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April 28, 2026

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

RE: In the matter of **DTE ELECTRIC COMPANY**'s submission of its Distribution System Plan pursuant to the Commission's Order in Case No. U-20147.
MPSC Case No: U-22104

Dear Ms. Felice:

Attached for electronic filing in the above referenced matter is DTE Electric Company's Distribution System Plan Report. Also attached is the Proof of Service.

Very truly yours,

Andrea E. Hayden

Digitally signed by Andrea E. Hayden
Date: 2026.04.28 14:57:06 -04'00'

Andrea E. Hayden

AEH/cdm
Enclosure

cc: Service List

DTE Electric Company
2026 Distribution System Plan

April 28, 2026

MPSC Case No. U-22104

DTE

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Preamble

Navigating DTE's 2026 Distribution System Plan

DTE Electric's (DTE or the Company) 2026 Distribution System Plan (DSP) is a comprehensive filing to explain why electric grid investments are needed, how priorities are established, and the Company's proposed actions to deliver customer-focused outcomes. Given the breadth and technical detail of the DSP, this preamble is intended to orient readers to the structure of the document and support navigation through its key components.

Following the Executive Summary, Chapter 2 establishes the strategic foundation of the DSP by summarizing the Michigan Public Service Commission directives and major drivers of investment shaping DTE's planning approach before introducing the integrated five-pillar reliability and modernization investment framework.

Chapter 3 describes DTE's pre-filing engagement with customers, communities, and technical stakeholders, as well as ongoing outreach activities. The chapter highlights key themes raised throughout pre-filing engagement and explains how stakeholder input impacted the final plan.

Chapter 4 provides an overview of the current state of the system and fulfills additional DSP requirements by including overviews of historical performance, storm response, distributed energy resources, environmental justice analyses, and other operational considerations.

Chapter 5 describes the forecasting methodologies, analytical tools, benefit-cost analyses, and prioritization frameworks used to balance reliability, affordability, and risk reduction. The chapter also presents projected near-term investments, expected impacts, and a longer-term outlook.

Chapter 6 details the investment programs within each of the five pillars that define DTE's reliability and modernization framework. For each program, the sections detail the grid needs, cost-effectiveness considerations, near-term investment plan, and longer-term outlook.

Chapter 7 focuses on execution and describes how the Infrastructure Recovery Mechanism and Performance-Based Ratemaking mechanism promote transparency and customer-focused delivery of the DSP.

Finally, the Appendix (Chapter 8) provides supporting materials, including a table of 215 exhibits, an acronym glossary, a DSP requirement fulfillment matrix, and other supplemental technical analyses to enhance transparency and provide additional detail for interested readers.

1. Executive Summary

DTE Electric (DTE or the Company) is committed to serving Michigan communities by delivering safe, reliable, and clean electricity while balancing affordability with the pace of required investments. DTE recognizes that earning and maintaining customer trust requires sustained focus, transparency, and continuous improvement. In this fourth Distribution System Plan (DSP),[1] the Company presents a transparent, data-driven strategic roadmap for Distribution Operations (DO) and its planned investments from 2026 through 2030. The plan outlines a coordinated approach to addressing the primary drivers of investment, including aging infrastructure and capacity constraints, increasingly severe weather, and customer adoption of distributed energy resources (DER) and other emerging technologies. Absent targeted action, these drivers place growing stress on an aging grid, strain existing capacity, and increase operational complexity, limiting DTE's ability to safely and reliably serve customers. Against this backdrop of grid needs, the Company remains committed to meeting customers' evolving expectations through a modern, resilient electric system.

[1] See Appendix 8.2 for a complete glossary of acronyms and terms.

Thousands of men and women across DTE are driven by the responsibility and privilege of serving the customers and communities who depend on the electric grid every day. While recent progress reflects sustained effort and targeted investments, the Company recognizes that additional work is needed. This plan builds on experience-based insights and continued customer feedback as DTE advances its responsibility to strengthen the grid, improve operational performance, and deliver lasting benefits for all customers.

Building a Stronger, Smarter, and More Resilient Grid

To meet evolving customer needs and continue improving safety and electric reliability, the Company must strengthen and modernize its electric grid. This filing builds on prior DSP submissions since 2018 and incorporates several important enhancements informed by regulatory guidance and stakeholder feedback:

- **Alignment with MPSC Performance Requirements**: DSP development was guided by Michigan Public Service Commission (MPSC or Commission) directives, with the Service Quality and Reliability Standards (SQRS)[2] and Performance-Based Ratemaking (PBR)[3] mechanism serving as central performance frameworks for planning and investment decisions, including targeted reductions in outage frequency and restoration duration.
- **Incorporation of Audit Recommendations:** The DSP reflects DTE's response to feedback from the Commission-ordered distribution audit (Audit Report), with audit findings and recommendations integrated throughout the plan to inform planning approaches, investment prioritization, and transparency.[4]
- **Demonstrated Results from Prior Reliability Investments:** The DSP is informed by recent reliability gains, reinforcing that targeted investments deliver measurable results. Over the past two years, the Company reduced outage duration by 70% from 2023 to 2024 and by an additional 60% in 2025, marking DTE's strongest performance in nearly two decades. Pending final benchmarking results, DTE expects its 2025 performance to rank in the first quartile for the first time since the Company began tracking in 2004.

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[2] See R 460.722 in Service Quality and Reliability Standards, available at https://ars.apps.lara.state.mi.us/AdminCode/DownloadAdminCodeFile?FileName=R%20460.701%20to%20R%20460.752.pdf, accessed March 12, 2026.

[3] Order U-21909 dated December 18, 2025, available at https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/068cs00001XbWwnAAF, accessed March 17, 2026.

[4] Order in Case No. U-21305 dated June 12, 2025, available at https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/068cs00000u4p0XAAQ, accessed February 27, 2026.

- **Expanded Benefit-Cost Analyses:** The DSP includes a refined and comprehensive benefit-cost analysis (BCA) framework that now incorporates sophisticated interdependencies among incremental investments and has been expanded to apply to nearly 80% of the five-year strategic capital portfolio, as described in Section 5.2.3 (Benefit-Cost Analyses Approach) and Appendix 8.14 (Benefit-Cost Analysis Report).
- **Enhanced Alternatives Analyses:** The DSP provides greater transparency into alternatives considered for defined projects, including the planning protocols used to prioritize 4.8 kV Conversions, as detailed in Section 5.2.3 (Benefit-Cost Analyses Approach), Section 6.3.1 (4.8 kV and 8.3 kV Conversions), and Appendix 8.9 (Alternatives Analyses Project List).
- **Updated State of the System:** The DSP presents a comprehensive, updated view of the current grid conditions, performance, and operations across key asset classes, along with the tools and programs that support daily operations, DER integration, storm response, and more, as detailed in Chapter 4 (State of the System and Additional DSP Requirements). A summary of key system facts and figures is shown in the table below:

DTE Facts and Figures	
Active Metered Customers	~2.3 million
Population Served	~5 million
Square Miles of Service Territory	~7,600
Number of Substations	822
Number of Circuits	3,932[5]
Five-Year Historic System Peak (Jul-24-2025)	11,258 MW
Overhead Circuit Miles	31,143
Underground Circuit Miles	14,855
Number of Poles	~1.2 million[6]

Much of DTE's subtransmission and distribution infrastructure is aging and increasingly constrained, with legacy designs, limited capacity, and asset deterioration elevating both reliability and safety risks — particularly across the 4.8 kV, 8.3 kV, and 24 kV systems. As assets age and severe weather impacts intensify, continued reliance on reactive maintenance is neither sustainable nor cost-effective. Capacity limitations, reduced load transfer capability, and outdated

[5] The number shown is inclusive of distribution circuits (3,296) and subtransmission lines (636).
[6] Including poles owned by third parties for joint use (e.g., AT&T, Comcast).

configurations constrain operational flexibility even under normal operating conditions. Proactive grid investments are essential to sustain reliability, improve resilience, and ensure the system can continue to safely and affordably meet evolving customer needs.

Partnering with Stakeholders and Communities

DTE's electric grid planning is informed not only by engineering and analytics, but also by sustained engagement with customers, communities, and stakeholders across its service area. Input from those who rely on the electric system every day helps align investment decisions with customer priorities to deliver meaningful local value. As described in Chapter 3 (Third-Party and Community Outreach), DTE maintains year-round engagement through customer communications, community outreach, local government coordination, and technical stakeholder forums.

Equity is a central consideration in this engagement approach. The Company places particular emphasis on outreach in communities that experience persistent reliability challenges or higher energy burdens, working with community leaders and advocacy organizations to ensure planning decisions reflect local needs and perspectives. These conversations help inform where investments can deliver the greatest reliability and resiliency benefits.

In advance of this DSP filing, DTE expanded its outreach to increase transparency around the planning process. The Company hosted 18 in-person, hybrid, and virtual events and conducted a comprehensive customer survey focused on the DSP and potential grid improvements. Feedback from these efforts both informed refinements to the plan and validated investment priorities. Across engagement channels, customers consistently emphasized the importance of improving reliability while balancing affordability — priorities that are embedded throughout the 2026 DSP and reinforced through disciplined BCAs.

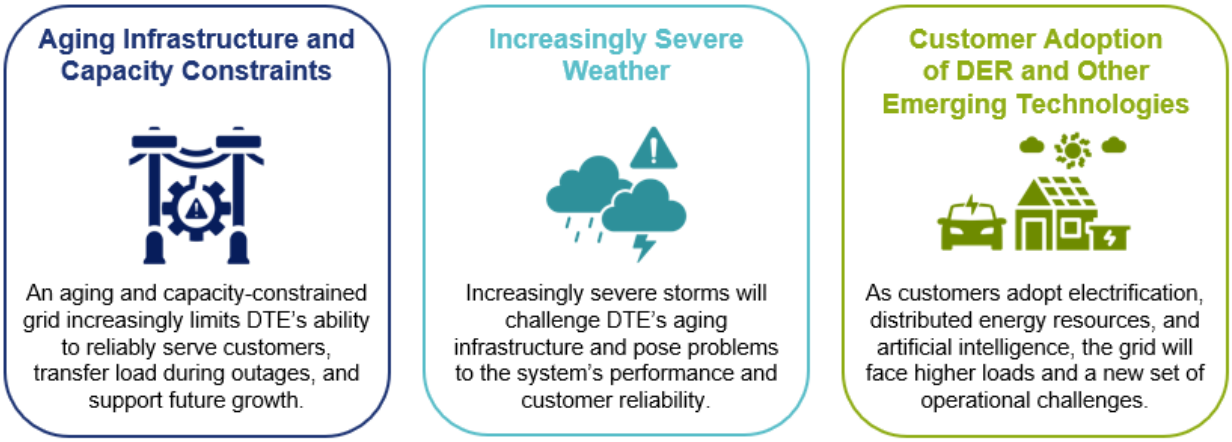
Responding to Drivers of Investment

DTE operates a large electric grid that includes significant portions of aging infrastructure dating back nearly a century, particularly in Detroit and nearby communities. As these assets age, they become more prone to failure, less tolerant of extreme conditions, and more costly to maintain through reactive repairs. Additionally, existing capacity constraints limit the Company's ability to reroute power during outages and support future growth. Deferring investment has real and impactful consequences, including increased outage risk, potential safety hazards, and longer restoration times when severe weather occurs.

These risks are amplified by external forces that are accelerating. Severe weather events, including high winds and ice storms, are becoming more frequent and intense across DTE's service area. At the same time, customer interest in electric vehicles (EVs), distributed generation (DG), advanced thermostats, heat pumps, and other forms of digital load are evolving, reshaping both the magnitude and the timing of electricity demand. Even when overall adoption levels appear modest, localized clusters of new load or generation can stress existing infrastructure that was never designed for bidirectional power flows or concentrated peaks.

These three drivers of investment — aging infrastructure and capacity constraints, increasingly severe weather, and customer adoption of DER and other emerging technologies, as discussed in Section 2.3 (Drivers of Investment) — are fundamentally shifting the demands placed on the electric grid and how DTE plans and operates the system:

Drivers of Investment for DTE's Electric Grid



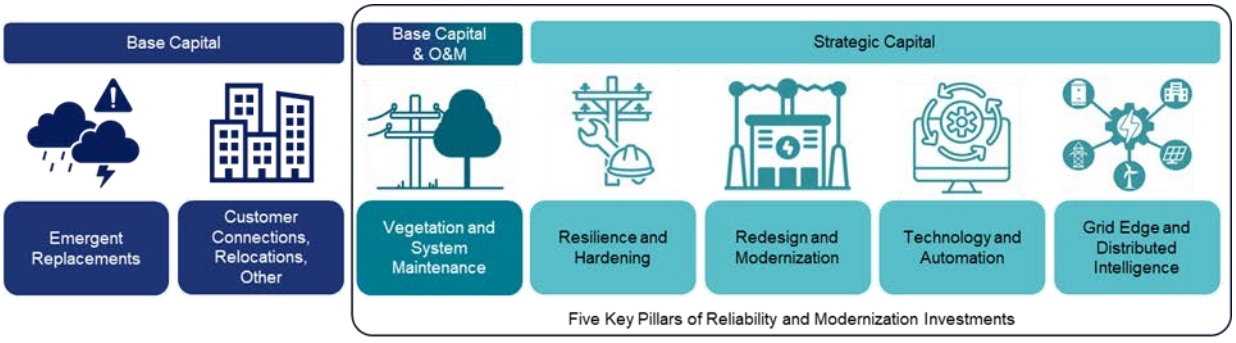
Together, these trends mean that maintaining the status quo is no longer sufficient. Continuing to rely primarily on reactive maintenance would increase long-term costs without addressing growing safety, reliability, and resiliency risks. The DSP, therefore, represents a continued evolution toward proactive, risk-informed investment — one that addresses known vulnerabilities while positioning the Company's grid to support Michigan's evolving energy economy.

Translating the Drivers of Investment into a Disciplined Strategy

Addressing these electric grid needs requires a cohesive strategic framework that aligns near-term investment decisions with long-term performance outcomes to deliver demonstrable value to the customers and communities DTE serves.

In developing its strategy, the Company identified the need to maintain and harden existing infrastructure to preserve recent reliability gains and reduce exposure to avoidable failures, while also making targeted investments that improve performance and prepare for the grid of the future. DTE prioritizes investments that maximize customer benefits and mitigate risk, while carefully managing the pace of investment to consider customer rate impacts. The DSP organizes these investments around five complementary pillars that build on the strong foundation established in prior DSPs, which emphasized Tree Trimming, Resilience and Hardening, Redesign and Modernization, and Technology and Automation. In this filing, the first pillar has been broadened from Tree Trimming to Vegetation and System Maintenance, elevating the role of disciplined, on-cycle system maintenance as a core driver of reliability. In addition, this DSP introduces a fifth pillar — Grid Edge and Distributed Intelligence — focused on grid edge capabilities, reflecting the growing need to support customers and their increasingly interconnected technologies through enhanced visibility, coordination, and control at the customer interface. Collectively, the five investment pillars work together to form a cohesive and balanced strategy to improve reliability while continuing to modernize the grid for the future.

Reliability and Modernization Investment Framework



- **Vegetation and System Maintenance:** Reinforces the fundamentals of grid reliability by maintaining asset health and reducing outage exposure through disciplined on-cycle inspections, routine maintenance, and timely corrective remediation of known issues.
- **Resilience and Hardening:** Hardens the electric grid where it is most effective by addressing known structural vulnerabilities and strengthening targeted, deteriorating infrastructure to better withstand severe weather and other external stresses.
- **Redesign and Modernization:** Rebuilds portions of the grid in areas with multiple, overlapping system needs by resolving persistent constraints and legacy configurations with more efficient, long-term solutions once continued maintenance of aging assets is no longer cost-effective.

- **Technology and Automation:** Further advances DTE's system to address growing operational complexity by adding the control layer that transforms a stronger grid into a smarter one, enabling faults to be detected, isolated, and restored in minutes rather than hours.
- **Grid Edge and Distributed Intelligence:** Invests in customer-centric technology by extending visibility and control to the edge of the grid, establishing a new strategic focus area in this DSP that enables the reliable integration of customer-side technologies while improving both system operations and the overall customer experience.

The investment programs within the five integrated pillars are discussed in detail in Chapter 6 (Distribution System Plan Investment Pillars). They are designed to complement each other and support effective work-scope management, coordinate the timing and pacing for capital deployment to improve efficiency, and deliver near-term reliability improvements while leveraging specialized expertise to execute more complex, long-term grid infrastructure investments.

Planning and Prioritizing Cost-Effective Investments

The breadth of grid needs across DTE's service area far exceeds what can be addressed within a single planning cycle. Accordingly, disciplined prioritization is foundational to the Company's investment plan approach. DTE applies a data-driven planning framework designed to direct investment toward programs and projects that are expected to deliver the greatest customer value relative to cost.

This process begins with a comprehensive assessment of system needs informed by asset condition data, load forecasts, and performance metrics. For each identified need, the Company evaluates a range of potential solutions including traditional infrastructure upgrades and, where appropriate, non-wire alternatives (NWAs). Subject matter experts (SMEs) assess technical feasibility and expected operational performance, while execution teams evaluate constructability, resource availability, and schedule risk. Only solutions that demonstrate both technical viability and implementation readiness advance for further consideration.

For select investments, particularly those driven primarily by reliability improvements, the Company conducts BCAs to assess cost-effectiveness. These evaluations consider avoided customer outage economic costs and reduced utility restoration costs, and the results are used in two ways. First, they inform the scale of investment over the next five years to ensure DTE is appropriately balancing the extensive breadth of grid needs. Second, they enhance portfolio level decision-making through the Company's Global Prioritization Model (GPM). The GPM serves as

DTE's overarching framework for grid investment prioritization, integrating BCA insights with additional dimensions that are more difficult to quantify, such as safety risk reduction, capacity relief, operational efficiency, and environmental justice (EJ) considerations. This layered approach directs capital toward projects that are not only technically sound and economically justified, but are also aligned with broader customer priorities and regulatory expectations.

Importantly, this framework reflects refinements made in response to prior Commission guidance and the Audit Report. As demonstrated in this DSP, the Company has strengthened transparency, expanded the use of quantitative justification, and more fully embedded risk-based decision making into its planning processes. Forecasted operations and maintenance (O&M) expenditures are expected to range from approximately $478 million in 2026 to $600 million in 2030, while capital investments — including both base and strategic investments — are projected to range from approximately $1.8 billion in 2026 to $2.5 billion in 2030. Taken together, the investment plan through 2030 includes approximately $4.8 billion in base capital investments, $6.0 billion in strategic capital investments, and $2.7 billion in O&M expenditures. These necessary and prudent expenditures and investments are focused on managing system risk, improving reliability and resiliency, and delivering measurable value for customers over the planning horizon.

Delivering Lasting Value to Customers and Communities

While the DSP is grounded in engineering rigor and analytical discipline, its ultimate purpose is to deliver measurable improvements that matter to customers. This DSP is designed to advance clear, customer-focused objectives by supporting the delivery of power that is safe, reliable, resilient, and clean, while emphasizing customer accessibility, community focus, and a balanced approach to affordability relative to the pace of required investments. These objectives are shared with DTE's Integrated Resource Plan (IRP), ensuring alignment across the Company's broader energy system investments.

The DSP investments are focused on meeting the SQRS set forth by the Commission, achieving the targets defined by the approved PBR mechanism, and implementing the recommendations from the Audit Report. Through these investments, the Company is upgrading aging infrastructure and deploying technology to create a smarter, more resilient grid that delivers the energy customers demand and deserve, while making measurable progress toward its aspiration of reducing power outages by 30% and cutting outage time in half by 2029.

The DSP is anchored in the recognition that sustained performance improvement must be demonstrated, not assumed, with customer value central to both planning and execution. While

recent reliability gains provide important momentum, DTE acknowledges that meaningful work remains. Accordingly, this filing presents a disciplined, executable strategy that balances near-term reliability and affordability needs with longer-term resilience, modernization, and support for a cleaner energy future. In doing so, the DSP responds directly to the key drivers of electric grid investment, including aging infrastructure and capacity constraints, increasingly severe weather, and evolving customer adoption trends that are contributing to greater system complexity — recognizing that continued focus and sustained investments are required to meet rising customer expectations.

By aligning engineering excellence with customer-focused outcomes and transparent prioritization, DTE is positioned to deliver on its commitments and provide lasting value for the customers and communities it serves as energy needs continue to evolve. Ultimately, this DSP reinforces the Company's core purpose: serving the people and communities who depend on DTE's grid to power their lives.

2. Introduction and Strategic Foundation

Chapter 2 provides the strategic foundation for the 2026 DSP. The chapter begins with historical context and defines the purpose of the DSP as the Company's roadmap for strengthening and transforming the subtransmission and distribution systems. The chapter then summarizes the MPSC directives underpinning DSP development and describes the key drivers of investment shaping both near- and long-term system needs. The chapter concludes by introducing DTE's integrated five-pillar investment framework, which organizes investments to deliver measurable improvements while maintaining an executable, disciplined pace of work. Collectively, these five reliability and modernization investment pillars establish a clear path toward a smarter, stronger, and more resilient electric grid that provides customers with the reliable power they expect and deserve.

2.1 Distribution System Plan Purpose

To meet evolving customer needs and to continue improving safety and electric reliability, DTE must strengthen and modernize its grid. The 2026 DSP presents the Company's near-term[7] investment roadmap for its subtransmission and distribution systems — collectively referred to as the electric grid — through 2030, while also providing a longer-term outlook to frame future system needs and planning considerations.

The DSP is intended to increase transparency into how DTE plans for, prioritizes, and executes electric grid investments. The plan describes the current condition of the existing system, identifies the MPSC directives underpinning DSP development and the evolving drivers of investment, and explains the rationale for proposed investments. By providing this context, the DSP enables customers, stakeholders, and the Commission to better understand how planned investments align with customer expectations, policy direction, and the needs of the electric grid to reliably meet those objectives.

Formerly known as the Distribution Grid Plan, or DGP, this filing represents the Company's fourth DSP, following prior submissions in 2018, 2021, and 2023. The scope and maturity of the DSP have evolved over time in response to MPSC directives in Case No. U-20147,[8] incorporating greater transparency, more robust analytics, and clearer linkages between identified grid needs and proposed investments. The DSP advances clear, customer-focused objectives by supporting the delivery of power that is safe, reliable, resilient, and clean, while emphasizing customer accessibility, community focus, and a balanced approach to affordability relative to the pace of required investments.[9]

Going forward, the DSP will be updated approximately every three years, or as directed by the Commission, and will continue to serve as the foundational document upon which future rate case proposals will be based. Through this DSP, DTE reaffirms its commitment to building a safe, reliable, and resilient grid that meets Michigan's energy needs today and into the future, while balancing affordability for customers.

[7] For purposes of this filing, "near term" refers to the 2026-2030 planning horizon addressed in this DSP.

[8] The MPSC opened Case No. U-20147 on April 12, 2018 to establish a structured framework under which regulated electric utilities such as DTE filed DSPs. Its purpose is to ensure transparency, stakeholder engagement, and alignment with grid planning objectives. Beginning in 2026, U-20147 will only be used for matters relative to overall planning efforts. As such, this DSP is filed in the new, individual docket U-22104.

[9] These objectives are shared with DTE's Integrated Resource Plan (IRP) for company-wide alignment.

2.2 MPSC Directives Underpinning DSP Development

DTE's DSP development is guided by Commission directives and recent findings from the Audit Report, which together shape the Company's approach to reliability improvements, execution discipline, and investment prioritization. The SQRS and PBR mechanism serve as central performance frameworks informing the Company's planning and investment decisions. Together, these strategic priorities reinforce the need for sustained, disciplined investment in electric grid infrastructure, while also emphasizing risk-informed planning, transparent decision-making, and measurable improvements in safety, reliability, service quality, and customer outcomes. The Audit Report provides a critical roadmap for the maintenance activities and investment priorities DTE must pursue to support long-term electric grid reliability.

2.2.1 Service Quality and Reliability Standards

The SQRS are a key guidepost for ensuring that the investments proposed in this DSP align with Commission expectations for improved customer outcomes. The SQRS framework establishes performance expectations across multiple dimensions of service quality and reliability, including outage frequency, restoration duration, and responsiveness to customer needs. As a result, meeting SQRS expectations requires a coordinated portfolio of investments across multiple programs and asset classes, rather than reliance on any single solution.

In developing the DSP, DTE evaluated how individual investment programs contribute to improving SQRS performance, focusing on those drivers that have the greatest impact on both outage frequency and restoration time. These include addressing high-risk and aging infrastructure, improving system segmentation and automation to limit the scope of outages, and strengthening inspection, maintenance, and Vegetation Management practices. The DSP therefore prioritizes investments that support durable, system-level improvements aligned with SQRS outcomes, rather than short-term or isolated fixes.

Importantly, SQRS also reinforces the need for an investment approach designed to stabilize the system, reduce backlogs, and create a foundation for sustained improvements in reliability performance, recognizing that SQRS targets cannot be achieved without disciplined delivery of both preventive and corrective work across the system.

2.2.2 Performance-Based Ratemaking Mechanism

The PBR mechanism further reinforces the importance of measurable improvements and performance accountability by directly linking aspects of the Company's financial outcomes to

service quality and reliability performance. Similar to SQRS, PBR metrics inform how the Company prioritizes investments that deliver observable, customer-facing benefits, particularly those that reduce the frequency and duration of outages during both day-to-day operations and major weather events. PBR metrics have strengthened the Company's focus on investments that address known failure modes, improve device performance and system visibility, and enhance operational flexibility during restoration.

The DSP reflects this performance-driven approach by aligning investment proposals with the reliability outcomes measured under the PBR framework, supporting continuous improvement and reinforcing execution discipline. Additional details on PBR metrics and the associated incentives and disincentives are provided in Section 7.2.2 (Performance Metrics).

2.2.3 Audit Report Recommendations

The Audit Report materially influenced DTE's near-term safety, maintenance, and prevention strategy. Recommendations related to hazard mitigation and wire-down response have been incorporated with increased emphasis on prevention in addition to reactive response. Recognizing the time required to rebuild portions of the legacy 4.8 kV system that contribute disproportionately to safety and reliability risk, DTE has advanced mitigation measures to reduce exposure while longer-term solutions are implemented. These actions are intended to lower near-term risk, improve system resilience, and support more consistent execution as broader rebuild efforts progress over time.

More specifically, six key Audit Report recommendations directly informed the Company's near-term prioritization of the following areas:

- Strengthened Weather Event Response and Restoration (Section 4.4.2)
- On-cycle Vegetation Management (Section 6.1.1)
- Reduced backlogs for Preventative Maintenance and Inspections (Section 6.1.2) and Corrective Maintenance (Section 6.1.3)
- Progression toward five-year pole-top and 10-year pole inspection cycles for Pole and Pole-Top Maintenance and Modernization (Section 6.2.1)
- Targeted selection of higher-risk 4.8 kV and 8.3 kV Conversions (Section 6.3.1)
- A refined approach to Distribution Automation (Section 6.4.1)

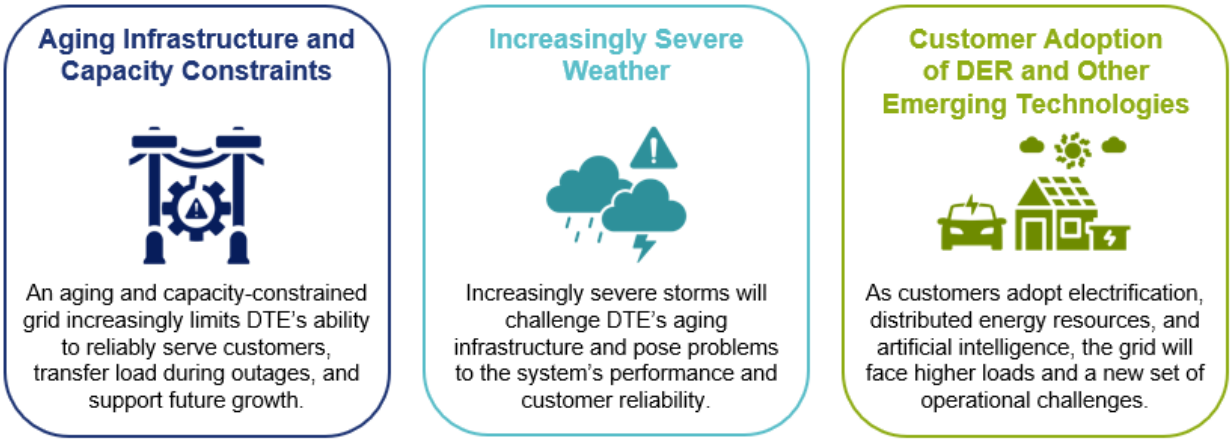
At the portfolio level, the Audit Report also sharpened DTE's approach to investment pacing and governance by highlighting the risks associated with deferring necessary investment and the

importance of sustaining existing assets through on-cycle preventive work and advancing toward condition-based asset management practices.

2.3 Drivers of Investment

Customer needs and external conditions are evolving, driving a shift in both the demands placed on the electric grid and the way DTE plans and operates the system. Underlying system conditions, such as aged assets, legacy 4.8 kV configurations, and capacity constraints, create a baseline of risk that is further exacerbated by more frequent and severe weather events and customer trends. As such, the Company has identified three drivers of electric grid investment: aging infrastructure and capacity constraints, increasingly severe weather, and customer adoption of DER and other emerging technologies.[10] The three drivers of investment are outlined in Exhibit 2.1 and are further detailed below. Additional detail on how the drivers of investment influence the Company's long-term strategy is provided in Section 5.3.4 (Long-Term Investment Outlook).

Exhibit 2.1 – Drivers of Investment for DTE's Electric Grid



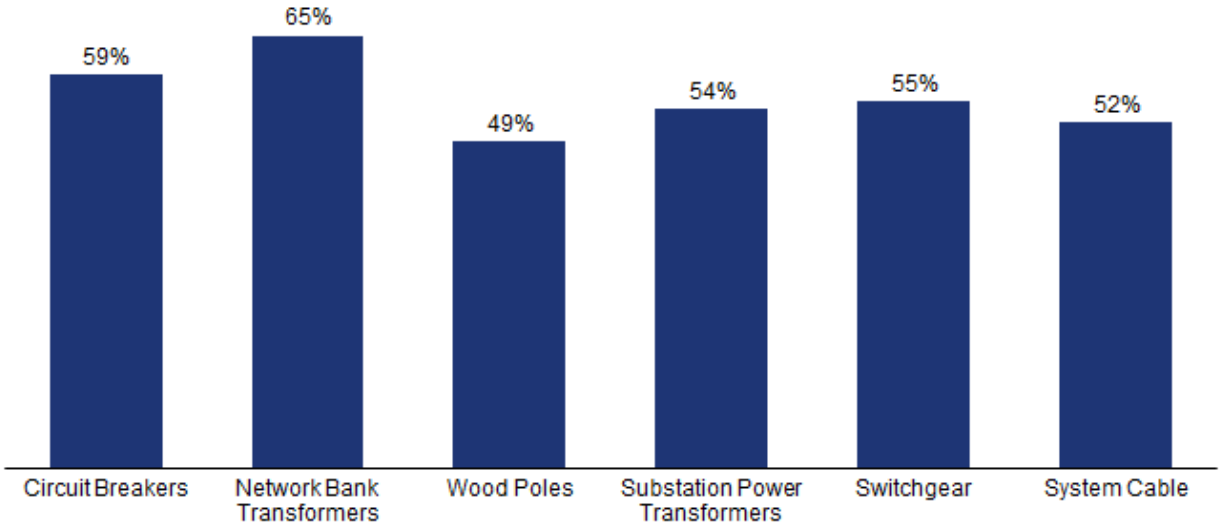
2.3.1 Aging Infrastructure and Capacity Constraints

Aging infrastructure is increasingly compromising the safety and reliability of DTE's electric grid. Many of the Company's 4.8 kV distribution circuits and 24 kV subtransmission lines were installed between 1920 and 1965, and much of the associated equipment is now beyond its expected useful life. Even portions of the more modern 13.2 kV distribution and 40 kV subtransmission systems include circuits and substations installed in the late 1960s that are approximately 60

[10] The 2023 DSP identified increased demand from electrification, increasing catastrophic storms, and growth in distributed generation and storage as key drivers of change. For the 2026 DSP, the first and third drivers have been combined into a single category (customer adoption of DER and other emerging technologies), and one additional driver has been added: aging infrastructure and capacity constraints.

years old. Electric grid assets that have reached, or are approaching, an advanced age require evaluation for near-term replacement. Although age is not the sole determinant of performance, older equipment generally has a higher likelihood of failure and is more prone to causing service interruptions and emergency repairs that divert resources from planned maintenance and modernization activities. As shown in Exhibit 2.2, the majority of assets across six major asset classes are at or beyond their useful life, with additional detail provided in Section 4.2 (General Asset Health and Condition).[11]

Exhibit 2.2 – Percentage of Assets at or Beyond Useful Life (as of Jan. 30, 2026)

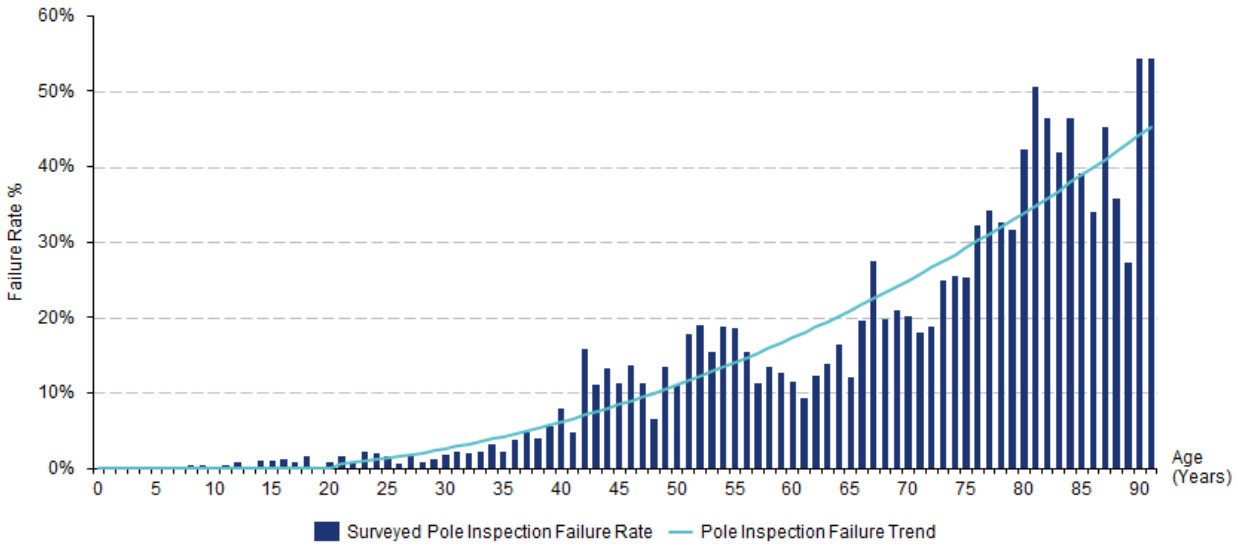


A clear example of increased risk from aging infrastructure is found in the Company's pole fleet, which forms the structural foundation of its overhead infrastructure. DTE's wood poles average 48 years in age, and nearly half have exceeded their 50-year useful life. Recent analyses indicate that pole inspection failure rates increase sharply with age — from just over 10% at 50 years to about 30% at 75 years, as shown in Exhibit 2.3.[12] As a greater share of the pole fleet enters higher-failure age bands, systemwide reliability risk increases without sustained investment in replacement and reinforcement.

[11] Useful life is a standard industry term that does not represent the maximum physical life of an asset, but rather the point at which an asset begins to experience increasing failure rates and declining performance, such that replacement becomes more prudent than continued repair and maintenance.

[12] Poles were inspected per DTE's PTMM program, detailed in Section 6.2.1 (Pole and Pole-Top Maintenance and Modernization).

Exhibit 2.3 – Inspection Failure Rate of Poles by Age[13]



In addition to age-related condition concerns, capacity constraints further limit the performance and flexibility of portions of the electric grid, particularly within the legacy 4.8 kV distribution system. Some of this infrastructure, built nearly 100 years ago, includes ungrounded delta designs, rear-lot construction, interconnected secondary configurations, and inherently limited capacity, all of which create ongoing operational challenges. During single line-to-ground events, fault currents can be too low to trigger protective devices, complicating detection, isolation, and de-energization of downed wires, thereby increasing safety and operational risks. The 4.8 kV system has significantly lower thermal capacity than the 13.2 kV system and contains most of the distribution system's small wire,[14] which heightens the risk of thermal and voltage issues, reduces efficiency, and increases breakage rates during windy and icy conditions. Similar age-related degradation and capacity limitations are also present on portions of the legacy 24 kV subtransmission system that serves these areas.

Capacity constraints across aging circuits and substations reduce DTE's ability to reroute power during outages, as neighboring circuits may lack sufficient available capacity to accept transferred load. As more infrastructure operates closer to its thermal and voltage limits, both planned work and outage restoration become more constrained. These limitations also restrict the Company's ability to add new customers and accommodate future load growth, driving the need for targeted investments to address both aging infrastructure and capacity constraints through the DSP.

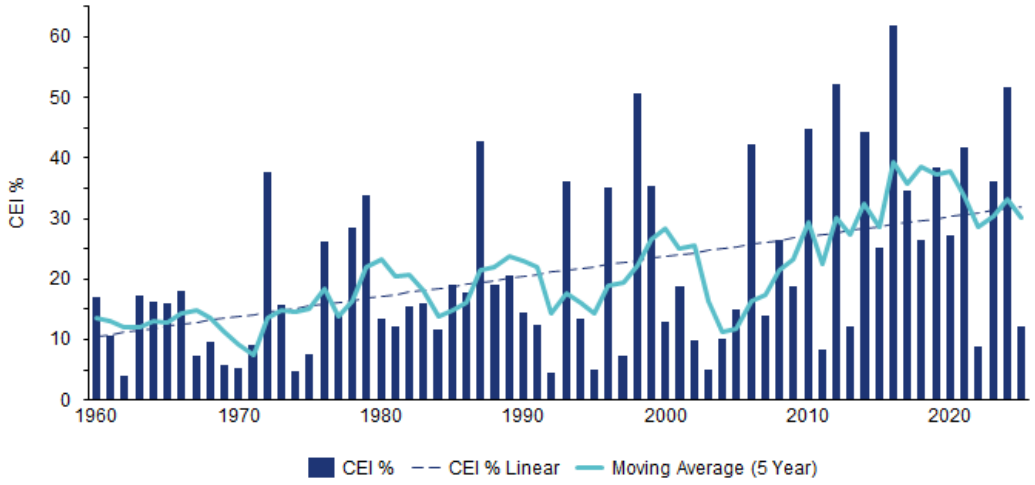
[13] Based on the inspection of approximately 30,000 poles in 2025.

[14] Small wire is defined as conductor sizes #8, #6, and #4 American Wire Gauge (AWG). It is no longer used in new installations due to its weaker mechanical strength and higher impedance.

2.3.2 Increasingly Severe Weather

The second factor shaping the grid's evolution and driving investment needs is the increasing frequency and severity of extreme weather events across the upper Midwest. As shown in Exhibit 2.4, the Climate Extremes Index (CEI), which is a composite measure of extreme precipitation, temperature, and drought conditions, has been trending upward over time, indicating growing climate variability across the region. The Great Lakes Integrated Sciences & Assessments has also reported increasingly severe weather for the Great Lakes region specifically, with an expectation that the trend is likely to continue as the effects of climate change become more pronounced.[15]

Exhibit 2.4 – Upper Midwest Climate Extremes Index[16]



The 2024 Michigan Hazard Mitigation Plan (MHMP) identifies severe wind and ice storms as major hazards across regions that include DTE's service area. Statewide, Michigan experiences an average of 381 high-wind events and 15 freezing-rain or sleet events annually, with the MHMP indicating these events are expected to intensify over time.[17] Within the Company's service area, this increasing wind risk is further evidenced by data from Detroit Metropolitan Airport, as shown in Exhibit 2.5. Comparing the five-year periods from 1995-2000 and 2020-2025, the annual

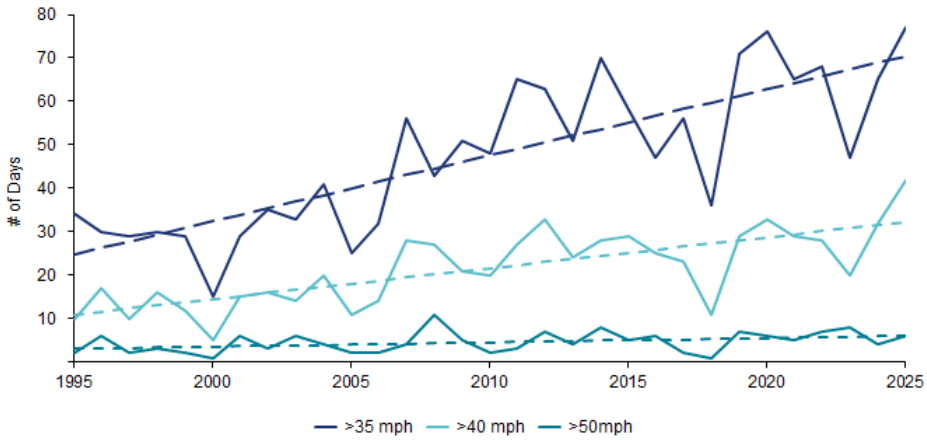
[15] Climate Change in Great Lakes Region References, available at https://glisa.umich.edu/climate-change-in-the-great-lakes-region-references/, accessed February 24, 2026.

[16] U.S. Climate Extremes Index (CEI), available at https://www.ncei.noaa.gov/access/monitoring/cei/graph/en/01-12/cei, accessed February 24, 2026.

[17] 2024 Michigan Hazard Mitigation Plan, available at https://www.michigan.gov/-/media/Project/Websites/msp/EMHSD/Publications/MHMP.pdf?rev=c70dec864e0146efad1d42ebc90a572e, accessed February 24, 2026.

average number of days with wind gusts exceeding 35 mph, 40 mph, and 50 mph roughly doubled, indicating a substantial increase in damaging wind conditions over the past 30 years.

Exhibit 2.5 – Detroit Metropolitan Airport Wind Gust Data[18]



There are significant uncertainties in forecasting the number of extreme weather events in annual planning cycles. Despite this uncertainty, available regional trends indicate DTE's service area will continue to experience increasingly severe weather patterns in the future. Weather impacts beyond wind and ice also pose growing risks to the electric grid. For example, prolonged heat waves place additional stress on the electric grid by overloading equipment and reducing the ability to transfer customer load during outages. Similarly, heavy precipitation can saturate soil, increasing the likelihood of trees uprooting and falling onto overhead lines during high-wind events. As a result, DTE's electric grid — with its aging infrastructure, legacy configurations, and limited capacity — is becoming increasingly vulnerable to this extreme weather.

2.3.3 Customer Adoption of DER and Other Emerging Technologies

The third factor driving investment need is the rapid adoption of DERs and other emerging technologies that are transforming how energy is generated, consumed, and managed across the distribution system. These trends include the growing electrification across transportation, buildings, and industrial processes. They also reflect the increasing adoption of DERs, such as rooftop solar and behind-the-meter (BTM) battery storage,[19] along with emerging capabilities to coordinate these resources through virtual power plants (VPPs). DTE is actively planning VPP pilots and evaluating the potential to aggregate and orchestrate DER load in ways that could offset

[18] Based on daily summary observations from Iowa Environmental Mesonet, available at https://mesonet.agron.iastate.edu/request/daily.phtml?network=MI_ASOS, accessed February 24, 2026.

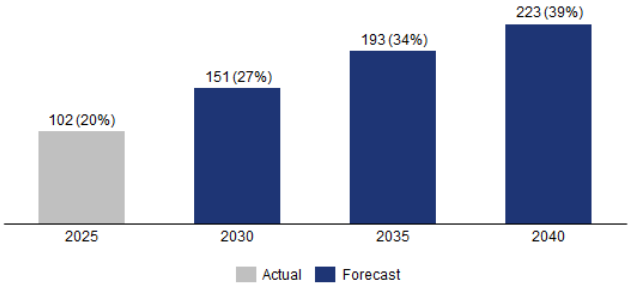
[19] DTE recognizes that there are many definitions of DER and takes an inclusive view of the different categories, such as the MPSC and IEEE definitions that include generation, storage, and demand-side management.

traditional capacity investments, treating DERs as integrated resources (rather than discrete grid assets) and incorporating them into the IRP process. From a grid planning perspective, electrification and DERs support the Company's goals of enabling a cleaner and more accessible grid and require strategic integration to mitigate the associated challenges, including higher and more variable loads, bidirectional power flows, DER aggregation and market participation, and localized clusters of adoption that can stress voltage and thermal limits.

While broader electrification remains sensitive to market factors such as pricing, availability, and public policy, DTE continues to prepare for greater DER penetration, since even localized adoption clusters can impact grid planning. For example, a cluster of EV adoption in a well-established neighborhood with older infrastructure will stress grid-edge assets like service transformers and secondary wire systems, creating localized overloads. These upgrades can include replacing portions of circuit feeders, upsizing small transformers, or adding transformers to reduce customer load per transformer.

As electrification increases, localized challenges will gradually work upstream to trigger investments at the circuit level, the substation level, or both. This is especially true for infrastructure in areas required to support electric fleets, given their substantial and concentrated electric loads. Substations with limited available capacity will reach or exceed their firm rating,[20] increasing the risk of outages during equipment failures and reducing DTE's ability to transfer load between locations for planned or emergent work. DTE has developed three scenarios to plan for a range of outcomes as described in Section 5.1 (Load Forecasts and Scenario Planning): low electrification, reference case, and high electrification. Under the high electrification scenario, the number of over-firm substations could increase substantially, as shown in Exhibit 2.6, if appropriate capacity upgrades are not conducted in parallel.

Exhibit 2.6 – Estimated Over-Firm Substations, High Electrification Scenario



[20] The firm rating of a substation is the maximum load it can reliably carry under a single contingency condition, such as one piece of equipment out of service due to failure or maintenance. Additional information on substation firm ratings is provided in Section 6.3.2 (System Loading).

In addition to grid changes that increase electric load, some DTE customers are also adopting DER technologies that reduce their electricity demand and, in some cases, export power back to the grid. Since 2007, through legacy net metering programs and the more recent Distributed Generation program,[21] the Company has supported DER integration. In November 2023, Michigan enacted Public Act 235, which raised the DG cap from 6% to 10%,[22] increased installation capacity up to 110% of annual electricity usage and removed the separate generation meter requirement for larger installations, thereby reducing perceived barriers to customer-owned DER adoption.

While rooftop solar has historically been the most common form of customer-owned DER, DTE and the Commission recognize that many technologies can also function as DERs. In its July 10, 2025 Order in Case No. U-20147, the MPSC designated flexible electrification devices as "demand DERs," defining them as a subset of demand-side management resources that includes EV chargers, smart thermostats, heat pumps, electric water heaters, and flexible commercial and industrial loads. Customers already use several of these devices to participate in demand response (DR) programs, demonstrating their role not only as new sources of load, but also as controllable assets that can support grid operations. In addition, automakers are adding power export capabilities to their EVs.[23] As these capabilities proliferate, EVs will increasingly function not only as significant new loads on the grid but also as DER interconnections, materially transforming the distribution planning landscape.

Advances in technology are reducing DER costs and shortening payback periods, which are expected to accelerate customer adoption over the long term. DER growth will also be supported by ongoing implementation of Federal Energy Regulatory Commission (FERC) Orders 841 and

[21] Distributed Generation Program, available at https://aem-qan1.newlook.dteenergy.com/us/en/residential/service-request/gmop/rooftop-solar-and-private-generation.html, accessed February 24, 2026.

[22] Prior to the 2023 Energy Legislation, DTE voluntarily increased the DG Cap in 2023 from 1% to 6% of the Company's average in-state peak load for the preceding five calendar years.

[23] UL 1741 Supplement C is currently in development. It establishes a certification pathway for bidirectional EV supply equipment (EVSE) and supports vehicle-to-grid operation by allowing the EVSE to act as the DER interface and communicate site-specific interconnection settings to a vehicle's onboard inverter.

2222 by the Midcontinent Independent System Operator (MISO). Once fully in place, these orders will allow residential, commercial, and industrial customers to participate directly in wholesale energy markets. Compliance with MISO's requirements for FERC Order 2222 is particularly significant because it fundamentally changes how DERs interact with the grid, requiring utilities to adapt operations, planning, and technology to maintain reliability and ensure coordination with customer-owned DERs.

In addition to the economic incentives driving customer adoption, DERs may provide ancillary benefits in specific circumstances — such as mitigating localized overload conditions or, in some cases, supporting power quality and voltage regulation — provided that appropriate system upgrades are implemented without shifting incremental costs to the broader customer base. DER adoption can also introduce localized challenges, such as thermal constraint violations and power quality issues. However, because DER adoption in Michigan remains in the earlier stages of the maturity cycle, the Company continues to refine its strategy for integrating additional DERs into future planning.

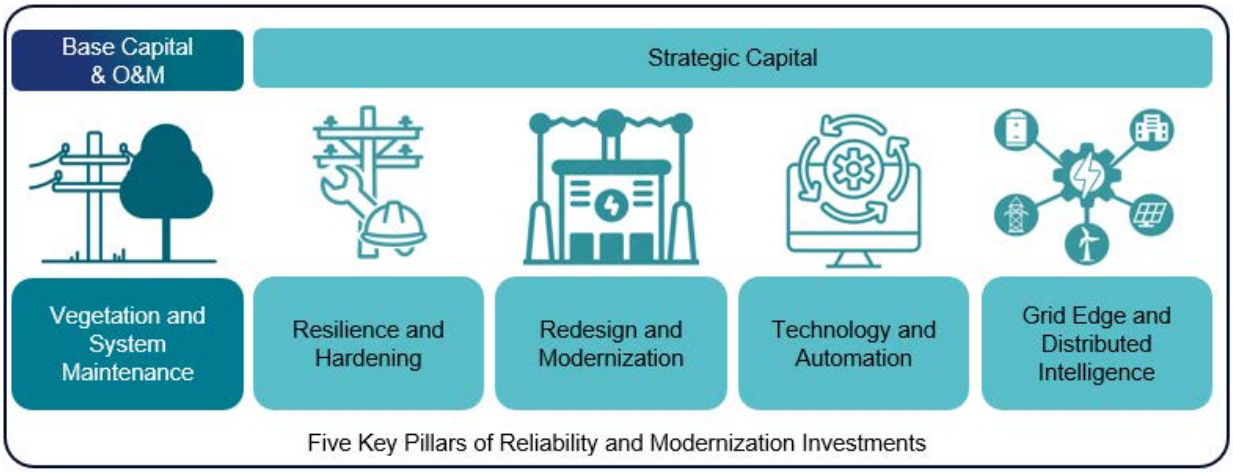
Beyond the increasing proliferation of EVs and DERs, the accelerating spread of Artificial Intelligence (AI) inference across everyday devices and distributed computing environments (e.g., phones, laptops, small servers, hospitals, retail operations, and municipal systems) could have implications for load growth. Unlike centralized training clusters, AI inference occurring on everyday devices and small compute nodes could potentially create incremental loads with variable demand distributed across neighborhoods, enterprises, commercial buildings, and industrial facilities.

2.4 Five Pillars of Reliability and Modernization Investments

Based on the MPSC directives and drivers of investment described above, DTE has organized its planned investments into five integrated pillars. These pillars are designed to complement one another by enabling effective work-scope management, coordinating the timing and pacing of capital deployment, and supporting efficient delivery of near-term reliability improvements while leveraging specialized expertise for more complex, longer-term grid infrastructure investments.

In response to the Audit Report's emphasis on sustaining existing assets, DTE has redefined one of its core reliability improvement pillars from the 2023 DSP, Tree Trimming, into a broader Vegetation and System Maintenance pillar. This deliberate shift reflects the Company's commitment to maintaining an on-cycle Vegetation Management program while strengthening preventative maintenance (PM), inspection, and corrective maintenance (CM) practices to achieve the greatest reliability impact in a cost-effective manner. Additionally, the 2026 DSP introduces a fifth pillar — Grid Edge and Distributed Intelligence — focused on expanding grid-edge capabilities to support customers and their increasingly interconnected technologies through enhanced system visibility, coordination, and control at the customer interface. Collectively, the five investment pillars work together to form a cohesive and balanced strategy to both improve reliability and modernize the grid for the future, as illustrated in Exhibit 2.7.

Exhibit 2.7 – Five Integrated Investment Pillars



While each pillar addresses a distinct set of needs, as further detailed in Chapter 6 (Distribution System Plan Investment Pillars), they are planned and executed as part of an integrated portfolio. Investments are guided by consistent prioritization frameworks and rigorous benefit-cost analyses to maximize customer benefits, reduce safety and reliability risk, and ensure prudent use of capital. At the same time, DTE carefully manages the pacing of investment to balance system needs with customer rate impacts.

Together, the five integrated investment pillars advance a single overarching purpose: delivering safe, reliable, and clean electricity to the customers and communities DTE serves, while balancing affordability with the pace of required investments.

3. Third-Party and Community Outreach

Chapter 3 describes how DTE engaged customers and communities during development of the DSP, as well as ongoing outreach efforts. The chapter begins with a summary of the structured outreach conducted in advance of the DSP filing, describing the types of meetings, events, and feedback mechanisms used to support transparency, enable participation, and ensure stakeholder perspectives were incorporated into the planning process. Across these channels, customers and stakeholders consistently emphasized the importance of balancing improved electric reliability with affordability. This feedback directly informed the DSP, including expanded use of BCA, refinements to investment justification frameworks, clearer articulation of prioritization methodologies, and a measured approach to emerging technologies.

The chapter then describes the Company's ongoing outreach efforts, highlighting the various teams, channels, and practices used to maintain regular engagement and communication. Together, these sections demonstrate how DTE organizes engagement activities and incorporates stakeholder input into both near-term planning decisions and longer-term grid investment strategies reflected in the DSP.

3.1 Summary of Pre-Filing Outreach

Meeting customer expectations is an essential part of DTE's investment planning. To support development of the DSP, the Company conducted targeted outreach across multiple channels to inform customers and community stakeholders about the planning process and gather feedback, including 18 in-person, hybrid, and virtual events and a customer survey. A summary of the outreach strategy is provided in Exhibit 3.1.

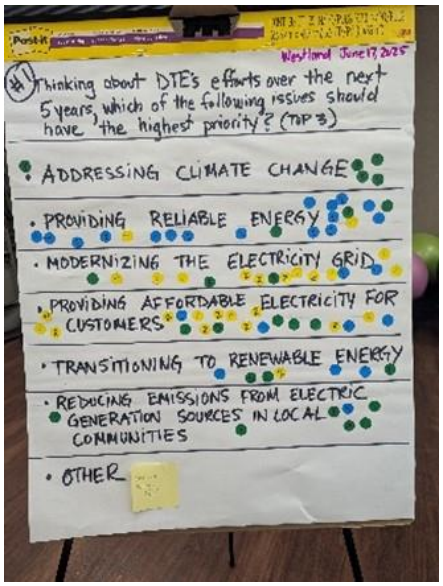
Exhibit 3.1 – Summary of DSP Pre-Filing Outreach Efforts[24]

Type of Outreach	Event Information			
Community Open Houses	*Type*	*Date*	*Location*	*Attendees*
Grassroots community events aimed at increasing awareness of DTE investments and programs, understanding customer experiences with their electric service, and creating opportunities for in-person dialogue and feedback	In Person	5/14/25	Farmington / Farmington Hills	123
	In Person	6/17/25	Westland	72
	In Person	8/14/25	Royal Oak / Oak Park / Madison Heights	145
	In Person	9/10/25	Dearborn / Dearborn Heights	48
	In Person	9/18/25	Ypsilanti	80
	In Person	10/9/25	Livonia / Redford	45
	In Person	11/17/25	Canton / Belleville / Van Buren Township	62
	In Person	4/2/26	Novi / Wixom	290
Powering Michigan Series	*Type*	*Date*	*Location*	*Attendees*
Recorded sessions to educate customers on the energy system, provide transparency into the DSP and IRP processes, and solicit feedback	Virtual	10/1/25	-	15
	Virtual	10/20/25	-	20
	Virtual	11/3/25	-	10
Community Conversations	*Type*	*Date*	*Location*	*Attendees*
Facilitated, in-depth conversations designed to understand customers' priorities around reliability, affordability, and clean energy, as well as any existing concerns. Conducted in collaboration with community-based organizations and a third-party consultant	In Person	11/12/25	Dearborn	12
	In Person	12/4/25	Monroe	18
	In Person	1/22/26	Detroit	12
	Virtual	2/17/26	-	2
Customer Survey	*Type*	*Dates*	*Location*	*Respondents*
Residential customer survey gathering perspectives on grid reliability, maintenance, and planned improvements, including future energy use expectations and investment priorities	Virtual	11/17/25 through 11/28/25	DTEs service area	400
Technical Conferences	*Type*	*Date*	*Location*	*Attendees*
Technical workshops to present preliminary approaches on key topics and gather feedback from interested stakeholders	Hybrid	11/6/25	Detroit	14
	Virtual	1/27/26	-	34
	Virtual	3/23/26	-	26

[24] Of the 11 in-person events, nine were held in EJ communities, defined as those at or above the 75th-percentile MiEJScreen score, including Dearborn (two events), Detroit, Oak Park/Madison Heights, Monroe, Redford, Westland, Wixom, and Ypsilanti.

3.1.1 Community Open Houses

Community open houses are a key component of the Company's ongoing customer engagement strategy as discussed in Section 3.2.2 (Community Outreach). Beginning in 2025, DTE leveraged community open houses to ask customers to rank their top three energy system priorities by dot-voting on easel paper. Based on votes from 222 participants,[25] affordability and electric reliability emerged as the top two priorities, respectively, underscoring the importance of balancing continued system improvements with the pace of investment. Beginning in November 2025, the team also began distributing informational materials to provide an overview of the DSP and to outline available channels for submitting feedback, including a DSP-specific email[26] monitored by the project team and a dedicated DSP website.[27]



Example dot-voting results

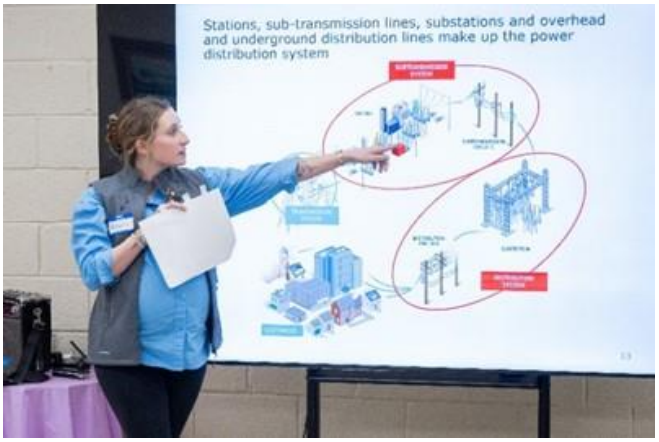
3.1.2 Powering Michigan Series

The virtual Powering Michigan series, which was open to the public and hosted in partnership with DTE's IRP team, featured three informational sessions to provide customers with a foundational understanding of the electric system as well as the DSP and IRP planning processes. Customers and stakeholders were invited to participate through multiple channels, including posts on the Company's LinkedIn account, DTE's Empowering Michigan blog, and email invitations to members of the Michigan Advisory Council on Environmental Justice (MAC EJ) and MPSC Listserv distribution list. The first session provided an introductory, high-level overview of the electric system and both planning processes, while the subsequent two sessions offered deeper dives into the DSP and IRP, respectively. In total, 45 individuals attended the Powering Michigan sessions. To maximize accessibility, the information sessions were scheduled outside of traditional work hours and offered live language transcription and closed captioning via Microsoft Teams. For individuals unable to attend, the final presentations, session recordings, and transcripts (in English, Spanish, and Arabic) were made available on the "Help shape Michigan's

[25] Including two additional dot-voting opportunities during Customer Resource Fairs in Detroit and Highland Park.
[26] Contact dte.dsp@dteenergy.com.
[27] Distribution System Plan, available at https://dteenergy.com/dsp, accessed February 12, 2026.

energy future"[28] page of the Company's Empowering Michigan blog. This page received more than 720 visits between September 22, 2025, and February 3, 2026.

3.1.3 Community Conversations



Community Conversations presentation

The DSP and IRP teams also collaborated to host a series of in-person community feedback sessions, referred to as Community Conversations, in select EJ communities. Through an evaluation process,[29] DTE selected Detroit, Dearborn, and Monroe as locations for in-person sessions and also offered a virtual session to further broaden participation. DTE engaged a third-party consultant to design and facilitate the sessions. In addition, the Company partnered with three community-based organizations (La Sed, ACCESS, and United Way of Monroe/Lenawee Counties) to advise DTE and the third-party consultant on session locations and scheduling, effective engagement strategies, and community-specific and cultural considerations. DTE conducted targeted outreach to customers within the selected communities primarily through social media advertising, the MAC EJ distribution, DTE's newsletter, and more than 57,000 direct customer emails, as applicable. Partnering organizations also performed community outreach to further raise awareness and encourage participation. To ensure the meetings were accessible to all who wished to participate, the Company arranged for any necessary accommodations, including special dietary options, transportation assistance, and translation services.

Following a presentation from the DSP and IRP teams and an open question-and-answer period, the third-party consultant facilitated break-out discussions centered on three key themes: electric reliability, cleaner energy, and affordability. With respect to reliability, participants emphasized the importance of consistent power delivery, increased transparency around how grid investments reduce outages, and improved communication during service disruptions. Regarding affordability, attendees expressed concern about the scale of investments for both the electric grid and

[28] Help shape Michigan's energy future - Empowering Michigan, available at https://empoweringmichigan.com/2026-cleanvision-integrated-resource-plan-public-meetings/, accessed February 12, 2026.

[29] DTE used the State of Michigan's MiEJScreen tool to identify EJ communities within its service area with cumulative scores at or above the 75th percentile as a starting point, then further evaluated asset locations, geographic diversity, community characteristics, and opportunities to partner with community-based organizations.

generation infrastructure and the potential impact on customer rates. Overall, consistent with feedback received from community open houses, participants expressed a strong desire for improved reliability while maintaining affordability.

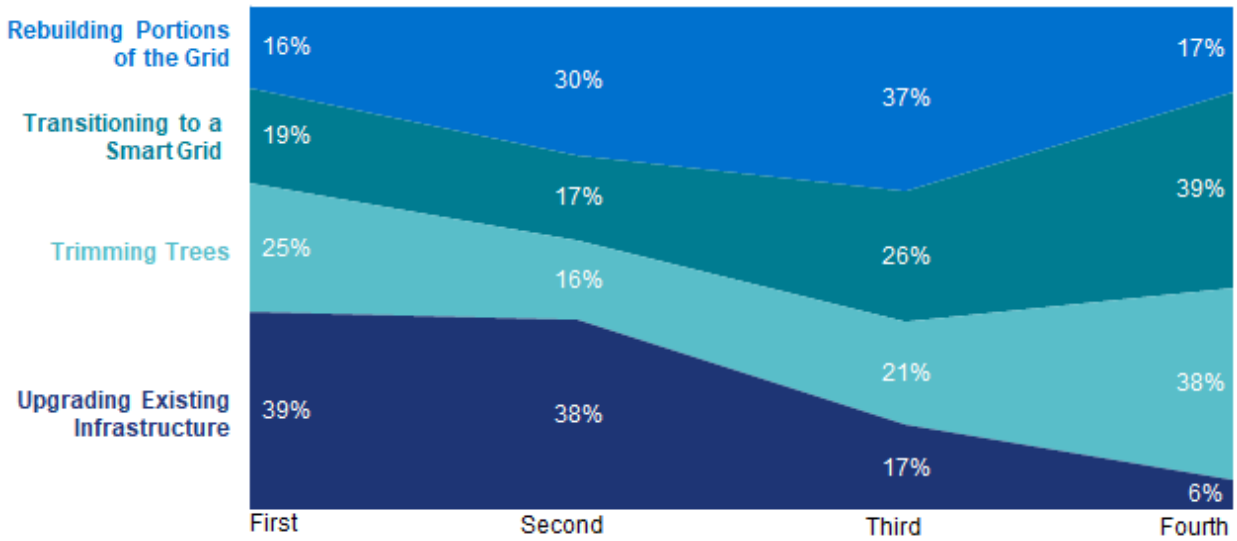
3.1.4 Customer Survey

DTE also gathered customer input on specific elements of its investment plan through a customer survey conducted in November 2025. The Company engaged a third-party provider to administer an anonymized survey to 400 customers across its service area. The survey collected background information, assessed customer awareness of DTE's investment plan, and gathered feedback on areas where customers believe the Company should prioritize investments.

Survey results indicated that customers wanted to learn more about DTE's investment plan and how planned investments will affect their local community. Many respondents reported limited familiarity with the Company's broader investment pillars beyond tree trimming activities. Customers also expressed a desire for greater transparency regarding infrastructure investments in their communities and the expected reliability benefits associated with those investments. DTE acknowledges that, while meaningful progress has been made to improve investment transparency, additional efforts are needed, and the Company will continue to explore ways to expand and enhance communication with customers.

The survey also asked customers to rank the importance of various grid improvement activities, organized by investment category, to better understand customer priorities. Exhibit 3.2 shows how surveyed customers prioritized grid improvement activities.

Exhibit 3.2 – Customer Priorities for DTE Action



Customers overwhelmingly identified upgrading existing infrastructure as a top priority, with 77% ranking it among the top two most important actions for DTE to take. Rebuilding portions of the grid followed, with 46% of customers ranking it as a top-two priority. This feedback closely aligns with the Company's recent prioritization of PTMM investment as it ramps toward a five-year pole-top and 10-year pole inspection cycle. At the same time, customers also identified the potential cost of these investments as an important consideration, underscoring the importance of balancing affordability with reliability.

3.1.5 Technical Conferences

Lastly, DTE hosted three DSP-focused technical conferences. Invitees included participants from prior technical conferences, recent intervenors in general rate cases, and individuals who expressed interest in the 2025-2026 conferences through the MPSC email distribution list or the DTE DSP email. The first conference, held in November 2025, focused on the Company's preliminary approach to investment justification in the DSP, including an overview of varying benefit-cost and alternatives analyses. DTE also invited a third-party expert to share best practices for conducting benefit-cost analyses based on benchmarking insights from other utilities. The conference was offered in a hybrid format, although no attendees participated in person. Key feedback from this session incorporated into this DSP includes the transition from version 1.0 to version 2.0 of the Interruption Cost Estimate (ICE) calculator and the addition of a resiliency analysis, both of which are integral components of the BCA conducted by the third-party consultant and detailed in Appendix 8.14 (Benefit-Cost Analysis Report).

The second technical conference, held in January 2026, introduced and discussed emerging technologies proposed for inclusion in the DSP filing given the five-year planning horizon. DTE SMEs led the discussion by presenting information on various technologies and responding to stakeholder questions. To align with participant preferences from the first conference, the second session was conducted virtually. In addition to exploring the potential operational and system benefits of emerging technologies, stakeholders emphasized the importance of understanding their cost implications and practical implementation considerations. The Company has incorporated this feedback into the DSP, particularly within the Grid Edge and Distributed Intelligence pillar, by taking a measured approach that leverages insights from early adopters to ensure future emerging technology investments are prudent, cost-effective, and structured to mitigate the risk of rapid technological obsolescence.

The third technical conference, held in March 2026, provided an opportunity for detailed collaboration with intervenors on three key focus areas: planning protocols and guidelines for circuit conversions, investment modeling tools (including the GPM), and DTE's approach to providing transparency into a third-party consultant's BCA model. DTE SMEs walked through the planning framework used to prioritize or defer 4.8 kV circuit conversions, including the safety, reliability, loadability, and operability criteria that guide decision-making. The session also included a deeper discussion of the GPM, including how model outputs are used in combination with BCAs to inform capital allocation decisions rather than as standalone determinants. In addition, DTE outlined its approach to increasing transparency into BCA assumptions and modeling practices, including plans to offer tutoring sessions directly with the third-party consultant. Feedback from this conference informed refinements to the DSP narrative, including clearer articulation of the circuit conversion planning protocols described in Section 6.3.1 (4.8 kV and 8.3 kV Conversions) and an enhanced explanation of the GPM and portfolio prioritization methodologies in Sections 5.2.4 (Global Prioritization Model) and 5.2.5 (Prioritization Summary and Results). Stakeholder feedback was primarily focused on clarifying questions, with no objections raised regarding the underlying methods or approaches.

Through its pre-filing outreach efforts, DTE actively engaged a broad and diverse set of stakeholders. Feedback gathered across all engagement channels consistently highlighted the importance of maintaining both affordability and reliability, priorities that directly align with this DSP's objectives. The Company has expanded its BCA to more investment programs than ever before to find the most cost-effective solutions to deliver the reliable power customers need and deserve. DTE values the feedback provided by customers, communities, and local governments and appreciates the time stakeholders have invested in sharing their perspectives and experiences. The Company recognizes that electric grid planning is an ongoing, iterative process and remains committed to listening, learning, and incorporating customer input into future planning efforts.

3.2 Summary of Ongoing Outreach Efforts

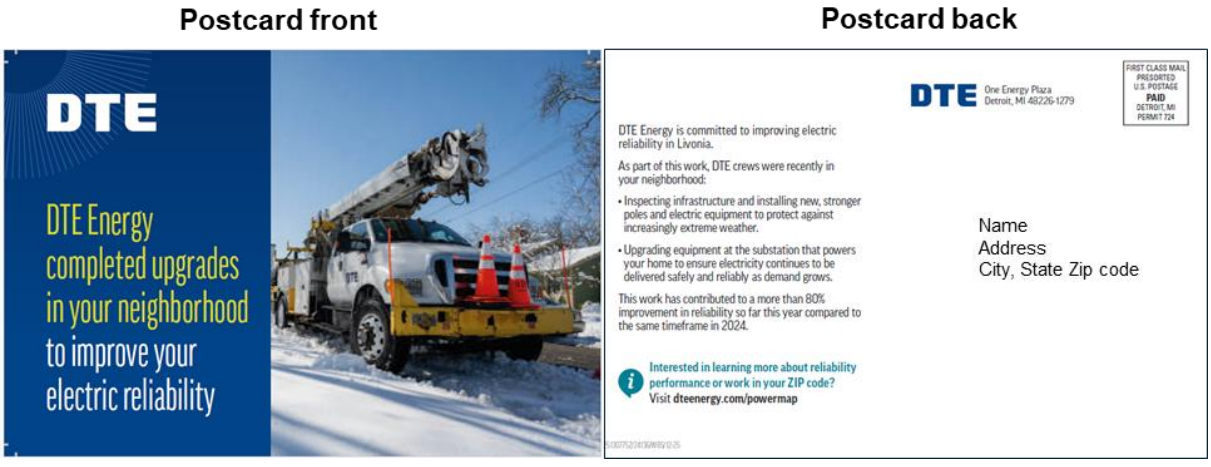
DTE is committed to regular engagement with customers, communities, and local governments to communicate updates and gather feedback throughout the year, as described in the sections below.

