time.
- Consistent with the general recommendations in this PFD that pilot results should be evaluated before further decisions are made, this PFD finds Staff's analysis persuasive and recommends that potential changes to the LIA credit, including adoption of a PSP-type program, be evaluated through the EAAC.

U-20697

Pages 12-13:

In light of the September 10, 2020 order in Case No. U-20650 (which included Consumers' agreement to develop a PIPP pilot for natural gas service), and the Commission's ongoing efforts in Case No. U-20757, as well as the conclusions of the December 15 report, the Commission went on in the December 17 order to state:

> the Commission finds it reasonable to direct Consumers to develop a PIPP pilot for its electric service. The Commission agrees with the ALJ that a low-income collaborative would be beneficial to develop the pilot, as well as to address other issues surrounding energy affordability, including many of the points raised by the MEC Coalition and the Attorney General. The Commission notes that on December 15, 2020, the Staff issued a report pursuant to a Commission directive in Case No. U-20757, detailing its findings and recommendations regarding energy affordability concerns that have been heightened in light of the COVID-19 pandemic. The Commission observes that the Staff's report will serve as a good starting point for the low-income workgroup. Therefore, the Commission directs the Staff to convene a low-income collaborative, with the participation of Consumers, to address energy affordability. In this collaborative, Consumers shall provide a proposal for a PIPP pilot for its electric service. ¶ As noted by the ALJ, the Commission's COVID-19 response, as well as emergency relief efforts, are being addressed in Case No. U-20757. PFD, p. 357, n. 1141. The Commission agrees that COVID-19-related relief and utility responses are better addressed in the existing Case No. U-20757 docket, and therefore, adopts the ALJ's recommendation. December 17 order, pp. 262-263; see, July 23, 2020 and February 18, 2021 orders in Case No. U-20757.

Thus, the Commission rejects the petitioners' argument that the December 17 order maintained the status quo. In the order, the Commission adopted an increased RIA credit and a substantial LIA credit (with the appropriate required funding), directed the development of a PIPP pilot, and directed the commencement of a low-income collaborative. 2 The Commission finds that it addressed all of the proposals and objections presented by the AG/MEC Group in the underlying proceeding, and that the determinations in the December 17 order were not based on a misunderstanding, but rather were based on consideration of the full record and the parties' arguments.

Additionally, as the Staff points out, the AG/MEC Group's petition for rehearing seeks a form of relief which was not presented by any party to the proceeding, namely the addition of $12.5 million to the utility's budget for low-income programs untethered to any particular credit proposal or eligible customer group. As the Commission often states, a petition for rehearing is not a vehicle for simply repeating arguments that were considered and rejected in the underlying proceeding. It is also true that a petition for rehearing is not a vehicle for seeking forms of relief that were not part of the underlying proceeding and for which the record is devoid of support. The Commission is required to examine whether rates are just and reasonable, and whether proposed rates reflect the cost of providing service to each customer class. MCL 460.11(1), (2); see, Ford Motor Co v Pub Serv Comm, 221 Mich App 370, 374; 562 NW2d 224 (1997). A requested increase to the utility's revenue requirement that includes no direction as to how the money is to be spent does not constitute a reasonable proposal for inclusion in rates. The Commission finds that the AG/MEC Group has not demonstrated that the December 17 order requires revision.

Summary:

In light of U-20650 and U-20757, the Commission directs Consumers to develop a PIPP pilot for electric service. The Commission agrees with the ALJ that a low-income collaborative would be helpful with the pilot's development, especially with energy affordability concerns that have been heightened due to COVID-19. Thus, the Commission directs Staff to convene a low-income collaborative with Consumers to ensure energy affordability. This order therefore repudiates petitioners' arguments that the December 17 order maintained the status quo, as the Commission in that order did several things, including the commencement of a low-income collaborative. All of this, along with other supporting evidence, shows that the Commission does not need to make any revisions to the December 17 order.

