ENVIRONMENTAL LAW
& POLICY CENTER

August 22, 2025

Ms. Lisa Felice
Michigan Public Service Commission
7109 W. Saginaw Hwy.
P. O. Box 30221
Lansing, MI 48909

RE: MPSC Case No. U-21860

Dear Ms. Felice:

Attached for paperless electronic filing is the Direct Testimony and Exhibits of William D. Kenworthy, Curt Volkmann, and Boratha Tan on behalf of The Ecology Center, The Environmental Law & Policy Center, Union of Concerned Scientists, and Vote Solar (collectively the "Clean Energy Organizations" or "CEO").

Sincerely,

Daniel Abrams (P87696)
Environmental Law & Policy Center
35 E Wacker Dr., Ste. 1600
Chicago, IL 60601
312-673-6500
dabrams@elpc.org

cc: Service List, Case No. U-21860

STATE OF MICHIGAN
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-21860

DIRECT TESTIMONY OF

WILLIAM D. KENWORTHY

ON BEHALF OF

THE ECOLOGY CENTER, THE ENVIRONMENTAL

LAW & POLICY CENTER, UNION OF CONCERNED SCIENTISTS, AND

VOTE SOLAR

August 22, 2025

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I. <u>Witness Identification and Qualifications</u>

Q: Please state for the record your name and business address.

A: My name is William D. Kenworthy (he/him). My business address is 1 S. Dearborn Street, 20th Floor, Chicago, Illinois 60603.

Q: By whom are you employed and in what capacity?

A: I serve as Senior Regulatory Director - Midwest for Vote Solar. I oversee policy development and implementation related to large-scale and distributed solar generation in the region. I also review regulatory filings, perform technical analyses, and testify in commission proceedings on issues relating to solar generation.

Vote Solar is an independent 501(c)(3) nonprofit working to repower the U.S. with clean energy by making solar power more accessible and affordable through effective policy advocacy. Vote Solar seeks to promote the development of solar at every scale, from distributed rooftop solar to large utility-scale plants. Vote Solar has over 90,000 members nationally, including over 2,700 members in Michigan. Vote Solar is not a trade organization, nor does it have corporate members.

Q: On whose behalf are you submitting this direct testimony?

A: I appear here in my capacity as an expert witness on behalf of the Ecology Center, the Environmental Law & Policy Center, the Union of Concerned Scientists, and Vote Solar. I refer to these parties collectively in this case as the Clean Energy Organizations, or "CEO."

Q: Please summarize your qualifications, experience, and education.

A: I have over 30 years of experience in the energy industry in both the public and private sectors working in the renewable energy business and in energy policy. Of that experience, I spent eight years in solar energy project development working primarily on commercial and industrial distributed solar projects in the Midwest. A copy of my resume is attached as Exhibit CEO-1.

I received a Master of Public & Private Management degree from the Yale University School of Management with a concentration in Regulation and Competitive Strategy. My research in graduate school focused on regulatory theory and practice. I also have a Bachelor of Science in Foreign Service from Georgetown University.

Q: Have you testified before the Michigan Public Service Commission previously?

A: Yes, I have provided testimony in the following proceedings before the MPSC:

- U-20162 – DTE Electric Co. Electric Rate Case
- U-20359 – Indiana Michigan Power Co. Electric Rate Case
- U-20471 – DTE Electric Co. Integrated Resource Plan
- U-20561 – DTE Electric Co. Electric Rate Case
- U-20697 – Consumers Energy Co. Electric Rate Case
- U-20649 – Consumers Energy Co. Voluntary Green Pricing Case
- U-20713/U-20851 – DTE Electric Co. Consolidated Voluntary Green Pricing and Renewable Energy Plan Amendment cases
- U-21090 – Consumers Energy Co. Integrated Resource Plan
- U-21134 – Consumers Energy Co. Voluntary Green Pricing Case
- U-20836 – DTE Electric Co. Electric Rate Case
- U-21124 – Consumers Energy Co. Electric Rate Case
- U-21193 – DTE Electric Co. Integrated Resource Plan
- U-21297 – DTE Electric Co. Electric Rate Case
- U-21389 – Consumers Energy Co. Electric Rate Case
- U-21461 – Indiana Michigan Power Co. Electric Rate Case
- U-21534 – DTE Electric Co. Electric Rate Case
- U-21585 – Consumers Energy Co. Electric Rate Case
- U-21662 – DTE Electric Co. Renewable Energy Plan Case

A complete listing of my testimony and comments is attached as Exhibit CEO-2.

Q: Are you sponsoring any exhibits?

A: Yes, I am sponsoring the following exhibits:

- Exhibit CEO-1: Resume of William D. Kenworthy
- Exhibit CEO-2: Testimony and Comments of William D. Kenworthy

- Exhibit CEO-3: U.S. Department of Energy, Pathways to Commercial Liftoff: Virtual Power Plants — 2025 Update.
- Exhibit CEO-4: The Brattle Group, Assessing VPP Performance: Impacts of a Test Event in California (August 1, 2025).
- Exhibit CEO-5: Solar United Neighbors, Distributed Power Plant Program (DPP) — Model Tariff v1 (June 2024)

II. Purpose and Summary

Q: What is the purpose of your testimony?

A: The purpose of my testimony is to evaluate DTE Electric Company's proposed distribution system investments, with a particular focus on the treatment of distributed energy resources (DERs), grid edge technologies, and customer-facing programs. My testimony examines whether the Company's proposed expenditures are supported by a clear business case and whether they deliver measurable benefits to customers in terms of reliability, affordability, and equity. I provide recommendations to ensure that DERMS and Grid Edge investments are tied to specific use cases such as virtual power plants, that non-wires alternatives are integrated into planning, and that distribution system spending is aligned with both Michigan's clean energy transition and customer needs. In addition, my testimony addresses the importance of equity in investment prioritization and the need to protect and assist low-income customers as they transition to time-of-use rates.

III. Witness Introduction

Q: In addition to yourself, who else is testifying on behalf of the Clean Energy Organizations ("CEO") in this proceeding?

A: In addition to my testimony, the CEO are presenting the testimony of two other expert witnesses: Curt Volkmann and Boratha Tan.

Q: Please summarize Mr. Volkmann's testimony.

A: Mr. Volkmann addresses DTE's distribution system condition, benefit-cost analysis methodologies, and specific program proposals. He explains that much of DTE's system is old, fragile, and hazardous, and emphasizes the urgent need to address safety issues on DTE's 4.8 kV circuits. He reviews the Company's Benefit-Cost Analyses, finding that while the methodologies are rigorous, they exclude important cost and risk factors. Mr. Volkmann recommends accelerating the installation of safety reclosers, conducting sensitivity analyses on potential cost escalations, and withholding Infrastructure Recovery Mechanism (IRM) treatment for subtransmission rebuilds until credible BCAs are developed. He also proposes improvements to ensure the IRM reconciliation process measures not only the efficiency but also the effectiveness of DTE's investments.

Q: Please summarize Mr. Tan's testimony.

A: Mr. Tan's testimony focuses on the Company's recent distribution spending and cost trends. He benchmarks DTE's capital additions against peer utilities, showing that while DTE's spending has increased significantly in recent years, customers have not yet experienced commensurate improvements in reliability. He also examines escalating labor and material costs, including the Producer Price Index for power distribution equipment, and highlights that DTE's analysis understates likely future costs. Finally, Mr. Tan provides recommendations for how the Commission should address cost escalation, benchmarking, and equity in evaluating DTE's proposals.

Q: How do these testimonies complement each other?

A: Collectively, the CEO witnesses provide a comprehensive review of DTE's proposals. Mr. Tan's benchmarking and cost analysis frame the affordability and equity context. Mr.

Volkmann's engineering and program-specific testimony addresses the safety, reliability, and planning implications of DTE's major capital proposals. My testimony builds on their analysis to emphasize the role of distributed energy resources, grid equity, and customer-facing solutions. Together, our testimonies present the Commission with a balanced set of recommendations to ensure DTE's investments are cost-effective, equitable, and aligned with Michigan's clean energy transition.

IV. DTE's DER and Grid Edge Programs Need Use Cases to Justify Investments

Q: Can you summarize what DTE Electric has proposed for DERMS investments?

A: DTE proposes implementing a Utility Distributed Energy Resource Management System (DERMS) with 2025-2026 investments shown in Exhibit A-12, Schedule B5.4, page 15, line 45. DTE Witness Rademacher explains the proposed DERMS investment in his testimony.[1] The proposal includes software licensing, configuration databases, and interfaces with existing demand response programs. However, DTE's stated approach focuses on "compliance requirements" (such as meeting FERC Order 2222 requirements) and "efficiency improvements for existing processes" rather than developing new customer programs. The testimony emphasizes system operator control, dispatch optimization, and FERC Order No. 2222 compliance, but provides no vision for how DERMS will enable new customer value propositions or comprehensive demand-side management programs.

Q: What has DTE proposed for Grid Edge Insights and New Technology?

A: DTE Witness Stephen Rademacher explains that "Grid Edge Insights and New Technology" is a key investment category within the Company's Grid Automation

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[1] Direct Testimony of Stephen P. Rademacher, at SPR-94-99.

program.[2] He supports the Company's proposed investments to "consolidate learnings from NWA pilot projects into a consistent platform" and develop standardized gateway systems for DER integration.[3] These are utility-led initiatives focused on enhancing visibility and control at the distribution edge. They test and deploy emerging technologies that allow the utility to better monitor distributed energy resources (DER) and system conditions. The programs emphasize system intelligence and innovation, but they largely stop at providing visibility rather than mapping out how DER might be actively used for load flexibility. Put differently, as discussed below, I am concerned that while these investments may have technical merit, they are designed primarily to provide the utility with visibility and control over distributed resources rather than to maximize customer benefits or develop innovative rate designs and programs that encourage beneficial load flexibility.

Q: How do these programs relate to DTE's Non-Wire Alternatives pilots?

A: DTE operates 8 NWA pilots including energy storage, mobile battery trailers, demand response, and EV charging demonstrations.[4] However, these pilots focus on narrow technical demonstrations rather than comprehensive customer programs. For example, the Fisher pilot achieved only 224 kW of energy waste reduction and enrolled 211 customers in demand response programs across an entire substation area.   The Grid Edge Insights program is designed to consolidate learnings from these limited pilots, but there's

[2] Direct Testimony of Stephen P. Rademacher Direct, SPR-10.

[3] Direct Testimony of Stephen P. Rademacher Direct, pg. SPR-59.

[4]Direct Testimony of Stephen P. Rademacher Direct, pg. SPR-48-59.

no evidence of scaling these into meaningful customer-facing programs that could drive significant load flexibility.[5]

Q: What are your concerns with DTE's approach to these investments?

A: My primary concerns are:

- First, utility-centric perspective: Both programs are designed from the utility's operational perspective to exercise control and provide visibility into DER operations, rather than from a customer value perspective that maximizes the benefits of these technologies.
- Second, missing customer value proposition: DTE's proposals lack comprehensive programs that help residential and small commercial customers actively participate in grid management, manage their energy costs, or monetize their flexibility.
- Third, narrow program scope: The NWA pilots and Grid Edge investments focus on technical demonstrations rather than scalable customer programs that could drive significant load flexibility and demand-side management.
- Fourth, absence of load flexibility strategy: There is no evidence of a comprehensive strategy to utilize these technologies for programs that provide customers with meaningful opportunities to shift usage, reduce costs, or participate in grid services markets.

[5] Direct Testimony of Stephen P. Rademacher Direct, at SPR-59.

Q: Has the Commission provided guidance in prior cases on utility requests to recover DERMS-related expenditures?

A: Yes. In Consumers Energy's recent electric rate case, the Commission specifically addressed the issue of DERMS. On pages 117–118 of its Order, the Commission made clear that recovery for DERMS-related costs must be supported by a robust business case. The Commission stated:

> Therefore, should Consumers seek recovery for a DERMS in a future electric rate case, it is incumbent on the company to provide a business case for the program, including a comprehensive BCA, that sufficiently identifies and justifies the program's costs and benefits to customers. When developing such a business case, Consumers should look at other states' best practices for examples of plans that can be readily implemented with regard to valuing the benefits of DERs and that are more actionable than the company's current proposal to hire a consultant to contract for the development of a strategy and business case.[6]

Q: What is your recommendation for this case in light of the Commission's prior guidance?

A: I recommend that the Commission adopt a similar rationale here. Just as in the Consumers case, the Company has not yet provided a clear and comprehensive business case demonstrating that the proposed DERMS and related "Grid Edge Insights and New Technology" expenditures will deliver measurable customer and grid benefits. Consistent with the Commission's prior Order, expenditures on DERMS should not be approved until the Company produces a comprehensive business case, including a benefit-cost analysis, that draws on best practices from other states and provides an actionable plan to

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[6] *In the matter of the application of Consumers Energy Company for authority to increase its rates for the generation and distribution of electricity and for other relief*, Michigan Public Service Commission Docket No. U-21585, Final Order (March 21, 2025) at 117-118.

integrate DER into programs that deliver load flexibility, help customers manage their energy use, and reduce distribution system costs.

Q: What should a comprehensive business case include?

A: A comprehensive business case should include:

- Market Assessment: Analysis of residential and small commercial customer market potential for demand response, time-varying rates, and DER programs, including quantification of available load flexibility.
- Customer Program Design: Specific programs for residential and small commercial customers including time-of-use rates, critical peak pricing, bring-your-own-device programs, managed EV charging, and smart appliance integration.
- Value Quantification: Analysis of all value streams including energy arbitrage, capacity value, ancillary services, distribution system deferrals, and customer bill savings.
- Technology Integration Plan: Customer-facing platforms, mobile applications, third-party aggregator partnerships, and advanced rate design capabilities that enable meaningful customer participation.
- Load Flexibility Strategy: Comprehensive approach to seasonal and daily load shaping, peak reduction, valley filling, and renewable integration that provides measurable grid benefits.

Q: What alternatives exist to DTE's current approach?

A: As discussed below in Section VI, leading utilities are implementing customer-focused DER and demand flexibility programs that provide both grid benefits and customer value. Examples include:

- Comprehensive time-varying rate offerings that reward customers for shifting usage;
- Bring-your-own-thermostat programs that provide bill credits for automated demand response;
- Community solar and storage programs that allow customer participation without individual capital investment;
- EV managed charging programs with bill incentives and grid integration;
- Whole-home energy management platforms that optimize customer usage patterns;
- Virtual power plant programs that aggregate residential and small commercial resources. This recommendation is discussed in greater detail below.

These programs utilize DERMS and grid edge technologies to create customer value while providing measurable grid benefits.

Q: What is your recommendation to the Commission?

A: I recommend the Commission defer approval of DTE's proposed DERMS and Grid Edge Insights and New Technology expenditures until DTE files a comprehensive business case that demonstrates:

- How these investments will enable specific customer programs that provide meaningful opportunities for demand-side management and load flexibility;

- Quantified benefits to customers through bill savings, rate options, and participation opportunities;
- Measurable grid benefits including peak reduction, resilience, renewable integration, and distribution system optimization;
- Clear timelines for program development and customer deployment;
- Performance metrics and targets for customer participation and grid benefits.

The business case should be developed with stakeholder input and demonstrate that these significant ratepayer investments will provide value beyond utility operational control.

Specifically, I recommend that the Company develop a Virtual Power Plant Program along the lines explained further below in Section VI of my testimony.

V. <u>Non-Wires Alternatives</u>

Q: What has the Company proposed with respect to Non-Wires Alternatives (NWA) pilots?

A: The Company has proposed to continue several NWA pilots intended to test whether targeted distributed energy resources can defer or avoid certain traditional distribution system investments.[7] These pilots are framed as exploratory projects to evaluate whether localized demand-side resources, such as solar, storage, or demand response, can be a cost-effective alternative to traditional poles-and-wires upgrades.

Q: What are your observations about the Company's NWA pilot proposals?

A: While I support the concept of piloting non-wires alternatives, the Company's approach remains limited and fragmented. The proposals do not articulate a systematic

[7] Direct Testimony of Stephen P. Rademacher Direct, at SPR-48-59.

methodology for identifying where grid needs exist, how to quantify the avoided distribution system investments, or how those avoided costs can be valued and incorporated into future resource procurement decisions. Without such a methodology, these pilots may remain isolated demonstrations rather than a foundation for scaling NWA solutions into broader utility planning and procurement practices.

Q: What is your concern with this approach?

A: My concern is that without developing a consistent and transparent framework, the Company will not be able to move beyond one-off projects. Ratepayers may end up funding pilot efforts that do not translate into actionable insights or enduring value streams for DER. In other words, the Company risks treating NWAs as experiments rather than integrating them as a core planning tool that can reduce costs and improve system efficiency.

Q: What do you recommend the Commission require with respect to NWAs?

A: I recommend that the Commission direct the Company to begin developing a methodology to identify grid needs and assign a value to avoided or deferred distribution system investments. This methodology should then be applied in evaluating DER solutions --including non-wires alternatives, Virtual Power Plants, and other customer-focused load flexibility programs -- so that DER can compete on a level playing field with traditional infrastructure. By doing so, the Commission will ensure that ratepayer investments in DERMS, Grid Edge Insights, and NWA pilots are aligned with a clear business case, tied to actual system needs, and capable of delivering quantifiable grid and customer benefits.

VI. Virtual Power Plants

Q: What do you mean by a "Virtual Power Plant" and why is it the right use case for DTE's proposed DERMS and Grid Edge investments?

A: A Virtual Power Plant (VPP) is an aggregation of distributed energy resources -- such as smart thermostats and water heaters, residential batteries paired with rooftop solar, EV managed charging, and flexible C&I loads -- coordinated to balance supply and demand and deliver utility-grade grid services. That is the customer-facing use case that makes DTE's DERMS and Grid Edge spend payoff: it organizes customer flexibility into dispatchable capacity that reduces peaks, defers distribution infrastructure investment, and lowers system costs.

Q: Why is now the time for a VPP in Michigan?

A: The Department of Energy's (DOE) 2025 Liftoff Update (attached as Ex. CEO-3) finds peak demand nationally is rising rapidly (roughly ~800 GW in 2024 to ~900 GW by 2030), while T&D and generation lead times and costs are climbing—making fast, flexible resources increasingly valuable. VPPs can be stood up quickly—basic peak-shaving VPPs can begin operating within about six months—buying time and reducing total cost to serve.

Q: How big is the near-term VPP opportunity, and what should the Commission expect over time?

A: DOE estimates that deploying 80–160 GW of VPP capacity by 2030—enough to serve roughly 10–20% of peak load—would reduce grid costs while supporting load growth.[8]

[8] Ex. CEO-3; VPP Liftoff Report, at 15.

The U.S. is already deploying ~33 GW across North America and needs to accelerate. In short: this is a significant, near-term, scalable resource if utilities enroll customer DERs.

Q: What are the customer and system benefits of a VPP relative to traditional options?

A: DOE summarizes that VPP peaking capacity is lower net cost than a gas peaker or a utility-scale battery on a $/kW-yr basis -- for an illustrative 400 MW Resource Adequacy product: ~$43 for a basic VPP vs. ~$69 for a utility-scale battery and ~$99 for a peaker (emissions/resilience benefits not even counted).[9] VPPs also defer distribution upgrades by shaving localized peaks, lowering rate pressure for all customers.

Q: Is there fresh empirical evidence that VPPs perform during the hours that matter?

A: Yes. On July 29, 2025, multiple California VPP aggregators discharged 535 MW of average output between 7–9 pm (typically peak hours in California). Output was consistent, mostly additive to status-quo operations (i.e., wouldn't have occurred without the event), and visibly reduced CAISO net load at the net peak—precisely when capacity is most valuable.[10]

Q: Won't DTE be required to allow aggregators of DER to participate in wholesale energy markets under FERC Order 2222?

A: Yes. Order 2222 requires an RTO/ISO pathway for DER aggregations, but that pathway is not yet available in MISO and will not be until 2030. FERC's most recent Order on MISO implementation of Order 2222 allows registration of DER Aggregator Resource

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[9] Ex. CEO-3; VPP Liftoff Report, at 13.

[10] Ex. CEO-4. The Brattle Group, Assessing VPP Performance: Impacts of a Test Event in California (August 1, 2025).

(DEAR) beginning in June 2029 and market participation beginning January 1, 2030, for DEAR market participation.[11]

Q: Does this mean that DTE must wait for the availability of wholesale market participation to implement VPP?

A: No. DTE does not need to wait for 2030 to realize VPP benefits. DTE can run utility-sponsored, retail-tariff VPPs now to deliver peak reduction, reliability, and targeted T&D deferrals. DOE's 2025 VPP Liftoff shows utility-led VPPs can be stood up in under six months with modest capital investment, reinforcing that waiting would delay achievable, near-term value. Just as important, VPPs are inherently scalable at a time when load growth is already materializing and data centers are seeking to bring new demand online immediately. Unlike large utility-scale projects, VPPs are not constrained by lengthy siting approvals or RTO interconnection queues. That flexibility makes the opportunity too important to leave on the table.

Q: What program design should the Commission require so DERMS and "Grid Edge" deliver measurable VPP value?

A: Defer approval of DERMS and Grid Edge Insights and New Technology until DTE files a VPP program that meets the following conditions:

- Multi-technology: Stacks customer devices: BYO smart thermostats/water heaters, residential batteries (including solar+storage), managed EV charging, and flexible C&I loads.

[11] Federal Energy Regulatory Commission, Order on Compliance, 190 FERC ¶ 61,031, Docket No. ER22-1640-003 (Jan. 16, 2025).

- Simplifies enrollment: one-click/QR enrollments, standard offers through retailers/installers, and aggregator channels.
- Uses pay-for-performance contracts with third-party aggregators, with availability/dispatch metrics and settlement tied to delivered kW/kWh.
- Targets distribution needs: procure VPP capacity at substations/feeders nearing thermal limits to defer capex.
- Centers equity and resilience: set carve-ins for low- and moderate-income customers, enable inclusive utility investment options, and support backup power for medically vulnerable households.
- Integrates planning & measurement and verification: include VPPs in IRP/DSP portfolios with transparent measurement, verified peak kW impact, and T&D deferral accounting. (DOE's Liftoff appendices provide practical menus on enrollment, standardization, planning, and market integration.)

Q: What models for program design would you suggest?

A: While there are several model programs in investor owned utilities (such as the ConnectedSolutions program in the Northeast)[12] and cooperative utilities (such as Holy Cross Energy's Power+Flex program),[13] I would recommend that the Company begin program design with Solar United Neighbors Model Distributed Power Plant (DPP) tariff.[14] (Attached as Exhibit CEO-5).

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[12] https://www.nationalgridus.com/MA-Home/Energy-Saving-Programs/ConnectedSolutions

[13] https://www.fortresspower.com/energybroker/holy-cross-energy-powerflex-program/

[14] Solar United Neighbors, Distributed Power Plant Program (DPP) — Model Tariff v1 (June 2024) Available at: https://solarunitedneighbors.org/wp-content/uploads/2024/07/SUN_Model-DPP-Tariff_v1-June-2024.pdf Note: Solar United Neighbors (SUN) uses the term Distributed Power Plant instead of Virtual Power Plant. Their rationale is that there is nothing virtual about these assets, they are concrete and very real assets. I concur with this

Q: Please describe how the Model Tariff addresses these barriers.

A: The Model Tariff is a standard-offer, open access tariff-based DPP program that draws from and builds upon successful programs designed for customer-sited batteries to provide peak load reduction and other grid support services, including the ConnectedSolutions program in Massachusetts and others operating around the country. The Model Tariff framework balances program standardization with the flexibility to adapt the model to meet the policy goals and grid needs of the implementing state and utility. The Model Tariff currently provides a battery storage program framework but is designed to allow for participation of other technologies (such as electric vehicles and smart thermostats) through adjacent program riders that can be added to the program framework over time.

Q: How should the Commission align this VPP direction with the Company's DERMS and Grid Edge proposals discussed earlier?

A: The Commission should tie approval of DERMS and Grid Edge funding to a VPP business case and implementation plan. That plan should specify the target devices and megawatts by year, demonstrate feeder and substation deferral use cases, and commit to standard pay-for-performance aggregator contracts. It should also include customer-facing enrollment and equity strategies, with annual reporting on participation levels, verified peak reduction, avoided costs, and bill impacts. In this way, the Commission would ensure that "control and visibility" spending is translated into a customer program that delivers tangible capacity, deferral, and affordability benefits.

characterization, but use the virtual power plants in my recommendation largely because it has been widely used previously, especially notably by the DOE Liftoff report. In my view, the terms are largely interchangeable.

Q: What specific Commission directives do you recommend?

A: I recommend that the Commission require the company to take the following steps to take advantage of the opportunities for virtual power plants in DTE service territory:

- Require a VPP filing within six months that includes program tariffs, aggregator contracts, enrollment channels, capacity targets, and measurement and verification. (DOE identifies VPPs as quick-to-deploy peak resources.)
- Condition DERMS/Grid Edge capex on the VPP filing approval and performance metrics.
- Adopt a benefit-cost framework that credits resource adequacy, ancillary services, and T&D deferrals, with pay-for-performance settlement. (DOE provides planning menus and BCA references.)
- De-couple VPP deployment from FERC Order 2222 implementation so that retail VPPs can move forward now, rather than being delayed until wholesale participation pathways are available.

VII. Distribution System Investment and Spending

A. Making the Grid Ready for Electrification

Q: What context frames your review of DTE's distribution O&M and capital budgets?

A: In evaluating DTE's proposed spending and investment in the distribution grid, I think the Commission should consider two important factors: First, today's DTE leadership has inherited an aging, brittle distribution system. As I will demonstrate below, DTE had several years of deferred capital investment relative to its regional peers in the mid-2000s. Perhaps more importantly, DTE likely deferred important system maintenance even more significantly during the entire decade, likely contributing to the acute problems we observe today. Second, Michigan is undergoing a rapid transition to clean energy and electrification—electric vehicles, building decarbonization, and growing distributed energy resources (DERs)—which requires a sturdier, smarter grid than the one we have today.

Q: Why invest now?

A: The grid must be made more resilient to more frequent/severe storms, more adaptable to changing load shapes and growth from electrification, and more capable of integrating DERs. The Company's rate case application discusses important blocking and tackling aspects of grid operations, such as hardening, targeted redesign/modernization, and foundational O&M. However, as I discuss below, the Commission should keep in mind broader state electrification and decarbonizations opportunities and goals. The 2023 clean energy laws introduced a number of new programs and initiatives designed to advance decarbonization and electrification that will depend in part on the grid's ability to support them.

Q: What in Michigan's 2023 energy laws requires utilities and the Commission to plan for electrification?

A: Public Act 231 of 2023 (amending MCL 460.6t) makes electrification a required input to IRP planning. The statute directs the MPSC to (1) establish modeling assumptions that include the "projected load impact due to electrification" and (2) conduct an assessment of the potential for electrification of transportation, buildings, and industry. It also requires IRPs to identify any transmission or distribution infrastructure needed to support proposed investments. Together, these provisions put grid-readiness for electrification squarely into core planning.[15]

Q: Where do the laws authorize building electrification programs and cost recovery?

A: Public Act 229 of 2023 authorizes utilities, beginning January 1, 2025, to file a Customer Energy Optimization Plan that may include an Efficient Electrification Measures Plan, allows cost recovery for those programs, and clarifies that nothing in that section prohibits transportation electrification programs approved by the Commission. It also specifies that such programs must not increase rates for non-participants.[16]

Q: Does Michigan law define what counts as "efficient electrification"?

A: Yes. Public Act 235 of 2023 defines an "efficient electrification measure" as equipment installed in an existing building to electrify end uses that would otherwise be served by fossil fuels, meeting best-practice efficiency standards. Examples include cold-climate heat pumps, heat-pump water heaters, high-efficiency electric cooking, and others.[17]

Q: How do the 2023 laws support grid flexibility for an electrified load?

A: Public Act 235 establishes a statewide energy storage target of at least 2,500 MW by December 31, 2029, with IOUs required to demonstrate compliance in their IRPs. Storage provides the flexibility needed to integrate building and transportation electrification while maintaining reliability and affordability.[18]

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[15] MCL 460.6t(1)(f)(iii) & (j), as amended by PA 231 (2023).

[16] MCL 460.1071, 460.1073 (Sections 71 and 73), as amended by PA 229 (2023).

[17] MCL 460.1005(5)(a) (Section 5(a)), as amended by PA 235 (2023).

[18] MCL 460.1009(1), PA 235 of 2023.

B. Current State of DTE's Grid and Historical Capital and O&M Spending

Q: Moving on to the distribution system spending and investment in this case, please summarize the Company's proposal?

A: The Company seeks substantial capital over the bridge period and projected test year, alongside a significant increase in distribution O&M to support inspections, condition assessment, corrective maintenance where appropriate, vegetation management, and data/process improvements. The Company's distribution system spending and investment is summarized by DTE Witness Bill Chiu and supported by DTE Witnesses Kryscynski, Robinson, Stowe, Rademacher, Hill, and Steudle, as well as 1898 & Co. Witness Jason De Stigter. My colleague CEO Witness Curt Volkmann's testimony focuses on whether the proposed portfolio of grid investments produce measurable reliability and safety outcomes per dollar.

Q: What did the Company say about the state of the current system and the need for increased sustained investment to make progress on improving reliability, much less making the grid ready for electrification?

A: DTE Witness Bill Chiu summarized the state of the system in his testimony. He then asserts:

> DTE Electric's system, in its current state, requires more than maintenance-level investment. Modest contributions or short-term injections of capital will not advance the system beyond the status quo. To meaningfully improve the system from its current state, it will require a significant and sustained level of investment over many years. The Company's customers and other stakeholders have been clear; virtually every intervenor in recent cases has advocated for increased reliability. The reality, however, is that improved reliability must come through consistent, and prioritized investment in the system. Greater reliability is

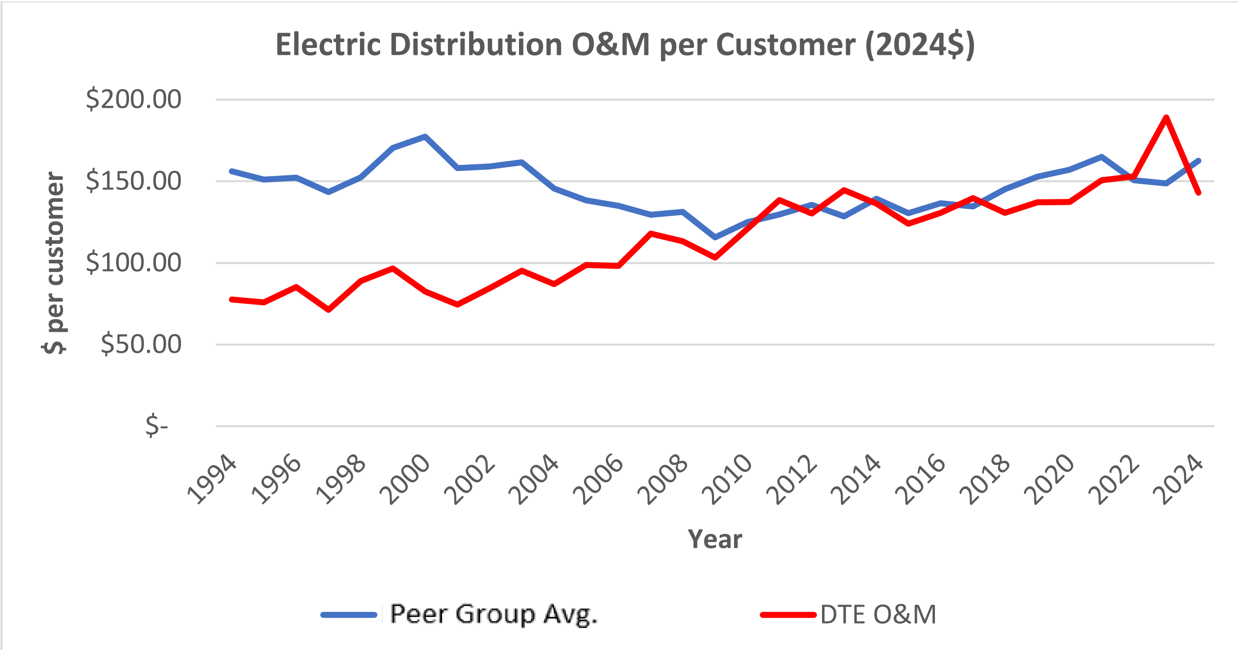
> only possible with increased investment in DTE Electric's distribution grid infrastructure for the benefit of our customers.[19]

Q: What does history tell us about DTE's prior distribution spending?

A: CEO Witness Volkmann requested that my colleague, CEO Witness Boratha Tan, collect data on DTE's historical capital additions relative to two utilities cited in the Commission ordered audits: ComEd and WEPCO. Based on the interesting findings of that first analysis, we decided to expand our analysis to see whether there was other important information that could be gleaned from comparison to peer utilities. Witness Volkmann and myself proposed the peer group based on our experience with other relatively large, investor-owned utilities in the Midwest with at least one medium to large city in their territory and similar topography to DTE's. Our peer-normalized review of FERC Form 1 data indicates that DTE's O&M spending trailed its peers through much of the 1990s and 2000s, while capital additions dipped below peers in the mid-2000s before recovering.[20] Figure 2 of Witness Tan's testimony illustrates this plainly:

[19] Direct Testimony of Bill Chiu, page BC-12.

[20] CEO Direct Testimony of Boratha Tan at 9, Figure 2.



In addition, plant-in-service per customer remained comparatively high. In plain terms, the long period of lower O&M likely contributed to today's asset-health needs and work backlogs that now require sustained attention.

Q: How does that history inform your view of today's proposals?

A: Cutting or deferring prudent programs now would repeat the mistake of under-maintaining the grid. But simply spending more is not the answer either. CEO Witness Volkman makes some excellent recommendations about prioritization (including prioritization of needed safety investments) and cost-effectiveness which I commend to the Commission's attention.

Q: How are you balancing the affordability crisis alongside the reliability crisis?

A: Multiple observers over the past several years have identified that DTE faces a dual crisis of poor reliability and high rates. Affordability remains a high priority for the Commission and for ratepayers. The Commission should evaluate portfolios on: (1) reliability benefit per dollar (including safety risk reduction), (2) pacing—sequencing work to maximize near-term risk reduction, (3) pairing capex with the O&M needed to preserve performance, and (4) transparent reporting of results so we can redirect funds to higher-yield work if outcomes lag. This is the foundational policy approach upon which Witness Volkmann builds his recommendations.

C. Balancing Affordability with the Need for Catch Up Spending and Investment

Q: How should the Commission approach the Company's proposed further ramp up of spending to improve reliability?

A: Sustained, targeted investment is needed to restore the system to an acceptable level of performance. At the same time, affordability concerns require disciplined pacing and transparent, feeder-level accountability so dollars flow to the highest-yield work. My testimony provides the performance- and equity-oriented framework for that accountability and, in doing so, reinforces my co-witness Mr. Volkmann's recommendations on reliability, safety prioritization, cost-effectiveness, and IRM design—without duplicating them.

Q: What do you mean by "catch-up" spending on safety and reliability?

A: As revealed by our analysis of historical distribution system O&M and capital investment (and supported by the results of the audit), the current state of the system is the result of underspending on O&M and some under investment in capital by the predecessors in the Company's management and approved by the Commission. This underspending arguably made the problems with the current state more acute. The situation warrants increased investment to "catch-up" with the system, e.g., accelerating inspection cycles and condition-based replacements, wiredown hazard mitigation on 4.8-kV circuits, substation component replacements driven by asset health, and clearing vegetation backlogs. Notably, the effort to get on even industry standard inspection and vegetation management cycles will require significant expenditures. These activities are necessary to restore a prudent steady-state, but they are not permanent step-changes in the ongoing run-rate.

Q: How do you propose to balance the necessary spending to achieve these goals?

A: I understand from our pre-filing discussions that MNSC Witness Douglas Jester will be proposing securitization of qualifying catch-up spending in his testimony. Pending the details of his proposal, I support the policy because it enables DTE to complete necessary safety and reliability work while minimizing near-term bill impacts and better aligning costs with beneficiaries.

Securitization is appropriate because it (1) aligns cost recovery with long-term benefits future customers will receive (intergenerational equity), (2) substitutes lower-cost securitization bonds for the utility's higher weighted average cost of capital, reducing bill impacts, and (3) avoids unduly enlarging rate base for work that remedies past shortfalls rather than expanding service.

Q: What guardrails should accompany any securitization of catch-up spending?

A: First, define an objective historic baseline for each asset class (inflation-adjusted) and treat only the spend above that baseline, for a limited period tied to the inspection/clearance cycle, as "surge." Second, limit eligibility to safety and reliability remediation (e.g., energized down-wire mitigation, PTMM where driven by condition, substation/component replacements addressing asset health, vegetation backlog clearance) -- not load growth or capacity expansion. Third, require that securitized amounts be excluded from rate base, with clear no-double-recovery provisions. Fourth, size transactions periodically (e.g., when deferred balances exceed a reasonable threshold) and require a bill-impact analysis demonstrating customer savings versus conventional recovery. Fifth, implement feeder-level performance reporting to verify that securitized work actually reduces outage risk and improves SAIDI/SAIFI as promised.

Q: Are you proposing changes to the Investment Recovery Mechanism (IRM)?

A: I am not making separate IRM recommendations. However, my focus on outcome-based accountability, feeder-level transparency, and business-case rigor directly reinforces Witness Volkmann's specific IRM recommendations. To the extent his testimony proposes outcome checks, effectiveness-based adjustments, and stronger BCA requirements, my analysis supplies the factual and policy rationale for those improvements without duplicating his proposals. I would also note that if the Commission adopts the recommendation to securitize a portion of the catch up spending, it would affect the amounts eligible for consideration in the IRM.

D. Grid Equity in Distribution System Planning and Investment

Q: What does DTE witness Allen J. Kryscynski Jr. say about how DTE uses environmental justice (EJ) in its business processes and distribution planning?

A: Witness. Kryscynski states that DTE integrated EJ into the 2023 Distribution Grid Plan through three objectives: (1) add an EJ component to the Global Prioritization Model (GPM) to inform investment decisions; (2) improve performance for vulnerable communities that experience poor reliability; and (3) support vulnerable customers during storms via community outreach.[21] He notes the Liberty Audit found the Company has made strides and plans to continue enhancing EJ integration; and that in U-21534 the

[21] Direct Testimony of A.J. Kryscynski, at AJK 42.

Commission deemed DTE's EJ considerations reasonable, recognized MiEJScreen as a reasonable starting point, and acknowledged mapping of reliability investments (e.g., 4.8 kV hardening/conversions) to vulnerable communities. He defines "vulnerable communities" as those at or above the 80th percentile MiEJScreen composite score. DTE plans to keep using MiEJScreen to analyze reliability and investment data, continue including EJ in investment decisions, address poor-performing circuits in vulnerable communities, and work with MPSC Staff/stakeholders on regression analysis for the next DGP as directed by the Commission.

I also note that the Company's lead distribution system witness, DTE Witness Chiu also ties EJ to investment selection and IRM prioritization, asserting that vulnerable communities are receiving high levels of investment with improving reliability metrics.[22]

Q: How does your testimony approach environmental justice (EJ) and equity?

A: I commend the Company for incorporating EJ into its prioritization tools and business processes. Building on that progress, I recommend that reliability reporting include distributions—not just averages—across EJ gradations, and that investment decisions pair MiEJScreen with reliability and energy-burden indicators so dollars close persistent service gaps without worsening affordability. This approach complements the Company's EJ integration and helps ensure benefits reach communities that have historically seen worse outcomes.

[22] Direct Testimony of Bill Chiu, at BC-32.

VIII. Transitioning D1.6 Customers to Time of Use Rates

Q: What is the background to DTE's transition away from D1.6, and what did the Commission decide?

A: In the January 23, 2025 Order in DTE's last rate case (U-21534), the Commission approved the Company's proposal to close Rate D1.6 and transition customers to the default rate for residential customers – Rate D1.11 – which the Company describes as its standard residential service rate with prices that vary by season and time of day.[23] However, the Commission required the Company to develop a mitigation plan to assist the small number of low-income customers that might be adversely impacted by transitioning to a time of use rate. Because it is important here, I quote the specific passage from the Order:

> The Commission finds that DTE Electric's proposal to retire Rate Schedule D1.6, to transition customers to Rate Schedule D1.11, and to extend the LIA credit to all residential base rates should be approved. The Commission finds persuasive the company's, the Staff's, and the CEOs' arguments that nearly two-thirds of low-income customers would experience reduced utility rates. See, DTE Electric's initial brief, pp. 310-311; Staff's initial brief, p. 123; CEOs' initial brief, p. 18. However, the Commission finds that DTE Electric did not sufficiently perform the impact study ordered in the December 1 order. Therefore, in its next general rate case, DTE Electric shall include, in relation to the transition from Rate Schedule D1.6 to Rate Schedule D1.11, an analysis of shutoff information, an analysis of the factors impacting household ability to shift usage, and regression analyses. For the remaining one-third of customers who may experience higher utility rates as a result of the transition, the Commission finds that the company shall implement the CEOs' recommended mitigation measures: expanded educational outreach to low-income customers regarding low-income energy efficiency programs, weatherization, and smart thermostats; and the use of smart meter data to identify customers and address energy-limiting

[23] Direct Testimony of Aaron Willis, at AW-10-11.

> behavior that is adverse to health and safety. See, CEOs' initial brief, p. 18.[24]

Q: How do the Company's witnesses divide responsibilities to implement and report on the Commission's requirements?

A: DTE Witness Quinn Gerdes testifies he is providing the regression analyses and the analysis of factors affecting the ability of households to shift usage.[25] Company Witness Jason Sparks discusses a number of low-income programs, including the Commission required shutoff analysis.[26] Company Witness Aaron Willis sponsors the tariff housekeeping necessary to effectuate the order – removing D1.6 from the rate book.[27]

Q: What did the Commission require regarding expected customer bill impacts, and how do the Company's witnesses describe those impacts?

A: The Company interpreted the Commission's order to require a regression analysis to measure customer bill impact. Witness Gerdes explains the results regression analysis he performed which found "average" D1.6 customer in the 2022 dataset would be expected to have a 0.17% lower bill on D1.11, while emphasizing that modeled predictors explain about 41.9% of the variance in percentage bill change and that each variable's marginal effect is small.[28] He adds that customers did not need above-median usage to benefit; holding other variables at medians, annual usage above ~6,000 kWh corresponded to a lower bill on D1.11.

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[24] Commission Order in U-21534, January 23, 2025, at. 393-394.

[25] Direct Testimony of Quinn Gerdes, at QG10-20.

[26] Direct Testimony of Jason Sparks, at. JES-49.

[27] Direct Testimony of Aaron Willis, at. AW-31.

[28] Direct Testimony of Quinn Gerdes t, at QG-19–20

Q: What does the Company say about the timing and content of the shutoff (disconnect) analysis the Commission required?

A: Witness Sparks explains that, as of this filing, the actual transition from D1.6 to D1.11 had not yet occurred and is scheduled later in 2025, so the Company could not yet present a before/after shutoff study specifically for the D1.6 cohort; instead, it analyzed disconnection rates pre- and post-time-of-use (TOU) implementation generally and found "very little impact" to overall disconnect rates in that comparison. He commits to providing the specific D1.6 to D1.11 shutoff analysis when a full year of post-transition data is available or in the next rate case or when the data is available (whichever is earlier).[29]

Q: What is the Company's plan for completing the Commission-ordered analyses after the transition is complete?

A: Witness Sparks indicates the Company will file the D1.6 to D1.11 shutoff analysis after a full year of post-transition data is available or in the next rate case, whichever occurs first, and notes that Witness Gerdes has already advanced the "ability to shift usage" and regression components; together these steps are designed to satisfy the order on shutoffs, shifting ability, and regression analysis in the subsequent general rate case.

Q: Do the witnesses' responses align with the Commission's mitigation expectations for customers who might see higher bills?

A: The Commission clearly expects educational outreach, weatherization and smart-thermostat promotion, and use of advanced meter data to identify energy-limiting behaviors that threaten health or safety. On the first expectation -- education and outreach

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[29] Direct Testimony of Jason Sparks, atJES-49.

-- the Company's testimony commits to communicating with all affected customers transitioning from D1.6 to D1.11 and to providing materials that explain low-income energy-efficiency offerings; Witness Sparks also points to a dedicated EAG support team for concerns that arise during the conversion. This aligns with the Commission's directive for expanded outreach to low-income customers.[30]

With respect to weatherization and smart-thermostat promotion, the witnesses do not yet describe a targeted promotion plan, but Witness Gerdes' survey results underscore why such a plan matters. He reports that low-income customers were 16% less likely than non-low-income customers to have their thermostats set to an energy-efficient program in winter, 10% more likely to keep a single setpoint, and – critically -- 20% less likely to have a smart or programmable thermostat at all.[31] Those findings both validate the Commission's emphasis on thermostat interventions and point to a concrete gap the Company can close via outreach and incentives.

Finally, on the expectation to "use smart meter data to identify customers and address energy-limiting behavior," the current testimony stops short of laying out an AMI-analytics plan that flags at-risk households and triggers tailored interventions. Witness Sparks references AMI in the context of cost allocation and meter-reading (which implies the data infrastructure exists) but does not describe using AMI data streams to proactively identify customers exhibiting energy-limiting or health-risk behaviors.[32] This appears to be a gap relative to the Commission's explicit direction.

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[30] Direct Testimony of Jason Sparks, at JES-49-50.

[31] Direct Testimony of Quinn Gerdes, at QG-13.

[32] Direct Testimony of Jason Sparks, at 13

Q: Please explain your understanding of the Company's current outreach plan for affected customers in the D1.6 to D1.11 transition?

A: Outside the filed testimony, the Company has begun implementing a rollout that is directionally consistent with the Commission's outreach expectations: for the roughly 30,000 remaining D1.6 customers, a "what-to-expect" mailer went out in early August, the mass transition to D1.11 is scheduled for October, and a "welcome kit" with program information will accompany that transition. As described, those materials are slated for all affected customers, which helps on broad education. To fully align with the Commission's mitigation standard—especially for the one-third who may see higher bills- I recommend that the Company explain in its rebuttal testimony the plan in greater detail and to clarify whether, and how, it will go beyond universal mailings to identify specific customers adversely affected by the transition period and intervene. In particular, the Company could describe how it will leverage advanced meter data and any existing "Home Energy Report" tools (which I understand are part of one of its Energy Waste Reduction programs to pinpoint customers exhibiting energy-limiting patterns (for example, persistent very low consumption during extreme temperatures) and to pair those customers with targeted measures such as smart-thermostat installation support, weatherization referrals, or safety checks. Witness Gerdes' testimony already notes that low-income customers express a desire and capability to shift usage, which suggests such targeted assistance would be actionable if the Company operationalizes the data-driven identification step the Commission called for.[33]

[33]Direct Testimony of Quinn Gerdes, at. 15.

IX. <u>Conclusions and Recommendations</u>

Q: Please summarize your recommendations.

A: I recommend that the Commission take the following actions pursuant to my testimony:

- Direct development of a transparent NWA/avoided-cost methodology so DER and VPP solutions can compete head-to-head with traditional wires investments.
- Require a VPP filing within six months that includes program tariffs, aggregator contracts, customer enrollment channels, capacity targets, and measurement and verification (M&V) plans.
- Condition approval of DERMS and grid edge capital expenditures on the VPP filing and on measurable performance metrics.
- Adopt a benefit-cost framework that recognizes the value of resource adequacy, ancillary services, and transmission and distribution deferrals, and that includes pay-for-performance settlement, consistent with DOE guidance.
- Support proposal by MNSC Witness Jester to securitization of one-time "catch-up" safety/reliability work with guardrails (limit to remediation, exclude from rate base, prevent double recovery, show bill savings, and require feeder-level performance reporting).
- Strengthen equity accountability by reporting reliability outcomes as distributions (not just averages) across MiEJScreen strata and pairing EJ mapping with reliability and energy-burden indicators in investment decisions.
- Identify and assist low-income customers during the D1.6 to D1.11 Time-of-Use transition by requiring AMI-based analytics to flag at-risk households; targeted, multilingual outreach; streamlined enrollment in assistance (e.g., LIA/arrears

management); and practical mitigations (e.g., smart-thermostat support, weatherization referrals, safety checks, and near-term bill-protection where warranted).

Q: Does this conclude your testimony?

A: Yes.

William D. Kenworthy

1 South Dearborn Street, Suite 2000
Chicago, IL 60603
Phone: (704) 241-4394
Email: will@votesolar.org

Summary:

Energy industry leader and advocate with extensive expertise in electric industry structure, energy economics, and policy. Proven track record in advancing renewable energy, optimizing energy systems, and leveraging data-driven approaches, including machine learning, for process and financial optimization. Deep experience in distributed generation economics, regulatory strategy, and policy development to drive a cleaner, more equitable energy future.

Experience

Vote Solar
Regulatory Director, Midwest | *July 2018 - Present*
Lead regulatory strategy and advocacy efforts to advance solar and distributed energy resources across the Midwest. Serve as an expert witness, delivering testimony on technical, economic, and financial aspects of regulatory filings, utility rate cases, and grid modernization plans. Conduct in-depth policy analysis to shape regulatory outcomes that drive equitable access to clean energy. Manage the development and execution of regulatory strategies, collaborating with policymakers, utilities, and stakeholders to accelerate the transition to a just and resilient energy system.

Microgrid Energy
Managing Director, Midwest | *October 2017-June 2018 and October 2014-April 2016*
Managed operations of Chicago office for solar energy project development and EPC (engineering, procurement, and construction) company. Coordinated business development, market development, state and local policy efforts. Leveraged industry experience, strategic industry insight and market knowledge to enter new markets.

Infer Energy / Root3 Technologies
President | *April 2016 – October 2017*
Primary responsibility for marketing & business development for startup technology firm focused on providing energy optimization services to large industrial energy users. Successfully expanded business to the point at which was folded into the customer equipment health and maintenance offering of a large on-site energy generation provider.

Tipping Point Renewable Energy
Executive Vice President, Marketing & Business Development | January 2010 – April 2016
Led sales, marketing and business development process for startup solar energy project development and installation company

Governmental Strategies Incorporated
Vice President / Partner | *October 1996 – December 2007*
Senior partner in governmental affairs consulting practice. Developed and implemented strategic plans and marketing campaigns to affect public policy on behalf of Fortune 100 electric utility companies.

Nuclear Energy Institute
Director, Federal Legislative Affairs | *May 1992 – October 1996*
Developed and implemented strategic plans affecting public policy related to the ownership and operation of the nation’s nuclear power plants and over 200 companies involved in the industry.

Provided technical assistance to legislators and their staffs in the development of energy policy, including facilitating cross-functional communications between technical personnel and legislative staff.

House Energy & Commerce Committee, U. S. House of Representatives
Professional Staff Member
May 1987 - August 1990
Represented Chairman John D. Dingell (D-MI) and Members of the Committee in dealings with other Members of Congress, the Executive Branch, private interests, and public organizations on energy & environmental policy. Professional staff team during the negotiation and drafting of the Clean Air Act Amendments of 1990.

Education

Yale University, School of Management
MBA / MPPM, Regulation and Competitive Strategies | May 1992

Georgetown University
BSFS, International Politics | May 1987

Community and Volunteer Activities

Jackalope Theater Company
Board Member | 2018-Present

Erie Family Health Foundation
Board Member | 2018 - 2021

Jefferson Avenue Center
President, Board of Trustees & Member | May 2012 – 2021

Georgetown University
Alumni Interviewer | June 2014 – Present

Columbus Academy
Member of Board of Trustees and Parent's Association President | June 2013 - December 2013

City of Upper Arlington Cultural Arts Commission
Commissioner and Chairman June 2012 – December 2013

CareRing of Charlotte
Member, Board of Trustees April 2004 - May 2008

Boy Scouts of America,
Assistant Scoutmaster, Cubmaster, Den Leader | September 2002 – September 2014

Skills / Software

Energy Modeling: NREL System Advisor Model (SAM), EnCompass
Productivity: Microsoft Office Suite
Business Intelligence / Data Visualization: Tableau, Tableau Prep, Python, NumPy
Adobe Creative Suite

Testimony and Comments of William D. Kenworthy

Regulatory Director, Midwest
Vote Solar
August 20, 2025

Testimony

Direct Testimony of William D. Kenworthy on behalf of the Iowa Environmental Council, the Environmental Law & Policy Center, and the Sierra Club, Iowa Utilities Commission, Docket No. RPU-2025-0001, In re: MidAmerican Energy Company, May 29, 2025.

Direct Testimony on Rehearing of William D. Kenworthy, Illinois Commerce Commission, *Revenue-neutral Tariff Changes Related to Rate Design*, Docket No. 24-0378, on behalf of the Environmental Law & Policy Center, Union of Concerned Scientists, and Vote Solar, April 29, 2025.

Direct Testimony of William D. Kenworthy on behalf of Solar United Neighbors, Virginia State Corporation Commission, Case No. PUR-2024-00222, *In re: Virginia Electric and Power Company, Application for approval of its 2024 DSM Update pursuant to § 56-585.1 A 5 of the Code of Virginia*, March 24, 2025

Direct Testimony of William D. Kenworthy on behalf of the Ecology Center, the Environmental Law & Policy Center, Union of Concerned Scientists, and Vote Solar, Michigan Public Service Commission, Case No. U-21375, *In the matter, on the Commission's own motion, regarding the regulatory reviews, revisions, determinations, and/or approvals necessary for DTE Electric Company to comply with Section 61 of 2016 PA 342*, February 13, 2025.

Direct Testimony of William D. Kenworthy on behalf of Vote Solar, Public Service Commission of Wisconsin, Docket No. 5-UR-111, *Joint Application of Wisconsin Electric Power Company and Wisconsin Gas LLC for Authority to Adjust Electric, Natural Gas, and Steam Rates*, August 21, 2024.

Direct Testimony of William D. Kenworthy on behalf of Vote Solar, Public Service Commission of Wisconsin, Docket No. 6690-UR-128, Joint Application of Wisconsin Electric Power Company and Wisconsin Gas LLC for Authority to Adjust Electric, Natural Gas, and Steam Rates, August 19, 2024.

Rebuttal Testimony of William D. Kenworthy on behalf of the Ecology Center, the Environmental Law & Policy Center, Union of Concerned Scientists, and Vote Solar, Michigan Public Service Commission, Case No. U-21534, *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*, August 16, 2024.

Direct Testimony of William D. Kenworthy on behalf of the Ecology Center, the Environmental Law & Policy Center, Union of Concerned Scientists, and Vote Solar, Michigan Public Service Commission, Case No. U-21585, *In the matter of the application of Consumers Energy Company for authority to increase its rates for the generation and distribution of electricity and for other relief*, September 27, 2024.

Direct Testimony of William D. Kenworthy on behalf of the Ecology Center, the Environmental Law & Policy Center, Union of Concerned Scientists, and Vote Solar, Michigan Public Service Commission, Case No. U-21534, *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*, July 26, 2024.

Rebuttal Testimony of William D. Kenworthy on behalf of the Environmental Law & Policy Center, the Environmental Defense Fund, the Natural Resources Defense Council, the Union of Concerned Scientists, and Vote Solar, *Illinois Commerce Commission On Its Own Motion vs. Commonwealth Edison Company, Order Requiring Commonwealth Edison Company to file an Initial Multi-Year Integrated Grid Plan and Initiating Proceeding to Determine Whether the Plan is Reasonable and Complies with the Public Utilities Act*, Illinois Commerce Commission, Case No. 22-0486 Refiled Grid Plan (RGP), July 17, 2024.

Rebuttal Testimony of William D. Kenworthy on behalf of Environmental Defense Fund Environmental Law & Policy Center, the Natural Resources Defense Council, the Union of Concerned Scientists, and Vote Solar, *Illinois Commerce Commission On Its Own Motion vs. Ameren Illinois Company Order Requiring Ameren Illinois Company to file an Initial Multi-Year Integrated Grid Plan and Initiating Proceeding to Determine Whether the Plan is Reasonable and Complies with the Public Utilities Act*, Illinois Commerce Commission, Case No. 22-0487 Refiled Grid Plan (RGP), July 3, 2024

Direct Testimony of William D. Kenworthy on behalf of Environmental Defense Fund, Environmental Law & Policy Center, the Natural Resources Defense Council, the Union of Concerned Scientists, and Vote Solar, *Illinois Commerce Commission On Its Own Motion vs. Commonwealth Edison Company Order Requiring Commonwealth Edison Company to file an Initial Multi-Year Integrated Grid Plan and Initiating Proceeding to Determine Whether the Plan is Reasonable and Complies with the Public Utilities Act*, Illinois Commerce Commission, Case No. 22-0486 Refiled Grid Plan (RGP), May 23, 2024.

Direct Testimony of William D. Kenworthy on behalf of Environmental Defense Fund Environmental Law & Policy Center, the Natural Resources Defense Council, the Union of Concerned Scientists, and Vote Solar, *Illinois Commerce Commission On Its Own Motion vs. Ameren Illinois Company Order Requiring Ameren Illinois Company to file an Initial Multi-Year Integrated Grid Plan and Initiating Proceeding to Determine Whether the Plan is Reasonable and Complies with the Public Utilities Act*, Illinois Commerce Commission, Case No. 22-0487 Refiled Grid Plan, May 13, 2024.

Rebuttal Testimony of William D. Kenworthy on behalf of the Ecology Center, the Environmental Law & Policy Center, and Vote Solar, *In the matter of the application of Indiana Michigan Power Company or authority to increase its rates for the generation and distribution of electricity and for other relief*, Michigan Public Service Commission, Case No. U-21389, February 2, 2024.

Direct Testimony of William D. Kenworthy on behalf of the Ecology Center, the Environmental Law & Policy Center, and Vote Solar, *In the matter of the application of Indiana Michigan Power Company or authority to increase its rates for the generation and distribution of electricity and for other relief*, Michigan Public Service Commission, Case No. U-21389, January 18, 2024.

Surrebuttal Testimony of William D. Kenworthy on behalf Vote Solar and Sierra Club, *Application of Wisconsin Power & Light Company for Authority to Adjust Electric and Natural Gas Rates*, Wisconsin Public Service Commission, Docket No. 6680-UR-124, September 25, 2023.

Surrebuttal Testimony of William D. Kenworthy on behalf Vote Solar and Sierra Club, *Application of Madison Gas and Electric Company for Authority to Adjust Electric and Natural Gas Rates*, Wisconsin Public Service Commission, Docket No. 3270-UR-125, September 20, 2023.

Rebuttal Testimony of William D. Kenworthy on behalf Vote Solar and Sierra Club, *Application of Wisconsin Power & Light Company for Authority to Adjust Electric and Natural Gas Rates*, Wisconsin Public Service Commission, Docket No. 6680-UR-124, September 19, 2023.

Direct Testimony of William D. Kenworthy on behalf Vote Solar and Sierra Club, *Application of Wisconsin Power & Light Company for Authority to Adjust Electric and Natural Gas Rates*, Wisconsin Public Service Commission, Docket No. 6680-UR-124, September 5, 2023.

Direct Testimony of William D. Kenworthy on behalf of the Ecology Center, the Environmental Law & Policy Center, and Vote Solar, *In the matter of the application of CONSUMERS ENERGY COMPANY for authority to increase its rates for the generation and distribution of electricity and for other relief,* Michigan Public Service Commission, Case No. U-21389, August 29, 2024.

Direct Testimony of William D. Kenworthy on behalf Vote Solar and Sierra Club, *Application of Madison Gas and Electric Company for Authority to Adjust Electric and Natural Gas Rates*, Wisconsin Public Service Commission, Docket No. 3270-UR-125, August 28, 2023.

Rebuttal Testimony of William D. Kenworthy on behalf of the Environmental Law & Policy Center, the Natural Resources Defense Council, the Union of Concerned Scientists, and Vote Solar, *Illinois Commerce Commission On Its Own Motion vs. Commonwealth Edison Company Order Requiring Commonwealth Edison Company to file an Initial Multi-Year Integrated Grid Plan and Initiating Proceeding to Determine Whether the Plan is Reasonable and Complies with the Public Utilities Act*, Illinois Commerce Commission, Case No. 22-0486, July 26, 2023.

Rebuttal Testimony of William D. Kenworthy on behalf of the Environmental Law & Policy Center, the Natural Resources Defense Council, the Union of Concerned Scientists, and Vote Solar, *Illinois Commerce Commission On Its Own Motion vs. Ameren Illinois Company Order Requiring Ameren Illinois Company to file an Initial Multi-Year Integrated Grid Plan and Initiating Proceeding to Determine Whether the Plan is Reasonable and Complies with the Public Utilities Act*, Illinois Commerce Commission, Case No. 22-0487, July 13, 2023.

Direct Testimony of William D. Kenworthy on behalf of the Ecology Center, the Environmental Law & Policy Center, Union Of Concerned Scientists, and Vote Solar, *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,* Michigan Public Service Commission, Case No. U-21297, June 13, 2023.

Direct Testimony of William D. Kenworthy on behalf of the Environmental Law & Policy Center, the Natural Resources Defense Council, the Union of Concerned Scientists, and Vote Solar, *Illinois Commerce Commission On Its Own Motion vs. Commonwealth Edison Company Order Requiring Commonwealth Edison Company to file an Initial Multi-Year Integrated Grid Plan and Initiating Proceeding to Determine Whether the Plan is Reasonable and Complies with the Public Utilities Act*, Illinois Commerce Commission, Case No. 22-0486, May 22, 2023.

Direct Testimony of William D. Kenworthy on behalf of the Environmental Law & Policy Center, the Natural Resources Defense Council, the Union of Concerned Scientists, and Vote Solar, *Illinois Commerce Commission On Its Own Motion vs. Ameren Illinois Company Order Requiring Ameren Illinois Company to file an Initial Multi-Year Integrated Grid Plan and Initiating Proceeding to Determine Whether the Plan is Reasonable and Complies with the Public Utilities Act*, Illinois Commerce Commission, Case No. 22-0487, May 11, 2023.

Direct Testimony of William D. Kenworthy on behalf of the Ecology Center, the Environmental Law & Policy Center, and Vote Solar, *In the matter, on the Commission's own motion regarding the regulatory reviews, revisions, determination and/or approvals necessary for DTE ELECTRIC COMPANY to comply with Section 61 of 2016 PA 342*, Michigan Public Service Commission, Case No. U-21172, April 21, 2023.

Rebuttal Testimony of William D. Kenworthy on behalf of the Ecology Center, the Environmental Law & Policy Center, the Union of Concerned Scientists, and Vote Solar, *In the matter of the application of DTE Electric Company for approval of its Integrated Resource Plan pursuant to MCL 460.6t, and for other relief*, Michigan Public Service Commission, Case No. U-21193, April 10, 2023.

Direct Testimony of William D. Kenworthy on behalf of the Ecology Center, the Environmental Law & Policy Center, the Union of Concerned Scientists, and Vote Solar, *In the matter of the application of DTE Electric Company for approval of its Integrated Resource Plan pursuant to MCL 460.6t, and for other relief*, Michigan Public Service Commission, Case No. U-21193, March 9, 2023.

Surrebuttal, Testimony of William D. Kenworthy on behalf of Vote Solar, *Verified Petition of Vote Solar of Distributed Energy Resource Systems in Wisconsin*, Wisconsin Public Service Commission, Docket No. 9300-DR-106, October 21, 2022

Direct Testimony of William D. Kenworthy on behalf of Vote Solar, *Verified Petition of Vote Solar of Distributed Energy Resource Systems in Wisconsin*, Wisconsin Public Service Commission, Docket No. 9300-DR-106, September 16, 2022.

Direct Testimony of William D. Kenworthy on behalf of the Ecology Center, the Environmental Law & Policy Center, and Vote Solar, *In the matter of the application of Consumers Energy Company for authority to increase its rates for the generation and distribution of electricity and for other relief.*, Michigan Public Service Commission, Case No. U-21224, August 24, 2022.

Rebuttal Testimony of William D. Kenworthy on behalf of the Environmental Law & Policy Center and Vote Solar, *Petition of for Approval of Performance and Tracking Metrics pursuant to 220 ILCS 5/16-108.18(e): Ameren Illinois Company d/b/a Ameren Illinois*. Illinois Commerce Commission, Case No. 22-0063, June 6, 2022.

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U.S. DEPARTMENT OF
ENERGY

Pathways to Commercial Liftoff: **Virtual Power Plants 2025 Update**

JANUARY | 2025

Comments

The Department of Energy welcomes input and feedback on the contents of this Pathway to Commercial Liftoff Report. Please direct all inquiries and input to liftoff@hq.doe.gov. Input and feedback should not include business sensitive information, trade secrets, proprietary, or otherwise confidential information. Please note that input and feedback provided is subject to the Freedom of Information Act.

Authors

Sonali Razdan, **Loan Programs Office and Office of Technology Transitions** *(Lead)*

Jennifer Downing, **Loan Programs Office**

Louise White, **Loan Programs Office and Office of Technology Transitions**

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Purpose of Liftoff Reports

The United States (U.S.) Department of Energy (DOE) has published a series of reports on The Pathways to Commercial Liftoff for emerging clean energy technologies. These Liftoff reports provide a roadmap for how the public and private sector can collectively accelerate the commercialization of the technologies needed to decarbonize the U.S. economy. Given the constantly and rapidly evolving market, technology, and policy environment, these reports are designed to be "living documents" and will be updated as the commercialization outlook on each technology evolves.

Spearheaded by DOE's Office of Technology Transitions (OTT), these Liftoff reports reinforce dialogue across not only DOE, but also other Federal departments and agencies. They build upon learnings from DOE investments and continued engagement with industry stakeholders. DOE continues to solicit input through industry forums, requests for information, and other interactions. Direct public input can be submitted via email to liftoff@hq.doe.gov.

Objectives and Scope of Virtual Power Plant Update

DOE published the **Pathways to Commercial Liftoff: Virtual Power Plants** report in September 2023. Since that publication, Virtual Power Plant (VPP) adoption has grown; new VPP deployments, new insights and analyses into benefits, and new tools and resources from within and outside DOE have emerged. However, deployment still needs to accelerate in the U.S. to reach 80-160 GW of VPPs (10-20% of peak load) that contribute to an affordable, reliable, and secure grid for all Americans.

This Update supplements – but does not replace – the original 2023 VPP Liftoff Report by providing additional real-world examples, new resources, and updated industry insights that support VPP deployment. This report aims to (1) communicate the differential value proposition of VPPs in meeting near-term grid challenges compared to alternatives and (2) provide proven solutions to inspire and inform near-term actions that can accelerate progress towards Liftoff.

Please reference the 2023 VPP Liftoff Report for the following:

- VPP and Distributed Energy Resource (DER) definitions
- VPP value proposition
- Associated business models
- Technology in use
- Deployment potential
- Five imperatives for VPP liftoff, associated challenges, and potential solutions

Terminology

VPPs are aggregations of DERs that can balance electricity demand and supply and provide utility-scale and utility-grade grid services.[i] This report uses the term 'Virtual Power Plants' (VPPs) given it is the predominant term used in the industry, though it recognizes that other organizations use varying terms to describe similar grid assets. The National Association of Regulatory Utility Commissioners (NARUC) uses aggregated DERs (ADERs) to describe groups of DERs capable of providing one or more services to the electric grid through dispatch or control.[ii] Electric Power Research Institute (EPRI) uses the term distributed energy resource aggregations (DERAs). Other industry actors use the term distributed power plants (DPPs). This report's definition of Virtual Power Plants includes grid assets that meet the definition of all these terms, including traditional demand response (DR).

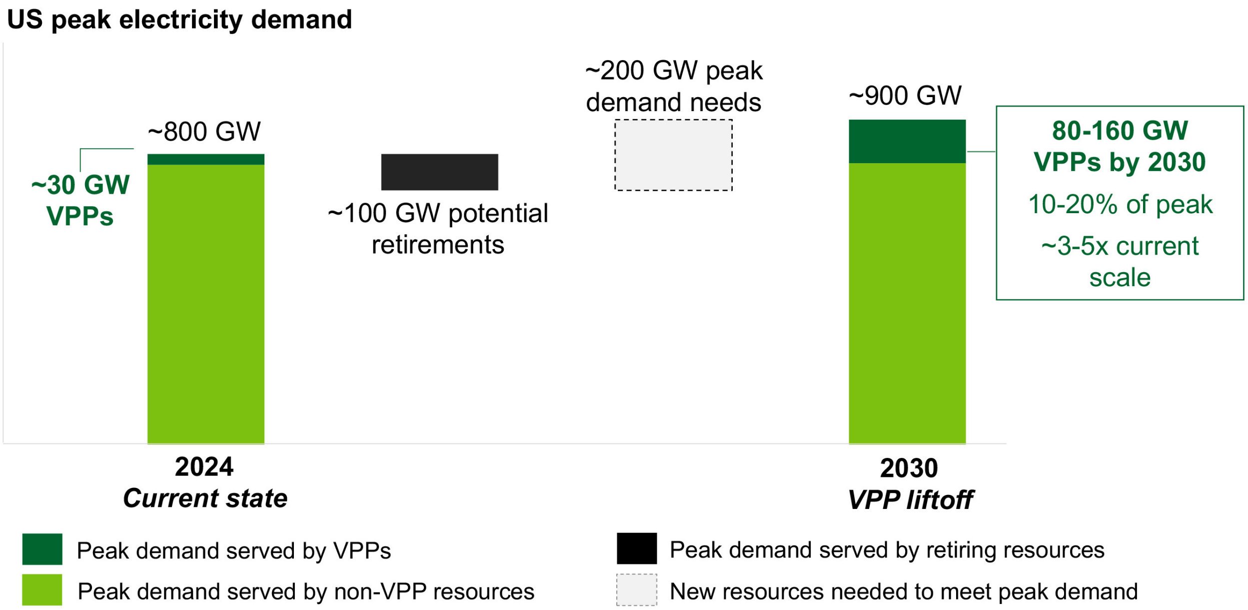
Executive Summary

Virtual Power Plants (VPPs) are solutions that can be deployed at scale in a short timeframe to maximize the use and value of existing grid infrastructure, minimize costs to ratepayers, and ensure a resilient, reliable, and secure grid for all Americans.

Recall from the 2023 Liftoff Report

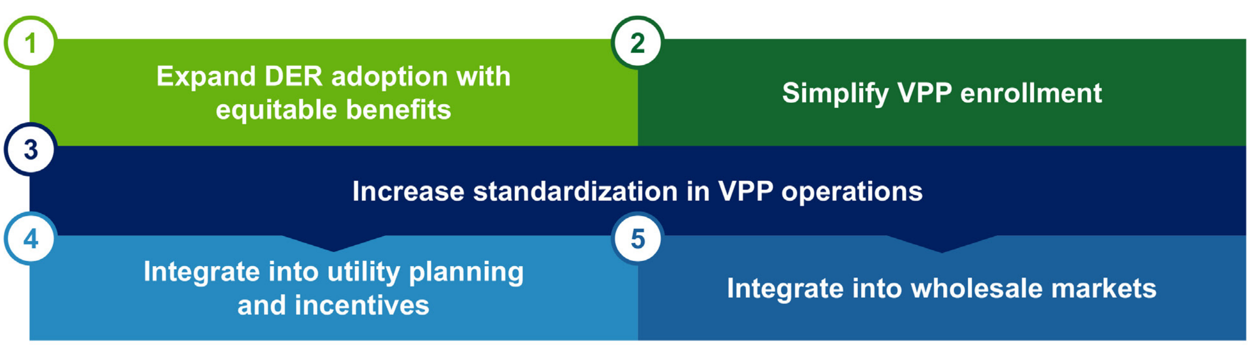
VPPs are aggregations of distributed energy resources (DERs) such as rooftop solar with behind-the-meter (BTM) batteries, electric vehicles (EVs) and electric water heaters, smart buildings and their controls, and flexible commercial and industrial (C&I) loads that can balance electricity demand and supply, as well as provide utility-scale and utility-grade grid services.

VPP liftoff



Deploying 80-160 GW of VPPs (enough to serve 10-20% of peak load) by 2030 could support rapid load growth while reducing overall grid costs. Although VPP scale has grown over the past year to 33 GW across North America[iii], the pace of deployment must accelerate to achieve liftoff.

Achieving liftoff will require progress on five imperatives:



Since DOE published the 2023 VPP Liftoff Report in September 2023, the pressures on the U.S. electric grid have intensified.

- **Reliability:** Peak demand is expected to increase from approximately 800 GW in 2024 to approximately 900 GW in 2030 due to growth in energy-intensive data centers, domestic manufacturing, and electrification of transport and heating.[iv]
- **Affordability:** Utility capital investments for the transmission and distribution grid have grown by 10.8% and 14.6% respectively from 2022 to 2023.[v] Capital investments are only expected to continue growing[vi] to meet rising load growth and replace aging assets, putting upward pressure on future electricity costs for ratepayers. This increases the importance of ensuring cost-effective grid investments to mitigate cost increases for ratepayers.
- **Resilience:** The U.S. experienced a record 28 'billion-dollar'[1] extreme weather events in 2023 that caused $95B of damage and injury.[vii] These extreme weather events are responsible for 75-80% of U.S. power outages for households and businesses.[viii]

VPPs are among the critical solutions to meet the pressing challenges the grid faces today and in the near term to keep electricity rates affordable while maintaining grid reliability and resilience.

Utilities, aggregators, policymakers, regulators, and other industry partners are taking action to implement solutions against each of the five imperatives for VPP liftoff. Replicating these proven solutions across the country could accelerate VPP deployment to reach liftoff by 2030.[2]

Expanding DER adoption with equitable benefits

Upfront incentives that stack across available Federal, state, city and tribal programs, inclusive utility investments, and partnerships with community-based organizations are strategies helping all communities today realize the reliability, resiliency, and affordability benefits from DERs and VPPs.

For example, San Diego Community Power's Solar Battery Savings program uses upfront, stackable incentives to provide the opportunity for no-cost solar panels and batteries for underserved communities.

Simplifying VPP enrollment

In addition to the ~30 GW of VPP capacity already enrolled today, enrolling 30-50% of the 150-200 GW of *new dispatchable* DER capacity that is projected to be added to the grid between now and 2030 could achieve liftoff nationally.

Utilities, regulators, and policymakers are harnessing existing and expected DER capacity and achieving best-in-class enrollment rates by pre-enrolling customers in VPP programs with opt-outs (instead of the opt-in method that is most common today), simplifying messaging about program benefits, and offering ongoing participation incentives.

For example, Arizona Public Service's marketplace pre-enrolls customers at point of purchase into their smart thermostat Cool Rewards program (9,290 pre-enrollments processed as of October 2024).

1 Billion-dollar events are weather and climate events that caused more than $1B of damage.

2 For additional information on challenges and potential solutions for each of the imperatives, see Chapter 4 in the 2023 VPP Liftoff Report (pages 38-52).

Increasing standardization in VPP operations

New efforts across the industry are designing standards for utility-aggregator interfaces, aggregator-DER interfaces, cybersecurity responsibilities, and other aspects of VPP operations.

Even in the absence of standards, many utilities are capturing near-term value now with basic VPP configurations that require less than $1M in upfront investment and can be deployed in less than six months to deliver valuable peak shaving benefits. Leading utilities leverage basic VPPs as the foundation for more sophisticated models (which require enabling hardware and software) that deliver distribution grid benefits in addition to bulk system-level peaking capacity.

- *Example standardization efforts include the development of a model grid services contract from the North American Energy Standards Board and device interoperability standards from the Mercury Consortium.*
- *An example of a rapid, utility-led VPP deployment is National Grid's ConnectedSolutions program, which launched in under four months and now has 250 MW of peak shaving capacity in MA and NY.*

Integrating into utility planning and incentives

Most utilities can implement some form of VPPs today without any policy or regulatory change. However, VPP deployment has been highest in areas where state regulators and policymakers have implemented VPP-supportive actions.

Regulators are motivating utility action that is more in line with ratepayer interest by establishing cost recovery pathways for VPP-related investments, improving system planning, supporting DER deployment and aggregation, and enhancing VPP operation and compensation models. Policymakers are using legislation to accelerate deployment by establishing a direction and removing ambiguity about VPP goals and other program parameters for utility regulators and other stakeholders.

- *An example of VPP-supportive regulation is the New York Public Service Commission's Value of Distributed Energy Resources (VDER) mechanism to compensate DERs based on their system value.*
- *An example of VPP-supportive legislation is a bill signed by Colorado's legislature in May 2024, SB24-218, that requires the state's largest Investor-Owned Utility (IOU), Xcel Energy, to submit a VPP plan to the Colorado Public Utility Commission.*

Integrating into wholesale markets

CAISO and ISO-NE have fully complied with the requirements of FERC Order 2222[3], theoretically unlocking wholesale market participation from a much wider range of DERs in those regions. Challenges to integrate VPPs into wholesale markets remain, particularly on data access, metering requirements, and participation models. However, market operators, state policymakers, and regulators, can collaborate to learn from each other's experiences and quickly iterate to enable VPPs to meet near-term grid capacity needs at lower costs for ratepayers.

➔ *For example, CAISO, NYISO, PJM, and SPP allow participants that meet certain criteria to use calculated telemetry readings based on sampling rather than requiring direct telemetry for each DER to participate. This allows a greater number of DERs to participate given relaxed telemetry requirements and reduced participation costs.*

Public and private sector stakeholders are taking action. This report includes over 75 examples of actions that utilities, aggregators, OEMs, regulators, policymakers, ISO/RTOs, ecosystem partners, and others are implementing today as well as **over 60 complementary programs and resources** that DOE and its collaborators have established to accelerate deployment. Stakeholders can adopt and adapt demonstrated best practices from across the country and leverage existing tools and resources to achieve VPP liftoff and contribute to a reliable, affordable, and resilient grid.

3 In September 2020, FERC (Federal Energy Regulatory Commission) approved Order 2222, which required the six FERC-jurisdictional Independent System Operators (ISOs) and Regional Transmission Organizations (RTOs) to allow participation of VPPs (referred to in the Order as "DER Aggregations") in wholesale markets. The six FERC-jurisdictional ISO/RTOs are California Independent System Operator (CAISO), Southwest Power Pool (SPP), Midcontinent Independent System Operator (MISO), New York Independent System Operator (NYISO), PJM Interconnection (PJM), and ISO New England (ISO-NE).

Introduction: Why VPPs now?

Key takeaways

- Rapid growth in peak electricity demand by 2030, capital-intensive transmission and distribution (T&D) upgrades to accommodate expected load growth, and outages due to extreme weather events and aging infrastructure are placing disproportionate pressure on grid reliability, affordability, and resilience.
- VPPs are cost-effective solutions for balancing the grid that can be deployed at scale within six months to maximize the use and value of existing infrastructure, minimize costs to ratepayers, and ensure a resilient, reliable, and secure grid for all.

Since the VPP Liftoff Report was published in September 2023, the near-term pressures on the U.S. electric grid have intensified. Forecasts of U.S. peak demand growth have increased sharply in the past year due to a surge in interest in artificial intelligence (AI) applications powered by energy-intensive data centers, hundreds of new domestic manufacturing site developments, and the continued electrification of transportation and heating. This increase in forecasted load growth will require greater utilization of local resources to satisfy electric power requirements. At the same time, recent extreme weather events have heightened awareness of the vulnerability of the grid and the need to invest in resilience. The culmination of these challenges necessitates historic investments to shore up the U.S. power system – costs that may fall on ratepayers already burdened by rising energy costs.

i. Near-term grid challenges

Reliability: *Rapid demand growth*

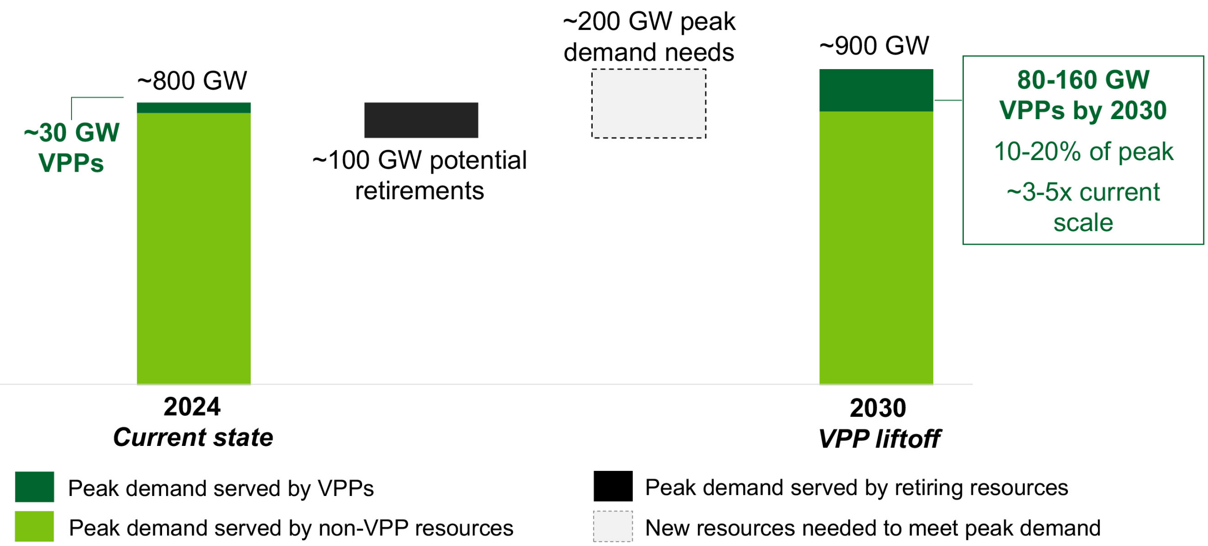
After two decades of flat electricity demand, the U.S. is returning to a period of rapid demand growth with total electricity demand expected to grow ~15-20% in the next decade.[4,5,ix,x] The 2023 VPP Liftoff report estimated that new resources serving over 200 GW of peak demand would need to be added to the grid by 2030 to meet demand growth and replace retiring resources. Since 2023, retirement schedules and growth forecasts have both shifted, but the net result of roughly 200 GW of peak demand needs by 2030 remains.

4 NERC forecasts from December 2024 suggest total electricity will increase from 150,540 GWh in 2024 to 176,040 GWh in 2034. Total electricity demand is measured over the course of a year and is distinct from peak demand, which is a point-in-time measurement.

5 See the DOE's Electricity Demand Growth Resource Hub for additional information about and DOE resources to support rising electricity demand.

VPP liftoff

US peak electricity demand



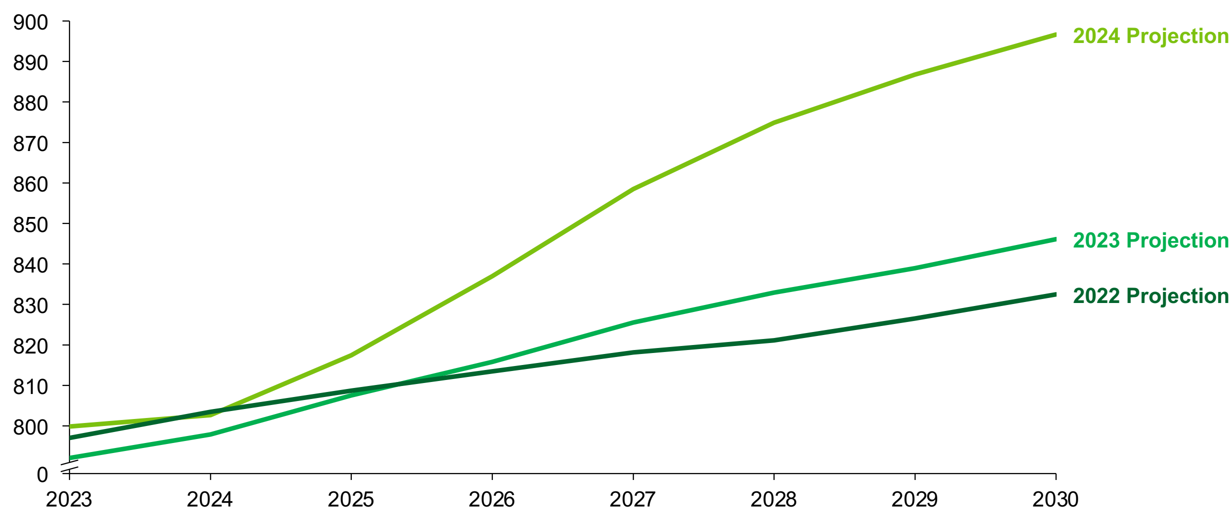
Note: NERC's Electricity Supply & Demand peak hour demand forecasts include 2024 peak summer demand as 803 GW and estimates 2030 peak summer demand to be 897 GW.[xi,xii,xiii] NERC's 2024 Long-Term Reliability Assessment estimates that 52 GW of generators are confirmed to retire by 2029, with anticipated and announced retirements estimated to be close to 100 GW by 2030.[xiv] For this reason, the need is estimated to be ~200 GW of firm capacity (~100 GW new peak demand + ~100 GW peak demand no longer served by retired assets, not accounting for planning reserve margin or the non-firm capacity de-rates of retiring resources). 30-60 GW estimate of VPP capacity in 2023 VPP Liftoff Report was adjusted to ~30 GW based on Wood Mackenzie's North America VPP Market Report,[xv] which estimates that there is 33 GW of VPP capacity in North America with the majority considered to be in the U.S.

Source: NERC 2024 Long-Term Reliability Assessment, NERC 2024 Electricity Supply & Demand data, Wood Mackenzie 2024 NA VPP Market Report

Demand growth reflects economic development, though the specific drivers of demand growth vary by region. At a national level, the three primary drivers of demand growth are data center development (including to support AI applications),[xvi] a surge in manufacturing investments (with over 900 new and expanded manufacturing facilities announced as of December 2024), and end-use electrification (e.g., transport, buildings, industrial).[xvii,xviii]

Demand growth forecasts continue to evolve rapidly. This uncertainty increases the importance of prioritizing the most cost-effective and flexible resources to serve rapidly changing conditions.[xix,xx]

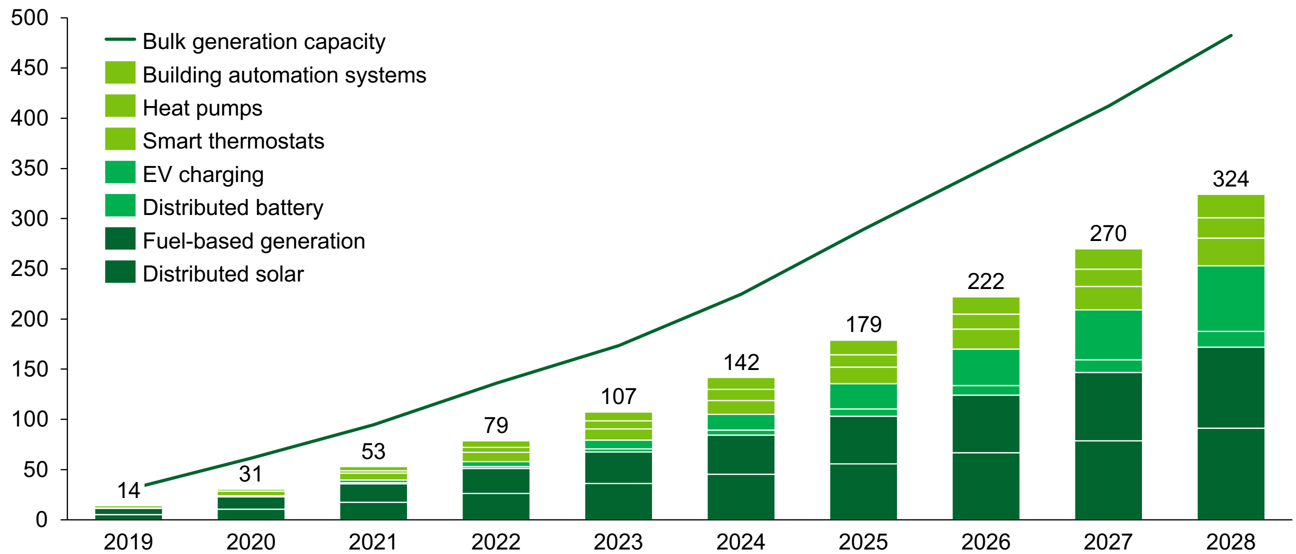
U.S. summer peak hour demand by year (2023-2030), GW



Source: NERC 2024 Electricity Supply and Demand data

Installed capacity of distributed energy resources (DERs) is forecasted to grow nearly as fast as forecasted bulk generation capacity in the next five years, with an incremental 217 GW of DERs expected by 2028.[xxi] DER growth is expected in every state, though the pace varies regionally, with growth likely to be concentrated in specific geographies. Without efficient management of these resources, such as with a VPP, expected growth of DER capacity at the grid-edge[6,xxii] in these regions could strain local, aging distribution systems and increase the cost to deliver electricity.

DER vs bulk generation capacity additions since 2019, GW



Source: Wood Mackenzie 2024 US DER Outlook

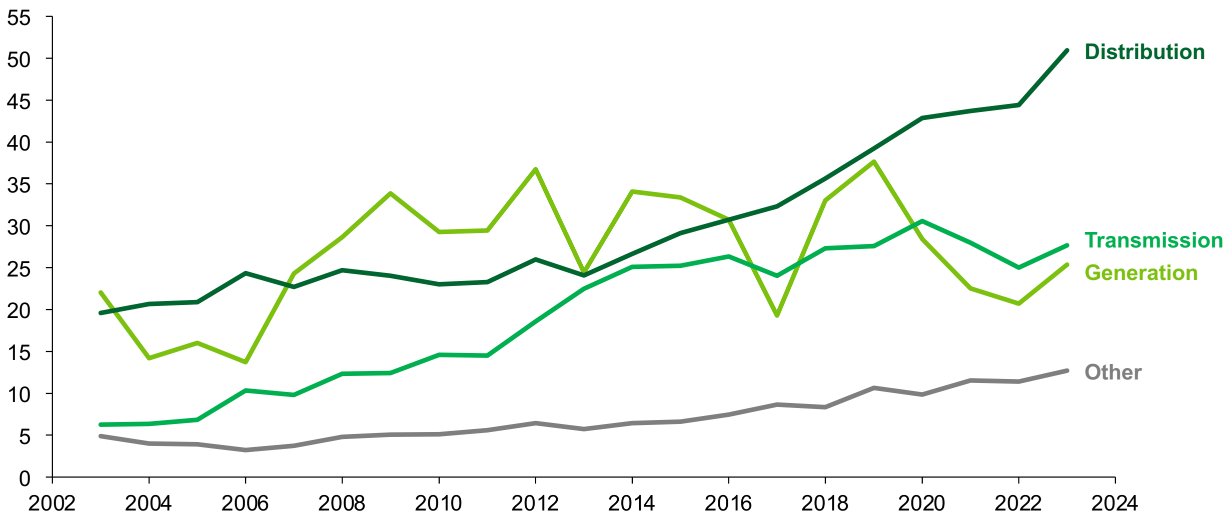
Affordability: *Upward pressure on customer costs from growing capital investments*

Capital investments in transmission and distribution (T&D) systems are growing to meet rising load growth and replace aging assets, impacting affordability. Over the last two decades, total utility spending on electricity generation has fallen, primarily due to lower fuel costs (e.g., growth in low-cost renewables, lower natural gas prices). However, these declines have been offset by a significant increase in T&D investment, particularly distribution investment, led by capital costs to upgrade, replace, and add new infrastructure.[xxiii]

Utility capital investments in the distribution system grew by 14.6% from 2022 to 2023; capital expenditures (versus operating & maintenance expenditures) now comprise the majority of spending for distribution infrastructure.[xxiv] In the U.S. Energy Information Administration's (EIA) 2023 Annual Energy Outlook (AEO 2023) projections, average combined transmission and distribution prices are expected to grow by 12% between 2023 and 2030 after accounting for inflation, even as total electricity prices decline.[xxv] Since the release of AEO 2023, load forecasts have increased and rising load growth will further increase grid investment needs. These higher grid investments put upward pressure on future electricity costs for ratepayers.

6 The grid edge is defined as the area where the electricity distribution system transitions between the utility and the end user. Additional details are included at DOE's Supercharging the Electric Grid Edge web page.

Annual U.S. capital expenditures by sector (2003-2023), billions of 2023 U.S. dollars ($)



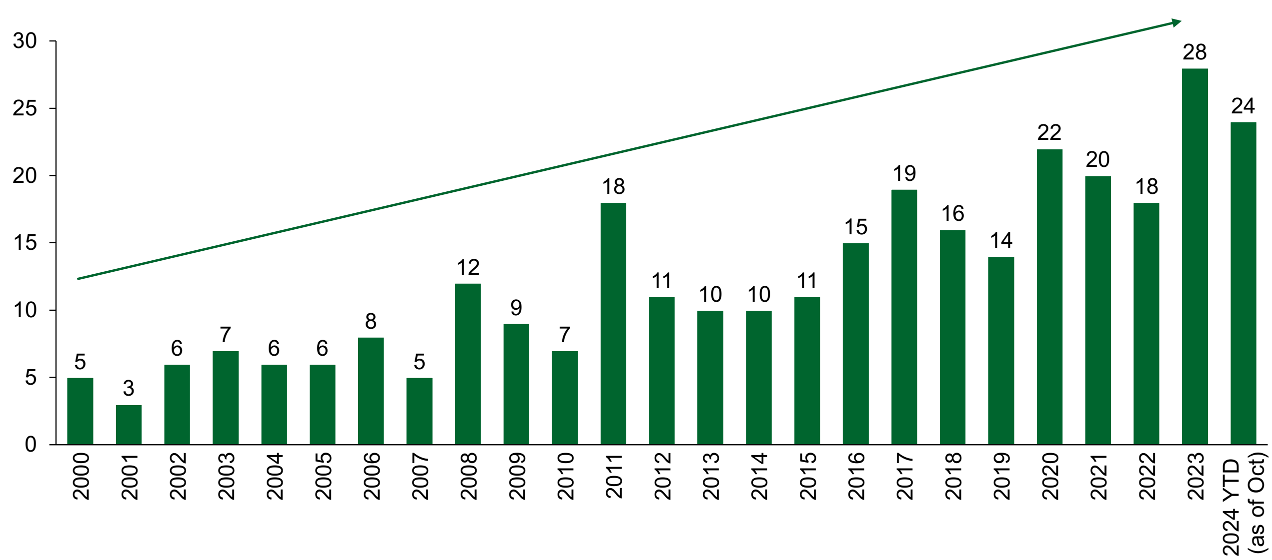
Source: FERC Form 1 (Electric Utility Annual Report)

Rising energy costs have a disproportionate impact on low-income Americans. Nearly one in four households in the U.S. was unable to pay their full energy bill for at least one month in the last year.[xxvi] Maintaining electricity affordability in the face of increasing utility transmission and distribution investments, which have increased from 10% of customer bills in 2005 to 24% in 2020,[xxvii] is particularly important for these households.

Resilience: *Increasingly frequent extreme weather events*

Increasingly frequent extreme weather threatens grid resilience. In 2023 alone, the U.S. experienced a record 28 separate billion-dollar climate disasters that caused $95B of damage and injury.[xxviii,7] 75-80% of U.S. power outages are due to extreme weather events, according to Climate Central.[xxix]

Number of billion-dollar climate and weather events, count / year (adjusted for inflation)



Source: NOAA Billion-Dollar Weather and Climate Disasters

7 Climate disasters disproportionately affect underserved communities, which already often have lower energy reliability than higher income areas.

ii. VPP value proposition

How VPPs address near-term grid challenges

Near-term grid challenge	VPP value proposition	Example
Reliability: Rapid demand growth	**Impact #1: VPPs provide valuable peak shaving benefits** 10-20% of 2030 peak demand could be served by VPPs	• **Portland General Electric's** VPP reduced peak demand load by 2% in 2024; PGE is targeting 25% of peak demand met by flexible load solutions by 2030.
	Impact #2: VPPs are quick to deploy Basic VPPs can be operationalized in <6 months to meet rapid growth	• **National Grid** launched its ConnectedSolutions program in under 4 months to provide peak shaving benefits.
Affordability: Upward pressure on customer costs from growing capital investments	**Impact #3: VPPs are low-cost solutions** VPP peaking capacity is 40%+ cheaper than a conventional peaker plant VPPs can reduce distribution costs by providing greater locational visibility and control VPPs can offset energy bills by compensating customers	• **ConEdison** deferred a $1.2B substation upgrade, spending $200M on DERs and demand reduction measures instead. • **United Power** used 95 MW of flexible DER capacity and improved grid visibility to reduce transformer outages from 25,000 min/year to near 0. • **San Diego Community Power** uses their Solar Battery Savings Program to incentivize customers to adopt residential batteries for daily dispatch to realize $5M of Resource Adequacy savings.
Resilience: Increasingly frequent extreme weather events	**Impact #4: VPPs improve grid reliability and resilience** Solar with batteries and/or fuel generator VPPs can provide backup power during emergencies	• **Duke Energy** spent $14.5M on a microgrid to provide reliable power to a rural town at a lower cost than alternatives. • **Green Mountain Power's** Zero Outages initiative plans to combine traditional resilience approaches with energy storage deployment through batteries and microgrids.

See 2023 VPP Liftoff Report pages 8-12 for detail on the VPP value proposition across resource adequacy, affordability, reliability & resilience, decarbonization & air pollution reduction, T&D infrastructure relief, community empowerment, and versatility & flexibility.[xxx]

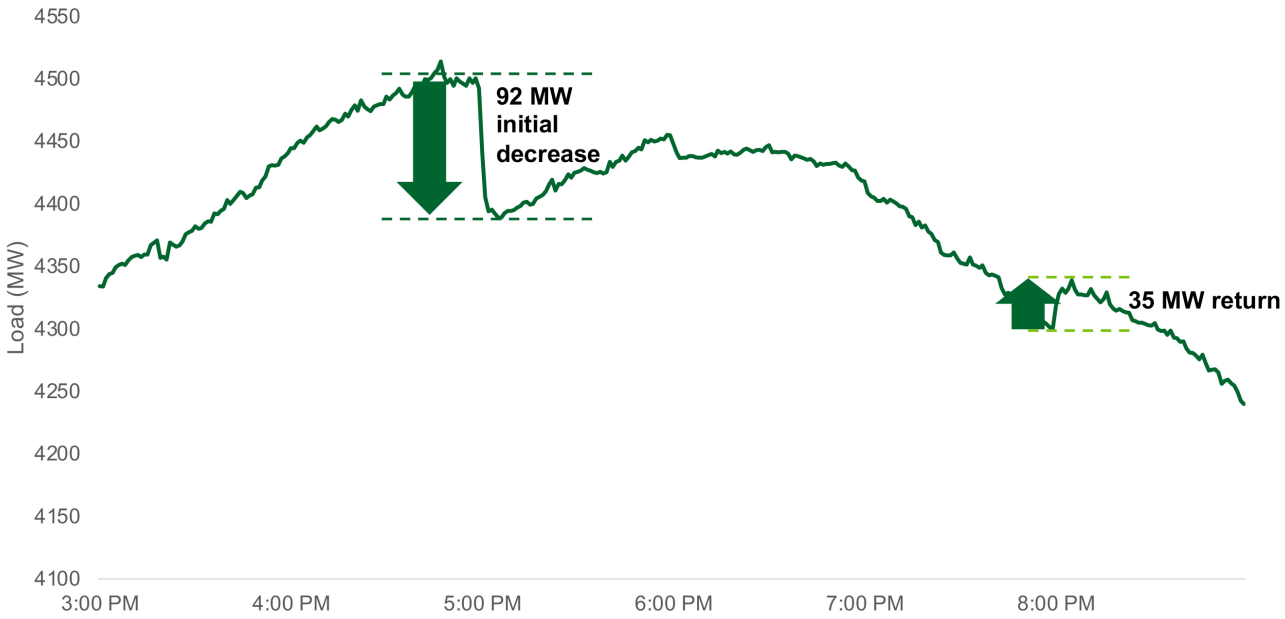
Impact #1: VPPs provide valuable peak shaving benefits

VPPs provide valuable peak shaving benefits to the grid. VPPs can aggregate DERs to serve, shift, and reduce energy demand to address growing peak demand needs and relieve grid capacity constraints. By more efficiently balancing the timing of demand with available supply, VPPs can address system constraints at the generation level (e.g., serve peak demand with storage DERs), at the transmission level (e.g., reduce peak demand when utility-scale supply is limited by transmission constraints), and distribution level (e.g., shift peak demand that threatens to exceed the safety limits of local equipment to earlier or later in the day).

One example of a utility taking advantage of this potential is **Portland General Electric (PGE)**. PGE plans to grow its VPP from serving ~2% of peak demand today to ~25% of peak in 2030.[8,xxxi,xxxii] PGE plans to increase its VPP capacity by encouraging greater participation from new and existing solar and storage assets, flexible customer loads, and customer back-up generation.

8 PGE has been growing their Customer Flexible Load programs and VPP capabilities for over two decades.

Bulk system impact from Portland General Electric's peak shaving program (August 14, 2023)



Source: Portland General Electric

Impact #2: VPPs are quick to deploy

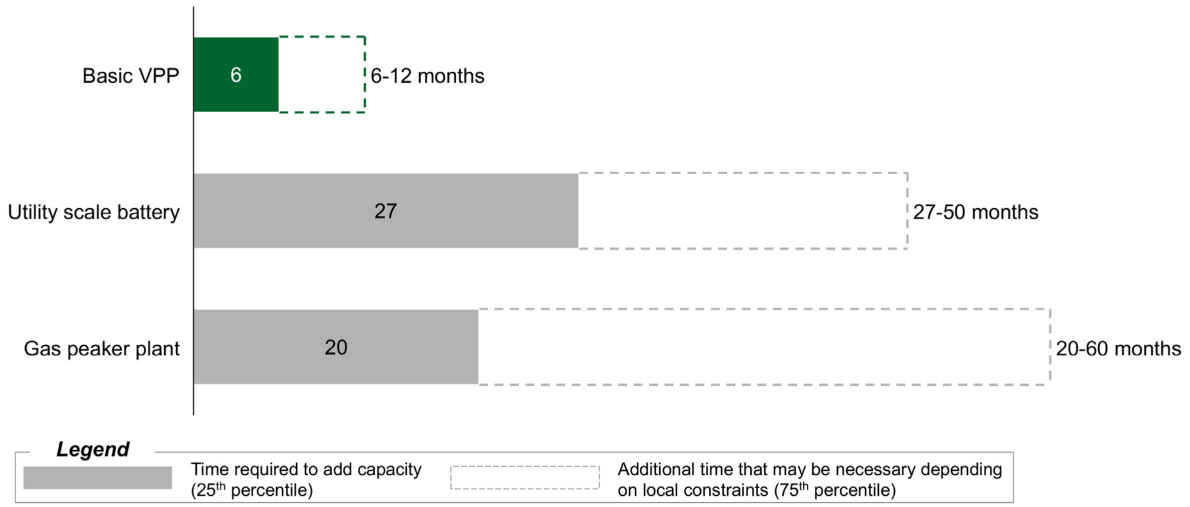
Basic VPPs that shave demand peaks can start operating within six months[xxxiii]; this can buy time for the construction of higher-capacity assets and increase the value of grid assets for which Americans have already paid. Basic VPP configurations[9] can leverage DERs that are *already on the grid* or expected to be deployed to serve as the foundation for fast-launching, large-scale VPP programs. Wood Mackenzie estimates that U.S. consumers and businesses will install 324 GW of new DERs between 2019-2028, representing 137 GW of curtailable capacity[10] if enrolled in VPPs.[xxxiv]

Traditional approaches to increasing grid capacity (utility-scale generation, transmission, distribution) rely on investing in large, centralized physical infrastructure, such as building fossil fuel-powered peaker plants and upgrading transformers. These upgrades are facing lengthening delays for several reasons. New electricity generation facilities are waiting four to six years in transmission interconnection queues before they can connect to the grid to supply power.[xxxv] Long distance greenfield transmission projects often face lengthy permitting timelines, with review periods that average 4.3 years and can extend up to 11 years.[xxxvi] Lead times to procure large transformers (greater than 500 MVA) are averaging three years due to supply chain issues.[xxxvii]

9 For an explanation of basic vs. more sophisticated VPP configurations, reference Chapter 3: Increasing standardization in VPP operations.

10 Curtailable capacity includes flexible capacity from smart thermostats, heat pumps, buildings with energy management systems, and export potential from batteries.

Timeline to add 20 MW of dispatchable peaking capacity, months



Note: Industry participant interviews informed the timeline for basic VPPs, supported by RMI's Reliability Brief from July 2024[xxxviii]. For utility scale battery and gas peaker plant, the timeline includes time from interconnection request to project Commercial Operations (COD) for projects with 2017-2023 CODs; displaying 25th to 75th percentile range. Median values are 40 months for battery and 42 months for gas projects.[xxxix]

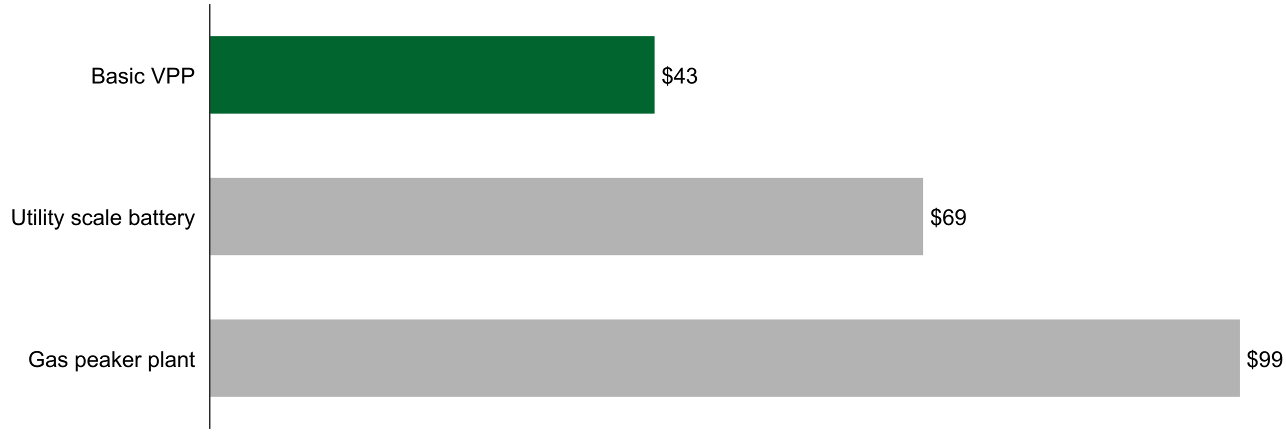
Source: Industry interviews, RMI Reliability Brief, Lawrence-Berkeley National Lab's 2024 Queued Up Report

As an example of how VPPs can address rising electricity demand, **NRG Energy** and **Renew Home** recently announced plans to launch a 1 GW VPP in Texas by 2035, equivalent to 12 gas-fired peaker plants, by leveraging flexible demand from smart thermostats. This announcement comes just months after the Electricity Reliability Council of Texas (ERCOT) revised its 2030 load growth forecasts to 148 GW[xl], **an increase of 40 GW from last year's forecast.**[xli] Rapid peak demand growth requires solutions that can be deployed rapidly.

Impact #3: VPPs are low-cost solutions

VPPs are a cost-effective peak capacity resource relative to traditional investments, both on the bulk power grid and the distribution grid. On the bulk power grid, procuring new system-level peak capacity from a VPP can be lower cost than procuring the same capacity from a natural gas peaker plant or utility-scale battery. These savings, as well as reduced distribution and transmission costs, accrue to all ratepayers (not just VPP participants). An RMI study of an example utility system in 2035 found that a VPP-enabled portfolio reduces net power generation costs by 20% or roughly $140 per household (including non-participating ratepayers) per year compared to a baseline scenario.[xlii] In New York, **ConEdison** deferred a $1.2B substation upgrade in 2014, spending $200M instead on DERs and demand reduction measures as part of the Brooklyn Queens Demand Management Program.[xliii] Beyond these system benefits for all ratepayers, additional financial benefits accrue to customers enrolled in the VPP in the form of incentive payments.

Comparison of net cost to an example utility of providing 400 MW resource adequacy across three options, Net cost per kW-year



Note: Values for 400 MW of peaking capacity are shown in $/kW-yr. The VPP analyzed consists of smart thermostats, smart water heating, home EV managed charging, and BTM battery demand response. Modeled equipment subsidy costs to utility are $75 for smart thermostats, $315 for smart water heaters, and $0 for EV charging and BTM batteries. Marketing costs assumed at $50 per device. Utility studied is assumed to have 50% renewable generation mix, with resource adequacy needs in summer and winter. 8760 hours were considered, and resources must be able to operate in 63 peak hours (when top 400 MW are needed) spanning 7 months, for 7 consecutive hours at a time. Benefits of emissions reduction and resilience are not shown; when included, VPP net cost is lower, though actual emissions impact will vary by local grid mix.[xliv]

Source: Brattle Group's Real Reliability: The Value of Virtual Power Report

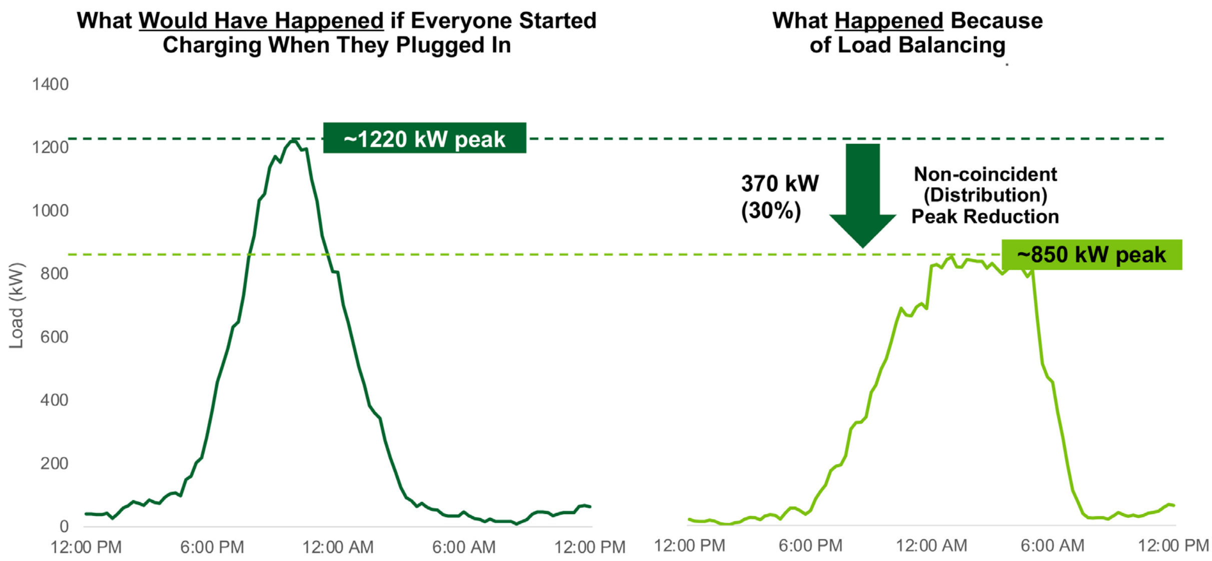
On the distribution grid, VPPs can help utilities defer costly system upgrades by shaving localized peak loads that would otherwise trigger the installation of new equipment. Many utilities facing rising demand are using VPPs as an interim solution until distribution grid capacity upgrades are absolutely necessary, saving ratepayers money in the meantime. A whitepaper co-authored by **AES Indiana** and **Camus Energy** found that deploying visibility solutions to detect where EVs are located on the grid and transitioning to grid-optimized managed charging programs could defer upgrades to 85% of eligible feeders and service transformers for an average of 8.5 years compared to a business-as-usual scenario. Capital cost savings from deferring upgrades were estimated to avoid close to $1B in cost overruns over the next decade, with savings going directly to consumers.[xlv] AES Indiana is *one* utility with 500,000 utility meters. While service areas across the U.S. are diverse, extrapolating to the 150 million meters across the U.S. would imply **significant potential savings[11] by deferring capital investments and optimizing the use of the existing electricity system across generation, transmission, and distribution.[12,xlvi]**

Baltimore Gas & Electric's (BGE) managed charging program demonstrates the peak shaving potential of VPPs on the distribution grid. With a feeder-level participant group of 880 vehicles, BGE's managed charging program created a non-coincident peak reduction of 30% while still serving customer's transportation energy needs. BGE plans to grow its managed charging program from 3,253 residential customers to 30,000 customers by 2027.[xlvii,xlviii]

11 A rough extrapolation of this example to the 150 million meters across the U.S. would imply potential savings of $300 billion over the next decade by deferring capital investments.

12 An LBNL study mentioned the U.S. building sector alone could avoid over $100B per year in power sector costs by leveraging demand-side solutions (e.g., smart thermostats, electric heat pumps, smart control systems) by 2050.

Distribution grid impact from Baltimore Gas & Electric's managed charging program



Source: WeaveGrid

Impact #4: VPPs improve grid reliability and resilience

VPPs provide resilience benefits that traditional generation assets cannot provide—and at a lower cost than alternatives. VPPs that include solar and storage or fuel generators at a household or commercial and industrial site provide power with far fewer possible points of failure than power supplied from a distance by a traditional power plant. VPPs also have the potential to help utilities restore power to impacted areas more quickly, reducing the length of outages for customers impacted by severe weather events.

Much of the grid hardening work in disaster-prone areas has been undergrounding power lines. Although this has been effective in some areas, including pockets of Florida during Hurricanes Helene and Milton[xlix], it has come at a high cost. The **Public Service Commission of Wisconsin** estimates that undergrounding a 69-kilovolt line costs ~5x more per mile versus aboveground installation.[l] Alternatively, utilities are using DERs and VPPs at the end of vulnerable transmission or distribution lines to ensure reliable power at a lower cost than undergrounding lines.

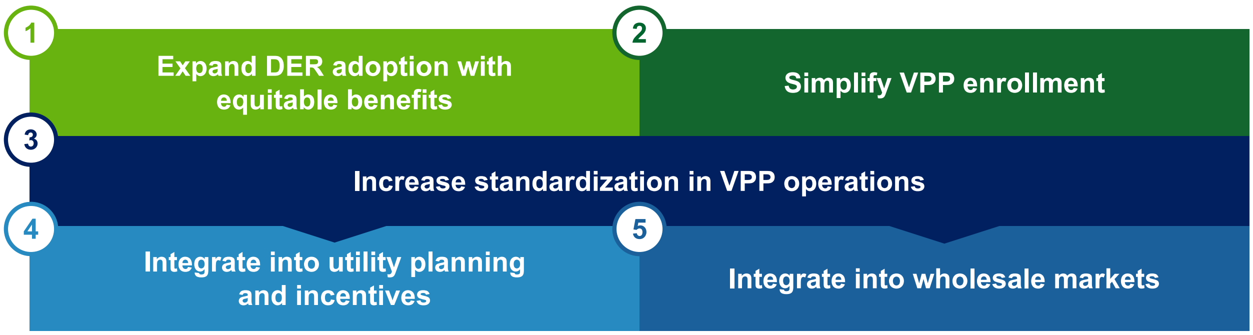
For example, in 2023, **Duke Energy** installed 2 MW of solar power and 4.4 MWh of battery storage along with VPP-enabling technology to create a microgrid in Hot Springs, a town of about 535 residents in North Carolina. With a cost of $14.5M, the microgrid was deemed less expensive than the grid upgrades that would have been required to provide reliable power for the rural town. For the residents of Hot Springs, the microgrid offered resilience; for the surrounding communities, it provided energy and bulk system benefits, such as frequency and voltage regulation and capacity during system peaks.[li] With the Hot Springs microgrid and VPP-enabling investments, Duke Energy restored power to residents quickly after Hurricane Helene in 2024, even though the local substation was severely impacted by flooding.[lii]

iii. Imperatives for VPP liftoff

VPPs are solutions that can be deployed at scale in a short timeframe to maximize the use and value of existing grid infrastructure, minimize costs to all ratepayers, and ensure a resilient, reliable, and secure grid for all Americans.

Deploying 80-160 GW of VPPs (enough to serve 10-20% of peak load) by 2030 could support rapid load growth while reducing overall grid costs. VPPs are not new and have been operating with commercially available technology for years.[liii] While VPP scale has grown over the past year to 33 GW across North America[liv], deployment must accelerate to achieve liftoff by 2030.

As explained in the 2023 VPP Liftoff Report, achieving liftoff for VPPs will require progress on five imperatives:



Utilities, policymakers, regulators, and other industry partners all have a role to play in accelerating action against these five imperatives to address the challenges hampering VPP adoption today.

The potential for VPPs to meet near-term grid needs cost-effectively for American ratepayers represents an urgent call to action for all grid stakeholders to do their part in advancing deployment. Building on the foundation of the 2023 VPP Liftoff Report, the remainder of this Update will explore each of the five imperatives. Starting with a brief overview of the imperative, each chapter and its corresponding appendix will focus on presenting new VPP case studies, new insights into VPP benefits, and new tools and resources from the Department of Energy and broader industry that can support power sector decisionmakers and accelerate progress towards VPP liftoff.

Chapter One: Expanding DER adoption with equitable benefits

Key takeaways

- DER adoption today is a fraction of its potential (e.g., 3.5-3.8% of households have rooftop solar, <1% have BTM batteries, and 12.9-13.8% have smart thermostats). Low DER adoption will limit available capacity for VPPs.
- The main barriers to scaling DER adoption include high upfront costs with limited low-cost financing options, split incentives between property owners and tenants, and knowledge gaps on available programs and incentives, all of which disproportionately affect underserved communities.
- Upfront incentives that stack across available Federal, state, city, and tribal programs, inclusive utility investments, and partnerships with community-based organizations are strategies helping communities today participate in reliability, affordability, and resilience benefits from DERs and VPPs.

1.i. DER adoption today

DER adoption today is a fraction of its potential (e.g., 3.5-3.8% of households have rooftop solar[lv], <1% have BTM batteries, and 12.9-13.8% have smart thermostats[lvi,lvii]). Low DER adoption will limit available capacity for VPPs and reduce the speed at which VPPs can be deployed at scale, delaying potential benefits to ratepayers and the grid. Barriers to accessing DERs include high upfront costs with limited low-cost financing options, 'split incentive gaps' between property owners and tenants for single-unit and multi-unit dwellings[13], and knowledge gaps on available incentives and programs. These barriers are even more pronounced for underserved communities.[14]

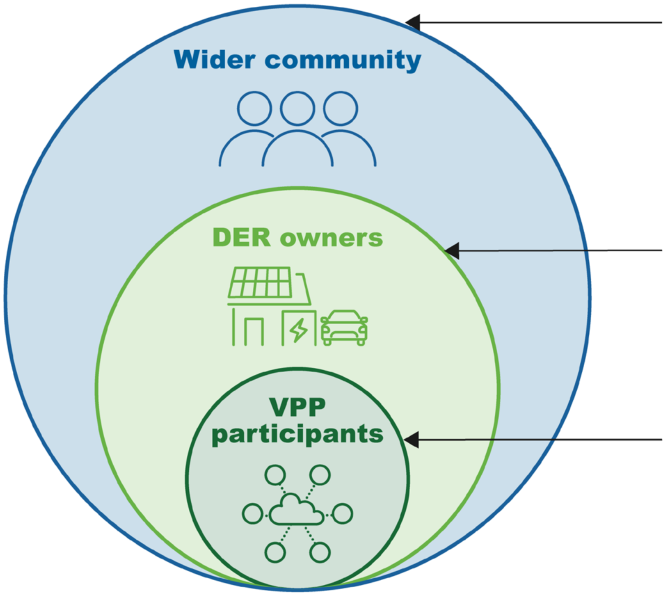
1.ii. Layers of benefits

Ensuring all groups – DER owners, VPP participants, and the wider community – can participate and realize benefits from DER and VPP deployment is critical to realizing reliability, affordability, and resilience benefits for individual households and businesses, and the overall grid.