3.2.1 Customer Engagement

Customer feedback is a core input to DTE's grid planning and communications. For example, customer research indicated that some residential customers had limited visibility into reliability improvements in their area, contributing to perceptions that electric grid maintenance and upgrades were not occurring locally. In response, DTE enhanced its communications by launching a Reliability Improvements blog[30] and providing county-specific information on planned work.

The Company uses a variety of channels, including email, direct mail, media outreach, newsletters, videos, and targeted social media posts, to provide transparency into past, current, and planned reliability investments. In 2025, reliability-focused electric content generated more than 33 million social media impressions, over 1 million video views, and more than 360,000 blog views. DTE also distributed more than 800,000 targeted emails and mailers, such as the sample postcard shown in Exhibit 3.3, to inform customers about community-specific reliability upgrades.

Exhibit 3.3 – Sample Customer Postcard Regarding Recent Reliability Work



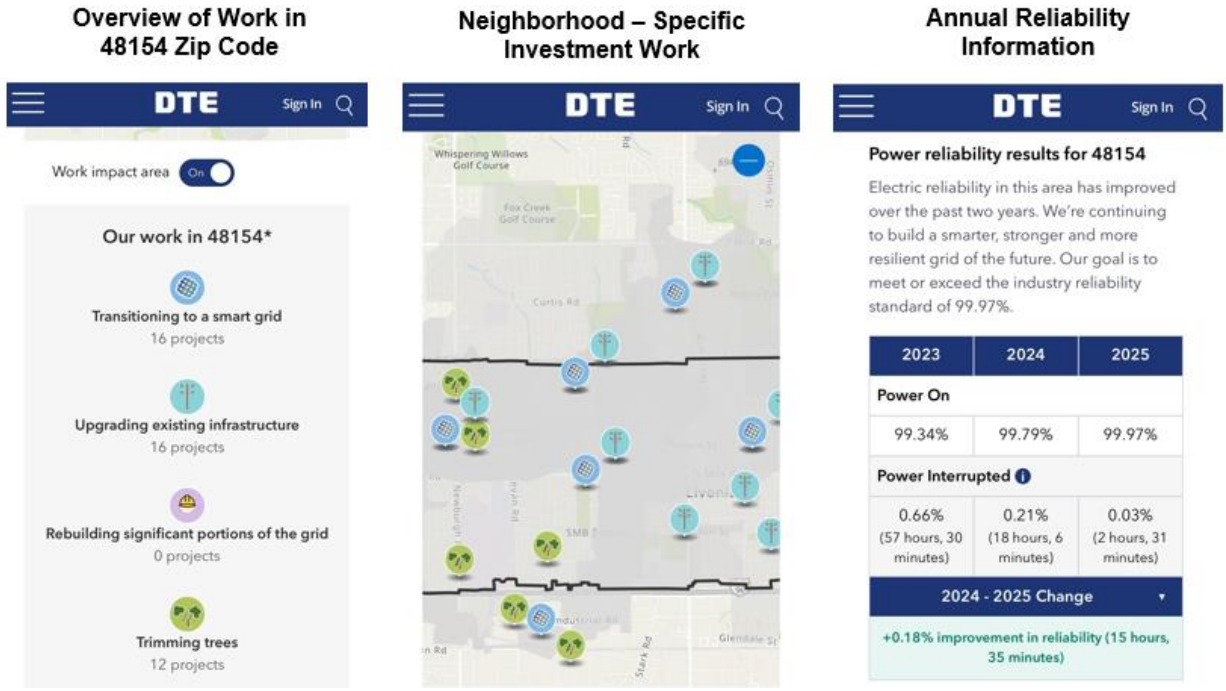
The Company also developed the Power Improvements Map[31] to provide customers with visibility into completed, ongoing, and planned reliability work, as well as historical reliability performance

[30] Powering southeast Michigan, available at https://empoweringmichigan.com/reliability-improvements/, accessed February 12, 2026.

[31] Power Improvements Map, available at https://www.dteenergy.com/us/en/business/service-request/system-improvements/system-improvements/power-improvements-map.html, accessed April 3, 2026.

by zip code, as shown in Exhibit 3.4. Project information and performance data are refreshed on a monthly and annual basis, respectively. Since its launch in June 2024, the website has received more than 442,000 interactions and 56,000 unique Michigan-based visitors.

Exhibit 3.4 – Power Improvements Map for Livonia (48154)[32]



3.2.2 Community Outreach

DTE's Community Engagement team supports ongoing, two-way engagement with customers and community stakeholders across the service area. Dedicated relationship managers connect with leaders from faith-based institutions, social service agencies, nonprofits, and civic and advocacy organizations. They also gather input through surveys and in-person conversations at homeowners' associations, block club meetings, cultural gatherings, and other local community events. For example, the Company hosts community open houses to educate residents on city-specific reliability investments and connect them with DTE SMEs. In 2024 and 2025, DTE engaged more than 1,500 residents through 13 community open houses.[33]

In addition to in-person engagement, relationship managers use virtual events, monthly stakeholder newsletters, and the Community Corner[34] blog to provide easy, centralized access to

[32] Number of icons shown differs between the images due to zooming on the map view.

[33] Including five in 2024 (Dearborn, Livonia, Pontiac, Southfield, and Westland) and eight in 2025 (Canton / Belleville / Van Buren Twp, Dearborn / Dearborn Heights, Farmington / Farmington Hills, Franklin, Livonia / Redford, Royal Oak / Oak Park / Madison Heights, Westland, and Ypsilanti). The 2025 Franklin open house was combined with their Main Street event.

[34] Community Corner, available at https://empoweringmichigan.com/communitycorner/, accessed February 12, 2026.

DTE information and resources. Collectively, these efforts informed customers and stakeholders about DTE's investment strategy, supported feedback gathering, and helped identify emerging community needs. In 2024 and 2025, the Community Engagement team conducted more than 650 engagements across over 100 communities, reaching approximately 150,000 customers.

Stakeholder feedback has consistently emphasized the importance of equity and EJ considerations in electric grid planning. DTE has incorporated this feedback by expanding outreach to vulnerable customers through resource fairs, mobile customer offices, and deployment of community vans during storm response. EJ engagement is guided by the reliability performance analysis outlined in Section 4.7 (Environmental Justice Analyses) to prioritize areas for focused outreach and discussion of planned investments. In 2025, more than 60% of Community Engagement activities occurred in Michigan EJ communities, including Dearborn, Detroit, Inkster, Pontiac, River Rouge, and Ypsilanti. Nine of the Company's 13 community open houses were also held in predominantly EJ communities.

3.2.3 Local Government Coordination

DTE coordinates closely with local governments through regional managers who provide regular updates on system reliability, planned work, new customer connections and support coordination of infrastructure projects. These managers engage through standardized reporting processes, attendance at local government meetings, and proactive collaboration with municipal staff, including regular meetings with the City of Detroit and county road commissions. Regional managers also serve as the primary point of contact for constituent inquiries received by local officials

At the state level, DTE partners with the Michigan Infrastructure Council (MIC) through the MiDIG portal[35] to support coordinated infrastructure planning and information sharing among utilities, government agencies, and other infrastructure owners. The Company is currently working with MIC to enhance secure data exchange capabilities within this statewide platform. Once fully operational, MiDIG will enable statewide sharing of capital improvement plans, streamline communications, enhance transparency, and support more effective coordination across infrastructure projects.

[35] MiDIG Portal, available at https://www.michigan.gov/mic/midig-portal, accessed February 12, 2026.

4. State of the System and Additional DSP Requirements

Chapter 4 provides a comprehensive overview of the key asset classes that make up DTE's subtransmission and distribution systems, collectively referred to as the electric grid, along with the tools and programs that support day-to-day operations. The chapter is organized into seven sections. The first two sections present an overview of the electric grid's architecture and the current condition of DTE's substation, overhead, underground, and associated technology and grid communication assets. The third section provides detailed historical information on safety, reliability, and past expenditures. The fourth section outlines the Company's operational functions and processes, followed by a fifth section that explains how DTE is managing the interconnection challenges and opportunities created by the growing number of DERs and EVs in its service area. The sixth section addresses material and workforce constraints that influence planning and execution, and the final section summarizes the Company's EJ analyses. Together, these elements provide important foundational context and inform the operational and investment decisions described throughout the DSP.

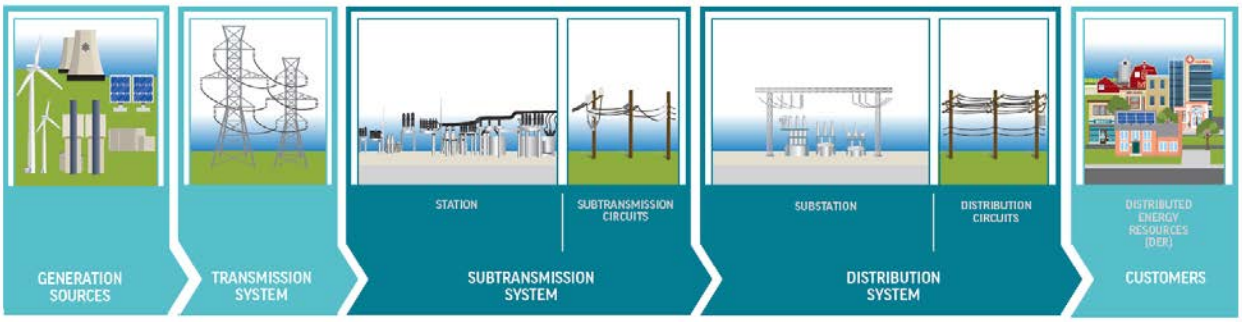
4.1 Subtransmission and Distribution System Overview

DTE provides electric service through a comprehensive and integrated network designed to deliver safe and reliable energy to its customers. The system is operated and maintained in accordance with applicable industry standards and regulatory requirements as well as a consistent focus on improving operational performance. The Company's service area spans approximately 7,600 square miles and includes urban, suburban, and rural communities as shown in Exhibit 4.1. Within this service area, DTE serves a population of about 5 million people through approximately 2.3 million residential, commercial, and industrial customers. This diverse customer base needs a resilient, adaptable grid capable of meeting variable load demands while supporting system reliability and future growth objectives.

Exhibit 4.1 – DTE Electric's Service Area

DTE's electric grid consists of approximately 31,000 miles of overhead and 14,500 miles of underground subtransmission and distribution lines. The distribution system delivers electricity from substations to customers, while the subtransmission system connects the distribution system to the high-voltage transmission system owned and operated by International Transmission Company (ITC). Each subtransmission circuit supplies one or more distribution substations, supporting customer loads ranging from a single customer to more than 14,000 customers. Exhibit 4.2 illustrates the electric system and highlights the portions that are part of this DSP: the subtransmission and distribution systems.

Exhibit 4.2 – Electric System Overview



4.1.1 The Subtransmission System

DTE's subtransmission system operates at three voltage levels: 24 kV, 40 kV, and 120 kV, as shown in Exhibit 4.3. It steps down the transmission voltage for delivery to distribution and industrial substations. The oldest portion of the subtransmission system operates at 24 kV and is primarily underground. Designed to support the grid of a past era, it currently does not align with modern standards. It supplies power to some of the oldest 4.8 kV distribution substations in areas such as Detroit, Monroe, and Port Huron. The predominant subtransmission voltage is 40 kV, delivered through a combination of overhead and underground circuits developed to accommodate suburban load growth as communities expanded outward from urban centers. The Company also operates distribution substations that interconnect with ITC's transmission system, as well as stations linking the transmission system to DTE's subtransmission system. Additionally, the Company owns and operates limited 120 kV radial lines that directly serve customer-dedicated substations.

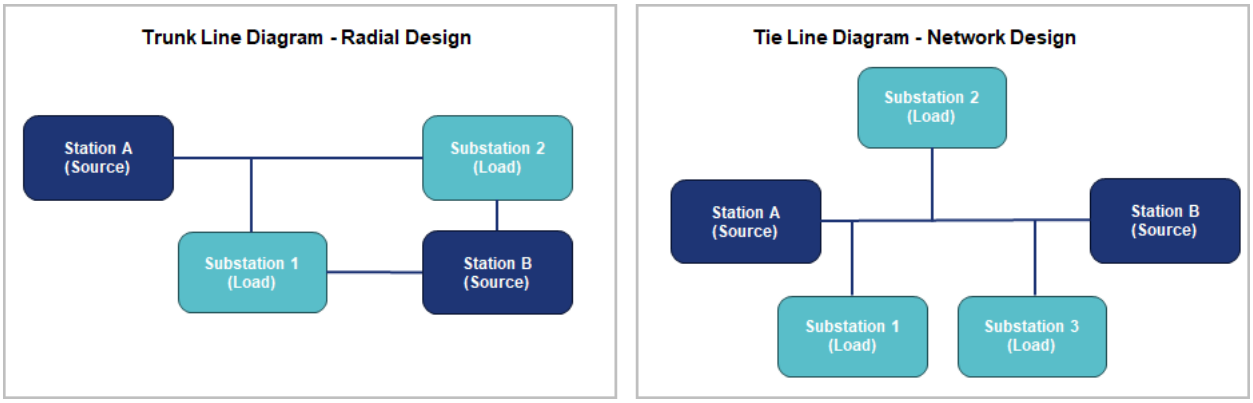
Exhibit 4.3 – DTE Subtransmission Circuits by Voltage

Voltage	Number of Circuits	Overhead Miles	Underground Miles	Total Miles
120 kV	68	59	8	**67**
40 kV	326	2,353	465	**2,818**
24 kV	242	177	732	**909**
Total	**636**	**2,589**	**1,205**	**3,794**

The subtransmission system is designed to reliably provide redundant sources to substations, which directly serve distribution circuits and customers. This redundancy, a standard in the industry, provides continuity of service to customers during a planned or unplanned outage, also known as a contingency situation. DTE's subtransmission system incorporates both radial and networked configurations as illustrated in Exhibit 4.4. The radial design, referred to as a trunk line,

consists of a single source station feeding one or multiple substations. The networked design, referred to as a tie line, consists of multiple source stations that can feed multiple substations, providing enhanced reliability and operational flexibility. DTE's subtransmission system faces challenges from localized overloads, limited automation, and aging infrastructure, all of which reduce reliability and limit system flexibility. Additionally, maintenance access to sections of the overhead subtransmission lines is regularly impeded by obstacles such as wooded areas and railroads, often delaying restoration after an outage.

Exhibit 4.4 – Subtransmission Radial and Network Designs



4.1.2 The Distribution System

DTE's distribution system operates at three voltage levels: 4.8 kV, 8.3 kV, and 13.2 kV, as shown in the color-coded maps in Exhibit 4.5. Just over half of the distribution system operates at 13.2 kV, or approximately 55% of all circuit miles, across both overhead and underground lines. Similar to the 40 kV subtransmission voltage, this system was developed to support load growth. The oldest portion of the distribution system operates at 4.8 kV and is primarily overhead. It accounts for approximately 60% of the distribution circuits and about 45% of circuit miles, as shown in Exhibit 4.6. There is also a very small legacy 8.3 kV network serving the area of Pontiac (less than 1% of circuit miles). In addition to these legacy voltage classes, portions of the system operate as isolation-down (ISO-down) areas, which occur when step-down transformers are installed on 13.2 kV circuits to reduce voltage to 4.8 kV for downstream service, typically in rural areas, as illustrated in Exhibit 4.5. These areas are shown in dark blue on the left map (4.8 kV line voltage) and light blue on the right map (13.2 kV substation/bus voltage). In most cases, the downstream 4.8 kV circuit is the original infrastructure, while the upstream 13.2 kV circuit and substation were rebuilt to alleviate loading constraints.

Exhibit 4.5 – DTE's Distribution Voltage Maps

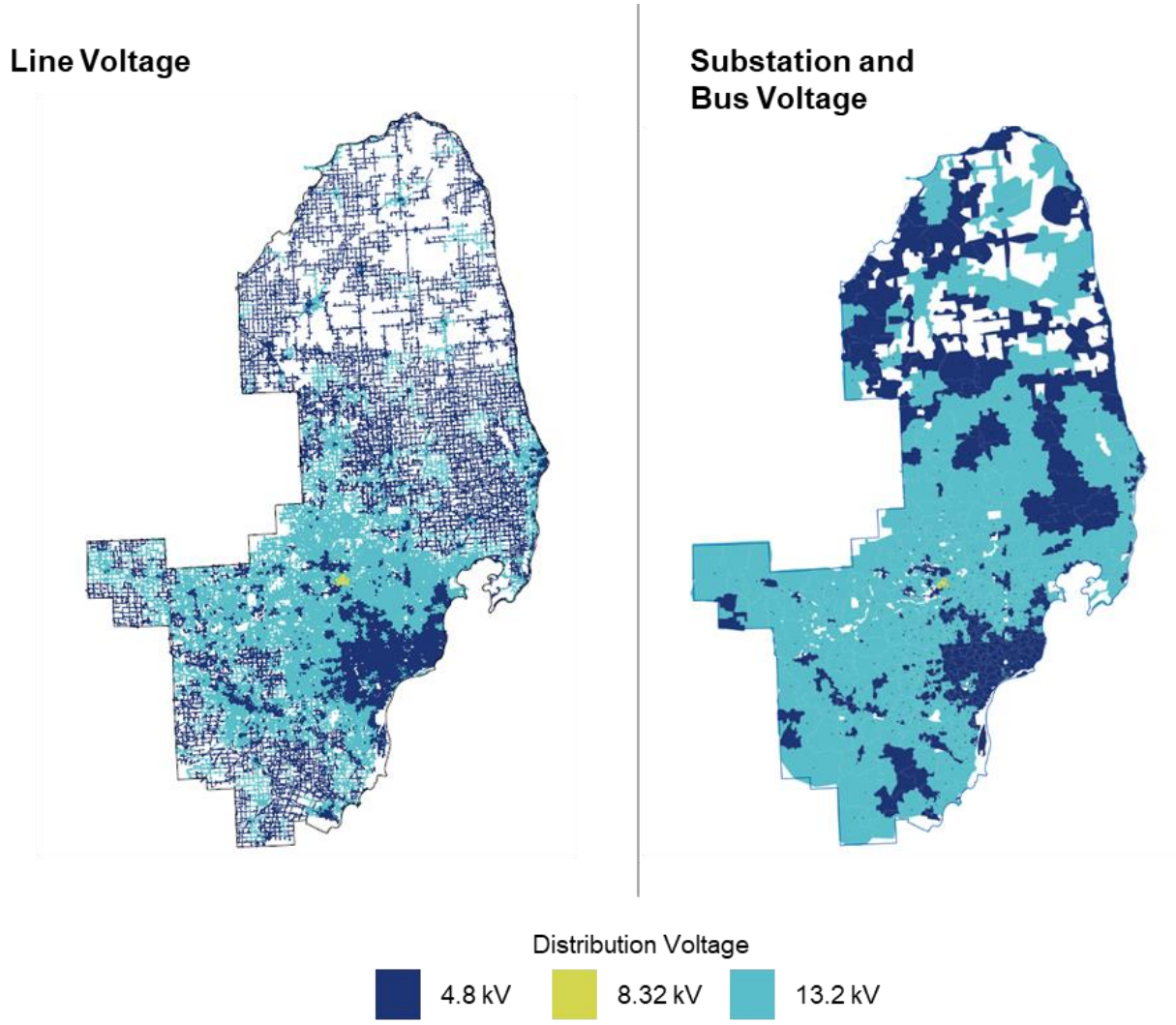


Exhibit 4.6 – DTE Distribution System Voltage

Bus Voltage	Number of Circuits	Overhead Miles			Underground Miles			Total Miles
		13.2 kV	8.3 kV	4.8 kV	13.2 kV	8.3 kV	4.8 kV	
13.2 kV	1,299	11,977	16	5,752	10,979	1	448	**29,173**
8.3 kV	13	-	44	-	-	18	-	**62**
4.8 kV	1,984	35	-	10,731	289	-	1,916	**12,971**
Total	**3,296**	**12,012**	**60**	**16,483**	**11,268**	**19**	**2,364**	**42,206**

DTE's legacy 4.8 kV distribution system was designed nearly a century ago as an ungrounded delta configuration. Due to its ungrounded design, fault locating can be challenging, creating safety hazards and complicating restoration efforts. In most neighborhoods, the 4.8 kV system

was constructed on overhead rear-lot poles and wires, which was aesthetically preferable to front-lot construction. Right-of-way (ROW) truck access was initially readily available through municipally-maintained alleys in many areas, including much of Detroit. In the mid-1900s, many municipalities began to abandon alleys and allowed property owners to extend their fence lines into the alley ways, preventing DTE trucks from accessing the poles and wires. Consequently, the limited access significantly increases the time required to locate and repair trouble, perform Vegetation Management, and complete other maintenance.

Conversion work in Detroit

The distribution system serving downtown Detroit is unique and is the earliest electrical grid in Michigan. Originally constructed as a Direct Current (DC) system in the early 1900s, significant portions were converted to Alternating Current (AC) infrastructure during the early 20th century. Today, the AC system operates entirely underground and typically consists of multiple underground 4.8 kV radial primary circuits. A large 120/208 V meshed secondary AC network is also installed in underground conduit and accessed through manholes located along heavily traveled city streets. Conversion of this legacy system to 13.2 kV is part of a multi-decade, multi-phased effort that began in 2015 and is discussed in detail in Section 6.3.1 (4.8 kV and 8.3 kV Conversion).

In assessing the condition and performance of these lower voltage systems, particularly with 4.8 kV overhead circuits, it is important to consider the role of small distribution and secondary wire, which is predominantly found on these circuits.[36] Approximately 87% of DTE's 3,600 miles of legacy small-gauge primary wires are located on the 4.8 kV system and are no longer adequate for current load demands or expected reliability performance. Their limited capacity and higher vulnerability to environmental stress during weather events make them increasingly unsuitable

[36] Small wire is defined as conductor sizes #8, #6, and #4 American Wire Gauge (AWG).

for modern operations. Accelerating their replacement is therefore an essential part of strengthening the distribution system.

The Company's substation and transformer infrastructure supporting the distribution system is summarized in Exhibit 4.7 and Exhibit 4.8.

Exhibit 4.7 – DTE Substations by Type and Voltage

Substation Type	Total Number of Substations	Number of Substations by Circuit/Low Side (kV)							
		4.8	8.3	13.2	4.8 & 13.2	24	40	24 & 40	Other
General Purpose	542	244	4	243	30	4	13	3	1
Single Customer	171	49	-	95	1	-	1	-	25
Customer-Owned	109	13	1	35	-	1	7	-	52
Total	**822**	**306**	**5**	**373**	**31**	**5**	**21**	**3**	**78**

Exhibit 4.8 – DTE Transformers by Voltage Level

Asset Category	High-Side Voltage	Number of Transformers	kVA Capacity
Subtransmission - Substation			
	40 kV	19	295,000
	120 kV	159	12,660,000
	345 kV	1	230,000
Distribution - Substation			
	13.2 kV	3	48,000
	24 kV	334	3,144,497
	40 kV	746	9,103,949
	120 kV	370	11,928,025
	230 kV	2	80,000
	345 kV	3	385,000
Distribution - Overhead and Pad-mount			
	4.8 kV	140,418	10,277,259
	8.3 kV	785	77,796
	13.2 kV	315,695	23,416,188

4.2 General Asset Health and Condition

DTE regularly assesses the condition of equipment and has identified the asset classes that present the greatest potential impact on electric grid reliability, resiliency, and operational performance. The average age, age range, and expected useful life for these asset classes are summarized in the substation, overhead, and underground asset sections below, with the most

critical asset classes discussed in greater detail. Useful life is determined using a combination of manufacturer specifications, industry benchmarks, and authoritative sources such as the Electric Power Research Institute (EPRI) Industry database and the National Electric Energy Testing, Research & Applications Center Asset Survival Plots, supplemented by DTE's historical performance data.[37] Rather than representing an asset's absolute lifespan, "useful life" is a standard industry term that reflects the point at which increasing failure rates and declining performance make proactive replacement more reliable and cost-effective than continued repair and maintenance.

Lineman works to install a new set of transformers

Asset age is a key factor in system planning and in reliability performance, as older equipment that has operated longer and been exposed to more weather and system events can experience accelerated deterioration and face limited replacement availability. In some cases, aging infrastructure increases the risk of equipment failure, contributes to a rapid decline in reliability, and may lead to non-compliance with regulatory performance requirements. To proactively address these risks, DTE performs annual asset health assessments that evaluate equipment condition using multiple indicators, including age.

Asset health rankings are an essential part of prioritizing capital investments within the DSP. The Company's asset health analysis assigns a risk score to each piece of equipment, categorizing assets into four tiers of failure risk: acceptable, elevated, high, and severe. Assets rated as severe have the highest likelihood of failure and require near-term replacement to maintain the safe and reliable operation of the electric grid in accordance with good utility practice. Equipment identified as severe is therefore targeted for accelerated replacement or refurbishment to reduce reliability risks and ensure continued compliance with regulatory obligations. These rankings also inform

[37] Note this is an operational useful life and may differ from the projected life for depreciation of some plant assets. Operational useful life refers to how long an asset can physically and safely perform its intended function based on engineering and environmental conditions, whereas depreciation useful life is an accounting concept that follows regulatory guidelines, tax rules, and financial planning for cost recovery.

long-term planning by identifying emerging trends in asset conditions, which enable DTE to allocate resources efficiently and align its investment strategy with regulatory objectives for safety, reliability, and resiliency.

4.2.1 Substation Assets

Substations serve as a vital connection between the subtransmission and distribution systems, enabling the safe, reliable, and efficient flow of power across the grid. Given their importance to overall system performance, proactive maintenance of substation equipment is essential to ensuring consistent service for thousands of customers. Exhibit 4.9 summarizes the age profiles for six major substation asset classes, with additional details provided on power transformers and circuit breakers below. As shown in the exhibit, a significant portion of the Company's substation assets have reached or exceeded their expected useful lives, increasing both reliability and operational risks. Several critical asset classes — including power transformers, network bank transformers, circuit breakers, relays, and switchgear — have average ages at or above industry useful life benchmarks, with roughly half or more of each fleet already at or beyond useful life. This condition underscores the need for sustained substation equipment replacement investment to maintain safe and reliable grid operations.

Substation power transformer

Exhibit 4.9 – Substation Asset Age Summary

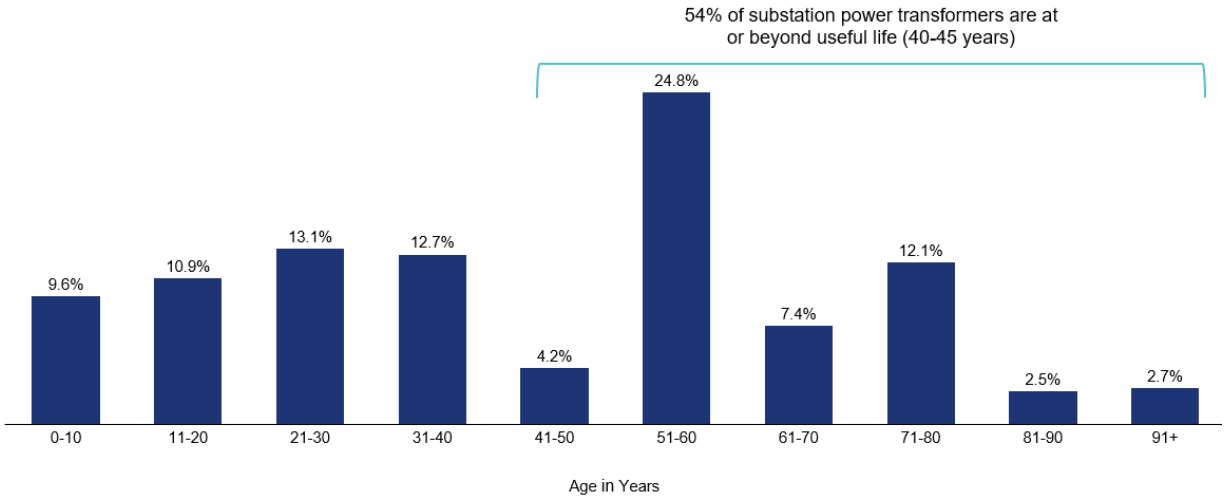
Asset Class	Approximate Quantity in DTE Fleet	Years			Percent of Fleet at or Beyond Useful Life
		Age Range	Average Age	Useful Life	
Substation Power Transformers	1,635	2-102	45	40-45	54%
Network Bank Transformers	532	1-121	47	20-30	65%
Circuit Breakers	6,204	0-90	51	30-40	59%
Circuit Switchers	386	1-39	20	40	0%
Relays	24,830	0-60	39[38]	15-50	47%
Switchgear	269	2-73	40	40	55%

[38] Based on average number of years since last configuration, not average age since date of install.

Substation Power Transformers

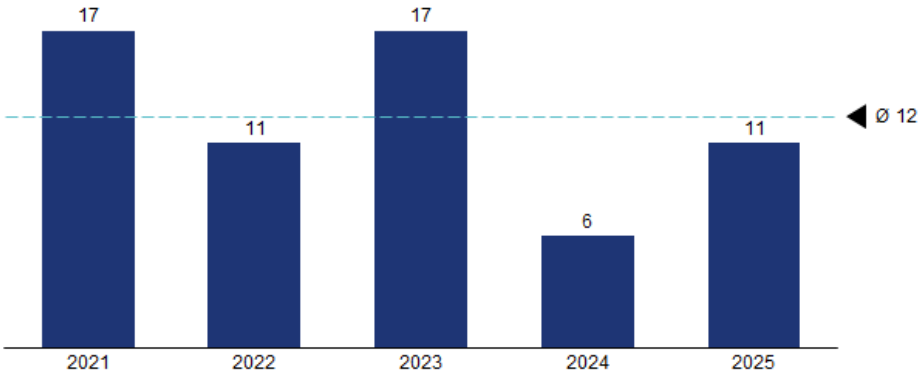
DTE maintains approximately 1,600 large substation power transformers that provide critical voltage step down interconnections between the transmission system (120 kV), the subtransmission system (24 kV and 40 kV), and the distribution system (4.8 kV, 8.3 kV, and 13.2 kV). The fleet has an average age of about 45 years, which is approaching or exceeding the expected useful life for a significant portion of these assets. Currently, approximately 54% of substation power transformers are at or beyond their expected useful life, as shown in Exhibit 4.9 and Exhibit 4.10.

Exhibit 4.10 – Substation Power Transformer Age Distribution



Over the past five years, the Company has experienced an average of 12 power transformer failures annually as shown in Exhibit 4.11, including units replaced proactively prior to catastrophic failures based on dissolved gas analysis (DGA) results. The primary failure modes — bushing deterioration, load tap changer malfunction, and winding insulation breakdown — account for approximately 65% of reported incidents. On average, transformers fail at approximately 48 years of age. Failures of substation power transformers pose a significant risk to system reliability and compliance with regulatory performance standards. A single failure can result in simultaneous outages across multiple circuits and substantially reduce system redundancy, heightening the risk for extended service interruptions. In severe cases, thousands of customers may experience prolonged outages while repairs or replacements are completed. In addition to the significant reliability implications, a substation transformer failure may also present safety considerations for on-site employees and potential environmental impacts associated with oil releases or response and mitigation activities.

Exhibit 4.11 – Five-Year Historical Substation Power Transformer Failures



In some cases, substation power transformers must be replaced reactively after unexpected in-service failures if the required repairs are deemed impractical or uneconomical. For proactive replacement, DTE conducts annual inspections and DGA testing as part of its Preventive Maintenance and Inspections program for all substation power transformers. DGA testing is an industry-recognized Substation Predictive Maintenance Inspection (SPdM) methodology used to detect internal transformer degradation and identify incipient failure conditions. In addition to predictive maintenance, standard PM activities include inspection and servicing of ancillary components, such as load tap changers and bushings, to mitigate failure risks and maintain system reliability. DTE uses these routine inspections and DGA testing to determine whether a transformer requires proactive replacement or repair. Based on the condition assessment factors shown in Exhibit 4.12, approximately 15% of substation power transformers are currently classified as candidates for replacement. These units typically exceed 70 years of age, exhibit abnormal DGA ratios, and utilize water-cooled designs with potential active water leaks into the unit — conditions that elevate both reliability and safety risks and require prioritized mitigation.

Exhibit 4.12 – Substation Power Transformer Condition Assessment Factors

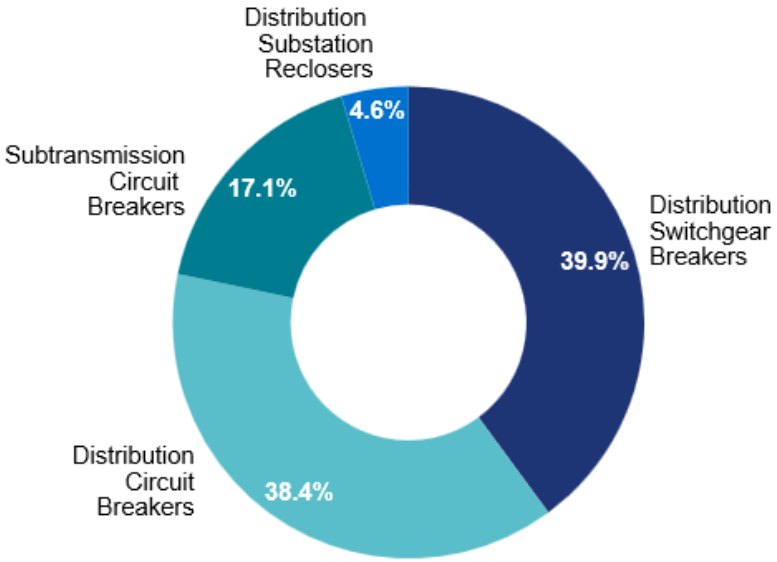
Factors	Impact
DGA Results Indicating Gassing in the Main Tank	• Indication of early stages of failure
Water Cooled Transformers	• High costs to maintain water cooling • Greater chance of failures due to water leaking into the unit
High Number of Faults	• High mechanical and electrical stress on the transformer core and winding insulation
70+ Years Old	• Deterioration of winding insulation • Uneconomical to repair
Chronic Leaking of Oil	• Environmental concern

Using historical replacement data from 2021 to 2025, DTE's current pace of replacement for substation power transformers is approximately 160 years.

Circuit Breakers

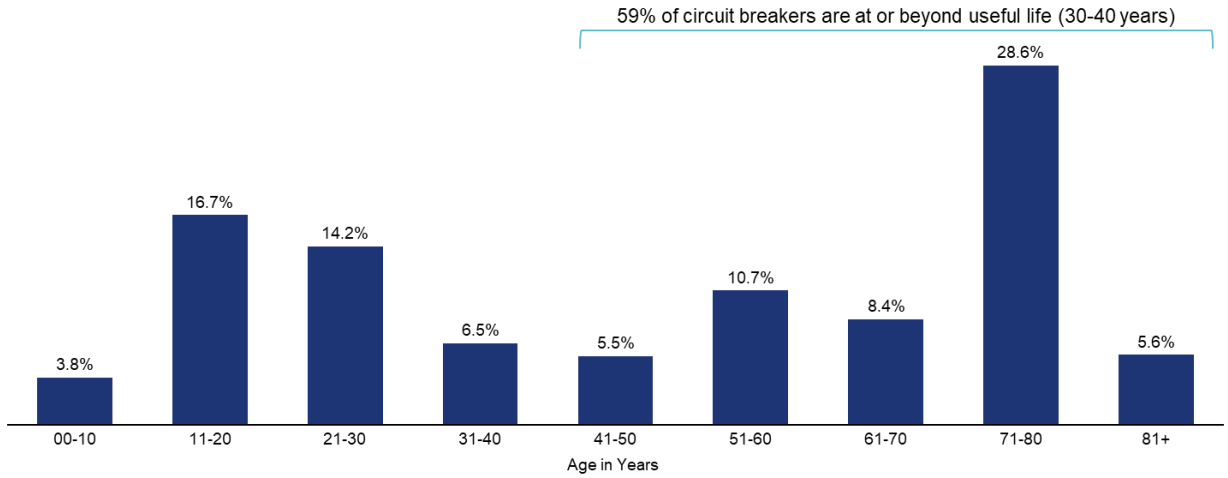
A substation circuit breaker is a critical protective device, functioning as an electrical switch that isolates faults on substation equipment, buses, and circuits. Its primary purpose is to interrupt current flow when a fault is detected, thereby mitigating equipment damage caused by high fault currents and isolating the affected component to maintain system integrity. DTE currently operates approximately 6,000 large substation circuit breakers across its electric grid. These assets include a mix of oil, air magnetic, gas, and vacuum breaker technologies. DTE maintains its circuit breaker fleet in accordance with good utility practice to ensure effective system protection and fault isolation. The fleet includes subtransmission breakers, distribution breakers, distribution switchgear breakers, and distribution substation reclosers as shown in Exhibit 4.13.

Exhibit 4.13 – Circuit Breakers by Application



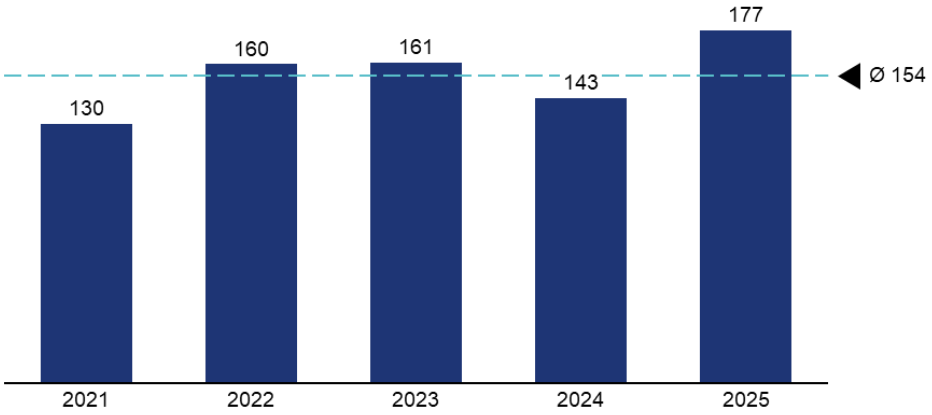
Legacy circuit breakers manufactured in the early- to mid-20th century have an estimated useful life of approximately 40 years. Modern circuit breaker designs, while engineered for improved maintainability and streamlined replacement, have a typical useful life of approximately 30 years. As illustrated in Exhibit 4.14, approximately 59% of DTE's circuit breaker fleet has exceeded its expected useful life, representing a significant reliability and compliance risk that warrants proactive asset management.

Exhibit 4.14 – Circuit Breaker Age Distribution



Over the past five years, the Company has experienced an average of 154 breaker failures annually, as shown in Exhibit 4.15. In-service failures include any instance in which a breaker does not perform its intended function, with severity ranging from repairable defects to full equipment loss. Although some failures can be addressed through repairs rather than a complete replacement, these repairs can still result in extended customer outages. When a full replacement is required, or when a major in-service failure occurs, outages may persist for prolonged periods, and the electric grid may need to operate under abnormal conditions until restoration activities are completed. Depending on the severity of the failure and any collateral damage to nearby equipment (such as from fire or explosion), these events can cause extended service interruptions for thousands of customers and can pose safety risks to employees working in the substation.

Exhibit 4.15 – Five-Year Historical Circuit Breaker Failures



DTE conducts periodic inspections of circuit breakers based on either defined time intervals or the number of fault operations. Circuit breakers that do not meet inspection standards are either

repaired when economically feasible or replaced. Over the past three years, an average of approximately 19 breakers per year have failed inspection. Based on the latest asset health assessment using the condition factors shown in Exhibit 4.16, approximately 54% of the Company's 6,000 circuits breakers are candidates for replacement. This includes DTE's entire fleet of approximately 2,000 older oil-filled breakers that pose an elevated risk and should thus be considered for replacement.

Exhibit 4.16 – Circuit Breaker Condition Assessment Factors

Factors	Impact
Interrupting Medium	Specific interrupting mediums have known issues: • Oil breakers are an environmental concern due to possible leaks. • Air magnetic breakers are prone to failure due to issues extinguishing arcs within the breaker.
High O&M Costs	High O&M costs due to more frequent repairs, longer troubleshooting times and shorter maintenance cycles
Unavailable Parts	Little or no vendor support and expensive to replace parts
Known Performance Issues	Known higher failure rates or frequent failure to operate

While DTE has implemented a risk-based capital replacement program to address aging circuit breakers, the Company's current pace of replacement is approximately 111 years using data from the last five years. Because breaker failures can cause multiple circuit outages and create safety hazards, DTE is planning to accelerate proactive replacements as detailed in Section 6.2.6 (System Equipment Replacement).

4.2.2 Overhead Assets

Overhead assets in the subtransmission and distribution systems include poles, wires, transformers, and other pole-mounted equipment. Exposed to weather and other impacts of age, this equipment is also the most visible part of the grid. DTE regularly reviews equipment standards and, in recent years, has implemented updates that include greater pole strength and more durable pole-top materials.

Overhead regulator on pole

Exhibit 4.17 provides the age profiles for six major overhead asset classes, with poles and three-phase reclosers discussed in greater detail below.

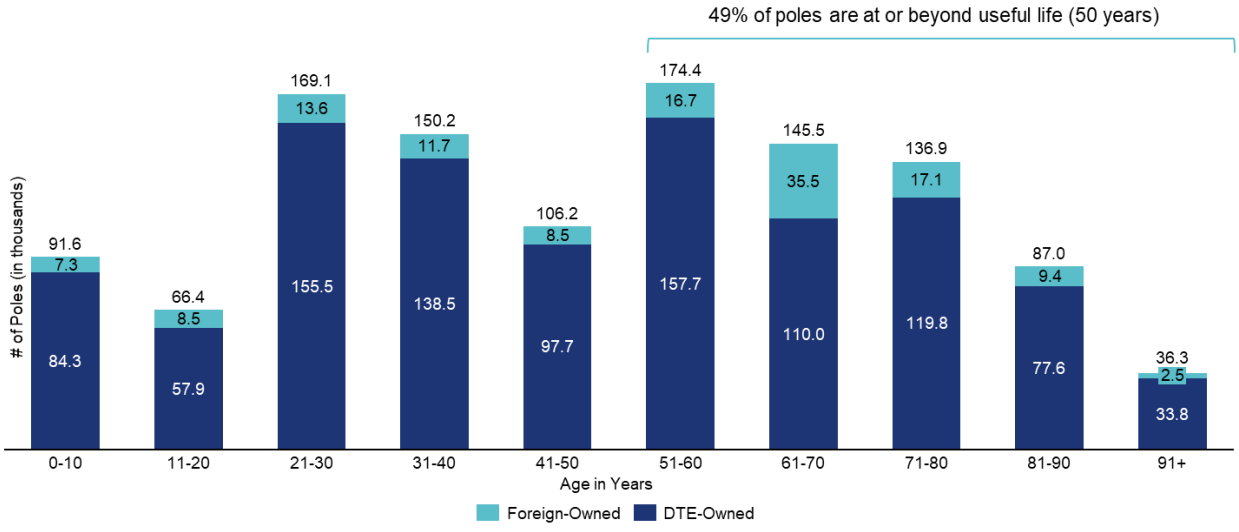
Exhibit 4.17 – Overhead Asset Age Summary[39]

Asset Class	Approximate Quantity in DTE Fleet	Years			Percent of Fleet at or Beyond Useful Life
		Age Range	Average Age	Useful Life	
Poles[40]	1,192,472	0-90+	48	40-50	49%
Three-Phase Reclosers	2,254	0-33	7	30	Not known
SCADA Pole-Top Switches	443	0-34	17	30-35	Not known
40 kV Automatic Pole-Top Switches	140	0-50+	16	40	11%
Overhead Capacitors	3,021	0-25+	Not known	30-35	Not known
Overhead Regulators	2,131	1-37	17	30-35	Not known

Poles

DTE owns more than 1 million poles across its electric grid. In addition, DTE has assets attached to nearly 200,000 “foreign” poles owned by other utilities such as AT&T and Comcast. Poles in the DTE fleet are, on average, approximately 48 years old. The useful life of a pole is 40 years for pine and 50 years for cedar, although the actual useful life can vary based on field conditions. Notably, approximately 49% of the Company’s poles are more than 50 years old, as shown in Exhibit 4.18.

Exhibit 4.18 – Pole Age Distribution

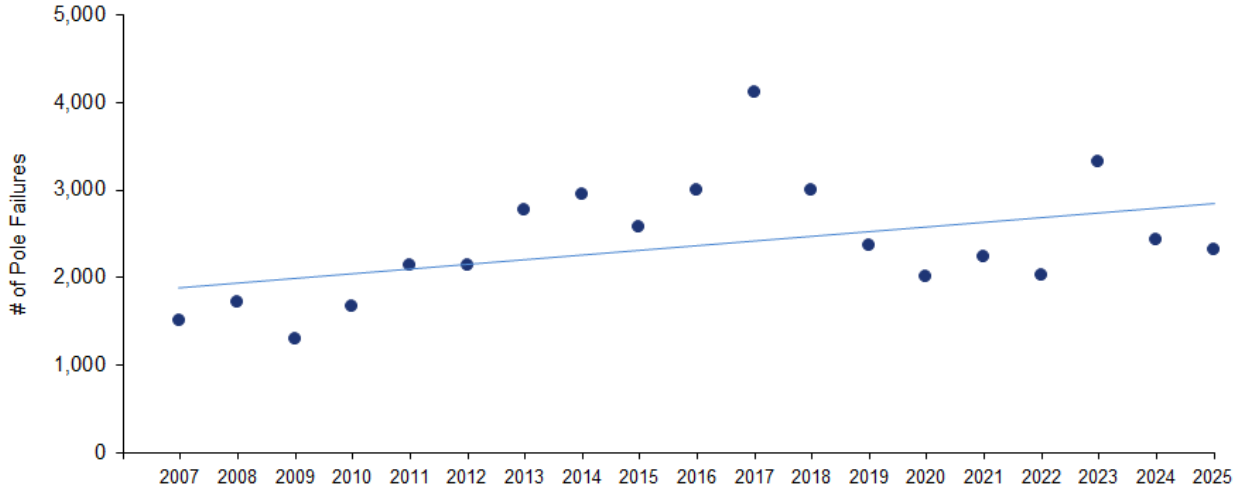


[39] Based on best available data, which is approximately 35% of three-phase recloser fleet and 67% of SCADA pole-top switch fleet. Where “Not known” is denoted, it is because the installation date for legacy assets was not captured, limiting DTE’s ability to estimate the value.

[40] Including poles owned by third parties for joint use (e.g., AT&T, Comcast). The percentage at or beyond useful life was calculated using a constant value of 50 years for useful life.

Exhibit 4.19 shows a slightly increasing trend of pole failures since 2007. Not all pole failures result in an immediate customer outage; in rare cases, a pole may be fractured or damaged while the conductors remain intact, allowing service to continue. However, these conditions leave the system in a significantly compromised state and require prompt remediation to eliminate the associated safety risks.

Exhibit 4.19 – Annual Pole Failure Events



Pole failures are not solely attributable to asset age. While some failures are related to pole condition, many are caused by external factors such as vehicle collisions, tree contact, ice accumulation, or wind loading that exceeds original design specifications. To proactively identify poles with deteriorating structural integrity, DTE conducts systematic pole testing through its PTMM program, as detailed in Section 6.2.1 (Pole and Pole-Top Maintenance and Modernization).

Three-Phase Reclosers

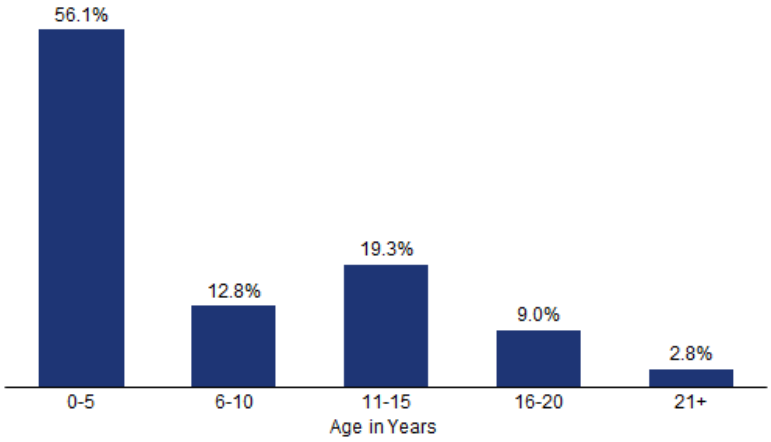
An overhead three-phase recloser is a sectionalizing device that is installed at key points on overhead circuits. It works like a circuit breaker when it detects high current from a downstream fault, such as a tree branch touching the distribution lines. Reclosers isolate the fault to the circuit section downstream of the recloser, leaving upstream customers' power intact. Unlike a

Three-phase recloser

fuse that will open and stay open, a recloser is designed to automatically reclose several times to restore the downstream customers if the fault has cleared. The open and reclose cycle allows temporary faults, such as a falling tree limb, to clear from the circuit which will allow the recloser to restore power to customers with only a momentary interruption. In the case of a sustained fault, the recloser will remain open and isolate the fault from the rest of the circuit.

Reclosers can also be used to join two circuits together and be programmed to automatically backfeed parts of a circuit in the event of a power outage. Modern three-phase reclosers offer additional functionality that can be utilized as part of a loop scheme with automated restoration steps. At a circuit level, loop schemes facilitate restoration by automatically transferring power into adjacent sections of the circuits when an outage is detected. Loop schemes are currently installed on approximately 6% of distribution circuits and are standard for all new or converted circuits. As shown in Exhibit 4.20, DTE has recently made significant investments in three-phase reclosers. The Company's efforts to automate specific aspects of the distribution system are described in Section 6.4.1 (Distribution Automation).

Exhibit 4.20 – Three-Phase Recloser Age Distribution



Although the average age of three-phase reclosers is only seven years, there is still a population that is identified as candidates for replacement. These devices present an elevated risk of operational failure, which can manifest an inability to either open or close during fault conditions. Such failures can significantly affect service continuity, resulting in a range of approximately 300 to 1,500 customer outages per event. Proactive replacement of these units is necessary to reduce reliability risks, limit exposure to large-scale outages, and ensure compliance with electric grid performance objectives. This initiative aligns with the Company's broader strategy to strengthen grid resiliency and maintain service quality standards for all customers.

Exhibit 4.21 – Three-Phase Recloser Condition Assessment Factors

Factors	Impact
Unavailable Parts	Many replacement parts are unavailable, and others are becoming increasingly difficult to obtain.
Known High Failure Rate	Frequent issues have been observed with batteries, controls, and mechanical components, with some units showing elevated mechanical part failures.
Environmental Issues	Certain units utilize oil, creating the potential for leakage during operation.
SCADA Capability	Certain units lack diagnostic capability; retrofitting SCADA functionality is cost prohibitive.

DTE also has a PM program for overhead three-phase reclosers. As outlined in Section 6.1.2 (Preventative Maintenance and Inspections), this program provides detailed requirements and guidance for inspection, testing, and maintenance activities. Reclosers that fail PM inspection or experience in-service failure are repaired or replaced to ensure continued compliance with reliability and safety standards.

4.2.3 Underground Assets

Exhibit 4.22 shows the asset ages for three major classes within the underground asset category, with system cable and underground residential distribution (URD) cable discussed in more detail below.

Exhibit 4.22 – Underground Asset Age Summary

Asset Class	Approximate Quantity in DTE Fleet	Years			Percent of Fleet at or Beyond Useful Life
		Age Range	Average Age	Useful Life	
System Cable	3,096 miles	0-100+	53	25-40	52%
URD Cable	11,354 miles	0-60+	27	40-50	23%
Manholes[41]	20,733	1-100+	81	Varies	Not known

System Cable

System cable is one of the most critical components of DTE's electric grid due to the significant impact of a failure and the high degree of difficulty involved in replacing failed system cable. These underground cables often form the first segment of a distribution circuit, carrying the entire electrical load before it branches into downstream equipment. Because a single system cable

[41] Not assigned a fixed useful life, as asset longevity depends on construction methods, materials, and local field conditions rather than uniform aging. Additionally, the installation date for legacy manholes was not captured, limiting DTE's ability to estimate the percentage at or beyond useful life.

may feed thousands of customers, its performance is directly tied to customer reliability, grid redundancy, and system resiliency.

DTE operates approximately 3,100 miles of system cable across its service area. These large-diameter, insulated conductors are typically installed in conduit systems with intermediate manholes or switch cabinets, depending on the cable type and route. While these installations are inherently more storm-resilient than overhead construction, they are also significantly more expensive and time-intensive to install, repair, and replace. Failures in system cable create extended outages, complicate load transfers, reduce redundancy, and require around-the-clock emergency repair efforts during peak demand periods. Because of these factors, maintaining the condition and performance of system cable is essential to preserving reliability for the large populations each cable segment serves.

DTE's system is comprised of six major system cable types, most of which are legacy designs from the prior century that are no longer deployed in new installations. Each of these cable types has its own unique design characteristics, aging profiles, performance attributes, useful life, and associated risk factors. Exhibit 4.23 presents the primary types installed across the system.

Exhibit 4.23 – Underground System Cable Types

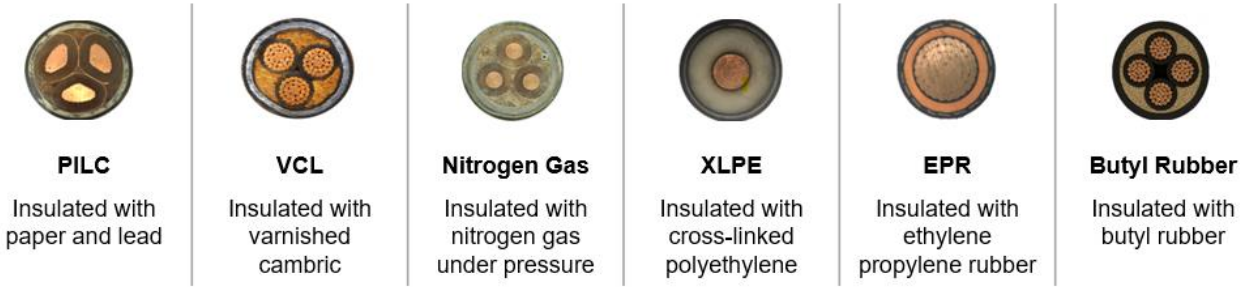


Exhibit 4.24 shows the population, age profile, and expected useful life of cable types.

Exhibit 4.24 – Underground System Cable Ages and Useful Life

Cable Type	PILC	VCL	Gas	XLPE Pre 1990 (Non-Tree Retardant)	XLPE Post 1990 (Tree Retardant)	EPR	Butyl Rubber
Miles	2,069	95	47	58	48	748	31
Percentage of Total Population	66.8%	3.1%	1.5%	1.9%	1.5%	24.2%	1.0%
Average Age	55	64	59	40	23	18	57
Useful Life	40	40	40	25	40	35	25

Across the system, 63% of system cable is at or beyond its useful life. Certain cable types, such as PILC, VCL, pre-1990 XLPE, and Butyl Rubber, exhibit known design and material vulnerabilities that compound age-related deterioration. As cables age, insulation breakdown, thermal stress, and moisture ingress increase failure risk. System cable failures present substantial reliability challenges because each failure can impact large customer groups and diminish circuit redundancy. Exhibit 4.25 shows the past five years of system cable failures by type.

Exhibit 4.25 – Five-Year Historical System Cable Failures by Type

Cable Type	Actual				
	2021	2022	2023	2024	2025
PILC	180	202	171	144	175
VCL	5	8	16	13	1
Gas	3	3	12	3	7
XLPE pre-1990	5	1	16	9	3
XLPE post-1990	-	-	-	-	-
EPR	17	24	37	28	27
Butyl Rubber	3	2	3	1	1
Total Cable Failures	**213**	**240**	**255**	**198**	**214**

Benchmarking shows an industry-typical failure rate of 0.7 to 2.0 failures per 100 conductor-miles,[42] whereas DTE's five-year average is 7.2 per 100 miles — more than five times higher — with annual values ranging from 6.2 to 8.0.[43] The Company's elevated failure rate is primarily driven by the advanced age of its cable population, which averages approximately 53 years compared to an industry average of roughly 35 years.[44] In some cases, failures may also damage nearby equipment, such as adjacent system cables, switchgear, or breakers, leading to larger outages, higher repair costs, and increased reliability risk. This reinforces the need for accelerated inspection, condition monitoring, and replacement strategies. Insulation type, age, and environmental conditions are primary determinants of failure risk. Because different insulation systems exhibit distinct aging mechanisms, failure modes, and service-life characteristics, insulation type plays a central role in underground cable condition assessments. Industry

[42] Failure Rates of Underground System Cable, available at https://distribution.epri.com/underground/public/failures/, accessed March 11, 2026.

[43] Failure rates were calculated as follows: Failures per 100 miles = (annual failures / total miles) * 100. This approach provides a normalized measure for comparison against industry benchmarks.

[44] EPRI Demography of Distribution Assets, available at https://distribution.epri.com/underground/public/demography/, accessed March 11, 2026.

guidance, such as EPRI's Underground Distribution Systems Reference Book, documents these differences and helps to inform risk-based asset management decisions for utilities. Exhibit 4.26 outlines the key condition assessment factors, including known defects associated with specific cable types. These risks are further amplified when cables experience overloads or have a history of failures. Overall, 28% of DTE's system cable is assessed as having a high risk of failure based on these factors.

Exhibit 4.26 – System Cable Condition Assessment Factors

Factors	Impact
Insulation Type	Specific cable types have known issues that lead to failure: • PILC > 60 years old is prone to failure due to age. As age increases, failure rates increase. • VCL (varnished cambric lead) cable is prone to failure under heavy loading and high temperature environments. The heavy loading or high temperature causes the insulation to degrade and lose its dielectric integrity. • Gas (gas-filled paper lead) cable has cavities within the insulating layer that are filled with gas (usually nitrogen gas) under pressure. This type of cable is prone to mechanical damage that leads to gas leaks and dielectric failures. Re-gassing this type of cable is very expensive. The Nitrogen Gas cable failure rate is approximately 0.15 failures per mile per year. • XLPE (cross-linked polyethylene) cable manufactured before 1990 has a design defect that leads to premature insulation breakdown and dielectric failures (also called "Treeing"). The XLPE cable failure rate is approximately 0.06 failures per mile per year. • BUTYL (polyisobutylene) cable can be found mostly in the secondary networks. Under high temperatures, the cable releases gases that can become explosive if an arc flash occurs in a manhole.
Cable Loading	Overloaded cables are prone to failure.
Past Failures	Cables that have experienced failures are more likely to fail again.[45]

While DTE has implemented a risk-based capital replacement program to address aging system cable, most replacements are still performed reactively, usually under outage conditions. Planned work is significantly more cost-effective and allows replacement during non-peak periods, avoiding the need for load transfers, mobile generations, or extended customer outages. Given the high number of customers served by each system cable and the critical role these cables play as the load-carrying backbone of distribution circuits, the Company is planning to increase proactive replacement as detailed in Section 6.2.6 (System Equipment Replacement).

[45] System cable circuits are made up of multiple sections. When one section faults and is replaced, the remaining sections stay in service but have already been exposed to damaging fault current from the original failure.

Underground Residential Distribution Cable

Unlike system cable, URD is smaller underground cable used in distribution laterals rather than backbone applications. Since January 1, 1971, all residential subdivisions in the Company's service area have been required by Michigan Administrative Code R 460.512 to use URD cable.[46] DTE's system now includes approximately 11,000 miles of URD in primary and secondary underground applications in residential areas. These cable runs connect ground-level pad-mounted transformers to pedestal-mounted secondary equipment, with underground service lines extending from the pedestals to customer meters.

As shown in Exhibit 4.27, URD consists of small-diameter conductors surrounded by cross-linked polyethylene insulation and was typically installed using direct-burial construction methods. In 2025, the Company updated its construction standards to require installation in conduit, reflecting industry experience with URD failure modes and the maintenance and replacement challenges associated with direct-buried cable.

Exhibit 4.27 – Example URD Cable

[46] Underground Electric Lines, available at https://gsaindexed.apps.lara.state.mi.us/ORR/824_10790_AdminCode.pdf, accessed March 4, 2026.

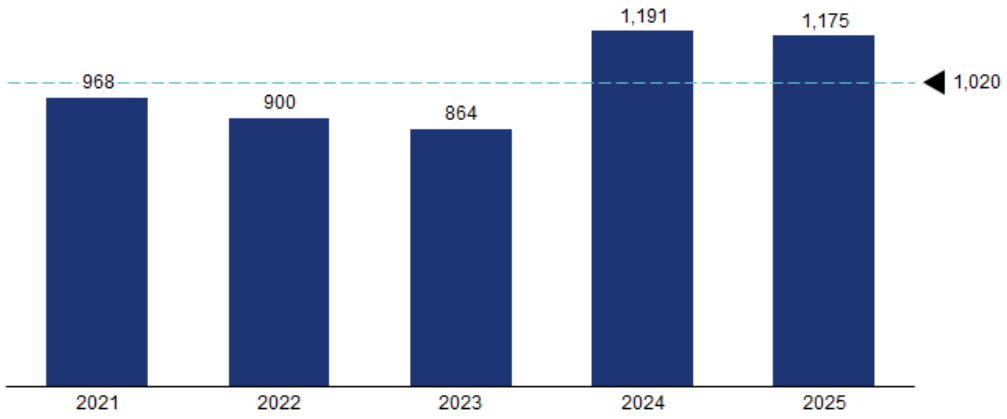
Because underground repairs generally take longer to locate and restore than overhead work, URD systems are commonly configured in a looped design to provide two independent paths for service. This configuration maintains service continuity during a single cable failure and supports compliance with reliability standards. There are two primary URD cable types distinguished by manufacturing era: cable installed prior to 1985 uses non-tree-retardant XLPE insulation, which is more prone to failure, while cable installed after 1985 incorporates tree-retardant XLPE (TR-XLPE) insulation to improve reliability and reduce insulation degradation. Approximately 23% of DTE's URD cable consists of pre-1985, non-tree-retardant cable as shown in Exhibit 4.28.

Exhibit 4.28 – URD Cable Types - Average Age and Useful Life

URD Type	Pre-1985	1985+
URD Cable Miles	2,618	8,736
Percentage of Total Population	23%	77%
Average Age (years)	45	25
Useful Life (years)	40	50

The likelihood of a URD cable failure generally increases with cable age and accelerates after an initial failure event. Based on an average of the two primary cable types, the manufacturer's expected useful life for URD cable is approximately 45 years. Over the past five years, approximately 1,020 URD cables failed annually, on average, as illustrated in Exhibit 4.29. This trend underscores the need for proactive cable replacement to mitigate reliability risks and reduce emergent restoration costs.

Exhibit 4.29 – Five-Year Historical URD Cable Failures



Single URD cable faults (outages) are typically restored promptly once an underground splicing crew arrives and bypasses the failed section by backfeeding customers from an alternate source

on the URD loop. Following this initial restoration, additional work is required to locate and repair or replace the original fault and return the electric grid to normal operating conditions. This interim condition, referred to as an "open loop," eliminates system redundancy and creates a heightened reliability risk. If a second URD failure occurs on the same loop while it remains open, customers will experience a new long-duration outage, often exceeding four hours, because no alternate feed is available during cable replacement.[47] Detailed outage data for URD double-cable failures are provided in Exhibit 4.30.

Exhibit 4.30 – Summary of URD Double Cable Failures within Six Months of First Failure

	2021	2022	2023	2024	2025
URD Double Cable Failures	59	32	115	125	99
Customers Impacted	2,542	1,749	5,415	4,558	4,566
Outage Duration (hours)	370	187	791	577	364
Average Outage Duration (hours)	6.3	5.9	6.9	5.8	3.6
Total Customer Outage (minutes)	837,078	683,363	2,574,899	1,410,736	837,344

DTE's URD cable has an average age of 27 years, with approximately 2,600 miles, or about 23%, at or beyond its useful life. Additionally, roughly 1,700 miles, or approximately 15% of the population, have been assessed as high risk for failure based on the condition assessment factors summarized in Exhibit 4.31.

Exhibit 4.31 – URD Cable Condition Assessment Factors

Factors	Impact
Manufacturing Year	Pre-1985, the insulation is XLPE (non-tree retardant). Post-1985, the insulation is TR-XLPE (tree retardant).
Number of Outages	The rate of URD cable failures increases with the age of the cable; the rate further increases once a cable experiences its first failure.

To address these risks within available funding constraints, DTE has implemented a risk-based URD replacement program that prioritizes the most impactful segments of the system. Similar to system cable replacement, the Company plans to accelerate proactive URD replacement, as described in Section 6.2.6 (System Equipment Replacement).

[47] In some cases, the Company can deploy a temporary cable to bypass one of the faults, restoring service to all customers before completing the full cable replacement.

4.2.4 Technology and Grid Communication Assets

As described in the preceding sections, DTE's grid is built on a foundation of long-lived physical infrastructure, including substations, overhead equipment, and underground systems. In parallel with this traditional infrastructure, operational and information technology systems that enable real-time monitoring, control, automation, data processing, and communication across the electric system are critical to the overall operation of the grid. These technological assets now play a central role in grid safety, reliability, and resiliency, and their importance continues to grow as the grid becomes increasingly automated and data driven. Exhibit 4.32 provides an overview of the four major groups of technological assets.

Exhibit 4.32 – Technology and Grid Communication Asset Overview by Group

Group	Purpose	Examples
Field Devices	Sense, measure, and control grid conditions	SCADA devices, smart meters, reclosers, automated switches, and communications radios
Control Center Platforms	Monitor, analyze, and operate the grid in real time	SCADA master systems, ADMS/OMS/GMS applications, and their associated servers, storage systems, and databases
Communications Infrastructure	Connects devices and control systems	AMI mesh networks, private fiber, microwave, and wireless backhaul links
Cybersecurity and Supporting Technology	Keeps the grid secure	Firewalls, endpoint protections, encryption systems, and monitoring tools

Together, these systems form the digital layer of modern grid operations, enabling DTE to detect and isolate outages more quickly, automate switching, integrate new DERs, maintain voltage and power quality, and respond to rapidly changing system conditions.

Overview of DTE's Technology and Grid Communication Assets

DTE now manages a large and fast-growing portfolio of technological assets, including:

- Approximately 1,000 operational servers located across two hardened data centers supporting SCADA, AMI, ADMS/OMS/GMS, and other mission critical grid applications.[48]
- More than 6,000 SCADA devices deployed throughout substations, on distribution circuits, and on pole-top equipment, enabling real-time control and visibility.

[48] SCADA indicates Supervisory Control and Data Acquisition. AMI indicates Advanced Metering Infrastructure. ADMS indicates Advanced Distribution Management System. OMS indicates Outage Management System. GMS indicates Generation Management System.

- 2.6 million electric meters, the majority of which are AMI-enabled and communicate over a dedicated mesh network.
- A substantial and expanding inventory of AMI routers, access points, relays, sensors, and field networking equipment, which serve as the communications backbone between field devices and central systems.

Exhibit 4.33 and Exhibit 4.34 provide an overview of the Company's AMI mesh networking equipment supporting communication with meters and SCADA equipment.

Exhibit 4.33 – Number of DTE Meters by Age (thousands)

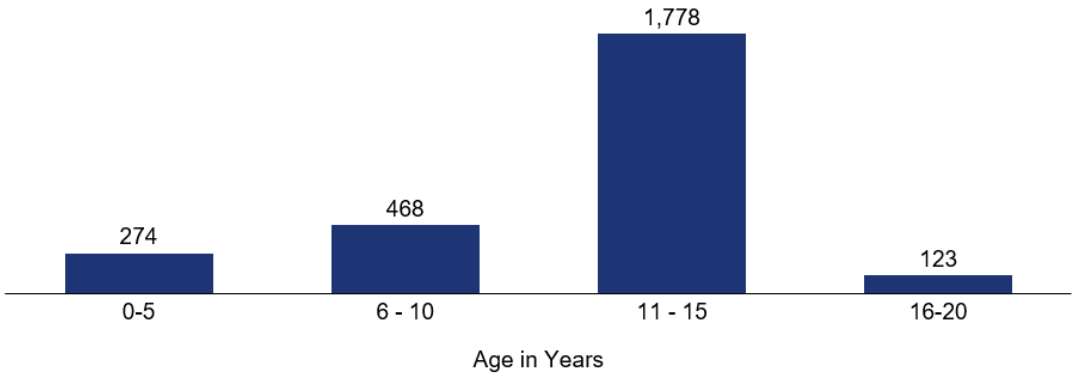
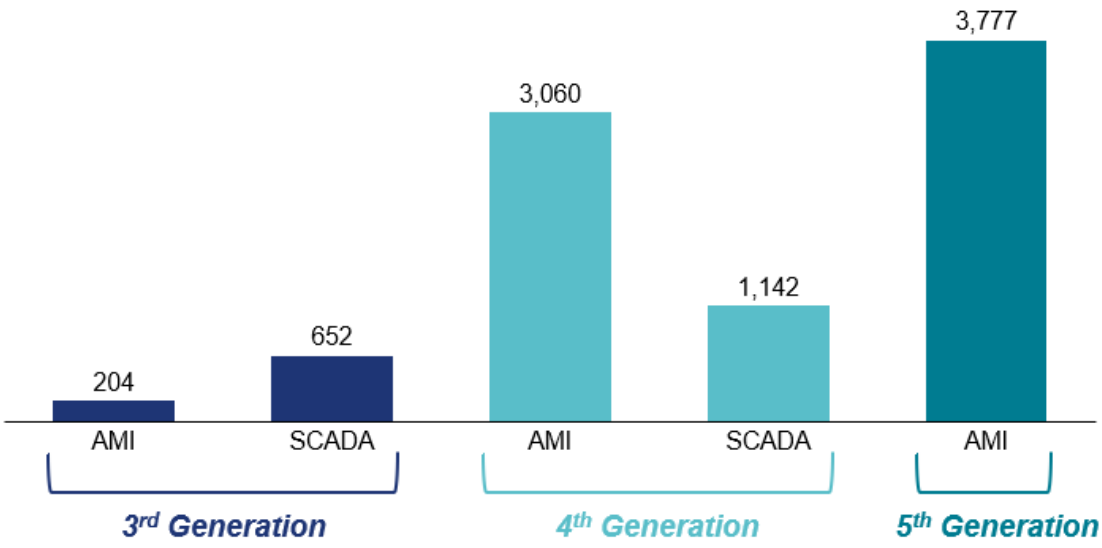


Exhibit 4.34 – Mesh Networking Equipment by Hardware Generation



The scale of this fleet reflects both the complexity of the modern grid and the critical role technology now plays in daily operations.