U-20940

Page 218:

…As well, the Commission is currently engaged in the Energy Affordability and Accessibility Collaborative, which will also inform its future decisions related to low-income programs and pilots…

U-20963

Pages 330-331:

The ALJ concluded that Consumers should be authorized to proceed with Phase 1 of its pilot, with the obligations to report on the Phase 1 pilot learnings to the Commission's Energy Affordability and Accessibility Collaborative (EAAC), and to consult with that group and conduct additional stakeholder outreach before proceeding to Phase 2. The ALJ recognized that Phase 1 of the pilot is focused on gathering the information that can develop the more detailed programmatic objectives and methods MNSC is calling for. And, as outlined in Consumers' reply brief, the ALJ noted that there will be opportunity for stakeholder engagement before Consumers seeks approval from the Commission to proceed to Phase 2. The ALJ also noted that the costs associated with Phase 1 of this pilot are modest at approximately $700,000. PFD, p. 461

In exceptions, the company clarifies that it is requesting to move forward with Phase 1 and Phase 2 of the low-income pilot, and the costs incorporated into this case are for both phases of the pilot. The company explains that the learnings from Phase 1 of the low-income DR pilot will allow the company to develop specific objectives for Phase 2 of the pilot. Accordingly, the company requests that the Commission approve the low-income DR pilot as originally proposed. Consumers' exceptions, pp. 325-327.

In replies to exceptions, MNSC argues that Consumers does not articulate any reason the Commission needs to approve Phase 2 of the pilot in this proceeding. Additionally, MNSC states that, given the opportunity that this program has the potential to begin to incorporate equity considerations into pilot design in Phase 2, it is reasonable and appropriate to delay approval of Phase 2 to a subsequent proceeding when there is more development and detail. MNSC requests that the Commission adopt the ALJ's recommendation. MNSC's replies to exceptions, pp. 106-109. The Commission finds the ALJ's reasoning to be sound and adopts her recommendation.

The Commission approves the Phase 1 pilot and directs the company to work with the EAAC, stakeholders, and parties to develop more specific equity related metrics for any Phase 2 request for future ratemaking. The Commission suggests that the company provide more investigation, insight, and detail in its next general electric rate case.

Pages 394-395:

Consumers argued that, as a general matter, it does not currently have the ability to collect all the requested data, and is unsure of the amount of time or cost involved. Consumers' initial brief, pp. 491-492; Consumers' reply brief, pp. 229-231. In rebuttal, Consumers noted the ongoing collaborative in Case No. U-20757, its belief that the objectives of the EAAC are the same objectives that MNSC is seeking with its recommendations, and that the collaborative will form the foundation for prioritizing equity in decision-making. 4 Tr 459-460.

MNSC argued that Consumers' rebuttal illustrates the shortcomings of the company's approach. MNSC argued that Consumers did not address the company's ability to make data available on a census tract level, but contended instead that MNSC is not asking the company to perform a one-one-one match of customers to programs, outage information, census data, arrearages, or other sources. MNSC noted that the company has the addresses of customers who participate in low-income programs, who are in arrears for long periods, and who face shutoffs. MNSC asserted that Consumers could, at a minimum, examine the information it already has to determine what additional data it needs to collect. MNSC disputed that the EAAC is an effective substitute for evaluating equity in Consumers' own provision of service. MNSC's initial brief, pp. 199-202.

Further, MNSC recommended that the Commission work with Consumers' (and other utilities) to develop plans and programs which would inform future rate case filings, EWR, voluntary green pricing, renewable energy plan cases, DR cases, and pilot program proposals, ex parte applications, and other relevant dockets to ensure equity is a consistent thread throughout Consumers' (and other utilities') services and offerings to its customers. In implementing this request for relief, MNSC recommended that the Commission work with "communities, community leaders, academia, and other stakeholders to elevate outreach, education, and testing and deployment of services, and require utilities to report on the effectiveness of outreach campaigns for different communities." Id., p. 202. MNSC noted that this would be consistent with the Commission's commitment to identify opportunities to promote DE&I in a fundamental, meaningful manner and to include DE&I context in regulatory strategies. Id., p. 203

Page 398:

The Commission agrees with the ALJ that these questions should be addressed by all interested persons and, as the ALJ recommended, the workgroups and other dockets should develop DE&I analyses, metrics, and data requirements that inform numerous cases. The Commission continues to examine how best to apply DE&I best practices and principles in this and other proceedings. Specific guidance will be provided through other venues including the EAAC order in Case No. U-20757, orders in Case No. U-18238, and Emergency Preparedness, Distribution Reliability, and Storm Response orders in Case No. U-21122

Pages 401-403:

The ALJ agreed, to some degree, with all the parties weighing in on this issue. The ALJ found persuasive the Staff's and the company's claim that MNSC's analysis was flawed to the extent that the resulting cost of service versus the actual bill comparisons cannot be relied upon. At the same time, she

noted that MNSC's demonstration that energy usage by low-income customers at peak times is significantly lower than that of generic customers was not challenged. Moreover, the ALJ stated, MNSC's argument that programs, and bill credits apply only to a fraction of Consumers' low-income customers is persuasive to the extent that a low-income subclass within the residential class might serve to include more of these customers who need assistance. Consistent with the foregoing discussion, the ALJ found that MNSC's request that the company present a refined COSS including a low-income subclass in its next general electric rate case should be rejected. Instead, the ALJ recommended that Consumers be directed to present a COSS, with low-income customers in a separate subclass, as part of the ongoing EAAC. PFD, p. 543.

In exceptions, Consumers agrees with the ALJ about rejecting MNSC's request for a low-income subclass in the next general electric rate case. However, the company disagrees with the ALJ's recommendation that it provide a COSS with low-income customers as a separate subclass as part of the ongoing EAAC based on the ALJ's contention that this might help more customers who need assistance. Consumers argues that by design, the COSS is a simplified representation of how customers use the system and is not intended to calculate the cost to serve individual customers, and therefore the recommendation should not be adopted. Consumers' exceptions, pp. 329-332.

In exceptions, the Staff argues that the ALJ erred in finding that the Staff did not dispute MNSC's demonstration that energy usage by low-income customers at peak times is significantly lower than that of generic customers; the Staff asserts that it challenged the demonstration on page 35 of its reply brief. However, the Staff agrees with the ALJ's recommendation to reject MNSC's proposal. Staff's replies to exceptions, pp. 12-13.

In replies to exceptions, MNSC contends that the Staff did not object to the COSS with a low-income customer subclass being required for the EAAC. MNSC also notes that Consumers acknowledges that it would be feasible to break out a subclass of low-income customers in the COSS. MNSC argues that the record shows that it is certainly feasible for Consumers to do this, but it is also apparent that the company will need the Commission's direction to make it happen. MNSC requests that the Commission adopt the ALJ's recommendation to direct Consumers to present a cost of service with low-income customers in a separate subclass, as part of the ongoing EAAC. MNSC's replies to exceptions, pp. 109-119.

The Commission agrees with the ALJ that all parties made valid points and ultimately the Commission agrees that a COSS with a low-income customer subclass may be beneficial and recommends the company include a low-income customer subclass in the COSS for the EAAC in Case No. U-20757, but does not require it for the company's next general electric rate case.

Summary:

The ALJ recommended and MNSC argued in exceptions to PFD that Consumers did not yet need to move onto Phase 2 of its pilot until further data was given from Phase 1 to the EAAC workgroup. The Commission agreed with the ALJ's recommendations (and MNSC) that while Consumers could complete Phase 1, the Company should first report the findings from Phase 1 before moving onto Phase 2.

Consumers also argued that they don't have the ability to collect all the needed information for the project (DE&I efforts) and that the objectives of the EAAC are the same as those MNSC is seeking. In turn, MNSC argued that this shows that Consumers' approach to the project is inherently flawed. MNSC contends that Consumers could at least examine the

information it already has in order to discern what additional information it should collect. MNSC also disputed that the EAAC is an appropriate substitute for evaluating equity in Consumers' service and recommended that the Commission work with Consumers, along with other utilities, to develop plans to assist with equity efforts across multiple programs/workgroups. The Commission agreed with the ALJ that questions relating to DE&I should be addressed by all interested parties/persons and that workgroups should develop DE&I metrics, data, etc.