13 The split incentive gap refers to the tension between property owners, who would be expected to pay for a distributed energy resource, and tenants, who would benefit from lower energy costs. This incentive misalignment is a significant barrier to DER adoption in rented properties.

14 See 2023 VPP Liftoff Report pages 13-17 on the rates of DER penetration and how DER adoption plays a role in VPPs. See pages 39-42 for additional discussion on the barriers for DER adoption and potential solutions

Layers of potential benefits from deploying VPPs



Access to community-wide benefits
Distribute benefits of lower energy bills, reduced impact of outages, improved air quality outcomes, and local workforce development opportunities to participating and non-participating ratepayers.

Access to DER ownership
Make DERs more affordable and increase access to financing so all households and businesses can reap benefits of DER ownership such as lower energy bills, backup power, and improved air quality.

Access to VPP participation
Reduce barriers to VPP enrollment, including lack of accessible programs and limited knowledge of existing programs, to reward participants with incentives that offset the cost of DER ownership.

- **Access to community-wide benefits: Retain and redirect cost savings from VPP deployment (vs. alternative CapEx heavy investments) toward reducing all utility customer bills, not just for those participating in VPPs.** Compensating for the total value of all the services VPPs provide to the grid is a way to make sure adoption is beneficial for DER adopters and all ratepayers, but few holistic DER/VPP value frameworks exist today. Additional benefits can be intentionally directed to underserved communities to help address those communities' higher energy burdens[15], increased incidence of outages, and lower air quality outcomes.[16]

- **Access to DER ownership: Make DERs more affordable and increase access to financing so the benefits of DER ownership (e.g., reduced energy bills from efficient appliances, backup power options from batteries and generators, and improved air quality from electric conversions) are accessible to all.** Today, DER adoption is an individual choice – households and C&I facilities choose whether installing these DERs is economical given their circumstances. High upfront and financing costs may limit access to widespread DER adoption.

- **Access to VPP participation: Reduce barriers to VPP enrollment so that more households and businesses can take advantage of VPP participation payments.** Homes and C&I facilities that have installed DERs choose to participate in a VPP by enrolling in available programs. Lack of accessible programs and limited knowledge of existing programs can limit participation.[17]

See Appendix A.i. for a comprehensive set of actions that stakeholders can take to expand access to community-wide benefits, DER ownership, and VPP participation.

1.iii. Case studies of expanding access to DER ownership

Public and private sector actors are taking action to reduce barriers to DER adoption and VPP participation, and to spread the benefits of VPP deployment more equitably across participating and non-participating ratepayers. This section, along with detail provided in Appendix A, shares how two utilities built VPP programs to expand access to DER ownership for their customers.

15 Energy burden is defined as the percentage of household income that goes toward energy costs.

16 According to RMI's Power Shift report, VPPs could avoid 12 million to 28 million tons of carbon dioxide emissions nationwide by 2035, or 2% to 4% of projected U.S. power sector emissions in 2035.

17 Additional detail on simplifying enrollment can be found in *Chapter 2: Simplifying VPP enrollment.*

Case Study: Roanoke Cooperative, NC

Roanoke Cooperative *uses an inclusive utility investment to reduce upfront cost and financing barriers to adopting water heater control switches and smart thermostats.*

- **Roanoke Cooperative (RC)** launched the Upgrade to $ave program in 2016 to reduce energy bills for the fourth lowest income Congressional district in the U.S.
- The Board of Directors targeted upgrading 1000 homes with energy efficiency and demand response measures. They approved use of the Pay As You Save® (PAYS®) system, an inclusive utility investment model, for the design of the utility program and tariff.[18,lviii,lix]
- RC paid upfront for all cost-effective energy upgrades at a member's residence and recovered its costs through a fixed, monthly cost recovery charge that was lower than the estimated savings from the upgrades on an annual basis.[lx,19]
- To enroll customers, RC assessed the energy savings potential of the building rather than the owner's income or creditworthiness, allowing all members to access low-cost financing options.
- Participating members reduced electricity usage by ~20% because of upgrades and the utility realized peak demand savings of ~20% during summer and winter peaks.
- Including the cost of capital and program operation costs, the utility sees $2M+ NPV over the lifetime of the upgrades.

Detailed case study provided in Appendix A.iii.

Case Study: San Diego Community Power, CA

San Diego Community Power *leverages upfront, stackable incentives to provide the opportunity for no-cost solar and batteries to qualified priority populations.*

- **San Diego Community Power (Community Power)** launched the Solar Battery Savings program in 2024.
- The program was designed to benefit all customers through upfront incentives to lower the initial cost of home solar and battery storage resources.
- Community Power worked with state and local programs to ensure their incentives could stack with other programs such as California's DAC-SASH and SGIP[20,lxi,lxii] programs and the City of San Diego's Solar Equity program to allow priority populations in particular to cover the entire cost of solar and storage resources through available incentives.

Detailed case study provided in Appendix A.iii.

See Appendix A for 13 case studies that are expanding DER adoption with equitable benefits (Appendix A.ii. and A.iii.), 5 additional resources (Appendix A.iv.) and 18 supportive DOE programs (Appendix A.v.).

18 PAYS Essential Elements and Minimum Program Requirements provides additional information on the utility program requirements for a PAYS program and PAYS model tariff shares the tariff design.

19 The program's annual cost recovery is set at less than the estimated savings from the upgrades to ensure immediate reductions in energy costs, and much larger cost reductions once the utility recovers its costs and ends the on-bill charge.

20 DAC-SASH is the Disadvantaged Communities – Single-Family Solar Homes program developed by the California Public Utilities Commission (CPUC) and administrated by GRID Alternatives. This state program provides $8.5 million in incentives annually to help homeowners in disadvantaged communities go solar. SGIP is the Self-Generation Incentive Program developed by the California Public Utilities Commission to provide rebates for qualifying distributed energy systems on the customer's side of the utility meter, including advanced energy storage systems, wind turbines, waste heat to power technologies, pressure reduction turbines, internal combustion engines, microturbines, gas turbines, and fuel cells.

Chapter Two: Simplifying VPP enrollment

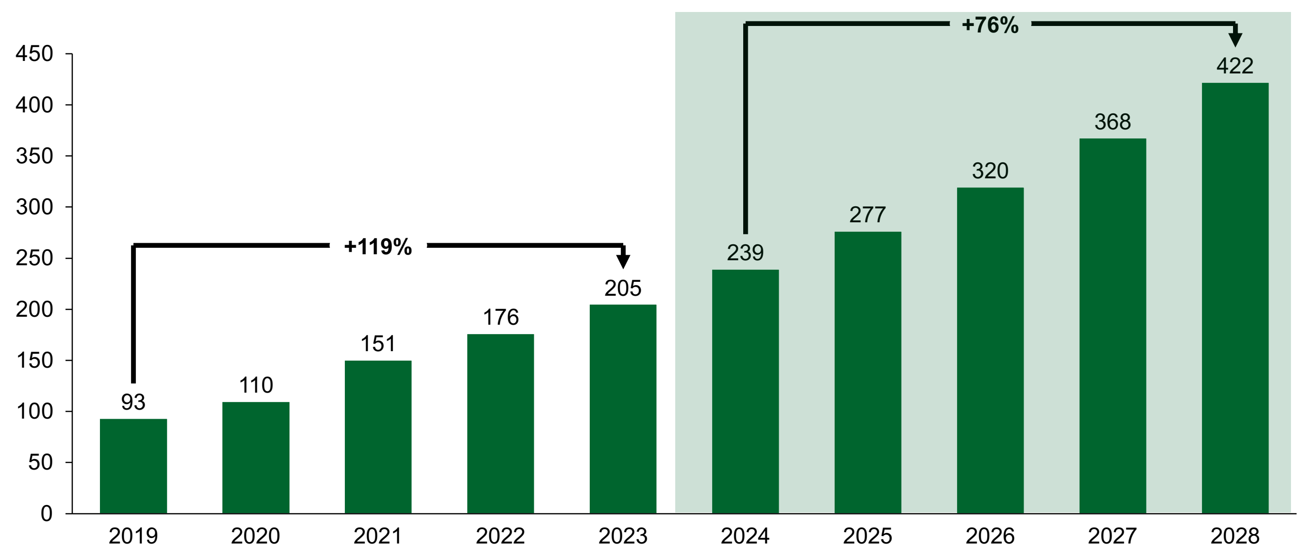
Key takeaways

- VPP deployment can be fast; VPPs can be built and scaled as quickly as customers enroll their devices.
- In addition to the 30 GW of VPP capacity already enrolled today, enrolling 30-50% of the 150-200 GW of *new dispatchable* DER capacity that is projected to be added to the grid between now and 2030 would result in 80-160 GW of VPP capacity nationally.
- Utilities, aggregators, and other industry partners are taking no-regrets (high-impact, low-effort) actions today to improve enrollment, such as communicating concise messaging about program benefits, offering ongoing participation payments, and offering the flexibility to opt out of events.
- These same entities are implementing additional high-impact actions (high-impact, high-effort), but these solutions may require time, effort, and investment to deliver value. For example, automatic enrollment at the point of DER purchase is not widespread today but has been proven to achieve high participation rates without attrition or consumer complaints.

2.i. DER forecasted capacity growth

Across the U.S., DER capacity doubled over the last five years and is expected to nearly double again in the next five years, growing by 217 GW across DER types.

Total DER capacity installed (historical and forecasted), GW

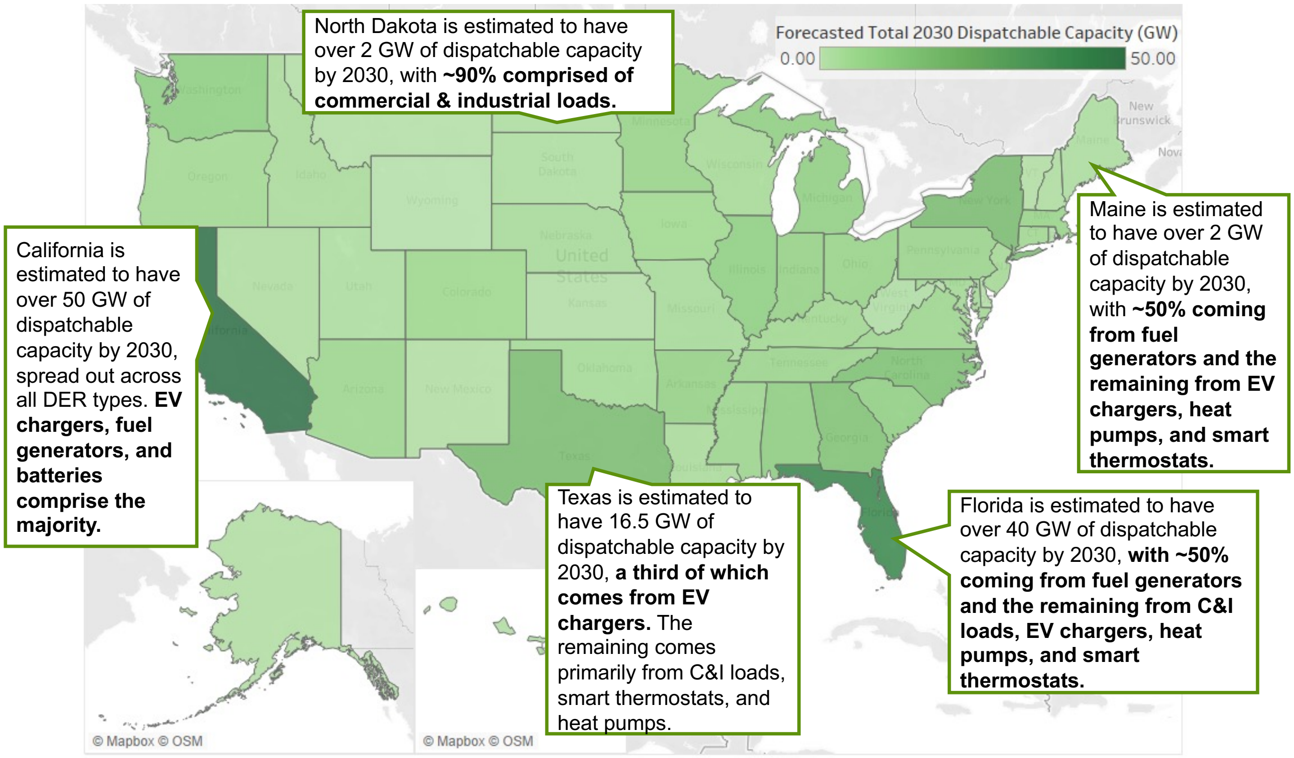


Note: DERs included in capacity projections are smart thermostats, heat pumps, diesel generators, natural gas generators, non-residential solar and storage, residential solar and storage, building automation systems (commercial & industrial loads), and passenger and commercial EV charging.[lxiii]

Source: Wood Mackenzie 2024 US DER Outlook

DER capacity is expected to grow in every state across the U.S., though the magnitude of growth and the types of DERs that come online will vary.

2030 total dispatchable capacity, GW



Note: 2030 total dispatchable capacity is estimated by taking a proportion of total 2030 capacity and applying simplifying assumptions on the proportion that is dispatchable. For solar, batteries, heat pumps, smart thermostats and water heaters, Ohm Analytics estimated 2030 total capacity by state[lxiv]. For EVs and EV charging, NREL's base scenario estimated 2030 total capacity by state.[lxv] For commercial & industrial loads (or building automation systems) and distributed fuel generation, national level estimates from Wood Mackenzie's US DER Market Report[lxvi] were extrapolated to 2030 and allocated to states based on 2022 metering data from EIA.

Source: Ohm Analytics State-Level Residential DER Capacity Forecast, Wood Mackenzie 2024 US DER Market Report, National Renewable Energy Lab The 2030 National Charging Network Report, EIA 2022 Meter Data

Without enrolling available DERs into VPPs, their rapid adoption could strain existing, aging distribution systems that are already near maximum capacity during peak events. Integrating these resources into system planning via VPPs can effectively manage impacts to the distribution system while unlocking additional reliability, affordability, and resilience value for ratepayers (e.g., deferred system upgrades, backup power during emergencies, maximizing use of renewables).

Deploying 80-160 GW of VPP capacity would require enrolling just 30-50% of the dispatchable DER capacity expected to be added to the grid between 2024-2030 – an enrollment rate that is in line with industry estimates for successful VPP programs today.[21] This means 10-20% of peak demand could be served by VPPs in a scenario with baseline forecasts of DER adoption and demonstrated best-in-class VPP enrollment rates.[22] This holds true at the state-level. For example, **Indiana's** state-level peak load for 2030 is estimated to be 19.9 GW and its resource needs are estimated to be 8.5 GW of new generation.[lxvii] Meanwhile, available dispatchable DER capacity is estimated at nearly 8 GW by 2030. Establishing VPP programs and enrolling 25% of total DER capacity in a VPP could meet 10% of peak load by 2030.

21 In Xcel Energy's Northern States Power service territory, over 50% of all eligible residential customers are voluntarily enrolled in some form of air-conditioning load control, with plans for future growth. Otter Tail Power, an investor-owned utility in Minnesota, can reduce its system peak demand by 15% through a portfolio of demand response programs, which are used regularly.

22 See section 4.ii. ('Simplify VPP enrollment') in the 2023 VPP Liftoff Report for detail on the challenges and potential solutions for this imperative (pages 41-43).

Case No. U-21860
Exhibit CEO-3
Witness: Kenworthy
Date: August 22, 2025
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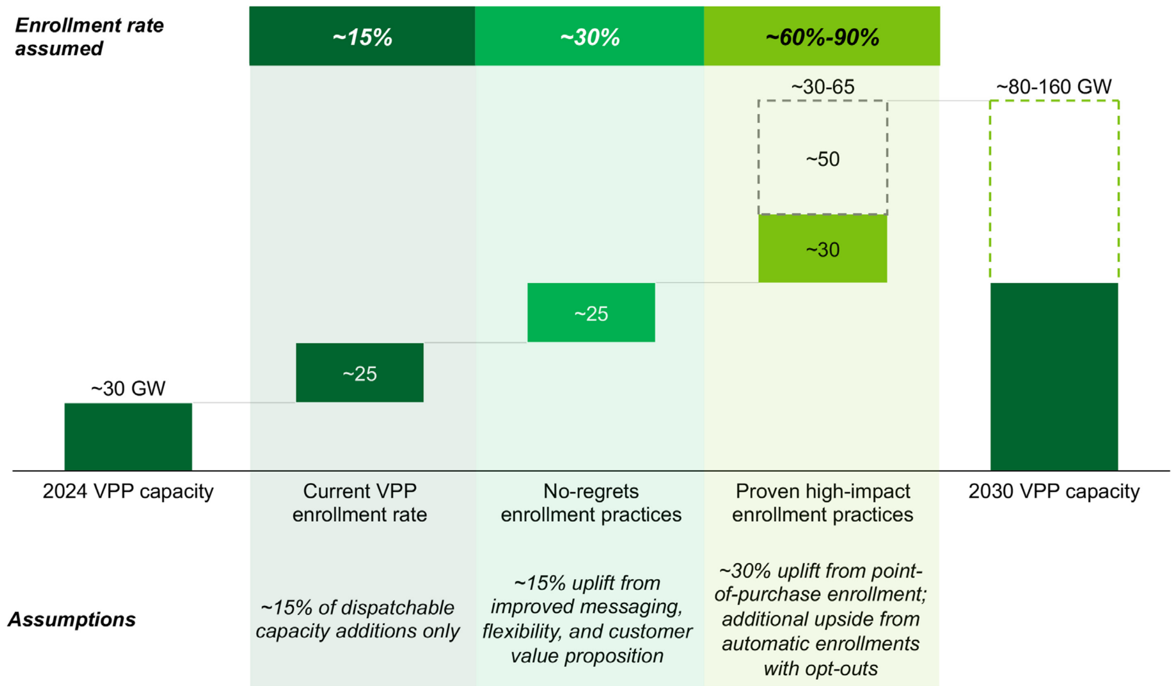
Utilities, aggregators, regulators, and policymakers can prioritize no-regrets and high-impact actions to encourage customers to enroll DERs and participate in the clean energy transition.

Total VPP capacity in various enrollment scenarios, GW



Note: 30 GW of VPP capacity today estimated from 33 GW of VPP capacity in North America based on Wood Mackenzie North America VPP Market Report (majority considered to be in the U.S.).[lxviii] Continued current state assumes ~15% of DER capacity additions are enrolled in VPPs, a relatively conservative estimate. Implementing no-regrets levers assumes ~30% of DER capacity additions are enrolled in VPPs, in line with programs today. Implementing high-impact actions assumes ~60% of DER capacity dispatchable additions are enrolled in VPPs, in line with analyses that calculate enrollment potential from point-of-purchase enrollment[23,lxix], with additional upside from automatic enrollments with opt-outs (up to ~90% of DER capacity additions could be enrolled). Analysis shown above only considers capacity potential from enrolling new DERs procured between 2024 and 2030. Enrolling DERs that are already on the grid as of the end of 2024 would be considered upside.

Source: DOE analysis

2.ii. Case studies of simplifying enrollment

Utilities, aggregators, and other industry partners are taking no-regrets actions today to improve enrollment processes with minimal effort. These entities are also implementing high-impact solutions[24], but these levers may require time, effort, and investment to deliver value.[lxx]

No-regrets actions

Low-cost actions that utilities and aggregators can easily implement to improve enrollment. Examples include clear communication of financial benefits, offering a compelling value proposition, and flexibility to opt out of events.

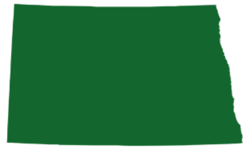
High-impact actions

Actions that can take VPP enrollment to the next level, but may require additional time, effort, and investment to implement. Examples include enrollment at point-of-purchase and automatic enrollment with opt-out.

23 Uplight, a flexibility management platform, found that over 60% of eligible customers purchasing a smart thermostat through their marketplace enrolled in demand response programs when offered at point of sale.

24 Lawrence Berkeley National Lab and Brattle Group conducted a study working with industry partners to determine the level of effort and the level of impact for 30 enrollment levers. No-regrets actions in this report are defined as levers that were deemed "high-impact" and "low-effort." in that analysis. High-impact solutions are defined as levers that were deemed "high-impact" and "high-effort" in that analysis. See the Distributed Energy, Utility Scale: 30 Proven Strategies to Increase VPP Enrollment for additional detail on 30 strategies to increase VPP enrollment.

Case Study: Minnkota Power Cooperative, ND *(No-regrets action)*



Minnkota Power Cooperative *enrolled 40% of customer base by communicating financial benefits of enrollment in simple and concise terms.*

- **Minnkota Power Cooperative's** demand response program has enrolled 55,000 customers (40% of customers) and can serve 350 MW, 35% of winter peak load,[lxxi] through the program.[lxxii]
- Minnkota provides clear financial benefits for enrollment and participation – upfront incentives to purchase the DERs and customer eligibility for the off-peak program rate, which is roughly half the standard rate, to enroll in the program.[lxxiii]
- During peak events, Minnkota is able to temporarily control DERs including heat pumps, water heaters, EV chargers, and commercial & industrial loads.
- Minnkota also worked to cultivate widespread buy-in from member distribution co-operatives to message the enrollment benefits, providing customers a uniform messaging approach.[lxxiv,lxxv]

Case Study: Arizona Public Service, AZ *(High-impact action)*

Arizona Public Service *Cool Rewards enrolled 97,500+ thermostats by establishing an online marketplace that offers pre-enrollment at point of purchase.*

- **Arizona Public Service (APS)** launched **Cool Rewards**, a smart thermostat program, in 2018 after the Arizona Corporation Commission authorized demand response and load management programs for the utility.
- As of November 2024, the Cool Rewards program has enrolled over 97,500 connected thermostats with the ability to shed over 160 MW of load during peak demand events from both residential and small to medium-sized business customers.
- APS established a smart thermostat marketplace on their website where all customers could get an instant $30 rebate at checkout.[lxxvi]
- APS allowed customers to receive an additional $85 off upfront by pre-enrolling into the Cool Rewards program after providing basic information (e.g., name and address).
- Embedding pre-enrollment into the point-of-sale process reduces marketing and recruiting costs for the program. As of the end of October 2024, 9,290 Cool Rewards pre-enrollments were processed through APS marketplace, which was built in partnership with **Enervee**.[lxxvii]

Detailed case study provided in Appendix B.ii.

See Appendix B for 9 case studies that are simplifying VPP enrollment (Appendix B.i. and B.ii.), 6 additional resources (Appendix B.iii.) and 2 supportive DOE programs (Appendix B.iv.).

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Chapter Three: Increasing standardization in VPP operations

Key takeaways

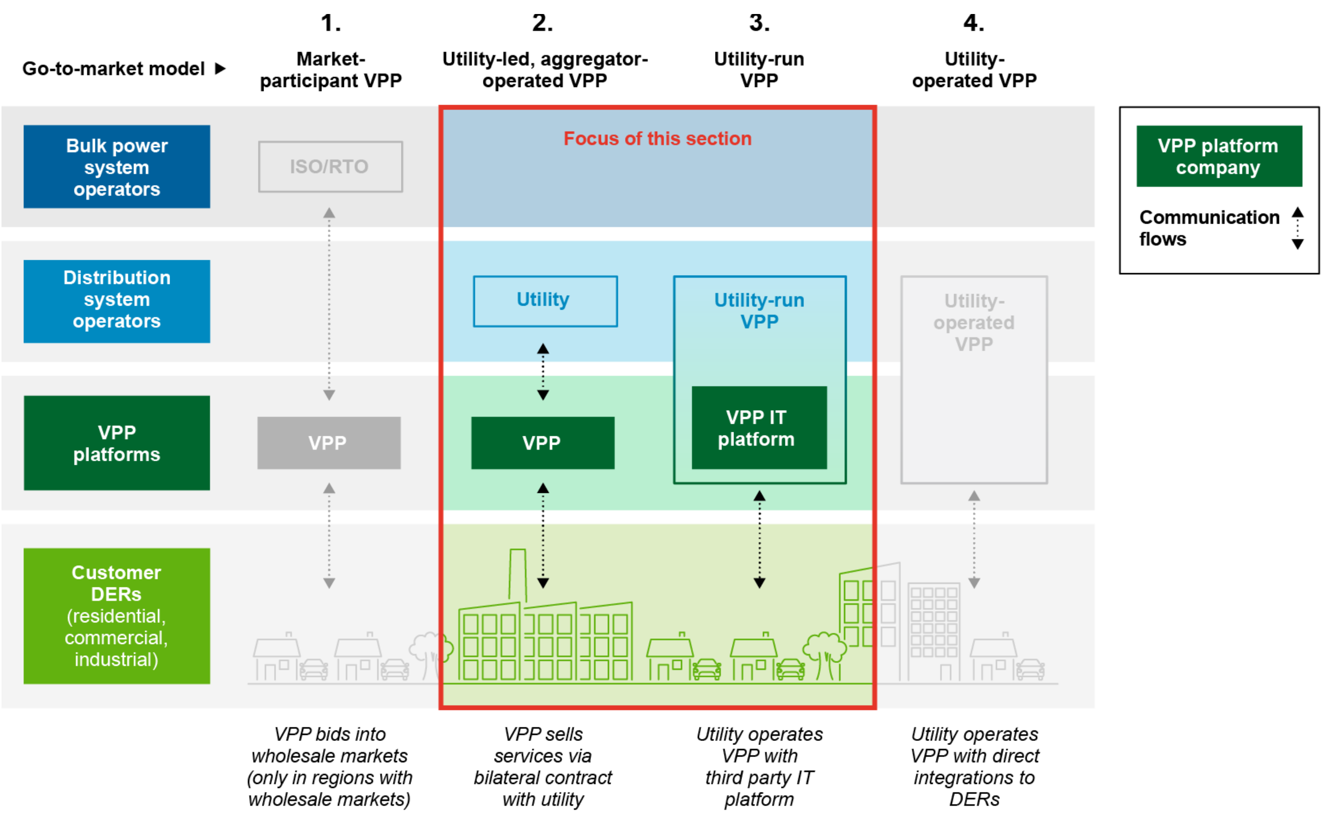
- Increased standardization can reduce the complexity and cost of deploying VPPs. New efforts are underway within and outside of DOE to align on industry standards for utility-aggregator interfaces, aggregator-DER interfaces, cybersecurity, and other aspects of VPP operations.
- Even in the absence of standards, many utilities today use basic VPP configurations to reduce system-level peak demand. This kind of VPP can be deployed at scale within six months with less than $1M in upfront investment and can create a foundation for more sophisticated VPP models that deliver a broader range of benefits.
- More sophisticated VPPs can deliver distribution grid services and unlock additional value streams (e.g., deferral of distribution system upgrades). These solutions may require the installation of additional hardware and software that provide (1) higher-resolution visibility into distribution grid conditions through sensors and improved data analytics and (2) more frequent and localized dispatch of DERs.

3.i. Variation in utility-led VPP operations

A lack of technology interoperability and other operational standards across utilities, state and tribal governments, and regional markets has made it difficult to repeat and scale proven VPP models nationally, but this has not prevented a proliferation of successful, albeit bespoke, VPP deployments. VPP platform companies and related service providers have had to customize individual VPP deployments to adapt to the protocols and systems of specific utilities, align to the program budget structures of specific state utility regulators, and abide by the rules of specific wholesale markets, minimizing positive economies of scale nationally.

Although the flexibility and adaptability of VPPs as a technology category is part of the value proposition, their variability has created the false impression that individual VPPs are inherently complex. In fact, an individual VPP can be simple for utilities and grid operators to deploy and operate (*see ConnectedSolutions case study in Section 3.iv.)*. This is particularly true when the orchestration of the DER aggregation is managed by third party aggregators and delivered to utilities as a single resource without integrating the aggregation platform into utility systems. The complexity arises when looking *across* VPPs at the many different ways operators structure and send data, define grid services, and design software interfaces in the absence of standardized approaches.

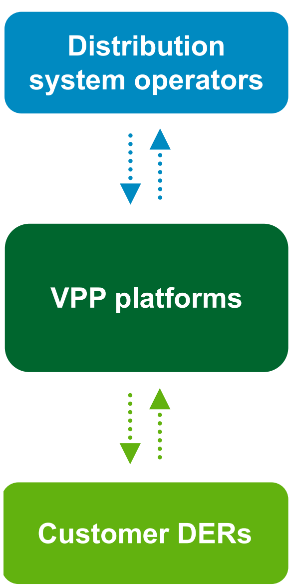
VPP market participation models[25]



3.ii. Standardization efforts recently launched or expanded

In the past year, DOE and other industry actors have launched or expanded efforts to standardize critical areas of VPP operations to reduce complexity and cost of implementation and increase reliability of performance.[26]

Recent efforts to increase standardization in VPP operations



	Focus area of recent standardization efforts	*Example initiatives (not exhaustive)*
1	**VPP platform to utility communication interface**	• FlexIT (EPRI) • TSO-DSO-DER Aggregator operational platform (DOE)
2	**Grid services definitions**	• Distribution System Transformation resources (DOE)
3	**Aggregator service contracts**	• Standardized services contract (NAESB, DOE)
4	**VPP platform to DER communication interface**	• Mercury Consortium (Kraken, industry) • Consortium for Energy Efficiency (industry-led)
5	**Meter data format and access rules**	• Green Button Standard (industry-led)
6	**VPP resource definition**	• Guide for VPP specifications (IEEE Working Group 2030.14, *forthcoming*)
7	**Shared DER registry**	• DER registry model (Collaborative Utility Solutions, DOE)
8	**Cybersecurity for DERs**	• DER Cybersecurity Best Practices (DOE) • UL 2941 cybersecurity certification standard for DERs (DOE, industry)

25 For a simple explanation of U.S. electricity market structures that influence VPP market participation models, see the 2023 VPP Liftoff Report.

26 See section 4.iii. ('Increase standardization in VPP operations') in the 2023 VPP Liftoff Report for detail on the challenges and potential solutions for this imperative (pages 43-47).

Successfully developing standards that are universally applicable will require diverse expert input from technology manufacturers, software developers, service providers, load serving entities, and other practitioners. Industry groups and community organizations can also play an important role by convening stakeholders to contribute to these efforts, and by packaging insights for policymakers and regulators to incorporate into their decision-making processes.

Area of operations	Description	Example standardization initiatives
VPP platform to utility communication interface	VPP platform providers must be able to send and receive information to and from a utility using an interface and data language compatible with utility IT systems, which vary from one utility to the next.	▸ **EPRI** launched the FlexIT initiative to deliver technical specifications for providing DER discovery and visibility, and to establish standards for the core utility-to-VPP/aggregator interactions involved in the provision of T&D grid services.[27,lxxviii] In addition to writing a standard and accompanying guidance, the initiative aims to build a mock utility and mock aggregator interface with reference code to test for interoperability.[lxxix] ▸ The **DOE Office of Electricity** is developing guidelines for a TSO-DSO-DER Aggregator operational platform as well as corresponding coordination requirements.
Grid services definitions	Grid services definitions make up the taxonomy and functional criteria of grid services procured for safe and reliable bulk power system, distribution system, and grid edge services. Today, different grid operators set their own definitions.	▸ **DOE's Office of Electricity** has published working definitions of grid services for bulk power, distribution, and grid edge services as part of its library of Distribution System Transformation resources.
Aggregator service contracts	The contract governing the delivery of grid services from a third-party aggregator for a utility includes terms and conditions around customer engagement plans, dispatch schedules, dispatch capacity limits, performance evaluation methods, settlement processes, and more. Given the rapidly evolving market, there has been little convergence to date on the structure of these contracts.	▸ The **North American Energy Standards Board (NAESB)**, in partnership with **DOE's Office of Electricity**, is developing a standardized services contract for VPP providers for distribution market interactions.[lxxx]

27 This initiative builds on past efforts such as the IEEE 2030.11 Guide for Distributed Energy Resources Management Systems (DERMS) Functional Specification, which DOE has supported.

VPP platform to DER communication interface	VPP platform providers' IT systems connect to and communicate with DERs through application programming interfaces (APIs) that must be compatible with the specific manufacturer-installed software.[28] Without interoperability standards (i.e., standardized software interfaces), each VPP platform must write brand-specific APIs and maintain them as manufacturers update their software.	▸ The Mercury Consortium, led by VPP platform **Kraken** and its partners, launched in 2024 to increase adoption of existing standards for flexible demand devices[29] and address gaps in testing and certification[30] of those standards as they are built into devices. Such standards may include OpenADR, CTA-2045, IEEE 2030.5, and MATTER. ▸ The Consortium for Energy Efficiency, an organization of utilities administering ratepayer-funded efficiency programs across North America, has adopted new specifications for heating, ventilation, and cooling (HVAC)[lxxxi] and water heating[lxxxii] equipment to require that equipment meet the relevant industry standard for "communication, infrastructure, and system functionality as these relate to the implementation of energy management strategies" starting in 2026.[31,lxxxiii]
Meter data format and access rules	The Green Button[32,lxxxiv] initiative is an industry-led effort to provide utility customers with easy and secure access to their energy usage information in a consumer-friendly and computer-friendly format.[lxxxv] Since its launch in 2012, utility implementation of the data and access standards has been voluntary, and many non-utility grid service providers point to insufficient implementation as a major obstacle to sharing grid data that could accelerate grid modernization.	▸ Additional utilities (**Consumers Energy** in Michigan[lxxxvi], **Louisville Gas & Electric** in Kentucky[lxxxvii], and **Entergy** in Texas[lxxxviii]) representing over two million customers have adopted the Green Button standard since 2023.

28 Problems can arise when VPP platforms do not properly integrate with devices. For example, in a practice called "screen scraping," an aggregator might write code that integrates with a consumer app (e.g., the EV brand app) rather than the device software itself (e.g., the EV telematics). This practice could violate terms of the device software, lead to bugs when the consumer app is updated and the code is not, and overall does not offer high-fidelity information exchange required for grid operations.

29 IEEE 1547 is a common communication standard for generation-capable devices. Complying with this standard requires following specified rules (e.g., IEEE 2030.5, SunSpec Modbus) for how DER capabilities are set and monitored, such as voltage regulation settings, power factor settings, and power export limits. These rules specify a structure for data to enable interoperability among system components made by different manufacturers. In contrast, flexible demand devices are generally less standardized in their communication protocols and data formats.

30 Testing and certification of products and their software are important to validate that standards are properly incorporated. Beyond testing and certification, incentives (carrots) or enforcement and penalties (sticks) would help increase standards adoption.

31 This action also means that the federalFederal tax credit for this equipment will only be available to DR-ready equipment. In 2023 alone, over 850,000 households claimed this credit for electric HVAC or water heating equipment.

32 Green Button is based on the Energy Services Provider Interface (ESPI) data standard released by the North American Energy Standards Board (NAESB) in the fall of 2011. The data standards development process was facilitated by the National Institute of Standards and Technology (NIST). The ESPI standard consists of two components: 1) a common XML format for energy usage information and 2) a data exchange protocol which allows for the automatic transfer of data from a utility to a third party based on customer authorization.

VPP resource definition	The term 'Virtual Power Plant' commonly refers to a category of resources rather than one narrowly defined asset. Even so, the term is interpreted differently across different stakeholders today.	▸ **IEEE Working Group 2030.14** is developing a guide for VPP functional specification for alternate and multi-source generation.
Shared DER registry	Recruiting VPP participants can be costly for a utility or aggregator. A DER registry would serve as an opt-in database of existing DERs in a given jurisdiction (the registry could be implemented state-wide or market-wide, where applicable) that logs information on the DER location, type, and functional ability to provide grid services. A primary goal of the registry is to accelerate the identification of DERs and enrollment into VPPs.	▸ **Collaborative Utility Solutions**, with support from **DOE**, developed and launched a **functional DER registry model**[lxxxix] that can be adopted and implemented by states and tribes and shared by their utilities so that each jurisdiction does not need to build their own independently. This model registry uses a common information model (CIM) for all users that covers critical inputs for the integration of DERs into grid operations.
Cybersecurity for DERs	Most DERs installed in homes and businesses today are connected to communications and control software and networks, and are interconnected with the electric grid. This increase in connection points widens the attack surface that could be exploited by malicious actors. Cybersecurity strategies ranging from data encryption to system governance can be engineered into utility and aggregator systems in many ways to secure grid operations and protect customers.	▸ **DOE's Office of Cybersecurity, Energy Security, and Emergency Response** is continuing to develop and disseminate cybersecurity "baselines" and **best practices for DERs** and VPPs to safeguard against risk. ▸ **DOE and industry partners** initiated the **UL 2941 cybersecurity certification standard for DERs** in 2023 to map hardware and software security requirements from industry best practices and provide information for industry stakeholders.

Three additional areas of VPP operations that market participants say sorely need more standardization are discussed in the context of FERC Order 2222 implementation in *Chapter 5: Integrating into Wholesale Markets*. They include electricity consumption data access, DER metering and telemetry, and DER aggregation participation models.

See Appendix C for 2 additional resources (Appendix C.iv.) and 17 supportive DOE programs (Appendix C.v.).

3.iii. VPP performance attributes

Not all variation in VPP configurations is counterproductive; new innovations in VPP design and implementation have increased the delivered benefits of VPPs across the country. The "right" configuration of VPP hardware and software will be determined by the desired performance attributes of the VPP, which are a function of the needs and priorities of the utility.

Relatively basic VPPs that deliver bulk system peaking capacity can be launched in a short timeframe (<6 months) with minimal upfront cost (<$1M), while providing high-value peak shaving benefits to ratepayers and the grid. These basic VPPs can build additional capabilities over time and establish a foundation for more sophisticated models in several ways.[33] Grid services, frequency of dispatch, and scale can all increase incrementally if and when needed.[34] Within the utility, operating a basic VPP at scale produces a wealth of historical DER and participant behavior data that can be used to train predictive models of VPP performance; this can help a utility set appropriate incentive payment levels, set event frequency limits to prevent participant attrition, test automatic enrollment effectiveness, and more.
Building the VPP's dispatch 'track record' can also help grid planning teams better understand the value of the resource and model the VPP resource into future generation, transmission, and distribution investment scenarios.[35] Outside of the utility, customers become familiar with VPP participation options and participants grow accustomed to potential changes in behavior (if any). Regulators also gain familiarity and comfort with VPPs as a reliable tool to manage the grid more affordably and reliably.

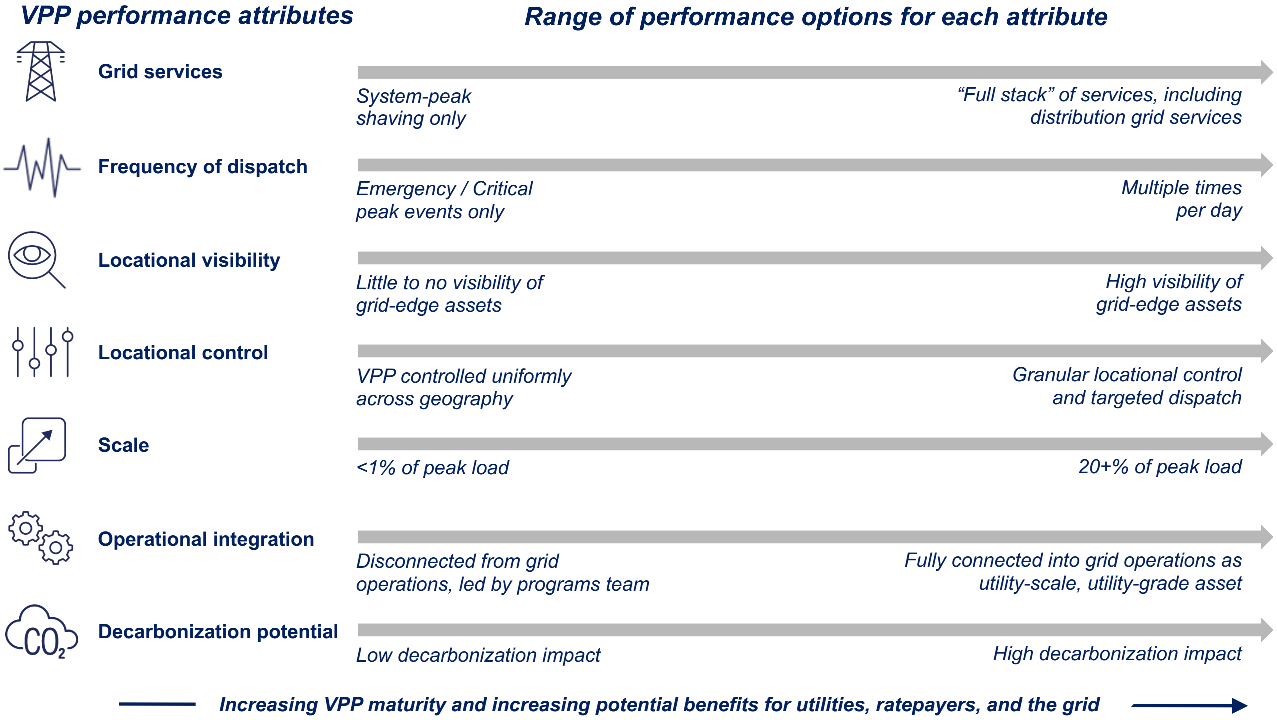
The progression from basic to more sophisticated utility-led VPP configurations can be assessed along at least seven performance attributes. A given VPP may not necessarily advance along all attributes in unison; rather, its specific performance requirements will be dictated by utility needs and priorities.

33 Capex-light, basic VPP-related investment may be low-risk for utilities because they avoid locking into one technology for long periods of time. Utilities can carefully analyze potential investments in durable equipment, and in particular metering infrastructure. While some VPPs rely on meter data for performance measurement, others operate independently of advanced meters by integrating DERMS software directly into DER software-based controls (e.g., smart thermostats, batteries) and collecting data directly from the device for performance measurement and settlement. Any significant investment in advanced metering infrastructure should involve a long-term technology and functionality roadmap that weighs the costs and benefits of different system architectures. This is particularly important in light of recent metering technology advancements that equip meters with new computing and communication capabilities with an associated cost increase from roughly $150-200 per meter to double that price or more.

34 Adding capabilities to existing programs that already have customers enrolled has advantages over adding new and separate programs, particularly in jurisdictions that only allow enrollment in a single program per meter.

35 The need to build a track record of performance data has often been cited as a reason to pilot a VPP before deploying it at scale. This has held back VPP growth when programs stay in the pilot stage without a path to scale in regulatory or utility management plans. This can be prevented by implementing first-time VPPs without an end-date or capacity limit, establishing go/no-go milestones as safeguards against poor performance, continuously monitoring performance indicators, and allowing for ongoing improvements to operational parameters.

VPP performance attributes and corresponding range of performance options



Each of these seven performance attributes is described in more detail below.

Grid services: System peak shaving or shifting is the most basic functionality of a VPP, but DER aggregations can provide additional services such as energy, frequency response, black start, and more[36,xc] with the right mix of DERs and the right underlying software and hardware.

Frequency of dispatch: While some basic VPPs are called only during critical grid events, more sophisticated VPPs can be dispatched more often – potentially multiple times per day – to support normal grid operations.

Locational visibility: For VPPs to go beyond system-level benefits and provide distribution grid benefits, a utility must understand where it faces distribution grid constraints or problems that VPPs might alleviate. This requires heightened situational awareness of conditions on the distribution grid, which is not common among distribution system operators today.[37,xci]

36 For a full list of grid services and definitions, see Bulk Power, Distribution, and Grid Edge Services Definitions from DOE's Office of Electricity.

37 A variety of grid technologies can enhance situational awareness. This includes advanced distribution management systems (ADMS), which are software platforms that integrate numerous utility systems and provide automated management of distribution grid performance. ADMS often collects data from supervisory control and data acquisition (SCADA) systems. Monitoring and management systems for distribution grid assets, up to and including a customer's meter are sometimes referred to as a "*Grid* DERMS" (distributed energy management system). This is distinct from an "***edge*** DERMS," described below. These few examples illustrate the variety of possible enabling technology configurations.

Locational control: Locational control goes hand-in-hand with locational visibility. For a VPP to react to, or prevent, a location-specific distribution grid constraint with services from a local DER aggregation, the VPP requires granular control of DER sub-aggregations within the overall resource. It also requires an understanding of how a DER's physical location – i.e., street address – maps to the topology of the grid, to ensure the right DERs are called upon to drop load (or export energy).[38]

Scale: As VPP capacity (MW or MWh) grows relative to system peak demand, grid operators rely on VPPs for a higher percentage of grid resources (generation supply and T&D capacity). More sophisticated VPPs manage a higher percentage of system peak demand.

Operational integration: The extent to which VPPs are incorporated into the planning process and regular operations of a utility's distribution, transmission, and generation teams varies widely. Historically, many basic VPPs have been managed by customer programs teams with little to no impact to other functional groups within utilities; this limits the potential benefits of the VPP for the broader utility system. In contrast, leading utilities who operate more sophisticated VPPs have incorporated them into integrated planning processes and operations (*discussed further in Chapter 4: Integrating into utility planning & incentives)*. In other words, these utilities consider VPPs in the option set alongside traditional resources when making decisions in capital planning, ratemaking, and maintenance schedules.

Decarbonization potential: Most VPPs dispatch to optimize one variable: costs. They reduce costs by decreasing demand during system peak hours to avoid high energy prices, or decrease local peak to defer a costly equipment upgrade. More sophisticated algorithms also consider the avoidance of greenhouse gas emissions, thereby optimizing around multiple desired outcomes.

As the descriptions above illustrate, most VPP performance attributes relate to *how* technology is used rather than *what* technology components (hardware and software) are used. An important exception may be among utilities who need to make incremental investments to implement technology such as ADMS and related tools to gain situational awareness at the grid edge and enable location-specific distribution grid services from VPPs. These systems create and transmit the data about grid conditions that dictate VPP operations and dispatch.[39]

Utilities that have launched active managed EV charging VPPs are leading examples of utilities investing in the capability to optimize distribution grid conditions. Rather than setting EV charging schedules (or calling events ad hoc) only in response to day-ahead energy prices from wholesale markets, these VPPs are *also* managing charging in response to real-time grid conditions based on data collected from distribution grid equipment.[40] Examples include programs operated by VPP provider **WeaveGrid** with utility partners **Baltimore Gas & Electric**, **Pacific Gas & Electric**, and others, and other programs operated by **EnergyHub** with utility partners such as **Eversource**.[xcii]

38 An "edge DERMS," refers to a software platform that controls or sends signals to equipment behind the customer's meter (i.e., directly to DERs or DER owners). The edge DERMS aggregates independent DERs and orchestrates them to act as a utility-scale resource. While an edge DERMS may know the address of the DER, it must be integrated into the utility's system (i.e., the ADMS or Grid DERMS) to know how the behavior of each DER impacts the distribution system.

39 Managing the enrolled DERs of a VPP to enhance distribution grid operations typically requires automated dispatch of DERs because a given utility may have thousands or tens of thousands of load limits to monitor across its distribution system – more than can be managed manually. Automation based on granular locational conditions often requires tight integration between the utility system and the edge DERMS, which requires investment from the utility.

40 For in-depth explanations and case studies of multi-layered optimization in EV managed charging programs – including optimization for distribution grid congestion and optimization for renewable energy generation–see the State of Managed Charging in 2024 report from the Smart Electric Power Alliance.

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3.iv. Case studies of utility-led VPP operations

VPPs can be deployed in less than six months with less than a million dollars of investment to avoid higher costs of traditional assets. Examining and comparing the operations of multiple utility-led VPPs can help illustrate the differences between a relatively basic versus more sophisticated VPP and provide context for areas where increased standardization can streamline implementation. This section, along with detail provided in Appendix C, explains how three real, utility-led VPPs operate to demystify the communication technology that enables a VPP and to compare their relative performance across the seven attributes outlined in the previous section. In doing so, the case studies may help stakeholders pinpoint where increased standardization is most needed (and where it is not).[41]

National Grid's 'ConnectedSolutions' in Massachusetts, Green Mountain Power's 'Energy Storage System' (ESS) Leasing program in Vermont, and Rocky Mountain Power's 'Wattsmart' in Utah each employ different information technology (IT) and operational technology (OT) configurations in their VPPs. Each has proven to be cost-effective and reliable for the utility and customers, and each is growing its capacity as more participants choose to enroll.

Case Study: National Grid, ConnectedSolutions, MA and NY

***National Grid established a multi-device VPP** within 4 months with <$500k upfront investment that now provides up to 250 MW of peak shaving benefits.*

- **National Grid** developed and launched its ConnectedSolutions 'bring-your-own-device' (BYOD) VPP in less than four months to provide low-cost, low-emissions peaking capacity in Massachusetts and New York.[42]
- In this configuration, National Grid contracts with **EnergyHub**, an edge DERMS vendor that integrates multiple DER software systems into one platform. The heterogenous aggregation is controlled as one cohesive, utility-scale resource.
- National Grid sends notices to EnergyHub in advance of peak hours to dispatch demand reductions from the customer-owned DER aggregation that EnergyHub manages on National Grid's behalf.
- National Grid required little change to its internal organizational operations to implement the VPP. System integration is low; a National Grid employee logs into EnergyHub's online portal to send instructions and collect data.

41 While this section focuses on utility-led VPPs, *Chapter 5: Integrating into wholesale markets* focuses on VPPs that sell grid services into wholesale markets and includes discussion of variation across ISO/RTOs.

42 For additional detail on the policy and regulatory context in which ConnectedSolutions was implemented, including the energy and non-energy benefits included in the cost-effectiveness test for the program, see the case study annex (page 66) of NARUC's ADER Resources in 2024: The Fundamentals.

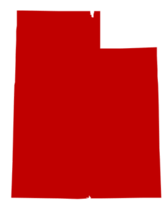
Case Study: Green Mountain Power, Energy Storage System Leasing Program, VT

***Green Mountain Power launched a utility-owned and operated battery VPP** that offers backup power for participants, peaking capacity, emissions reduction, and transmission benefits for the grid, and lower costs for all customers.*

- **Green Mountain Power** fully launched the Energy Storage System (ESS) Leasing program in 2020 to improve system reliability in the face of extreme weather while reducing costs for all customers.[43]
- GMP operates the program with **Tesla** technology. Tesla supplies the battery hardware (Powerwalls) and acts as the software platform that aggregates and orchestrates battery dispatch.
- Tesla uses real-time load data provided by Green Mountain Power via an API to strategically dispatch batteries to shave peaks on the distribution system.

Case Study: Rocky Mountain Power, WattSmart, UT

***Rocky Mountain Power developed a battery VPP** that integrates directly into its grid operations system and enables many grid services.*



- **Rocky Mountain Power** developed its Wattsmart battery VPP in partnership with **sonnen** to deliver high-value grid services cost-effectively and increase battery adoption among customers.
- RMP creates significant value for the grid by obtaining a "full stack" of valuable grid services from the batteries, paying participants upfront and ongoing performance incentives.
- Unlike VPPs used only during peak hours or peak seasons (summer, winter), RMP may use its batteries 365 days of the year, 24 hours per day.
- RMP's grid operations team directly dispatches the batteries using a distributed battery grid management system (DGBMS) that integrates battery controls directly into the utility's energy management system without any intermediate software layers.
- The network of batteries can respond automatically to grid signals in as little as three seconds (sonnen and Core+ batteries) and no slower than 50 seconds (other brands). RMP personnel can override automated dispatch at any time.
- The Wattsmart VPP is growing rapidly, with a near-term goal of reaching 100 MW by recruiting customers with solar arrays (>80,000 in Utah) and offering battery incentives to motivate customers to 'firm' their renewable power.

See Appendix C for detailed case studies that include program overviews, communication protocols & operations, and IT and OT components for each of the three VPPs referenced in this section.

43 For additional detail on the policy and regulatory context in which GMP implemented its VPP, including the monetized and non-monetized benefits of the program, see the case study annex (page 63) of NARUC's ADER Resources in 2024: The Fundamentals.

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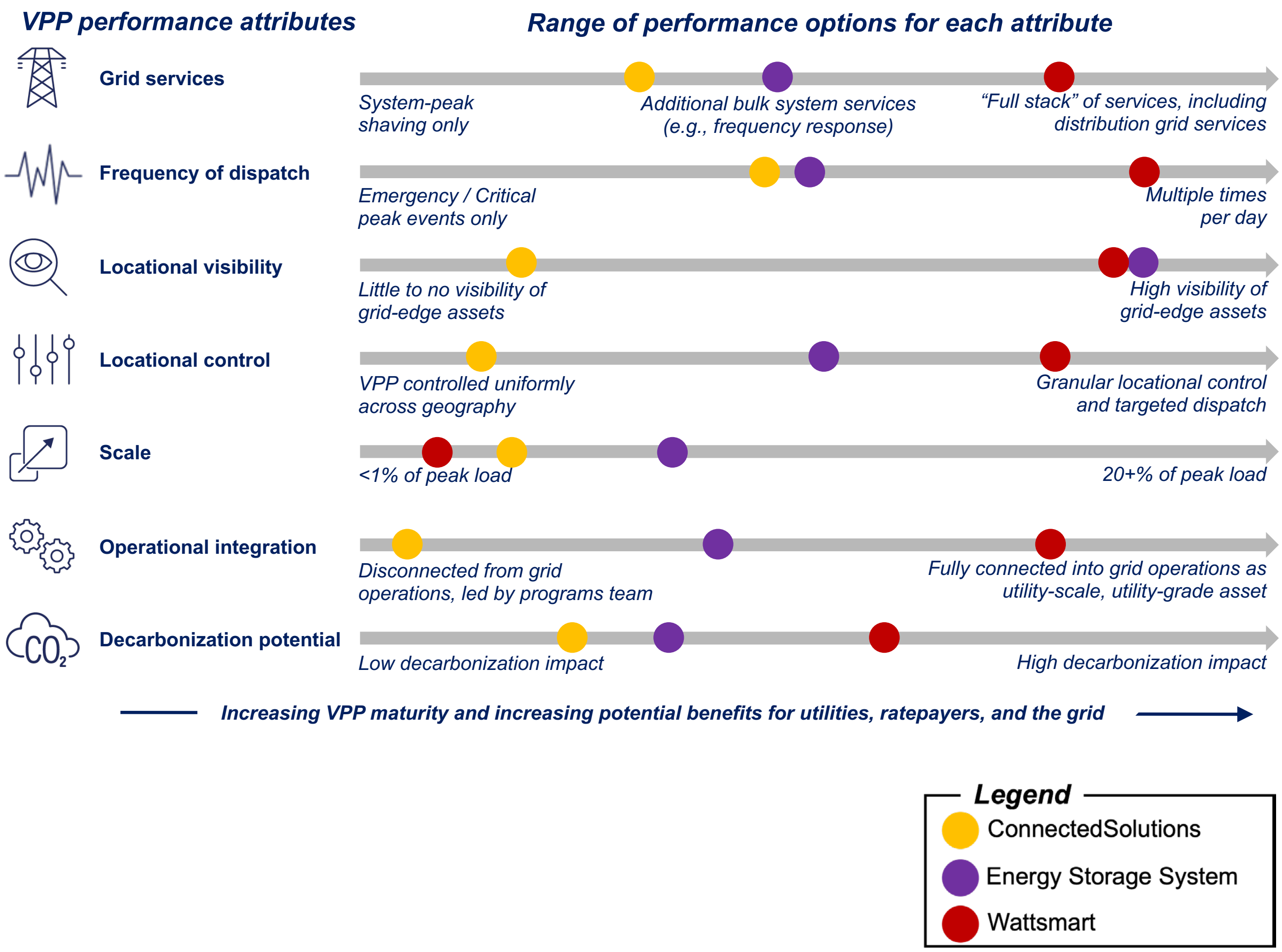
As the ConnectedSolutions example demonstrates, VPPs can be quick and extremely cost-effective to implement for system-level peak shaving benefits.[44,xciii] ESS and Wattsmart demonstrate that VPPs can deliver a wider range of grid services with incremental IT and OT capabilities that integrate VPP operations into utility systems. Each of the examples is designed to meet the needs of the specific utility and its customers. Below, the examples are compared along the seven performance attributes.

VPP performance for three utility-led VPPs



44 LUMA's Customer Battery Energy Sharing program in Puerto Rico is another example of a VPP providing peaking capacity (over 10 MW) without incremental investments in grid modernization; LUMA operates its VPP without a DERMS and without advanced metering infrastructure.

Chapter Four: Integrating into utility planning & incentives

Key takeaways

- Across the U.S., VPP deployment has been highest in the states with supportive state regulatory and/or policy actions.
- Many state utility regulators – public utilities commissions (PUCs) and public service commissions (PSCs) – have opened regulatory proceedings within the last 18 months to advance VPP adoption. Examples include requiring longer-term distribution grid planning that incorporates consideration of VPPs and establishing or revising compensation mechanisms to better align utility financial incentives to positive grid and customer outcomes.
- Legislative changes to utility regulations or policy are not necessary for investor-owned utilities to deploy VPPs today, but can accelerate deployment by establishing a direction and removing ambiguity about VPP goals and other program parameters (e.g., types of DERs, desired grid services). Examples include Colorado and Maryland legislative actions.
- Regulators and policymakers approaching VPPs today can draw from the menu of 22 policy actions underway across the U.S. to inform program design and integrate VPPs into utility planning and incentives.

Note: This chapter discusses state regulatory and policy actions that are most relevant for investor-owned utilities (IOUs) regulated by state PUCs/PSCs. Governing bodies of other utilities (e.g., member boards of co-ops, city councils overseeing public power, tribal utility authorities) can also look to these levers for consideration, but the historical financial disincentives impacting IOUs may be less relevant to nonprofit cooperatives and municipally run utilities.

4.i. Utility financial incentives and VPP deployment

In the era of flat electricity demand over the last two decades, VPP deployment by investor-owned utilities (IOUs) was in part stifled by a lack of financial incentives because it meant lower utility profits. Under conventional regulatory models, IOUs can earn an authorized return on equity (typically 9-11% annually) on capital investments; thus, IOUs deploying a low-capex VPP to add system capacity instead of a traditional capex-heavy investment (e.g., a peaker plant) would have realized lower profits.[45]

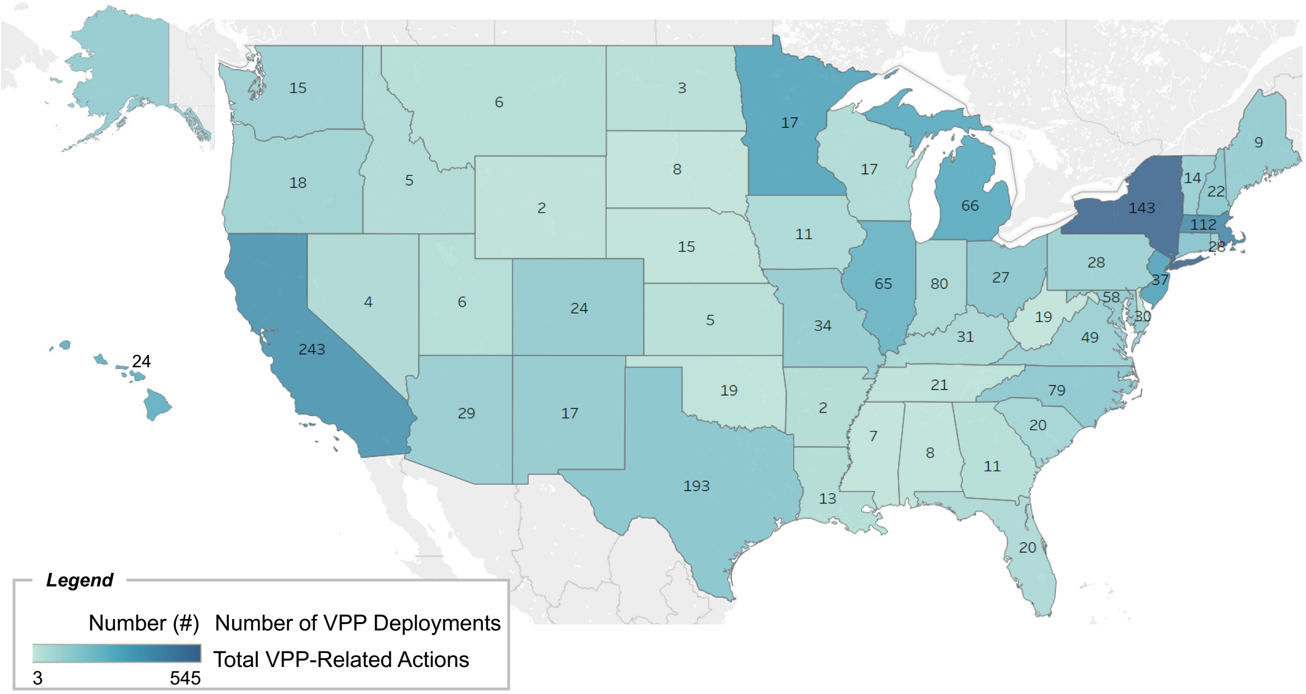
Today, rising electricity demand and the need to replace aging grid infrastructure means many utilities have rapidly growing capital needs. In this context, IOUs can deploy VPPs to help meet system needs and interconnect more load,[46,xciv,xcv] while creating room in their budgets for necessary capital-intensive investments elsewhere (e.g., transmission expansion, new bulk power generation assets). Additionally, state regulators and policymakers are applying pressure to limit capital expenditure and increasingly pushing back on utility investment plans to ensure any increase in customer bills is fully warranted. For example, in December 2023, the **Illinois Commerce Commission** rejected **Ameren Illinois** and **Commonwealth Edison**'s multi-year integrated grid plans over concerns that the utilities did not adequately "consider affordability and cost-effectiveness [criteria] so that customers are not unfairly asked to shoulder undue costs."[xcvi]

45 See page 48 of the 2023 VPP Liftoff report for additional detail on utility compensation structures.

46 For example, since 2017, Arizona Public Service (APS) has been developing demand response and load management programs (with approval from the Arizona PUC) to aggregate DERs into VPP programs, helping manage growing load (as discussed in APS' 2019 IRP Draft). In Minnesota, Northern States Power Company (doing business as Xcel Energy) introduced the concept of distributed capacity procurement (DCP) in comments for an IRP filing (Docket No. E002/RP-24-67) and said the program could provide 400 – 1,000 MW of capacity; actual plans with specifics would be included in the future IRP.

While IOUs can start implementing VPPs without any regulatory or policy changes, supportive regulatory and policy action is accelerating VPP deployment. Across the U.S., localities where state regulators or policymakers have taken VPP-supportive actions have seen the highest number of total VPP deployments to date.

Number of VPP deployments (as of July 2024) vs. state policy/regulatory VPP-related actions (2020-Q3 2024), count



Note: Number of VPP deployments based on Wood Mackenzie data as of July 2024.[xcvii] Wood Mackenzie defines a VPP deployment as: "The association of a vendor aggregation and a DER program. Aggregation is broadly defined to consist of DERs or loads directly under vendor management, or under the management of a downstream device partner. Example: If three vendors partner on a VPP that is monetized through two programs, there will be six deployments recognized." State regulatory and policy actions based on North Carolina Clean Energy Technology Center and includes data from Q1 2020 – Q3 2024.[xcviii] VPP-related state policy/regulatory actions include all types of actions tracked by DSIRE Insight (studies, policy, incentives, deployment, rates) that include the technology tag: demand response, grid modernization, smart grid, storage, AMI, DER, distribution system planning, data access, VPPs.
Source: Wood Mackenzie 2024 NA VPP Market Report, North Carolina Clean Energy Technology Center Policy & Regulatory Actions

State regulators and policymakers play a critical role in enabling a statewide VPP approach to support easier scale up across utility jurisdictions. While several utilities have pursued VPP deployments before any policy or regulatory action, state policy and regulatory efforts have been important to supporting broader adoption by integrating VPPs into standard utility processes (including planning and cost recovery) and aligning utility and ratepayer incentives. As discussed in the 2023 VPP Liftoff Report, increased VPP standardization will accelerate VPP integration in utility planning and incentives.[47]

47 See page 35 of the 2023 VPP Liftoff Report for additional discussion on the imperatives.

4.ii. Supportive regulator actions for integration into utility planning and incentives

All state regulators have the authority to pursue actions that could support VPP deployment.[48] As part of their mandate to ensure affordable and reliable electricity service, PUC/PSCs can proactively direct utilities to fairly consider VPPs alongside ongoing conventional capital investments (e.g., bulk power generation, transmission, distribution) to meet grid needs. In many states, PUCs' legacy organizational models, limited staff capacity, and reactive cultures have resulted in limited proactive engagement with utilities before they submit investment plans (e.g., providing proactive guidance on considering VPPs).[xcix] This is starting to change as mounting load growth, affordability, and reliability pressures on the grid are motivating several state PUCs to proactively provide direction and establish programs that can influence IOU investments, including VPP deployments.

Supportive regulator actions for VPP integration into utility planning and incentives *(not exhaustive)*

Utility cost recovery	System planning	DER deployment	DER aggregation	VPP operations
Establishing utility cost recovery methods for VPP-related investments	Improving grid planning processes to better integrate VPPs as a solution	Implementing or revising programs to increase DER deployments, which enhance VPP potential	Developing DER aggregation models and deployment requirements to enable VPPs	Supporting VPP operations to proactively address common VPP deployment barriers
• Massachusetts • Michigan • Vermont	• Georgia • Massachusetts • Minnesota	• Colorado • Michigan • New York • South Carolina	• California • Colorado • Texas	• Connecticut • Massachusetts • New York • Rhode Island

See Appendix D.i. for a menu of additional regulatory and policy options that regulators and policymakers can consider alongside case studies of how those options have been implemented to date.

Example types of actions that PUCs have pursued recently to drive uptake of VPPs include:

1. **Utility cost recovery: Establishing utility cost recovery methods for VPP-related investments.** PUCs are implementing performance incentive mechanisms (PIMs)[49,c] and clarifying what types of VPP-related investments are eligible for cost recovery (e.g., including DERs in utility rate base,[50,ci] capitalizing software costs).

2. **System planning: Improving grid planning processes (e.g. integrated distribution system planning) to incorporate VPPs as a solution.** PUCs can implement integrated distribution system planning to require objective-driven planning (e.g., grid reliability improvements, customer empowerment), planning over long-term time horizons (e.g., 10+ years), and consideration of comprehensive solutions to address grid needs (e.g., DERs, VPPs).[51,cii] Today, 21 states and the District of Columbia require utilities to file integrated distribution system plans[ciii];

48 State regulators include public utility and public service commissions (PUC/PSCs) that regulate most investor-owned utility (IOU) planning, operations, and retail compensation as relates to VPP deployment and the distribution system. PUC/PSCs review and approve IOU capital investment plans and have authority over determining IOU capital return rates, customer rate designs, and other distribution system plans. See VPP Liftoff report page 20 of the 2023 VPP Liftoff Report for additional info on state regulator roles and responsibilities.

49 Performance incentive mechanisms (PIMs) is a type of performance-based regulation (PBR). PBR is a regulatory model that financially rewards utilities for positive ratepayer outcomes, rather than returns on capital expenditures. See NARUC's PBR Overview to learn more. See RMI's PIM Database for a longer suite of examples of PIMs that PUCs and utilities have implemented.

50 Proposals for utilities to own behind-the-meter devices, such as batteries or generators, have drawn criticism from some industry participants who say that although such an approach may lead to faster scale-up of VPPs, it may lead to higher electricity prices for customers because of the utility's monopoly power, lack of competition to drive down prices, and its guaranteed financial return on the devices when included in the rate-base.

51 See Lawrence Berkeley National Lab's Integrated Distribution System Planning resource hub, which includes an interactive planning framework, a map and detail on existing planning requirements by state, and information on technical assistance and resources available to PUCs and policymakers.

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broader use of integrated distribution system planning practices could promote a more proactive utility investment approach to better consider and use DERs and VPPs. Regulatory approaches requiring or directing utilities to invest in grid orchestration platforms (e.g., DERMS) as part of broader grid modernization efforts can help distribution utilities manage an increasingly complex and digital grid, which also establishes the technology foundation for future VPP deployments.[52]

3. **DER deployment: Implementing or revising programs to increase DER deployments, which enhance VPP potential.** PUCs are studying and establishing methods to increase DER deployments, such as streamlining interconnection processes, establishing customer incentives, and testing pay-for-performance compensation mechanisms and DER-supportive tariffs. DERs can support net cost savings for customers and increase the resources available for DER aggregation.

4. **DER aggregation: Developing DER aggregation models and deployment requirements to enable VPPs.** PUCs are requiring utilities to develop pilots or consider how to aggregate DERs into a VPP program to be used as a grid asset.

5. **VPP operations: Supporting VPP operations to proactively address common VPP deployment barriers.** PUCs are increasingly influencing VPP operations to maximize system value, including by engaging on data access challenges[53] and establishing tariff structures that better compensate VPPs for their full suite of grid benefits (e.g., capacity, reliability, decarbonization impacts, etc.) and enabling value stacking (including stacking across both retail and wholesale market revenue streams).

Specific state examples illustrate how PUCs are putting these types of actions into practice.

Case Study: Colorado PUC, CO

***Colorado PUC** established a performance incentive mechanism to accelerate DER interconnection, helping improve DER deployment to support VPP potential.*

- **Colorado PUC** approved a performance incentive mechanism for **Xcel Energy** to speed up interconnection of DERs (Order 23AL-0188E) in October 2023.[civ]
- The PIM requires Xcel to refund customers 4% of the interconnection fee per day delayed beyond Xcel's internal timeline targets (e.g., 50 days).
- If Xcel interconnects the DER faster than the target timeline, the value would be credited against any penalties accrued for exceeding the target.
- The PIM aims to align Xcel incentives with ratepayer interests to support DER interconnection, enabling faster DER deployment and supporting greater VPP potential at scale.

52 See DOE's Innovative Grid Deployment Liftoff report for additional information on other grid modernization technologies and foundational platforms available to support modernizing distribution grids.

53 See Chapter 5.iv for additional detail on VPP-related data access challenges and potential solutions.

Case Study: New York State PSC, NY

***New York State PSC** implemented a value compensation methodology to reward DERs for a range of delivered grid benefits.*

- In 2017, **New York State PSC** implemented a Value of Distributed Energy Resources Value Stack (VDER, or the Value Stack) to better compensate and incentivize DERs for provided grid value.
- The Value Stack includes six values to determine DER compensation:
  - Energy Value (Locational Based Marginal Price, LBMP)
  - Capacity Value (Installed Capacity, ICAP)
  - Environmental Value (E)
  - Demand Reduction Value (DRV)
  - Locational System Relief Value (LSRV)
  - Community Credit (CC)
- This model allows for value stacking across multiple revenue streams (including wholesale market revenues) to fully reward DERs for delivered grid benefits.
- The Value Stack provides location-specific compensation to reward VPPs that have the greatest impact on alleviating distribution system constraints.

Detailed case study provided in Appendix D.ii.

State by state, PUC/PSCs have different policy contexts and starting points of regulatory frameworks that can be used – or adjusted – to encourage VPP deployment. [54] When motivated to support VPP deployment, PUC/PSCs can leverage components of the real-world examples described above to tailor regulatory actions that are appropriate for their state's context and grid objectives.

Regulators have reported success with directing a few staff members to develop simple VPP regulatory frameworks (e.g., a smart thermostat program) and then adding resources and scaling up over time towards more complex regulatory efforts as impacts are proven out and lessons are learned.[cv]

Regulatory approaches will likely continue evolving over time as VPP program design and underlying technology also evolve. To enable continuous improvement, PUCs could consider establishing processes that enable and encourage evolution. For example, the **Hawaii PUC** built in iteration to revisit elements of DER programs (e.g., incentive levels, operational characteristics) every three years with stakeholders to keep pace with an evolving grid.[55] The **Connecticut Public Utilities Regulatory Authority (PURA)** implemented a "regulatory sandbox" program that fosters new grid technology deployments and informs enabling regulation.[56,cvi]

54 For policymakers/regulators considering implementing a VPP initiative, RMI/VP3 defined a set of guiding policy principles that can help inform initial actions to maximize long-term benefit (See Appendix D.v. for the full set of policy principles.

55 See additional detail about Hawaii's DER program evolution in NARUC's Aggregated DER in 2024: The Fundamentals (page 69).

56 Connecticut PURA established the Innovative Energy Solutions Program in 2023 to encourage grid innovation, including defining features such as a four phase process from ideation to scale up, cost recovery guidance, and screening and performance metrics.

4.iii. Supportive policymaker actions for integration into utility planning and incentives

Legislative changes to utility regulations or related policy are often not *necessary* for investor-owned utilities to deploy VPPs or for regulators to take action, but they can be an *accelerant*. Legislation and other policy measures can shorten design and deployment timelines by removing ambiguity about VPP goals and other program parameters or aligning expectations with state energy and climate goals.

At the state level, policymakers (e.g., legislators, governors, tribal governments) can empower PUC/PSCs in states where regulators may not consider it their role to proactively shape VPP programs and/or the processes underpinning their deployment (e.g., filing dockets, RFIs, etc.). In these states, policymakers can accelerate regulatory processes, potentially by years, by providing direction and focus while giving PUCs and utilities room to determine the most effective regulatory frameworks. Similarly, tribal governments can also provide direction to tribal utilities to advance VPP-supportive actions. In Colorado, Massachusetts, and New York, actions by policymakers built on previous PUC actions to strengthen and provide explicit support to grid modernization and VPP supportive efforts.

Three types of actions that state policymakers have recently taken to support VPP deployments include:

1. **Establishing grid modernization policies and VPP-enabling requirements to enhance system planning:** **Washington State** passed HB 1589 in March 2024 that required utilities to submit integrated system plans. VPP-enabling features include requiring plans to align with state clean energy goals and emission reduction targets.

2. **Requiring utilities and PUCs to develop VPP programs and/or supportive tariff mechanisms:** **Colorado** passed SB24-218 in May 2024 that requires the state's largest IOU (Xcel) to submit a VPP plan to the PUC. This built on ongoing actions by the **Colorado PUC** to advance VPP programs as part of an effort to serve rising demand while mitigating costs for ratepayers.

3. **Clarifying VPP stakeholder roles and requirements:** **Texas** legislators passed SB 1699 to establish third-party aggregation requirements for DERs and to authorize the **TX PUC** to establish rules and requirements for DER aggregators.

See Appendix D for a menu of 22 regulatory and policy options to support VPPs (Appendix D.i.), detailed case studies on New York PSC's Value of DER (VDER) Value Stack compensation method and Massachusetts legislation on grid modernization planning requirements (Appendix D.ii.), 6 additional resources (Appendix D.iii.), 9 supportive DOE programs (Appendix D.iv.), VPP policy principles from the Virtual Power Plant Partnership (VP3) (Appendix D.v.), and a summary of existing benefit-cost assessment frameworks available to support VPPs from NARUC (Appendix D.vi.).

Chapter Five: Integrating into wholesale markets

Key takeaways

- In the last decade, wholesale markets have been the primary mechanism to provide and monetize grid services from distributed flexible loads – particularly commercial and industrial loads.
- FERC Order 2222 has the potential to unlock wholesale market participation from an enormous amount of DER capacity. At a time when capacity markets are tight (e.g., PJM), VPP participation in wholesale markets has never been more important for system affordability and reliability.
- Although industry actors have been excited about the potential impact of Order 2222, slow implementation timelines, varied approaches across ISO/RTOs, and obstructive state, ISO/RTO, and utility rules have blocked the full integration of VPPs into wholesale markets.
- Technology, regulatory, and policy solutions are emerging domestically and internationally to remove barriers for VPP integration into wholesale markets. Industry collaboration is needed to share learnings and accelerate implementation.

5.i. VPP wholesale market participation today

In the last decade, wholesale markets have been the primary mechanism to provide and monetize grid services through demand response for distributed loads – particularly commercial and industrial loads. Today, 29 GW of demand response participates in wholesale markets.[cvii]

All seven of the U.S. ISO/RTOs allow wholesale market participation from VPPs that manage demand without exporting power to the grid. Well-established demand response aggregators such as **CPower** continue to focus their business strategy on wholesale markets, which offer large potential revenue streams from the energy, capacity, and ancillary services markets as well as greater long-term revenue certainty given the durability of wholesale markets. In comparison, individual utility-level VPP programs tend to have short-term contracts (1-2 years), which creates greater revenue uncertainty for aggregators.[57]

See Appendix E.i. for a detailed case study on how Leap aggregates demand response to participate in the CAISO market.

While total revenue potential across wholesale markets is large, each ISO/RTO has a unique set of rules and processes that require deep expertise to navigate, creating barriers for new entrants. As a result, participating in wholesale markets may provide lower levels of compensation than current utility-led VPPs receive today. Additionally, most ISO/RTOs only allow large-load demand response and do not yet allow DERs that store or generate energy (e.g., distributed storage and solar PV) to export power to the grid. This limits the value that DERs can bring to wholesale markets to a fraction of their technical functionality.

Streamlining wholesale market integration and allowing the full range of potential grid services from installed DERs could help address increasing capacity constraints that are causing price spikes and diminishing reserve margins across the U.S. For example, **PJM**, an RTO that coordinates wholesale electricity markets in all or parts of 13 states and the District of Columbia, held a capacity auction in summer of 2024 that resulted in final capacity prices nearly 10x higher than the previous year's auction.[58,cviii,cix,cx,cxi]

57 Uncertainty around grid services revenue increases the cost of capital for industry actors investing in VPP participant recruitment and/or DER deployment. Longer-term contracts with greater revenue predictability can reduce the overall cost of VPP deployment, resulting in higher savings to pass on to customers.

58 In early 2024, PJM updated its capacity accreditation methodology to reflect the marginal contribution each resource can provide to system resource adequacy given the anticipated resource mix. As a result, many supply resources (including solar PV, gas, coal, hydropower, demand response) had lower capacity that could bid into the capacity market, resulting in lower capacity. Simultaneously, many existing power plants were forecasted to retire, further constraining supply and increasing PJM capacity prices.

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As a result, PJM ratepayers will be responsible for $14.7 billion in capacity costs for the 2025-2026 delivery year, as compared to $2.2 billion for the 2024-2025 delivery year.[cxii,cxiii] In early 2024, PJM updated its capacity accreditation methodology for all supply resources, including demand response. PJM's accreditation is based on PJM's existing requirement that DR resources be available for dispatch only between 10am-10pm during the summer and between 6am-9pm during the winter, even though DR resources could also perform outside these windows – effectively derating demand response because of PJM's rules rather than technological reality.

5.ii. Overview of FERC Order 2222

FERC Order 2222 has the potential to dramatically accelerate national action towards integrating VPPs into wholesale markets, which could maximize the value of DERs in restructured regions and help address rising affordability and reliability challenges to meet demand growth. Issued in September 2020, Order 2222 *requires* the six FERC-jurisdictional ISO/RTOs[59] to establish participation models that enable DER aggregations to participate in energy, capacity, and ancillary services wholesale markets.[60,cxiv]

In issuing the Order, FERC recognized that a much wider range of DERs can provide wholesale market services, including those that export power and smaller individual assets.[61] The Order is meant to offer a path to expand supply-side participation by DERs beyond demand response and place downward pressure on prices in markets with high demand and low supply. However, successful implementation of Order 2222 will require coordinated action from a broad range of stakeholders including ISO/RTOs, utilities, aggregators, regulators, and policymakers across the country.

5.iii. ISO/RTO Order 2222 compliance status

ISO/RTO compliance with FERC Order 2222 requirements has been varied: CAISO, NYISO, and ISO-NE are leading implementation while PJM, MISO, and SPP are seeking to implement much of their Order 2222 compliance proposals several years later. Although all six FERC-jurisdictional ISO/RTOs have filed compliance proposals with FERC, and FERC has issued orders on these filings, **CAISO** and **ISO-NE** are the only ISO/RTOs that have fully complied with the requirements of FERC Order 2222 as of December 2024.[cxv,cxvi]

59 FERC does not have ratemaking jurisdiction with respect to ERCOT in Texas.

60 Specifically, Order 2222 requires each ISO/RTO to (a) develop tariff provisions that ensure that market rules facilitate the participation of DER aggregations, (b) allow DER aggregations to participate directly in ISO/RTO markets, and (c) establish DER aggregators as a type of market participant that can register DER aggregations.

61 FERC declined requiring ISO/RTOs to adopt minimum capacity requirements for individual distributed energy resources to participate in the markets, given those resources would only participate in the markets through a DER aggregation which would act as a single resource. However, some market operators have adopted minimums for individual DERs. For example, NYISO proposed a minimum capacity of 10 kW for each individual DER in any aggregation for a VPP to be eligible to participate, which would exclude many residential DER types.

Order 2222 compliance status

Issue Areas	CAISO	ISO-NE	NYISO	PJM	MISO	SPP
Metering and telemetry system requirements	In compliance	In compliance	In compliance	Not yet in compliance	Not yet in compliance	Not yet in compliance
Participation model	In compliance	In compliance	Not yet in compliance	In compliance	Not yet in compliance	Not yet in compliance
Double counting of services	In compliance	In compliance	In compliance	Not yet in compliance	In compliance	Not yet in compliance
Locational requirements	In compliance	In compliance	In compliance	In compliance	Not yet in compliance	Not yet in compliance
Role of distribution company	In compliance	In compliance	In compliance	Not yet in compliance	Not yet in compliance	Not yet in compliance
Ongoing operational coordination	In compliance	In compliance	In compliance	Not yet in compliance	Not yet in compliance	Not yet in compliance
Small utility opt-in	In compliance	In compliance	In compliance	In compliance	In compliance	In compliance
Interconnection	In compliance	In compliance	In compliance	In compliance	Not yet in compliance	Not yet in compliance
Definitions of DER and DER aggregator	In compliance	In compliance	In compliance	In compliance	In compliance	In compliance
Types of technologies	In compliance	In compliance	In compliance	In compliance	In compliance	Not yet in compliance
Allow a DER to serve as its own aggregator	In compliance	In compliance	In compliance	In compliance	In compliance	In compliance
Min and max size of aggregation	In compliance	In compliance	In compliance	In compliance	In compliance	In compliance
Min and Max size for DER in an aggregation	In compliance	In compliance	In compliance	In compliance	In compliance	Not yet in compliance
Distribution factors and bidding parameters	In compliance	In compliance	In compliance	In compliance	Not yet in compliance	Not yet in compliance
Information and data requirements	In compliance	In compliance	In compliance	Not yet in compliance	Not yet in compliance	In compliance
Role of RERRA	In compliance	In compliance	In compliance	In compliance	Not yet in compliance	Not yet in compliance
Modifications to list of resources in aggregation	In compliance	In compliance	In compliance	In compliance	In compliance	In compliance
Market participation agreements	In compliance	In compliance	In compliance	In compliance	Not yet in compliance	Not yet in compliance
Demand response opt-out	In compliance	In compliance	In compliance	In compliance	In compliance	Not yet in compliance

Legend: In compliance / Not yet in compliance

Source: Lawrence Berkeley National Lab DER Participation in Wholesale Markets Report, FERC filings

ISO/RTO compliance plans exhibit individualized, disparate approaches to DER wholesale market participation, resulting in a patchwork of rules and requirements that make it difficult for aggregators to scale across jurisdictions. Order 2222 did not provide a technical implementation roadmap, leaving it up to the ISO/RTOs to make their own decisions on VPP integration standards and protocols. Market operators are taking different approaches to compliance with varying rules, baselining methodologies, grid services definitions, and operational protocols. For example, **ISO New England** requires telemetry readings to be actual data for all assets while **PJM** allows telemetry readings to be calculated based on a sample of DERs.[cxvii]

While some variation is expected given varying market conditions and needs, the degree of variation across regions is introducing delays in scaling up proven VPP models nationally to address near-term grid needs. For example, one industry analysis estimated that standardizing ISO/RTO metering and settlement approaches alone could create $75B in savings due to reductions in data computing, storage, and management costs.[cxviii]

Even in achieving Order 2222 compliance, ISO/RTOs could still limit VPP participation. For example, separate from its compliance with Order 2222, **NYISO** proposed a minimum capacity of 10 kW for each individual DER in any aggregation for a VPP to be eligible to participate, which would exclude many residential DER types.[62,cxix] In California, even though **CAISO** has reached full compliance with Order 2222, **California Public Utilities Commission (CPUC)** does not recognize aggregations of DERs as qualified to provide resource adequacy, which is one of the major barriers for aggregators that want to directly participate in CAISO's resource adequacy construct.[cxx]

62 In a September 2022 presentation, NYISO wrote, 'Given the NYISO's current technical resources and capabilities for initial DER deployment, allowing small (<10 kW) DER will require a substantial amount of additional manual work to complete tasks that are core to the timely participation of DERs.'

5.iv. Common challenges for integration into wholesale markets

VPP aggregators, ISO/RTOs, and utilities have noted three key issue areas that impact VPP integration into wholesale markets.[cxxi]

Common issue areas to VPP integration into wholesale markets

Data access	Metering and telemetry	Participation models
Lack of access to high quality customer energy data, grid data, and information about the ownership and location of DERs	Varied requirements for measuring and reporting data	Different approaches to how DER aggregations can bid into markets and the grid services they can provide

These common issues increase costs and complexity for all available assets to participate to their fullest potential

1. **Data access: Lack of access to high quality customer energy data, grid data, and information about the ownership and location of DERs limits aggregators' ability to establish and operate reliable VPPs that can participate in wholesale markets.**

   Hourly and daily customer energy data is required for aggregators to complete wholesale market processes such as receiving customer consent to access data, calculating baselines and performance, and implementing settlement procedures. Most ISO/RTOs require VPP aggregators to use customer energy data from utility-owned meters, yet most utilities limit third-party data access, citing cybersecurity and data privacy concerns. Aggregators must follow varied and often lengthy processes to access customer energy data from utilities, which makes it difficult to know if, when, and in what format data will be shared across utilities even within the same ISO/RTO region.[63] Aggregators have had limited success in improving data access rules despite filing complaints and requesting improvements.[64,cxxii,cxxiii] FERC has stated that customer usage data access is not within FERC's jurisdiction, leaving it to individual ISO/RTOs, states, tribes, or utilities to determine data access policies.[cxxiv]

2. **Metering and telemetry: Each ISO/RTO is developing individual frameworks to determine how to measure and report DER energy data, which increases the complexity and cost for aggregators to deploy and scale VPPs.**

   As relates to Order 2222, "metering" refers to the rules that determine how DER aggregations measure energy injection and withdrawal; "telemetry" refers to how aggregations report the real-time data needed to provide grid services. ISO/RTOs require VPPs to use meter data for planning, operations, and settlement purposes. While the technological capabilities exist to capture this data, such as with

63 For example, sometimes aggregators must email utilities with a form requesting a customer's data. In other cases, utilities have portals where aggregators can access the data directly.

64 For example, CPower, an aggregator who works closely with utilities and supports utility programs, brought a complaint before FERC (EL23-104) showing that lack of data access limits demand response participation in wholesale markets. CPower argued that PJM rules limit the participation of aggregators by refusing to allow statistical sampling for measurement purposes. If statistical sampling were allowed, CPower could measure behavior of a representative sample of customers in their aggregation who have advanced metering infrastructure (AMI) and extrapolate the performance to the full aggregation. PJM, however, requires measurement from every individual meter for interval metered customers, which dramatically reduces CPower's capacity contribution because utilities in the region block access to data from many meters where customers could otherwise participate. FERC denied the complaint and noted that customer usage data access is not within their jurisdiction. Additional detail provided here: CPower Statement Regarding September 19 FERC Decision - CPower Energy; Order Denying Complaint re Enerwise Global Technologies, LLC v. PJM Interconnection, L.L.C. under EL23-104

advanced metering infrastructure (AMI)[65] or metering manufactured into devices, most utilities do not measure demand at this granularity and ISO/RTO telemetry requirements can be too costly or complex for certain asset types.

For Order 2222 compliance, FERC did not provide strict guardrails for either metering or telemetry, approving each ISO/RTO's framework so long as they justify how their requirements are just and reasonable and do not pose an unnecessary and undue barrier to individual DERs joining an aggregation. This has led to a wide variety of approaches that are seeking to balance data granularity with the costs of reporting high frequency data. For example, **NYISO** requires six-second telemetry for every DER asset that is at least 100 kW, regardless of the service provided. **PJM** allows one-minute scans for resources that do not provide regulation services and entirely exempts DERs under 10 MW from telemetry reporting.[cxxv]

3. **Participation models: ISO/RTOs are taking different approaches to develop market participation rules that define how DER aggregations are allowed to bid into wholesale markets and the grid services they can provide, making it difficult for aggregators to replicate similar models across markets.**

   ISO/RTOs have multiple choices in determining market participation rules that define how aggregations bid into the market. An ISO/RTO can choose between requiring aggregators to comply with rules already established for existing supply resources (e.g., applying rules for utility-scale batteries to aggregations of residential behind-the-meter batteries), creating new participation models specifically for DER aggregations, or using a hybrid approach.

   There are trade-offs between these approaches. For example, leveraging models for existing supply resources could avoid slow, expensive processes to create new participation rules, but may restrict participation from aggregations that have multiple types of DERs. Creating a single, new participation model for DER aggregations could simplify aggregator choice on how to participate in a wholesale market but may require all types of DER aggregations to comply with the same rules (e.g., battery-only aggregation may have the same rules as an aggregation with batteries, thermostats, and commercial & industrial loads).[66] Offering a hybrid approach, as **NYISO** and **ISO-NE** are currently suggesting, allows aggregators to choose the option that is highest value to their business model.[cxxvi]

Outside these three challenges, additional issue areas include how to coordinate and compensate dual participation of DERs across wholesale and retail markets[67] (i.e., avoiding 'double counting' for the same service), locational requirements on aggregating DERs across eligible pricing nodes, and ongoing coordination between distribution utilities, market operators, and aggregators.

65 AMI or 'smart meters' are used to measure a customer's energy consumption during set time intervals. AMI includes technologies to measure and communicate energy use and other data and notifications at intervals that are granular enough to support grid and market operations.

66 ISO-NE created multiple DER aggregation participation models to address the drawbacks of creating only one new participation model that would apply to every type of DER aggregation.

67 There is still a role for utilities to play to compensate VPPs for distribution benefits separately and in addition to wholesale market compensation to cover the full value stack of potential services. A VPP that delivers benefits to the transmission system and to the distribution system (even if during the same event) can be fairly compensated for both.

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5.v. Supportive actions for VPP integration into wholesale markets

ISO/RTOs, state regulators, utilities, and aggregators can collaborate to streamline learnings and converge on comparable approaches that address common issues, enabling VPPs to better meet near-term grid capacity needs at lower costs for ratepayers.

There are multiple solutions available globally that could be adopted to support VPP integration into wholesale markets.

Case Study: Australian Energy Market Operator (AEMO)

Australian Energy Market Operator *established a centralized, standardized DER registry to provide visibility to DER specifications and location to eligible entities.*

- In 2020, the **Australian Energy Market Operator (AEMO)** established a centralized DER registry to better manage the grid, improve system reliability as the grid becomes more decentralized, and deliver energy at a more affordable price.
- The register provides a common, standardized information fact base with visibility to DER specifications (e.g., type, capabilities, resource ownership) and location.
- Customers, AEMO, distribution utilities, DER industry, and other third parties (such as emergency services) can access the register.
- Entities are required to provide data in certain formats and timelines; for example, utilities are required to provide DER information in accordance with the DER Register Information Guidelines under the National Electricity Rules to ensure standardization, and DER installers are required to submit data within 20 days of installation.[68,cxxvii,cxxviii,cxxix]

Case Study: Ontario Independent Electricity System Operator (IESO)

Ontario Independent Electricity System Operator (IESO) *created market-wide standards for meter registration to standardize data collection and reduce IT costs*

- **Ontario IESO** has established market-wide standards for meter registration across numerous distribution utilities and 5 million smart meters.[cxxx]
- Market rules require that each metering installation used for settlement purposes is on a list of pre-approved meters established by IESO that meet specific performance standards (e.g., accuracy, security).
- Establishing a market-wide approach to metering simplifies and standardizes data collection while reducing IT costs to develop, manage, and protect the database.
- This spurred additional engagement with various grid stakeholders to expand third-party access to this database, including for demand response aggregators.[cxxxi,69]

See Appendix E for 6 case studies on actions ISO/RTOs have been taking domestically and internationally to integrate VPPs into wholesale markets (Appendix E.iii.), 6 additional resources (Appendix E.iv.) and 3 supportive DOE programs (Appendix E.v.).

68 The Australian Energy Market Commission made a rule obligating AEMO to establish this register in the National Electricity Market in September 2018. AEMO engaged with a wide range of partners, including utilities and industry groups, to design the register and align on the corresponding data sets and data collection processes.

69 Another example is ConnectedSolutions, which has metering authority across multiple utilities in Massachusetts. Common program design across utilities enables standardization of data access, dispatch, monitoring and verification, and DERMS while providing economies of scale for enrollment.

In parallel with ISO/RTO implementation of Order 2222, state policymakers and regulators can act to build enabling VPP regulations and policies that further integrate VPPs into wholesale markets. Example actions include:

- **Lifting state-level 'opt outs' on Order 719:** FERC Order 719 was introduced in 2008 to allow demand response to participate in wholesale markets alongside traditional supply-side resources.[cxxxii] However, states were allowed to 'opt out,' by prohibiting third-party aggregators from directly contracting with customers. These 'opt outs' have greatly limited DER market participation in these states. **Missouri PSC** ruled to partially lift its FERC Order 719 opt out in October 2023 by allowing energy customers above 100 kW (commercial & industrial loads) to enter **MISO's** demand response market.[cxxxiii] By starting with commercial and industrial loads, Missouri state regulators and utilities could test and learn to inform more complex future policies and VPP integration approaches. **Michigan** and **Wisconsin** have also partially lifted their initial 'opt out' of Order 719. Ten states still have 'opt outs' in place for Order 719.[70]

- **Determining the state regulator's role in Order 2222 implementation:** **Pennsylvania PUC** issued an Advanced Notice of Proposed Rulemaking in February 2024 to investigate the PUC's role in Order 2222 implementation. Topics identified for stakeholder input included DER interconnection rules, metering requirements, data sharing protocols, and cost allocation processes.[cxxxiv]

- **Requiring utilities to meet data sharing standards:** **Connecticut PUC** created a Data Access and Privacy Framework to clarify data requirements for IOUs deploying AMI, including data sharing expectations with third-party aggregators.[cxxxv] In response, **Eversource** agreed to adopt Green Button Connect to enable third-party data access.[cxxxvi] Similarly, **Rhode Island PUC** is requiring **Narragansett Electric Company** to submit a plan about data access (including for VPPs) as part of the utility's planned investment into AMI.[cxxxvii]

70 The ten states that continue to fully opt out of Order 719 are Arkansas, Indiana, Iowa, Kentucky, Louisiana, Minnesota, Mississippi, Montana, North Dakota, and South Dakota.

Closing

The U.S. electric grid is increasingly under stress from rising peak demand, climbing utility investments in aging distribution systems and other assets, and increasingly frequent blackout-inducing extreme weather events. "**Virtual Power Plants" or "VPPs" are cost-effective solutions that can be deployed at scale in a short timeframe to maximize the use and value of existing grid infrastructure, minimize costs to ratepayers, and ensure a resilient, reliable, and secure grid for all Americans.**

VPP awareness and deployment is growing, as demonstrated by the 75 case studies, 50 DOE supportive programs, and 20 resources highlighted in this report. Just in the last year, utilities and aggregators have launched increasingly sophisticated VPPs that provide distribution grid benefits in addition to system peak shaving; state regulators and policymakers have implemented VPP-supportive policies; and industry groups have released new solutions to address gaps identified in the 2023 VPP Liftoff Report.

Momentum is building, but the success of many of these efforts hinges on further action and continuous improvement. Many of the case studies presented in this report are early indications of progress, and their full impacts remain to be seen. By tracking, disseminating, and acting upon lessons learned from VPPs across the country (and internationally), stakeholders can accelerate near-term VPP deployment in the pursuit of a more resilient, reliable, and low-cost energy future.

Appendices

Each Appendix directly relates to the five chapters in the main report. Each chapter of the Appendix includes additional case studies of how various industry actors are taking action on the five imperatives today, detailed overviews of select case studies, key resources to support the work of practitioners, and example supportive actions from the Department of Energy.

Appendix A: Expanding DER adoption with equitable benefits

A.i. Levers to expand access to VPP participation, DER ownership, and community-wide benefits

This section provides a list of barriers to expanding access to VPP participation, DER ownership, and community-wide benefits as well as supportive actions that various stakeholder groups can take to address these barriers.

Access to VPP participation

Primary barriers	Levers by stakeholder group
Low awareness of VPP participation opportunities	» **Utilities, policymakers, philanthropy organizations:** Fund and educate community organizations to educate consumers on VPP participation opportunities and consumer benefits » **DER OEMs, DER retailers, utilities, community organizations:** Publicize VPP participation opportunities and educate consumers on their benefits
Qualifying DER too expensive	» **Utilities:** Prioritize integration of low-cost DERs for VPP programs
Community mistrust *(especially for underserved communities due to historic divestment)*	» **Utilities, aggregators:** Partner with trusted community organizations and inform program launch with thoughtful community outreach » **Utilities:** Set equity targets for customer programs; track and publicly report progress against key metrics » **Policymakers:** Require strong customer protections for VPP programs
Lack of reliable connection	» **Policymakers:** Ensure allocation of available broadband grants[71] to rural communities
Lack of flexibility in energy usage[72]	» **Utilities, aggregators:** Offer flexible, opt-out options for DER orchestration

Access to DER ownership

Primary barriers	Levers by stakeholder group
High upfront DER costs with limited low-cost financing options	» **Policymakers, utilities:** Provide upfront, tiered incentives with caps » **Policymakers, regulators, utilities:** Allow incentive stacking to unlock cheapest cost » **Utilities, regulators, policymakers:** Leverage inclusive utility investments to provide access to low-cost financing options
Split incentives between property owners and tenants	» **Utilities, regulators:** Include multi-family housing, especially affordable multi-family housing, in DER programs » **Utilities, regulators:** Develop tariffs to share benefits of DER programs between property owners and tenants
Additional home integration costs	» **Utilities, policymakers:** Ensure upgrade costs (e.g., minor construction) qualify for financing and incentive programs
Lack of education on DERs and available incentives	» **Utilities, policymakers, philanthropy organizations:** Fund and educate community organizations to conduct outreach to match appropriate incentive programs to eligible consumers, particularly in underserved communities

71 Broadband access is important for VPPs that rely on Wi-Fi connection to the device (either directly to the aggregator platform, or through a consumer app that in turn connects with the aggregator's platform). Some VPPs use other communication mechanisms; for example, radio frequency has been used in water heater programs for decades.

72 Low-income communities and other underserved communities may not have the ability to shift or reduce their energy usage as they are already trying to minimize energy usage to reduce utility bills. Lack of flexibility might impact their desire to enroll in a VPP which may cede control of their device at times that may be inconvenient to their circumstances.

Access to community-wide benefits

Types of VPP benefits	Levers by stakeholder group
Reduced pollution burden	» **Utilities, regulators:** Consider VPP deployment prior to approving construction of a new fossil fuel-powered peaker plant » **Utilities, regulators:** Deploy VPPs in communities which have a disproportionate number of fossil fuel plants sited nearby to reduce usage of existing polluting infrastructure
Reduced impact of outages	» **Utilities, regulators:** Target VPP deployment to communities with higher rates of system outages » **Policymakers, regulators:** Prioritize VPP deployment in disaster recovery and resiliency work » **Utilities:** Explore deploying microgrids for vulnerable parts of the grid, wherein the microgrid's DERs can either be islanded for resilience (e.g., at local community centers) or used for bulk grid services to help offset their cost
Lower utility bills	» **Utilities, regulators:** Share cost savings from VPP deployment with all ratepayers[73] » **Utilities:** Spread VPP economic benefits out over the year to minimize large swings in energy bills and ensure consistent bill reductions
Local workforce development	» **Policymakers, regulators:** Partner with Registered Apprenticeship Programs and local technical schools to create pipeline of high-quality workforce in local communities for DER installation » **Utilities:** Partner with a local and diverse contractor base for DER installation

A.ii. Case studies by lever

This section provides case studies of VPP and related deployments that showcase the real-life applications of the levers identified in Appendix A.i. Two of the case studies, Roanoke Cooperative's Upgrade to $ave program and San Diego Community Power's Solar Battery Savings program, have detailed overviews provided in Appendix A.iii.

Access to VPP participation

Lever	Example
Prioritize integration of low-cost DERs for VPP programs	Shifted Energy's 2.5 MW VPP in Hawaii installs smart, programmable water heaters for VPP participation.[cxxxviii] **Allowing low-cost DERs such as water heaters to participate creates more inclusive programs** for priority populations.[cxxxix] Shifted Energy has partnered with local community organizations to reach more than 3,000 families, including low-income residents in areas where trust in the utility is low and would otherwise prevent customers from enrolling in VPP programs that offer energy bill savings.[74,cxl,cxli]
Fund trusted community organizations and inform program launch with thoughtful community outreach	Mass Saves, a collaborative of Massachusetts' electric and natural gas utilities and energy efficiency service providers[cxlii], established the Community First Partnership to increase participation in energy efficiency programs. This **partnership funds community-based organizations, who have the knowledge of and relationships with local communities, to conduct targeted outreach** for these programs, prioritizing renters, low- and moderate-income households, customers who speak languages other than English, and small businesses in participating communities.[cxliii] Mass Saves itself is funded by energy efficiency charges on all customers' gas and electric bills.[cxliv]

73 Utilities that set participant incentive levels high enough to attract large-scale participation, but low enough to be measurably cheaper than alternative grid investments can pass on the savings to all customers by avoiding or deferring unnecessary increases in the ratebase.

74 Smart thermostats are also effective DERs to prioritize for equity considerations, given their affordability and short payback periods.

Access to DER ownership

Lever	Example
Use inclusive utility investments to provide accessible financing options	Roanoke Cooperative (RC) launched the Upgrade to $ave program in 2016 to reduce energy bills for the fourth lowest income Congressional district in the U.S. The Board of Directors targeted upgrading 1000 homes with energy efficiency and demand response measures. They approved use of the Pay As You Save® (PAYS®) system, an inclusive utility investment model, for the design of the utility program and tariff.[75] **RC paid upfront for all cost-effective energy upgrades at a member's residence and recovered its costs through a fixed, monthly cost recovery charge that was lower than the estimated savings from the upgrades on an annual basis.**[cxlv,76] Participating members reduced electricity usage by ~20% because of upgrades and the utility realized peak demand savings of ~20% during summer and winter peaks. *Detailed case study provided in Appendix A.iii.*
Provide upfront incentives that stack with available programs	San Diego Community Power (Community Power) is a Community Choice Aggregator that launched the Solar Battery Savings program in 2024. **The program was designed to benefit all customers through upfront incentives[77] to lower the initial cost of home solar and battery storage resources** and provided ongoing performance incentives for battery power provided during on-peak periods. Community Power **worked with state and local programs to ensure their incentives could stack with programs** such as California's DAC-SASH and SGIP programs[78] and the City of San Diego's Solar Equity program to allow priority populations to cover the entire cost of solar and storage resources through available incentives. *Detailed case study provided in Appendix A.iii.*
Include multi-family housing in DER programs and share benefits between property owners and tenants	Solar energy company PearlX partnered with SolarEdge, a distributed solar OEM, on Project TexFlex to make community solar and storage programs accessible to tenants in multifamily communities around Texas.[cxlvi] PearlX addresses the split incentive challenge associated with rental units by paying the property owner for the right to install the solar and batteries and passing on benefits of lower energy bills and backup power during outages to renters. PearlX manages the assets, providing flexibility and capacity services to the energy market. This approach uses a non-credit based underwriting method, which allows tenants to access the rewards of solar generation and battery storage without having to provide their credit score. Pilot results indicate solar energy supplied 46% of participating tenant's daily energy consumption, reducing grid demand for ERCOT, and **saving tenants $60 per month on their energy bills on average**.[cxlvii] PearlX is now exploring expanded offerings to help build resilience for multifamily communities while also providing new amenities to residents and supporting the grid.

75 PAYS Essential Elements and Minimum Program Requirements provides additional information on the utility program requirements for a PAYS program and PAYS model tariff shares the tariff design.

76 The program's annual cost recovery is set at less than the estimated savings from the upgrades to ensure immediate reductions in energy costs, and much larger cost reductions once the utility recovers its costs and ends the on-bill charge.

77 Upfront incentives can be more effective at overcoming initial barriers to DER adoption than incentives paid at a later date, such as rebates. This is because customers would have to pay the upfront cost of the resource and wait to receive the rebate with limited visibility and certainty on when the incentive would be provided. Even rebates that cover 100% of the cost of the underlying asset may not be effective, especially for underserved communities.

78 DAC-SASH is the Disadvantaged Communities – Single-Family Solar Homes program developed by the California Public Utilities Commission (CPUC) and administrated by GRID Alternatives. This state program provides $8.5 million in incentives annually to help homeowners in disadvantaged communities go solar. SGIP is the Self-Generation Incentive Program developed by the California Public Utilities Commission to provide rebates for qualifying distributed energy systems on the customer's side of the utility meter, including advanced energy storage systems, wind turbines, waste heat to power technologies, pressure reduction turbines, internal combustion engines, microturbines, gas turbines, and fuel cells.

Include affordable multi-family housing in DER programs and share benefits between property owners and tenants	PowerTree is working with a 40-unit low-income apartment building in central California to provide BTM solar and batteries. PowerTree works with the property owner to install these assets behind-the-meter and orchestrate them to optimize energy usage. **Renters immediately benefit from lower energy bills, and property owners benefit from a slight increase in rent**, which increases the cash flows of the property and the equity value of the building. The savings in energy bills offset the rent increase, with households able to save $700 in total per year on net given 60% to 100% of tenant load is served from the onsite solar and storage, and an average 31% peak reduction for the building.
Address necessary home upgrades for income-eligible homes	Missouri utility Evergy is using $1M of their Income-Eligible Single Family[79] budget to **help homes that have been deferred for weatherization upgrades to receive the necessary repair work to qualify for existing programs.** Evergy is leveraging a partnership with nonprofit Bridging the Gap to make the necessary structural or home health repairs through local minority contractors. Evergy is also providing income-qualified customers (200% Federal poverty level) free energy-savings items, such as adhesive weather strips, 2-pipe insulation pieces, and switch and outlet gaskets on their online Offer Center to provide a multi-channel approach in increasing home eligibility for their programs.
Bundle the DER purchase and installation process to streamline customer experience	SMUD partnered with Uplight Marketplace to provide instant rebates for EV chargers with bundled installation offers and prequalified installation incentives. Chargers with upfront rebates at the point of purchase are 3 to 5 times more likely to sell on the marketplace than a non-rebated charger. Uplight partnered with Qmerit, a national network of electricians certified to install Level 2 chargers, to schedule charger installations when customers purchase the charger from their utility website. **40% of customers who received quotes scheduled and completed their charger installation by Qmerit.**
Conduct outreach and education to match appropriate incentive programs to eligible consumers	A team from Colorado School of Mines is working to upgrade 16 homes in a manufactured home community[80] in Lake County, Colorado by providing new insulation, LED lighting, high-efficiency furnaces, with plans to install electric heat pumps and batteries in the next few months. Funding was provided by the Weatherization Assistance Program (WAP) and DOE grants. The team **surveyed every participating unit to ensure qualification for the program before the time-intensive application process was started**. Their team is now working to help residents subscribe to Xcel Energy's community solar garden which will credit homeowners on their energy bills for solar energy provided, reducing energy bills.[cxlviii]

79 Evergy has a Low-Income Single-Family program to provide assistance for income-qualified households to overcome structural or home health barriers that otherwise prevents the resident from receiving needed weatherization upgrades.

80 Manufactured homes are energy-intensive, and residents of these homes report high energy insecurity. Many manufactured homeowners are unable to access home equity loans to finance major renovations, making it difficult to adopt distributed energy resources and energy efficiency upgrades.

Access to community-wide benefits

Lever	Example
Deploy VPPs in underserved communities to reduce usage of existing polluting infrastructure	Dominion Energy initiated its Electric School Bus Program in 2019 to assist public school districts in Virginia in overcoming the challenges associated with electric school bus adoption and to advance bi-directional EV Charging and Vehicle-to-Grid (V2G) capabilities. The initial pilot phase of the program commenced in 2019, during which Dominion Energy collaborated with 15 public school districts in Virginia to deploy 50 electric school buses across Dominion Energy Virginia's service regions and underserved communities. Since 2021, funding from the Virginia Department of Environmental Quality (DEQ) and the EPA Clean School Bus Program have provided additional resources to promote electric school bus adoption, with a focus on rural, low-income, and poor air quality districts. Currently, public schools in Virginia that receive EPA funding can partner with Dominion Energy, which will cover the costs of chargers, infrastructure, and installation to support the electric school buses. In return, Dominion Energy is granted the ability to use the buses and chargers for V2G during summer vehicle dwell times. **The program enables school districts and underserved communities to benefit from electric school buses, including improved air quality (with air quality inside a diesel bus being five times worse than outside the bus), decreased noise pollution, and reduced operational and maintenance costs for schools (up to a 60% reduction in costs)**.[cxlix]
Target VPP deployment to communities with higher energy burdens and / or higher rates of system outages[81]	Nimiipuu Energy, a tribally owned energy company, is installing solar and battery systems in tribal homes of the Nez Perce Tribe[cl] to eliminate / lower power bills, decrease dependency on grid supplied power (specifically power generated by the Snake River Dam), and build tribal energy independence. Each home is receiving a rooftop solar array and two Tesla Powerwalls. Tribal nations have reported experiencing outages over six times more frequently than the national average.[cli] **Building this community-owned VPP is meant to provide income for the Tribe while eliminating / lowering power bills for residents**.[clii]
Prioritize VPP deployment in disaster recovery and resiliency work[82]	In 2017, Hurricanes Irma and Maria devastated Puerto Rico's grid and communities. **Since then, significant efforts to prioritize DER adoption in disaster recovery have led to high levels of residential solar PV and battery storage resources.** Puerto Rico's electric utility provider, LUMA, launched the Customer Battery Energy Sharing Program (CBES) in late 2023. Serving primarily residential customers through a number of aggregators[cliii], CBES includes over 7,000 participants and provides 28 MW of available capacity. The program compensates participants via aggregators $1.25/kWh for battery energy supplied during events. Last year, 53 events were called, dispatching 23 MWh of energy. LUMA plans to propose a permanent version of the program by early January 2025.[cliv,clv]
Explore VPP islanding for community centers, especially in disaster-prone areas	In Louisiana, the Community Lighthouse Project has built solar and storage systems on churches to transition these buildings into self-sustaining microgrids. Churches such as First Grace United Methodist Church **operate during times of emergency to provide a haven for their communities**.[clvi]

81 Another great example is California's SGIP program which offers rebates for installing energy storage technology that can work during an outage at residential and non-residential buildings. The program prioritizes communities that live in high fire-threat areas, communities that have experienced two or more utility Public Safety Power Shut-off events, and low income and medically vulnerable households.

82 According to the U.S. News and World Report, racial minorities may have a higher social vulnerability to natural disasters in the U.S. based on a "National Risk Index."

A.iii. Detailed case studies

Detailed case study #1: Roanoke Cooperative's Upgrade to $ave Program

Inclusive utility investment reduces upfront cost barriers to adopting water heater control switches and smart thermostats.

VPP summary			
Utility	Roanoke Cooperative (RC)	**VPP size** *(as of November 2024)*	1.75 MW (with plans to double, 2.5-3% of system peak)
Utility type	Rural electric cooperative (distribution cooperative)	**Type of DERs**	Water heater control switch, smart thermostat, efficiency[83]
Market structure	Within organized market (PJM), utility does not own generation	**Upfront investment cost**	$4.5M including efficiency and flexible demand
Location	North Carolina	**Time to operationalize**	12 months
Size of utility	14,000 member-owners (60-70 MW system peak)	**Number of customers enrolled in VPP**	750 (5%)
Compensation structure	▸ Upfront incentive: $950 (smart thermostat and water heater control switch were provided for free) ▸ Performance incentive: $4 monthly bill credit for participating customers (Roanoke Cooperative Smart Grid Device program)		
Grid services	▸ Peak shaving (summer and winter)		

Utility objectives with VPP program *(not exhaustive)*

- **Reduce energy bills** by upgrading 1000 homes (7% of member base) with energy efficiency (EE) and demand response (DR) measures to reduce system-wide peak demand and deliver services at lower cost
- **Enable widespread accessibility** by addressing barriers of high upfront costs of resources, low credit scores limiting traditional low-cost financing options, and limited willingness to take on debt

83 Although energy efficiency upgrades are not considered distributed energy resources in this report, investments in EE help reduce demand for individual households and across the system.

Program summary

Roanoke Cooperative (RC) launched the Upgrade to $ave program in 2016 to reduce energy bills for the fourth lowest income Congressional district in the U.S., where average annual energy costs are more than 6%[84] of the median income. The Board of Directors targeted upgrading 1000 homes with energy efficiency and demand response measures. They approved use of the Pay As You Save® (PAYS®) system, an inclusive utility investment model, for the design of the utility program and tariff.[85]

In this program, RC paid upfront for all cost-effective energy upgrades at a member's residence and recovered its costs through a fixed, monthly cost recovery charge on the bill of participating members that was lower than the estimated savings from the upgrades on an annual basis.[clvii,86] To enroll customers, RC assessed the energy savings potential of the building rather than the owner's income or creditworthiness, allowing all members to access low-cost financing options.[87]

Participating members reduced electricity usage by ~20% because of upgrades and the utility realized peak demand savings of ~20% during summer and winter peaks.[88] Including the cost of capital and program operation costs, the utility sees $2M+ NPV over the lifetime of the upgrades for those already installed, excluding the continuing cash flow value from exercising demand response.[clviii]

Other programs are exploring similar solutions to improve accessibility to DERs:

- Duke Energy's Improve and Save program is leveraging Roanoke's experience to offer inclusive utility investments in heat pumps while it is also piloting a VPP called Power Pair.[clix]
- Illinois' Commerce Commission is guiding development of the Equitable Energy Upgrade Program required by the state's Climate and Equitable Jobs Act with essential elements that are similar to Pay As You Save® and it includes the potential to accelerate the adoption of rooftop solar and storage for low-income customers.

Key success factors to expand DER adoption with equitable benefits *(not exhaustive)*

- **Leverage innovative financial solutions,** such as an inclusive utility investment[89], to deploy money-saving distributed energy upgrades at customer locations, including demand flexibility
- **Partner with a trusted organization** that has instituted these programs before to maximize operational efficiency and member-owner benefits
- **Build significant consumer protections** into program design to ensure installation quality, realization of energy savings, and associated reduction in energy bills, with protocols to suspend or adjust cost recovery charge, if needed[clx]

84 Communities where energy costs are more than 6% of income are typically considered communities with high energy burdens. The national average, in comparison, is 2.9%.

85 PAYS Essential Elements and Minimum Program Requirements provides additional information on the utility program requirements for a PAYS program and PAYS model tariff shares the tariff design.

86 The program's annual cost recovery is set at less than the estimated savings from the upgrades to ensure immediate reductions in energy costs, and much larger cost reductions once the utility recovers its costs and ends the on-bill charge.

87 After running the program for 2 years, REC transferred program management to EEtility, an operator that was managing Ouachita Electric Cooperative's PAYS® program, which was producing better results. EEtility introduced several best practices that improved energy savings by 46%, peak load reductions by 71%, and member acceptance of offers by 17%. Best practices included targeted outreach to homes with high energy use per square foot and direct installation of low-cost upgrades for homes that were initially deferred from enrollment due to structural repair needs. At no cost to the residents, these homes received LED lights, smart strips, aerators, water heater blankets, and AC coil cleaning.

88 Roanoke is leveraging North Carolina Electric Membership Cooperation's (NCEMC) DERMS platform, which is an OATI product, to shed or shift demand from the distributed energy resources.

89 Inclusive utility investments have emerged as a more equitable solution with strong consumer protections that has been implemented by 23 utilities in 10 states, with most choosing to apply the Pay As You Save® (PAYS®) system to implement.

Detailed case study #2: San Diego Community Power's Solar Battery Savings Program

Upfront, stackable incentives provide opportunity for no-cost solar and batteries to qualified priority populations.

VPP summary			
Utility	San Diego Community Power	**VPP size** *(as of November 2024)*	7.3 MW (0.4% of system peak)
Utility type	Community Choice Aggregator	**Type of DERs**	Solar, BTM battery
Market structure	Within organized market (CAISO), utility does not own generation	**Upfront investment cost**	$11.5M with 45% ($5M) as cost-neutral through RA savings
Location	California[90]	**Time to operationalize**	12 months
Size of utility	1 million customer accounts	**Number of customers enrolled in VPP** *(as of November 2024)*	1,600[91] (~0.2%)
Compensation structure	» Upfront incentive: • Market Rate: $350/kWh for storage • Underserved Community Rate (e.g., CARE/FERA and/or Communities of Concern): Up to $450/kW-AC for solar and up to $500/kWh for storage » Performance incentive: $0.10/kWh of battery power discharged during on-peak periods		
Grid services	» Daily load cycling (charging during the day, discharging during daily two-hour peak window)		

Utility objectives with VPP program *(not exhaustive)*

- **Improve outcomes for underserved communities** by allocating 50% of budget for solar and storage incentives to Communities of Concern
- **Decarbonize power supply** by charging batteries with solar during the day and using daily during peak hours to reduce emissions
- **Lower costs and energy bills** by utilizing battery during on-peak periods to realize $5M of resource adequacy savings, which reduces on-peak consumption system-wide and lowers utility bills for all customers

90 San Diego Community Power operates in seven cities in San Diego County in California.

91 This program was launched in August 2024. The program hit its budget cap of ~$11.5M in **3 months** (August – November), indicating high customer interest. 1,600 customers have been approved to enroll in the program as of November 2024, with 200 customers fully operationalized and providing daily dispatch from their batteries.

Program summary

San Diego Community Power (Community Power) launched the Solar Battery Savings program in 2024 to support customers and the solar and storage industry in the transition from net energy metering (NEM) to net billing tariff (NBT).[92] Community Power (CP) used a portion of the expected savings in the transition from NEM to NBT and resource adequacy savings from leveraging batteries during times of peak demand to fund the program.

The program was designed to benefit all customers through upfront incentives[93] to lower the initial cost of home solar and battery storage resources and provided ongoing performance incentives for battery power provide during on-peak periods. Community Power tailored incentives to provide priority populations[94] (i.e., CARE/FERA[clxi] and / or Communities of Concern[clxii]) with higher incentives to meet their needs and improve equity outcomes, embedding equity goals and metrics into program design from the start. Community Power worked with state and local programs to ensure their incentives could stack with programs such as California's DAC-SASH and SGIP programs and the City of San Diego's Solar Equity program to allow priority populations to cover the entire cost of solar and storage resources through available incentives. Prioritizing a no-cost solution for the most energy burdened communities is critical to ensure realization of direct and immediate benefits.