Differences from Traditional Infrastructure

Unlike poles, cables, transformers, and other hardware components described above, technological assets operate under fundamentally different lifecycle characteristics. First, technology lifecycles are compressed — typically only seven to 10 years — due to rapid innovation and more frequent software upgrade needs. Second, operational technology (OT) systems are highly interconnected as changes to one component can affect many others, requiring careful coordination. Third, as connectivity expands, so does the third-party attack surface, driving the need for enhanced security controls and regulatory compliance. Finally, because large utility technology deployments often take 18 to 36 months to implement, utilities must plan several years in advance to ensure that essential systems are modern, supported, secure, and fully integrated.

These differences require distinct planning, management, and investment strategies as compared to physical grid infrastructure. The 2026 DSP covers these areas in more detail throughout the report, particularly in Sections 4.4.2 (Weather Event Response and Restoration), 5.2.2 (Operational Technology Prioritization Framework), 6.4 (Technology and Automation), and 6.5 (Grid Edge and Distributed Intelligence).

4.3 Historical Grid Performance Data

Sections 4.3.1 through 4.3.5 present a comprehensive, data-driven review of DTE's recent operational performance, covering grid safety, reliability, outage events, historical investment, and overlay maps. This analysis builds on Section 4.2 (General Asset Health and Condition) to provide additional basis and context for the DSP.

4.3.1 Grid Safety and Historical Safety Incidents

Safety is DTE's top priority and one of the foremost planning objectives for the DSP as noted in Section 2.1 (Distribution System Plan Purpose). The grid is designed to operate and maintain high voltages safely and reliably. Through rigorous training, continuous improvement, adherence

to good utility practices, and public communications, the Company's top priority is to protect its workforce and the communities it serves. As equipment ages, the risk of failures increases, including poles failing during vehicle impacts or extreme weather events and downed wires from old, brittle conductors. Additionally, the grid also has many older vintage oil circuit breakers that could have failures and potentially result in ancillary damage and fires.

The Company notifies the Commission regarding safety incidents associated with grid assets as required per Michigan Administrative Rule R 460.3804, which states "An electric utility or cooperative shall promptly notify the commission of fatalities and serious injuries that are substantially related to the facilities or operations of the facilities."[49] Between January 2023 through December 2025, there were eight incidents that hit the threshold of serious injuries or fatalities. Six of these incidents involved contractors or members of the public coming into contact with overhead lines or equipment, one was a member of the public who contacted a downed ungrounded wire, and one was an employee struck by a piece of equipment. These incidents include injuries resulting from other non-utility structures or equipment contacting overhead lines and other incidents that do not bear on the relative safety of the system.

DTE is committed to learning from every event and is continuously strengthening its safety culture. In addition, the Company is actively strengthening its electric grid to further reduce safety risk exposure. Examples of these initiatives include:

- **URD Replacement:** Replaces live-front transformers with safer, modern dead-front designs.
- **4.8 kV Conversions:** Upgrades aging infrastructure to the more modern 13.2 kV system.
- **Distribution Automation:** Enhances the system's ability to rapidly detect and de-energize downed wires, in addition to providing significant reliability benefits across the system.

Further information on these programs is provided in Sections 6.2.6 (System Equipment Replacement), 6.3.1 (4.8 kV and 8.3 kV Conversions), and 6.4.1 (Distribution Automation).

[49] Michigan Administrative Code R 460.3804, available at https://ars.apps.lara.state.mi.us/AdminCode/DownloadAdminCodeFile?FileName=R%20460.3101%20to%20R%20460.3908.pdf, accessed April 2, 2026.

4.3.2 Historical Reliability Metrics

DTE utilizes five standardized reliability metrics in accordance with Standard 1366 from the Institute of Electrical and Electronics Engineers (IEEE),[50] as shown in Exhibit 4.35, to measure system performance and identify opportunities for improvement.

Exhibit 4.35 – IEEE 1366 Standardized Reliability Indices

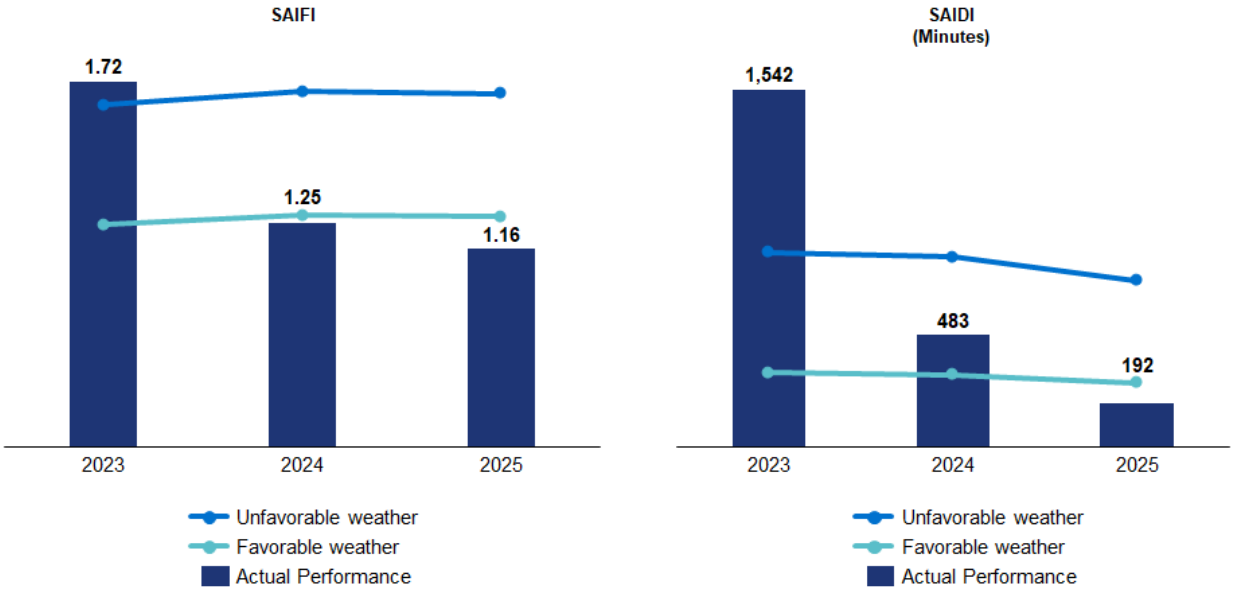
Index	Full Name	Definition
SAIFI	System Average Interruption Frequency Index	Average number of outages per customer per year
SAIDI	System Average Interruption Duration Index	Average total outage duration per customer per year
CAIDI	Customer Average Interruption Duration Index	Average duration of outages experienced by affected customers per year
CEMI-n	Customers Experiencing Multiple Interruptions	Percentage of customers experiencing specified number of outages (n) or more in a year
CELID-n	Customers Experiencing Long Interruption Durations	Percentage of customers experiencing at least one outage longer than a specified threshold per year (n hours)

The Company follows MPSC guidance and industry practices by monitoring CEMI-4 (percentage of customers with four or more sustained outages) and CELID-8 (percentage of customers with outages lasting eight or more hours). All five of these reliability metrics are typically calculated under all-weather (AW) conditions. A Major Event Day (MED) is defined as any 24-hour period where there is a significant statistical difference in daily SAIDI as defined in IEEE Standard 1366 and summarized in Appendix 8.5 (Additional Reliability and Outage Information). The MED threshold is based on five years of trailing daily SAIDI data and updated annually. Excluding MEDs gives a clearer picture of day-to-day system performance and customer experience absent variable, significant weather events.

Exhibit 4.36 presents the comparison between the reliability projections from the 2023 DGP with actual system performance from 2023 through 2025. DTE's actual performance in 2024 and 2025 met or exceeded the Company's prior reliability projections presented in the 2023 DGP. The exception is in calendar year 2023, during which system performance was adversely impacted by three catastrophic storm events.

[50] IEEE 1366-2022 - IEEE Guide for Electric Power Distribution Reliability Indices, available at https://ieeexplore.ieee.org/document/9955492/metrics#metrics, accessed March 5, 2026.

Exhibit 4.36 – Comparison of 2023 DGP All-Weather Reliability Projections and Actual Performance, 2023–2025



Peer Utility Benchmarking

Exhibit 4.37 shows DTE historical AW reliability metrics for the last five years in comparison to peer utility performance quartiles. The Company uses quartile benchmarks published annually by IEEE to evaluate its performance against industry peers. The IEEE report is a blind report that aggregates reliability results from more than 70 utilities. Reliability results for the IEEE benchmark are self-submitted by each utility, with each utility using their own interpretation of what constitutes a reportable outage, so the results have some variability based on these individual company interpretations. Since DTE includes every outage in its metrics, the Company expects this comparison to provide a conservative representation of actual reliability performance when compared to industry peers. The AW reliability metrics can vary by time and region of the country based on localized weather patterns in a given year. However, they best represent the reliability that customers have experienced in a year.

Exhibit 4.37 – DTE All-Weather Reliability Metrics[51]

DTE's AW performance in 2025, measured against 2024 quartile benchmarks, is projected to rank in the second quartile for outage frequency (SAIFI) and the first quartile for outage duration (SAIDI). Capital investments in the grid, paired with process improvements and a year of less severe weather, drove a nearly 70% reduction in outage minutes between 2023 and 2024. Reliability continued to improve in 2025, with outage duration falling by approximately 60% from 2024 levels, making it the most reliable year DTE customers have experienced in nearly two decades. While 2025 experienced weather that was, on average, more favorable than in recent

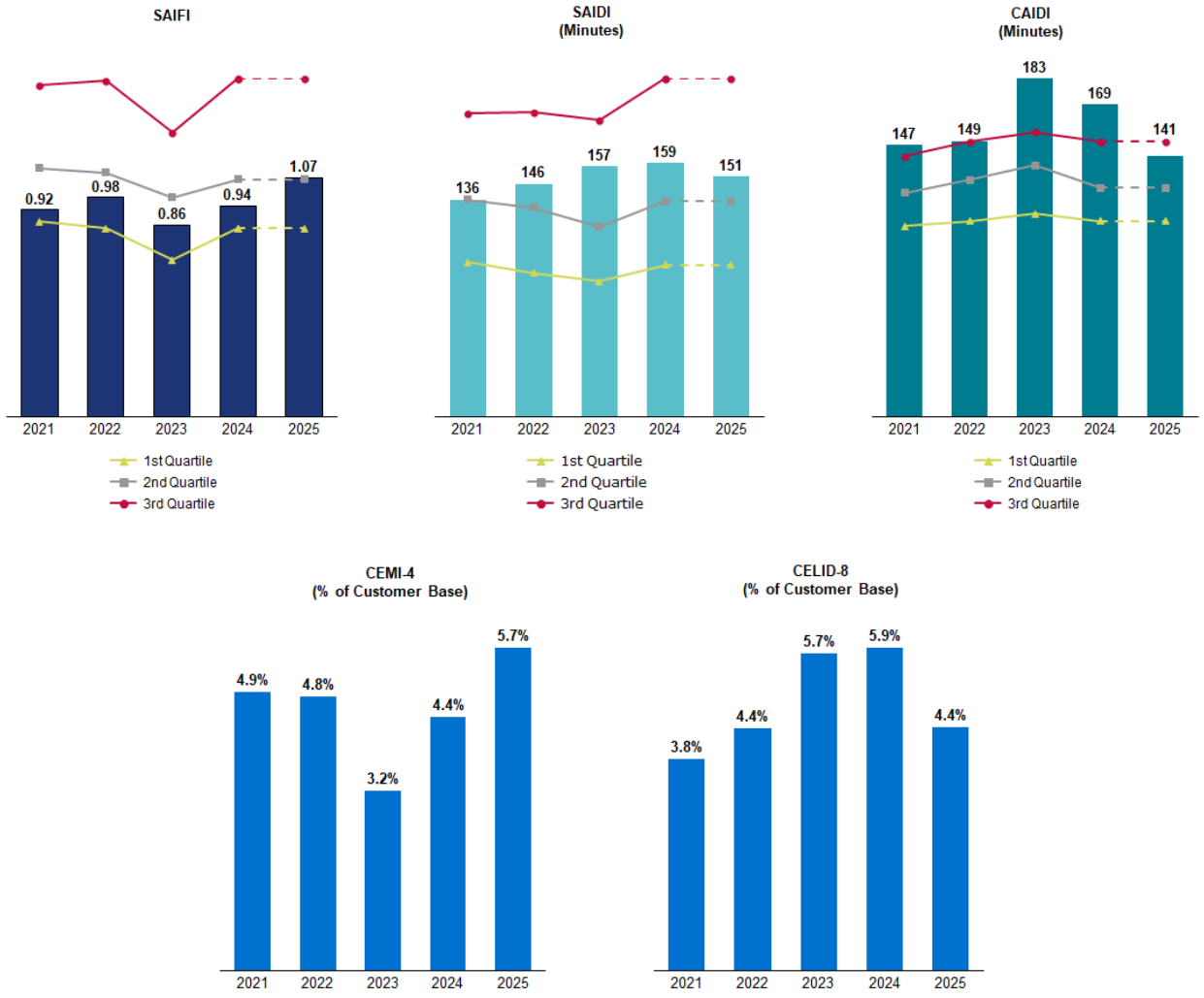
[51] IEEE does not provide quartiles for CEMI-4 and CELID-8. CEMI-4 benchmark quartile data shown is separately derived by EEI. The 2025 quartile data shown reflect a linear extrapolation of the 2024 data for reference only, as 2025 quartile data are not yet available (anticipated in Q4 2026).

years in terms of storm events, these results still demonstrate that the Company's strategic grid investments and ongoing process improvements are delivering clear, measurable, and meaningful improvements in system reliability.

Reliability metrics that exclude major event days (exMED) allow for a review of trends over time and provide a comparison between utilities in different weather regions of the country, with some of the variability of weather impacts excluded from the data. DTE's exMED reliability metrics have generally remained steady or improved. It is important to note that because the exMED threshold is based on historical daily SAIDI over a rolling five-year window, an outlier event within that five-year window can distort the exMED results. When an extreme event occurs in the look-back window, it raises the exMED threshold and causes higher-impact days — days that would normally be excluded — to be included in the exMED calculation in the year following the five-year window. For DTE, the significant outlier weather events in 2021 and 2023 continue to materially influence recent exMED performance. Assuming events of this magnitude do not recur, this effect is expected to phase out in 2027 through 2029, as 2021 and 2023 daily SAIDI drop from the five-year look-back window. Exhibit 4.38 compares DTE's exMED performance over the past five years with the IEEE-provided utility performance quartiles.

Storm restoration – downed secondary wire

Exhibit 4.38 – DTE exMED Reliability Metrics[52]



Performance by MPSC-Defined Conditions

Beyond IEEE-standardized MED conditions, DTE also measures the three primary reliability metrics under Normal, Gray Sky, and Catastrophic conditions. For both Gray Sky and Catastrophic conditions, DTE utilizes a 24-hour rolling methodology to determine the event window as explained in Appendix 8.5 (Additional Reliability and Outage Information). In Case No. U-20629,[53] the MPSC defined Gray Sky conditions as events that impact more than 1% but less than 10% of customers and Catastrophic conditions as events affecting 10% or more of the customer base. Normal conditions are those that do not meet either threshold. As discussed

[52] The 2025 quartile data shown for SAIFI, SAIDI, and CAIDI reflect a linear extrapolation of the 2024 data for reference only, as 2025 quartile data are not yet available (anticipated in Q4 2026). IEEE does not provide quartiles for exMED CEMI-4 and CELID-8. No other benchmark data is available for exMED CEMI-4 or exMED CELID-8.

[53] Order dated March 24, 2023 in Case No. U-20629, available at https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/0688y000007IzfgAAC, accessed March 5, 2026.

earlier and shown in Exhibit 4.39, Exhibit 4.40 and Exhibit 4.41, restoration performance has improved over the last two years, and the Company did not experience any Catastrophic condition events in 2025.

Exhibit 4.39 – DTE Historical Reliability Metrics, Normal Conditions

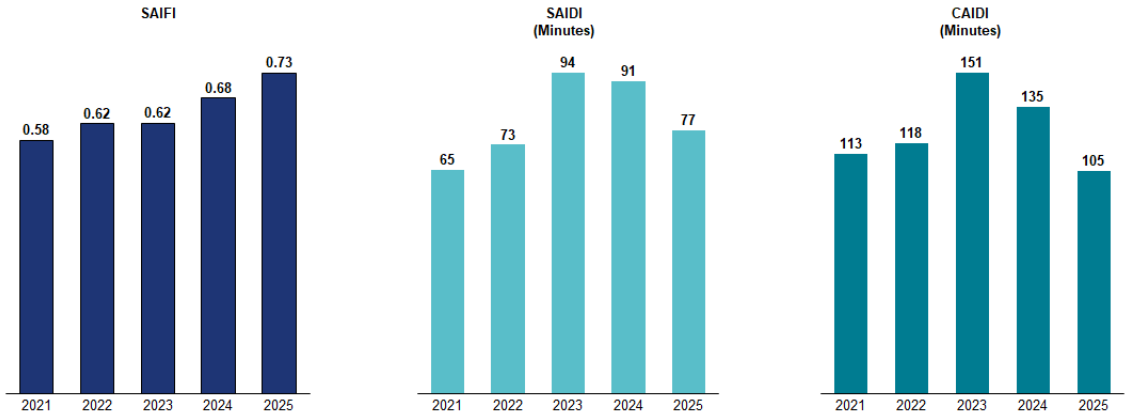


Exhibit 4.40 – DTE Historical Reliability Metrics, Gray Sky Conditions

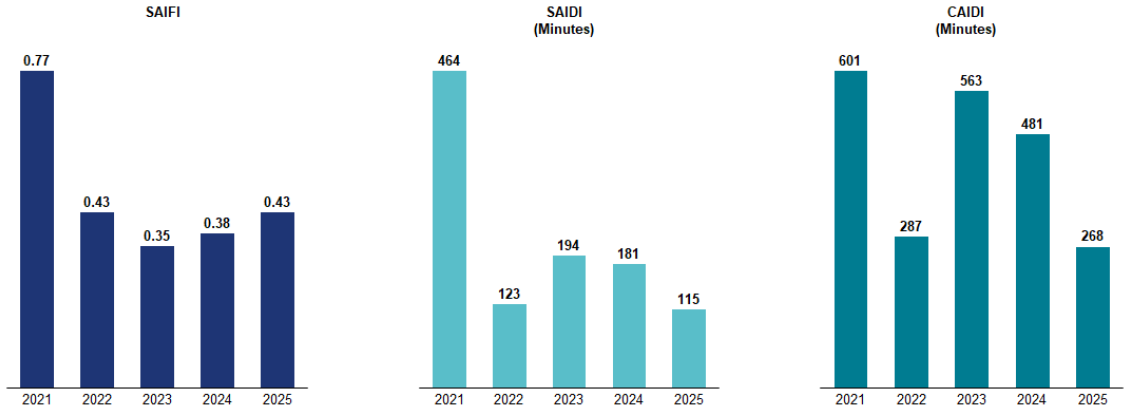
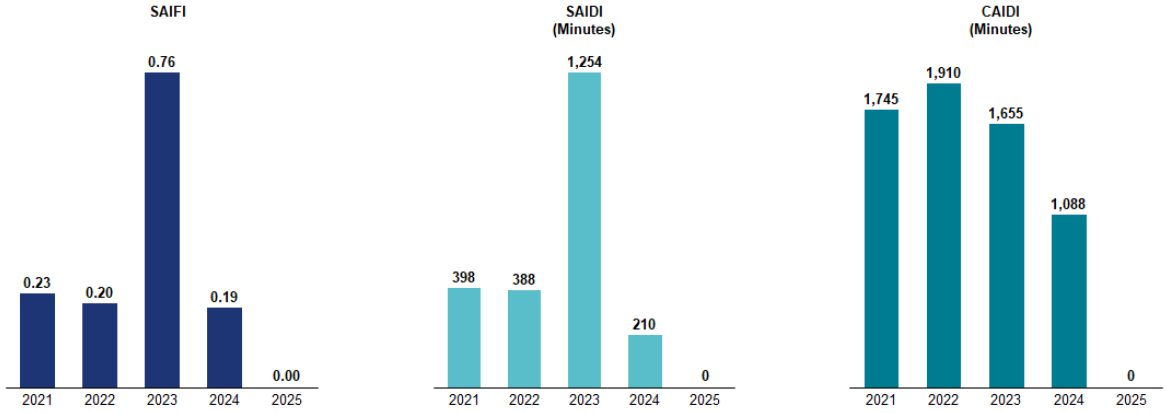


Exhibit 4.41 – DTE Historical Reliability Metrics, Catastrophic Conditions



Several of the metrics described in this section are also incorporated into the PBR mechanism, discussed further in Section 7.2.2 (Performance Metrics). DTE continues to leverage both system investments and operational improvements to meet or exceed MPSC-defined targets. The Company will maintain its use of AW, exMED, and MPSC-defined conditions to monitor system performance and guide its investment strategy moving forward.

4.3.3 Historical Outage Events

DTE, like other utilities, experiences interruptions in electric service to customers. Outages may occur under any weather conditions, but the frequency and size of outages tend to increase as weather conditions shift from Normal to Gray Sky to Catastrophic conditions, as defined in Section 4.3.2 (Historical Reliability Metrics). The Company tracks large historical outage events affecting more than 1% of the customer base to better understand primary outage drivers, address root causes, and inform future investment plans. From 2021 to 2025, DTE experienced a total of 88 Gray Sky and Catastrophic outage events that affected more than 1% of its customer base. A list of 82 historical Gray Sky outage events from the past five years is provided in Appendix 8.5 (Additional Reliability and Outage Information), including each event's start and end dates, the number of customers affected, and the percentage of the customer base impacted. Exhibit 4.42 provides a similar list of the six Catastrophic outage events the Company experienced from 2021 to 2025, along with the associated cost of restoration required. Maps of these events, including circuit-level percentages of customers affected, are included in Appendix 8.5 (Additional Reliability and Outage Information).

Linemen restoring power

Exhibit 4.42 – Five-Year Historical Catastrophic Outage Events

Event No.	Event Start Date	Event End Date	Unique Customers Affected	Percentage of Customer Base Affected	O&M Costs Incurred ($ millions)	Capital Costs Incurred ($ millions)
1	08/08/2021	08/19/2021	450,575	20%	19.9	107.0
2	08/29/2022	09/04/2022	421,043	19%	26.0	65.2
3	02/22/2023	03/07/2023	676,283	30%	98.6	106.7
4	07/26/2023	07/30/2023	316,657	14%	25.5	35.3
5	08/23/2023	08/30/2023	400,224	18%	27.7	68.2
6	08/27/2024	09/01/2024	386,880	17%	23.2	62.9

The Company also tracks the underlying causes of interruptions to the electrical system. Gray Sky events are primarily associated with notable weather conditions, such as high winds and thunderstorms. Catastrophic events have been driven by significant weather and storm activity experienced in DTE's service area, including multiple rounds of heavy rain and strong winds during the summer of 2021 and a major ice and snowstorm in the winter of 2023. Exhibit 4.43 and Exhibit 4.44 present a detailed breakdown of outage event contributions to SAIFI and SAIDI, respectively, by cause using IEEE Level 1 standard classifications.

Exhibit 4.43 – Five-Year System Average Interruptions by Cause (SAIFI)

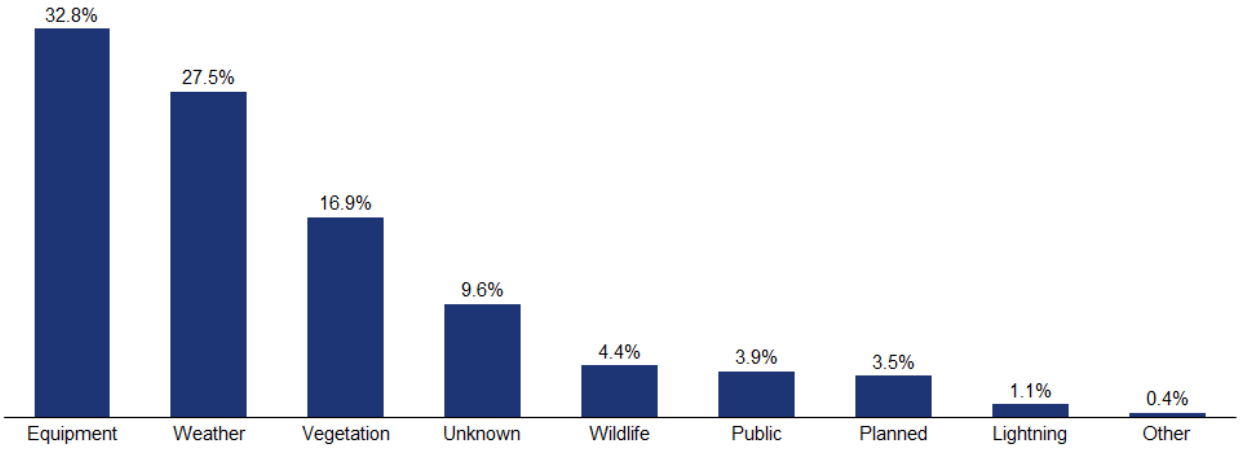
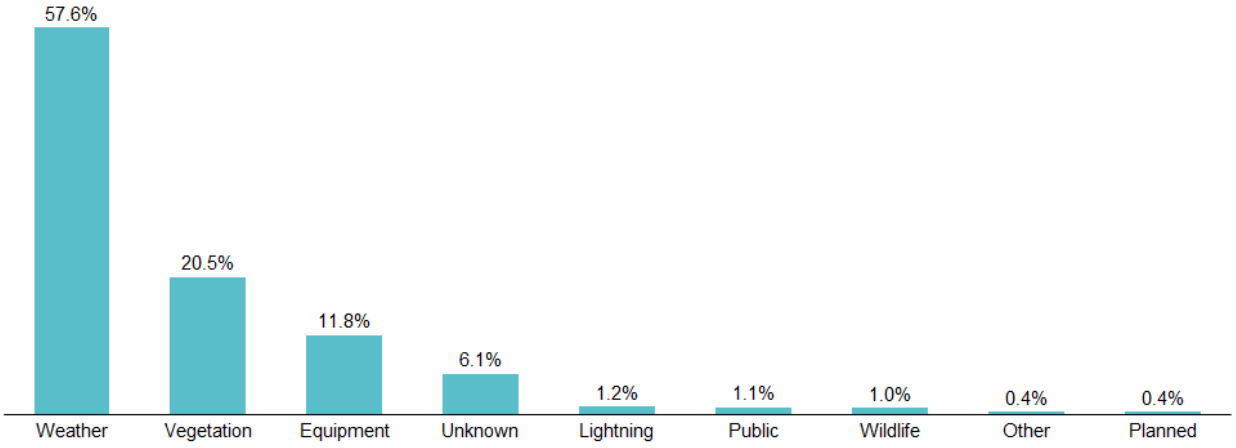


Exhibit 4.44 – Five-Year System Average Interruption Duration by Cause (SAIDI)



Based on a five-year average, equipment, weather, and vegetation are the top three causes of outages. While these outage causes are reported using IEEE Level 1 standardized classifications, certain underlying drivers may be underrepresented when viewed at this high level. For example, vegetation-related impacts are often captured within the broader "weather" cause code, even

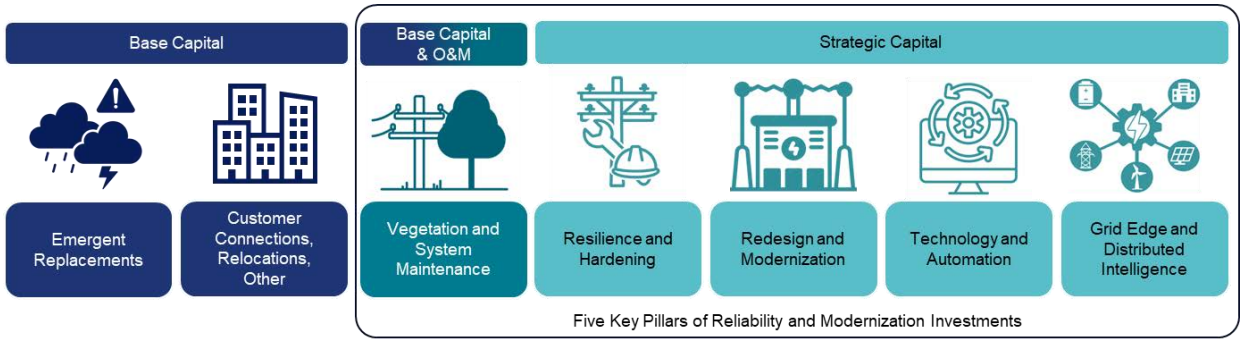
though a portion of these outages ultimately involves vegetation contacting energized facilities. In addition, aged equipment built to older, less-robust engineering standards — such as small-wire conductors or condemned poles — is more likely to fail during external events. As a result, although equipment-related outages account for a relatively smaller share of SAIDI when viewed narrowly, equipment condition and system hardening play a significant role in mitigating outage impacts that might otherwise be attributed to weather or vegetation.

Interpreting outage data therefore requires consideration of both the initiating cause and the ability of the underlying infrastructure to withstand that condition. In many cases, outages result from the interaction of these two factors. Consistent with industry practices, DTE classifies outages based on the initiating cause and supplements this categorization with secondary cause analysis to support more detailed root cause evaluation. Outage data is a critical input to the Company's planning process and informs how investments are targeted toward the leading drivers of customer interruptions. To further strengthen this approach, DTE continues to enhance its cause classification framework and pursue more granular outage data to better assess system performance under specific conditions. These efforts improve insight into outage drivers, support more effective root cause analysis, and better align future investments with the conditions that most affect customer reliability.

4.3.4 Historical O&M and Capital Spend

Operations and maintenance (O&M) expenses and capital investments are categorized, consistent with standard utility accounting practices and in compliance with the guidance in the FERC Uniform System of Accounts, to clearly distinguish between O&M costs that support the ongoing operation, maintenance, and restoration of the electric grid and capital investments that upgrade or construct the physical assets necessary to provide electric service. O&M expenses are grouped into Base, Non-Storm Emergent, Storm Emergent, Preventative Maintenance, and Vegetation Management categories, while capital investments are organized into Base Capital and Strategic Capital. Exhibit 4.45 illustrates how the strategic framework introduced in Section 2.4 (Five Pillars of Reliability and Modernization Investments) aligns to these O&M and capital categories.

Exhibit 4.45 – Overview of O&M and Capital Investment



O&M Expenditures

O&M expenditures are organized into categories that reflect the type of work performed on the electric grid. Base O&M captures routine activities required to operate and sustain existing infrastructure. Emergent O&M addresses restoration and repair work and is split into Non-Storm Emergent activities, which occur outside of major weather events, and Storm Emergent activities, which arise in response to weather-related events in storm conditions. PM includes inspections, testing, and other proactive efforts designed to identify and resolve potential issues before they impact system performance. Vegetation Management encompasses costs associated with controlling vegetation growth to maintain system safety and reliability. Pole and Pole-Top Maintenance and Modernization (PTMM) inspections are comprehensive inspections of poles and associated pole-top equipment on subtransmission and distribution overhead circuits, including crossarms, insulators, and related components, to assess actual asset condition.

This DSP presents historical O&M expenses based on internal O&M reporting, which is consistent with the basis used for the O&M forecast presented in Section 5.3.1 (Forecasted O&M and Capital Investments). This excludes benefits, payroll tax, and incentive compensation. Since this presentation differs from the FERC accounting required in electric rate cases, the Company provides an overview of adjustments between internal O&M reporting and FERC accounting in Appendix 8.6 (Historical Regulatory Financial Alignment). Exhibit 4.46 provides the five-year historical O&M expenses aggregated into Base, Non-Storm Emergent, Storm Emergent, Preventative Maintenance, and Vegetation Management categories.

Exhibit 4.46 – Historical O&M Expenses, 2021-2025 ($ thousands)[54]

	2021	2022	2023	2024	2025
Base O&M	72,550	82,227	67,771	77,221	77,046
Non-Storm Emergent	54,703	69,581	60,163	57,355	72,561
Storm Emergent	75,769	59,921	183,786	59,563	20,061
Preventative Maintenance	7,142	11,332	6,495	11,749	10,618
Vegetation Management[55]	171,659	239,570	169,670	159,193	238,648
PTMM Inspections[56]	-	-	136	625	967
Historical O&M Expenses Total[57]	381,823	462,630	488,022	365,706	419,901
Adjustments for FERC Accounting	36,996	-51,586	7,715	14,407	17,838
Total Distribution Expenses Exhibit A-13 Schedule C5.6 and C5.6.1[58]	**418,819**	**411,044**	**495,737**	**380,113**	**437,739**

Capital Investments

Similar to O&M, capital investments are categorized to reflect the nature of the corresponding work. Base Capital supports essential investments to address emergent issues and specific customer needs. These investments are grouped into Emergent Replacements — covering storm, non-storm, and substation reactive programs, including Corrective Maintenance within Vegetation and System Maintenance — and Customer Connections, Relocations, and Other (CCRO).[59] Strategic Capital investments harden and modernize the system and digitize operations, so reliability continues to improve even as the system grows more complex. Strategic capital is organized into four pillars: Resilience and Hardening, Redesign and Modernization, Technology and Automation, and Grid Edge and Distributed Intelligence.

Exhibit 4.47 provides historic capital investments based on the categorization described above. Accordingly, the historic totals match the overall investment levels previously presented in the Company's regulatory filings, while individual pillar allocations may differ as projects and programs have moved between pillars or into new pillars. DTE provides additional detail on

[54] Totals may not match exactly to the mathematical summation in the table due to rounding of the source data.

[55] Including Regulatory Asset costs (in $ thousands) of 70,500 in 2021, 58,200 in 2022, 67,000 in 2023, 54,438 in 2024, and 128,962 in 2025.

[56] The Company updated its capitalization policy effective January 1, 2023 to no longer capitalize pole inspection and testing costs associated with the PTMM Program.

[57] Historical Corrective Maintenance expenses are included in Non-storm Emergent and Storm Emergent. The Corrective Maintenance forecast is identified separately in Section 5.3.1 (Forecasted O&M and Capital Investments).

[58] U-21297, U-21534, U-21860, U-21860 MNSC-3.16 DO 2024 O&M Actuals, U-22046.

[59] Other includes Electric System Equipment, Normal Retirement Unit Change-out (NRUC) and Improvement Blankets, and General Plant, Tools, & Equipment, and Miscellaneous.

historical capital aligned to the current investment pillars in Appendix 8.6 (Historical Regulatory Financial Alignment).

Exhibit 4.47 – Historical Capital Investment, 2021-2025 ($ thousands)[60,61]

Type	Pillar	2021	2022	2023	2024	2025
Base						
	Emergent Replacements	650,531	484,722	524,073	472,039	534,675
	CCRO	262,252	296,474	282,897	348,520	380,032
Strategic						
	Resilience and Hardening	187,406	420,748	384,588	363,451	343,241
	Redesign and Modernization	100,842	181,392	284,871	324,466	338,845
	Technology and Automation	62,574	96,472	128,284	151,149	152,238
	Grid Edge and Distributed Intelligence	10,239	16,328	21,679	21,200	6,825
Total		**1,273,844**	**1,496,136**	**1,626,392**	**1,680,825**	**1,755,856**

4.3.5 Historical Overlay Maps

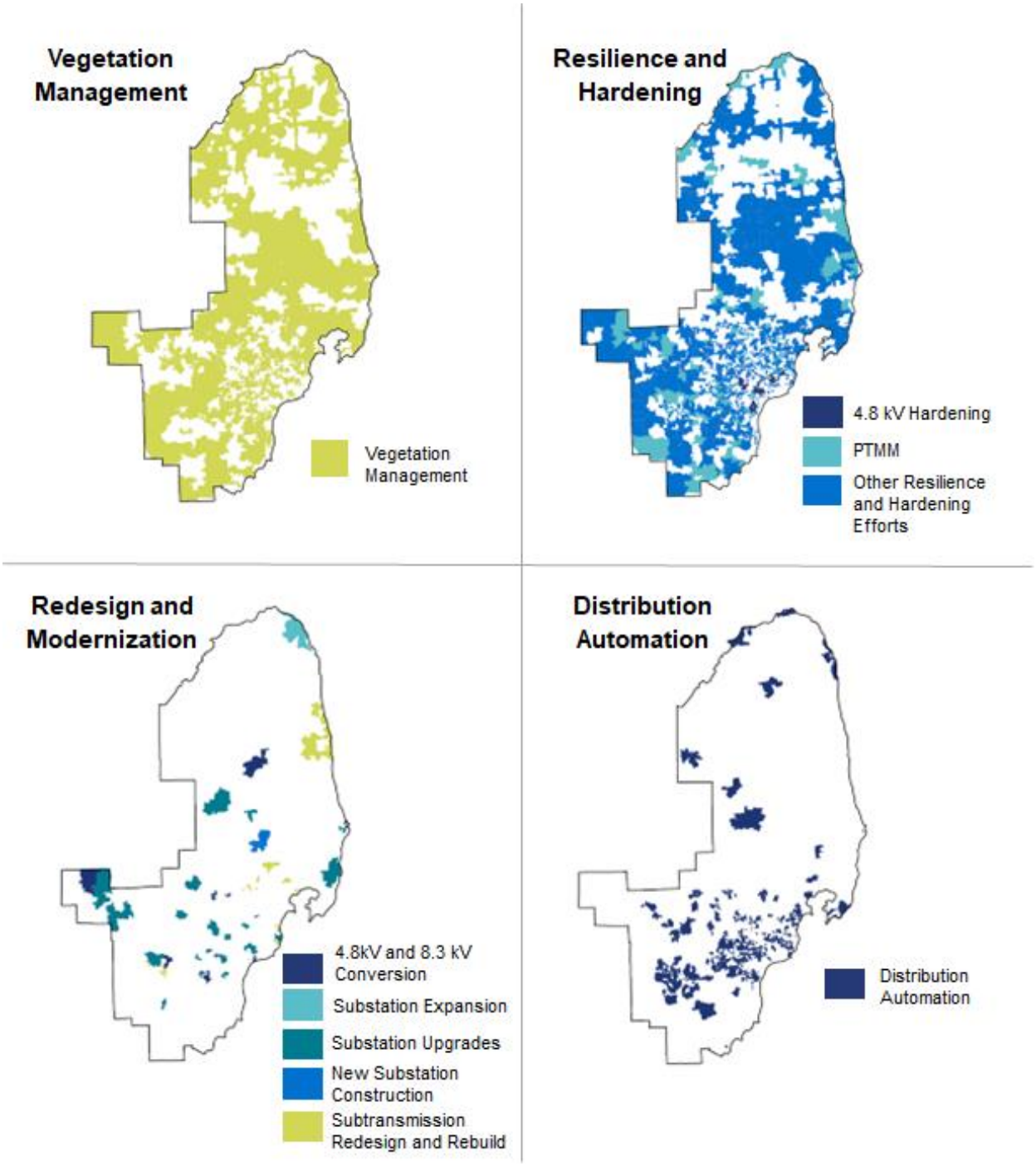
Customers and other interested stakeholders can review the Company's historical reliability-focused investments dating back to 2023 through the Power Improvements Map[62] described in Section 3.2.1 (Customer Engagement). The maps presented in Exhibit 4.48 summarize work completed between January 2023 and December 2025, organized by investment pillar. Together, these exhibits illustrate the geographic distribution of major reliability improvement initiatives.

[60] Historical investment levels include amounts recovered through base rates and the Infrastructure Recovery Mechanism (IRM). The IRM was authorized by the Commission beginning December 1, 2023, in Case No. U-21297. Accordingly, 2021-2022 investments reflect rate case filings, while 2023-2025 levels incorporate both rate case and IRM filings. Totals may not match exactly to the mathematical summation in the table due to rounding of the source data.

[61] Since its 2025 Electric Rate Case filing in Case No. U-21860, select programs have been realigned to appropriate investment pillars. For example, from the Technology and Automation pillar, Non-Wire Alternatives has shifted to Redesign and Modernization and Distributed Energy Resource Management System (DERMS) and Grid Automation Telecommunications have shifted to Grid Edge and Distributed Intelligence.

[62] Power Improvements Map, available at https://www.dteenergy.com/us/en/residential/service-request/system-improvements/system-improvements/power-improvements-map.html, accessed March 8, 2026.

Exhibit 4.48 – Investment Pillar Work Completed, January 2023-December 2025[63]



[63] "Other Resilience and Hardening Efforts" includes Frequent Outage, Strategic Reliability Improvement Program (SRIP), and System Cable Replacement.

4.4 Operations

The next four sections provide a brief overview of DTE's current operations that are not included in the investment programs discussed in Chapter 6 (Distribution System Plan Investment Pillars), to avoid duplication. These sections summarize asset management practices, weather event response and restoration activities, and Base Capital operations, including Emergent Replacements and CCRO.

4.4.1 Asset Management

Effective asset management is essential to the safety, reliability, and efficiency of utility operations. By managing physical assets across their full lifecycle — from planning and acquisition through operation, maintenance, and retirement — utilities can enhance performance, control costs, and deliver long-term value to customers and stakeholders. Key benefits of a structured asset management program include:

- **Service Continuity:** Proactive monitoring and maintenance help prevent equipment failures, reduce outages, and avoid unnecessary costs.
- **Optimized Asset Performance:** Lifecycle management, supported by condition-based monitoring, enables proactive identification of emerging issues, extends asset life, and reduces unplanned repairs.
- **Improved Risk Management:** Accurate, up-to-date asset condition information helps mitigate risks associated with aging infrastructure and severe weather.
- **Data-Driven Decision Making:** Technology such as Internet of Things (IoT) sensors, geographic information systems (GIS), and predictive analytics provide real-time asset health insights that can inform repair, replacement, and investment decisions.

To ensure reliable grid operations, DTE uses a comprehensive asset management framework aligned with EPRI guidance and ISO 55001 standards. It provides a consistent, structured approach to each stage of an asset's lifecycle, from initial planning through end-of-life decommissioning as illustrated in Exhibit 4.49.

Exhibit 4.49 – DO Asset Management Lifecycle Overview[64]

In addition to applying this structured framework, DTE is shifting from predominantly manual, reactive monitoring practices to a proactive, risk-based management approach. This transition moves maintenance activities away from time-based and corrective actions and toward condition-based and predictive strategies. By anticipating equipment failures and extending asset life, this approach helps prevent outages and improves the cost-effectiveness of maintenance activities. These enhancements are supported by expanded inspection programs, advanced sensing and diagnostic capabilities, and improved analytics, as described in Sections 6.1.2 (Preventative Maintenance and Inspections) and 6.4.4 (Asset Condition Monitoring Technology). To support this transition, the Company is implementing the following initiatives:

- **Digitizing Maintenance Records:** Replacing manual paper forms with digital workflows to improve data accuracy, standardization, and timeliness. Real-time field data capture strengthens asset health assessments and supports better decision-making.

[64] During the Retire phase of the asset management lifecycle, the end of an asset's useful life does not necessarily coincide with the end of its depreciable life.

- **Implementing Condition-Based Maintenance:** Prioritizing maintenance based on actual equipment condition rather than just age or elapsed time to reduce likelihood of catastrophic failures, minimize unplanned downtime, and optimize intervention timing.
- **Modernizing Asset Management Systems:** Upgrading Maximo and ESRI to enable real-time data integration, improve spatial accuracy, enhance field mobility, centralize asset health monitoring, and prepare for future cloud capabilities.

The Audit Report affirmed the direction of the Company's efforts, finding that "DTE's enhancements to its systems for supporting asset management are sound" and concluding that the "changes made and continuing to be made will move the Company forward."[65] This external validation underscores the value of DTE's investment in modernizing asset management processes and systems. Asset management is a strategic capability essential to delivering safe, reliable, and cost-effective service. By strengthening long-term planning, improving data quality, and integrating modern technologies, DTE is enhancing its ability to make informed investment decisions that balance reliability with affordability. These efforts position the grid to better withstand emerging risks and support a resilient energy future for Michigan.

4.4.2 Weather Event Response and Restoration

As discussed in Section 2.3 (Drivers of Investment), storms affecting Michigan are becoming more frequent and more severe. Storms that cause outages are typically driven by high winds, but rain, icing, and other factors can also have a significant impact on the electric grid. While losing power for any reason is difficult for customers, it is especially challenging when widespread damage extends restoration times. DTE has a robust and comprehensive process to respond to storms that is led by the Emergency Preparedness and Response (EP&R) organization. The EP&R team continuously monitors evolving weather conditions so it is in a constant state of preparedness and can quickly respond to the worst-case scenario. Storm response typically begins well before anticipated weather impacts and continues until the last affected customer is fully restored.

Scalable Weather Response and Restoration Overview

The Company defines eight operational modes to support weather response, ranging from Normal (fewer than 10,000 customers out) to CAT II Storm (220,000 or more customers out) as shown in Exhibit 4.50. Each operational mode is determined by the level of resources required to manage active outage events. Under Normal, operations proceed under standard conditions. High Normal

[65] Final Report, Utility Distribution Audit of DTE Energy (page 30), available at https://mipsc.my.site.com/sfc/servlet.shepherd/version/download/068cs00000AyaNpAAJ, accessed April 21, 2026.

and High Impact Day reflect an elevated response posture that includes deploying additional field crews, activating expanded support functions, and adjusting customer estimates. The storm operational modes, from Small Storm through CAT II Storm, represent sustained outage events that require resources beyond DTE's daily workforce to ensure efficient and effective restoration. Across categories, the Company scales its response across people, processes, and technology to match the anticipated system impact. By securing restoration-capable and pre-flighting support resources in advance, DTE is positioned to mitigate system risks early and begin immediate response to hazard and outage events as the weather moves through the electric system.

Exhibit 4.50 – Overview of DTE Operational Modes[66]

Operational Mode	Active Outage Events	Total Customers Affected	Total Estimated # of OHL Crews	Crew Types			Additional Support[67]
				DTE	Baseload	Foreign	
Normal	0 - 149	0 - 10k	< 75	70	5	-	None
High Normal	150 - 305	10k - 15k	75 - 125	70	50	-	Sometimes
High Impact Day	306 - 759	15k - 25k	125 - 190	70	120	-	Probable
Small Storm	760 - 1,006	25k - 40k	190 - 250	70	120	60	Always
Medium Storm	1,007 - 1,253	40k - 75k	250 - 275	70	120	85	Always
Large Storm	1,254 - 1,400	75k - 110k	275 - 300	70	120	110	Always
CAT I Storm	1,401 - 2,800	110k - 220k	300 - 525	70	120	335	Always
CAT II Storm	2,801+	220k+	525+	70	120	>335	Always

A storm is typically declared when outage volume exceeds 760 active outage events across at least 200 circuits for more than one hour, triggering activation of the formal Incident Command Structure (ICS). When forecasts indicate that outage levels may approach these thresholds, DTE proactively initiates its storm response process. DTE utilizes an ICS-based organizational structure to coordinate outage response during storm events, although it may also be executed at scale during other operational modes as needed. The ICS format is based on the Federal Emergency Management Agency (FEMA) National Incident Management System (NIMS) recommendation to establish a coordinated response among various jurisdictions during emergency conditions. The goal of ICS is to supplement normal daily operations by providing dedicated strategic and tactical leadership when the scale of outages and resources exceeds

[66] The Company reserves the right to amend, suspend, or terminate these levels at any time.

[67] Additional Support may include Public Protection, Service Restoration, Damage Assessment, and so forth as needed. Typical shifts are 12-16 hours but may be exceeded for emergencies.

normal capacity. The Central ICS organization is led by the Central Incident Commander (IC) and supported by six section chiefs with dedicated functions as described in Exhibit 4.51. The Central ICS organization sets objectives, aligns communications, and oversees the storm response.

Exhibit 4.51 – Key ICS Roles and Responsibilities

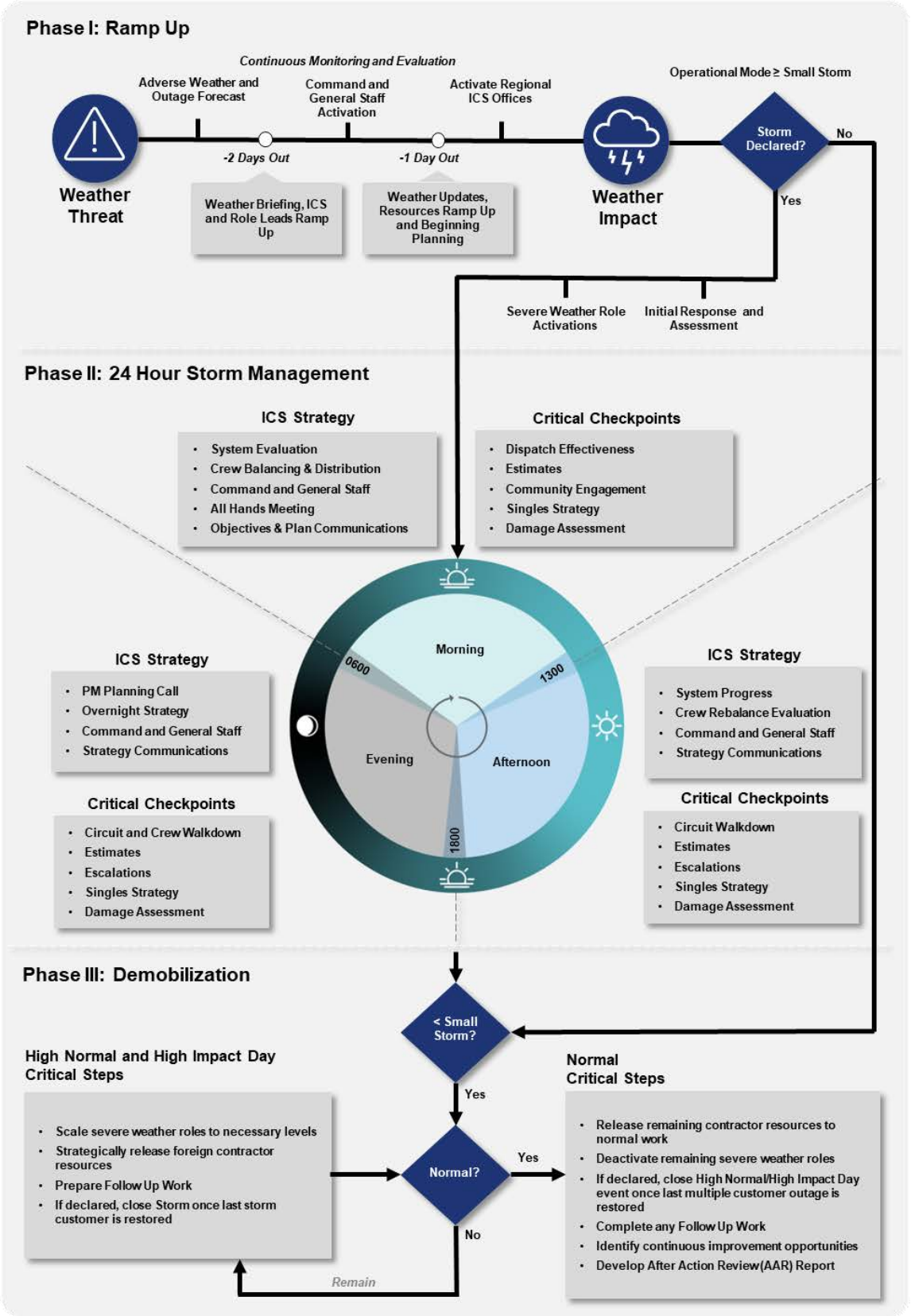
Role	Responsibilities
Incident Commander	Leader of the storm response. Charged with the overall decision-making authority for objectives, strategy, execution, and communications.
Operations Chief	Oversees field operations through Regional ICs to drive restoration aligned with Central IC, objectives, including overhead, underground, Vegetation Management, and substations restoration processes. Also includes the Emergency Field Leader (EFL) program coordination to connect contract resources with technical field crew oversight and guidance for safe operations.
System Operations Chief[68]	Oversees Electric System Operations Center (ESOC) and field operations to drive restoration aligned with Central IC objectives, including system supervision and electric dispatch teams responsible for switching, tagging, system reconfiguration, and field crew assignments. Also includes field teams performing preflight and restoration activities for specific outage and non-outage tasks related to a single location (i.e., customer home), including wire-down response.
Finance Chief	Tracks and projects the financial spend associated with a storm event.
Planning Chief	Oversees customer-experience functions, including coordination of internal and external communications, customer estimate strategy, damage evaluation scope for restoration teams, response for customer escalations, and compiling progress and performance data.
Logistics Chief	Oversees all contractor field labor and materials, inclusive of baseload contractors, local foreign contractors, and foreign contractors.[69] Also includes establishing staging sites for crews, material yards, and lodging accommodations as appropriate.
Technology Chief	Monitors and resolves issues related to critical technology responsible for event management, including communication systems, reporting, and applications.

Since DTE divides its service area into four regions, the Company has implemented a Regional ICS that mirrors the central command. This structure ensures decisions are made close to field activity, improving operational efficiency and accuracy. The Operations Chief leads and governs Regional ICS, which oversee their respective areas and are accountable for achieving the objectives from Central ICS. Once a storm is forecasted, DTE activates both its Central and Regional ICS to initiate communication and facilitate alignment around the Company's response plan as outlined in Exhibit 4.52.

[68] This role is adapted from an extension of the traditional NIMS ICS structure to distinguish between field operations and control room operations. Utilities require dedicated coordination for dispatching, switching, and grid reconfiguration, so the System Operations Chief is defined separately from the Operations Chief to ensure clear responsibilities and aligned decision-making.

[69] Baseload contractors refer to the embedded contractor workforce that are part of DTE's regular daily crew complement performing work on the electric system. Local foreign contractors refer to those contractors performing work outside of the electric system such as joint use and streetlighting but are qualified to perform line work if needed. Foreign contractors are resources brought onto DTE property, in many cases from outside Michigan, as needed.

Exhibit 4.52 – Storm Playbook Overview



Communications During Storms

The Company follows a comprehensive, scalable storm communications playbook that is fully aligned with its storm preparation, response, and restoration processes. This integrated approach ensures that customer and stakeholder communications closely track operational activities before, during, and after severe weather events. Communication tactics, including proactive social media and media outreach, website and outage center messaging, and direct-to-customer notifications, are deployed in proportion to storm severity and anticipated restoration duration.

Communications begin as soon as severe weather is forecasted. Ahead of a storm, DTE updates its outage center to reflect expected conditions and shares preparedness and safety information across social media channels. For large-scale or potentially catastrophic events, the Company may also conduct media briefings to outline readiness activities, establish restoration expectations, and reinforce public safety messaging. Following a storm, DTE uses all available channels to provide timely, transparent updates on system damage, customer outage impacts, crew mobilization, and estimated restoration times.

Social media storm safety graphic

During restoration, the Company supplements systemwide communications with community-specific outreach, including social media posts notifying customers when community vans will be deployed to distribute water, ice, and other essential supplies. A dedicated Social Care team actively monitors digital channels to respond to customer inquiries and escalate issues as needed. In parallel, DTE Regional Managers and Community Engagement teams maintain regular communication with state and local officials to provide situational updates, address community-specific concerns, and support escalation of constituent needs, such as requests for generators or wellness checks.

In response to Audit Report recommendations to continue enhancing the customer outage experience, the Company implemented WISMO, a new tool that provides real-time visibility into outage history, prior communications, and crew notes, enabling more informed and consistent responses to customer inquiries. The tool also provides guidance and talking points to help

explain outage causes and streamline outage reporting when customers call in. In addition, DTE is enhancing customer messaging to provide clearer updates when jobs are cancelled, outages move into follow-up phases after temporary repairs, or planned outage work is scheduled. To better support vulnerable customers during extended weather events, the Company has expanded proactive outreach, including information on heating and cooling centers, water availability, and support options such as hotel accommodations or generators. In 2025, the Company introduced an application to streamline this process and track key metrics, including calls completed, hotel rooms offered or accepted, and generators deployed. This new application enhances DTE's ability to help vulnerable customers receive timely, coordinated, and compassionate support.

Key Achievements and Enablers

When a storm of any size is declared, the Company aims to restore each customer within 48 hours of losing their power and has implemented several process and technology enhancements to support this goal. Pre-staging resources is essential to meeting this objective and proved effective during the June 2025 storm, when DTE restored 100% of nearly 90,000 affected customers within 48 hours — its first time achieving the 48-hour restoration target. Five supporting themes enabled this milestone: wire-down response, damage assessment, singles strategy, traditional foreign crews through mutual assistance, and non-traditional foreign resources.

First, to support wire-down response, DTE has trained nearly 2,000 people, including nearly 900 DTE employees, as part of the Company's Public Protection Program. Every participating DTE employee receives extensive training, including mentored storm work in the field, until they have graduated from the training program. Upon successful program completion, these employees can safely and effectively secure downed wires in the field for public safety. Notably, employees in the Public Protection Program come from non-traditional field roles across the Company, allowing linemen to focus exclusively on customer restoration work. The remaining 1,100 program members are contracted trained members of the public the Company can engage if additional resources are needed during extreme weather events.

Second, like wire-down response, damage assessment teams are critical support crews that evaluate customer reports and outages ahead of the restoration teams to define clear work scope, identify resource needs, and provide pictures as applicable. These teams enable DTE to coordinate the right crew with the right work and ensure that necessary materials arrive on site so restoration can begin as soon as the crew arrives on the job site. The number of employees performing damage assessments has increased to approximately 300. If additional resources are needed, the Company can engage an additional 400 contracted trained individuals.

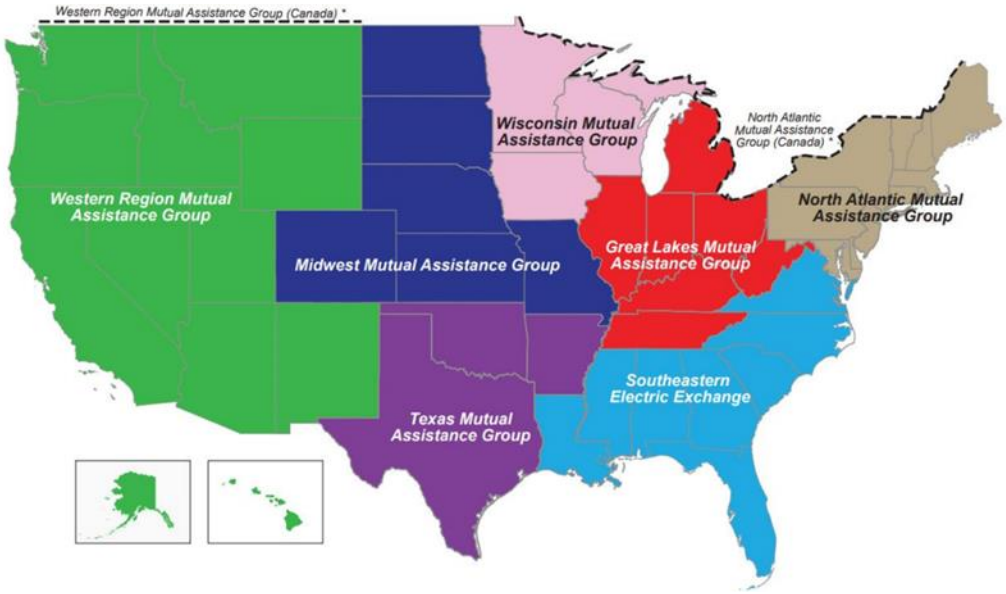
Third, the singles strategy helps ensure that single customer outage restoration is coordinated in parallel with larger outages in real time. Traditional storm response philosophy calls for fixing the largest outages first, which often leaves single-customer outages until the very end, creating a long "tail of the storm." For customers who are the last to be restored, this delay does not meet the service standards DTE aims to provide. To address this, DTE now coordinates a dedicated singles strategy during storm events so that single-customer outages are restored in parallel with the larger jobs through targeted crews while maintaining focus on restoring outages affecting multiple customers. After training more than 200 employees on the updated storm dispatch process and redesigning real-time dashboards that are integrated directly into the Outage Management System (OMS), single-customer outages are now being restored before or within four hours of the final multiple customer job. This improvement has effectively eliminated the "tail of the storm" for the last six storms.

Fourth, when a forecasted storm is expected to exceed DTE's daily staffing capacity, the Company has the option to engage outside resources to increase available crew strength proactively ahead of weather. DTE is a member of the Great Lakes Mutual Assistance (GLMA) program as shown in Exhibit 4.53. GLMA is comprised of neighboring utilities around the Great Lakes area that have all signed the Edison Electric Institute (EEI) Mutual Aid Agreement.[70] Once the need for foreign resources is established, member utilities conduct a call to discuss crew needs and availability across the entire region. Each utility then decides whether to release crews or hold them based on the expected weather or potential damage in their own service area. In most cases, this process begins after the weather's impact is assessed, as utilities typically retain their crews locally until their situation is fully understood or resolved. Once released, available crews will travel to the Company's service area to support restoration efforts. If there are still not

[70] EEI members are divided amongst Regional Mutual Assistance Groups (RMAGs) to share utility resources during severe weather and other catastrophic conditions impacting electric reliability for customers.

enough crews to meet the demand, DTE will request support from other mutual assistance groups across the United States and Canada.

Exhibit 4.53 – Mutual Assistance Groups within the United States[71]



Finally, since 2020, DTE has expanded restoration resources by partnering with contractors across the Midwest who are affiliated with GLMA utilities. Since these contractors are independent, they can respond quickly without needing approval from a parent or host utility before sending crews into DTE's service area to assist with customer restoration. These crews typically arrive within four to 16 hours of being requested and will remain on-site until they are no longer needed. DTE has also signed contracts with several Michigan-based electric utility contractors who do not perform day-to-day work for the Company. This adds roughly 15 crews of about 50 full-time equivalent (FTE) workers, who can be rapidly deployed during storms. In addition, the Company has secured a right-of-first refusal agreement with a Michigan-based, multi-state lineman company. This gives DTE priority access to approximately 200 linemen before any other utility can request them. Through a combination of non-utility contractors, local foreign resources, and right-of-first refusal crews, the Company is positioned to mobilize up to 3,000 crews (approximately 10,000 FTEs) within 16 hours of a weather event.

[71] Department of Energy Electricity Advisory Committee, available at https://www.energy.gov/sites/prod/files/2018/02/f49/1_Mutual%20Assistance%20Agreements%20-%20David%20Bonenberger%2C%20EEI.pdf, accessed March 9, 2026.

Crews preparing for dispatch at storm yard

Together with these enhancements and less-severe weather, DTE delivered its best SAIDI performance in nearly two decades in 2025, restoring power to 95.58% of customers within 24 hours during storm events. The Company also achieved several notable improvements in its storm response and restoration performance in 2025:

- **Accelerated Wire-Down Response:** The Company recorded a median wire-down response time of 54 minutes, outperforming the 133-minute target. This improvement facilitated faster mitigation and improved public safety.
- **Reduced Number of Declared Storms:** Only two storms met the criteria for formal Storm declaration. While DTE's service area did not experience as many severe weather events in 2025, more efficient response and repair activities also helped maintain outage levels below declaration thresholds.
- **Enhanced 24-hour Coverage Plan:** EP&R strengthened its existing continuous coverage model by expanding overnight staffing and deploying full restoration, damage assessment, and pole haul crews on night shifts, supporting safe and sustained restoration efforts during severe weather events.
- **Enhanced Restoration Estimate Accuracy:** EP&R achieved a 90% accuracy rate in restoration time estimates, significantly exceeding the 67% target. This improvement provided customers with more reliable outage restoration information.

- **Improved Outage Volume Forecasting:** EP&R introduced advanced predictive models that increased the accuracy of outage volume forecasts. More precise forecasting enabled the Company to allocate resources effectively and avoid both over-mobilizing or under-resourcing, contributing to cost efficiencies and expedited restoration efforts.

Although DTE delivered strong storm response performance in 2025, it is important to note that its service area did not experience any catastrophic weather events during the year. Consequently, it remains uncertain whether similar performance levels could be sustained under more extreme or widespread storm conditions. Early 2026 results, however, demonstrate ongoing improvement. During the first storm of the year on January 6, 2026, winds of more than 60 mph coupled with sporadic snow squalls interrupted service for more than 56,000 customers. Crews restored power to more than 99% of impacted customers within 24 hours, and all remaining customers were restored the following day, again meeting the Company's 48-hour restoration goal.

Advanced Technology Deployment

While DTE's storm response is still anchored in the expertise of trained personnel restoring power and addressing electrical hazards, the Company is also adopting new technologies that have consistently improved restoration performance during extreme weather events. These include:

- **Public Protection Dispatching Chatbot:** Launched in 2021, this internal auto-dispatch tool has significantly reduced DTE's wire-down response times each year. The chatbot has been maintained through the 2023 deployment of the advanced distribution management system (ADMS), ensuring the Company's tools remain integrated with the most up-to-date systems.
- **Everyday Daily Plan (EDDP):** Launched in late 2023, EDDP is a web-based application that automatically groups work packages from OMS for large outages and single-customer event routes specific to the field crew best suited for the work. EDDP updates work bundles in near real time and prioritizes them dynamically based on factors such as safety risks, number and type of customers affected, and outage duration. EDDP is used to deploy most field crews at the start of each shift in all weather conditions. The tool saved more than 10,000 hours in crew wait time in 2024 and more than 5,600 hours in 2025, directly translating to earlier crew arrival on jobs.[72] Further, as crews complete

[72] Crew wait time savings are proportional to storm volume experienced on the DTE grid. With roughly half the storms in 2025 compared to 2024, there was approximately half the savings.

their first job, EDDP's "continuous assignment" feature is able to automatically assign the next highest priority work package relative to the crew's geographic location, with geographic routing technology reducing drive time by up to nearly 75%. In the future, DTE plans to expand EDDP's use to support trouble work, storm response, and planned work on the electric system, with related investments included in Section 6.4.3 (Operational Technology – Mobile Tools Expansion).

- **Mega Model:** Using daily forecasts from DTE's internal weather team, the Mega Model resource forecasting tool enables ICS team members to run scenarios to determine the number of crews needed against existing and incoming weather threats. By estimating how many outages will remain at the end of each day, the tool helps to identify required staffing much sooner to advance restoration objectives. The tool's predictive damage multiplier component highlights potential severe damage within four to six hours of a storm's passage, helping to optimize damage assessment crew assignments at the circuit level. The tool also recommends customer restoration estimates based on outage start time and crew assignment status, contributing to achieving over 90% first estimate accuracy at the "day of" level. DTE is exploring using the application to forecast other resource needs as well as forecasting circuit risk and potential mitigation opportunities up to five days before a weather event.
- **Utility Restoration Management Application (URMA):** Launched in mid-2024, URMA initially streamlined rostering for foreign contractors supporting DTE during severe weather events. The Company has since expanded its usage to provide the same rostering experience for all overhead contractors, Vegetation Management crews, and underground contractors, and now connects directly with DTE's enterprise timesheet system for faster billing. By the end of Q2 2026, URMA will become a mobile tool for contractors to manage all trouble work in real time, giving DTE unprecedented visibility into work progress. As development of this system continues, URMA will serve as a unified platform that includes rostering, event management (a mobile tool for trouble and planned work), and timesheets for DTE and contractors, including auxiliary support crews. This integration enables cross-feature validation to improve efficiency and accuracy and supports seamless, end-to-end crew resource management. The related investment is described further in Section 6.4.3 (Operational Technology – External Crew Efficiency).

By refining operational modes, strengthening ICS processes, expanding and accelerating resource deployment, and leveraging advanced technologies, DTE has transformed the way it prepares for and responds to severe weather. Together, these improvements have delivered measurable results, creating a safer, more efficient customer experience during storm-related outages.

4.4.3 Emergent Replacements

Emergent Replacements field work covers three primary areas: storm, non-storm, and substation reactive programs. Investments in these programs are essential for public safety and for maintaining reliable service for the Company's customers. When the Company replaces a damaged asset, it is upgraded to current engineering standards. For example, a defective wooden crossarm will be replaced with a more durable fiberglass crossarm, strengthening the grid and helping reduce the likelihood of future outages. Sections 4.3.4 (Historical O&M and Capital Spend) and 5.3.1 (Forecasted O&M and Capital Investments) provide further information about the Company's five-year historical and projected investments related to Emergent Replacements, respectively.

Lineman installing fiberglass crossarm

Storm Replacements

Storm Emergent Replacements include labor and material expenditures resulting from damage to overhead, underground, and substation infrastructure occurring during weather events. As described in Section 4.4.2 (Weather Event Response and Restoration), a storm is typically declared when outage volume exceeds 760 active outage events across at least 200 circuits for more than one hour. These expenditures are necessary to restore customers' power and address public hazards, such as downed wires or severely leaning poles. Typical material replaced during storm restoration includes transformers, poles, conductors, crossarms, line hardware, capacitors, reclosers, switches, and cutouts. Exhibit 4.54 provides examples of prior weather events,

including ice storms and tornados, that impacted DTE's service area and required Storm Emergent Replacements.