The Commission agreed with the ALJ that a COSS with a low-income customer subclass would be beneficial and therefore recommends that Consumers include a low-income customer subclass in the COSS for the EAAC for U-20757, but it is not required for Consumers' next electric rate case.

U-20881 & U-20876

Pages 11-12:

Reporting. DTE Gas will develop and make available a Microsoft SharePoint or similar site that provides access to all reporting items mentioned in Attachment C. Stakeholders will be notified when new content is added. DTE Gas will respond to any inquiries about reported items and/or host at least two meetings per year with stakeholders. Additional meetings and materials will be held with the EWR Collaborative and EWR Low-Income Workgroup, and/or Energy Affordable and Accessibility Collaborative upon request. DTE Gas will provide a status updates on items included within this settlement agreement within its annual reconciliation filings. Customer data and information provided on this SharePoint (or similar site that provides access to any reporting items) will comply with current Commission data and privacy regulations. All data collection is subject to future Commission regulation on the collection, storage, and dissemination of customer information whether individual or in aggregate. Although the information reported on this site may only be accessed by Stakeholders, the information will be considered public for purposes of the Company compliance with current and future Commission customer data privacy regulations.

Pages 17-18:

Phase 2

3. Interim presentation of customer research findings and customer engagement metrics to Low Income Working Group and Energy Affordability and Accessibility working group. presentation to be included on working group websites

4. Final presentation to Low Income Working Group and Energy Affordability and Accessibility Working Group presentation to be included on working group websites.

Phase 3

3. Presentation of draft plan to Low Income Working Group and Energy Affordability and Accessibility Working Group (Presentation will be made available for public comment to DTE Gas)

5. Final presentation to Low Income Working Group and Energy Affordability and Accessibility working group.

Summary:

DTE Gas will develop and make available a SharePoint or similar site that provides access to all reporting items to stakeholders. Stakeholders will also be notified when new content is added. DTE will also host at least two meetings per year with stakeholders and hold additional

meetings, including with the Energy Affordability and Accessibility Collaborative, upon request, along with providing status updates to various stakeholders. Data collection will comply with current Commission data and privacy regulations. The second chunk discusses a presentation of customer research findings to different workgroups during two phases.

U-21021

Pages 3-5:

The Commission has reviewed the amended application with attached support, along with the Staff's recommendation, and finds that the amended application is reasonable, is in the public interest, and should be approved, subject to the recommendations made by the Staff. First, the Commission underscores that, as agreed to in Case No. U-20650, current funds will be used cover the costs for the pilot. Second, while the Commission does not find that customers in the pilot should be required to participate in EWR programs as a condition of participating in the PIPP, the Commission does however believe that a better balance to the promotion and use of such programs by PIPP participants should be more than simply by invitation. As shown in the Commission's Energy Affordability and Accessibility Collaborative,3 EWR and energy assistance are closely tied together, in that EWR can play an important role in assisting utility customers in reducing their energy consumption and thereby reduce their energy burden over the long-term. Further, it is a priority of the collaborative and its stakeholders to ensure that customers use EWR services to decrease their energy needs. The Commission thus finds that, wherever practicable, Consumers should automatically refer PIPP participants, upon enrollment, to the company's EWR program servicers to do an assessment on each participant's needs and recommend appropriate EWR services. Recommendations should include, but are not limited to, EWR weatherization kits, if appropriate based on the assessment. With this, the Commission finds that Consumers should also document which EWR services are delivered to each PIPP participant using the reporting template developed for the Low-Income Home Energy Assistance Program Direct Support Program and work with the Staff to determine the correct data elements to specifically include in this report. Third, it is the Commission's understanding that costs for this pilot will also include administrative funding for the experienced, community-based human service agencies that will be administering this proposal in this case, as such agencies have many benefit programs to administer with increased commitments during the continuation of the COVID-19 pandemic.