Community Power also led contractor outreach and training prior to program launch to ensure workforce development opportunities offer accessible training, education, and contracting opportunities to a diverse and local contractor base. Community Power continues to accept new contractor applicants and tracks participation of all approved contractors, including minority-owned, for the solar and battery storage installations.

Other programs are deploying similar solutions to improve accessibility to DERs:

- New Mexico's Home Electrification and Appliance Rebate (HEAR), funded by the Inflation Reduction Act of 2022, was launched as a coupon-style incentive program to provide upfront discounts of up to $1,600 off insulation, air sealing, and ventilation for low-income, single-family homeowners.
- New York utility Orange & Rockland partnered with Sunrun, a distributed solar provider, to launch a 2 MW VPP in NY with **over 300 solar and storage systems, 50% of which are in areas designated as a 'disadvantaged community'** by the state. Participating customers who were installing solar from Sunrun received upfront incentives to install a free or heavily discounted home battery when enrolling in the 10-year program.[clxiii,clxiv,95]

Key success factors to expand DER adoption with equitable benefits *(not exhaustive)*

- **Redirect system cost savings to all customers**
- **Provide higher, upfront incentives** to priority populations to minimize or eliminate costs of adopting distributed solar and behind-the-meter batteries that can stack with available state and Federal programs
- **Partner with a local and diverse contractor base for DER installation** to build local workforce development opportunities through these programs (38% of over 50 local contractors approved are disadvantaged business enterprises or DBEs; 6% are represented by a union)

92 Net billing tariff provides greater economic value for installing solar and storage rather than stand-alone solar.

93 Upfront incentives can be more effective at overcoming initial barriers to DER adoption than incentives paid at a later date, such as rebates. This is because customers would have to pay the upfront cost of the resource and wait to receive the rebate with limited visibility and certainty on when it would come through. Even rebates that cover 100% of the cost of the underlying asset may not be effective, especially for underserved communities.

94 CARE (California Alternative Rates for Energy) and FERA (Family Electric Rate Assistance) are California-specific programs to provide discounts to low-income customers on their electric and natural gas bills. Communities of Concern are disadvantaged communities identified by the Cities of San Diego and Chula Vista through their Climate Equity Index reports.

95 The VPP was initiated by O&R and approved as a demonstration project by the NY Department of Public Service. O&R conducted targeted outreach to underserved communities by mailing brochures to every customer living in an area designated as a 'disadvantaged community'.

A.iv. Key resources for practitioners

- **Clean Energy Financing Toolkit for Decisionmakers** (EPA) provides an overview of available financing programs and policies that state, local governments, and other industry actors use to support investments in clean energy (including inclusive utility investments).
- **NREL Virtual Power Plants and Energy Justice** (October 2023, National Renewable Energy Lab) shares barriers and example solutions specific to advancing energy justice outcomes through Virtual Power Plants.
- **Practical Guide for Distributional Equity Analysis for Energy Efficiency and Other Distributed Energy Resources** (May 2024, DOE) shares an analytical framework for utilities, regulators, communities, and other stakeholders to answer questions about the equity implications of utility investments and to embed implications alongside traditional cost-effectiveness analyses.
- **Energy Equity for Homeowners Initiative** (ACEEE) includes resources and technical assistance to support programs in establishing evaluation processes and metrics to scale energy efficiency, especially for underserved communities.
- **US DER Resource Outlook 2024** (June 2024, Wood Mackenzie) provides analysis of DER deployment and market size from 2019-2028.

A.v. Actions from the Department of Energy

- **Loans and Loan Guarantees** to support VPP projects with a focus on low- to moderate-income communities, including lowering the cost of financing for VPP-eligible DERs
- **Home Energy Rebates** to reduce the cost of efficiency retrofits and electrification measures in homes and other buildings, providing low and moderate-income families up to $14,000 for products like electric heat pumps, electric stoves, and more
- **Weatherization Assistance Program** for energy efficient and electric technologies in low-income households, including improved insulation to help reduce total energy bills
- **Low-Income Energy Affordability Data (LEAD) Tool** to help states consider strategic deployment of funding relative to energy burden and household income, among other building characteristics
- **Clean Energy Funding and Technical Assistance** to provide no cost technical assistance to tribal entities and funding for planning and deployment of energy solutions
- **Technical Assistance for New and Stretch Code Adoption** for adoption and enforcement of new and stretch building codes
- **Training for Residential Energy Contractors** to fund state energy offices so they can train, test, and certify residential energy efficiency and electrification contractors
- **Energy Efficiency Grants** for energy efficiency audits, upgrades, and retrofits, including for deployment of DERs, for residential and commercial buildings
- **Energy Efficiency Revolving Loan Fund Capitalization Grants** to fund states to provide loans and grants for energy efficiency, upgrades, and retrofits, including distributed solar
- **Residential and Commercial Workforce Training Programs** that include training on smart tech and grid network systems
- **Community Power Accelerator** to provide training, resources, and technical assistance to developers

and organizations and connect them to investors, lenders, and philanthropies to finance and deploy equitable solar and storage projects in communities across the country

- **National Community Solar Partnership** to expand access to affordable community solar; expanded program provides technical and financial assistance for developers interested in hosting or participating in a VPP from DOE National Labs
- **Clean Cities and Communities** to deploy affordable, efficient, and clean transportation fuels and energy efficient mobility systems, including EVs and EV charging
- **SolSmart** to provide no-cost technical assistance to local governments to make it easier for residents and businesses to go solar in their community
- **Charging Smart** to equitably expand electric vehicles (EVs) and EV charging infrastructure in rural, urban, and suburban communities by reducing soft costs (i.e., permitting, inspection, and load service requests)
- **Distributed Wind Smart** to develop and share best practices in zoning, planning, inspection, community engagement, and financing for distributed wind
- **Renewables Advancing Community Energy Resilience (RACER) Funding** to fund projects that enable communities to use solar and solar-plus-storage to prevent disruptions in power and rapidly restore electricity if needed
- **SolarAPP+** to automate and expedite permitting for residential rooftop PV and PV plus energy storage systems for solar contractors

Appendix B: Simplifying VPP enrollment

B.i. Case studies by lever

This section provides case studies of VPP and related deployments that showcase additional no-regrets and high-impact actions that are simplifying enrollment. One of these case studies, Arizona Public Service's Cool Rewards program, has a detailed overview provided in Appendix B.ii.

No-regrets actions

Lever	Example
Communicate program benefits in simple and concise terms *(especially financial benefits)*	Minnkota Power Cooperative's demand response program has **enrolled 55,000 customers (40% of customers) and can serve 350 MW, 35% of winter peak load,**[clxv] through the program.[clxvi] Minnkota is able to temporarily control DERs including heat pumps, water heaters, EV chargers, and commercial & industrial loads during peak events. To encourage enrollment and participation, Minnkota provides clear financial benefits – upfront incentives to purchase the DERs and eligibility for the off-peak program rate, which is roughly half the standard rate.[clxvii] Minnkota cultivated widespread buy-in from member distribution co-operatives to message the same.[clxviii,clxix]
Offer ongoing performance-based incentives to encourage continued participation	California's Demand Side Grid Support (DSGS) program **has enrolled over 265,000 participants with 515 MW of capacity in two years.** Customers can enroll by submitting an application to their DSGS provider.[clxx] The program is managed by Olivine which includes a 200 MW storage VPP, one of the largest in the world, to provide power back to the grid. Participants are paid based on net load reductions provided, with some earning $2/kWh of energy shared with the grid. The VPP was activated 16 times in 2024 to avoid a grid crisis during four heatwaves in the summer.[clxxi]
Offer a compelling value proposition to customers, with minimal additional effort on their part	One major Southern California utility partners with a program administrator to **deploy backup generation, solar, and battery storage assets with a 94% enrollment rate sustained over four years**. The program targeted communities that experienced the highest level of power outages and Public Safety Power Shutoff (PSPS) events on specific circuits and transmission lines. Deployment services included customer outreach campaigns by mail, email, telephone, and in-person to conduct in-home consultations to encourage eligible customers to apply and enroll in the program. Households were provided the assets for free, and the program administrator partnered with a local group of vendors to support the full customer lifecycle from first call to site visit and installation through five years of preventive maintenance and service.[96] As a continuation of this program, the utility instituted a VPP pilot program to use these resources (including smart thermostats, well-pump controllers, and water heaters) to shed load during peak hours.
Offer flexibility to opt out of events	Rocky Mountain Power's Cool Keeper program has enrolled **over 100,000 customers (~8.3% of customers, 280 MW of flexible load),**[clxxii] **with more than 98% of program participants satisfied with the program.** The program allows participants to opt out of events and un-enroll at any time at no additional cost by calling a phone number specific to the program.[clxxiii] Easy opt-out mechanisms put customers at ease when enrolling for programs and ensures appropriate customer protections are in place.
Leverage a multi-channel marketing approach	Ontario's Independent Electricity System Operator's (IESO) Save on Energy Peak Perks Program **has enrolled over 125,000 devices with over 100 MW of peak load reduction in less than one year.** The program leveraged a multi-channel marketing approach, including in-app messages by partnering with OEMs to get extra program visibility beyond standard in-app marketing, emails, and microsites. IESO worked with a marketing agency to spread the word through influencers and social media to enroll customers.[clxxiv] In 2024, the program delivered a maximum load shed of 133 MW during its first event.

96 Another example is SMUD who leveraged higher customer incentives to encourage participation in their Partner+ program. These incentives are meant to compensate customers for mandatory participation in the year-round use of their solar and storage systems.

High-impact actions

Lever	Example
Minimize customer time and effort to enroll in programs	EnergyHub, an edge DERMS provider with more than 1.3 million devices under management, **saw a 70% increase in "Enroll" button clicks on average by redesigning their utility microsite navigation and eliminating six clicks** from the path to enrollment. This increased accepted devices per month by over 1,000 across the programs that used the new template.[clxxv]
Offer point-of-purchase enrollment	APS launched Cool Rewards, a smart thermostat program, in 2018 after the Arizona Corporation Commission authorized demand response and load management programs for the utility. As of November 2024, the Cool Rewards program has enrolled over 97,500 connected thermostats with the ability to shed over 160 MW of load during peak demand events. **APS established a smart thermostat marketplace on their website** where *all* customers could get an instant $30 rebate at checkout and an additional $85 off upfront by pre-enrolling into the program.[clxxvi] As of the end of October 2024, 9,290 Cool Rewards pre-enrollments were processed through APS marketplace. Embedding enrollment into the point-of-sale process reduces marketing and recruiting costs for the program. *Detailed case study provided in Appendix B.ii.*
Enroll customers in multiple programs at once	AES Indiana partnered with Uplight Plus to pilot a subscription energy bundle by offering budget billing, digital payments, and green energy enrollment *all in one package*. Within the first three months of launching Uplight Plus with a pilot population of 2,000 residential customers, **AES Indiana saw a 26% increase in autopay enrollment and a 67% increase in green energy program enrollment**.[clxxvii]
Allow customers to set control ranges	Maryland utility Baltimore Gas & Electric partnered with WeaveGrid, a managed EV charging provider, to pilot a distribution-level charging program with over 3,000 residential customers. **WeaveGrid prioritizes optimizing EV charging for customers based on who has the lowest state of charge and who has the earliest departure time to maximize customer satisfaction.** 92% of charging load managed through the program complied with the charging schedule set by BGE and WeaveGrid, optimizing benefits for customers and the grid. The Maryland PSC approved BGE's proposal to expand the pilot to a full program with 30,000 participants by 2027.[clxxviii]

B.ii. Detailed case studies

Detailed case study #1: Arizona Public Service's Cool Rewards Program

Clear incentives and simple messaging allow APS to shed up to 160 MW of load (~2% of peak demand) by enrolling 97,500+ thermostats in the Cool Rewards program.

VPP summary			
Utility	Arizona Public Service	**VPP size** *(as of 2024)*	160 MW (2% of system peak)
Utility type	Investor-owned utility	**Type of DERs**	Smart thermostat
Market structure	Not in organized market, utility owns generation	**Upfront investment cost**	*Not available*
Location	Arizona	**Time to operationalize**	12 months
Size of utility	1.4 million customers (8.2 GW system peak)[clxxix]	**Number of customers enrolled in VPP**	72,000 (5%)
Compensation structure	» Upfront incentive: $50 one-time enrollment credit and $30 credit towards the purchase of a smart thermostat » Performance incentive: $35 annual participation credit		
Grid services	» Peak shaving, load shifting, location-based demand response		

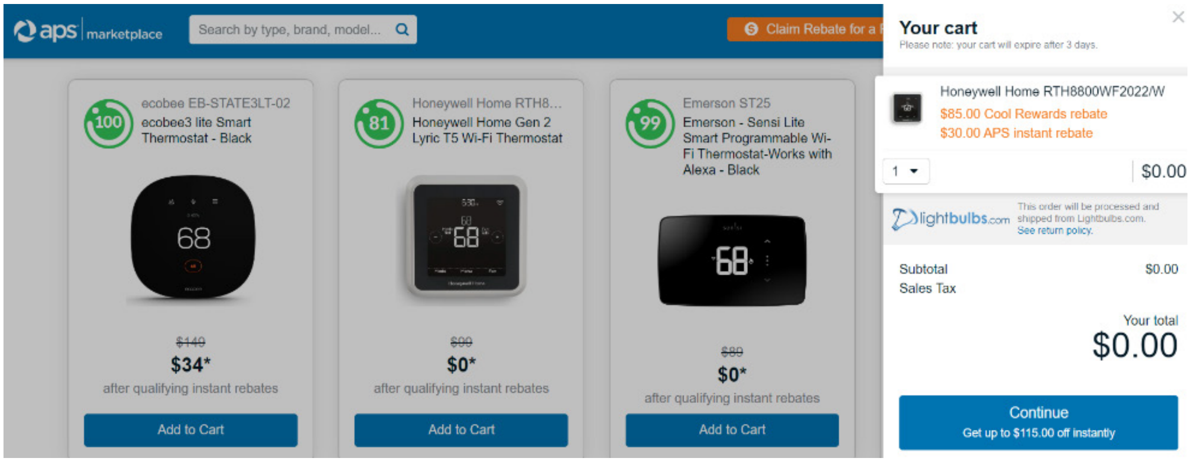
Utility objectives with VPP program (not exhaustive)

- **Reduce customer costs during times of peak demand** to ensure affordability of energy bills, especially given time-of-use rates[clxxx]
- **Decarbonize power supply** by achieving a resource mix that is 65% clean energy by 2030 by maximizing demand-side resource potential[clxxxi]
- **Maximize potential of demand-side resources** by meeting 19% of coincident peak demand by 2038 through optimizing energy efficiency, distributed resources, and demand response programs

Program summary

APS launched a smart thermostat program in 2018 after the Arizona Corporation Commission authorized demand response and load management programs for the utility. The Cool Rewards program is at the forefront of APS' VPP portfolio[97], incorporating smart thermostats for both residential and small to medium-sized business customers. As of November 2024, the utility had enrolled over 97,500 connected thermostats with the ability to shed over 160 MW of load during peak demand events.

97 APS' Cool Rewards program is one part of a broader VPP portfolio (193 MW as of November 2024) that mainly consists of smart thermostats, battery storage, and behavioral demand response, all working together to support the grid.



APS simplified the enrollment and participation process to maximize value from the demand response program, while minimizing customer inconvenience. APS established a smart thermostat marketplace on their website where all customers could get an instant $30 rebate at check-out.[clxxxii] With simple and clear messaging, APS allowed customers to receive an additional $85 off upfront by pre-enrolling into the Cool Rewards program after providing basic information (e.g., name and address).[98] Embedding enrollment into the point-of-sale process reduces marketing and recruiting costs for the program. As of the end of October 2024, 9,290 Cool Rewards pre-enrollments were processed through APS marketplace, which was built in partnership with Enervee.[clxxxiii]

APS offers virtual assistance for customers needing support with installing their smart thermostat after purchase. For those unable to install virtually, in-home installation support is also available. These partnerships help ensure thermostats are properly installed, connected, and ready for use, enhancing customer value.

APS ensures ongoing participation by prioritizing customer comfort, allowing flexible opt-outs, offering ongoing incentives, and communicating social impacts of participation. To ensure customer comfort, some thermostat manufacturers may lower a customer's thermostat(s) temperature a few degrees to pre-cool the home before the peak event, increase the thermostat by a couple of degrees during a conservation event, and return the thermostat to its original setting or schedule after the event.

Customers can easily opt out of events by directly changing the thermostat setting. In 2023, APS launched the Cool Rewards Promise which reinforces that the customer will always remain in control of their thermostat and can adjust or opt-out at any time. APS provides annual participation incentives, which APS increased from $25 to $35 per year after receiving customer input and has seen a corresponding increase in enrollment. APS also communicates the social impacts of the program by sending messages such as, "This summer, your participation made a positive difference for our environment and community" to encourage continued participation.

Key success factors to simplify VPP enrollment *(not exhaustive)*

- ✔ **Capture customers at point of purchase by establishing an online marketplace,** clearly communicating financial benefits to purchase a smart thermostat ($30 instant rebate) and additional upfront incentives to pre-enroll in the Cool Rewards program ($85 enrollment credit and first year participation credit)
- ✔ **Provide installation support** to help customers easily connect their smart thermostat
- ✔ **Launch the Cool Rewards Promise** to remind customers of the event's purpose, ensuring they remain in control of their device
- ✔ **Communicate social impacts** to keep customers engaged in the program after enrollment

98 Uplight, a flexibility management platform, found that over 60% of eligible customers purchasing a smart thermostat through their marketplace enrolled in demand response programs when offered at point of sale.

B.iii. Key resources for practitioners

- **Distributed Energy, Utility Scale: 30 Proven Strategies to Increase VPP Enrollment** (December 2024, Lawrence Berkeley National Lab) discusses 30 proven strategies to scale VPPs by maximizing enrollment with concrete case studies and proof points.
- **Insights into Scaling Virtual Power Plants** (January 2025, Lawrence Berkeley National Lab) provides a publicly available inventory of VPPs in the U.S.
- **North America Virtual Power Plant (VPP) Market Report** (July 2024, Wood Mackenzie) provides an overview of the state of the VPP market today in the U.S. and Canada, including technology trends, VPP offtake, and wholesale market and regulatory landscape.
- **VPP Flipbook** (July 2024, RMI and VP3) includes discussion of 22 VPP programs in operation across the U.S., including details on effective VPP program design and implementation.
- **Utility VPP Comparison Matrix** (June 2024, RMI) shares program design information for 22 VPP programs featured in the RMI VP3 Flipbook.
- **National Roadmap for Grid-Interactive Efficient Buildings** (May 2021, DOE) includes an overview of grid-interactive efficient buildings (GEB), and the barriers and solutions to accelerating GEB deployment across the country.

B.iv. Actions from the Department of Energy

- **V2X MOU** to establish partnership and business case demonstration projects that identify interconnection standards, market access needs, and interoperability approaches for EV charging and discharging with public and private sector engagement
- **Computational tools**[99] developed and applied by National Laboratories to help regulators and utilities determine how to apply DERs, including microgrids, to better serve equity and resilience needs

99 Page 69 of the 2023 VPP Liftoff Report includes detailed information on the modeling tools available from select DOE-partnered national laboratories.

Appendix C: Increasing standardization in VPP operations

This section provides an explanation of the communication protocols and IT/OT components and configurations for three VPP programs: National Grid's 'ConnectedSolutions' in Massachusetts and New York, Green Mountain Power's 'Energy Storage Solutions' in Vermont, and Rocky Mountain Power's 'Wattsmart' in Utah. The purpose of the case studies is to demystify the communication technology that enables a VPP and help stakeholders understand where increased standardization will be valuable – e.g., interoperability of DER and VPP software, grid services definitions, etc.

To reference the framework that shares the possible go-to-market models, see page 23 of this report in Section 3.i.

Go-to-market model:	**① Utility-led, aggregator-operated VPP**	**①③ Utility-run VPP and market-participant VPP**	**③ Utility-run VPP**
Case study:	**ConnectedSolutions**	**Energy Storage System**	**Wattsmart**
Bulk system operators	ISO New England	Green Mountain Power	Rocky Mountain Power
Distribution system operators	National Grid	Green Mountain Power	Rocky Mountain Power
VPP platforms	EnergyHub	Tesla	sonnen
Customer DERs (residential, commercial, industrial)	• 10 Smart thermostat brands • 17 Battery brands • 19 EV and EV supply equipment brands • 7+ Commercial & industrial aggregators	ESS program: • Tesla Powerwalls or equivalent compatible equipment	• Any battery that meets functional criteria, including sonnen. • Four additional battery manufacturers under testing and review.

C.i. Detailed case study #1: ConnectedSolutions

VPP overview

National Grid's ConnectedSolutions Program

Multi-device VPP established within 4 months with <$500k upfront investment cost provides up to 250 MW of system-level peak shaving benefits.

VPP summary			
Utility	National Grid	**VPP size** *(as of 2024)*	250 MW (2% of system peak)
Utility type	Investor-owned utility	**Type of DERs**	Residential DERs: Smart thermostats, batteries. Commercial DERs: HVAC, manufacturing loads, bidirectional EV chargers, water heaters, thermal storage, batteries.
Market structure	Within organized market (ISO-NE and NYISO), utility does not own generation	**Upfront investment cost**	$500k
Location	Massachusetts and New York	**Time to operationalize**	4 months
Size of utility	20 million customers (11.5 GW peak demand)	**Number of customers enrolled in VPP**	100,000
Compensation structure	Residential: » Thermostats: $25 – $50 upfront incentive per thermostat; additional $20 incentive for staying enrolled. » Batteries: 0% Interest 7-Year Loan for battery costs; $275/kW performance incentive. Commercial: » $30 - $200/kW performance incentives depending on the location and number of dispatches per year.		
Grid services	» Electric and natural gas peak shaving, non-wires alternatives		

Utility objectives with VPP program *(not exhaustive)*

- **Meet rising demand** by delivering bulk system-level capacity during peak hours.
- **Reduce cost** by pursuing all cost-effective demand reduction measures[100,clxxxiv] to reduce customer energy bills.
- **Alleviate grid constraints** by using flexible demand as non-wires alternatives to address grid congestion or load limits of grid equipment.

100 The 2016 State of Charge: A Comprehensive Study of Energy Storage in Massachusetts Report found that 40% of each year's electric costs were due to the 10% of hours with the highest electricity demand.

Program summary

National Grid developed and launched its ConnectedSolutions 'bring-your-own-device' (BYOD) VPP in less than four months to provide low-cost, low-emissions peaking capacity in Massachusetts and New York.[101] The program launched fully in 2019. In this configuration, National Grid contracts with EnergyHub, an Edge DERMS vendor that integrates multiple single-brand VPP software systems (e.g., Tesla) into one platform. National Grid sends notices to EnergyHub in advance of peak hours to dispatch demand reductions from the customer-owned DER aggregation that EnergyHub manages on National Grid's behalf. By relying on EnergyHub to manage the customer enrollment and participation experience, and to turn the heterogeneous portfolio of DERs into a utility-scale and utility-grade resource, National Grid required little change to its internal organizational operations.

Delivered outcomes

- ✔ **Reduced costs of peak demand,** providing an estimated $300M in system benefits since the start of all of National Grid's demand response programs by reducing the buildout of power plants, the grid, and reducing energy use at expensive peak times.
- ✔ **Met regulator goals** by earning financial profit for National Grid (specific incentive mechanisms vary by state).
- ✔ **Reduced cost of ownership of DERs** by compensating them for grid benefits delivered.

VPP communication protocols & operations

National Grid works with EnergyHub to operate ConnectedSolutions in the following ways:

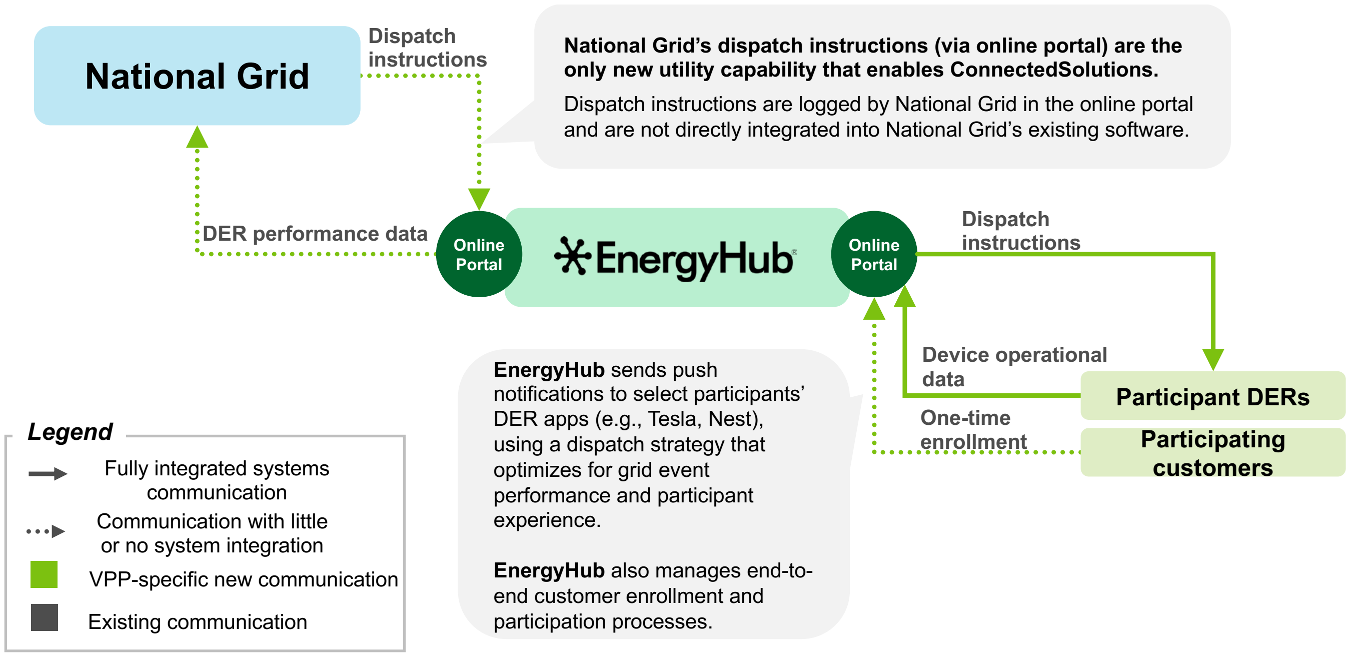
1. National Grid or EnergyHub (depending on the jurisdiction) estimates peak demand and establishes the level at which grid events will be called.
2. National Grid or EnergyHub (depending on the jurisdiction) tees up and then triggers demand response events when loads on the grid are forecasted to exceed the established levels.
3. EnergyHub communicates the demand response event parameters to various DER device manufacturers and providers, curtailment service providers and aggregators. The communication happens through a variety of open protocols and proprietary APIs. Depending on how much grid relief is needed, dispatch happens in three levels:
   a. The first level call is to maximize demand reduction by discharging residential-scale and commercial-scale batteries. Batteries are called on approximately 50 times per summer.
   b. The second level adds (in addition to the first) in HVAC load reduction through smart thermostats to optimize for customer comfort and maximize continued participation in events.[102] HVAC is called on approximately 15 times per summer.
   c. The third level adds (in addition to the first and second) commercial & industrial load reduction. This is a last resort given load size and potential costs of, for example, shutting down an entire assembly line. These assets are called on approximately 5 times per summer.
4. EnergyHub receives DER energy consumption data and meter data through a variety of open protocols and proprietary API connections with DER manufacturers, providers, curtailment service providers, and aggregators.

101 For additional detail on the policy and regulatory context in which ConnectedSolutions was implemented, including the energy and non-energy benefits included in the cost-effectiveness test for the program, see the case study annex (page 66) of NARUC's ADER Resources in 2024: The Fundamentals.

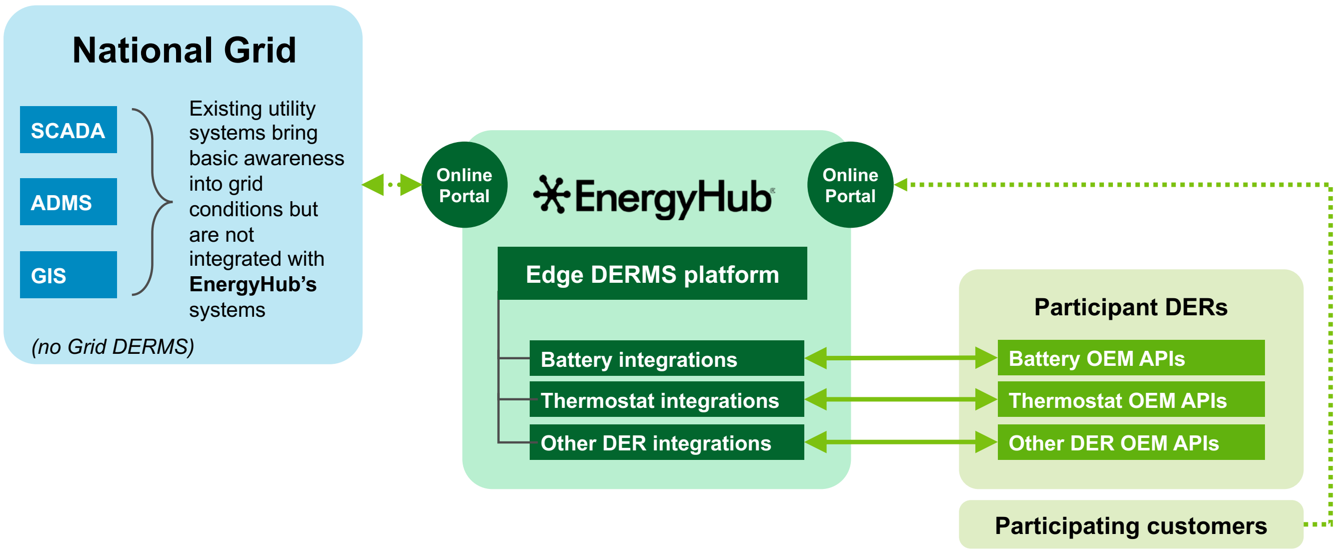
102 Customers can opt out of an event by re-adjusting their smart thermostats.

5. EnergyHub uses the DER telemetry to calculate the performance for each DER and end each event.
6. EnergyHub shares performance data with 15-minute telemetry to National Grid.[103]

VPP communications



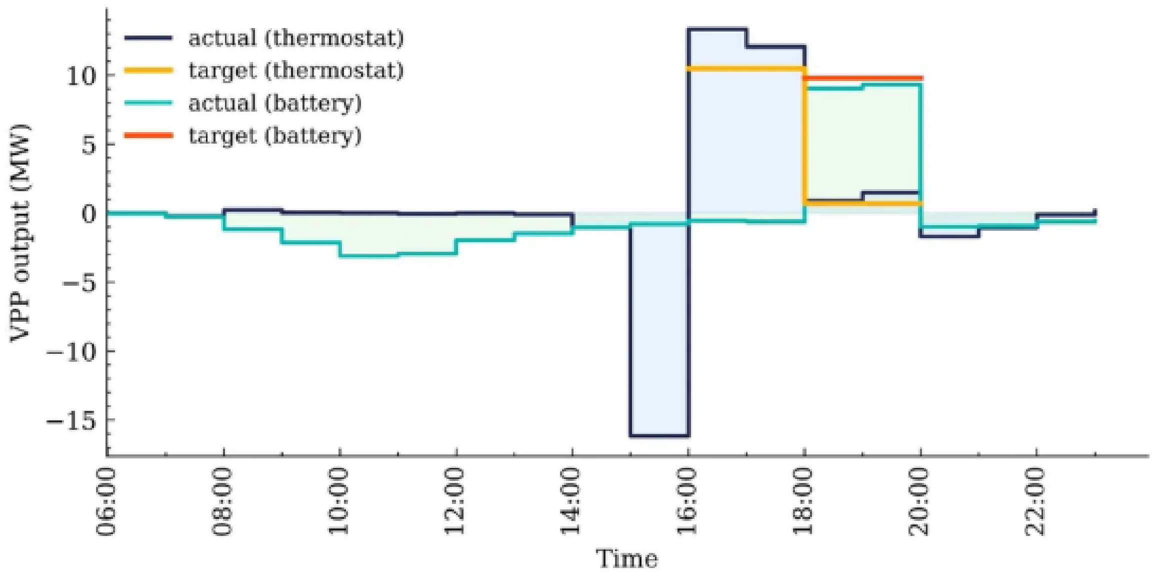
IT and OT components



103 For devices that are not equipped to provide minutely telemetry, EnergyHub conducts modeling to estimate what the capacity would be from those resources on a minute-by-minute basis and provides that to National Grid.

Delivered outcomes

The chart below shows the MW output of the thermostats and batteries enrolled in ConnectedSolutions during a four-hour peak reduction event. As the chart shows, thermostats adjust to pre-cool buildings and homes from 3pm to 4pm, then reduce air conditioning load at 4pm when the event begins. After two hours, thermostats return to normal operations and batteries dispatch to deliver the second two hours of reduced load on the grid.[clxxxv]



Source: EnergyHub

C.ii. Detailed case study #2: Energy Storage System (ESS) Leasing Program

VPP overview

Green Mountain Power's Energy Storage System Leasing Program

Utility-owned and operated battery VPP offers backup power for participants, peaking capacity, emissions reduction, and transmission benefits for the grid, and lower costs for all customers.

VPP summary			
Utility	Green Mountain Power	**VPP size** *(as of 2024)*	36 MW (5% of system peak)
Utility type	Certified B Corp, Investor-owned utility	**Type of DERs**	BTM battery
Market structure	Within organized market (ISO-NE), utility owns generation	**Upfront investment cost**	*Not available*
Location	Vermont	**Time to operationalize**	12-24 months
Size of utility	275,000 customers (663 MW peak demand)	**Number of customers enrolled in VPP**	4,800 customers
Compensation structure	» GMP maintains ownership of batteries and leases them to customers for a 10-year period, either for a one-time payment of $5500 or a $55 monthly fee. Customer continues to get battery backup at no cost after 10 years. » In return, customers are equipped with backup power during outages for a significantly lower price than they would have paid for a non-enrolled battery.		
Grid services	» Peak shaving, frequency regulation		

Utility objectives with VPP program *(not exhaustive)*

- **Reduce costs for all customers** by decreasing GMP's capacity obligation in ISO-New England and GMP's service territory transmission charges, and reducing demand during peak hours. Achieve additional cost savings through energy arbitrage (discharging batteries during peak hours and recharging during off-peak when prices are lower).
- **Improve resilience** by offering seamless backup power for participants to keep customers connected during increasingly severe weather and other events.

Program summary

Green Mountain Power fully launched the Energy Storage System Leasing (ESS) program in 2020, after two successful pilots, to improve system reliability in the face of extreme weather while reducing costs for all customers.[104] GMP operates the program with Tesla technology. Tesla supplies the battery hardware (Powerwalls) and acts as the software platform that aggregates and orchestrates battery dispatch. GMP sends real-time load data (generated by metering integrated with their SCADA system)[105] to Tesla via an API to communicate demands on the distribution grid. Tesla uses that information to strategically dispatch batteries to shave peaks on the distribution system. The program is open to additional battery systems as well and GMP continues to test the latest available battery technology to integrate into the program.

GMP's ESS program is continuously evolving to produce more value. Initially, the utility used the batteries for peak shaving and back up power, but then piloted and now tariffed the use of the same batteries for frequency response, which it sells into the ISO-NE market to generate revenue it can use to directly reduce costs for all GMP customers. Future goals of the program include:

- **Additional grid services:** GMP is working to identify opportunities to use the batteries in targeted locations to alleviate grid constraints at the substation level, which would allow deferrals of costly equipment upgrades.
- **Integration with other resources:** GMP separately operates a bring-your-own-device VPP using a Virtual Peaker platform, as well as a commercial flexible load program using the platform of a Vermont-based software company, Dynamic Organics. The utility is also collaborating with customers to create benefits with other distributed resources such as smart EV chargers.
- **Automation:** With experience and historical data, GMP will be able to automate how a VPP reacts to grid conditions and external conditions (e.g., distributed solar output and weather).

Delivered outcomes

- ✔ **Reduced costs for all customers** by reducing Green Mountain Power's capacity obligation in ISO-New England forward capacity auction by 36+ MW per year (reducing system costs by as much as $3M in some years for all customers – both participants and non-participants).
- ✔ **Generated revenue** of $250,000 from frequency regulation to return to customers.
- ✔ **Improved customer resilience** by enrolling over 4,800 customers in the ESS program, equipping each with backup power to stay connected during extreme weather and other events.

104 For additional detail on the policy and regulatory context in which GMP implemented its VPP, including the monetized and non-monetized benefits of the program, see the case study annex (page 63) of NARUC's ADER Resources in 2024: The Fundamentals.

105 Supervisory control and data acquisition systems (SCADA) are a collection of systems used to monitor, report on, and remotely operate grid equipment.

VPP communication protocols & operations

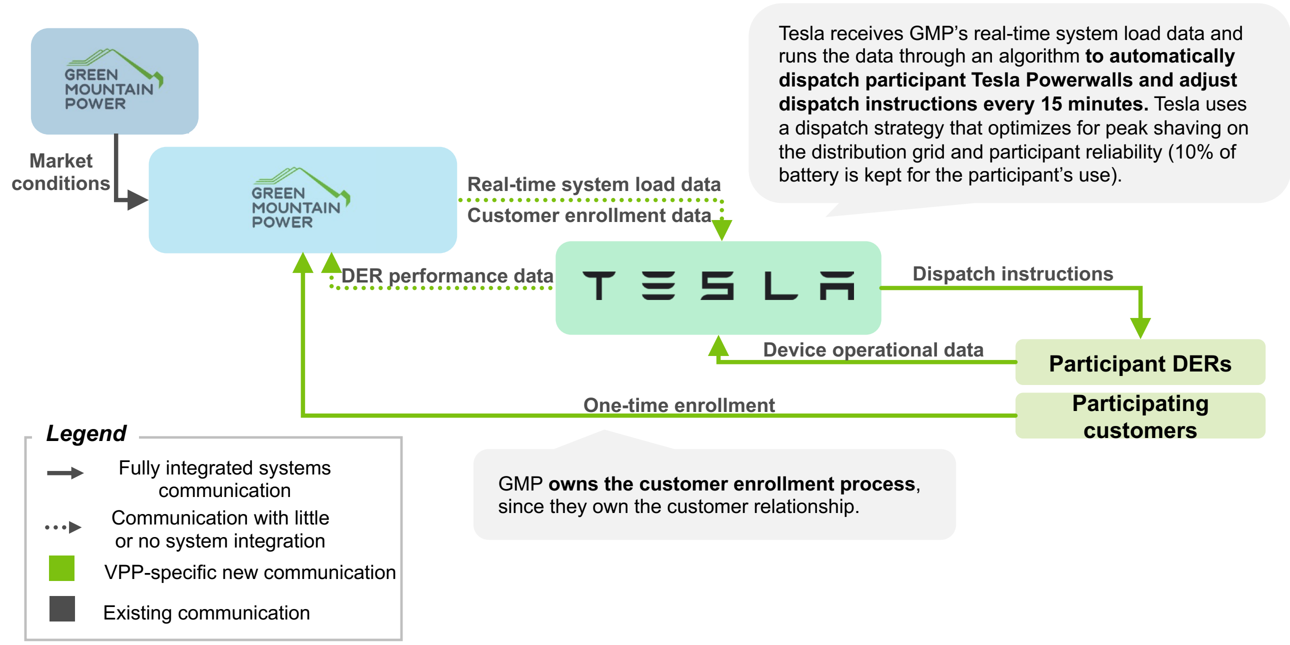
Green Mountain Power works with Tesla to operate ESS in the following way:

1. GMP provides real-time system load data from their SCADA system to Tesla through an API connection.
2. Tesla receives the load data and uses its own algorithm to determine optimal usage of Tesla Powerwalls across the distribution grid, primarily for peak shaving.
3. Tesla manages the Powerwalls through direct integration, adjusting usage of batteries every 15 minutes (or in the case of frequency regulation every four seconds) to respond to system conditions.[106]
4. Tesla receives real-time performance data of batteries and pushes data through the API to GMP in real-time.

Additionally, Green Mountain Power completed a successful pilot and has now tariffed a program to bid their fleet of Tesla batteries into ISO-NE for fast frequency response services (ancillary services market), using the same technology architecture *(excluded from communications protocols and IT / OT components diagrams)*:

5. Tesla receives real-time market signals and pricing information through an API connection with ISO-NE.[107]
6. Tesla's updated algorithm manages GMP's batteries to optimize for load, while bidding into ISO-NE for fast frequency response services, adjusting usage of batteries every four seconds.[108]

VPP communications

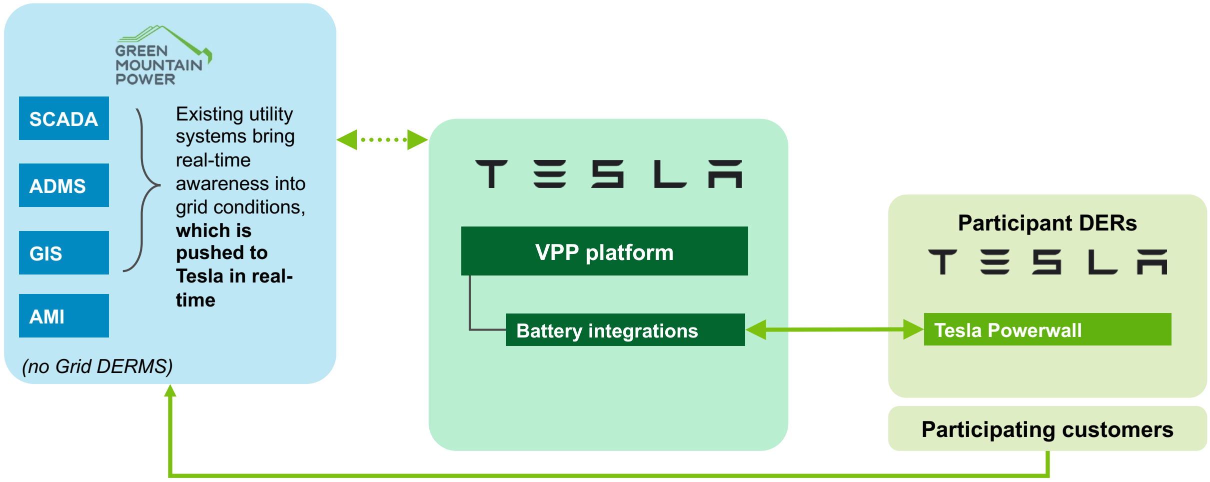


106 Tesla's algorithm continuously monitors Vermont and ISO-NE load and dispatches the batteries accordingly to maximize peak shaving. Customer backup is always prioritized, however, which means weather events override peak shaving.

107 GMP provides the bids for frequency regulation on a weekly basis (i.e., hour-by-hour MW availability for the week) to a third-party who bids them into ISO-NE. During hours the batteries clear the market and are performing regulation, Tesla receives the signals every four seconds from ISO-NE via API and adjusts the batteries charge / discharge to match the signal.

108 The response time for data communicated from GMP to the battery (over the internet), then to the market (also over the internet) is two seconds.

IT and OT Components



C.iii. Detailed case study #3: Wattsmart

VPP overview

Rocky Mountain Power's Wattsmart

Battery VPP that integrates directly into utility's grid operations system enables many grid services.

VPP summary			
Utility	Rocky Mountain Power	**VPP size** *(as of November 2024)*	28 MW (0.5% of system peak)
Utility type	Investor-owned utility	**Type of DERs**	BTM battery
Market structure	Not in organized market, utility owns generation	**Upfront investment cost**	$5 million
Location	Utah	**Time to operationalize**	3 years
Size of utility	1.2 million customers (5.58 GW peak demand)	**Number of customers enrolled in VPP**	4,200
Compensation structure	» Upfront cash enrollment incentive based on battery capacity available for discharge. As of 2023, up to $600 per kW, with the highest incentive offered to customers who are "firming" existing distributed solar. » Ongoing participation incentive in the form of an annual bill credit of $15 per kW, starting in the second year of participation.		
Grid services	» Fast frequency response, daily load cycling		

Utility objectives with VPP program (not exhaustive)

- **Keep costs low** (some of the lowest energy prices in the nation) by procuring bulk grid and distribution grid services including energy, capacity, and fast frequency response to cost-effectively transition to a decarbonized power supply.
- **Improve resilience** and reduce severity of weather-related outages by providing backup power from BTM batteries to customers.
- **Decarbonize power supply** by maximizing usage of cheap solar and reduce reliance on peaker plants by charging batteries during the day and discharging batteries during peak periods (supporting decarbonization goals of cutting greenhouse gas emissions by 70% by 2030 and 100% by 2050[clxxxvi]).

Program summary

Rocky Mountain Power developed its Wattsmart battery VPP to deliver high-value grid services cost-effectively and increase battery adoption among customers. By obtaining a "full stack" of valuable grid services from the batteries, RMP creates significant value for the grid and in turn pays participants both an upfront and an ongoing performance incentive that helps offset the purchase price of the battery. Wattsmart is among the most advanced VPPs in the U.S. due to its degree of integration into the utility's overall system operations and the wide array of uses (grid services) of the battery aggregation. Unlike VPPs used only during peak hours or peak seasons (summer, winter), RMP may use its batteries 365 days of the year, 24 hours per day.

RMP directly dispatches the batteries using a distributed battery grid management system (DGBMS) that integrates into the utility's energy management system without any intermediate layer of an edge-DERMS.

The network of batteries can respond to dispatch signals in as little as three seconds (sonnen and Core+ batteries) and no slower than 50 seconds (other brands). The system is programmed to dispatch targeted clusters of batteries daily to support peak periods and as needed in response to real-time grid conditions and solar output, which are monitored and communicated via RMP's Energy Management System. The VPP delivers eight grid services:

- System-level demand response and peak shaving
- Firm dispatchable capacity for system requirements
- Storage of renewable energy for dispatch to meet grid load requirements
- Secondary frequency response to load and inject power to rebalance system frequency
- Daily load cycling to charge batteries during low-cost off-peak periods and discharge batteries during peak hours
- Backup power for resiliency
- Non-wires alternative for local load pocket decongestion
- Spinning and non-spinning reserve capacity to provide emergency stabilization power

RMP worked closely with battery manufacturer and software provider sonnen to ensure the battery chemistries and controls would allow for multiple battery dispatches per day in addition to a high degree of visibility and control.[109] The Wattsmart VPP is growing rapidly, with a near-term goal of reaching 100 MW by recruiting customers with solar arrays (>80,000 in Utah) and offering battery incentives to motivate customers to 'firm' their renewable power.

109 Sonnen underwent rigorous certification and testing to ensure the program met all necessary cybersecurity requirements.

Delivered outcomes

- **Reduced costs for all customers** by storing excess renewable energy during low-cost off-peak periods (<3 cents kWh) and dispatches that energy during high-cost peak periods (costs as much as 10x more) to reduce system peaks.
- **Improved customer resilience without raising rates,** enrolling over 5,000 customers in the program and equipping each with backup power.
- **Achieved high usage for real-time system needs** by calling 153 real-time frequency response events from October 2023-November 2024.
- **Developed standards for battery manufacturers** by establishing a clear roadmap for battery designs that ensures products are able to integrate with utilities systems.
- **Developed an open innovation platform** to continually improve based upon customer feedback and inclusion of new innovation.[110,clxxxvii]

See delivered outcomes section for visualizations of battery dispatch data for peak management operations and distribution circuit congestion event.

VPP communication protocols & operations

Rocky Mountain Power works with sonnen to operate WattSmart in the following way:

1. Rocky Mountain Power's grid operating team can view the real-time grid services available from sonnen's VPP within their existing SCADA system– the team does not need to log into any other system due to API integrations.
2. If services from Wattsmart batteries are required to manage the electric grid, the SCADA system will automatically send a signal to the VPP, or the grid operating team can select an option from their operations screen.
3. Sonnen's VPP software layer receives the dispatch signal in real-time and calls the necessary sonnen batteries and non-sonnen batteries to respond.
   a. Batteries typically respond within 5 seconds and no longer than 50 seconds.
   b. The batteries respond and use the same channels to send operational data back to sonnen's VPP.[111]
4. The VPP provides real-time operational data to Rocky Mountain Power sharing how batteries are performing with 2-3 second precision.
5. The VPP software layer, in combination with Wattsmart program qualified battery, is optimized for all eight primary grid services that benefits both customers and utilities.[clxxxviii]
6. Sonnen's VPP software layer receives the dispatch signal in real-time and calls the necessary sonnen batteries and non-sonnen batteries to respond.
   a. It calls sonnen's batteries through direct dispatch instructions and receives direct operational data from these batteries in real-time.
   b. It calls non-sonnen batteries by sending dispatch instructions using IEEE 2030.5 protocols to an IEEE 2030.5 compliant server in Germany and in the U.S. This server then sends dispatch instructions to the non-sonnen batteries using IEEE 2030.5 protocols, ensuring no concern of

110 For an in-depth, 20-page case study of the program benefits realized by Utah's Wattsmart Battery program across frequency regulation services, peak load management, congestion relief, and backup power, see 'Utah WattSmart Batteries Program: Grid Service Benefits Analysis.'

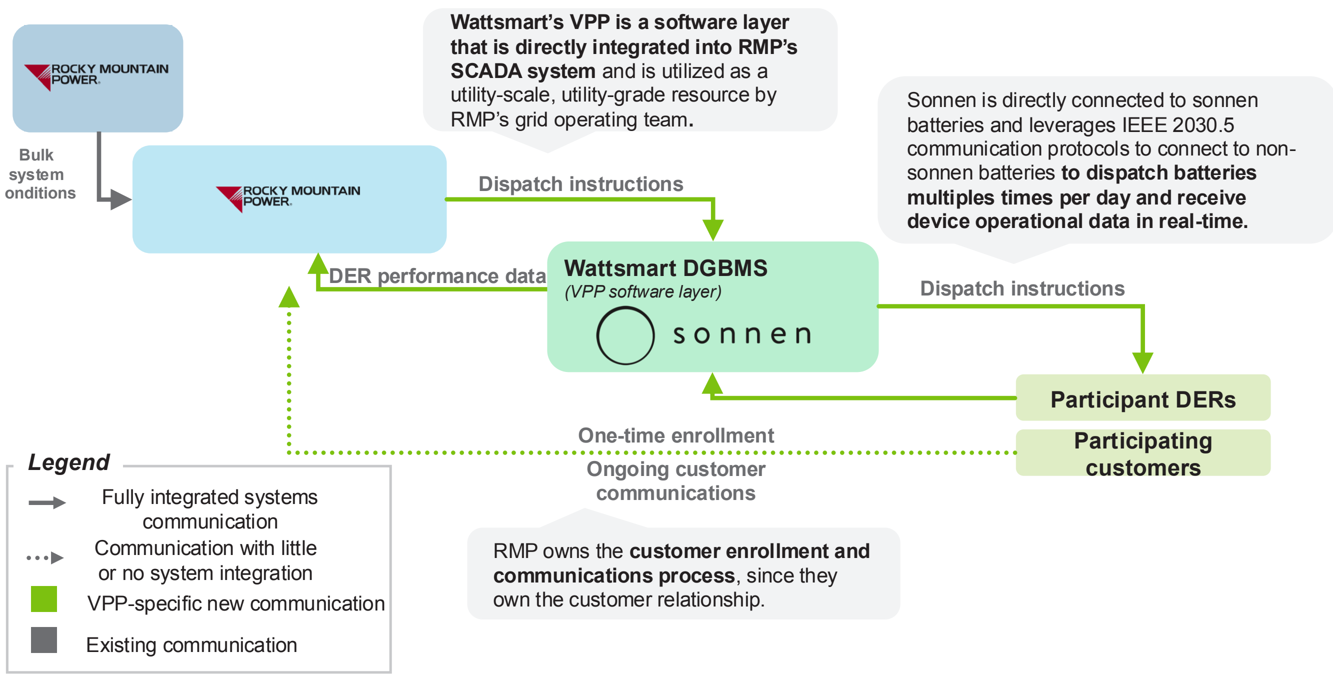
111 The Wattsmart Battery program requires participating batteries to be IEEE 2030.5 protocol compliant, ensuring no intellectual property exchange occurs while utilizing RMP's SCADA system and sonnen's VPP.

intellectual property exchange between battery manufacturers. The batteries respond and use the same channels to send operational data back to sonnen's VPP.

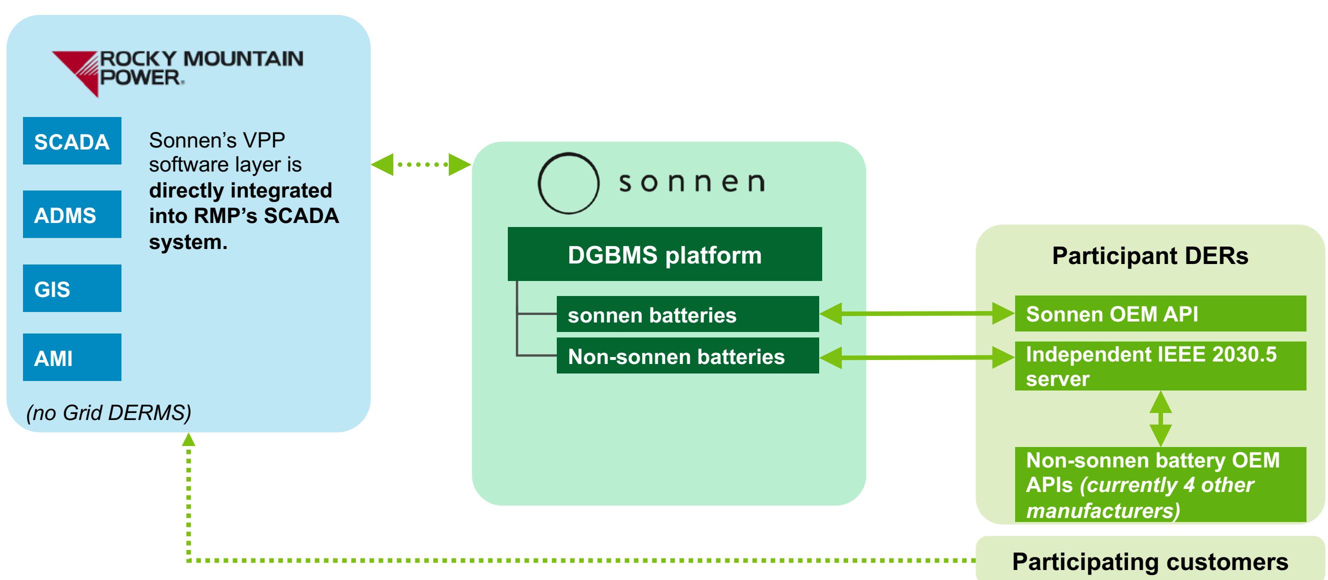
7. After dispatching necessary batteries, sonnen provides real-time operational data to Rocky Mountain Power sharing how batteries are performing with 2-3 second precision.[112]

8. In addition, sonnen's VPP software layer optimizes for daily load cycling, directing batteries to soak up solar when it is cheap during the day and discharge batteries during daily peak hours.

VPP communications



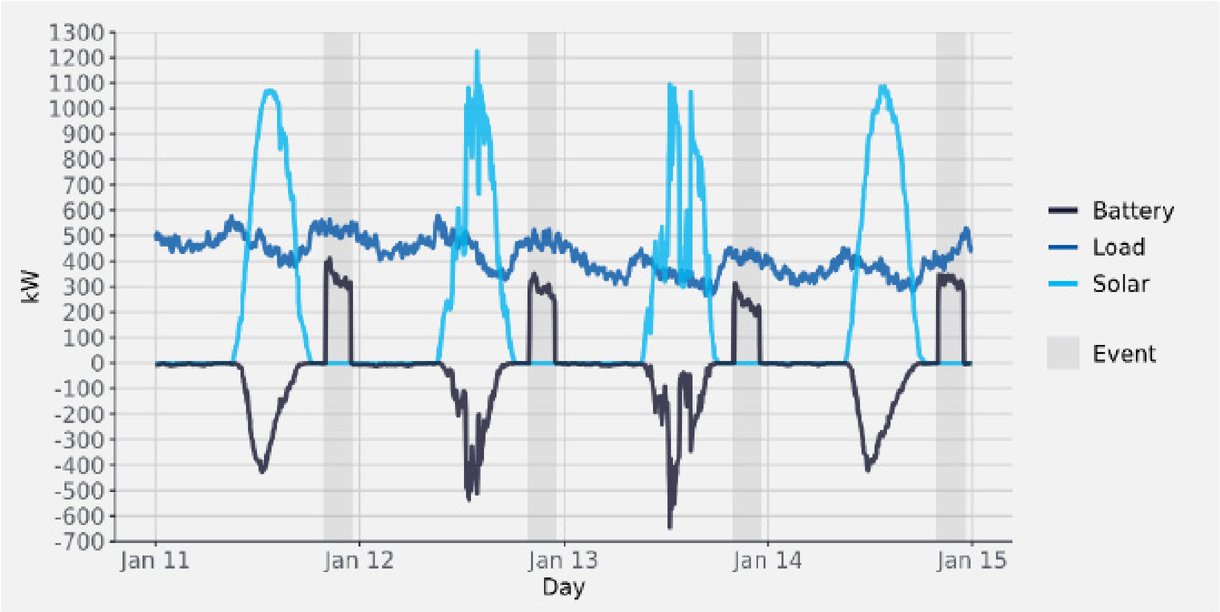
IT and OT components



112 Long term, this operational data helps RMP and sonnen understand the value and performance of the system to improve operations and inform proposed customer incentives.

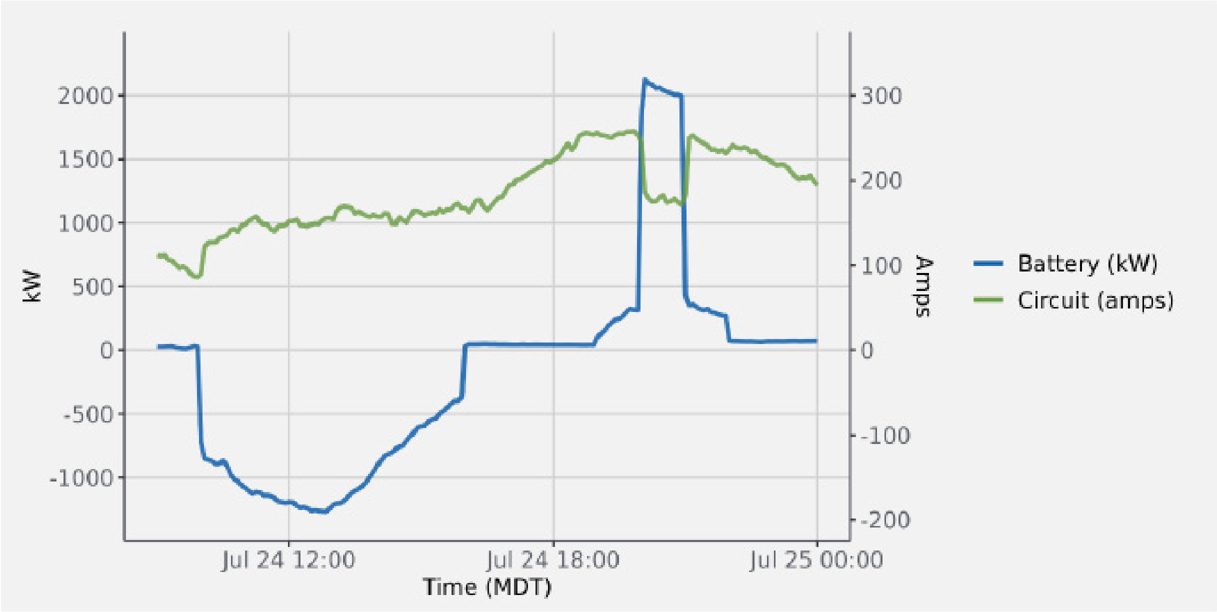
Delivered outcomes

Peak management operations: The chart below shows four days in January 2021 when RMP dispatched battery systems in the evening that had been charged with solar earlier in the day to reduce peak demand during evening peak hours of 8 pm to 11 pm (peak events are depicted by the darker gray bars).



Source: Rocky Mountain Power, Cadmus

Distribution circuit congestion event: The chart below shows the dispatch of battery systems to relieve congestion on a distribution circuit on July 24, 2021. Between 8-9pm, the Wattsmart battery systems were dispatched to reduce load at the circuit and relieve transmission congestion. In aggregate, the batteries delivered approximately 2 MW throughout the event hour during which time load at the circuit was reduced by 30%.



Source: Rocky Mountain Power, Cadmus

C.iv. Key resources for practitioners

- **Stakeholder Perspectives on the Role of Standards in Establishing a Load-Flexible Ecosystem** (August 2024, CalFlexHub) shares qualitative results of 52 stakeholder calls on the role of standards in California.
- **Cybersecurity Considerations for Distributed Energy Resources on the U.S. Electric Grid** (October 2022, DOE) provides an overview of cybersecurity considerations for DERs that can be considered by the electric sector.

C.v. Actions from the Department of Energy

- **Grid Solutions program**, a collection of tech programs, to define coordination and system requirements to enable the utilization of grid services from DERs and VPPs in collaboration with regulators and utilities
- **Distributed Resource Utilization** to support state organizations and utilities in standardizing processes between utilities and third-party DER aggregators, reducing barriers to implementation and enabling more effective operational coordination
- **Aggregator Standard Contract** to define how to govern aggregators using a standard contract for VPP and aggregator services to expedite the approval process while ensuring consumer protections
- **National EV Infrastructure Standards** to ensure federally-funded charging equipment is capable of smart charging
- **Building Energy Codes Program** to support development, adoption, implementation, and enforcement of codes to achieve energy efficiency
- **Distribution system cybersecurity baselines**, as part of the National Cybersecurity Strategy, led by NARUC and the Office of Cybersecurity, Energy Security, and Emergency Response at DOE, to develop a set of cybersecurity baselines for electric distribution systems and the DERs that connect to them
- **Distributed Energy Resource Cybersecurity Framework**, a no-cost interactive web tool, to evaluate a facility's DER cybersecurity health and provide recommendations
- **Cyber-Informed Engineering** to provide tools, case studies, and lessons to support designers, manufacturers, and asset owners in applying cyber-informed engineering principles
- **Energy Threat Analysis Center** to launch cybersecurity threat collaboration between industry and government to enable collective defense
- **VPP-related research, development, and deployment (RD&D) programs** focused on systems integration to address key technical challenges in power system planning and operations
- **EVs@Scale National Laboratory Consortium** to bring together national laboratories and key stakeholders to conduct research and development to address challenges and barriers for high-power EV charging infrastructure to enable greater safety, grid operation reliability, and consumer confidence
- **Connected Communities Program**, focusing on technical measures at the grid edge in buildings, industry, and transportation to prepare the electric grid for these new loads, and improve the resilience of customers and the grid

- **Grid Resilience Utility and Industry Grants** and **Smart Grid Grants**, which are part of the GRIP Program, to fund deployment of comprehensive transformational transmission and distribution technology to increase the flexibility, efficiency, and reliability of the electric power system and modernize the grid to reduce impacts due to extreme weather and natural disasters
- **Interconnection Innovation e-Xchange (i2X)** to provide technical assistance and engage stakeholders to improve interconnection practices and processes for electricity distribution and transmission systems
- **Sustainable and Holistic Integration of Energy Storage and Solar PV (SHINES)** to develop and demonstrate integrated PV and energy storage solutions that are scalable, secure, reliable, and cost-effective
- **Solar Technologies' Rapid Integration and Validation for Energy Systems (STRIVES)** to fund research, development, and demonstration projects to improve power systems simulation software tools and demonstrate new business models for distribution systems operations
- **Operation and Planning Tools for Inverter-Based Resource Management and Availability for Future Power Systems (OPTIMA)** to fund projects that will develop new state-of-the-art planning and operations tools for utilities and bulk system operators. These projects will help address challenges with integrating variable inverter-based renewable generation and distributed energy resources, as well as T&D coordination and co-optimization

Appendix D: Integrating into utility planning and incentives

D.i. Menu of VPP-supportive regulatory and policy options

This menu of options provides a range of choices for state and tribal regulators, policymakers, and utilities to explore alongside examples of regulators and policymakers that are implementing these strategies today. This list aims to capture the breadth of actions available to support VPP deployment but is not an exhaustive list. Two of these case studies, New York's Value of DER (VDER) Program and Massachusetts' Electric Sector Modernization Plans, have a detailed overview provided in Appendix D.ii.

Notes: These levers particularly apply to IOUs that are regulated at the state and federal level. Governing bodies of other utilities (e.g., member boards of co-ops, city councils overseeing public power, tribal utility authorities) can also look to these levers for consideration. These policy and regulatory levers identified are primarily focused on VPP related programs and are not exhaustive of the best practices and policy/regulatory levers to support grid modernization generally.

Utility cost recovery

Regulatory and policy options	Examples
• **Use performance-based ratemaking (PBR)**, performance incentive mechanisms, and / or multi-year rate plans • **Allow utilities to include DERs and VPP foundational infrastructure (e.g., DERMS) in rate base**[113]	**Massachusetts Department of Public Utilities (DPU)** has established a performance incentive mechanism for energy efficiency programs, which includes the ConnectedSolutions VPP program; the total incentive is significant with a total of $190M profit potential for all of MA's IOUs over the current 2025-2027 planning period if the goals are met. Utilities must meet at least 80% of efficiency goals to generate any profit, with a maximum profit of up to 125% over the goal.
	Vermont PUC issued an order in 2023 (Case No. 23-1335-TF) that allowed **Green Mountain Power (GMP)** to include customer-leased batteries in its rate base, enabling GMP to earn an approved rate of return on the capital investments for the batteries.
	Michigan PSC, since 2019, has had a performance incentive (Docket U-20164) to allow **Consumers Energy** to earn up to 15% return on operations and maintenance (O&M) costs if it achieves its demand response capacity growth target (and no payment if less than 50% was achieved). In June 2024, the PUC directed Consumers (Order U-21410) to explore alternative financial incentive mechanisms with a focus on shared savings to enhance the cost-effectiveness and maximize the system impact of demand response programs.[114,clxxxix]

113 Allowing utilities to make a financial return on DER and VPP foundational infrastructure investments by including these investments in utilities' approved rate bases can be controversial as it may inequitably distribute costs among all ratepayers and deter market competition. Cost effectiveness tests can measure the net impact for customers to ensure a reduction in energy bills compared to alternate scenarios and confirm that utility-owned DERs and VPPs are the most cost-effective resources.

114 In 2023, Consumers Energy was criticized by MI PSC staff for the high cost of the demand response program (Staff's Initial Brief, U-21410) and staff recommended that the Commission not approve the program for the incentive. This led to the PUC June 2024 action to explore alternative mechanisms to reduce costs.

System planning

Regulatory and policy options	Examples
Clarify benefit-cost assessment frameworks for DERs and VPPs to ensure VPP benefits are comprehensively valued **Require VPPs to be considered in current planning processes** (e.g., IRPs, resource adequacy assessments, asset replacement, distribution system planning) so that VPPs are considered as viable options alongside conventional assets **Require integrated grid system planning** (e.g., integrated distribution system plan, integrated transmission & distribution plan, grid modernization plans) **Require open-source and/or distributed capacity procurement so that VPPs** can compete against conventional assets during capacity procurement process **Require a minimum proportion of resource adequacy procurement to be from VPPs**	**Massachusetts** passed a bill (G.L.c.164, 92B-92C) in 2022 that requires IOUs to submit Electric Sector Modernization Plans (ESMP) to achieve the state's clean energy goals.[cxc] This bill expanded existing grid modernization planning requirements initiated by the **Massachusetts Department of Public Utilities (DPU)** in 2014. The new ESMP requirements enhanced the focus on proactive upgrades to the distribution system and established a Grid Modernization Advisory Council (GMAC) as part of the process. *Detailed case study provided in Appendix D.ii.*
	Since 2018, the **Minnesota PUC** has required utilities to file Integrated Distribution System plans that include DER baseline data, future DER scenario analysis, hosting capacity, multiple time horizons (5- and 10-year), non-wires alternative analysis, and transportation electrification plans.[cxci]
	Georgia PSC approved **Georgia Power's** 2023 Integrated Resource Plan (IRP) only after the utility agreed to several stipulations, including committing to developing a distributed solar and battery storage pilot to provide grid capacity and reliability benefits and including the program in its 2025 IRP analysis.[cxcii]
	In a 2024 State of the State report, the **New York Governor** directed the **NY PSC** to implement a *Grid of the Future* proceeding to "identify smart grid technologies that enable flexible services, like virtual power plants, that can be deployed to achieve New York's clean energy goals at a manageable cost."[cxciii]
	Washington passed a bill (HB 1589) in March 2024 that requires utilities to submit integrated system plans; VPP-enabling features of the legislation include requiring plans to align with state clean energy plans and emission reduction targets and to consolidate multiple existing plans (e.g., transportation electrification plans, muti-year rate plans).

DER deployment

Regulatory and policy options	Examples
Provide financial incentives for DER installation (especially for low-income customers) **Allow utilities to subsidize DERs** (especially for low-income customers) **Streamline DER permitting and interconnection processes** (e.g., provide incentives, set maximum review timelines) **Publish distribution system hosting capacity maps** with clear data standards and regular update requirements **Modify state and tribal energy codes and standards to support DER deployments** where current standards are a barrier **Require distribution utilities to deploy a grid orchestration platform** to better manage the distribution grid and DERs	The **South Carolina PUC** is reviewing proposed modifications to **Duke Energy**'s existing On-Site Generation Service and Premier Power Service Programs that allow the utility to own, operate, and maintain backup generation on-site for large non-residential customers that can be dispatched for grid relief only during emergencies. The proposed change involves introducing a cost-sharing mechanism to incentivize customers to install on-site generation that Duke Energy can dispatch more frequently (not just during emergencies). The cost share would be based on the value of the on-site generation to the utility's system.[cxciv]
	Colorado PUC approved a performance incentive mechanism for **Xcel Energy** to speed up interconnection of DERs (Order 23AL-0188E) in October 2023. The PIM requires Xcel to refund customers 4% of the interconnection fee per day delayed beyond Xcel's internal timeline targets (e.g., 50 days). If Xcel interconnects the DER faster than the target timeline, the value would be credited against any penalties accrued for exceeding the target.[cxcv]
	In November 2024, **New Jersey Board of Public Utilities** proposed upfront fixed and ongoing performance-based incentives for front-of-the-meter and behind-the-meter distributed energy storage systems (Docket QO22080540). Distributed systems could receive $150-300/kW in combined upfront and performance payments based on system size, with additional incentives available for "overburdened communities."
	California PUC issued a series of decisions in 2019, 2020, and 2021 to streamline DER interconnection (Electric Rule 21); the decisions include requirements to establish standard interconnection agreements, conduct public hosting capacity analysis, allow DERs to perform within existing grid constraints, and avoid grid upgrades.[cxcvi] Beyond California, fourteen states across the U.S. (from **California** and **Nevada** to **Illinois** and **Minnesota** to **Maine** and **Vermont**) require utilities to publish hosting capacity maps to share data about where DERs can be deployed on the grid.[115,cxcvii] Utilities have published over 70 maps across over 25 states.
	The **New York PSC** launched a Grid of the Future proceeding (Case 24-E-0165) in April 2024 to study near-term actions that could enhance deployment of grid flexibility resources (including VPPs and DERs) and integrate these assets into grid planning and operations. Initial required elements of the plan included an inventory of what resources are needed, how much is needed, and how to procure these resources, with additional requirements being developed with stakeholder input.[cxcviii]

115 See DOE's U.S. Atlas of Electric Distribution System Hosting Capacity Maps for a summary of utilities with published maps; LBNL's Integrated Distribution System Planning map for additional detail on the states requiring hosting capacity maps, including specific docket information; and NREL's Advanced Hosting Capacity Analysis for additional detail on best practices for hosting capacity maps (e.g., development process, data validation, regulatory reviews).

DER aggregation

Regulatory and policy options	Examples
• **Authorize default VPP-opt in** enrollment models • **Allow all DER types to participate in VPPs** (e.g., solar, storage, demand response, heat pumps, etc.) • **Align VPP aggregation standards across IOUs** (e.g., data access rules) • **Provide clear methods for VPP capacity accreditation** • **Ensure open participation for multiple aggregators and OEMs** • **Limit DER incentives to smart, connected DERs** (e.g., smart thermostats instead of standard thermostats that cannot be controlled) • **Direct utilities to file VPP program plans to state PUCs** • **Establish interoperability standards and communications protocols**	In response to Winter Storm Uri and related major generation shortfalls as well as industry requests to allow aggregated DERs to register as supply resources in ERCOT, the **Texas PUC** established an Aggregated Distributed Energy Resource (ADER) Pilot and Task Force (Order 53911) in 2022 to develop a VPP program. Within a year of the PUC initiating this pilot, 7.2 MW of VPP capacity was participating in the pilot and providing dispatchable power to the Texas grid.[cxcix,cc] In December 2023, Texas PUC Commissioners affirmed a desire to expand this initial program to scale VPP deployments across the state.[cci]
	In 2023, **Texas** legislators passed a bill (SB 1699) to establish third-party aggregation requirements for DERs and to authorize the TX PUC to establish rules and requirements for DER aggregators.
	Colorado PUC opened a proceeding (23M-0466EG) in September 2023 to explore implementing third-party managed VPP pilots. The resulting studies enabled additional state VPP actions, including the legislature passing a bill in 2024 requiring **Xcel Energy** to submit a VPP program plan to the PUC by 2025.
	Colorado signed into law (SB24-218) in May 2024 legislation that requires the state's largest IOU (**Xcel**) to submit a VPP plan to the PUC. This built on ongoing actions by the Colorado PUC to advance VPP programs as part of an effort to serve rising demand while mitigating costs for ratepayers.
	Maryland passed the Distributed Renewable Integration and Vehicle Electrification (DRIVE) Act (HB 1256) in May 2024 that requires the state PSC to implement regulations that support bidirectional EV charging and that establish VPP pilot programs throughout the state (including incentive mechanisms that compensate EVs and other DER owners and aggregators).

VPP operations

Regulatory and policy options	Examples
• **Implement compensation models that compensate VPPs for the full range of grid benefits delivered** (e.g., capacity benefit, infrastructure costs deferred, environmental benefit)	**New York PSC** has implemented a Value of Distributed Energy Resources (VDER) to compensate DERs based on their system value, including a broad range of benefits such as energy value as well as locational system relief value. *Detailed case study provided in Appendix D.ii.*
	Massachusetts DPU established a Distribution Circuit Multiplier that doubles the financial incentives for system load reduction for DERs that are sited on the top 10% most constrained circuits (published annually by the states' distribution IOUs). This enables DER companies to target sales in areas where devices can offer the greatest value to the grid. Eligible DERs include demand response, renewable generation, and storage.[116,ccii]
	CA Public Utilities Commission established the Avoided Cost Calculator (ACC) in 2005 to determine the value of DERs; the methodology is updated every other year. The avoided cost of electricity is determined based on the value of generation energy, generation capacity, ancillary services, transmission and distribution capacity, and decarbonization policy compliance.

116 See the Clean Peak Distribution Circuit Multiplier Guideline for additional information on eligible DERs, distribution circuit selection, and application processes.

D.ii. Detailed case studies

Detailed case study #1: New York: Value of Distributed Energy Resources (VDER)

Valuation model rewards DERs (and VPPs) for the full set of grid services provided.

VPP regulation summary			
Regulator	NY Department of Public Services (DPS)	**Key VPP regulation (order #)**	Order Regarding Value Stack Compensation (Case 15-E-0751)
IOUs	Con Edison, National Grid, NYSEG, Central Hudson, Orange and Rockland	**Year passed**	2017
Market structure	Within organized market (NYISO), utilities typically do not own generation	**Type of DERs**	Solar, storage, combined heat and power (CHP), digesters, wind, hydro, and fuel cells.
Key features	» Created the Value Stack, a valuation methodology used to determine and compensate DERs for a broad range of system benefits » Compensation is delivered to customers through bill credits		

State and regulator grid objectives with VPP program *(not exhaustive)*

- **Decarbonize power sector** to advance NY's state goal of 100% zero-emissions power by 2040.
- **Manage costs for ratepayers** to maximize the value of the existing grid and available cost-effective resources to reduce costs for New York ratepayers while achieving state clean energy goals.

Program summary

The NY DPS (part of the NY Public Service Commission) refined net metering models first established in 1997 to create the Value of Distributed Energy Resources (VDER) framework used today. With input from stakeholder working groups, NY DPS passed the first VDER Order in 2017, implementing two phases: i) VDER Phase One NEM, and ii) VDER Value Stack. The VDER Phase One NEM program compensates customers for any net excess generation (kWh) provided to the grid (provided as a credit to the customer's next monthly bill). The VDER Value Stack compensates customers based on the system value of the distributed generation (e.g., accounting for the hour of day, location on grid, etc).[cciii] In these early orders, NY DPS proactively included an expectation for a Phase Two to continue refining the Value Stack (e.g., modifying to account for other bulk system, distribution system, and societal values).

The VDER Value Stack compensates projects based on when and where they provide electricity to the grid. The Value Stack compensates DERs for the actual benefits delivered and the utility costs they offset, which includes a broader set of system benefits that were not accounted for in original net metering tariffs. Compensation is delivered in the form of bill credits.

Key success factors to integrate VPPs into utility planning and incentives *(not exhaustive)*

- **Assign value of DER compensation to a range of system benefits** to account for energy, capacity, environmental, demand reduction, locational system relief, and community value.
- **Align economic incentives** to compensate DERs based on monetary value delivered to the grid (not just based on volumetric generation) and allow value stacking across multiple grid benefits, including wholesale market value.
- **Provide location-specific compensation** to reward VPPs that have highest impact on alleviating distribution system constraints.

The VDER Value Stack includes six values for DER compensation:

Value name	Description	Eligible DERs
Energy Value (Locational Based Marginal Price, LBMP)	LBMP is the day-ahead wholesale energy price as determined by NYISO. It changes hourly and is different according to geographic zone.	All technologies.
Capacity Value (Installed Capacity, ICAP)	ICAP is the value of how well a project reduces New York State's energy usage during the most energy-intensive days of the year. Developers can choose from three payout alternatives: 1) pay out based on generation (kWh) delivered to the grid during the year, 2) pay out based on generation (kWh) delivered to the grid during peak windows, 3) pay out based on generation (kWh) delivered during the single peak hour of the year. Alternative 1 and 3 rates change monthly; the Alternative 2 rate is set annually.	All technologies. Dispatchable technologies (stand-alone storage, combined heating and power, digesters, and fuel cells) receive Alternative 3.
Environmental Value (E)	This the value of how much environmental benefit a clean kilowatt-hour brings to the grid and society. The E value is locked in for 25 years.*	PV, wind, hydro, and storage charged exclusively from PV or wind energy. Stand-alone storage is not eligible at this time
Demand Reduction Value (DRV)	DRV is determined by how much a project reduces the utility's future needs to make grid upgrades. DRV is locked in for 10 years.*	All technologies.
Locational System Relief Value (LSRV)	LSRV is available in utility-designated locations where DERs can provide additional benefits to the grid. Each location has a limited number of MW of LSRV capacity available. The LSRV is locked in for 10 years.*	All technologies. Project must be on a utility-specified substation.
Community Credit (CC)	CC is available on a limited basis to encourage the development of Community Distributed Generation (CDG) projects. CC is the successor to the Market Transition Credit (MTC) and is similar in structure. The CC is locked in for 25 years.*	Available for CDG projects including PV and digesters. Wind, hydro, and fuel cells receive CC at a derated value.

Table adapted from NYSERDA's Value Stack Fact Sheet (last updated in 2020).

*Projects will set a fixed rate for their E, DRV, LSRV, and CC values when they make their 25% upgrade payment to the utility. If no utility upgrade costs are required, the values are set when the interconnection agreement is fully executed.

In response to FERC Order 2222 (further discussed in *Chapter 5: Integrating into wholesale markets*), New York introduced the Wholesale Value Stack (WVS) in July 2023, which allows qualifying DER customers to receive compensation for energy and capacity from NYISO in addition to still receiving compensation from VDER environmental, demand reduction, locational system relief, and community credit values.[cciv] Value stacking improves VPP economics by allowing the VPP to qualify for multiple revenue streams (rather than capacity value alone, for example), which provides greater revenue certainty to VPP operators.[ccv]

The VDER tariff is intended to be technology agnostic but primarily focuses on distributed generation resources. DPS is currently conducting a Grid Flexibility Study to evaluate and determine appropriate compensation models that better value flexible resources.

Detailed case study #2: Massachusetts Electric Sector Modernization Plans (ESMP)

State policymakers empower PUC and utilities with stronger grid modernization planning requirements.

VPP regulation summary			
Regulator	MA Department of Public Utilities (DPU)	**Key policy and regulations**	*Legislation:* G.L. c. 164, §§ 92B-92C; An Act Driving Clean Energy and Offshore Wind, St. 2022, c. 179, §53 *PUC Order*: ESMP Order (D.P.U. 24-10/D.P.U. 24-11/D.P.U. 24-12)
IOUs in State	National Grid, Eversource, Until	**Year passed**	2022 Order passed 2024 First filings due
Market structure	Within organized market (ISO-NE), utilities do not own generation	**Type of DERs**	Distributed generation, energy storage, flexible load and demand response solutions
Key features	» Each IOU must develop an electric-sector modernization plan (ESMP) to proactively upgrade the distribution network to support the State's clean energy goals » Explicitly included goals to promote DER adoption and minimize costs to ratepayers		

State and regulator grid objectives (not exhaustive)

- **Enhance decarbonization** by enable integration of renewable energy and distributed energy resources and promoting energy storage and electrification technologies.
- **Enhance grid resilience** by improving overall grid reliability and resilience to climate driven impacts.
- **Minimize impacts to ratepayers** by prioritizing solutions to protect ratepayers while enabling decarbonization goals.

Program summary

In 2012, the MA DPU first opened a gird modernization proceeding to encourage IOUs to invest in distribution system modernization that would enhance reliability, reduce electricity costs, and empower customers.[ccvi] In 2015, the DPU approved the IOUs' first Grid Modernization Plans, preauthorizing certain grid modernization investments through 2021, including DERMS and other foundational communications infrastructure (effectively proactively deeming these as prudent investments that can be included in a utility's rate base).

Building on this work, in 2022, MA policymakers passed legislation as part of the Driving Clean Energy and Offshore Wind Act that requires investor-owned distribution companies to submit an Electric Sector Modernization Plan (ESMP) to the DPU every five years. The ESMP plans should consider nine factors, from extreme weather resilience measures to DER adoption forecasts.[117]

The MA legislature provided explicit direction and authority to the state PUC, empowering regulators to review utility investment plans in the context of broader state goals (e.g., reliability, decarbonization and electrification, affordability). The requirements established in the ESMP process, such as deploying energy storage technologies and advanced metering and telemetry, provide the necessary environment to accelerate DER adoption, establish VPP-enabling infrastructure, and deploy VPPs at scale in Massachusetts.

117 See Section 92 of the MA ESMP legislation for the full list of nine factors that must be considered in utility plans (e.g., describing the availability and suitability of new technologies (e.g., smart inverters, advanced metering and telemetry and energy storage technology) to meet forecasted reliability and resiliency needs; describing alternatives to proposed investments, including changes in rate design, load management and other methods for reducing demand, enabling flexible demand and supporting dispatchable demand response).

Key success factors for utility planning and incentives *(not exhaustive)*

- **Provide explicit direction to the PUC and utilities,** leveraging state policymakers to strengthen the regulatory authority and helped speed up action to promote cost-effective grid modernization.
- **Establish common statewide approaches** for all state IOUs to use (e.g., data access, DER monitoring and verification processes, foundational infrastructure expectations) to help standardize VPP operations and support faster deployment.
- **Adopt best practices for distribution planning** by linking planning requirements to specific grid objectives (listed below), including multiple planning horizons (5-year, 10-year, 2050), and requiring consideration of DERs.
- **Establish diverse stakeholder group,** leveraging the Grid Modernization Advisory Council (GMAC)[118] to provide input on the plans to the utilities ahead of submission to the PUC, helping keep IOUs accountable to ensure system-optimal set of solutions were considered (e.g., VPPs).

D.iii. Key resources for practitioners

VPP Resources

- **Aggregated Distributed Energy Resources in 2024: The Fundamentals** (July 2024, NARUC and NASEO) is an accessible guidebook specifically geared for state regulators and policymakers to understand the fundamentals of VPP grid services, valuation options, and approaches to compensation. **The report includes detailed case studies on MA, HI, and VT VPP programs—including context on the impetus and process that states followed to develop these programs.**
- **VPP Policy Principles** (Feb 2024, RMI and VP3) outlines simple foundational principles to support policymakers in enabling VPPs. *Policy Principles for Enabling Virtual Power Plants (VPPs)* presentation (May 2024) includes specific examples of states and utilities where these principles have been done well. See Appendix D.v. for a summary of the policy principles.
- **Distributed Power Plant Model Tariff** (June 2024, Solar United Neighbors) includes model tariff and model legislation to support state regulators, policymakers, and utilities in implementing VPP-supportive regulatory mechanisms. Solar United Neighbors developed these resources to address the gap identified by the 2023 VPP Liftoff report of a lack of model tariff language that PUCs can adapt for their state.
- **VPP Flipbook** (July 2024, RMI and VP3) includes discussion on effective VPP program design and implementation, including specific examples and resources that could support regulators and policymakers (pages 64-66).

General Grid Planning and Modernization Resources

- **50 States of Grid Modernization** (DSIRE, operated by the N.C. Clean Energy Technology Center) provides a quarterly and annual summary of state policy and regulatory actions supporting grid modernization, including VPP related proceedings. Reports include a summary of specific actions, docket and bill numbers, and broad themes.
- **Integrated Distribution System Planning** (Lawrence Berkeley National Laboratory, DOE): Includes an interactive framework, a catalog of existing state regulatory requirements and policy actions, and additional training materials and best practice information.

118 The Grid Modernization Advisory Council is a stakeholder group that reviews and advises on Massachusetts investor-owned electric distribution utilities' electric-sector modernization plans to promote transparency and engagement in grid planning for Massachusetts.

D.iv. Actions from the Department of Energy

- **Grid Innovation Program**, part of the Grid Resilience and Innovation Partnerships (GRIP) Program, provides financial assistance to states, Tribes, local governments, and public utility commissions to deploy projects that use innovative approaches to T&D and storage infrastructure to enhance grid resilience and reliability
- **Grid Resilience State and Tribal Formula Grant Program**, designed to strengthen and modernize America's power grid against wildfires, extreme weather, and other natural disasters, distributes funding to states, territories, and federally recognized Indian tribes, including Alaska Native Regional Corporations and Alaska Native Village Corporations. The states, territories, and tribes then award these funds to a diverse set of projects
- **Integrated Distribution System Planning** Training and Guidelines to assist regulators in developing requirements for, and in assessing, integrated distribution plans of utilities that consider integrating and utilizing DER services, as well as in understanding needed investments
- **Energy Innovator Fellowship** to fund recent graduates and energy professionals to support public utility commissions, co-ops, Puerto Rican energy associations, Tribes, and other grid operators
- **State Energy Program** to provide funding and technical assistance to enhance energy security, advance state-led initiatives, and increase energy affordability, with a portion of funds allocated to states for energy planning
- **DER Integration and Compensation Initiative** to engage regulators via a cooperative agreement with the National Association of Regulatory Utility Commissioners
- **Grid Modernization Initiative (GMI)** coordinates activities and strategy to create the modern grid of the future
- **State Technical Assistance program** tto provide responsive, on-demand technical assistance to PUCs and state energy offices and match them to subject matter experts at the national labs, as well as a help desk that can address quick, short inquiries
- **EVGrid Assist** to develop best practice guides in collaboration with stakeholders to share learnings, accelerate decision making, and support development of data, tools and analysis to support EV-grid integration

D.v. VPP policy principles from the Virtual Power Plant Partnership

The Virtual Power Plant Partnership (VP3) is a coalition organized by RMI, an independent nonprofit, made up of nonprofit and industry organizations focused on supporting market and policy actions to scale VPP deployment. In February 2024, VP3 released a set of VPP policy principles "to support the fair and efficient growth, integration, valuation, compensation, and advancement of virtual power plants."[ccvii]

The seventeen policy principles identified are:

Category	Principle
DER Asset Base	1. Advance policies to expand beneficial DER adoption by diverse end-users 2. Enable inclusion of all DER technologies in VPPs
VPP Design	3. Utilize best practices in program design 4. Use open communication protocols and standards 5. Enable VPP participation in wholesale and retail markets 6. Regularly update grid service needs to reflect the evolving grid 7. Support comprehensive utility planning and investment decisions
Equitable Compensation	8. Fairly compensate VPPs for services delivered 9. Enable value stacking to maximize benefits 10. Support policies that value VPP contributions to resilience, reliability, and sustainability 11. Uphold equitable penalties and liabilities
Customer Experience	12. Maintain customer choice in DER operational control 13. Uphold customer data ownership and simplify enrollment 14. Protect and educate customers 15. Support customer participation in structuring VPP offerings through procedural equity
Utility and System Operator Roles	16. Encourage participation of competitive hardware and service providers 17. Use open-source software and make grid data available

Access additional detail at: https://rmi.org/insight/vpp-policy-principles

D.vi. Summary of existing benefit-cost assessment frameworks from NARUC

NARUC and NASEO's Aggregated Distributed Energy Resources 2024: The Fundamentals report (which was funded by DOE) includes a summary of existing tools for valuing grid services.

Below is the excerpt of Table 13 from the report (page 45) summarizing these tools:

Summary of Existing Tools & Examples of Grid Service Valuation

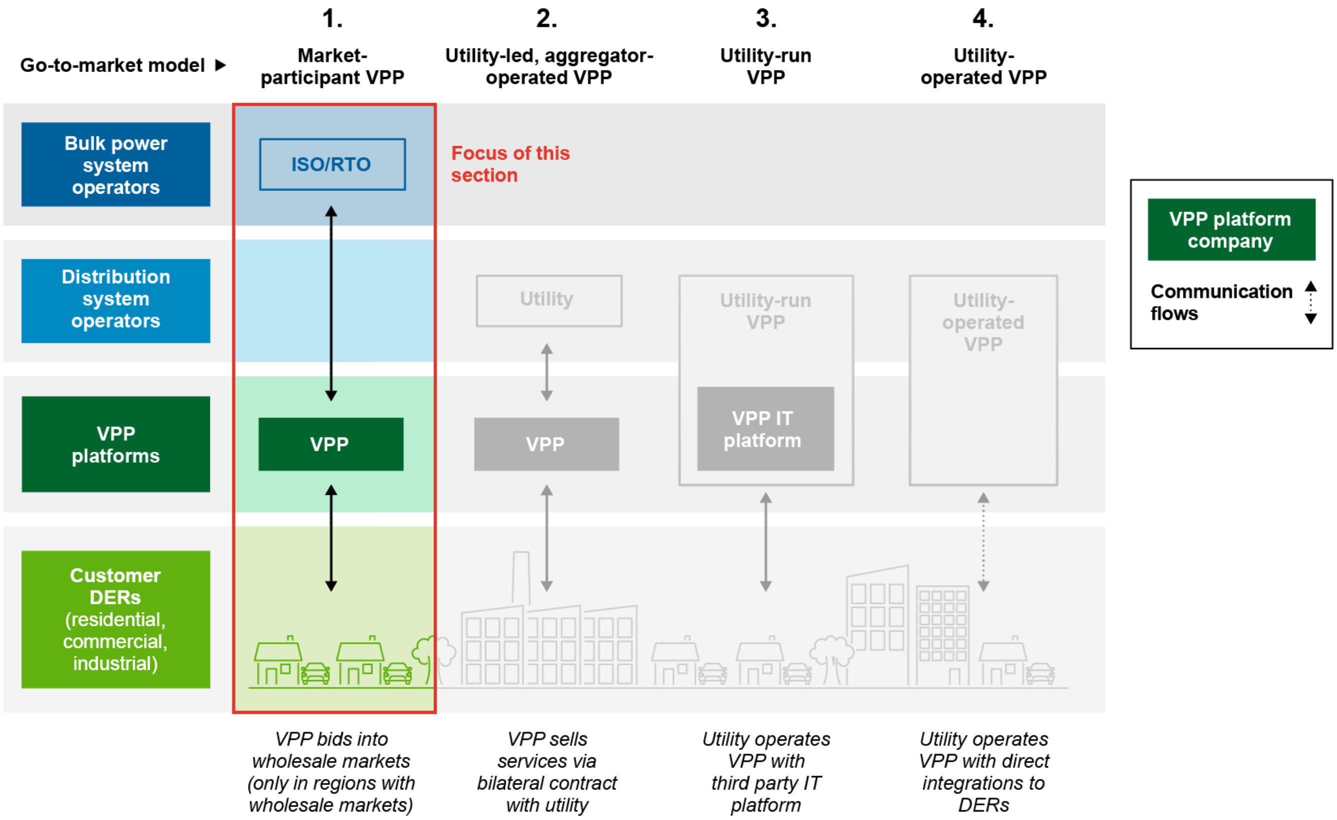
Tool / Methodology Handbook	Description	Energy Benefits Evaluated				Non-Energy Benefits Evaluated	
		Bulk Power Energy & Capacity Grid Services	Bulk Power Essential Reliability Services	Distribution Grid Services	Grid Edge Services	GHGs	Pollutant Emissions or Social Equity
National Standard Practice Manual (NSPM) for Benefit-Cost Analysis of Distributed Energy Resources	Summarizes the BCA principles for DERs and summarizes cost-effectiveness considerations for multiple DERs.	✔	✔	✔		✔	✔
New England Avoided Energy Supply Costs Report	Forecast of estimated annual electric and gas costs that would be avoided due to reductions in gas and electricity use and methods for estimating avoided costs.	✔	✔	✔		✔	
California Avoided Cost Calculator	Estimates '8,760' benefits by year for a DER in California.	✔	✔			✔	
New York Solar Value Stack Calculator	Calculator used to estimate the value of distributed solar in NY.	✔				✔	
Time-Sensitive Value Calculator	Calculator estimates the hourly value of ADERs.	✔	✔			✔	
LBL Interruption Cost Estimator	Estimates the value of lost load by customer type based on region and current SAIDIs and CAIDIs.			✔	✔		
Central Hudson Benefit Cost Handbook (page 587)	Detailed methodology used by Central Hudson Utility in New York for estimating all of the costs and benefits used to estimate cost-effectiveness of DERs.	✔	✔	✔		✔	

EPA Co-Benefits Risk Assessment Health Impacts Screening and Mapping Tool	Helps state and local governments explore how clean energy policies and programs affect human health and the value of the health benefits that result from these programs.						✔
Distributional Equity Analysis Guidance	Provides guidance on how utility investments in DERs impact specific populations and communities.						✔

Appendix E: Integrating into wholesale markets

E.i. Detailed case studies

The next section provides an explanation of the communication protocols for a demand response program participating in its corresponding market.



[Detailed case study #1: Leap's participation in CAISO]

VPP overview

Automation capabilities and partnerships with DER technology providers allow VPP scalability in California.

VPP summary			
Program operator	Leap	**VPP size** *(as of 2024)*	500 MW
Market structure	Within organized market (CAISO), utilities own generation	**Type of DERs**	Residential & commercial EV charging, residential & commercial HVAC, residential & commercial batteries, cold storage, water pumping
Location	California ISO	**Time to operationalize**	18 months

Compensation structure	» Capacity payments are based on performance against pre-determined commitments to the ISO, usually via annual contracts. » Energy payments are determined by market prices and clearing results in day-ahead and real-time markets.
Grid services	» Energy (payment from CAISO) and capacity (payment from utilities and Community Choice Aggregators)

Aggregator objectives with VPP program *(not exhaustive)*

- **Monetize DERs** through Resource Adequacy (RA) grid services programs in California.
- **Expand access to VPP participation** beyond large commercial loads, enabling homes and businesses with grid-interactive technologies to easily access these revenue streams.
- **Help reduce upfront costs of DERs** by unlocking new revenue streams for technology providers.
- **Demonstrate the viability of VPPs** as reliable flexible load.

Program summary

Leap partners with technology companies that manufacture and manage DERs to provide energy and capacity services in the CAISO market. Leap contracts with these companies to aggregate residential and commercial DERs, including battery storage systems, electric vehicle charging infrastructure, and smart building technologies.

Leap uses a software solution to integrate with partners' existing systems. Leap connects its partners to the market through API integrations.

Delivered outcomes

- **Provides capacity and energy** services that can competitively bid into CAISO markets.
- **Monetizes 500 MW** of DER capacity for ~40 technology companies.

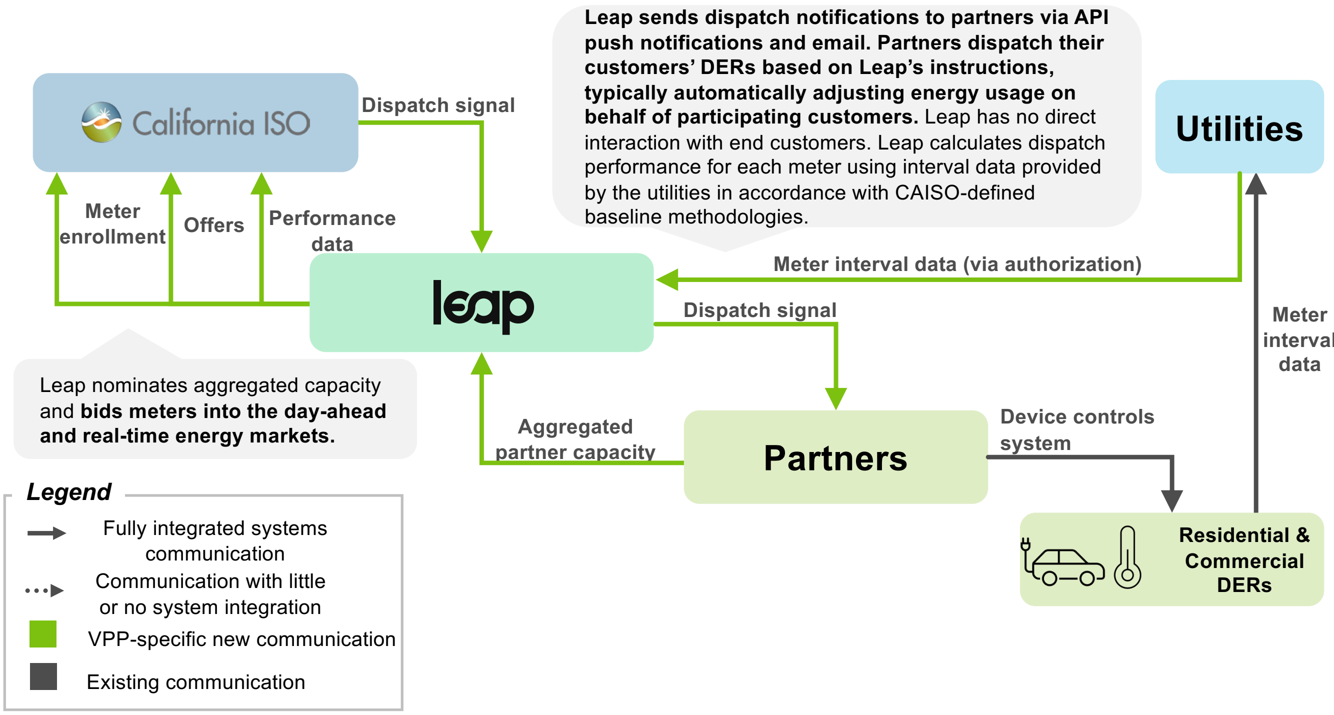
VPP communication protocols & operations

Leap operates in the CAISO energy and capacity markets:

1. Leap's partners start by determining load shed capabilities of their device portfolio, in context with their needs and participation preferences.
2. Partners invite end customers to enroll their DERs for grid services participation through the Leap platform, enabling customers to authorize access to their utility meter interval data for Pacific Gas & Electric, Southern California Edison, and San Diego Gas & Electric through a single interface.
3. Once Leap receives the utility authorization, Leap submits the service account associated with the meter through CAISO's Demand Response Registration System (DRRS) to register for participation in the appropriate programs. Partners use the Leap portal and API to track the status of program enrollment.

4. Leap sets a curtailment capacity for each meter, aggregates meters with similar characteristics, and submits the aggregation through DRRS each month. Additionally, Leap bids aggregations of customer service accounts into the energy market as a resource bid on an hourly and daily basis through CAISO's Scheduling Infrastructure Business Rules (SIBR) based on partners' bidding preferences.
5. Once CAISO chooses Leap's bids, Leap receives a dispatch signal through the CAISO Customer Market Results Interface (CMRI).
6. Leap then sends dispatch notifications to partners via API push notifications and email. Each dispatch notification will include an amount in kW that is expected to be curtailed.
7. Partners dispatch their customers' DERs, typically automatically adjusting energy usage on behalf of participating customers.
8. Leap receives interval data provided by the utilities for each of their customers. This data is used to calculate performance based on CAISO-defined baseline methodologies. Leap provides performance data through CAISO's Market Results Interface-Settlements system (MRI-S) each month.
9. Leap receives compensation for provided capacity from market counterparties such as utilities and Community Choice Aggregators (CCAs) and receives compensation for energy services from CAISO. Leap then disperses payment to partners, providing settlement and performance details through the Leap portal and API.

VPP communications



E.ii. Market operator case studies of common issue areas and potential solutions

This section provides case studies that share potential approaches that market operators can consider to address issue areas outlined in *Chapter 5: Integrating into wholesale markets* – lack of data access, varied metering & telemetry requirements, and different approaches to aggregator participation models.

Data access

Lever	Example
Create a common and standardized DER register with clear rules on data access	In 2020, the Australian Energy Market Operator (AEMO) established a centralized DER register to provide visibility of DER specifications (e.g., type, capabilities, resource ownership) and location to better manage the grid, improve system reliability as the grid becomes more decentralized, and deliver energy at a more affordable price to customers. Utilities are required to provide DER information in accordance with the DER Register Information Guidelines under the National Electricity Rules. The register provides a common, standardized information fact base that the DER industry, customers, AEMO, distribution utilities, and other third parties such as emergency services can request to access.[119,ccviii,ccix,ccx]

Metering and telemetry

Lever	Example
Establish market-wide metering standards	Ontario IESO has established market-wide standards for meter registration across numerous distribution utilities and 5 million smart meters.[ccxi] Market rules require that each metering installation used for settlement purposes is on a list of pre-approved meters established by IESO that meet specific performance standards, including meeting or exceeding 0.2% accuracy, meeting security requirements, and are programmed according to the IESO Conforming Meter Framework.[ccxii] Regulatory amendments expanded IESO's authority to process and manage bi-directional smart metering data through a centralized Meter Data Management / Repository (MDM/R) in July 2023.[ccxiii] Establishing a market-wide approach to metering simplified and standardized data collection while reducing IT costs to develop, manage, and protect the database. This spurred additional engagement with various grid partners to expand third-party access to this database, including for demand response aggregators.[ccxiv,120]
Allow sub-metering (i.e., meters embedded in DERs) for data collection	SPP, CAISO, NYISO, and MISO allow submetering as the basis for measuring DER performance and compensation for grid services provided. Submetering involves using meters embedded in DERs (e.g., inverters in batteries, meters in solar arrays) for data collection. Allowing submetering in all ISO/RTOs could increase DER participation, since nearly all generation and storage DERs already include device-level meters. The benefits of allowing sub-metering need to be determined against the potential burden of validating and verifying device-level meter data against customer metering data for settlement.
Match telemetry requirements to provided service	CAISO only requires telemetry for resources that provide ancillary services or resources above 10 MW. Rather than requiring these same strict telemetry standards across all services (e.g., 2-6 second telemetry for all DERs and all services), CAISO matches telemetry required to the services offered. This flexible approach allows assets that may not be able to provide sub-hourly telemetry to still participate in wholesale markets and all assets to benefit from reduced participation costs, particularly smaller DERs for which requiring high-frequency telemetry could be a costly barrier.[ccxv]
Allow calculated readings based on a sampling	CAISO, NYISO, PJM, and SPP allow participants to use calculated telemetry readings based on sampling rather than requiring direct telemetry for each DER to participate. This allows a greater number of DERs to participate given relaxed telemetry requirements and reduced participation costs.

119 The Australian Energy Market Commission made a rule obligating AEMO to establish this register in the National Electricity Market in September 2018. AEMO engaged with a wide range of partners, including utilities and industry groups, to design the register and align on the corresponding data sets and data collection processes.

120 Another example is ConnectedSolutions, which has metering authority across multiple utilities in Massachusetts. Common program design across utilities enables standardization of data access, dispatch, monitoring and verification, and DERMS while providing economies of scale for enrollment.

Participation models

Lever	Example
Allow DER aggregations to choose from existing participation models or a new set of participation rules for DER aggregations	NYISO and ISO-NE have adopted a hybrid approach to aggregator participation models to address concerns that existing models may limit participation from DER aggregations. This allows DER aggregators to choose to participate using the model that is most economical for them – either existing models (e.g., storage DER aggregation participating through storage participation models) or a new participation model that is specific to DER aggregations.

E.iii. Key resources for practitioners

- **DER Participation in Wholesale Markets** (January 2025), Lawrence Berkeley National Lab) provides an overview of the six most complex challenges in FERC Order 2222 compliance, various ISO/RTO approaches to address these challenges, and the roles of state energy regulators in the implementation and success of these programs.
- **FERC Order 2222 Implementation** (September 2024, Office of Electricity) shares updates on FERC Order 2222 implementation through bi-monthly reports and webinars. The website includes a DER policy tracker and a library of resources from DOE, NARUC, and NERC.
- **FERC Order 2222 Explainer** (FERC) provides a high-level overview of FERC Order 2222, how it addresses current barriers to DER participation in markets, anticipated timelines for implementation, and additional resources.
- **Grid Investments to Support FERC Order 2222** (January 2024, GridWise Alliance) discusses technologies and corresponding investments that may be required to support FERC Order 2222 implementation.
- **NARUC DER Integration and Compensation Initiative** (March 2023, NARUC) includes a summary of state actions, considerations, and enabling policies related to FERC Order 2222 implementation for state energy decision makers such as PUCs and State Energy Offices.
- **DER Integration into Wholesale Markets and Operations** (January 2022, August 2022, August 2022, ESIG) includes a series of three reports on changes required to integrate DERs into wholesale markets and operations, an assessment of DER initiatives in the UK and Australia, and a proposal for technical foundations, least-regrets strategies, and dialogue to resolve challenges in the U.S.

E.iv. Actions from the Department of Energy

- **Aggregator Code of Conduct** to address the roles and responsibilities of all participants (DER owners, VPPs, distribution system operators, bulk system operators, and regulators) to support DER integration and scale use of DER services
- **Technical assistance** for the use and applications of DERs to support distribution and bulk power system operations for ISO/RTOs, regulators, states, and communities
- **Market and Retail-rate Know-how for the Energy Transition (MARKET)**, led by the National Renewable Energy Lab and Lawrence Berkeley National Lab, to study how existing wholesale markets and retail rates may need to evolve to continue operating the electricity system without compromising reliability and cost. The portfolio of projects includes retail rates, VPPs, wholesale electricity markets, and reliability

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Assessing VPP Performance:
Impacts of a Test Event in California

PREPARED BY

Ryan Hledik
Kate Peters
Purvaansh Lohiya

PREPARED FOR

Sunrun
Tesla

AUGUST 1, 2025

Brattle

The VPP test event

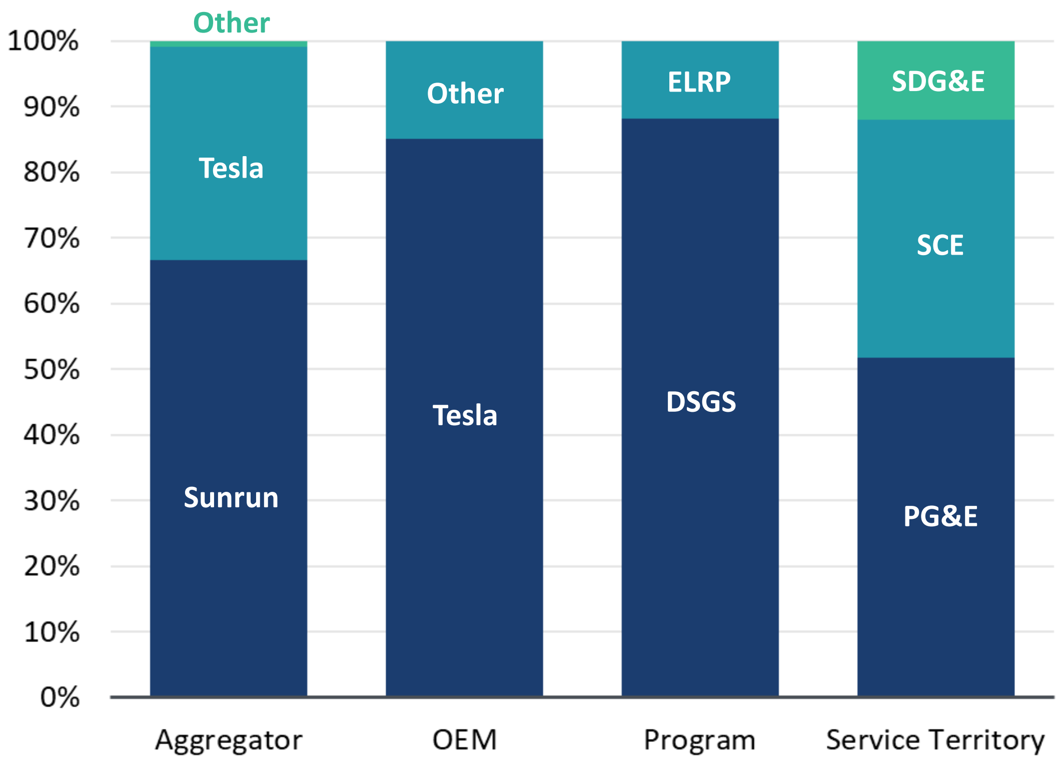
On July 29, 2025, several virtual power plant (VPP) aggregators in California discharged their portfolio of batteries between 7 and 9 pm, producing 535 MW of average output.

The aggregators conducted the event to assess the performance capability of their battery fleet heading into California's summer peak season, when the VPP's grid services will be needed most.

The participants accounted for a diverse mix of battery manufacturers, aggregators, VPP programs, and geographic locations. In general, Sunrun was the largest aggregator, Tesla was the largest OEM, and most of the batteries were enrolled in California's Demand-Side Grid Support (DSGS) program.

The aggregators provided Brattle with data to analyze the impact of the event. This presentation summarizes our initial findings. Further detail will be provided in a forthcoming report by Brattle for Sunrun and Tesla.

Composition of VPP Event Participants



Notes: Based on Brattle analysis of 5-minute telemetry data provided by Sunrun and Tesla. Percentages indicate share of 535 MW impact. DSGS = Demand Side Grid Support, ELRP = Emergency Load Reduction Program.

VPP operational profile

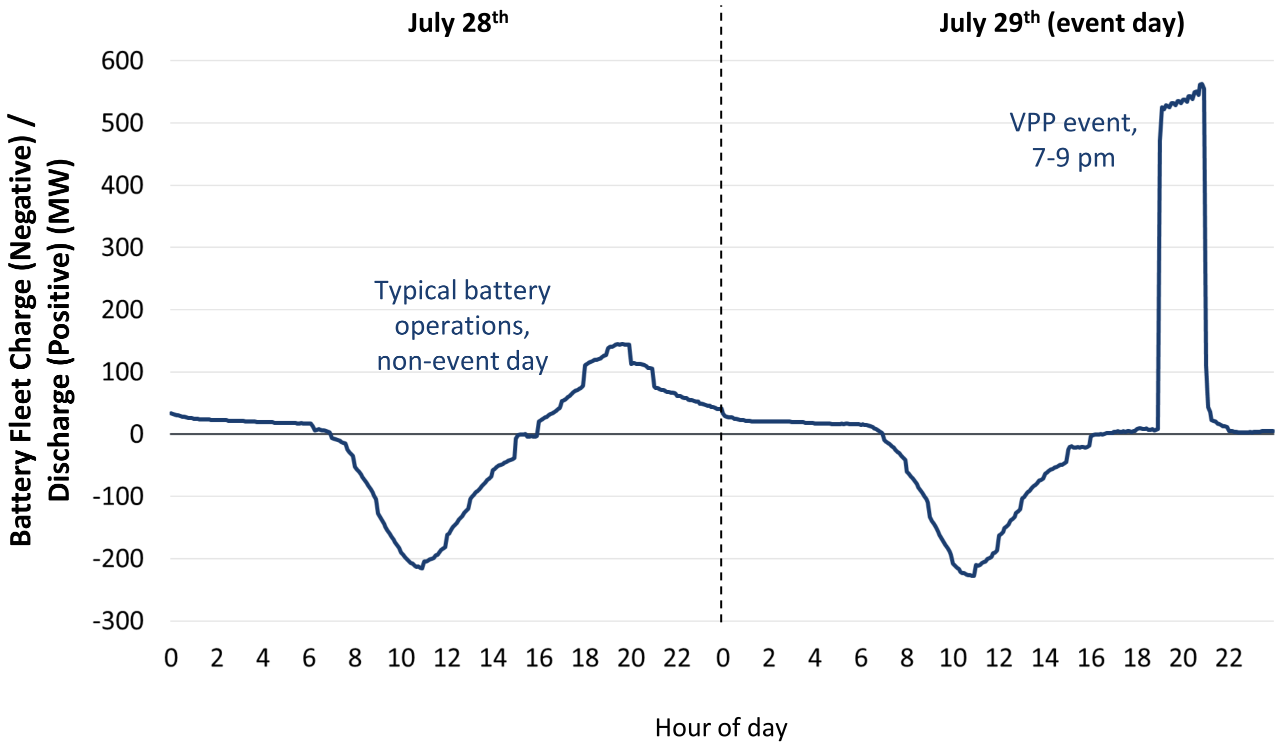
Aggregate VPP performance during the event was consistent and mostly additive to status quo operations.

The figure at right compares the operation of the batteries on the day before the event to their operation on the day of the event.

Battery performance during the event demonstrates a significant departure from status quo operations. In other words, most of the 535 MW of battery output was additive; it would not have occurred in the absence of calling an event.

Additionally, the figure illustrates relatively consistent output from the batteries for the duration of the event, without significant fluctuations or any performance attrition.

Battery Operations Before and During the Event



Notes: Based on Brattle analysis of 5-minute telemetry data provided by Sunrun and Tesla. Battery dispatch is raw power output, without any baseline adjustments.

CAISO system impact

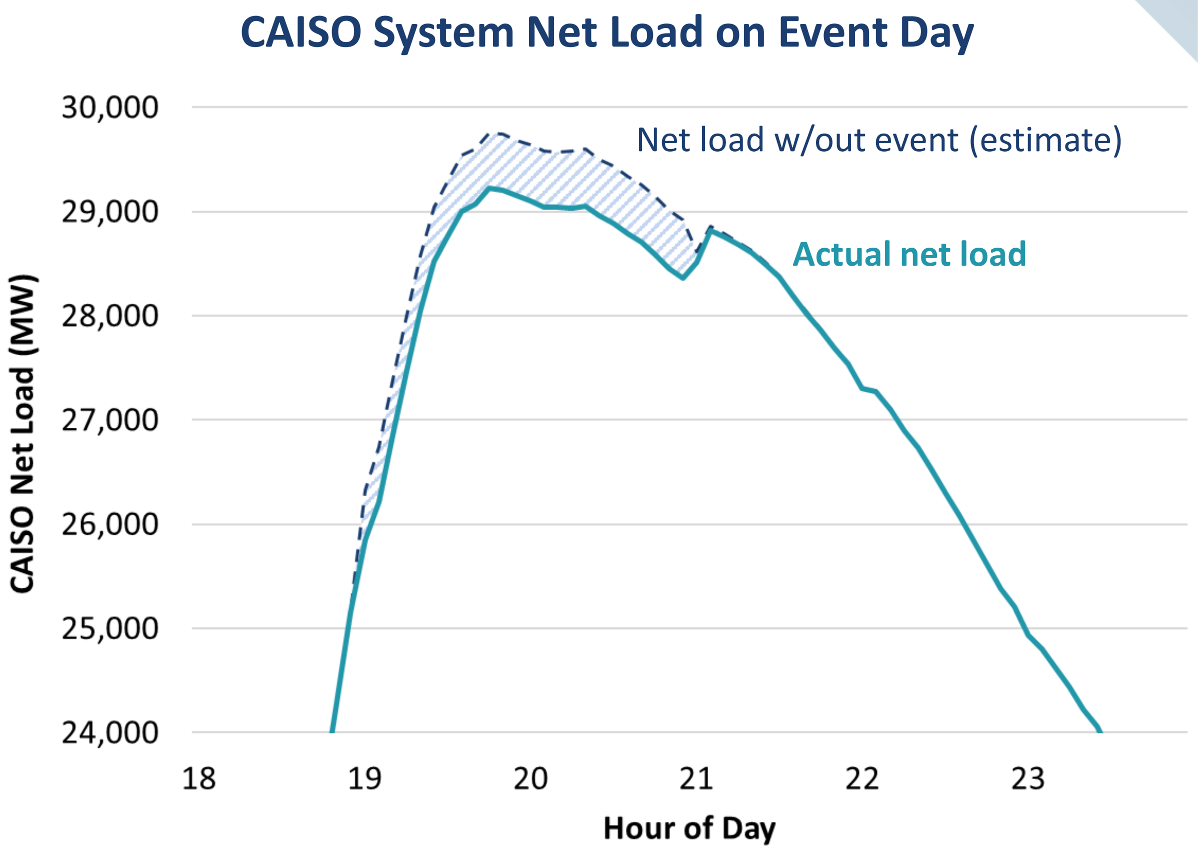
The VPP operated during CAISO's net system peak, the time when output typically is most valuable to the system.

The timing of the event coincided with CAISO's net peak demand on the event day (i.e., load minus wind and solar generation). There was a visible reduction in net load.

On peak days, using VPPs to serve CAISO's net peak could reduce the need to invest in new generation capacity and/or relieve strain on the system associated with the evening load ramp.

In other words, the batteries could help to mitigate some of the challenges associated with California's "duck curve".

Optimized VPP program design and coordination with the system operator could further maximize the value of the battery output to the system.



Notes: Net load sourced from CAISO and reflects actual demand less solar and wind output. Baseline net load in the absence of the event was constructed using 5-minute telemetry data provided by Sunrun and Tesla. All battery output is shown as a reduction in net load.

Utility Co., Inc.