Exhibit 4.54 – Example Storm Events Requiring Emergent Replacements

South Lyon

South Lyon

Ann Arbor

Clinton

Dearborn Heights

Waterford

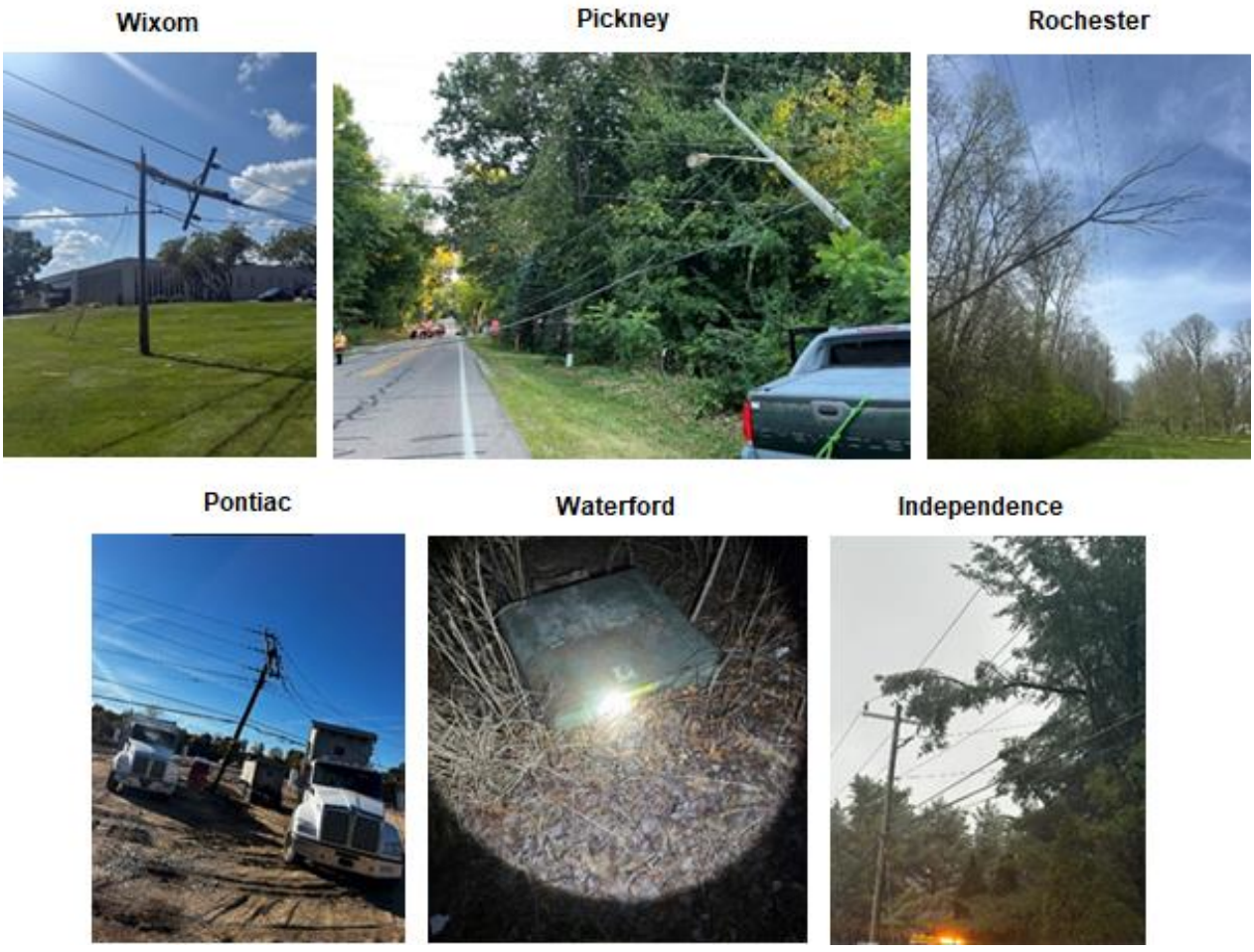
Howell

Non-Storm Replacements

Similarly, Non-Storm Emergent Replacements include labor and material costs necessary to restore power, eliminate public safety hazards, and return the system to its normal operating

condition. Although these events are classified as non-storm, this designation does not imply that weather was not a contributing factor. In many cases, non-storm damage is still driven by weather conditions — such as rain, high winds, or heat — but the resulting customer outage volume did not meet DTE's criteria for declaring a storm as described in Exhibit 4.50 (Overview of DTE Operational Modes). Other non-weather causes include public interference (e.g., vehicles striking poles), trees, animals, and equipment-related failures. Exhibit 4.55 provides examples of events requiring Non-Storm Emergent Replacements in the Company's service area.

Exhibit 4.55 – Example Non-Storm Events Requiring Emergent Replacements[73]



Non-Storm Emergent Replacements are grouped into four categories for resolution, as outlined in Exhibit 4.56.

[73] The Waterford image depicts a buried transformer that required excavation prior to replacement.

Exhibit 4.56 – Non-Storm Emergent Replacement Categories

Category	Description	Examples (Issue → Resolution)
Emergent	Emergency replacement of equipment occurring outside of a declared storm, when customers experience power supply issues under both outage and non-outage conditions, and overall outage volumes remain below storm thresholds.	Vehicle (e.g., garbage truck, hauler, etc.) contacted a communications line, ripped down five spans of primary wire and broke four poles and cross arms. → Immediately cleared hazards, replaced wires and poles, and restored customers.
Reactive	Scheduled equipment replacements that do not require immediate action, including follow-up replacement of failed devices after initial work has restored power and addressed any safety concerns.	Broken pole due to a vehicle accident; crew stabilized the pole to remove hazard and restore power to customer. → The damaged pole is temporarily fixed (braced) and is scheduled to be replaced at a future time.
Corrective	Equipment replacements required to restore the system to its original configuration and that require coordination with the ESOC.	Failed underground cable caused an outage that was restored but left the system in an abnormal condition. → Coordinated planned outage the following week to replace the damaged cable.
Environmental	Disposal of environmentally hazardous materials from the Company's retired units or assets that are replaced outside of a declared storm.	Car hit pad-mounted transformer, damaging it and causing an oil leak. → Removed transformer and replaced it; environmental crew cleaned up oil.

Substation Reactive Replacements

The substation reactive category of Emergent Replacements covers investments needed to replace substation equipment that has failed or will imminently fail. Because a single substation typically serves multiple distribution circuits, an equipment failure can affect thousands of customers. These investments address equipment that has failed, caused customer outages, created a risk of future outages, or reduced the operability of the electrical system. This category also includes non-electrical assets, such as physical security barriers used to protect North American Electric Reliability Corporation (NERC)-regulated equipment. As shown in Exhibit 4.57, Substation Reactive Emergent Replacements are divided into four categories based on equipment classification.

Exhibit 4.57 – Substation Reactive Emergent Replacement Categories

Category	Examples (Issue → Resolution)
Major Equipment	**Twelve Mile Substation** Fire led to catastrophic failure and complete loss of substation. → Deployed portable equipment including multiple generators.
Minor Equipment	**Unionville Substation** 40 kV insulator broke free. → Replaced three 40 kV insulators.
Transformers and Regulators	**Middlebelt Substation** 40-year-old transformer failed internally, causing outages. → Switched load to another transformer for several days until transformer replacement was complete.
Non-Electrical Equipment	**Essex Substation** Condensation found in control house, creating erosion risk to the equipment. → Added HVAC unit for temperature and humidity control.

Storm, non-storm, and substation reactive Emergent Replacements collectively form a vital backbone of DTE's ability to respond and maintain a safe, reliable, and resilient electric grid. As infrastructure continues to age and weather-related impacts intensify, these emergent replacement activities remain essential for safeguarding the public, restoring power, minimizing service disruptions, and ensuring overall system operability. By quickly addressing damaged or deteriorating assets and replacing them with modern, engineered components, the Company not only restores service but also strengthens the grid's durability and performance for future events.

4.4.4 Customer Connections, Relocations, and Other

Customer Connections, Relocations, and Other (CCRO) investments support new customer connections, accommodate load growth, strengthen economic development efforts, and enhance overall customer service. This category of work is led by the Regional Engineering and Planning team, which specializes in energizing new customers, supporting existing customers with load increases, and ensuring the reliability of the grid. Sections 4.3.4 (Historical O&M and Capital Spend) and 5.3.1 (Forecasted O&M and Capital Investments) provide further information about the Company's five-year historical and projected investment related to CCRO, respectively.

CCRO Sub-categories

The CCRO investment portfolio is organized into five key sub-categories: 1) Customer Connections and New Load, 2) Relocations, 3) Electric System Equipment, 4) Normal Retirement Unit Change-out (NRUC) and Improvement Blankets, 5) and General Plant, Tools, and Equipment.

The first sub-category, Customer Connections and New Load, is further divided into two groups: Small Load Growth and Customer Connections or New Business projects. Small Load Growth and Customer Connections projects address new customer load, new service connections, or minor upgrades to resolve localized loading issues on the system. These projects are typically under $350,000 and are developed and executed by Regional Engineering and Planning. Activities supporting these customer needs may include reconductoring existing lines, making minor substation expansions, or transferring load to adjacent circuits for load relief. Other common projects in this sub-category include installing additional overhead and underground lines to serve small commercial businesses or new residential developments such as subdivisions. Because these projects are often initiated by customers, they may involve a Contribution in Aid of Construction (CIAC), where the customer pays a portion of the cost based on their requested load and service requirements.

New Business projects are larger customer-driven projects that exceed $350,000 and require Central Engineering and Project Management Organization (PMO) support for design and implementation. Like Small Load Growth and Customer Connections projects, they support new customer service connections or address loading issues on a larger scale. These projects often include extensive overhead and underground line installations, major upgrades to existing substations, or even construction of new substations to serve large commercial or industrial customers. CIAC may also apply to New Business projects, where the requesting customer contributes toward system upgrade costs depending on the existing system conditions, the requested load, and the impact to the electric grid.

The second sub-category, Relocations, includes projects initiated when customers, municipalities, or other governmental agencies, such as the Michigan Department of Transportation, request that DTE move existing facilities to accommodate construction or infrastructure upgrades. These requests commonly arise from roadway or bridge modifications, watermain or sewer work, alley realignments, and other development activities within a defined

Gordie Howe bridge relocation

geographic area. DTE facilities requiring relocation may include overhead lines and poles, underground lines and pad-mount transformers, or possibly substations and system cable. With steady federal funding expected for municipal infrastructure improvements, the number of relocation projects is anticipated to grow over the next decade. These investments help enable economic development, support future customer capacity needs, and are often required by regulation or at the direct request of municipalities. Like Customer Connections and New Load, some relocation projects may involve CIAC where the requesting party pays a portion of the cost to move DTE assets.

Third, the Electric System Equipment category includes investments in inventory of critical spare equipment, particularly long-lead-time items, to support both Emergent Replacements and planned projects. Equipment purchased under this sub-category includes substation transformers, distribution transformers, regulators, meters, and other essential items. These investments ensure that critical equipment is readily available, enabling the Company to meet customer needs promptly and to avoid delays in urgent work due to supply constraints.

NRUC and Improvement Blankets is the fourth sub-category and further classified into three groups: System Improvements, NRUC, and OT. System Improvements are small projects managed by regional operations to immediately address customer issues, repeat outage concerns, and service quality complaints. These projects require minimal planning or design and do not exceed $350,000. NRUC involves the scheduled replacement of assets that have reached end of life, such as pole-top switches, reclosers, capacitors, and regulators. Overhead linemen and power quality technicians assess these components through field inspections to determine when replacement is necessary. OT covers the infrastructure and applications that support the AMI platform and its data systems.[74] This includes annual work such as testing new meter types, designing and installing system configurations, replacing communications equipment, and testing changes for new equipment.

The fifth and final sub-category, General Plant, Tools and Equipment, includes new tools, replacement tools, and specialized equipment needed by linemen, splicers, engineers, and technicians to perform their daily work safely and effectively. It also encompasses investments in substation physical security. These investments ensure that DTE field crews and technical teams are properly equipped to maintain system reliability and support ongoing operations. Examples of

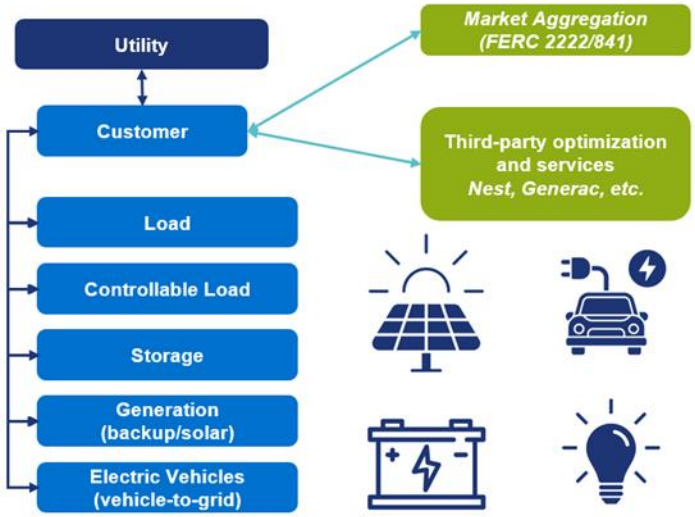
[74] Note, the OT group within NRUC and Improvement Blankets is different than the investment category in the Technology and Automation pillar, which focuses on software and hardware to enable the grid as described in Section 6.4.3 (Operational Technology).

equipment within this category include Very Low Frequency (VLF) trucks used to test cables at frequencies between 0.02 and 0.1 Hz, DC hi-potential testers for verifying insulation integrity on cables, breakers, and transformers, oil processing trailers, insulated high voltage rubber gloves and blankets, and other essential field and shop equipment.

4.5 Distributed Energy Resources and Interconnection Process

Grid modernization is essential to reliably integrate rapidly growing DERs, which are customer-owned or third-party assets such as rooftop solar, energy storage, transportation electrification, microgrids, and other controllable loads as described in Section 2.3 (Drivers of Investment). As these resources proliferate, the distribution system must operate with far greater flexibility, coordinating real and reactive-power, activating demand-side resources, and responding dynamically to changing conditions. These needs and drivers are illustrated in Exhibit 4.58.

Exhibit 4.58 – Overview of DER Components and Interactions[75]



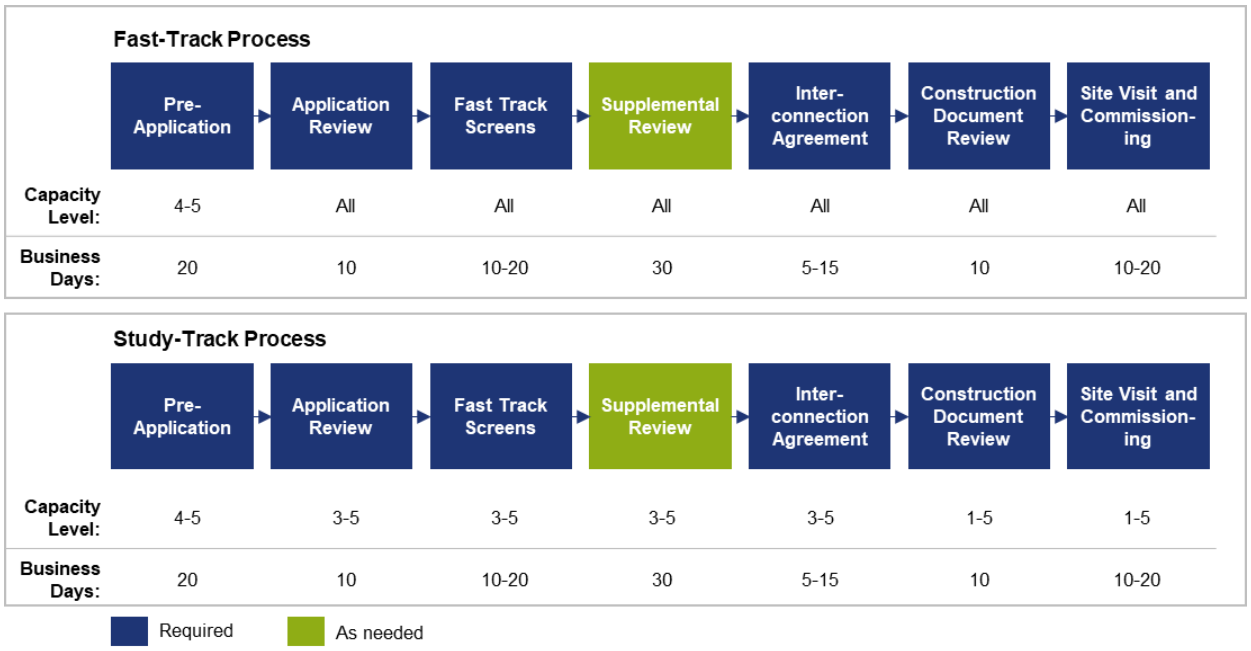
As DER penetration and dynamic loads increase, secure and high-quality communications between field devices and utility control centers become critical. The distribution system must reliably support bidirectional power flow so DERs and energy storage can serve as NWAs and provide system benefits. Related communications investments are further detailed in Sections 6.4.3 (Operational Technology), 6.4.5 (Grid Technology), and 6.5.3 (Distributed Energy Resource Management System).

[75] Once fully in place, FERC Orders 2222 and 841 will allow residential, commercial, and industrial customers to participate directly in wholesale energy markets. Compliance with MISO's requirements for FERC Order 2222 is particularly significant because it fundamentally changes how DERs interact with the grid, requiring utilities to adapt operations, planning, and technology to maintain reliability and ensure coordination with customer-owned DERs.

Interconnection Process

A safe, consistent, and transparent interconnection process protects customers and the grid while providing DTE the data needed for accurate modeling, planning, and operations. The Company uses three primary tracks, two of which are shown in Exhibit 4.59. The fast track supports simpler projects that can be evaluated quickly; the study track addresses more complex projects, particularly those above 550 kW, that may interact with other grid elements in ways that require detailed engineering analyses. Not shown is the non-export track, which streamlines review for projects configured to prevent power export to the grid, reflecting their limited system impact.

Exhibit 4.59 – DER Interconnection Process Tracks



DTE has updated its interconnection procedures to align with Michigan's revised statewide interconnection rules finalized under Case No. U-21482[76] and Public Act 235, and with evolving federal guidance under FERC Orders 2222 and 901.[77] These updates, reflected on DTE's website,[78] streamline applications, reviews, payments, and approvals via digital platforms and

[76] Order dated December 5, 2025 in Case No. U-21482, available at https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/068cs00001UwfifAAB, accessed March 9, 2026.

[77] FERC Order 901 directs the development of new or modified NERC Reliability Standards addressing inverter-based resources (IBRs), including DERs. Although the Order applies to IBR facilities greater than 20 MW, it establishes no lower capacity threshold, making the identified reliability risks relevant to distribution-connected DERs as adoption increases.

[78] Rooftop Solar and Private Generation, available at https://solutions.dteenergy.com/dte/en/Services/CleanVision-Service/Rooftop-Solar-and-Private-Generation/p/ROOFTOP_SOLAR?_gl=1*15xxqws*_gcl_au*MTAyNDU3ODI2Ni4xNzYyNzgyMDg2*_ga*MTc3NTE5MzM5NC4xNjgyNTM0MDE0*_ga_J2R5W9DWE4*czE3Njc2NTY4MDIkbzI4MiRnMSR0MTc2NzY1NjgwNCRqNTgkbDAkaDA.%23interconnection#about, accessed March 9, 2026.

improve forecasting and technical evaluations to maintain state and federal compliance. The process also incorporates the MISO Affected System Study[79] requirements and annual planning model updates, which necessitate more detailed DER data. These enhancements have reduced paperwork, improved timeline performance, and increased transparency for customers and developers. New automation and machine learning tools are further enhancing efficiency by accelerating initial screening and improving early detection of inconsistencies. Investments supporting these improvements are detailed in Section 6.4.3 (Operational Technology - Interconnection Process Enablement).

Current interconnection challenges are frequently project specific and non-technical, such as incomplete applications, equipment installed prior to approval, inconsistent documentation, or system changes after approval. Technical upgrades may include service modifications, high voltage mitigation, revised protection and automation, and, for larger projects, grid upgrades.

DER Adoption

DER adoption continues to grow across DTE's service area. Small Level 1 projects less than or equal to 20 kW are 95% of applications and are primarily rooftop solar, with approximately 20% also including energy storage. While far fewer in application volume, Level 5 projects greater than 1 MW account for 80% of the total installed capacity and span technologies such as solar generation, rotating generation, dynamometer systems, and energy storage. As of the end of 2025, DTE has completed 12,455 projects totaling 519,703 kW AC, with an additional 2,231 projects pending (totaling 349,843 kW AC). Detailed counts and capacities by interconnection level are reflected in Exhibit 4.60.

Exhibit 4.60 – Overview of DER Projects by Capacity Level as of Dec. 31, 2025[80]

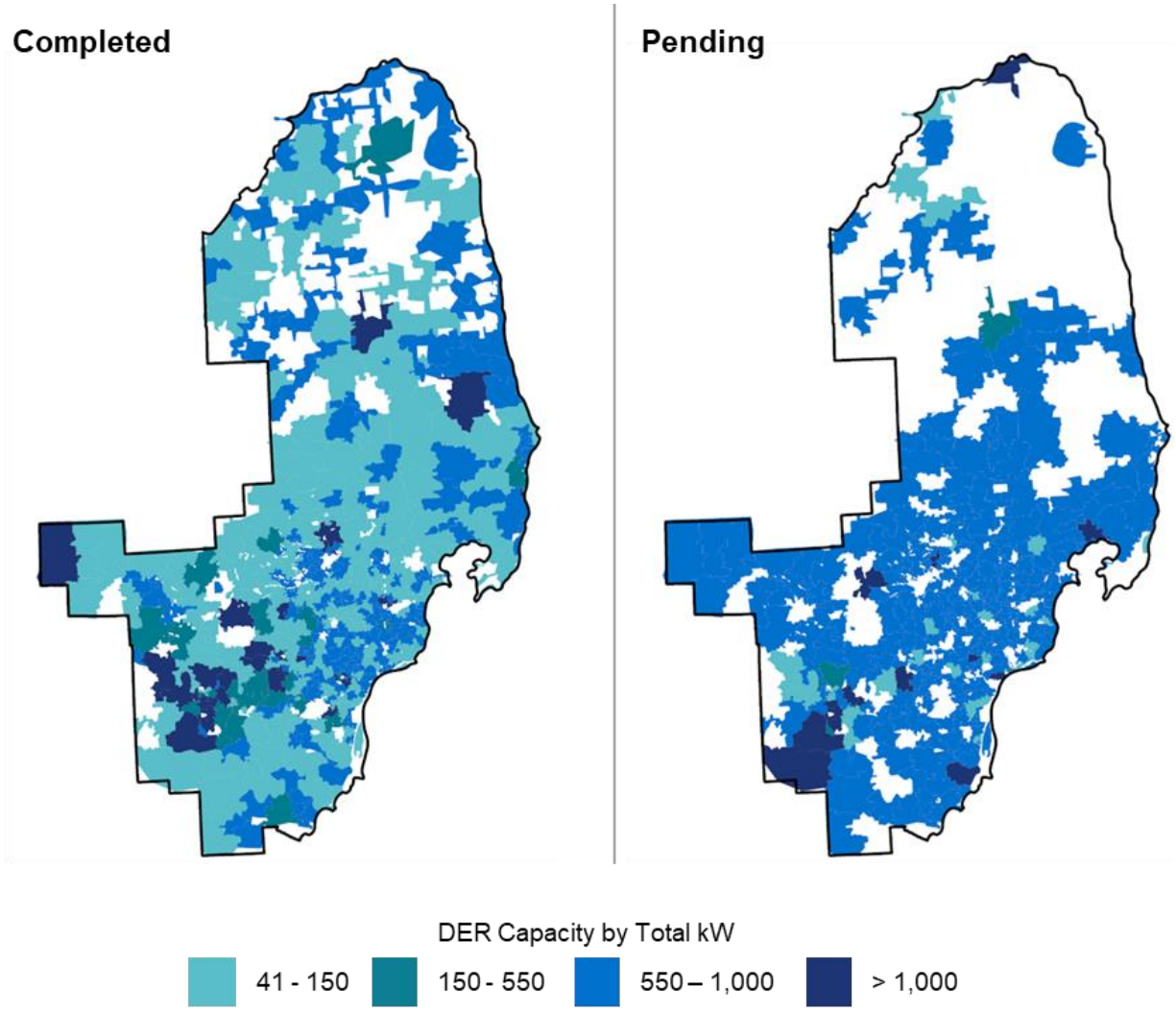
Level	Range of Capacity (Size Nameplate AC)	Completed		Pending	
		Volume	Total Capacity (kW AC)	Volume	Total Capacity (kW AC)
1	Project ≤ 20 kW	11,972	82,399	1,929	13,499
2	20 kW < Project ≤ 150 kW	383	20,116	207	10,413
3	150 kW < Project ≤ 550 kW	44	16,644	29	9,618
4	550 kW < Project ≤ 1 MW	15	11,811	10	8,909
5	Project > 1 MW	41	388,733	56	307,404
Total		**12,455**	**519,703**	**2,231**	**349,843**

[79] Distribution Interconnection Coordination, available at https://www.misoenergy.org/planning/resource-utilization/distribution/#t=10&p=0&s=FileName&sd=desc, accessed March 10, 2026.

[80] Projects that are not certified under 150 kW are considered Level 3.

Completed and pending DER projects are widespread, with notable concentrations in and around Ann Arbor, as shown in Exhibit 4.61.

Exhibit 4.61 – DER Projects by Location



Interconnection Evolution

To integrate DERs and increasingly flexible loads, DTE is enhancing planning tools and processes and has established a roadmap that aligns investments with regulatory expectations. Planning must become more granular, with detailed load allocation and impact analyses across multiple time horizons. Over time, discrete one-off studies will give way to automated analyses that incorporate complex scenarios, highlight key results, and aggregate distribution portfolio benefits at system scale. The investments described in Section 6.4.3 (Operational Technology) will enable engineers to evaluate projects against forecast scenarios, choose appropriate modeling approaches, and identify necessary investment adjustments.

Michigan's updated rules require more rapid, detailed analysis, including minimum-load evaluations at circuit and line-segment levels, over-voltage checks, reverse-power-flow assessments, and contingency reviews. Because DER output can mask actual peak loads and alter operations, models must incorporate gross load, disaggregated DER by type, and dynamic representations aligned to transmission nodes. DERs seeking market participation may require additional validation studies. Traditional peak-based planning is no longer sufficient; reliable operation now requires daily and hourly modeling across scenarios reflecting EVs, storage, DERs, and DR. Full-year (8,760-hour) studies are particularly important for limited-duration resources that must recharge between events. These changes shift planning from point-in-time methods to dynamic modeling that better represents year-round behavior.

Some detailed outputs, such as systematic locational value analysis, cannot be produced until foundational data and tools are in place. Today, estimating the value of individual projects is a manual, time-intensive effort applied mainly to projects exceeding certain funding thresholds. Ongoing investments will make this faster, more consistent, and more reliable, improving forecasting, modeling, scenario analysis, distribution planning, hosting capacity, interconnection screening and studies, and power-quality analysis, while enabling more granular evaluation of DER and NWA opportunities.

Operational Integration

Beyond streamlining interconnection, grid modernization focuses on control and monitoring capabilities needed to leverage advanced DER functions. Most DERs are customer driven and designed for individual goals, such as renewable self-supply, resiliency via backup power, or load shifting with storage. Grid benefits depend on location, circuit characteristics, and alignment with system needs, and distribution level opportunities are often localized and time dependent. DTE is advancing its ability to use DERs to defer or replace traditional infrastructure investments through a suite of pilots as discussed in Section 6.3.4 (Non-Wire Alternatives).

EV charger and energy storage

Only a subset of DERs currently provide full real- and reactive-power control for broader grid benefits. Where functions exist, they are typically configured to offset only the DER's own impacts. As standards evolve and device requirements are codified, advanced functions will become more common. This will increase the need for robust configuration management to understand not only the built-in capabilities of DERs, but also how those capabilities are configured by installers and how customer preferences — such as the amount of stored energy reserved for grid support — affect performance. Investments supporting these needs are described in Section 6.4.5 (Grid Technology).

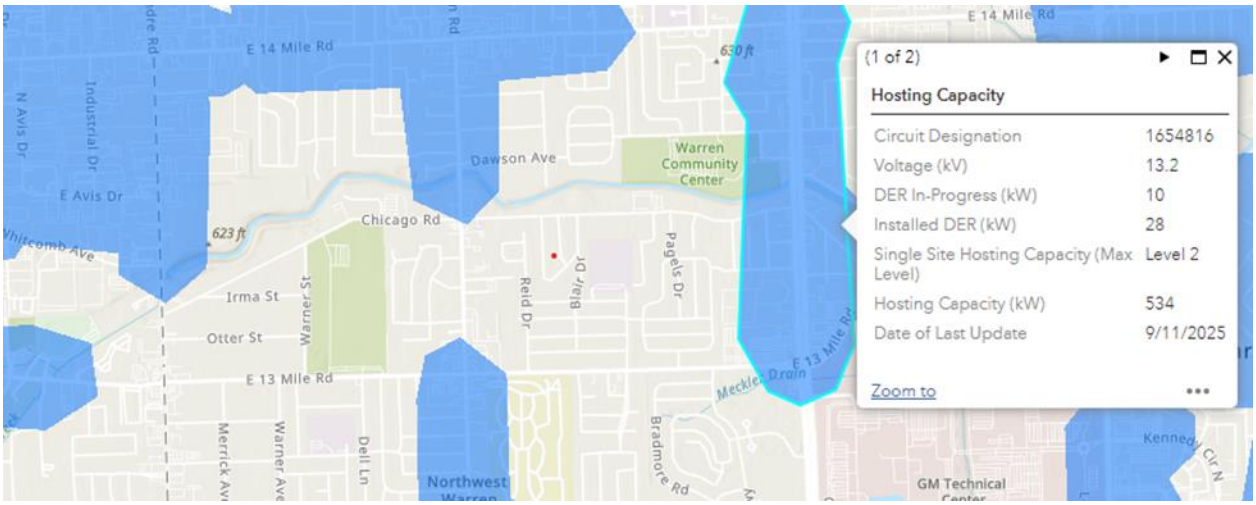
DTE follows a rigorous, standardized process to evaluate, test, and document new automation and grid hardware, collaborating with regional and national utility groups to identify effective solutions. New tools undergo field demonstrations and integration testing at the Company's Technical Training Center prior to deployment, ensuring solutions are validated, operational changes are understood, and training materials are fully developed. The center's DER lab enables hardware-in-the-loop testing with real-time networking and cybersecurity evaluation, providing validation that field deployments will perform as intended so complex control schemes can be tested and verified before field use. These investments are also described, in part, in Section 6.4.5 (Grid Technology).

DERs and grid-edge technologies are rapidly shifting from passive to dynamic, multifunctional systems. Managing these capabilities requires consistent configuration control and secure communications. Advanced inverters can be actively controlled in real time, with settings updated as grid conditions change. New switching devices and transformers using power electronics technology offer greater flexibility, consolidating functions or enabling new capabilities. These technologies rely on software with hundreds — or even thousands — of configuration parameters and multiple control modes, making it increasingly important to understand both the potential and the limitations of these functions, as well as how to manage and track system configurations. Grid-edge gateways are becoming essential for cybersecurity, centralized management, anomaly detection, protocol conversion, and site-wide optimization. As industry frameworks and standards mature, Next-Generation Advanced Metering Infrastructure (Next-Gen AMI) and certified third-party gateways may support secure deployment of utility applications, as discussed in more detail in Section 6.5 (Grid Edge and Distributed Intelligence).

4.5.1 Hosting Capacity Analysis

Hosting capacity analysis examines the distribution system to determine the approximate amount of capacity available for new interconnections, including generation, storage, and additional load. DTE provides two publicly-available hosting capacity maps: one for DER interconnections available at DER Hosting Capacity[81] and another for load, including EV charging installations, available at EV Hosting Capacity.[82] These interactive maps allow customers, developers, and potential interconnection applicants to search specific locations and view distribution-circuit-level data. As shown in Exhibit 4.62, information includes the date of last update, circuit designation, circuit voltage, current connected load or DER, the amount in the interconnection queue, the circuit's maximum hosting capacity, and the maximum capacity for a single connection, if applicable. Currently, hosting capacity is shown for overhead distribution circuit backbones, which are three-phase lines.

Exhibit 4.62 – Hosting Capacity Map Sample Image



The underlying data for both hosting capacity maps is refreshed annually as part of the planning cycle. The DER hosting capacity map receives additional updates at least quarterly, with circuit-specific revisions occurring monthly when large projects greater than 500 kW enter the queue or reach interconnection. As projects advance through the interconnection process, the map is

[81] Hosting Capacity, available at https://dte.maps.arcgis.com/apps/webappviewer/index.html?id=64e9f4e0f82c42e7b7ed847273ec2764, accessed March 10, 2026.

[82] EV Hosting Capacity, available at https://dte.maps.arcgis.com/apps/webappviewer/index.html?id=15bba98a360740929f0d5c6bec8fdd6c, accessed March 10, 2026.

adjusted to reflect the corresponding reduction in available hosting capacity based on the project's parameters.

DTE's hosting capacity analysis gives customers an initial indication of whether a proposed interconnection could require distribution system upgrades or if sufficient capacity potentially exists for typical project types. However, hosting capacity results cannot determine the precise requirements of any given project. Factors such as line extensions, site-specific loading, and other service-level design considerations must be evaluated individually. While the hosting capacity analysis provides a general assessment of the grid's ability to accommodate changes in generation or load, an accurate assessment for a specific address or project can only be obtained by following the formal service request or interconnection evaluation process.

Planned enhancements to the hosting capacity maps will continue over the next few years. Some upgrades will require close coordination with investments in planning tools, load allocation processes, and system modeling, as outlined in Section 6.4.3 (Operational Technology – Hosting Capacity Enablement). The first planned improvement will extend hosting capacity data beyond the circuit backbone to include additional zones on the primary overhead and URD systems. Backend improvements will also shift updates from manual to automated processes, allowing interconnection project status changes to be updated more frequently.

As update frequency increases, supporting systems and interfaces will need to evolve to more efficiently share information about system changes, customer requests, and planned upgrades. Additional improvements to underlying system models will help accelerate the pace at which foundational circuit data can be refreshed. While these updates will enhance transparency and improve the customer experience, the formal interconnection and service request processes will continue to provide the most accurate assessment for individual projects.

4.5.2 Transportation Electrification Plan

DTE is committed to advancing Michigan's decarbonization goals, including integrating EVs onto the distribution system and accelerating transportation electrification in alignment with state policy and regulatory directives. Since launching Charging Forward in 2019, the Company has continuously refined its EV strategy through benchmarking, stakeholder engagement, and MPSC directives. DTE's first comprehensive Transportation Electrification Plan (TEP) was filed in January 2024. Per MPSC requirements, an updated plan outlining DTE's five-year investment strategy for EV programs will be filed in April 2026, concurrent with this DSP.

DTE's TEP is designed to support Michigan's clean energy transition, maximize the benefits of EV adoption, and minimize overall costs for customers and communities. The plan is informed by the MI Healthy Climate Plan[83] and MI Future Mobility Plan[84], supporting the state's goal of advancing transportation electrification. DTE's market assessment forecasts EV adoption in its service area to increase from approximately 114,000 vehicles in 2025 to more than 355,000 vehicles by 2030, requiring the installation of approximately 178,000 additional chargers across single-family homes, multi-unit dwellings, fleet depots, workplaces, and public areas.

DTE EV Overpass at Community Event

Regardless of the specific incentives ultimately approved for charger deployment, DTE anticipates significant demand for new or upgraded electric service as customers install additional chargers. Based on historical work order analysis and the latest cost data, an estimated $173 million in distribution-side investment will be needed to connect the 178,000 chargers required to support EV adoption through 2030. DTE expects to fund approximately 85% of this investment, with the remainder covered by CIAC. Accordingly, $147 million is included in the new CCRO portion of the 2026 to 2030 capital investment plan.

DTE's TEP and DSP have been developed in alignment with the Commission's Order in Case No. U-21492 approving TEP filing requirements,[85] which mandates robust scenario planning, equity analysis, BCA, and annual status reporting. The TEP portfolio is informed by comprehensive benchmarking against peer utilities and direct stakeholder engagement, including surveys and collaborative sessions with national industry policy and advocacy organizations. This

[83] MI Healthy Climate Plan, available at https://www.michigan.gov/egle/about/organization/climate-and-energy/mi-healthy-climate-plan, accessed March 10, 2026.

[84] MI Future Mobility Plan, available at https://www.michiganbusiness.org/4aecec/globalassets/documents/mobility/state-strategy-for-the-future-of-mobility-and-electrification-detailed-version.pdf, accessed March 10, 2026.

[85] Order dated January 23, 2025, available at https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/068cs00000X2NGsAAN, accessed March 10, 2026.

process ensures that DTE's programs reflect good utility practices nationally, adapt to evolving market conditions, and remain responsive to stakeholder and regulatory expectations.

DTE's proposed programs are expected to support approximately 27,000 chargers with rebates over the five-year DSP timeframe. Over the useful life of the distribution upgrades required to support EV charging, these programs are expected to deliver meaningful affordability benefits for DTE customers by enabling incremental load growth that helps spread fixed system costs across a larger sales base. This approach leverages a mix of public, private, and government funding to maximize customer and community benefits. Together with DTE's grid modernization and capital investment strategy, these programs ensure that the electric grid remains reliable, resilient, and capable of accommodating future EV adoption.

4.6 Resource Management

Successful distribution system planning, along with its execution, depends on securing both the necessary physical materials and the skilled workforce required to complete work on schedule and within budget. In recent years, the utility sector has faced challenges in these areas, including supply chain disruptions, rising costs for critical components, and shortages of qualified skilled trade labor. While some challenges, such as pandemic-related supply chain disruptions, have largely been resolved, addressing the skilled labor shortage is expected to have a longer recovery period. DTE's proactive planning, supplier diversification, and partnerships with training and engineering firms have mitigated many of these concerns.

4.6.1 Material Procurement

DTE's Supply Chain organization has been instrumental in helping the Company address the lingering impact of the global COVID-19 pandemic and unprecedented demand from utilities nationwide amid growing investment needs. DTE has taken several steps to proactively ensure that it has critical components and equipment on hand so that shortages do not impede its planned improvement work. For example, distribution transformers had been backlogged from Q2 2023

through the end of 2024. To mitigate this risk, the Company diversified its portfolio from four to 10 suppliers and implemented long-term procurement agreements with both domestic and international companies. In addition to expanding its supplier base, DTE secured reserved production slots with existing suppliers to help shorten lead times, ensure inventory availability, and eliminate backlogs. These efforts, along with an overall reduction in lead times for critical distribution materials, have lessened some procurement challenges. However, access to power transformers and breakers remain constrained due to global manufacturing limits and heightened demand from data centers, renewable energy projects, and substation modernization. The Company continues to forecast future material requirements to align supply with demand, as described in Section 7.1.2 (Forecasted Workforce and Material Resources).

4.6.2 Workforce Availability

DTE is focused on proactively addressing the shrinking pool of skilled labor. Nationwide, it is estimated that 45 to 50% of linemen will retire in the next decade.[86] According to local unions, nearly a third of overhead linemen are set to retire within the next five years. While attrition is increasing, demand for linemen is also increasing as utilities work to strengthen their systems, modernize the grid, and meet customer demand. The Company is working closely with the International Brotherhood of Electrical Workers (IBEW) and the National Electrical Contractors Association (NECA) to support the training of new apprentices through their joint training program with the American Line Builders Apprenticeship Training Committee. Additionally, the Company is working with Utility Workers Union of America (UWUA) Local 223 to grow the underground workforce. DTE also offers four Department of Labor-registered apprenticeship programs for the following roles: linemen, cable splicers, substation operators, and substation electricians. Each program combines classroom instruction with hands-on, on-the-job training. Apprenticeships for linemen, cable

Westland Technical Training Center

[86] Addressing the Challenges Presented by a Retiring Utility Workforce, available at https://www.powermag.com/addressing-the-challenges-presented-by-a-retiring-utility-workforce, accessed March 10, 2026.

splicers, and substation operators span four years, while the substation electrician program spans five years. Together, these collaborations and programs support development of the Company's workforce across a broad range of electrical disciplines, including overhead line operations, cable splicing, substation work, and underground systems.

In addition to the skilled labor shortage, DTE faces challenges when major storms impact the nation. Similar to the Company requesting foreign crew assistance during storm events, as described in Section 4.4.2 (Weather Event Response and Restoration), the Company offers support in cases of catastrophic events outside of its service area. While some local resources may temporarily leave to support impacted areas, DTE works closely with its vendors to maintain a stable base of local contract crews, ensuring adequate coverage for the Company's planned work during these periods.

DTE is also hiring a growing number of engineers, project managers, and technicians to support the increasing workload forecasted in the Company's workforce planning model described in Section 7.1.2 (Forecasted Workforce and Material Resources). In addition to hiring experienced employees, DTE also hires interns and co-ops from local high schools and colleges. These students are provided with significant on-the-job training and coaching throughout their assignments and often transition into full-time roles upon graduation or return to DTE later in their careers.

To meet increasing engineering demand, the Company has established long-term partnerships with engineering and design firms that now perform detailed work previously only completed by DTE engineers. These partnerships support multiple contracting approaches, including the use of Owner's Engineers and Engineer-Procure-Construct (EPC) arrangements, expanding the Company's capacity to execute an increased volume of work. While engineering service providers supplement the current workforce, DTE engineers continue to provide the necessary oversight to ensure high-quality scope development and cost-effective solutions. The Company remains committed to maintaining and strengthening its internal technical expertise and will continue to hire based on current and projected needs.

4.7 Environmental Justice Analyses

DTE formalized its commitment to EJ customers and communities during development of the 2021 DSP by integrating EJ concepts and analysis into its planning processes. This commitment was strengthened through the 2022 IRP and further advanced in the 2023 DSP with enhanced EJ analysis informed by population data from the State of Michigan's MiEJ Screening Tool.[87] In this DSP, EJ continues to be a foundational planning principle guiding DTE's planning approach.

The MiEJ Screening Tool defines EJ as "the equitable treatment and meaningful involvement of all people, regardless of race, color, national origin, ability, or income in the development and application of laws, regulations, and policies that affect the environment, as well as the places people live, work, play, worship, and learn." The tool uses population data from the 2020 federal census and provides a range of demographic descriptive data by census tract. Incorporating the demographic and geographic factors into the tool results in an EJ score for each census tract, ranging from 0 to 100, with 100 being those experiencing the greatest impacts.

For the purposes of distribution planning, the Company uses the term "EJ community" to describe a vulnerable population that is at or above the 80-point threshold within the range of population in the MiEJ Screening Tool.

4.7.1 EJ Reliability Compared to System Average

Based on the definition above, 484 census tracts in DTE's electric service area are identified as EJ communities. These tracts represent 27% of all census tracts in the Company's service area and include approximately 551,000 residential customers. By leveraging the census tract-specific EJ scores and translating those scores to zip codes and circuits, DTE has been able to geographically represent reliability investment across the Company's service area relative to where vulnerable customers reside.

Using residential customer meters matched to census tracts, the Company linked 2025 SAIFI and SAIDI reliability data to each tract census tract and categorized the results into DTE's reliability quartiles. Customers in the first quartile (shown in green) experience the best reliability, while those in the fourth quartile (shown in red) experience the least reliable service. Exhibit 4.63 and Exhibit 4.64 present systemwide 2025 reliability quartiles for all customers and for vulnerable census tracts within the Company's service area.

[87] MiEJScreen: Environmental Justice Screening Tool, available at https://www.michigan.gov/egle/maps-data/miejscreen?adlt=strict, accessed March 12, 2026.

Exhibit 4.63 – 2025 All-Weather SAIFI by Census Tracts in DTE's Service Area

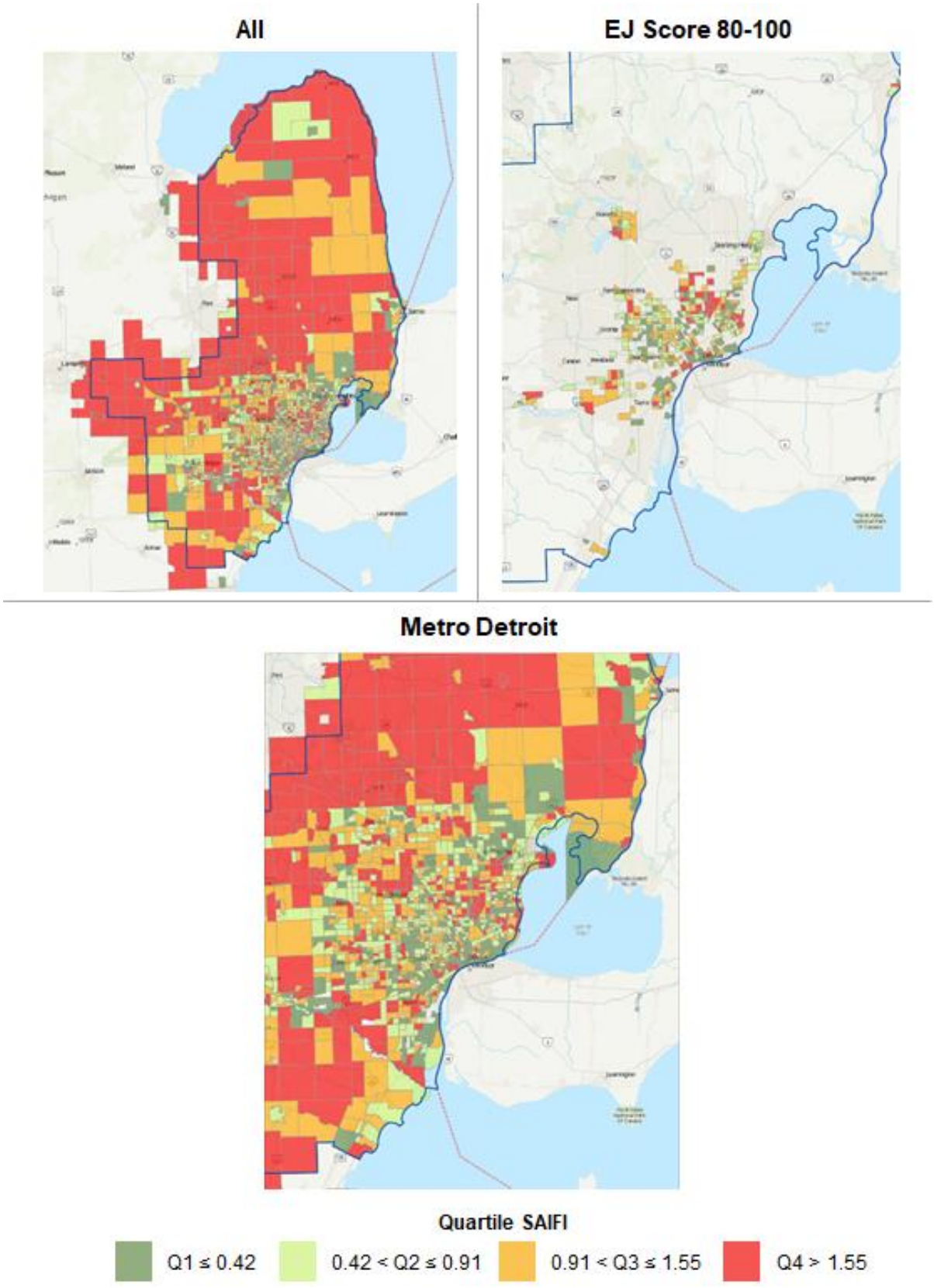
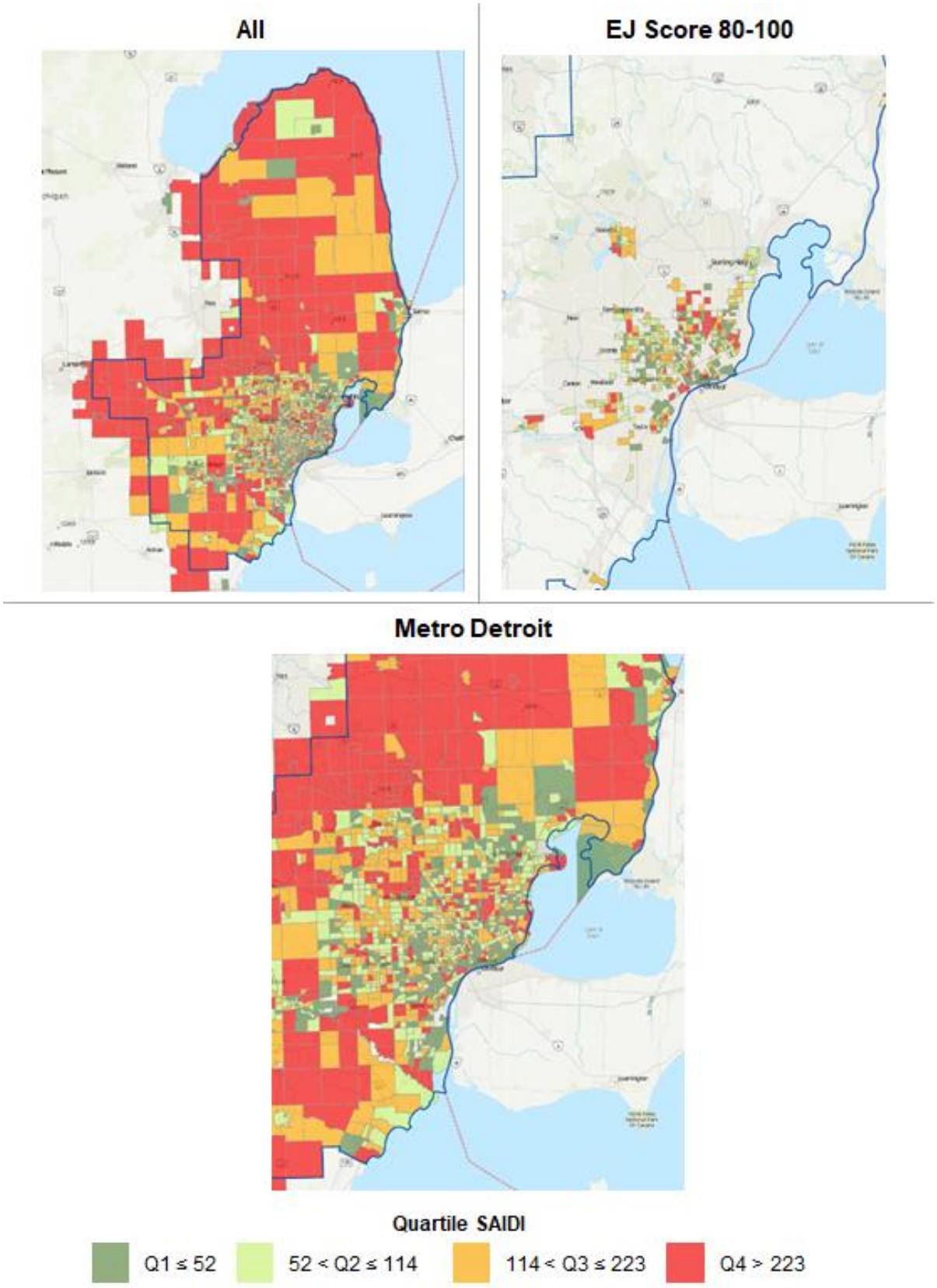


Exhibit 4.64 – 2025 All-Weather SAIDI by Census Tracts in DTE's Service Area



DTE conducted a comprehensive analysis of trends in reliability performance in EJ community census tracts compared to the rest of the Company's system. The 2025 assessment shows that the targeted investments made in these communities — particularly within the City of Detroit — are contributing to continued improvements in reliability. As a result, in 2025, EJ communities had, on average, better reliability performance across all four metrics than the system average. Across all 484 vulnerable census tracts, reliability performance from 2021 through 2025 spans the full range of outcomes, from first to fourth quartile, when benchmarked against systemwide SAIDI and SAIFI performance as shown in Exhibit 4.65.

Exhibit 4.65 – Reliability Performance of EJ Census Tracts Versus System Average

Category	2021	2022	2023	2024	2025
All-Weather SAIFI Vulnerable Communities	1.30	1.12	1.50	0.99	0.89
All-Weather SAIFI System Average	1.58	1.25	1.72	1.25	1.16
exMED SAIFI Vulnerable Communities	0.75	0.81	0.72	0.77	0.84
exMED SAIFI System Average	0.92	0.98	0.86	0.94	1.07
All-Weather SAIDI Vulnerable Communities	823	732	1507	367	137
All-Weather SAIDI System Average	927	584	1542	483	192
exMED SAIDI Vulnerable Communities	116	130	136	131	116
exMED SAIDI System Average	136	146	157	159	151

Over Performing System Average Under Performing System Average System Average

DTE also evaluated how its three largest reliability investment programs have reached EJ communities. As shown in Exhibit 4.66, DTE has directed significant investment toward these areas through 2025. The Company plans to maintain and expand this focus in future years as part of its long-term distribution system strategy, as discussed in Section 5.4 (Environmental Justice in Distribution Planning).

Exhibit 4.66 – Reliability Investments in EJ Communities, 2021-2025[88]

Investment Program (2021-2025)	Total Investment ($ millions)	Total Investment in Vulnerable Census Tracts ($ millions)	% Of Investment in Vulnerable Census Tracts
Conversion	784	455	**58%**
4.8 kV Hardening	542	465	**86%**
Tree Trim (Vegetation Management)	966	227	**23%**

[88] Vegetation Management investment includes both program investment and investment in support of other initiatives, such as 4.8 kV Conversions, 4.8 kV Hardening, and PTMM.

4.7.2 EJ Regression Analysis

As awareness and understanding of energy justice principles and related data have matured, the Company and other stakeholders have continued to refine their analytical approaches to better assess electric reliability and the impacts of investments on vulnerable customers. In addition to the geographic mapping and comparisons to system averages for EJ communities described above, DTE's analysis has evolved to include regression-based methods.

In response to the Commission's Order in Case No. U-21297[89] directing a more detailed regression-based analysis of how electrical reliability outcomes might differ for customers in vulnerable communities, the Company initiated an EJ regression study in 2024 in collaboration with outside parties, most notably the Commission Staff and Clean Energy Organizations (CEO). The objective of this effort was to evaluate the hypothesis that a statistical correlation exists between the EJ score and reliability performance, as measured by SAIFI and SAIDI, after adjusting for circuit level characteristics known to influence reliability outcomes. To test this hypothesis, the Company worked with stakeholders to design and execute a series of regression analyses examining the potential relationship between vulnerable communities and reliability performance. All analyses were conducted at the circuit level to ensure that variations in circuit construction, geographic exposure, and operational practices were appropriately reflected in the results.

To prepare the dataset, DTE gathered and validated reliability metrics and circuit characteristics, reviewing more than 10,000 data points to ensure completeness and accuracy. The team examined the distribution of each independent variable and applied log transformations when variables were heavily skewed. Overhead and underground line-miles required log transformations due to right-skewed distributions, and the same transformation was applied to AW and exMED SAIFI and SAIDI metrics to support nonlinear modeling.

As an initial review of data, the Company ran a simple univariate analysis comparing vulnerable to non-vulnerable customers across four metrics: SAIFI and SAIDI under both AW and exMED conditions. This analysis revealed a statistically significant relationship with EJ customers experiencing better reliability across all four metrics. These results are compelling at a high level and likely reflect the effects of targeted investments in specific communities, including 4.8 kV

[89] Order dated December 1, 2023, available at https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/0688y00000At0VBAAZ, accessed March 12, 2026.

Hardening in Detroit. The findings also align with the comparison of average reliability metrics for vulnerable communities versus system averages described earlier.

In addition to the comparison of EJ community reliability to system averages, stakeholders sought a more detailed regression-based evaluation to determine whether factors such as circuit configuration and vegetation management cycles may have contributed to the improved reliability experienced by vulnerable customers. DTE worked with stakeholders to develop and perform several regression-based analyses.

In summary, multiple regression methodologies were applied to evaluate the relationship between vulnerable communities and reliability, but the various regression methodologies did not yield conclusive results. At the highest level with the most straight forward approach, the higher the EJ score, the better the reliability (simple linear regression). Two additional regression methodologies violated regression assumptions, rendering the results invalid. An additional more complex regression methodology relaxed the adherence to core assumptions in order to resolve the violations; while the results showed statistical significance, the results are not actionable outside of the current path to fundamentally upgrade the infrastructure in these areas. Regardless of what these studies indicate, the Company plans to continue its significant investment in EJ communities to replace old infrastructure and improve reliability. Full details of the EJ regression analysis are provided in Appendix 8.7 (Environmental Justice Regression Analysis).

4.7.3 Changing Demographics Analysis

As noted earlier, DTE uses the MiEJ Screening Tool to identify EJ communities. The tool was developed with input from stakeholders across Michigan and incorporates demographic data from the 2020 federal census. Over time, demographic shifts naturally occur, and in Case No. U-21534, some stakeholders expressed concerns about relying on data that may no longer fully reflect current community characteristics. As part of its Order in Case No. U-21534, the Commission required the Company to "evaluate changing demographics over time using data consistent with the underlying data sets for the detailed regression analysis."[90] In response, DTE met with stakeholders from the Detroit Area Advocacy Organization (DAAO), which originally requested the analysis in Case No. U-21534, and CEO to align on a methodology for assessing whether meaningful demographic changes have occurred since the MiEJ Screening Tool was released. Working collaboratively, the Company used data from the American Community Survey, an annual

[90] Order dated January 23, 2025 (p. 124), available at https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/068cs00000X23rkAAB, accessed March 12, 2026.

U.S. Census Bureau dataset that provides social, economic, housing, and demographic studies, to evaluate changes within census tracts from 2019 to 2024. The analysis focused on the following four variables:

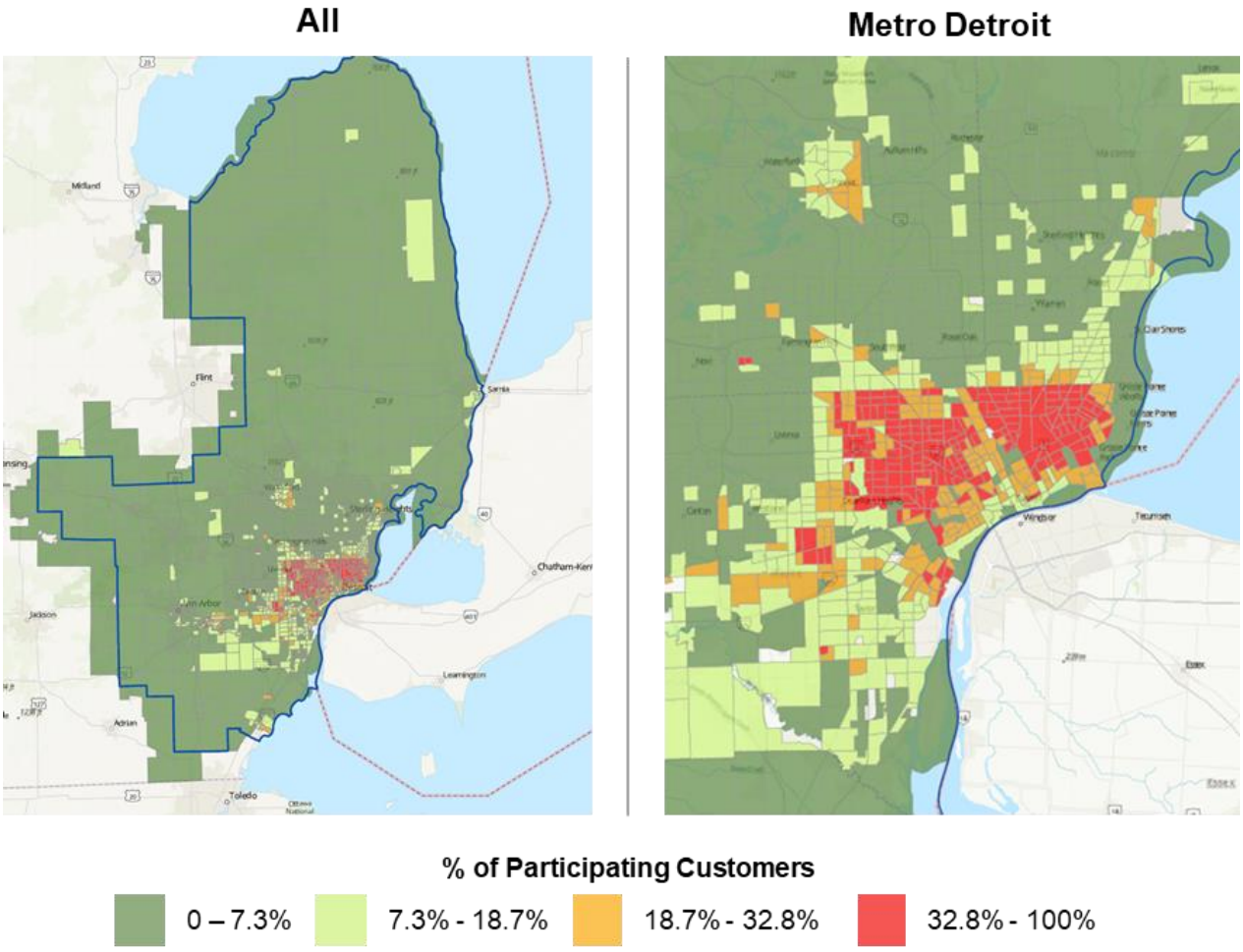
1. Percentage of households in poverty
2. Percentage of residents identifying as Black, Indigenous, or People of Color (BIPOC)
3. Percentage of residents identifying as Black/African American
4. Percentage of households receiving public assistance as part of income

Across DTE's service area, comparisons of data between 2019 and 2024 at the census-tract level showed statistically significant shifts; however, the magnitude of these changes was very small — generally within 1 to 2%. Within Detroit, census tracts in the Downtown and Midtown areas exhibited little to no change over the same period. While a small number of individual tracts showed larger shifts in one or more variables, these occurrences were scattered randomly across the DTE service area and may reflect sampling variability or incomplete survey responses rather than true population changes. The full report for this revised demographic analysis is in Appendix 8.8 (Environmental Justice Changing Demographic Analysis).

4.7.4 Participation in Low-Income Customer Programs

As part of the DSP requirements, DTE evaluated participation in low-income customer service programs at the census tract level. Using active residential premises as the denominator, approximately 10% of customers were enrolled in a low-income program in 2025, though participation varied significantly by tract. Across all tracts, the median participation rate was 5%, with an interquartile range of roughly 2% to 17%, indicating that certain communities have much higher concentrations of income qualified customers. Several census tracts showed participation rates above 30%, with a maximum of 57%, while others had minimal or no enrollment. Exhibit 4.67 shows where low-income program participation is concentrated across the service area. This analysis highlights where income qualified customers are more prevalent and helps inform targeted planning, outreach, and customer assistance efforts within EJ communities.

Exhibit 4.67 – Participation in Low-Income Customer Service Programs by Census Tract



4.7.5 EJ Conclusions

In summary, DTE's various EJ analyses demonstrate that the Company's investments are driving measurable improvements in reliability for vulnerable communities across its service area. By integrating MiEJ Screening Tool data, evaluating demographic shifts, assessing customer program participation, and expanding analytical methods such as regression modeling, DTE continues to strengthen its understanding of the needs and experiences of vulnerable populations. Together, these efforts reflect an ongoing commitment to ensuring equitable, data-driven investment that supports reliability for all communities in the Company's service area. Additional information on how EJ is considered in distribution prioritization of investments and in planning is provided in Section 5.2.4 (Global Prioritization Model) and Section 5.4 (Environmental Justice in Distribution Planning).

5. Distribution and Subtransmission System Planning

Chapter 5 describes the methodologies, analytical tools, and prioritization frameworks DTE uses in system planning to address capacity constraints from load growth and integrate reliability-driven investments into a coordinated portfolio. The chapter begins with an overview of the Company's integrated system- and circuit-level forecasting approach, followed by a description of the analytical frameworks and cost-effectiveness analyses that inform investment prioritization. Chapter 5 also presents projected near-term investments, estimated reliability and customer affordability impacts, and a longer-term investment outlook. The chapter concludes by explaining how EJ considerations are incorporated into planning and presents maps that illustrate the types and locations of projected grid investments through December 2028.[91]

[91] Order dated June 12, 2025 in Case No. U-21305 (Exhibit A, page 7), "[DSPs shall include] planned investment overlay maps showing year of and two years following of planned investments following the utilities filed plan."

5.1 Load Forecasts and Scenario Planning

In its 2022 IRP for generation load planning and 2023 DSP for distribution load planning, DTE introduced the Integrated Forecasting Solution (IFS) to centralize and standardize load forecasting inputs across key planning activities and regulatory filings, including DSPs, TEPs, IRPs, and rate cases. Historically, system-level load forecasts and subtransmission/distribution planning load forecasts were developed independently due to the technical challenges of spatially granular forecasting. This separation limited the ability to consistently translate system-level planning assumptions across the fleet of generation resources into localized impacts at the substation and circuit level.

The IFS addresses these historical limitations by producing 8,760-hourly load forecasts at both the substation and circuit level using the same set of inputs, assumptions, and weather patterns applied in the IRP's system-level forecast. This integrated approach ensures technical alignment between generation resource and distribution planning, enhances transparency across filings, and strengthens coordination across business units.

The use of a shared forecasting platform in both the 2026 DSP and 2026 IRP responds directly to growing regulatory expectations for coordinated planning. By tying high-level system projections to geographically granular circuit forecasts, the IFS ensures consistent treatment of emerging technologies — such as DG, battery storage, and demand response — across all planning horizons and filing types. Together, the DSP and IRP draw from a unified data foundation that improves modeling consistency, supports regulatory reviews, and advances a coordinated strategy for long-term reliability, resilience, and clean energy objectives.

5.1.1 System-Level and Circuit-Level Forecasting Integration

Circuit-level forecasting introduces spatial detail, such as individual circuit characteristics and the localized adoption of EVs, that is not typically considered in traditional system-level forecasting. While system forecasts emphasize hourly timing and aggregate usage patterns, distribution forecasting must account for both temporal and locational variations across more than 3,000 distinct nodes, each with unique customer mixes and geographic attributes.

Advancements in metering data, spatial data integration, and analytical modeling have enabled DTE to bridge this gap. The IFS connects system-level and circuit-level forecasting by combining high-temporal-resolution modeling with location-specific insights, allowing the Company to forecast not only how much load is expected, but also where and when it will materialize across the grid.

5.1.2 Key Components of the IFS

The IFS incorporates hourly profile modeling, consistent load shapes, typical weather patterns, and long-term drivers of investment. First, DTE develops reference hourly forecasts for each circuit and substation using the IRP's bottoms-up hourly forecasting methodology. These models rely on historical hourly data from 2022-2024 and 2024 Area Load Analysis (ALA) data, described further in Section 6.3.2 (System Loading). The IFS uses regression-based and neural network techniques to capture localized responses to temperature and other conditions, producing weather-normalized baseline hourly profiles prior to incorporating future load drivers such as EVs, DG, or customer expansions.

To maintain consistency between system-level and circuit-level planning, the IFS applies the same hourly load shapes used in the IRP for residential and commercial customers, solar photovoltaics (PV), battery storage, and EV charging. These shapes are scaled to circuit- and substation-specific adoption assumptions and layered onto the reference hourly forecasts noted above. This approach provides a transparent and reproducible method for quantifying the impacts of emerging technologies on both peak demand and annual energy consumption at each node.

DTE also applies a standardized "normal weather" year across system and circuit forecasts, defined as a 50/50 weather scenario based on a 15-year historical period (2010–2024). The Company adopted this definition of normal weather in response to a Commission directive in Case No. U-20471.[92] Hourly weather profiles reflect a realistic mix of severe, moderate, and mild conditions and are paired with location-specific weather response functions. Using consistent weather assumptions across planning processes ensures alignment between resource and distribution forecasts.

Lastly, the IFS incorporates several key drivers that influence long-term load growth and shape outcomes at both the system and circuit level:

- **Customer Growth:** The IFS incorporates residential and commercial customer projections for each circuit and substation using S&P Global zip code-level economic forecasts. Incremental load is calculated using average residential and commercial hourly shapes, which are incorporated into the reference hourly profile for each circuit or substation. This data is then reconciled with system-level customer growth assumptions to ensure consistency across filings.

[92] Order dated February 20, 2020, available at https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/068t0000009jWc2AAE, accessed March 30, 2026.

- **Customer Projects:** Large new business connections or approved customer expansions that are not captured in the standard customer growth projections described above are also incorporated during the annual ALA process. DTE planning engineers adjust forecasts at the circuit and substation level to reflect known, approved changes anticipated within the next one to two years. Additional future large business loads beyond this horizon are not currently reflected in the long-term projections.
- **DG and Battery Storage Growth:** DG has grown steadily across DTE's service area over the past five years, as detailed in Section 4.5 (Distributed Energy Resources and Interconnection Process). For forecasting purposes, the Company defines DG as customer-sited resources that are interconnected on the customer side of the meter and installed primarily to offset on-site load with incidental export. For modeling purposes, the forecast also assumes that the projected additional DG resources are solar PV. DTE developed a propensity model that analyzes geographic, demographic, behavioral, and psychographic attributes of current DG adopters to identify where future installations are likely. This approach yields a unique DG and battery storage capacity projection for each circuit and substation, which is then reconciled to the system-level forecast. The load impacts from DG and battery storage are applied by using the hourly DG generation (expressed as a subtraction from load) and battery storage impact load shape, scaled to the forecasted capacity for each circuit and substation, and layered into the reference hourly load profile for each node.
- **EV Penetration:** EV adoption in the Company's service area has grown rapidly, with annual EV sales increasing from approximately 8,000 vehicles in 2021 to nearly 48,000 in 2025. As a result, there are now nearly 114,000 EVs registered within DTE's service area, contributing approximately 90 MW of non-coincident peak demand and 400 GWh of annual energy consumption on the distribution system. Looking ahead, the Company forecasts EV adoption to exceed 355,000 vehicles by 2030, corresponding to approximately 320 MW of non-coincident peak demand and 1,500 GWh of annual energy consumption.[93] Because customers are not required to report EV ownership, DTE developed an EV Identification Tool that uses neural-network analysis of hourly AMI data to detect EV-charging patterns. These insights inform a propensity-based spatial adoption model that forecasts future EV distribution load. Hourly EV load shapes are

[93] Additional information on DTE's EV programs is described in Section 4.5.2 (Transportation Electrification Plan).

applied at the circuit and substation level and reconciled with system-level EV forecasts used in the IRP and TEP.

- **Building Electrification:** DTE incorporates the emerging adoption of air-source and ground-source heat pumps into long-term planning by allocating system-level electrification forecasts to circuits and substations using zip-code-level census fuel use data, weighted toward regions with greater delivered fuel prevalence. Residential heating load shapes are then applied and integrated into each node's hourly reference profile.

5.1.3 Scenario Planning and DER Outlook

Consistent with MPSC requirements for DSPs in Case No. U-20147, DTE developed two alternative electrification scenarios — low electrification and high electrification — alongside the reference case. The reference case reflects the Company's most probable outlook under the current federal and state policy conditions and serves as the planning basis for other regulatory filings, including rate cases, IRPs, and TEPs.[94] The alternative scenarios capture a range of plausible outcomes, particularly given uncertainties surrounding adoption rates of emerging technologies and their grid impacts.

The low electrification scenario reflects slower adoption of EVs and building electrification, driven by reduced incentives, rolled-back regulations, slower public charging infrastructure deployment, and consumer hesitancy toward new heating technologies. The high electrification scenario reflects accelerated EV adoption driven by improved customer familiarity, declining total cost of ownership, and expanded charging infrastructure. It also reflects building electrification projections increased in alignment with the State of Michigan's 2025 Efficient Electrification Study.[95] This scenario represents a future in which a formal building electrification program is in place, supported by incentives that encourage customers to switch fuels in a manner that satisfies the Ratepayer Impact Measure (RIM) test.

Exhibit 5.1 and Exhibit 5.2 illustrate EV and heat pump adoption trajectories, respectively, under the low electrification, reference, and high electrification scenarios.

[94] The large-load data center included in the 2026 general rate case and to be included in the 2026 IRP is not considered in this DSP because it connects directly to the transmission system rather than the electric grid covered by this DSP. The load classes aside from the large data center are identical across the reference cases in the IRP and general rate case.

[95] 2025 Energy Waste Reduction Demand Response and Efficient Electrification Statewide Potential Study, available at https://www.michigan.gov/mpsc/commission/workgroups/2025-energy-waste-reduction-demand-response-and-efficient-electrification-statewide-potential-study, accessed March 30, 2026.