The Commission finds that Consumers' proposal, with the above conditions, will provide meaningful insight into the current status of energy affordability for low-income customers, along with possible modifications to existing energy assistance programs that could lead to more successful and/or diversified options moving forward. Additionally, given the approval of the company's voluntary refund request in the May 13, 2021 order in Case No. U-20932 (May 13 order), including Consumers' specific request to use $1 million of the voluntary refund to partially fund the implementation of the PIPP once approved,4 the Commission finds that the company can now, in conjunction with the approval provided in this order, use its requested voluntary refund funds for PIPP-related IT costs. Lastly, because approval of the company's request in the instant case will not result in an increase in the cost of service for any customer, the Commission finds ex parte review and approval to be appropriate. See, MCL 460.6a(3).

THEREFORE, IT IS ORDERED that Consumers Energy Company's amended application for a percent of income payment plan pilot for both electric and natural gas service is approved, as set forth in the order.

The Commission reserves jurisdiction and may issue further orders as necessary.

Summary:

This mostly concerns EWR, noting that EWR and energy affordability/assistance are closely tied together and that if customers can use EWR to decrease their energy consumption and therefore their energy burden long-term. The Commission also found that Consumers' proposal will provide meaningful insight into the current status of energy affordability for low-income customers.

U-20875

Page 16:

28. Reporting. For all reporting identified above, and unless otherwise reflected, Consumers Energy will provide reporting and status updates on data and reporting items and settlement item progress overall in biannual update meetings with the parties and in annual reconciliation reports, (certain reporting items (as named above) will begin with the 2023 EWR Reconciliation). Updates and reporting on these items will also be provided at the EWR Collaborative, EWR Low-Income Workgroup, and/or the Energy Affordability and Accessibility Collaborative at least once a year.

Attachment B, page 5:

Data / Reporting Commitments

The reporting listed below will be included in the EWR Annual Report, filed with the Company's annual EWR Reconciliation. The Company will also provide a multifamily program status update to interested parties in biannual update meetings and at the EWR Collaborative, EWR Low-Income Workgroup, and/or the Energy Affordability and Accessibility Collaborative at least once a year (as noted in paragraph 28 of the Settlement Agreement). Consumers Energy will also meet with interested stakeholders in Q3 or Q4 2022 to assess and potentially update this list of reporting items.

Summary:

Consumers will provide reporting and status updates on data and reporting items, et al, in biannual meetings with all parties and in annual reconciliation reports. Consumers will also provide a multifamily program status update to interested parties in biannual updates meetings, at the EWR Collaborative, EWR Low-Income Workgroup, and/or the Energy Affordability and Accessibility Collaborative at least once a year.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of **DTE ELECTRIC COMPANY** for authority to increase its rates, amend its rate schedules and rules governing the distribution and supply of electric energy, and for miscellaneous accounting authority.	Case No. U-21534

Proof of Service

On the date below, an electronic copy of **Official Exhibits and Exhibit List of Michigan Environmental Council, Natural Resources Defense Council, Sierra Club, and Citizens Utility Board of Michigan** was served on the following:

Name/Party	E-mail Address
Administrative Law Judge Hon. Sally Wallace	wallaces2@michigang.gov
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PROTEC (The Michigan Coalition to Protect the Public Rights of Way) Michael J. Watza	 mike.watza@kitch.com

{signature on following page}

The statements above are true to the best of my knowledge, information and belief.

Troposphere Legal, PLC
Counsel for MEC, NRDC, SC & CUB

Date: September 17, 2024 By: 

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STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of **DTE ELECTRIC COMPANY** for authority to increase its rates, amend its rate schedules and rules governing the distribution and supply of electric energy, and for miscellaneous accounting authority.	Case No. U-21534

Confidential Proof of Service

On the date below, an electronic copy of **Official Exhibits of Michigan Environmental Council, Natural Resources Defense Council, Sierra Club, and Citizens Utility Board of Michigan** was served on the following:

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The statements above are true to the best of my knowledge, information and belief.

Troposphere Legal, PLC
Counsel for MEC, NRDC, SC & CUB

Date: September 17, 2024 By: 

Digitally signed by Breanna Thomas
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