Distributed Power Plant Program

Acronyms Used in This Document

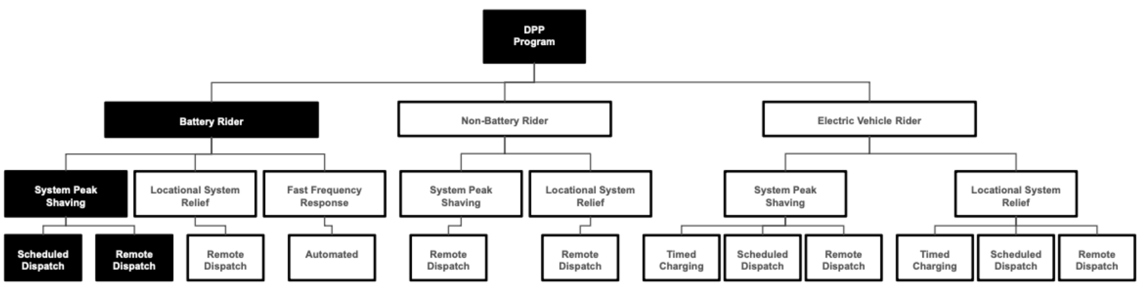
AMI	Advanced Meter Infrastructure
BTM	Behind the Meter
DERs	Distributed Energy Resources
DERMS	Distributed Energy Resource Management System
DPP	Distributed Power Plant
FTM	Front of the Meter
kW	Kilowatt
kWh	Kilowatt hour
LMI	Low- and Moderate-Income

Distributed Power Plant Program

General Terms and Conditions

A. PURPOSE

The Distributed Power Plant Program ("DPP Program" or "Program") enables Participants (Aggregators or Customers that participate directly) to provide Grid Services from customer-sited Distributed Energy Resources ("DERs"). Customers enroll and participate in the Program either through an Aggregator or directly with the Company. The Aggregator and/or Company coordinates the operation of the enrolled DERs to deliver the specified Grid Service(s) in accordance with the terms of the tariff's Rider(s) governing the respective Grid Service(s) provided. Participants are compensated pursuant to the compensation schedule for each Grid Service, as available under the Program Rider for each technology (the *Battery Rider*, the *Non-Battery Rider* and the *Electric Vehicle Rider*). The table below illustrates this framework, highlighting the Battery Rider with System Peak Shaving Grid Service opportunities for Scheduled and Remote Dispatch.



B. DEFINITIONS

The following terms and definitions apply to the Program.

<u>Aggregator</u> – A third-party entity that enrolls Customers in the Program and coordinates the operation of Enrolled Devices. An Aggregator is a Participant in the Program.

<u>Base Service Tariff</u> – The underlying service tariff that includes rates and charges charged by the Company to provide electric service to a Customer.

<u>Battery</u> – A behind-the-meter ("BTM") energy storage device and associated equipment that operate together to fulfill Program requirements.

Capability Period – The calendar period during which Customers' devices may be called upon to provide a Grid Service, as defined in the applicable Grid Service opportunity in the Program Rider.

[Commission – Public Utilities Commission or other applicable state agency that regulates electric utilities].

Committed Capacity – The capacity that a Customer makes available for dispatch during the Dispatch Window.

Company – name of utility company.

Customer – An active electric service account holder of the Company.

Customer Agreement – the agreement between a Customer and the Company governing the Customer's participation in the Program.

Direct Participant – A Customer that enrolls in the Program directly with the Company rather than via an Aggregator.

Dispatch Window – The specific dates, time, and duration during which the Company may remotely call upon or schedule Eligible Devices to provide a Grid Service during a Capability Period.

Distributed Energy Resource (DER) – A customer or third party-owned BTM device, including but not limited to solar PV, batteries, smart thermostats, and electric vehicles, that provides energy and/or energy management capabilities for the Customer or the grid.

Eligible Device – A customer or third party-owned DER that meets the requirements for participation in the Program as specified in the relevant Program Rider.

Emergency Event – An event called by the Company with fewer than 24 hours notice.

Enrolled Customer – A Customer that participates in the Program through either an Aggregator or as a Direct Participant.

Enrolled Device – An Enrolled Customer's Eligible Device, as specified in the relevant Program Rider.

Environmental Justice Community – [As defined by applicable state or insert federal definition].

Existing Battery – A Customer-sited Battery that received permission to operate from the Company more than six months before the Customer's enrollment in the Program.

Grid Event – A grid condition for which the Company schedules or remotely dispatches Enrolled Devices to respond to as specified in the Grid Service opportunities for each Program Rider.

Grid Service – A capacity, energy, or ancillary service that supports grid operations.

Grid Service Export Credit – Value equal to the retail cost of a kilowatt hour (kWh) as charged by the Company at the time of a Grid Event and applied as a credit to the Enrolled Customer's monthly bill for all kWhs exported from an Eligible Device during a Grid Event.

Interconnection Agreement – The agreement between a Customer and the Company that governs the terms of interconnection and operation of certain Customer-sited devices interconnected to the Company's distribution system, as distinct from the Customer Agreement governing the Customer's participation in the Program.

Interconnection Tariff – The document approved by the Commission describing the process and requirements for a Customer to connect certain DERs to the Company's system, including technical and operating requirements, metering and billing options.

New Battery – A Battery that receives permission to operate from the Company within six-months prior to the date of the Customer's enrollment in the Program.

Participant – An Aggregator or a Direct Participant in the Program.

Performance Payment – A payment made to the Participant based on the performance of an Enrolled Device(s) providing a Grid Service during a Grid Event.

Performance Payment Rate – The compensation rate paid to Participants for providing a particular Grid Service during a Grid Event.

Program Rider(s) – One or more of the *Battery Rider*, the *Non-Battery Rider*, the *EV Rider*, and such other DPP Program riders as the Commission may approve from time to time.

Remote Dispatch – A dispatch method where the Company issues a signal to Aggregators and/or to Direct Participants' Enrolled Devices with instructions for providing a particular Grid Service.

Renewable Energy Generating Facility – A solar PV system or other BTM resource interconnected at the Customer's premises that generates electricity from a renewable energy source.

Registered Aggregator – An Aggregator registered with the Company to enroll customers and participate in the Program.

Scheduled Dispatch – A dispatch method where the Enrolled Device provides a Grid Service on a predetermined schedule without the need for Remote Dispatch.

Interconnection Rate Exports – Energy exported by an Enrolled Customer outside of a Grid Service Event.

Interconnection Rate Export Credit – The bill credit provided to Enrolled Customers for energy exported outside of a Grid Event, as specified in the customer's Interconnection Tariff.

Summer Capability Period – June 1 to September 30.

System Peak Shaving – A reduction in aggregate load across the Company's system during peak demand periods via reduced consumption, self-consumption of self-generated electricity, and/or the export of energy from a Renewable Energy Generating Facility and/or Battery.

Test Event – An event called by the Company to confirm that an Enrolled Device is able to perform as anticipated.

Upfront Payment – A one-time payment made at the time of enrollment.

Verification Process – The process through which a Direct Participant completes a Test Event and provides performance data to verify an Enrolled Device's ability to operate on a scheduled basis or respond to a remote dispatch signal.

Winter Capability Period – December 1 to March 31.

C. PROGRAM AVAILABILITY

The Program is available to Direct Participants and Aggregators that meet requirements of one or more of the Program Riders. The Program will begin enrollment in the *Battery Rider* on [date]. Additional Program Riders and Grid Service opportunities will be added as they become available.

The Company shall maintain on its website a list of the available Program Riders and Grid Service opportunities within each Rider. The Company shall file a quarterly report with the [Commission] no later than fifteen (15) days following the end of each quarter. The report shall list the number of Registered Aggregators and Direct Participants enrolled in the Program, the total capacity of DERs enrolled in each Program Rider broken out by technology type, customer class, the Grid Service(s) that the DER is enrolled to provide, and such other information as the Commission may require.

The DPP Program and its respective Program Riders and Grid Service opportunities will remain open for enrollment unless otherwise ordered by the Commission.

D. AGGREGATOR REGISTRATION

An Aggregator who meets the eligibility requirements listed in Appendix [X] may apply for registration through the Company's secure web portal. Upon successfully responding to a Test Event demonstrating the ability to communicate with the Company and dispatch its fleet, the Aggregator is enrolled and eligible to participate as a Registered Aggregator. The Company shall maintain an up-to-date list of Registered Aggregators on its website. The term "Aggregator" as used herein refers to a "Registered Aggregator" unless otherwise specified.

Distributed Power Plant Program

Battery Rider

System Peak Shaving: Scheduled Dispatch

A. PURPOSE

The System Peak Shaving service via Scheduled Dispatch ("Scheduled Peak Shaving") pays Participants for providing capacity from enrolled Batteries to reduce demand on the grid during seasonal peak periods pursuant to a preset schedule.

B. ELIGIBILITY

1. Customers with new or existing Batteries may enroll to provide Scheduled Peak Shaving through a Registered Aggregator or directly with the Company, where:

    a. The Customer has an active residential or light commercial electric service account with the Company.
    b. The Battery is installed BTM pursuant to a valid Interconnection Agreement.
    c. The Customer or a third-party owns the Battery.
    d. The Battery is charged from a new or existing BTM Renewable Energy Generating Facility installed at the Customer's premises that operates pursuant to a valid Interconnection Agreement with the Company.
    e. The Battery has metering accuracy of ANSI C-12.1-2008 or a specification rating with an accuracy of +/- 2.0%.
    f. The Customer executes the Customer Agreement provided in Attachment A.

2. When a Customer participates through an Aggregator, the Aggregator is the Participant. When the Customer participates directly with the Company, the Customer is the Participant.

3. Scheduled Peak Shaving will remain open unless otherwise ordered by the Commission.

C. ENROLLMENT

1. Customers enroll in Scheduled Peak Shaving through a Registered Aggregator as follows:

    a. Customers submit to the Aggregator the following information:
        i. Legal name of the Customer.

Distributed Power Plant Program

Battery Rider

System Peak Shaving: Scheduled Dispatch

ii. Customer representative's name and title (if representative is different from Customer or if Customer is a business) and contact information.
iii. Customer's valid, active utility account number.
iv. Service account address, phone number on file with the Company, and such other information as necessary to verify eligibility.
v. Battery, solar PV system, inverter, and other equipment specifications as required by the Aggregator.
vi. The Committed Capacity of the Battery.
vii. Election to participate in the Summer Capability Period, Winter Capability Period, or both.
viii. Authorization for access and use of Customer information from the Company and access and use of data from the Customer's battery, solar PV, inverter, site electric load, and such other related data necessary to verify eligibility and performance of Enrolled Devices and otherwise facilitate Program participation.
ix. Acknowledgement and agreement from the Customer that:
    1. The information submitted is accurate and complete.
    2. The Customer agrees to the terms and conditions of the Program.
    3. Such other information the Aggregator deems necessary to enable participation in the program.

b. Aggregators may collect Customer information through a form provided by the Aggregator.
c. Once a Customer completes the Aggregator's submission process, the Customer's Battery is enrolled in the Scheduled Peak Shaving and is immediately eligible to participate as part of the Aggregator's fleet of enrolled Batteries.
d. Customers enrolled through an Aggregator are not required to complete an independent Verification Process.
e. Aggregators provide updated Enrolled Customer information to the Company as new Customers are enrolled and Enrolled Customers are disenrolled.
f. Aggregators shall retain Customer enrollment information, which may be reviewed by the [Commission] from time to time.

2. Customers enroll in Scheduled Peak Shaving directly with the Company as follows:

a. Submit a Program Application directly to the Company with the following information in a form provided by the Company:
    i. Legal name of the Customer.
    ii. Customer representative's name and title (if representative is different from Customer or if Customer is a business) and contact information.
    iii. Customer's valid, active utility account number.
    iv. Service account address, phone number on file with the Company, and such other information as necessary to verify eligibility.
    v. Battery, solar PV system, inverter, and other equipment specifications as required by the Company.
    vi. The Committed Capacity of the Battery.
    vii. Election to participate in the Summer Capability Period, Winter Capability Period, or both.
    viii. Authorization for access and use of Customer data and access and use of data from the Customer's battery, solar PV, inverter, site electric load, and such other related data necessary to facilitate Program participation.
    ix. Acknowledgement and agreement from the Customer that:
        1. The information submitted is accurate and complete.
        2. The Customer agrees to the terms and conditions of the Program.
        3. Such other information the Company deems necessary to enable participation in the program.

b. The Company will send email notification to the Customer within ten (10) days of receipt of a complete application and schedule the Verification Process within (5) days of date of the email notification.
    i. For incomplete applications, the Company shall notify the Customer via email within the initial ten (10) days following receipt of the application explaining the deficiencies and the steps required to correct each deficiency.
    ii. The Company shall send email notification of enrollment to the Customer within five (5) business days of receipt of a corrected application unless the application remains incomplete.

iii. The Company shall notify the Customer via email within (5) business days of receipt of a subsequently corrected but still incomplete application of any remaining deficiencies and the steps required to remedy each deficiency.

c. The Company will schedule the Verification Process with the Customer to complete a Test Event and provide performance data to verify Battery performance during the Test Event. The Company will notify the Customer via email within (5) days of successful completion of the Verification Process and confirm the Customer's enrollment as a Direct Participant.
   i. If the Customer does not successfully complete the Verification Process, the Company shall notify the Customer via email within five (5) days of receipt of the performance data from the Test Event explaining the cause(s) and the steps required to correct the issue(s).
   ii. The Company shall work with the Customer to schedule a subsequent Test Event within five (5) days of receiving email notification from the Customer that it has corrected the issues identified by the Company.

D. <u>OPERATION</u>

1. Participants deliver the Scheduled Peak Shaving service by discharging the Committed Capacity of their enrolled Batteries for [two] consecutive hours to reduce the daily system peak during the Capability Period. Each [two]-hour discharge period is defined as a Grid Event for the Scheduled Peak Shaving service.

2. At the time of enrollment, the Company will assign a start time for each enrolled Battery to align the [two-hour] Dispatch Window with the anticipated daily system peak over the course of the Capability Period. The Capability Period is defined as follows:

   a. <u>Summer Capability Period</u>. The Summer Capability Period runs from [June 1 to September 30]. The Company will assign each Customer a Dispatch Window between the hours of [5 and 9 pm] for the duration of the Summer Capability Period.
   b. <u>Winter Capability Period</u>. The Winter Capability Period runs from [December 1 to March 31]. The Company will assign each Customer a Dispatch Window between the hours of [5 and 9 pm] for the duration of the Winter Capability Period.

Distributed Power Plant Program

Battery Rider

System Peak Shaving: Scheduled Dispatch

3. The Participant ensures that enrolled Batteries are set to automatically discharge for [two] consecutive hours starting at the time assigned by the Company for each day during the applicable Capability Period.

4. The assigned Dispatch Window for each enrolled Battery will not change during a given Capability Period. The Company will provide [six months] written notice to Participants of any changes to the Capability Period or the Dispatch Window for a subsequent Capability Period.

E. PERFORMANCE MEASUREMENT, VERIFICATION & REPORTING

1. Performance is measured by directly metering at the device total Battery discharge during a Grid Event. Performance per Grid Event is equal to the average discharge rate of the Battery in kW_{AC} over the Dispatch Window. A separate meter shall not be required to measure Battery performance.

2. Performance in the Capability Period is equal to the average discharge rate over the Dispatch Window measured in kW_{AC} of the Battery during each Grid Event in the Capability Period ("Average Performance").

3. For the purpose of measuring performance during a Grid Event, energy discharged from a Battery may serve on-site load, export energy to the grid, or both.

4. If an Enrolled Customer's Battery does not perform during a Grid Event, or performance data for a Grid Event is not available, the Battery will have zero (0) kW_{AC} performance for that Grid Event.

5. Following the conclusion of a Capability Period, Participants shall make performance data available to the Company in the form of 15-minute interval data for each Grid Event during the Capability Period to verify performance and receive the Performance Payment. Aggregators may make performance data available for their fleet of Batteries in aggregate format.

F. COMPENSATION

1. Participants receive a one-time Upfront Payment and an ongoing Performance Payment.

Distributed Power Plant Program

Battery Rider

System Peak Shaving: Scheduled Dispatch

2. Upfront Payment: New Batteries are eligible for the one-time Upfront Payment based on the Committed Capacity provided at the time of enrollment. Existing Batteries are not eligible for the Upfront Payment. The currently applicable Upfront Payment rate is as follows:
    a. [$150 per kW] of Committed Capacity.
    b. [$300 per kW] of Committed Capacity for LMI Qualified Customers and Customers in Environmental Justice Communities.

3. Performance Payment: New and Existing Batteries are eligible for Performance Payments based on the average kW_{AC} discharged during each Grid Event averaged over the Capability Period ("Average Performance"). The Performance Payment is calculated as follows:
    a. Performance Payment Rate x Average Performance = Performance Payment. The current applicable Performance Payment Rate is as follows:
        i. [$275 per kW_{AC}-season during the Summer Capability Period.]
        ii. [$135 per kW_{AC}-season during the Winter Capability Period.]
    b. Enrolled Customers lock in the Performance Payment Rate applicable at the time of enrollment for five (5) years. At the end of the 5-year term, the Enrolled Customer may re-enroll at the then applicable Performance Payment Rate for a subsequent 5-year term.

4. Energy Exports: Enrolled Customers shall be credited for energy exported during Grid Events ("Grid Service Export Credits") at the retail rate at which the Company sells energy during the Grid Event, irrespective of the export credit rate specified in the Enrolled Customer's underlying Interconnection Tariff. Grid Service Export Credits shall be applied to the Customer's bill pursuant to Section G. Energy exports occurring outside of Grid Events ("Interconnection Rate Exports") shall be compensated at the export rate provided in, and credited to, the customer in accordance with the customer's underlying Interconnection Tariff ("Interconnection Rate Export Credits").

Distributed Power Plant Program

Battery Rider

System Peak Shaving: Scheduled Dispatch

G. METERING AND BILLING, PROGRAM PAYMENTS, AND BILL CREDITING SETTLEMENT

1. All rates, terms, and conditions from the Customer's applicable Base Service Tariff and Interconnection Agreement, as applicable, continue to apply, except as provided herein.

2. Participation in Scheduled Peak Shaving does not require an additional meter, advanced meter, or other AMI.

3. The Company shall issue the Upfront Payment to the Participant within fifteen (15) days of Customer enrollment, as provided in Section C.

4. The Company shall issue Performance Payments to Participants within fifteen (15) days of receipt of performance data from the Participant, as provided in Section E.

5. Grid Service Export Credits earned in a given month shall be applied to the Customer's bill at the same time as any Interconnection Rate Export Credits earned in the same month.

6. Grid Service Export Credits shall be applied to offset the same charges on the Customer's bill that Interconnection Rate Export Credits are applied to offset.

7. For Direct Participants who elect to receive the Performance Payment as a bill credit and who also receive Grid Service Export Credits, the Grid Service Export Credits shall be applied first to offset applicable bill charges. The Performance Payment bill credit will then be applied to offset any remaining charges. The Performance Payment bill credit shall be applicable to all remaining charges on the Customer bill, including charges to which the Grid Service Export Credit is not applicable.

8. At the end of their annual Program period, a Direct Participant may elect to (i) cash out any unused Grid Service Export Credits and any unused Performance Payment bill credits or (ii) carry the value of those credits over to apply to bill charges in the following year. Where such programs exist, the Direct Participant may donate all or a portion of unused Grid Service Export Credits or Performance Payment bill credits

to a Commission approved LMI customer assistance program.

9. At the end of their annual Program period, Enrolled Customers who participate through an Aggregator may elect to (i) cash out any unused Grid Service Export Credits or (ii) carry the value of those credits over to apply to bill charges in the following year. Where such programs exist, the Enrolled Customer may donate all or a portion of unused Grid Service Export Credits to a Commission approved LMI customer assistance program.

10. Grid Service Export Credits and Performance Payment bill credits shall not expire.

H. <u>CO-PARTICIPATION WITH OTHER PROGRAMS</u>

Enrolled Customers providing Scheduled Peak Shaving may co-participate in any applicable underlying Interconnection Tariff and may provide multiple Grid Services and/or co-participate in other Riders under the DPP Program, or other grid service programs outside the DPP Program, including wholesale market programs, except as otherwise provided by the Commission. Enrolled Customers shall remain eligible to receive state and federal incentives in addition to any compensation received for participating in the DPP Program.

I. <u>TERMINATION AND ASSIGNMENT</u>

1. An Enrolled Customer may terminate their participation in the Program at any time.

2. If an Enrolled Customer terminates participation prior to the conclusion of the 5-year rate lock term, the Customer must wait one (1) year before reenrolling to provide the System Peak Shaving service.

3. An Enrolled Customer may assign and transfer their Customer Agreement to a new Customer with written or digital notice provided thirty (30) days prior to the date of transfer without terminating the Customer Agreement or triggering the provisions of Subpart 2 of this Section.

Distributed Power Plant Program:

Battery Rider

System Peak Shaving: Remote Dispatch

A. PURPOSE

The System Peak Shaving Remote Dispatch ("Remote Peak Shaving") service pays Participants for providing capacity from enrolled Batteries to reduce demand on the grid during seasonal peak periods when requested by the Company.

B. ELIGIBILITY

1. Customers with new or existing Batteries may enroll to provide the Remote Peak Shaving through a Registered Aggregator or directly with the Company, where:

    a. The Customer has an active residential or commercial electric service account with the Company.
    b. The Battery is installed BTM at the Customer's premises pursuant to a valid Interconnection Agreement.
    c. The Customer or a third-party owns the Battery.
    d. The Battery is charged from a new or existing BTM Renewable Energy Generating Facility installed at the customer's premises that operates pursuant to a valid Interconnection Agreement with the Company.
    e. The Battery has metering accuracy of ANSI C-12.1-2008 or a specification rating with an accuracy of +/- 2.0%.
    f. The Customer executes the Customer Agreement provided in Appendix A.
    g. The Battery either participates through an Aggregator or is capable of communicating directly with the Company.

2. When a Customer participates through an Aggregator, the Aggregator is the Participant. When the Customer participates directly with the Company, the Customer is the Participant.

3. Remote Peak Shaving will remain open unless otherwise ordered by the Commission.

C. ENROLLMENT

1. Customers enroll in Remote Peak Shaving through a Registered Aggregator as follows:
    a. Customers submit to the Aggregator the following information:

Distributed Power Plant Program:

Battery Rider

System Peak Shaving: Remote Dispatch

i. Legal name of the Customer.
ii. Customer representative's name and title (if representative is different from Customer or if Customer is a business) and contact information.
iii. Customer's valid, active utility account number.
iv. Service account address, phone number on file with the Company, and such other information as necessary to verify eligibility.
v. Battery, solar PV system, inverter, and other equipment specifications as required by the Aggregator.
vi. The Committed Capacity of the Battery.
vii. Election to participate in the Summer Capability Period, Winter Capability Period, or both.
viii. Authorization for access and use of Customer information from the Company and access and use of data from the Customer's battery, solar PV, inverter, site electric load, and such other related data necessary to verify eligibility and performance of Enrolled Devices and otherwise facilitate Program participation.
ix. Acknowledgement and agreement from the Customer that:
    1. The information submitted is accurate and complete.
    2. The Customer agrees to the terms and conditions of the Program.
    3. Such other information the Aggregator deems necessary to enable participation in the program.

b. Aggregators may collect Customer information through a form provided by the Aggregator.
c. Upon completing the Aggregator's submission process, the Customer's Battery is enrolled in the Remote Peak Shaving and immediately eligible to participate as part of the Aggregator's fleet of enrolled Batteries.
d. Customers enrolled through an Aggregator are not required to complete an independent Verification Process.
e. Aggregators shall provide updated Enrolled Customer information to the Company as new Customers are enrolled and Enrolled Customers are disenrolled.
f. Aggregators shall retain Customer enrollment information, which may be reviewed by the [Commission] from time to time.

Distributed Power Plant Program:

Battery Rider

System Peak Shaving: Remote Dispatch

2. Customers enroll in Remote Peak Shaving directly with the Company as follows:

    a. Submit a Program Application directly to the Company with the following information in a form provided by the Company:
        i. Legal name of the Customer.
        ii. Customer representative's name and title (if representative is different from Customer or if Customer is a business) and contact information.
        iii. Customer's valid, active utility account number.
        iv. Service account address, phone number on file with the Company, and such other information as necessary to verify eligibility.
        v. Battery, solar PV system, inverter, and other equipment specifications as required by the Company.
        vi. The Committed Capacity of the Battery.
        vii. Election to participate in the Summer Capability Period, Winter Capability Period, or both.
        viii. Authorization for access and use of Customer data and access and use of data from the Customer's battery, solar PV, inverter, site electric load, and such other related data necessary to facilitate Program participation.
        ix. Acknowledgement and agreement from the Customer that:
            1. The information submitted is accurate and complete.
            2. The Customer agrees to the terms and conditions of the Program.
            3. Such other information the Company deems necessary to enable participation in the program.

    b. The Company will send email notification to the Customer within ten (10) days of receipt of a complete application and schedule the Verification Process within (5) days of date of the email notification.
        i. For incomplete applications, the Company shall notify the Customer via email within the initial ten (10) days following receipt of the application explaining the deficiencies and the steps required to correct each deficiency.
        ii. The Company shall send email notification of enrollment to the Customer within five (5) business days of receipt of

Distributed Power Plant Program:

Battery Rider

System Peak Shaving: Remote Dispatch

a corrected application unless the application remains incomplete.

iii. The Company shall notify the Customer via email within (5) business days of receipt of a subsequently corrected but still incomplete application of any remaining deficiencies and the steps required to remedy each deficiency.

c. The Company will schedule the Verification Process with the Customer to complete a Test Event. The Company will notify the Customer via email within (5) days of successful completion of the Verification Process and confirm the Customer's enrollment as a Direct Participant.

   i. If the Customer does not successfully complete the Verification Process, the Company shall notify the Customer via email within five (5) days of receipt of the performance data from the Test Event explaining the cause(s) and the steps required to correct the issue(s).

   ii. The Company shall work with the Customer to schedule a subsequent Test Event within five (5) days of receiving email notification from the Customer that it has corrected the issues identified by the Company.

D. OPERATION

1. Participants deliver the Remote Peak Shaving service by discharging the Committed Capacity of their enrolled Batteries for [two] consecutive hours in response to dispatch instructions received from the Company during the Capability Period. The [two]-hour Dispatch Window for each day the Company issues Remote Dispatch instructions is defined as a Grid Event for Remote Peak Shaving.

2. Batteries are discharged for [two] consecutive hours beginning at the start time specified in the dispatch instructions.

3. The Company will call Grid Events to target the highest seasonal system peak hour(s) and the forecasted monthly system peak hour(s) during the Capability Period. The Capability Period is defined as follows:

   a. Summer Capability Period. The Summer Capability Period runs from [June 1 to September 30]. The Company may call a Grid Event between the hours of [5 and 9 pm] on any day during the Summer Capability Period. The Company will call between [40

Distributed Power Plant Program:

Battery Rider

System Peak Shaving: Remote Dispatch

and 80] Grid Events, inclusive of Test Events, during the Summer Capability Period.

b. Winter Capability Period. The Winter Capability Period runs from [December 1 to March 31]. The Company may call a Grid Event between the hours of [5 and 9 pm] on any day during the Winter Capability Period. The Company will call between [20 and 40] Grid Events, inclusive of Test Events, during the Winter Capability Period.

4. For Aggregators, the Company will issue dispatch instructions [twenty-four (24) hours] before each Grid Event via the Aggregator's selected communication protocol. The Aggregator will communicate directly with its Batteries to manage Battery performance during the Grid Event. An Enrolled Customer may opt-out of a Grid Event by notifying the Aggregator in the manner prescribed by the Aggregator.

5. For Direct Participants, the Company will notify the Customer within [twenty-four (24) hours] before each Grid Event or Test Event via the communication protocol elected by that Direct Participant. The Company will directly communicate with the Customer's Battery for dispatch during the Grid Event or Test Event. A Direct Participant may opt-out of a Grid Event by notifying the Company in the manner prescribed by the Company.

6. The start and end time of the Dispatch Window is subject to change for any individual Grid Event or Test Event, as applicable, but will always occur within the hours provided in subpart 3 of this Section during the Capability Period. The Company will provide [six months] written notice of any changes to the provisions of this Section for a subsequent Capability Period.

7. The Company will make reasonable attempts to not call a Grid Event or Test Event within 48 hours of major storms reasonably anticipated to cause widespread system outages.

E. PERFORMANCE MEASUREMENT, VERIFICATION & REPORTING

1. Performance is measured by directly metering at the device total Battery discharge during a Grid Event. Performance per Grid Event is equal to the average discharge rate of the Battery in kW_{AC} during the

Distributed Power Plant Program:

Battery Rider

System Peak Shaving: Remote Dispatch

Dispatch Window. A separate meter shall not be required to measure Battery performance.

2. Performance in the Capability Period is equal to the average discharge rate measured in kW_{AC} of the Battery over the Dispatch Window averaged over all Grid Events in the Capability Period ("Average Performance").

3. For the purpose of measuring performance during a Grid Event, energy discharged from a Battery may serve on-site load, export energy to the grid, or both.

4. If an Enrolled Customer's Battery does not perform during a Grid Event, or performance data for a Grid Event is not available, the Battery will have zero (0) kW_{AC} performance for that Grid Event.

5. Following the conclusion of a Capability Period, Participants shall make performance data available to the Company in the form of 15-minute interval data for each Grid Event during the Capability Period to verify performance and receive the Performance Payment. Aggregators may make performance data available for their fleet of Batteries in aggregate format.

F. <u>COMPENSATION</u>

1. Participants receive a one-time Upfront Payment and an ongoing Performance Payment.

2. Upfront Payment: New Batteries are eligible for the one-time Upfront Payment based on the Committed Capacity provided at the time of enrollment. Existing Batteries are not eligible for the Upfront Payment. The currently applicable Upfront Payment rate is as follows:
   a. [$150 per kW] of Committed Capacity.
   b. [$300 per kW] of Committed Capacity for LMI Qualified Customers and Customers in Environmental Justice Communities.

3. Performance Payment: New and Existing Batteries are eligible for Performance Payments based on the average kW_{AC} discharged during each Grid Event averaged over the Capability Period ("Average Performance"). The Performance Payment is calculated as follows:

Distributed Power Plant Program:

Battery Rider

System Peak Shaving: Remote Dispatch

a. Performance Payment Rate x Average Performance = Performance Payment. The current applicable Performance Payment Rate is as follows:
    i. [$275 per kW_{AC}-season during the Summer Capability Period.]
    ii. [$135 per kW_{AC}-season during the Winter Capability Period.]
b. Enrolled Customers lock in the Performance Payment Rate applicable at the time of enrollment for five (5) years. At the end of the 5-year term, the Enrolled Customer may re-enroll at the then applicable Performance Payment Rate for a subsequent 5-year term.

4. Energy Exports: Enrolled Customers shall be credited for energy exported during Grid Events (“Grid Service Export Credits”) at the retail rate at which the Company sells energy during the Grid Event irrespective of the export credit rate specified in the Enrolled Customer’s underlying Interconnection Tariff. Grid Service Export Credits shall be applied to the Customer’s bill pursuant to Section G. Energy exports occurring outside of Grid Events (“Interconnection Rate Exports”) shall be compensated at the export rate provided in, and credited to, the customer in accordance with the customer’s underlying Interconnection Tariff (“Interconnection Rate Export Credits”).

G. METERING AND BILLING, PROGRAM PAYMENTS, AND BILL CREDITING SETTLEMENT

1. All rates, terms, and conditions from the Customer’s applicable Base Service Tariff and Interconnection Agreement, as applicable, will apply except as provided herein.

2. Participation in Remote Peak Shaving does not require an additional meter, advanced meter, or AMI.

3. The Company shall issue the Upfront Payment to the Participant within fifteen (15) days of Customer enrollment, as provided in Section C.

4. The Company shall issue Performance Payments to Participants within fifteen (15) days of receipt of performance data from the Participant, as provided in Section E.

5. Grid Service Export Credits earned in a given month shall be applied to the Customer's bill in the subsequent month and at the same time as any Interconnection Rate Export Credits earned in the same month.

6. Grid Service Export Credits shall be applied to offset the same charges on the Customer's bill that Interconnection Rate Export Credits are applied to offset.

7. For Direct Participants who have elected to receive the Performance Payment as a bill credit and who also receive Grid Service Export Credits, the Grid Service Export Credits shall be applied first to offset applicable bill charges. The Performance Payment bill credit will then be applied to offset any remaining charges. The Performance Payment bill credit shall be applicable to all remaining charges on the Customer bill, including charges to which the Grid Service Export Credit is not applicable.

8. At the end of the annual Program period, a Direct Participant may elect to (i) cash out any unused Grid Service Export Credits and any unused Performance Payment bill credits or (ii) carry the value of those credits over to apply to bill charges in the following year. Where such programs exist, the Direct Participant may donate all or a portion of unused Grid Service Export Credits or Performance Payment bill credits to a Commission approved LMI customer assistance program.

9. At the end of their annual Program period, Enrolled Customers who participate through an Aggregator may elect to (i) cash out any unused Grid Service Export Credits or (ii) carry the value of those credits over to apply to bill charges in the following year. Where such programs exist, the Enrolled Customer may donate all or a portion of their unused Grid Service Export Credits to a Commission approved LMI customer assistance program.

10. Grid Service Export Credits and Performance Payment bill credits shall not expire.

H. CO-PARTICIPATION WITH OTHER PROGRAMS

Enrolled Customers providing Remote Peak Shaving may co-participate in any applicable underlying Interconnection Tariff and may provide multiple Grid Services and/or co-participate in other Riders under the DPP Program, or other grid service programs outside the DPP Program, including wholesale market programs, except as otherwise provided by the Commission. Enrolled Customers shall remain eligible to receive state and federal incentives in addition to any compensation received for participating in the DPP Program.

I. <u>TERMINATION AND ASSIGNMENT</u>

1. An Enrolled Customer may terminate their participation in the Program at any time.

2. If an Enrolled Customer terminates their participation prior to the conclusion of the 5-year rate lock term, the Customer must wait one (1) year before reenrolling to provide the System Peak Shaving service.

3. An Enrolled Customer may assign and transfer their Customer Agreement to a new Customer with written or digital notice provided thirty (30) days prior to the date of transfer without terminating the Customer Agreement or triggering the provisions of Subpart 2 of this Section.

Distributed Power Plant Program: Non-Battery Rider

[Service and Dispatch Protocol]

Distributed Power Plant Program:
Electric Vehicle Rider

[Service and Dispatch Protocol]

APPENDIX A

CUSTOMER AGREEMENT

APPENDIX [X]

AGGREGATOR REGISTRATION

STATE OF MICHIGAN
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-21860

DIRECT TESTIMONY OF

CURT VOLKMANN

ON BEHALF OF

THE ECOLOGY CENTER, ENVIRONMENTAL LAW & POLICY CENTER, UNION OF CONCERNED SCIENTISTS, AND VOTE SOLAR

August 22, 2025

Table of Contents

I. INTRODUCTION AND PURPOSE OF TESTIMONY

Q: PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND CURRENT POSITION.

A: My name is Curt Volkmann. My business address is 1400 Waterview Way, Lake Geneva, Wisconsin, 53147. I am President and founder of New Energy Advisors, LLC.

Q: PLEASE SUMMARIZE YOUR EDUCATION AND PROFESSIONAL EXPERIENCE.

A: I have a BS in Electrical Engineering from the University of Illinois with a concentration in Electrical Power Systems. I also have an MBA from the University of California at Berkeley with a concentration in Finance. I have 41 years of experience in the utilities industry, primarily in electric transmission and distribution. My work experience includes nine years at Pacific Gas & Electric in various transmission and distribution engineering roles, and eighteen years at Accenture with several positions including Executive Director in the North American Utilities practice. Since 2015, I have worked independently and supported clients in various distribution planning and grid modernization regulatory proceedings across the United States. Ex. CEO-6 provides a statement of my qualifications and experience.

Q: HAVE YOU PREVIOUSLY TESTIFIED OR COMMENTED BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION ("COMMISSION" OR "MPSC")?

A: Yes. I have testified before the MPSC in Case Nos. U-17752 and U-21534 and contributed to comments in Case Nos. U-20147 and U-21305. I have also testified and commented before regulatory commissions in fourteen other states. Ex. CEO-7 provides a summary of my prior testimony and contributions to comments.

Q: ON WHOSE BEHALF ARE YOU SUBMITTING TESTIMONY?

A: I am submitting testimony on behalf of the Ecology Center, Environmental Law & Policy Center, Union of Concerned Scientists, and Vote Solar (collectively, the Clean Energy Organizations ("CEO")).

Q: ARE YOU SPONSORING ANY EXHIBITS?

A: Yes. I am sponsoring the following exhibits:

- Exhibit CEO-6: Qualifications and Experience of Curt Volkmann
- Exhibit CEO-7: Prior Testimony and Comments of Curt Volkmann
- Exhibit CEO-8: DTE response to DR MNSCDE-1.7
- Exhibit CEO-9: DTE response to DR CEODE-4.4
- Exhibit CEO-10: DTE response to DR MNSCDE-7.1c
- Exhibit CEO-11: DTE response to DR ABDE-2.28a
- Exhibit CEO-12: DTE response to DR CEODE-6.1
- Exhibit CEO-13: DTE response to DR CEODE-4.1ai
- Exhibit CEO-14: DTE response to DR CEODE-4.1aiv
- Exhibit CEO-15: DTE response to DR CEODE-1.3b
- Exhibit CEO-16: DTE response to DR CEODE-1.4
- Exhibit CEO-17: DTE response to DR CEODE-1.5
- Exhibit CEO-18: DTE response to DR STDE-3.28.a
- Exhibit CEO-19: DTE response to DR CEODE-4.1aii
- Exhibit CEO-20: DTE response to DR CEODE-4.2b

Q: WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A: My testimony is in response to the application of the DTE Electric Company ("DTE" or "Company") before the MPSC for authority to increase its rates. In my testimony, I provide perspectives on DTE's:

- Responsiveness and transparency in this proceeding.
- Distribution system condition and strategy.
- Approach to Benefit-Cost Analyses ("BCAs").
- Pole and Pole-Top Maintenance and Modernization ("PTMM"), Distribution Automation ("DA"), and Substation Redesign and Rebuild ("SRR") programs.
- Proposed Infrastructure Recovery Mechanism ("IRM")[1] extension from 2027-2029.

II. DTE'S OVERALL RESPONSIVENESS AND TRANSPARENCY

Q: HAS DTE BEEN TRANSPARENT AND RESPONSIVE IN THIS PROCEEDING?

A: Yes. Similar to our experience with DTE last year in Case No. U-21534, the Company continues to be very engaged, transparent and responsive to CEO inquiries. Our virtual and in-person interactions with DTE over the last ten months have included:

- A Teams call on November 8, 2024, to discuss the recommendations from the 2024 Liberty Consulting Audit ("Audit", "Liberty Audit", or "Audit Report")[2] and DTE's responses.

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[1] In Case No. U-21297, DTE witness Neal T. Foley explained in direct testimony that an IRM is a regulatory tool that allows a utility to recover the costs associated with certain capital investments between rate cases through a customer IRM surcharge.

[2] Case No. U-21305, Liberty Consulting Group Utility Distribution Audit of DTE Electric, September 23, 2024.

- An in-person meeting in Westland, MI on November 22, 2024, to tour DTE's Technical and Development Center and conduct a field visit of neighborhoods with 4.8kV circuits. This visit provided an opportunity to see first-hand the condition of DTE's 4.8kV distribution system and its associated challenges.
- A preview of the Company's U-21860 rate case filing via a Teams call on March 3, 2025.
- In-person meetings on May 29, 2025, in Clarkston, MI to tour the Company's PTMM Training Yard, and the Waterford Service Center to discuss initial CEO questions about the rate case filing. Among other insights, this visit allowed the CEO to better understand DTE's PTMM program strategy and methods.
- A Teams call on July 18, 2025, to discuss additional CEO questions about the current rate case application.

As in Case No. U-21534, DTE fully disclosed its Global Prioritization Model ("GPM")[3] and Reliability Model[4] in this proceeding. I also feel that DTE has been thorough and responsive to the voluminous data requests it has received.

Q: HAS DTE BEEN TRANSPARENT WITH ITS BCA IN THIS PROCEEDING?

A: Yes. The Company and its BCA consultant 1898 & Co. have been very transparent and responsive. The CEO had a 1-hour Teams call with 1898 & Co. on June 4, 2025, to discuss some initial BCA questions. 1898 & Co. subsequently hosted two technical conferences

[3] The GPM is the tool DTE uses to prioritize investments by ranking projects and programs based on the benefits the project or program delivers for a given level of investment. (Direct Testimony of Allen J. Kryscynski ["Kryscynski"] at AJK-17:11-14).

[4] DTE's Reliability Model calculates expected circuit-level reliability improvement based on historical performance and the impact of planned investments on each circuit, then sums the projected performance of all circuits to provide a system level reliability improvement projection. (Kryscynski at AJK-33:15-18).

(7.5 hours on June 11, 2025, 3 hours on June 26, 2025) to explain the BCA methodologies and to answer questions from the CEO and other stakeholders. 1898 & Co. also joined the CEO's July 18, 2025, Teams call with DTE to further explain the BCA analysis. For the most part, I found 1898 & Co.'s responses to the numerous questions and data requests to be thoughtful, thorough, and credible.

Q: HAS DTE BEEN RESPONSIVE TO RECOMMENDATIONS FROM THE LIBERTY AUDIT?

A: Yes. In this proceeding, DTE witnesses Chiu, Hill, Kryscynski, Rademacher, Robinson, Steudle, and Stowe directly respond to recommendations from the Liberty Audit.

III. DTE'S DISTRIBUTION SYSTEM AND STRATEGY

Q: PLEASE DESCRIBE THE STATE OF DTE'S DISTRIBUTION SYSTEM.

A: Significant portions of DTE's distribution system are very old, fragile, hazardous, and difficult to access. For example:

- 28% of distribution poles were installed before 1960.
- 24% of substation transformers were installed before 1970.
- Half of the conductors with known ages date back to before 1970.
- 52% of circuit breakers and reclosers were installed before 1980, with a few dating as far back as the 1930s.[5]

The preponderance of 4.8kV distribution construction on DTE's system poses unique challenges. The Company explains, "[a]pproximately 19,000 miles, or 45% of the Company's approximately 42,000 miles of distribution infrastructure, is composed of aged

[5] Audit Report, Part One at 10.

4.8kV lines that were primarily constructed between 1930 and 1965 and pose significant operational and safety challenges."[6]

The technical configuration of DTE's 4.8kV system is particularly problematic as energized down wires are common. The Company explains, "Any wiredown on the system has the potential to be energized and is treated as such when considering the necessary protections to complete restoration. However, because of the original design of the 4.8kV delta ungrounded system, a wiredown will not generate sufficient fault current to open a protective device. Therefore, all 4.8kV, non-phase-to-phase, wiredowns that are connected to a source may remain energized."[7]

The Audit Report noted this unique characteristic of the Company's system, stating, "[t]he predominance of ungrounded 4.8kV circuits on (DTE's) system is extraordinary."[8] Additionally, the auditors observed that they, "know of no other utility with so large a portion of its system composed of ungrounded 4.8kV distribution circuits."[9]

Q: HOW COMMON ARE WIREDOWNS ON DTE'S 4.8KV SYSTEM?

A: The Company states, "[o]ver the last 5 years, there have been an average of approximately 14,000 wiredowns (per year) on the 4.8kV system."[10]

1898 & Co. states that wiredowns on the DTEE's 4.8kV system that remain energized pose a "life-threatening risk to the general public."[11] As I will explain, the Company has determined that the installation of reclosers on its 4.8kV system can mitigate this risk and I recommend accelerated deployment of this equipment.

[6] Direct Testimony of Bill Chiu ("Chiu") at BC-10:5-8.
[7] Ex. CEO-8, DTE response to DR MNSCDE-1.7.
[8] Audit Report, Part Two at 67.
[9] Audit Report, Part Two at 118.
[10] Ex. CEO-8-, DTE response to DR MNSC 1.7.
[11] Exhibit A-28, Schedule R3 ("1898 & Co. Report") at p. 100 of 135.

Q: WHY ARE PORTIONS OF DTE'S DISTRIBUTION SYSTEM DIFFICULT TO ACCESS?

A: The Company explains, "[i]n most neighborhoods, the 4.8kV system was constructed in rear lot right-of-way for aesthetic reasons since it utilized overhead poles and wires. Initially, right-of-way truck access was readily available through municipally maintained alleys in many areas, including much of Detroit. Much of this right-of-way truck access is no longer as readily available due to alley maintenance abandonment."[12]

Today, DTE estimates that only 51% of poles have street access,[13] which prolongs the time to locate and repair damage to the system, perform tree trimming, and conduct other maintenance work.

Q: HOW HAS DTE'S SYSTEM CONDITION IMPACTED ITS RELIABILITY?

A: From 2019 to 2023, DTE's all-weather outage duration was in the 4th quartile (worst) compared to industry peers in four of the five years. DTE's all-weather outage frequency was in the 2nd or 3rd quartile all five years.[14] Reducing the duration of customer outages is a primary challenge for DTE.

Q: HOW IS DTE RESPONDING TO THESE CHALLENGES?

A: After a period of relative underinvestment (2005-2007), DTE's distribution capital spending has increased significantly since 2017 compared to peer utilities. Figure 1 below provides a comparison of DTE's distribution capital additions per customer over the last 30 years (adjusted for inflation) compared to a peer group of mostly urban utilities with

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[12] Direct Testimony of Ryan M. Stowe ("Stowe") at RMS-15:6-10.
[13] 1898 & Co. Report at 41 of 135.
[14] Case No. U-21534, Direct Testimony of Allen J. Kryscynski at AJK-19:1-9.

more than 500,000 customers serving major cities in the rust belt.[15] The comparative analysis of DTE's spending compared to peer utilities was conducted by (and discussed in more detail) in the testimony of CEO Witness Boratha Tan.[16]

Figure 1 - Distribution Capital Additions per Customer ($2024)[17]

Q: WHAT ARE THE RESULTS OF DTE'S RECENT EXPENDITURES?

A: DTE's recent capital investments and less extreme weather resulted in a nearly 70% decrease in outage duration between 2023-2024. Compared to the 2019-2023 average, outage frequency decreased by 14% and outage duration decreased by 38% in 2024.[18]

[15] Utilities included in the peer group are Columbus Southern/Ohio Power (Columbus), Commonwealth Edison (Chicago), Duquesne Light (Pittsburgh), The Illuminating Company (Cleveland), Indianapolis Power & Light (Indianapolis), Northern States Power - MN (Minneapolis/St. Paul), PECO (Philadelphia), and Wisconsin Electric Power Co. (Milwaukee).
[16] Direct Testimony of Boratha Tan at 4-19.
[17] *Id.* at 8.
[18] Chiu at BC-11:12-17.

Q: WHAT IS DTE'S STRATEGY IN THIS PROCEEDING?

A: DTE plans to continue its significant distribution and subtransmission modernization investments[19] to:

1) Improve safety.
2) Reduce outage frequency by 30% and outage duration by 50% by 2029.[20]
3) Increase system capacity for future load and DER growth.

The Company is increasingly providing BCAs for its major spending programs to demonstrate cost effectiveness. Finally, DTE is seeking to increase certainty of cost recovery by extending its distribution IRM.

Q: WHAT DO YOU CONCLUDE ABOUT DTE'S OVERALL APPROACH?

A: As the Company ramps up spending to achieve its objectives, it is more important than ever that DTE supports its proposed investments with credible BCAs demonstrating that customer benefits exceed customer costs. As I will explain, I am concerned that the Company's BCAs in this proceeding do not fully reflect the potential customer costs. I will also address the need for DTE to re-prioritize its DA investments to more quickly address the safety issues on its 4.8kV system.

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[19] DTE categorizes its strategic distribution and subtransmission investments across four "pillars": 1) Tree Trimming, 2) Infrastructure Resilience and Hardening, 3) Infrastructure Redesign and Modernization, and 4) Technology and Automation.

[20] Direct Testimony of Marco A. Bruzzano at MAB-6:25 – MAB-7:1.

IV. DTE'S BENEFIT-COST ANALYSIS (BCA) METHODOLOGIES

Q: WHAT IS THE SCOPE OF DTE'S BCAS IN THIS PROCEEDING?

A: The Company hired consulting firm 1898 & Co. to develop BCAs for PTMM, DA, Strategic Undergrounding, and Grid Automation Telecommunications. My testimony is limited to a discussion of the PTMM and DA BCAs.

Q: PLEASE PROVIDE A HIGH-LEVEL OVERVIEW OF THE BCA METHODOLOGIES.

A: 1898 & Co. applied rigorous and sophisticated methodologies that integrate information from DTE's outage management system, customer information system, geographic information system, asset registers, and historical inspection records.[21] The methodologies compare the monetized benefits of a planned investment on each circuit with the initial capital cost plus future O&M. For each investment program and circuit/substation, the methodologies calculate a benefit-cost ratio ("BCR") where a BCR greater than 1 means that customer benefits exceed customer costs. I will further describe the PTMM and DA BCA methodologies later in my testimony.

Q: WHAT CUSTOMER BENEFITS ARE INCLUDED IN THE BCA METHODOLOGIES?

A: The BCA methodologies include the customer benefits of avoided or reduced reactive costs (i.e., costs incurred to restore service and repair equipment after an outage) and avoided customer outage costs.

[21] Direct Testimony of Jason D. De Stigter ("De Stigter") at JDDS-11:14-19.

Q: HOW DO THE METHODOLOGIES QUANTIFY AVOIDED CUSTOMER OUTAGE COSTS?

A: The methodologies rely on the original version of the Department of Energy's Interruption Cost Estimator ("ICE") Calculator to quantify the economic value of avoided customer outage costs. The ICE Calculator is commonly used by electric utilities for this purpose.

Lawrence Berkeley National Laboratory and Resource Innovations recently partnered with several utilities (including DTE) to refresh the underlying data in the tool and to provide an enhanced version with new features ("ICE 2.0").[22] While ICE 2.0 was released after DTE's BCAs had been performed in this proceeding, DTE has confirmed that it will use ICE 2.0 in future rate cases and grid plan proceedings.[23]

Q: ARE THERE BENEFITS NOT INCLUDED IN THE BCA METHODOLOGIES?

A: Yes. 1898 & Co.'s methodologies do not include the difficult-to-quantify benefits of improved safety or reduced cyber-security risks.[24]

Q: DO YOU HAVE CONCERNS ABOUT THE BCA METHODOLOGIES?

A: Yes. I'm concerned that the methodologies do not incorporate the full customer costs of DTE's planned investments. The methodologies include DTE's direct and indirect capital and O&M costs but do not reflect the full revenue requirements (which also include financing costs and taxes).[25] 1898 & Co. explains the exclusion by stating that it uses an "economic model" rather than a "financial model,"[26] a distinction I don't fully understand.

[22] https://icecalculator.com/.
[23] Ex. CEO-9; DTE response to DR CEODE-4.4.
[24] De Stigter at JDDS-11:1-5.
[25] Ex. CEO-10, DTE response to DR MNSCDE-7.1c.
[26] Ex. CEO-11, DTE response to DR ABDE-2.28a.

As I recommended in Case No. U-21534,[27] I again recommend that DTE reflect the full revenue requirements of its planned investments in future BCAs.

As I will explain later in my testimony, I am also concerned that the BCAs do not reflect any potentially significant future cost escalations for labor and materials.

V. POLE AND POLE-TOP MAINTENANCE AND MODERNIZATION (PTMM)

Q: PLEASE PROVIDE A BRIEF DESCRIPTION OF DTE'S OVERHEAD SYSTEM AND PTMM PROGRAM.

A: DTE has approximately 31,000 miles of overhead distribution and subtransmission lines consisting of over one million wood poles and associated pole-top equipment.[28] Utility poles have an expected useful life expectancy of 40-50 years with an increased risk of failure as they age beyond their useful life.[29] 46% of DTE's poles are >50 years old.[30]

DTE's PTMM program involves inspecting all wood poles and pole-top equipment on distribution and subtransmission overhead circuits, and replacing any that fail inspection with stronger, higher-class poles and upgraded pole-top materials to improve reliability, resilience, and safety.[31] The Company currently inspects poles and pole-tops every 20-30 years[32] but is aiming to conduct pole-top inspections on a 5-year cycle and pole inspections every 10 years.[33] If the Commission approves PTMM funding as requested by DTE in this proceeding, the Company anticipates achieving the 5- and 10-year cycles by 2029.[34]

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[27] Case No. U-21534, Direct Testimony of Curt Volkmann at 17:8-11.
[28] Such equipment includes overhead transformers, crossarms, insulators, lightning arrestors, and fused cutouts. See U-21860 Exhibit A-23, Schedule M10 for a full description of DTE's pole-top equipment.
[29] Direct Testimony of Joseph E. Robinson ("Robinson") at JER-20:7-11.
[30] *Id.* at JER-21:2.
[31] *Id.* at JER-19:6-18.
[32] Audit Report, Part Two at 33.
[33] Robinson at JER-23:5-7.
[34] *Id.* at JER-29:17-20.

Q: HAS THE COMMISSION PREVIOUSLY ADDRESSED DTE'S PTMM PROGRAM?

A: Yes. DTE first proposed 5- and 10-year PTMM cycles in Case No. U-21534 and supported the proposal with an initial PTMM BCA. The Commission viewed this favorably, stating "DTE Electric aspires to implement a 5-year cycle for pole-tops and a 10-year cycle for poles, which includes inspection and construction. The Commission supports these work activities . . . . In the company's next rate case, the Commission expects to see progress in DTE Electric's goal of reaching the 5-year and 10-year cycles, utilizing the reliability tier model and BCA output, to select the optimal mix of circuits to improve customer reliability."[35]

Q: DID THE AUDIT ADDRESS DTE'S PTMM PROGRAM?

A: Yes. The Audit Report is critical of DTE's current overhead inspection program, stating "DTE does not conduct the four- to five-year visual overhead circuit inspection program cycles its benchmarking and our experience demonstrate as typical. The current 20-year PTMM cycle falls well outside the range of good practice. DTE's 2023 plans did not even meet the level of work needed to sustain a 20-year cycle. The planned 1,000 circuit miles for 2023 better reflected a 30- year duration."[36]

The Audit Report recommends that DTE "[a]dopt a four- to five-year visual overhead inspection program, focusing on securing visual control of the system and adjusting repair/replacement scope in the first cycle to account for what can be expected to be very high first-cycle costs."[37]

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[35] Case No. U-21534, Commission Order, January 23, 2025 at 108 (internal quotations omitted).
[36] Audit Report, Part Two at. 40.
[37] *Id.* at 43.

Q: PLEASE PROVIDE AN OVERVIEW OF DTE'S APPROACH TO THE PTMM BCA.

A: The approach used by 1898 & Co. for the PTMM BCA[38] calculates the benefits of replacing existing infrastructure. It forecasts the probability-weighted consequence of failure for a range of failure types based on how assets fail over their lifecycle, including inspection-based failures. Consequences include restoration costs and the monetization of customer outages (using the ICE Calculator) in the event of an asset failure.

The approach calculates each asset's lifecycle restoration costs and customer outage costs for two scenarios. The first is a Status Quo scenario where the asset is not proactively replaced; the second is the Investment scenario in which the asset is upgraded proactively to the new equipment standard. The benefit of replacing infrastructure is the difference between the two scenarios.[39]

Q: WHAT ARE THE RESULTS OF THE PTMM BCA?

A: For pole inspections, 2,703 of 3,108 (86%) distribution and subtransmission circuits have BCRs greater than 1. The expected avoided customer-minutes of interruption ("CMI") percentage for all beneficial projects averaged 11%, ranging from 9% to 14%.[40]

For pole-top inspections, 82% of circuits have BCRs greater than 1. The expected avoided CMI for beneficial projects averaged 9% and ranged from 5% to 10%.[41]

Q: WHAT IS DTE REQUESTING FOR PTMM IN THIS PROCEEDING?

A: The Company explains, "The PTMM program is currently funded, in 2025, with approximately $121 million, which will cover approximately 1,200 miles of both pole-top

[38] 1898 & Co. refers to this approach as its Equipment Failure Mitigation Model.
[39] De Stigter at JDDS-11:23 – JDDS-12:14.
[40] *Id.* at JDDS-21:23 – JDDS-22:6.
[41] *Id.* at JDDS-22:11-16.

and groundline pole maintenance. In the instant case, the Company is requesting an increase to $200 million for 2026. To fund pole-top and groundline pole maintenance on the 5-year and 10-year cycles,[42] … The forecast of required investment beyond 2026 is:

- 2027: $263.4 million
- 2028: $376.8 million
- 2029: $482.6 million

This reflects the full expected capital investment for the PTMM program from 2027 to 2029."[43] As I will discuss later, DTE is requesting IRM treatment for PTMM beginning in 2027.

Q: DO YOU AGREE WITH THIS REQUEST?

A: I understand the Company's rationale for the request, but I am concerned that DTE may be significantly underestimating the total investment required to achieve its desired 5- and 10-year PTMM cycles. Specifically, I am concerned that DTE has not accounted for the possibility of significant cost escalations for labor and materials over the next several years.

Q: HAS THE COMPANY RECENTLY EXPERIENCED SIGNIFICANT LABOR COST ESCALATIONS?

A: Yes. DTE explained, "[t]he Company has experienced an upward trend in both DTE Electric labor and contract labor costs … Using 2019 as the base year, cumulative contract labor rate escalations for underground, overhead, and tree trim labor resources have been 18%, 31% and 34%, respectively."[44]

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[42] Robinson at JER-29:9-13.
[43] *Id.* at JER-34:4-9.
[44] Direct Testimony of Brian L. Hill ("Hill") at BLH-11:3-10.

Q: HAS THE COMPANY RECENTLY EXPERIENCED SIGNIFICANT MATERIAL COST ESCALATIONS?

A: Yes. DTE stated, "The Company has experienced substantial material increases on all major commodities (e.g., transformers, poles, conductors, etc.) over the five-year period of 2020-2024."[45] Table 1 below summarizes DTE's recent cost escalations for common materials.

	% Change in Cost (2020-2024)
Overhead transformers	318%
Wood poles	114%
Fused cutouts	47%
Insulators	43%
Overhead conductor	40%
Overhead crossarms	36%

Table 1 – DTE's Material Cost Escalations[46]

Q: ARE THESE RECENT MATERIAL COST ESCALATIONS OCCURING ACROSS THE UTILITIES INDUSTRY?

A: Yes. As CEO witness Boratha Tan explains, the Producer Price Index for manufacturers of electric power distribution equipment has increased by 26.2% from 2020-2024.[47]

Q: HAS DTE REFLECTED SUCH SIGNIFICANT LABOR OR MATERIAL COST ESCALATIONS IN ITS PTMM ANALYSIS?

A: No. For determining the amount of spending required to establish the desired 5- and 10-year PTMM cycles, DTE used a 3.1% inflation rate from 2025-2026, and 2.2% per year

[45] Hill at BLH-11:17-BLH-12:1.
[46] Hill at BLH-12, Table 1.
[47] Direct Testimony of Boratha Tan at 19.

thereafter.[48] The Company explained, “This adjustment reflects a general consideration of cost trends, including inflationary impacts, rather than specific historical material cost increases.”[49] For the PTMM BCA, 1898 & Co. used a 2.5% annual escalation rate for labor and materials.[50]

Q: WHAT DO YOU RECOMMEND?

A: I acknowledge that there is significant uncertainty about the future cost of labor and materials (e.g., the impact of tariffs), and any increases are very difficult to predict with any precision. However, based on DTE’s recent experience and what’s occurring across the industry, it is reasonable to assume that there will likely be labor and material cost escalations higher than 2-3% per year over the next several years.

I recommend that DTE, in its rebuttal testimony, include a sensitivity analysis[51] on the impact of potential increases to wood pole, pole-top component, and labor costs. For example, DTE’s sensitivity analysis could provide answers to questions such as:

- What is the total amount of investment required to achieve the desired 5- and 10-year PTMM cycles, and which circuits have PTMM benefits in excess of costs if, over the next four years:
    - Wood pole costs increase by 25% or 100%?
    - Overhead transformer costs increase by 25% or 100%?
    - PTMM labor costs increase by 10% or 30%?

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[48] Ex. CEO-12, DTE response to DR CEODE-6.1.
[49] Ex. CEO-13, DTE responses to DRs CEODE-4.1ai and Ex. CEO-14; CEODE-4.1aiv.
[50] 1898 & Co. Report at 10 of 135.
[51] A sensitivity analysis is a method to determine how changes in variables impact an outcome based on a given set of assumptions and is often used to answer “what if” questions under conditions of uncertainty.

VI. DISTRIBUTION AUTOMATION (DA)

Q: PLEASE EXPLAIN THE SCOPE OF THE COMPANY'S DA PROGRAM.

A: DTE's Distribution Automation Program is primarily focused on the installation of two categories of pole-top reclosers:

> ***Reliability Reclosers*** - Supervisory Control and Data Acquisition ("SCADA") enabled reclosers on larger circuits with more than 400 customers to enable, at a minimum, one midline recloser and a SCADA enabled tie point; and reclosers near the start of 13.2 kV circuits that currently do not have SCADA enabled circuit breakers in the substation.[52] Reclosers installed at midpoints on a circuit will operate when a fault is detected and isolate the outage to smaller area, impacting fewer customers. Reclosers installed at a tie point on the end of a circuit provide the ability to reconfigure circuits and reroute power around damaged sections by connecting to adjacent circuits. These devices also provide circuit-level SCADA monitoring and control to the System Operations Center.[53]
>
> ***Safety Reclosers*** - Reclosers near the start of the overhead portion of all ungrounded 4.8 kV circuits to enable ground detection and isolation.[54] A ground on a 4.8 kV delta circuit is a potential indicator of an energized wiredown condition that could pose a safety hazard to the public. Currently, when a ground alarm appears on a circuit, DTE dispatches an operator to the substation to manually identify which circuit has a ground, then sends a field crew to locate the ground and isolate. With the ability to automatically identify this condition, the potential hazard can be detected and deenergized much more quickly and efficiently through automated isolation, quickly eliminating the risk associated with the downed wire.[55]

Q: HAS THE COMMISSION PREVIOUSLY ADDRESSED DTE'S DA PROGRAM?

A: Yes. In its Case No. U-21534 Order, the Commission stated that it "finds persuasive the company's rebuttal testimony … (regarding) the significant benefits of DA (i.e., offering measurable safety benefits, notably in terms of ground detection to detect and isolate grounds mitigating potential safety hazards; improving reliability; and shortening the

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[52] Direct Testimony of Stephen P. Rademacher ("Rademacher") at SPR-18:18 – SPR-19:3.
[53] *Id*. at SPR-19:23 – SPR-20:7.
[54] *Id.* at SPR-18:22 – SPR-19:1.
[55] *Id.* at SPR-19:7-16.

duration of outages). The Commission also notes that the company is working toward a BCA for DA moving forward and looks forward to these results."[56]

Q: DID THE AUDIT ADDRESS DTE'S DA PROGRAM?

A: Yes. The Audit Report states:

> Apart from improving reliability, DTE must undertake significant expansions to address safety issues with its ungrounded 4.8kV system … Its installation of reclosers on the 4.8kV system dedicates some to substation exit points, which will address energized down wire concerns on its delta-configured circuits, and some to other locations where the reclosers will generate reliability improvements. Not placing higher priority on installing the devices at those substation exit points will leave larger safety risks for longer durations. Completing the safety-driven installations as promptly as practicable, which we believe is appropriate, will leave fewer allocated to reliability improvement, absent further expenditures to compensate. The reliability impacts of shifting DTE's planned allocation of reclosers for safety, as opposed to reliability reasons, does not present a suitable justification for not giving primary emphasis to measures necessary to mitigate the risks of customer harm from downed wires[57] … ***DTE should complete the installation of reclosers at substation exit points as soon as possible***.[58]

The Audit Report also recommended that the Company slow the deployment of reclosers until it better understands the expected reliability improvements, but the "limitations addressed in this recommendation should not serve to constrain those safety-driven installations."[59]

[56] Case No. U-21534, Commission Order, January 23, 2025 at 147-148.
[57] Audit Report, Part Two at 67.
[58] Audit Report, Part Two at 84, (emphasis added).
[59] Audit Report, Part Two at 94.

Q: PLEASE PROVIDE AN OVERVIEW OF DTE'S APPROACH TO ITS DA BCA.

A: As I previously stated, DTE's BCA methodology excludes the difficult-to-quantify benefit of safety (i.e., Safety Reclosers), therefore the DA BCA only includes the benefits and costs of Reliability Reclosers.

The approach used by 1898 & Co. for the DA BCA[60] utilizes historical DTE outage data and recalculates the number of customers impacted and outage duration for each event assuming the investments were originally in place. The approach monetizes each outage's recalculated customer impacts using the DOE ICE Calculator, calculates the lifecycle present value of avoided customer outages and compares it to the cost of the investments.[61]

Q: WHAT ARE THE RESULTS OF THE DA BCA?

A: 1,838 of DTE's 2,721 distribution circuits have more than 400 customers, and are therefore suitable for DA. Of these 1,838 circuits, 64% have BCRs greater than 1. The expected avoided CMI percentage for all beneficial projects averaged 26%, ranging from 15% to 51%.[62]

Q: WHAT IS DTE REQUESTING FOR DA IN THIS PROCEEDING?

A: The Company included $26.8 million of DA investments in the 2023 historical test year, $125.1 million in the 24-month 2024-2025 bridge period, and $115.6 million in the 2026 test year.[63]

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[60] 1898 & Co. refers to this approach as its Outage Mitigation Model.
[61] De Stigter at JDDS-12:20 – JDDS-13:9.
[62] De Stigter at JDDS-23:20 – JDDS-24:4.
[63] Exhibit A-12, Schedule B5.4, page 14, Line No. 3.

DTE's DA investments are currently split between recovery through base rates and the IRM. DTE is requesting full IRM recovery treatment of DA beginning in 2027 and is seeking $165 million in 2027, $250 million in 2028, and $320 million in 2029.[64]

Q: HAS THE COMPANY CLEARLY EXPLAINED THE RATIONALE FOR ITS PROPOSED DA IRM SPENDING AMOUNTS?

A: No. The workpaper provided by DTE in response to a CEO data request seeking this explanation did not contain total amounts that match the IRM request. The Company stated, "[n]ote a portion of the investment is to generally account for building new ties which are not currently allocated to circuits. If the investment is not required for ties, the Company will invest in additional circuits for automation in a given year."[65]

In a separate data request, the CEO asked if the IRM amounts would cover the 64% of circuits identified in the DA BCA with benefits greater than costs. DTE responded, "The Company plans to evaluate each circuit with detailed engineering analysis, based on the benefit cost ratios completed by 1898. The detailed engineering analysis and review of practical considerations in the field, may result in some of the circuits not being automated during this evaluation."[66]

In summary, the CEO are unclear on the basis for DTE's DA IRM request and do not fully understand what the Company intends to accomplish with the requested amount.

Q: HOW MUCH DOES DTE INTEND TO INVEST IN SAFETY RECLOSERS?

A: DTE states, "The Company expects to dedicate approximately one third of the total capital investment allotted to the Distribution Automation program … toward the installation of

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[64] Willis at AW-21:5, Table 2.

[65] Ex. CEO-15, DTE response to DR CEODE-1.3b.

[66] Ex. CEO-16, DTE response to DR CEODE-1.4.

start of circuit safety reclosers. If the Company's request is approved, DTE Electric would invest approximately $25 million in 2025, $50 million in 2026, and $55 million in 2027, on safety reclosers … This plan would result in the majority of 4.8 kV overhead load carrying circuits completed with safety recloser installations in early 2028."[67]

Q: WHY DOES DTE NOT INTEND TO COMPLETE THE INSTALLATION OF SAFETY RECLOSERS BEFORE EARLY 2028?

A: The Company states,

> "DTE Electric recognizes the customer benefits to both start of circuit (safety) reclosers on 4.8kV circuits and those installed at midpoints and tie points ... A combined approach was determined prudent to address safety related to minimizing the potential hazard of energized downed wires and safety that comes with improved reliability for the Company's customers. The determination of where to start the deployment of start of circuit reclosers considered impact risks like customer density, proximity to schools and frequency of wiredown events. These customers also depend on electricity for many critical safety needs, including lifesaving medical equipment, air conditioning and heat during extreme weather events, and first responder services during emergency situations."[68]

Q: DO YOU AGREE WITH THIS APPROACH?

A: No. The Audit Report states that DTE should complete the installation of Safety Reclosers at substation exit points "as soon as possible,"[69] and I concur. The Company has stated that its "guiding principles and processes are to prioritize and respond as quickly as possible to safely secure downed wires,"[70] and accelerated installation of Safety Reclosers is consistent with these principles.

Although it only considered Reliability Reclosers in its BCA, 1898 & Co. seems to also agree that Safety Reclosers are a high priority, stating "[t]his (DA) program also

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[67] Rademacher at SPR-24:7-15.
[68] Ex. CEO-17, DTE response to DR CEODE-1.5.
[69] Audit Report, Part Two at 84.
[70] Ex. CEO-18, DTE response to DR STDE-3.28. a.

focuses on deploying reclosers outside of 4.8 kV circuits to minimize the risks of energized-wire down situations … Given the historical frequency of these type of faults that are not identified by the current protection scheme, this investment is justified on mitigating this life threatening risk to the general public."[71] 1898 & Co. also stated, "the investment in 4.8 kV circuit reclosers to manage safety risks due to live-wire down risks is a cost effective solution to manage this risk."[72]

With DTEE's 14,000 wiredowns per year on its 4.8kV system, I agree that mitigating this risk is critical and urgent.

Q: DO YOU HAVE OTHER CONCERNS?

A: Yes. As with PTMM, I am concerned that the DA BCA does not fully reflect potential future escalation (beyond general inflation) for the cost of labor, reclosers, and overhead conductor. DTE acknowledges that it did not take into account any such increases.[73]

Q: WHAT DO YOU RECOMMEND?

A: I recommend that the Commission require the Company to accelerate the planned installation of Safety Reclosers to complete the deployment in 2026. I also recommend that the Company, in rebuttal testimony, provide a sensitivity analysis of its DA BCA to provide answers to questions such as:

- Which circuits have DA reliability benefits in excess of costs, if:
  - Recloser costs increase over the next four years by 20% or 100%?
  - Overhead conductor costs increase by 20% or 40%?

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[71] 1898 & Co. Report at p. 20 of 135.
[72] 1898 & Co, Report at p. 27 of 135.
[73] Ex. CEO-19, DTE response to DR CEODE-4.1aii.

- o DA labor costs increase by 10% or 30%?

VII. SUBTRANSMISSION REDESIGN AND REBUILD (SRR)

Q: PLEASE PROVIDE A BRIEF OVERVIEW OF DTE'S SUBTRANSMISSION SYSTEM AND ITS CONDITION.

A: DTE's subtransmission system links the unaffiliated International Transmission Company and DTE's distribution system. The subtransmission system is a mix of overhead and underground circuits and is operated at voltages of 24kV,[74] 40kV, and 120kV. The main subtransmission voltage in DTE's system is 40kV.[75]

Similar to its distribution system, DTE's subtransmission system is aging (beyond 80 years old in some areas), while facing storm-related resiliency challenges and increased loading in some areas leading to loss of redundancy. Portions of the subtransmission overhead system are in difficult-to-access, deeply wooded areas and along railroads, increasing the time and difficulty for restoring service or maintaining equipment.[76]

Q: PLEASE EXPLAIN THE SCOPE OF THE COMPANY'S SRR PROGRAM.

A: DTE's SRR Program is focused on improving reliability and increasing capacity by installing new station equipment (transformers, capacitor banks, and associated equipment), as well as rebuilding both the overhead and underground portions of its subtransmission system. The rebuild work involves updating equipment to new, more

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[74] The oldest part of DTE's subtransmission system operates at 24kV and is primarily underground, supplying power to 4.8kV distribution substations in Detroit, Monroe, and Port Huron. This system includes some of the oldest cables in the network and, due to its age and increasing failures, DTE developed a plan to decommission the 24kV subtransmission system in conjunction with the 4.8kV Conversions Programs.

[75] Stowe at RMS-88:3-21.

[76] Stowe at RMS-100:5-10.

resilient standards and replacement of smaller and aging cable and conductors with larger wires.[77]

Q: HAS THE COMMISSION PREVIOUSLY ADDRESSED SRR?

A: Yes. In its U-21534 Order, the Commission agreed that, "going forward, a greater level of detail and quantifiable support is needed from DTE Electric to support its subtransmission projects", including the development of a project-specific BCA for all subtransmission projects over $10 million.[78]

Q: DID THE AUDIT ADDRESS DTE'S SRR PROGRAM?

A: Yes. The Audit Report states:

> The Distribution Grid Plan calls for somewhat more than $0.5 billion in (subtransmission) investment, which indicates annual spending at a rate more than three times the reported levels of recent years. The plan cites capacity as a major driver, but includes automation, reliability, and rebuilding to modern standards as included benefits … (T)he subtransmission system does not significantly contribute to SAIDI minutes … There is … opportunity to appropriately account for the reliability impact of the subtransmission system to further strengthen the justification of subtransmission redesign and rebuild projects.[79]

The Audit Report also recommends that DTE "[i]solate and provide Subtransmission Redesign and Rebuild Investments for those required for capacity reasons and 4.8k Conversion."[80]

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[77] Stowe at RMS-102:7-20.
[78] Case No. U-21534, Commission Order, January 23, 2025 at 133.
[79] Audit Report, Part Two at 83.
[80] Audit Report, Part Two at 84.

Q: WHAT SRR INVESTMENTS HAS DTE INCLUDED IN THIS PROCEEDING?

A: DTE included $73.2 million of SRR investments in the 2023 historical test year, $90.6 million in the 24-month 2024-2025 bridge period, and $19.0 million in the 2026 test year.[81]

DTE's STRR investments are currently split between recovery through base rates and the IRM. DTE is requesting full IRM recovery treatment of SRR from 2027-2029[82] and is seeking $105 million in 2027, $115 million in 2028, and $120 million in 2029.[83]

Q: HAS DTE DEVELOPED A BCA FOR ITS SRR INVESTMENTS?

A: No. DTE explains:

> Benefit Cost Analysis (BCA) for subtransmission is particularly complicated due to the networked nature of the subtransmission grid. Benefits such as load relief, planning criteria violations, and reliability improvements are much harder to quantify compared to the distribution system. Building a BCA framework that can identify and capture these benefits will take a significant amount of time, expertise, and effort … The Company will develop a comprehensive subtransmission BCA framework designed to evaluate new subtransmission projects. The Company plans to complete the framework before the next rate case filing and will apply the framework to all new subtransmission projects over $10M.[84]

Q: WHAT DO YOU RECOMMEND?

A: I recommend that the Commission decline the inclusion of SRR investments in the IRM until the Company develops a BCA for SRR and identifies which projects have customer benefits that exceed customer costs.

VIII. DISTRIBUTION INFRASTRUCTURE RECOVERY MECHANISM (IRM)

Q: PLEASE PROVIDE BACKGROUND ON DTE'S DISTRIBUTION IRM.

[81] Exhibit A-12, Schedule B5.4 at 11-12.
[82] Stowe at RMS-123.
[83] Willis at AW-21:5, Table 2.
[84] Stowe at RMS-103:11 – RMS-104:4.

A: The Commission first authorized a two-year Distribution IRM in its December 2023 Order in Case No. U-21297, supporting IRM treatment for five capital investment programs (including DA and SRR) totaling $61.9 million in 2024 and $290.1 million in 2025. The Commission also authorized new annual IRM planning and reconciliation processes and directed that a contested reconciliation proceeding should occur at the end of each IRM plan year.

In Case No. U-21534, DTE proposed a two-year extension of the IRM, including capital investments of $530 million in 2026 and $720 million in 2027. The Company also proposed that PTMM be authorized for IRM treatment. In its January 2025 Order, the Commission approved a partial extension of the previously approved 2025 investment levels but declined to approve PTMM for 2026 IRM authorization.[85]

Q: WHAT INFORMATION DOES DTE PROVIDE DURING THE IRM RECONCILIATION PROCESS?

A: In the initial IRM reconciliation proceeding for DTE (Case No. U-21485), the Company has provided 2024 approved and actual in-serviced investments, 2024 Construction Work in Progress,[86] units of work completed for each project/program,[87] and average costs per unit for each project/program.[88]

Q: WHAT CHANGES TO THE DISTRIBUTION IRM IS DTE PROPOSING IN THIS PROCEEDING?

A: DTE is proposing to extend the IRM through 2029 with new investment authorizations (including new authorizations for PTMM and System Cable) shown in Table 2 below.

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[85] Direct testimony of Aaron Willis ("Willis") at AW-15:18 – AW-16:17.
[86] Expenditures made on IRM projects/programs that will be placed in-service in a future IRM plan year.
[87] DTE reported miles of circuits converted/rebuilt/installed, number of breakers replaced, feet of URD replaced, and DA reclosers installed and circuits completed for the authorized IRM capital spending amount.
[88] Case No. U-21485, Direct Testimony of Bryant F. Miller at BFM-7:8 – BFM-17:19.

	Previously Approved			Proposed		
Capital Program	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**
Conversions	1.6	185.8	0	0	0	0
Subtransmission Redesign & Rebuild	5.5	53.8	53.8	105	115	120
Breaker Replacement	13.7	12.6	12.6	15	22	26
URD Replacement	14.6	13.5	13.5	15	20	26
System Cable	n/a	n/a	n/a	25	30	34
Distribution Automation[2]	26.4	24.4	24.4	165	250	320
PTMM	n/a	n/a	n/a	263.4	376.8	482.6
Total	**61.9**	**290.1**	**104.3**	**588.4**	**813.8**	**1,008.6**

Table 2 - DTE's Proposed IRM Investment Levels ($M)[89]

Q: WHAT ARE THE BENEFITS OF THE IRM?

A: The Company has claimed that the benefits of the IRM include:

- Increased accountability – disclosure of actual project and unit costs through the reconciliation process.
- Review and input – opportunities for stakeholders to review the Company's IRM plan and provide feedback during a stakeholder forum.
- Increased transparency – disclosure of project-level metrics that are more detailed than in rate cases, explanations of variances between planned and actual investments.

[89] Willis at AW-21, Table 2.

- Investment certainty – specified investment amounts in each IRM program with customers refunded the difference if DTE does not achieve the authorized investment levels.[90]

Q: DO YOU AGREE?

A: I agree that the IRM planning and reconciliation processes provide accountability and transparency into the authorized investments. DTE has identified another benefit of the IRM, stating "If the Commission approves the proposed IRM investment levels … the Company expects that it can defer or reduce the scope of future rate case filings by the investment amounts reflected in those tables. By securing dedicated funding through the IRM mechanism, the Company can address a portion of its infrastructure needs outside of the traditional rate case process; thereby, potentially reducing the frequency or size of future filings related to these specific investments."[91]

However, the IRM reconciliation process provides visibility into the ***efficiency*** of DTE's IRM investments (i.e., how many units of work the Company achieved with the authorized spending amounts vs. the Company's plan), but not the ***effectiveness*** of the IRM investments (i.e., whether or not the Company is realizing its expected safety and reliability improvement outcomes from the authorized spending).

I am concerned that if the Commission approves DTE's proposed IRM investment levels through 2029, the spending is "locked in" regardless of the spending effectiveness (i.e., regardless of whether DTE is achieving its planned safety and reliability improvements or other customer-beneficial outcomes).

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[90] *Id.* at AW-18:16 – AW-19:19.
[91] Ex. CEO-20, DTE response to DR CEODE-4.2b.

For example, what if the Commission authorizes DTE's proposed IRM treatment for $735 million of DA from 2027-2029 in this proceeding, but the Company subsequently learns that the reliability benefits from automation are only half (or less) of what it currently anticipates? What is an appropriate way to protect customers and adjust authorized IRM spending if the expected reliability improvement outcomes do not materialize?

Q: HOW COULD THE IRM PROCESS BE AMENDED TO ACCOUNT FOR THIS?

A: One possibility would be to use the IRM reconciliation process not just to confirm the efficiency of IRM spending, but also as a means to monitor IRM effectiveness. Over the last few cases, the CEO have urged DTE to include more actual system data and outcomes in its reliability modeling, GPM, and BCAs. The IRM reconciliation process is the next frontier of that recommendation. The Commission, the Company, Staff and intervenors can use the IRM reconciliation process to adjust future IRM authorized spending based on the effectiveness of different programs.

For example, if DTE projects a 25% SAIDI reduction from its PTMM program and it achieves a reduction between 90-100% of that value, IRM spending remains unchanged (or put another way, this confirms the accuracy of the BCA). However, if the PTMM spending in the given time period only results in 75% of the total projected SAIDI reduction, the Commission could order the future IRM spending totals to be reduced (or for the Company to re-run its BCA based on a more accurate estimate of potential savings).

As currently designed, the IRM reconciliation just checks whether the Company spent what it said it would while accomplishing the units of work it had planned. It is important to amend this process to confirm that the significant proposed IRM spending delivers the projected customer benefits.

Q: WHAT DO YOU RECOMMEND?

A: I recommend that the Company, in its rebuttal testimony, propose modifications to the IRM planning and reconciliation processes to provide increased transparency/accountability for both the efficiency ***and*** effectiveness of its proposed IRM investments.

IX. <u>SUMMARY OF RECOMMENDATIONS</u>

Q: PLEASE SUMMARIZE YOUR RECOMMENDATIONS.

A: I recommend that the Commission:

- Require the Company to accelerate the planned installation of Safety Reclosers to complete the deployment in 2026.
- Decline the inclusion of SRR investments in the IRM until DTE develops a BCA for SRR and identifies which projects have customer benefits that exceed customer costs.

I also recommend that the Company:

- Reflect the full revenue requirements of its planned investments in future BCAs.
- In its rebuttal testimony, include a sensitivity analysis on the impact of potential increases to wood pole, pole-top component, recloser, overhead conductor and labor costs for its PTMM and DA programs to provide answers to questions such as:
    1) What is the total amount of investment required to achieve the desired 5- and 10-year PTMM cycles, and which circuits have PTMM benefits in excess of costs if, over the next four years:
        a. Wood pole costs increase by 25% or 100%?
        b. Overhead transformer costs increase by 25% or 100%?

c. PTMM labor costs increase by 10% or 30%?

2) Which circuits have DA reliability benefits in excess of costs, if:

a. Recloser costs increase over the next four years by 20% or 100%?

b. Overhead conductor costs increase by 20% or 40%?

c. DA labor costs increase by 10% or 30%?

- In its rebuttal testimony, propose modifications to the IRM planning and reconciliation processes to provide increased transparency/accountability for both the efficiency and effectiveness of its proposed IRM investments.

Q: DOES THIS CONCLUDE YOUR TESTIMONY?

A: Yes.

Statement of Qualifications for Curt Volkmann

Professional Experience

I am President and founder of New Energy Advisors, LLC (http://www.newenergy-advisors.com/), an independent consulting firm. With 41 years of experience in the utilities industry, I work with clean energy advocates across the US in a variety of regulatory proceedings related to distribution system planning, distributed energy resources, and grid modernization. I have testified or commented before regulatory commissions in 15 states.

Prior to founding New Energy Advisors, I worked for the Environmental Law & Policy Center (ELPC) as a Senior Clean Energy Specialist. My work at ELPC focused on providing technical advice and expert witness testimony in several renewable energy and energy efficiency regulatory proceedings.

Prior to ELPC, I was employed for eighteen years by Accenture, a global management consulting and technology firm. I held several positions at Accenture, including Executive Director in Accenture's North America Utilities practice, with client leadership responsibilities for several gas, electric, and water utilities. In this role, I oversaw utility cost reduction and operational improvement programs.

Prior to Accenture, I worked for the consulting firm UMS Group, where I led multi-utility benchmarking studies examining global best practices in electric transmission and distribution. Participating utilities in the studies were from North America, Europe, Australia, New Zealand, and Africa.

I began my professional career working for nine years at Pacific Gas and Electric in various transmission and distribution roles. This included a role as a Distribution Planning Engineer, where I evaluated the impacts of cogeneration on distribution system protection and the impacts of demand-side management programs on the deferral of distribution substation upgrades.

Education

I have a BS in Electrical Engineering from the University of Illinois at Urbana-Champaign with a concentration in Electrical Power Systems. I also received an MBA from the University of California at Berkeley with a concentration in Finance.

I held a Registered Professional Electrical Engineer license in California from 1987 to 1995.

Recent Publications

Curt Volkmann. "*Integrated Distribution Planning - A Path Forward.*" GridLab. June 2018. https://gridlab.org/wp-content/uploads/2019/04/IDPWhitepaper_GridLab-1.pdf

Ric O'Connell, Curt Volkmann, Paul Brucke. "*Regulating Voltage: Recommendations for Smart Inverters.*" GridLab. September 2019. https://gridlab.org/wp-content/uploads/2019/09/GridLab_Regulating-Voltage-report.pdf

Sara Baldwin, Ric O'Connell, Curt Volkmann. "*A Playbook for Modernizing the Distribution Grid; Volume I: Grid Modernization Goals, Principles and Plan Evaluation Checklist.*" IREC and GridLab. May 2020. https://gridlab.org/wp-content/uploads/2020/05/Grid-Modernization-Playbook-report-1.pdf

Prior Testimony & Comments by Curt Volkmann

Prior Testimony Filed by Curt Volkmann

(as of August 2025)

State	Date	Proceeding	Case/Docket #
AR	8/19/16 and 9/9/16	AR PSC in the matter of net metering and the implementation of Act 827 of 2015	16-027-R
	8/26/16 and 9/23/16	AR PSC investigation of policies related to distributed energy resources	16-028-U
AZ	2/25/16 and 4/7/16	Arizona Corporation Commission investigation into the value and cost of distributed generation	E-00000J-14-0023
	5/19/17 and 9/29/17	The Application of Tucson Electric Power Company for approval of its 2016 renewable energy standard implementation plan	E-01933A-15-0239
	5/19/17 and 9/29/17	The Application of UNS Electric, Inc. for the establishment of just and reasonable rates and charges	E-04204A-15-0142
CA	5/2/17	CA Public Utilities Commission (CPUC) review of Southern California Edison's application for authority to increase its authorized revenues in 2018	A.16-09-001
	7/26/19	CPUC review of the application of Pacific Gas and Electric Company for authority to increase rates and charges for electric and gas service in 2020	A.18-12-009
	5/5/20	CPUC review of Southern California Edison's application for authority to increase its authorized revenues in 2021	A.19-08-013
CO	9/28/22, 11/2/22	PUC of CO's review of Public Service Company of Colorado's first Distribution System Plan	22A-0189E
FL	6/21/21	Florida PSC's review of a petition for rate increase by Florida Power and Light	20210015-EI

Prior Testimony Filed by Curt Volkmann (continued)
(as of August 2025)

State	Date	Proceeding	Case/Docket #
IA	10/2/18	IA Utility Board's approval of Interstate Power & Light's energy efficiency 5-year plan	EEP-2018-0003
	8/1/19	Interstate Power & Light's GRC application and grid modernization plan	RPU-2019-0001
IL	10/18/13	Illinois Commerce Commission (ICC) approval of Ameren IL's Energy Efficiency and Demand Response Plan	13-0498
	11/14/13	ICC approval of ComEd's Energy Efficiency and Demand Response Plan	13-0495
	12/4/14	ICC investigation of ComEd's cost of service for low-use residential customers	14-0384
	6/20/18 and 8/10/18	Ameren IL proceeding for approval of its customer generation rebate and customer generation charge.	18-0537
	7/17/18 and 8/28/18	ComEd proceeding for approval of its customer generation rebate and customer generation charge.	18-0753
	2/5/21	Investigation into an annual process and formula for the calculation of Ameren IL's distributed generation rebates	20-0389
	5/11/23 and 7/13/23, 5/13/24, 7/3/24	Ameren IL's Initial and Refiled Multi-Year Integrated Grid Plan	22-0487
	5/22/23, 7/26/23, 5/23/24, 7/17/24	ComEd's Initial and Refiled Multi-Year Integrated Grid Plan	22-0486

Prior Testimony Filed by Curt Volkmann (continued)
(as of August 2025)

State	Date	Proceeding	Case/Docket #
MI	2/24/15	MPSC in its investigation into the application of Consumers Energy to amend its renewable energy plan	U-17752
	7/26/24	DTEE's application for authority to increase its rates, amend its rate schedules and rules governing the distribution and supply of electric energy	U-21534
MN	10/3/22	MN PUC's review of Northern States Power Company's application for authority to increase rates for electric service in Minnesota	E002/GR-21-63
OH	1/17/19	PUC of OH in the matter of the filings by FirstEnergy of a Grid Modernization Business Plan and Distribution Platform Modernization Plan	16-481-EL-UNC and 17-2436-EL-UNC
UT	3/3/20, 7/15/20, 9/15/20	Rocky Mountain Power's application to establish export credits for customer generated electricity	17-035-61 Phase 2
VA	12/20/19	Review by the VA State Corporation Commission (SCC) of Dominion's second petition for approval of a Grid Transformation Plan	PUR-2019-00154
	9/24/21	SCC's review of Dominion's third petition for approval of a Grid Transformation Plan	PUR-2021-00127
WI	9/5/23	Application of Wisconsin Power and Light Company for authority to adjust electric and natural gas rates	6680-UR-124

Prior Comments Filed by or with Contributions from Curt Volkmann
(as of August 2025)

State	Date	Proceeding/Topic	Case/Docket #
CA	8/31/15, 1/26/16, 3/3/16	CPUC's proceeding regarding policies, procedures, and rules for development of Distribution Resources Plans (DRPs)	R.14-08-013
MA	5/28/21	MA Department of Public Utilities' investigation into DER planning and costs	20-75
MI	5/14/18, 2/16/24, 3/15/24	MPSC's investigation into DTEE's and Consumers Energy's five-year distribution investment and maintenance plans	U-20147
	10/5/18	MPSC's Staff Report on a Michigan distribution planning framework	U-20147
	12/16/24	MPSC's matter to investigate, audit and review methods employed by DTEE and Consumers Energy to secure good electric service and the safety of the public	U-21305
MN	9/15/15, 11/18/15, 8/21/17, 9/21/17	MN PUC investigation into grid modernization and distribution planning	E002/M-15-962 E999/CI-15-556
	2/2/18 and 2/28/18	Xcel Energy's 2017 distribution system hosting capacity report	E002/M-17-777
	7/6/18 and 2/22/19	Distribution system planning for Xcel Energy	E002/CI-18-251
	3/17/20 and 4/22/20	Xcel Energy's Integrated Distribution Plan (IDP) and Advanced Grid Intelligence and Security certification request	E002/M-19-666
	9/25/20	Stakeholder process informing the metrics, performance evaluation methods, and consumer protection conditions for Xcel Energy's AMI and FAN projects	E999/CI-20-627

Prior Comments Filed by or with Contributions from Curt Volkmann (continued)
(as of August 2025)

State	Date	Proceeding/Topic	Case/Docket #
MN (cont.)	2/25/22 and 4/11/22	Xcel Energy's 2021 IDP and Request for Certification of Distributed Intelligence and the Resilient Minneapolis Project	E002/M-21-694
	3/1/24 and 4/12/24	Xcel Energy's 2023 IDP	E002/M-23-452
NY	4/13/18, 5/7/18, 8/27/18	New York PSC's investigation into the matter of the Value of DER working group regarding value stack	17-01276

MPSC Case No: U-21860	
Requester: MNSC	
Question No.: MNSCDE-1.7	
Respondent: S. Rademacher	
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Question: 7. Refer to U-21860 Exhibit: A-28 page 94 which states "First, the program effectively has two sub-programs. The first is targeted toward safety mitigation. For the 4.8 kV distribution system, events may occur where the current substation protection does not identify a fault current and appropriately lockout. In these instances, there can be live-wire situations, which is a serious safety concern." Please provide a list of the times in the last 10 years that the "current substation protection" failed to "identify a fault current and appropriately lockout" and resulted in a "live-wire situation."

Answer: Any wiredown on the system has the potential to be energized and is treated as such when considering the necessary protections to complete restoration. However, because of the original design of the 4.8kV delta ungrounded system, a wiredown will not generate sufficient fault current to open a protective device. Therefore, all 4.8kV, non phase-to-phase, wiredowns that are connected to a source may remain energized. Over the last 5 years, there have been an average of approximately 14,000 wiredowns on the 4.8kV system.

Attachment: None.

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Requester: CEO	
Question No.: CEODE-4.4	
Respondent: B. Chiu	
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Question: 4. Refer to Exhibit A-28 Schedule R3 (the 1898 & Co. report), pp. 47-48 of 135. Please confirm that DTEE will use the updated version of the DOE ICE Calculator (ICE 2.0) in future rate cases and Distribution Grid Plans. If not, please explain why.

Answer: Yes. DTE Electric will use the updated version of the DOE ICE Calculator (ICE 2.0) to quantify the cost of interruptions once the data refresh has been validated and released for use.

Attachment: None

MPSC Case No: U-21860	
Requester: MNSC	
Question No.: MNSCDE-7.1c	
Respondent: J. De Stigter	
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Question: 1. Refer to U-21860 MNSCDE-1.13-02 DA BCR Summary, tab “Circuit”.

c. Referring to column B, “Project Cost”, please confirm that this is the project cost to DTE, and does not include interest expense, return on equity, property taxes, state and federal income taxes and other costs to ratepayers in addition to DTE project costs. If this is confirmed, please explain in detail why these costs are excluded from the “Project Cost.”.

Answer: The “Project Cost” in column B do not include interest expense, return on equity, or state and federal income taxes. 1898 & Co. is not aware of the definition of “other costs to ratepayers” and what is assumed to be included in that category. The project costs are assumed to include both direct and indirect costs, including applied corporate overheads. As discussed in ABDE-2.28a, the discounted cash flow modeling is performed on an “economic basis” not a “financial basis”. This means the discounted cash flows incorporate the full cost of the project upfront and do not incorporate how DTE may finance investments overtime. Additionally, the benefit cost evaluation is from a customer perspective. As such, the discount rate includes the opportunity costs that these projects need to overcome to have benefits in excess of costs for customers. The discount rate of 6.5 percent is the hurdle rate for the investment and incorporates debt rate (and by implication interest expenses) and return on equity elements within the discounted cash flow methodology. So while the project costs do not include these items, the discounted cash flow methodology utilized within the benefit cost analysis does factor them within the discount rate.

With respect to taxes (property and state & federal income taxes), these elements are not traditionally evaluated in an “economic model” for the type of projects evaluated by 1898 & Co. These factors would be included within a “financial model”. Additionally, these factors are challenging to estimate at in individual project basis as they are based on DTE’s whole company (distribution, gas, generation, etc..) income statement. To accurately estimate

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Respondent: J. De Stigter	
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these items, the net impact of a project to the whole company financials would need to be known. In the case where overall capital investment limits are established, the net impact of an investment on income taxes would be minimal. Since these expense types are more driven by the organization overall financial statements, that the impacts would be minimal, and the costs to evaluate are not insignificant these expenses were not incorporated into the benefit cost evaluation.

Attachment: *N/A*

MPSC Case No: U-21860
Requester: ABATE
Question No.: ABDE-2.28a
Respondent: J. De Stigter
Page: 1 of 2

Question: 28. Regarding the June 11th Technical Conference, at which 1898 and Co. described the BCA tools developed for DTE as “economic models” as opposed to “financial models,” please: a. Describe the impacts on the BCA tools that using the economic model approach has on development.

Answer: For clarity, 1898 & Co. used these two terms, “economic model” and “financial model” to describe the discounted cash flow methodology employed with the Integrated Resiliency, Reliability, and Risk Investment Model. By the term “economic model”, 1898 & Co. assumes that benefits and costs are on a cash basis. This means the investment is a cash negative upfront (day 0 of the discounted cash flow time horizon) with benefits being cash positive over the life of the asset and the discounted cash flow time horizon (report Table 3-1 in Exh A-28 Sch R3 for the time horizons for each program).
By the term “financial model”, 1898 & Co. assumes that investments are financed (i.e. a loan is taken) and depreciation expenses occur. A “financial model” would also incorporate taxes.

There are several elements to consider when deciding which model type to utilize. First, a cash based discounted cash flow model (what 1898 & Co. refers to as an “economic model”) is typically viewed as more conservative as the upfront investment is a large negative cash flow in Year 1 of the profile. Since the escalation rate is lower than the discount rate, whenever a negative cash flow can be deferred without impacting any other positive cashflows, the net present value will increase. When financing of the investment is incorporated (i.e. “financial model” basis), this upfront investment can be deferred thus increasing the investment’s net present value. Put another way, an “economic model” assumes 100% equity while a “financial model” would assume some mix of debt and equity. This is why a cash-based discounted cash flow model is viewed as more conservative. Second, the discount rate employed in the modeling may need to be different depending on the risk profiles. Third, an “economic model’s” primary purpose is to understand if the investment should be done. A “financial model’s” primary purpose is to

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Requester: ABATE	
Question No.: ABDE-2.28a	
Respondent: J. De Stigter	
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optimize the Net Present Value of an investment based on risk tolerance profiles and the cost of debt.

For investment decision analysis, 1898 & Co. utilizes an “economic model” based methodology since it is more conservative and meets the primary purpose of the modeling approach, i.e. should we do this investment. Based on this, 1898 & Co. considered an “economic model” or cash-flow based discounted cash flow model to be appropriate for DTE’s rate case investment decision analysis.

Attachment: *N/A*

MPSC Case No: U-21860	
Requester: CEO	
Question No.: CEODE-6.1	
Respondent: J. Robinson	
Page: 1 of 1	

Question: 1. Please refer to the Company's responses to CEODE-4.1ai discussing the inflation rate the Company used in projecting the costs of the PTMM program. Please provide the exact inflation rate (expressed as a percentage) the Company used over time in determining the cost effectiveness of the PTMM program.

Answer: Assuming the question seeks to understand the inflation rates used to determine the PTMM program's investment levels, the Company would answer as follows:

The PTMM program's projected investment levels were calculated using total estimated investments, based on projected system-wide averages, and inflation rates, as explained in CEODE-4.1ai. Specific investment levels and inflation rates are provided as part of CEODE-1.1. The applied inflation rates match the Company's projections. For 2026, see Witness Uzenski's Exhibit A-13, C5.15. For the inflation rates used between 2027 and 2029, see Witness Leuker's Exhibit A-15, Schedule E4. The 2029 rate was locked for all future years.

Year	Inflation Rate (%)
2026	3.1
2027	2.2
2028	2.3
2029 and beyond	2.2

Attachment: *None*

MPSC Case No: U-21860	
Requester: CEO	
Question No.: CEODE-4.1ai	
Respondent: J. Robinson	
Page: 1 of 1	

Question: 1. Refer to the testimony of Brian Hill at BLH-10:17 through BLH-12:7 and Table 1.

a. Did the Company factor in the historical material cost increases discussed by Witness Hill into the following forward-looking analyses?

i. PTMM BCA;

Answer: As noted in footnote 26 on page JER-33 of Witness Robinson's testimony, "[t]he costs below have been adjusted for inflation." This adjustment reflects a general consideration of cost trends, including inflationary impacts, rather than specific historical material cost increases.

Attachment: None

MPSC Case No: U-21860	
Requester: CEO	
Question No.: CEODE-4.1aiv	
Respondent: J. Robinson	
Page: 1 of 1	

Question: 1. Refer to the testimony of Brian Hill at BLH-10:17 through BLH-12:7 and Table 1.

a. Did the Company factor in the historical material cost increases discussed by Witness Hill into the following forward-looking analyses?

iv. Witness Robinson’s discussion on annual spending for PTMM found at JER-34:1 through JER-34:12.

Answer: As noted in footnote 26 on page JER-33 of Witness Robinson’s testimony, “The costs below have been adjusted for inflation.” This adjustment reflects a general consideration of cost trends, including inflationary impacts, rather than specific historical material cost increases.

Attachment: None

MPSC Case No: U-21860	
Requester: CEO	
Question No.: CEODE-1.3b	
Respondent: S. Rademacher	
Page: 1 of 1	

Question: 3. Refer to Table 2 on p. AW-21 of the direct testimony of Aaron Willis: b. Please provide all data, analysis, workpapers, or spreadsheets with formulas intact supporting the 2027-2029 proposed IRM investments levels for Distribution Automation.

Answer: DTE Electric objects to the request for the reasons that the request is over broad, seeks excessive detail, and 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. The Company also objects because the request 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.

Without waving these objections, but subject to them, the Company responds as follows: Please see the attachment for the planned investment from 2025 through 2029 in 2025 dollars and prioritization. Note a portion of the investment is to generally account for building new ties which are not currently allocated to circuits. If the investment is not required for ties, the Company will invest in additional circuits for automation in a given year.

Attachment: NDA CEII U-21860 CEODE-1.3b-01 Distribution Automation Prioritization.xlsx

Co-Respondent(s): A. Willis

MPSC Case No: U-21860	
Requester: CEO	
Question No.: CEODE-1.4	
Respondent: S. Rademacher	
Page: 1 of 1	

Question: 4. Refer to Table 2 on p. AW-21 of the direct testimony of Aaron Willis, and lines 22-25 on p. JDDS-23 of Jason De Stigter's direct testimony. Please confirm that, if the Commission authorizes the 2027-2029 proposed IRM investment levels for Distribution Automation shown in Table 2, DTEE will automate approximately 64% of the 1,838 eligible circuits with quantified benefits in excess of costs. If not, please explain.

Answer: The Company plans to evaluate each circuit with detailed engineering analysis, based on the benefit cost ratios completed by 1898. The detailed engineering analysis and review of practical considerations in the field, may result in some of the circuits not being automated during this evaluation.

Attachment: *None*

MPSC Case No: U-21860	
Requester: CEO	
Question No.: CEODE-1.5	
Respondent: S. Rademacher	
Page: 1 of 1	

Question: 5. Refer to lines 13-15 on p. SPR-24 of Steven Rademacher's direct testimony. Please explain why DTEE does not intend to complete the installation of safety reclosers on 4.8 kV load carrying circuits until early 2028.

Answer: DTE Electric recognizes the customer benefits to both start of circuit reclosers on 4.8kV circuits and those installed at midpoints and tie points (on 4.8kV and 13.2kV distribution voltages). A combined approach was determined prudent to address safety related to minimizing the potential hazard of energized downed wires and safety that comes with improved reliability for the Company's customers. The determination of where to start the deployment of start of circuit reclosers considered impact risks like customer density, proximity to schools and frequency of wiredown events. These customers also depend on electricity for many critical safety needs, including lifesaving medical equipment, air conditioning and heat during extreme weather events, and first responder services during emergency situations.

Attachment: *None*

MPSC Case No: U-21860	
Requester: Staff	
Question No.: STDE-3.28.a.	
Respondent: B. Hill	
Page: 1 of 2	

Question: 28. Please refer to Company witness Brian Hill's testimony on page 20 lines 6-10.

a. Please explain in detail the Company's wire down response procedure from start to finish.

Answer: The Company's guiding principles and processes are to prioritize and respond as quickly as possible to safely secure downed wires. During storms, the Company's process will supplement field resources with trained office and administrative staff to respond to the increased volume of severe weather-related wire downs. As a result of more frequent and intense storms, the Company expanded this process in 2022 by adding external resources to assist with downed wires.

DTE Electric dispatches qualified teams to reported wire downs where they assess the field conditions, install yellow barrier tape at a safe distance around the downed wire, as shown in STDE3.28b. They also inform nearby residents of the hazard and report the location for the restoration crew. They escalate and continuously standby the downed wire if it meets DTE Electric's standby criteria until relieved by a qualified restoration crew. If the conditions do not meet the standby criteria, the team notifies the auto-dispatching tool they are available to move to another wire location. The teams continue this process until all wire downs are addressed.

DTE Electric's process includes continuous standing by downed wires if it meets the specified criteria of being on or near a road, near a park, near a school, or on a normally occupied building. The DTE Electric process also allows the qualified team to escalate any wire down that may not meet the specified criteria for review and continuous standby.

In 2025, DTE Electric is expanding its response to include having teams return to 4.8kV wire downs that did not meet the standby criteria. The return to these locations will occur after all wire downs have been secured. At these revisited locations, the teams will again review field conditions including the barrier tape and notification of nearby residents. The teams will then provide continuous standby coverage of 4.8kV downed wires not in a backyard.

Attachment: None

MPSC Case No: U-21860	
Requester: CEO	
Question No.: CEODE-4.1aii	
Respondent: S. Rademacher	
Page: 1 of 1	

Question: 1. Refer to the testimony of Brian Hill at BLH-10:17 through BLH-12:7 and Table 1.

a. Did the Company factor in the historical material cost increases discussed by Witness Hill into the following forward-looking analyses?

ii. Distribution Automation BCA;

Answer: No.

Attachment: None

MPSC Case No: U-21860	
Requester: CEO	
Question No.: CEODE-4.2b	
Respondent: J. Robinson	
Page: 1 of 1	

Question: 2. Refer to the testimony of Aaron Willis at AW-20:12 through AW-21:5 including Table 2, and at AW-25:1 through AW-26:2 including Table 3.

b. If the Commission approves the proposed IRM investment levels shown in Table 2 or Table 3, does DTEE expect that it can defer or reduce the scope of future rate case filings?

i. If yes, please explain in what ways the Company expects to defer or reduce the scope of future rate case filings.

ii. If no, please explain.

Answer: Yes. If the Commission approves the proposed IRM investment levels for the PTMM program as shown in Table 2 or Table 3 of Witness Willis's testimony, the Company expects that it can defer or reduce the scope of future rate case filings by the investment amounts reflected in those tables. By securing dedicated funding through the IRM mechanism, the Company can address a portion of its infrastructure needs outside of the traditional rate case process; thereby, potentially reducing the frequency or size of future filings related to these specific investments.

Attachment: None

STATE OF MICHIGAN
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-21860

DIRECT TESTIMONY OF

BORATHA TAN

ON BEHALF OF

THE ECOLOGY CENTER, ENVIRONMENTAL LAW & POLICY CENTER, UNION OF CONCERNED SCIENTISTS, AND VOTE SOLAR

August 22, 2025

Table of Contents

I. INTRODUCTION AND PURPOSE OF TESTIMONY

Q: PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND CURRENT POSITION.

A: My name is Boratha Tan. My business address is 1 S. Dearborn St, Chicago, IL 60603. However, I work remotely from home in Detroit, MI. I serve as the Senior Regulatory Manager, Midwest for Vote Solar.

Q: BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A: At Vote Solar as Senior Regulatory Manager, I oversee policy development and implementation related to large scale and distributed solar generation in the Midwest region. I also review regulatory filings, perform technical analyses, and testify in commission proceedings on issues relating to solar generation.

Vote Solar is an independent 501(c)3 nonprofit working to repower the U.S. with clean energy by making solar power more accessible and affordable through effective policy advocacy. Vote Solar seeks to promote the development of solar at every scale, from distributed rooftop solar to large utility-scale plants. Vote Solar has over 90,000 members nationally, including over 2,700 members in Michigan. Vote Solar is not a trade organization, nor does it have corporate members.

Q: PLEASE SUMMARIZE YOUR EDUCATION AND PROFESSIONAL EXPERIENCE.

A: I graduated from Villanova University, with a Bachelor of Science in Mechanical Engineering and a minor in Peace and Justice. I worked at Ford Motor Company for six years in various capacities within the Electrical Systems Engineering department of the company; my work included designing, prototyping, and testing various high voltage components for future electric vehicles. My team and I have five patents on AI-related tools for electric motors. I also graduated with a Master's in Public Policy from the University of Michigan. I have experience in different engineering and analysis tools, including Autodesk, MATLAB, Ansys, RStudio, and Stata. My CV is attached as Ex. CEO-21.

Q: HAVE YOU PREVIOUSLY TESTIFIED OR COMMENTED BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION ("COMMISSION" OR "MPSC")?

A: Yes, I have testified before the MPSC in various cases including Case Nos. U-21193 (2022 DTE Integrated Resource Plan), U-21297 (2023 DTE Rate Case), and U-21534 (2024 DTE Rate Case). I have also testified in front of the Illinois Commerce Commission and the Indiana Utility Regulatory Commission. A list of these dockets can be found in my CV, submitted as exhibit CEO-21.

Q: ON WHOSE BEHALF ARE YOU SUBMITTING TESTIMONY?

A: I am submitting testimony on behalf of the Ecology Center, Environmental Law & Policy Center, Union of Concerned Scientists, and Vote Solar (collectively, the Clean Energy Organizations ("CEO")).

Q: WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A: The purpose of my testimony is to analyze electric distribution spending information contained in FERC Form 1, with respect to DTE and other comparable utilities around the Midwest. I will also analyze reliability data gathered from EIA Form 861, and compare how distribution spending relates to said reliability. This information is also used by CEO Witness Curt Volkmann in his direct testimony. I will also present Producer Price Indexes for Electric Power Generation, from the US Bureau of Labor Statistics. Finally, I will present and analyze DTE's residential electric disconnections during 2024, through regression analysis.

Q: PLEASE SUMMARIZE YOUR RECOMMENDATIONS.

A: My recommendations are:

- Require DTE to run regression analysis on reliability and disconnections for future rate cases, as well as distribution planning cases;
- Require DTE to collect disconnection information, aggregated to census tracts; and
- Require DTE to review its disconnection policies if disparities do exist when running a more detailed regression model.

Q. ARE YOU SPONSORING ANY EXHIBITS?

A. Yes. I am sponsoring these exhibits to accompany my direct testimony:

- CEO-21: Boratha Tan CV
- CEO-22: U-21860 BT FERC Form 1 Distribution Data
- CEO-23: U-21860 BT BLS Electric Power Generation Data
- CEO-24: U-21860 CEODE-5 & 5.1 2024 Non-payment Disconnects
- CEO-25: U-21680 BT RCode Disconnections 2025

II. DISTRIBUTION SPENDING

Q: WHY DID YOU ANALYZE DISTRIBUTION SPENDING INFORMATION FOR THIS CASE?

A: CEO Witnesses Curt Volkmann and Will Kenworthy requested this information from me. Specifically, they wanted to see DTE's annual Distribution Capital Additions. In 2024, Liberty Consulting (Liberty) conducted an audit on DTE's distribution grid.[1] Liberty's audit report highlighted the various ages of the distribution grid, such as:

- 28% of distribution poles were installed before 1960.
- 24% of substation transformers were installed before 1970.
- Half of the conductors with known ages date back to before 1970.[2]

Witness Volkmann discusses the Liberty audit report in more detail in his direct testimony. With a non-insignificant percentage of the distribution grid being over fifty years old, Witness Volkmann, Witness Kenworthy, and I hypothesized that the Company's historical spending on the distribution system could help explain why this is the case.

Witness Volkmann, Witness Kenworthy, and I posited that the Company has historically underinvested in the distribution system, compared to other utilities in the Midwest, which led to the significant amount of aging equipment in use today. This, in turn, would explain the resulting reliability issues that the Company consistently faces.

To make these comparisons, Witness Volkmann requested the same information be pulled for other utilities in the region. These "peer" utilities are Commonwealth Edison, Wisconsin Electric Power Company, Cleveland Electric, AES Indiana, Columbus

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[1] Case No. U-21305, Liberty Consulting Group Utility Distribution Audit of DTE Electric, September 23, 2024.
[2] Case No. U-21305, Liberty Consulting Audit Report, Part One at 10.

Southern, Duquesne, PECO, Consumers Energy, and Northern States Minnesota. These utilities each have at least half a million customers and are in the Midwest and/or the Rust Belt region.

Additionally, Witness Kenworthy asked to include Distribution Operation & Maintenance (O&M) and Distribution Plant in Service for my data consolidation.

Q: HOW DID YOU GATHER THE DISTRIBUTION SPENDING INFORMATION OF DTE ELECTRIC AND OTHER ELECTRIC UTILITIES?

A: I used the Federal Energy Regulatory Commission's (FERC's) Form No. 1. Per FERC's website, this Form is a "comprehensive financial and operating report submitted annually for electric rate regulation, market oversight analysis, and financial audits by Major electric utilities, licensees and others."[3] FERC currently allows the public to download Form No. 1 dating back to 1994.

Within FERC Form No. 1, Distribution Capital Additions are in Schedule 204. A utility's average number of customers are in Schedule 304. Spending for Distribution O&M can be found in Schedule 320. Finally, Distribution Plant in Service can be found in Schedule 204.

To access FERC Form No. 1, I downloaded Microsoft Access and FERC's Visual FoxPro Database.[4] I also used the Catalyst Cooperative's "Public Utility Data Liberation Project", or PUDL. The Catalyst Cooperative is a data engineering and analysis consultancy, specializing in energy systems and utility financial data.[5] The PUDL is an

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[3] https://www.ferc.gov/general-information-0/electric-industry-forms .

[4] https://www.ferc.gov/ferc-online/ferc-online/connecting-visual-foxpro-database-through-microsoft-access .

[5] https://catalyst.coop

"open-source python ETL pipeline that takes publicly available information about the US electricity sector and makes it publicly usable."[6]

Q: DID YOU USE ANY ADDITIONAL DATA SOURCES?

A: Yes, I did. I used the Energy Information Administration's (EIA's) Form 861.[7] EIA Form 861 hosts a utility's historic reliability metrics. Specifically, I searched for SAIFI (System Average Interruption Frequency Index), SAIDI (System Average Interruption Duration Index), and CAIDI (Customer Average Interruption Duration Index) information from the utilities I listed above. EIA currently allows the public to download Form 861, and reliability information dates to 2013.

Q: PLEASE DESCRIBE HOW YOU ANALYZED THE DATA.

A: In FERC Form No. 1, I pulled Schedules 204 (which contains all Electric Plants in Service), 304 (which contains customer count and electric sales information), and 320 (which contains O&M). I copied Distribution Capital Additions, average number of monthly customers, Distribution O&M, and Distribution Plant in Service into Exhibit CEO-22, U-21860 BT FERC Form 1 Distribution Data. For the Distribution-related data, I used the Bureau of Labor Statistics' Consumer Price Index (CPI) to adjust the data into 2024 dollars.[8] The CPI for electricity can be found searching for Series ID "CUURS000SEHF01." The inflation adjustment can also be determined using the BLS's inflation calculator.[9] Finally, for each utility, I divided each of these Distribution items by the total number of customers. In other words, I calculated the Distribution Capital

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[6] https://catalyst.coop/pudl/
[7] https://www.eia.gov/electricity/data/eia861/
[8] https://www.bls.gov/cpi/factsheets/household-energy.htm .
[9] https://www.bls.gov/data/inflation_calculator.htm .

Additions per customer, Distribution O&M per customer, and Distribution Plant in Service per customer. All this consolidated information can be found in Exhibit CEO-22, U-21860 BT FERC Form 1 Distribution Data.

Next, I took the average of all other utilities (excluding DTE) to find the "peer average." These values are what I use to compare against DTE.

Q: WHY DID YOU CONDUCT THIS ANALYSIS?

A: As stated earlier, the CEO hypothesized that DTE's historical underinvestment in the distribution system led to an aging grid that is contributing to worsening reliability. Because of reliability issues and the need to replace the oldest distribution equipment, the Company in turn has requested rate increases every year to catch up on the need to repair and upgrade the distribution system.

Institute of Electrical and Electronics Engineers (IEEE) hosts a "PES Distribution Reliability Working Group" that publishes annual electric utility reliability benchmark reports.[10] This benchmark report separates utilities' reliability performances into "quartiles", where the first quartile is the best and fourth quartile is the worst. For example, since 2017, DTE has been in the third and fourth quartiles for SAIDI. The Company has also done poorly in SAIFI and CAIDI.[11] My analysis of the Company's Distribution spending and historical reliability metrics attempts to help explain the Company's poor reliability performance.

[10] IEEE Benchmark Year 2024 Results for 2023 data. https://cmte.ieee.org/pes-drwg/wp-content/uploads/sites/61/2024-IEEE-Benchmarking-Survey.pdf .

[11] The comparisons are done by looking at the IEEE Benchmark 2024 Results for 2023 at 10, and Exhibit CEO-22.

Q: WHAT DID YOU FIND IN YOUR DATA ANALYSIS?

A: First, let's look at Distribution Capital Additions. This category best describes the new physical investments (such as poles, lines, and substations) a utility adds for that year. Regarding Distribution Capital Additions per customer, DTE was near or slightly above the peer average between 1994 and 2004. However, from 2005 to 2007, DTE's Additions fell below the peer average, picking back up in 2008. Since 2019, the Company has outspent the peer average. CEO Witness Volkmann discusses how the Company's Distribution Capital Additions per Customer relates to the Company's current spending an investment strategy.

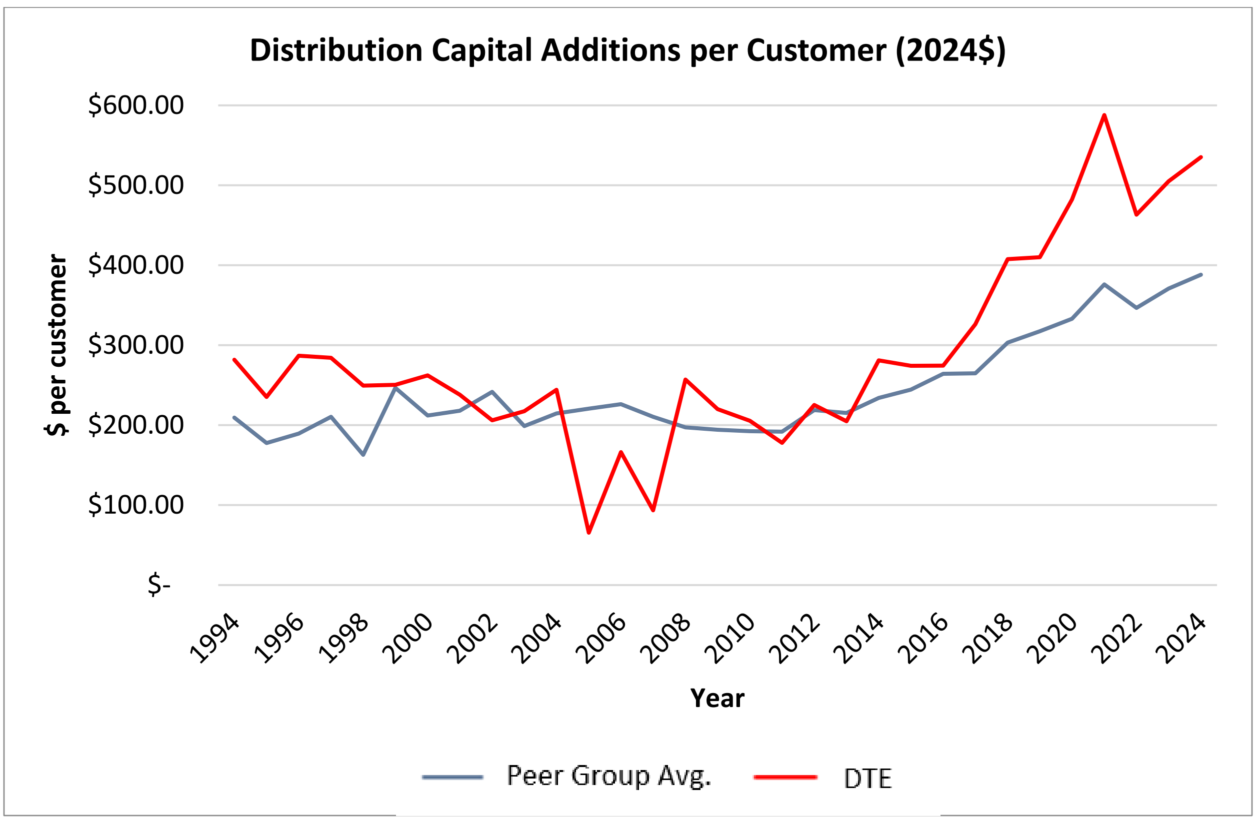


Figure 1: Distribution Capital Additions per Customer (to 2024 $)

Next, let's look at the Distribution Operations and Maintenance (O&M). Distribution O&M are expenses a utility incurs related to maintaining the grid, such as line and pole inspections, storm response, etc. For Distribution O&M per customer, DTE spent ***below the peer average from 1994 through around 2009***. Since then, the Company has been on par with the peer average.