Exhibit 5.1 – Cumulative Light-Duty EV Forecast Scenarios in DTE's Service Area

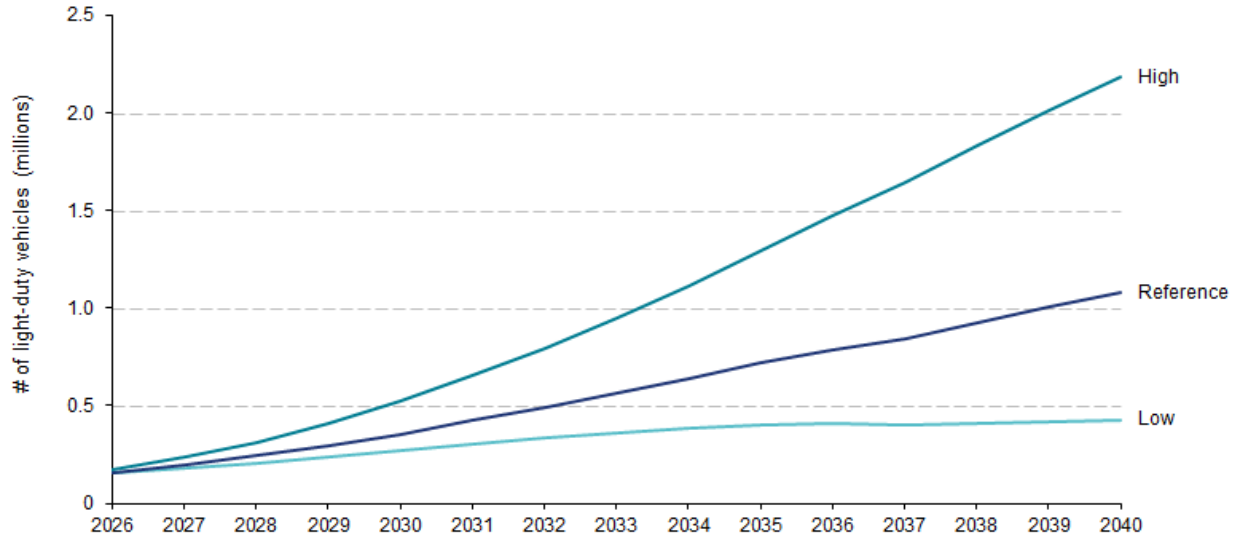
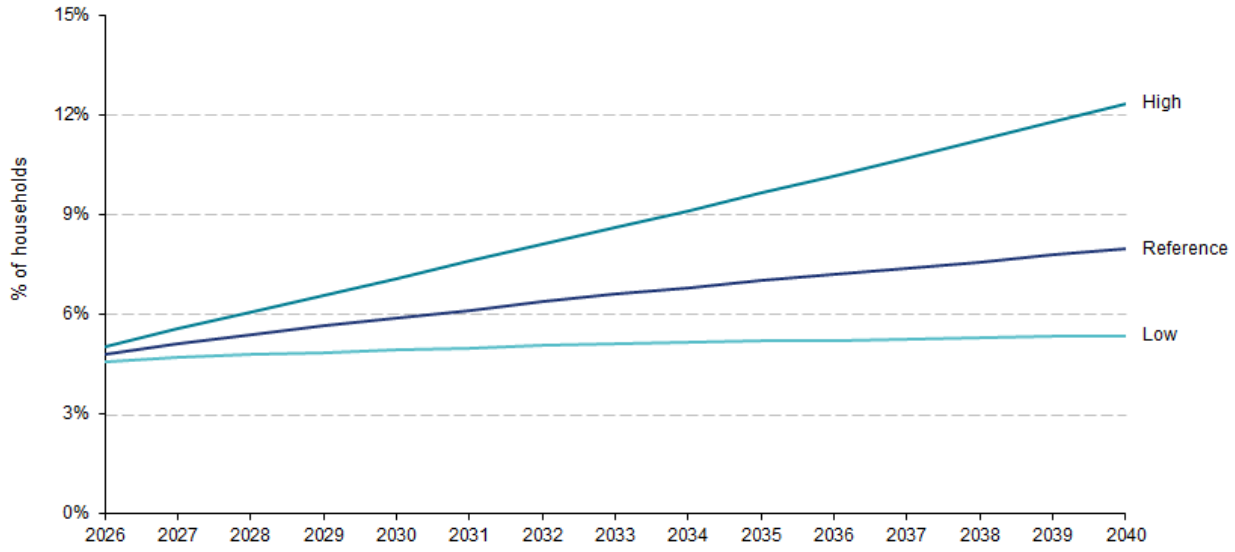


Exhibit 5.2 – Cumulative Heat Pump Saturation Scenarios in DTE's Service Area[96]



As shown in Exhibit 5.3 and Exhibit 5.4 for a representative circuit, DTE evaluates three future scenarios for every circuit and substation to assess hourly impacts on summer and winter peak days under varying levels of EV, DG, and electrification adoption. These 15-year projections, extending through 2040, capture changes in peak magnitude, peak timing, surrounding peak-hour conditions, and load duration curves. The results inform project planning and are incorporated into the GIS-based planning tool referenced in Section 6.3 (Redesign and Modernization); this

[96] Includes air-source and ground-source heat pumps.

tool serves as a key input to prioritization scoring as discussed in Section 5.2.4 (Global Prioritization Model).

Exhibit 5.3 – Summer Peak Day Example

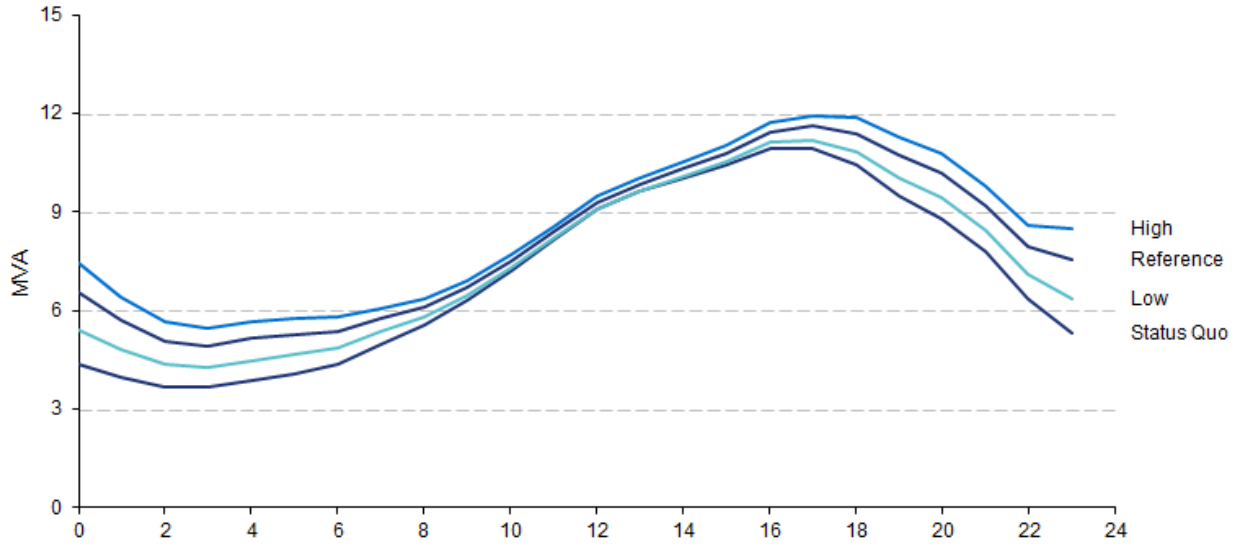
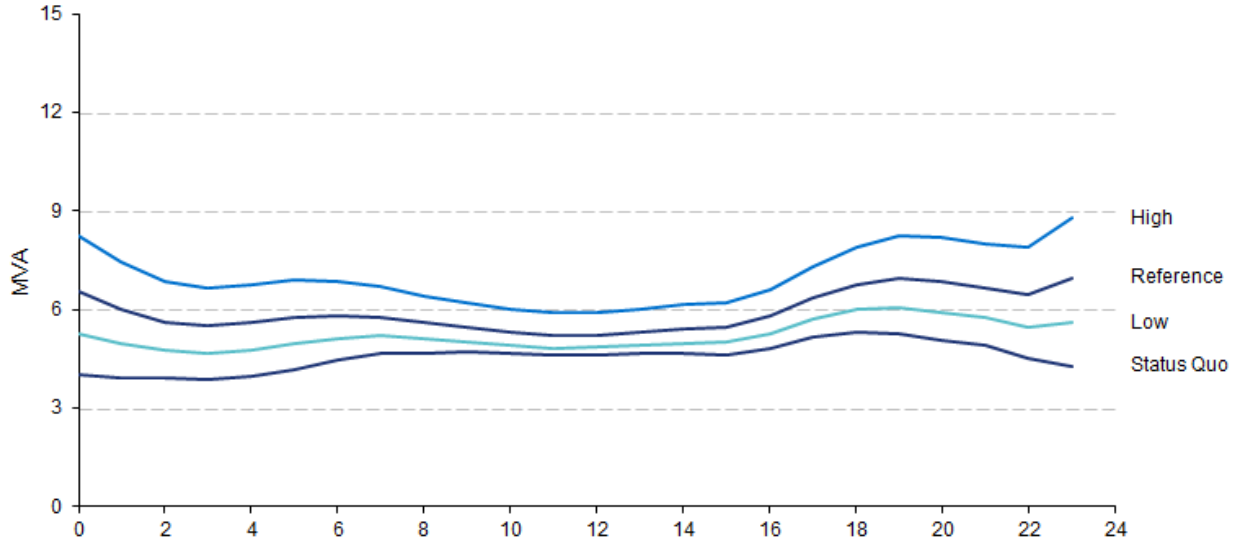


Exhibit 5.4 – Winter Peak Day Example



The IFS establishes a unified, transparent, and technically-aligned forecasting foundation across DTE's planning processes. By reconciling system-level and circuit-level assumptions within a single analytical framework, the IFS improves modeling consistency, strengthens regulatory cohesion across filings, and enhances the accuracy of localized planning decisions. This

approach ensures that forecasts credibly reflect a range of plausible outcomes driven by emerging technologies, providing a robust basis for prudent investment planning and prioritization.

5.2 Investment Prioritization

A robust approach to evaluating and prioritizing electric grid investments is fundamental to developing an investment plan that delivers the greatest benefit to customers. Based on the grid needs discussed in Sections 2.3 (Drivers of Investment) and 4.2 (General Asset Health and Condition), fully transforming the grid to meet evolving customer needs will require substantial investment over a multi-decade horizon, extending well beyond the timeframe of this DSP. As a result, disciplined prioritization is essential to identify the investments that deliver the highest value in the near and medium term while supporting DTE's long-term strategy. This section describes the analytical processes used to evaluate alternatives, prioritize OT investments, conduct BCAs, and rank grid investments across the Company's overall portfolio.

5.2.1 Alternatives Analyses Process

When the need for a new project is identified, DTE's alternatives analysis process provides a structured and transparent method for evaluating alternative technical solutions before the project scope is formalized. This framework ensures that each identified system need is reviewed systematically by examining a range of feasible options. By comparing alternative solutions on costs, operational benefits, risks, and long-term system implications, the Company can identify the investment option that best supports grid reliability, customer affordability, and long-term system resilience. The process promotes disciplined decision-making, improves the quality and consistency of documentation, and strengthens the justification for the selected solution.

As part of this process, each alternative undergoes a detailed technical review by SMEs, who assess engineering feasibility, operability, expected system performance, and alignment with applicable standards. SMEs also confirm that each option appropriately addresses the underlying system drivers and planning needs. In parallel, DTE's PMO evaluates execution feasibility, including constructability considerations, material and equipment availability, and labor and contractor capacity. This dual-layered review ensures that the recommended solution is both technically sound and realistically achievable. The Company also maintains a separate but complementary process for evaluating NWAs, which is discussed further in Section 6.3.4 (Non-Wire Alternatives). For projects in the Redesign and Modernization pillar with a more significant

scope,[97] a standardized project template is applied to ensure consistency and completeness of the information presented, as shown in Appendix 8.9 (Alternatives Analyses Project List). This includes an overview of the project need, the number of alternatives considered, a brief description of each potential solution, high-level cost estimates, expected operational and reliability benefits, and the implications of selecting or rejecting each alternative. This consistent format enables clear comparisons across options and enhances transparency in planning decisions.

The Goodison Substation project illustrates the structured alternatives analyses framework. At the time of evaluation, the substation was operating at 138% of its firm rating, with both distribution circuits exceeding the Distribution Design Order (DDO) limit, thus initiating a project to address System Loading concerns. Three alternatives were evaluated using the standardized approach, as summarized in Exhibit 5.5.

Exhibit 5.5 – Alternatives Analysis for Goodison Substation (System Loading)

Project — System Loading: Goodison

This project will construct a new 40-13.2kV Class A Substation to relieve existing overloads through load transfers and provide additional capacity for future load growth in Oakland Charter Twp for residential and electrification. The new substation, Paint Creek (PNTCK), will split the GODSN circuits and COLRD9100, which reduces customer count and outages per circuit. Additionally, operability improves as there are more circuits, and each circuit has less load and customers than today's configuration.

NWA analysis performed - is NOT a candidate.

	Proposed Solution	Alternative 1	Alternative 2
Brief Description	Build New Class 'A' two-transformer substation Operating voltage: 40-13.2 kV Transformers: (2) 15/20/25 MVA Power distribution center: (1) 9-POS -Establish conduit and cable -Establish OH circuits and sectionalizing	Build New Class 'A' three-transformer substation Operating voltage: 40-13.2 kV Transformers: (3) 15/20/25 MVA Power distribution center: (2) 9-POS -Establish conduit and cable -Establish OH circuits and sectionalizing	Expand existing Goodison class 'R' substation to class 'A' substation Operating voltage: 40-13.2 kV Transformer: (1) 15/20/25 MVA Power distribution center: (1) 9-POS -Establish conduit and cable -Establish OH circuits and sectionalizing
If constructable, provide high-level estimate.	$56 million	$65-80million	n/a – not constructable
What benefits does the alternative provide?	-Increases area capacity to support current and future load growth for 15+ years -Relieves load off of GODSN and COLRD substation and circuits -Leaves two spare positions for additional circuits	-Increases area capacity to support current and future load growth for 25+ years -Relieves load off of GODSN and COLRD substation and circuits -Leaves eight spare positions for additional circuits	-Increases substation capacity to support current and future load growth for 15+ years -Relieves load off of GODSN and COLRD substation and circuits -Leaves two spare positions for additional circuits
Why was this solution not selected?	N/A - Selected	-More costly -Selected project leaves the option for additional substation expansion as load growth materializes	Not enough footprint to expand and inability to procure adjacent property

[97] The criteria for the alternative analysis are intended to align with the feedback from the MPSC Order in Case No. U-21534 on larger project scope exceeding the $10M threshold.

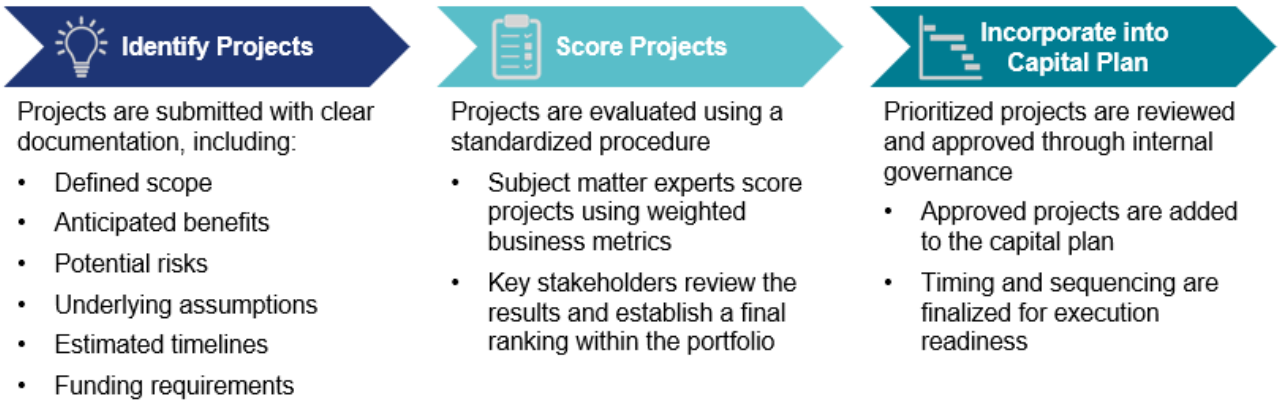
In this specific example, the proposed solution — a new Class "A" two-transformer substation — was selected because it provides more than 15 years of projected load growth capacity, relieves loading on neighboring substations, maintains flexibility for future expansion, and has a lower estimated cost than Alternative 1. While Alternative 1's three-transformer design would have provided additional long-term capacity, it involved higher projected costs and greater construction complexity. Alternative 2 was determined to be infeasible due to site constraints and the inability to procure adjacent property. The SME and PMO both reviewed and confirmed the proposed solution as technically appropriate, constructible, and supportable with resource availability.

Overall, DTE's alternatives analyses framework ensures that major capital investments are selected through a disciplined, transparent, and technically rigorous process. The Goodison substation example demonstrates how this approach supports well-informed decisions that appropriately balance cost-effectiveness, system needs, and long-term planning considerations. By consistently evaluating multiple solutions and documenting decision rationales, the process strengthens planning quality and reinforces confidence in investment decisions.

5.2.2 Operational Technology Prioritization Framework

Operational Technology (OT) projects are essential to system safety, reliability, and customer satisfaction. To avoid inconsistent or fragmented prioritization, the OT Prioritization Framework provides a unified model that aligns project funding decisions with enterprise objectives and regulatory requirements. The framework applies a structured, data-driven methodology to ensure that OT investments are evaluated consistently and allocated strategically. Through a transparent and collaborative process, DTE can focus resources on the initiatives that deliver the greatest operational value, ensure compliance, and enhance long-term operational resilience. The OT prioritization framework has three key process steps as detailed in Exhibit 5.6.

Exhibit 5.6 – OT Prioritization Process Overview



SMEs assess each project's impact across various dimensions using a one to three scoring scale. Each dimension is weighted according to its strategic importance from one to five. An overview of the impact dimensions, evaluation drivers, and associated weights is provided in Exhibit 5.7.

Exhibit 5.7 – Overview of Operational Technology Scoring Dimensions

Dimension	Impact Drivers	Weight
End of Life	Projects that replace or upgrade equipment or software that have reached or will soon reach the end of its useful life, such as updating applications or hardware that a vendor will no longer support to prevent major security or operational risks	5
Safety	Projects that affect the health and safety of employees and customers	3
Compliance	Projects required by laws or regulations, such as NERC, FERC, or MPSC rules, that are necessary to maintain compliance and ensure continued operations (e.g., implementing DERMS to meet FERC Order 2222)	2
48-hour Storm	Projects focused on restoring service quickly after major storms (e.g., deploying Compass, the new mobile tool that helps field crews manage trouble work more efficiently)	1
Customer Impact	Projects that have a direct effect on customer experience, including those initiatives designed to enhance the speed and accuracy of communications	1

The scoring and weighting methodology helps ensure that the total score drives decisions toward the highest business priorities. The top 24 OT projects based on the most recent prioritization evaluation are shown in Exhibit 5.8.

Exhibit 5.8 – Operational Technology Prioritization Framework Top 24 Projects

Rank	OT Project Name
1	Interconnection Process Enablement
2	Field Service Management
3	Customer Power Status Visibility
4	Meter Improvements
5	ADMS: DMS/OMS Mobile Tool
6	SOC Phone and Radio Dispatch
7	Other Modernize Grid Management
8	Operational Technology and Error Free Communication
9	ESRI Utility Network Model Upgrade
10	ADMS: Network Management System
11	Vegetation Management Re-platform
12	ADMS/GMS Hardware

Rank	OT Project Name
13	Enhance and Expand Cybersecurity
14	DERMS
15	ADMS Enhancements
16	Mobile Timesheets
17	FLISR Implementation
18	Hosting Capacity Program
19	External Crew Efficiency
20	Mobile Tools Expansion
21	Power Quality Analysis Program
22	Load Forecasting & Analytics
23	Substation Design Tool Upgrades
24	Automation Configuration and Test Record Database

The OT Prioritization Framework strengthens DTE's ability to make consistent, transparent, and data-informed investment decisions that align with enterprise priorities and regulatory obligations. By fostering cross-functional collaboration and establishing a clear, structured evaluation process, the framework ensures that resources are directed toward projects that improve grid reliability, enhance compliance, reduce risk, and improve system stability.

5.2.3 Benefit-Cost Analyses Approach

The grid needs in DTE's service area are wide-ranging and complex, requiring a long-term investment strategy that balances safety, reliability, affordability, and system resilience. To support prudent investment decision-making, the Company has expanded the use of BCAs across a broader set of strategic investment programs, particularly those driven by reliability improvements and cost-avoidance benefits. At the same time, DTE recognizes that not all necessary investments produce benefits that can be readily monetized. Investments aimed at improving safety, addressing capacity constraints, meeting customer obligations, or establishing foundational system capabilities may provide substantial value but are not well suited for traditional BCA methods. In addition, conducting detailed BCAs for every investment category would impose additional analytical costs without commensurate benefit. As the Commission observed in its Order in Case No. U-21534, "requiring a full BCA for every investment category is not practical or advisable."[98]

Accordingly, DTE applies a balanced investment justification framework that aligns the analytical method with the nature of the benefits delivered, as summarized in Exhibit 5.9. Depending on the type of investment, programs and projects are supported using Monetized BCA, Hybrid analysis, Least-Cost/Best-Fit evaluation, or Descriptive Justification. This framework is intended to guide — not replace — planning decisions. The Hybrid, Least-Cost/Best-Fit, and Descriptive Justification methodologies are appropriate for investments that produce significant non-monetizable benefits or when the strategic investment is considered critical to improve the customer experience. For example, a 4.8 kV Conversion project will include significant safety and system capacity benefits that are difficult to monetize, and these benefits need to be considered when making investment decisions.

[98] Order dated January 23, 2025 (page 97), available at https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/068cs00000X23rkAAB, accessed March 30, 2026.

Exhibit 5.9 – DTE's Investment Justification Approach

Investment Support Method	Description	Example Types of Strategic Capital Investments
Monetized BCA	• Analytical approach comparing dollar value of benefits versus costs • Utilization of robust industry valuation framework for reliability-driven projects (e.g., ICE calculator and avoided reactive spend)	• Breaker Replacement • Distribution Automation • NWAs • PTMM • Small Wire Replacement • Subtransmission SCADA • System Cable Replacement • Communications Network • URD Replacement
Hybrid	• Combination of monetary benefits and descriptive justification that together demonstrate cost-effectiveness • Typically includes alternatives analysis to provide further support on selected projects	• 4.8 kV and 8.3 kV Conversions • Subtransmission Redesign & Rebuild
Least-Cost/ Best-Fit	• Usually applies to projects utilities must take on to serve customers and fulfill utility obligations • Coupled with alternative studies to demonstrate adherence to Least-Cost/Best-Fit standard	• System Loading
Descriptive Justification	• Robust descriptive discussion to demonstrate cost-effectiveness for benefits that are hard to monetize • Also applicable for projects that have gained industry-wide support, are for compliance purposes, or are still in the pilot stage	• Substation Risk • OT and DERMS • Frequent Outage • Next-Gen AMI evaluation phase • Other System Equipment Replacement investments

In recent years, DTE conducted detailed BCAs primarily for its PTMM and Distribution Automation programs. For the 2026 DSP, the Company refined those analyses and expanded quantitative BCAs to include six additional investment programs, as well as more than 30 subtransmission and conversion projects evaluated under a Hybrid justification approach. The remainder of this section focuses on the BCA methodology and results for these investment categories, as summarized in Exhibit 5.10.

Exhibit 5.10 – Investments Evaluated Using Quantitative BCAs

Investment Approach	Investment Category	Corresponding DSP Section
Monetized BCA		
	PTMM	6.2.1
	Small Wire Replacement	6.2.4
	Breaker Replacement	6.2.6
	System Cable Replacement	6.2.6
	URD Replacement	6.2.6
	Distribution Automation	6.4.1
	Subtransmission SCADA	6.4.2
	Communications Network	6.5.1
Hybrid		
	4.8 kV and 8.3 kV Conversions	6.3.1
	Subtransmission Redesign and Rebuild	6.3.3

Monetized BCA Methodology

DTE partnered with a leading third-party consultant to develop and conduct the monetized BCAs. The analysis incorporates DTE-specific inputs, including asset data across the subtransmission and distribution systems, asset health assessments, customer counts by class, outage history, and system configuration data. Additional detail on modeling assumptions and analytical methods is provided in Appendix 8.14 (Benefit-Cost Analysis Report).

As shown in Exhibit 5.11, the monetized BCAs capture two primary categories of customer benefits: avoided customer economic costs and avoided utility restoration costs.[99] The avoided customer economic cost is calculated using the recently released Department of Energy (DOE) ICE Calculator 2.0,[100] as previously supported by the Commission in Case No. U-21860.[101] Avoided utility restoration costs are estimated based on DTE's historical costs to restore customers during trouble and storm events.

[99] In addition to the two primary benefit categories, the BCA includes oil spill cost avoidance and collateral damage cost avoidance; however, these benefits are significantly smaller and apply only to select programs.

[100] ICE Calculator, available at https://icecalculator.com/, accessed March 30, 2026.

[101] Order dated February 19, 2026 in Case No. U-21860 (page 125), available at https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/068cs00001kHayeAAC, accessed March 30, 2026.

Exhibit 5.11 – Benefits to Customers

	Description	Monetization Method
Avoided Customer Economic Cost	The avoided outage economic costs experienced by customers as electric reliability improves	ICE Calculator
Avoided Utility Restoration Costs	The avoided utility costs to restore customers during outage events, because outages happen less often or outages are easier to restore	Utility restoration cost per truck roll

On the cost side of the equation, each BCA includes the forecasted investment required for the program or project. The resulting benefit-cost ratio (BCR) reflects the ratio of the Net Present Value (NPV) of total monetized benefits to the NPV of total costs over the expected asset's useful life.

Interpreting BCR Results and Thresholds

Because the BCA framework captures only two primary benefit categories, it understates the full value of investments that deliver significant non-monetizable benefits, such as safety improvements, capacity relief, system operability, resiliency, and community impacts. Therefore, investments with BCRs below 1.0 may still represent prudent and necessary investments. For this reason, DTE identifies investments with a BCR of 0.9 or greater as cost effective to customers, recognizing that non-quantified benefits may reasonably justify projects with BCRs below 1.0.

Exhibit 5.12 summarizes the level of investment across each program that achieved a BCR of 0.9 or higher. Project-specific BCAs are included in Sections 6.3.1 (4.8 kV and 8.3 kV Conversions) and 6.3.3 (Subtransmission Redesign and Rebuild).

Exhibit 5.12 – Investment Amount with BCRs Greater Than 0.9 by Program ($ millions)

Strategic Capital Investment	Total Investment with BCR ≥ 0.9
Breaker Replacement	857
Distribution Automation	380
PTMM	3,687
Small Wire Replacement	2,390
Subtransmission SCADA	93
System Cable Replacement	1,220
URD Replacement	420

These values represent a baseline indication of cost-effective investment, instead of a prescriptive level of total investment needed. There are two important considerations when interpreting these results. First, as already discussed above, the investment amount tabulated in Exhibit 5.12 does not include projects that remain cost-justified based on benefits that are not as easily quantified or monetized. Second, the BCA results are an excellent indication of value and are confirmed by detailed engineering and design, which ultimately determine the final project scope and cost.

Exhibit 5.13 presents the approximate benefits, costs, and BCR results for DTE's major investment categories within the five-year planning horizon; additional details on all BCAs conducted are provided in Appendix 8.14 (Benefit-Cost Analysis Report).

Exhibit 5.13 – Investment Category Benefits, Costs, and BCR Results

Strategic Capital Investment	Total Benefit Forecast ($ millions)	Total Spend Forecast 2026-2030 ($ millions)	BCR
Breaker Replacement	172	137	1.3
Distribution Automation	1,146	355	3.2
PTMM	8,716	1,863	4.7
Small Wire Replacement	431	68	6.3
Subtransmission SCADA	1,160	64	18.1
System Cable Replacement	234	164	1.4
URD Replacement	166	140	1.2

Climate Risk and Resiliency Analysis

In response to Commission direction to incorporate climate risk into distribution planning,[102] DTE's BCA analyses include a dedicated climate risk and resiliency assessment, as further described in Appendix 8.14 (Benefit-Cost Analysis Report). Historical weather event data from the National Oceanic and Atmospheric Administration (NOAA) from 2007 through 2025 were linked with the Company's outage records over the same period, as illustrated in Exhibit 5.14 and Exhibit 5.15.

[102] Order dated September 26, 2024 in Case No. U-20147, available at https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/068cs00000BgOPWAA3, accessed March 30, 2026.

Exhibit 5.14 – NOAA Weather Event Locations, 2007 – 2025

Exhibit 5.15 – CMI Distribution in DTE Service Territory, 2007 – 2025

DTE experienced a total of 21.8 billion customer minutes interrupted (CMI) between 2007 and September 30, 2025. Approximately 79% of the total CMI was attributable to NOAA weather events, which totaled 1,078 events in DTE's service area. Exhibit 5.16 demonstrates that thunderstorm wind events alone accounted for more than half of historical CMI, while Exhibit 5.17 shows that ice storms, though less frequent, produced the highest average CMI per event. [103]

Exhibit 5.16 – Total CMI for Top 10 Weather Events, 2007 – 2025

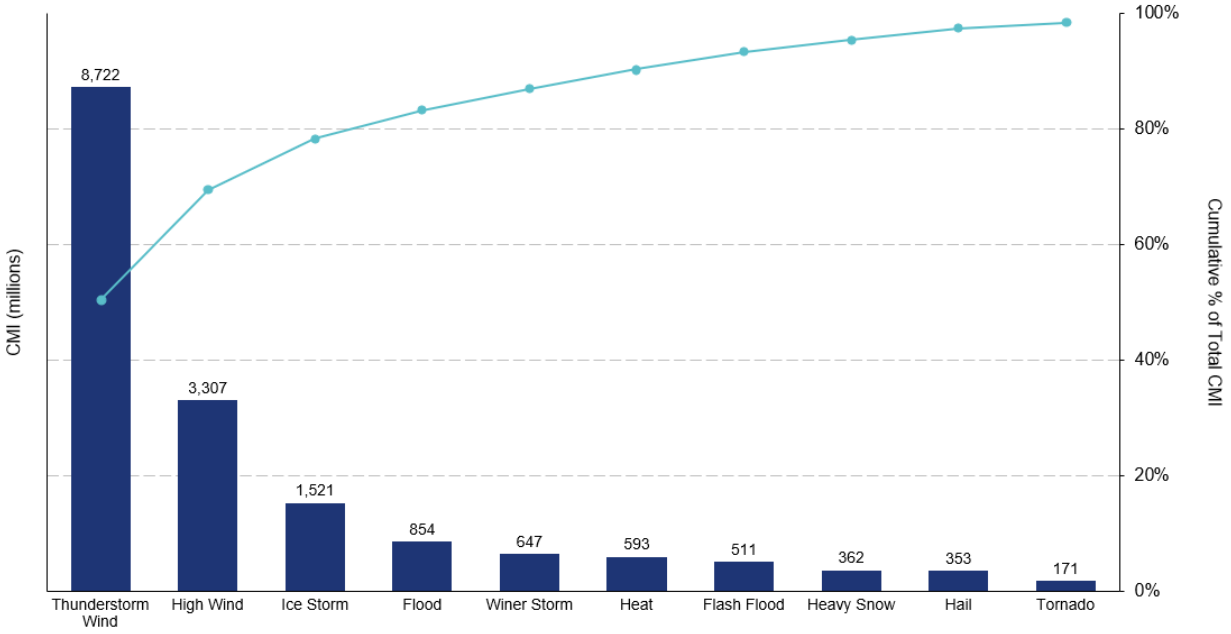
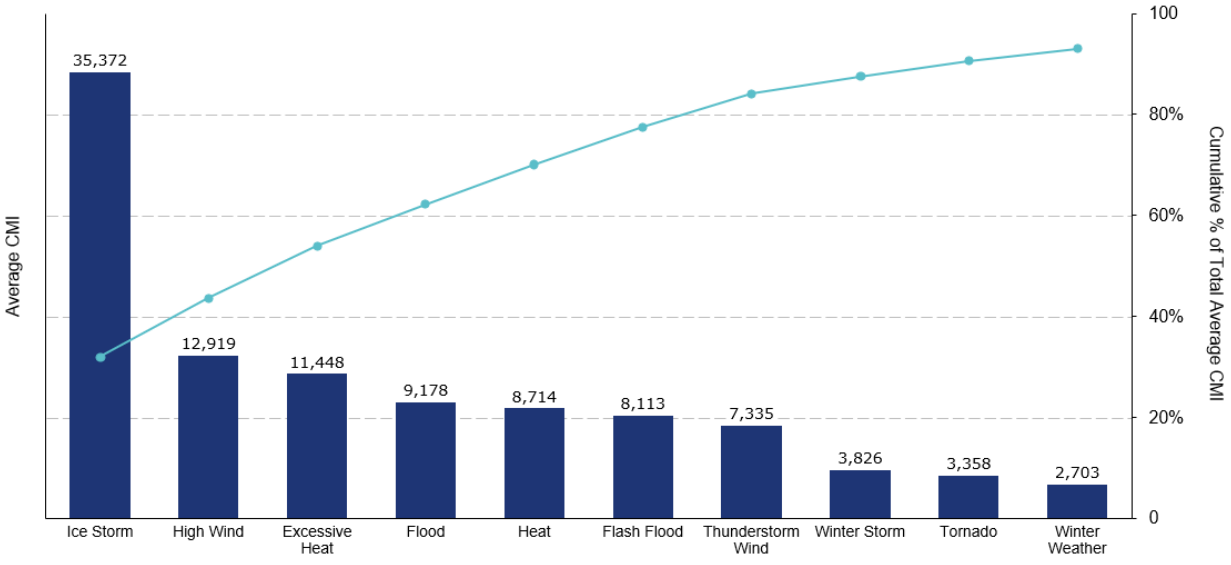


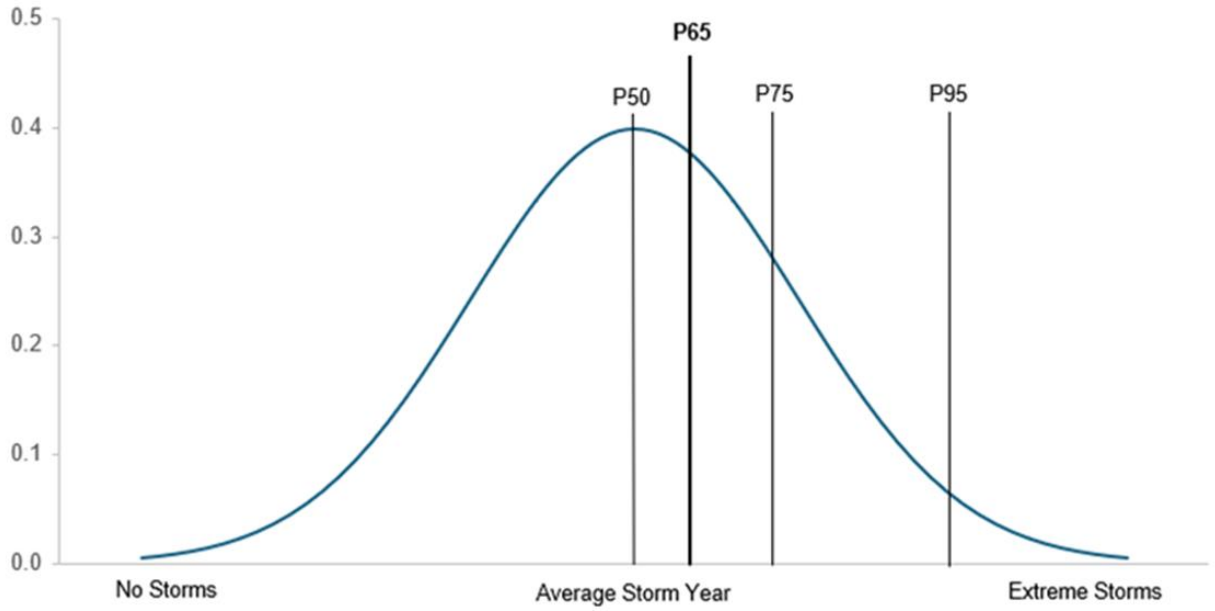
Exhibit 5.17 – Average CMI for Top 10 Events, 2007 - 2025 (thousands)



[103] Full list can be found in Appendix 8.14 (Benefit-Cost Analysis Report).

Using this information, the third-party consultant developed a probabilistic distribution of future climate conditions and evaluated investment benefits under multiple weather severity scenarios, as illustrated conceptually in Exhibit 5.18. Monte Carlo simulations were used to generate expected (P50, or 50th percentile), high (P75, or 75th percentile), and extreme (P95, or 95th percentile) climate outlooks. Among the three scenarios, the highest likelihood was assigned to the expected future, or P50 scenario, while the lowest likelihood was assigned to the extreme, P95 scenario. Weighted by likelihood, the resulting climate outlook corresponded most closely to the P65 case, which reflect elevated — but not extreme — future climate risk. The climate risk was incorporated into the resilience modeling of the BCA analysis and reflected in the BCR results discussed in this section.

Exhibit 5.18 – Conceptual Climate Risk Distribution Curve



Using BCA Results to Inform Investment Portfolio

Together, these analyses demonstrate how quantitative benefit-cost results inform DTE's assessment of the relative cost-effectiveness of key investment programs, while appropriately recognizing the limitations of monetized BCAs in capturing the full benefits of the investment programs. Additional details on the BCA methodologies, assumptions, and investment-specific analyses are provided in Appendix 8.14 (Benefit-Cost Analysis Report). Chapter 6 (Distribution System Plan Investment Pillars) presents individual investments in greater detail and provides additional descriptive justification tied to underlying grid support and customer needs. The monetized BCA results serve as a key input into DTE's GPM, which integrates BCA results with

broader risk, customer, and system considerations to prioritize investments across the portfolio, as described in the next section.

5.2.4 Global Prioritization Model

Grid investments frequently deliver multiple, interconnected benefits that are difficult to disaggregate, creating challenges when evaluating and comparing investments using purely quantitative methods. For example, converting an overhead circuit to a higher voltage can simultaneously increase capacity, improve safety, and enhance reliability. Similarly, investing in a new substation — particularly one that replaces aging infrastructure — reduces the risk of a major substation outage, provides capacity for new load, and reduces emergent restoration costs. These types of projects deliver "joint and interdependent benefits," meaning the value of the investment arises from the combination of outcomes rather than from a single, isolated outcome.

As noted earlier in the BCA section, many of these benefits, including safety improvements, capacity relief, avoidance and recovery from extreme events, and risk reduction, are not easily or appropriately translated into dollar values. To effectively compare and prioritize investments that deliver joint and interdependent benefits — and that include significant non-monetizable benefits — a different analytical approach is required. For this purpose, DTE uses the GPM, which is based on an established economic evaluation concept commonly referred to as "Least-Cost/Best-Fit."

The Company has used the GPM to prioritize investments since it was developed in 2018. The model has been enhanced over time to reflect evolving system needs and regulatory guidance, including updates made as part of the 2023 DGP and refinements incorporated in the 2025 General Rate Case No. U-21860. The GPM methodology applied in the 2026 DSP is substantively unchanged from the version used in 2025, retaining the same impact dimensions, benefit definitions, and weighting structure.

GPM Structure and Methodology

The GPM provides a transparent and consistent framework for ranking projects and programs by quantifying the benefits they deliver to customers. The model evaluates eight distinct benefit categories, referred to as impact dimensions, each of which includes one or more measurable drivers used to quantify expected benefits. Projects and programs are assigned scores, generally ranging from 0 to 100, in each impact dimension based on the amount of expected benefit relative to the total investment cost (in most cases).

Projects that deliver greater benefits per dollar invested receive higher scores within a given dimension. Each dimension score is then multiplied by a weighting factor, with higher weights assigned to dimensions aligned with key customer outcomes such as safety and reliability. The weighted dimension scores are added together to produce an initial GPM score for each project or program.

Incorporating Environmental Justice Considerations

The Company incorporates EJ considerations into the GPM through a multiplier, which adjusts a project's initial score based on the proportion of vulnerable customers impacted. The multiplier ranges from 1.0x to 2.0x and is calculated as:

EJ multiplier = *1 + (number of residential customers living in vulnerable census tracts impacted by the project ÷ total residential customers impacted by the project)*

Under this approach, a project with no residential customers in vulnerable census tracts receives a multiplier of 1.0x, while a project where all impacted residential customers are in vulnerable census tracts receives a multiplier of 2.0x. For example, if 80% of the residential customers impacted by a project reside in vulnerable census tracts, the resulting multiplier would be 1.8x.

GPM Impact Dimensions and Scoring

The final output of the GPM is the initial weighted impact dimension score multiplied by the EJ multiplier. Projects and programs with higher final GPM scores are considered to deliver greater overall value and are prioritized for implementation. This approach results in a portfolio that emphasizes investments providing the greatest improvements in safety, reliability, and load relief, particularly in areas with vulnerable customer populations. The full set of impact dimensions, associated drivers, and weighting factors is presented in Exhibit 5.19.

Exhibit 5.19 – Global Prioritization Model Impact Dimensions

Impact Dimension	Drivers	Weight
Reduce Electrical Hazards	Reduction in wire-down events	**3**
Overload Relief	Elimination of overloaded equipment	
SAIDI	Reduction in duration of outages	
SAIFI	Reduction in frequency of outage events	
Major Event Risk	Reduction in extensive substation outage events that lead to a large amount of stranded load for more than 24 hours	**2**
Capacity Relief	Elimination of system capacity constraints	
O&M Avoidance	Trouble event reduction and truck roll reduction Preventive maintenance investment reduction	**1**
Capital Avoidance	Trouble event reduction and truck roll reduction Reduction in capital replacement either during equipment failures or avoided planned capital work	
Multiplying Factor		
Investment in EJ Communities	100% plus the percent of customers impacted by investment in EJ communities, such that the multiplication factor is 100% (or 1.0) if none of the customers impacted by a project live in vulnerable census tracts, and 200% (or 2.0) if all of the customers impacted by a project live in vulnerable census tracts The initial total GPM score (sum of the other eight impact dimensions) is multiplied by the EJ factor (which ranges from 1.0 to 2.0) to provide a final GPM score	

Similar to the BCAs, there are circumstances in which the benefits of a project or program are not captured within the defined impact dimensions of the GPM. In these cases, the investment receives a score of zero. Examples include projects that primarily benefit the transmission system (e.g., Transformer High-Side Protection Program or Reverse Power Relay Scheme Program), projects serving specific industrial customers (e.g., Detroit Wastewater – Maxwell and Tempest Phase II), and projects focused on major risk mitigation or contingency support (e.g., Flood Defense and the Mobile Fleet programs). These investments provide important system- or customer-specific benefits that fall outside the scope of the GPM's modeling framework.

Updates Since the Prior GPM Iteration

While the overall structure of the GPM remains consistent, DTE has implemented several updates for this DSP:

- **Inclusion of O&M Investments:** Vegetation Management and the five largest Preventative Maintenance programs by expenditure are now evaluated alongside capital investments to enable more holistic portfolio comparisons.[104]

[104] Including Preventative Maintenance for circuit breakers, URD transformers, SCADA pole-top switches, 40 kV automatic pole-top switches, and overhead capacitors and regulators.

- **Project Refresh:** Newly identified projects have been added, and completed projects are no longer scored.
- **Annual Data Refresh:** Underlying inputs, including cost estimates, reliability performance, loading conditions, and expected benefits, are updated annually to reflect the most current information.

Exhibit 5.20 maps key investment areas to the GPM impact dimensions, illustrating that most investment categories can deliver benefits across multiple dimensions, including non-monetizable dimensions of Reduce Electrical Hazards, Overload Relief, Major Event Risk, and Capacity Relief.

Exhibit 5.20 – Mapping of Investment Area to GPM Dimension

Investment Area	GPM Dimensions								GPM mult.
	Reduce Electrical Hazards	Overload Relief	SAIDI	SAIFI	Major Event Risk	Capacity Relief	O&M Avoidance	Capital Avoidance	Investment in EJ Communities[105]
Substation Risk					X				*
4.8kV Hardening	X		X	X			X	X	X
PTMM	X		X	X			X	X	P
Cable Replacement			X	X	X			X	P
Frequent Outage			X	X			X	X	P
Breaker Replacement			X	X	X		X	X	P
URD Replacement			X	X			X	X	P
Subtransmission Redesign	X	X	X	X	X	X	X	X	*
CODI	X	X	X	X	X	X	X	X	*
4.8kV Conversion	X	X	X	X	X	X	X	X	*
System Loading	X	X	X	X	X	X	X	X	*
Automation	X		X	X					P
Vegetation Management	X		X	X			X	X	P
PM: 40 kV Pole-Top Switches			X	X					P
PM: Breakers			X	X				X	P
PM: Distribution Remote Devices			X	X					P
PM: URD Pad-mounted Transformers	X								P
PM: Overhead Capacitor and Regulator Controls							X	X	P

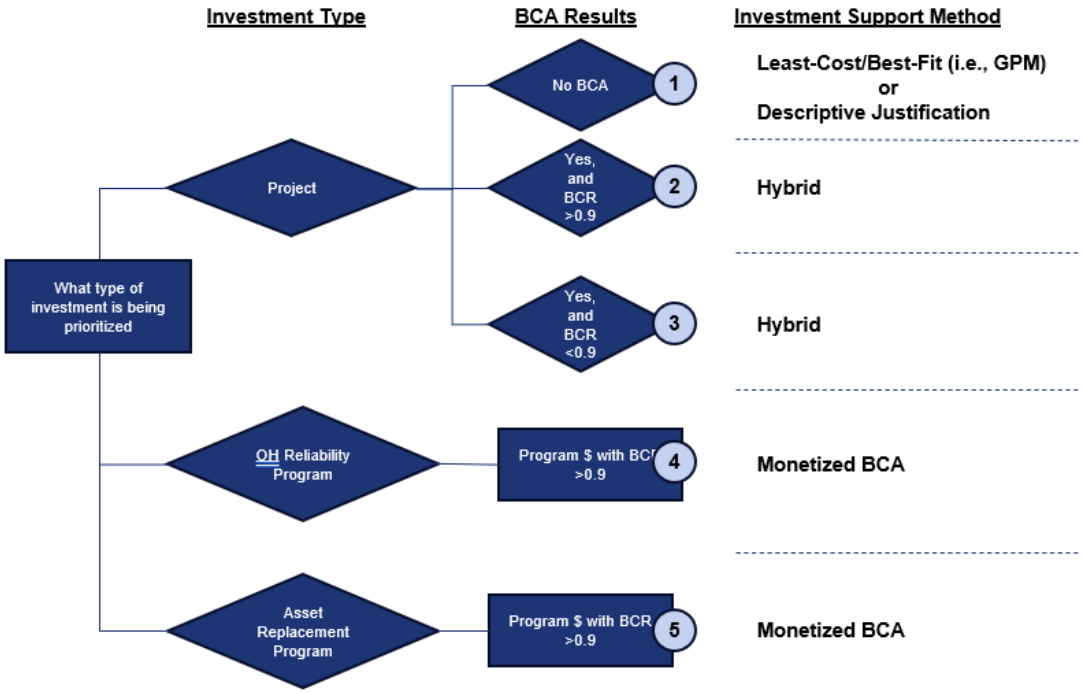
[105] Legend: * denotes the potential to address EJ communities depending on project location; X denotes the investment addresses EJ communities; P denotes a program with partial implementation in EJ communities.

This further reinforces the joint and interdependent benefits of many investments in the portfolio, a key consideration for the summary prioritization results discussed in the next section.

5.2.5 Prioritization Summary and Results

The GPM remains DTE's overarching framework for prioritizing grid investments, with BCRs incorporated as an input to enhance prioritization results. This integrated approach reflects that BCAs are well suited to quantify certain types of benefits, while the GPM provides a broader, more comprehensive view of customer and system value by capturing benefits that are not readily monetized, as discussed previously. Exhibit 5.21 illustrates how BCA results apply alongside the GPM.

Exhibit 5.21 – Categorization of Investment Types and Potential BCA Outcome



The interaction between GPM and BCA results varies depending on the nature of the investment:

- **Projects Not Evaluated using a BCA:** Some projects do not undergo a BCA because the majority of their benefits are not meaningfully captured through monetized reliability or cost-avoidance metrics. System Loading projects are a primary example, as their purpose is to relieve capacity constraints or address imminent overload conditions on the electric system. In these cases, a BCR would not provide an informative measure of value, therefore, the project's priority is determined using its GPM score, which more appropriately reflects the load-driven benefit.

- **Projects with a BCR ≥ 0.9:** For projects where the BCR exceeds 0.9, the results confirm that monetized benefits approach or exceed project costs. These projects generally also deliver additional benefits that are not included in the BCA, resulting in a BCR that underestimates total project value. Accordingly, both the GPM score and the BCR are considered together when prioritizing these projects within the overall portfolio.
- **Projects with a BCR < 0.9:** When a project has a BCR below 0.9, the BCA results alone are not sufficient to justify investment. In these instances, DTE evaluates whether the project provides substantial benefits in GPM dimensions that are not captured in the BCA. If these additional benefits are not significant, the timing or scope of the project may be reconsidered.
- **Overhead Reliability Programs:** For certain reliability programs, BCAs complement — but do not replace — the GPM. While the GPM produces an overall program-level score, the BCA helps quantify how much of the program's investment delivers monetized benefits that exceed costs. For example, the PTMM BCA demonstrates that significant portions of the system yield BCRs above 0.9. Although PTMM is executed systemwide for safety reasons regardless of BCR, the results support a larger scale of PTMM investment than prior plans. Similarly, for Distribution Automation, BCR results help inform the total scope of investment under current assumptions. In addition to informing investment levels, circuit-level BCRs are used in annual planning. Strong GPM rankings combined with favorable BCA results directly affect DTE's investment strategy.
- **Asset Replacement Programs:** For asset replacement programs, BCA results again help determine the overall long-term potential investment, but they do not fully capture the value associated with addressing asset conditions and risk. Equipment heath assessments consider factors beyond reliability and cost avoidance and, as a result, BCAs represent only one input into replacement planning. Over time, BCAs may inform prioritization of specific asset replacements, but they are applied alongside GPM results and engineering judgment rather than used in isolation.

By integrating BCA results with GPM scores as appropriate for each investment type, the Company develops a balanced and transparent grid investment prioritization. Exhibit 5.22 summarizes portfolio-level outcomes, presenting the Top 50 investments ranked by GPM score, indicating whether a BCA was performed, and summarizes the corresponding results, including specific BCR values for projects or the five-year program BCR results presented in Exhibit 5.13 above. GPM scores for all investments can be found in Appendix 8.10 (Complete GPM Rankings).

Exhibit 5.22 – Prioritization Summary

GPM Rank	Investment	Proposed Expenditure[106] ($ million)	BCR[107]
1	Preventative Maintenance: Breakers	9.4	
2	Preventative Maintenance: 40 kV Pole Top Switch	5.5	
3	Distribution Automation	354.9	3.2
4	Substransmission SCADA	66.0	18.1
5	CODI: Charlotte Network Upgrade	76.1	
6	Preventative Maintenance: Distribution Remote Devices	17.3	
7	Vegetation Management	1,179.0	
8	Preventative Maintenance: OH Capacitor and Regulator Controls	25.4	
9	Preventative Maintenance: URD Transformers	42.5	
10	4.8 kV Hardening	143.4	
11	NWA: Port Austin Load Relief	6.6	1.4[108]
12	40 kV: Automatic Pole-Top Switch	37.0	
13	Substation Risk: Seville	7.1	
14	Subtransmission Redesign & Rebuild: Sandusky Transformer 101 Breaker	4.1	
15	CODI: Amsterdam Conversion Initiative	202.3	
16	CODI: Garfield Network Upgrade	288.0	1.24
17	Subtransmission Redesign & Rebuild: Trunk 3509	6.2	
18	CODI: Alfred Substation Expansion	24.2	
19	Pole and Pole Top Maintenance and Modernization (PTMM)	1,862.8	4.7
20	Frequent Outage Program (CEMI)	126.9	
21	Cable Replacement Program	163.5	1.4
22	CODI: Targeted Network Secondary Cable Replacement	3.0	
23	Subtransmission Redesign & Rebuild: Trunk 4266	5.2	
24	4.8 kV CC: Zenon Substation and Circuit Conversion - Phase 2	303.5	2.28
25	8.3 kV CC: Pontiac Overhead/Underground Conversion	93.8	2.3, 0.69
26	CODI: Howard Conversion	103.9	1.50
27	4.8 kV CC: I-94 Substation and Circuit Conversion (Promenade)	320.4	2.15
28	4.8 kV CC: Hawthorne Relief and Circuit Conversion	203.0	0.71
29	Subtransmission Redesign & Rebuild: Hurst	9.6	
30	4.8 kV CC: Grosse Pointe Substation and Circuit Conversion - South	297.1	1.27
31	Substation Risk: Chestnut	19.9	
32	Subtransmission Redesign & Rebuild: Bernard	3.4	
33	URD Replacement Program	17.6	
34	System Loading: Otsego/Capac/Shaw	20.2	

[106] For defined projects, the GPM evaluates the project using total cost, which may include costs incurred before or after the DSP planning timeframe.

[107] BCR is not applicable for programs or projects in the case where 1) project is targeted to specific customer needs, or 2) greater than 50% of total spend already incurred, or 3) the project or program is a one-time O&M activity, or 4) there is relatively low annual investments within the DSP timeframe.

[108] See Section 6.3.4 (Non-Wire Alternatives) for details on the BCA performed by DTE.

GPM Rank	Investment	Proposed Expenditure[106] ($ million)	BCR[107]
35	Substation Risk: Hood	8.0	
36	4.8 kV CC: Calla Circuit Conversion and Phase 2	10.6	1.61
37	CODI: Kent/Gibson Conversion	106.7	2.51
38	4.8 kV CC Barber Substation and Circuit Conversion	207.2	0.43
39	Substation Risk: Belleville Switchgear Decommission	4.3	
40	Subtransmission Redesign & Rebuild: Badax Transformer 102 Addition	14.1	
41	4.8 kV CC: Birmingham Decommissioning and Circuit Conversion	129.9	
42	CODI: Islandview Substation	234.2	
43	4.8 kV CC: Melvindale	707.9	
44	NWA: Veridian	7.2	
45	4.8 kV CC: Hilton Substation and Circuit Conversion	324.9	1.15
46	4.8 kV CC: SCOTN	2.4	
47	4.8 kV CC: ISO Conversion Program	124.8	
48	Substation Risk: Apache	24.8	
49	Breaker Replacement Program	137.6	
50	Subtransmission Redesign & Rebuild: Trunk 4911	50.1	

5.3 Investment Plan

This section presents an integrated view of DTE's forecasted outlook over the planning horizon. The section begins with projected O&M and capital investments informed by the prioritization analyses described above, which aligns investment decisions with risk, performance needs, and cost-effectiveness. Building on this investment portfolio, the section then outlines forecasted reliability metrics and targets, evaluates the anticipated impacts on customer rates by class, and concludes with a long-term investment outlook that frames how today's decisions position the electric grid to meet evolving customer, reliability, and resilience needs over time.

5.3.1 Forecasted O&M and Capital Investments

Section 2.3 (Drivers of Investment) and Chapter 4 (State of the System and Additional DSP Requirements) identify the key challenges affecting DTE's electric grid and define the underlying grid needs by asset class and voltage level. Together, these sections describe the conditions driving investment — ranging from aging infrastructure and capacity constraints exacerbated by increased exposure to weather and evolving load pattern — and establish the basis for targeted, risk-informed planning.

Section 2.4 (Five Pillars of Reliability and Modernization Investments) explains how DTE responds to these identified grid needs through five strategic investment pillars focused on reducing outage exposure, strengthening and modernizing the system, and improving safety, reliability, and long-term resilience. Appendix 8.11 (Mapping Investments to Grid Needs) further illustrates how individual investment categories align with — and collectively address — the electrical system needs described above. Rather than relying on single-purpose solutions, the portfolio reflects an integrated approach in which complementary programs work together to mitigate risk, improve performance, and enhance system flexibility across multiple dimensions.

Section 5.2 (Investment Prioritization) outlines how the Company evaluates and prioritizes these investment programs to balance system risk, anticipated performance benefits, and cost-effectiveness, thus ensuring that investments are directed toward the highest-value needs. Application of this framework results in the forecasted O&M expenditures and capital investment portfolios presented in Exhibit 5.23 and Exhibit 5.24, respectively. These forecasts combine the base funding required to operate and maintain the system with strategic capital investments focused on addressing the most critical safety, reliability, resiliency, and modernization needs over the five-year planning horizon.

Exhibit 5.23 – Forecasted O&M Expenditures, 2026-2030 ($ millions)[109]

	2026	2027	2028	2029	2030	2026-2030 Total
Non-Storm Emergent	56.2	57.9	59.6	61.3	63.1	**298.3**
Storm Emergent	82.0	84.5	86.9	89.5	92.0	**434.9**
Preventative Maintenance	18.0	18.0	19.5	15.5	17.5	**88.5**
Corrective Maintenance	19.9	19.8	18.9	18.7	17.1	**94.4**
System Cable Testing	2.0	3.0	4.0	5.0	5.0	**19.0**
Vegetation Management[110]	200.0	229.0	236.0	253.0	261.0	**1,179.0**
PTMM (inspections)	4.9	5.8	7.2	7.8	8.2	**34.0**
Next-Gen AMI	2.4	3.8	2.8	4.6	5.3	**18.9**
Last Mile Communication	-	-	4.0	6.0	6.0	**16.0**
Base O&M[111]	94.1	103.1	117.9	121.3	124.8	**561.2**
Total O&M Expenditures	**479.6**	**524.9**	**556.9**	**582.7**	**600.1**	**2,744.2**

[109] Certain O&M forecast values may vary over time, as they are developed using rolling five-year historical averages and will be updated as actual results from prior years become available. Totals may not match exactly to the mathematical summation in the table due to rounding of the source data.

[110] Includes $20 million in potential Regulatory Asset (non-O&M for 2026), pending achievement of $180 million in O&M execution.

[111] Base O&M includes multiple categories such as supervision and other labor, meter expenses, OT, and other miscellaneous expenses. Excluding Community Lighting (see Appendix 8.4).

Exhibit 5.24 – Forecasted Capital Investment, 2026-2030 ($ millions)[112]

Investment Area	Capital Investments ($ Millions)					
	2026	2027	2028	2029	2030	2026 - 2030 Total
Base Capital						
Emergent Replacements (Reactive Trouble and Storm Capital)	561	570	574	582	591	**2,878**
Customer Connections, Relocations, and Others	367	375	392	407	422	**1,963**
Total – Base Capital	**927**	**945**	**966**	**990**	**1,013**	**4,841**
Strategic Capital						
Resilience and Hardening	420	461	533	698	813	**2,924**
Redesign and Modernization	320	311	382	417	484	**1,913**
Technology and Automation	151	186	221	135	93	**786**
Grid Edge and Distributed Intelligence	15	20	66	140	132	**373**
Total - Strategic Capital	**905**	**978**	**1,202**	**1,390**	**1,522**	**5,997**
Total - Distribution Capital	**1,843**	**1,923**	**2,168**	**2,379**	**2,535**	**10,838**

Taken together, the forecasted O&M and capital investments reflect a needs-driven, strategically-aligned portfolio that directly responds to identified grid risks while balancing affordability, safety, and long-term grid modernization objectives.

5.3.2 Forecasted Reliability Benefits

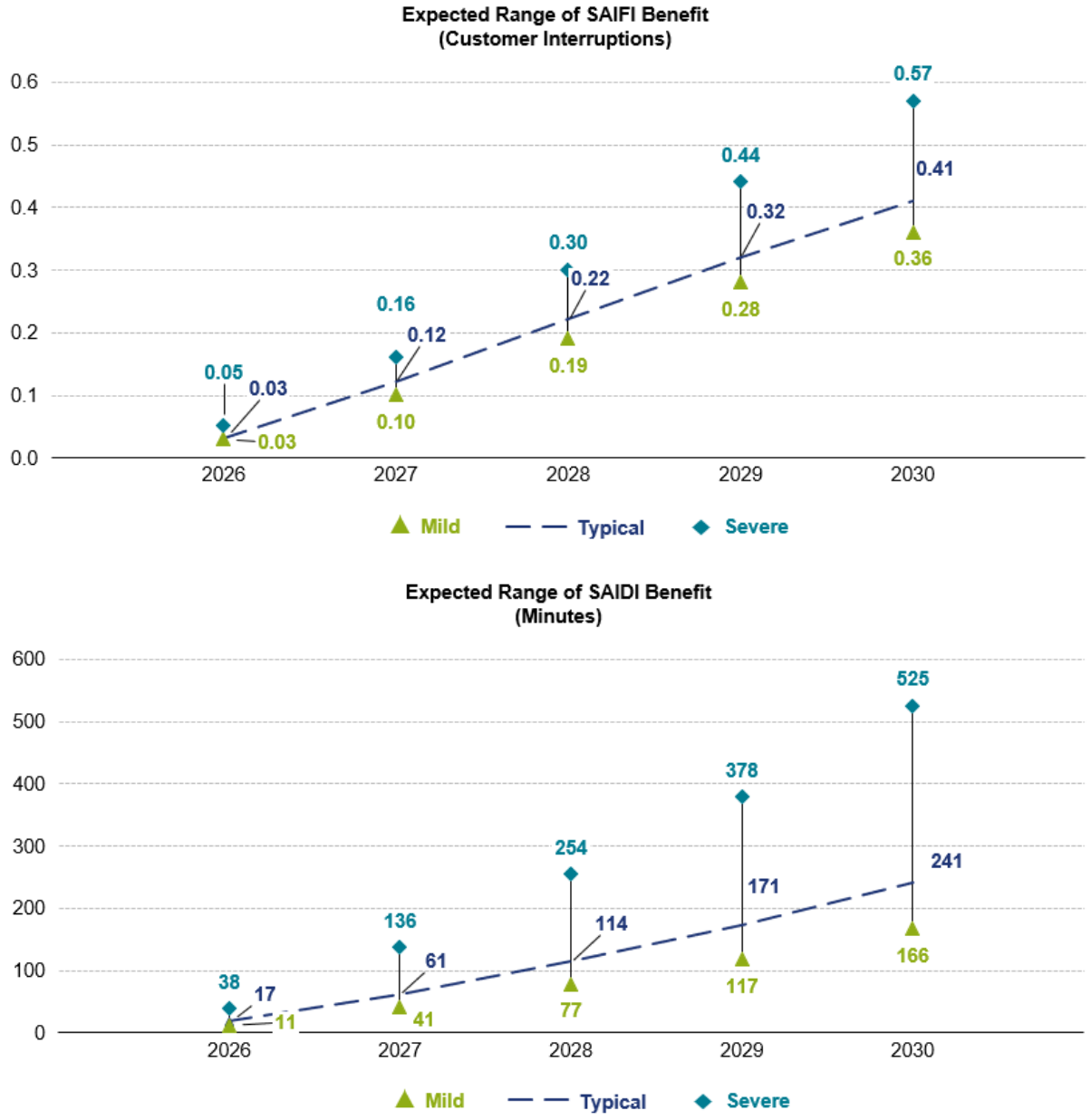
The investment portfolio outlined above and detailed in Chapter 6 (Distribution System Plan Investment Pillars) will provide significant customer benefits, including improved safety and enhanced reliability and resilience during both normal operating conditions and severe weather. These investments will also improve overall system operability, including the ability to accommodate new and emerging customer loads.

Investments planned for the 2026-2030 period across the five investment pillars are projected to reduce both the frequency (SAIFI) and duration (SAIDI) of power outages. While the entire portfolio of strategic investments is necessary to address identified grid needs, Vegetation Management, PTMM, and Distribution Automation are expected to be the primary drivers of reliability improvements over the next five years. Exhibit 5.25 illustrates the anticipated reliability benefits under multiple weather scenarios delivered by the planned capital and O&M portfolio, compared to a scenario in which strategic capital investments and Vegetation Management

[112] Certain capital forecast values may vary over time, as they are developed using rolling five-year historical averages and will be updated as actual results from prior years become available. Totals may not match exactly to the mathematical summation in the table due to rounding of the source data.

expenditures are not funded. As shown in Exhibit 5.25, reliability benefits compound over time as sustained investments in the electric system continue.

Exhibit 5.25 – Cumulative Reliability Benefits of DSP Investments (For All-Weather Conditions Across Three Weather Scenarios)



All-weather (AW) SAIFI during typical normal weather is projected to achieve first-quartile performance by 2029 and be 0.42 lower by the end of 2030 than a no-investment scenario.[113] By

[113] A typical weather year includes a number of MEDs that is close or equal to the average of the last 10 years. DTE has experienced nine MEDs on average per year over the last ten years. There are exceptions, like 2017 where system experienced an average number of MEDs, but the 2 MEDs from the March 2017 windstorm had an outsized impact on reliability metrics.

2030, AW SAIDI is projected to be 242 minutes better in normal weather relative to a no-investment scenario, improving to second-quartile performance.

The Company has provided reliability projections based on an analytical reliability model since the 2023 DSP. This modeling approach forecasts expected reliability benefits associated with the planned investments described in the DSP, including estimating circuit-level improvements for circuits with planned PTMM activities over the five-year planning horizon. Since the reliability model submitted in the 2025 General Rate Case (Case No. U-21860), DTE has further advanced this approach to provide a more sophisticated and comprehensive representation of system assets, programs, and weather variability. Additional detail on the updated methodology, as well as projections for annual AW and exMED reliability metrics, is provided in Appendix 8.13 (Reliability Model Technical Report).

5.3.3 Customer Affordability Analysis

While the investment strategy outlined is expected to benefit customers with improved safety, reliability, and long-term performance, the Company recognizes that continued investment in the electric grid also affects customer rates. The estimated incremental rate impacts associated with the DSP investment portfolio, by customer class, are summarized in Exhibit 5.26.

Exhibit 5.26 – Estimated Rate Impacts by Customer Class

Customer Class	Current Average Rate[114]	Incremental DSP Rate Impact (c/kWh)				
		2026	2027	2028	2029	2030
Residential	20.63	0.00	0.17	0.60	1.18	1.83
Commercial	14.87	0.00	0.11	0.38	0.74	1.15
Industrial	6.84	0.00	0.02	0.09	0.17	0.26
Other (Lighting)	42.50	0.00	0.66	2.32	4.55	7.06

For each customer class — residential, commercial, industrial, and other — Appendix 8.12 (Detailed Customer Affordability Analysis) presents the estimated rates without DSP strategic investments, the incremental rate changes associated with those investments, and the resulting total estimated rates when both are combined. The base revenue requirement is projected using DTE's most recently approved electric rate case and assumes annual inflation of 3% over the five-year DSP period. The incremental revenue requirement reflects the cost of the strategic investment included in this DSP, net of anticipated reductions to emergent capital spending that

[114] Average rate by class per the Commission Order dated February 19, 2026 in Case No. U-21860.

these investments are expected to deliver. Estimated rates without DSP strategic investments do not reflect the significant increase in emergent or reactive spending that would likely occur in the absence of the DSP investment portfolio.

Both the base and incremental revenue requirements are allocated to customer classes using the allocation factors from the Company's last approved electric rate case and are divided by the corresponding sales forecasts to calculate projected base rates and incremental DSP-related rate impacts. DTE emphasizes that these estimates are provided for informational purposes only and do not constitute a request for cost recovery. Any actual recovery of costs, and the resulting rates, will be addressed through a future general rate case.

Although these investments result in incremental rate impacts, they are expected to deliver long-term value by improving safety and reliability, reducing outage risk, and generating broader economic benefits for customers and the state of Michigan. From 2021 through 2025, the Company's total electric bill growth was 5.3%, compared to 24.4% across the Great Lakes region, and DTE's actual customer bills remain below both regional and national averages. Exhibit 5.26 and Appendix 8.12 (Detailed Customer Affordability Analysis) illustrate how rates would change if the Commission were to approve all incremental strategic costs outlined in this DSP. Consistent with filing requirements, the rate impacts shown reflect only changes in cost and do not capture the offsetting economic benefits customers are expected to receive from improved reliability.

5.3.4 Long-Term Investment Outlook

DTE's five-year investment plan is designed to address the most critical system risks facing the grid today while establishing a foundation for sustained improvement over the decades ahead. Over the near term, the Company's focus is to stabilize an aging and increasingly constrained system, restore it to a more manageable operating condition, and, in parallel, strengthen the electric grid to improve resilience. This includes returning Corrective Maintenance, Preventative Maintenance and Inspections, PTMM, and Vegetation Management to sustained, on-cycle execution. It also includes scaling critical asset replacement programs, such as breakers, URD, and system cable, and continuing to strengthen storm restoration and resilience readiness processes. Together, these investments are intended to reduce exposure to known failure modes, shorten restoration times, and create the operational stability required to shift away from reactive maintenance over time.

As these foundational investments continue to improve grid reliability and asset conditions, the Company expects both risk and emergent costs to decline. In particular, following the first full

PTMM cycle, subsequent PTMM cycle costs are expected to come down, as defect rates are expected to be far lower. In that same timeframe, DTE also plans to have completed the necessary investments to automate its system, including Subtransmission SCADA and Distribution Automation programs. As a result, capital investments will increasingly focus on more strategic, forward-looking initiatives that further modernize the system.

Therefore, over the 10- to 25-year horizon, the Company expects investment priority to shift toward programs that fundamentally transform grid capability and operational flexibility. These programs include 4.8 kV Conversions, System Loading, Subtransmission Redesign and Rebuild, and other large-scale modernization initiatives that address legacy designs, expand load transfer capability, and enable more efficient system operations. Investments during this phase focus on structural solutions that deliver durable improvements in safety, reliability, and affordability, positioning the grid to reliably serve customers amid continued system complexity and evolving demand.

Importantly, this long-term outlook is not static. While the strategic framework provides a clear direction, the timing, scale, and composition of investments may evolve as conditions change. DTE's prioritization framework is designed to dynamically reallocate investments across categories as the relative strength of system drivers changes over time. Rather than reacting after risks materialize, the Company uses leading indicators and signposts identified in Section 2.3 (Drivers of Investment) to assess where incremental investments can deliver the greatest value.

Exhibit 5.27 illustrates this adaptive approach by showing the alignment of investment categories with the three drivers of investment highlighted in this DSP: aging infrastructure and capacity constraints, increasingly severe weather, and customer adoption of DER and other emerging technologies. The degree of shading indicates the importance of the investment category in addressing each driver. As signposts indicate increasing pressure from a particular drive, DTE will adjust its mix of investments across its portfolio to proactively manage emerging needs. This flexibility ensures that capital is directed toward the most pressing risks and opportunities at any given time while remaining aligned with long-term strategic objectives.