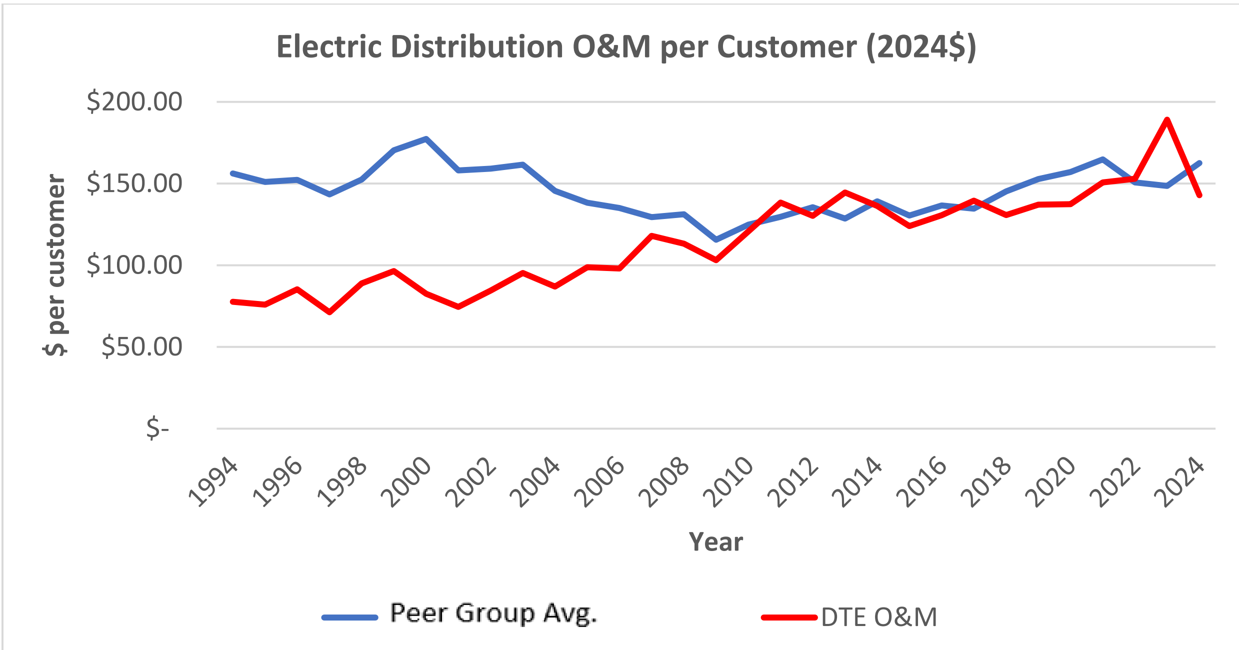


Figure 2: Electric Distribution O&M per Customer (to 2024 $)

Finally, let's look into Distribution Plant in Service, Figure 3 below. This category can be described as the overall (or total) value of all the distribution capital assets in the distribution grid. For Distribution Plant in Service per customer, the value of DTE's distribution system has been above the peer average in most years since 1994. CEO Witness Kenworthy details both categories in his testimony.

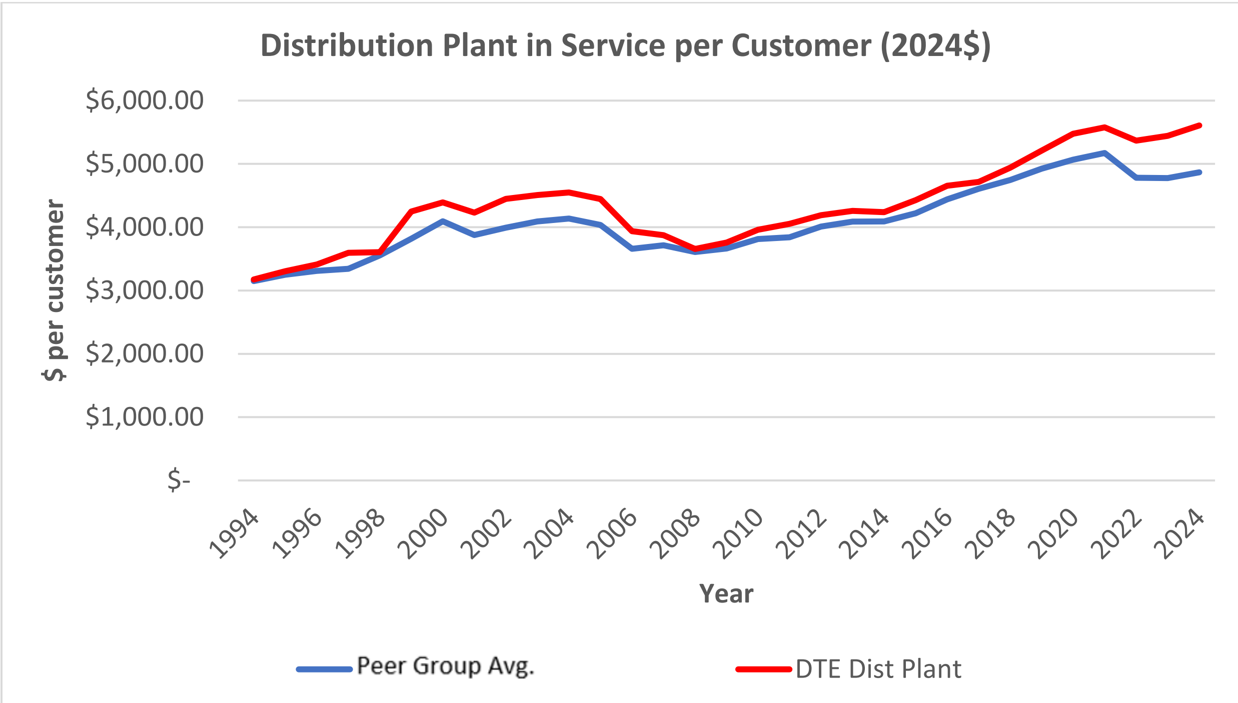


Figure 3: Distribution Plant in Service per Customer (to 2024 $)

Q: WHAT DO YOU MAKE OF THESE DISTRIBUTION SPENDING COMPARISONS?

A: I have a few takeaways. First, the Company's Distribution Capital (Dist. Cap.) Additions from 2005 to 2007 demonstrate that DTE significantly reduced their installations of new poles, wires, substations, and more during that time period. Second, despite the Company being on par with peer utilities on the Distribution Plant in Service, DTE spent less on O&M from 1994 to 2009 compared to peer utilities. In other words, for 15 years DTE was not spending as much to maintain the grid as other utilities. Meanwhile, its system reliability performance suffered.

Q: DID YOU DO ANY OTHER ANALYSES WITH THE DISTRIBUTION SPENDING INFORMATION?

A: Yes, I did. Using the reliability data gathered from EIA Form 861, I wanted to see if there were any trends between Distribution Capital Additions and reliability. As described earlier, the CEO expert team posit that the reliability issues DTE faces today are influenced by its historical distribution investments. For my testimony, I analyzed SAIDI with respect to Distribution Capital Additions. Because SAIDI measures the average duration of power interruptions, higher SAIDI scores means that customers were without power for longer. However, Exhibit CEO-22 also contains SAIFI and CAIDI data. A set of year-over-year graphs will be provided at the end of this section as well.

Between 2013 and 2019, DTE's SAIDI score without Major Event Days (MEDs)[12] remained close to 170 and 200 minutes. In the same amount of time, DTE increased their Distribution Capital Additions per customer, from around $200 to $400. However, when looking at 2020 onwards, DTE's SAIDI dropped to below 150 minutes and slowly climbed up through 2024, to just above 150 minutes. This coincides with the Company's rapid increase in their Distribution Capital Additions per customer, briefly spiking to nearly $600.

[12] Major Event Days (MEDs) are defined by IEEE 1366; a MED occurs when reliability performance affected from an extreme event, such as an ice storm or tornado. MEDs are determined by certain statistical thresholds from IEEE 1366.

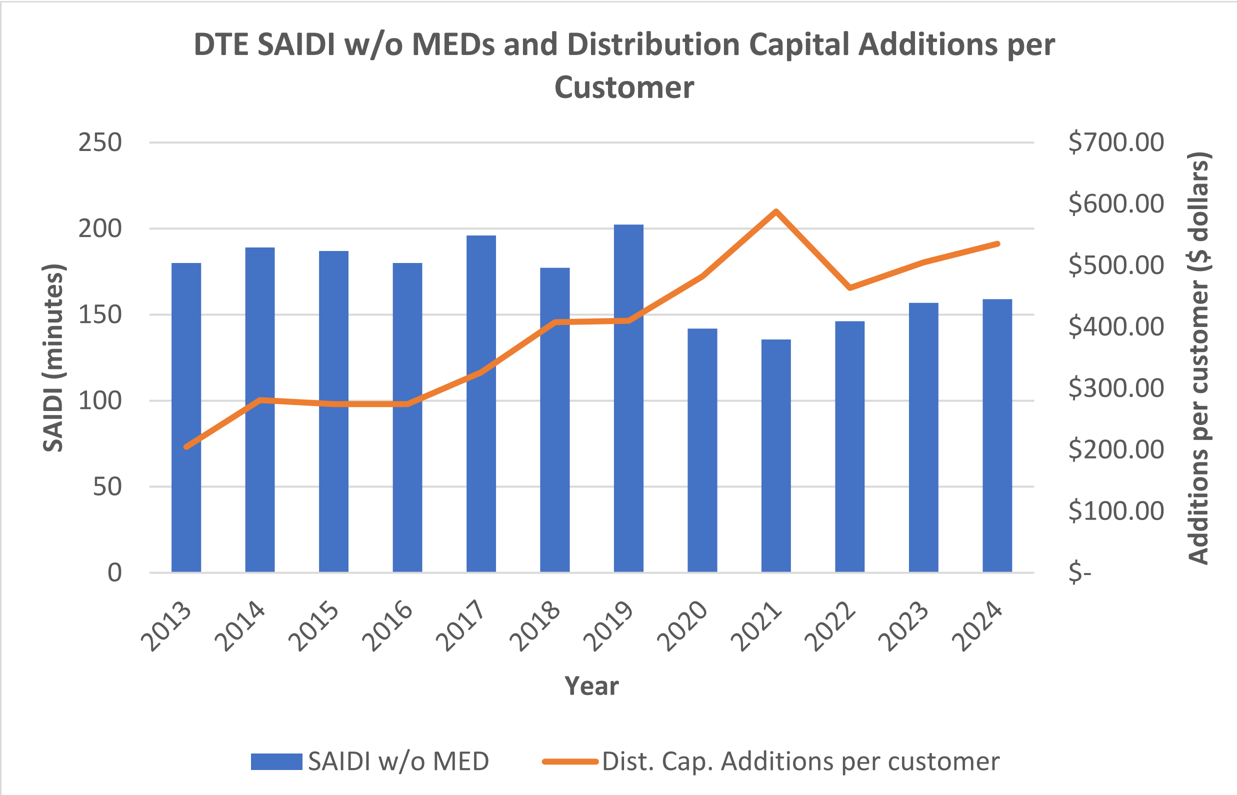


Figure 4: DTE SAIDI (without MEDs) versus Distribution Capital Additions per Customer (to 2024 $)

Based on this timeframe, there is a correlation between the rapid increase in Distribution Capital Additions and decline in SAIDI without MEDs starting in 2020. In other words, the Company's sharp increase in spending correlated to improved reliability. This correlation does make sense; as noted by DTE Witness Bill Chiu, outage duration decreased 38% compared to previous years because of the Company's capital investments.[13] Replacing old, ready-to-fail distribution equipment will help reliability.

Next, I included data from SAIDI with MEDs into the graph. SAIDI with MEDs have much wider scores, between 200 and over 1000 minutes. For a year like 2023, there were severe storms that impacted DTE's distribution system. Despite the Company's

[13] DTE Electric Company Direct Testimony of Witness Bill Chiu at BC-11:12-17.

Distribution Capital Additions in this time frame, DTE's grid still struggled to maintain reliability in the face of storms. In other words, the Company's distribution system needs to be more resilient.

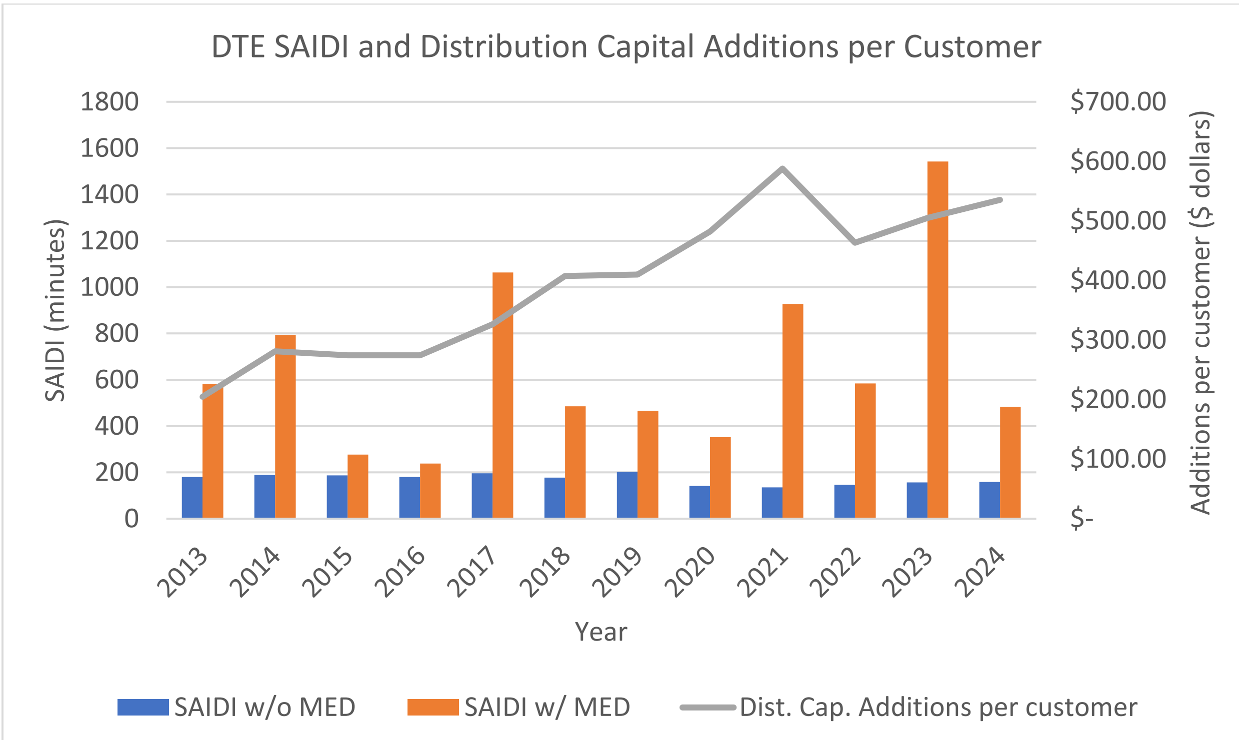


Figure 5: DTE SAIDI versus Distribution Capital Additions per Customer (to 2024$)

Finally, I looked at the peer average SAIDI versus DTE. Based on the 10 years of data available from the EIA, below is the comparison of SAIDI with and without MEDs. In this timeframe, DTE's SAIDI metrics are higher than the peer average, both with and without MEDs. The differences vary widely, with 2023 showing the worst difference between DTE and the peer utilities; DTE's SAIDI with MEDs is over 1500 minutes, while the peer average is around 360 minutes. Generally, compared to peer utilities, DTE's system was less reliable and its customers were impacted by longer power outages. Please note that reliability data for 2024 was not available for the peer utilities in EIA Form 861. Therefore, DTE's 2024 data was excluded from the comparisons below.

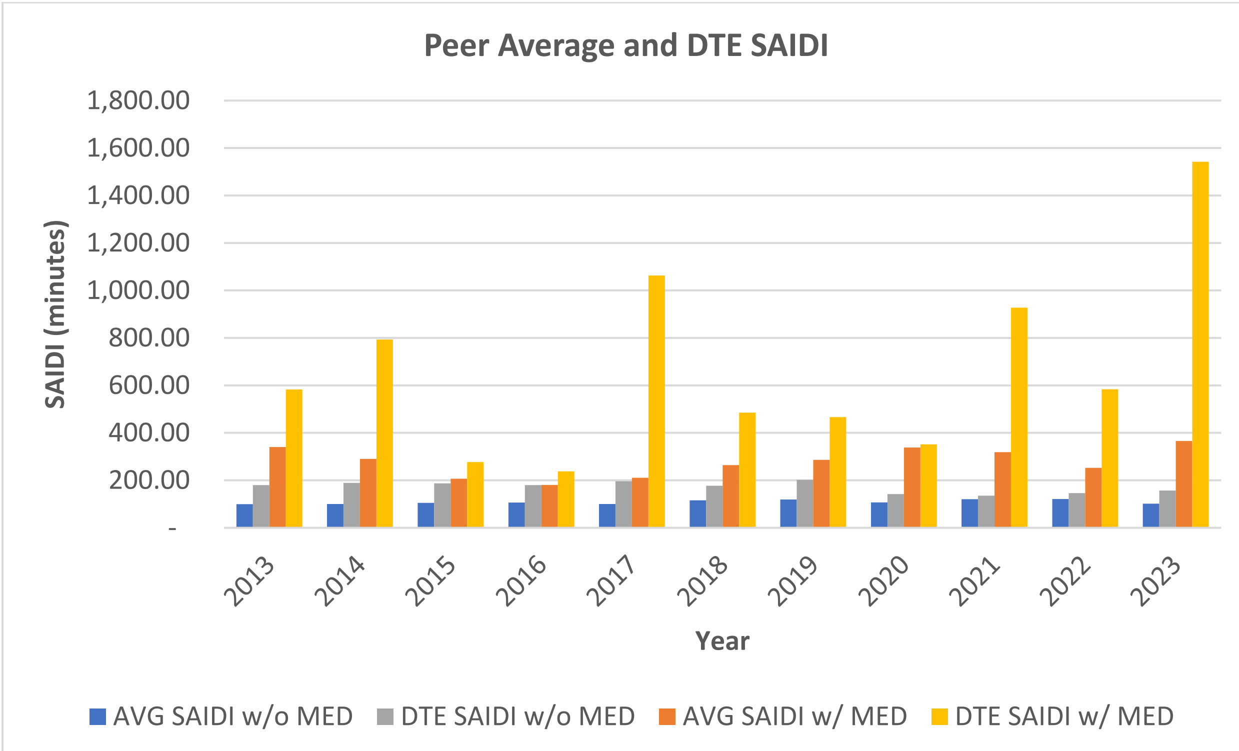


Figure 6: SAIDI Score, Peer Average versus DTE

Next, let's include Distribution Capital Additions into the SAIDI graphs. As mentioned earlier in my testimony, DTE has spent above the peer average for approximately the last ten years. In Figure 7 below, the SAIDI without MED score is compared to Distribution Capital Additions. DTE's SAIDI score remains higher than the peer average, and the Company's Distribution Capital Additions spending, overall, is higher than the peer average as well.

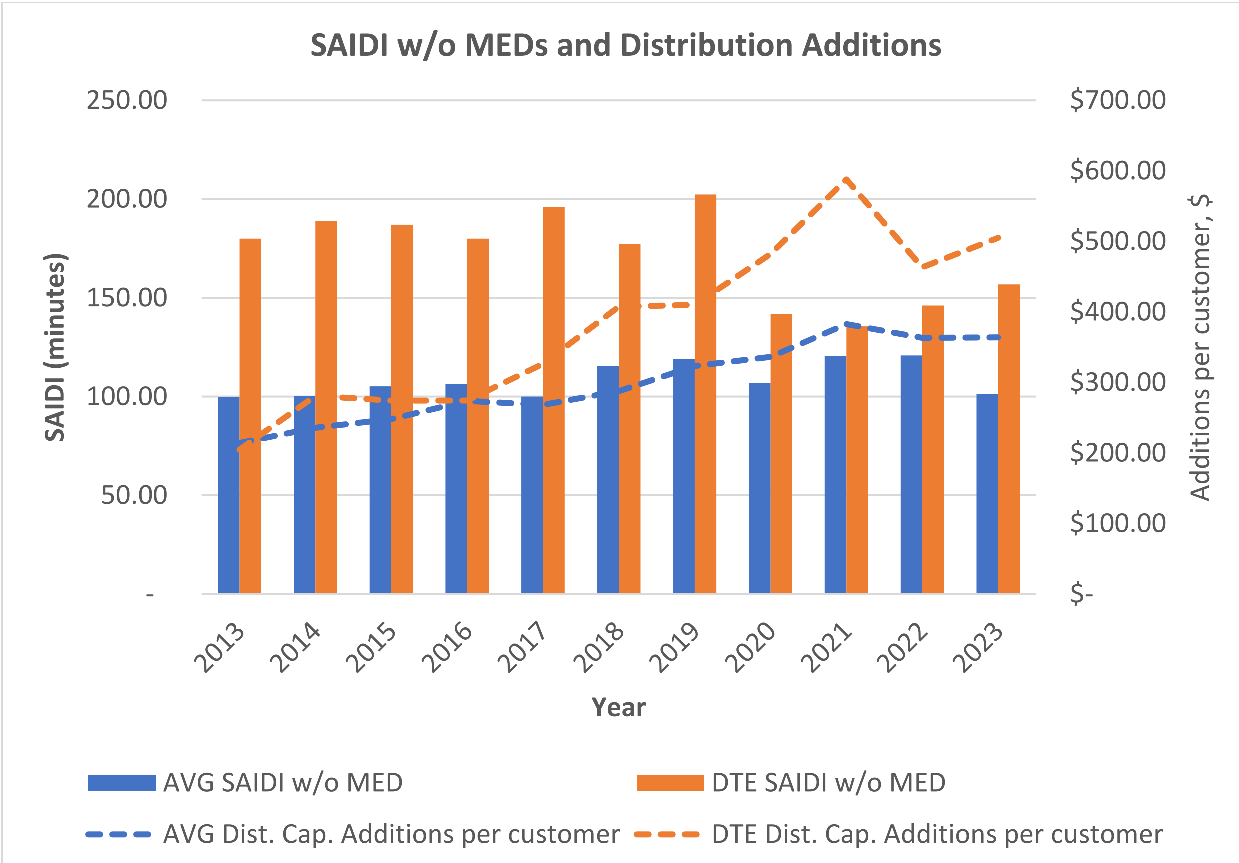


Figure 7: SAIDI, without MEDs, versus Distribution Capital Additions per Customer (to 2024 $)

Finally, I included the Distribution Capital Additions information into the SAIDI with MEDs graph. We see the same trends: DTE's SAIDI with MED score is higher than the peer average, and the Distribution Capital Addition spending is more than the peer average. Additionally, we see that DTE's top three highest SAIDI years, 2017, 2021, and 2024 are much higher than the peer average SAIDI scores of the same years.

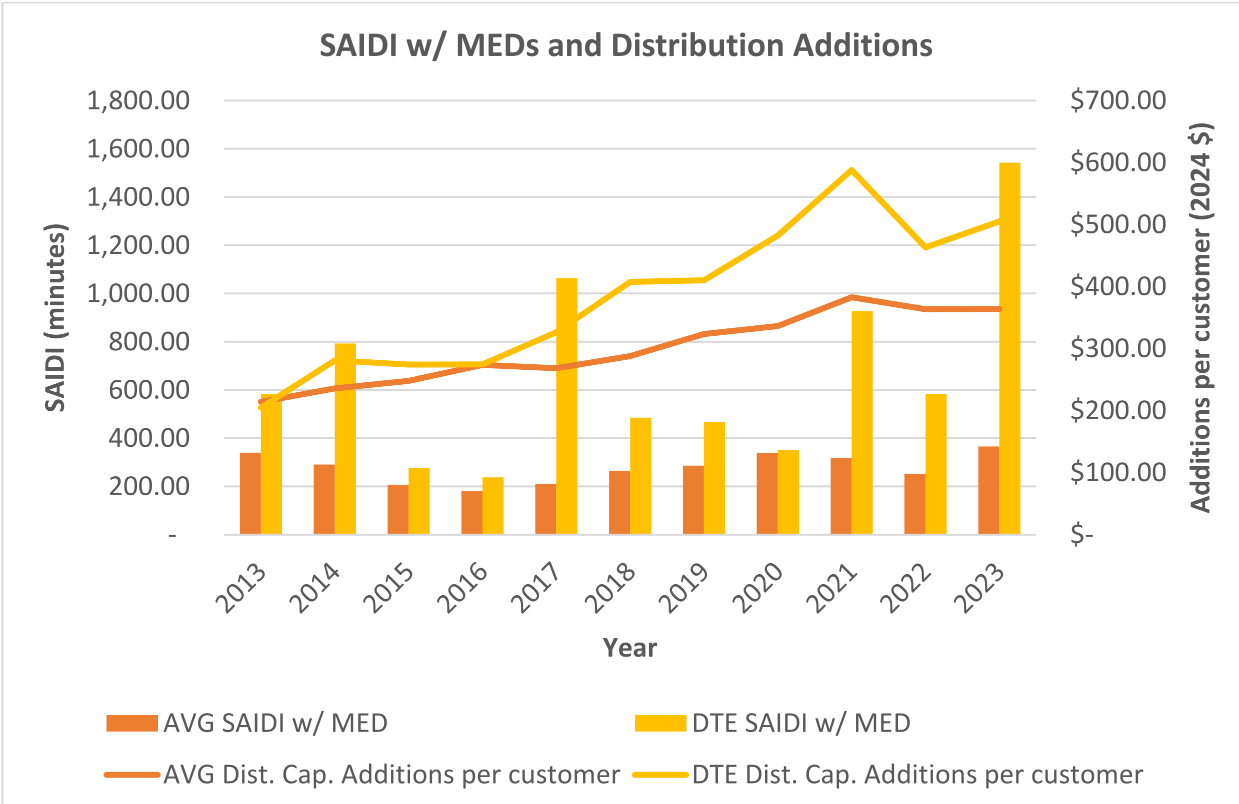


Figure 8: SAIDI, with MEDs, versus Distribution Capital Additions per Customer (to 2024 $)

Q: WHAT OTHER OBSERVATIONS DO YOU HAVE?

A: Based on observations in SAIDI data, it seems like DTE is attempting to improve its SAIDI score by spending above the peer average. While these increased investments are correlated with improved reliability in recent years, DTE remains behind its peer utilities because it is playing catch up from past years of under-investments in O&M and Distribution Capital. Even though SAIDI without MEDs, in the last few years, fell overall, the Company continues to struggle with reliability during storms and other Major Event Days. While DTE's Distribution Plant in Service is consistently above peer average, the Company's data shows that it has underinvested in O&M and Distribution Capital Additions in the past. DTE's historical distribution spending demonstrates that the Company is trying to catch up on fixing, maintaining, and improving the distribution grid. However, the

Company's reliability metrics, especially when facing Major Event Days, show that it is still lagging behind DTE's peer utilities. Without being able to dig through the historical spending in detail and getting a full picture of how DTE maintained the grid since 1994, I believe we need to look deeper into the Company's proposed Benefit Cost Analysis (BCA), Pole-Top Maintenance & Modernization (PTMM) program, and Distribution Automation (DA). In his testimony, Witness Volkmann goes into detail on all of these DTE programs.

Finally, I want to recognize that the peer utilities used for my distribution and reliability analyses are located throughout the Midwest and the Rust Belt. Based on their location and topology, each utility experiences weather differently; some operate in high elevation and/or forested areas, while others might experience more snow and sleet than others. Large storms might roll into a service territory like DTE's and dissipate by the time the clouds reach Duquesne Electric. If the Company would like to dig deeper into the peer average reliability data, I believe that accounting for location and topology (that I described above) can help further normalize the peer average data.

Q: CAN YOU SHARE THE YEAR-OVER-YEAR SAIFI AND CAIDI OBSERVATIONS?

A: Yes. Please see below for Figures 9 and 10. Just like what was seen in the SAIDI figures, DTE's SAIFI and CAIDI metrics are consistently higher than peer utilities in this ten-year period.

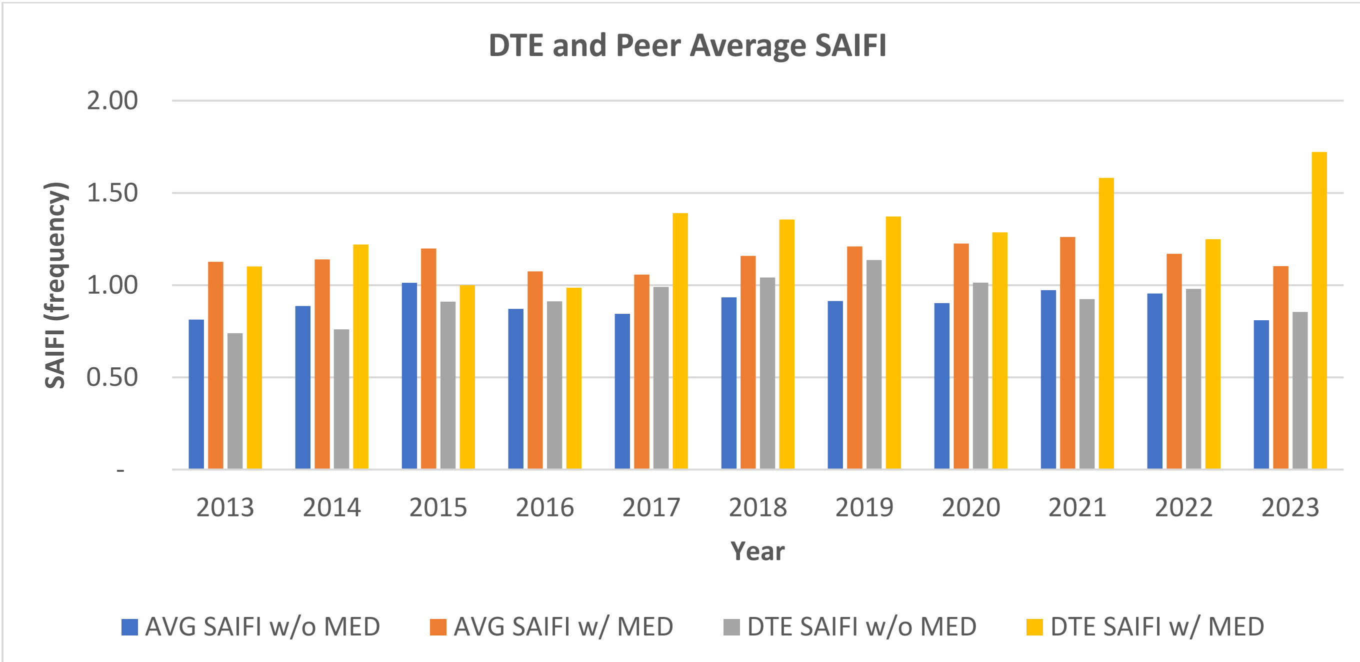


Figure 9: DTE vs Peer Average SAIFI, with and without MEDs

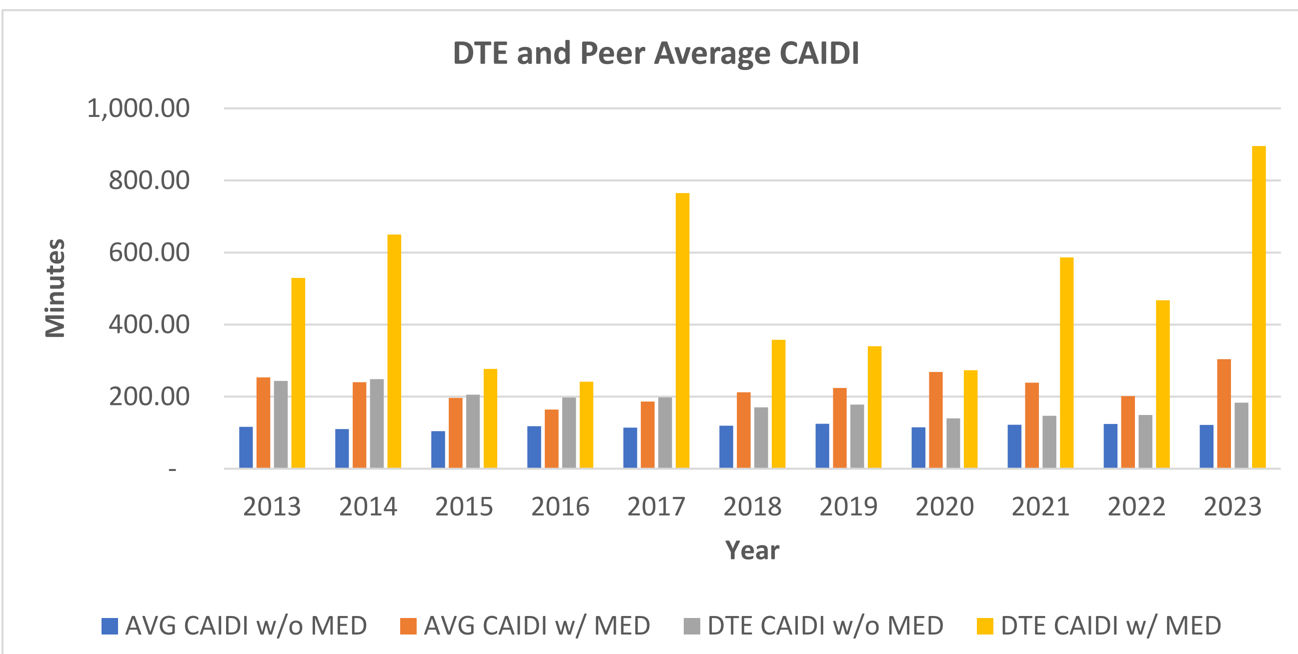


Figure 10: DTE CAIDI, with and without MEDs

III. PRODUCER PRICE INDEX

Q: WHAT IS THE PRODUCER PRICE INDEX?

A: The Producer Price Index (PPI) is provided by the U.S. Bureau of Labor Statistics (BLS). According to BLS, the PPI "measures the average change over time in the selling prices received by domestic producers for their output."[14] BLS hosts various industry data for the PPI. The relevant PPI industry data pertains to Electric Power Distribution. The Series ID to search for this PPI is "PCU221122221122."

Q: WHY IS THE PPI IMPORTANT?

A: The PPI is important because it helps us see how the prices of electric distribution equipment are escalating over time.

Q: HOW DID YOU ANALYZE THE PPI DATA?

A: The BLS PPI data goes back to 2003. However, I pulled data from the last ten years and indexed the price to 2020. In other words, I chose 2020 as the base year. This information can be found in Exhibit CEO-23, U-21860 BT BLS Electric Power Generation Data. Please see the table below for the results.

Year	Indexed to 2020
2020	100.0
2021	106.8
2022	123.5
2023	123.3
2024	126.2

Table 1: BLS-PPI for Electric Power Distribution, Indexed to 2020

When I indexed the PPI data to 2020 as the base year, the 2024 index is 126.2. In other words, material costs in 2020 for this sector were 26.2% higher than in 2020.

[14] https://www.bls.gov/ppi/

IV. RESIDENTIAL DISCONNECTIONS AND REGRESSION ANALYSIS

Q: CAN YOU DESCRIBE YOUR USE OF REGRESSION ANALYSIS IN PREVIOUS RATE CASES?

A: Yes. I used regression analysis in Case Nos. U-21297 and U-21534. In these DTE rate cases, I argued that the Company should use regression analysis as another tool to analyze reliability metrics, beyond comparing reliability averages, to better understand how different communities are experiencing outages.

My regression analysis in those cases used census tract demographic information to compare against DTE's SAIFI, SAIDI, and CAIDI information. I also argued that, to the extent possible, grid characteristics should be included in the regression model. This includes average age of poles, wires, recency of tree trimming, and more. By including these grid characteristics, the Company can control for certain variables to better understand if they correlate to improving or worsening reliability.

Q: WHY ARE YOU ANALYZING DISCONNECTION DATA?

A: In addition to outages, disconnections are an important indicator as to how customers experience the grid. Especially for low-income customers, their ability to pay utility bills and prevent disconnections relates to how often outages occur, because outages can be expensive for customers (*e.g.*, paying for more food and medicine after a long outage). Disconnections are another indicator that DTE should analyze when running future regression models. Therefore, I would like to understand if there are any patterns or disparities in the Company's residential disconnection information. By using regression analysis, I can control for certain factors to observe said disparities, if any.

Q: ARE YOU RUNNING THE SAME REGRESSION ANALYSIS FOR THIS RATE CASE AS USED IN PREVIOUS CASES?

A: No, I am not running the same regression model on reliability metrics, but instead focusing on disconnections. Even though I am not running a regression analysis on DTE's reliability metrics, I still recommend the Commission order the Company to run regression analysis for every rate case, as well as DTE's Distribution Grid Plans. Such an order would be consistent with the Commission's directive in Consumers Energy 2024 Rate Case, Case No. U-21585, where the Commission ordered Consumers Energy to run a regression analysis for future rate cases.

Q: DID YOU RUN REGRESSION DIFFERENTLY FOR THIS CASE?

A: Yes, I did. I ran a regression analysis using DTE's residential disconnection information. Specifically, I analyzed the Company's 2024 data on residential disconnections due to nonpayment.[15] The regression model on disconnections is the same model I ran for the Consumers Energy 2024 Rate Case.[16]

Q: HOW DID YOU SET UP THE REGRESSION MODEL?

A: The Company provided me disconnection data aggregated to zip codes.[17] Because disconnections often stem from late and unpaid bills, there is likely an income component to disconnections in that zip codes with lower incomes will experience higher disconnection rates. Therefore, I chose area median income (AMI) as an independent variable. Additionally, I chose race (or BIPOC/Black, Indigenous, People of Color) as the

[15] Exhibit CEO-25, CEODE-5.1 2024 Non-payment Disconnects.
[16] Case No. U-21585, Rebuttal Testimony of CEO Witness Boratha Tan at 6.
[17] Exhibit CEO-24, U-21860 CEODE-5 Discovery Response.

other independent variable. In my regression model, I converted AMI into $10,000 increments, and converted BIPOC into a percentage of the population in a zip code.

Q: WHAT DID YOU FIND?

A: Table 3 shows my regression output. Also, please see the bullet points below to see how to interpret the regression results:

- In column 1, I only analyzed AMI. For a $10,000 increase in AMI, a zip code experiences 134 fewer residential disconnections.
- In column 2, I only analyzed percent (%) BIPOC. A 100% BIPOC zip code experiences, on average, 2499 more residential disconnections than a 0% BIPOC zip code. Of course, many zip codes have different concentrations of BIPOC residents. Therefore, column 2 can also be interpreted as: a 1% increase in BIPOC concentration, say from 20% to 21% BIPOC, is associated with an increase of 24.99 (or 25) disconnections.
- In column 3, I analyzed both independent variables. Holding income constant, a 100% BIPOC zip code experiences, on average, 2348 more residential disconnections than a 0% BIPOC zip code. Just like in column 2, a realistic way to interpret this result is: holding income constant, a 1% increase in BIPOC concentration is associated with an increase of 23.48 disconnections in a particular zip code.

Table: 2024 Residential Disconnection Results w/ Income and % BIPOC

	Dependent variable:		
	disconnect		
	(1)	(2)	(3)
ami	-134.088***		-34.929**
	(17.614)		(13.862)
bipoc		2,499.159***	2,348.124***
		(126.715)	(139.486)
Constant	1,562.203***	52.310	328.155***
	(129.310)	(44.297)	(117.728)
Observations	293	295	293
R^2	0.166	0.570	0.578
Adjusted R^2	0.163	0.569	0.575
Residual Std. Error	787.737 (df = 291)	564.466 (df = 293)	561.183 (df = 290)
F Statistic	57.949*** (df = 1; 291)	388.984*** (df = 1; 293)	198.784*** (df = 2; 290)
Note:			*p<0.1; **p<0.05; ***p<0.01

Table 2: DTE Residential Disconnections via Zip Code, with Area Median Income and % BIPOC

Q: DID YOU ATTEMPT TO LOOK AT INDIVIDUAL ZIP CODES?

A: Yes, I did. I looked at zip codes that corresponded to Wayne County and Washtenaw County. Wayne County contains the City of Detroit, and Washtenaw County contains the city of Ann Arbor. I wanted to analyze disconnections in these two areas to see if one city faced more disconnections than another.

Q: WHAT DID YOU FIND?

A: Table 4 shows the results of my regression between both counties. Here is how I interpret the results:

- For Wayne County, holding income constant, a 100% BIPOC zip code experiences 2136 more disconnections than a 0% BIPOC zip code.
- For Washtenaw County, holding income constant, a 100% BIPOC zip code experiences 2731 more disconnections than a 0% BIPOC zip code.

Please note that there are 13 zip codes in the Washtenaw analysis. According to the central limit theorem, a data set is normally considered "sufficiently large" when it includes at least 30 samples. Therefore, I would take this analysis with a grain of salt. Additionally, area median income does not have a significant effect on Wayne County zip codes. Despite these, this county analysis does reflect the values seen in the overall regression analysis.

Table: 2024 Wayne vs Washtenaw Disconnection Results

	Dependent variable:	
	disconnect	
	Wayne Cty Zip	Washtenaw Cty Zip
	(1)	(2)
ami	-30.985	-73.408
	(68.450)	(87.882)
bipoc	2,136.050***	2,731.107**
	(561.176)	(1,009.595)
Constant	684.114	500.025
	(620.676)	(829.130)
Observations	61	13
R^2	0.389	0.551
Adjusted R^2	0.368	0.461
Residual Std. Error	985.438 (df = 58)	521.491 (df = 10)
F Statistic	18.437*** (df = 2; 58)	6.131** (df = 2; 10)
Note:		*p<0.1; **p<0.05; ***p<0.01

Table 3: DTE Residential Disconnection via Zip Code, Comparing Wayne and Washtenaw Counties

Q: DO YOU HAVE ANY OTHER OBSERVATIONS?

A: Yes, I do. While the regression results do show that there is a significant number of disconnections occurring in BIPOC zip codes, the geographic size of zip codes does limit how confidently we can make conclusions based on this data. A single zip code can contain a number of communities with distinct demographics, including income and race. Additionally, there is not an equal spread of race in all the zip codes in DTE's service territory. For example, please look at Figure 11 below. Each circle represents a zip code. A vast number of circles are concentrated in the zero to 20% BIPOC population range. This means that we need to acknowledge any potential skewing that might be occurring in the data.

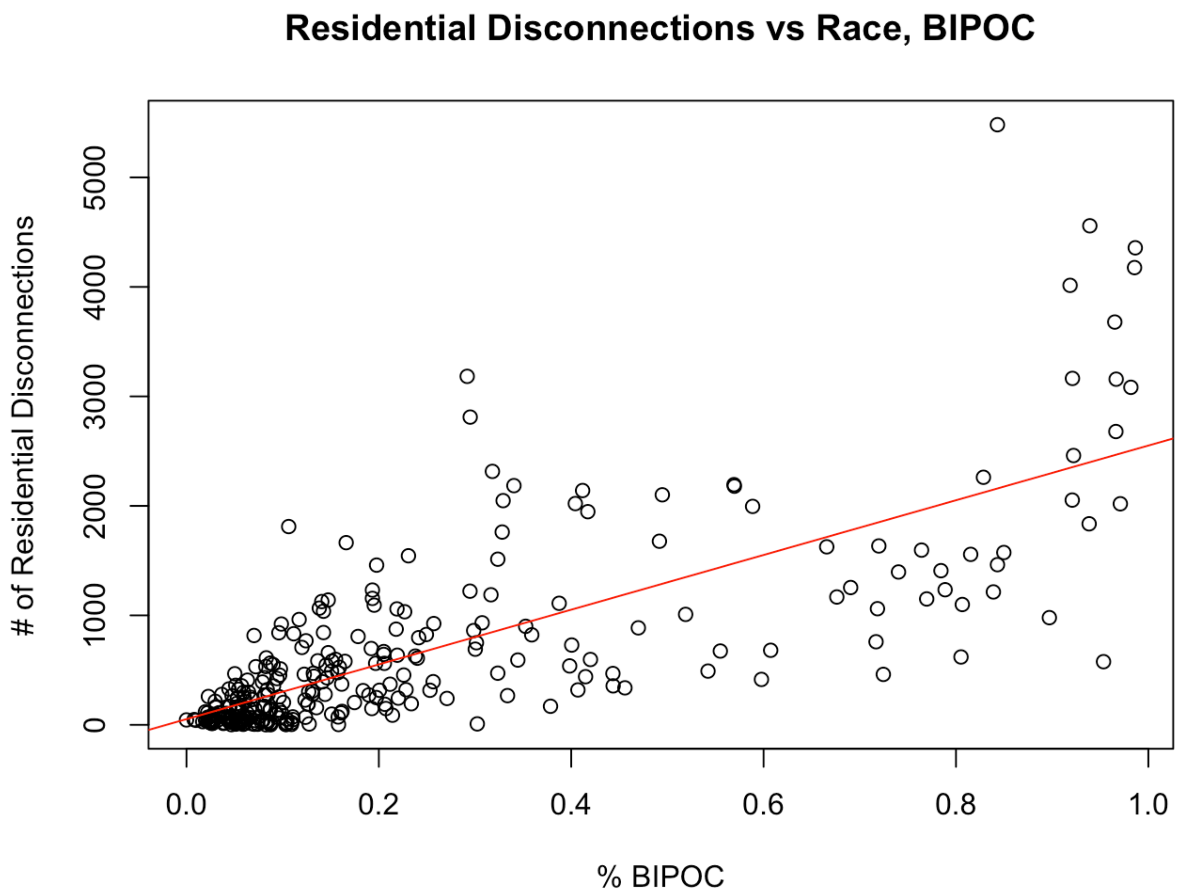


Figure 11: DTE's 2024 Residential Disconnections versus Race, based on % BIPOC

Next, let's look at Figure 12, showing a histogram of how BIPOC communities are in each zip code. Out of a total of 1,620,993 BIPOC residents in these zip codes,[18] Figure

[18] CEO Witness Boratha Tan's Workpaper "Workpaper_U-21860_RegressionTables.txt", based on 2020 US Census data, aggregated to zip codes.

12 shows us that the BIPOC residents are mostly concentrating in a select number of zip codes (the right side of the histogram).

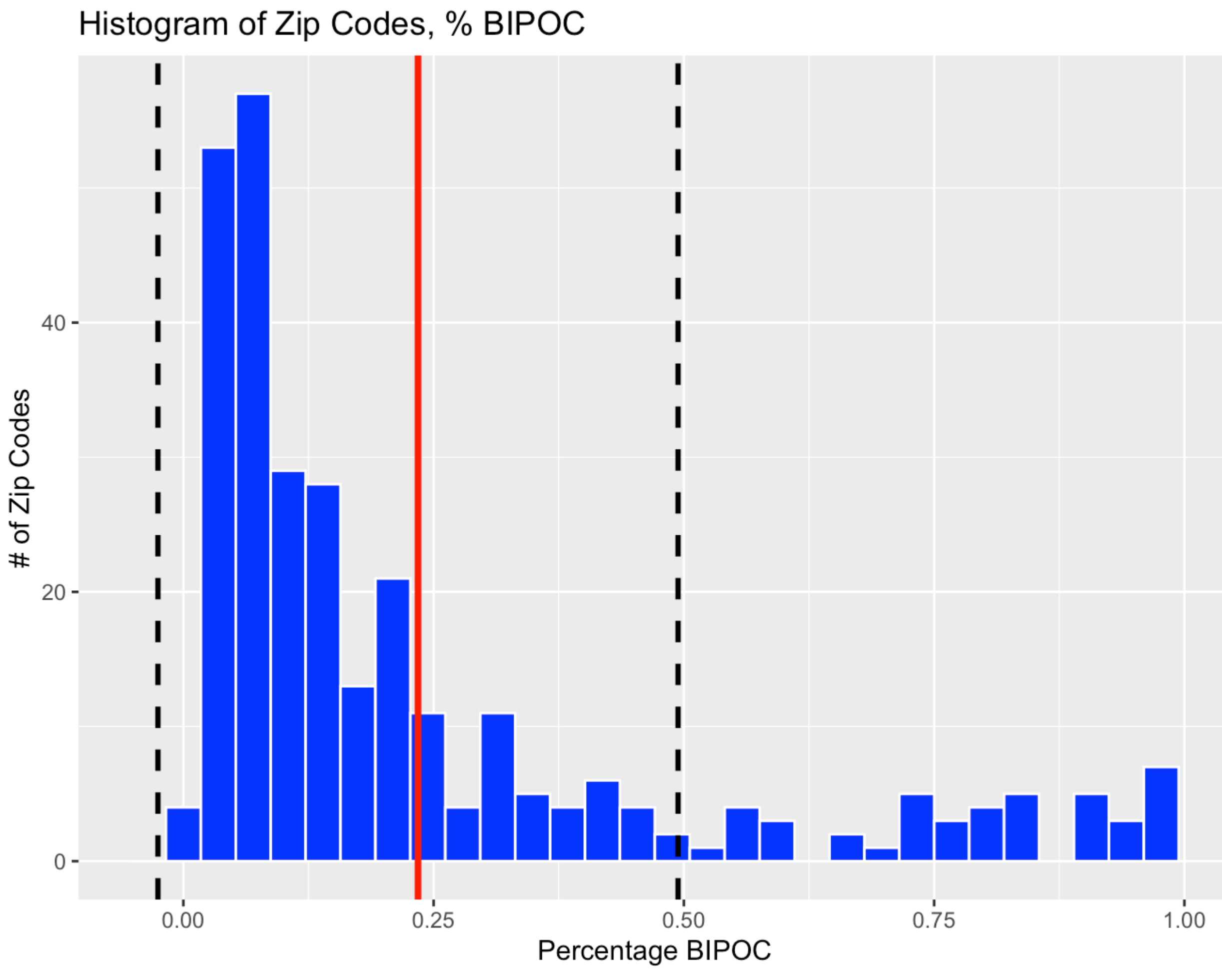


Figure 12: Number of Zip Codes based on Percentage BIPOC Population, DTE's Service Territory (Note: the red line denotes the mean of % BIPOC)

Instead, using smaller geographical areas, such as census tracts, would do a much better job describing the demographics of a community. Because of this, I recommend the Company record and maintain its residential disconnection data aggregated to census tracts.

Notwithstanding the use of zip code-level data, I do believe these results strongly demonstrate a need for analyzing disconnections more closely. The "R-squared" seen in

Table 3, Column 3 is a very high value. In the field of statistics, the R-squared is an indicator of how well the independent variables captures the dependent variable. In other words, both area median income and percentage BIPOC do a good job in predicting the number of disconnections in a particular zip code. In fact, this R-squared is the highest R-squared I have ever seen while running regression analyses for Vote Solar. This indicates extremely strong correlations between disconnections and income levels as well as disconnections and the racial makeup of customers' neighborhoods.

Not only should DTE review its disconnection policies, but DTE should also analyze if indeed customers are disconnected differently based on where they live (such as Wayne County versus Washtenaw County), or the racial makeup or income levels of their neighborhoods.

V. <u>CONCLUSIONS AND RECOMMENDATIONS</u>

Q: WHAT ARE YOUR RECOMMENDATIONS AND CONCLUSIONS?

A: Here are some of my conclusions:

- The Company's historical Distribution Capital Additions and O&M showed that it has underinvested compared to its peer utilities, and
- The Company's historical reliability metrics are always worse than its peer utilities.

I recommend DTE Electric to:

- Collect and aggregate disconnections into census tracts, as well as zip codes, and
- Review its residential disconnection policies.

I also request the Commission to:

- Order DTE Electric to include regression analysis as part of all future rate cases and Distribution Grid Plans, and
- Order DTE to also include residential disconnections in these regression analyses.

Q: DOES THIS CONCLUDE YOUR TESTIMONY?

A: Yes

Boratha Tan
515 Rosedale Ct, Detroit, MI 48202
Work: Btan@votesolar.org

Education

University of Michigan, Gerald R. Ford School of Public Policy — Ann Arbor, MI
Master of Public Policy — 2023

Relevant Coursework: Cybersecurity for Future Leaders, Science and Technology Policy, Public Management, Sustainable Energy Systems, Narrative Advocacy & Policy Change

Villanova University — Villanova, PA
Bachelor of Science Mechanical Engineering — 2016
Minor: Peace and Justice Education

Professional Experience

Vote Solar — Detroit, MI
-*Senior Regulatory Manager, Midwest* — Feb 2025 to Present

- Lead modeling studies of distributed generation assumptions in utility cases
- Lead data analysis of utility reliability
- Work with non-profit stakeholders to promote cleaner, more affordable energy for low-income families
- Participate in utility rate cases, resource cases, and grid reliability cases in Michigan, Illinois, Indiana, and Minnesota
- Advance arguments for grid equity and energy justice in utility regulation

-*Regulatory Manager, Midwest* — Dec 2022 to Feb 2025

National Conference of State Legislatures — Denver, CO
-*Policy Analyst Intern*, Environment, Energy, and Transportation — May 2022 to Aug 2022

- Provide state legislators with regional energy policies
- Support research requests on energy policy
- Lead program deliverables for the Department of Energy
- Support energy program planning and logistics for state legislators

Candidate, US House of Representatives — Detroit, MI
-*Michigan 13th District Candidate* — May 2022

- Write-in campaign for the August 2022 Primary

Ford Motor Company — Dearborn, MI
-*Core Electric Drive Engineer*, Electrified Systems Engineering — Jan 2019 to Apr 2022

- Lead early prototype builds, testing of future products
  - Delivered motor results critical to program progression
- Oversee early prototype timeline
- Manage later-stage prototype testing
  - Led root-cause analysis of first in-house motor
- Lead cross-functional team lessons learned meetings

-*Ford College Graduate Engineer*, Electrified Systems Engineering — Jul 2016 to Jan 2019

- Core high voltage battery engineer, future battery packs
- Core motor engineer, motor design

- Design and release engineer, Ford Escape Hybrid and Lincoln Corsair

Golden West Humanitarian Foundation
-*Research Engineer*, Cambodia Field Office May 2016 to July 2016
- Lead in-field testing and troubleshooting of low-cost Explosive Ordnance Disposal Robot

Leadership and Service

Villanova University
-*Board Member,* Young Adult Alumni Council (YAAC) Oct 2023 to Present

University of Michigan Rackham Graduate School
-*Student Government Sustainability Officer* Aug 2022 to Apr 2023
- Lead sustainability programs for UofM graduate students

Villanova College of Engineering
-*Board Member,* Young Alumni Board Oct 2021 to Present
- Provide recommendations on the College's mission
- Promote DEI initiatives within the College

Detroit Design Core (DDC)
-*DDC Design Challenge Advisor* Mar 2021 to Mar 2022
- Facilitate design thinking sessions with non-profits
- Provide technical input on non-profit projects

Villanova Alumni Association
-*Vice President,* Club of Michigan Feb 2021 to Present
- Support planning for professional development and social events for local alumni
- Lead new programs to engage regional alumni

Freedom House Detroit
-*Fundraising Committee* Jan 2021 to Oct 2021
- Lead production crew for hybrid programming

Community Action Network (CAN)
-*Advisor* Feb 2020 to June 2020
- Provide input for STEM activities, which were implemented in summer programs

Contemplative Leaders in Action (CLA)
-*Detroit Cohort* Aug 2018 to Apr 2020
- Incorporate Ignatian contemplation into leadership
- Create a design of an early childhood reading program for local parish

Ss. Peter and Paul Jesuit Church
-*Parish Council and Social Justice Committee* Feb 2017 to May 2023
- Lead town halls for community input
- Support strategic plan development
- Lead DEI events for parish
- Participate in ecumenical meetings to address city's inequality

Thirty Under 30
-*Ford Cohort* Jan 2017 to Dec 2017
- Incorporate human-centered design into non-profit outreach

FIRST Robotics
-*Mentor,* Hamtramck High School Jan 2017 to Mar 2021
- Mentor high school students in robotics program

Skills

Additional Language: Khmer (native speaking)
Software & Apps: R (RStudio), Stata, Arduino, MATLAB, SOLIDWORKS, Autodesk, Microsoft Office, Westlaw, State Net (LexisNexis), Python
Certificates: NMSU Center for Public Utilities "The Basics"

Awards & Patents

Methods for Predicting Stator Insulation Condition, US 2025/12333735 B2 – US Patent 2025
Methods for Varnish Analysis of Stator Images, US 2025/12293507 B2 – US Patent 2025
Non-destructive E-Motor Analysis, US 2024/0112350 A1 – US Patent 2024
Methods for Stator Varnish Analysis, US 2024/0112319 A1 – US Patent 2024
Methods for Predicting Stator Insulation, US 2024/0112351 A1 – US Patent Office 2024

Rev. Ray Jackson Community Service Award – Villanova University 2021
Illuminating Innovation and Excellence Award – Ford Motor Company 2021

Op-Eds & Writings

"When the Lights Go Out: Michigan's Tale of Two Power Grids." *Vote Solar*, 2 Apr. 2025, https://votesolar.org/when-the-lights-go-out-michigans-tale-of-two-power-grids/
"Wiring the Divide: The Impact of Redlining on Electric Infrastructure." *Vote Solar*, 13 Nov. 2024, https://votesolar.org/wiring-the-divide-the-impact-of-redlining-on-electric-infrastructure/
"Advancing energy justice: A new paradigm in grid equity and reliability analysis." *Utility Dive*, 26 Feb. 2024, https://www.utilitydive.com/news/advancing-energy-justice-grid-equity-reliability-regression-analysis/707350/.
"Tan and Shah: Development of clean energy stifled by utilities." *The Detroit News*, 17 Oct. 2023, https://www.detroitnews.com/story/opinion/2023/10/17/tan-and-shah-development-of-clean-energy-stifled-by-utilities/71215180007/.
"Environmental Justice and Grid Equity is Necessary for Michigan's Energy System." *Vote Solar*, 28 Feb. 2023, https://votesolar.org/environmental-justice-and-grid-equity-is-necessary-for-michigans-grid/.
"States Move to Protect Energy Infrastructure." *National Conference of State Legislatures*, 9 Nov. 2022, https://www.ncsl.org/state-legislatures-news/details/states-move-to-protect-energy-infrastructure.
"Facing Extreme Weather, States Explore Ways to Improve Energy Resilience." *National Conference of State Legislatures*, 12 Oct. 2022, https://www.ncsl.org/state-legislatures-news/details/facing-extreme-weather-states-explore-ways-to-improve-energy-resilience.

Regulatory Cases

Michigan
- *U-20147, comments (Distribution Grid Plans)*

- *U-20890, comments (Distributed Generation Case)*
- *U-21193 (DTE IRP 2022)*
- *U-21297 (DTE Rate Case 2023)*
- *U-21374 (Consumers Volunteer Green Pricing 2023)*
- *U-21389 (Consumers Rate Case 2023)*
- *U-21400 (Utility Financial Incentives and Disincentives)*
- *U-21461 (I&M Rate Case 2023)*
- *U-21480, comments (Consumers Interconnection Procedures)*
- *U-21482, comments (DTE Interconnection Procedures)*
- *U-21534 (DTE Rate Case 2024)*
- *U-21585 (Consumers Rate Case 2024)*
- *U-21637, comments (Rate Case Improvement Docket)*
- *U-21638, comments (Public Engagement Docket)*
- *U-21860 (DTE Rate Case 2025)*

Illinois

- *22-0486 (INITIAL and REFILED ComEd MYIGP/RP 2022/23)*
- *22-0487 (REFILED AIC MYIGP/RP 2022/23)*
- *23-0714 (IPA Long-Term Renewable Resource Procurement Plan)*
- *25-0083 (AIC Rate Design Investigation)*

Indiana

- *AES Indiana IRP – 2022*
- *CenterPoint Energy Indiana South IRP – 2023*
- *Duke Energy IRP – 2024/25*

Minnesota

- 24-0067 (*Xcel Integrated Resource Plan 2024*)

DTE		Schedule 204		Schedule 304			Schedule 320				Schedule 204				EIA 861 Reliability					
report_year	Inflation adj to 2024	additions (no inflation adj)	Additions (infl adj)	avg customers per month	Additions per customer (additions/customers)	Additions per customers (infl adj)	Dist O&M	Dist O&M (infl adj)	Dist O&M per customer (dist OM/customers)	Dist O&M per customer (infl adj)	Dist plant in service	Dist plant in service (infl adj)	Dist Plant per customer (Dist/customer)	Dist Plant per customer (infl adj)	SAIFI w/o MED	SAIDI w/o MED	CAIDI w/o MED	SAIFI w/ MED	SAIDI w/ MED	CAIDI w/ MED
1994	2.2026	$ 229,956,832	$ 506,502,918	1,796,781	$ 127.98	$ 281.89	$ 139,565,424	$ 307,406,803	$ 77.68	$ 171.09	$ 2,589,734,400	$ 5,704,148,989	$ 1,441.32	$ 3,174.65						
1995	2.1538	$ 198,338,080	$ 427,180,557	1,815,372	$ 109.25	$ 235.31	$ 137,704,912	$ 296,588,839	$ 75.85	$ 163.38	$ 2,785,385,984	$ 5,999,164,332	$ 1,534.33	$ 3,304.65						
1996	2.1182	$ 248,676,384	$ 526,746,317	1,835,944	$ 135.45	$ 286.91	$ 156,516,256	$ 331,532,733	$ 85.25	$ 180.58	$ 2,956,629,504	$ 6,262,732,615	$ 1,610.41	$ 3,411.18						
1997	2.1071	$ 250,813,760	$ 528,489,674	1,859,432	$ 134.89	$ 284.22	$ 132,467,624	$ 279,122,531	$ 71.24	$ 150.11	$ 3,173,227,264	$ 6,686,307,168	$ 1,706.56	$ 3,595.89						
1998	2.1914	$ 234,637,840	$ 514,185,363	2,061,668	$ 113.81	$ 249.40	$ 183,401,120	$ 401,905,214	$ 88.96	$ 194.94	$ 3,393,239,296	$ 7,435,944,593	$ 1,645.87	$ 3,606.76						
1999	2.207	$ 237,499,104	$ 524,160,523	2,091,894	$ 113.53	$ 250.57	$ 201,854,560	$ 445,493,014	$ 96.49	$ 212.96	$ 4,025,910,272	$ 8,885,183,970	$ 1,924.53	$ 4,247.44						
2000	2.1723	$ 253,761,584	$ 551,246,289	2,101,123	$ 120.77	$ 262.36	$ 173,381,824	$ 376,637,336	$ 82.52	$ 179.26	$ 4,249,324,288	$ 9,230,807,151	$ 2,022.41	$ 4,393.27						
2001	2.0254	$ 248,934,480	$ 504,191,896	2,116,890	$ 117.59	$ 238.18	$ 157,709,568	$ 319,424,959	$ 74.50	$ 150.89	$ 4,422,054,400	$ 8,956,428,982	$ 2,088.94	$ 4,230.94						
2002	2.0486	$ 214,472,544	$ 439,368,454	2,132,404	$ 100.58	$ 206.04	$ 180,204,080	$ 369,166,078	$ 84.51	$ 173.12	$ 4,628,989,952	$ 9,482,948,816	$ 2,170.78	$ 4,447.07						
2003	2.0008	$ 232,107,536	$ 464,400,758	2,136,358	$ 108.65	$ 217.38	$ 203,550,400	$ 407,263,640	$ 95.28	$ 190.63	$ 4,813,080,064	$ 9,630,010,592	$ 2,252.94	$ 4,507.68						
2004	1.9642	$ 267,038,848	$ 524,517,705	2,146,636	$ 124.40	$ 244.34	$ 186,689,696	$ 366,695,901	$ 86.97	$ 170.82	$ 4,971,232,768	$ 9,764,495,403	$ 2,315.82	$ 4,548.74						
2005	1.8504	$ 76,410,808	$ 141,390,559	2,158,201	$ 35.40	$ 65.51	$ 213,229,888	$ 394,560,585	$ 98.80	$ 182.82	$ 5,184,641,024	$ 9,593,659,751	$ 2,402.30	$ 4,445.21						
2006	1.6497	$ 218,527,568	$ 360,504,929	2,168,455	$ 100.78	$ 166.25	$ 212,646,672	$ 350,803,215	$ 98.06	$ 161.78	$ 5,175,689,216	$ 8,538,334,500	$ 2,386.81	$ 3,937.52						
2007	1.5873	$ 127,479,088	$ 202,347,556	2,163,360	$ 58.93	$ 93.53	$ 255,312,480	$ 405,257,500	$ 118.02	$ 187.33	$ 5,281,574,400	$ 8,383,443,045	$ 2,441.38	$ 3,875.20						
2008	1.4913	$ 370,790,496	$ 552,959,867	2,150,421	$ 172.43	$ 257.14	$ 243,484,080	$ 363,107,809	$ 113.23	$ 168.85	$ 5,272,567,296	$ 7,862,979,609	$ 2,451.88	$ 3,656.48						
2009	1.4482	$ 324,093,792	$ 469,352,630	2,133,001	$ 151.94	$ 220.04	$ 220,035,312	$ 318,655,139	$ 103.16	$ 149.39	$ 5,535,201,280	$ 8,016,078,494	$ 2,595.03	$ 3,758.12						
2010	1.4453	$ 301,288,864	$ 435,452,795	2,119,747	$ 142.13	$ 205.43	$ 256,031,232	$ 370,041,940	$ 120.78	$ 174.57	$ 5,807,703,552	$ 8,393,873,944	$ 2,739.81	$ 3,959.85						
2011	1.4186	$ 265,827,456	$ 377,102,829	2,120,262	$ 125.37	$ 177.86	$ 293,444,416	$ 416,280,249	$ 138.40	$ 196.33	$ 6,056,464,384	$ 8,591,700,375	$ 2,856.47	$ 4,052.19						
2012	1.4196	$ 336,843,040	$ 478,182,380	2,123,370	$ 158.64	$ 225.20	$ 276,530,624	$ 392,562,874	$ 130.23	$ 184.88	$ 6,266,139,136	$ 8,895,411,117	$ 2,951.03	$ 4,189.29						
2013	1.3902	$ 314,418,496	$ 437,104,593	2,134,162	$ 147.33	$ 204.81	$ 308,569,280	$ 428,973,013	$ 144.59	$ 201.00	$ 6,536,733,184	$ 9,087,366,472	$ 3,062.90	$ 4,258.05	0.73900002	180	243.572403	1.10099995	583	529.518616
2014	1.3416	$ 449,126,784	$ 602,548,493	2,143,851	$ 209.50	$ 281.06	$ 292,153,120	$ 391,952,626	$ 136.27	$ 182.83	$ 6,771,782,144	$ 9,085,022,924	$ 3,158.70	$ 4,237.71	0.75999999	189	248.684204	1.22000003	793	650
2015	1.3341	$ 443,163,616	$ 591,224,580	2,154,874	$ 205.66	$ 274.37	$ 267,184,128	$ 356,450,345	$ 123.99	$ 165.42	$ 7,150,810,112	$ 9,539,895,770	$ 3,318.44	$ 4,427.12	0.91000003	187	205.494507	1	277	277
2016	1.3484	$ 441,562,080	$ 595,402,309	2,169,416	$ 203.54	$ 274.45	$ 283,326,880	$ 382,037,965	$ 130.60	$ 176.10	$ 7,491,101,184	$ 10,101,000,837	$ 3,453.05	$ 4,656.09	0.912	180	197.368423	0.986	238	241.379303
2017	1.32	$ 539,491,648	$ 712,128,975	2,181,941	$ 247.25	$ 326.37	$ 304,549,824	$ 402,005,768	$ 139.58	$ 184.24	$ 7,794,792,960	$ 10,289,126,707	$ 3,572.41	$ 4,715.58	0.99000001	196	197.979797	1.38999999	1063	764.74823
2018	1.3107	$ 683,083,904	$ 895,318,073	2,196,473	$ 310.99	$ 407.62	$ 287,085,952	$ 376,283,557	$ 130.70	$ 171.31	$ 8,279,078,400	$ 10,851,388,059	$ 3,769.26	$ 4,940.37	1.04100001	177.188004	170.209412	1.35599995	485.341003	357.921082
2019	1.308	$ 692,457,856	$ 905,734,876	2,208,925	$ 313.48	$ 410.03	$ 302,949,184	$ 396,257,533	$ 137.15	$ 179.39	$ 8,799,541,248	$ 11,509,799,952	$ 3,983.63	$ 5,210.59	1.13600004	202.375	178.147003	1.37199998	466.289001	339.860779
2020	1.3004	$ 825,708,032	$ 1,073,750,725	2,226,501	$ 370.85	$ 482.26	$ 305,837,696	$ 397,711,340	$ 137.36	$ 178.63	$ 9,377,028,096	$ 12,193,887,336	$ 4,211.55	$ 5,476.70	1.01400006	141.884003	139.925049	1.28600001	351.820007	273.576965
2021	1.2465	$ 1,058,814,336	$ 1,319,812,070	2,244,945	$ 471.64	$ 587.90	$ 338,360,896	$ 421,766,857	$ 150.72	$ 187.87	$ 10,046,570,496	$ 12,523,050,123	$ 4,475.20	$ 5,578.33	0.92400002	135.600998	146.754333	1.58099997	927.403992	586.593323
2022	1.1026	$ 948,677,760	$ 1,046,012,098	2,257,415	$ 420.25	$ 463.37	$ 345,413,184	$ 380,852,577	$ 153.01	$ 168.71	$ 10,987,799,552	$ 12,115,147,786	$ 4,867.43	$ 5,366.82	0.98000002	146.154007	149.136734	1.24899995	583.893005	467.488403
2023	1.0421	$ 1,098,552,064	$ 1,144,801,106	2,266,460	$ 484.70	$ 505.11	$ 428,612,960	$ 446,657,566	$ 189.11	$ 197.07	$ 11,839,088,640	$ 12,337,514,272	$ 5,223.60	$ 5,443.52	0.85500002	156.843002	183.442108	1.722	1542.29602	895.642273
2024	1	$ 1,220,065,920	$ 1,220,065,920	2,279,071	$ 535.33	$ 535.33	$ 325,675,360	$ 325,675,360	$ 142.90	$ 142.90	$ 12,779,676,672	$ 12,779,676,672	$ 5,607.41	$ 5,607.41						

ComEd		Schedule 204			
report_year	Inflation adj to 2024	additions (no inflation adj)		Additions (infl adj)	
1994	2.2026	$	277,431,424	$	611,070,455
1995	2.1538	$	296,509,920	$	638,623,066
1996	2.1182	$	336,175,776	$	712,087,529
1997	2.1071	$	273,995,616	$	577,336,162
1998	2.1914	$	348,456,800	$	763,608,232
1999	2.207	$	345,244,896	$	761,955,485
2000	2.1723	$	407,538,560	$	885,296,014
2001	2.0254	$	584,044,992	$	1,182,924,727
2002	2.0486	$	652,187,200	$	1,336,070,698
2003	2.0008	$	424,949,248	$	850,238,455
2004	1.9642	$	620,115,200	$	1,218,030,276
2005	1.8504	$	536,886,400	$	993,454,595
2006	1.6497	$	587,709,888	$	969,545,002
2007	1.5873	$	706,408,128	$	1,121,281,622
2008	1.4913	$	747,675,968	$	1,115,009,171
2009	1.4482	$	649,989,760	$	941,315,170
2010	1.4453	$	548,312,704	$	792,476,351
2011	1.4186	$	643,554,880	$	912,946,953
2012	1.4196	$	718,158,272	$	1,019,497,483
2013	1.3902	$	782,666,560	$	1,088,063,052
2014	1.3416	$	967,797,952	$	1,298,397,732
2015	1.3341	$	1,304,735,104	$	1,740,647,102
2016	1.3484	$	1,551,281,408	$	2,091,747,851
2017	1.32	$	1,369,474,560	$	1,807,706,419
2018	1.3107	$	1,321,555,840	$	1,732,163,239
2019	1.308	$	1,266,700,032	$	1,656,843,642
2020	1.3004	$	1,403,264,896	$	1,824,805,671
2021	1.2465	$	1,426,933,504	$	1,778,672,613
2022	1.1026	$	1,521,603,968	$	1,677,720,535
2023	1.0421	$	1,666,741,376	$	1,736,911,188
2024	1	$	1,427,625,088	$	1,427,625,088

Schedule 304 avg customers per month	Additions per customer (additions/customers)	Additions per customers (infl adj)	Schedule 320 Dist O&M
3,206,194	$ 86.53	$ 190.59	$ 202,668,672
3,242,340	$ 91.45	$ 196.96	$ 192,086,272
3,266,032	$ 102.93	$ 218.03	$ 207,138,560
3,555,345	$ 98.01	$ 214.78	$ 263,889,056
3,487,169	$ 99.00	$ 218.50	$ 319,095,136
3,524,102	$ 115.64	$ 251.21	$ 428,098,496
3,234,466	$ 180.57	$ 365.72	$ 361,535,264
3,605,711	$ 180.88	$ 370.54	$ 327,213,696
3,641,723	$ 116.69	$ 233.47	$ 293,173,760
3,676,920	$ 168.65	$ 331.26	$ 279,335,936
3,711,762	$ 144.64	$ 267.65	$ 286,020,128
3,754,162	$ 156.55	$ 258.26	$ 315,590,048
3,802,140	$ 185.79	$ 294.91	$ 372,460,832
3,822,023	$ 195.62	$ 291.73	$ 390,075,136
3,807,167	$ 170.73	$ 247.25	$ 297,464,864
3,824,555	$ 143.37	$ 207.21	$ 313,141,152
3,833,099	$ 167.89	$ 238.17	$ 414,483,584
3,843,338	$ 186.86	$ 265.26	$ 409,805,312
3,856,692	$ 202.94	$ 282.12	$ 438,781,024
3,880,172	$ 249.42	$ 334.62	$ 466,698,784
3,913,498	$ 333.39	$ 444.78	$ 465,651,520
3,969,041	$ 390.85	$ 527.02	$ 469,752,960
4,006,465	$ 341.82	$ 451.20	$ 465,285,056
4,036,731	$ 327.38	$ 429.10	$ 465,822,432
4,063,034	$ 311.76	$ 407.78	$ 476,394,624
4,089,726	$ 343.12	$ 446.19	$ 563,998,080
4,095,261	$ 348.44	$ 434.32	$ 497,332,896
4,111,174	$ 370.11	$ 408.09	$ 543,245,312
4,130,538	$ 403.52	$ 420.50	$ 544,591,424
4,130,749	$ 345.61	$ 345.61	$ 604,819,136

Schedule 204

Dist O&M (infl adj)	Dist O&M per customer (dist OM/customers)	Dist O&M per customer (infl adj)	Dist plant in service
$ 446,398,017	$ 63.21	$ 139.23	$ 4,733,373,440
$ 413,715,413	$ 59.24	$ 127.60	$ 4,983,128,576
$ 438,760,898	$ 63.42	$ 134.34	$ 5,232,055,808
			$ 5,549,578,240
$ 578,286,477	$ 74.22	$ 162.65	$ 5,808,628,224
$ 704,242,965	$ 91.51	$ 201.95	$ 6,136,199,680
$ 929,958,363	$ 121.48	$ 263.89	$ 7,522,267,136
$ 732,253,524	$ 111.78	$ 226.39	$ 8,140,225,536
$ 670,329,978	$ 90.75	$ 185.91	$ 8,583,601,152
$ 586,582,059	$ 80.50	$ 161.07	$ 9,213,193,216
$ 548,671,645	$ 75.97	$ 149.22	$ 9,597,741,056
$ 529,251,645	$ 77.06	$ 142.59	$ 10,156,855,296
$ 520,628,902	$ 84.06	$ 138.68	$ 10,566,695,936
$ 591,207,079	$ 97.96	$ 155.49	$ 11,064,663,040
$ 581,719,050	$ 102.06	$ 152.20	$ 11,608,706,048
$ 430,788,616	$ 78.13	$ 113.15	$ 12,097,052,672
$ 452,582,907	$ 81.88	$ 118.34	$ 12,661,134,336
$ 587,986,412	$ 108.13	$ 153.40	$ 13,091,342,336
$ 581,759,621	$ 106.63	$ 151.37	$ 13,623,869,440
$ 609,993,380	$ 113.77	$ 158.16	$ 14,183,568,384
$ 626,123,089	$ 120.28	$ 161.36	$ 14,749,678,592
$ 621,225,693	$ 118.99	$ 158.74	$ 15,508,575,232
$ 633,414,891	$ 118.35	$ 159.59	$ 16,579,603,456
$ 614,176,274	$ 116.13	$ 153.30	$ 17,844,461,568
$ 610,553,462	$ 115.40	$ 151.25	$ 18,939,340,800
$ 623,124,168	$ 117.25	$ 153.36	$ 20,100,849,664
$ 733,423,103	$ 137.91	$ 179.33	$ 21,182,435,328
$ 619,925,455	$ 121.44	$ 151.38	$ 22,383,499,264
$ 598,982,281	$ 132.14	$ 145.70	$ 23,532,603,392
$ 567,518,723	$ 131.85	$ 137.40	$ 24,836,229,120
$ 604,819,136	$ 146.42	$ 146.42	$ 26,238,744,576

Dist plant in service (infl adj)	Dist Plant per customer (Dist/customer)	Dist Plant per customer (infl adj)	EIA 861 Reliat SAIFI w/o MED
$ 10,425,728,339	$ 1,476.32	$ 3,251.75	
$ 10,732,662,327	$ 1,536.89	$ 3,310.16	
$ 11,082,540,613	$ 1,601.96	$ 3,393.27	
$ 11,693,516,310			
$ 12,729,027,890	$ 1,633.77	$ 3,580.25	
$ 13,542,592,694	$ 1,759.65	$ 3,883.55	
$ 16,340,620,900	$ 2,134.52	$ 4,636.82	
$ 16,487,212,801	$ 2,516.71	$ 5,097.35	
$ 17,584,365,320	$ 2,380.56	$ 4,876.81	
$ 18,433,756,987	$ 2,529.90	$ 5,061.82	
$ 18,851,882,982	$ 2,610.27	$ 5,127.09	
$ 18,794,245,040	$ 2,736.40	$ 5,063.43	
$ 17,431,878,286	$ 2,814.66	$ 4,643.35	
$ 17,562,939,643	$ 2,910.11	$ 4,619.22	
$ 17,312,063,329	$ 3,037.32	$ 4,529.55	
$ 17,518,951,680	$ 3,177.44	$ 4,601.57	
$ 18,299,137,456	$ 3,310.49	$ 4,784.64	
$ 18,571,378,238	$ 3,415.34	$ 4,845.00	
$ 19,340,445,057	$ 3,544.80	$ 5,032.20	
$ 19,717,996,767	$ 3,677.65	$ 5,112.67	0.75999999
$ 19,788,168,799	$ 3,801.30	$ 5,099.82	0.87
$ 20,689,990,217	$ 3,962.84	$ 5,286.83	0.86000001
$ 22,355,937,300	$ 4,177.23	$ 5,632.58	0.722
$ 23,554,689,270	$ 4,453.92	$ 5,879.17	0.65600002
$ 24,823,793,987	$ 4,691.75	$ 6,149.48	0.69999999
$ 26,291,911,361	$ 4,947.25	$ 6,471.00	0.63
$ 27,545,638,901	$ 5,179.43	$ 6,735.33	0.55000001
$ 27,901,031,833	$ 5,465.71	$ 6,813.00	0.58999997
$ 25,947,048,500	$ 5,724.06	$ 6,311.35	0.51999998
$ 25,881,834,366	$ 6,012.83	$ 6,265.97	0.47999999
$ 26,238,744,576	$ 6,352.05	$ 6,352.05	

bility

SAIDI w/o MED	CAIDI w/o MED	SAIFI w/ MED	SAIDI w/ MED	CAIDI w/ MED
62	81.578949	0.98000002	143	145.918365
74	85.0574722	1.04999995	205	195.238098
72	83.720932	0.97000003	109	112.371132
63	87.2576218	0.85600001	97	113.317757
55.4140015	84.4725647	0.81800002	95.2850037	116.485329
57.8289986	82.612854	0.81999999	120.294998	146.701218
51.3320007	81.4793625	0.79000002	88.4420013	111.951897
39.9500008	72.6363678	0.82999998	341.100006	410.963867
43.4599991	73.6610184	0.76999998	101.599998	131.948044
37.6399994	72.384613	0.63	65.8000031	104.444443
35.0400009	73	0.61000001	93.3000031	152.950821

WEP Co

report_year	Inflation adj to 2024	Schedule 204 additions (no inflation adj)	Additions (infl adj)
1994	2.2026	$ 92,629,032	$ 204,024,706
1995	2.1538	$ 104,745,088	$ 225,599,971
1996	2.1182	$ 100,282,248	$ 212,417,858
1997	2.1071	$ 122,745,488	$ 258,637,018
1998	2.1914	$ 121,614,328	$ 266,505,638
1999	2.207	$ 141,258,752	$ 311,758,066
2000	2.1723	$ 151,430,272	$ 328,951,980
2001	2.0254	$ 158,959,968	$ 321,957,519
2002	2.0486	$ 157,220,624	$ 322,082,170
2003	2.0008	$ 176,693,648	$ 353,528,651
2004	1.9642	$ 155,071,504	$ 304,591,448
2005	1.8504	$ 162,939,936	$ 301,504,058
2006	1.6497	$ 176,198,144	$ 290,674,078
2007	1.5873	$ 168,797,184	$ 267,931,770
2008	1.4913	$ 157,099,600	$ 234,282,633
2009	1.4482	$ 146,773,264	$ 212,557,041
2010	1.4453	$ 136,456,768	$ 197,220,967
2011	1.4186	$ 157,155,136	$ 222,940,276
2012	1.4196	$ 180,454,384	$ 256,173,044
2013	1.3902	$ 190,113,040	$ 264,295,148
2014	1.3416	$ 216,010,368	$ 289,799,510
2015	1.3341	$ 238,644,336	$ 318,375,409
2016	1.3484	$ 252,001,760	$ 339,799,173
2017	1.32	$ 287,163,552	$ 379,055,889
2018	1.3107	$ 288,385,376	$ 377,986,712
2019	1.308	$ 285,465,728	$ 373,389,172
2020	1.3004	$ 297,758,304	$ 387,204,899
2021	1.2465	$ 291,949,760	$ 363,915,376
2022	1.1026	$ 285,599,712	$ 314,902,242
2023	1.0421	$ 323,079,264	$ 336,680,901
2024	1	$ 455,193,664	$ 455,193,664

Schedule 304 avg customers per month	Additions per customer (additions/customers)	Additions per customers (infl adj)	Schedule 320 Dist O&M
846,745	$ 109.39	$ 240.95	$ 71,270,928
857,924	$ 122.09	$ 262.96	$ 58,095,356
867,917	$ 115.54	$ 244.74	$ 56,578,760
876,776	$ 140.00	$ 294.99	$ 53,339,740
886,635	$ 137.16	$ 300.58	$ 64,031,112
897,333	$ 157.42	$ 347.43	$ 62,594,776
916,029	$ 165.31	$ 359.11	$ 71,589,328
931,714	$ 170.61	$ 345.55	$ 71,683,384
945,298	$ 166.32	$ 340.72	$ 72,968,896
954,757	$ 185.07	$ 370.28	$ 72,423,720
966,842	$ 160.39	$ 315.04	$ 65,222,304
977,820	$ 166.64	$ 308.34	$ 67,158,160
1,097,510	$ 160.54	$ 264.85	$ 70,100,464
1,105,477	$ 152.69	$ 242.37	$ 73,136,648
1,111,797	$ 141.30	$ 210.72	$ 91,488,256
1,115,500	$ 131.58	$ 190.55	$ 81,737,984
1,118,695	$ 121.98	$ 176.30	$ 89,884,168
1,120,964	$ 140.20	$ 198.88	$ 94,070,176
1,123,784	$ 160.58	$ 227.96	$ 91,142,008
1,126,869	$ 168.71	$ 234.54	$ 92,451,792
1,130,631	$ 191.05	$ 256.32	$ 80,130,744
1,136,446	$ 209.99	$ 280.15	$ 80,602,344
1,142,983	$ 220.48	$ 297.29	$ 92,874,208
1,122,771	$ 255.76	$ 337.61	$ 78,375,896
1,130,435	$ 255.11	$ 334.37	$ 79,197,248
1,138,054	$ 250.84	$ 328.09	$ 79,670,896
1,144,981	$ 260.06	$ 338.18	$ 65,800,552
1,144,822	$ 255.02	$ 317.88	$ 80,781,328
1,148,141	$ 248.75	$ 274.27	$ 94,440,856
1,159,300	$ 278.68	$ 290.42	$ 88,338,528
1,170,318	$ 388.95	$ 388.95	$ 89,085,160

Schedule 204

Dist O&M (infl adj)	Dist O&M per customer (dist OM/customers)	Dist O&M per customer (infl adj)	Dist plant in service
$ 156,981,346	$ 84.17	$ 185.39	$ 1,467,968,896
$ 125,125,778	$ 67.72	$ 145.85	$ 1,544,385,792
$ 119,845,129	$ 65.19	$ 138.08	$ 1,607,558,912
$ 112,392,166	$ 60.84	$ 128.19	$ 1,696,043,264
$ 140,317,779	$ 72.22	$ 158.26	$ 1,804,818,432
$ 138,146,671	$ 69.76	$ 153.95	$ 1,913,354,752
$ 155,513,497	$ 78.15	$ 169.77	$ 2,042,225,920
$ 145,187,526	$ 76.94	$ 155.83	$ 2,175,845,376
$ 149,484,080	$ 77.19	$ 158.13	$ 2,282,460,928
$ 144,905,379	$ 75.86	$ 151.77	$ 2,432,772,352
$ 128,109,650	$ 67.46	$ 132.50	$ 2,588,865,536
$ 124,269,459	$ 68.68	$ 127.09	$ 2,721,063,936
$ 115,644,735	$ 63.87	$ 105.37	$ 2,862,217,984
$ 116,089,801	$ 66.16	$ 105.01	$ 3,006,946,048
$ 136,436,436	$ 82.29	$ 122.72	$ 3,144,981,248
$ 118,372,948	$ 73.27	$ 106.12	$ 3,273,123,328
$ 129,909,588	$ 80.35	$ 116.13	$ 3,389,240,320
$ 133,447,952	$ 83.92	$ 119.05	$ 3,488,803,072
$ 129,385,195	$ 81.10	$ 115.13	$ 3,614,330,880
$ 128,526,481	$ 82.04	$ 114.06	$ 3,755,987,456
$ 107,503,406	$ 70.87	$ 95.08	$ 3,911,845,888
$ 107,531,587	$ 70.92	$ 94.62	$ 4,087,849,984
$ 125,231,582	$ 81.26	$ 109.57	$ 4,293,928,960
$ 103,456,183	$ 69.81	$ 92.14	$ 4,500,722,688
$ 103,803,833	$ 70.06	$ 91.83	$ 4,600,231,424
$ 104,209,532	$ 70.01	$ 91.57	$ 4,835,220,480
$ 85,567,038	$ 57.47	$ 74.73	$ 5,081,256,448
$ 100,693,925	$ 70.56	$ 87.96	$ 5,317,189,120
$ 104,130,488	$ 82.26	$ 90.69	$ 5,549,991,424
$ 92,057,580	$ 76.20	$ 79.41	$ 5,798,524,928
$ 89,085,160	$ 76.12	$ 76.12	$ 6,087,434,240

Dist plant in service (infl adj)	Dist Plant per customer (Dist/customer)	Dist Plant per customer (infl adj)	EIA 861 Reliat SAIFI w/o MED
$ 3,233,348,290	$ 1,733.66	$ 3,818.56	
$ 3,326,298,119	$ 1,800.14	$ 3,877.15	
$ 3,405,131,287	$ 1,852.20	$ 3,923.34	
$ 3,573,732,762	$ 1,934.41	$ 4,075.99	
$ 3,955,079,112	$ 2,035.58	$ 4,460.77	
$ 4,222,773,938	$ 2,132.27	$ 4,705.92	
$ 4,436,327,366	$ 2,229.43	$ 4,843.00	
$ 4,406,957,225	$ 2,335.31	$ 4,729.95	
$ 4,675,849,457	$ 2,414.54	$ 4,946.43	
$ 4,867,490,922	$ 2,548.05	$ 5,098.15	
$ 5,085,049,686	$ 2,677.65	$ 5,259.44	
$ 5,035,056,707	$ 2,782.79	$ 5,149.27	
$ 4,721,801,008	$ 2,607.92	$ 4,302.29	
$ 4,772,925,462	$ 2,720.04	$ 4,317.53	
$ 4,690,110,535	$ 2,828.74	$ 4,218.50	
$ 4,740,137,204	$ 2,934.22	$ 4,249.34	
$ 4,898,469,034	$ 3,029.64	$ 4,378.74	
$ 4,949,216,038	$ 3,112.32	$ 4,415.14	
$ 5,130,904,117	$ 3,216.21	$ 4,565.74	
$ 5,221,573,761	$ 3,333.12	$ 4,633.70	0.54000002
$ 5,248,132,443	$ 3,459.88	$ 4,641.77	0.5
$ 5,453,600,664	$ 3,597.05	$ 4,798.82	1.53999996
$ 5,789,933,810	$ 3,756.77	$ 5,065.63	0.55000001
$ 5,940,953,948	$ 4,008.58	$ 5,291.33	0.51300001
$ 6,029,523,327	$ 4,069.43	$ 5,333.81	0.59500003
$ 6,324,468,388	$ 4,248.67	$ 5,557.27	0.64999998
$ 6,607,665,885	$ 4,437.85	$ 5,770.98	0.69999999
$ 6,627,876,238	$ 4,644.56	$ 5,789.44	0.73000002
$ 6,119,420,544	$ 4,833.89	$ 5,329.85	0.81999999
$ 6,042,642,827	$ 5,001.75	$ 5,212.32	0.68000001
$ 6,087,434,240	$ 5,201.52	$ 5,201.52	

bility

SAIDI w/o MED	CAIDI w/o MED	SAIFI w/ MED	SAIDI w/ MED	CAIDI w/ MED
56	103.703697	0.67000002	165	246.268661
52	104	0.67000002	123	186.363647
51.4000015	33.3766212	2.00999999	89.1999969	128.612717
62	112.727272	0.69099998	95	137.370743
57	111.111107	0.74800003	137	186.301376
70	117.647057	0.73199999	119	148.571426
85	130.769226	0.94	280	300
94	134.285706	0.87	140	162.352936
102	139.726028	1.13	417	369.02655
121	147.560974	1.04999995	279	267.307678
85	125	1.03999996	272	261.538452

Cleveland report_year	Inflation adj to 2024	Schedule 204 additions (no inflation adj)	Additions (infl adj)
1994	2.2026	$ 55,796,672	$ 122,897,750
1995	2.1538	$ 39,835,416	$ 85,797,519
1996	2.1182	$ 42,631,032	$ 90,301,052
1997	2.1071	$ 57,537,080	$ 121,236,381
1998	2.1914	$ 16,744,223	$ 36,693,290
1999	2.207	$ 39,104,080	$ 86,302,705
2000	2.1723	$ 29,987,620	$ 65,142,107
2001	2.0254	$ 31,219,280	$ 63,231,530
2002	2.0486	$ 35,893,336	$ 73,531,088
2003	2.0008	$ 57,245,980	$ 114,537,757
2004	1.9642	$ 54,075,848	$ 106,215,781
2005	1.8504	$ 77,576,416	$ 143,547,400
2006	1.6497	$ 74,851,376	$ 123,482,315
2007	1.5873	$ 110,733,088	$ 175,766,631
2008	1.4913	$ 107,675,912	$ 160,577,088
2009	1.4482	$ 87,025,528	$ 126,030,370
2010	1.4453	$ 91,107,648	$ 131,677,884
2011	1.4186	$ 88,096,472	$ 124,973,655
2012	1.4196	$ 139,991,760	$ 198,732,302
2013	1.3902	$ 87,701,456	$ 121,922,564
2014	1.3416	$ 86,646,976	$ 116,245,583
2015	1.3341	$ 83,331,272	$ 111,172,250
2016	1.3484	$ 105,433,792	$ 142,166,925
2017	1.32	$ 96,725,144	$ 127,677,190
2018	1.3107	$ 115,826,064	$ 151,813,222
2019	1.308	$ 103,639,216	$ 135,560,095
2020	1.3004	$ 129,635,208	$ 168,577,624
2021	1.2465	$ 182,381,696	$ 227,338,784
2022	1.1026	$ 142,144,384	$ 156,728,398
2023	1.0421	$ 115,481,400	$ 120,343,167
2024	1	$ 137,468,320	$ 137,468,320

Schedule 304 avg customers per month	Additions per customer (additions/customers)	Additions per customers (infl adj)	Schedule 320 Dist O&M
668,542	$ 83.46	$ 183.83	$ 42,606,216
668,904	$ 59.55	$ 128.27	$ 52,188,496
665,428	$ 64.07	$ 135.70	$ 65,959,300
663,168	$ 86.76	$ 182.81	$ 49,305,616
742,096	$ 22.56	$ 49.45	$ 57,072,504
738,174	$ 52.97	$ 116.91	$ 59,927,224
693,754	$ 43.23	$ 93.90	$ 58,333,212
746,261	$ 41.83	$ 84.73	$ 50,480,124
751,430	$ 47.77	$ 97.85	$ 51,587,632
752,330	$ 76.09	$ 152.24	$ 56,673,712
753,315	$ 71.78	$ 141.00	$ 41,352,220
761,559	$ 101.87	$ 188.49	$ 51,431,396
761,997	$ 98.23	$ 162.05	$ 51,339,536
758,319	$ 146.02	$ 231.78	$ 52,795,728
755,807	$ 142.46	$ 212.46	$ 62,065,672
753,865	$ 115.44	$ 167.18	$ 38,396,300
752,207	$ 121.12	$ 175.06	$ 42,838,940
748,935	$ 117.63	$ 166.87	$ 39,997,748
745,328	$ 187.83	$ 266.64	$ 48,791,592
744,879	$ 117.74	$ 163.68	$ 35,045,612
744,410	$ 116.40	$ 156.16	$ 36,239,160
745,641	$ 111.76	$ 149.10	$ 42,853,808
747,748	$ 141.00	$ 190.13	$ 47,826,760
750,660	$ 128.85	$ 170.09	$ 53,812,972
751,980	$ 154.03	$ 201.88	$ 54,829,992
752,471	$ 137.73	$ 180.15	$ 63,507,080
754,024	$ 171.92	$ 223.57	$ 72,657,680
755,210	$ 241.50	$ 301.03	$ 76,516,368
755,417	$ 188.17	$ 207.47	$ 77,380,584
756,673	$ 152.62	$ 159.04	$ 86,704,112
758,454	$ 181.25	$ 181.25	$ 166,016,160

Schedule 204

Dist O&M (infl adj)	Dist O&M per customer (dist OM/customers)	Dist O&M per customer (infl adj)	Dist plant in service
$ 93,844,451	$ 63.73	$ 140.37	$ 967,728,896
$ 112,403,583	$ 78.02	$ 168.04	$ 1,011,502,848
$ 139,714,989	$ 99.12	$ 209.96	$ 1,027,724,032
$ 103,891,863	$ 74.35	$ 156.66	$ 1,061,292,032
$ 125,068,685	$ 76.91	$ 168.53	$ 1,115,153,664
$ 132,259,383	$ 81.18	$ 179.17	$ 1,125,430,144
$ 126,717,236	$ 84.08	$ 182.65	$ 1,160,605,056
$ 102,242,443	$ 67.64	$ 137.01	$ 1,174,303,744
$ 105,682,423	$ 68.65	$ 140.64	$ 1,198,441,984
$ 113,392,763	$ 75.33	$ 150.72	$ 1,229,107,328
$ 81,224,031	$ 54.89	$ 107.82	$ 1,275,851,392
$ 95,168,655	$ 67.53	$ 124.97	$ 1,324,349,440
$ 84,694,833	$ 67.37	$ 111.15	$ 1,395,512,448
$ 83,802,659	$ 69.62	$ 110.51	$ 1,466,382,592
$ 92,558,537	$ 82.12	$ 122.46	$ 1,554,539,264
$ 55,605,522	$ 50.93	$ 73.76	$ 1,639,928,192
$ 61,915,120	$ 56.95	$ 82.31	$ 1,713,592,576
$ 56,740,805	$ 53.41	$ 75.76	$ 1,843,761,920
$ 69,264,544	$ 65.46	$ 92.93	$ 1,912,303,232
$ 48,720,410	$ 47.05	$ 65.41	$ 2,023,605,376
$ 48,618,457	$ 48.68	$ 65.31	$ 2,081,675,136
$ 57,171,265	$ 57.47	$ 76.67	$ 2,142,700,416
$ 64,489,603	$ 63.96	$ 86.25	$ 2,208,477,952
$ 71,033,123	$ 71.69	$ 94.63	$ 2,294,002,176
$ 71,865,671	$ 72.91	$ 95.57	$ 2,376,656,640
$ 83,067,261	$ 84.40	$ 110.39	$ 2,462,972,928
$ 94,484,047	$ 96.36	$ 125.31	$ 2,551,395,328
$ 95,377,653	$ 101.32	$ 126.29	$ 2,661,487,360
$ 85,319,832	$ 102.43	$ 112.94	$ 2,811,678,720
$ 90,354,355	$ 114.59	$ 119.41	$ 2,845,140,992
$ 166,016,160	$ 218.89	$ 218.89	$ 2,940,297,728

Dist plant in service (infl adj)	Dist Plant per customer (Dist/customer)	Dist Plant per customer (infl adj)	EIA 861 Reliat SAIFI w/o MED
$ 2,131,519,666	$ 1,447.52	$ 3,188.31	
$ 2,178,574,834	$ 1,512.18	$ 3,256.93	
$ 2,176,925,045	$ 1,544.46	$ 3,271.47	
$ 2,236,248,441	$ 1,600.34	$ 3,372.07	
$ 2,443,747,739	$ 1,502.71	$ 3,293.03	
$ 2,483,824,328	$ 1,524.61	$ 3,364.82	
$ 2,521,182,363	$ 1,672.93	$ 3,634.12	
$ 2,378,434,803	$ 1,573.58	$ 3,187.14	
$ 2,455,128,248	$ 1,594.88	$ 3,267.27	
$ 2,459,197,942	$ 1,633.73	$ 3,268.78	
$ 2,506,027,304	$ 1,693.65	$ 3,326.67	
$ 2,450,576,204	$ 1,739.00	$ 3,217.84	
$ 2,302,176,885	$ 1,831.39	$ 3,021.24	
$ 2,327,589,088	$ 1,933.73	$ 3,069.41	
$ 2,318,284,404	$ 2,056.79	$ 3,067.30	
$ 2,374,944,008	$ 2,175.36	$ 3,150.36	
$ 2,476,655,350	$ 2,278.09	$ 3,292.52	
$ 2,615,560,660	$ 2,461.85	$ 3,492.37	
$ 2,714,705,668	$ 2,565.72	$ 3,642.30	
$ 2,813,216,194	$ 2,716.69	$ 3,776.74	0.87
$ 2,792,775,362	$ 2,796.41	$ 3,751.66	1.02999997
$ 2,858,576,625	$ 2,873.64	$ 3,833.72	1.16999996
$ 2,977,911,670	$ 2,953.51	$ 3,982.51	1.102
$ 3,028,082,872	$ 3,055.98	$ 4,033.89	1.06200004
$ 3,115,083,858	$ 3,160.53	$ 4,142.51	0.96899998
$ 3,221,568,590	$ 3,273.18	$ 4,281.32	1.01900005
$ 3,317,834,485	$ 3,383.71	$ 4,400.17	0.972
$ 3,317,543,994	$ 3,524.17	$ 4,392.88	1.07799995
$ 3,100,156,957	$ 3,722.02	$ 4,103.90	1.12600005
$ 2,964,921,428	$ 3,760.07	$ 3,918.37	0.81800002
$ 2,940,297,728	$ 3,876.70	$ 3,876.70	

bility

SAIDI w/o MED	CAIDI w/o MED	SAIFI w/ MED	SAIDI w/ MED	CAIDI w/ MED
89	102.298851	1.15999997	237	204.310333
105	101.94175	1.46000004	222.029999	152.075333
138.5	118.376068	1.20000005	145.600006	121.333328
114	103.44828	1.33399999	215.300003	161.394302
120.223	113.20433	1.34200001	281.533997	209.786896
126.389999	130.433441	1.25199997	296.138	236.531952
130.468002	128.035324	1.5	365.756989	243.837997
114.163002	117.451653	1.57500005	543.14502	344.853973
135.692001	125.87384	1.56400001	394.937012	252.517258
162.057007	143.922745	1.20700002	185.541	153.720795
117.688004	143.872864	1.24199998	558.909973	450.008057

Consumers

report_year	Inflation adj to 2024	Schedule 204 additions (no inflation adj)	Additions (infl adj)
1994	2.2026	$ 167,696,352	$ 369,367,985
1995	2.1538	$ 156,991,152	$ 338,127,543
1996	2.1182	$ 159,609,968	$ 338,085,834
1997	2.1071	$ 159,238,560	$ 335,531,570
1998	2.1914	$ 166,894,576	$ 365,732,774
1999	2.207	$ 198,132,240	$ 437,277,854
2000	2.1723	$ 176,409,184	$ 383,213,670
2001	2.0254	$ 179,403,648	$ 363,364,149
2002			
2003			
2004			
2005	1.8504	$ 180,254,352	$ 333,542,653
2006	1.6497	$ 226,204,256	$ 373,169,161
2007	1.5873	$ 199,732,240	$ 317,034,985
2008	1.4913	$ 289,617,216	$ 431,906,154
2009	1.4482	$ 253,121,168	$ 366,570,075
2010	1.4453	$ 289,344,416	$ 418,189,484
2011	1.4186	$ 307,115,296	$ 435,673,759
2012	1.4196	$ 325,300,224	$ 461,796,198
2013	1.3902	$ 350,005,472	$ 486,577,607
2014	1.3416	$ 382,395,744	$ 513,022,130
2015	1.3341	$ 413,481,664	$ 551,625,888
2016	1.3484	$ 486,493,920	$ 655,988,402
2017	1.32	$ 551,042,432	$ 727,376,010
2018	1.3107	$ 489,148,960	$ 641,127,542
2019	1.308	$ 621,082,880	$ 812,376,407
2020	1.3004	$ 590,199,488	$ 767,495,414
2021	1.2465	$ 734,039,552	$ 914,980,302
2022	1.1026	$ 805,292,032	$ 887,914,994
2023	1.0421	$ 803,629,504	$ 837,462,306
2024	1	$ 877,646,784	$ 877,646,784

Schedule 304 avg customers per month	Additions per customer (additions/customers)	Additions per customers (infl adj)	Schedule 320 Dist O&M
1,535,041	$ 109.25	$ 240.62	$ 91,170,208
1,555,743	$ 100.91	$ 217.34	$ 84,368,056
1,580,347	$ 101.00	$ 213.93	$ 74,959,640
1,601,685	$ 99.42	$ 209.49	$ 92,838,272
1,627,792	$ 102.53	$ 224.68	$ 91,682,216
1,651,437	$ 119.98	$ 264.79	$ 98,954,816
1,677,235	$ 105.18	$ 228.48	$ 93,482,608
1,700,014	$ 105.53	$ 213.74	$ 106,011,592
1,777,225	$ 101.42	$ 187.68	$ 134,014,344
1,790,472	$ 126.34	$ 208.42	$ 174,651,424
1,795,374	$ 111.25	$ 176.58	$ 150,721,104
1,802,190	$ 160.70	$ 239.66	$ 154,121,008
1,787,254	$ 141.63	$ 205.10	$ 142,488,288
1,788,635	$ 161.77	$ 233.80	$ 133,282,632
1,788,799	$ 171.69	$ 243.56	$ 175,986,480
1,788,525	$ 181.88	$ 258.20	$ 179,351,776
1,790,148	$ 195.52	$ 271.81	$ 203,882,240
1,791,366	$ 213.47	$ 286.39	$ 183,777,888
1,795,336	$ 230.31	$ 307.25	$ 171,489,072
1,804,630	$ 269.58	$ 363.50	$ 167,789,232
1,826,166	$ 301.75	$ 398.31	$ 185,796,560
1,816,438	$ 269.29	$ 352.96	$ 202,638,704
1,836,668	$ 338.16	$ 442.31	$ 237,644,544
1,855,672	$ 318.05	$ 413.59	$ 215,658,160
1,870,123	$ 392.51	$ 489.26	$ 347,022,688
1,875,019	$ 429.48	$ 473.55	$ 327,464,608
1,884,290	$ 426.49	$ 444.44	$ 381,870,624
1,893,531	$ 463.50	$ 463.50	$ 366,258,976

Dist O&M (infl adj)	Dist O&M per customer (dist OM/customers)	Dist O&M per customer (infl adj)
$ 200,811,500	$ 59.39	$ 130.82
$ 181,711,919	$ 54.23	$ 116.80
$ 158,779,509	$ 47.43	$ 100.47
$ 195,619,523	$ 57.96	$ 122.13
$ 200,912,408	$ 56.32	$ 123.43
$ 218,393,279	$ 59.92	$ 132.24
$ 203,072,269	$ 55.74	$ 121.08
$ 214,715,878	$ 62.36	$ 126.30
$ 247,980,142	$ 75.41	$ 139.53
$ 288,122,454	$ 97.54	$ 160.92
$ 239,239,608	$ 83.95	$ 133.25
$ 229,840,659	$ 85.52	$ 127.53
$ 206,351,539	$ 79.72	$ 115.46
$ 192,633,388	$ 74.52	$ 107.70
$ 249,654,421	$ 98.38	$ 139.57
$ 254,607,781	$ 100.28	$ 142.36
$ 283,437,090	$ 113.89	$ 158.33
$ 246,556,415	$ 102.59	$ 137.64
$ 228,783,571	$ 95.52	$ 127.43
$ 226,247,000	$ 92.98	$ 125.37
$ 245,251,459	$ 101.74	$ 134.30
$ 265,598,549	$ 111.56	$ 146.22
$ 310,839,064	$ 129.39	$ 169.24
$ 280,441,871	$ 116.22	$ 151.13
$ 432,563,781	$ 185.56	$ 231.30
$ 361,062,477	$ 174.65	$ 192.56
$ 397,947,377	$ 202.66	$ 211.19
$ 366,258,976	$ 193.43	$ 193.43

Schedule 204

Dist plant in service	Dist plant in service (infl adj)	Dist Plant per customer (Dist/customer)
$ 1,822,875,392	$ 4,015,065,338	$ 1,187.51
$ 1,971,257,984	$ 4,245,695,446	$ 1,267.08
$ 2,108,649,472	$ 4,466,541,312	$ 1,334.30
$ 2,255,166,464	$ 4,751,861,256	$ 1,408.00
$ 2,399,741,184	$ 5,258,792,831	$ 1,474.23
$ 2,549,604,352	$ 5,626,976,805	$ 1,543.87
$ 3,046,335,488	$ 6,617,554,581	$ 1,816.28
$ 3,198,211,328	$ 6,477,657,224	$ 1,881.29
$ 3,950,847,744	$ 7,310,648,665	$ 2,223.04
$ 4,104,599,296	$ 6,771,357,459	$ 2,292.47
$ 4,303,084,032	$ 6,830,285,284	$ 2,396.76
$ 4,476,264,448	$ 6,675,453,171	$ 2,483.79
$ 4,746,751,488	$ 6,874,245,505	$ 2,655.89
$ 4,970,284,544	$ 7,183,552,251	$ 2,778.81
$ 5,247,776,768	$ 7,444,496,123	$ 2,933.69
$ 5,533,711,872	$ 7,855,657,373	$ 3,094.01
$ 5,825,750,016	$ 8,098,957,672	$ 3,254.34
$ 6,135,002,112	$ 8,230,718,833	$ 3,424.76
$ 6,481,975,808	$ 8,647,603,925	$ 3,610.45
$ 6,803,789,824	$ 9,174,230,199	$ 3,770.19
$ 7,143,689,216	$ 9,429,669,765	$ 3,911.85
$ 7,599,538,176	$ 9,960,714,687	$ 4,183.76
$ 7,954,563,584	$ 10,404,569,168	$ 4,330.98
$ 8,517,033,984	$ 11,075,550,993	$ 4,589.73
$ 9,050,886,144	$ 11,281,929,578	$ 4,839.73
$ 9,736,976,384	$ 10,735,990,161	$ 5,193.00
$ 10,512,885,760	$ 10,955,478,250	$ 5,579.23
$ 11,261,171,712	$ 11,261,171,712	$ 5,947.18

	EIA 861 Reliability			
Dist Plant per customer (infl adj)	SAIFI w/o MED	SAIDI w/o MED	CAIDI w/o MED	SAIFI w/ MED
$ 2,615.61				
$ 2,729.05				
$ 2,826.30				
$ 2,966.79				
$ 3,230.63				
$ 3,407.32				
$ 3,945.51				
$ 3,810.36				
$ 4,113.52				
$ 3,781.88				
$ 3,804.38				
$ 3,704.08				
$ 3,846.26				
$ 4,016.22				
$ 4,161.73				
$ 4,392.25				
$ 4,524.18	1	218	218	2
$ 4,594.66	0.91399997	168.399994	184.245087	1.102
$ 4,816.71	0.98100001	177	180.428131	1.17999995
$ 5,083.72	1.00699997	207	205.561066	1.15100002
$ 5,163.64	0.88999999	160.899994	180.786514	1.30999994
$ 5,483.65	1.01699996	200.899994	197.541794	1.29499996
$ 5,664.92	1.12399995	233.341003	207.598755	1.58200002
$ 5,968.49	1.03400004	194.699997	188.297867	1.34800005
$ 6,032.72	1.05299997	227.899994	216.429245	1.60099995
$ 5,725.80	0.96100003	181.990005	189.375656	1.28699994
$ 5,814.11	0.95599997	176.380005	184.49791	1.37100005
$ 5,947.18				

SAIDI w/ MED	CAIDI w/ MED
1109	554.5
376.600006	341.742279
440.700012	373.474579
284	246.741959
605.799988	462.442749
406.799988	314.131256
691.046021	436.817963
510.299988	378.560822
911.200012	569.144287
466.549988	362.509705
913.030029	665.959167

Indianapolis PL/AES Indiana Schedule 204

report_year	Inflation adj to 2024	additions (no inflation adj)	Additions (infl adj)
1994	2.2026	$ 60,079,556	$ 132,331,230
1995	2.1538	$ 36,523,168	$ 78,663,599
1996	2.1182	$ 40,875,864	$ 86,583,255
1997	2.1071	$ 35,398,896	$ 74,589,014
1998	2.1914	$ 24,076,312	$ 52,760,830
1999	2.207	$ 42,866,968	$ 94,607,398
2000	2.1723	$ 41,111,424	$ 89,306,346
2001	2.0254	$ 15,007,288	$ 30,395,761
2002	2.0486	$ 92,162,160	$ 188,803,401
2003	2.0008	$ 29,270,348	$ 58,564,112
2004	1.9642	$ 43,848,680	$ 86,127,577
2005	1.8504	$ 33,689,072	$ 62,338,259
2006	1.6497	$ 34,070,216	$ 56,205,635
2007	1.5873	$ 49,690,800	$ 78,874,207
2008	1.4913	$ 44,791,244	$ 66,797,182
2009	1.4482	$ 36,303,768	$ 52,575,117
2010	1.4453	$ 49,446,436	$ 71,464,934
2011	1.4186	$ 43,902,304	$ 62,279,808
2012	1.4196	$ 49,740,464	$ 70,611,563
2013	1.3902	$ 42,490,180	$ 59,069,848
2014	1.3416	$ 58,730,008	$ 78,792,179
2015	1.3341	$ 63,909,976	$ 85,262,299
2016	1.3484	$ 69,591,168	$ 93,836,731
2017	1.32	$ 67,746,304	$ 89,425,121
2018	1.3107	$ 60,472,716	$ 79,261,589
2019	1.308	$ 71,915,768	$ 94,065,825
2020	1.3004	$ 97,145,336	$ 126,327,795
2021	1.2465	$ 187,550,464	$ 233,781,653
2022	1.1026	$ 238,153,888	$ 262,588,477
2023	1.0421	$ 289,153,600	$ 301,326,967
2024	1	$ 305,680,512	$ 305,680,512

Schedule 304 avg customers per month	Additions per customer (additions/customers)	Additions per customers (infl adj)	Schedule 320 Dist O&M
357,824	$ 167.90	$ 369.82	$ 26,524,130
362,590	$ 100.73	$ 216.95	$ 27,088,628
367,138	$ 111.34	$ 235.83	$ 28,063,476
371,919	$ 95.18	$ 200.55	$ 27,623,258
423,397	$ 56.86	$ 124.61	$ 29,595,870
430,051	$ 99.68	$ 219.99	$ 29,877,348
436,045	$ 94.28	$ 204.81	$ 31,212,418
441,039	$ 34.03	$ 68.92	$ 29,057,342
446,614	$ 206.36	$ 422.74	$ 35,493,236
452,340	$ 64.71	$ 129.47	$ 39,018,504
458,796	$ 95.57	$ 187.73	$ 33,249,168
462,837	$ 72.79	$ 134.69	$ 35,591,700
466,833	$ 72.98	$ 120.40	$ 35,391,356
416,836	$ 119.21	$ 189.22	$ 31,630,964
468,203	$ 95.67	$ 142.67	$ 39,571,808
467,683	$ 77.62	$ 112.42	$ 35,468,656
468,161	$ 105.62	$ 152.65	$ 35,618,360
468,195	$ 93.77	$ 133.02	$ 35,397,840
470,961	$ 105.61	$ 149.93	$ 38,285,320
474,120	$ 89.62	$ 124.59	$ 36,906,692
478,007	$ 122.86	$ 164.83	$ 37,732,716
486,635	$ 131.33	$ 175.21	$ 39,364,252
486,827	$ 142.95	$ 192.75	$ 41,073,876
436,314	$ 155.27	$ 204.96	$ 43,242,604
440,788	$ 137.19	$ 179.82	$ 43,730,048
448,210	$ 160.45	$ 209.87	$ 63,240,968
511,501	$ 189.92	$ 246.97	$ 65,709,784
456,739	$ 410.63	$ 511.85	$ 75,812,440
519,319	$ 458.59	$ 505.64	$ 93,054,176
523,395	$ 552.46	$ 575.72	$ 89,494,824
530,802	$ 575.88	$ 575.88	$ 100,619,848

Schedule 204

Dist O&M (infl adj)	Dist O&M per customer (dist OM/customers)	Dist O&M per customer (infl adj)	Dist plant in service
$ 58,422,049	$ 74.13	$ 163.27	$ 551,217,216
$ 58,343,487	$ 74.71	$ 160.91	$ 600,287,488
$ 59,444,055	$ 76.44	$ 161.91	$ 630,990,720
$ 58,204,967	$ 74.27	$ 156.50	$ 665,247,040
$ 64,856,390	$ 69.90	$ 153.18	$ 695,320,576
$ 65,939,307	$ 69.47	$ 153.33	$ 713,932,480
$ 67,802,736	$ 71.58	$ 155.49	$ 752,313,408
$ 58,852,740	$ 65.88	$ 133.44	$ 783,618,176
$ 72,711,443	$ 79.47	$ 162.81	$ 792,510,912
$ 78,068,223	$ 86.26	$ 172.59	$ 879,205,248
$ 65,308,016	$ 72.47	$ 142.35	$ 904,618,816
$ 65,858,882	$ 76.90	$ 142.29	$ 939,189,504
$ 58,385,120	$ 75.81	$ 125.07	$ 965,812,736
$ 50,207,829	$ 75.88	$ 120.45	$ 994,429,184
$ 59,013,437	$ 84.52	$ 126.04	$ 1,090,395,008
$ 51,365,708	$ 75.84	$ 109.83	$ 1,129,738,752
$ 51,479,216	$ 76.08	$ 109.96	$ 1,160,026,880
$ 50,215,376	$ 75.60	$ 107.25	$ 1,184,433,664
$ 54,349,840	$ 81.29	$ 115.40	$ 1,219,070,336
$ 51,307,683	$ 77.84	$ 108.22	$ 1,249,445,376
$ 50,622,212	$ 78.94	$ 105.90	$ 1,283,390,464
$ 52,515,849	$ 80.89	$ 107.92	$ 1,323,190,400
$ 55,384,014	$ 84.37	$ 113.77	$ 1,371,028,864
$ 57,080,237	$ 99.11	$ 130.82	$ 1,433,043,968
$ 57,316,974	$ 99.21	$ 130.03	$ 1,487,380,480
$ 82,719,186	$ 141.10	$ 184.55	$ 1,534,062,336
$ 85,449,003	$ 128.46	$ 167.06	$ 1,594,208,512
$ 94,500,206	$ 165.99	$ 206.90	$ 1,671,861,120
$ 102,601,534	$ 179.19	$ 197.57	$ 1,831,029,120
$ 93,262,556	$ 170.99	$ 178.19	$ 2,036,696,960
$ 100,619,848	$ 189.56	$ 189.56	$ 2,313,028,096

Dist plant in service (infl adj)	Dist Plant per customer (Dist/customer)	Dist Plant per customer (infl adj)	EIA 861 Reliat SAIFI w/o MED
$ 1,214,111,040	$ 1,540.47	$ 3,393.04	
$ 1,292,899,192	$ 1,655.55	$ 3,565.73	
$ 1,336,564,543	$ 1,718.67	$ 3,640.50	
$ 1,401,742,038	$ 1,788.69	$ 3,768.94	
$ 1,523,725,510	$ 1,642.24	$ 3,598.81	
$ 1,575,648,983	$ 1,660.11	$ 3,663.87	
$ 1,634,250,416	$ 1,725.31	$ 3,747.89	
$ 1,587,140,254	$ 1,776.75	$ 3,598.64	
$ 1,623,537,854	$ 1,774.49	$ 3,635.21	
$ 1,759,113,860	$ 1,943.68	$ 3,888.92	
$ 1,776,852,278	$ 1,971.72	$ 3,872.86	
$ 1,737,876,258	$ 2,029.20	$ 3,754.83	
$ 1,593,301,271	$ 2,068.86	$ 3,413.00	
$ 1,578,457,444	$ 2,385.66	$ 3,786.76	
$ 1,626,106,075	$ 2,328.89	$ 3,473.08	
$ 1,636,087,661	$ 2,415.61	$ 3,498.28	
$ 1,676,586,850	$ 2,477.84	$ 3,581.22	
$ 1,680,237,596	$ 2,529.79	$ 3,588.76	
$ 1,730,592,249	$ 2,588.47	$ 3,674.60	
$ 1,736,978,962	$ 2,635.29	$ 3,663.59	0.57999998
$ 1,721,796,647	$ 2,684.88	$ 3,602.03	0.70999998
$ 1,765,268,313	$ 2,719.06	$ 3,627.50	0.66000003
$ 1,848,695,320	$ 2,816.25	$ 3,797.44	0.69999999
$ 1,891,618,038	$ 3,284.43	$ 4,335.45	0.80000001
$ 1,949,509,595	$ 3,374.37	$ 4,422.78	0.949
$ 2,006,553,535	$ 3,422.64	$ 4,476.82	0.884
$ 2,073,108,749	$ 3,116.73	$ 4,052.99	0.93400002
$ 2,083,974,886	$ 3,660.43	$ 4,562.73	1.31500006
$ 2,018,892,708	$ 3,525.83	$ 3,887.58	1.36500001
$ 2,122,441,902	$ 3,891.32	$ 4,055.14	0.98299998
$ 2,313,028,096	$ 4,357.61	$ 4,357.61	

bility

SAIDI w/o MED	CAIDI w/o MED	SAIFI w/ MED	SAIDI w/ MED	CAIDI w/ MED
48	82.7586212	0.70999998	92	129.577454
56.7099991	79.8732376	0.95999998	189.979996	197.895828
48.7000008	73.7878799	0.94	219.449997	233.457443
62	88.5714264	1.20000005	232	193.333328
59.6399994	74.5500031	1	80	80
67.4589996	71.0842972	1.13399994	149.029007	131.418869
75.6029968	85.5237579	1.22099996	213.123993	174.548737
73.3939972	78.5802994	1.15900004	154.658005	133.440903
104.443001	79.4243317	1.60699999	176.386002	109.761047
112.485001	82.4065933	1.50699997	147.264008	97.7199707
86.685997	88.1851501	1.38399994	466.753998	337.25