Exhibit 5.27 – Alignment of Investment Categories with Drivers of Investment

0	No benefit to the driver
1	Limited, secondary benefit; not a primary program objective
2	Clear and intentional alignment with the driver, with defined benefits, but not solely focused on addressing it
3	Directly designed to address the driver; without the investment, the grid would face significant risk

Investment Programs	Drivers of Investment		
	Aging Infrastructure and Capacity Constraints	Increasingly Severe Weather	Customer Adoption of DER and Other Emerging Technology
Vegetation and System Maintenance			
Vegetation Management	1	3	0
Preventative Maintenance and Inspections	3	3	1
Corrective Maintenance	3	3	1
Resilience and Restoration Readiness			
PTMM	3	3	1
4.8 kV Hardening	3	3	0
Frequent Outage	3	3	1
Small Wire Replacement	3	3	2
Undergrounding	1	3	0
System Equipment Replacement	3	3	1
Substation Risk	3	3	1
Restoration Readiness and Customer Resilience	2	3	0
Redesign and Modernization			
4.8 kV and 8.3 kV Conversion	3	3	3
System Loading	3	3	3
Subtransmission Redesign and Rebuild	3	3	3
Non-Wire Alternatives	2	2	3
Technology and Automation			
Distribution Automation	3	3	1
Subtransmission SCADA	3	3	1
Operational Technology	3	3	3
Asset Condition Monitoring Technology	3	3	2
Grid Technology	1	3	3
ADMS	3	3	3
Grid Edge and Distributed Intelligence			
Communications Network	3	3	3
Next-Gen AMI and Distributed Intelligence	3	3	3
DERMS	0	1	3

DTE's long-term investment outlook reflects a deliberate progression: first stabilizing and strengthening the existing system, then modernizing and transforming it to deliver safe and reliable power well into the future, while balancing the need to deliver customer value in the most

affordable way possible. Through disciplined prioritization and continuous monitoring of system conditions, the Company is positioned to adapt its investment strategy as drivers of investment evolve, ensuring that customer value remains central to long-term planning decisions.

5.4 Environmental Justice in Distribution Planning

DTE remains committed to advancing EJ and ensuring that vulnerable communities experience meaningful and sustained improvements in reliability, customer support, and investment prioritization. Section 4.7 (Environmental Justice Analyses) describes the Company's EJ commitment and its multi-year efforts to develop data and tools to identify EJ communities across its service area and evaluate their reliability performance relative to system averages, as well as reliability-focused investments made in EJ communities over the past five years. Feedback from customers, community leaders, regulators, and other stakeholders has consistently reinforced the importance of elevating EJ considerations within DTE's planning and decision-making processes.

While meaningful progress has been made since the 2023 DSP, the Company recognizes that continued focus and refinement are necessary to achieve equitable outcomes across its service area. Accordingly, the 2026 DSP expands and refines DTE's EJ objectives to further integrate EJ considerations into planning, investment prioritization, and operational response. Building on prior plans, the 2026 DSP centers on following four core EJ objectives:

- Integrate EJ considerations across planning and investment prioritization through continued refinement of the GPM and other decision-support tools.
- Improve system performance and reliability in vulnerable communities with historically poor performance by aligning targeted investment programs with demonstrated needs.
- Enhance customer support during outage events through strengthened community response strategies and partnerships that address the needs of vulnerable populations.
- Continue community and stakeholder engagement, including partnerships to support future regression analyses.

As described in Section 5.2.4 (Global Prioritization Model), DTE has integrated EJ considerations directly into the GPM through an EJ multiplier that increases scores for investments in areas identified as EJ Communities. When all other criteria are equal, projects located in vulnerable communities receive higher GPM scores and are prioritized over comparable projects in non-EJ areas. This approach helps ensure that vulnerable communities are intentionally prioritized for distribution system investments. In addition, the Company has also begun applying the EJ multiplier to prioritize circuits within the PTMM and Distribution Automation programs.

Looking ahead, DTE will continue exploring opportunities to incorporate EJ factors into new BCA results for System Equipment Replacement programs such as breakers, URD, and system cable. Further, consistent with the Commission's Order in Case No. U-21860, the Company will engage with Staff and stakeholders to discuss appropriate methods for incorporating an EJ component into short-cycle Frequent Outage Strategic Reliability Improvement Program (SRIP) and Customer Excellence (CE) programs, with adjustments expected to be implemented in 2027.

DTE has made meaningful progress in integrating EJ considerations into distribution planning and remains committed to strengthening this focus over time. The Company will continue to monitor reliability outcomes in EJ communities, track the progress of ongoing and planned investments, and adjust strategies as needed to support sustained improvements for vulnerable populations. Exhibit 5.28 summarizes planned investments in EJ communities over the next two years for three of DTE's significant investment areas.

Exhibit 5.28 – Investments in Vulnerable Communities 2026-2027 for Select Programs (Census Tracts with MiEJ Score of 80% to 100%)

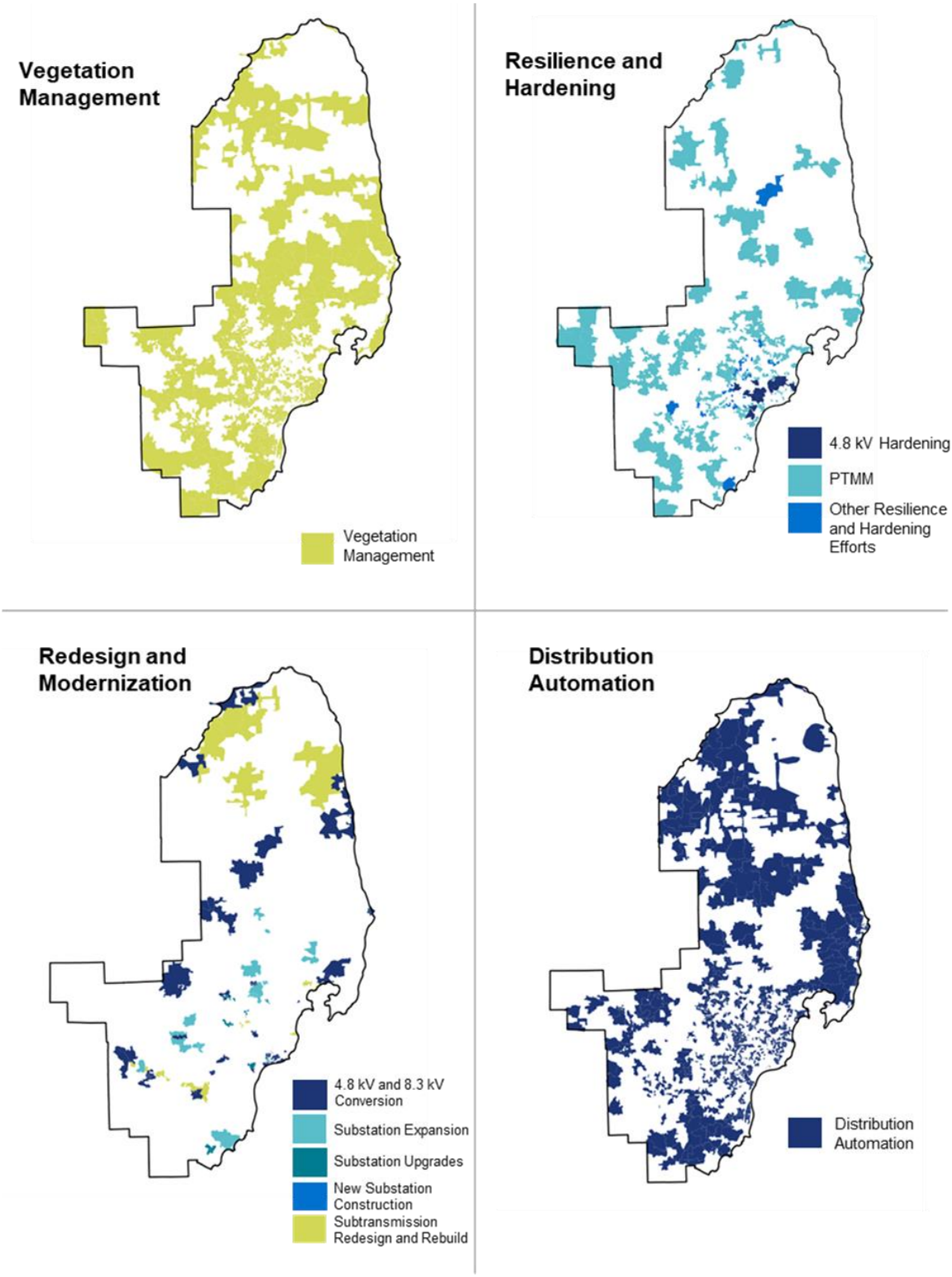
Investment Program (2026-2027)	Total Investment by Program ($ millions)	Total Investment by Program in Vulnerable Census Tracts ($ millions)	% Of Investment in Vulnerable Census Tracts
Conversions	397	188	**47%**
4.8 kV Hardening	143	116	**81%**
Vegetation Management	360	50	**14%**

The Company will continue engaging customers, community organizations, and other stakeholders to refine its approach and ensure that community perspectives inform future planning cycles, as discussed in Section 3.2 (Summary of Ongoing Outreach Efforts).

5.5 Planned Investment Overlay Maps

Based on the investment portfolio outlined in Section 5.3.1 (Forecasted O&M and Capital Investments), Exhibit 5.29 maps planned across the DTE service area from January 2026 through December 2028 by investment category. These plans reflect the current implementation strategy based on constraints and prioritization at the time of filing. Any changes to the five-year investment plan resulting from DTE's ongoing capital management and review processes will be described in future rate cases and DSP filings.

Exhibit 5.29 – Investment Pillar Work Planned, January 2026-December 2028[115]

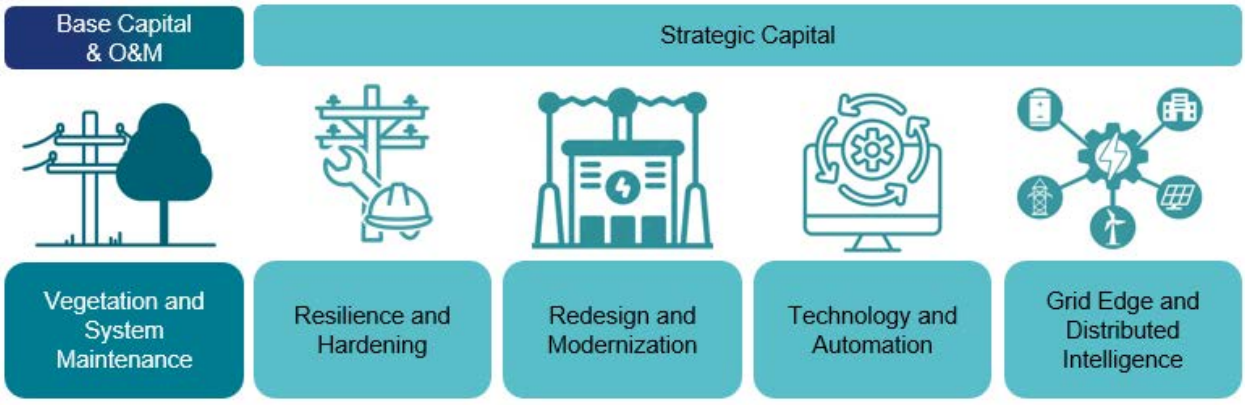


[115] "Other Resilience and Hardening Efforts" includes Frequent Outage, Strategic Reliability Improvement Program (SRIP), and System Cable Replacement.

6. Distribution System Plan Investment Pillars

The Company's Reliability and Modernization Investment Framework is organized around five interdependent pillars. These necessary and prudent investments are guided by MPSC policy objectives established through the SQRS and PBR proceedings, supported by Audit Report recommendations, and informed by robust analytical evidence. Chapter 6 provides detailed information on these five investment pillars that together define DTE's approach for addressing near term reliability needs while advancing the longer-term modernization of the electric grid. The chapter is divided into five sections, corresponding to the five investment pillars:

Reliability and Modernization Investment Framework



Within each pillar, individual investment subsections describe the challenge being addressed, the purpose and scope of the program, cost-effectiveness considerations, near-term investment requirements, and the longer-term outlook. Where applicable, the sections also summarize key updates, alternatives considered, and the rationale behind major program decisions. Together, these five investment pillars provide a clear and structured roadmap for a modern, resilient, and intelligent electric grid — one that delivers customer value, strengthens communities, drives economic growth, and supports a more sustainable energy future.

6.1 Vegetation and System Maintenance

In response to the Audit Report's emphasis on the importance of sustaining existing assets, DTE has redefined one of its core reliability improvement pillars, Tree Trimming, to a broader Vegetation and System Maintenance pillar. This shift reflects the Company's commitment to not only maintaining an on-cycle Vegetation Management program but also to enhancing inspection and corrective maintenance practices to achieve the greatest reliability impact at the most cost-effective levels. The Vegetation and System Maintenance pillar provides the foundational work necessary to sustain the reliability improvements achieved in recent years. It reduces exposure to avoidable failures and preserves the health of existing infrastructure through three key areas of investment: Vegetation Management, Preventative Maintenance and Inspections, and Corrective Maintenance.

6.1.1 Vegetation Management

Grid Needs

Trees and tree branches falling onto and damaging electric equipment is the leading cause of time customers are without power. In an attempt to both reduce and prevent outages, the Company manages vegetation encroachment near overhead infrastructure through its Vegetation Management program. Formerly known as "Tree Trim," DTE has renamed the program "Vegetation Management" to more accurately reflect the full range of activities used to prevent vegetation interference with power lines, which extend well beyond branch trimming, and aligns with utility industry terminology and standards. Vegetation Management of approximately

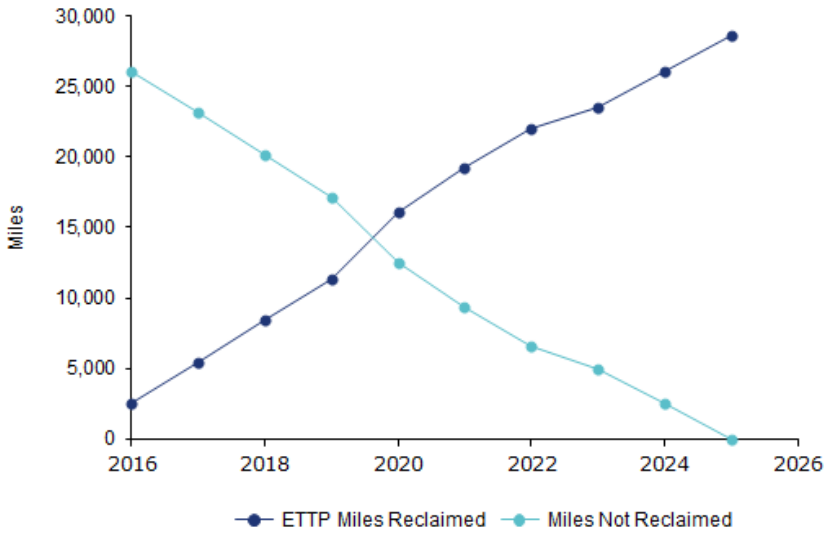
50,000 miles over the past decade has led to a significant improvement in safety and reliability for customers. On average, customers on treated circuits experienced roughly 40% fewer wire-downs and nearly 35% fewer outages compared to customers on circuits that have not been maintained. Because trees and other vegetation can grow quickly, proactively managing this growth near power lines is essential to minimize outages and maintain a safe, resilient, and reliable electric system.

Program Overview and Key Updates

In 2016, the Company began transitioning from a reactive posture to a proactive approach for reducing vegetation-related outages with the launch of its Enhanced Tree Trimming Program (ETTP). This program introduced a more rigorous and comprehensive trimming specification designed to reclaim ROWs, remove or reduce vegetation hazards near power lines, and establish clear trimming standards for managing vegetation encroachment across the system.

Building on the success of ETTP, DTE launched its Surge program in 2019, significantly accelerating both funding levels and execution to apply ETTP specifications across nearly all 28,600 miles of overhead distribution infrastructure over a seven-year period,[116] excluding a small number of miles delayed by customer refusals or permitting issues. DTE successfully completed the Surge at the end of 2025 as shown in Exhibit 6.1, which illustrates progress in miles trimmed to ETTP (reclaimed) versus remaining miles (miles not reclaimed) from 2016 through 2025.

Exhibit 6.1 – Cumulative Miles Reclaimed vs. Remaining Miles by Year



[116] Subtransmission assets were already maintained on a three-year Vegetation Management cycle at the time the Surge program was launched in 2019.

Throughout Surge, DTE evaluated ETTP effectiveness by comparing performance between miles reclaimed and miles not yet reclaimed (control group). Results showed that reclaimed miles achieved reductions in outage events, customer interruptions, and wire-downs compared to those within the control group as summarized in Exhibit 6.2. As expected, the benefits experienced by circuits trimmed to ETTP specifications, while still measurable, gradually declined after the first year due to natural regrowth.

Exhibit 6.2 – Miles Reclaimed vs. Control Group Circuit Performance[117]

	Percent Reduction in Outage Events	Percent Reduction in Customer Interruptions	Percent Reduction in Wire-Downs
1 Year Post-Trim	-51%	-56%	-55%
2 Years Post-Trim	-30%	-53%	-54%
3 Years Post-Trim	-42%	-40%	-38%
4 Years Post-Trim	-14%	-41%	-9%
Average	**-34%**	**-48%**	**-39%**

Now that Surge has been completed and all circuit miles have been trimmed to ETTP specifications, the historical control group used to measure post-Surge effectiveness no longer exists. To evaluate performance during the post-Surge maintenance phase, DTE has developed a new methodology that establishes a three-year pre-trim exMED baseline for each circuit. The Company then compares post-trim performance against this baseline annually until the next trim cycle occurs. Exhibit 6.3 shows the percentage reduction in outages achieved in each year following a trim. Vegetation Management continues to deliver meaningful reliability improvements through year five, with a gradual decline over time as vegetation naturally regrows.

Exhibit 6.3 – Vegetation Management Reliability Improvement (exMED)[118]

	Years Post-Trim				
	1	2	3	4	5
Annual Outage Reduction	-44%	-39%	-27%	-11%	-14%

The next phase of the Company's Vegetation Management program focuses on transitioning to a five-year trimming cycle while implementing more targeted, proactive tree and vegetation removals through updated expansion specifications. When DTE launched its Surge program in

[117] Performance data as of year-end 2025.

[118] Excluding Major Event Days (exMED) refers to removing days in which significant events occur that exceed the normal operating limits of the electric power system.

2019, the intention was to shift to a fixed trimming cycle — five years for overhead distribution and three years for subtransmission — which would require trimming approximately 6,600 miles annually. In response to the Commission's Order in Case No. U-21860,[119] the Company is executing a phased approach to establish a fixed, five-year Vegetation Management cycle. Because the Order was issued after the start of the 2026 year, DTE will use 2026 as a transition year to fully align resources and processes, during which it is targeting approximately 5,200 miles for trimming, with full alignment to a five-year cycle planned for 2027. In parallel, DTE plans to conduct a BCA to determine whether moving to a four-year cycle would be prudent.

As part of its updated expansion specifications, informed by internal reviews and the Audit Report findings, the Company has identified three primary areas that will improve reliability and generate long-term savings. The first involves the strategic removal of softwood overhang beyond the first protective device in Zone 1 — where softwood has already been cleared — and expanding this effort into Zones 2 and 3.[120] These areas tend to be more susceptible to wind- and storm-related damage, making proactive removal essential. The second focus area is an increased emphasis on "floor clearing." Small trees and brush that grow beneath power lines can eventually encroach on overhead equipment and create reliability risks. DTE will intensify efforts to remove, mow, and apply herbicide treatments to this vegetation where appropriate. Exhibit 6.4 highlights the significant increase in visibility and clearance after the floor clearing work was completed.

Exhibit 6.4 – Example Distribution Segment, Before and After Floor Clearance

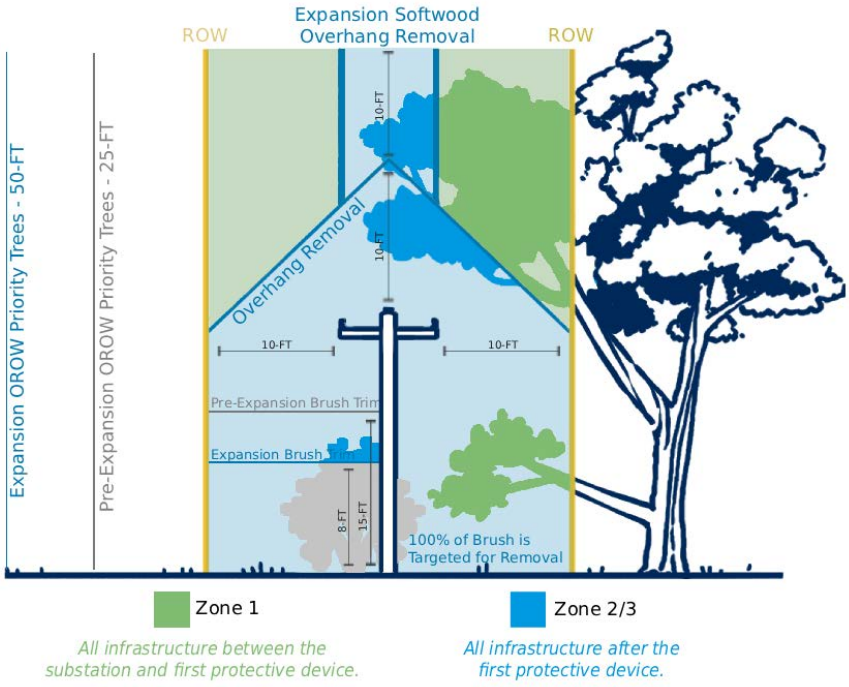
[119] Order dated February 19, 2026 in Case No. U-21860, available at https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/068cs00001kHayeAAC, accessed March 13, 2026.

[120] Zone 1 is defined as all infrastructure between the substation and the first protective device. Zones 2 and 3 are defined as all infrastructure after the first protective device.

Finally, the Company is working to address outside-of-right-of-way (OROW) trees. Under this initiative, DTE will expand its Vegetation Management scope of work to identify high-risk trees located outside of established easements that could threaten overhead equipment if they fall or become damaged. Although these trees are located beyond the standard trimming zone and are generally not included in current trimming specifications, they can still pose a risk to system reliability. This focused program will enable more proactive identification and removal of OROW risk trees, further strengthening overall system resilience.

Exhibit 6.5 illustrates the enhanced expansion specifications. The area shaded in green (Zone 1) represents everything before the first protective device. The area shaded in blue (Zone 2/3) represents DTE's existing trimming standards after the first protective device. Under these specifications, there can be areas within the ROW that do not present an immediate risk to infrastructure and are typically left in place. The area shared in green shows expansion into Zone 1 and reflects DTE's enhanced trimming specifications, which increases the removal rate of softwood overhang up to 20 feet above the conductor in Zones 2 and 3. Additionally, in all zones, the Company targets 100% removal of all brush. Where 100% removal isn't possible, DTE will then target trimming to approximately eight feet from the ground, rather than its previous specification of 15 feet. Lastly, in all zones, the Company targets removal of hazard trees up to 50 feet from pole center, an increase from the previous 25 feet.

Exhibit 6.5 – Vegetation Management Expansion Specifications



To execute targeted expansion specifications while remaining on a five-year trimming cycle, efficient contract management is essential. In 2025, DTE established three-year agreements with four contract vegetation management companies to execute the Company's annual Vegetation Management plan, support storm response, and perform emergent project work. These agreements clearly delineate responsibilities across the three stages of the process — planning, trimming, and auditing — and transition much of the work from a fixed-bid model, where costs were estimated by circuit, to a unit-based approach. Under this model, most maintenance contractors now receive work plans expressed in standardized units developed by an independent third-party planner, enabling DTE to more accurately track the type and volume of work completed per mile. Completed maintenance is then audited by a separate third party to ensure compliance with the Company's specifications. Additionally, DTE consolidates high-volume mechanized work,[121] specifically subtransmission trimming and large OROW hazard removals, under two maintenance contractors. Because this work involves both high volumes and the use of specialized machinery, consolidating these work scopes under contractors who can efficiently scale equipment and logistics creates meaningful economies of scale.

The Company remains committed to maintaining an adequate number of local, qualified tree trimmers and supplements staffing gaps with non-local resources, such as traveling "outsource" crews. With approximately 1,000 trimmers currently on site, DTE can coordinate with its vegetation management partners to bring in additional crews as needed. This flexibility allows the Company to respond effectively to inclement weather by temporarily redirecting resources away from routine maintenance to support storm response, especially because they are already properly trained on DTE's local Vegetation Management program. The Company continues to see

[121] Mechanized work refers to vegetation management activities that rely primarily on heavy or specialized mechanical equipment, rather than manual climbing or bucket-based trimming.

positive results from its Tree Trim Academy, which is now benchmarked by other utilities, including the graduation of 28 journeymen, 59 apprentices, and 31 registered pesticide applicators. DTE also remains committed to helping returning citizens build stable, meaningful careers in vegetation management as they re-enter Michigan's workforce. Through the Parnall Correctional Facility Outreach Program in Jackson, participating inmates receive training and support that prepare them to move directly into the Company's apprenticeship program upon release. The Vocational Village administration prioritizes applicants whose home counties allow for a manageable commute, helping ensure a viable path to long-term employment.

Expected Benefits and Cost-Effectiveness

Vegetation Management remains one of the most effective reliability investments DTE can make. By reducing tree- and vegetation-related outages, improving clearances around overhead infrastructure, and mitigating hazard trees before they fail, the program delivers measurable and sustained reliability improvements for customers as demonstrated above. With its strong performance and cost-effectiveness, Vegetation Management ranks seventh in DTE's GPM, reflecting both its critical role in system reliability and its high return on investment relative to other grid improvement initiatives. Additional detail on ranking methodology is provided in Section 5.2.4 (Global Prioritization Model).

To further improve cost-effectiveness, DTE is continuing to explore new technological advancements, both in the software used to manage and track work as well as in the tools and data analytics that guide decision-making. Specifically, DTE has started to replace its current work management software, which is slated to reach end of life in 2027. The Company plans to transition to a fully integrated work management solution that includes Power BI dashboards, Smartsheets, and email automation tools, enabling more streamlined reporting, better visibility into contractor performance, and improved coordination of field activities.

DTE is also expanding its use of technologies related to Light Detection and Ranging (LiDAR). In 2021, the Company acquired LiDAR data across all its overhead infrastructure, allowing DTE to

map vegetation conditions around overhead infrastructure in great detail.[122] This data was used to assess clearances, vegetation density, and encroachment conditions, which were then incorporated into DTE's vegetation model described below. With advancements in 3D modeling and the growing availability of cost-effective collection methods, such as drones and vehicle-mounted platforms, LiDAR can now serve as an asset management tool for infrastructure mapping and support the potential development of a condition- or risk-based approach to trimming tailored to each circuit's vegetation risk profile. The Company anticipates LiDAR becoming a core technology that is applied on a regular cycle (e.g., 20% of the electric grid each year).

Finally, as additional field data is collected and refreshed and LiDAR inputs are further integrated, DTE expects to leverage these datasets through advanced machine learning techniques. Over time, these analytical tools could significantly enhance the Company's ability to predict potential failures across its overhead distribution system, enabling increasingly proactive, targeted, and cost-efficient Vegetation Management strategies.

Near-Term Expenditures

Between 2026 and 2030, DTE anticipates a total of $1,179 million in Vegetation Management expenditures, as shown in Exhibit 6.6.

Exhibit 6.6 – O&M Expenditures for Vegetation Management, 2026-2030 ($ millions)[123]

Vegetation Management	2026	2027	2028	2029	2030	2026 – 2030 Total
O&M	200.0	229.0	236.0	253.0	261.0	**1,179.0**

Long-Term Outlook

Vegetation Management will remain a critical component of the Company's long-term strategy for maintaining a safe, reliable, and resilient electric system. This continued importance is driven by the significant density of trees across DTE's service area, the relatively weak mechanical strength of the small-gauge wire used on much of the Company's overhead 4.8 kV system, and the increasing frequency and severity of storms that elevate the risk of vegetation and tree-limb-related outages. While the majority of vegetation management work is delivered directly through the Vegetation Management program, it is also an essential supporting element of other initiatives, including PTMM and 4.8 kV Conversions. Under PTMM, vegetation clearing improves access and

[122] LiDAR data consists of high-resolution, three-dimensional measurements collected by laser-based sensors mounted on aircraft or vehicles.

[123] Includes $20 million in potential Regulatory Asset (non-O&M for 2026), pending achievement of $180 million in O&M execution.

enables the safe and efficient inspection, testing, and replacement of poles. For 4.8 kV Conversions, targeted clearing supports safe construction of new overhead or underground configurations and reduces the likelihood of vegetation-related interruptions on newly redesigned circuits.

Looking ahead, the Company will maintain its five-year trimming cycle based on recent Commission directives; however, DTE anticipates that ongoing data refinement, cost-effectiveness updates, and technological advancements — such as LiDAR enabled risk modeling — could support alternative approaches over time. These may include shifting to a four-year cycle or adopting a risk-based trimming strategy that prioritizes circuits based on vegetation conditions, failure likelihood, localized system characteristics, and vegetation growth rate. As these analytics mature, the Company will continue to evaluate the most effective long-term strategy to sustain reliability improvements, manage costs, and ensure that Vegetation Management continues to serve as an effective core program for maintaining reliability.

6.1.2 Preventative Maintenance and Inspections

Grid Needs

The Preventive Maintenance and Inspections program is a critical component of DTE's asset management strategy, designed to reduce equipment failures, extend asset life, and support overall grid reliability amid aging and increasingly vulnerable infrastructure. As described in Section 4.2 (General Asset Health and Condition), many of the Company's assets have already reached or surpassed their expected useful life, underscoring the importance of maintaining an appropriate inspection pace, eliminating backlogs, and keeping inspections on-cycle — a key recommendation emphasized in the Audit Report. Although increasing inspection activity may lead to higher near-term corrective costs, these efforts help avert failures and ultimately reduce long-term costs compared to repairing equipment after failure has occurred. PM activities performed during inspections remain an essential, cost-effective way to mitigate known risks, helping to minimize unplanned outages and reduce the need for CM. By routinely evaluating asset conditions, the Company can detect early warning signs of deterioration — such as wear, corrosion, or abnormal operating characteristics — and take timely action to prevent issues from escalating into customer interruptions or equipment damage.

Program Overview and Key Updates

The PM program is guided by Company maintenance policies that are informed by manufacturer recommendations, industry standards, historical data, equipment condition assessments,

engineering analyses, and benchmarking against peer utilities. These policies ensure inspection scopes and intervals align with proven methodologies and reflect good utility practice. Assets are organized into three categories: substations, overhead equipment, and underground equipment. Exhibit 6.7 summarizes asset inspections or PM activities and their associated maintenance intervals.

Exhibit 6.7 – Preventative Maintenance Activity Overview

Asset Category	PM Asset Type	Approximate Population	General Inspection Cycle (Years)[124]
Substation			
	120 kV Disconnects	352	10
	120 kV Breakers	32	10/12
	24/40 KV Breakers	1,055	3/10/12
	Distribution Breakers	5,381	3/10/12
	Buses	244	10
	Regulators	249	10
	Portable Substations	10	1
	Single Tap Substations	112	10
	13.2 kV Capacitor Banks	231	1
	AC Netback Transformers	505	5
	AC Netbank Structures	384	10
	DC Systems	651	1
	Dissolved Gas Analysis (DGA)	3,345	1
	Substation Predictive Maintenance Inspection (SPdM)	1,640	3
	Voltage Control Periodics	1,717	1
	Relay Periodics	9,887	5/7/10
Overhead (OH)			
	40 kV Pole-Top Switches	868	8
	Distribution Remote Devices	1,894	4/8
	OH Capacitor and Regulator Controls	5,120	1
	OH Distribution Device Battery Replacements	1,894	4
	Towers	500	10
	DTE Equipment in High Rise Structures	52	10
Underground (UG)			
	Primary Switch Cabinets	1,914	5/10/15
	Manholes	18,610	10
	URD Pad-Mounted Transformers	148,180	10
	Vaults	13	2

[124] Inspection cycles listed with multiple intervals (e.g., 3/10/12/) reflect variations based on specific asset requirements, operating conditions, and applicable maintenance standards. For example, DTE has multiple types of breakers that have different inspection cycles.

In recent years, the Company's PM program has developed backlog volumes across several asset categories, as documented in the August 2025 backlog report.[125] Through targeted, sustained efforts, DTE has begun reducing the PM backlog from 109,800 units in August 2025 to 103,400 units in December 2025, as shown in Exhibit 6.8.

Exhibit 6.8 – Updated PM Backlog Activities, August 2025 to December 2025

Asset Category	PM Asset Type	PM Backlog Activity	
		As of Aug. 15, 2025	As of Dec. 31, 2025
Substation		**1,406**	**1,061**
	120 kV Disconnects	29	38
	120 kV Breakers	-	7
	24/40 kV Breakers	20	146
	Distribution Breakers	201	418
	Buses	27	35
	Regulators	10	22
	Portable Substations	5	10
	Single Tap Substations	29	29
	13.2 kV Capacitor Banks	1	-
	AC Netback Transformers	129	76
	AC Netbank Structures	-	46
	DC Systems	-	-
	Dissolved Gas Analysis (DGA)	-	-
	Substation Predictive Maintenance Inspection (SPdM)	-	-
	Voltage Control Periodics	955	234
Overhead (OH)		**4,083**	**4,297**
	40 kV Pole-Top Switches	138	151
	Distribution Remote Devices	850	911
	OH Capacitor and Regulator Controls	2,296	2,313
	OH Distribution Device Battery Replacements	777	899
	Towers	15	-
	DTE Equipment in High Rise Structures	7	23
Underground (UG)		**104,271**	**98,038**
	Primary Switch Cabinets	156	174
	Manholes	1,775	3,025
	URD Pad-Mounted Transformers	102,340	94,839
	Vaults	-	-
Total PM Backlog Units		**109,760**	**103,396**

[125] Backlogged Inspections and Maintenance Report, available at https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/068cs0000183rVjAAI, accessed March 16, 2026.

Year-over-year spending on PM inspections has typically been approximately $10 million, which is insufficient to maintain the required inspection cycles, let alone reduce the existing PM backlog. An additional annual investment of $2.3 million above the current $10 million is needed to support compliance with established inspection intervals and prevent the buildup of new backlogs. Consistent with the Commission's Order in the Audit Report,[126] DTE is implementing a backlog-reduction initiative designed to eliminate the current PM backlog over a three-year period. This initiative requires an additional $5 million per year in 2026, 2027, and 2028, with no additional backlog-reduction funding anticipated in 2029 or 2030. The total funding required to bring the Preventative Maintenance and Inspections program into full compliance is summarized in Exhibit 6.10 below. The Company will prioritize the areas identified in the Audit Report, including overdue PM activities for pad-mount transformers, manholes, and SCADA devices.

In addition to clearing the backlog, DTE is committed to refining its maintenance processes to improve efficiency and accelerate the transition toward predictive maintenance. This will shift the Company away from time-based corrective actions toward condition-based and predictive strategies that anticipate equipment failures, extend asset life, and enhance the cost-effectiveness of maintenance activities. Inspection intervals are being optimized using engineering analyses, historical results, asset condition data, and failure trends, enabling more risk-informed planning. As SPdM systems mature, predictive analytics will increasingly drive inspection schedules and work prioritization, supported by intelligent devices that provide real-time diagnostics and remote troubleshooting. DTE will also continue to coordinate maintenance activities across equipment types to further minimize planned outages and operational disruptions, improving both workforce efficiency and enhancing the customer experience.

Expected Benefits

Preventative Maintenance and Inspections reduce equipment failures and extend asset life, providing reliability and asset-health benefits. In response to the Commission's Order in the Audit Report requesting an analysis of the trade-offs between capital and O&M, DTE included certain PM activities in its GPM for the first time. As detailed in Section 5.2.4 (Global Prioritization Model), the Company selected the top five PM activities by annual investment for inclusion: distribution remote devices, distribution breakers, URD pad-mount transformers, overhead capacitor and regulator controls, and 40 kV pole-top switches. Exhibit 6.9 presents the GPM ranking for the in-scope PM programs and highlights the impact dimensions with high scores that informed those

[126] Order dated June 12, 2025 in Case No. U-21305, available at https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/068cs00000u4p0XAAQ, accessed March 14, 2026.

rankings. The incorporation of PM programs into the GPM resulted in comparatively high rankings across the portfolio, reflecting their strong performance across reliability-focused impact dimensions and their ability to deliver significant benefits per dollar invested.

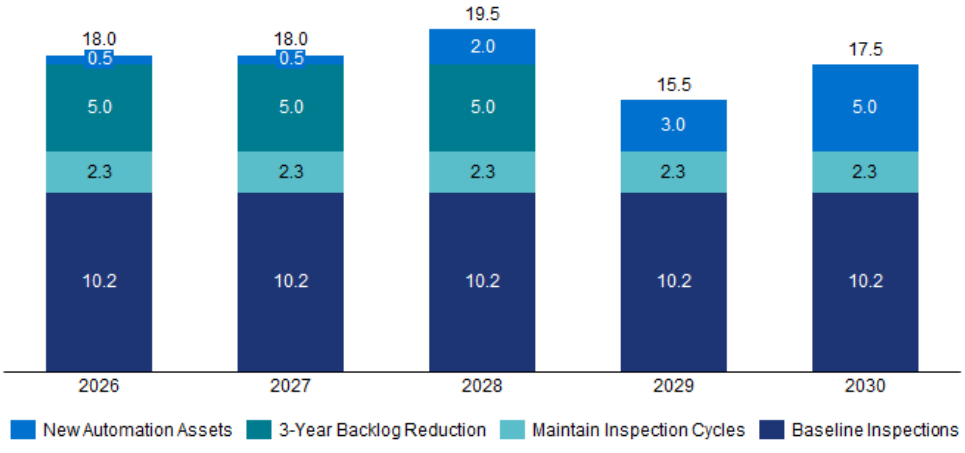
Exhibit 6.9 – GPM Ranking Overview for Top Five PM Programs by Annual Investment

PM Programs (in-scope for GPM)	GPM Ranking	Key Impact Dimension(s) with High Scores
Breakers	1	• SAIDI • SAIFI • Capital Avoidance
40 kV Pole-Top Switches	2	• SAIDI • SAIFI
Distribution Remote Devices	5	• SAIDI • SAIFI
Overhead Capacitor and Regulator Controls	7	• O&M Avoidance • Capital Avoidance
URD Pad-Mounted Transformers	8	• Reduce Electrical Hazards

Near-Term Expenditures

In addition to the incremental funding needed to maintain established inspection cycles and resolve the PM backlog, DTE anticipates increased PM inspection requirements driven by system modernization and automation initiatives. The Company estimates that the growing fleet of automation assets placed into service will require incremental funding of approximately $0.5 million in 2026, rising to about $5.0 million by 2030. Exhibit 6.10 summarizes total projected Preventative Maintenance and Inspections expenditures over the next five years. Together, these near-term actions will restore compliance with inspection cycles, enhance asset condition visibility, reduce outage risk, and ultimately improve overall reliability.

Exhibit 6.10 – O&M Expenditures for Preventative Maintenance and Inspections, 2026-2030 ($ millions)



As mentioned above, DTE anticipates an increase in CM work as PM activity expands, because more frequent and comprehensive inspections will identify a greater number of asset conditions requiring correction remediation. Further discussion of these implications is provided in Section 6.1.3 (Corrective Maintenance).

Long-Term Outlook

Looking ahead, DTE's Preventative Maintenance and Inspections program will remain a cornerstone of the Company's long-term asset management strategy and a critical tool for addressing its aging infrastructure. Sustaining disciplined inspection cycles and eliminating backlogs will be essential to reversing the impacts of years of deferred maintenance and restoring the asset health across the electric grid. As predictive maintenance technologies and advanced diagnostic capabilities mature, DTE's Preventative Maintenance and Inspections program will continue shifting toward data-driven, risk-informed practices that identify deterioration earlier and enable more targeted, cost-effective interventions. Over the long term, this transition will enhance operational efficiency, optimize lifecycle costs, strengthen system resilience, reduce CM needs, and support a more reliable and modern grid capable of meeting future customer expectations.

6.1.3 Corrective Maintenance

Grid Needs

DTE's grid is increasingly strained by the realities of aging infrastructure, with many assets operating well beyond their intended useful life and becoming more prone to malfunction. As equipment continues to deteriorate due to natural aging, environmental stressors, and decades of wear, unplanned breakdowns are occurring more frequently and with greater severity. While PM reduces risk, it cannot fully anticipate every failure mode within an aging system, making timely CM essential. When failures do occur, CM restores service quickly, stabilizes critical infrastructure, and prevents minor equipment issues from escalating into major outages or catastrophic damage. Compounding this challenge, the Company must simultaneously address a legacy backlog of unresolved conditions while preparing for the higher volume of CM work that will naturally result from expanded PM activities. The urgency is further amplified by DTE's grid modernization efforts, such as automation, advanced monitoring, and system upgrades, which require a stable and well-maintained foundation to function effectively. Without prompt corrective repairs, these technologies cannot deliver their full capability or performance benefits. For these reasons, CM is not merely a routine operational task but a critical necessity for DTE's near-term strategy to support a resilient, modern grid.

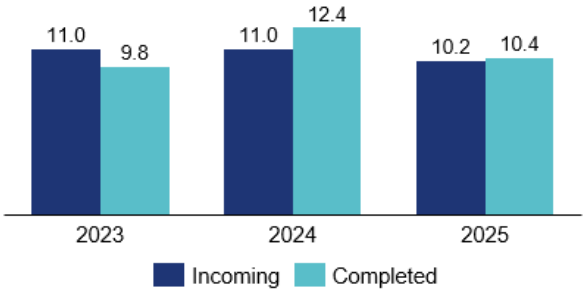
Program Overview and Key Updates

The CM program focuses on repairing or replacing electrical and structural assets that have failed in-service, show signs of imminent failure, are damaged by storms or external events, or present unsafe operating conditions. Collectively, these activities ensure that equipment remains functional, safe, and compliant with performance standards. CM activities are identified through several pathways:

- **Assets With Actual or Potential Failure:** Assets that have lost or have potential to lose their ability to perform one or more required functions within specified performance limits and require repair, replacement, or removal from service.
- **Assets in Abnormal State:** Assets that remain operational but are operating outside their normal, designed, or expected performance or parameter range, indicating elevated risk of failure if not addressed.
- **Assets Damaged by Storms or External Events:** Assets that suffered physical damage from external impacts and requires repair or replacement, such as utility poles, overhead conductors, switching points, and oil-filled equipment.
- **Routine Maintenance Findings:** Issues discovered during routine inspections, condition monitoring, asset health, or reliability reviews.
- **Preventative Maintenance Findings:** A PM inspection identifies a failure or abnormal condition or an issue that poses a safety or environmental risk, initiating immediate remediation.

DTE sets standard repair expectations and timeframes for completing CM work based on asset criticality. Any CM work not completed within these timeframes is considered backlog. As reported in the August 2025 backlog report in Case No. U-21305, the Company had 1,561 backlogged CM jobs across multiple categories. Due to aging infrastructure and increasingly severe weather, the Company is continuing to experience a high level of new incoming CM volumes. For example, the major 2023 ice storm led to widespread damage to poles, wires, and pole-top equipment, significantly increasing CM workload. In addition, periods of low ambient temperatures are associated with higher occurrences of low oil level indications on substation transformers, driven by the contraction of insulating oil as temperatures decrease. This temperature-related effect results in a measurable increase in low oil level alarms that must be investigated and addressed. Despite these challenges, DTE remains committed to managing incoming CM work to prevent the formation of new backlogs and sustain the overall health of the electric grid. Over the past two years, the Company has completed more CM work than it has received, as shown in Exhibit 6.11.

Exhibit 6.11 – 2023-2025 Incoming vs. Completed CM Jobs (thousands)



Between August 2025 and March 2026, DTE reduced its CM backlog by 24%, decreasing from 1,561 to 1,181 jobs as shown in Exhibit 6.12.[127] The most significant reductions occurred within storm-related categories, lowering the number of CM backlog jobs associated with assets damaged by storms and other external events. While some backlog remains in that area, the progress achieved now allows the Company to broaden its focus to other CM categories, including Trouble Requests for Shutdowns (TRSDs), Electronic Turnover Cards (ETOs), and SCADA devices.

Exhibit 6.12 – Updated CM Backlog, August 2025 to March 2026

CM Category	Work Type	CM Backlog Activities		Percent Change
		As of Aug. 15, 2025	As of Mar. 12, 2026	
Assets Failed or Potential Fail				
	TRSDs	88	97	10%
Assets in Abnormal Configuration				
	ETOs	767	738	-4%
	Open Loop Repairs or Replacements	117	100	-15%
Assets Damaged by Storms or External Events				
	Poles	188	68	-64%
	Pole-Top Equipment	136	31	-77%
	Wire	102	14	-86%
	Oil Filled Equipment	29	7	-76%
Control, Monitoring and Automation Devices				
	SCADA	134	126	-6%
Total CM Backlog		**1,561**	**1,181**	**-24%**

[127] Backlogged Inspections and Maintenance Report, available at https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/068cs0000183rVjAAI, accessed March 16, 2026.

DTE will continue to implement a structured, systemwide approach to reduce the backlog of CM jobs. This includes maintaining a standardized, transparent view of all backlog work, strengthening intake and prioritization processes based on safety, reliability, and operational risk, executing targeted backlog reduction initiatives, and tracking key performance metrics such as backlog age and schedule compliance. A sustainable governance model will also prevent future backlog escalation.

Value of Corrective Maintenance

CM delivers substantial safety, reliability, and cost-effectiveness benefits. By addressing asset failures and abnormal conditions quickly, CM decreases the likelihood of extended outages, prevents cascading failures, and ensures that the grid can withstand increasingly severe weather. Timely repairs also protect customers, utility workers, and first responders by eliminating hazards such as exposed energized equipment, deteriorated manholes, and transformer oil leaks. From a cost-effectiveness standpoint, CM reduces expenses associated with emergency repairs and premature asset replacements and extends the useful life of infrastructure where repair is feasible. Integrating PM inspection findings into CM workflows enables the Company to prioritize issues efficiently, perform the right remediation more effectively, and refine maintenance strategies over time.

Near-Term Investment

The Company will continue prioritizing backlog mitigation through 2026 and beyond to sustain compliance with established repair timeframes based on asset criticality. Additionally, the Company expects CM volumes to continue rising as PM activities are brought fully on-cycle, as described in Section 6.1.2 (Preventative Maintenance and Inspections). For example, inspections of approximately 1,000 manholes identified 149 requiring structural remediation to prevent collapse, water intrusion, and equipment damage. Similarly, inspections of about 20,000 pad-mount transformers found 511 instances of oil leaks or cases of exposed cable, which pose electrical, fire, environmental, and reliability risks if not corrected. Other PM activities identified 131 netbank structures requiring remediation, while routine maintenance efforts uncovered 4,878 conditions presenting safety or reliability concerns, such as degraded protective relays that may not operate properly during fault conditions. Recent findings and estimated investment for necessary CM remediation are summarized in Exhibit 6.13.

Exhibit 6.13 – Recent PM Findings Driving Increased CM Funding Needs

PM Findings Category	Definition	CM Jobs as of Mar. 15, 2026	Estimated Funding Required ($ millions)	
			Capital	O&M
PM Findings				
	Manholes requiring corrective structural maintenance	149	8.0	-
	URD pad-mount transformer oil leaks and exposed cable	511	7.6	0.5
	Netback structure repairs	131	-	1.4
Routine Maintenance Findings				
	Routine maintenance inspection findings	4,878	0.1	1.0

The resulting projected capital and O&M needs for CM work over the next five years, including investment necessary to clear the CM backlog and resolve recent PM findings, are provided in Exhibit 6.14.

Exhibit 6.14 – Capital Investment Plan and O&M Expenditures for CM, 2026-2030 ($ millions)[128]

CM	2026	2027	2028	2029	2030	2026 – 2030 Total
Capital	35.0	33.0	21.7	20.6	30.0	**140.3**
O&M	19.9	19.8	18.9	18.8	17.1	**94.5**

Long-Term Outlook

Looking ahead, CM will continue to play a critical and expanding role in maintaining system reliability as DTE's infrastructure continues to age and extreme weather becomes more frequent and severe. As the Company brings Preventive Maintenance and Inspection activities fully on cycle, there may be a greater volume of emerging issues leading to higher near-term corrective capital costs, but these efforts will help avert failures and ultimately reduce long-term costs compared to repairing equipment after failure has occurred. Over the long term, a well-resourced, responsive CM program is essential to prevent backlogs, mitigate small issues from escalating into major failures, and ensuring the grid remains resilient in the face of ongoing environmental and operational challenges. By increasing CM investment to adequately remediate incoming

[128] Totals may not match exactly to the mathematical summation in the table due to rounding of the source data. Capital CM investment shown is incremental to base capital required to remediate identified issues and address existing backlogs. O&M reflects total funding to maintain compliance in base operations, address incremental CM work from PMs, and resolve remaining CM backlogs.

workload, DTE will be positioned to manage increasing corrective demands while supporting a safer, more reliable, and more durable electric system for customers.

6.2 Resilience and Hardening

The Company's Resilience and Hardening pillar represents the next critical pillar of investment, aimed at eliminating structural weaknesses and strengthening the existing system in the face of increasingly frequent and severe weather events. These programs focus on vulnerable segments of the grid and proactively replace aging equipment with known failure modes. The Resilience and Hardening pillar encompasses eight key investment areas: PTMM, 4.8 kV Hardening, Frequent Outage, Small Wire Replacement, Undergrounding, System Equipment Replacement, Substation Risk, and Resilience and Restoration Readiness. Collectively, these initiatives reduce avoidable outages and enhance the day-to-day safety and reliability customers depend upon. The following sections provide detailed descriptions of the programs and their specific contributions to overall system resilience.

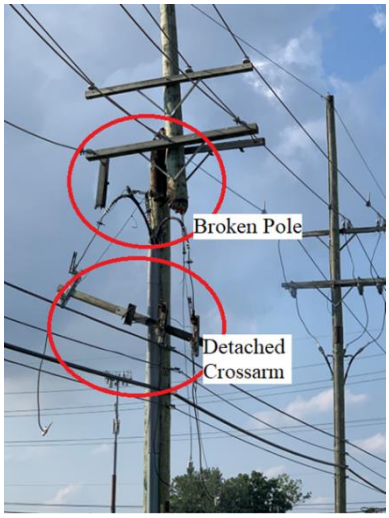
6.2.1 Pole and Pole-Top Maintenance and Modernization

Grid Needs

Nearly 70% of DTE's grid infrastructure is overhead, consisting of approximately 31,000 miles of overhead distribution and subtransmission lines supported by more than 1 million company owned poles. An additional 200,000 poles are owned by other utilities, including AT&T and Comcast. While these assets play a critical role in maintaining reliable service, they are increasingly vulnerable due to age and continuous exposure to environmental elements. Utility poles typically have an industry-recognized useful life of 40-50 years, and about half of the Company's pole fleet now exceeds that range, as discussed in Section 4.2.2 (Overhead Assets). DTE also observed higher-than-anticipated pole inspection condemnation rates in 2025, signaling that a greater percentage of this asset class is approaching the end-of life bathtub curve with higher failure rates.

Poles and pole-top equipment endure constant exposure to harsh weather conditions such as heat, rain, lightning, sunlight, wide-ranging temperature fluctuations, high winds, ice accumulations, and the mechanical shock load from tree impacts. Over time, environmental exposure progressively weakens components and increases the likelihood of structural failures. Without regular PTMM, the risk of outages, safety hazards, and wire-down events rises sharply. Exhibit 6.15 below provides an example of a pole-top failure involving a broken pole and detached crossarm.

Exhibit 6.15 – Example of Overhead Pole-Top Failure



These conditions highlight a growing need for proactive asset management, systematic inspection cycles, and targeted modernization of pole-top equipment to maintain safety, reliability, and grid resiliency.

Program Overview and Key Updates

The PTMM program is the Company's comprehensive approach for assessing and managing overhead infrastructure. While pole age provides a general indication of remaining useful life, it is not used as the sole basis for replacement decisions. Instead, DTE relies on detailed pole testing and pole-top inspections to evaluate the actual condition and structural integrity of each asset. Through this program, the Company conducts thorough inspections of poles and associated overhead equipment on both distribution and subtransmission circuits, including crossarms, insulators, and related components, to determine their true condition. Assets that fail to meet condition standards are replaced with higher-class poles and upgraded materials. These modern materials, including fiberglass crossarms and polymer insulators, offer greater mechanical strength and durability, reducing equipment failures and improving customer reliability.

The Company is progressing toward a five-year inspection cycle for pole-top equipment and a 10-year inspection and intrusive testing cycle for poles. The result of these inspection and testing findings will determine the scope of the remediation work, up to and including replacement of pole-top equipment or the poles themselves. This approach aligns with the Audit Report's recommendation to "adopt a four-to-five year visual overhead circuit inspection program, focusing on securing visual control of the system".[129] It also reflects the MPSC's recent guidance that "[it] expects to see progress in DTE Electric's goal of reaching the 5- and 10-year cycles."[130] These inspection intervals are further supported by internal engineering evaluations and industry benchmarking across multiple regions as summarized in Exhibit 6.16.

Exhibit 6.16 – Industry Benchmarking of PTMM Cycles

Company	Region	Pole Inspection Cycle (Years)	Pole-Top Inspection Cycle (Years)
#1	Northeast	10	4
#2	Northeast	5	5
#3	Midwest	10	5
#4	Midwest	10	5
#5	Midwest	10	5
#6	Midwest	12	12
#7	Midwest	8-12	8-12

To meet these targets, DTE has implemented new business processes that enhance both efficiency and risk-based prioritization. Beginning in 2025, the Company implemented a structured pole-top hazard patrol process that classifies identified issues into three categories:

- **Immediate Action:** Safety hazards or imminent outage conditions such as broken poles or leaking transformers.
- **Program-year Repairs:** Conditions likely to result in outages or failures in the near future and scheduled for remediation and/or replacement within the program calendar year.
- **Future-cycle Work:** Conditions that warrant monitoring and will be addressed during the next inspection cycle.

This framework ensures the most critical conditions are addressed promptly, while lower-priority needs are systematically scheduled and tracked — consistent with the Audit Report's

[129] Final Report, Part Two (page 43), available at https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/068cs00000AyaNpAAJ, accessed March 18, 2026.

[130] Order dated January 23, 2025 in Case No. U-21534 (page 108), available at https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/068cs00000X23rkAAB, accessed March 18, 2026.

recommendation to “pac[e] the scope and timing of repair and replacement activities to mitigate the added costs that the first cycle will produce.”[131] The PTMM team is also modernizing its asset management systems to improve tracking of inspection results, remediation progress, and overall program performance. These enhancements strengthen coordination between inspection and construction teams, reduce backlogs, and improve transparency in program execution. Collectively, these enhancements support the Company’s ability to meet increased inspection targets, reduce failure risk, and move toward industry standard maintenance cycles.

Expected Benefits and Cost-Effectiveness

As described in Section 5.2.3 (Benefit-Cost Analyses Approach), DTE partnered with a third-party consultant to perform a BCA for the PTMM program to assess the value of replacing poles and pole-top equipment across the system. The BCA results demonstrate that the PTMM investments are cost-effective and expected to deliver positive net benefits to customers. Additional detail on the methodology and results can be found in Appendix 8.14 (Benefit-Cost Analysis Report). It is also important to note that the BCA does not quantify safety benefits, such as reductions in live wire-down events, that are expected outcomes of the PTMM program.

When evaluated under the GPM described in Section 5.2.4 (Global Prioritization Model), the PTMM program consistently ranked above the top quartile (19th) among projects and programs considered. Taken together, the GPM results and BCA findings provide strong justification for DTE’s PTMM investment strategy, which supports long-term reliability goals and aligns with good utility practice.

Near-Term Investment

To advance toward the audit recommended inspection intervals, the Company has developed a ramp up plan, increasing from $200 million in 2026 to $540 million in 2030. During the 2025 calendar year, DTE observed pole inspection condemnation rates that were higher than previously expected. While the BCA discussed above remains positive, the higher level of identified remediation will increase the expected cost per mile. Although this elevated replacement rate will improve reliability through the installation of modern equipment, it may also extend the time needed to complete the initial five- and 10-year inspection cycles. The Company will continue to monitor condemnation and failure rates through 2026 to confirm whether this represents a sustained trend.

[131] Order dated June 12, 2025 in Case No. U-21305 (page 23), available at https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/068cs00000u4p0XAAQ, accessed March 18, 2026.

In addition to capital investment, PTMM also requires O&M funding to support inspections, testing, and maintenance activities. The five-year capital and O&M investment required to advance toward the five-year pole-top and 10-year pole maintenance cycle, as well as the estimated units, is outlined in Exhibit 6.17.

Exhibit 6.17 – Capital Investment Plan, O&M Expenditures, and Estimated Units for PTTM, 2026-2030[132]

PTMM	2026	2027	2028	2029	2030	2026- 2030 Total
Circuit Miles[133]	1,627	1,743	2,774	3,660	3,640	**13,444**
Total Poles Replaced / Reinforced	10,270	11,585	15,961	18,747	20,093	**76,656**
Capital Investment ($ millions)	200.0	263.4	376.8	482.6	540.0	**1,862.8**
O&M Expenditures ($ millions)	4.9	5.8	7.2	7.8	8.2	**34.0**

The comprehensive BCA has determined the PTMM program to be a cost-effective investment well beyond the Company's proposed five-year investment plan. Consistent with the Audit Report, MPSC guidance, and the BCA results, ramping up investment to bring the PTMM program on-cycle delivers strong value to customers. Accordingly, DTE is proposing to continue PTMM for Infrastructure Recovery Mechanism (IRM) treatment through 2030, as outlined in Section 7.2.1 (Infrastructure Recovery Mechanism).

Long-Term Outlook

The PTMM program remains central to DTE's long-term strategy to enhance safety, reliability, and system resiliency. As climate-driven weather events intensify and the Company's overhead infrastructure continues to age, maintaining an on-cycle PTMM program becomes increasingly critical. Through systematic inspections, modernized materials, and targeted upgrades, PTMM reduces failure risks, mitigates storm impacts, and supports sustained improvements in reliability. After completing the first full inspection and remediation cycle anticipated around 2030, DTE expects investment levels to stabilize. By that time, customers will have benefited from fewer outages, improved service quality, and a more resilient electric grid that is hardened to withstand the increasingly severe weather conditions. With the additional system performance data obtained through the initial inspection and remediation cycle, the Company will be better positioned to evaluate and determine the appropriate long-term pacing and scope of the PTMM program.

[132] Totals may not match exactly to the mathematical summation in the table due to rounding of the source data.
[133] Including 524 and 899 of pole-top only miles in 2029 and 2030, respectively (total of 1,423 pole-top only miles).

6.2.2 4.8 kV Hardening

Grid Needs

The Company continues to face significant risks associated with legacy 4.8 kV circuits — particularly in the City of Detroit — where some of the oldest and most failure prone infrastructure in the service area experiences disproportionately high outage rates and wire-down events. These challenges are compounded by two conditions unique to Detroit: the presence of abandoned Detroit Public Lighting Department (DPLD) arc wire and its co-location on DTE assets. Because this abandoned arc wire is situated near energized conductors, it poses a risk of accidental energization — an unacceptable safety hazard that must be eliminated. Routine maintenance efforts alone are insufficient to resolve this long-standing issue. While full conversion represents the most robust long-term solution to the inherent design limitations of the 4.8 kV system, targeted and comprehensive 4.8 kV Hardening provides a necessary and cost-effective strategy for reducing safety and reliability risk in the near term.

Program Overview and Key Updates

The Company launched the 4.8 kV Hardening Program in 2018 to systematically modernize this aging part of the system and improve reliability across the 4.8 kV circuits in the City of Detroit. In addition to removing co-located wire, hardening activities include replacing deteriorated poles and aging pole-top equipment. The program focuses specifically on arc wire co-located with Company assets. Non-co-located wire does not pose the same operational or safety threat, so it is not included within the scope of this program. When arc wire appears on any portion of a circuit, the Company hardens the entire circuit. This approach improves investment efficiency and avoids unnecessary mobilization costs so that all customers on the circuit benefit from improved safety and reliability.

The 4.8 kV Hardening program has already achieved substantial progress. From launch through 2025, the program hardened approximately 1,878 miles and removed roughly 873 miles of arc wire. DTE will address the remaining 402 miles of DPLD co-located arc wire through a combination of 4.8 kV Hardening and 4.8 kV Conversions projects, with full removal targeted by 2030. Under this strategy, about 187 miles of arc wire will be eliminated through hardening activities by 2027, while the remaining 215 miles will be removed as part of planned conversion work.[134] This allocation is designed to optimize capital efficiency by minimizing duplicative mobilization and avoiding hardening investments on circuits slated for near-term conversion.

Value of 4.8 kV Hardening

The Audit Report affirmed the prudency of DTE's 4.8 kV Hardening program, stating that "[c]ompletion of the City of Detroit 4.8 kV hardening program…is sound," and concluding that the program "has improved resiliency and safety." These independent findings confirm the effectiveness of the Company's Hardening strategy in enhancing system performance, public safety, and overall grid resilience.

Near-Term Investment

DTE expects the 4.8 kV Hardening program to address the remaining 313 miles of in-scope circuits through 2027 to bring the program to a successful conclusion. The capital investment required to complete this work is approximately $143.4 million, as shown in Exhibit 6.18.

Exhibit 6.18 – Investment Plan and Estimated Units for 4.8 kV, 2026-2027

4.8kV Hardening	2026	2027	2028	2029	2030	2026 – 2030 Total
Miles Hardened	175	138	-	-	-	**313**
Arc Wire Miles	105	82	-	-	-	**187**
Capital Investment ($ millions)	82.0	61.4	-	-	-	**143.4**

When combined with planned conversion projects, the Company remains on track to achieve full removal of co-located DLPD arc wire by 2030.

[134] Planned 4.8 kV Conversions projects to eliminate co-located arc wire include City of Detroit Infrastructure (CODI) initiatives (such as Garfield, Islandview Substation, Kent/Gibson Conversion, Howard Conversion) and conversion-related work associated with the I 94 (Promenade) and Zenon substations.

6.2.3 Frequent Outage

Grid Needs and Program Overview

In addition to systemwide reliability initiatives, the Company deploys targeted short-term efforts that address localized areas where customers experience persistent reliability challenges. DTE's Frequent Outage program focuses on improving service reliability for customers with repeated interruptions as shown by the CELID-8 and CEMI-4 reliability metrics discussed in Section 4.3.2 (Historical Reliability Metrics). These efforts include the CE program and SRIP, each designed to address different types and severities of reliability issues at the circuit level.

The CE program delivers focused improvements for customers experiencing poor reliability over a relatively short timeframe. Circuit selection incorporates recent performance data, regional expertise, and operational considerations. After a circuit is selected, engineering and field teams conduct a detailed patrol to assess equipment and vegetation conditions. Work typically includes verifying correct operation of field devices, conducting fault studies to ensure proper fuse sizing, and installing additional protective equipment — such as reclosers and animal guards — to prevent future outages. By contrast, SRIP takes a broader, multi-year view of reliability trends and addresses more complex, persistent challenges. Circuits are selected based on both historical performance and localized engineering insights regarding customer impacts. Some SRIP projects focus on specific segments of a circuit, while others require upgrades across the entire circuit.

Near-Term Investment

The Frequent Outage program plays a key role in quickly reducing outage frequency and duration, complementing DTE's systemwide reliability investments. Under the GPM described in Section 5.2.4 (Global Prioritization Model), the Frequent Outage program ranked 20th. Impact dimensions with high scores included SAIFI, SAIDI, Capital Avoidance, and O&M Avoidance.

The Company expects Frequent Outage to continue over the next five years. Between 2026 and 2030, DTE plans to invest $170.1 million in Frequent Outage programs, as shown in Exhibit 6.19. Annual investment levels are expected to vary as other system reliability initiatives, such as PTMM, expand and address additional portions of the system.

Exhibit 6.19 – Investment Plan for Frequent Outage Programs, 2026-2030 ($ millions)

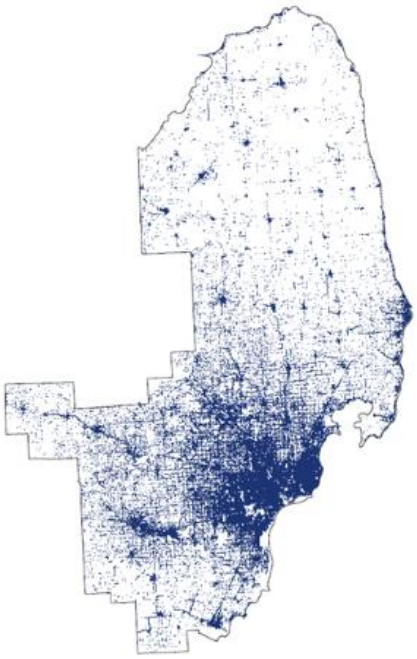
Frequent Outage	2026	2027	2028	2029	2030	2026 – 2030 Total
Capital	42.1	25.5	32.5	35.0	35.0	**170.1**

6.2.4 Small Wire Replacement

Grid Needs

Small wire refers to legacy distribution conductors smaller than gauge 1/0 (approximately 0.8 cm in diameter) or non-ACSR (Aluminum Conductor Steel Reinforced) conductors, most of which were installed during the early to mid-20th century and are no longer used in modern-day utility overhead power line construction. DTE's overhead primary system contains about 3,600 miles of this small-gauge wire,[135] concentrated primarily on the legacy 4.8 kV system, as shown in Exhibit 6.20. For example, the Company's system includes approximately 2,900 miles of #6 copper small wire, which represents about 9% of total overhead conductor mileage but accounts for approximately 39% of all wire-down events. Additionally, a significant portion of the Company's secondary conductors are open-wire construction, consisting of individual conductors supported on insulator racks rather than modern, more robust multiplexed configurations with an ACSR messenger neutral.[136] This open-wire construction increases exposure to outages from foreign-object contact and results in higher breakage rates during wind and ice events, elevating safety risks for both the public and DTE employees.

Exhibit 6.20 – Small Wire in DTE's Service Area



[135] Overhead primary distribution conductors operate at distribution voltage levels and deliver electricity from substations to distribution transformers, where it is stepped down for delivery to customers.

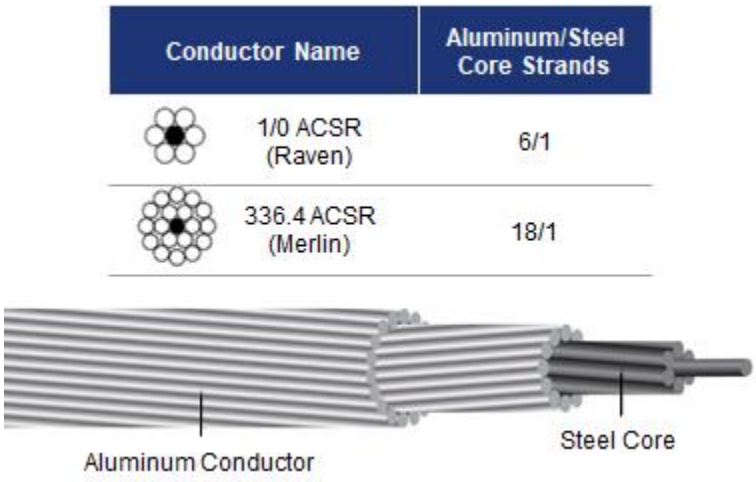
[136] Secondary distribution conductors operate at lower voltage downstream of distribution transformers and deliver electricity closer to individual customer premises.

While full conversion remains the most comprehensive long-term solution to the inherent design limitations of the 4.8 kV system, proactive Small Wire Replacement offers a necessary and cost-effective strategy for mitigating safety and reliability risks in the near term — similar in purpose to the 4.8 kV Hardening program.

Program Overview

The Small Wire Replacement program was developed to proactively replace small wire as a more comprehensive strategy for reducing wire-down risk. Historically, conductor upgrades have occurred in conjunction with large-scale conversion projects or in reaction to emergent issues such as customer complaints or equipment failures. Under this new program, DTE will target high-risk 4.8 kV circuits based on historical wire-down frequency, customer impact metrics, vegetation exposure, and the presence of rear-lot infrastructure that limits access for maintenance and restoration activities. Program scope may also include the replacement or removal of open-wire secondary conductors where engineering evaluation determines such actions are appropriate and cost-effective. Replacement work will deploy larger ACSR conductors, as illustrated in Exhibit 6.21, as well as insulated triplex wire where secondary replacements occur, resulting in improved mechanical strength, lower failure rates, and increased current-carrying capability.

Exhibit 6.21 – ACSR Conductors for Small Wire Replacement



Because of the age and condition of associated infrastructure, poles and crossarms will often require replacement to meet the structural demands of upgraded conductor specifications. The program complements the 4.8 kV Conversions initiative by addressing high-risk laterals in the near term with modern conductor standards, thereby reducing the scope of future conversion projects.

Expected Benefits and Cost-Effectiveness

Small Wire Replacement investments were evaluated at a circuit level using the BCA framework described in Section 5.2.3 (Benefit-Cost Analyses Approach). The BCA results indicate favorable cost-effectiveness for a substantial portion of the circuits analyzed. These quantitative results are supplemented by qualitative considerations related to safety, operability, and system hardening. Additional detail on the BCA methodology and results is provided in Appendix 8.14 (Benefit-Cost Analysis Report).

When evaluated under the Global GPM described in Section 5.2.4 (Global Prioritization Model), the Small Wire Replacement program ranked 87th among projects and programs considered. The program's GPM performance is primarily driven by the Reduce Electrical Hazards impact dimension, reflecting its effectiveness in mitigating wire-down risk. While the GPM provides a portfolio-level prioritization across multiple investment types, these results are directionally consistent with the BCA findings and highlight the program's role in addressing safety driven reliability risks.

Near-Term Investment

Following program launch, the Company plans to increase Small Wire Replacement investment from $10 million in 2026 to $20 million by 2030. The five-year investment plan and projected miles for the Small Wire Replacement program are presented in Exhibit 6.22.

Exhibit 6.22 – Investment Plan and Estimated Units for Small Wire Replacement, 2026-2030 ($ millions)

	2026	2027	2028	2029	2030	2026 -2030 Total
Capital	10.0	10.0	10.0	18.0	20.0	**68.0**
Projected Range of Replacement Miles[137]	5-20	5-20	5-20	9-36	10-40	**34-136**

Notably, the proposed five-year investment represents less than 3% of the cost-effective opportunity identified through the BCA results, demonstrating that the planned investment level will deliver strong value to customers while materially reducing safety and reliability risks.

[137] Actual mileage will vary based on circuit conditions, pole and crossarm replacement needs, access constraints, and field productivity observed during program execution.

Long-Term Outlook

Over the long term, addressing the extensive presence of legacy small wire across DTE's distribution system will remain essential to delivering sustained improvements in 4.8 kV system safety, reliability, and performance. With the substantial amount of cost-effective investment identified through the BCA, there is a clear need for a multi-decade transition toward modern conductor standards. While full 4.8 kV conversion offers the most comprehensive solution, its extended implementation timeframe and significant capital requirements underscore the importance of a parallel strategy focused on proactive Small Wire Replacement. As customer adoption of new technologies accelerates and severe weather events place increasing strain on service reliability, the Company expects Small Wire Replacement to serve as a foundational element of long-term grid modernization — delivering meaningful risk reduction while enabling a deliberate and cost-effective transition to a fully modernized distribution system over time.

6.2.5 Undergrounding

Grid Needs

More frequent and severe storms across DTE's service area continue to expose the vulnerabilities of a largely overhead distribution system. While programs such as Vegetation Management and PTMM play critical roles in reducing risk and strengthening the grid, undergrounding power lines offers an even greater opportunity to improve system performance, reduce storm-related wire-downs, and enhance public safety. More than 30% of DTE's distribution system is already underground, largely due to subdivision requirements introduced in the 1970s. Internal analysis shows that these areas experience more than 30% better reliability than comparable overhead circuits.

Despite its clear reliability and safety advantages, an Undergrounding program at scale remains constrained by its high cost.[138] Converting existing neighborhoods from overhead to underground can be five to six times more expensive than rebuilding overhead systems, creating significant challenges amid increasing investment needs to maintain and modernize an aging system, as well as broader economic pressures. To address this, the Company is strategically advancing the Undergrounding program through pilots and benchmarking peer utilities to identify approaches that maximize reliability and resiliency benefits while better managing installation costs.

[138] Since its 2025 Electric Rate Case filing in Case No. U-21860, the Company has simplified "Strategic Undergrounding" naming to "Undergrounding."

Since 2018, DTE has launched several overhead-to-underground conversion pilots in different neighborhoods, each designed to capture learnings from varying circuit topologies and customer densities. The goal of these projects is to evaluate how undergrounding performs in varied environments, how it aligns with 4.8 kV Conversions work, where joint construction with DTE Gas can create efficiencies, and how undergrounding compares economically to rebuilding overhead systems. The goal is to determine when and where undergrounding is a cost-effective option for improved reliability.

Completed Undergrounding Pilots

Undergrounding work on Buffalo Charles project

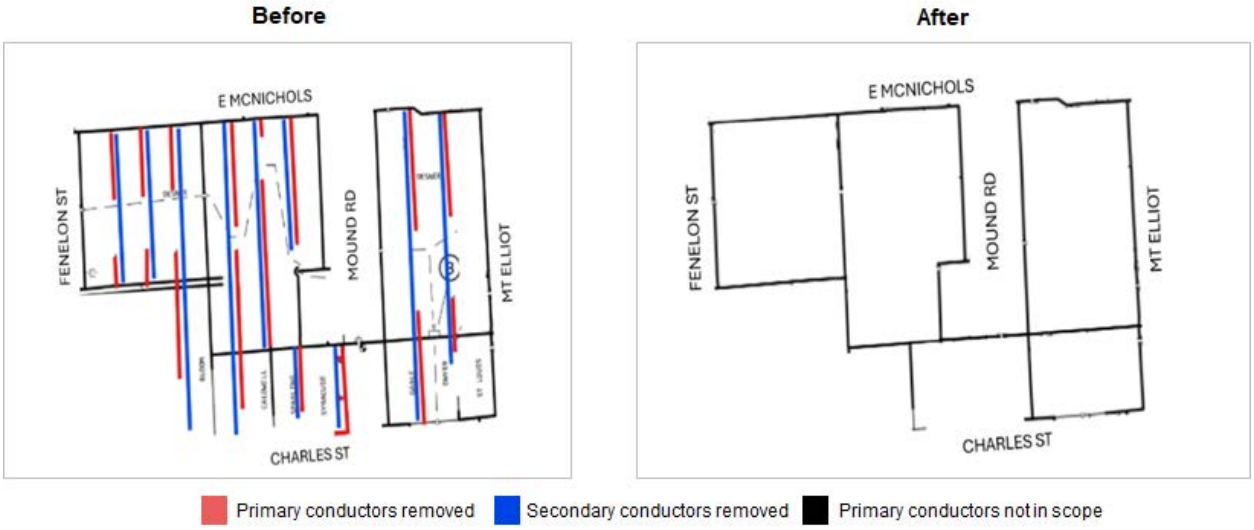
To date, DTE has completed two Undergrounding pilot projects — Appoline and Buffalo Charles — both located in Detroit. The Appoline pilot, launched in 2018 on the DC 1346 Appoline circuit, focused on converting rear-lot overhead lines to URD. The project aimed to assess installation costs, customer acceptance, and opportunities for efficiency. The project served 61 residential customers across two Detroit blocks and installed a looped URD system consisting of approximately 1,300 feet of primary conductor, six transformers, and associated underground services. After the system was energized, the overhead infrastructure was removed, and the project concluded in 2023. This work demonstrated that rear-lot undergrounding presents significant challenges: dense vegetation, debris, and restricted access increased costs and extended construction timelines. It also confirmed that early, direct customer engagement is critical. Securing approvals from landlords and absentee owners often delayed progress; resource-intensive door-to-door outreach proved far more effective than mailers or door hangers.

In 2022, the Company applied lessons learned from the in-flight Appoline pilot — such as improving easement and service-conversion agreements and addressing rear-lot access barriers — to a larger-scale, front-lot Undergrounding pilot on the DC 1366 St. Louis circuit in Detroit's Davison and Buffalo Charles neighborhoods. The area was selected in collaboration with the City of Detroit due to alignment with revitalization efforts and the availability of City- and Detroit Land Bank Authority (DLBA)-owned parcels suitable for transformer easements. This pilot aimed to

evaluate a large-scale urban underground conversion and to assess construction efficiencies enabled by coordination with DTE Gas main replacement activities. DTE removed roughly 160 poles and more than 2.8 miles of overhead conductor and installed a front-lot underground system consisting of 4.3 miles of primary cable, 3.3 miles of secondary cable, 9.5 miles of service cable, 60 transformers, 147 handholes, 459 junction boxes (allowing customers to retain interior wiring), and 11.7 miles of conduit. The pilot was completed in 2025 for a total cost of approximately $14.5 million, or about $5.1 million per overhead primary line mile removed. Coordinating with DTE Gas created both construction and cost efficiencies by enabling shared directional boring and reducing customer disruption. Lower customer density also helped moderate costs.

The pilot further highlighted the need to update sidewalk-handhole standards for urban areas and reaffirmed the importance of securing all equipment easements in advance. While DLBA parcels supported many transformer locations, private easement acquisition still created delays, particularly under the project's accelerated schedule. Extending the design phase would help mitigate these issues in future efforts. Customer conversion agreements also contributed to delays, often due to unresponsive or out-of-state landlords. To address this, the Company adopted a notification process modeled after one used by DTE Gas that allows work to proceed after a defined non-response period. Exhibit 6.23 illustrates the project's impact.

Exhibit 6.23 – DC 1136 St. Louis Circuit Topology

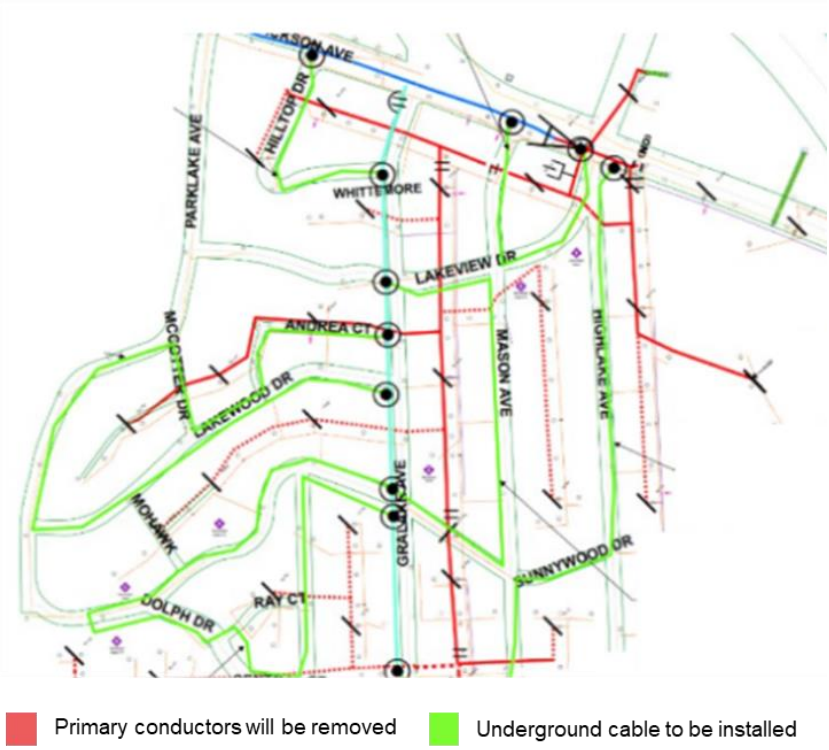


In-Progress Undergrounding Pilots

Two Undergrounding pilots are currently in progress: Spruce and Attica. The Spruce project is designed to improve reliability by reducing exposure to dense vegetation. The area was selected

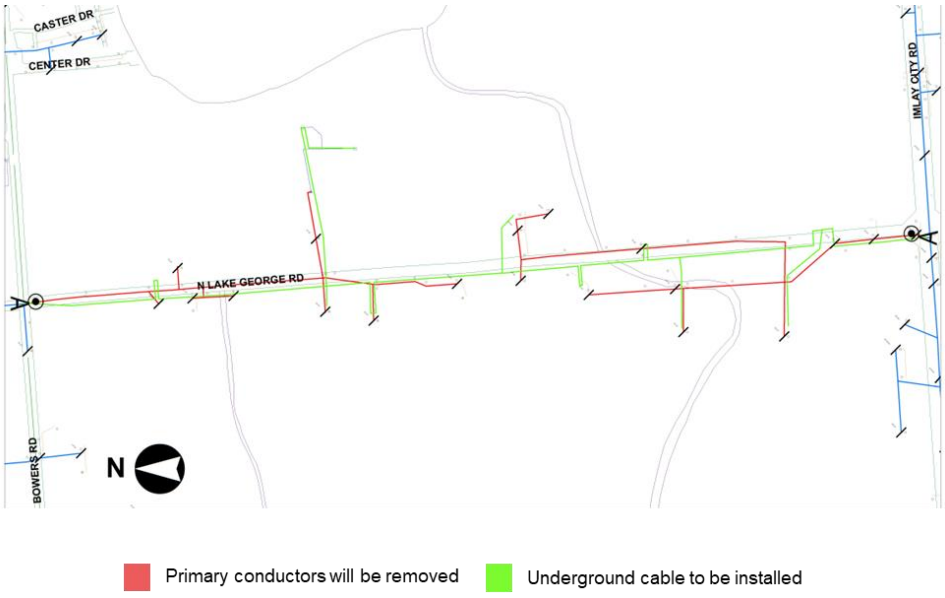
in coordination with the City of Ann Arbor to align undergrounding work with an upcoming municipal road-resurfacing project, thereby reducing installation and restoration expenses. Its suburban setting will offer valuable insights into easement acquisition timelines and construction costs in higher-density neighborhords. The scope includes undergrounding 263 customer services and converting more than 1.8 miles of single-phase overhead distribution, as illustrated in Exhibit 6.24. The project is currently in the design phase, with construction scheduled to be completed in 2027.

Exhibit 6.24 – DC 9836 Spruce Circuit Scope



The Attica project provides DTE with an opportunity to pilot undergrounding in a rural environment, where the challenges and efficiencies differ significantly from urban and suburban settings. The scope includes converting more than 1.7 miles of 4.8 kV overhead primary laterals to underground within the road ROW, as illustrated in Exhibit 6.25. Twenty customers will be served through pad-mount transformers that backfeed existing secondary and service leads to off-road homes. By excluding customer service conversions, the project is expected to achieve substantially lower per-mile costs compared to pilots in higher-density areas. Construction is scheduled to begin and conclude in 2026.

Exhibit 6.25 – DC 302 Attica Circuit Scope



Key Lessons Learned and Process Improvements

Across the Company's Undergrounding pilot programs, several consistent themes have emerged regarding opportunities to improve program efficiency:

- Thorough, upfront design significantly shortens overall execution timelines by identifying constructability constraints early.
- Early and proactive community engagement is fundamental for building public support, particularly in neighborhoods with high renter populations or absentee landlords, where delayed outreach can hinder customer participation.
- Securing all required easements in advance is critical to avoiding construction delays and ensuring uninterrupted workflow.

To support more efficient project delivery, DTE's PMO partnered with design vendors to develop enhanced easement tracking tools that identify potential roadblocks early in the design phase, allowing teams to adjust scope proactively. Exhibit 6.26 provides an example of the PMO's dashboard used to monitor underground easement progress. Additionally, the Company implemented a service-underground notification process to obtain agreements from non-responsive or out-of-state property owners, further reducing schedule risk and improving project throughput.

Exhibit 6.26 – PMO Underground Easement Tracking Dashboard

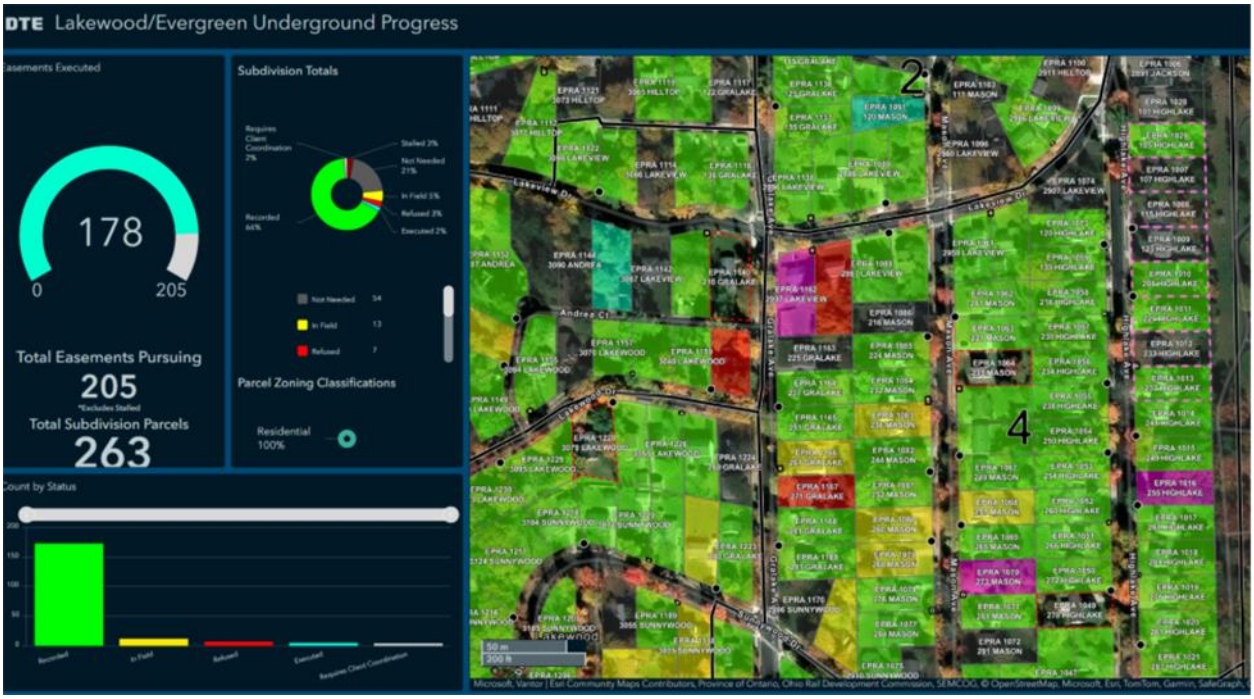


Exhibit 6.27 compares DTE's completed and active projects, showing that rural undergrounding achieves the lowest cost per mile due to simpler construction requirements and lower customer density requiring fewer transformers and less service point conversion work, while urban and suburban projects incur higher costs by comparison.

Exhibit 6.27 – Undergrounding Pilot Comparisons

	Project Name			
	Appoline	**Buffalo Charles**	**Spruce**	**Attica**
Project Type	Urban Rear Overhead to Rear Underground	Urban Rear Overhead to Front Underground	Suburban Rear Overhead to Front Underground	Rural Front Overhead to Front Underground
Overhead Asset Type Undergrounded	Primary, Secondary, and Services	Primary, Secondary, and Services	Primary, Secondary, and Services	Primary and Secondary Only
Project Status	Complete	Complete	In Design	In Design
Number of Customers	+/- 61	+/- 459	+/- 263	+/- 20
Estimated Cost per Mile ($ millions)	1.3	6.1	6.6	2.3[139]
Actual Cost per Mile ($ millions)	3.7	5.1	TBD	TBD

[139] In 2026, approximately $100K additional costs would have been incurred had the Company included underground conversion service for all 20 homes.

DTE is complementing its Undergrounding projects with an extensive benchmarking effort involving more than 10 peer utilities to identify configurations that best balance reliability, cost, constructability, and customer satisfaction. These comparisons consistently show that front-lot URD provides stronger reliability performance, improved aesthetics, and better customer engagement outcomes than rear-lot designs. Peer utilities also emphasize the importance of securing easements and customer agreements prior to construction, a practice that helps avoid schedule delays and reduces project risk. In addition, many utilities achieve meaningful cost efficiencies through high-volume execution and economies of scale, enabling more consistent construction practices and streamlined vendor mobilization.

Project selection methodologies observed across peer utilities typically incorporate lifecycle NPV, expected reliability benefits, and comparative construction costs. Most utilities focus their undergrounding strategies on single-phase laterals, given that undergrounding three-phase or backbone lines requires substantially more complex and costly duct-bank construction. Utilities also frequently prioritize rural areas, where low customer density, fewer obstructions, and minimal pavement allow for easier trenched installation. This results in significantly lower cost per mile compared to urban and suburban areas, where higher customer density and the need for non-trenching construction methods — such as missile boring and directional drilling — drive costs upward.

Near-Term Investment

Collectively, insights from benchmarking and the Company's pilot project experience will continue to shape DTE's Undergrounding strategy and guide the design and execution of any future, scalable Undergrounding program. In the near-term, the Company's strategy remains intentionally measured — focused on completing its ongoing pilots and evaluating performance outcomes before advancing a broader proposal. This disciplined approach aligns with the Audit Report recommendation that, "it is appropriate to limit expenditures to a pilot program before deciding whether undergrounding should have widespread application."[140] The undergrounding pilots were evaluated using the GPM, as described in Section 5.2.4 (Global Prioritization Model), and ranked 68th overall. DTE expects to invest approximately $14.0 million to complete the Attica and Spruce pilots, as shown in Exhibit 6.28.

[140] Final Report, Part Two (page 83), available at https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/068cs00000AyaNpAAJ, accessed March 19, 2026.

Exhibit 6.28 – Investment Plan for Undergrounding Pilots, 2026-2030 ($ millions)

UG Pilot	2026	2027	2028	2029	2030	2026-2030 Total
Attica	3.5	-	-	-	-	**3.5**
Spruce	2.5	8.0	-	-	-	**10.5**
Total	**6.0**	**8.0**	**-**	**-**	**-**	**14.0**

Long-Term Outlook

Looking ahead, DTE will continue to evaluate emerging technologies, materials, and construction practices to further enhance the cost-effectiveness of undergrounding. The Company remains actively engaged in industry research, including participation in an EPRI initiative focused on alternative underground construction methods. DTE will also assess opportunities to integrate Undergrounding into 4.8 kV Conversions work where overhead rebuilding creates electrical-clearance constraints or where critical backbone segments cannot be relocated away from dense vegetation. While undergrounding significantly reduces service interruptions within converted areas, customers may still experience outages originating from upstream overhead sections or substation equipment. Nevertheless, during major storms, systemwide restoration times may improve, because underground segments require fewer resources to address wire-down hazards and storm-related damage.

Lessons learned from both completed and ongoing pilots will continue to guide project selection, refine cost estimates, support benefit-cost analyses, and inform the Company's long-term Undergrounding strategy. Given the substantially higher cost of undergrounding relative to overhead rebuilds, DTE will prioritize projects that demonstrate effective benefit-cost outcomes — primarily those tied to conversion work where infrastructure rebuilding is already planned. The Company will continue to incorporate new insights and industry developments into its planning; however, DTE is not currently proposing or supporting a larger-scale Undergrounding program.

6.2.6 System Equipment Replacement

Grid Needs

Equipment at DTE's Warren Service Center

To ensure the electric system performs as designed, system equipment — such as substation breakers and regulators, distribution and subtransmission cables, automated pole-top switching devices, switchers, and critical ancillary components like batteries and chargers — must be maintained in good physical and operational condition. This equipment plays a vital role in delivering electricity to customers, isolating and locating faults, and maintaining proper voltages and power quality on the grid. For the grid to operate reliably, this infrastructure must perform as intended under normal operating conditions and withstand the stresses associated with system fault events. As equipment ages, repair becomes less effective and more costly, and there comes a point where proactive replacement is the most efficient and reliable strategy to manage lifecycle costs and ensure continued system performance. Additional detail on the age profile of DTE's system equipment and the Company's ongoing health assessments can be found in Section 4.2 (General Asset Health and Condition).

Given the Company's aging and increasingly failure-prone infrastructure, proactive replacements are necessary to mitigate at-risk assets and prevent major outage events that can impact thousands of customers for extended periods. DTE conducts routine asset health assessments that evaluate multiple condition indicators, in addition to equipment age, to identify assets at elevated risk of failure and to appropriately prioritize investments. This approach is in line with good utility practice and consistent with guidance from the Commission that "while the age of equipment is a factor to consider, it should not be the sole factor when determining equipment replacement."[141]

[141] Order dated June 12, 2025 in Case No. U-21305 (page 26), available at https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/068cs00000u4p0XAAQ, accessed March 20, 2026.

Program Overview and Cost-Effectiveness

The programs within System Equipment Replacement reduce the likelihood of unexpected failures that can lead to service interruptions, safety concerns, and high emergency repair costs. Proactive replacements also enable better planning of resources, materials, and crew availability. While some equipment replacements are strategically integrated into larger projects to minimize customer disruptions and streamline work execution, this section focuses on the replacement of the most at-risk equipment to maintain continued system safety, reliability, and performance.

To assess whether the benefits of proactive System Equipment Replacement justify the associated costs, DTE partnered with a third-party consultant to conduct BCAs on the program's highest investment categories, as described in Section 5.2.3 (Benefit-Cost Analyses Approach). Where a BCA was performed, the results are summarized below. Additional detail on the BCA methodology and results is provided in Appendix 8.14 (Benefit-Cost Analysis Report).

Substation Equipment Replacements

Breakers: Circuit breakers are critical protective devices as described in detail in Section 4.2.1 (Substation Assets). To the extent possible, breaker replacements are coordinated with other capital or maintenance work to reduce costs and minimize customer disruption. In most cases, these replacements also include relay upgrades, enabling SCADA control and expanding the penetration of remote substation monitoring and control capabilities. Together, these investments are expected to deliver significant customer benefits through improved substation operability.

The Breaker Replacement program was evaluated as part of the Company's BCA, as described in Section 5.2.3 (Benefit-Cost Analyses Approach), which found a large portion of the overall investment portfolio delivers net positive value to customers. Breaker Replacement was also evaluated as part of the GPM, where it ranked 49th overall, driven primarily by Capital Avoidance impact dimension score. The BCA and GPM results demonstrate that proactive breaker replacement delivers overall customer benefits; however, the current replacement pace — equivalent to a 111-year cycle — significantly exceeds the equipment's 50-year useful life. As a result, nearly 60% of DTE's circuit breaker fleet is now at or beyond its expected useful life. To address this growing backlog and reduce the risk of major outage events, the Company is accelerating its annual investment in Breaker Replacements from $12.6 million in 2026 to $55.0 million in 2030. This increased investment level would allow DTE to replace approximately 117 units over the next five years, representing roughly 5% of breakers currently identified as candidates for replacement.

Substation Regulators: Regulators maintain voltage within normal operating limits. Replacing deteriorating units will ensure proper voltage regulation and prevent out-of-range conditions that can damage customer equipment or cause reliability issues. DTE identifies candidates for replacement by considering the vintage of technology used for regulation because multiple types are obsolete and no longer have repair parts readily available. Induction and delta triplex regulators are prioritized for replacement to remove aging equipment before failure, increase the availability of spare parts through salvage of replaced units, and maintain operational flexibility, as the replacement regulators do not interface with the technology that is being replaced. The Company plans to invest $5 million to replace 10 substation regulators over the next five years.

Subtransmission Disconnect Switches: Subtransmission disconnect switches provide a visible, de-energized isolation point on subtransmission lines or equipment so crews can safely work. Failure during manual opening or closing can create safety hazards, reduce system operability, and require additional equipment to be taken out of service to allow critical work to continue. DTE identifies candidates for replacement by considering known safety concerns or operational issues. Disconnects that have cap and pin insulators or bearing failures are prioritized for replacement to ensure safety concerns are addressed around failing insulators causing equipment to fall and to keep operational functionality across the system. The Company plans to invest $15.0 million to replace 58 subtransmission disconnect switches over the next five years.

Circuit Switchers: Circuit switchers connect the 120 kV transmission system and the 40 kV subtransmission system to the primary side of a substation power transformer. The purpose of the circuit switchers is to protect substation equipment from damage caused by high fault currents. For some substation designs, it is a smaller, less expensive alternative to a circuit breaker. A circuit switcher failure can cause significant damage to other equipment because, without a functioning circuit switcher, the system must rely on upstream transmission or subtransmission sources to clear high fault currents. In many cases, this alternative protection is slower, less reliable, and may not effectively isolate the fault, resulting in unnecessary equipment damage. DTE identifies candidates for replacement by considering known failure modes and inadequate ratings.

Circuit switcher

Circuit switchers that have low fault interrupting ratings or have been found to have failing insulating columns are prioritized for replacement to ensure that the circuit switchers reliably operate and will not have the ability to operate beyond their rated capability. The Company plans to invest $9.5 million to replace 17 circuit switchers over the next five years.

Batteries and Chargers: DC systems are the backbone of substation control and protection and include a combination of batteries and chargers. These systems are used to provide a reliable power source to trip equipment protectively during fault conditions. When these systems are degraded, it introduces significant operational and safety risks. Failure of these systems would result in the inability to clear faults, greater damage to equipment, larger outages, and increased hazards due to significantly longer duration faults. To maintain the ability to isolate faults on the distribution system, batteries and chargers must be addressed proactively. DTE identifies candidates for replacement by evaluating whether a DC system exhibits signs of premature failure or has reached the end of its useful life. DC systems that have exceeded expected useful life — typically seven years for sealed lead-acid batteries and 15 years for flooded batteries — or that exhibit physical deterioration or degradation identified through electrical testing are prioritized for replacement to ensure reliable tripping capability and proper operation of fault-interrupting equipment. The Company plans to invest $15.0 million to replace 370 batteries and chargers over the next five years.

Overhead System Equipment Replacements

40 kV Automatic Pole-Top Switch (APTS): The APTS functions to sectionalize, isolate, and reconfigure portions of the subtransmission system. A failure of any APTS device can interrupt service to thousands of customers or create significant operational constraints. DTE identifies replacement candidates by evaluating equipment vintage and the availability of spare parts needed to maintain functionality. Units installed under now-obsolete standards or those with poor asset health ratings are prioritized for replacement to ensure continued operability and reliability of the subtransmission system. APTS was evaluated under the GPM, ranking 12th overall, driven by high scores in SAIFI and SAIDI impact dimensions. The Company plans to invest $37.0 million to replace 77 APTS units over the next five years.

SCADA Pole-Top Devices: This category of equipment is comprised of two types of pole-top devices: distribution SCADA Pole-Top Switches (PTS) and overhead three-phase reclosers, which are discussed in more detail in Section 4.2.2 (Overhead Assets). A distribution SCADA PTS allows the ESOC to remotely reconfigure the grid to restore customers by isolating faults or transferring load to adjacent circuits during both planned and unplanned outages. An overhead three-phase recloser is a sectionalizing device that is located at key points on overhead distribution circuits. It acts like a substation breaker, by opening under detection of high current due to a downstream fault, such as a tree branch across two phases. DTE plans to invest $20.1 million to replace 160 of these devices over the next five years.

Steel Pole Highway Crossings: Overhead power structures at freeway and highway crossings are among the most critical assets on the electric system due to their proximity to high-speed traffic and the important role they play in maintaining continuity of service across major transportation corridors. A structural failure at these locations can have severe consequences, including widespread customer outages, significant public safety hazards, prolonged roadway closures, and complex emergency response requirements. To mitigate these high-impact risks, DTE developed a program to replace aging wood poles with more resilient steel poles at highway crossings. Highway poles that have been in service for more than 20 years are prioritized for condition assessment. The Company evaluates pole condition using several diagnostic methods, including visual inspections, pole boring, excavation, and vibration analysis. Any pole that does not meet established acceptance criteria is replaced with a steel pole. The Company plans to invest $9.0 million to replace and rebuild 12 crossings over the next five years as part of this longer-term effort.

Underground System Equipment Replacements

System Cable: DTE is increasingly concerned about the failure risk posed by the current condition of system cable, because of the significant impact these failures can have on the overall system. Additional details on failure impacts, historical failure rates, and replacement drivers are provided in Section 4.2.3 (Underground Assets). System Cable Replacement was one of the programs the Company evaluated for cost-effectiveness, as detailed in Section 5.2.3 (Benefit-Cost Analyses Approach) and Appendix 8.14 (Benefit-Cost Analysis Report). The BCA

results demonstrate that there is a large portion of cable replacement work on the system that DTE should execute to deliver overall customer benefits. System Cable Replacement was also included in the GPM, ranking 28th. The primary impact dimensions driving this ranking were Capital Avoidance, SAIDI and SAIFI. To proactively address this system risk, the Company is accelerating its annual investment in System Cable Replacement from $12.3 million in 2026 to $55.0 million in 2030. This increased investment level would allow DTE to replace approximately 50 miles of system cable, which accounts for 5% of the cable currently identified as candidates for replacement.

To support and optimize these replacement decisions, the Company has developed a complementary System Cable Testing program. This program provides critical condition data that enables DTE to identify high-risk cable segments and prioritize replacements where they deliver the greatest reliability benefit. The testing effort is designed to scale over time through a structured, cost-conscious approach that gradually increases the number of circuits evaluated each year. Under this approach, the Company's forecasted testing activity and associated budget are expected to increase from approximately $2.0 million to evaluate 40 to 80 circuits in 2026 to $5.0 million to evaluate approximately 200 circuits in 2030. Testing costs are treated as O&M expenses and include planning, switching, and diagnostic execution.

URD Cable: Because underground repairs can require extended time to complete, URD systems are typically — though not always — configured in loops to provide alternate feeder paths if one cable fails. Additional detail on URD failure impacts, historical failure rates, and replacement drivers is provided in Section 4.2.3 (Underground Assets). The URD Replacement program improves system reliability and safety by replacing deteriorated URD cable and related equipment in locations where risk and customer impact are highest. The program also includes the replacement of live-front transformers with dead-front transformers. Some existing URD cable is supplied from live-front transformers, which is an obsolete design standard because they lack protective barriers over energized components. Once external coverings are removed, live-front transformers expose field personnel to energized parts, presenting elevated safety risks during routine O&M activities.

In addition, inspections conducted during URD replacement activities have identified defective dead-front underground transformers that also pose safety and environmental risks. Observed conditions include deterioration of protective barriers over energized components, resulting in exposed conductors, as well as oil leaks attributable to corrosion and other forms of environmental degradation. Oil leakage presents both an environmental concern and an indicator of potential

imminent equipment failure. Replacing defective dead-front transformers concurrently with URD cable replacement represents the most cost-effective approach to mitigating these risks by leveraging the same construction window, crews, site access, and outage coordination required for the URD work. This integrated execution avoids future mobilizations to the same locations and prevents duplicative construction and service costs. However, because defective dead-front underground transformers represent critical safety and environmental risks, they are also identified through routine preventive inspections and replaced through the CM program as discussed in Sections 6.1.2 (Preventive Maintenance and Inspections) and 6.1.3 (Corrective Maintenance).

A BCA analysis was performed on the URD Replacement program, as described in Section 5.2.3 (Benefit-Cost Analyses Approach) and Appendix 8.14 (Benefit-Cost Analysis Report). Through the BCA, the URD Replacement program proved to be cost-effective for customers. The program ranks 29th in the GPM, scoring high in the Capital Avoidance impact dimension. Consistent with the approach used for System Cable Replacement, the Company plans to mitigate ongoing system risk by increasing annual URD Replacement investment from $13.5 million in 2026 to $55.0 million in 2030. This would allow DTE to replace approximately 339 miles over the next five years, representing roughly 21% of URD cable currently identified as candidates for replacement.

In parallel with full cable replacement, the Company is evaluating cable injection, also referred to as cable rejuvenation, through a targeted field trial as a potential cost-effective alternative to full cable replacement. Cable injection involves introducing a specially formulated fluid into existing URD conductors to restore insulation performance and potentially extend the cable’s useful life. Recent industry advancements have resulted in fifth-generation injection technology, which DTE is currently assessing. Preliminary estimates indicate that, on a per-mile basis, cable injection may reduce costs by approximately 25% compared to conventional URD replacement. Following an initial field demonstration on a 30-foot URD cable section, the Company will partner with EPRI to further assess performance, quantify benefits, and identify any potential risks through accelerated aging studies on injected cables. DTE plans to present results from the evaluation of cable injection in a future rate case or DSP filing.

Station Upgrade Projects

Station Upgrade projects are designed to enhance the safety, reliability, and resilience of the electric grid by upgrading critical station infrastructure and modernizing protective relaying, including relay systems at points of interconnection with ITC. These projects improve system protection performance, enable advanced monitoring and control capabilities, reduce reactive power costs, and strengthen overall grid performance. The current portfolio of Station Upgrade projects includes Lincoln Station, Navarre Station, and 120 kV Relay Upgrades in coordination with ITC Projects. These efforts include replacement of aged breakers and associated relay panels and deployment of modern, microprocessor-based relaying integrated with advanced SCADA functionality such as fault detection, alarms, event recording, and remote monitoring.

Lincoln Station Project: Lincoln Station requires a comprehensive upgrade due to the presence of 24 kV relay panels that are more than 60 years old and can no longer be maintained or modified, as well as at-risk breakers and disconnects. Space constraints within the existing station layout prevent installation of new panels, necessitating a reconfiguration of station infrastructure. The Lincoln Station project will replace 14 aged 24 kV oil circuit breakers with gas circuit breakers, install 20 new microprocessor-based relay panels, and remove the existing oil circuit breakers and associated relay panels. The new protection scheme will include three bus relay panels and one underfrequency relay panel, improving protection performance, maintainability, and operational visibility.

Lincoln station

Navarre Station Project: Similar to Lincoln Station, Navarre Station requires a comprehensive upgrade due to obsolete 24 kV relay panels that have been in service for more than 60 years and can no longer be maintained or modified, along with aging breakers and disconnects. Space limitations also necessitate a new station configuration. The Navarre Station project will replace 20 24 kV oil circuit breakers with gas circuit breakers, install 35 new microprocessor-based relay panels, and remove the existing oil circuit breakers and associated relay panels. The upgraded protection system will include three bus relay panels and one underfrequency panel, with the same expected benefits as Lincoln's new scheme.

120 kV Relay Upgrades: ITC periodically initiates projects to upgrade 120 kV relaying at interconnection points with DTE. In coordination with these efforts, DTE proactively replaces obsolete relays on its system at a lower cost than reactive repair or standalone capital work. This coordinated approach reduces the risk of unfavorable shutdowns due to abnormal operating conditions or system peak loads. A total of 40 relay upgrades are planned across multiple stations from 2026 to 2030. The new microprocessor-based relays provide alarms, light emitting diode (LED) indications, and time-stamped event reports that improve troubleshooting, enable targeted maintenance, and reduce outage frequency and duration. Selected relays also provide enhanced remote-control functionality, while relay failure alarms offer advanced warning of potential issues, allowing replacement prior to an actual event without a shutdown due to redundant protective schemes. Together, these relay upgrades strengthen grid protection, improve operational resiliency, and enhance coordination between DTE and ITC systems.

Near-Term Investment Outlook

Given the critical role of the System Equipment Replacement program in maintaining safe and reliable operations across an aging electric system, DTE is strategically increasing annual investment in this program from approximately $55.3 million in 2026 to $189.6 million by 2030. This ramp-up is focused on cost-effective investments that mitigate major failure risk, enhance system performance, and deliver measurable value to customers. Additionally, the System Cable program will require approximately $19.0 million in O&M investment to support system cable testing, beginning with $2.0 million in 2026 and increasing to $5.0 million in 2030. Exhibit 6.29 provides information on the equipment types and quantities planned for replacement by year and projected investment needs.

Exhibit 6.29 – Investment Plan and Estimated Units for System Equipment Replacement, 2026-2030 ($ millions)[142]

System Equipment	2026	2027	2028	2029	2030	2026 – 2030 Total
Breakers						
Capital	12.6	15.0	20.0	35.0	55.0	**137.6**
Units	*13*	*16*	*19*	*26*	*43*	***117***
Substation Regulators						
Capital	1.0	1.0	1.0	1.0	1.0	**5.0**
Units	*2*	*2*	*2*	*2*	*2*	***10***
Disconnect Switches						
Capital	3.0	3.0	3.0	3.0	3.0	**15.0**
Units	*12*	*12*	*12*	*11*	*11*	***58***
Switchers						
Capital	1.9	1.9	1.9	1.9	1.9	**9.5**
Units	*3*	*4*	*4*	*3*	*3*	***17***
Batteries and Chargers						
Capital	3.0	3.0	3.0	3.0	3.0	**15.0**
Units	*80*	*75*	*75*	*70*	*70*	***370***
40 kV APTS						
Capital	5.0	6.5	8.5	8.5	8.5	**37.0**
Units	*13*	*13*	*17*	*17*	*17*	***77***
SCADA Pole-Top Devices						
Capital	2.0	2.6	5.2	5.2	5.2	**20.1**
Units	*20*	*20*	*40*	*40*	*40*	***160***
Steel Pole Highway Crossings						
Capital	1.0	2.0	2.0	2.0	2.0	**9.0**
Units	*1*	*2*	*3*	*3*	*3*	***12***
System Cable						
Capital[143]	12.3	18.0	31.0	40.0	55.0	**156.3**
Miles	*4.2*	*5.8*	*9.4*	*12.2*	*18.9*	***50.5***
URD Cable						
Capital	13.5	15.0	20.0	35.0	55.0	**138.5**
Miles	*39.8*	*42.6*	*55*	*69.1*	*133*	***339.5***
Total Capital Investment	**55.3**	**68.0**	**95.6**	**134.6**	**189.6**	**543.2**

The proposed five-year investment levels for the System Cable, URD, and Breaker Replacement programs are below the amount of cost-effective investment identified through DTE's BCA

[142] Totals may not match exactly to the mathematical summation in the table due to rounding of the source data.
[143] Excludes Lancaster project, which adds approximately $7.2 million over the 2026–2028 period.

analyses. This indicates that the proposed portfolio for each of these three programs is well within the range of investment that delivers strong value to customers. Accordingly, the Company is proposing all three of these programs for IRM treatment, as discussed in Section 7.2.1 (Infrastructure Recovery Mechanism). As the Company ramps up these programmatic efforts to replace aging and deteriorated system equipment, it will evaluate the potential need for a more dedicated relay replacement approach, rather than continuing to address relay replacements within the existing Breaker Replacement program.

For Station Upgrade projects, the planned investment over the five-year DSP timeframe is $36 million for the three projects described above as shown in Exhibit 6.30.

Exhibit 6.30 – Investment Plan for Station Upgrade Projects, 2026-2030 ($ millions)

Project	2026	2027	2028	2029	2030	2026-2030 Total
Lincoln Station	-	-	-	0.5	2.0	**2.5**
Navarre Station	-	0.5	2.0	6.0	5.0	**13.5**
120 kV Relay Upgrades for ITC	3.0	3.5	3.5	5.0	5.0	**20.0**
Total Investment	**3.0**	**4.0**	**5.5**	**11.5**	**12.0**	**36.0**

Long-Term Outlook

Looking ahead, the System Equipment Replacement program will remain a foundational element of DTE's long term strategy to sustain safe, reliable, and resilient electric service across a deteriorating grid that is increasingly exposed to severe weather and other external stresses. As equipment continues to exceed its expected useful life and more frequent and intense storms impose greater electrical, mechanical, and operational demands, the Company's disciplined, condition-based replacement approach positions DTE to strengthen system resilience, systematically reduce major outage exposure, and manage lifecycle costs over time. By prioritizing the most critical and cost-effective investments, integrating asset health insights into long-term planning, and leveraging emerging technologies where appropriate, DTE is establishing a durable investment trajectory that balances near-term risk mitigation with long-term system performance. This sustained focus will be essential to maintaining grid operability, maintaining public and employee safety, and delivering measurable value to customers as system demands and weather volatility continue to evolve.

6.2.7 Substation Risk

Grid Needs

A resilient electric grid must maintain operational flexibility, respond effectively to equipment failures and unforeseen events, and restore service quickly, even under conditions that could otherwise result in a full substation outage. A single substation outage can affect thousands of customers and may take days to fully restore, depending on system configuration and available restoration options. In recent years, DTE has experienced several major events that resulted in significant, long-duration customer outages, driven largely by high-risk infrastructure and environmental vulnerabilities. In particular, failures associated with older switchgear and flooding at certain substations have increased operational risk, underscoring the need to address these vulnerabilities proactively.

The most recent example is the Lancaster substation fire that occurred in the summer of 2025. The Lancaster substation, located in Southfield, is a 13.2 kV facility with three transformers and two switchgear lineups, serving approximately 4,200 residential, commercial, and industrial customers. During the event, one switchgear unit failed, resulting in a fire. To maintain service, circuits were temporarily transferred to neighboring feeders, causing those circuits to operate above normal loading levels and outside DTE design standards. This event illustrates the systemwide consequences that can result from localized equipment failures and highlights the importance of strengthening substation resilience and operational flexibility. It also underscores the importance of designing redundancy into the distribution system — particularly for major substation equipment that can represent single points of failure and lead to extended duration outages affecting large numbers of customers.

Program Overview and Key Updates

DTE's substation outage risk model evaluates and ranks substations across its system to identify the most vulnerable locations and prioritize capital investments that reduce customer outage exposure. The model supports decision-making aligned with safety, reliability, and cost-effectiveness objectives, while enhancing transparency and consistency by applying uniform, risk-based evaluation criteria across the substation fleet. Under this approach, each substation is assigned a composite risk score based on two primary components:

- **Stranded Load at Peak (N-1 Contingency Exposure):** The amount of customer load that cannot be restored during peak demand conditions following the failure of a single critical substation component, such as a transformer, breaker, or switchgear, resulting in

the loss of service to all or a substantial portion of customers served by the substation. Because system demand is highest during peak periods, these failures can result in prolonged outages with significant customer impacts. Substations with limited ability to support portable substations or mobile equipment are prioritized, as an N-1 contingency at these locations may prevent timely restoration and lead to outages exceeding 24 hours. Stranded load under N-1 conditions therefore represents a significant reliability risk and is a key input to capital investment prioritization and scheduling.

- **Asset Condition Risk:** The condition-based probability of failure for four critical asset classes: system cables, transformers, breakers, and switchgear. These assets were selected because a single failure within any of them has the potential to interrupt multiple circuits simultaneously.

By combining stranded-load risk with asset-condition risk, the model produces a comprehensive risk profile for each substation. This information is used to identify and prioritize substations with the greatest vulnerability and highest potential customer impact.

Substation Risk projects focus on mitigating single-point-of-failure risks by replacing high-risk equipment, most commonly switchgear. Switchgear houses circuit breakers, protective relays, control wiring, and other devices that manage and protect multiple distribution circuits. Because multiple circuits often depend on a single switchgear lineup, the failure of a single breaker, cable, or internal component can interrupt several circuits at once, resulting in large-scale outages. Upgrading to modern, more reliable equipment significantly reduces the likelihood of multi-circuit outages and strengthens overall system resilience. Additionally, replacing a single large switchgear lineup with multiple smaller units limits customer impact if a failure does occur and improves operational flexibility.

An example of a project addressing substation outage risk is planned at the Company's Sterling substation in Sterling Heights. This substation has three transformers connected to a single straight-bus switchgear configuration — an outdated, non-standard design that creates a major single-point-of-failure risk for more than 10,000 customers. Planned upgrades will replace the straight-bus switchgear with a 12-position lineup, eliminating the single-point-of-failure risk while creating additional capacity to split heavily loaded circuits and support future customer growth.

Alternatives Analyses and Cost-Effectiveness

To ensure these investments are delivered cost-effectively and with minimal future disruption, DTE prioritizes completing other foundational substation work, such as below-grade

improvements and conduit installations, concurrently with Substation Risk projects. Coordinating this work during a single construction window avoids the need for repeated outages, shutdowns, and mobilizations, thus reducing both customer impacts and overall project costs. Close coordination with internal teams and external partners further enhances efficiency by aligning schedules and eliminating redundant work. In addition, early planning for resources, materials, and outage windows shortens construction timelines and minimizes disruption to customers.

The Company also operates several complementary programs that address substation risks at different scales, including System Equipment Replacement (described in the section above), System Loading projects to relieve overcapacity conditions (discussed in Section 6.3.2), and an expanded fleet of mobile generation, portable substations, and mobile switchgear to support restoration during equipment failure events, as described in Section 6.2.8 (Restoration Readiness and Community Resilience). A focused alternative analysis for Substation Risk projects evaluates composite risk scores from the substation outage risk model alongside these mitigation strategies to determine the best option that balances long-term system safety and reliability with cost-effectiveness. The primary determinant of solution scale is the number of customers affected and the amount of load stranded under a catastrophic failure scenario. While each program provides important benefits, they vary in scope, duration, and effectiveness, as summarized in Exhibit 6.31.

Exhibit 6.31 – Comparison of Substation Risk-Mitigation Programs

Alternative	Description	Pros	Cons
System Equipment Replacement	Replacement of at-risk equipment such as breakers and cable	• Provides direct, targeted risk reduction • Can be executed relatively quickly	• Limited to specific assets • Typically impacts smaller number of customers
System Loading	Projects to address system overcapacity and loading constraints	• Relieves substation load through load cascading • Delivers long-term system benefits	• Requires multi-year design and construction timelines • Does not mitigate near-term substation outage risk
Mobile Fleet	Expansion of mobile generation, portable substations, mobile switchgear	• Enhances DTE's ability to rapidly restore customers • Provides short-term operational flexibility and efficient repairs	• Does not reduce inherent substation outage risk • Increases operating costs due to mobilization, setup time, and equipment transport
Substation Risk	Reconfiguration of system and substation layouts to reduce single point of failure risks for substation level outages	• Major reduction in circuit level outages • Reduced long term maintenance burden • Safer for field personnel	• Significant construction coordination required • Physical space constraints • Long lead time for materials

Near-Term Investment

As shown in Exhibit 6.32, the near-term Substation Risk investment plan includes 10 projects totaling $65.0 million over the next five years, with brief descriptions provided for each project.

Exhibit 6.32 – Investment Plan for Substation Risk Projects, 2026-2030 ($ millions)[144]

Substation Risk Projects	2026	2027	2028	2029	2030	2026-2030 Total
Apache *GPM ranking of 48* The project will install two new switchgears to replace the at-risk 19-position switchgear, increase distribution capacity by rerouting circuits to parallel ducts, and improve overall operability.	1.9	-	-	-	-	**1.9**
Chestnut *GPM ranking of 31* The project replaces high-risk equipment, switchgear, eliminates a single point of failure, and adds 13.2 kV circuit positions to meet future load and reliability needs.	2.0	3.6	-	-	-	**5.6**
Flood Defense Program *GPM ranking of 109* The project includes installing and maintaining one-way backflow prevention valves, emergency dewatering pumps for ground-level discharge during sewer backup conditions, and sealed conduit penetrations at five substations (SCOTN, FRISB, WALKR, MADSN, and ORCHD), with an as-is risk analysis conducted for the MCGRW substation.	1.2	-	-	-	-	**1.2**
Hood *GPM ranking of 35* The project will decommission the skid-mounted substation and build a new 13.2 kV, two-transformer lineup at the HOOD site, adding redundancy and capacity from 13 MVA to 40.2 MVA for improved reliability and operability.	1.0	-	-	-	-	**1.0**
Lancaster *GPM ranking of 71* The project replaces both the damaged (from a fire) and aging switchgear and restores the substation to normal configuration while adding capacity to relieve overloading at nearby substations.	2.5	6.3	1.8	-	-	**10.5**
McGraw *GPM ranking of 80* The project will reconfigure McGraw 24/4.8 KV from a Class C substation into a Class A substation. The project will install a new (2) Transformer 24/4.8 kV substation with (1) 9-position switchgear, create 4 new circuit buses from the existing linkage bus, and decommission all damaged positions and equipment.	4.8	-	-	-	-	**4.8**
Savage Switchgear Replacement *GPM ranking of 56* The project will replace at-risk switchgear with two new PDCs to ensure substation operability and reliability is not compromised in the case of the switchgear failing.	0.1	1.5	6	5.5	-	**13.1**

[144] Totals may not match exactly to the mathematical summation in the table due to rounding of the source data. Projects with a GPM rank of 112 indicate that their benefits are not captured within the defined impact dimensions of the GPM and therefore receive a score of zero under the model.

Substation Risk Projects	2026	2027	2028	2029	2030	2026-2030 Total
Seville *GPM ranking of 13* The project is a class A station with a 7-position PDC switchgear serving three load circuits and one throwover. Position B is inoperable, forcing the SELVE DC 9364 load onto neighboring circuits. This project replaces the switchgear, transfers all circuits to new equipment, and restores SELVE DC 9364 to Seville substation.	-	-	0.1	1.5	5.0	**6.6**
Sterling *GPM ranking of 81* The project will build a new 120-13.2 kV general purpose class A substation to decommission at risk switchgear.	-	0.2	2	7.9	10.0	**20.1**
Waterman *GPM ranking of 109* The project will upgrade the DC system by relocating wiring onto accessible cable trays, transferring DC feeds, and abandoning grounded conductors.	0.2	-	-	-	-	**0.2**
Total	**13.7**	**11.6**	**9.9**	**14.9**	**15.0**	**65.0**

Project schedules reflect each substation's risk profile, resource availability, site-specific conditions, and other execution constraints that influence sequencing. Cost and schedule estimates are based on the best information available at the time of planning and may be refined due to unforeseen site conditions, supply chain constraints, permitting requirements, or new findings during detailed design and construction.

Long-Term Outlook

Looking ahead, proactive substation risk management will remain an important element of DTE's long-term resilience strategy. More frequent and severe weather is placing increasing stress on aging and vulnerable equipment, elevating both the likelihood and consequences of full-substation outages. At the same time, the continued electrification of homes and businesses means that service interruptions carry greater customer and system impacts than ever before. Together, these trends underscore the need for a deliberate, forward-looking approach to substation risk management to maintain reliable and resilient service in the years ahead. By integrating data-driven planning, cross-functional coordination, and robust alternatives analysis, the Company is strengthening its ability to manage substation risk efficiently and cost-effectively over the long-term.

6.2.8 Restoration Readiness and Community Resilience

Grid Needs

The MPSC has established restoration targets that DTE must meet under varying system conditions based on the percentage of customers affected.[145] These targets — ranging from eight hours during Normal conditions to 48 hours during Catastrophic conditions — serve as foundational benchmarks for service reliability and guide DTE's operational planning and resource deployment. Providing rapid and effective restoration of customer outages is a primary objective of distribution planning and a key focus of the DSP.

Achieving 48-hour restoration during Catastrophic conditions requires coordinated planning, clearly defined response frameworks, and scalable operational processes that can adapt to a wide range of operating conditions. To support this objective, DTE relies on three core processes: Weather Event Response and Restoration (detailed in Section 4.4.2), System Contingency Restoration, and Significant Event Activation. As part of the overall planning and preparation to recover from potential major catastrophic events, the Company recognizes that force majeure events may exceed planning criteria, resulting in extended outages for a subset of customers. To prepare for these situations, DTE proactively coordinates with local emergency services organizations across its service area as part of broader community resilience efforts, including support for sheltering and cooling or warming centers during extreme weather events. In addition, to support both contingency operations and significant event restorations, the Company maintains a robust fleet of portable equipment (Mobile Fleet) designed to temporarily replace grid functionality when permanent infrastructure is unavailable.

Together, these processes ensure the Company can respond effectively to both routine outages and large-scale disruptions while maintaining adequate system capacity and customer service levels. The latter two processes, System Contingency Restoration and Significant Event Activation, are particularly critical when the grid is operating outside normal conditions, including during non-storm emergencies such as substation fires, flooding, major equipment failures, or, in rare instances, a broader system blackout.

[145] See R 460.722 in Service Quality and Reliability Standards, available at https://ars.apps.lara.state.mi.us/AdminCode/DownloadAdminCodeFile?FileName=R%20460.701%20to%20R%20460.752.pdf, accessed March 12, 2026.

Program Overview

DTE's Resilience and Restoration Readiness program builds on the Company's existing Mobile Fleet investment category and expands its scope to more explicitly integrate the operational processes, planning frameworks, and portable resources required to restore service during abnormal system conditions. While the underlying assets and investments remain consistent with prior Mobile Fleet planning, this updated framing reflects the increasingly interconnected role of portable equipment, contingency planning, and coordinated response in meeting MPSC restoration requirements.

Portable substation trailer

The System Contingency Restoration process is activated whenever portions of the grid must operate in an abnormal configuration for an extended period, whether due to planned upgrades or unexpected equipment failures. The DTE system is designed to withstand the loss of a single component (N-1) with minimal customer impact. When such a condition occurs, engineers first assess outage duration and determine whether restoration can be achieved within eight hours. They then evaluate potential N 1-1 contingencies — secondary failures that could occur while the system is already compromised — and develop restoration plans to ensure customers can be returned to service within established MPSC targets. Restoration strategies prioritize switching and temporary circuit connections within the existing grid. When these options introduce unacceptable risks related to equipment overload or voltage instability, the Company deploys portable equipment to maintain service continuity. This proactive approach allows customers to remain connected wherever feasible, even during complex or extended system conditions.

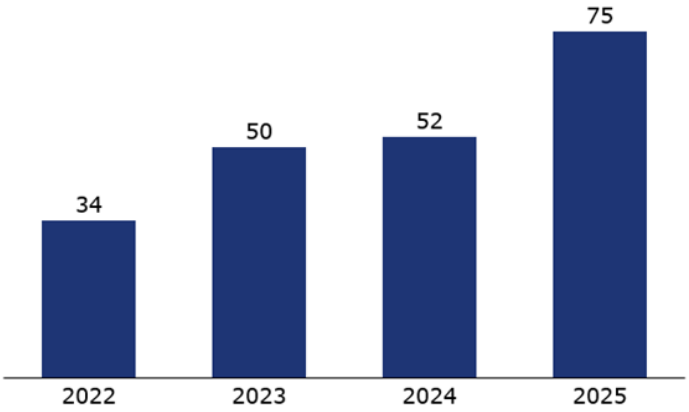
When a singular emergent event exceeds the ability of the ESOC to restore service within acceptable thresholds, DTE declares a "significant event" and activates its escalation protocol. Triggers including outages affecting more than 200 customers with restoration expected to exceed eight hours, complete de-energization of a substation, single-event outages impacting 5,000 or more customers, loss of major equipment or critical telecommunications, or threats to critical

customers or overall system reliability. Upon declaration, the ESOC initiates the FEMA ICS structure described in Section 4.4.2 (Weather Event Response and Restoration) to coordinate resources and restoration efforts, ensuring disciplined execution, clear communication, and efficient mobilization.

Once the ICS structure and key stakeholders are established, the ESOC transitions from declaration to coordinated action, initiating the structured communication and oversight processes required to manage the event effectively. Significant event calls serve as the central coordination mechanism, bringing together cross-functional teams to assess system conditions, establish operational objectives, evaluate restoration strategies, determine resource needs, develop estimated restoration timelines, coordinate customer support activities (such as community vans and warming or cooling centers), and align messaging across Corporate Communications, Customer Service, and Regional Relations. This integrated process strengthens DTE's ability to manage large-scale outages predictably and with a strong customer focus.

To support both contingency operations and significant event restorations, DTE maintains a robust fleet of portable equipment. The Mobile Fleet includes 13 diesel generators providing 25.3 MW of capacity and 12 isolation transformers totaling more than 45 Mega Volt Ampere (MVA), enabling temporary connectivity at 480 V, 4.8 kV, 8.32 kV, and 13.2 kV. The Company also operates five 1-MW load banks for generator testing and unbalanced load support, as well as 14 portable substations ranging from 5 MVA to 15 MVA. These substations can transform primary voltages of 24 kV, 40 kV, and 120 kV to secondary voltages or either 4.8 kV or 13.2 kV. Driven by an increasing number of significant system events and construction-related needs to minimize customer disruptions during system modernization, deployment of portable equipment more than doubled between 2022 and 2025, as shown in Exhibit 6.33.

Exhibit 6.33 – Deployment of Portable Equipment



The Significant Event Activation process also addresses rare but high-impact scenarios, including an Electrical System Blackout, loss of critical technology or communications systems, and significant loss of key staff (e.g., pandemic conditions). DTE maintains detailed Business Continuity Plans for these events, which are reviewed and exercised annually through scenario-based drills involving key stakeholders.

Near-Term Investment Outlook

Capital and O&M investments required to maintain the Mobile Fleet and support Restoration Readiness and Community Resilience are shown in Exhibit 6.34. Capital investments in years 2026 and 2027 include $3.5 million and $2.0 million, respectively, to develop dedicated sites for storing portable substations. Remaining capital funds support the expansion and modernization of portable equipment and diesel generators. O&M expenditures cover compliance inspections and ongoing maintenance necessary to maintain the fleet's operational readiness.

Exhibit 6.34 – Investment Plan for Mobile Fleet, 2026-2030 ($ millions)

Mobile Fleet	2026	2027	2028	2029	2030	2026 - 2030 Total
Capital	5.0	4.0	1.5	1.5	1.5	**13.5**

Long-Term Outlook

As aging infrastructure converges with increasingly severe weather, restoration readiness and a well-maintained Mobile Fleet will remain vital to DTE's long-term reliability and resilience strategy. Through the Restoration Readiness and Community Resilience efforts, the Company is strengthening both its physical restoration capabilities and the operational processes required to deploy them efficiently and effectively during abnormal system conditions, while actively partnering with local community emergency services to enhance community resilience and accelerate recovery from catastrophic events.

New technologies, such as the mobile battery trailers, will be evaluated and integrated into the fleet as capabilities mature and use cases are proven. Additional emerging technologies will continue to be assessed to improve restoration speed, flexibility, and efficiency. While major new equipment purchases are not currently forecast, incremental investments in portable resources may be pursued in future years as system needs evolve and restoration requirements change.

6.3 Redesign and Modernization

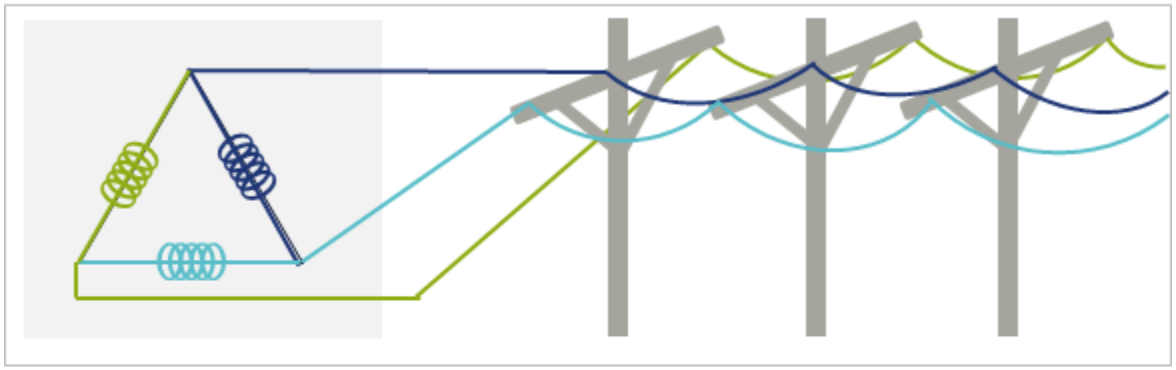
In addition to protecting and strengthening its existing infrastructure, the Company must continue to modernize its grid and digitize operations to ensure reliability improves even as the grid grows more complex. Large portions of DTE's grid were built many decades ago and were not designed to accommodate today's higher loading, more frequent and severe weather events, or the growing adoption of EVs and DERs. Redesign and Modernization — the third investment pillar — addresses these persistent constraints and legacy configurations through targeted investments such as 4.8 kV and 8.3 kV Conversions, System Loading, and Subtransmission Redesign and Rebuild projects. These investments provide more efficient long-term solutions by optimizing system configurations, adding jumpering and sectionalization devices, and creating capacity headroom for economic growth. In certain circumstances, NWAs can be deployed to defer or replace traditional infrastructure upgrades while still relieving capacity constraints. Collectively, this section describes how the Company is deploying these strategic redesign initiatives and systemwide modernization efforts to build the grid of the future — one that is smarter, stronger, and better equipped to meet evolving customer needs.

6.3.1 4.8 kV and 8.3 kV Conversions

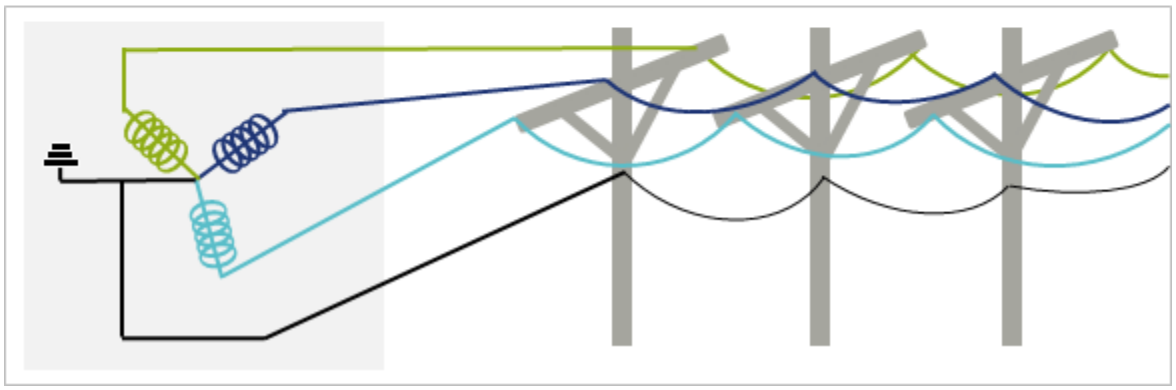
DTE operates a large and geographically dispersed 4.8 kV distribution system, as described in detail in Section 4.1 (Subtransmission and Distribution System Overview). Approximately 15% of this infrastructure — roughly 2,000 miles — is located within the City of Detroit, with the remainder spread across the service area. Much of the system was designed nearly a century ago during the early electrification of the City of Detroit and surrounding communities, based on standards applicable at the time. Those standards included an ungrounded, three-phase delta configuration with no neutral conductor. As a result of this design, when a single conductor comes down on a 4.8 kV circuit, it can remain energized until it is addressed by the Company, creating a potential public safety hazard. More modern wye designs, by contrast, use a grounded four-wire configuration with three phase conductors and a neutral. In most cases, this grounded design eliminates the hazard associated with an energized downed conductor. Exhibit 6.35 illustrates the differences between legacy 4.8 kV and modern 13.2 kV design configurations.

Exhibit 6.35 – 4.8 kV and 13.2 kV Design Configurations

4.8 kV Ungrounded Delta 3 - Wire System



13.2 kV Grounded Wye 4 - Wire System



The ungrounded delta design was originally intended to deliver improved system reliability and fewer interruptions through the use of “4.8 kV rings,” consisting of multiple paralleled sections of primary circuits and banked secondary systems. However, the primary conductors used in this legacy system consist largely of small wire, discussed in Section 6.2.4 (Small Wire Replacement), which has lower mechanical strength than modern conductor designs. The ring configuration enables bidirectional power flow within each ring, complicating the application and coordination of protective devices. In addition, customers located near the end of 4.8 kV circuits can experience significant voltage drops when substantial load is tapped near the circuit origin. To mitigate these impacts, long, untapped overhead segments — referred to as “4.8 kV feeders” — were constructed to deliver power directly to load centers and reduce voltage-drop concerns.

Because of the lower operating voltage of the 4.8 kV system, a greater number of circuits are required to serve a comparable geographic area than would be needed under a higher-voltage system such as 13.2 kV. Combined with the feeder and ring design characteristics, this has resulted in multiple circuits being installed on the same pole line. This practice elevates system

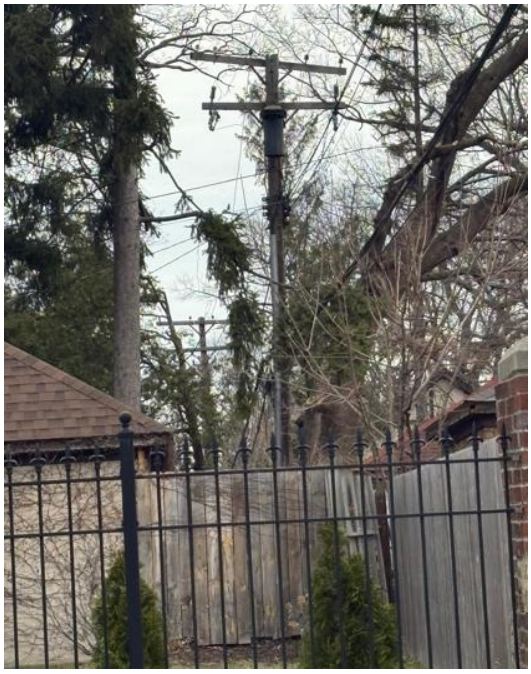
risk, as a single wire-down event on one circuit can mechanically or electrically affect adjacent circuits, resulting in concurrent outages. The consequence is an increased likelihood of multi-circuit service interruptions, broader customer impact, and potentially heightened safety hazards for both workers and the public.

The lower 4.8 kV operating voltage also drives the need for additional substations, as it typically takes two to four 4.8 kV substations to serve the same load as a single 13.2 kV substation. As a result, DTE must operate and maintain significantly more substations and associated equipment (such as breakers) in 4.8 kV areas, increasing both preventive and corrective maintenance requirements. Additionally, because 4.8 kV substations have lower capacity than 13.2 kV substations, these lower-voltage substations and circuits are more susceptible to overloading as load grows in the areas they serve. Currently, approximately 17% of 4.8 kV and 8.3 kV substations exceed their firm ratings, and 16% of the circuits exceed the Company's DDO limits. If the Company does not take action to begin increasing capacity at these locations, overload conditions are projected to worsen, with 32% of substations exceeding their designed loading limits by 2040 due to the long lead times associated with placing capacity investments into service. Areas experiencing multiple overloaded substations and circuits are therefore strong candidates for conversion to 13.2 kV. Failure to address these overloaded substations can result in lengthy outages due to stranded load, an inability to serve new load requests, and delay the interconnection of DER technologies.

Additionally, DTE historically utilized a banked secondary design, which was an industry standard at the time the 4.8 kV network was constructed. This design interconnects multiple transformers through secondary fusing to serve a local area. While originally intended to improve service continuity, this configuration complicates troubleshooting for field crews and is no longer included in the Company's current design standards. When a secondary fuse operates, customers downstream may experience low-voltage conditions, which can lead to cascading transformer failures and an increased likelihood of secondary wire-down events. Compounding these risks, a significant portion of the Company's secondary conductors are open-wire construction, consisting of individual conductors supported on insulator racks rather than modern, more robust multiplexed configurations with an ACSR messenger neutral. This open-wire construction increases exposure to outages from foreign-object contact and results in higher breakage rates during wind and ice events, elevating potential safety risks for both field personnel and the public.

Another distinguishing feature of the 4.8 kV system is the presence of 4.8 kV pockets served by 13.2 kV substations, referred to as ISO-down areas, which comprise approximately 35% of the

4.8 kV system. ISO-down segments experience the same safety, reliability, and capacity challenges as circuits fed directly from 4.8 kV substations. Section 4.1 (Subtransmission and Distribution System Overview) provides maps of DTE's distribution system across each operating voltage level.



Legacy 4.8 kV rear-lot construction in Detroit

Over time, aging infrastructure, rear-lot construction, and subsequent configuration changes have further degraded system performance.[146] Much of the 4.8 kV infrastructure has exceeded its industry-recognized useful life, increasing the risk of equipment failure and unplanned outages. Many circuits were originally constructed as rear-lot overhead lines to preserve neighborhood aesthetics, relying on alley access that has become increasingly unreliable due to declining municipal alley maintenance and the City of Detroit's practice of vacating alleys to private property, which is often subsequently built into by new property owners. These changes have encumbered utility access and complicated routine maintenance, emergency response, and restoration activities. As a result, the system no longer operates as originally intended and its legacy design and operating characteristics now present increasing safety, operational, and reliability risks.

Conversions Strategic Framework

While interim measures such as Vegetation Management, PTMM, 4.8 kV Hardening, and Distribution Automation have improved the performance of the 4.8 kV system, their effectiveness is inherently limited by the system's legacy design characteristics described above. As a result, 4.8 kV and 8.3 kV Conversions remain the most comprehensive, long-term grid modernization strategy. Converting to a standard voltage of 13.2 kV provides greater capacity, enables the use of larger and stronger primary and secondary conductors, improves reliability performance, strengthens resiliency through compatibility with neighboring circuits, and supports advanced automation with FLISR capabilities.[147] Conversion also allows the Company to retire large

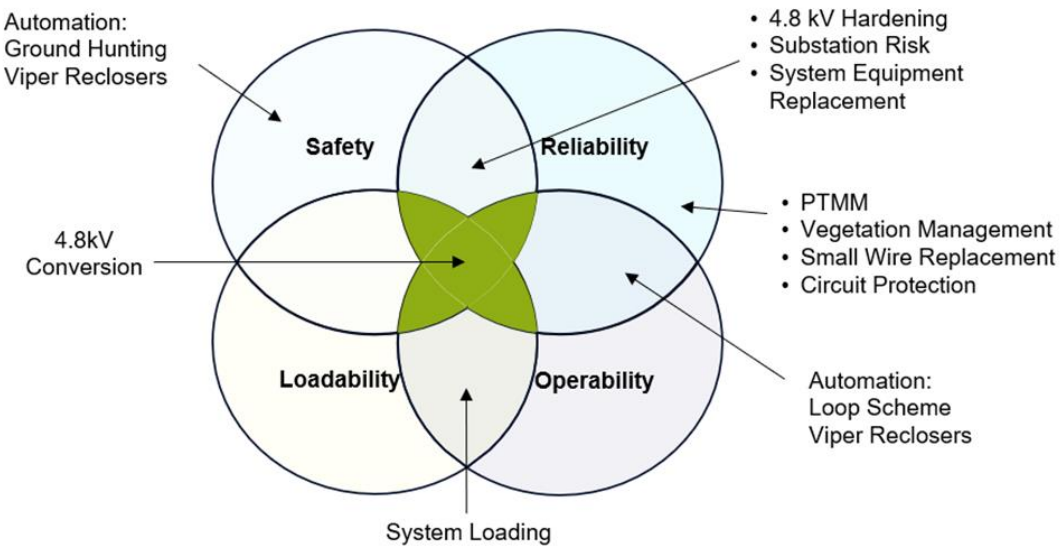
[146] An example configuration change includes updates to de-parallel primary and secondary leads to approximate a grounded wye system and accommodate additional protective devices.