Columbus Southern		Schedule 204	
report_year	Inflation adj to 2024	additions (no inflation adj)	Additions (infl adj)
1994	2.2026	$ 47,633,692	$ 104,917,970
1995	2.1538	$ 51,131,016	$ 110,125,982
1996	2.1182	$ 51,262,832	$ 108,584,931
1997	2.1071	$ 51,176,112	$ 107,833,186
1998	2.1914	$ 21,138,750	$ 46,323,457
1999	2.207	$ 108,729,152	$ 239,965,238
2000	2.1723	$ 77,567,920	$ 168,500,793
2001	2.0254	$ 75,117,080	$ 152,142,134
2002	2.0486	$ 62,199,916	$ 127,422,748
2003	2.0008	$ 56,183,560	$ 112,412,067
2004	1.9642	$ 60,461,892	$ 118,759,248
2005	1.8504	$ 52,597,684	$ 97,326,754
2006	1.6497	$ 154,801,232	$ 255,375,592
2007	1.5873	$ 96,785,856	$ 153,628,189
2008	1.4913	$ 93,095,752	$ 138,833,695
2009	1.4482	$ 144,748,064	$ 209,624,146
2010	1.4453	$ 77,147,712	$ 111,501,588
2011	1.4186	$ 163,892,832	$ 232,498,371
2012	1.4196	$ 230,563,216	$ 327,307,541
2013	1.3902	$ 210,569,968	$ 292,734,370
2014	1.3416	$ 255,519,616	$ 342,805,117
2015	1.3341	$ 271,496,672	$ 362,203,710
2016	1.3484	$ 229,540,880	$ 309,512,923
2017	1.32	$ 224,803,520	$ 296,740,646
2018	1.3107	$ 407,686,240	$ 534,354,355
2019	1.308	$ 475,966,240	$ 622,563,842
2020	1.3004	$ 447,014,400	$ 581,297,526
2021	1.2465	$ 434,322,656	$ 541,383,191
2022	1.1026	$ 455,761,280	$ 502,522,387
2023	1.0421	$ 456,551,296	$ 475,772,106
2024	1	$ 464,668,480	$ 464,668,480

Schedule 304 avg customers per month	Additions per customer (additions/customers)	Additions per customers (infl adj)	Schedule 320 Dist O&M
582,623	$ 81.76	$ 180.08	$ 43,062,560
593,333	$ 86.18	$ 185.61	$ 42,981,452
603,841	$ 84.89	$ 179.82	$ 41,115,128
615,088	$ 83.20	$ 175.31	$ 42,874,972
629,760	$ 33.57	$ 73.56	$ 39,193,908
645,491	$ 168.44	$ 371.76	$ 43,652,460
661,790	$ 117.21	$ 254.61	$ 47,537,624
673,208	$ 111.58	$ 226.00	$ 41,652,536
683,801	$ 90.96	$ 186.34	$ 45,828,600
692,873	$ 81.09	$ 162.24	$ 51,860,520
703,295	$ 85.97	$ 168.86	$ 66,136,136
709,305	$ 74.15	$ 137.21	$ 58,559,440
739,949	$ 209.21	$ 345.13	$ 51,575,932
745,133	$ 129.89	$ 206.18	$ 60,611,028
747,099	$ 124.61	$ 185.83	$ 62,565,868
749,192	$ 193.21	$ 279.80	$ 72,280,288
749,275	$ 102.96	$ 148.81	$ 82,865,560
1,459,875	$ 112.26	$ 159.26	$ 141,745,312
1,460,393	$ 157.88	$ 224.12	$ 155,564,704
1,460,980	$ 144.13	$ 200.37	$ 136,595,520
1,463,881	$ 174.55	$ 234.18	$ 187,980,576
1,464,068	$ 185.44	$ 247.40	$ 189,705,312
1,467,725	$ 156.39	$ 210.88	$ 192,513,472
1,472,768	$ 152.64	$ 201.48	$ 177,928,992
1,484,322	$ 274.66	$ 360.00	$ 194,083,312
1,490,120	$ 319.41	$ 417.79	$ 179,542,672
1,501,571	$ 297.70	$ 387.13	$ 172,757,360
1,511,444	$ 287.36	$ 358.19	$ 187,848,976
1,519,057	$ 300.03	$ 330.81	$ 214,659,056
1,523,794	$ 299.61	$ 312.23	$ 246,568,144
1,533,266	$ 303.06	$ 303.06	$ 279,979,136

Schedule 204

Dist O&M (infl adj)	Dist O&M per customer (dist OM/customers)	Dist O&M per customer (infl adj)	Dist plant in service
$ 94,849,595	$ 73.91	$ 162.80	$ 755,342,080
$ 92,573,451	$ 72.44	$ 156.02	$ 797,569,600
$ 87,090,064	$ 68.09	$ 144.23	$ 843,228,224
$ 90,341,854	$ 69.71	$ 146.88	$ 885,266,560
$ 85,889,530	$ 62.24	$ 136.38	$ 926,178,048
$ 96,340,979	$ 67.63	$ 149.25	$ 936,613,056
$ 103,265,981	$ 71.83	$ 156.04	$ 1,030,184,128
$ 84,363,046	$ 61.87	$ 125.31	$ 1,094,289,024
$ 93,884,470	$ 67.02	$ 137.30	$ 1,157,035,136
$ 103,762,528	$ 74.85	$ 149.76	$ 1,206,989,696
$ 129,904,598	$ 94.04	$ 184.71	$ 1,252,495,104
$ 108,358,388	$ 82.56	$ 152.77	$ 1,298,986,752
$ 85,084,815	$ 69.70	$ 114.99	$ 1,336,142,336
$ 96,207,885	$ 81.34	$ 129.12	$ 1,473,624,832
$ 93,304,479	$ 83.75	$ 124.89	$ 1,550,865,664
$ 104,676,313	$ 96.48	$ 139.72	$ 1,622,867,840
$ 119,765,594	$ 110.59	$ 159.84	$ 1,742,606,720
$ 201,079,900	$ 97.09	$ 137.74	$ 3,417,861,888
$ 220,839,654	$ 106.52	$ 151.22	$ 3,540,883,200
$ 189,895,092	$ 93.50	$ 129.98	$ 3,718,113,536
$ 252,194,741	$ 128.41	$ 172.28	$ 3,872,948,480
$ 253,085,857	$ 129.57	$ 172.86	$ 4,083,984,384
$ 259,585,166	$ 131.16	$ 176.86	$ 4,284,075,264
$ 234,866,269	$ 120.81	$ 159.47	$ 4,454,773,760
$ 254,384,997	$ 130.76	$ 171.38	$ 4,623,848,448
$ 234,841,815	$ 120.49	$ 157.60	$ 4,939,755,520
$ 224,653,671	$ 115.05	$ 149.61	$ 5,320,952,320
$ 234,153,749	$ 124.28	$ 154.92	$ 5,706,016,768
$ 236,683,075	$ 141.31	$ 155.81	$ 6,068,306,944
$ 256,948,663	$ 161.81	$ 168.62	$ 6,447,761,408
$ 279,979,136	$ 182.60	$ 182.60	$ 6,837,295,616

Dist plant in service (infl adj)	Dist Plant per customer (Dist/customer)	Dist Plant per customer (infl adj)	EIA 861 Reliak SAIFI w/o MED
$ 1,663,716,465	$ 1,296.45	$ 2,855.56	No data
$ 1,717,805,404	$ 1,344.22	$ 2,895.18	
$ 1,786,126,024	$ 1,396.44	$ 2,957.94	
$ 1,865,345,169	$ 1,439.25	$ 3,032.65	
$ 2,029,626,574	$ 1,470.68	$ 3,222.86	
$ 2,067,105,015	$ 1,451.01	$ 3,202.38	
$ 2,237,868,981	$ 1,556.66	$ 3,381.54	
$ 2,216,372,989	$ 1,625.48	$ 3,292.26	
$ 2,370,302,180	$ 1,692.06	$ 3,466.36	
$ 2,414,944,984	$ 1,742.01	$ 3,485.41	
$ 2,460,150,883	$ 1,780.90	$ 3,498.04	
$ 2,403,645,086	$ 1,831.35	$ 3,388.73	
$ 2,204,234,012	$ 1,805.72	$ 2,978.90	
$ 2,339,084,696	$ 1,977.67	$ 3,139.15	
$ 2,312,805,965	$ 2,075.85	$ 3,095.72	
$ 2,350,237,206	$ 2,166.16	$ 3,137.03	
$ 2,518,589,492	$ 2,325.72	$ 3,361.37	
$ 4,848,578,874	$ 2,341.20	$ 3,321.23	
$ 5,026,637,791	$ 2,424.61	$ 3,441.98	
$ 5,168,921,438	$ 2,544.94	$ 3,537.98	1.153
$ 5,195,947,681	$ 2,645.67	$ 3,549.43	1.26800001
$ 5,448,443,567	$ 2,789.48	$ 3,721.44	1.32299995
$ 5,776,647,086	$ 2,918.85	$ 3,935.78	1.23699999
$ 5,880,301,363	$ 3,024.76	$ 3,992.69	1.31599998
$ 6,060,478,161	$ 3,115.12	$ 4,082.99	1.46200001
$ 6,461,200,220	$ 3,315.01	$ 4,336.03	1.38800001
$ 6,919,366,397	$ 3,543.59	$ 4,608.08	1.23899996
$ 7,112,549,901	$ 3,775.21	$ 4,705.80	1.25600004
$ 6,690,915,236	$ 3,994.79	$ 4,404.65	1.19299996
$ 6,719,212,163	$ 4,231.39	$ 4,409.53	0.95999998
$ 6,837,295,616	$ 4,459.30	$ 4,459.30	

ility

SAIDI w/o MED	CAIDI w/o MED	SAIFI w/ MED	SAIDI w/ MED	CAIDI w/ MED
164	142.23764	1.40100002	345	246.252686
191.5	151.025238	1.34099996	213.399994	159.134964
201.5	152.305374	1.39100003	239.199997	171.962616
174.699997	141.228775	1.29200006	189.899994	146.981415
199	151.215805	1.46700001	254.699997	173.619629
218.399994	149.384399	1.57500005	255.600006	162.285706
202.399994	145.821335	1.62699997	307.200012	188.813766
166.800003	134.624695	1.42900002	254.600006	178.16655
171.399994	136.464966	1.36399996	231	169.354843
179.399994	150.377197	1.73599994	595.299988	342.914764
147.600006	153.75	1.23599994	326.100006	263.834961

Duquesne		Schedule 204	
report_year	Inflation adj to 2024	additions (no inflation adj)	Additions (infl adj)
1994	2.2026	$ 47,067,648	$ 103,671,201
1995	2.1538	$ 33,733,176	$ 72,654,514
1996	2.1182	$ 36,507,416	$ 77,330,009
1997	2.1071	$ 42,808,100	$ 90,200,948
1998	2.1914		
1999	2.207	$ 39,902,536	$ 88,064,897
2000	2.1723	$ 67,116,128	$ 145,796,365
2001	2.0254	$ 51,958,104	$ 105,235,944
2002	2.0486	$ 50,720,924	$ 103,906,885
2003	2.0008	$ 53,632,168	$ 107,307,242
2004	1.9642	$ 62,153,660	$ 122,082,219
2005	1.8504	$ 130,700,856	$ 241,848,864
2006	1.6497	$ 105,432,992	$ 173,932,807
2007	1.5873	$ 59,094,616	$ 93,800,884
2008	1.4913	$ 74,241,312	$ 110,716,069
2009	1.4482	$ 103,893,672	$ 150,458,816
2010	1.4453	$ 157,428,080	$ 227,530,804
2011	1.4186	$ 106,786,144	$ 151,486,824
2012	1.4196	$ 122,522,912	$ 173,933,526
2013	1.3902	$ 118,855,848	$ 165,233,400
2014	1.3416	$ 120,190,464	$ 161,247,527
2015	1.3341	$ 122,883,040	$ 163,938,264
2016	1.3484	$ 125,143,240	$ 168,743,145
2017	1.32	$ 166,433,776	$ 219,692,584
2018	1.3107	$ 216,864,048	$ 284,243,708
2019	1.308	$ 181,399,264	$ 237,270,237
2020	1.3004	$ 179,394,960	$ 233,285,206
2021	1.2465	$ 211,898,416	$ 264,131,376
2022	1.1026	$ 187,408,304	$ 206,636,396
2023	1.0421	$ 293,628,256	$ 305,990,006
2024	1	$ 216,374,112	$ 216,374,112

Schedule 304 avg customers per month	Additions per customer (additions/customers)	(CV added formulas 8-9-2 Additions per customers (infl adj)	Schedule 320 Dist O&M
521,733	$ 90.21	$ 198.71	$ 40,013,336
521,896	$ 64.64	$ 139.21	$ 36,608,492
522,004	$ 69.94	$ 148.14	$ 37,071,308
522,624	$ 81.91	$ 172.59	$ 38,218,608
			$ 39,417,040
582,106	$ 115.30	$ 250.46	$ 36,874,612
584,428	$ 88.90	$ 180.07	$ 24,374,056
585,667	$ 86.60	$ 177.42	$ 27,096,318
586,184	$ 91.49	$ 183.06	$ 28,622,844
587,202	$ 105.85	$ 207.90	$ 27,614,486
586,981	$ 222.67	$ 412.02	$ 30,410,492
586,050	$ 179.90	$ 296.79	$ 28,995,900
585,678	$ 100.90	$ 160.16	$ 27,176,080
585,837	$ 126.73	$ 188.99	$ 28,418,548
582,474	$ 178.37	$ 258.31	$ 28,136,344
599,126	$ 262.76	$ 379.77	$ 39,585,688
587,610	$ 181.73	$ 257.80	$ 33,497,764
588,676	$ 208.13	$ 295.47	$ 34,887,692
590,346	$ 201.33	$ 279.89	$ 39,294,364
591,422	$ 203.22	$ 272.64	$ 42,058,936
587,359	$ 209.21	$ 279.11	$ 43,206,368
587,954	$ 212.85	$ 287.00	$ 47,866,544
594,106	$ 280.14	$ 369.79	$ 41,523,392
597,498	$ 362.95	$ 475.72	$ 44,504,232
600,804	$ 301.93	$ 394.92	$ 48,889,800
603,791	$ 297.11	$ 386.37	$ 56,186,136
606,085	$ 349.62	$ 435.80	$ 55,502,608
609,008	$ 307.73	$ 339.30	$ 58,571,080
611,282	$ 480.35	$ 500.57	$ 50,410,824
613,786	$ 352.52	$ 352.52	$ 52,889,648

Schedule 204

Dist O&M (infl adj)	Dist O&M per customer (dist OM/customers)	Dist O&M per customer (infl adj)	Dist plant in service
	$ 76.69		$ 1,070,731,776
	$ 70.15		$ 1,110,954,368
	$ 71.02		$ 1,202,114,944
	$ 73.13		$ 1,233,225,728
			$ 1,272,220,416
	$ 63.35		$ 1,303,290,496
	$ 41.71		$ 1,346,472,320
	$ 46.27		$ 1,426,399,616
	$ 48.83		$ 1,468,460,800
	$ 47.03		$ 1,476,487,296
	$ 51.81		$ 1,527,368,064
	$ 49.48		$ 1,587,202,816
	$ 46.40		$ 1,676,825,344
	$ 48.51		$ 1,717,040,000
	$ 48.30		$ 1,779,820,288
	$ 66.07		$ 1,846,375,168
	$ 57.01		$ 1,986,667,904
	$ 59.26		$ 2,053,646,720
	$ 66.56		$ 2,155,211,776
	$ 71.11		$ 2,260,183,296
	$ 73.56		$ 2,360,760,576
	$ 81.41		$ 2,421,961,728
	$ 69.89		$ 2,495,813,376
	$ 74.48		$ 2,621,719,552
	$ 81.37		$ 2,771,538,944
	$ 93.06		$ 2,918,899,968
	$ 91.58		$ 3,076,685,056
	$ 96.17		$ 3,262,545,664
	$ 82.47		$ 3,434,001,152
	$ 86.17		$ 3,709,851,904

Dist plant in service (infl adj)	Dist Plant per customer (Dist/customer)	Dist Plant per customer (infl adj)	EIA 861 Reliat SAIFI w/o MED
	$ 2,052.26		No data
	$ 2,128.69		
	$ 2,302.88		
	$ 2,359.68		
	$ 2,238.92		
	$ 2,303.91		
	$ 2,435.51		
	$ 2,505.12		
	$ 2,514.45		
	$ 2,602.07		
	$ 2,708.31		
	$ 2,863.05		
	$ 2,930.92		
	$ 3,055.62		
	$ 3,081.78		
	$ 3,380.93		
	$ 3,488.59		
	$ 3,650.76		
	$ 3,821.61		
	$ 4,019.28		
	$ 4,119.30		
	$ 4,200.96		
	$ 4,387.83		
	$ 4,613.05		
	$ 4,834.29		
	$ 5,076.33		
	$ 5,357.15		
	$ 5,617.70		
	$ 6,044.21		

bility

SAIDI w/o MED	CAIDI w/o MED	SAIFI w/ MED	SAIDI w/ MED	CAIDI w/ MED

PECO		Schedule 204	
report_year	Inflation adj to 2024	additions (no inflation adj)	Additions (infl adj)
1994	2.2026	$ 108,284,672	$ 238,507,819
1995	2.1538	$ 69,750,888	$ 150,229,463
1996	2.1182	$ 110,109,144	$ 233,233,189
1997	2.1071		
1998	2.1914	$ 126,069,824	$ 276,269,412
1999	2.207	$ 137,293,632	$ 303,007,046
2000	2.1723	$ 41,831,144	$ 90,869,794
2001	2.0254	$ 213,430,544	$ 432,282,224
2002	2.0486	$ 134,313,040	$ 275,153,694
2003	2.0008	$ 133,697,072	$ 267,501,102
2004	1.9642	$ 135,798,208	$ 266,734,840
2005	1.8504	$ 147,158,048	$ 272,301,252
2006	1.6497	$ 191,168,000	$ 315,369,850
2007	1.5873	$ 211,056,896	$ 335,010,611
2008	1.4913	$ 221,697,872	$ 330,618,037
2009	1.4482	$ 190,057,840	$ 275,241,764
2010	1.4453	$ 186,647,520	$ 269,761,661
2011	1.4186	$ 255,265,872	$ 362,120,166
2012	1.4196	$ 223,782,864	$ 317,682,154
2013	1.3902	$ 306,219,584	$ 425,706,466
2014	1.3416	$ 329,378,976	$ 441,894,834
2015	1.3341	$ 272,950,720	$ 364,143,556
2016	1.3484	$ 261,060,512	$ 352,013,994
2017	1.32	$ 281,031,712	$ 370,961,860
2018	1.3107	$ 340,861,536	$ 446,767,215
2019	1.308	$ 518,700,224	$ 678,459,893
2020	1.3004	$ 492,752,800	$ 640,775,741
2021	1.2465	$ 592,154,304	$ 738,120,340
2022	1.1026	$ 625,152,896	$ 689,293,583
2023	1.0421	$ 639,987,072	$ 666,930,528
2024	1	$ 906,036,800	$ 906,036,800

Schedule 304 avg customers per month	Additions per customer (additions/customers)	Additions per customers (infl adj)	Schedule 320 Dist O&M
1,560,480	$ 69.39	$ 152.84	$ 133,154,072
1,464,232	$ 47.64	$ 102.60	$ 129,909,192
1,467,636	$ 75.02	$ 158.92	$ 132,634,352
1,487,689	$ 84.74	$ 185.70	$ 105,447,584
1,256,756	$ 109.24	$ 241.10	$ 125,960,080
1,253,848	$ 33.36	$ 72.47	$ 114,074,952
1,523,075	$ 140.13	$ 283.82	$ 157,771,296
1,528,884	$ 87.85	$ 179.97	$ 150,717,200
1,530,715	$ 87.34	$ 174.76	$ 158,397,040
1,536,985	$ 88.35	$ 173.54	$ 131,505,400
1,543,543	$ 95.34	$ 176.41	$ 129,796,104
1,551,632	$ 123.20	$ 203.25	$ 186,339,712
1,555,342	$ 135.70	$ 215.39	$ 158,529,536
1,570,294	$ 141.18	$ 210.55	$ 168,495,904
1,564,433	$ 121.49	$ 175.94	$ 171,033,600
1,566,871	$ 119.12	$ 172.17	$ 204,150,800
1,658,184	$ 153.94	$ 218.38	$ 222,327,440
1,622,584	$ 137.92	$ 195.79	$ 233,081,968
1,586,969	$ 192.96	$ 268.25	$ 200,354,144
1,594,763	$ 206.54	$ 277.09	$ 315,412,480
1,604,902	$ 170.07	$ 226.89	$ 248,455,520
1,616,079	$ 161.54	$ 217.82	$ 261,731,008
1,629,569	$ 172.46	$ 227.64	$ 262,334,832
1,642,852	$ 207.48	$ 271.95	$ 334,461,888
1,656,514	$ 313.13	$ 409.57	$ 315,741,920
1,671,433	$ 294.81	$ 383.37	$ 411,616,928
1,681,439	$ 352.17	$ 438.98	$ 358,282,400
1,690,627	$ 369.78	$ 407.71	$ 349,747,808
1,700,223	$ 376.41	$ 392.26	$ 356,033,664
1,704,093	$ 531.68	$ 531.68	$ 366,073,184

Schedule 204

Dist O&M (infl adj)	Dist O&M per customer (dist OM/customers)	Dist O&M per customer (infl adj)	Dist plant in service
$ 293,285,159	$ 85.33	$ 187.95	$ 2,422,852,864
$ 279,798,418	$ 88.72	$ 191.09	$ 2,498,414,848
$ 280,946,084	$ 90.37	$ 191.43	$ 2,528,721,152
$ 231,077,836	$ 70.88	$ 155.33	$ 2,740,557,056
$ 277,993,897	$ 100.23	$ 221.20	$ 2,864,341,248
$ 247,805,018	$ 90.98	$ 197.64	$ 2,964,402,432
$ 319,549,983	$ 103.59	$ 209.81	$ 2,997,245,440
$ 308,759,256	$ 98.58	$ 201.95	$ 3,224,741,376
$ 316,920,798	$ 103.48	$ 207.04	$ 3,352,293,120
$ 258,302,907	$ 85.56	$ 168.06	$ 3,404,804,864
$ 240,174,711	$ 84.09	$ 155.60	$ 3,535,773,952
$ 307,404,623	$ 120.09	$ 198.12	$ 3,597,658,624
$ 251,633,932	$ 101.93	$ 161.79	$ 3,757,691,392
$ 251,277,942	$ 107.30	$ 160.02	$ 3,941,010,944
$ 247,690,860	$ 109.33	$ 158.33	$ 4,135,239,680
$ 295,059,151	$ 130.29	$ 188.31	$ 4,322,385,920
$ 315,393,706	$ 134.08	$ 190.20	$ 4,489,936,896
$ 330,883,162	$ 143.65	$ 203.92	$ 4,723,425,792
$ 278,532,331	$ 126.25	$ 175.51	$ 4,895,539,200
$ 423,157,383	$ 197.78	$ 265.34	$ 5,140,508,160
$ 331,464,509	$ 154.81	$ 206.53	$ 5,290,494,976
$ 352,918,091	$ 161.95	$ 218.38	$ 5,538,991,616
$ 346,281,978	$ 160.98	$ 212.50	$ 5,771,083,264
$ 438,379,197	$ 203.59	$ 266.84	$ 6,019,876,352
$ 412,990,431	$ 190.61	$ 249.31	$ 6,320,071,168
$ 535,266,653	$ 246.27	$ 320.24	$ 6,794,556,928
$ 446,599,012	$ 213.08	$ 265.61	$ 7,222,986,752
$ 385,631,933	$ 206.87	$ 228.10	$ 7,755,823,104
$ 371,022,681	$ 209.40	$ 218.22	$ 8,297,078,272
$ 366,073,184	$ 214.82	$ 214.82	$ 8,859,033,600

Dist plant in service (infl adj)	Dist Plant per customer (Dist/customer)	Dist Plant per customer (infl adj)	EIA 861 Reliak SAIFI w/o MED
$ 5,336,575,718	$ 1,552.63	$ 3,419.83	
$ 5,381,085,900	$ 1,706.30	$ 3,675.02	
$ 5,356,337,144	$ 1,722.99	$ 3,649.64	
$ 6,005,656,733	$ 1,842.16	$ 4,036.90	
$ 6,321,601,134	$ 2,279.15	$ 5,030.09	
$ 6,439,571,403	$ 2,364.24	$ 5,135.85	
$ 6,070,620,914	$ 1,967.89	$ 3,985.77	
$ 6,606,205,183	$ 2,109.21	$ 4,320.93	
$ 6,707,268,074	$ 2,190.02	$ 4,381.79	
$ 6,687,717,714	$ 2,215.25	$ 4,351.19	
$ 6,542,596,121	$ 2,290.69	$ 4,238.69	
$ 5,935,057,432	$ 2,318.63	$ 3,825.04	
$ 5,964,583,547	$ 2,415.99	$ 3,834.90	
$ 5,877,229,621	$ 2,509.73	$ 3,742.76	
$ 5,988,654,105	$ 2,643.28	$ 3,828.00	
$ 6,247,144,370	$ 2,758.61	$ 3,987.02	
$ 6,369,424,481	$ 2,707.74	$ 3,841.20	
$ 6,705,375,254	$ 2,911.05	$ 4,132.53	
$ 6,805,778,596	$ 3,084.84	$ 4,288.54	0.69999999
$ 6,896,505,747	$ 3,223.37	$ 4,324.47	0.80000001
$ 7,058,049,347	$ 3,296.46	$ 4,397.81	0.75
$ 7,468,776,295	$ 3,427.43	$ 4,621.54	0.82999998
$ 7,617,829,908	$ 3,541.48	$ 4,674.75	0.79000002
$ 7,890,251,935	$ 3,664.28	$ 4,802.78	0.89999998
$ 8,266,653,088	$ 3,815.28	$ 4,990.39	0.87
$ 8,835,641,829	$ 4,065.11	$ 5,286.27	0.81999999
$ 9,003,452,986	$ 4,295.72	$ 5,354.61	0.82999998
$ 8,551,570,554	$ 4,587.54	$ 5,058.22	0.77999997
$ 8,646,385,267	$ 4,879.99	$ 5,085.44	0.75999999
$ 8,859,033,600	$ 5,198.68	$ 5,198.68	

bility

SAIDI w/o MED	CAIDI w/o MED	SAIFI w/ MED	SAIDI w/ MED	CAIDI w/ MED
66.5	95	0.69999999	66.5	95
73	91.25	1.52999997	880	575.163391
65	86.6666641	0.94	227	241.489365
76	91.5662613	1.01999998	114	111.764709
74.4000015	94.1772156	0.87	91	104.597702
87.9000015	97.6666641	1.50999999	641.900024	425.099335
94	108.045982	1.15999997	221	190.517242
76	92.68293	1.51999998	629	413.815796
88	106.024101	1.00999999	186	184.158417
82	105.128212	0.86000001	97	112.790703
79	103.947372	0.88	126	143.181824

Northern States Power MN report_year	Inflation adj to 2024	Schedule 204 additions (no inflation adj)	Additions (infl adj)
1994	2.2026	$ 86,329,728	$ 190,149,859
1995	2.1538	$ 106,644,880	$ 229,691,743
1996	2.1182	$ 110,554,272	$ 234,176,059
1997	2.1071	$ 141,651,520	$ 298,473,918
1998	2.1914	$ 115,364,776	$ 252,810,370
1999	2.207	$ 122,740,896	$ 270,889,157
2000	2.1723	$ 122,587,264	$ 266,296,314
2001	2.0254	$ 120,828,624	$ 244,726,295
2002	2.0486	$ 100,444,624	$ 205,770,857
2003	2.0008	$ 122,431,952	$ 244,961,850
2004	1.9642	$ 131,001,816	$ 257,313,767
2005	1.8504	$ 106,169,968	$ 196,456,909
2006	1.6497	$ 126,329,984	$ 208,406,575
2007	1.5873	$ 119,647,088	$ 189,915,823
2008	1.4913	$ 122,366,200	$ 182,484,714
2009	1.4482	$ 115,667,632	$ 167,509,865
2010	1.4453	$ 119,994,216	$ 173,427,640
2011	1.4186	$ 160,661,456	$ 227,914,341
2012	1.4196	$ 125,564,584	$ 178,251,483
2013	1.3902	$ 171,685,584	$ 238,677,299
2014	1.3416	$ 188,374,816	$ 252,723,653
2015	1.3341	$ 166,340,416	$ 221,914,749
2016	1.3484	$ 206,460,000	$ 278,390,664
2017	1.32	$ 172,860,864	$ 228,176,340
2018	1.3107	$ 195,037,744	$ 255,635,971
2019	1.308	$ 218,751,360	$ 286,126,779
2020	1.3004	$ 291,692,672	$ 379,317,151
2021	1.2465	$ 257,531,712	$ 321,013,279
2022	1.1026	$ 418,238,016	$ 461,149,236
2023	1.0421	$ 473,057,152	$ 492,972,858
2024	1	$ 673,210,112	$ 673,210,112

Schedule 304 avg customers per month	Additions per customer (additions/customers)	Additions per customers (infl adj)	Schedule 320 Dist O&M
1,192,366	$ 72.40	$ 159.47	$ 75,572,424
1,211,688	$ 88.01	$ 189.56	$ 79,759,464
1,199,895	$ 92.14	$ 195.16	$ 77,949,904
1,258,372	$ 112.57	$ 237.19	$ 89,342,440
1,318,195	$ 87.52	$ 191.79	$ 97,511,888
1,281,491	$ 95.78	$ 211.39	$ 100,092,272
1,270,285	$ 96.50	$ 209.64	$ 100,589,152
1,288,737	$ 93.76	$ 189.90	$ 95,719,776
1,308,944	$ 76.74	$ 157.20	$ 81,123,592
1,322,813	$ 92.55	$ 185.18	$ 91,179,680
1,342,231	$ 97.60	$ 191.71	$ 91,789,768
1,392,265	$ 76.26	$ 141.11	$ 91,162,568
1,303,517	$ 96.91	$ 159.88	$ 99,303,544
1,327,035	$ 90.16	$ 143.11	$ 100,502,704
1,344,989	$ 90.98	$ 135.68	$ 102,935,472
1,367,070	$ 84.61	$ 122.53	$ 102,529,688
1,363,421	$ 88.01	$ 127.20	$ 109,895,712
1,399,830	$ 114.77	$ 162.82	$ 112,987,360
1,407,496	$ 89.21	$ 126.64	$ 111,134,720
1,417,543	$ 121.11	$ 168.37	$ 121,107,048
1,429,379	$ 131.79	$ 176.81	$ 117,777,816
1,441,799	$ 115.37	$ 153.92	$ 106,451,560
1,454,285	$ 141.97	$ 191.43	$ 110,969,208
1,466,398	$ 117.88	$ 155.60	$ 111,165,600
1,478,542	$ 131.91	$ 172.90	$ 122,695,864
1,491,047	$ 146.71	$ 191.90	$ 121,335,096
1,504,894	$ 193.83	$ 252.06	$ 102,836,728
1,522,746	$ 169.12	$ 210.81	$ 115,243,272
1,538,707	$ 271.81	$ 299.70	$ 114,482,648
1,556,301	$ 303.96	$ 316.76	$ 113,896,840
1,577,476	$ 426.76	$ 426.76	$ 123,465,792

Dist O&M (infl adj)	Dist O&M per customer (dist OM/customers)	Dist O&M per customer (infl adj)
$ 166,455,821	$ 63.38	$ 139.60
$ 171,785,934	$ 65.83	$ 141.77
$ 165,113,487	$ 64.96	$ 137.61
$ 188,253,455	$ 71.00	$ 149.60
$ 213,687,551	$ 73.97	$ 162.11
$ 220,903,644	$ 78.11	$ 172.38
$ 218,509,815	$ 79.19	$ 172.02
$ 193,870,834	$ 74.27	$ 150.43
$ 166,189,791	$ 61.98	$ 126.96
$ 182,432,304	$ 68.93	$ 137.91
$ 180,293,462	$ 68.39	$ 134.32
$ 168,687,216	$ 65.48	$ 121.16
$ 163,821,057	$ 76.18	$ 125.68
$ 159,527,942	$ 75.73	$ 120.21
$ 153,507,669	$ 76.53	$ 114.13
$ 148,483,494	$ 75.00	$ 108.61
$ 158,832,273	$ 80.60	$ 116.50
$ 160,283,869	$ 80.72	$ 114.50
$ 157,766,849	$ 78.96	$ 112.09
$ 168,363,018	$ 85.43	$ 118.77
$ 158,010,718	$ 82.40	$ 110.55
$ 142,017,026	$ 73.83	$ 98.50
$ 149,630,880	$ 76.30	$ 102.89
$ 146,738,592	$ 75.81	$ 100.07
$ 160,817,469	$ 82.98	$ 108.77
$ 158,706,306	$ 81.38	$ 106.44
$ 133,728,881	$ 68.33	$ 88.86
$ 143,650,739	$ 75.68	$ 94.34
$ 126,228,568	$ 74.40	$ 82.04
$ 118,691,897	$ 73.18	$ 76.27
$ 123,465,792	$ 78.27	$ 78.27

Schedule 204

Dist plant in service	Dist plant in service (infl adj)	Dist Plant per customer (Dist/customer)
$ 1,435,672,576	$ 3,162,212,416	$ 1,204.05
$ 1,510,066,304	$ 3,252,380,806	$ 1,246.25
$ 1,598,777,856	$ 3,386,531,255	$ 1,332.43
$ 1,694,299,392	$ 3,570,058,249	$ 1,346.42
$ 1,821,065,728	$ 3,990,683,436	$ 1,381.48
$ 1,909,547,392	$ 4,214,371,094	$ 1,490.10
$ 2,009,101,824	$ 4,364,371,892	$ 1,581.62
$ 2,101,884,672	$ 4,257,157,215	$ 1,630.96
$ 2,191,862,784	$ 4,490,250,099	$ 1,674.53
$ 2,280,591,616	$ 4,563,007,705	$ 1,724.05
$ 2,403,079,680	$ 4,720,129,107	$ 1,790.36
$ 2,524,849,920	$ 4,671,982,292	$ 1,813.48
$ 2,620,871,424	$ 4,323,651,588	$ 2,010.62
$ 2,639,294,976	$ 4,189,352,915	$ 1,988.87
$ 2,735,476,480	$ 4,079,416,075	$ 2,033.83
$ 2,831,273,472	$ 4,100,250,242	$ 2,071.05
$ 2,928,723,200	$ 4,232,883,641	$ 2,148.07
$ 3,031,579,648	$ 4,300,598,889	$ 2,165.68
$ 3,168,661,248	$ 4,498,231,508	$ 2,251.28
$ 3,233,191,680	$ 4,494,783,074	$ 2,280.84
$ 3,379,693,568	$ 4,534,196,891	$ 2,364.45
$ 3,538,749,952	$ 4,721,046,311	$ 2,454.40
$ 3,677,421,824	$ 4,958,635,587	$ 2,528.68
$ 3,868,125,184	$ 5,105,925,243	$ 2,637.84
$ 4,001,157,888	$ 5,244,317,644	$ 2,706.15
$ 4,136,835,072	$ 5,410,980,274	$ 2,774.45
$ 4,306,162,688	$ 5,599,733,959	$ 2,861.44
$ 4,554,114,048	$ 5,676,703,161	$ 2,990.72
$ 4,778,338,816	$ 5,268,596,379	$ 3,105.42
$ 5,162,167,808	$ 5,379,495,073	$ 3,316.95
$ 5,601,847,296	$ 5,601,847,296	$ 3,551.15

	EIA 861 Reliability			
Dist Plant per customer (infl adj)	SAIFI w/o MED	SAIDI w/o MED	CAIDI w/o MED	SAIFI w/ MED
$ 2,652.05				
$ 2,684.17				
$ 2,822.36				
$ 2,837.05				
$ 3,027.38				
$ 3,288.65				
$ 3,435.74				
$ 3,303.36				
$ 3,430.44				
$ 3,449.47				
$ 3,516.63				
$ 3,355.67				
$ 3,316.91				
$ 3,156.93				
$ 3,033.05				
$ 2,999.30				
$ 3,104.60				
$ 3,072.23				
$ 3,195.91				
$ 3,170.83	0.89999998	95	105.555557	1.38999999
$ 3,172.14	1	82	82	1
$ 3,274.41	0.81999999	87.4100037	106.597557	0.95999998
$ 3,409.67	0.81999999	92.7399979	113.097557	1.04999995
$ 3,481.95	0.73000002	73.8899994	101.219177	0.89999998
$ 3,546.95	0.88	95.0199966	107.977272	0.94999999
$ 3,628.98	0.74199998	80.6600037	108.7062	0.85699999
$ 3,721.02	0.96799999	96.5230026	99.7138443	1.074
$ 3,727.94	0.93400002	92.2699966	98.7901535	1.04200006
$ 3,424.04	0.87099999	89.9889984	103.316879	1.08299994
$ 3,456.59	0.83999997	83.4599991	99.3571396	1.05999994
$ 3,551.15				

SAIDI w/ MED	CAIDI w/ MED
564	405.755402
115	115
184.369995	192.052078
214.300003	204.095245
141.679993	157.422226
124.949997	131.526321
124.498001	145.271881
134.190002	124.94413
129.934998	124.697701
184.179001	170.063705
168.410004	158.877365

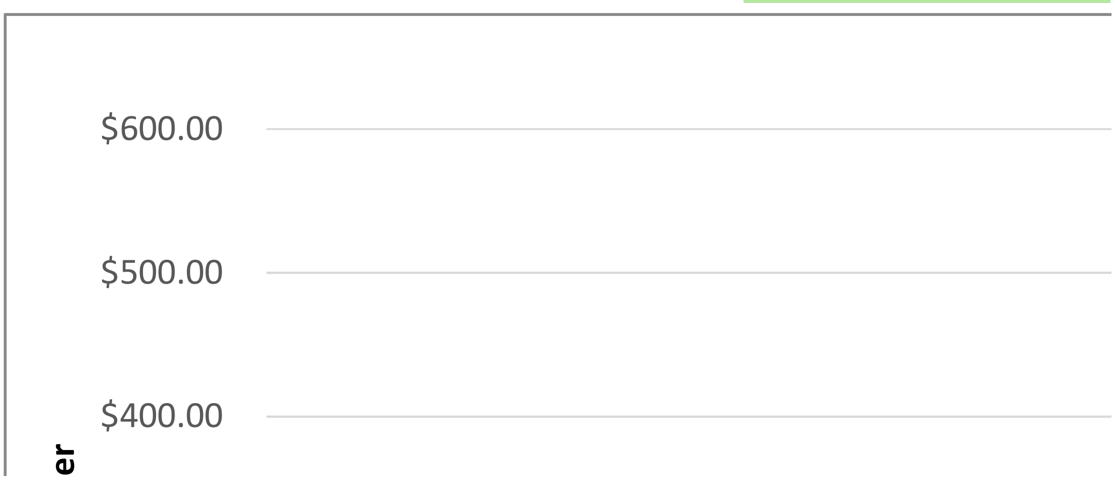
report_year	Schedule 204 additions (no inflation adj)	Schedule 304 avg customers per month	Additions per customer (additions/customers)
1994	$ 104,772,086	1,163,505	$ 96.70
1995	$ 99,540,523	1,164,294	$ 84.58
1996	$ 109,778,728	1,171,138	$ 90.76
1997	$ 110,568,922	844,233	$ 99.86
1998	$ 117,544,949	1,333,864	$ 77.87
1999	$ 130,585,906	1,298,488	$ 112.82
2000	$ 123,953,280	1,223,910	$ 98.45
2001	$ 158,885,503	1,235,882	$ 107.44
2002	$ 160,642,728	1,232,044	$ 117.93
2003	$ 131,762,997	1,241,717	$ 99.38
2004	$ 157,815,851	1,253,198	$ 109.27
2005	$ 158,663,637	1,324,811	$ 117.31
2006	$ 186,307,343	1,339,125	$ 135.99
2007	$ 191,327,322	1,343,482	$ 130.18
2008	$ 206,473,453	1,356,471	$ 135.47
2009	$ 191,953,411	1,354,960	$ 134.96
2010	$ 183,987,278	1,358,994	$ 136.30
2011	$ 214,047,821	1,451,721	$ 139.32
2012	$ 235,119,853	1,450,121	$ 157.32
2013	$ 251,145,299	1,449,838	$ 159.34
2014	$ 289,449,436	1,456,003	$ 178.81
2015	$ 326,419,244	1,463,965	$ 188.54
2016	$ 365,222,964	1,475,252	$ 204.18
2017	$ 357,475,763	1,478,357	$ 211.84
2018	$ 381,759,836	1,486,621	$ 235.56
2019	$ 415,957,857	1,497,436	$ 253.35
2020	$ 436,539,785	1,515,288	$ 262.95
2021	$ 479,862,452	1,515,985	$ 311.82
2022	$ 519,928,276	1,529,608	$ 327.16
2023	$ 562,367,658	1,538,422	$ 363.79
2024	$ 607,100,430	1,545,831	$ 396.58

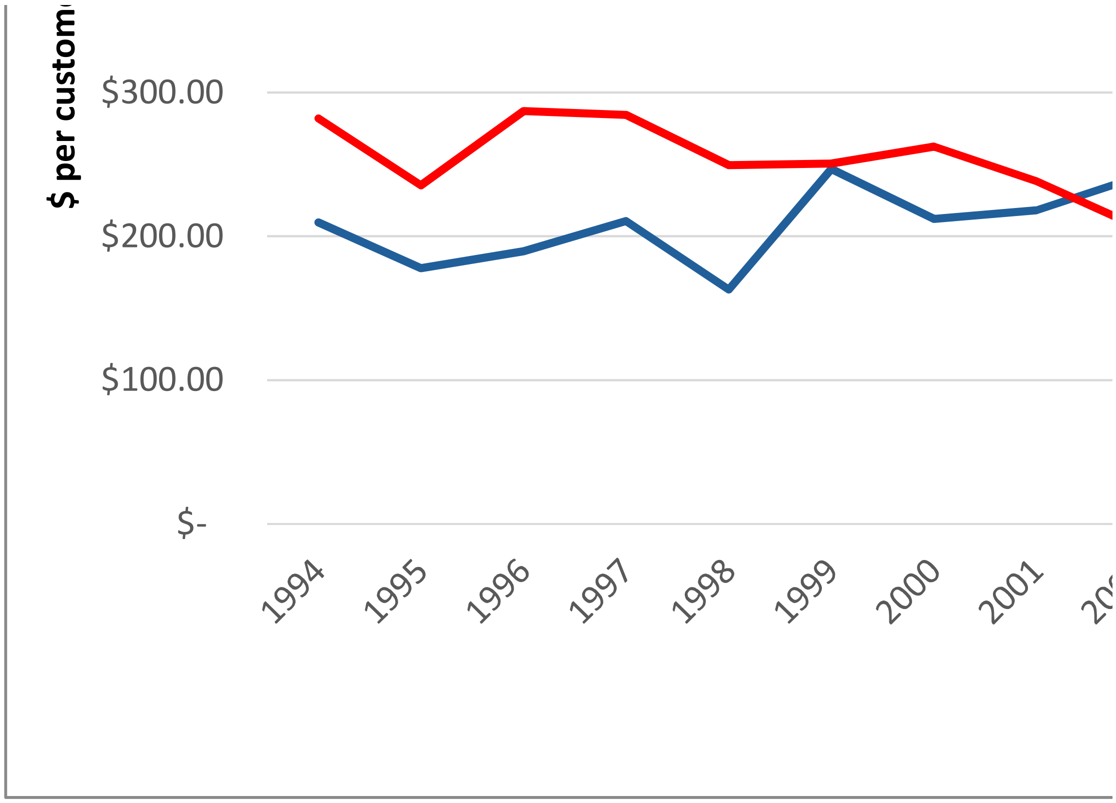
Schedule 320 Dist O&M	Dist O&M per customer (dist OM/customers)	Schedule 204 distribution plant in service
$ 80,671,394	$ 71.55	$ 1,691,973,682
$ 78,120,601	$ 70.12	$ 1,780,840,868
$ 80,163,381	$ 71.78	$ 1,864,424,569
$ 56,220,415	$ 68.75	$ 1,880,014,840
$ 93,553,017	$ 69.58	$ 2,163,932,864
$ 97,730,128	$ 77.22	$ 2,157,915,947
$ 109,088,045	$ 79.60	$ 2,425,636,210
$ 104,253,930	$ 74.00	$ 2,556,899,513
$ 99,003,646	$ 73.74	$ 2,607,131,736
$ 98,918,723	$ 76.75	$ 2,757,826,672
$ 92,025,677	$ 70.73	$ 2,862,992,968
$ 98,238,259	$ 72.17	$ 3,108,809,401
$ 112,587,546	$ 78.24	$ 3,226,301,511
$ 114,173,847	$ 77.66	$ 3,375,882,382
$ 122,193,075	$ 83.62	$ 3,535,475,456
$ 107,726,224	$ 76.33	$ 3,695,088,412
$ 116,807,001	$ 84.15	$ 3,859,374,407
$ 141,165,967	$ 87.59	$ 4,198,018,233
$ 144,671,677	$ 91.46	$ 4,376,655,858
$ 144,935,382	$ 89.59	$ 4,560,045,867
$ 163,089,900	$ 100.12	$ 4,757,213,966
$ 154,197,751	$ 95.06	$ 4,979,809,081
$ 159,155,252	$ 99.08	$ 5,242,142,165
$ 157,718,434	$ 98.44	$ 5,533,968,356
$ 171,329,302	$ 106.77	$ 5,807,749,973
$ 176,218,622	$ 112.89	$ 6,117,318,855
$ 191,913,490	$ 117.68	$ 6,474,100,167
$ 199,371,442	$ 127.72	$ 6,849,413,959
$ 208,116,236	$ 132.16	$ 7,258,588,174
$ 217,545,443	$ 135.91	$ 7,707,831,822
$ 238,800,782	$ 154.03	$ 8,205,411,641

Dist Plant per customer (Dist/customer)	EIA 861 Reliability SAIFI w/o MED	SAIDI w/o MED	CAIDI w/o MED	SAIFI w/ MED
$ 1,498.99				
$ 1,577.48				
$ 1,645.15				
$ 1,696.68				
$ 1,622.86				
$ 1,730.10				
$ 1,924.44				
$ 1,956.88				
$ 2,009.47				
$ 2,102.07				
$ 2,156.78				
$ 2,227.56				
$ 2,273.17				
$ 2,399.10				
$ 2,476.21				
$ 2,588.29				
$ 2,687.67				
$ 2,783.17				
$ 2,898.30				
$ 3,019.83	0.81287	99.81250	116.39166	1.12637
$ 3,135.81	0.88650	100.32625	109.92410	1.13912
$ 3,258.07	1.01300	105.18875	104.40740	1.19888
$ 3,385.36	0.87100	106.43000	117.93228	1.07425
$ 3,568.87	0.84463	100.05837	113.84209	1.05687
$ 3,705.91	0.93400	115.48725	119.29347	1.15850
$ 3,860.06	0.91337	119.10050	124.49749	1.20962
$ 4,001.32	0.90213	106.94125	114.78417	1.22563
$ 4,252.51	0.97325	120.64562	122.04921	1.26100
$ 4,449.30	0.95450	120.82013	124.30911	1.17000
$ 4,699.02	0.80962	101.35675	121.45130	1.10287
$ 4,998.71				

SAIDI w/ MED	CAIDI w/ MED
340.18750	253.44786
290.62625	240.32669
206.81500	196.84416
180.18750	164.37493
210.87487	186.33199
264.21400	212.03326
286.38338	223.96994
338.37413	268.38737
318.50725	238.82602
252.57925	201.43397
365.56300	304.20008

report_year	Schedule 204 additions (infl adj)	Schedule 304 avg customers per month	(CV excl. Consumers 8-9 Peer Group Ave.
1994	$ 230,770,997	1,163,505	$ 209.54
1995	$ 214,390,378	1,164,294	$ 177.77
1996	$ 232,533,302	1,171,138	$ 189.54
1997	$ 232,979,774	844,233	$ 210.57
1998	$ 257,588,000	1,333,864	$ 162.92
1999	$ 288,203,094	1,298,488	$ 246.73
2000	$ 269,263,709	1,223,910	$ 212.03
2001	$ 321,806,698	1,235,882	$ 218.09
2002	$ 329,092,693	1,232,044	$ 241.60
2003	$ 263,631,404	1,241,717	$ 198.84
2004	$ 309,981,895	1,253,198	$ 214.63
2005	$ 293,591,194	1,324,811	$ 220.74
2006	$ 307,351,224	1,339,125	$ 226.33
2007	$ 303,693,858	1,343,482	$ 210.39
2008	$ 307,913,860	1,356,471	$ 197.33
2009	$ 277,986,929	1,354,960	$ 194.25
2010	$ 265,916,813	1,358,994	$ 192.39
2011	$ 303,648,239	1,451,721	$ 191.90
2012	$ 333,776,144	1,450,121	$ 218.98
2013	$ 349,142,195	1,449,838	$ 215.23
2014	$ 388,325,363	1,456,003	$ 234.08
2015	$ 435,475,914	1,463,965	$ 244.57
2016	$ 492,466,645	1,475,252	$ 264.29
2017	$ 471,868,007	1,478,357	$ 264.80
2018	$ 500,372,617	1,486,621	$ 303.22
2019	$ 544,072,877	1,497,436	$ 317.51
2020	$ 567,676,336	1,515,288	$ 332.98
2021	$ 598,148,546	1,515,985	$ 376.11
2022	$ 573,272,917	1,529,608	$ 346.62
2023	$ 586,043,336	1,538,422	$ 370.94
2024	$ 607,100,430	1,545,831	$ 388.21




$ per custom
$300.00
$200.00
$100.00
$-
1994
1995
1996
1997
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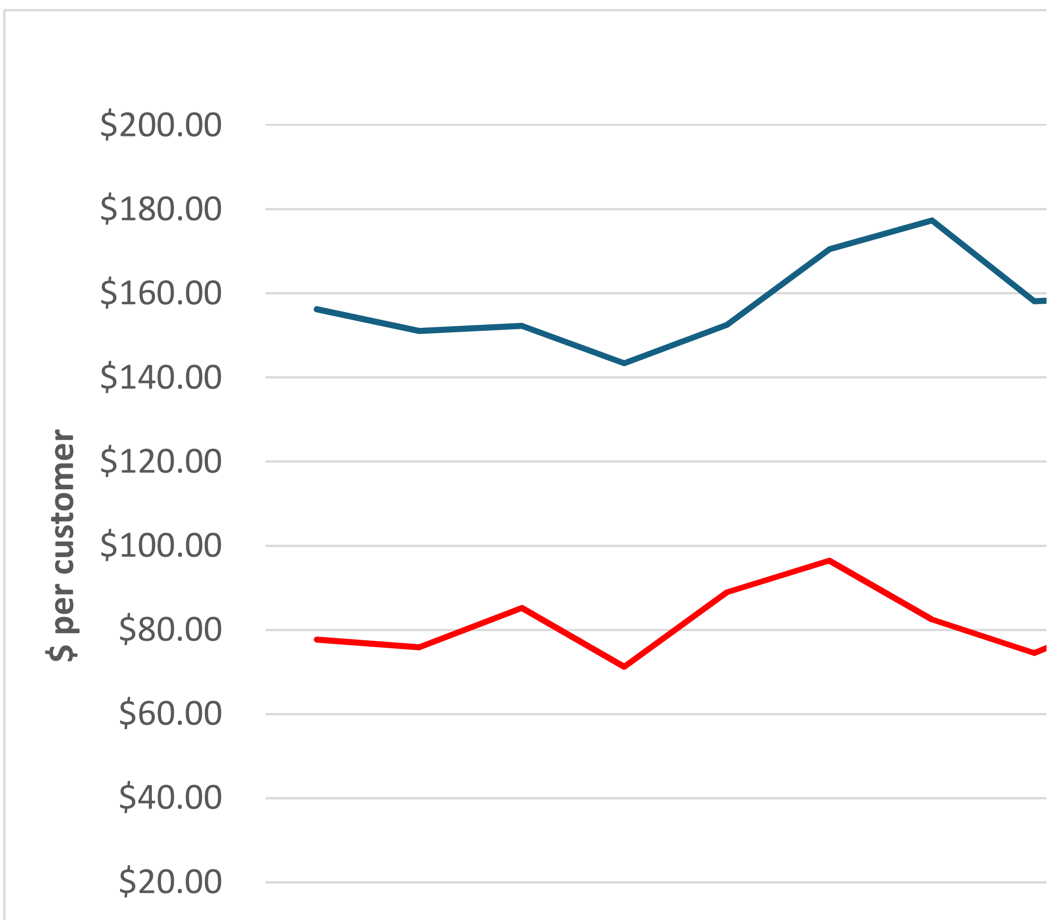
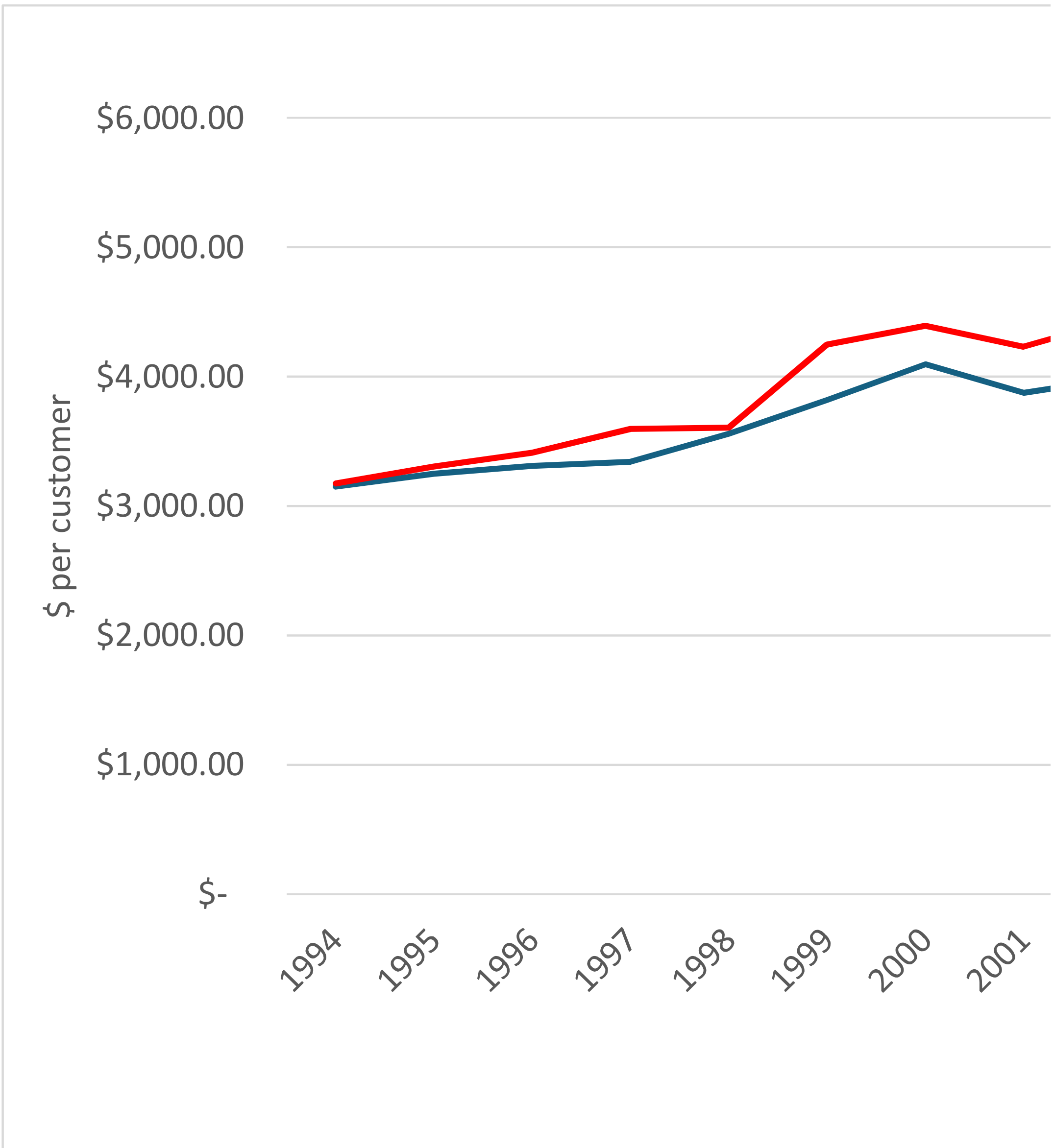
1999
2000
2001

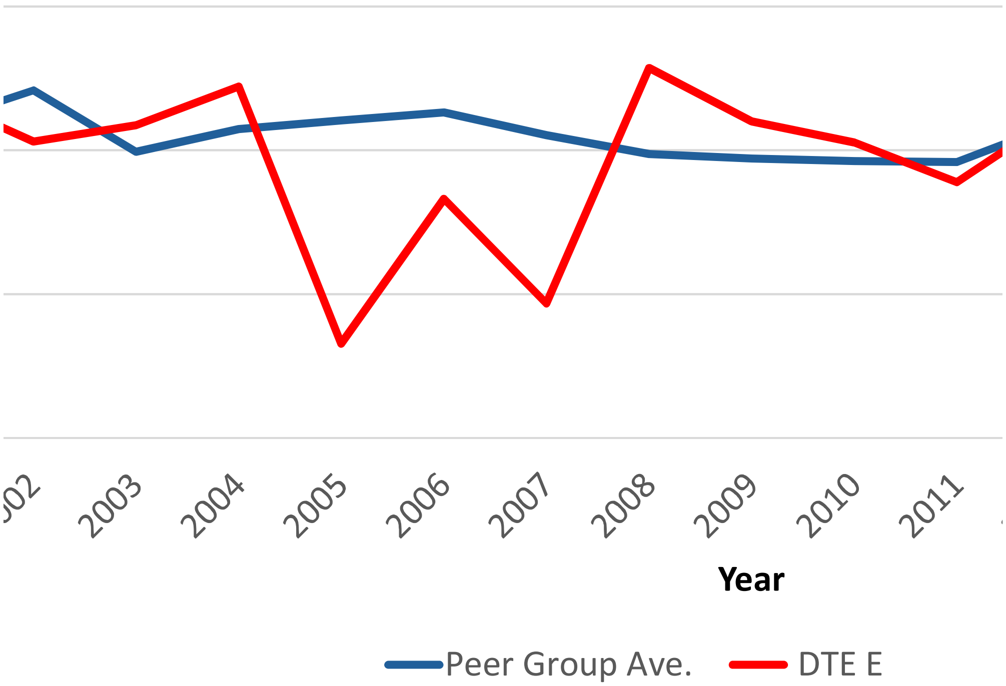

$ per customer
$200.00
$180.00
$160.00
$140.00
$120.00
$100.00
$80.00
$60.00
$40.00
$20.00


$-
1994
1995
1996
1997
1998
1999
2000
2001

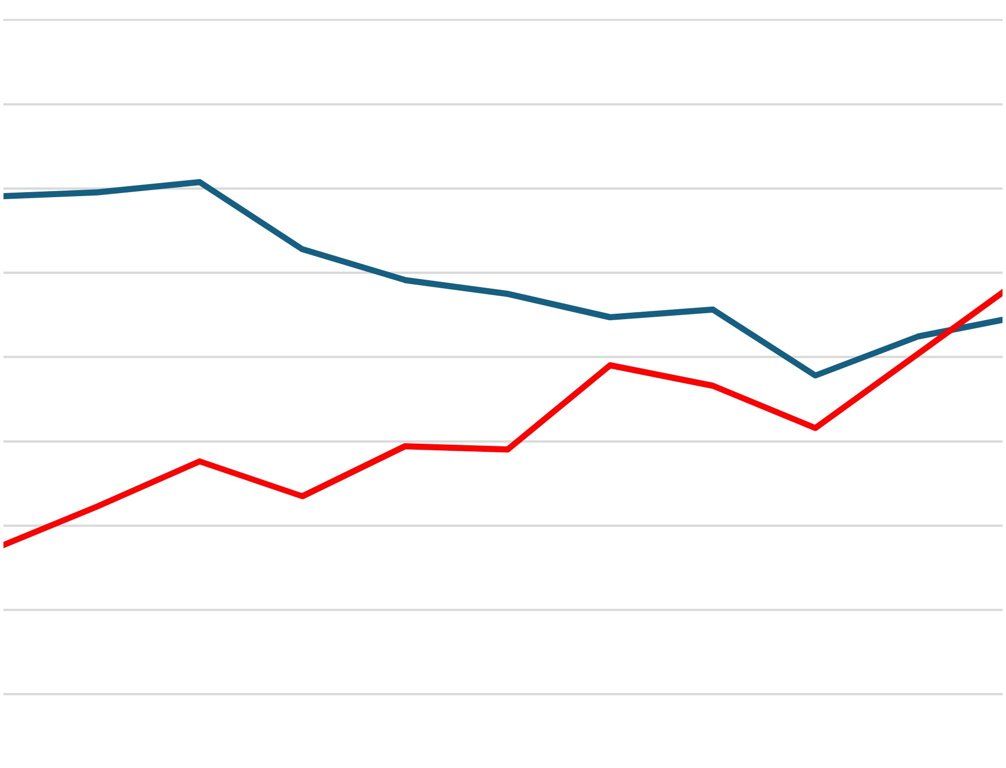

$ per customer
$6,000.00
$5,000.00
$4,000.00
$3,000.00
$2,000.00
$1,000.00
$-
1994
1995
1996
1997
1998
1999
2000
2001

Schedule 320 Dist O&M (infl adj)	Peer Group Ave. (Dist O&M)	Schedule 204 distribution plant in service (infl adj)
$ 188,880,992	$ 156.18	$ 3,897,784,659
$ 179,432,248	$ 151.01	$ 4,015,925,253
$ 181,211,777	$ 152.25	$ 4,124,587,153
$ 124,783,971	$ 143.33	$ 4,156,072,032
$ 205,012,082	$ 152.48	$ 4,742,042,478
$ 231,777,516	$ 170.44	$ 5,006,861,749
$ 256,580,614	$ 177.32	$ 5,573,968,488
$ 231,379,497	$ 158.07	$ 5,485,194,178
$ 223,863,063	$ 159.10	$ 5,686,519,763
$ 218,009,151	$ 161.55	$ 5,886,397,211
$ 198,830,616	$ 145.57	$ 6,012,544,279
$ 197,468,637	$ 138.25	$ 6,118,328,297
$ 202,973,317	$ 135.00	$ 5,660,432,243
$ 198,489,592	$ 129.48	$ 5,695,652,260
$ 199,707,276	$ 131.25	$ 5,611,433,647
$ 170,416,875	$ 115.62	$ 5,697,938,451
$ 182,772,155	$ 124.89	$ 5,941,627,306
$ 219,350,305	$ 129.68	$ 6,347,436,362
$ 224,857,081	$ 135.55	$ 6,625,318,627
$ 219,846,936	$ 128.55	$ 6,757,275,808
$ 239,098,303	$ 139.18	$ 6,801,030,300
$ 224,224,420	$ 130.41	$ 7,080,322,371
$ 233,362,654	$ 136.58	$ 7,543,845,908
$ 227,360,514	$ 134.65	$ 7,806,133,801
$ 245,340,019	$ 145.24	$ 8,134,209,149
$ 251,312,220	$ 152.81	$ 8,548,488,078
$ 271,626,783	$ 157.03	$ 8,996,817,650
$ 270,933,065	$ 164.84	$ 9,125,632,822
$ 250,080,023	$ 150.68	$ 8,554,073,880
$ 248,475,479	$ 148.59	$ 8,589,051,410
$ 262,039,674	$ 162.51	$ 8,767,356,608

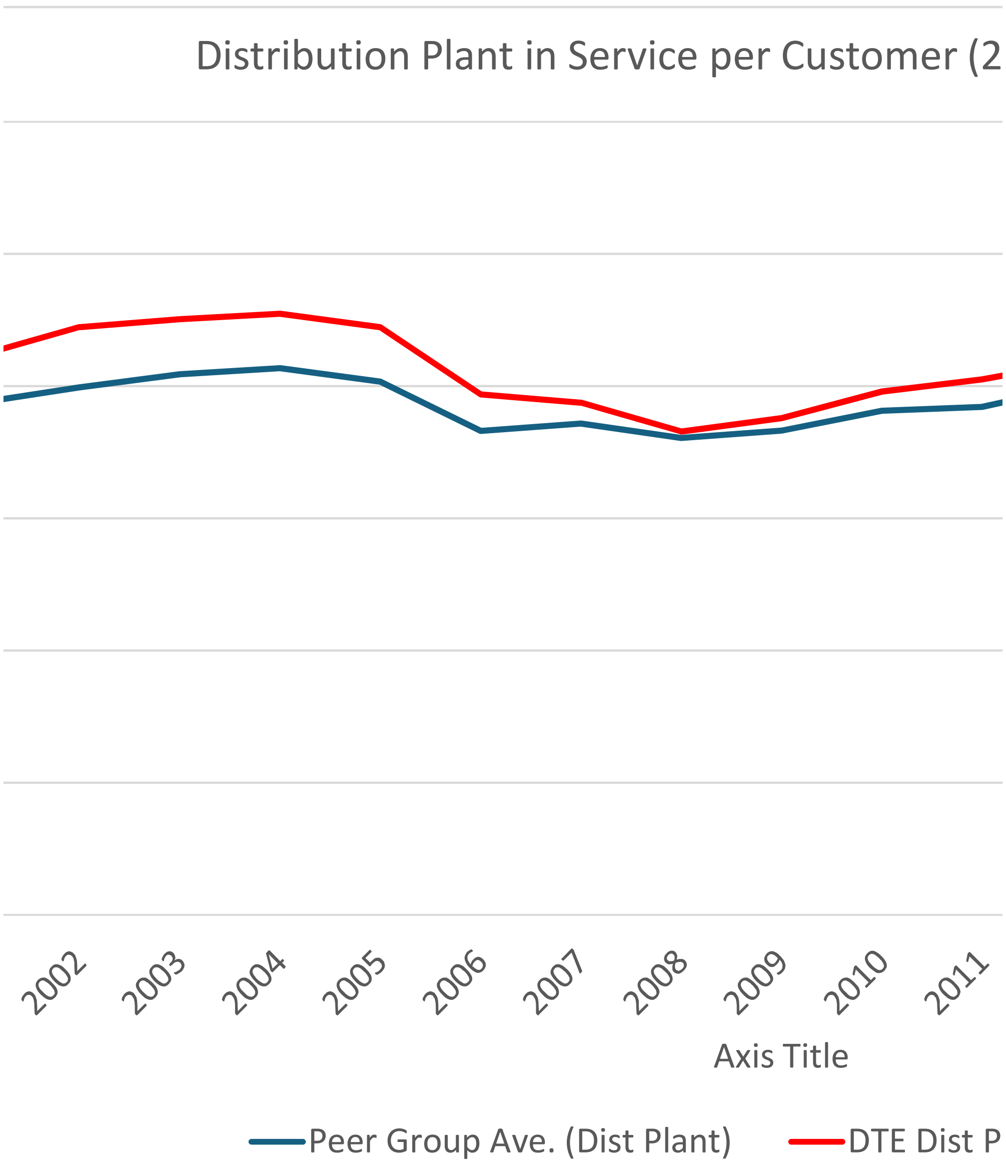
Distribution Capital Additions per Customer (2



Electric Distribution O&M per Customer

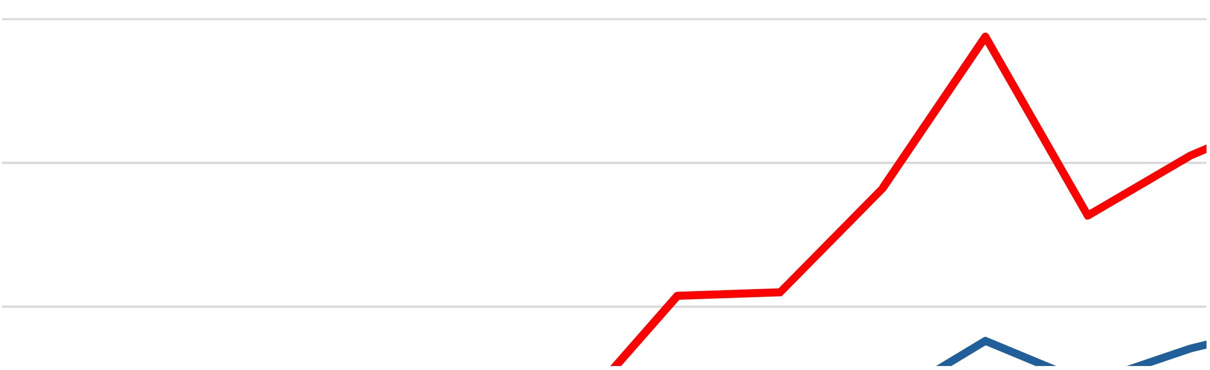


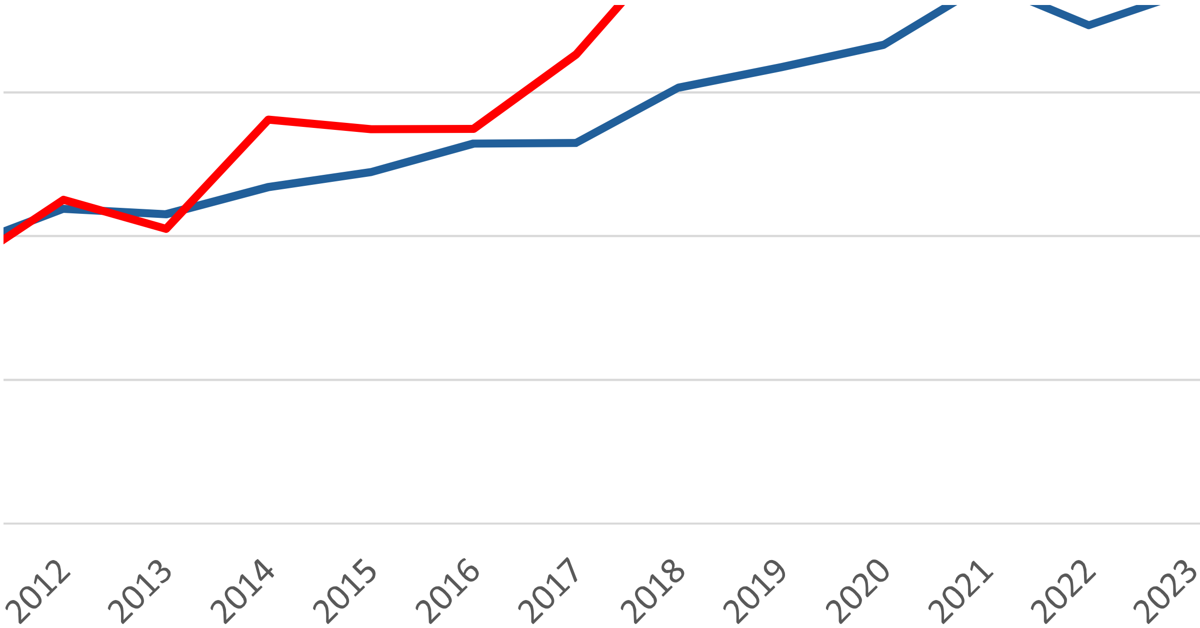

2002
2003
2004
2005
2006
2007
2008
2009
2010
Year
Peer Group Ave. (Dist O&M)
DTE


Distribution Plant in Service per Customer (2
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011
Axis Title
Peer Group Ave. (Dist Plant)
DTE Dist P

Peer Group Ave. (Dist Plant)	EIA 861 Reliability SAIFI w/o MED	SAIDI w/o MED	CAIDI w/o MED	SAIFI w/ MED
$ 3,149.34				
$ 3,249.17				
$ 3,310.60				
$ 3,342.25				
$ 3,556.33				
$ 3,818.32				
$ 4,095.06				
$ 3,875.60				
$ 3,991.92				
$ 4,090.62				
$ 4,135.99				
$ 4,035.25				
$ 3,660.33				
$ 3,716.03				
$ 3,608.00				
$ 3,663.77				
$ 3,813.29				
$ 3,842.21				
$ 4,009.69				
$ 4,088.53	0.81287	99.81250	116.39166	1.12637
$ 4,092.00	0.88650	100.32625	109.92410	1.13912
$ 4,219.65	1.01300	105.18875	104.40740	1.19888
$ 4,441.11	0.87100	106.43000	117.93228	1.07425
$ 4,606.61	0.84463	100.05837	113.84209	1.05687
$ 4,745.62	0.93400	115.48725	119.29347	1.15850
$ 4,925.84	0.91337	119.10050	124.49749	1.20962
$ 5,067.92	0.90213	106.94125	114.78417	1.22563
$ 5,172.39	0.97325	120.64562	122.04921	1.26100
$ 4,780.67	0.95450	120.82013	124.30911	1.17000
$ 4,777.18	0.80962	101.35675	121.45130	1.10287
$ 4,868.02				

2024$)




2012
2013
2014
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2016
2017
2018
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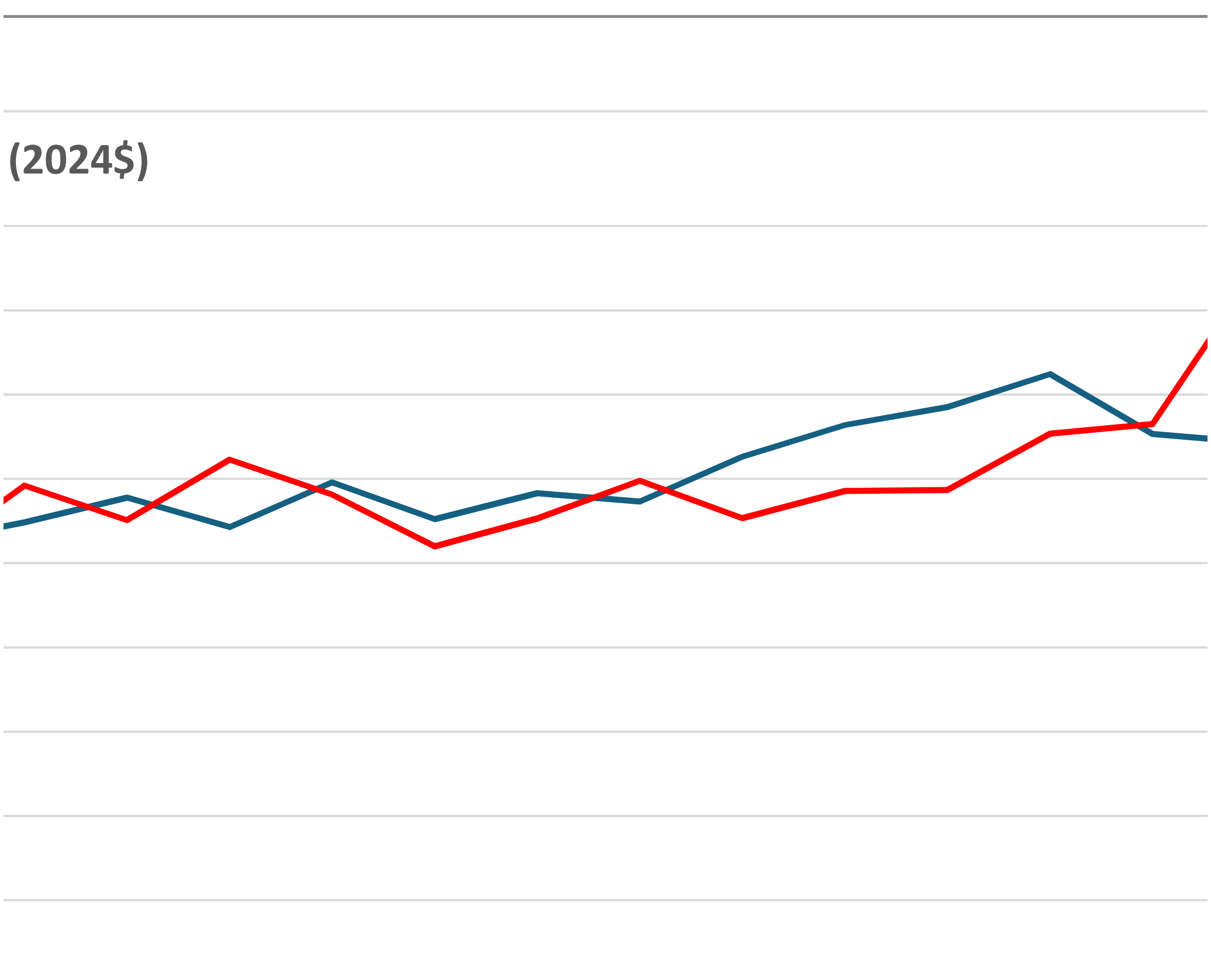
2020
2021
2022
2023


(2024$)


2012
2013
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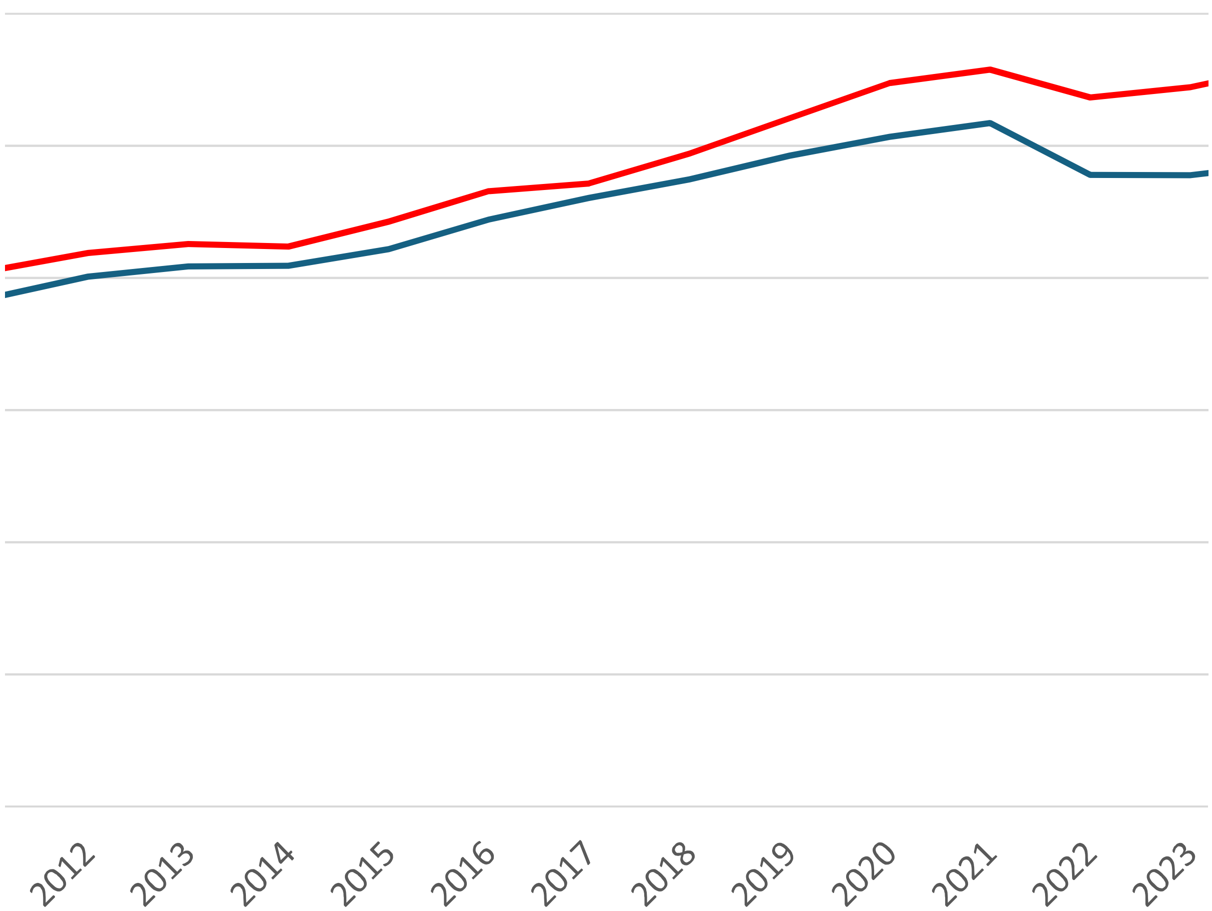
2016
2017
2018
2019
2020
2021
2022

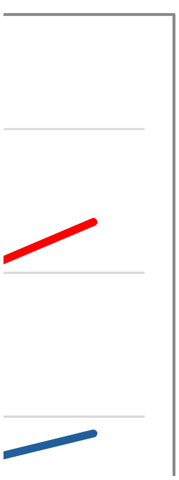
O&M

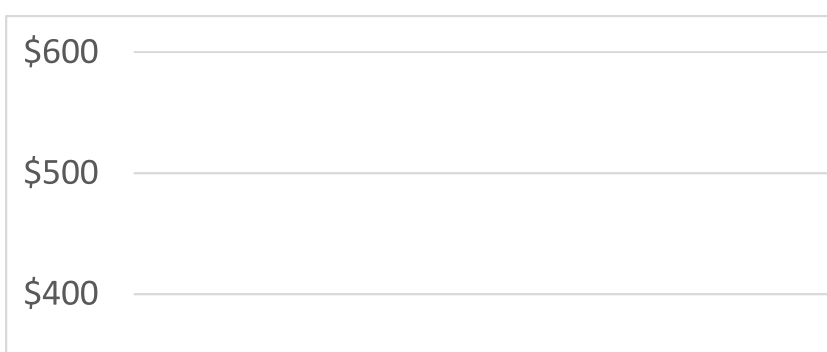
.024$)


2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023

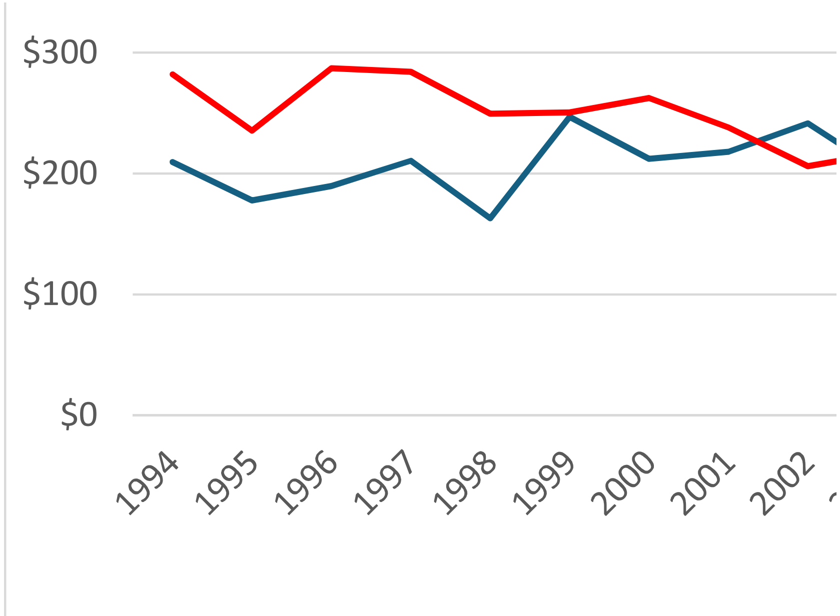
lant

SAIDI w/ MED	CAIDI w/ MED
340.18750	253.44786
290.62625	240.32669
206.81500	196.84416
180.18750	164.37493
210.87487	186.33199
264.21400	212.03326
286.38338	223.96994
338.37413	268.38737
318.50725	238.82602
252.57925	201.43397
365.56300	304.20008





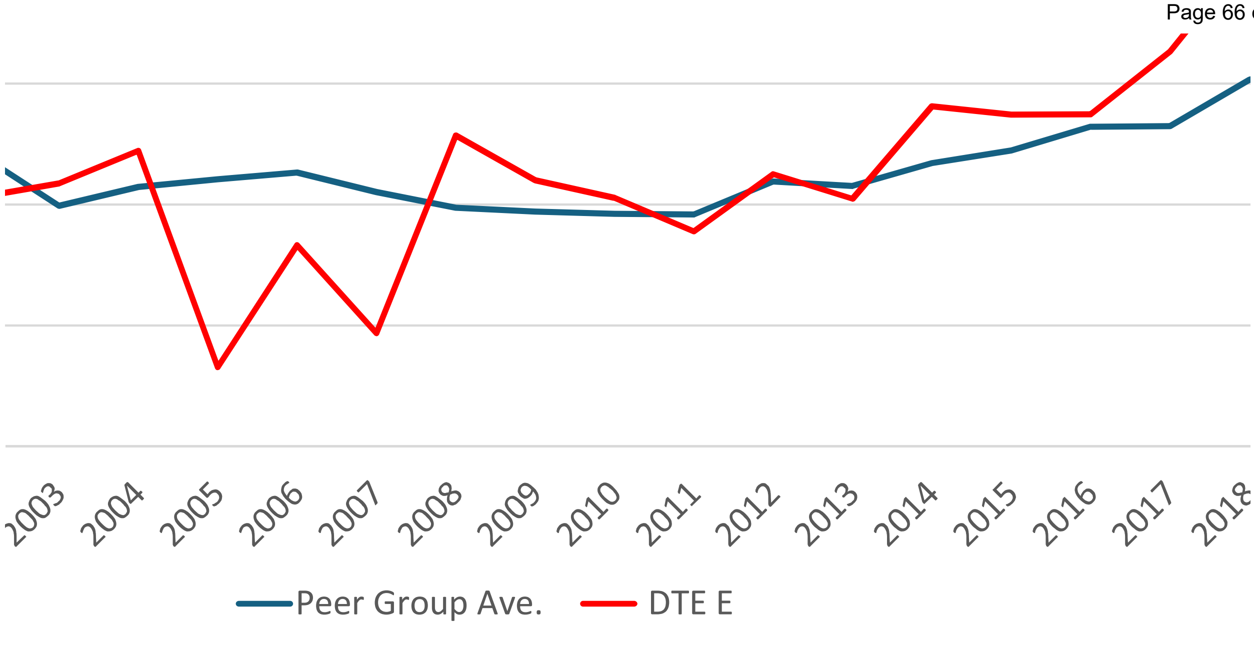

2024


$300
$200
$100
$0
1994
1995
1996
1997
1998
1999
2000
2001
2002


2023
2024


2024

DTE E
$ 281.89
$ 235.31
$ 286.91
$ 284.22
$ 249.40
$ 250.57
$ 262.36
$ 238.18
$ 206.04
$ 217.38
$ 244.34
$ 65.51
$ 166.25
$ 93.53
$ 257.14
$ 220.04
$ 205.43
$ 177.86
$ 225.20
$ 204.81
$ 281.06
$ 274.37
$ 274.45
$ 326.37
$ 407.62
$ 410.03
$ 482.26
$ 587.90
$ 463.37
$ 505.11
$ 535.33


2003
2004
2005
2006
2007
2008
2009
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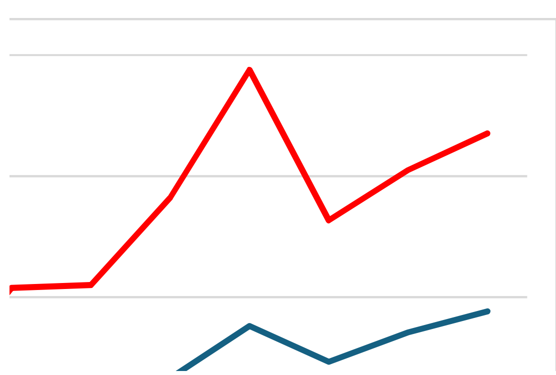
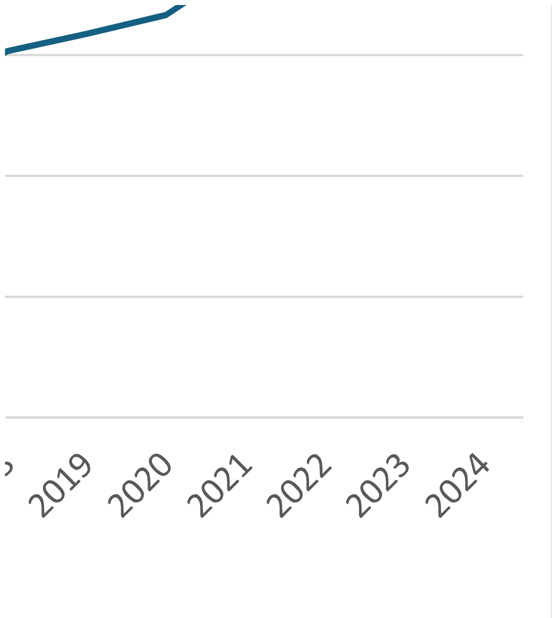
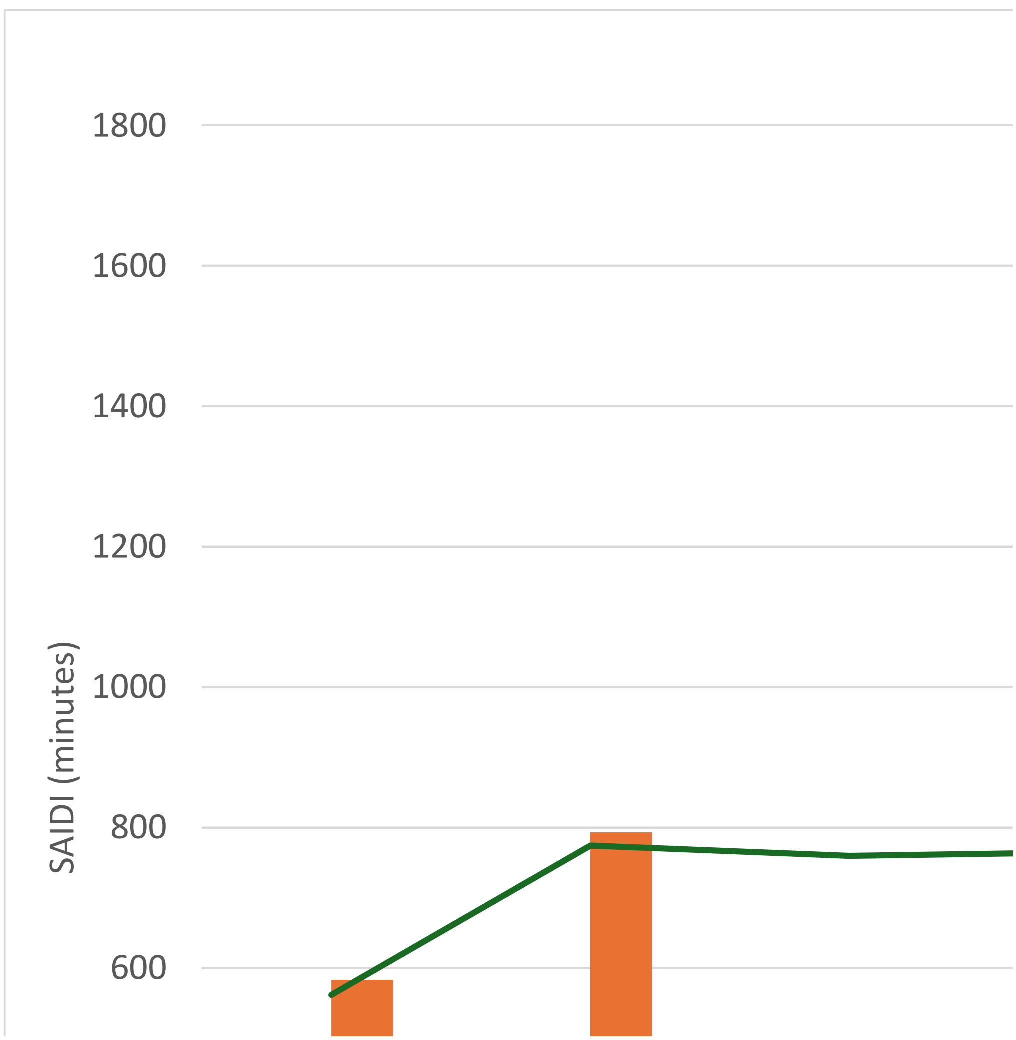
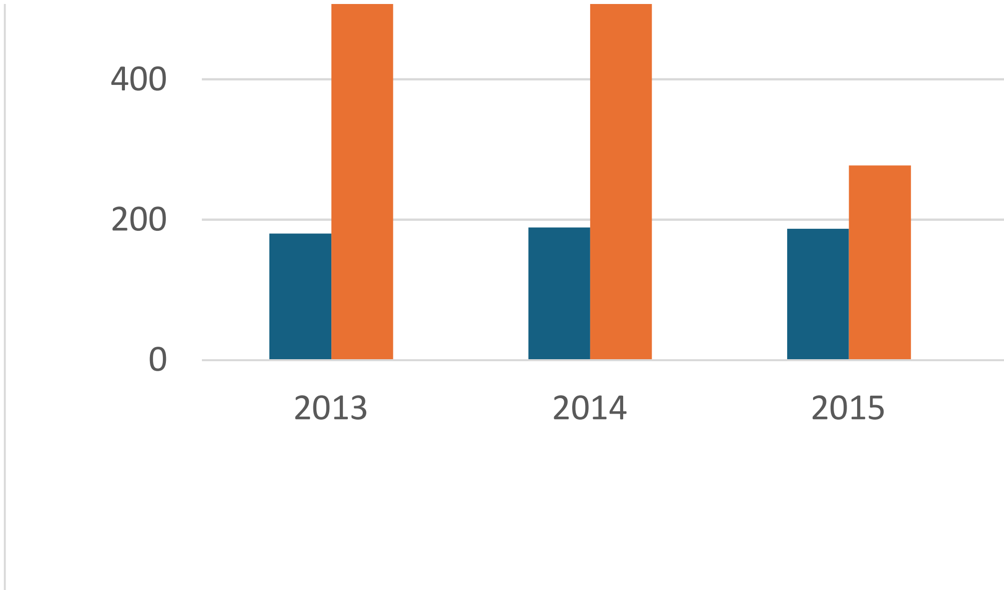
2011
2012
2013
2014
2015
2016
2017
2018
Peer Group Ave.
DTE E

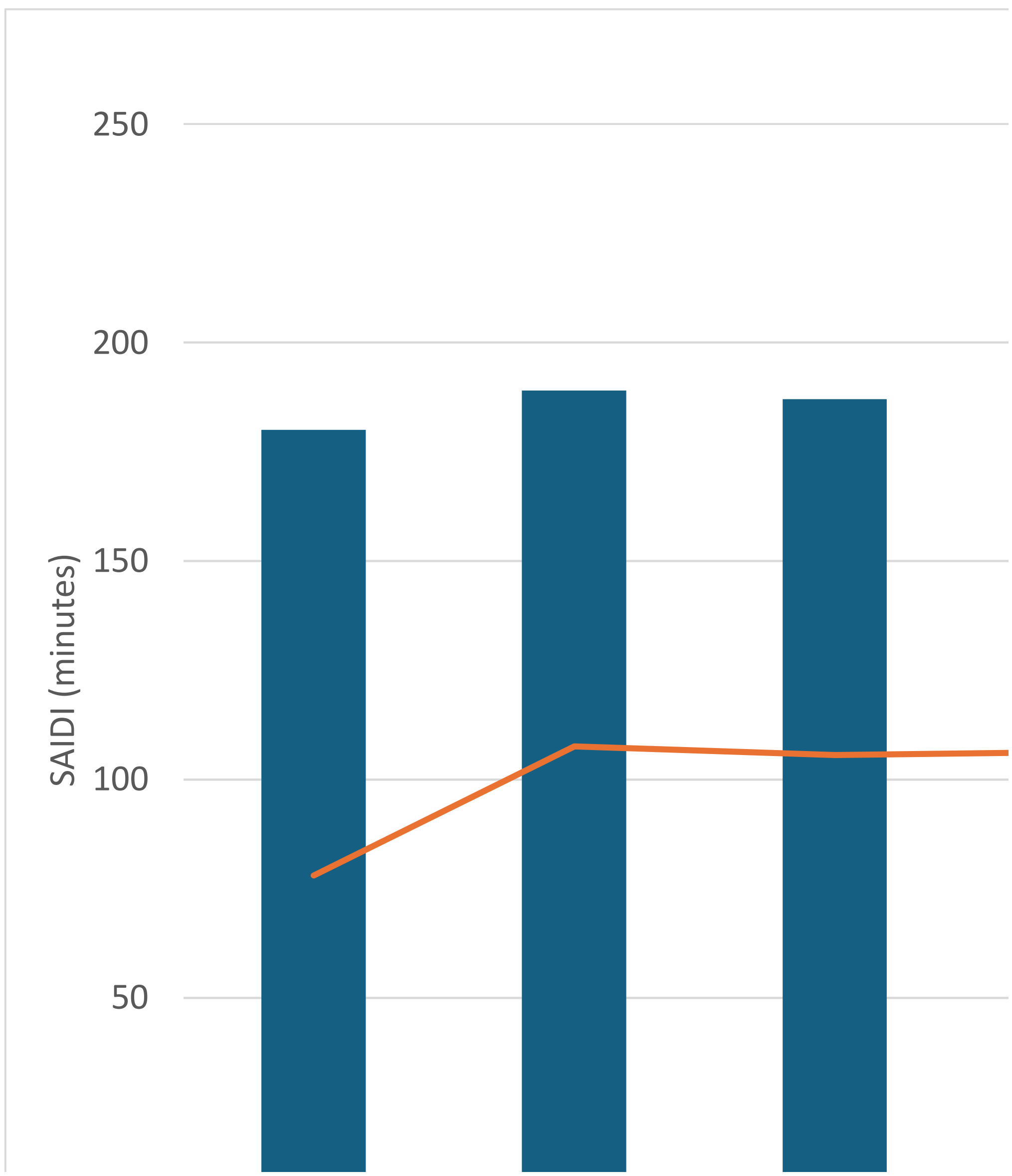


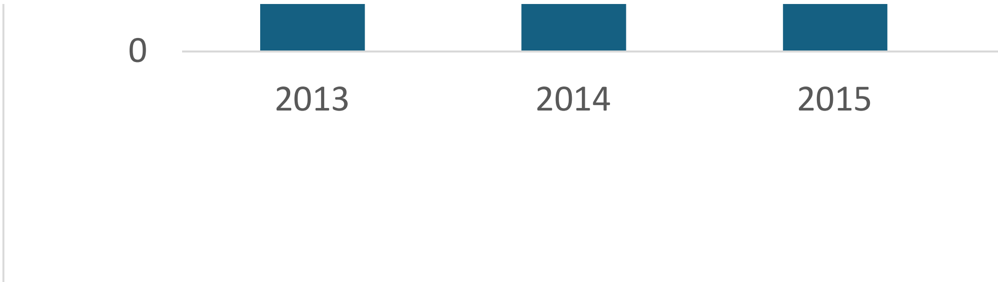

2019
2020
2021
2022
2023
2024

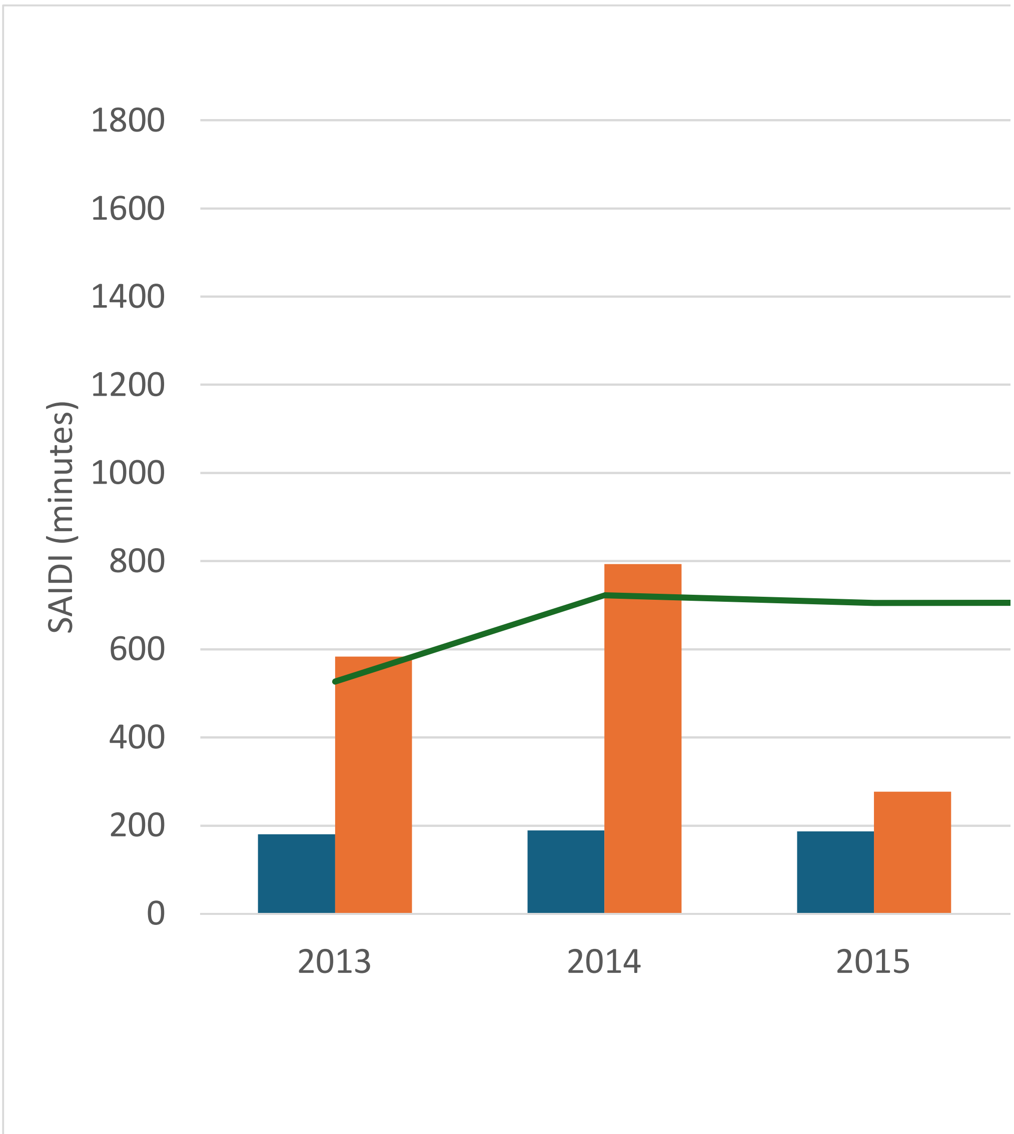
report_year	Dist. Capital Additions	avg customers per month	Dist. Cap. Additions per customer	Dist O&M
2013	$ 437,104,593	2,134,162	$ 204.81	$ 428,973,013
2014	$ 602,548,493	2,143,851	$ 281.06	$ 391,952,626
2015	$ 591,224,580	2,154,874	$ 274.37	$ 356,450,345
2016	$ 595,402,309	2,169,416	$ 274.45	$ 382,037,965
2017	$ 712,128,975	2,181,941	$ 326.37	$ 402,005,768
2018	$ 895,318,073	2,196,473	$ 407.62	$ 376,283,557
2019	$ 905,734,876	2,208,925	$ 410.03	$ 396,257,533
2020	$ 1,073,750,725	2,226,501	$ 482.26	$ 397,711,340
2021	$ 1,319,812,070	2,244,945	$ 587.90	$ 421,766,857
2022	$ 1,046,012,098	2,257,415	$ 463.37	$ 380,852,577
2023	$ 1,144,801,106	2,266,460	$ 505.11	$ 446,657,566
2024	$ 1,220,065,920	2,279,071	$ 535.33	$ 325,675,360

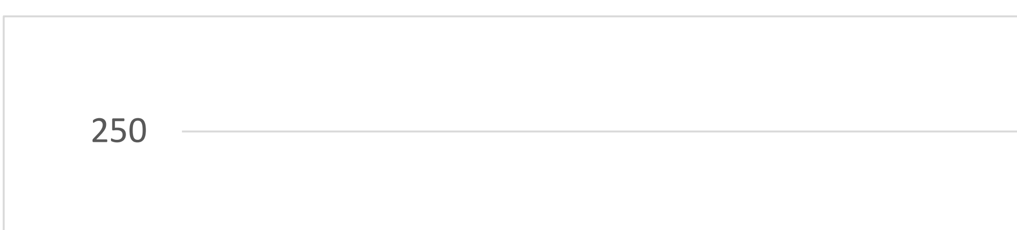


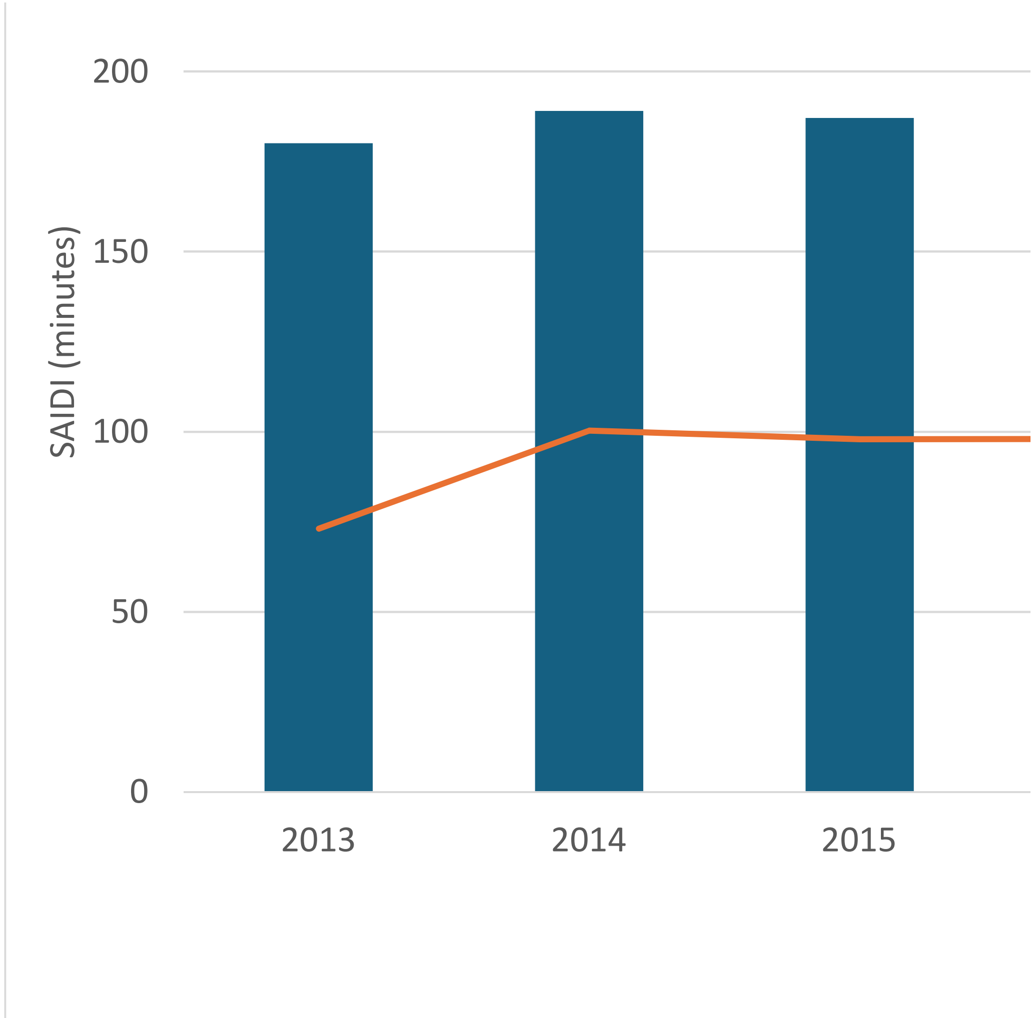

400
200
0
2013
2014
2015

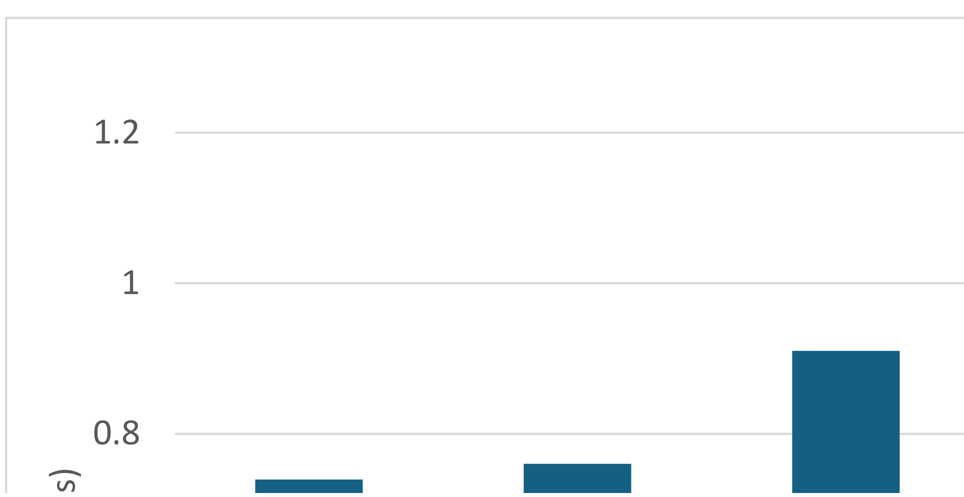

250
200
150
100
50
SAIDI (minutes)

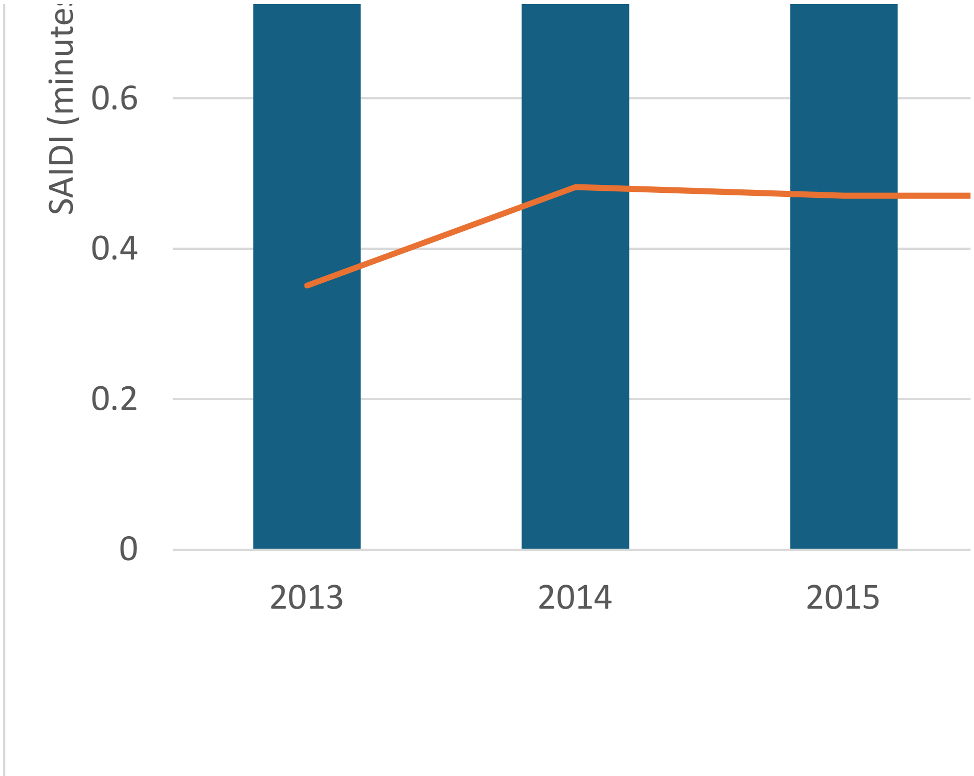

0
2013
2014
2015

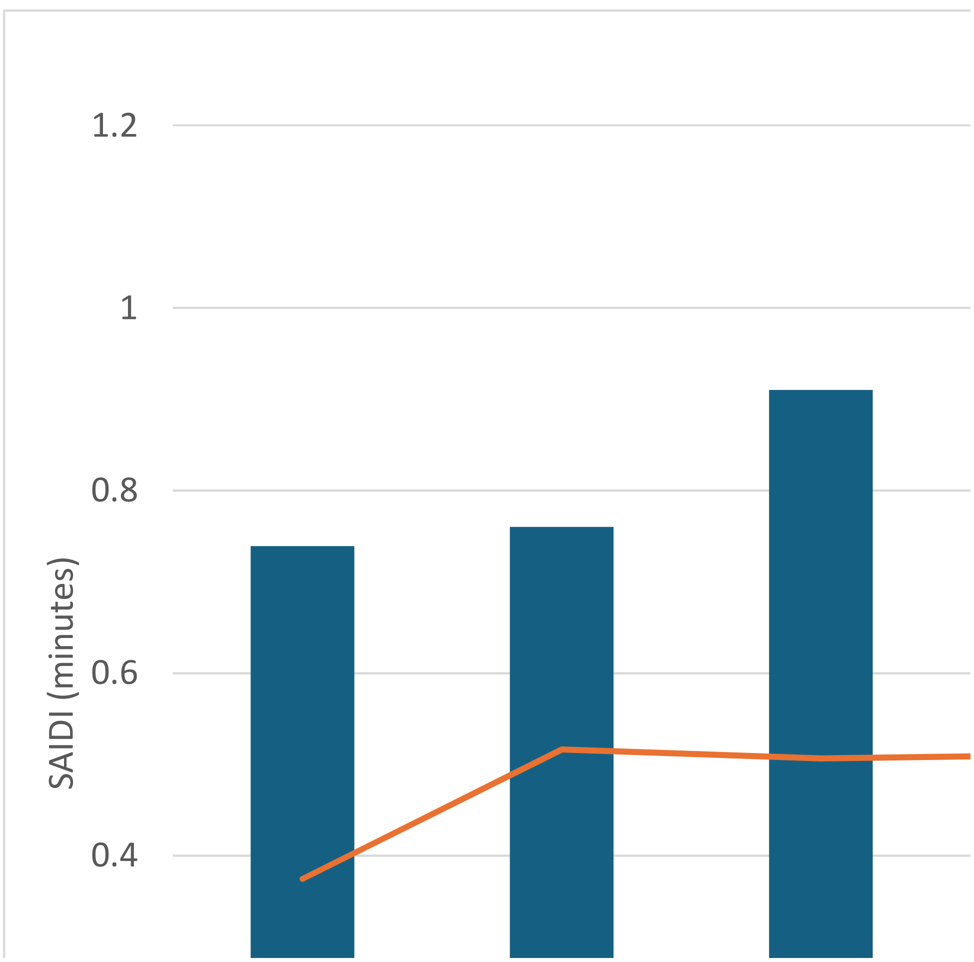

SAIDI (minutes)
1800
1600
1400
1200
1000
800
600
400
200
0
2013
2014
2015

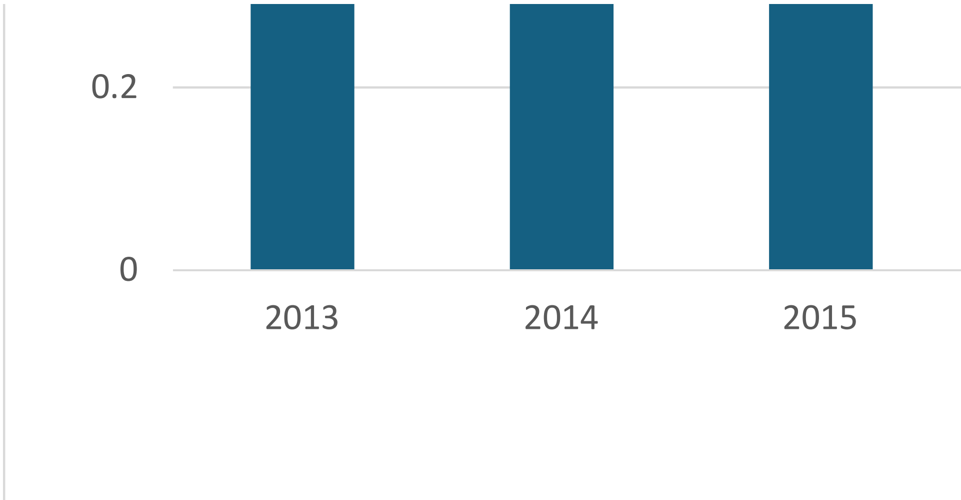

250


200
150
100
50
0
SAIDI (minutes)
2013
2014
2015

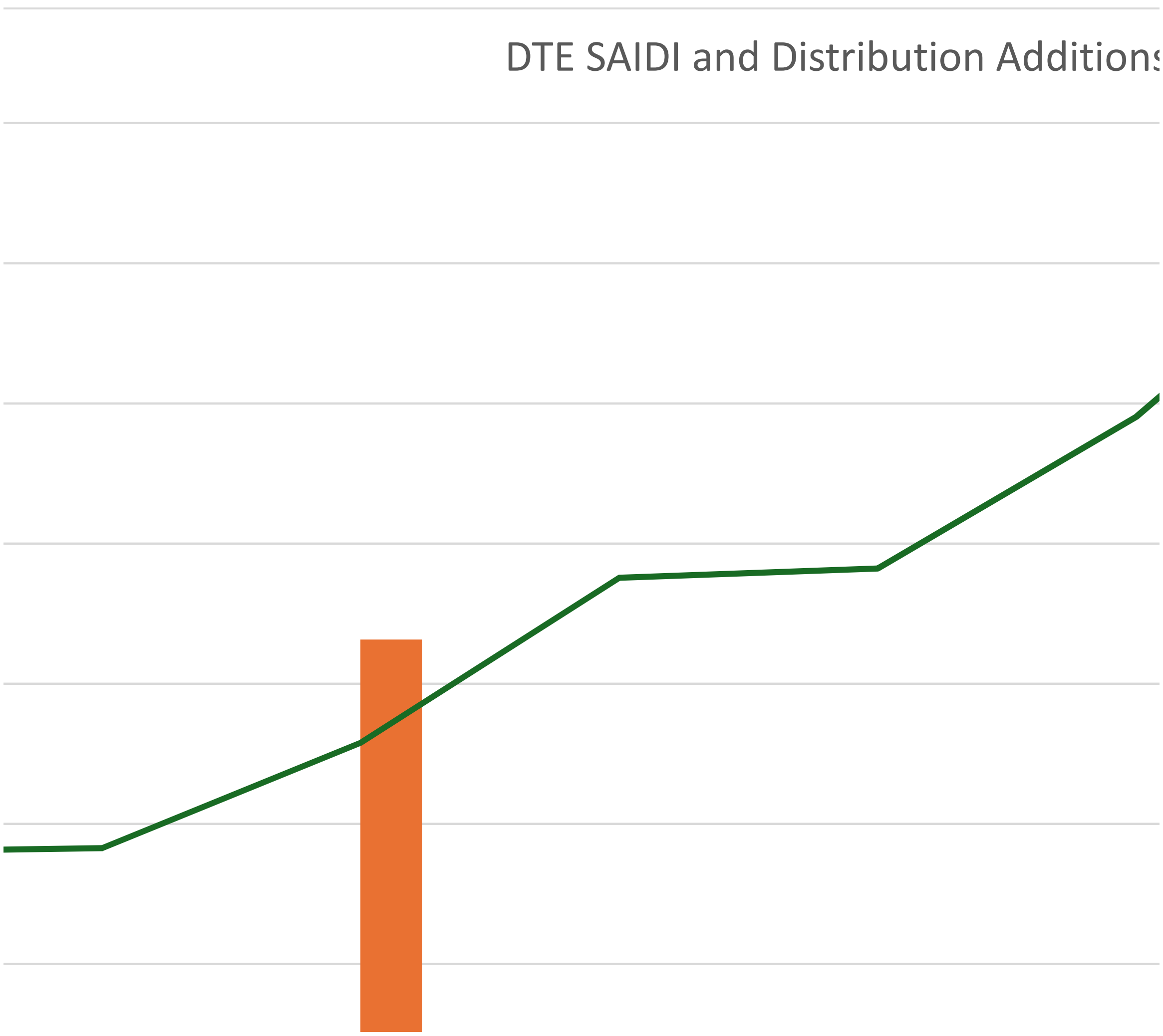

1.2
1
0.8

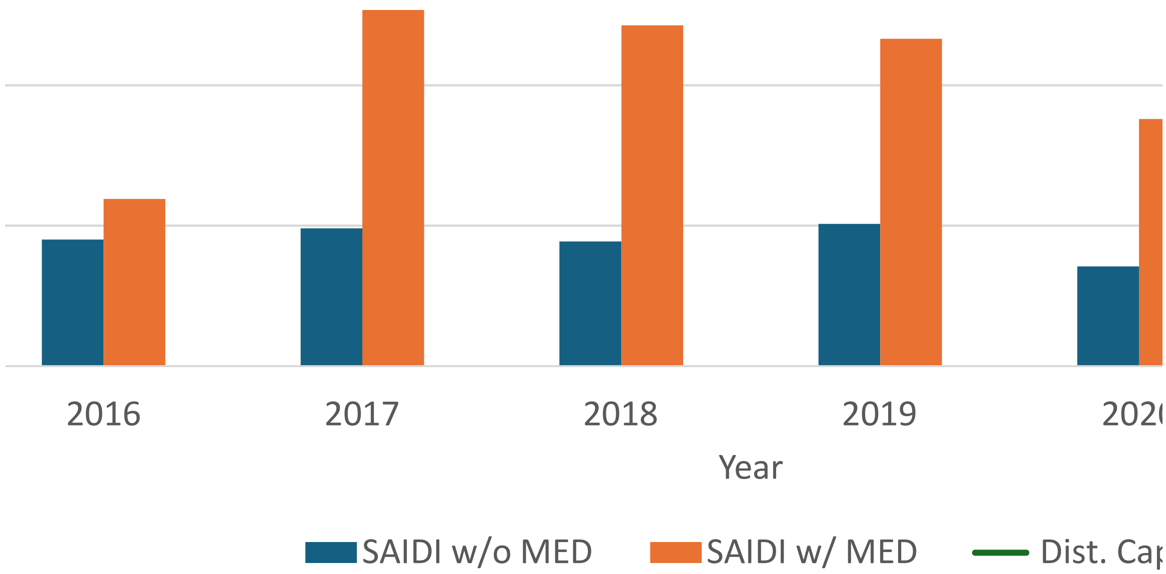

SAIDI (minutes
0.6
0.4
0.2
0
2013
2014
2015

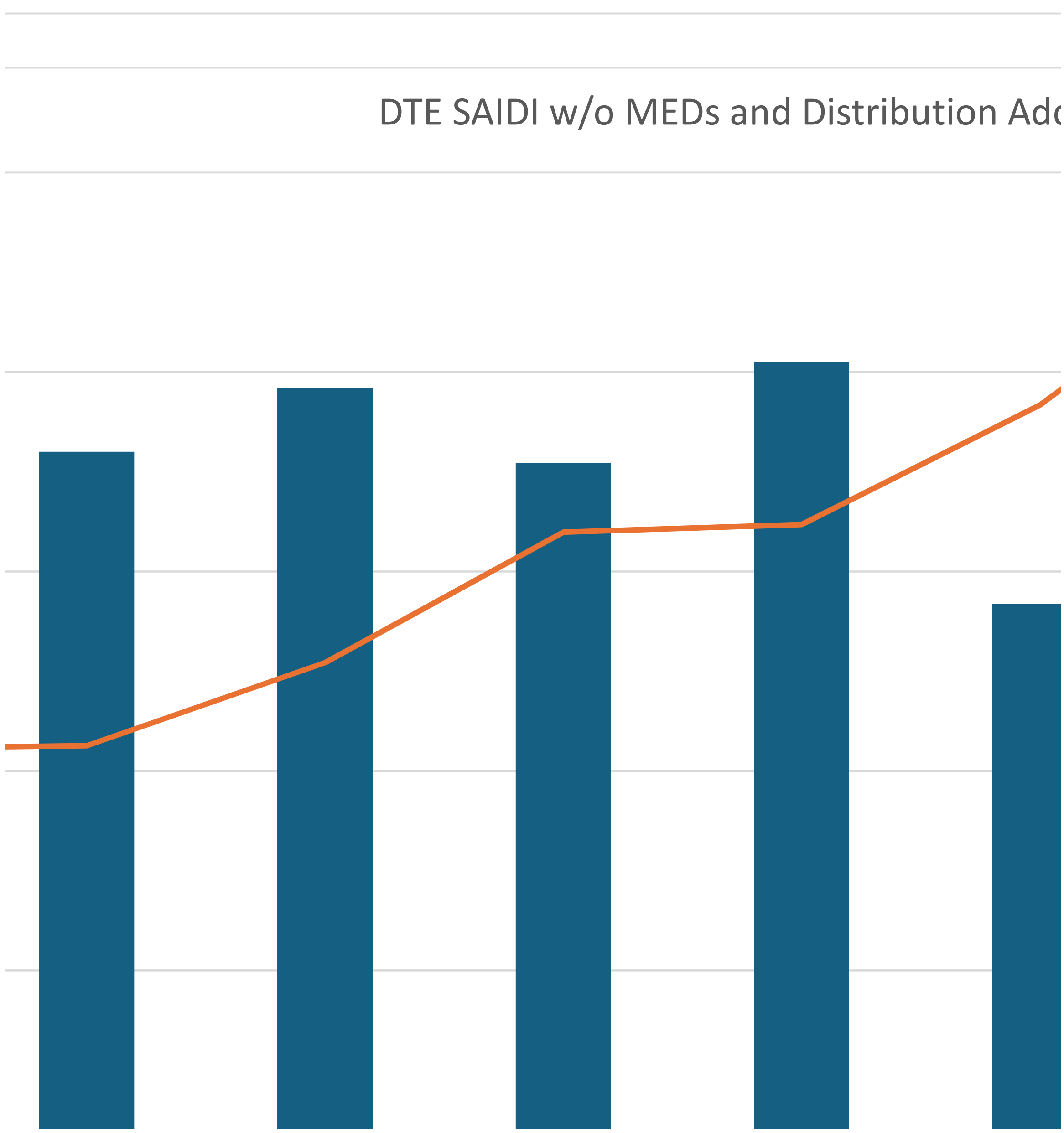

1.2
1
0.8
0.6
0.4
SAIDI (minutes)

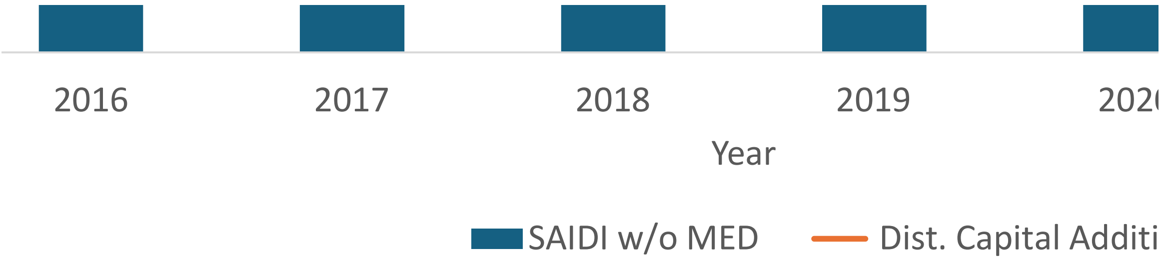

0.2
0
2013
2014
2015

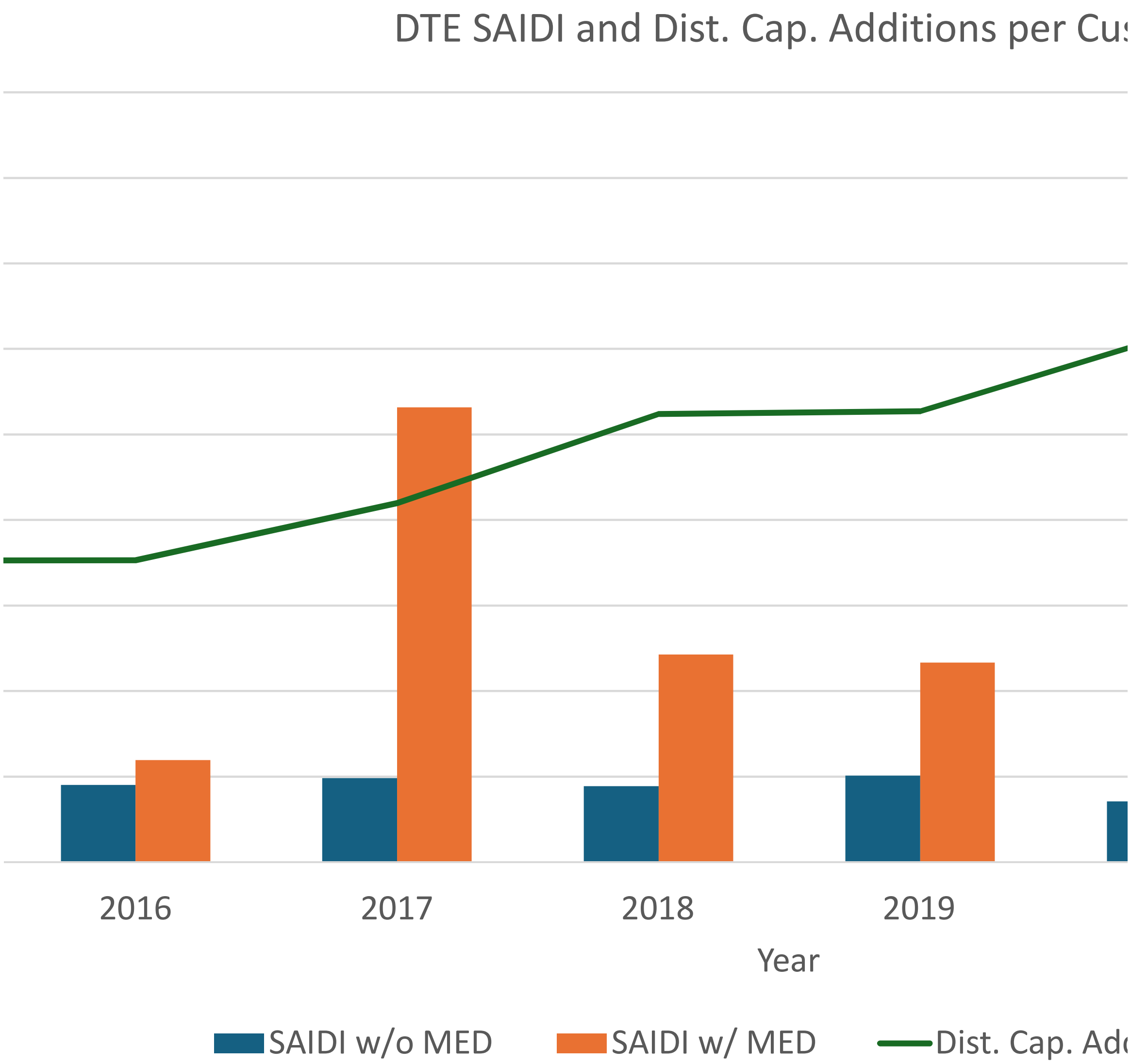
Dist O&M per customer	distribution plant in service	Dist Plant per customer	SAIFI w/o MED	SAIDI w/o MED
$ 201.00	$ 9,087,366,472	$ 4,258.05	0.73900002	180
$ 182.83	$ 9,085,022,924	$ 4,237.71	0.75999999	189
$ 165.42	$ 9,539,895,770	$ 4,427.12	0.91000003	187
$ 176.10	$ 10,101,000,837	$ 4,656.09	0.912	180
$ 184.24	$ 10,289,126,707	$ 4,715.58	0.99000001	196
$ 171.31	$ 10,851,388,059	$ 4,940.37	1.04100001	177.188004
$ 179.39	$ 11,509,799,952	$ 5,210.59	1.13600004	202.375
$ 178.63	$ 12,193,887,336	$ 5,476.70	1.01400006	141.884003
$ 187.87	$ 12,523,050,123	$ 5,578.33	0.92400002	135.600998
$ 168.71	$ 12,115,147,786	$ 5,366.82	0.98000002	146.154007
$ 197.07	$ 12,337,514,272	$ 5,443.52	0.85500002	156.843002
$ 142.90	$ 12,779,676,672	$ 5,607.41	0.94	159



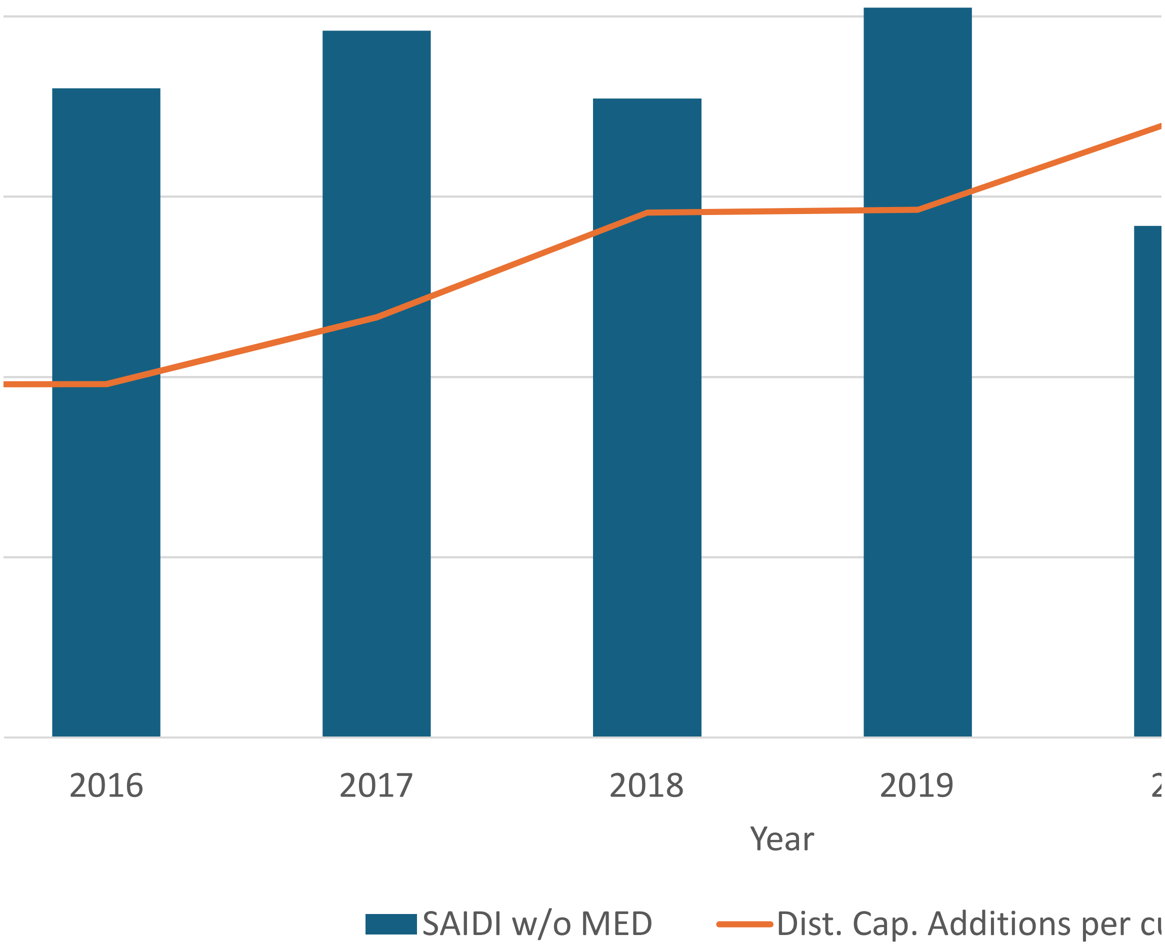

2016
2017
2018
2019
202
Year
SAIDI w/o MED
SAIDI w/ MED
Dist. Ca


DTE SAIDI w/o MEDs and Distribution Ad

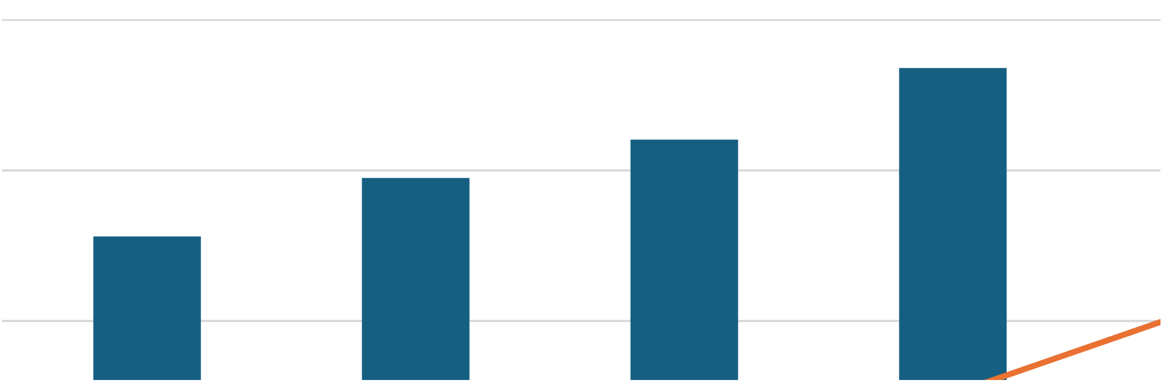


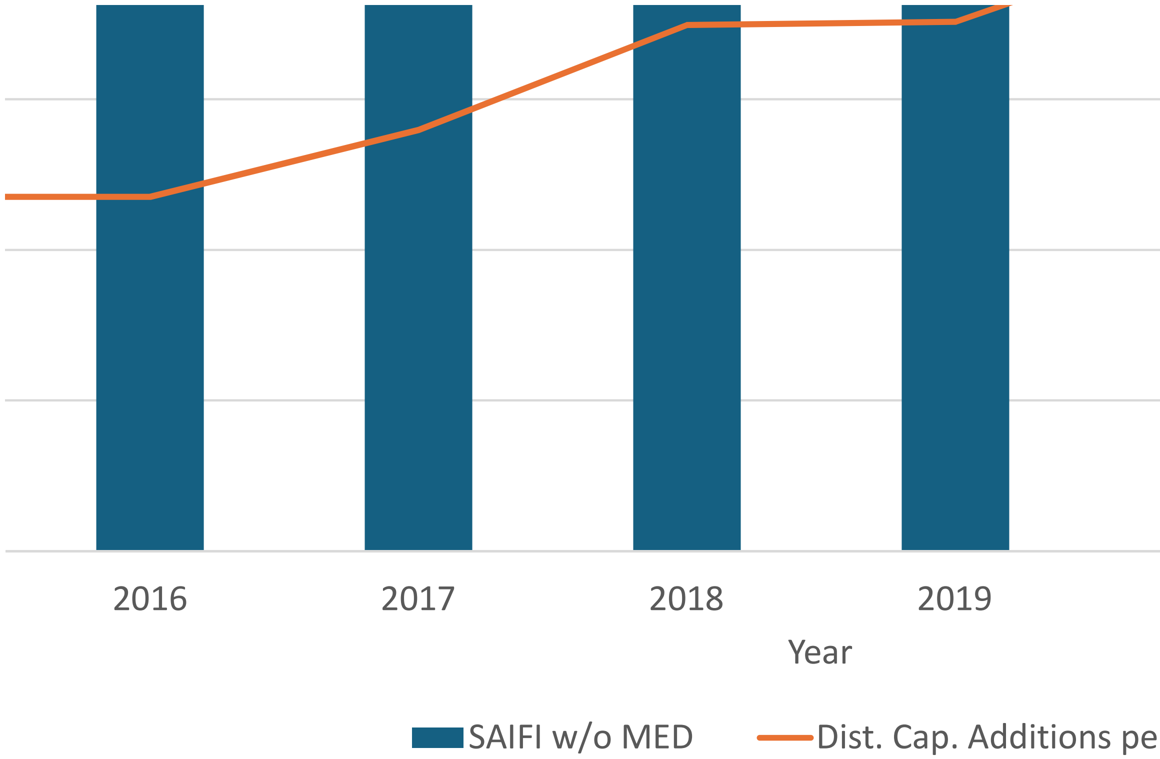


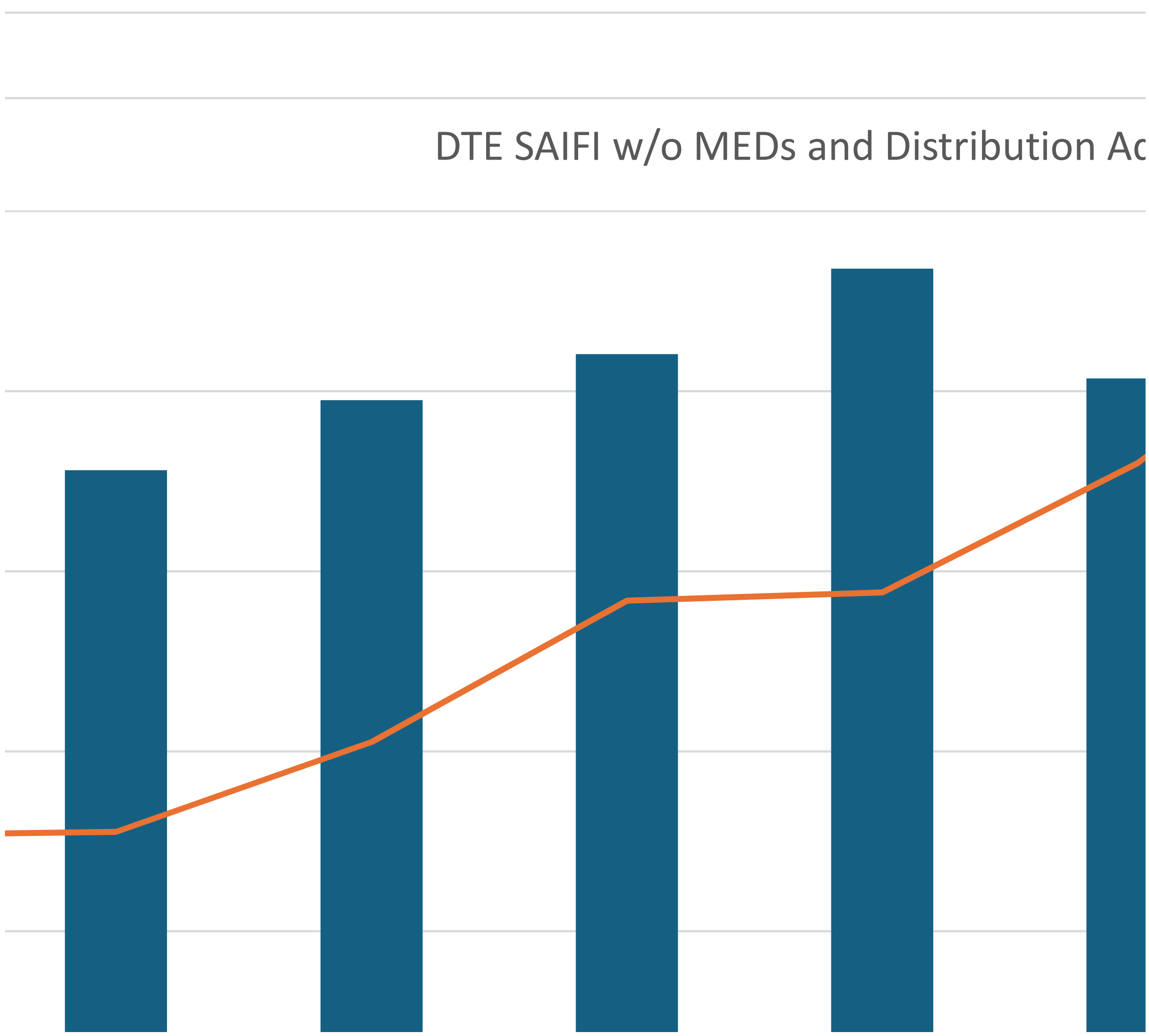
DTE SAIDI w/o MEDs and Additions per Cus

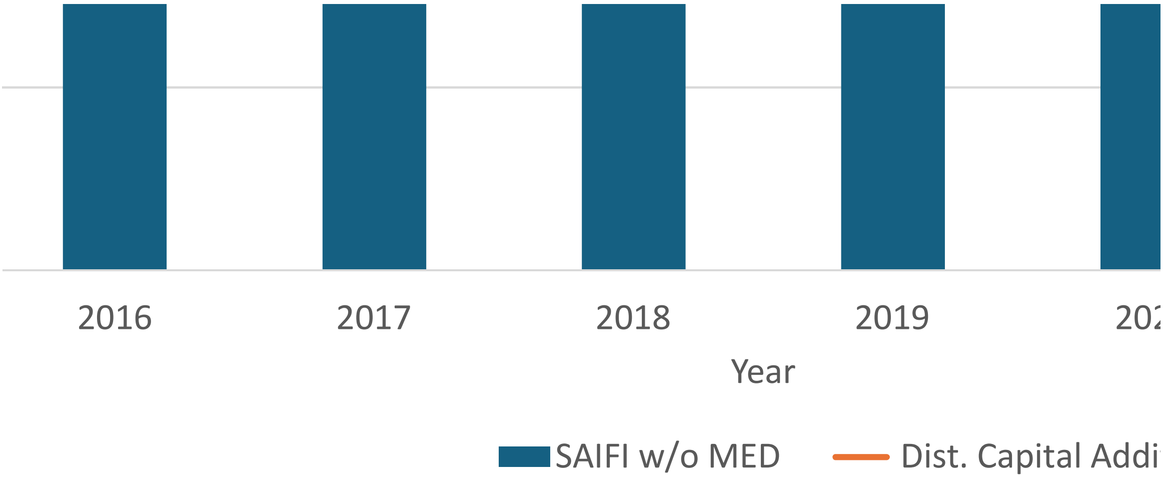


DTE SAIFI w/o MEDs and Additions per Cu

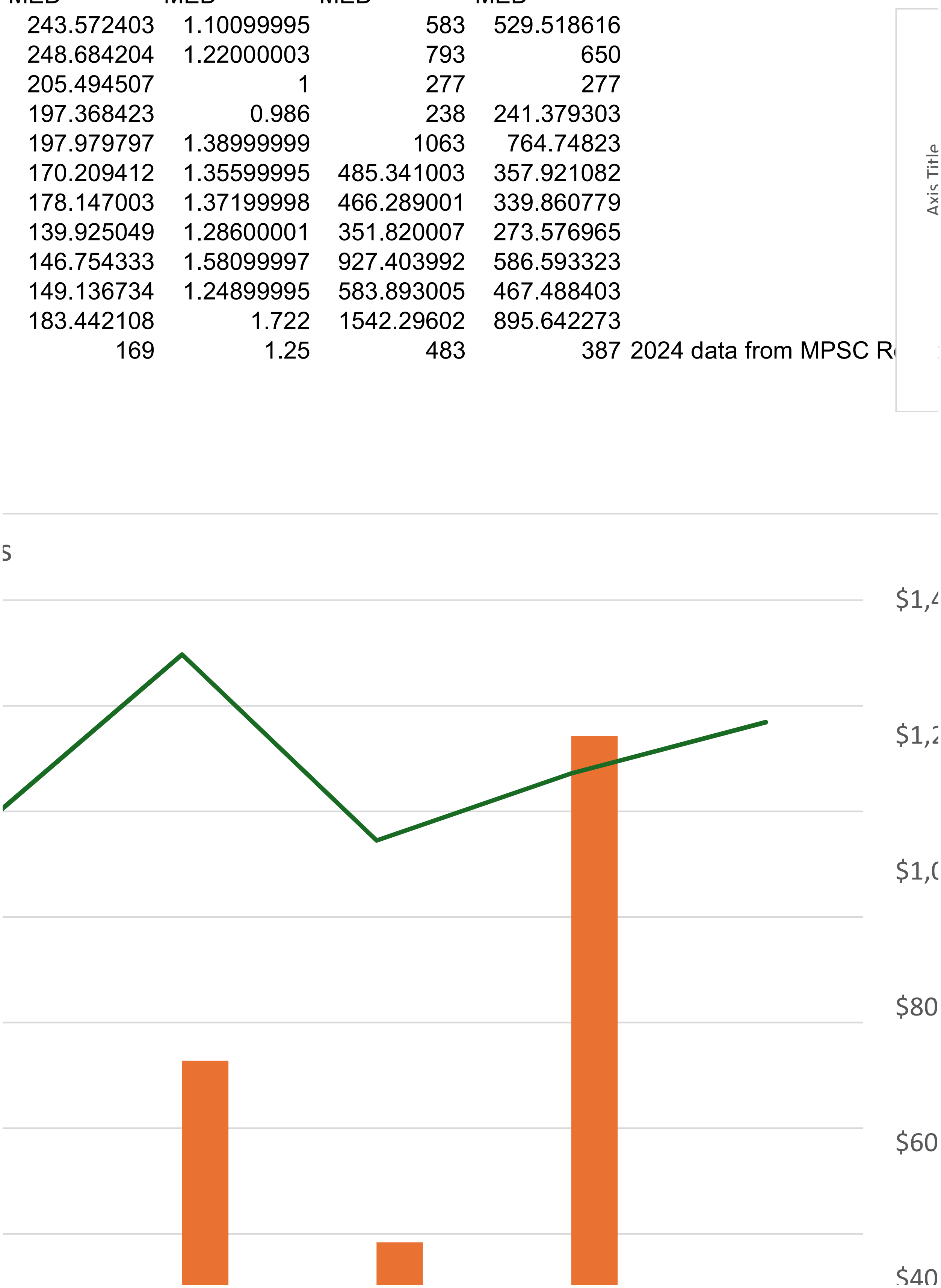


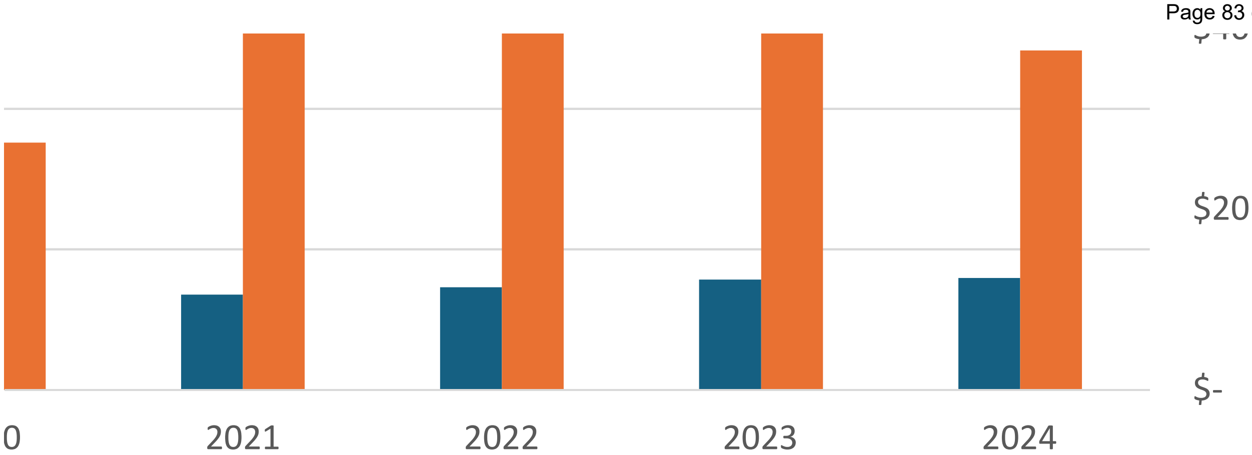

2016
2017
2018
2019
Year
SAIFI w/o MED
Dist. Cap. Additions pe

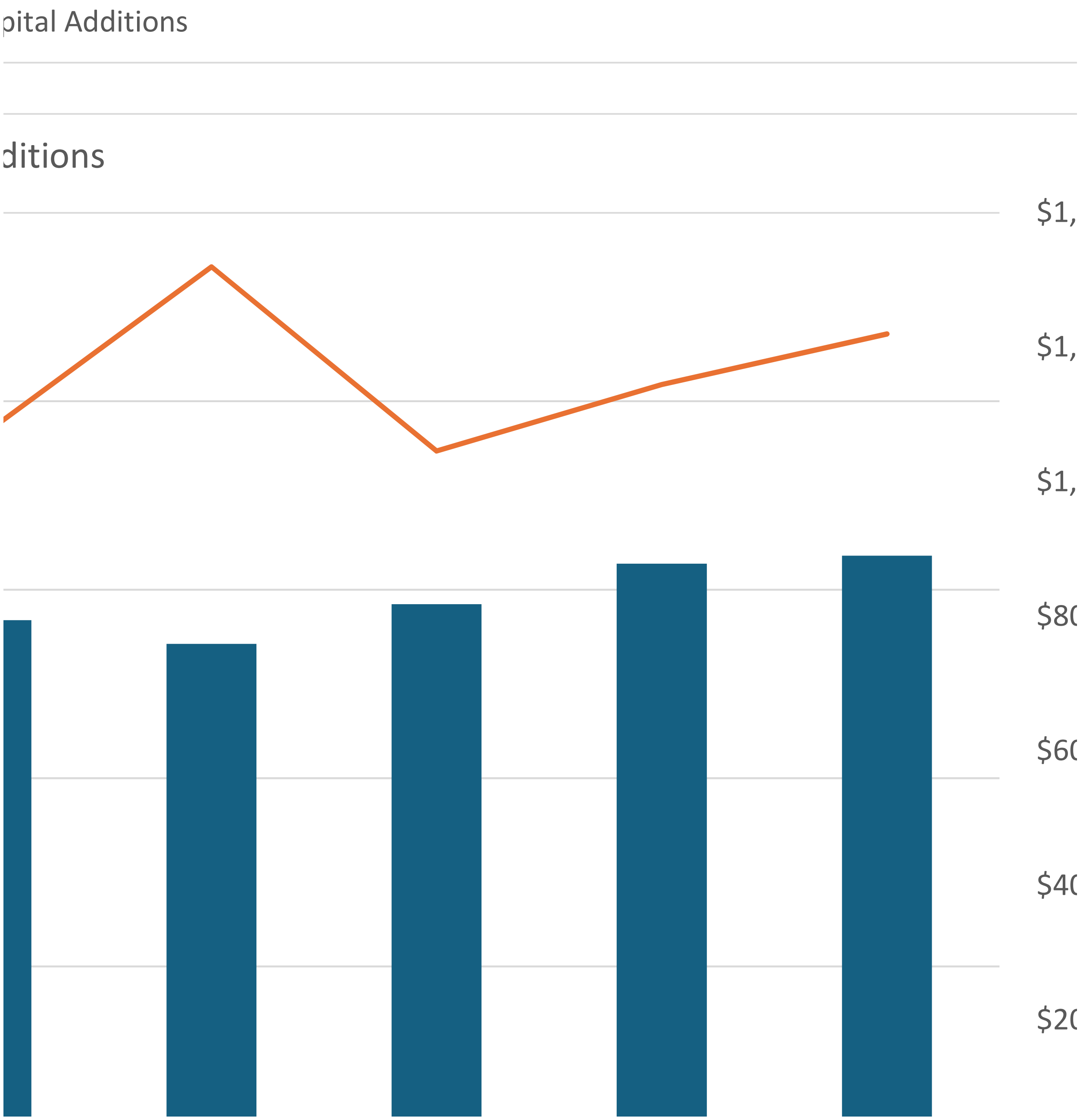

DTE SAIFI w/o MEDs and Distribution Ad


2016
2017
2018
2019
Year
SAIFI w/o MED
Dist. Capital Addi

CAIDI w/o MED	SAIFI w/ MED	SAIDI w/ MED	CAIDI w/ MED	
243.572403	1.10099995	583	529.518616	
248.684204	1.22000003	793	650	
205.494507	1	277	277	
197.368423	0.986	238	241.379303	
197.979797	1.38999999	1063	764.74823	
170.209412	1.35599995	485.341003	357.921082	
178.147003	1.37199998	466.289001	339.860779	
139.925049	1.28600001	351.820007	273.576965	
146.754333	1.58099997	927.403992	586.593323	
149.136734	1.24899995	583.893005	467.488403	
183.442108	1.722	1542.29602	895.642273	
169	1.25	483	387	2024 data from MPSC R




$20
$-
2021
2022
2023
2024



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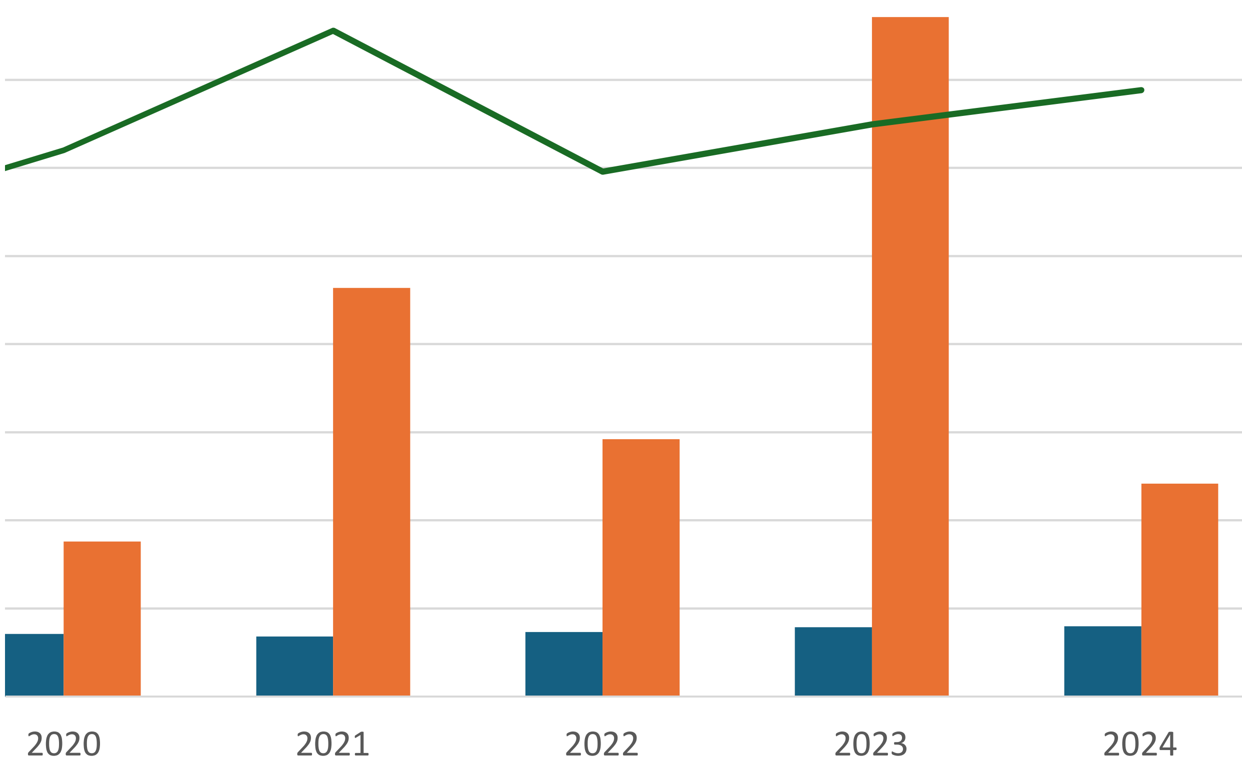
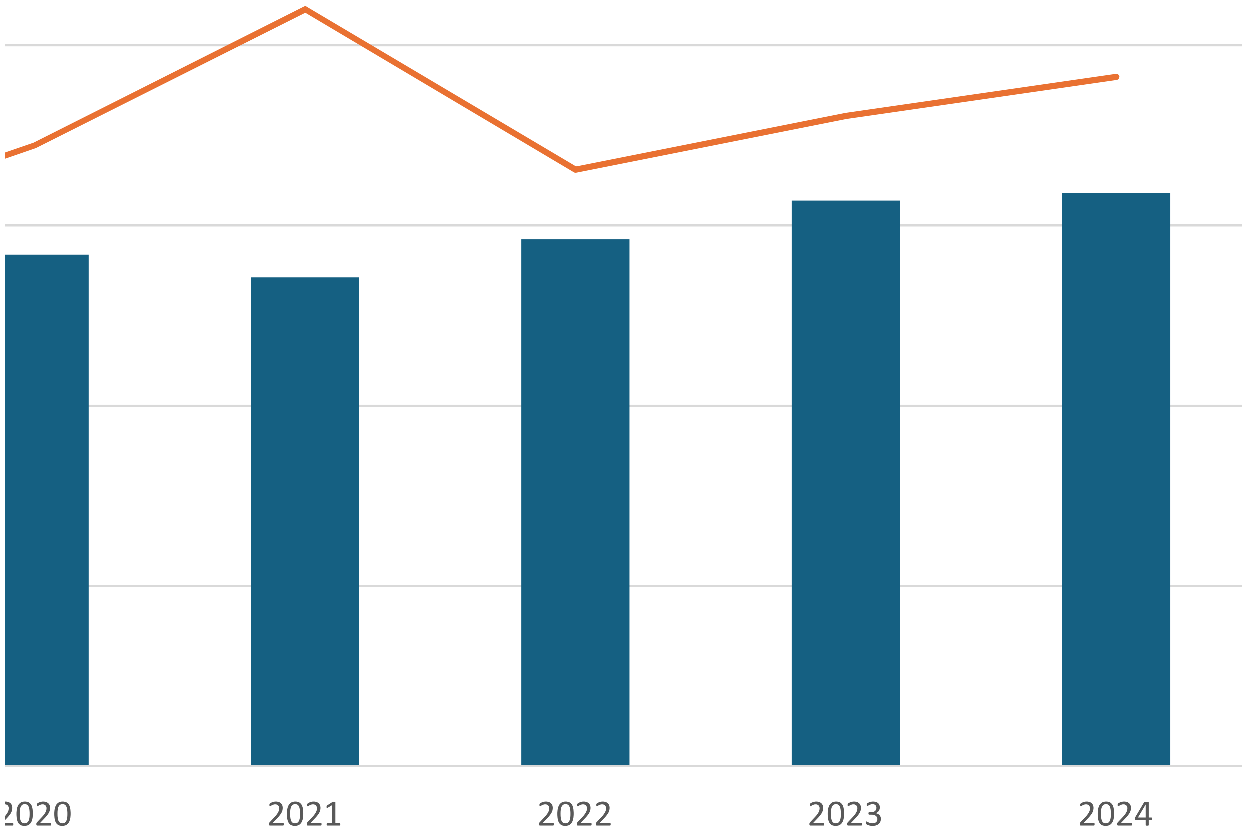
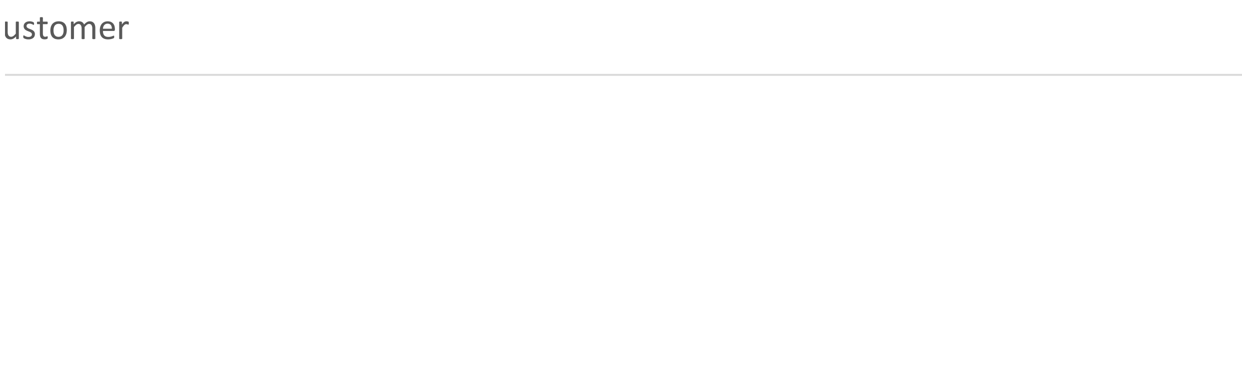


ditions per customer

tomer


2020
2021
2022
2023
2024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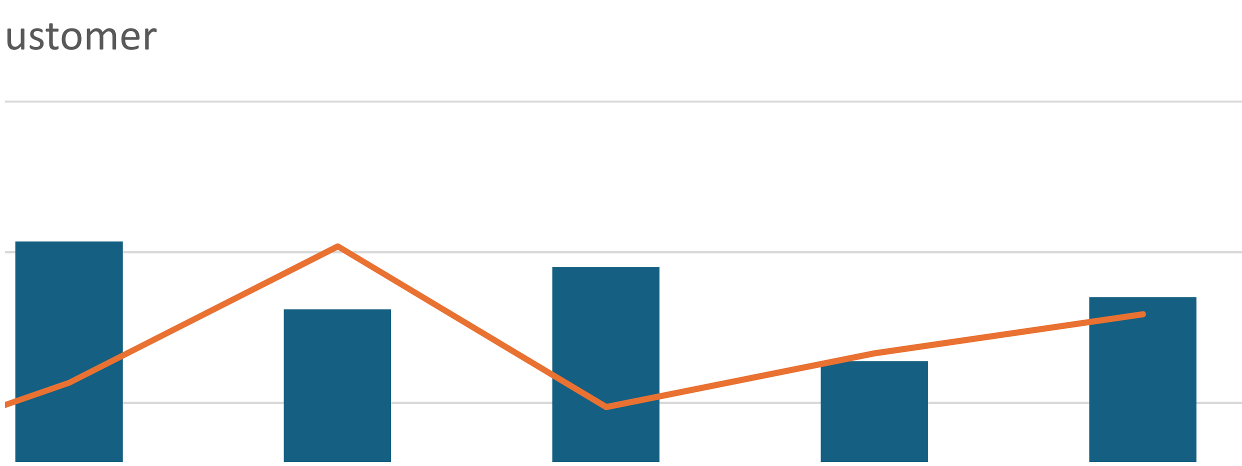
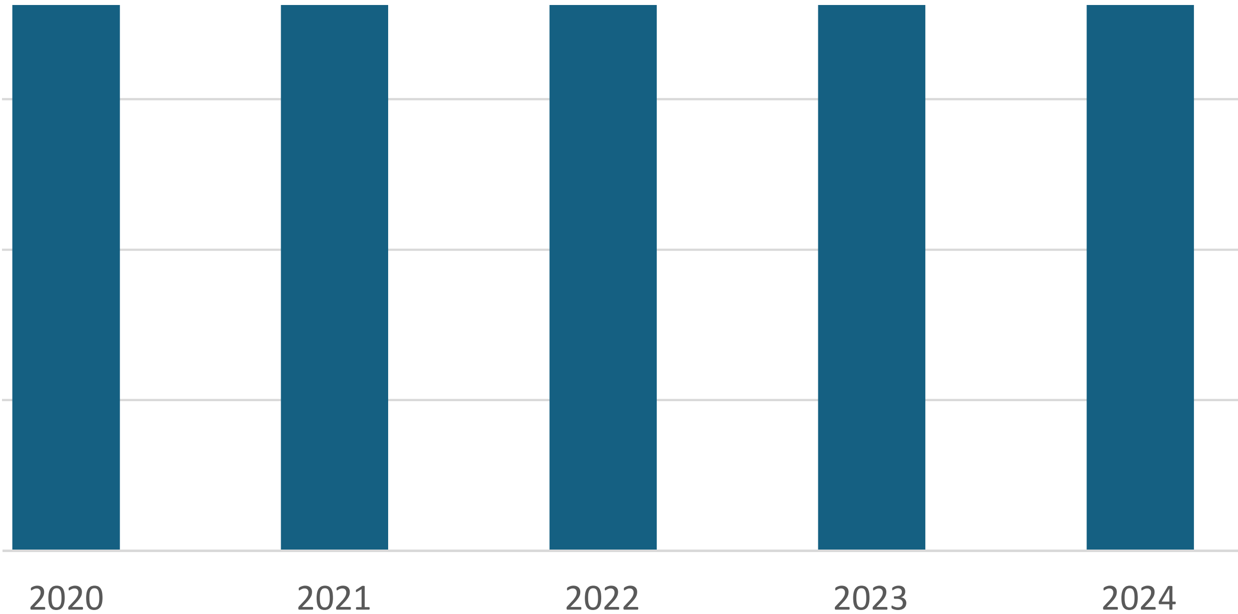
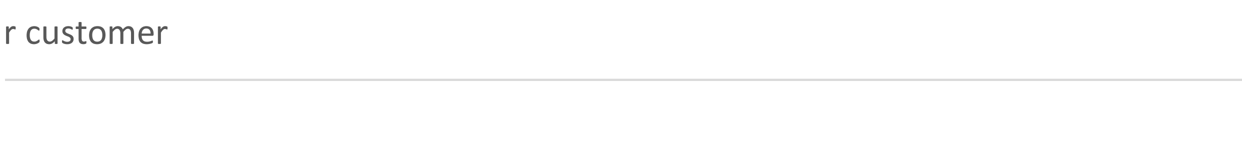
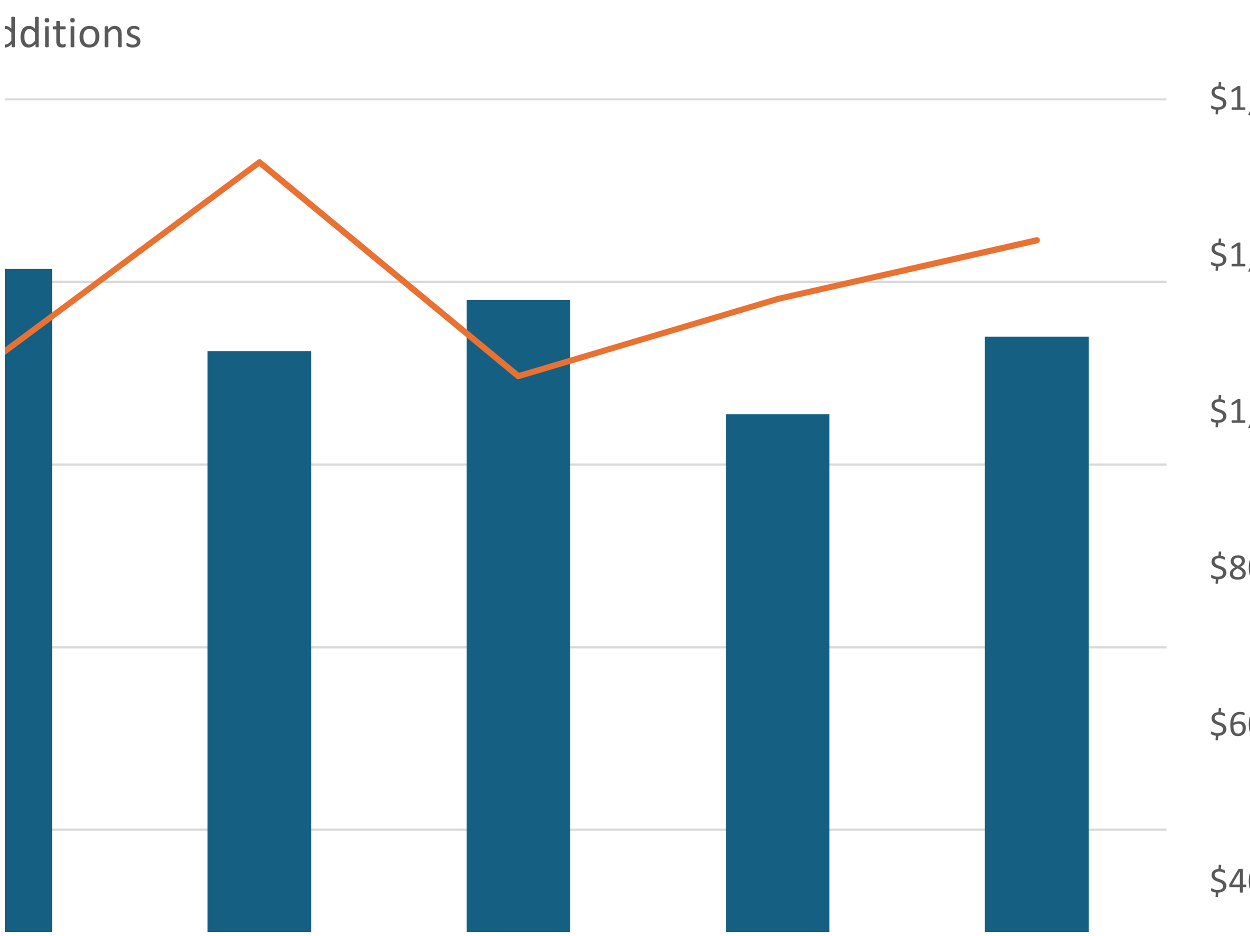
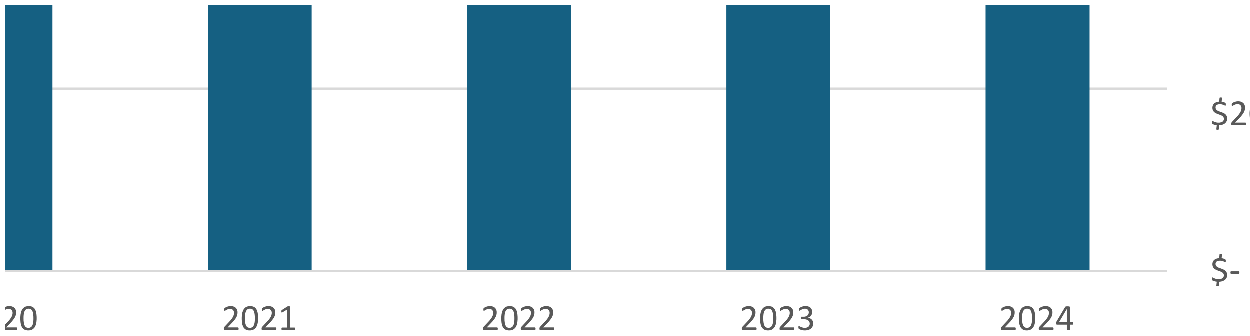

ustomer

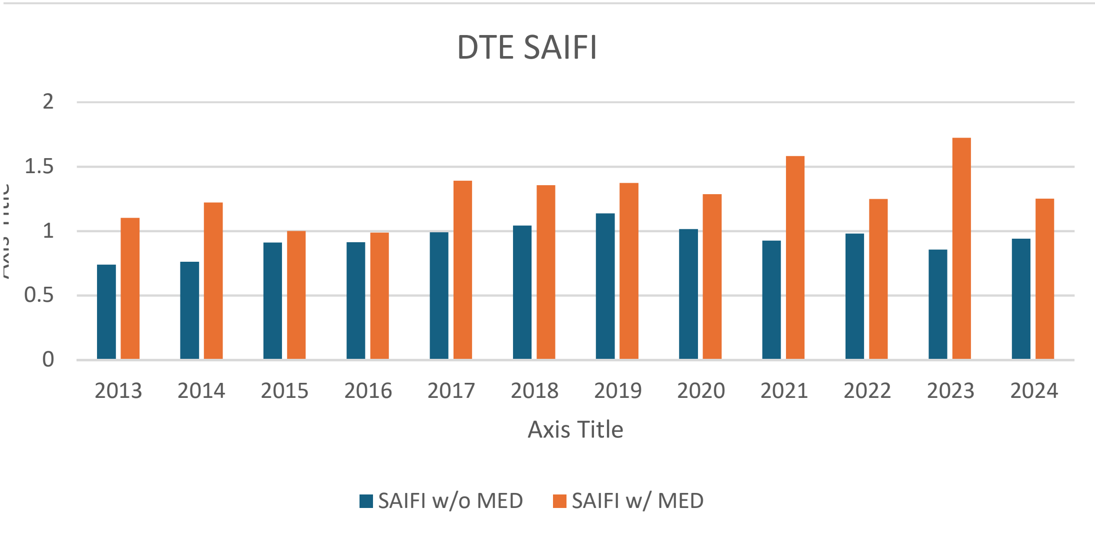

2020
2021
2022
2023
2024


r customer


dditions
$1,
$1,
$1,
$8
$6
$4



tions


DTE SAIFI
2
1.5
1
0.5
0
2013
2014
2015
2016
2017
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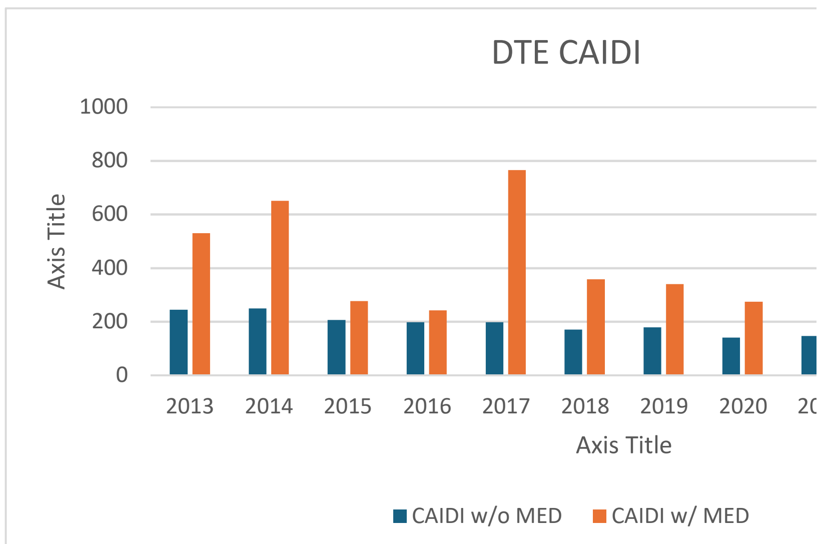
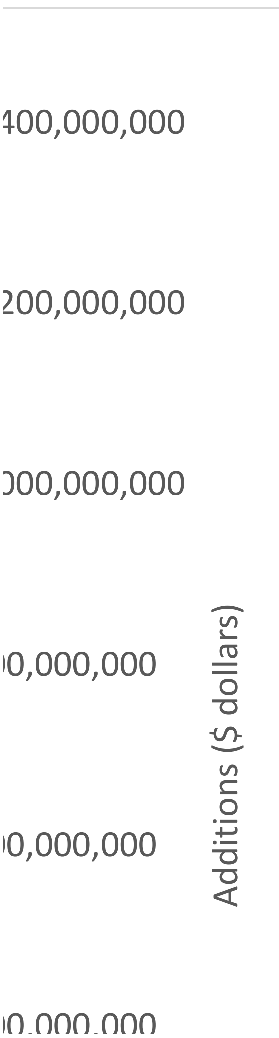
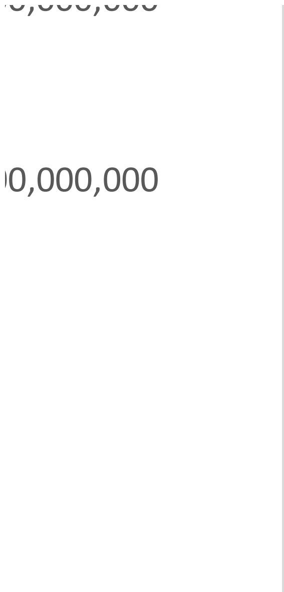
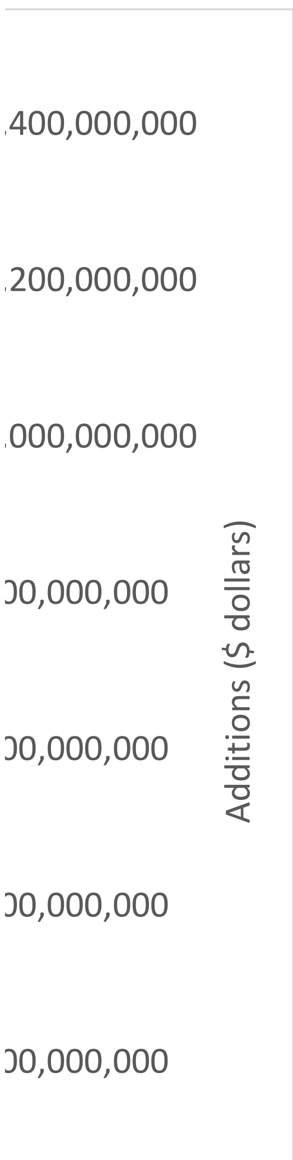
2019
2020
2021
2022
2023
2024
Axis Title
SAIFI w/o MED
SAIFI w/ MED


DTE CAIDI
1000
800
600
400
200
0
Axis Title
2013
2014
2015
2016
2017
2018
2019
2020
Axis Title
CAIDI w/o MED
CAIDI w/ MED


Additions ($ dollars)


0,000,000


400,000,000
200,000,000
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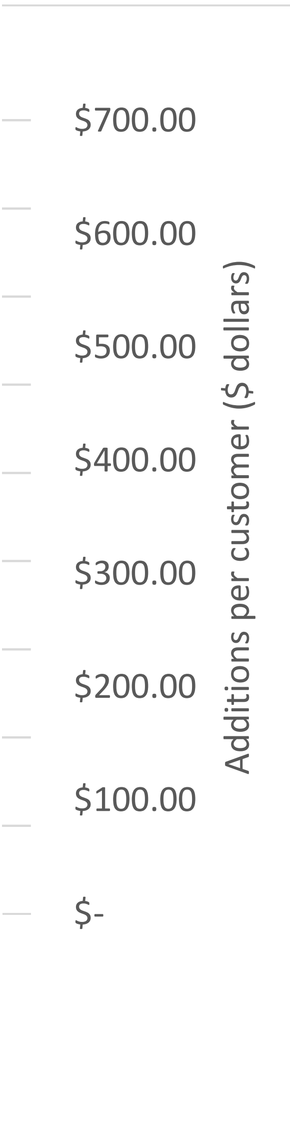
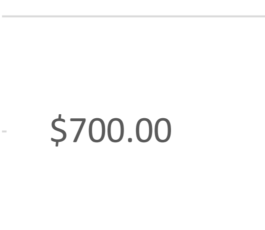
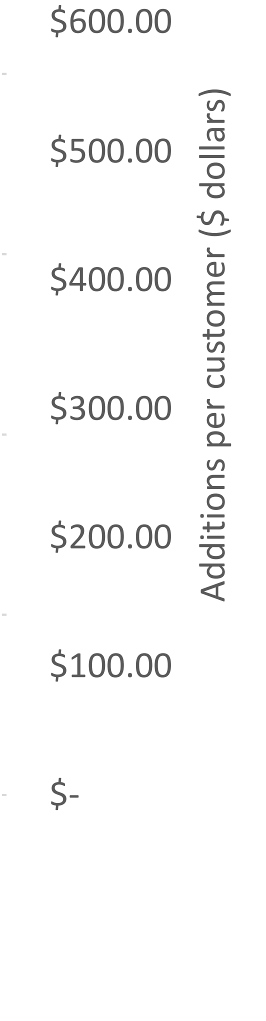
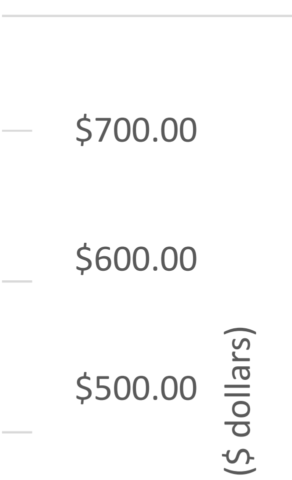
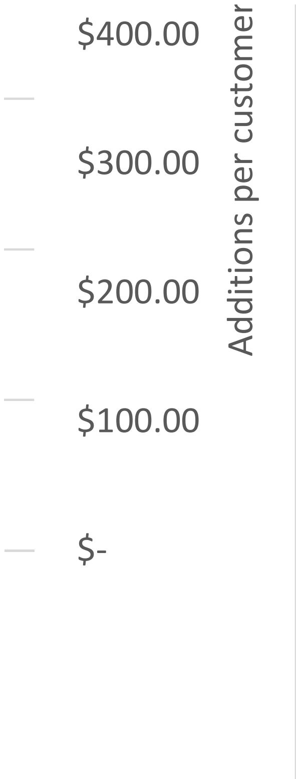
00,000,000
00,000,000
Additions ($ dollars)


$700.00
$600.00
$500.00
$400.00
$300.00
$200.00
$100.00
$-
Additions per customer ($ dollars)


$700.00


$600.00
$500.00
$400.00
$300.00
$200.00
$100.00
$-
Additions per customer ($ dollars)


$700.00
$600.00
$500.00


$400.00
$300.00
$200.00
$100.00
$-
Additions per customer


,400,000,000
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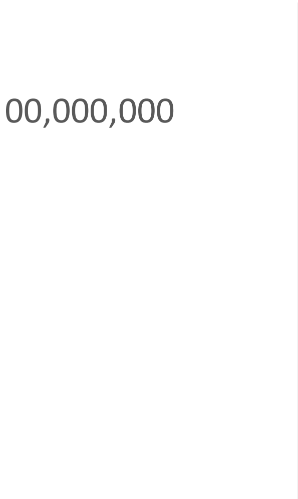
Additions ($ dollars)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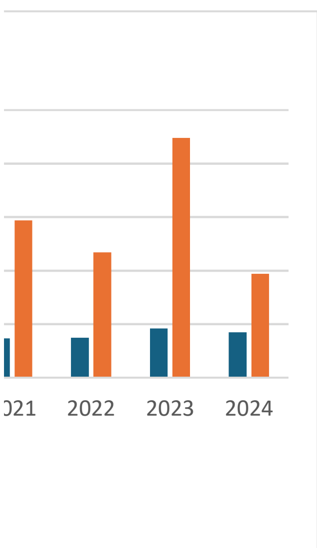
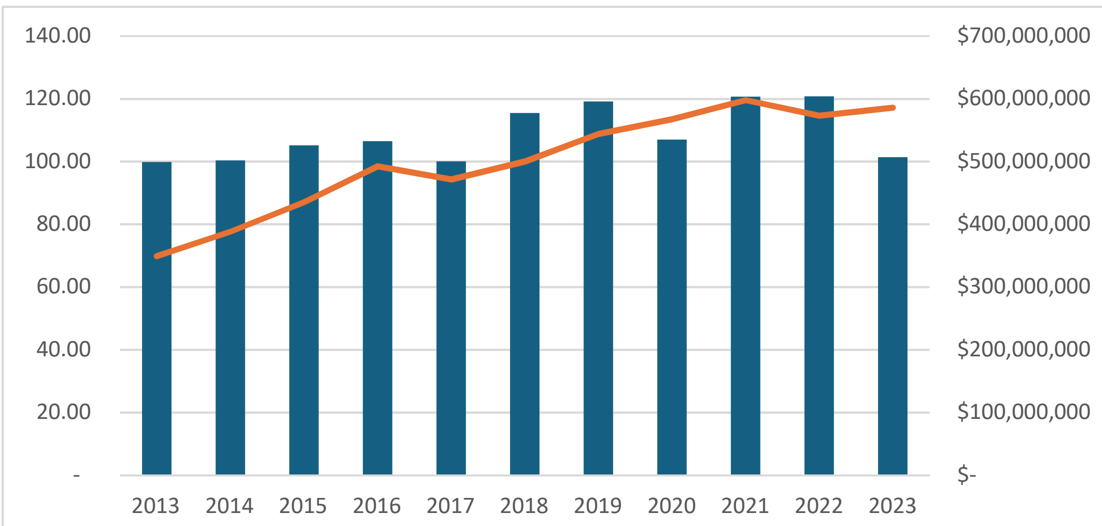
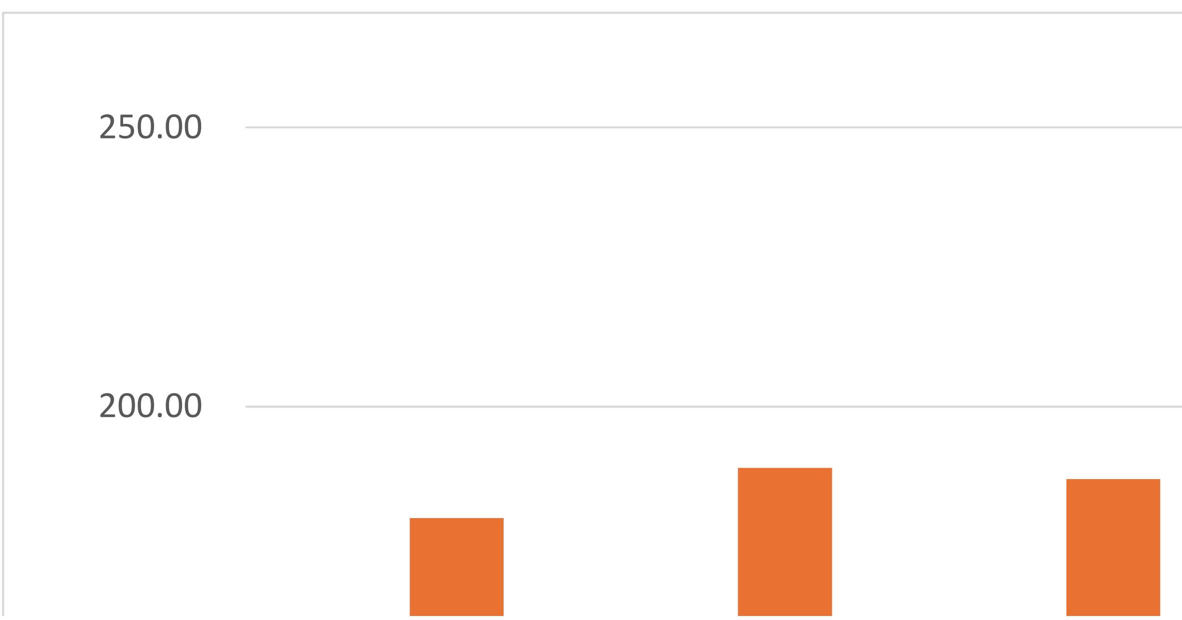
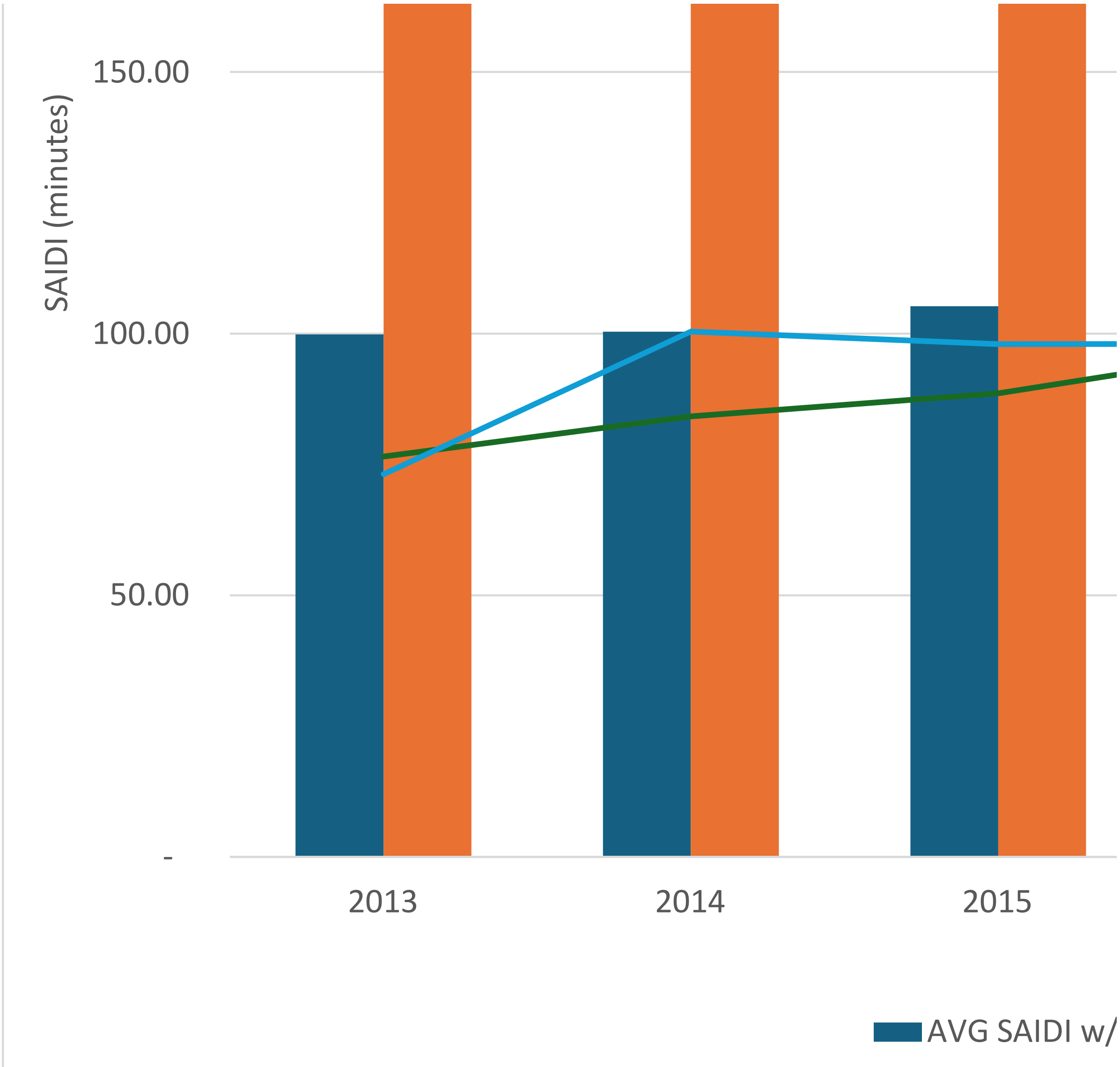

021
2022
2023
2024

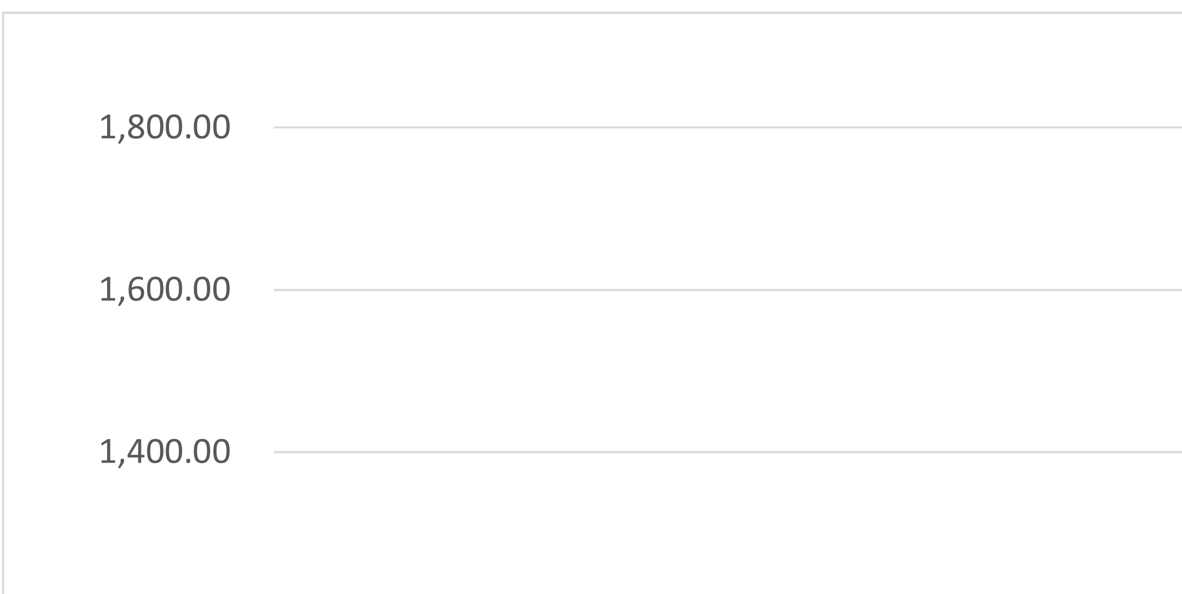
AVG

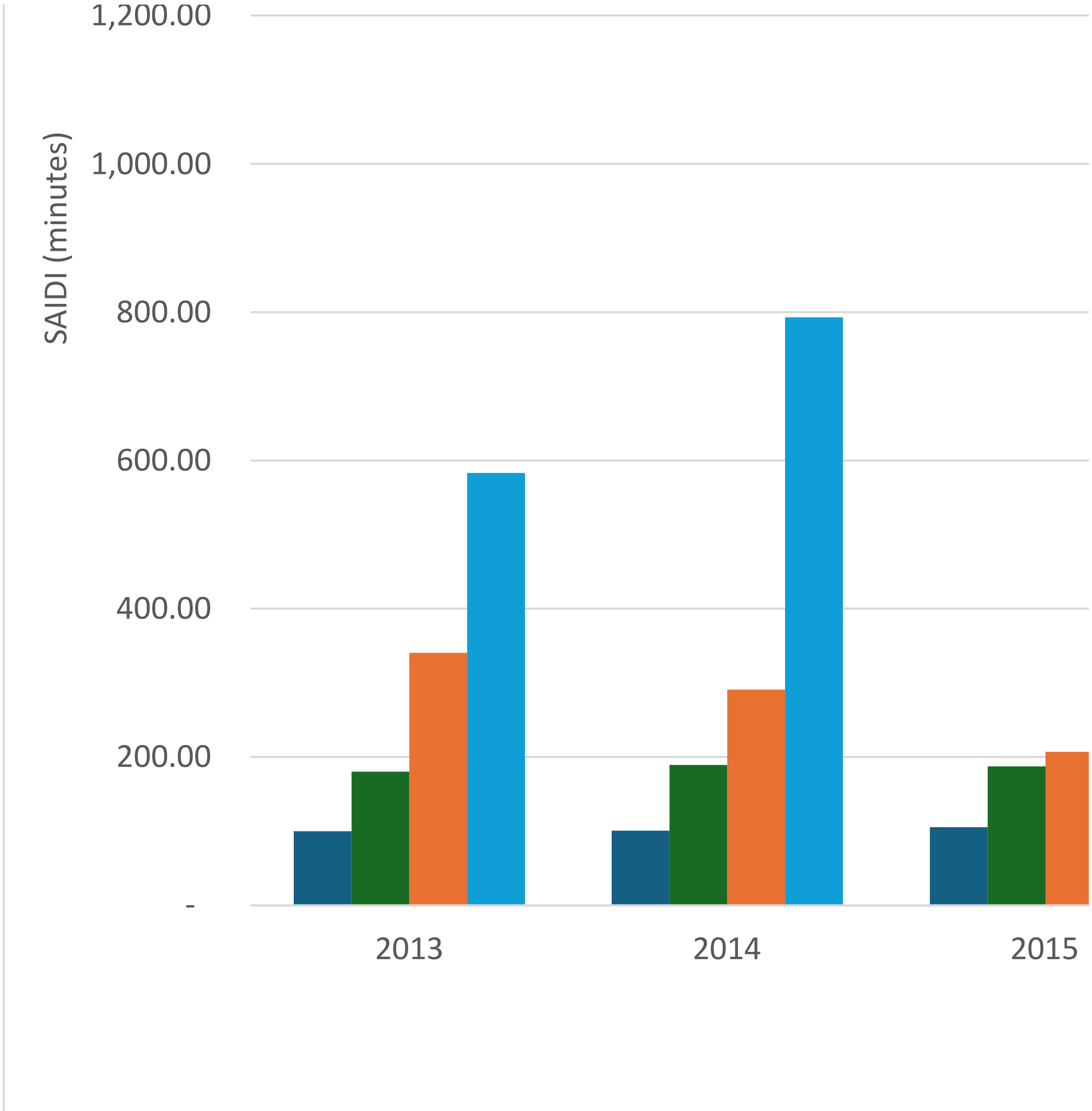
report_year	AVG additions (infl adj)	AVG Dist. Cap. Additions per customer	AVG SAIFI w/o MED	AVG SAIDI w/o MED	AVG CAIDI w/o MED
2013	$ 349,142,195	$ 214.22	0.81	99.81	116.39
2014	$ 388,325,363	$ 235.80	0.89	100.33	109.92
2015	$ 435,475,914	$ 248.09	1.01	105.19	104.41
2016	$ 492,466,645	$ 273.85	0.87	106.43	117.93
2017	$ 471,868,007	$ 268.36	0.84	100.06	113.84
2018	$ 500,372,617	$ 287.87	0.93	115.49	119.29
2019	$ 544,072,877	$ 323.43	0.91	119.10	124.50
2020	$ 567,676,336	$ 336.38	0.90	106.94	114.78
2021	$ 598,148,546	$ 382.79	0.97	120.65	122.05
2022	$ 573,272,917	$ 363.41	0.95	120.82	124.31
2023	$ 586,043,336	$ 363.92	0.81	101.36	121.45

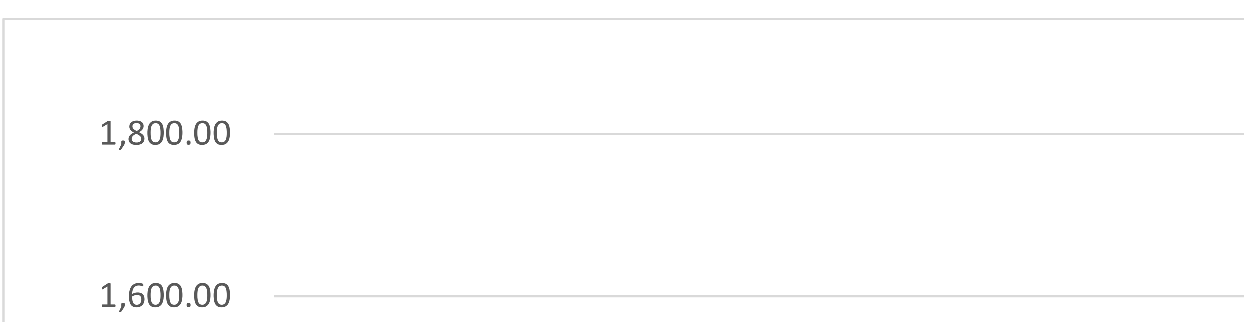


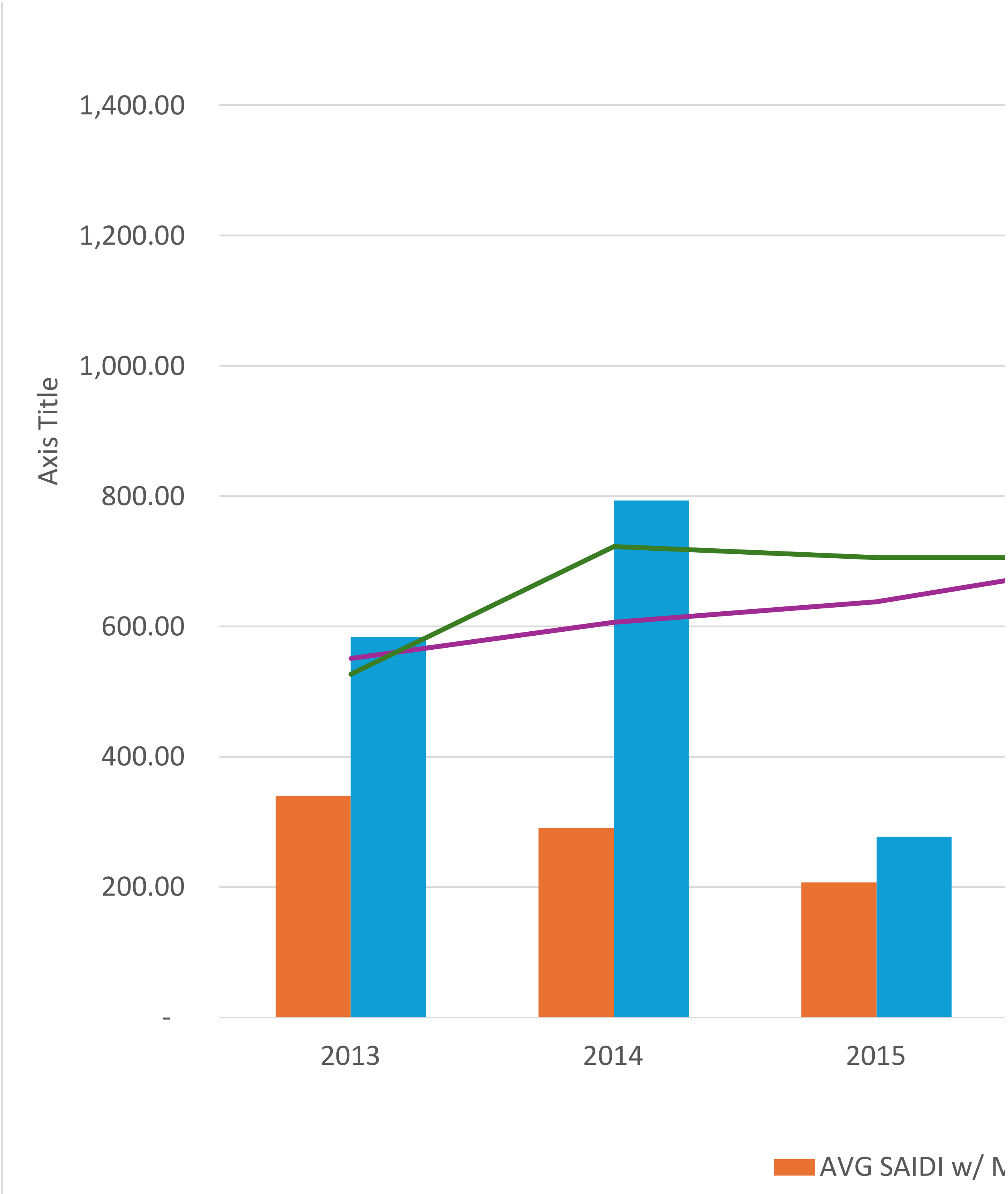



SAIDI (minutes)
150.00
100.00
50.00
-
2013
2014
2015
AVG SAIDI w/

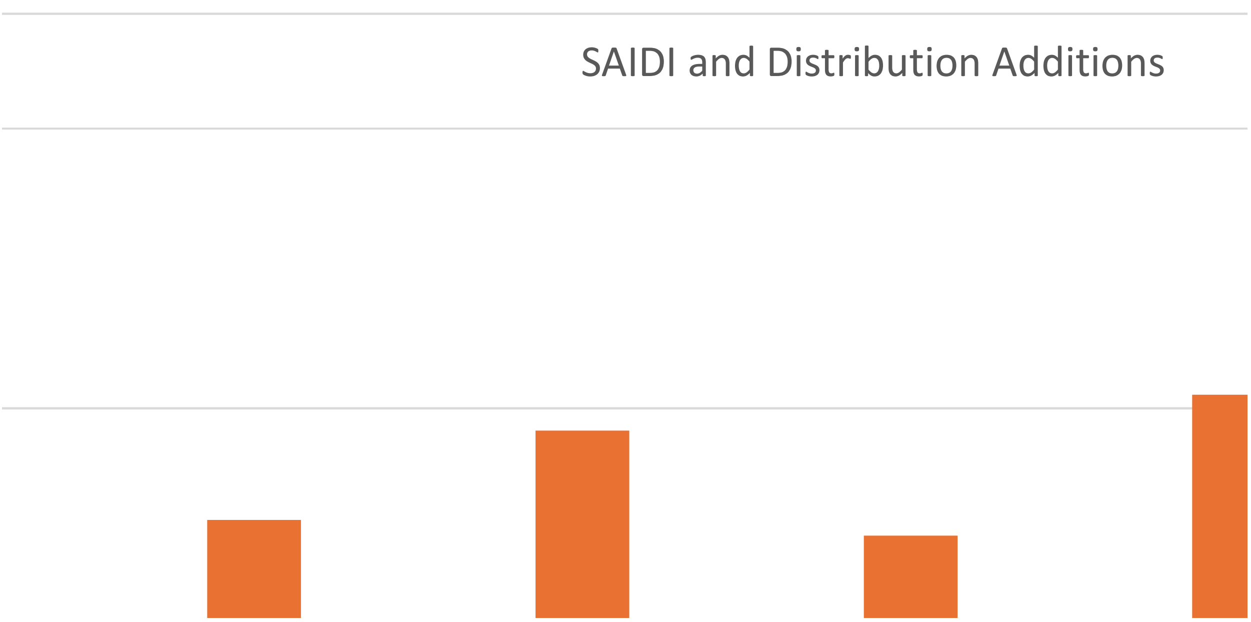

1,800.00
1,600.00
1,400.00

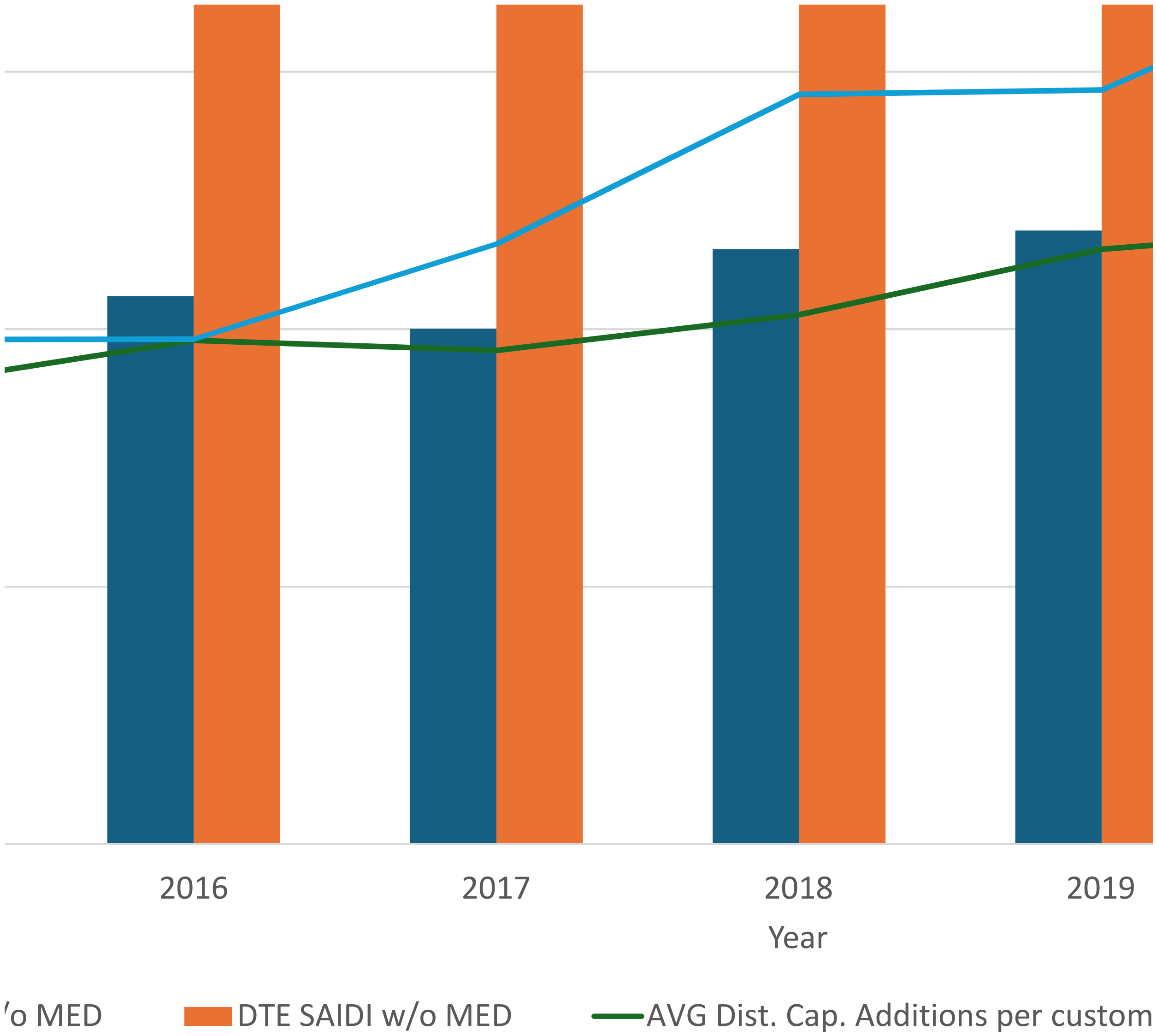

1,200.00
1,000.00
800.00
600.00
400.00
200.00
-
SAIDI (minutes)
2013
2014
2015

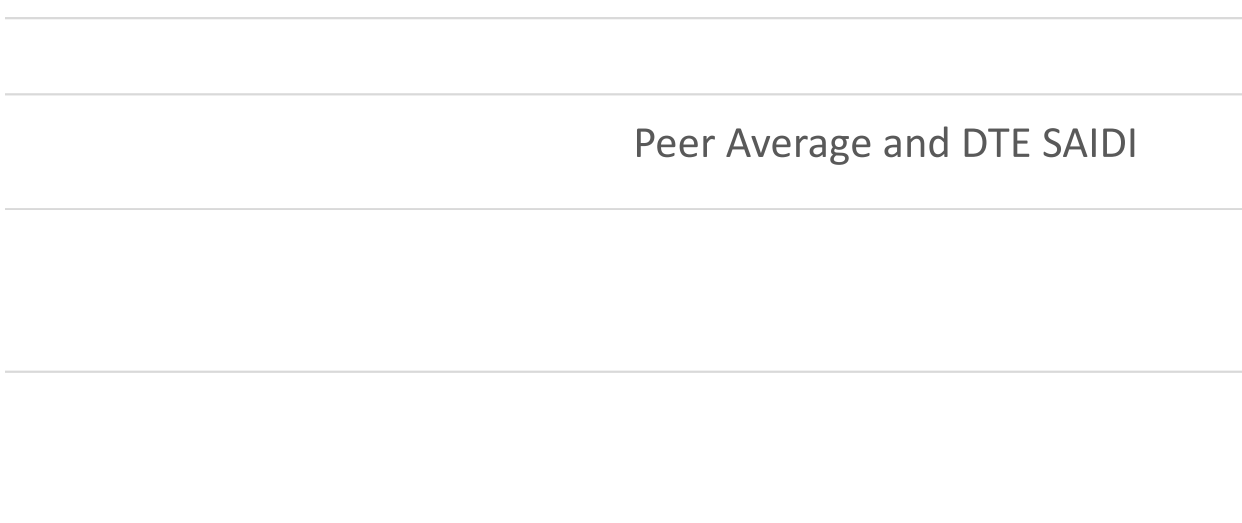

1,800.00
1,600.00

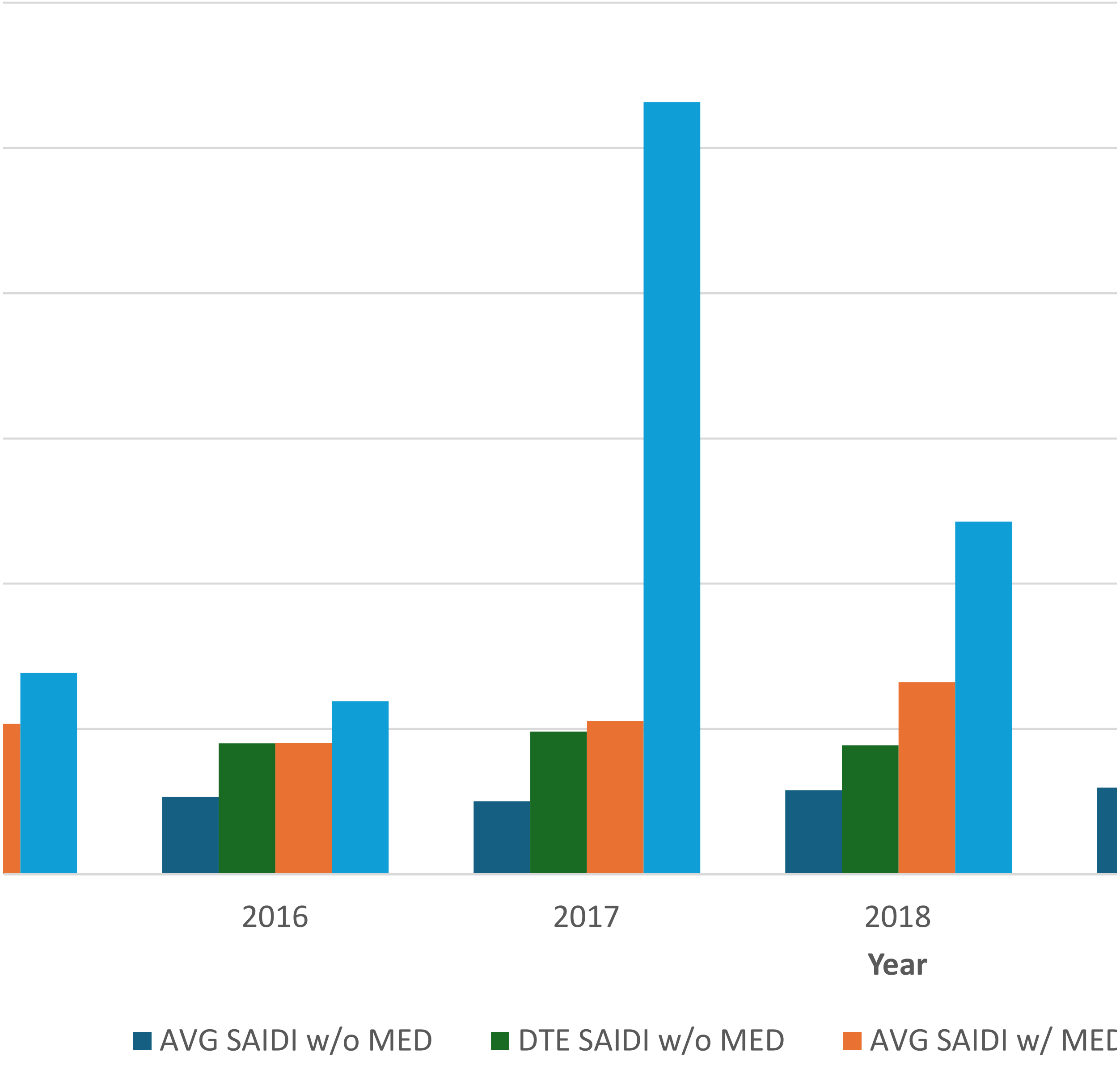

1,400.00
1,200.00
1,000.00
800.00
600.00
400.00
200.00
-
Axis Title
2013
2014
2015
AVG SAIDI w/ M

AVG SAIFI w/ MED	AVG SAIDI w/ MED	AVG CAIDI w/ MED	DTE report_year
1.13	340.19	253.45	2013
1.14	290.63	240.33	2014
1.20	206.82	196.84	2015
1.07	180.19	164.37	2016
1.06	210.87	186.33	2017
1.16	264.21	212.03	2018
1.21	286.38	223.97	2019
1.23	338.37	268.39	2020
1.26	318.51	238.83	2021
1.17	252.58	201.43	2022
1.10	365.56	304.20	2023

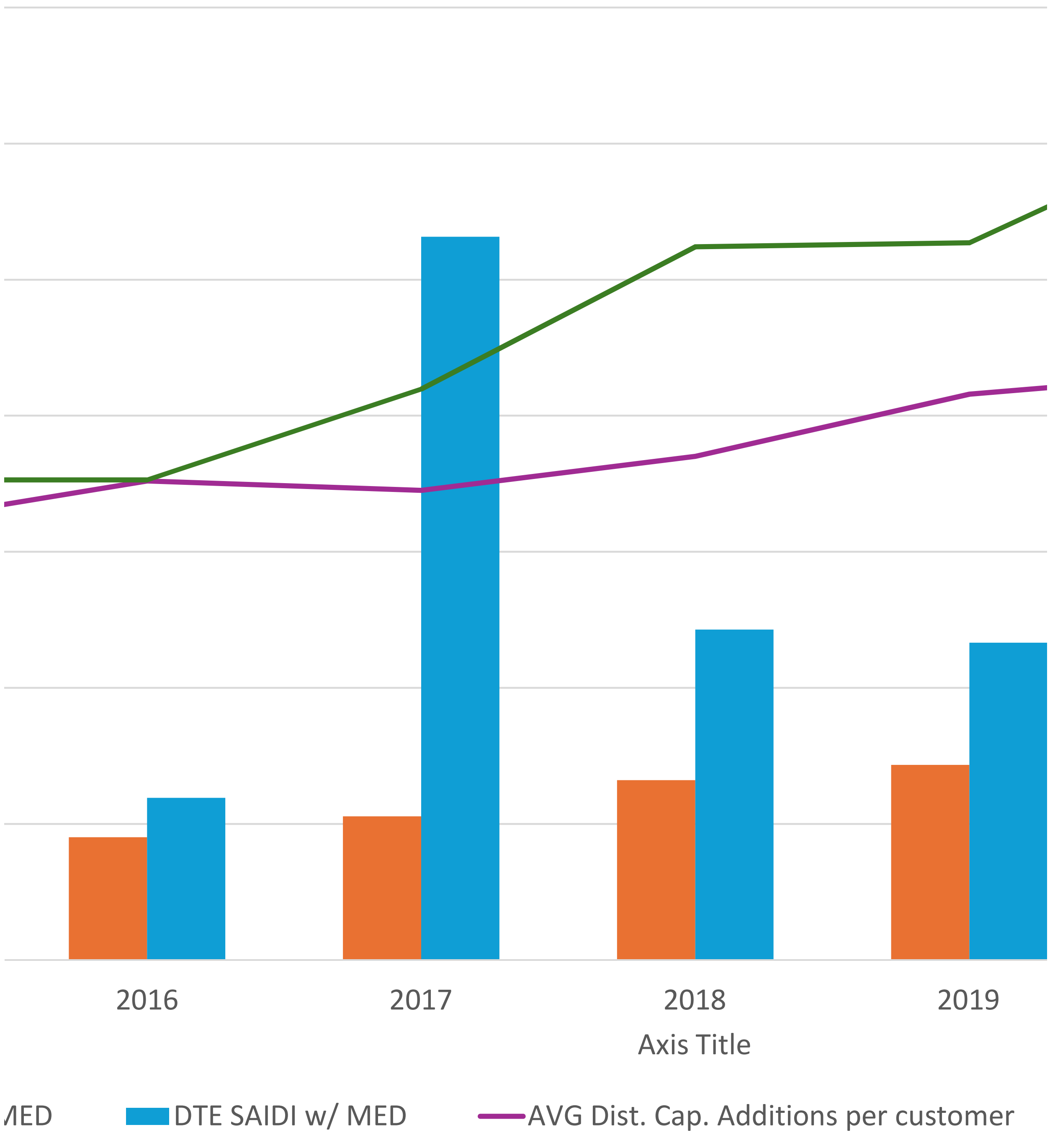



2016
2017
2018
2019
Year
/o MED
DTE SAIDI w/o MED
AVG Dist. Cap. Additions per custom

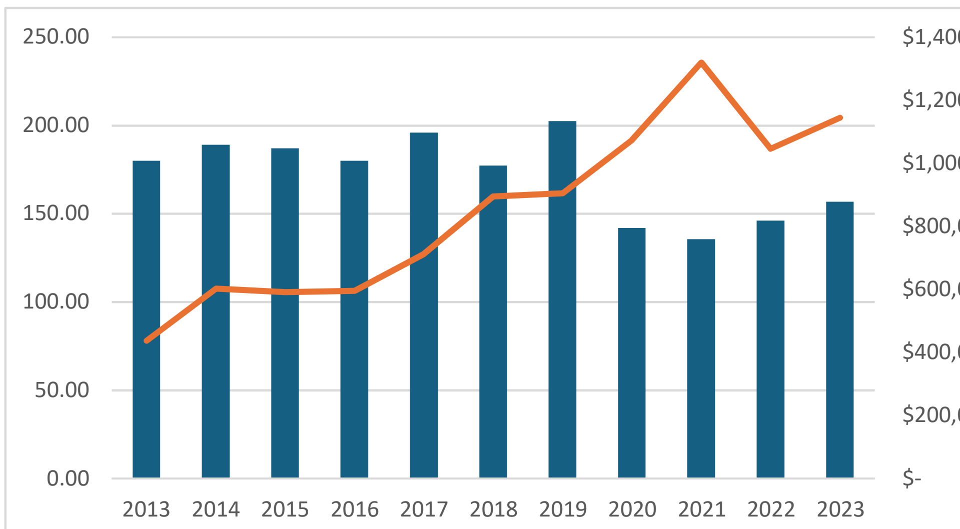

Peer Average and DTE SAIDI

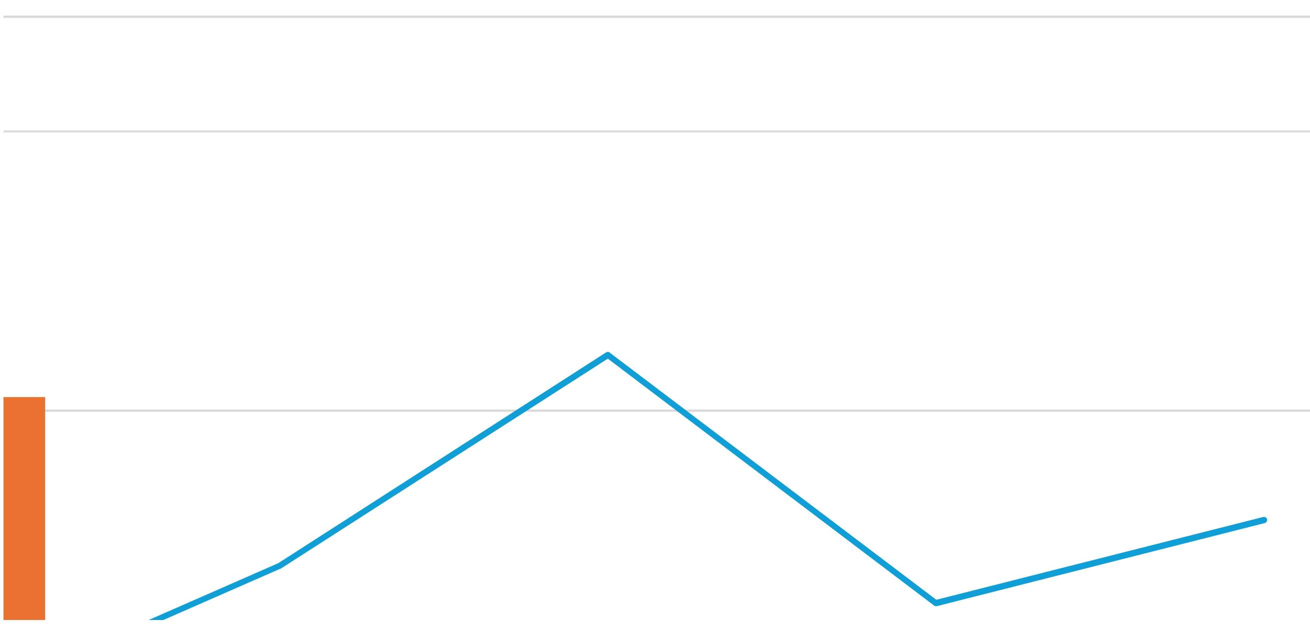


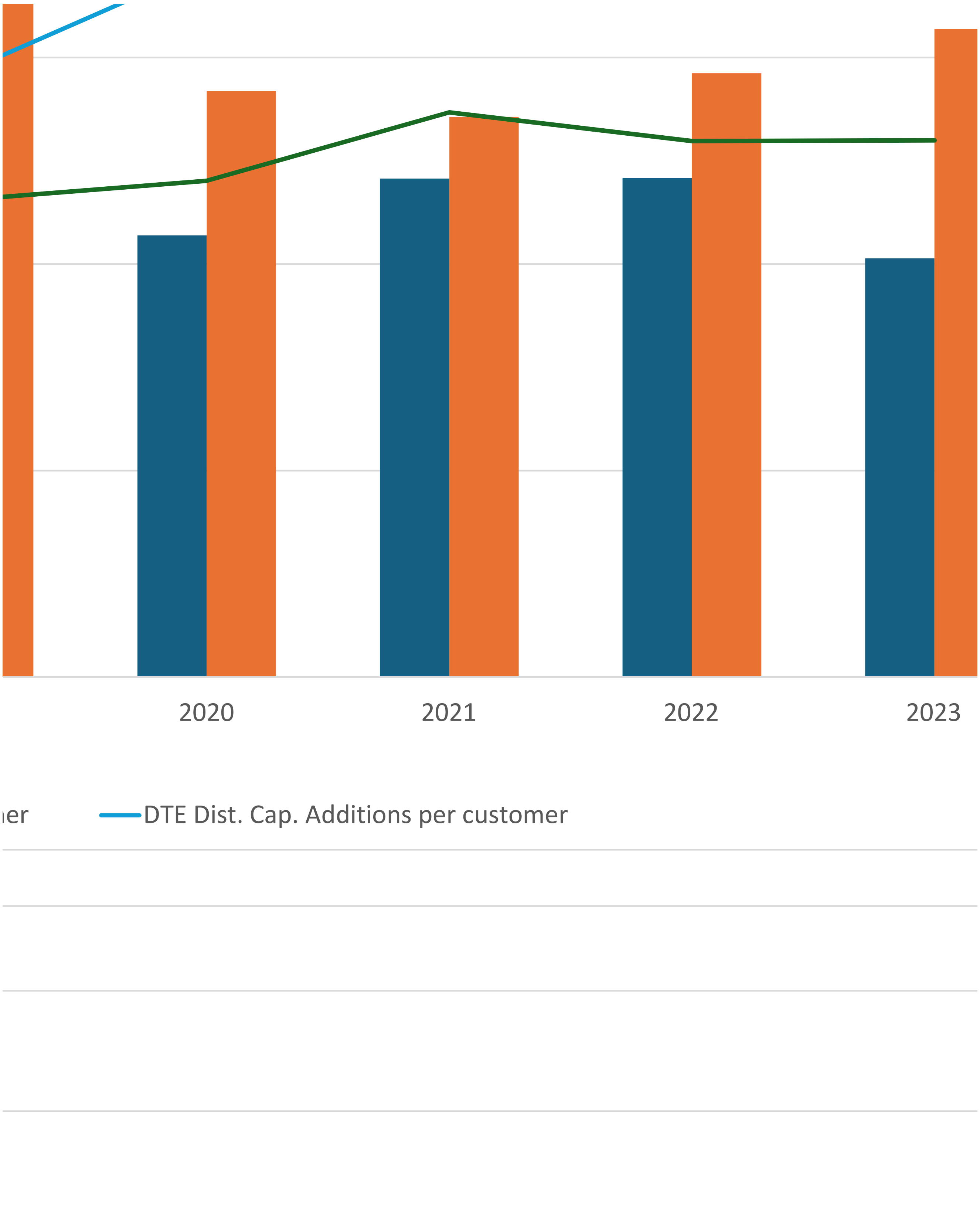
SAIDI w/ MED Comparison

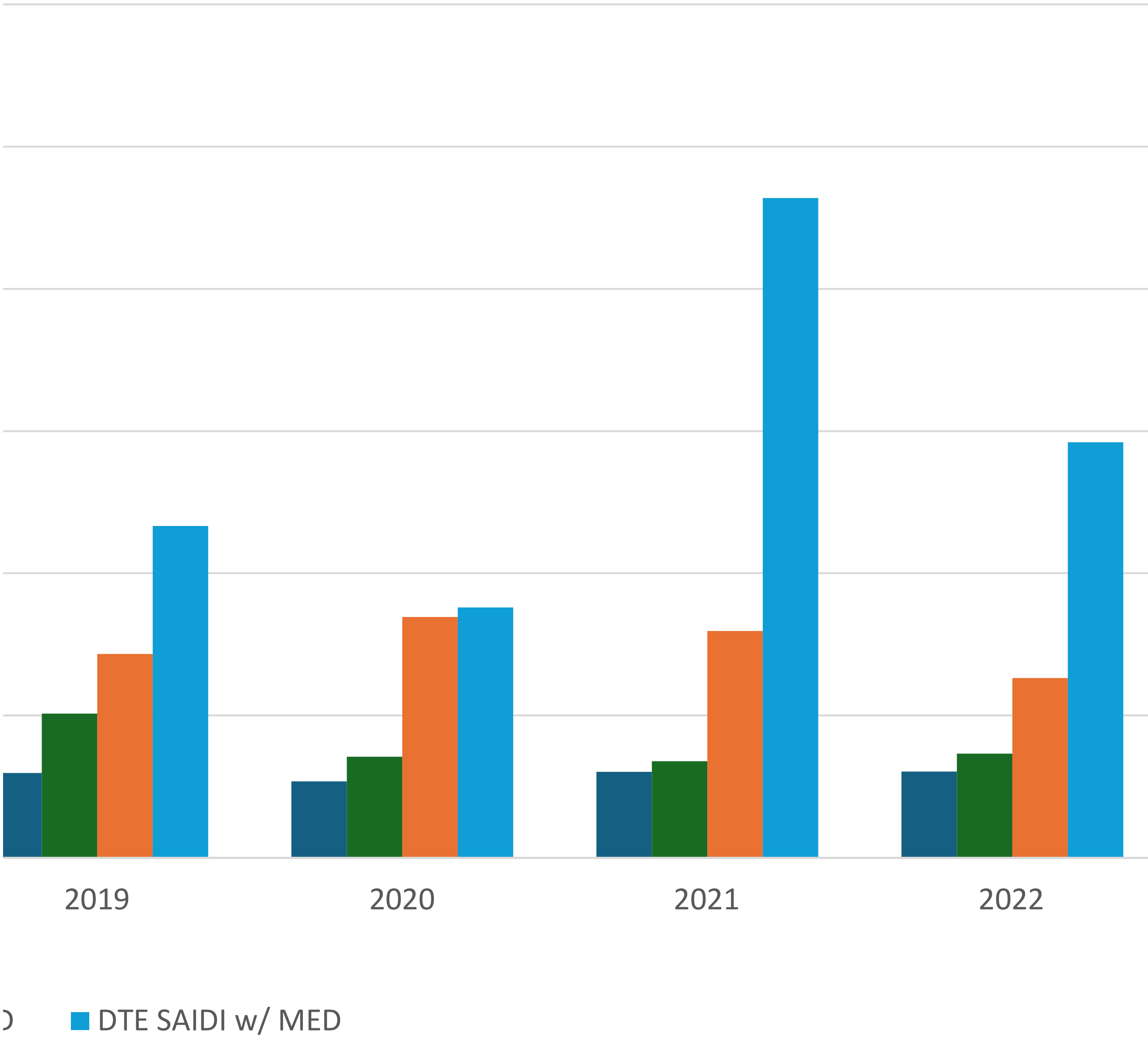

2016
2017
2018
2019
Axis Title
MED
DTE SAIDI w/ MED
AVG Dist. Cap. Additions per customer

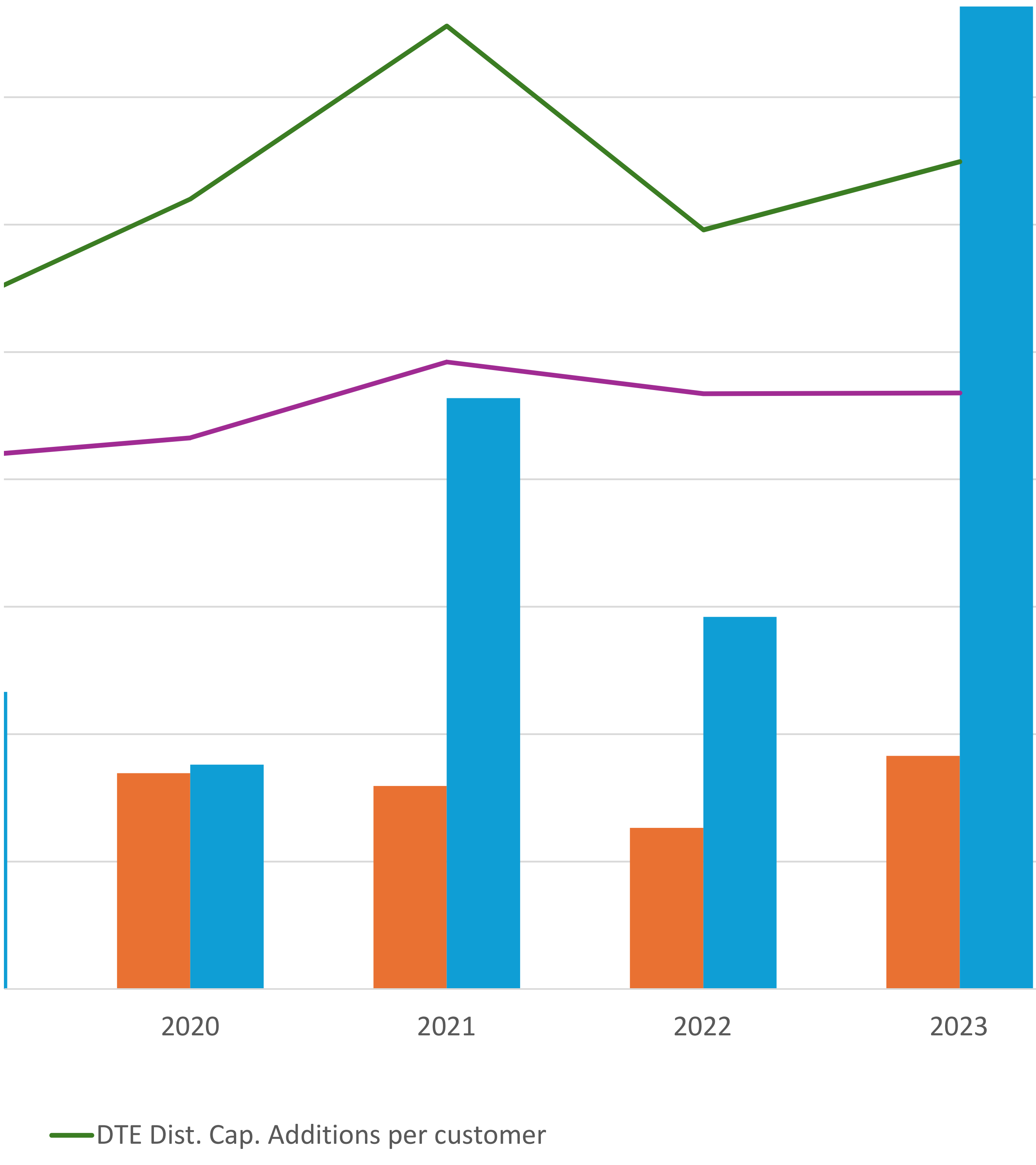
DTE additions (infl adj)	DTE Dist. Cap. Additions per customer	DTE SAIFI w/o MED	DTE SAIDI w/o MED	DTE CAIDI w/o MED	DTE SAIFI w/ MED
$ 437,104,593	$ 204.81	0.74	180.00	243.57	1.10
$ 602,548,493	$ 281.06	0.76	189.00	248.68	1.22
$ 591,224,580	$ 274.37	0.91	187.00	205.49	1.00
$ 595,402,309	$ 274.45	0.91	180.00	197.37	0.99
$ 712,128,975	$ 326.37	0.99	196.00	197.98	1.39
$ 895,318,073	$ 407.62	1.04	177.19	170.21	1.36
$ 905,734,876	$ 410.03	1.14	202.38	178.15	1.37
$ 1,073,750,725	$ 482.26	1.01	141.88	139.93	1.29
$ 1,319,812,070	$ 587.90	0.92	135.60	146.75	1.58
$ 1,046,012,098	$ 463.37	0.98	146.15	149.14	1.25
$ 1,144,801,106	$ 505.11	0.86	156.84	183.44	1.72



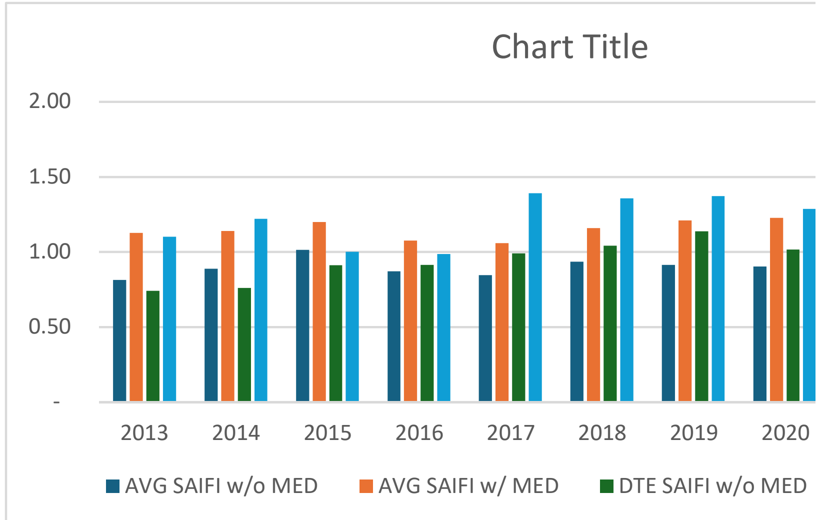


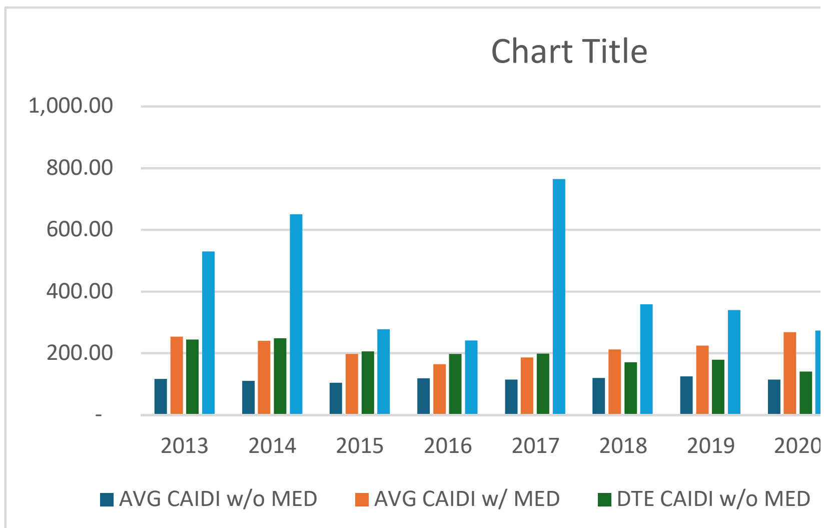

2020
2021
2022
2023
ıer
DTE Dist. Cap. Additions per customer

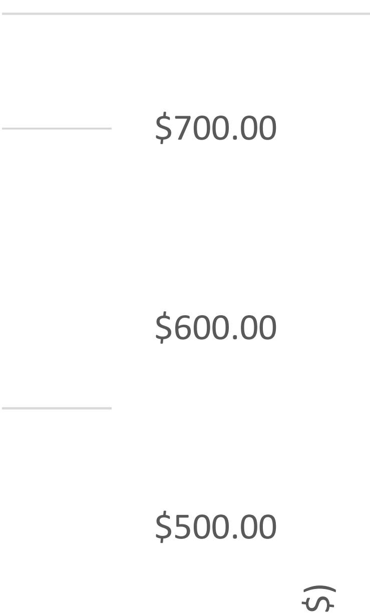

2019
2020
2021
2022
DTE SAIDI w/ MED

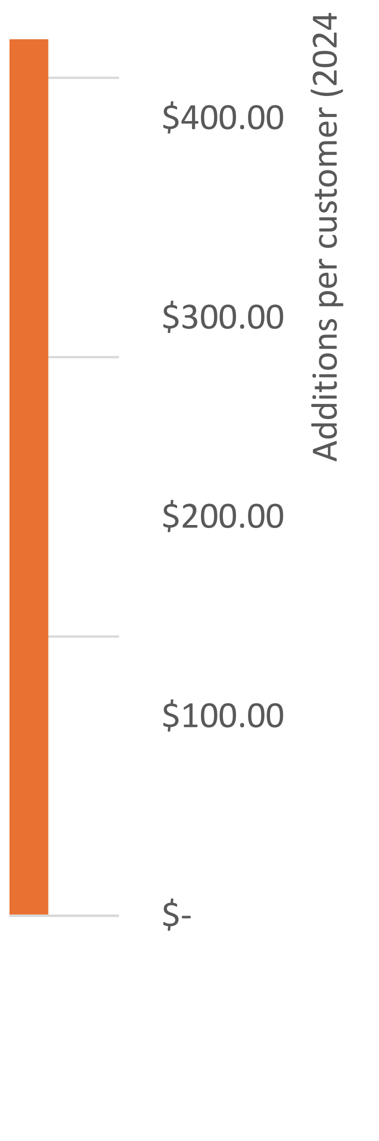

2020
2021
2022
2023
DTE Dist. Cap. Additions per customer

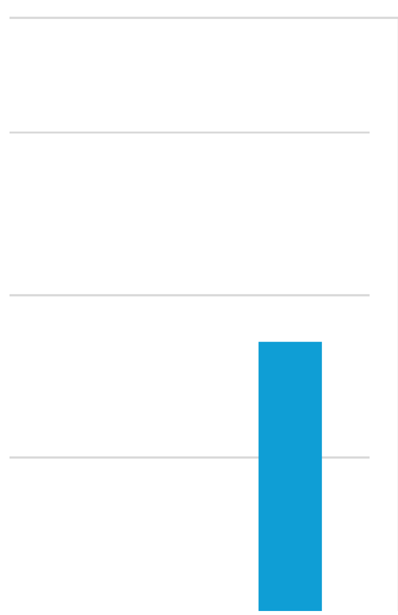
DTE SAIDI w/ MED	DTE CAIDI w/ MED
583.00	529.52
793.00	650.00
277.00	277.00
238.00	241.38
1063.00	764.75
485.34	357.92
466.29	339.86
351.82	273.58
927.40	586.59
583.89	467.49
1542.30	895.64

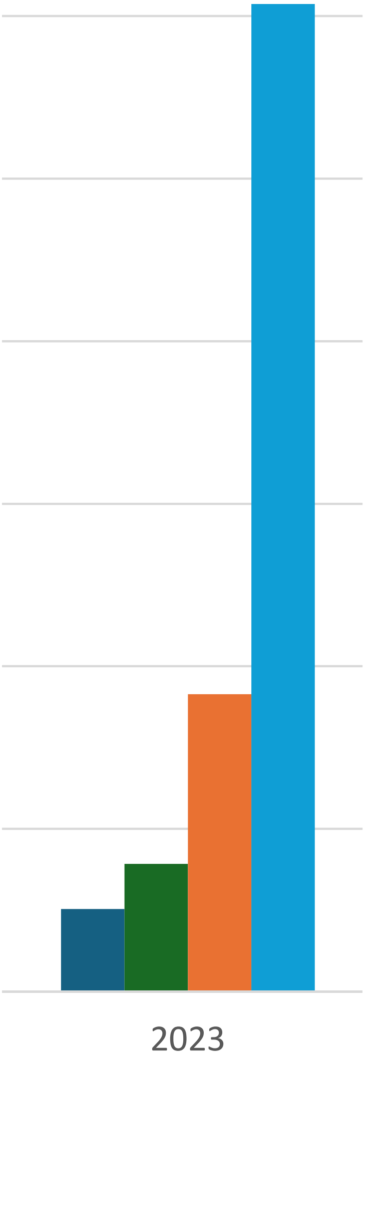


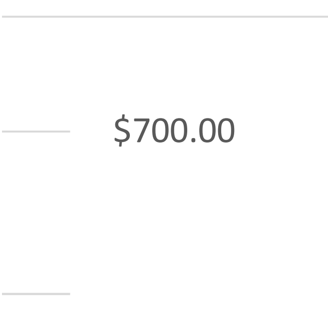





Additions per customer (2024
$400.00
$300.00
$200.00
$100.00
$-




2023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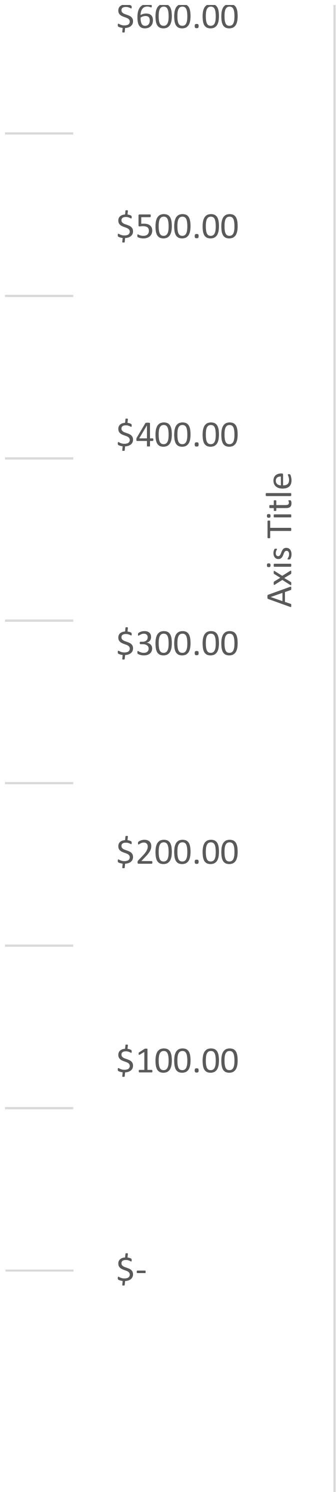
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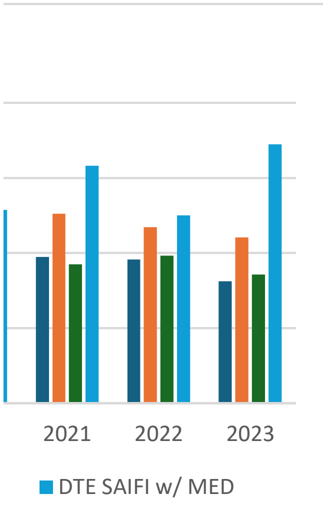
2021
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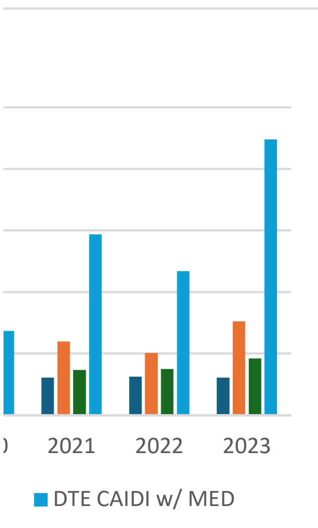
DTE SAIFI w/ MED


2021
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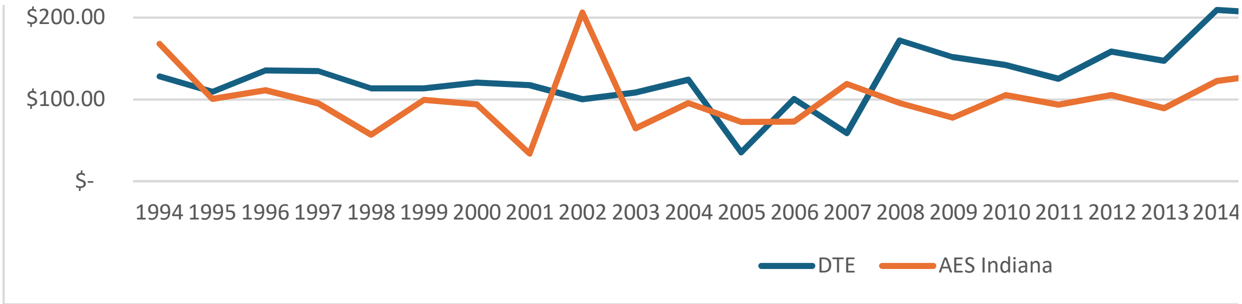
DTE CAIDI w/ MED

year	DTE	ComEd	WEP Co	Cleveland	Consumers
1994	$ 127.98	$ 86.53	$ 109.39	$ 83.46	$ 109.25
1995	$ 109.25	$ 91.45	$ 122.09	$ 59.55	$ 100.91
1996	$ 135.45	$ 102.93	$ 115.54	$ 64.07	$ 101.00
1997	$ 134.89		$ 140.00	$ 86.76	$ 99.42
1998	$ 113.81	$ 98.01	$ 137.16	$ 22.56	$ 102.53
1999	$ 113.53	$ 99.00	$ 157.42	$ 52.97	$ 119.98
2000	$ 120.77	$ 115.64	$ 165.31	$ 43.23	$ 105.18
2001	$ 117.59	$ 180.57	$ 170.61	$ 41.83	$ 105.53
2002	$ 100.58	$ 180.88	$ 166.32	$ 47.77	
2003	$ 108.65	$ 116.69	$ 185.07	$ 76.09	
2004	$ 124.40	$ 168.65	$ 160.39	$ 71.78	
2005	$ 35.40	$ 144.64	$ 166.64	$ 101.87	$ 101.42
2006	$ 100.78	$ 156.55	$ 160.54	$ 98.23	$ 126.34
2007	$ 58.93	$ 185.79	$ 152.69	$ 146.02	$ 111.25
2008	$ 172.43	$ 195.62	$ 141.30	$ 142.46	$ 160.70
2009	$ 151.94	$ 170.73	$ 131.58	$ 115.44	$ 141.63
2010	$ 142.13	$ 143.37	$ 121.98	$ 121.12	$ 161.77
2011	$ 125.37	$ 167.89	$ 140.20	$ 117.63	$ 171.69
2012	$ 158.64	$ 186.86	$ 160.58	$ 187.83	$ 181.88
2013	$ 147.33	$ 202.94	$ 168.71	$ 117.74	$ 195.52
2014	$ 209.50	$ 249.42	$ 191.05	$ 116.40	$ 213.47
2015	$ 205.66	$ 333.39	$ 209.99	$ 111.76	$ 230.31
2016	$ 203.54	$ 390.85	$ 220.48	$ 141.00	$ 269.58
2017	$ 247.25	$ 341.82	$ 255.76	$ 128.85	$ 301.75
2018	$ 310.99	$ 327.38	$ 255.11	$ 154.03	$ 269.29
2019	$ 313.48	$ 311.76	$ 250.84	$ 137.73	$ 338.16
2020	$ 370.85	$ 343.12	$ 260.06	$ 171.92	$ 318.05
2021	$ 471.64	$ 348.44	$ 255.02	$ 241.50	$ 392.51
2022	$ 420.25	$ 370.11	$ 248.75	$ 188.17	$ 429.48
2023	$ 484.70	$ 403.52	$ 278.68	$ 152.62	$ 426.49
2024	$ 535.33	$ 345.61	$ 388.95	$ 181.25	$ 463.50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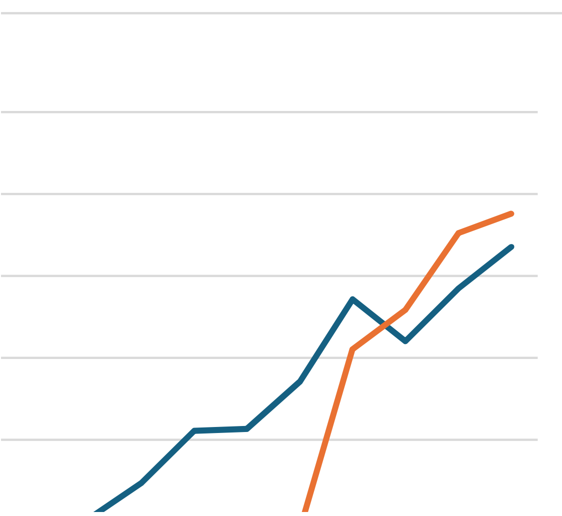
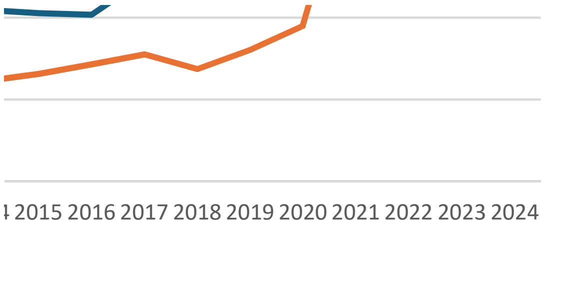
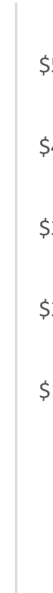
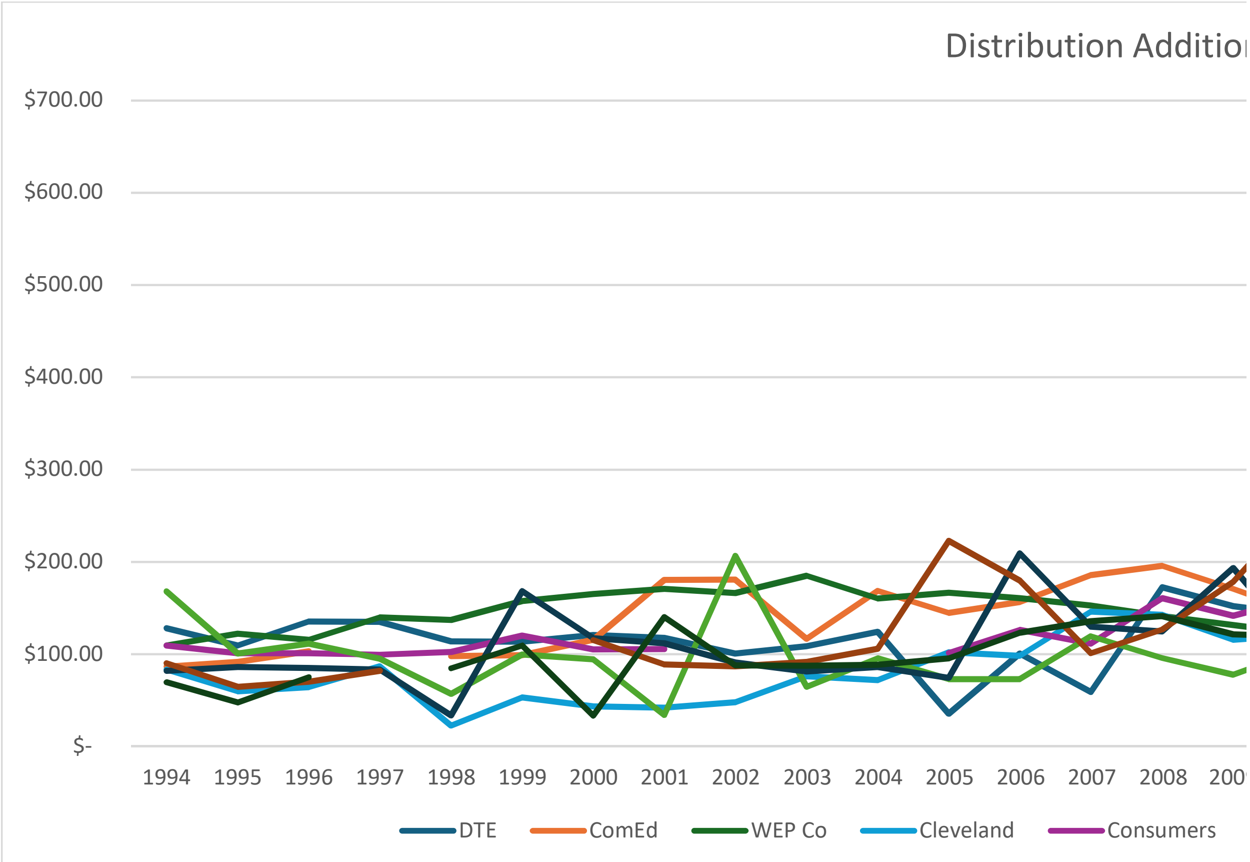
1994 1995 1996 1997 1998 1999 2000 2001 2002 2003 2004 2005 2006 2007 2008 2009 2010 2011 2012 2013 2014
DTE
AES Indiana

AES Indiana	Columbus Sou	Duquesne	PECO
$ 167.90	$ 81.76	$ 90.21	$ 69.39
$ 100.73	$ 86.18	$ 64.64	$ 47.64
$ 111.34	$ 84.89	$ 69.94	$ 75.02
$ 95.18	$ 83.20	$ 81.91	
$ 56.86	$ 33.57		$ 84.74
$ 99.68	$ 168.44		$ 109.24
$ 94.28	$ 117.21	$ 115.30	$ 33.36
$ 34.03	$ 111.58	$ 88.90	$ 140.13
$ 206.36	$ 90.96	$ 86.60	$ 87.85
$ 64.71	$ 81.09	$ 91.49	$ 87.34
$ 95.57	$ 85.97	$ 105.85	$ 88.35
$ 72.79	$ 74.15	$ 222.67	$ 95.34
$ 72.98	$ 209.21	$ 179.90	$ 123.20
$ 119.21	$ 129.89	$ 100.90	$ 135.70
$ 95.67	$ 124.61	$ 126.73	$ 141.18
$ 77.62	$ 193.21	$ 178.37	$ 121.49
$ 105.62	$ 102.96	$ 262.76	$ 119.12
$ 93.77	$ 112.26	$ 181.73	$ 153.94
$ 105.61	$ 157.88	$ 208.13	$ 137.92
$ 89.62	$ 144.13	$ 201.33	$ 192.96
$ 122.86	$ 174.55	$ 203.22	$ 206.54
$ 131.33	$ 185.44	$ 209.21	$ 170.07
$ 142.95	$ 156.39	$ 212.85	$ 161.54
$ 155.27	$ 152.64	$ 280.14	$ 172.46
$ 137.19	$ 274.66	$ 362.95	$ 207.48
$ 160.45	$ 319.41	$ 301.93	$ 313.13
$ 189.92	$ 297.70	$ 297.11	$ 294.81
$ 410.63	$ 287.36	$ 349.62	$ 352.17
$ 458.59	$ 300.03	$ 307.73	$ 369.78
$ 552.46	$ 299.61	$ 480.35	$ 376.41
$ 575.88	$ 303.06	$ 352.52	$ 531.68




2015 2016 2017 2018 2019 2020 2021 2022 2023 2024

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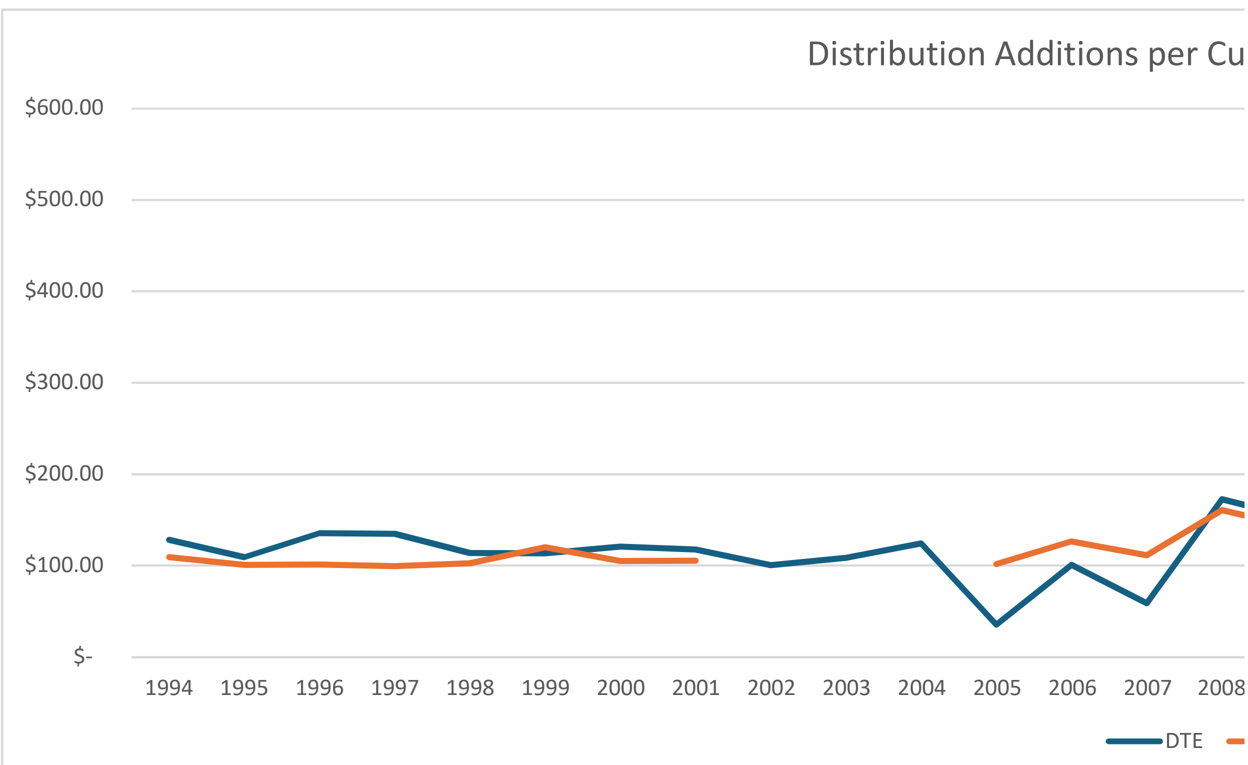
Consumers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Distribution Addtions per Cu
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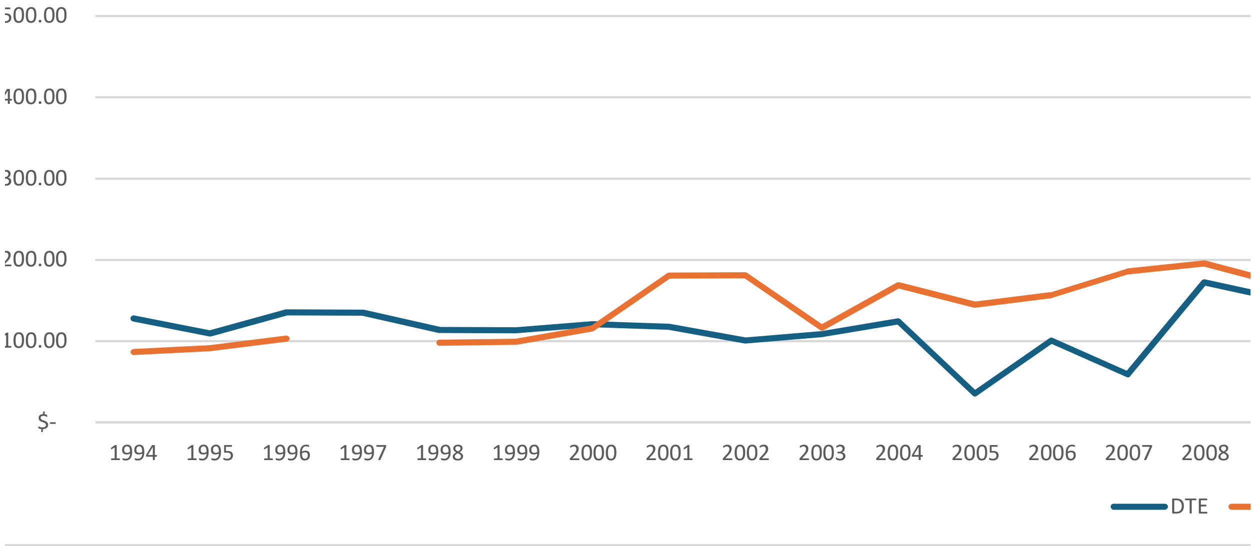
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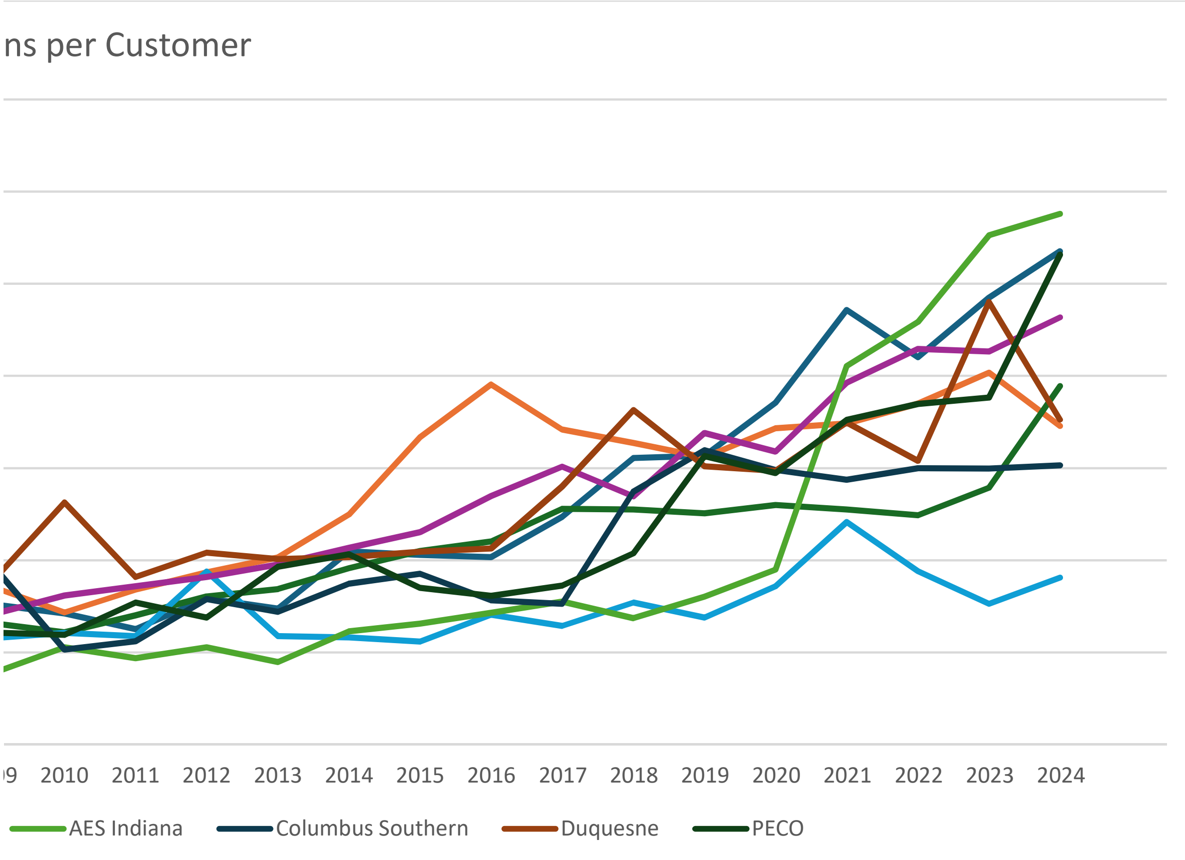
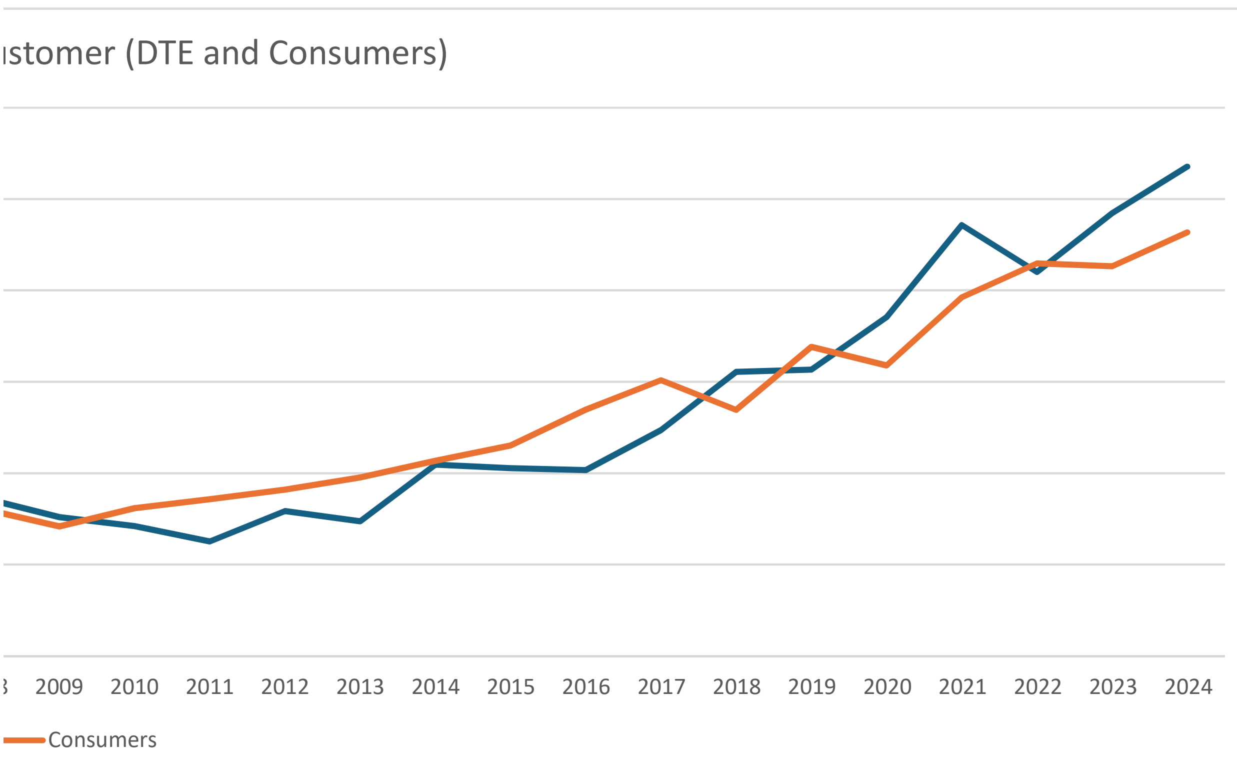

ns per Customer
)9 2010 2011 2012 2013 2014 2015 2016 2017 2018 2019 2020 2021 2022 2023 2024
AES Indiana
Columbus Southern
Duquesne
PECO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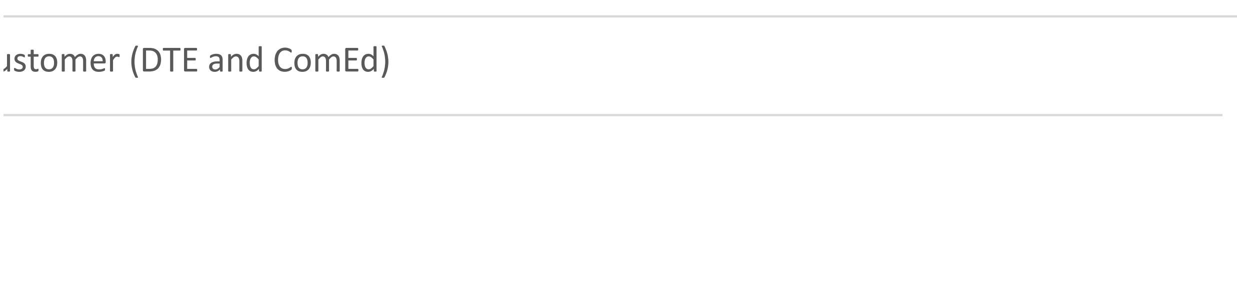
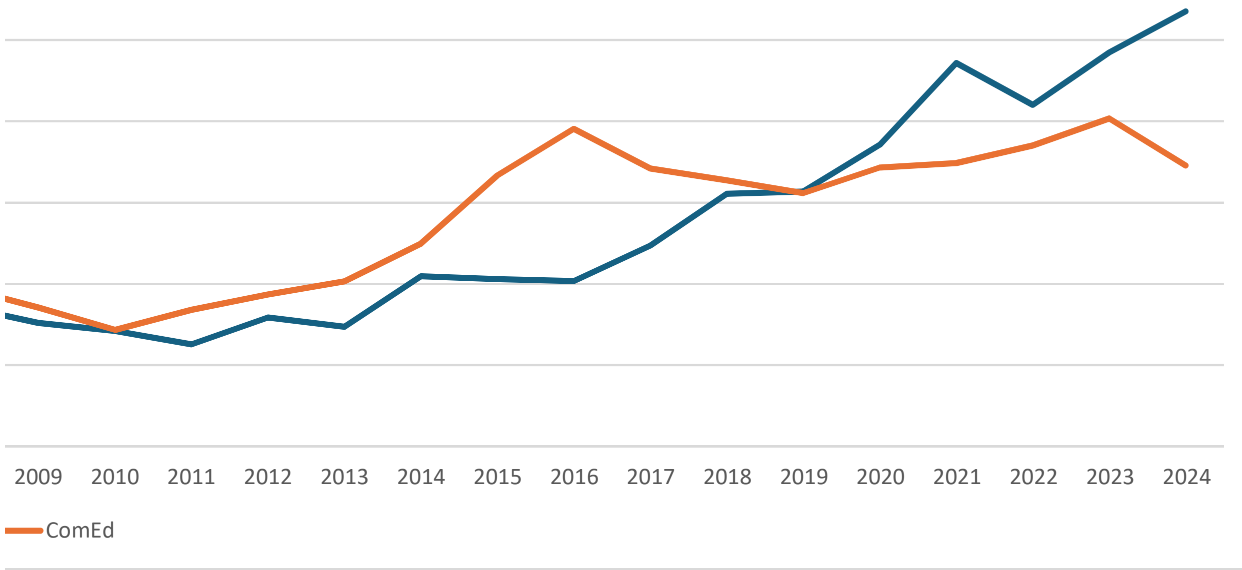
3 2009 2010 2011 2012 2013 2014 2015 2016 2017 2018 2019 2020 2021 2022 2023 2024
Consumers


ıstomer (DTE and ComEd)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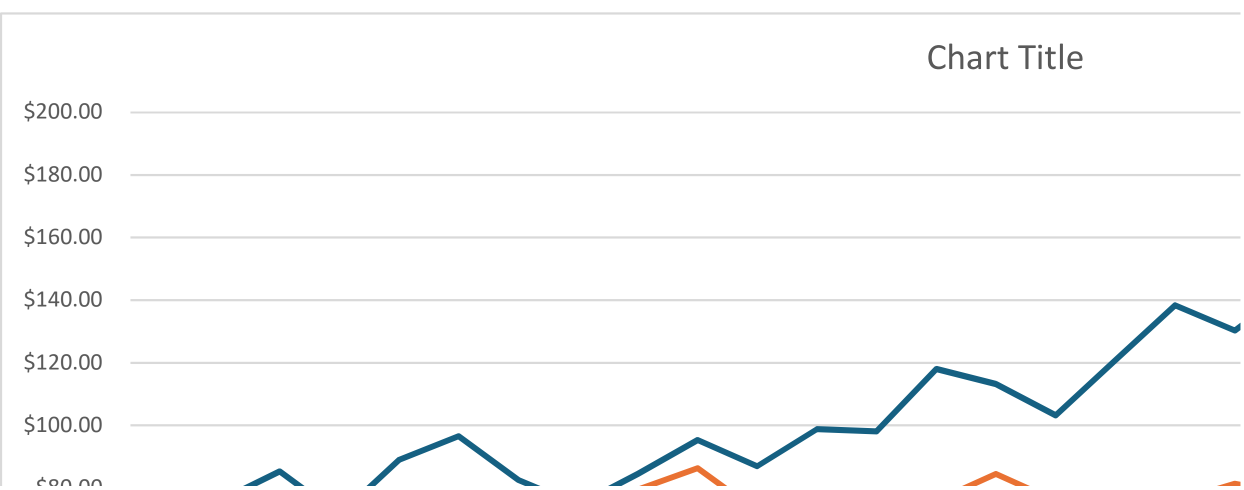
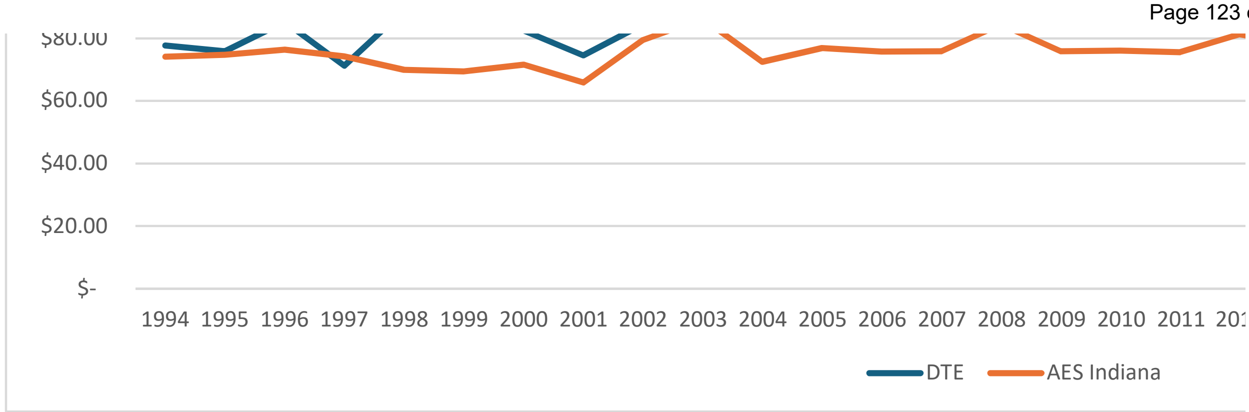
ComEd

year	DTE	ComEd	WEP Co	Cleveland	Consumers
1994	$ 77.68	$ 63.21	$ 84.17	$ 63.73	$ 59.39
1995	$ 75.85	$ 59.24	$ 67.72	$ 78.02	$ 54.23
1996	$ 85.25	$ 63.42	$ 65.19	$ 99.12	$ 47.43
1997	$ 71.24		$ 60.84	$ 74.35	$ 57.96
1998	$ 88.96	$ 74.22	$ 72.22	$ 76.91	$ 56.32
1999	$ 96.49	$ 91.51	$ 69.76	$ 81.18	$ 59.92
2000	$ 82.52	$ 121.48	$ 78.15	$ 84.08	$ 55.74
2001	$ 74.50	$ 111.78	$ 76.94	$ 67.64	$ 62.36
2002	$ 84.51	$ 90.75	$ 77.19	$ 68.65	
2003	$ 95.28	$ 80.50	$ 75.86	$ 75.33	
2004	$ 86.97	$ 75.97	$ 67.46	$ 54.89	
2005	$ 98.80	$ 77.06	$ 68.68	$ 67.53	$ 75.41
2006	$ 98.06	$ 84.06	$ 63.87	$ 67.37	$ 97.54
2007	$ 118.02	$ 97.96	$ 66.16	$ 69.62	$ 83.95
2008	$ 113.23	$ 102.06	$ 82.29	$ 82.12	$ 85.52
2009	$ 103.16	$ 78.13	$ 73.27	$ 50.93	$ 79.72
2010	$ 120.78	$ 81.88	$ 80.35	$ 56.95	$ 74.52
2011	$ 138.40	$ 108.13	$ 83.92	$ 53.41	$ 98.38
2012	$ 130.23	$ 106.63	$ 81.10	$ 65.46	$ 100.28
2013	$ 144.59	$ 113.77	$ 82.04	$ 47.05	$ 113.89
2014	$ 136.27	$ 120.28	$ 70.87	$ 48.68	$ 102.59
2015	$ 123.99	$ 118.99	$ 70.92	$ 57.47	$ 95.52
2016	$ 130.60	$ 118.35	$ 81.26	$ 63.96	$ 92.98
2017	$ 139.58	$ 116.13	$ 69.81	$ 71.69	$ 101.74
2018	$ 130.70	$ 115.40	$ 70.06	$ 72.91	$ 111.56
2019	$ 137.15	$ 117.25	$ 70.01	$ 84.40	$ 129.39
2020	$ 137.36	$ 137.91	$ 57.47	$ 96.36	$ 116.22
2021	$ 150.72	$ 121.44	$ 70.56	$ 101.32	$ 185.56
2022	$ 153.01	$ 132.14	$ 82.26	$ 102.43	$ 174.65
2023	$ 189.11	$ 131.85	$ 76.20	$ 114.59	$ 202.66
2024	$ 142.90	$ 146.42	$ 76.12	$ 218.89	$ 193.43

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1994 1995 1996 1997 1998 1999 2000 2001 2002 2003 2004 2005 2006 2007 2008 2009 2010 2011
DTE
AES Indiana

AES Indiana	Columbus Sou	Duquesne	PECO
$ 74.13	$ 73.91	$ 76.69	$ 85.33
$ 74.71	$ 72.44	$ 70.15	$ 88.72
$ 76.44	$ 68.09	$ 71.02	$ 90.37
$ 74.27	$ 69.71	$ 73.13	
$ 69.90	$ 62.24		$ 70.88
$ 69.47	$ 67.63		$ 100.23
$ 71.58	$ 71.83	$ 63.35	$ 90.98
$ 65.88	$ 61.87	$ 41.71	$ 103.59
$ 79.47	$ 67.02	$ 46.27	$ 98.58
$ 86.26	$ 74.85	$ 48.83	$ 103.48
$ 72.47	$ 94.04	$ 47.03	$ 85.56
$ 76.90	$ 82.56	$ 51.81	$ 84.09
$ 75.81	$ 69.70	$ 49.48	$ 120.09
$ 75.88	$ 81.34	$ 46.40	$ 101.93
$ 84.52	$ 83.75	$ 48.51	$ 107.30
$ 75.84	$ 96.48	$ 48.30	$ 109.33
$ 76.08	$ 110.59	$ 66.07	$ 130.29
$ 75.60	97.094143	$ 57.01	$ 134.08
$ 81.29	106.522494	$ 59.26	$ 143.65
$ 77.84	93.4958179	$ 66.56	$ 126.25
$ 78.94	128.412471	$ 71.11	$ 197.78
$ 80.89	129.574113	$ 73.56	$ 154.81
$ 84.37	131.164538	$ 81.41	$ 161.95
$ 99.11	120.812641	$ 69.89	$ 160.98
$ 99.21	130.755531	$ 74.48	$ 203.59
$ 141.10	120.488734	$ 81.37	$ 190.61
$ 128.46	115.051077	$ 93.06	$ 246.27
$ 165.99	124.284443	$ 91.58	$ 213.08
$ 179.19	141.310732	$ 96.17	$ 206.87
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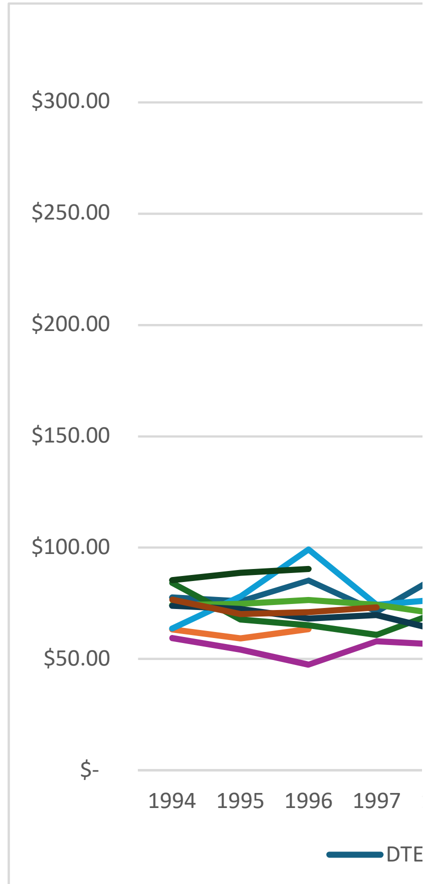

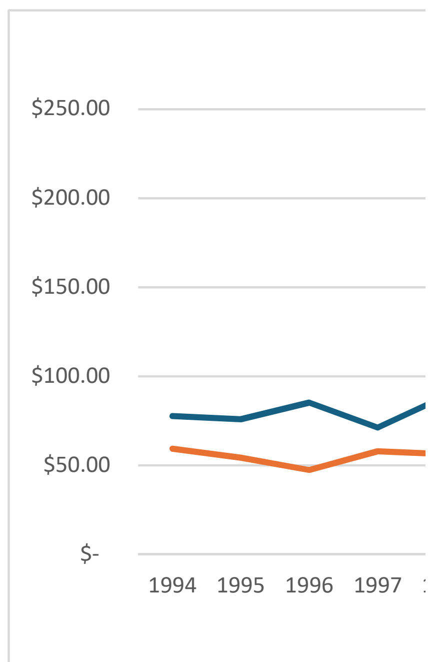

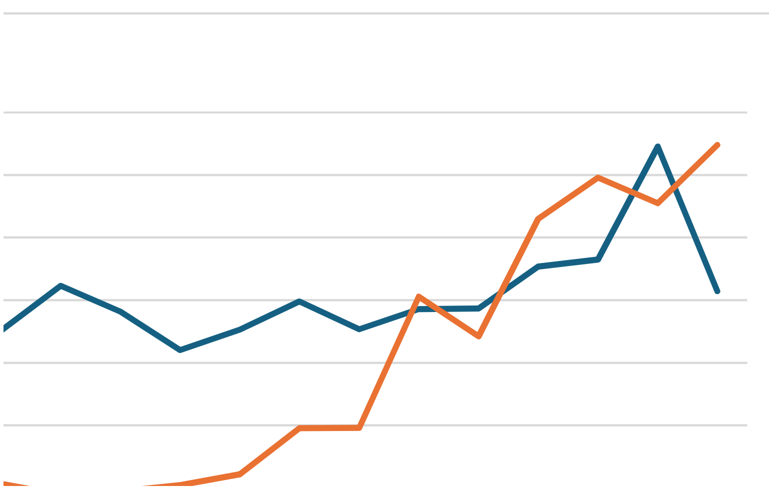


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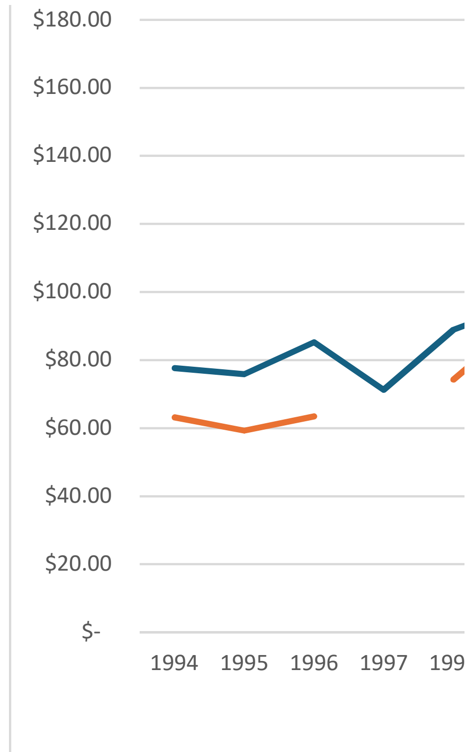
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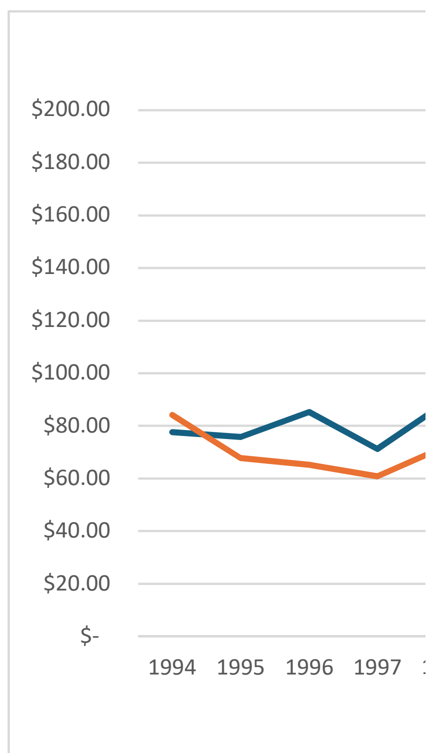
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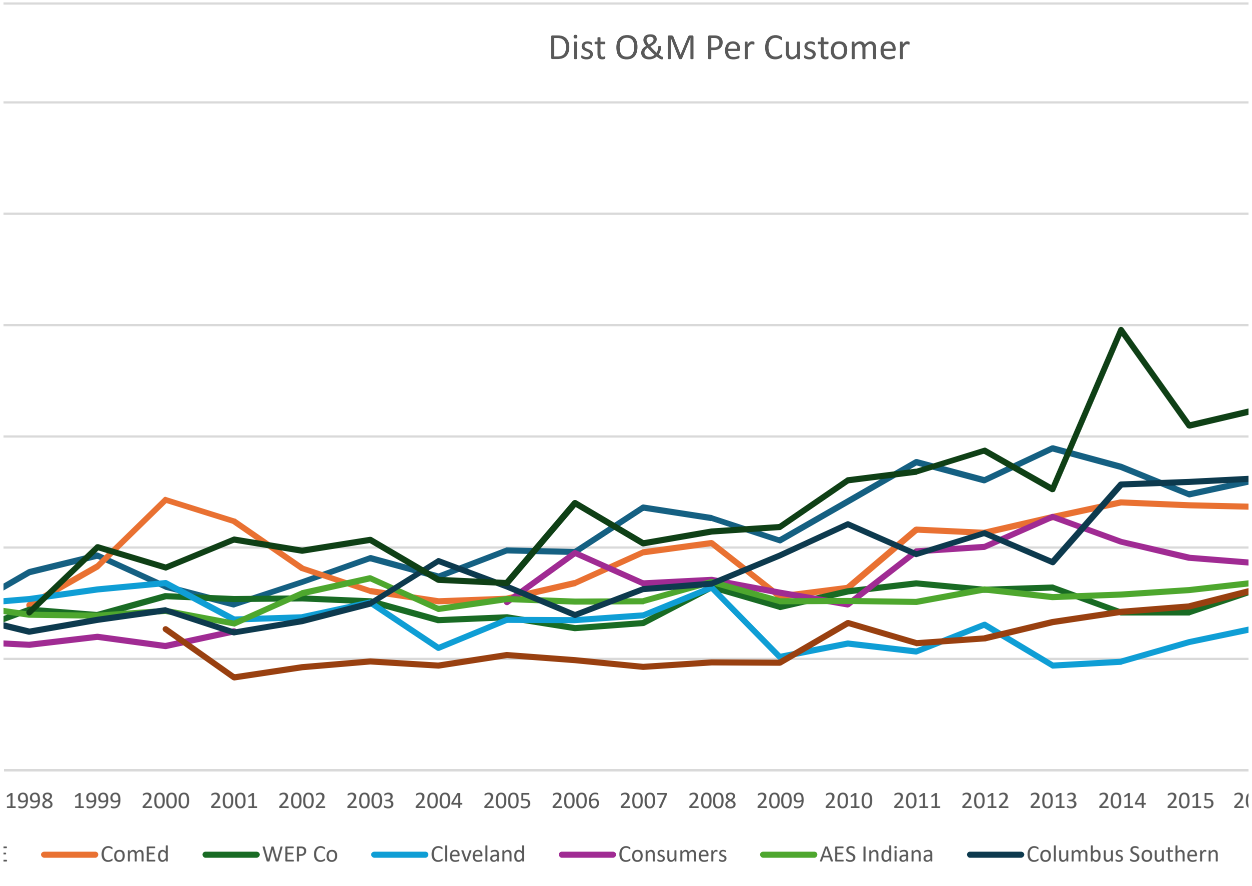
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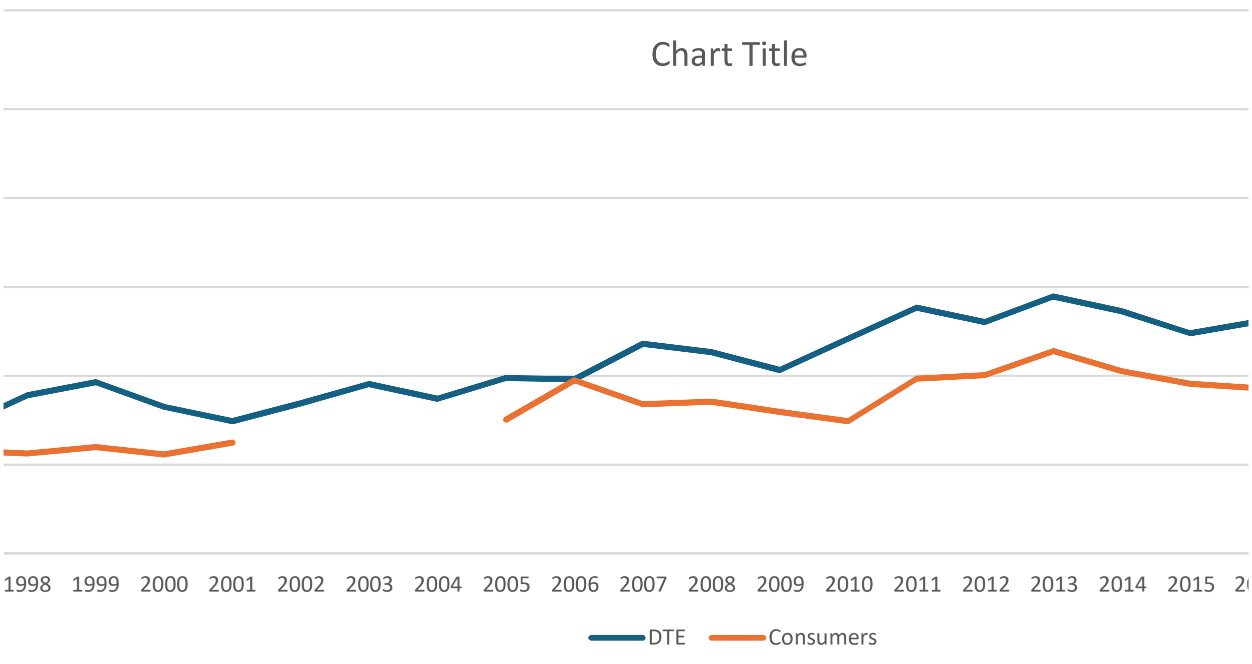
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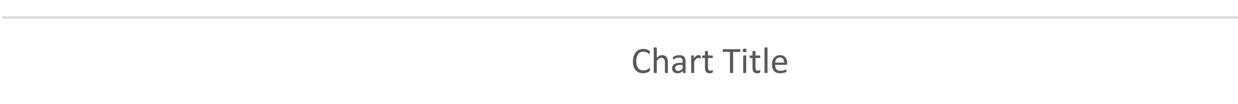
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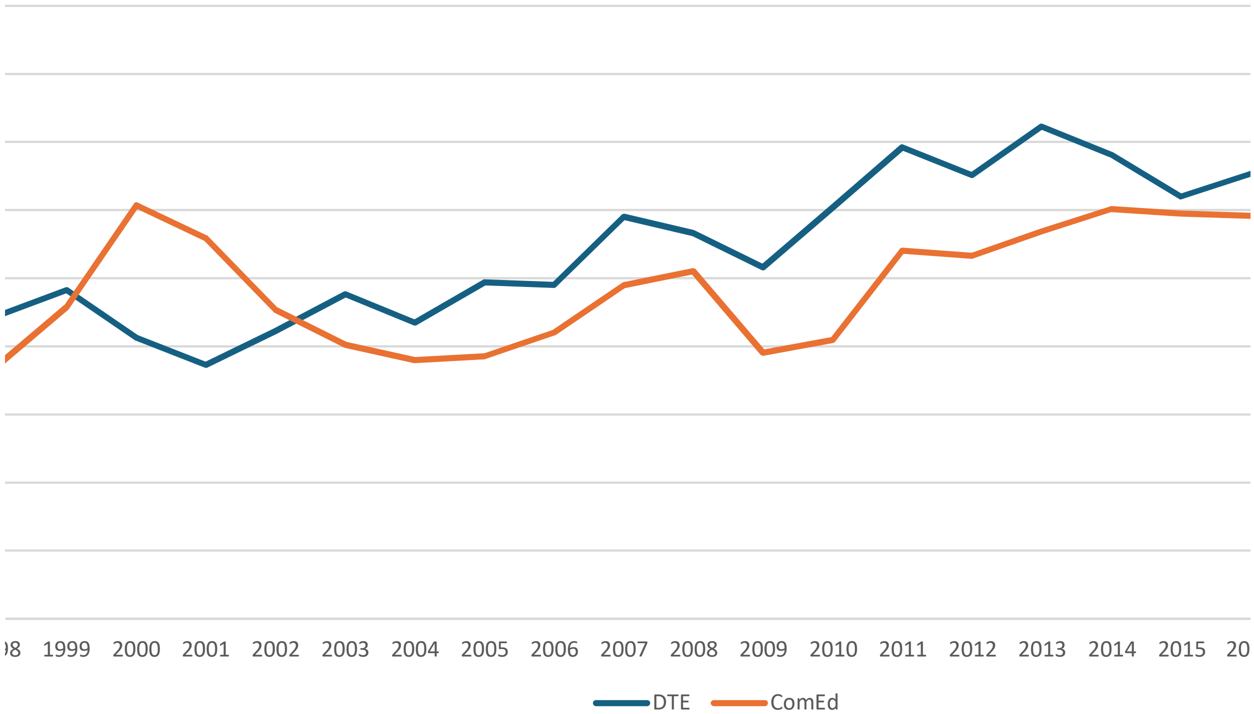
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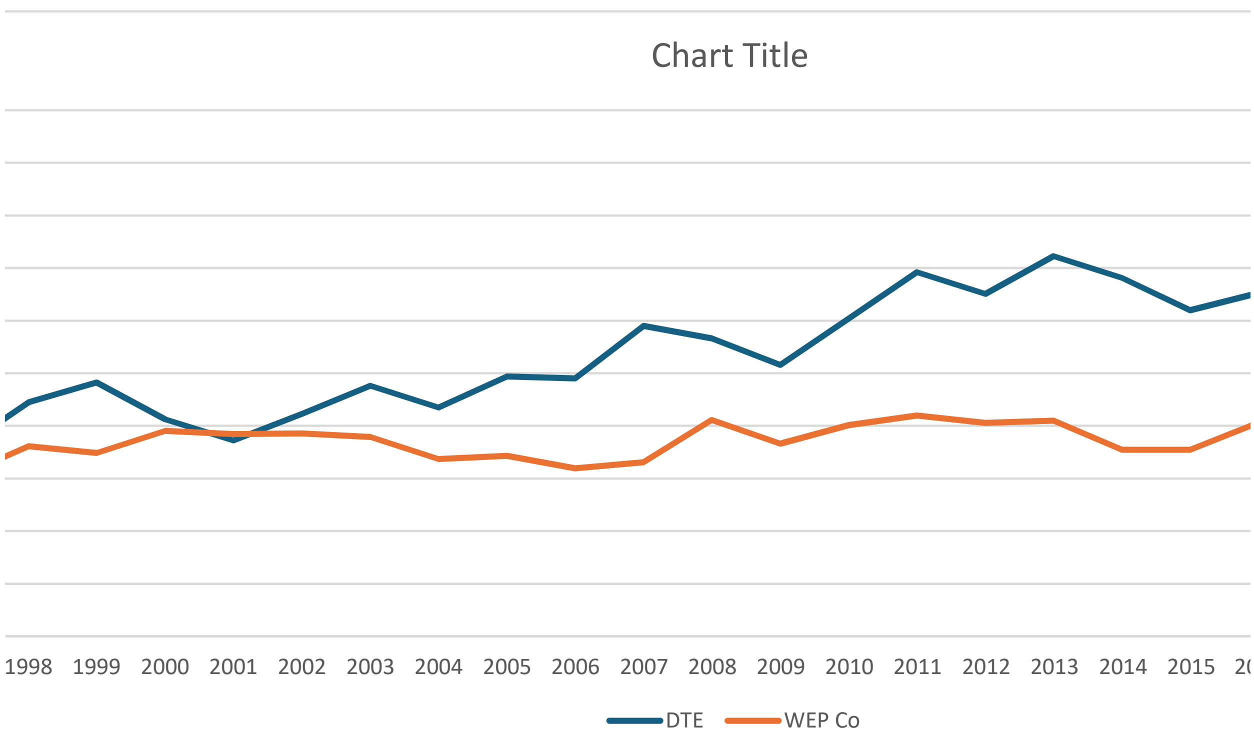
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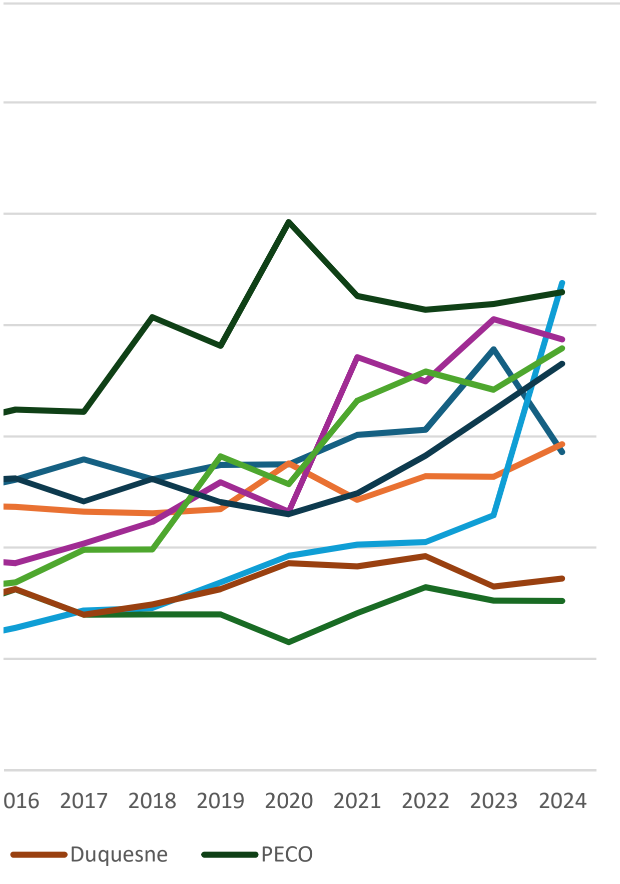
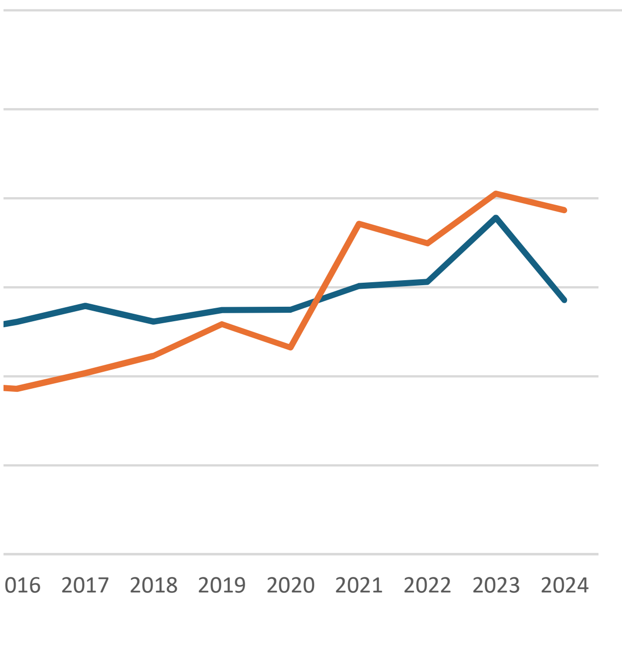

016 2017 2018 2019 2020 2021 2022 2023 2024
Duquesne
PECO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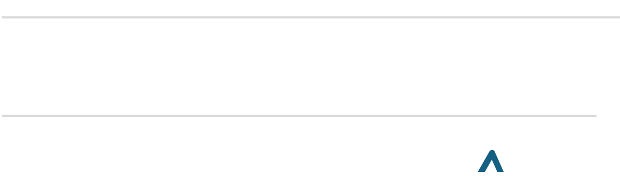

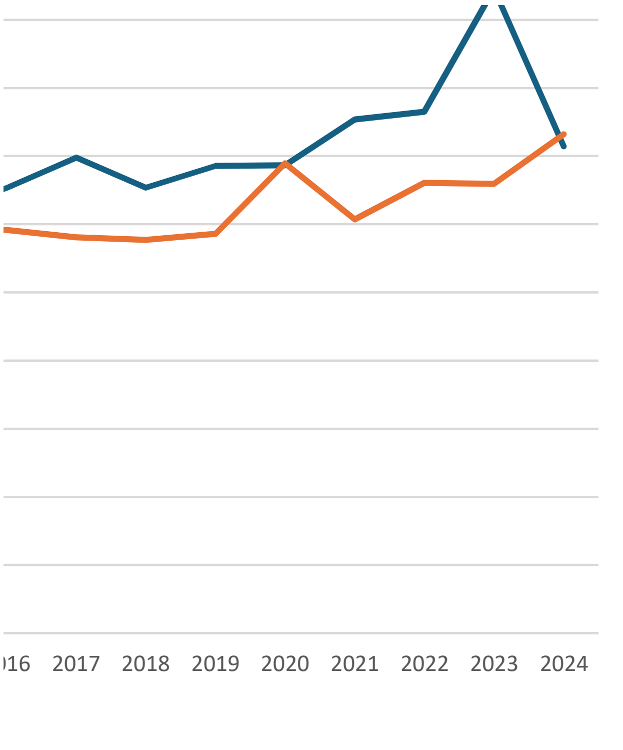
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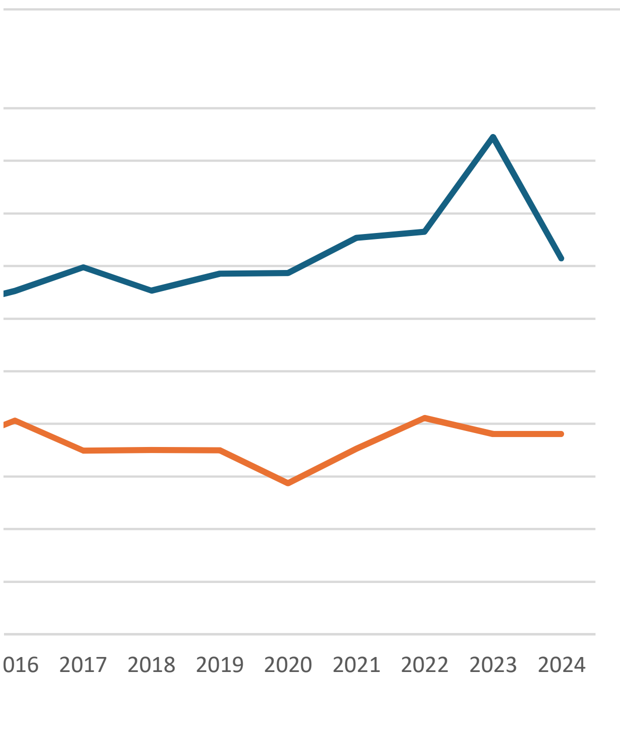
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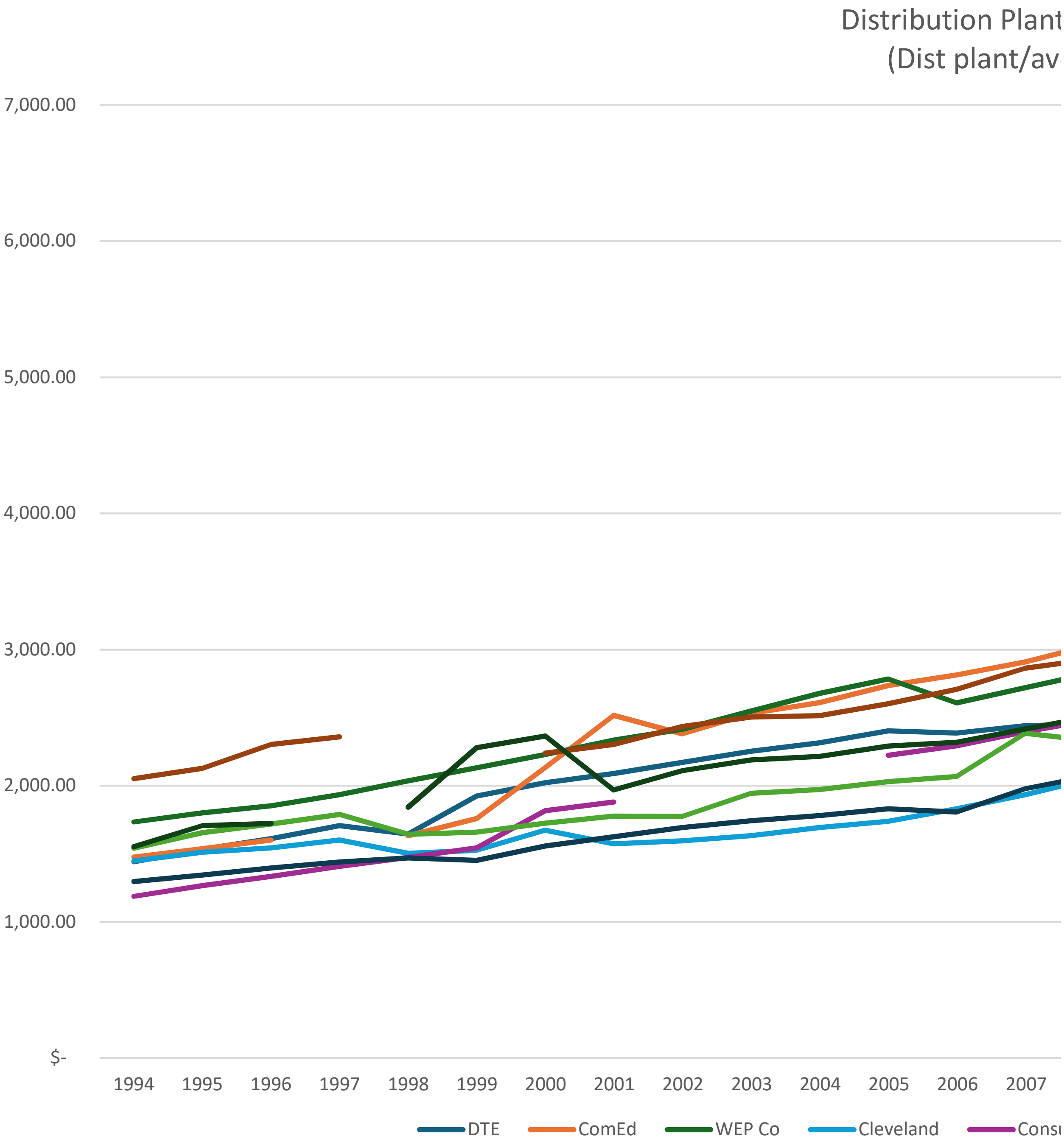
year	DTE	ComEd	WEP Co	Cleveland	Consumers
1994	$ 1,441.32	$ 1,476.32	$ 1,733.66	$ 1,447.52	$ 1,187.51
1995	$ 1,534.33	$ 1,536.89	$ 1,800.14	$ 1,512.18	$ 1,267.08
1996	$ 1,610.41	$ 1,601.96	$ 1,852.20	$ 1,544.46	$ 1,334.30
1997	$ 1,706.56		$ 1,934.41	$ 1,600.34	$ 1,408.00
1998	$ 1,645.87	$ 1,633.77	$ 2,035.58	$ 1,502.71	$ 1,474.23
1999	$ 1,924.53	$ 1,759.65	$ 2,132.27	$ 1,524.61	$ 1,543.87
2000	$ 2,022.41	$ 2,134.52	$ 2,229.43	$ 1,672.93	$ 1,816.28
2001	$ 2,088.94	$ 2,516.71	$ 2,335.31	$ 1,573.58	$ 1,881.29
2002	$ 2,170.78	$ 2,380.56	$ 2,414.54	$ 1,594.88	
2003	$ 2,252.94	$ 2,529.90	$ 2,548.05	$ 1,633.73	
2004	$ 2,315.82	$ 2,610.27	$ 2,677.65	$ 1,693.65	
2005	$ 2,402.30	$ 2,736.40	$ 2,782.79	$ 1,739.00	$ 2,223.04
2006	$ 2,386.81	$ 2,814.66	$ 2,607.92	$ 1,831.39	$ 2,292.47
2007	$ 2,441.38	$ 2,910.11	$ 2,720.04	$ 1,933.73	$ 2,396.76
2008	$ 2,451.88	$ 3,037.32	$ 2,828.74	$ 2,056.79	$ 2,483.79
2009	$ 2,595.03	$ 3,177.44	$ 2,934.22	$ 2,175.36	$ 2,655.89
2010	$ 2,739.81	$ 3,310.49	$ 3,029.64	$ 2,278.09	$ 2,778.81
2011	$ 2,856.47	$ 3,415.34	$ 3,112.32	$ 2,461.85	$ 2,933.69
2012	$ 2,951.03	$ 3,544.80	$ 3,216.21	$ 2,565.72	$ 3,094.01
2013	$ 3,062.90	$ 3,677.65	$ 3,333.12	$ 2,716.69	$ 3,254.34
2014	$ 3,158.70	$ 3,801.30	$ 3,459.88	$ 2,796.41	$ 3,424.76
2015	$ 3,318.44	$ 3,962.84	$ 3,597.05	$ 2,873.64	$ 3,610.45
2016	$ 3,453.05	$ 4,177.23	$ 3,756.77	$ 2,953.51	$ 3,770.19
2017	$ 3,572.41	$ 4,453.92	$ 4,008.58	$ 3,055.98	$ 3,911.85
2018	$ 3,769.26	$ 4,691.75	$ 4,069.43	$ 3,160.53	$ 4,183.76
2019	$ 3,983.63	$ 4,947.25	$ 4,248.67	$ 3,273.18	$ 4,330.98
2020	$ 4,211.55	$ 5,179.43	$ 4,437.85	$ 3,383.71	$ 4,589.73
2021	$ 4,475.20	$ 5,465.71	$ 4,644.56	$ 3,524.17	$ 4,839.73
2022	$ 4,867.43	$ 5,724.06	$ 4,833.89	$ 3,722.02	$ 5,193.00
2023	$ 5,223.60	$ 6,012.83	$ 5,001.75	$ 3,760.07	$ 5,579.23
2024	$ 5,607.41	$ 6,352.05	$ 5,201.52	$ 3,876.70	$ 5,947.18

AES Indiana	Columbus Sou	Duquesne	PECO
$ 1,540.47	$ 1,296.45	$ 2,052.26	$ 1,552.63
$ 1,655.55	$ 1,344.22	$ 2,128.69	$ 1,706.30
$ 1,718.67	$ 1,396.44	$ 2,302.88	$ 1,722.99
$ 1,788.69	$ 1,439.25	$ 2,359.68	
$ 1,642.24	$ 1,470.68		$ 1,842.16
$ 1,660.11	$ 1,451.01		$ 2,279.15
$ 1,725.31	$ 1,556.66	$ 2,238.92	$ 2,364.24
$ 1,776.75	$ 1,625.48	$ 2,303.91	$ 1,967.89
$ 1,774.49	$ 1,692.06	$ 2,435.51	$ 2,109.21
$ 1,943.68	$ 1,742.01	$ 2,505.12	$ 2,190.02
$ 1,971.72	$ 1,780.90	$ 2,514.45	$ 2,215.25
$ 2,029.20	$ 1,831.35	$ 2,602.07	$ 2,290.69
$ 2,068.86	$ 1,805.72	$ 2,708.31	$ 2,318.63
$ 2,385.66	$ 1,977.67	$ 2,863.05	$ 2,415.99
$ 2,328.89	$ 2,075.85	$ 2,930.92	$ 2,509.73
$ 2,415.61	$ 2,166.16	$ 3,055.62	$ 2,643.28
$ 2,477.84	$ 2,325.72	$ 3,081.78	$ 2,758.61
$ 2,529.79	$ 2,341.20	$ 3,380.93	$ 2,707.74
$ 2,588.47	$ 2,424.61	$ 3,488.59	$ 2,911.05
$ 2,635.29	$ 2,544.94	$ 3,650.76	$ 3,084.84
$ 2,684.88	$ 2,645.67	$ 3,821.61	$ 3,223.37
$ 2,719.06	$ 2,789.48	$ 4,019.28	$ 3,296.46
$ 2,816.25	$ 2,918.85	$ 4,119.30	$ 3,427.43
$ 3,284.43	$ 3,024.76	$ 4,200.96	$ 3,541.48
$ 3,374.37	$ 3,115.12	$ 4,387.83	$ 3,664.28
$ 3,422.64	$ 3,315.01	$ 4,613.05	$ 3,815.28
$ 3,116.73	$ 3,543.59	$ 4,834.29	$ 4,065.11
$ 3,660.43	$ 3,775.21	$ 5,076.33	$ 4,295.72
$ 3,525.83	$ 3,994.79	$ 5,357.15	$ 4,587.54
$ 3,891.32	$ 4,231.39	$ 5,617.70	$ 4,879.99
$ 4,357.61	$ 4,459.30	$ 6,044.21	$ 5,198.68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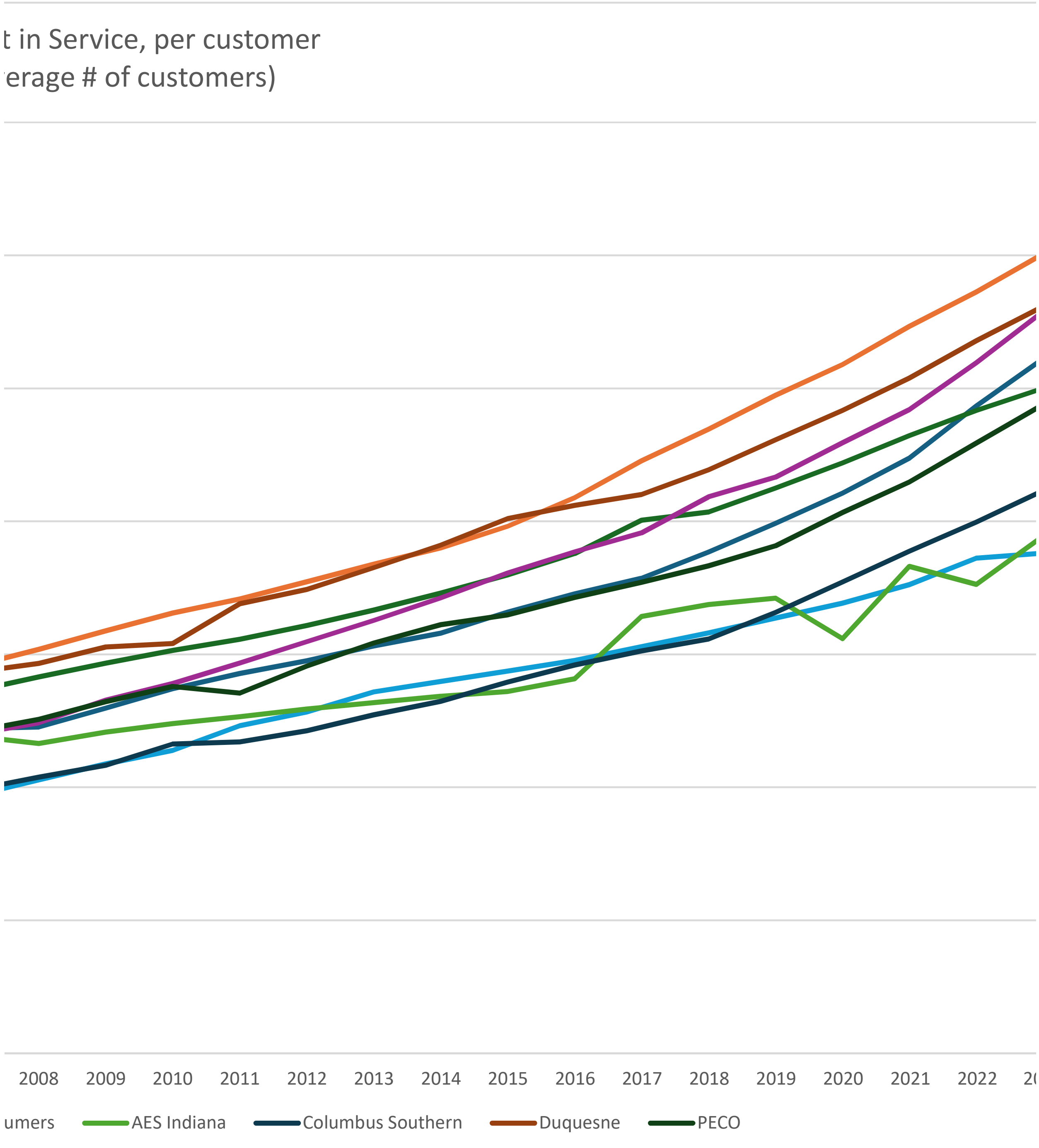
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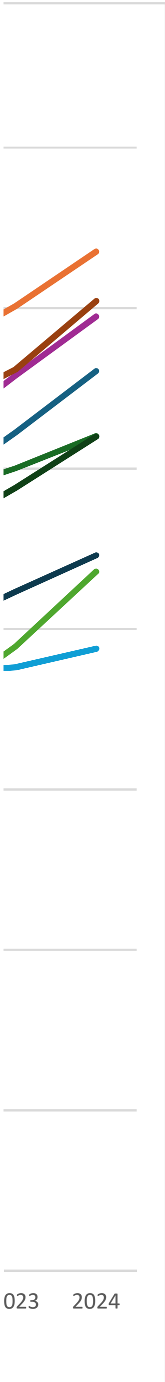
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PPI Industry Data
Original Data Value

Series Id: PCU221122221122
Series Title: PPI industry data for Electric power distribution, not
Industry: Electric power distribution
Product: Electric power distribution
Base Date: 200312
Years: 2014 to 2024

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	AVG
2014	138.7	137.7	139.7	139.0	141.3	145.6	146.7	147.1	146.6	143.2	139.9	140.5	142.2
2015	142.8	142.4	142.2	141.1	142.6	149.3	150.0	149.8	148.9	143.2	140.6	141.0	144.5
2016	139.9	138.9	140.4	138.8	140.6	146.0	147.5	147.9	148.3	143.2	141.3	141.4	142.9
2017	144.4	145.9	146.3	145.0	148.1	152.8	154.0	153.7	152.7	148.7	146.2	146.4	148.7
2018	148.4	149.8	148.0	146.7	149.2	155.1	155.6	154.9	154.0	150.0	146.9	148.5	150.6
2019	149.2	148.2	148.7	147.9	149.8	155.6	155.7	155.7	155.0	147.5	146.0	145.7	150.4
2020	146.7	145.5	145.3	144.2	145.7	153.1	153.9	154.6	156.4	148.4	148.2	147.7	149.1
2021	148.6	150.2	154.9	150.7	152.6	161.8	164.738	166.524	167.066	165.560	165.389	163.067	159.3
2022	166.733	171.577	170.235	171.794	177.688	192.103	192.161	214.031	201.237	188.039	179.125	184.723	184.1
2023	187.708	181.582	177.730	174.328	177.089	188.313	191.042	191.085	191.547	183.429	181.680	180.524	183.8
2024	183.455	184.006	184.913	184.748	184.671	200.169	196.808	192.589	192.854	186.855	182.787	185.592	188.3

Year	Jan	Feb	Mar	Apr	May	Jun
2014	97.6	96.9	98.3	97.8	99.4	102.4
2015	100.4	100.2	100.0	99.2	100.3	105.0
2016	98.4	97.7	98.8	97.6	98.9	102.7
2017	101.6	102.6	102.9	102.0	104.2	107.5
2018	104.4	105.4	104.1	103.2	104.9	109.1
2019	104.9	104.2	104.6	104.0	105.4	109.4
2020	103.2	102.3	102.2	101.4	102.5	107.7
2021	104.5	105.7	109.0	106.0	107.3	113.8
2022	117.3	120.7	119.7	120.8	125.0	135.1
2023	132.0	127.7	125.0	122.6	124.6	132.5
2024	129.0	129.4	130.1	130.0	129.9	140.8

Indexing to 2020

2020	98.4	97.6	97.4	96.7	97.7	102.7
2021	99.6	100.7	103.9	101.0	102.3	108.5
2022	111.8	115.0	114.1	115.2	119.1	128.8
2023	125.9	121.8	119.2	116.9	118.7	126.3
2024	123.0	123.4	124.0	123.9	123.8	134.2

Jul	Aug	Sep	Oct	Nov	Dec	AVG
103.2	103.5	103.1	100.7	98.4	98.8	100.0
105.5	105.4	104.7	100.7	98.9	99.2	101.6
103.8	104.0	104.3	100.7	99.4	99.5	100.5
108.3	108.1	107.4	104.6	102.8	103.0	104.6
109.4	109.0	108.3	105.5	103.3	104.5	105.9
109.5	109.5	109.0	103.8	102.7	102.5	105.8
108.3	108.7	110.0	104.4	104.2	103.9	104.9
115.9	117.1	117.5	116.5	116.3	114.7	112.0
135.2	150.5	141.6	132.3	126.0	129.9	129.5
134.4	134.4	134.7	129.0	127.8	127.0	129.3
138.4	135.5	135.7	131.4	128.6	130.5	132.4

103.2	103.7	104.9	99.5	99.4	99.0	100
110.5	111.7	112.0	111.0	110.9	109.3	106.785718
128.8	143.5	134.9	126.1	120.1	123.9	123.453428
128.1	128.1	128.4	123.0	121.8	121.0	123.264067
132.0	129.1	129.3	125.3	122.6	124.4	126.247248

Year	Indexed to 2014
2014	100.0
2015	101.6
2016	100.5
2017	104.6
2018	105.9
2019	105.8
2020	104.9
2021	112.0
2022	129.5
2023	129.3
2024	132.4

Year	Indexed to 2020
2020	100.0
2021	106.8
2022	123.5
2023	123.3
2024	126.2

Bureau of Labor Statistics

Series Title	Electricity in Size Class A, all urban consumers, not seasonally adjusted
Series ID	CUURS000SEHF01
Seasonality	Not Seasonally Adjusted
Survey Name	Consumer Price Index for All Urban Consumers (CPI-U)
Measure Data Type	Electricity
Area	Size Class A
Item	Electricity

Year	Period	Label	Observation Value	Annual average
1994	M12	1994 Dec	124.7	126.2
1995	M12	1995 Dec	127.4	130.2
1996	M12	1996 Dec	127.9	131.2
1997	M12	1997 Dec	128.0	131.7
1998	M12	1998 Dec	123.2	129.0
1999	M12	1999 Dec	123.0	127.4
2000	M12	2000 Dec	126.7	128.9
2001	M12	2001 Dec	136.0	139.2
2002	M12	2002 Dec	132.8	137.8
2003	M12	2003 Dec	135.7	140.7
2004	M12	2004 Dec	138.1	142.9
2005	M12	2005 Dec	154.3	152.5
2006	M12	2006 Dec	169.1	173.5
2007	M12	2007 Dec	178.839	181.5
2008	M12	2008 Dec	192.565	192.3
2009	M12	2009 Dec	194.018	199.0
2010	M12	2010 Dec	194.956	200.1
2011	M12	2011 Dec	196.958	201.9
2012	M12	2012 Dec	194.521	200.2
2013	M12	2013 Dec	201.239	203.7
2014	M12	2014 Dec	206.827	210.3
2015	M12	2015 Dec	202.008	210.3
2016	M12	2016 Dec	205.071	208.2
2017	M12	2017 Dec	210.127	212.5
2018	M12	2018 Dec	213.810	215.5
2019	M12	2019 Dec	212.169	215.8
2020	M12	2020 Dec	220.527	218.6
2021	M12	2021 Dec	235.935	231.1
2022	M12	2022 Dec	263.433	260.7
2023	M12	2023 Dec	276.215	274.9
2024	M12	2024 Dec	282.772	286.6

Bureau of Labor Statistics

Consumer Price Index for All Urban Consumers (CPI-

-U)

Bureau of Labor Statistics

Year	Annual CPI average	Index with 2014	Index with 2020
1994	126.2		
1995	130.2		
1996	131.2		
1997	131.7		
1998	129.0		
1999	127.4		
2000	128.9		
2001	139.2		
2002	137.8		
2003	140.7		
2004	142.9		
2005	152.5		
2006	173.5		
2007	181.5		
2008	192.3		
2009	199.0		
2010	200.1		
2011	201.9		
2012	200.2		
2013	203.7		
2014	210.3	100.0	
2015	210.3	100.0	
2016	208.2	99.0	
2017	212.5	101.1	
2018	215.5	102.5	
2019	215.8	102.6	
2020	218.6	104.0	100
2021	231.1	109.9	105.720977
2022	260.7	124.0	119.257554
2023	274.9	130.7	125.753657
2024	286.6	136.3	131.077542

Year	Indexed to 2014
2014	100.0
2015	100.0
2016	99.0
2017	101.1
2018	102.5
2019	102.6
2020	104.0
2021	109.9
2022	124.0
2023	130.7
2024	136.3

PPI and CPI Indexed to 2014		
Year	PPI	CPI
2014	100.0	100.0
2015	101.6	100.0
2016	100.5	99.0
2017	104.6	101.1
2018	105.9	102.5
2019	105.8	102.6
2020	104.9	104.0
2021	112.0	109.9
2022	129.5	124.0
2023	129.3	130.7
2024	132.4	136.3

PPI and
Year
2020
2021
2022
2023
2024

PPI Indexe
Year
2020
2021
2022
2023
2024

CPI Indexed to 2020	
PPI	CPI
100.0	100.0
106.8	105.7
123.5	119.3
123.3	125.8
126.2	131.1

ed to 2020
PPI
100.0
106.8
123.5
123.3
126.2

MPSC Case No: U-21860	
Requester: CEO	
Question No.: CEODE-5.1	
Respondent: J. Kryscynski	
Page: 1 of 1	

Question: 1. Please refer to the Company Discovery Response to CEODE-2.2f. Please provide the number of 2024 residential disconnections (due to nonpayment), aggregated to zip codes.

Answer: Please see the attachment.

Attachment: U-21860 CEODE-5.1 2024 Non-payment Disconnects

Co-respondent(s): J. Sparks

Michigan Public Service Commission
DTE Electric Company
U-21860 CEODE-5.1 2024 Non-payment Disconnects

MPSC Case No.: U-21860
Requestor: CEO
Question No.: CEODE-5.1
Respondent: J. Kryscynski

Zip Code	# of non-payment AMI Disconnects in 2024
48001	328
48002	70
48003	133
48005	77
48006	93
48009	302
48014	109
48015	319
48017	163
48021	2180
48022	44
48023	215
48025	149
48026	444
48027	70
48028	31
48030	669
48032	40
48033	1099
48034	1214
48035	1513
48036	1188
48037	1
48038	1544
48039	259
48040	211
48041	88
48042	391
48043	900
48044	1126
48045	1038
48047	768
48048	393
48049	110
48050	38
48051	643
48054	164
48059	431
48060	1459
48062	190
48063	111
48064	176
48065	205
48066	2811
48067	491
48069	20
48070	39

Michigan Public Service Commission
DTE Electric Company
U-21860 CEODE-5.1 2024 Non-payment Disconnects

MPSC Case No.: U-21860
Requestor: CEO
Question No.: CEODE-5.1
Respondent: J. Kryscynski

Zip Code	# of non-payment AMI Disconnects in 2024
48071	874
48072	226
48073	582
48074	270
48075	1234
48076	1254
48079	250
48080	843
48081	612
48082	551
48083	592
48084	356
48085	316
48088	636
48089	2140
48091	1677
48092	861
48093	691
48094	355
48095	55
48096	71
48097	136
48098	170
48101	807
48103	796
48104	394
48105	338
48108	597
48111	2315
48114	251
48116	357
48117	298
48118	15
48120	321
48122	729
48124	1066
48125	1231
48126	1811
48127	1664
48128	321
48130	136
48131	169
48134	697
48135	962
48137	27
48138	124
48139	9

Michigan Public Service Commission
DTE Electric Company
U-21860 CEODE-5.1 2024 Non-payment Disconnects

MPSC Case No.: U-21860
Requestor: CEO
Question No.: CEODE-5.1
Respondent: J. Kryscynski

Zip Code	# of non-payment AMI Disconnects in 2024
48140	48
48141	2261
48146	2185
48150	546
48152	580
48154	471
48158	17
48159	69
48160	273
48161	832
48162	921
48164	231
48165	190
48166	564
48167	455
48168	149
48169	278
48170	454
48173	462
48174	1947
48175	9
48176	279
48178	423
48179	98
48180	3183
48182	14
48183	1140
48184	932
48185	2048
48186	1761
48187	1221
48188	1110
48189	325
48190	45
48191	88
48193	562
48195	1155
48197	2021
48198	2101
48201	1061
48202	1396
48203	2053
48204	2679
48205	3679
48206	1836
48207	1557
48208	620

Michigan Public Service Commission
DTE Electric Company
U-21860 CEODE-5.1 2024 Non-payment Disconnects

MPSC Case No.: U-21860
Requestor: CEO
Question No.: CEODE-5.1
Respondent: J. Kryscynski

Zip Code	# of non-payment AMI Disconnects in 2024
48209	1408
48210	1596
48211	415
48212	1995
48213	2019
48214	1463
48215	979
48216	461
48217	577
48218	681
48219	4558
48220	609
48221	3164
48223	2460
48224	4014
48225	1168
48226	674
48227	4176
48228	5481
48229	759
48230	372
48234	3157
48235	4357
48236	598
48237	1626
48238	3083
48239	2194
48240	1009
48301	188
48302	241
48304	193
48306	204
48307	825
48308	1
48309	371
48310	1093
48312	1033
48313	707
48314	562
48315	511
48316	533
48317	1059
48318	13
48320	157
48321	2
48322	822
48323	316

Michigan Public Service Commission
DTE Electric Company
U-21860 CEODE-5.1 2024 Non-payment Disconnects

MPSC Case No.: U-21860
Requestor: CEO
Question No.: CEODE-5.1
Respondent: J. Kryscynski

Zip Code	# of non-payment AMI Disconnects in 2024
48324	313
48326	886
48327	659
48328	925
48329	585
48331	472
48334	538
48335	491
48336	750
48340	1634
48341	1150
48342	1574
48346	526
48348	430
48350	99
48353	95
48356	159
48357	298
48359	249
48360	123
48362	282
48363	72
48366	1
48367	89
48370	20
48371	531
48374	267
48375	440
48376	5
48377	469
48380	71
48381	247
48382	308
48383	467
48386	408
48390	477
48393	628
48401	50
48412	119
48413	148
48415	5
48416	160
48418	13
48419	47
48420	25
48421	195
48422	73

Michigan Public Service Commission
DTE Electric Company
U-21860 CEODE-5.1 2024 Non-payment Disconnects

MPSC Case No.: U-21860
Requestor: CEO
Question No.: CEODE-5.1
Respondent: J. Kryscynski

Zip Code	# of non-payment AMI Disconnects in 2024
48423	5
48426	11
48427	74
48428	110
48430	26
48432	14
48434	1
48435	63
48438	13
48440	2
48441	74
48442	63
48444	244
48445	26
48446	841
48450	94
48453	106
48454	29
48455	169
48456	23
48461	265
48462	273
48464	48
48465	3
48466	34
48467	36
48468	15
48469	24
48470	6
48471	169
48472	44
48475	42
48701	51
48720	41
48723	277
48725	37
48726	130
48727	24
48729	31
48731	41
48733	40
48734	1
48735	43
48741	48
48744	105
48746	143
48754	22

Michigan Public Service Commission
DTE Electric Company
U-21860 CEODE-5.1 2024 Non-payment Disconnects

MPSC Case No.: U-21860
Requestor: CEO
Question No.: CEODE-5.1
Respondent: J. Kryscynski

Zip Code	# of non-payment AMI Disconnects in 2024
48755	58
48757	69
48758	1
48759	21
48760	16
48767	27
48768	256
48819	6
48836	361
48840	3
48843	816
48854	4
48855	165
48872	20
48892	162
48895	142
49229	21
49236	31
49270	66
49285	7
49286	8
Grand Tot	188,271

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# Boratha Tan, Vote Solar
# August 22, 2025
# DTE Rate Case U-21860
# Regression Analysis of Electric Residential Disconnections, Aggregated to Zip Codes
# Demographic information pulled from the ACS (American Community Survey): BIPOC, Area
Median Income

# https://api.census.gov/data.html

# Steps to regression models:
# A. Extract zip code info
# B. Combine these  tables, into a single table
# C. Merge new table with utility spreadsheet
# D. Delete zip codes that are not in the utility's territory

#####################################
# Packages

# Use this to clear the global environment
rm(list=ls())

# Use this to set the working directory. I will use my dropbox folder.
setwd("/Users/borathatan/Vote Solar Dropbox/Boratha Tan/Boratha/MI/DTE/2025/U-21860 Rate
Case/Tan Testimony/Workpapers")

# Install all the libraries; you do this only once
install.packages(c("tidycensus", "tidyverse", "geofacet", "ggridges"))
install.packages("tigris")
install.packages("viridis")
install.packages("readxl")
install.packages("writexl")
install.packages("ggplot2")
install.packages("spatialreg")
install.packages("spdep")
install.packages("stargazer")

# Load LIBRARIES
library(tidycensus)
library(tidyverse)
library(tigris)
options(tigris_use_cache = TRUE)
library(viridis)
library(readxl)
library(writexl)
library(ggplot2)
library(sf)
library(spatialreg)
library(spdep)
library(stargazer)

census_api_key("5e3ed46bfa93083d3f07ca6e36e3b0a8d8e826d8", install = TRUE)

#####################################
# Import DTE data
Workpaper_DTE_disconnections <- read_excel("U-21860 Disconnects.xlsx")
# All rows will NULL were removed from the dataset

colnames(Workpaper_DTE_disconnections)[1] = "GEOID"


#####################################
# Census importing data

# Pull zip code data population from tidycensus
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# Race
mi_pop_race <- get_acs(geography = "zcta",
                       variables = c("B02001_001"),
                       survey = "acs5",
                       geometry = TRUE,
                       keep_geo_vars = TRUE,
                       year = 2020)

mi_white <- get_acs(geography = "zcta",
                    variables = c("B03002_003"),
                    survey = "acs5",
                    geometry = TRUE,
                    keep_geo_vars = TRUE,
                    year = 2020)


mi_pop_race <- mi_pop_race %>%
  mutate(white = mi_white$estimate,
         bipoc = (mi_pop_race$estimate-mi_white$estimate)/mi_pop_race$estimate,
         bipoctotal = mi_pop_race$estimate-mi_white$estimate)
# the bipoc column is automatically converted to 0-100% BIPOC

# Income
mi_income <- get_acs(geography = "zcta",
                     variables = "B19013_001",
                     survey = "acs5",
                     geometry = TRUE, year = 2020)
mi_income <- mi_income %>%
  mutate(ami = mi_income$estimate / 10000) #here, I divide by 10k so that my
interpretation will be "for every 10k increase in income..."


#####################################

# Delete unnecessary columns
Workpaper_pop_race <- mi_pop_race[,!names(mi_pop_race) %in% c("STATEFP.x", "ZCTA5CE20",
"AFFGEOID20", "AFFGEOID.x", "NAME20", "LSAD20",
                                                                                    "ALAND20",
"AWATER20", "NAME", "estimate", "variable", "moe", "geometry",
                                                                                    "white")]

Workpaper_income <- mi_income[,!names(mi_income) %in% c("NAME", "variable", "estimate",
"moe", "geometry",
                                                              "white")]


#Export to excel, then re-read so that I don't have to deal with spatial dataframes

write_xlsx(Workpaper_income,"/Users/borathatan/Vote Solar Dropbox/Boratha
Tan/Boratha/MI/DTE/2025/U-21860 Rate Case/Tan Testimony/Workpaper/mi_income.xlsx")
mi_income_ready <- read_excel("mi_income.xlsx")
write_xlsx(Workpaper_pop_race,"/Users/borathatan/Vote Solar Dropbox/Boratha
Tan/Boratha/MI/DTE/2025/U-21860 Rate Case/Tan Testimony/Workpaper/mi_pop_race.xlsx")
mi_pop_race_ready <- read_excel("mi_pop_race.xlsx")


# Merge ACS tables
mi_temp_a <- merge(mi_pop_race_ready, mi_income_ready, by = "GEOID")
Workpaper_DTE_final <- merge(mi_temp_a, Workpaper_DTE_disconnections, by = "GEOID")
# Export
write_xlsx(Workpaper_DTE_final,"/Users/borathatan/Vote Solar Dropbox/Boratha
Tan/Boratha/MI/DTE/2025/U-21860 Rate Case/Tan
Testimony/Workpaper/Workpaper_Tan_DTE_final.xlsx")
# in this workpaper, the "bipoctotal" column is the number of BIPOC residents in a given
```

```
zip code

bipoc_total = sum(Workpaper_DTE_final$bipoctotal)


#####################################

# Regression

Disconnectvsincome <- lm(disconnect~ami, data = Workpaper_DTE_final)
summary(Disconnectvsincome)
DisconnectvsBIPOC <- lm(disconnect~bipoc, data = Workpaper_DTE_final)
summary(DisconnectvsBIPOC)
DisconnectBI <- lm(disconnect~ami+bipoc, data = Workpaper_DTE_final)
summary(DisconnectBI)

plot(Workpaper_DTE_final$bipoc,Workpaper_DTE_final$disconnect,
     main='Residential Disconnections vs Race, BIPOC',
     xlab='% BIPOC',
     ylab='# of Residential Disconnections')
abline(DisconnectvsBIPOC, col='red')

plot(Workpaper_DTE_final$ami,Workpaper_DTE_final$disconnect,
     main='Residential Disconnections vs AMI',
     xlab='AMI, per $10k',
     ylab='# of Residential Disconnections')
abline(Disconnectvsincome, col='red')

ggplot(Workpaper_DTE_final, aes(x=bipoctotal)) + geom_histogram(color="white",
fill="olivedrab", bins = 10) +
  labs(title="Histogram of Zip Codes, # BIPOC", x="# of BIPOC residents", y="# of Zip
Codes") +
  geom_vline(aes(xintercept = mean(Workpaper_DTE_final$bipoctotal)), color = "red", size =
1.25) +
  geom_vline(aes(xintercept = mean(Workpaper_DTE_final$bipoctotal) +
sd(Workpaper_DTE_final$bipoctotal)), color = "#000000", size = 1, linetype = "dashed") +
  geom_vline(aes(xintercept = mean(Workpaper_DTE_final$bipoctotal) -
sd(Workpaper_DTE_final$bipoctotal)), color = "#000000", size = 1, linetype = "dashed")

ggplot(Workpaper_DTE_final, aes(x=bipoc)) + geom_histogram(color="white", fill="blue") +
  labs(title="Histogram of Zip Codes, % BIPOC", x="Percentage BIPOC", y="# of Zip Codes")
+
  geom_vline(aes(xintercept = mean(Workpaper_DTE_final$bipoc)), color = "red", size =
1.25) +
  geom_vline(aes(xintercept = mean(Workpaper_DTE_final$bipoc) +
sd(Workpaper_DTE_final$bipoc)), color = "#000000", size = 1, linetype = "dashed") +
  geom_vline(aes(xintercept = mean(Workpaper_DTE_final$bipoc) -
sd(Workpaper_DTE_final$bipoc)), color = "#000000", size = 1, linetype = "dashed")

#####################################

# Print all regression tables into .txt file
sink("Workpaper_U-21860_RegressionTables.txt")
cat("2024 DTE Disconnections with respect to Zip Codes \nlog(nonwhite) = % population in
Census Tract that is BIPOC \nami = Per $10,000 increase in Area Median Income \n")

print("Disconnections")
print("Total BIPOC Population")
print(bipoc_total)
print(summary(Disconnectvsincome))
print(summary(DisconnectvsBIPOC))
print(summary(DisconnectBI))

sink()
```

```
stargazer(Disconnectvsincome,DisconnectvsBIPOC,DisconnectBI, align = TRUE, type = "html",
title = "Table: 2024 Residential Disconnection Results w/ Income and % BIPOC", out = "2024
DTE Disconnection.html")



# Using Michigan's DHHS to get Zip Codes for Washtenaw and Wayne Counties: https://mdhhs-
pres-prod.michigan.gov/olmweb/ex/RF/Public/RFT/101.pdf
Workpaper_Washtenaw <- read_excel("Washtenaw_MI_zip.xlsx")
Workpaper_Wayne <- read_excel("Wayne_MI_zip.xlsx")
Workpaper_DTE_Washtenaw <- merge(Workpaper_Washtenaw, Workpaper_DTE_final, by = "GEOID")
Workpaper_DTE_Wayne <- merge(Workpaper_Wayne, Workpaper_DTE_final, by = "GEOID")

# Washtenaw
Washtenaw_Disconnectvsincome <- lm(disconnect~ami, data = Workpaper_DTE_Washtenaw)
summary(Washtenaw_Disconnectvsincome)
Washtenaw_DisconnectvsBIPOC <- lm(disconnect~bipoc, data = Workpaper_DTE_Washtenaw)
summary(Washtenaw_DisconnectvsBIPOC)
Washtenaw_DisconnectBI <- lm(disconnect~ami+bipoc, data = Workpaper_DTE_Washtenaw)
summary(Washtenaw_DisconnectBI)

stargazer(Washtenaw_Disconnectvsincome,Washtenaw_DisconnectvsBIPOC, align = TRUE, type =
"html", title = "Table: 2024 Washtenaw Disconnection Results", out = "2024 DTE Washtenaw
Disconnection.html")

# Wayne
Wayne_Disconnectvsincome <- lm(disconnect~ami, data = Workpaper_DTE_Wayne)
summary(Wayne_Disconnectvsincome)
Wayne_DisconnectvsBIPOC <- lm(disconnect~bipoc, data = Workpaper_DTE_Wayne)
summary(Wayne_DisconnectvsBIPOC)
Wayne_DisconnectBI <- lm(disconnect~ami+bipoc, data = Workpaper_DTE_Wayne)
summary(Wayne_DisconnectBI)

stargazer(Wayne_Disconnectvsincome,Wayne_DisconnectvsBIPOC, align = TRUE, type = "html",
title = "Table: 2024 Wayne Disconnection Results", out = "2024 DTE Wayne
Disconnection.html")

stargazer(Wayne_DisconnectBI,Washtenaw_DisconnectBI, align = TRUE, type = "html",
column.labels = c("Wayne Cty Zip", "Washtenaw Cty Zip"), title = "Table: 2024 Wayne vs
Washtenaw Disconnection Results", out = "2024 DTE Wayne vs Washtenaw Disconnection.html")
```

STATE OF MICHIGAN
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-21860

PROOF OF SERVICE

I hereby certify that a true copy of the foregoing *Direct Testimony of William D. Kenworthy, Curt Volkmann, and Boratha Tan on behalf of The Ecology Center, The Environmental Law & Policy Center, Union of Concerned Scientists, and Vote Solar* was served by electronic mail upon the following Parties of Record, Friday, August 22, 2025.

Administrative Law Judge Hon. Sally L. Wallace	wallaces2@michigan.gov
DTE Electric Company Jon P. Christinidis John Janiszewski Carlton Watson Breanne Reitzel Andrea Hayden Mihaela Turculet	 jon.christinidis@dteenergy.com mpscfilings_account@dteenergy.com John.janiszewski@dteenergy.com Carlton.watson@dteenergy.com Breanne.reitzel@dteenergy.com Andrea.hayden@dteenergy.com mihaela.turculet@dteenergy.com
Michigan Public Service Commission Staff Monica M. Stephens Heather M.S. Durian Anna B. Stirling Adam Cozort Lori Mayabb, case coordinator Ryan Boutet Jessica Duell Ally Durfee Nicholas Evans Jung Shi	 stephensm11@michigan.gov durianh@michigan.gov stirlinga1@michigan.gov cozarta1@michigan.gov mayabbl@michigan.gov BoutetR@michigan.gov DuellJ@michigan.gov DurfeeA1@michigan.gov EvansN@michigan.gov ShiJ@michigan.gov

Department of Attorney General Joel B. King Lucas Wollenzien Sebastian Coppola Paul Alvarez Dennis Stephens Rick Bunch Julielyn Gibbons Douglas Jester Amanda Churchill	kingj38@michigan.gov wollenzienl@michigan.gov AG-ENRA-Spec-Lit@michigan.gov sebcoppola@corplytics.com palvarez@wiredgroup.net dennis.stephens@hotmail.com rbunch@5lakesenergy.com jgibbons@5lakesenergy.com djester@5lakesenergy.com ChurchillA1@michigan.gov
The Ecology Center, Environmental Law & Policy Center, Union of Concerned Scientists, and Vote Solar (CEO) Daniel Abrams Brad Klein Katie Duckworth Boratha Tan James Gignac Lee Shaver William D. Kenworthy Curt Volkmann Alondra Estrada Katie Toolan	dabrams@elpc.org bklein@elpc.org kduckeworth@elpc.org btan@votesolar.org jgignac@ucsusa.org btan@votesolar.org lshaver@ucsusa.org will@votesolar.org curt@newenergy-advisors.com aestrada@elpc.org mpscdocket@elpc.org ktoolan@elpc.org
MEC/NRDC/SC/CUB (MNSC) Tracy Jane Andrews Christopher Bzdok Holly Hillyer Natasha Fowles Paul Alvarez Rick Bunch Julielyn Gibbons Douglas Jester Dennis Stephens Moksha Menghaney Peter James Schultz Patrick Sullivan Matt Bandyk Graham Woolley	tjandrews@tropospherelegal.com chris@tropospherelegal.com holly@tropospherelegal.com natasha@tropospherelegal.com service@5lakesenergy.com palvarez@wiredgroup.net rbunch@5lakesenergy.com djester@5lakesenergy.com dstephens@wiredgroup.net mmenghaney@5lakesenergy.com pschultz@5lakesenergy.com gwoolley@5lakesenergy.com pp.sullivan@sullivanconsultingwi.com mbandyk@synapse-energy.com
ABATE Michael Pattwell Stephen Campbell	mpattwell@clarkhill.com scampbell@clarkhill.com bholwerda@clarkhill.com

Benjamin Holwerda James Dauphinais Jessica York Christina Hildebrandt Brian Andrews Colin Fitzhenry Christopher C. Walters	jdauphinais@consultbai.com jyork@consultbai.com childebrandt@consultbai.com bandrews@consultbai.com cfitzhenry@consultbai.com cwalters@consultbai.com
FA/EM/MEIBC/IEI/AEU (MEIU) Laura Chappelle Timothy Lundgren Justin Ooms John D. Albers Sophia Schuster Laura Sherman	lachappelle@varnumlaw.com tjlundgren@varnumlaw.com jkooms@varnumlaw.com JAlbers@advancedenergyunited.org sophia@mieibc.org laura@mieibc.org
GLREA Don Keskey	donkeskey@publiclawresourcecenter.com
UWUA Local 223 Richard Mack, Jr. Jacob Porcarelli Susan Brohman Adrienne Mack	richardmack@millercohen.com jporcarelli@millercohen.com sbrohman@millercohen.com amack@millercohen.com
City of Ann Arbor Valerie Jackson	vjackson@a2gov.org
Electrify America Krystal Hermiz Stephen Bright Jigar Shah Jeremy Wiley	khermiz@grsm.com steve.bright@electrifyamerica.com jigar.shah@electrifyamerica.com extern.jeremy.wiley@electrifyamerica.com
Walmart, Inc. Melissa Horne	mhorne@hcc-law.com
MI-MAUI/PROTEC Michael Watza Nathan Inks	Mike@bloomsluggett.com nathan@bloomsluggett.com
Soulardarity Amanda Urban Mark Templeton Madison Wilson David Elkins Davis Han Melody Yu Ashley Zhu Jacob Schuhardt	aurbanlaw@gmail.com templeton@uchicago.edu aelc_mpsc@lawclinic.uchicago.edu madisonswilson@uchicago.edu delkins@lawclinic.uchicago.edu melodyyu@lawclinic.uchicago.edu ahzhu@lawclinic.uchicago.edu jschuhardt@uchicago.edu finance-director@soulardarity.com

DAAO Consultants Rahul Bejarano Monica Booker Akanke Hill Elizabeth Jacob Yunus Kinkhabwala Bethany Kwoka Tyler LaBerge Gloria Lowe Patrick Murphy Shimekia Nichols Amani Sawari Justin Schott	rahul@energyequityproject.org monica@soulardarity.com finance-director@soulardarity.com ljacob@sugarlaw.org y.kinkhabwala@psehealthyenergy.org bkwoka@psehealthyenergy.org tyler@energyequityproject.org gloria@wewantgreentoo.org patrick@psehealthyenergy.org shimekia@soulardarity.com amani@wewantgreentoo.org justin@energyequityproject.org
The Kroger Co. Kurt Boehm Michael Kurtz Justin Bieber Rebecca Forbes Jason Kiengsiri Jared Robertson	kboehm@bkllawfirm.com mkurtz@bkllawfirm.com jbieber@energystrat.com rforbes@energystrat.com jkiengsiri@energystrat.com jrobertson@energystrat.com
Gerdau MacSteel, Inc. Jennifer Utter Heston	jheston@fraserlawfirm.com
ITC Richard Aaron Courtney Kissel Olivia Flower Hannah Buzolits	raaron@dykema.com ckissel@dykema.com oflower@dykema.com hbuzolits@dykema.com MPSCFilings@dykema.com
Michigan Cable Telecommunications Associations Sean Gallagher Jon Austin	sgallagher@fraserlawfirm.com jaustin@fraserlawfirm.com

Daniel Abrams (P87696)
Environmental Law & Policy Center