[147] FLISR is an industry acronym for Fault Location, Isolation, and Service Restoration. See Section 6.4 (Technology and Automation) for additional discussion of FLISR functionality and associated customer benefits.

amounts of aging and higher-risk substations and equipment, as a single 13.2 kV substation can eliminate two to four 4.8 kV substations. This consolidation enables the decommissioning of obsolete assets — including associated subtransmission facilities — thereby reducing long-term maintenance requirements and operational risk.

However, a full system conversion from 4.8 kV to 13.2 kV is estimated to cost approximately $28 billion and would require more than 100 years to complete at current investment levels. Accordingly, planning protocols and strategic prioritization are necessary to balance system performance improvements with customer affordability. To guide these decisions, DTE applies a structured framework that evaluates a full range of solution alternatives for each substation area based on four primary project drivers: safety, reliability, operability, and loadability, which is the maximum load that a distribution system can serve before an electrical or operational constraint violation is encountered. The presence of one or two drivers alone does not necessarily warrant near-term conversion as there are often sufficient, cost-effective alternatives available, as summarized in Exhibit 6.36.

Exhibit 6.36 – General Overview of Project Drivers and Associated Solutions[148]



When three or more project drivers are present, conversion is necessary to best serve customers over the long term. Depending on local conditions, the Company may pursue one of two conversion paths: full conversion or source conversion with 4.8 kV ISO pockets. In addition, 13.2 kV circuits with existing 4.8 kV ISO pockets will be evaluated for conversion when elevated

[148] Programs that are depicted are aligned generally to main drivers and may not always fully align to this overview.

reliability issues are present. Each option reflects a different balance of scope, cost, and operational impact. A summary of these approaches, including their respective advantages and limitations, is provided in Exhibit 6.37 below.

Exhibit 6.37 – Overview of Conversion Options

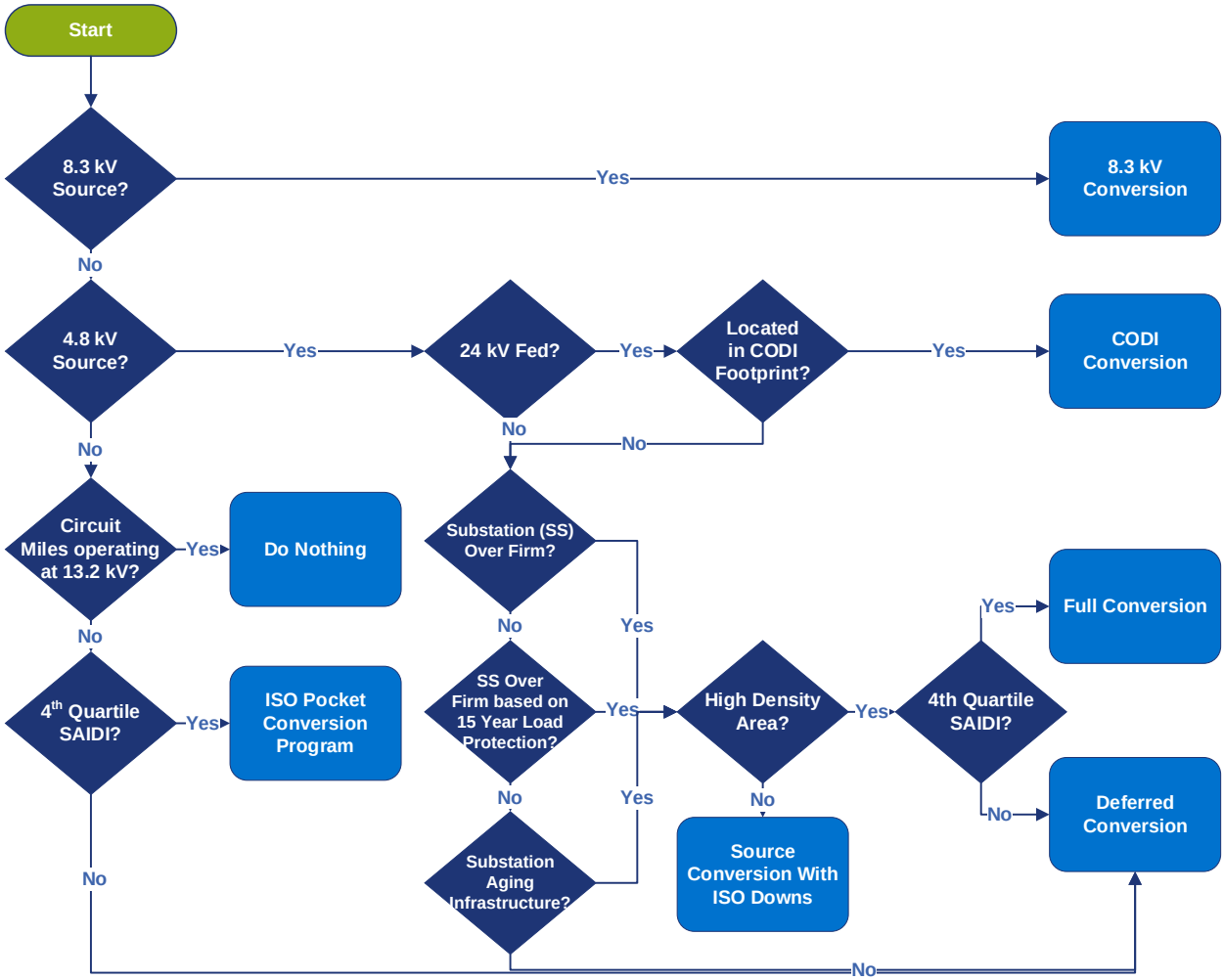
Level	Scope	Pros	Cons
Full Conversion	New 13.2 kV source substation as well as conversion of 4.8 kV circuits to operate at 13.2 kV	Addresses all drivers of safety, capacity, reliability, and operability	• Most costly and longest execution • Best suited for areas of high customer density and groups of 4.8 kV substations with multiple challenges
Source Conversion with ISO Pockets	New 13.2 kV source substation as well as partial conversion of 4.8 kV circuits to operate at 13.2 kV. The remainder of each circuit operates at 4.8 kV via new ISOs.	Less costly and faster to implement where capacity or aging substation infrastructure is the main driver	• Only feasible in areas of low customer density due to low transformer ratings • Does not address circuit safety or reliability issues • Can cause operability issues by limiting ability to jumper ISO down sections of circuits
ISO Pocket Conversion (ISO Down)	Conversion of existing 4.8 kV ISO pockets to operate at 13.2 kV	Addresses safety and reliability issues in existing ISO pockets	• High cost for areas of low customer density

To consistently apply this framework, DTE's Planning Engineering team developed qualifying parameters to identify the appropriate conversion category for each substation area. These parameters incorporate project drivers, customer density, cost effectiveness, and feedback from the Audit Report. Using circuit one-line diagrams, satellite imagery, and prior project experience, the team grouped 4.8 kV substations into conversion categories according to the following qualifying criteria:

- **Full Conversion Candidates:** High-density areas with aging infrastructure, poor reliability, and current or projected capacity constraints.
- **Source Conversion Candidates:** Low-density areas where 4.8 kV source substations are over firm, aging, and expected to exceed capacity within a 15-year planning horizon.
- **ISO Pocket Conversion Candidates:** Areas served from 13.2 kV source substations that include ISO-down segments with poor reliability performance, as measured by a five-year average fourth-quartile reliability rating.
- **Deferred Conversion:** Areas with one or two near-term drivers that are better suited for interim solutions or longer-term planning.

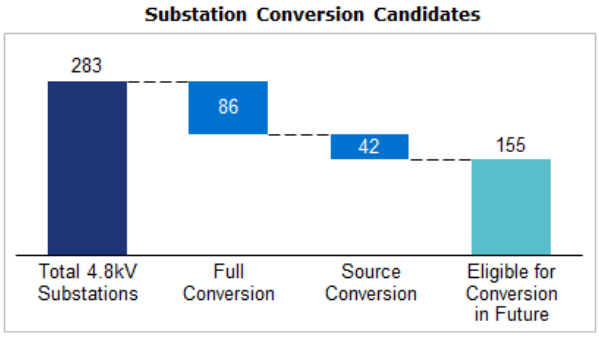
The resulting decision tree used to evaluate and categorize conversion initiatives is illustrated in Exhibit 6.38.

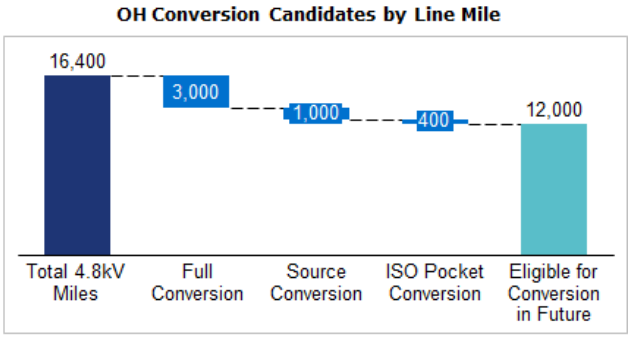
Exhibit 6.38 – Decision Tree for 4.8 kV and 8.3 kV Conversion Tiers



The conversion segmentation derived from this framework is presented in Exhibit 6.39.

Exhibit 6.39 – DTE 4.8 kV Conversion Tiered Approach



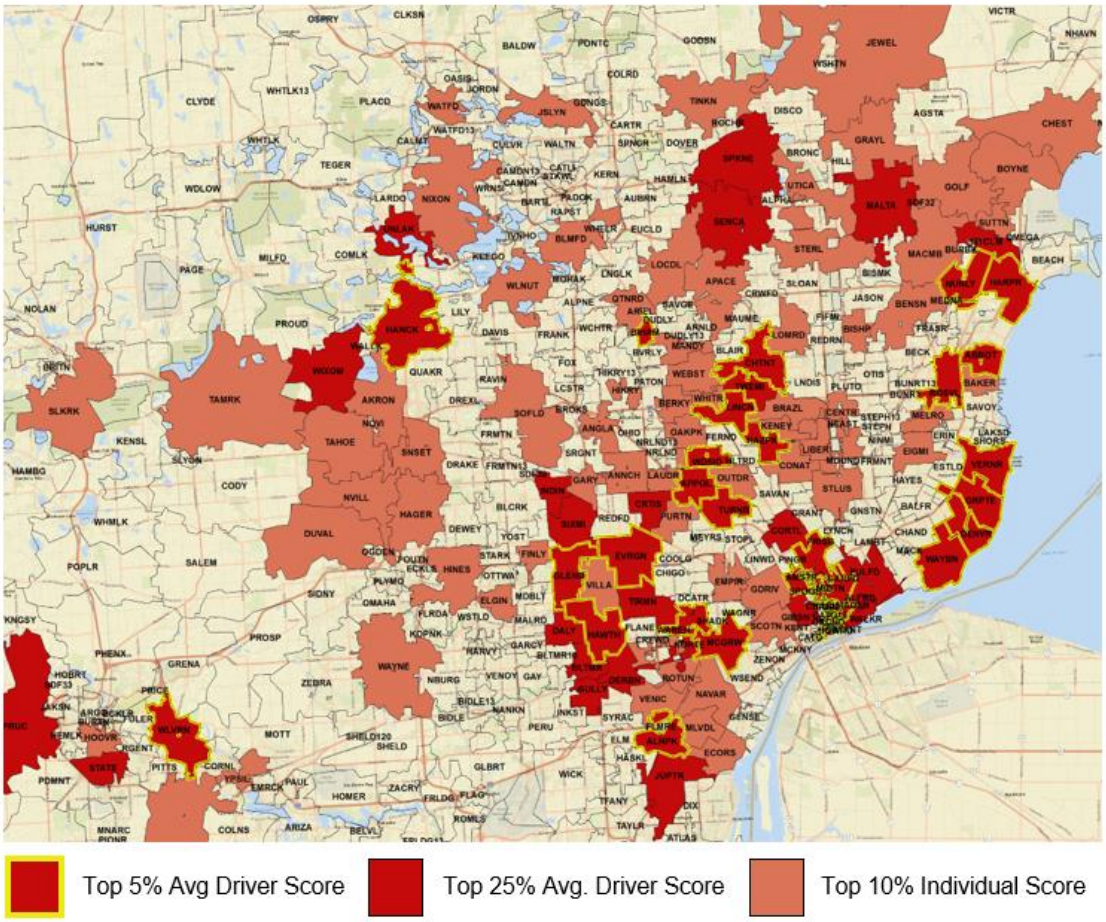


The non-deferred conversion portfolio includes all conversion projects initiated over the past 10 years, many of which are already underway or nearing completion. This portfolio represents approximately $9 billion in investment over a 15- to 25-year horizon. Near-term focus areas, described in more detail below, include the City of Detroit Infrastructure (CODI) program in Detroit, other full 4.8 kV conversions driven primarily by capacity constraints, and the 8.3 kV system conversion in Pontiac. ISO pocket conversions are generally deferred in the near term to allow greater investment in PTMM, Vegetation Management, 4.8 kV Hardening, and Distribution Automation to address immediate safety and reliability needs.

Conversion work in Wayne

As near-term projects are completed, DTE will refresh and reprioritize the remaining conversion candidates using its GIS-based area planning tool. This tool visualizes substation area needs based on four key project drivers: safety, reliability, loadability, and operability. Engineers score each substation area against these criteria, which are combined into a weighted average score to support consistent and transparent prioritization. As shown in Exhibit 6.40, substations ranking in the top 25% of the weighted average scores are highlighted in dark red, with the top 5% further outlined in yellow. Additionally, substation areas ranking in the top 10% for any individual project driver — representing the worst 55 substations in that category — are highlighted in light red. The tool also reflects substation areas addressed through other programs, such as PTMM, Vegetation Management, or 4.8 kV Hardening, which are intentionally not highlighted. DO Engineering uses this visual framework to group geographically proximate issues and identify opportunities for strategic, coordinated projects as part of its ALA process, described in Section 5.1 (Load Forecast and Scenario Planning). Consistent with the ALA process and using this visual tool, deferred conversion projects will be reevaluated as conditions evolve and new drivers emerge. Source-conversion candidates driven primarily by loading constraints may also be evaluated for potential NWAs, as outlined in Section 6.3.4 (Non-Wire Alternatives).

Exhibit 6.40 – GIS Area Planning Tool



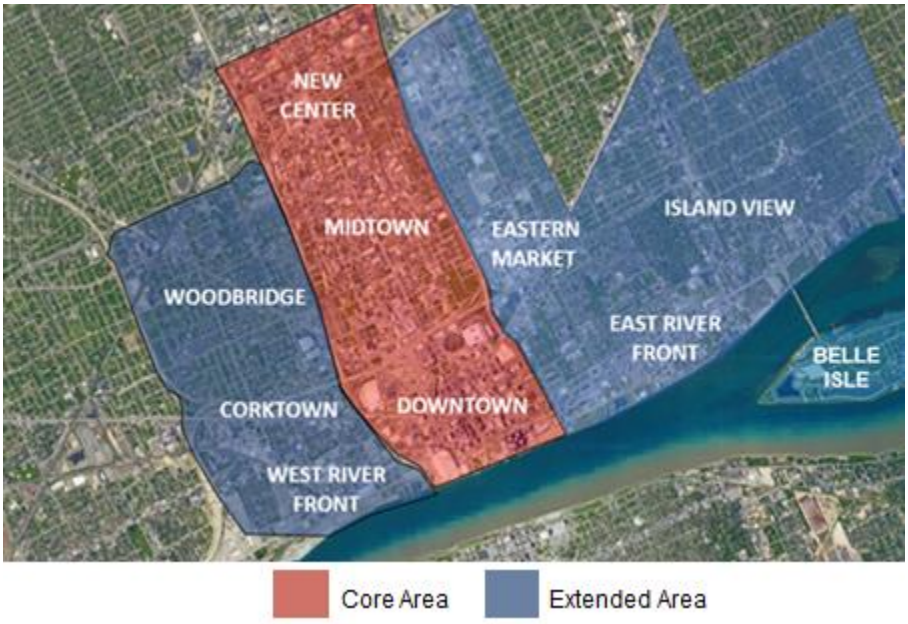
CODI Program

As discussed in Chapter 4 (State of the System and Additional DSP Requirements) and above, the electric grid serving Detroit's inner core was constructed in the early 20th century and is unique relative to other parts of the Company's grid. This area includes an extensive network of underground primary and secondary cables routed beneath streets and through manholes, which significantly increases the complexity of operations, maintenance, and system upgrades. Today, this area is also at the center of Detroit's economic resurgence, supporting growth across Michigan's economy. It serves approximately 31,800 customers, including hospitals, federal and municipal emergency centers, multiple corporate headquarters, and major entertainment venues, making reliability and capacity particularly critical.

The CODI program was initiated in 2015 as a comprehensive, phased effort to rebuild aging infrastructure and modernize system design within Detroit's highly complex and constrained downtown environment. The program is intended to improve reliability, increase capacity, and

better align the system with current and anticipated load growth and customer expectations. The geographic footprint of the CODI program is shown in Exhibit 6.41.

Exhibit 6.41 – CODI Footprint and Extended Area



As illustrated in Exhibit 6.41, the CODI Program's "core area" includes the Downtown, Midtown, and New Center areas of Detroit, bounded by Grand Boulevard to the north, I-75 to the east, the Detroit River to the south, and the M-10 Lodge highway to the west. The core area's 4.8 kV distribution system is fed by a 24 kV subtransmission system that also feeds substations outside the core area, which predominantly support overhead distribution load. To fully enable the decommissioning of the 24 kV system within the core area, the CODI program has been extended to include surrounding substations in the "extended area." The extended area includes Eastern Market, Corktown, Woodbridge, Islandview, Belle Isle, and the West and East riverfronts.

The CODI program consists of multiple, interrelated projects, including:

- Redesign in 2015 of two planned Class A substations into a new 120 kV-13.2 kV Class S AC Network substation design (Temple and Stone Pool) to support future Network conversions within the CODI footprint
- Construction of two new 120 kV-13.2 Class A substations (Corktown and Islandview)
- Expansion of three existing 120 kV-13.2 kV substations (Midtown, Alfred, and Cato)

- Decommissioning of nine 24 kV-4.8 kV substations (Charlotte, Walker, Howard, Kent, Gibson, Garfield, Amsterdam, Madison, and Orchard), among the oldest substations in the DTE system
- Conversion and consolidation of the AC network from 4.8 kV to 13.2 kV
- Conversion and consolidation of associated overhead circuits from 4.8 kV to 13.2 kV
- Decommissioning of the aging 4.8 kV all-underground distribution system and the 24 kV subtransmission system

Executing upgrades within the CODI footprint requires complex system shutdowns in a congested downtown district serving numerous critical customers. As a result, grid investment work in this area has been carefully planned and sequenced to minimize disruption while maintaining service to essential facilities. Since the program's inception, substantial progress has been made beyond the network secondary cable replacement program. Completed work includes the commissioning of four new 120-13.2 kV substations (Temple, Stone Pool, Corktown, and Islandview), the expansion of one existing 120-13.2 kV substation (Midtown), DTE's first AC Network conversion from 4.8 kV to 13.2 kV (Charlotte), and approximately 100 miles of pre-conversion or conversion work in the Garfield, Kent, and Islandview areas of Detroit.

Islandview substation

Other 4.8 kV Conversion Projects

The remaining near-term 4.8 kV Conversion projects focus on full conversion of 4.8 kV circuits served by 4.8 kV substations outside of the CODI geographic area. These projects address critical capacity constraints in locations where multiple substations are overloaded and traditional load-transfer options have been exhausted. While the 4.8 kV system can technically support EVs and DERs, many circuits already operate near thermal and voltage limits, making the additional load and operational complexity associated with EV and DER adoption increasingly difficult to accommodate. Continued load growth heightens the risk of overheating equipment and unacceptable service level voltage drops.

Converting these areas to a higher primary operating voltage of 13.2 kV increases system capacity, enables the use of larger and stronger conductors, reduces voltage drop, and improves overall reliability. These projects introduce new 13.2 kV feeder sources, rebuild circuits to modern design standards, add automation, and retire legacy 4.8 kV infrastructure. Collectively, these upgrades deliver increased capacity and public safety benefits while establishing a hardened, automated network that enhances reliability, power quality, resiliency, and operational flexibility — better positioning the system to support future electrification and evolving customer demands.

The Pontiac 8.3 kV Project

Similar to the challenges addressed through 4.8 kV Conversions, 8.3 kV Conversions are another near-term focus area. DTE did not originally construct the City of Pontiac's 8.3 kV distribution system as it was acquired from Consumers Energy in the 1980s. Today, the system is supplied by three aging substations — Bartlett, Rapid Street, and Stockwell — and serves approximately 5,000 customers across 11 distribution circuits. Two of the three substations rank in the fourth quartile for SAIDI performance. The system was previously supplied by the Paddock substation, which has been decommissioned, further reducing operational flexibility.

Because the 8.3 kV voltage is unique within DTE's system, the Pontiac network operates as an electrical island with limited contingency support from surrounding areas at standard system voltages. The system relies on obsolete, non-standard equipment, creating an elevated risk of stranded load during equipment or substation outages. For example, during a transformer failure, the entire Bartlett substation area impacting 3,100 customers had to be islanded on diesel generators. Non-standard clearance distances between equipment also present safety hazards for personnel and require full substation outages to perform routine maintenance, resulting in extended customer interruptions and prolonged abnormal system conditions. In addition, the need for specialized crew training to support the unique voltage and equipment increases O&M expenses. These challenges are compounded by continued load growth in the Pontiac area over the past decade.

To address these issues and better support customers and field personnel, DTE developed a phased conversion plan beginning with upgrades to unsafe underground vaults. These vaults contained live-front equipment, offered inadequate arc-flash clearances, and required work in confined underground spaces, increasing overall safety risk. While the vault upgrades were completed in 2023, the Company is continuing construction to transition commercial customers to the upgraded vault system. In parallel, DTE is finalizing implementation of an automated

switching scheme that uses SCADA-enabled switches installed in each vault to isolate cable failures and restore customers without manual field intervention. This remaining work is expected to be completed in 2026.

Subsequent circuit conversions will transfer load to a new substation adjacent to the existing site. These conversions require upgrades to all customer services currently supplied by 8.3 kV-rated underground equipment, including the replacement of customer-owned switchgear, fuses, transformers, and cables rated below 15 kV. Upon completion of this work, the three remaining 8.3 kV substations will be decommissioned by 2029. In addition, upgrades at the Wheeler substation will enable load to be transferred off Bloomfield substation, allowing that facility to be decommissioned and removing its at-risk switchgear from service.

Cost Effectiveness and Process Improvements

DTE partnered with a third-party consultant to conduct BCAs on 4.8 kV and 8.3 kV Conversions projects with a more significant scope as described in Section 5.2.3 (Benefit-Cost Analyses Approach). The resulting BCRs for projects meeting these criteria are presented in Exhibit 6.42. While the BCA framework is designed to quantify monetized benefits and does not fully capture certain safety-related and operational benefits associated with conversions, the results nevertheless indicate positive net benefits for a substantial portion of the evaluated portfolio. Additional detail regarding BCA assumptions, methodology, and project-level results is provided in Appendix 8.14 (Benefit-Cost Analysis Report).

In addition to the BCA evaluation, project-level GPM rankings were also developed for 4.8 kV and 8.3 kV Conversions, as described in Section 5.2.4 (Global Prioritization Model). Exhibit 6.42 includes GPM rankings for in-scope projects.

In parallel, DTE is actively implementing process improvement strategies to enhance execution efficiency and reduce overall program costs across the Conversions portfolio. These efforts include streamlining permitting activities to avoid schedule compression, piloting improved scheduling and coordination practices to optimize workflow and construction sequencing, and developing standardized design packages for contract designers to improve consistency, reduce rework, and shorten review and approval cycles. The Company is also conducting constructability reviews to ensure designs can be constructed safely and efficiently, performing early easement validation to minimize property-related delays, and refining its contracting approach to better manage project risk and prevent cost overruns. In addition, DTE will continue to evaluate new

equipment, technologies, standards, and construction methodologies to provide the most efficient use of resources while minimizing customer disruption.

Near-Term Investment Outlook

A summary of the Company's planned investment in Conversions projects, informed by the Conversions Strategic Framework, BCA, and GPM results, is provided in Exhibit 6.42.

Exhibit 6.42 – Investment Plan for 4.8 kV and 8.3 kV Conversions, 2026-2030 ($ millions)[149]

Conversions Projects	2026	2027	2028	2029	2030	2026-2030 Total
4.8 kV CC: Almont Relief and Circuit Conversion (Midas OH) *GPM ranking of 91* This project will build a new 120-13.2 kV Class R substation to relieve existing overloads, increase capacity, and convert 4.8 kV Almont substation.	0.8	-	-	-	-	**0.8**
4.8 kV CC: Ann Arbor AC Network Conversion *BCR of 1.31; GPM ranking of 61* This project is to upgrade an existing substation from 40-4.8 kV to 40-13.2 kV and will enable the modernization of Ann Arbor AC Network system, providing the necessary infrastructure for enhanced load capability, operational flexibility, and long-term grid resilience.	5.0	11.0	22.5	17.5	21.0	**77.0**
4.8 kV CC: Barber Substation and Circuit Conversion *BCR of 0.43; GPM ranking of 38* This project will construct a new 120-13.2 kV Class A substation (TENMI) to relieve existing circuit overloads, convert and decommission (1) 4.8 kV substation. The project converts and consolidates distribution circuits from (5) nearby substations and decommissioning a 24 kV trunk line.	-	-	-	1.9	12.5	**14.4**
4.8 kV CC: Belleville Substation and Circuit Conversion *BCR of 1.30; GPM ranking of 60* This project incorporates full conversion, consolidation, and decommissioning of the remaining 4.8 kV facilities at the BELVL Class "T" substation, including the two associated 4.8 kV circuits. The upgraded equipment, together with the existing 13.2 kV assets, will be integrated to establish a new 120-13.2 kV Class "R" substation.	0.3	1.5	4.5	7.0	6.0	**19.3**

[149] Totals may not match exactly to the mathematical summation in the table due to rounding of the source data. Projects with a GPM rank of 112 indicate that their benefits are not captured within the defined impact dimensions of the GPM and therefore receive a score of zero under the model.

Conversions Projects	2026	2027	2028	2029	2030	2026-2030 Total
4.8 kV CC Birmingham Decommissioning and Circuit Conversion *GPM ranking of 41* This project will construct a new 120-13.2 kV Class A substation to convert and decommission (3) 4.8 kV substations within the Birmingham and Troy areas.	4.2	-	-	-		**4.2**
4.8 kV CC: Buckler Circuit Conversion *GPM ranking of 65* This project will complete the 4.8 kV circuit conversions at the Argo substation by transferring all remaining circuits onto the existing 40–13.2 kV Buckler transformer. Upon completion of these conversions, the Argo substation will be fully decommissioned.	3.9	3.0	-	-	-	**6.9**
4.8 kV CC: Calla Circuit Conversion Phase 2 *BCR of 1.61; GPM ranking of 36* This project utilizes newly constructed 120/13.2 kV Class T substation to relieve existing overloads at Diamond substation, improve reliability, and operability in the Dexter Township area.	4.0	3.5	-	-	-	**7.5**
4.8 kV CC: CAMDN Decommissioning *GPM ranking of 109* Project is to decommission CAMDN 4.8kV substation.	1.4	0.1	-	-	-	**1.5**
4.8 kV CC: Fairgrove *GPM ranking of 84* This project proposes a new 40-13.2 kV pad-mount STDF near a business location, and an extension of TIE3318 to feed the new STDF. This project will provide capacity for future load growth and will transfer 1.2 MVA of load relief for FGROV DC302.	-	-	3.5	-	-	**3.5**
4.8 kV CC: Grosse Pointe Substation and Circuit Conversion – South *BCR of 1.27; GPM ranking of 30* This project is driven by safety, reliability, loadability, and operability and includes constructing a new 120 kV-13.2 kV Class A substation to convert 4.8 kV Wayburn and Denver substations along with their associated 24 kV cable.	1.0	4.3	14.0	28.4	43.0	**90.7**
4.8 kV CC: Hawthorne Relief and Circuit Conversion *BCR of 0.71; GPM ranking of 28* The first phase of this project is to expand an existing 13.2 kV Mallard substation to relieve circuit overloads from Hawthorne and convert and decommission (1) 4.8 kV substation.	13.4	11.9	21.2	34.8	30.5	**111.7**

Conversions Projects	2026	2027	2028	2029	2030	2026-2030 Total
4.8 kV CC: Hemlock Decommissioning and Circuit Conversion *BCR of 0.57; GPM ranking of 57* This project will construct a new 40/13.2 kV Class A substation to relieve existing overloads, improve reliability, operability and increase capacity in the Ann Arbor area which will ultimately result in the decommissioning of (1) 4.8 kV substation.	0.8	5.3	12.0	12.0	18.6	**48.7**
4.8 kV CC: Hilton Substation and Circuit Conversion - Phase 2 *BCR of 1.15; GPM ranking of 45* The HLTRD project will increase operability, capacity, and reliability for commercial and residential customers in the Ferndale, Hazel Park, Pleasant Ridge, Royal Oak Charter Township, and Oak Park area.	6.3	19.3	13.3	10.0	10.4	**59.2**
4.8 kV CC: I-94 Substation and Circuit Conversion (Promenade) *BCR of 2.15; GPM ranking of 27* This project will construct a new 120-13.2 kV Class A substation to relieve existing overloads, improve reliability, operability and increase capacity in the I-94 Industrial Park region. This will enable the decommission of (3) 4.8 kV substations.	20.6	18.7	23.5	22.6	13.5	**98.9**
4.8 kV CC: ISO Conversion Program *GPM ranking of 47* 4.8kV ISO down circuits are already fed from a 13.2kV substation which removes the substation firm rating and the substation risk ranking from prioritization consideration. Additionally, a new substation source is not needed to complete conversion. Without the need to consider substation factors, safety (wire-down reduction), reliability (customer minute interruptions), and costs (avoided O&M and capital) become the driving factors for prioritization of 4.8kV ISO-down circuits.	7.9	-	-	-	-	**7.9**
4.8 kV CC: Melvindale *GPM ranking of 43* This project is to obtain property to construct a new 120-13.2 kV Class A substation for future circuit conversion work in the Allen Park area.	2.3	-	-	-	-	**2.3**
4.8 kV CC: New Baltimore *BCR of 0.40; GPM ranking of 75* This project will construct a new 40-13.2 kV Class A substation to relieve existing overloads, improve reliability, operability, and increase capacity in the New Baltimore area and decommission (1) 4.8 kV and (1) Class R 13.2 kV substation.	8.5	15.6	13.8	10.0	9.8	**57.7**
4.8 kV CC: Northville Substation 4.8 kV Removal Northville 4.8 kV substation was decommissioned in 2018. This project is to fully decommission and remove all equipment associated with the 4.8 kV site.	1.2	-	-	-	-	**1.2**

Conversions Projects	2026	2027	2028	2029	2030	2026-2030 Total
4.8 kV CC: Pinegrove Substation Relocation and Conversion *GPM ranking of 90* This project is driven by MDOT and its expansion of the Bluewater Bridge. As part of this work, the existing Pinegrove substation will be decommissioned and replaced with a new 40-13.2 kV Class A substation (Neon). The project will accommodate MDOT's request and eliminate existing overload conditions, enhance system reliability and operability, and provide additional capacity to support current and future load growth in the Port Huron area.	9.3	5.0	-	-	-	**14.3**
4.8 kV CC: Pittsfield Substation and Circuit Conversion *BCR of 0.83; GPM ranking of 59* This project will construct a new 40/13.2 kV substation to improve reliability, operability, and increase 13.2 kV capacity in the Ann Arbor area. This will result in the decommissioning of (1) 4.8 kV substation.	0.2	1.3	9.0	10.5	1.0	**22.0**
4.8 kV CC: Rochester Decommissioning and Tienken Relief *BCR of 0.28; GPM ranking of 94* This project will construct a new 120-13.2 kV Class A substation to convert and decommission ROCHR substation, relieve existing overloads through load-transfers and provide additional capacity for future projected load growth in the TINKN 13.2 kV substation area.	3.7	1.5	7.9	14.2	20.3	**47.5**
4.8 kV CC: SCOTN *GPM ranking of 46* In June 2021, a flood at SCOTN substation condemned (36) associated position brakers. The intent of this project is to minimize the number of breakers to be replaced by consolidating lightly loaded circuits to put the substation back to normal configuration.	0.1	-	-	-	-	**0.1**
4.8 kV CC: Unionville DC 301 B1 Conversion *GPM ranking of 58* This project will convert a section of Unionville 4.8 kV into 13.2 kV by the installation of ISO up transformers.	0.5	-	-	-	-	**0.5**
4.8 kV CC: White Lake Decommissioning and Circuit Conversion *BCR of 0.53; GPM ranking of 63* This project will construct a new 40-13.2 kV Class R-R substation to relieve existing overloads, improve reliability, operability and increase capacity in White Lake, Springfield township, and Highland township which will ultimately result in the decommissioning of (1) 4.8 kV substation.	-	-	1.5	4.6	14.5	**20.6**

Conversions Projects	2026	2027	2028	2029	2030	2026-2030 Total
4.8 kV CC: Zenon Substation and Circuit Conversion - Phase 2 *BCR of 2.28; GPM ranking of 24* This project will expand Zenon substation to convert and decommission (2) 4.8 kV substations. This will relieve existing overloads, improve reliability, operability and increase capacity in the broader West Riverfront and Corktown area.	0.2	1.7	13.5	28.1	36.0	**79.4**
8.3 kV CC: Pontiac Overhead Conversion *BCR of 2.30; GPM ranking of 25* This project will upgrade an existing 120-13.2 kV Class A substation to convert and decommission (4) 8.3 kV and (1) 13.2 kV substations in the Pontiac area.	13.1	7.2	10.8	13.7	-	**44.7**
8.3 kV CC: Pontiac Underground Conversion *BCR of 0.69; GPM ranking of 25*[150] This project is to upgrade (15) customer-owned service vaults along with transferring several critical services to the upgraded 13.2 kV system.	2.0	2.5	3.0	3.5	-	**11.0**
CODI: Alfred Substation Expansion *GPM ranking of 18* This project is to expand the existing 120-13.2 kV substation into a (3) transformer, (2) PDC substation to increase capacity and enable the conversion of nearby OH and UG circuits within Detroit's Midtown and Eastern Market areas.	7.6	-	-	-	-	**7.6**
CODI: Amsterdam Conversion *GPM ranking of 15* Amsterdam is an existing 24-4.8 kV substation whose network and distribution system will be transferred to nearby 120-13.2 kV substations, ultimately enabling its decommissioning.	-	-	-	-	0.1	**0.1**
CODI: CATO Substation Expansion *GPM ranking of 89* This project will decommission the 4.8 kV side of CATO to allow ITC to add a third 120 kV transmission feed and expand CATO's 120-13.2 kV substation to enable future CODI conversion/consolidation projects.	2.0	0.5	6.8	4.0	10	**23.3**
CODI: Charlotte Network Upgrade *GPM ranking of 5* Charlotte is an existing 24-4.8 kV substation whose network and distribution system will be transferred to nearby 120-13.2 kV substations, ultimately enabling its decommissioning.	6.4	4.2	-	-	-	**10.6**

[150] Pontiac Overhead and Underground Conversion projects were combined in the GPM analysis.

Conversions Projects	2026	2027	2028	2029	2030	2026-2030 Total
CODI: Garfield *BCR of 1.24; GPM ranking of 16* Garfield is an existing 24-4.8 kV substation whose network and distribution system will be transferred to nearby 120-13.2 kV substations, ultimately enabling its decommissioning.	17.0	31.1	34.9	28.3	27.1	**138.4**
CODI: Howard Conversion *BCR of 1.50; GPM ranking of 26* Howard is an existing 24-4.8 kV substation whose network and distribution system will be transferred to nearby 120-13.2 kV substations, ultimately enabling its decommissioning.	16.0	8.8	7.3	9.0	17.2	**58.3**
CODI: Islandview Substation *GPM ranking of 42* The project will construct a new 120-13.2 kV Class A substation to relieve existing overloads, improve reliability, operability and increase capacity in the Detroit Riverfront area and decommission (1) 4.8 kV substation.	32.5	16.9	14.0	1.1	8.5	**73.0**
CODI: Kent/Gibson Conversion *BCR of 2.51; GPM ranking of 37* The project will help serve load along the West Detroit Riverfront. It will utilize the newly-built 13.2 kV Corktown substation to convert and consolidate the 4.8 kV in the area to 13.2 kV.	16.0	12.1	2.8	4.4	12.0	**47.3**
CODI: Midtown Substation Expansion *GPM ranking of 64* Midtown is a 2-transformer Class 'A' general purpose substation constructed in 1973 that serves the downtown Detroit New Center and Midtown areas. This project will expand MIDTN substation into a (3) transformer, (2) PDC site and extend fiber.	0.4	-	-	-	-	**0.4**
CODI: Targeted Network Secondary Cable Replacement *GPM ranking of 22* This cable program is designed to replace targeted 4.8 kV secondary network cable system in Detroit that has a higher probability of failure. This will reduce the secondary network cable failures and manhole events in the downtown area in the City of Detroit.	3.0	-	-	-	-	**3.0**
Total	**211.5**	**186.8**	**239.6**	**265.4**	**311.9**	**1,215.2**

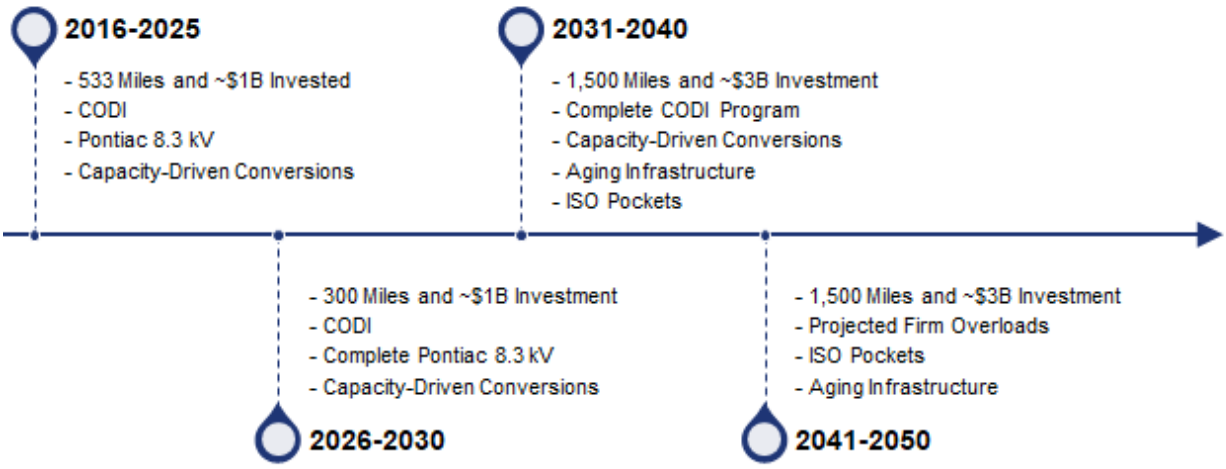
Long-Term Outlook

Looking beyond 2030, DTE's highest priority will be completing conversion projects initiated during the five-year planning horizon. Because large-scale conversion efforts typically span

multiple years — from conceptual engineering through construction and close-out — many initiatives launched in the near term will extend well beyond 2030.

Exhibit 6.43 presents the Company's longer-term outlook for conversion projects. Between 2031 and 2040, DTE forecasts completing approximately 1,500 miles of conversion at an estimated investment of $3 billion to complete the CODI program, address capacity constraints, modernize aging infrastructure, and mitigate reliability risks within ISO-constrained pockets. Beginning in 2031, the Company also plans to resume expansion of 4.8 kV ISO-down area conversions. These ISO-down candidates will be prioritized based on safety- and reliability-driven factors, including wire-down risk, historical reliability performance, and opportunities to avoid recurring operational- and trouble-related costs. From 2041 through 2050, DTE plans an additional 1,500 miles of conversion and approximately $3 billion of investment to relieve projected firm overloads, address remaining ISO pocket constraints, and continue replacing aging infrastructure to support long-term system reliability and anticipated load growth.

Exhibit 6.43 – Historical and Longer-Term Conversion Timeline



Taken together, these projections underscore that 4.8 kV Conversions will remain a critical component of DTE's long-term investment strategy. While other programs — such as Vegetation Management, PTMM, and Small Wire Replacement — deliver important safety and reliability benefits, they do not address the underlying system loading and configuration constraints inherent to the 4.8 kV network. Conversion of the 4.8 kV system remains the primary means of relieving localized capacity limitations while transitioning from an electrically ungrounded configuration to a modern, grounded system design.

6.3.2 System Loading

Grid Needs

DTE's grid is experiencing sustained growth in peak demand driven by electrification, increased customer usage, population shifts, and new customer connections. In certain locations, this growth is pushing substations and circuits toward — or beyond — their capacity limits. When equipment operates near or above its ratings under normal or contingency conditions, outage risk increases, restoration flexibility is reduced, and the likelihood of equipment failure grows, particularly during storms or unplanned outages.

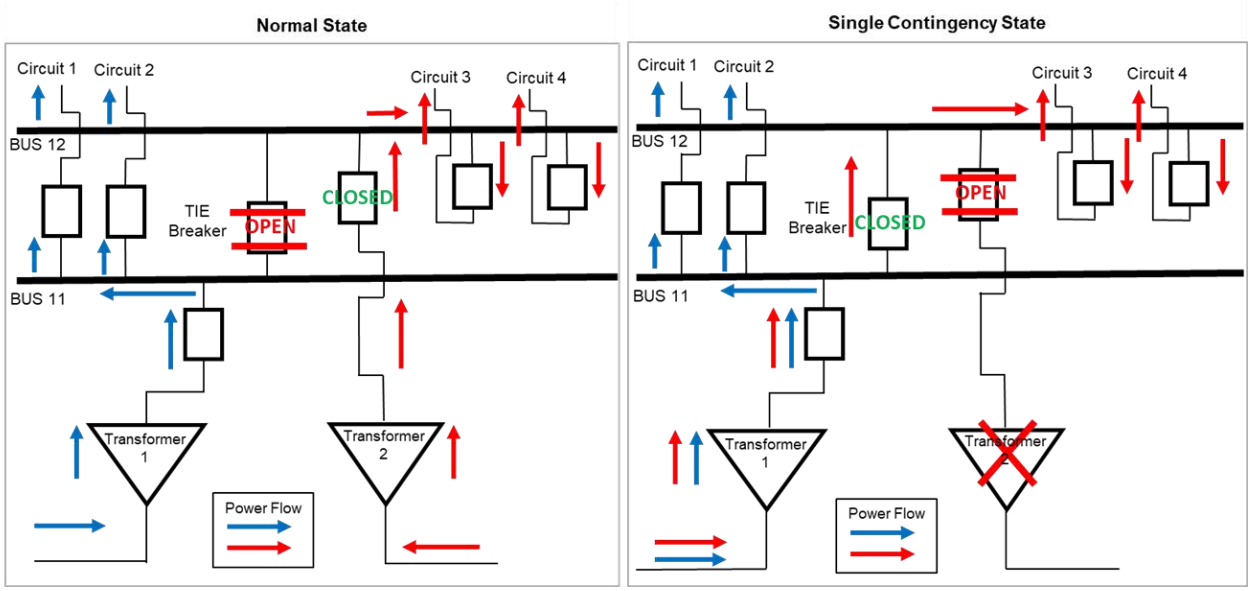
Capacity constraints can also restrict DTE's ability to serve new customer load. In some cases, constrained infrastructure may delay a customer's desired service date or require the requesting customer to fund their portion of an upgrade. Because major infrastructure investments require years to plan, permit, procure, and construct, early identification of loading constraints is necessary to maintain reliability, support economic development, and position the system to accommodate future demand.

The System Loading program addresses these challenges by providing substations and circuits with sufficient capacity to operate reliably under both normal and contingency conditions. Through substation- and circuit-level demand assessments, the program focuses on preventing overloads and equipment failures, enabling load transfers and automation during outages, and supporting planned maintenance and upgrades without customer interruptions. Together, these actions enable the grid to accommodate future load growth from electrification and new development while maintaining reliable operations.

Program Overview

Capacity needs are evaluated under two grid conditions: normal state and contingency state. The normal state reflects system operation when all equipment is in service and operating as designed. The contingency state represents conditions during planned outages or unexpected equipment failures — such as subtransmission lines, transformers, cables, or breakers — when remaining equipment must carry higher loads. As illustrated in Exhibit 6.44, sufficient excess capacity is required to maintain reliable service during these events.

Exhibit 6.44 – Illustrative Example of Substation in Normal and Contingency States



Substation load limits are defined through a combination of day-to-day and emergency equipment ratings, firm substation ratings, emergency load control schemes, and DDOs. These criteria ensure equipment can operate safely throughout its useful life and that load can be shifted during outages or planned work. DTE's rating and loading criteria are summarized in Exhibit 6.45.

Exhibit 6.45 – DTE Rating and Loading Criteria Definitions

Equipment Ratings	Emergency Rating	• Indicates the load level at which equipment can operate only for short periods of time (usually <8 hours) • Operating above this rating can lead to imminent or immediate failure resulting in loss of the equipment
	Day-to-day (Normal)	• Indicates nominal/nameplate equipment rating of equipment • Operating above this rating may shorten lifespan of equipment
	Planning – Design Criteria	• Consistent with industry practice, distribution circuits are designed for a level lower than the day-to-day rating to facilitate operating between circuits for restoration/automation capabilities and load growth
Substation	Firm Rating	• 'Firm Rating' is an industry practice whereas substations shall be designed to support a first contingency (n-1) • For a (2) transformer substation, this is calculated as the limiting element's Emergency rating of either transformer side – Example: If Transformer 1 has an emergency rating of 25MVA, and Transformer 2 has an emergency rating of 30MVA, the Firm Rating would be 25MVA. Any load above 25MVA would be at risk of blocking (outage) in event of a failure of Transformer 2

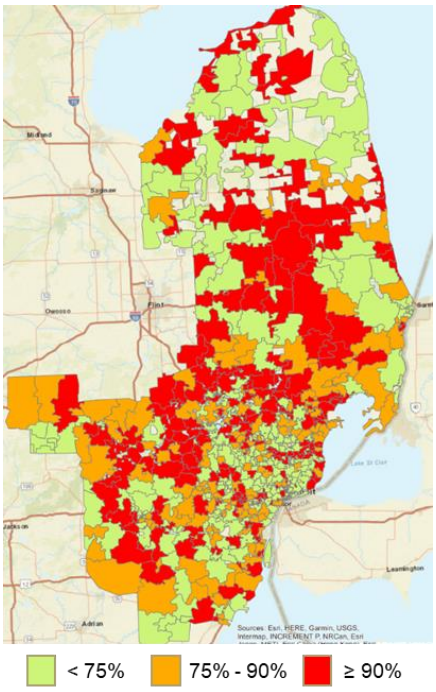
In addition to substation equipment limitations, available subtransmission capacity can further constrain substation loading. In these cases, Emergency Load Control (ELC) schemes are used

to prevent excessive load transfer through tie breakers or to shed load on individual distribution circuits when necessary. Where subtransmission limitations are lower than the substation's firm rating, effective substation capacity is reduced, increasing the need for system upgrades.

To proactively identify loading risks, DTE distribution planning engineers conduct an annual ALA following the summer peak, as described in Section 5.1 (Load Forecasts and Scenario Planning). The ALA evaluates current and historical peak loading, forecasted new load, equipment and firm ratings, system configurations, monitoring data, and input from large customers and municipalities. Ongoing improvements to the ALA include enhancing data accuracy through the deployment of Smart Fault Indicators (SFIs), which provide real-time load data at substations without SCADA and improve the precision of loading assessments. In parallel, DTE is strengthening long-term load forecasting by partnering with Corporate Forecasting to incorporate 15-year load projections into planning decisions, enabling earlier identification of area-specific growth trends and better alignment of infrastructure investments with electrification and evolving customer demand.

Through the annual ALA, substations operating above firm rating, as well as substations or circuits with peak loading at or above 90% of emergency ratings, are flagged for mitigation. Based on the 2025 ALA, approximately 20% of DTE's substations exhibited some level of loading constraint, as shown in Exhibit 6.46.

Exhibit 6.46 – Substation Loading Percentages Based on 2025 ALA



Following completion of the ALA, DTE engineers implement short-cycle mitigation measures, such as load transfers, phase balancing, and targeted upgrades, to reduce risk ahead of the next peak season. Equipment operating at or above 100% of emergency rating or averaging at or above 90% of emergency rating is prioritized for remediation. For substations exceeding firm ratings, Emergency Load Relief Plans are developed to guide real-time load transfers by the ESOC. In heavily constrained areas where transfers are not feasible, mobile generation or controlled customer interruptions may be required during peak conditions.

Substation construction

Where operational measures are insufficient due to the magnitude of constraints, system configuration, or site limitations, the Company develops permanent capacity solutions. These include overhead and underground line upgrades, substation expansions, and new substations. System Loading projects often address multiple needs simultaneously, supporting load growth, enabling new customer connections, replacing aging infrastructure, and improving overall reliability. In some cases, strategic load relief investments also reduce risk at neighboring substations and provide broader reliability benefits across the surrounding area.

Cost Effectiveness and Process Improvements

All potential System Loading solutions first undergo a Project Value Analysis (PVA) and peer review to evaluate alternatives such as NWAs, scope optimization, and project sequencing. Through this disciplined and transparent process — described further in Section 5.2.1 (Alternatives Analyses Process) — DTE identifies the Least-Cost/Best-Fit solution for addressing each System Loading need.

Once the preferred alternative is identified, larger-scale System Loading projects are prioritized using DTE's GPM, described in more detail in Section 5.2.4 (Global Prioritization Model). The GPM evaluates loading-driven needs across five dimensions: substation equipment overload severity, substation over firm rating, circuit equipment overload severity, expected future load growth, and circuits exceeding DDO limits. These factors are combined into a composite score

that establishes a relative priority ranking across candidate projects and informs inclusion and sequencing within the five-year plan. GPM ranking for System Loading projects is included in Exhibit 6.47.

In parallel, DTE is working to improve cost effectiveness of System Loading investments through targeted process improvements. These include streamlining property acquisition to secure land earlier in the planning cycle and identifying long-lead equipment, such as transformers and switchgear, earlier to reduce schedule risk. In rural areas where permanent infrastructure solutions require additional time, DTE is also deploying pad-mounted subtransmission distribution facilities (STDFs) as an interim solution. These facilities provide a faster, smaller-footprint means of meeting customer demand while long-term projects progress.

Collectively, these prioritization and execution practices reduce project delays, improve execution certainty, and position DTE to address system loading constraints proactively while continuing to meet customer needs safely, reliably, and efficiently.

Near-Term Investment

Near-term System Loading investments emphasize timely, incremental solutions — particularly in 4.8 kV areas — while preserving flexibility for future system conversion. These solutions include targeted load transfers, equipment replacements, and incremental capacity additions designed to relieve constraints efficiently. Where incremental measures are insufficient to address loading needs, new 13.2 kV substations are advanced to provide durable capacity relief. The 2026-2030 plan includes a sequenced portfolio of capital projects totaling approximately $281.2 million as outlined in Exhibit 6.47.

Exhibit 6.47 – Investment Plan for System Loading, 2026-2030 ($ millions)[151]

Project	2026	2027	2028	2029	2030	2026-2030 Total
Brown City *GPM ranking of 62* This project will build a new Class T substation and convert an existing Class E substation to a Class R substation to relieve overloads in the area. Conversion and consolidation of circuits in the area will improve reliability and operability and allow decommissioning of two 4.8 kV substations.	5.5	2.3	-	-	0.1	**7.9**

[151] Totals may not match exactly to the mathematical summation in the table due to rounding of the source data.

Project	2026	2027	2028	2029	2030	2026-2030 Total
Cody *GPM ranking of 55* This project will expand the existing 120-13.2 kV Class T substation to a Class A substation, increasing capacity from 39.6 MVA to 60 MVA. Establishing additional circuits will also improve operability and provide relief for the area.	2.2	1.6	2.8	-	-	**6.6**
Goodison *GPM ranking of 85* This project will build a new 40-13.2 kV Class A substation, relieve existing overloads in the area, increase capacity for future load growth, and improve operability.	1.5	4.7	16.0	23.5	15.5	**61.2**
Grenada *GPM ranking of 70* This project will build a new 40-13.2 kV Class A substation and decommission an existing 4.8 kV substation. The project will also convert and consolidate circuits in the area to improve reliability and operability.	7.5	12.3	13.2	8.0	6.0	**47.0**
Kings Pointe *GPM ranking of 67* This project will build a new 120-13.2 kV Class A substation to relieve existing overloads in the area, increase capacity for future load growth, and improve operability.	-	-	-	2.7	8.5	**11.2**
Lark / Spruce *GPM ranking of 82* This project will build a new 120-13.2 kV Class R substation at Lark to relieve overloads on Spruce circuits, increase capacity for future load growth, and improve reliability and operability for the area.	0.7	-	-	2.5	10.4	**13.6**
Mohican *GPM ranking of 79* This project will rebuild an existing Class I substation with no load at Mohican to a general-purpose substation, provide additional capacity for future load growth, and improve reliability and operability for the area.	0.3	-	-	-	-	**0.3**
Otsego / Capac / Shaw *GPM ranking of 34* This project will transfer load from the Otsego and Capac substations over to the newly built Midas substation. The project provides load relief through load-transfers to Midas.	-	1.0	1.5	0.1	1.0	**3.6**
Port Sanilac *GPM ranking of 69* This project will build a new 40-13.2 kV Class T substation and convert and consolidate circuits in the area to improve reliability and operability. The project will also decommission an existing 4.8 kV substation.	0.5	-	-	-	-	**0.5**
Richmond / Armada *GPM ranking of 54* This project will build a new 40-13.2 kV Class A substation and decommission one-of-a-kind vintage switchgear at the existing Richmond substation. The project will provide relief to existing overloads, increase capacity for future load growth, and improve reliability and operability for the area.	3.8	2.8	8.0	14.0	14.2	**42.8**

Project	2026	2027	2028	2029	2030	2026-2030 Total
Spokane / Seneca *GPM ranking of 76* This project will expand an existing 120-13.2 kV Class A substation and add a third transformer and second switchgear. The project will provide load relief for existing overloads, increase capacity for future load growth, and eliminate flood risk by establishing a drainage system.	1.1	3.5	10.0	10.0	11.0	**35.6**
Wixom *GPM ranking of 52* This project will expand an existing 120-13.2 kV Class A substation and add a third transformer and second switchgear. The project will provide load relief for existing overloads and increase capacity for future load growth for an industrial area.	9.5	8.5	7.6	10.5	15.0	**51.1**
System Loading Total	**32.6**	**36.6**	**59.0**	**71.3**	**81.7**	**281.2**

Long-Term Outlook

Over the long term, the System Loading program supports a capacity strategy that is deliberately aligned with evolving customer demand and the accelerating adoption of new technologies, including electrification, DERs, and other load-shaping technologies. As customers increasingly rely on EVs, heat pumps, on-site generation, and storage, maintaining sufficient capacity at the substation and circuit levels is important for ensuring safe, reliable service and preserving operational flexibility. The System Loading program enables DTE to anticipate and accommodate these changes by planning capacity ahead of demand, reducing overload risk, and ensuring the system can perform effectively under both normal and contingency conditions. In this way, the program also serves as a foundational element of 4.8 kV Conversions and broader grid modernization — two long-term objectives that require adequate capacity, compatible system configurations, and coordinated investment. By proactively addressing loading constraints, the System Loading program helps maintain near-term service continuity while positioning the distribution system to meet evolving customer needs and expectations over time.

6.3.3 Subtransmission Redesign and Rebuild

Grid Needs

The subtransmission system is a vital link between the ITC transmission network and DTE's distribution system, as described in detail in Section 4.1 (Subtransmission and Distribution System Overview). With 636 circuits spanning nearly 3,800 miles, the subtransmission system serves as the backbone of the distribution system, supporting multiple substations and — in many

cases — tens of thousands of downstream customers. While ITC owns and operates most of the 120 kV lines supplying general-purpose substations, DTE owns the 120 kV radial lines serving customer-dedicated substations, as well as all 40 kV and 24 kV systems. As the 4.8 kV distribution system continues its multi-decade voltage conversion, much of the associated 24 kV subtransmission system will ultimately be retired.

The subtransmission system is designed to provide redundant sources to distribution substations, enabling continuity of service during both planned and unplanned outages, commonly referred to as contingency conditions. Because subtransmission infrastructure serves as upstream sources for multiple substations, outages, overloads, or equipment failures at this level can result in significantly larger customer impacts than comparable events on the distribution system. For example, while subtransmission-related outages accounted for less than 0.4% of total outage events between January 2025 and February 2026, they contributed to 16% of AW SAIFI and 14% of AW SAIDI during that time.

The challenges facing the subtransmission system mirror the broader system drivers discussed in Section 2.3 (Drivers of Investment), including aging infrastructure, increasingly severe weather, and rising localized load. Together, these pressures have increased failure frequency, constrained capacity in fast-growing areas, and elevated the risk for large, sustained outages. Moreover, because permanent repairs or upgrades often require extended timeframes to design and construct, subtransmission outages frequently necessitate costly interim measures, such as mobile generation or portable substations, to restore service in the near term.

In response to these challenges, the Company's subtransmission strategy focuses on a coordinated portfolio of reliability improvements. Near-term maintenance programs, described in Sections 6.1.1 (Vegetation Management) and 6.2.1 (Pole and Pole-Top Maintenance and Modernization), play a critical role in reducing outage risk and strengthening system performance. Increased automation, detailed in Section 6.4.2 (Subtransmission SCADA), further enhances DTE's ability to isolate faults and prevent long-duration outages. Where maintenance and automation alone are insufficient, Subtransmission Redesign and Rebuild projects focus on rebuilding the most vulnerable or constrained segments of the system in order to improve safety, reliability, operability, and capacity.

Program Overview

Because of its extensive downstream impact, DTE applies more stringent planning, design, and construction standards to the subtransmission system. These standards include stronger

structures, larger conductors, tighter voltage and thermal criteria, and higher levels of automation, all of which are intended to enhance resilience, improve reliability, and support future load growth. Subtransmission Redesign and Rebuild projects can include substation, overhead, and underground work.

Substation upgrades focus on increasing capacity and redundancy through the installation of larger transformers, capacitor banks, and related equipment, while also improving voltage support. Overhead subtransmission improvements replace aging wooden poles, porcelain insulators, and small-diameter conductors with steel poles, polymer clamp-top insulators, and modern conductors that provide substantially greater strength and capacity. These designs are engineered to withstand 90 mph wind events, reduce wire-down risk, and mitigate tree-related impacts, while improving voltage performance over long distances and reducing the likelihood of power-quality issues. Underground subtransmission work similarly targets cables that are overloaded or at elevated risk of failure.

To target the most critical subtransmission needs, DTE applies a structured prioritization framework built around six criteria as shown in Exhibit 6.48. The first four criteria represent planning criteria violations, which occur when the system lacks sufficient capacity — under either normal operating conditions or a single-contingency scenario — to serve existing load without exceeding equipment ratings or voltage limits. These four criteria, together with the fifth criterion of strong load growth prospects, are capacity driven. The sixth criterion addresses reliability performance.

Exhibit 6.48 – Subtransmission Redesign and Rebuild Prioritization Framework

Subtransmission Criteria	Definition
Load Loss for Single Contingency	Total load that would be shed under certain conditions when a subtransmission line can no longer support a substation and no back-up source is available
Load over Emergency Rating, for Single Contingency	Load exceeding the emergency rating of a subtransmission line during a contingency event
Load over Day-to-Day Rating, Normal Conditions	Load exceeding the normal operating rating of a subtransmission line
Voltage Violation	Voltage drop exceeding standards when a line is not in its normal configuration due to an outage
Strong Load Growth Prospect	Subtransmission lines forecasted to experience significant future load growth
Reliability	History of outages or equipment failures on the subtransmission circuit

The subtransmission Annual System Review incorporates distribution ALA results to identify thermal and voltage planning criteria violations, rank them by severity, and determine which projects most urgently require investment. These candidate projects are coordinated with distribution system projects to ensure that new or expanded substations, as well as the retirement of aging assets, are appropriately supported by the subtransmission system. In parallel, the Subtransmission Planning Engineering group closely monitors reliability performance, with circuits exhibiting repeated reliability issues flagged for more detailed analysis. Where reliability concerns overlap with capacity constraints or future load growth, projects are designed to deliver multiple system benefits.

Expected Benefits and Cost-Effectiveness

Using the BCA framework described in Section 5.2.3 (Benefit-Cost Analyses Approach), Subtransmission Redesign and Rebuild projects with a more significant scope were evaluated to assess cost effectiveness. The resulting BCRs for projects meeting these criteria are presented in Exhibit 6.49, and additional detail on the BCA methodology and results is provided in Appendix 8.14 (Benefit-Cost Analysis Report).

Consistent with DTE's broader investment planning approach, all candidate projects are then evaluated using the GPM, described in Section 5.2.4 (Global Prioritization Model). The GPM incorporates the subtransmission prioritization criteria into broader impact dimensions to compare projects across the Company's investment portfolio on a consistent basis. Projects delivering greater benefits per dollar invested receive higher GPM scores and are prioritized accordingly in DTE's investment plan.

Near-Term Investment

Based on the subtransmission prioritization framework, BCA results, and GPM, the five-year investment plan for Subtransmission Redesign and Rebuild includes a set of sequenced capital projects totaling approximately $415.2 million as outlined in Exhibit 6.49.

Exhibit 6.49 – Investment Plan for Subtransmission Redesign and Rebuild, 2026-2030 ($ millions)[152]

Project	2026	2027	2028	2029	2030	2026-2030 Total
Ann Arbor System Improvements *GPM ranking of 108* This project reconfigures the Ann Arbor area power system by constructing new 120/40 kV stations and realigning subtransmission and distribution circuits to improve service reliability.	3.0	4.0	1.0	-	-	**8.0**
Badax Transformer 102 Addition *GPM ranking of 40* This project adds a second 120/40 kV transformer (TRF 102) to mitigate voltage planning-criteria violations under single-contingency (N-1) conditions following the loss of TRF 101.	1.0	-	-	-	-	**1.0**
Bernard *GPM ranking of 32* This project will install a new capacitor bank and capacitor switcher to mitigate a single-contingency (N-1) voltage planning-criteria violation following the loss of a section of TIE 807.	0.7	0.7	2.0	-	-	**3.4**
Boyne *GPM ranking of 53* This project adds a second 120/40 kV transformer (TRF 102) and upgrades limiting sections of surrounding circuits to mitigate voltage and thermal planning-criteria violations under single-contingency (N-1) conditions following the loss of TRF 101. The project also increases capacity to support future load growth, including new business development.	0.6	-	-	-	-	**0.6**
Cortland Station Expansion *BCR of 0.22; GPM ranking of 93* Due to space constraints at Cortland station, work on existing Transformers 101 and 102 is not feasible. This project expands the station footprint and replaces the existing units with two new 120/24 kV transformers.	0.2	0.6	2.2	8.1	0.3	**11.3**
Maxwell Cable Replacement *GPM ranking of 109* This project replaces the 120 kV pipe-type cables serving a critical facility as a proactive measure following multiple cable failures in 2017 and 2025. The existing 120 kV gas-filled cables exceed their expected service life, are obsolete, require ongoing maintenance, and involve lengthy restoration outages.	0.4	1.4	5.5	2.0	-	**9.3**
Dunn Station *GPM ranking of 109* Dunn station is no longer serving load, has been disconnected from the industrial customer, and contains ~70-year-old equipment that does not meet current protection standards and is planned for decommissioning.	1.0	0.5				**1.5**

[152] Totals may not match exactly to the mathematical summation in the table due to rounding of the source data. Projects with a GPM rank of 112 indicate that their benefits are not captured within the defined impact dimensions of the GPM and therefore receive a score of zero under the model.

Project	2026	2027	2028	2029	2030	2026-2030 Total
French Landing *GPM ranking of 107* This project involves an area reconfiguration to mitigate existing equipment failures and aging substation infrastructure at French Landing substation to prevent future outages.	-	0.05	0.3	4.0	2.0	**6.4**
Hurst *GPM ranking of 29* This project adds a second 120/40 kV transformer (TRF 102) to mitigate voltage planning-criteria violations under single-contingency (N-1) conditions following the loss of TRF 101.	-	-	-	1.0	2.5	**3.5**
Imlay *BCR of 0.32; GPM ranking of 106* This project will rebuild the Imlay station at a nearby location. The existing station layout lacks adequate clearances, creating potential safety risks, and the limited space does not allow the facility to be rebuilt to current design standards.	-	-	-	2.1	11.9	**14.0**
Kennett *GPM ranking of 103* Kennet substation is no longer serving load, has been disconnected from the industrial customer, and is planned for removal and decommissioning.	-	1.3	-	-	-	**1.3**
Pigeon *BCR of 0.52; GPM ranking of 86* The northwest Thumb region experiences multiple planning-criteria thermal and voltage violations under various contingencies, resulting in customer load shed. This project will construct a new 120/40 kV station and reconfigure the subtransmission system to resolve these violations and provide additional system capacity.	1.0	-	4.8	19.8	28.2	**53.8**
Reverse Power Relay Scheme Program *GPM ranking of 109* Various ITC shutdowns require DTE to open subtransmission breakers to prevent reverse power flow to ITC's transmission system, reducing reliability, limiting shutdown flexibility, and increasing operational complexity. This project installs reverse power relay schemes at key locations identified by DTE and ITC Operations, eliminating the need for these complex operating procedures.	1.0	1.0	1.0	1.0	1.0	**5.0**
Sandusky Transformer 101 Breaker *GPM ranking of 14* This project replaces Sandusky Transformer 101's 40 kV secondary breaker to address summer normal planning-criteria thermal overload conditions and reduce the risk of equipment failure.	1.6	-	-	-	-	**1.6**
Tempest Phase II *GPM ranking of 109* Tempest is an industrial customer substation that does not meet DTE's current design and clearance standards. This project will rebuild the Tempest substation to comply with current DTE standards.	3.0	3.1	-	-	-	**6.1**

Project	2026	2027	2028	2029	2030	2026-2030 Total
Tie 1473 *GPM ranking of 74* This project will rebuild and relocate the worst-performing sections of TIE 1473 to improve customer reliability. The line has experienced frequent outages, and much of the overhead infrastructure has exceeded its life expectancy. Relocating the line out of deep right-of-way will reduce tree interference.	-	-	-	-	1.0	**1.0**
Tie 3205 *BCR of 0.62; GPM ranking of 92* This project will rebuild and relocate TIE 3205 to improve customer reliability. The line has experienced frequent outages and escalated customer complaints, with most infrastructure beyond its service life. The existing deep right-of-way route is highly susceptible to tree interference and limits access, increasing outage frequency and duration.	2.5	4.6	8.5	15.0	18.0	**48.6**
Tie 3416 *GPM ranking of 72* This project addresses summer normal and emergency planning-criteria thermal overloads on TIE 3416 that could result in manual load shed. The project upgrades overhead conductor and station equipment to resolve these overloads and prevent customer load shed.	0.5	6.0	-	-	-	**6.5**
Tie 4104 North *BCR of 0.59; GPM ranking of 98* This project will reconductor the poor performing sections of TIE 4104 and relocate the circuit out of deep right-of-way to improve customer reliability. The line has deteriorated conductor and end-of-life poles that have caused equipment failures. The current deep right-of-way location is highly susceptible to tree interference and limits access, increasing frequency and outage duration.	7.1	15.0	15.0	12.0	14.0	**63.1**
Tie 4105 *GPM ranking of 96* This project will rebuild and relocate the worst performing sections of TIE 4105 to improve customer reliability. The line has experienced frequent outages and escalated customer complaints, driven by deteriorated conductor, end-of-life poles, and a deep right-of-way route that is susceptible to tree interference and limits access, increasing outage frequency and duration.	6.0	-	-	-	0.7	**6.7**
Tie 6602 *GPM ranking of 95* This project addresses summer emergency planning- criteria thermal overloads on TIE 6602 that result in load shed. The project replaces limiting overhead conductors to resolve potential overloads and prevent customer load shed.	8.4	0.05	-	-	-	**8.4**
Tie 7504 *BCR of 0.94; GPM ranking of 97* This project will rebuild and relocate TIE 7504 to improve customer reliability and address planning-criteria voltage violations. The line has experienced frequent outages and escalated customer complaints, with most infrastructure beyond its service life. The existing deep right-of-way route is highly susceptible to tree interference and limits access, increasing outage frequency and duration.	11.8	12.0	12.0	2.0	-	**37.8**

Project	2026	2027	2028	2029	2030	2026-2030 Total
Tie 810 *GPM ranking of 83* TIE 810 experiences thermal and voltage planning-criteria violations under multiple single contingency (N-1) scenarios, placing customers at risk of load shed and limiting load growth. This project constructs a new 120/40 kV station, reconfigures TIE 810 into three circuits, and replaces limiting overloaded conductors to resolve these violations.	1.4	-	-	-	-	**1.4**
Transformer High Side Protection Program *BCR of 0.22; GPM ranking of 109* Several subtransmission and distribution transformers require high side protection to address NERC reportable reliability risks identified in ITC annual studies and confirmed by MISO. These issues could result in the loss of more than 100 MVA of customer load under contingency conditions and must be mitigated to comply with NERC TPL 001 4 standards. The program installs high side switching devices at transformers across stations and replaces or relocates transformers due to space constraints.	3.5	6.5	6.5	5.0	-	**21.5**
Trunk 2308 *GPM ranking of 73* This project addresses summer emergency planning-criteria thermal overloads on TRK 2308 that result in load shed by replacing identified limiting overhead conductors to eliminate the planning-criteria overloads and prevent future load shed.	0.4	-	-	-	-	**0.4**
Trunk 2455 *BCR of 0.53; GPM ranking of 101* The conduit at the 8 Mile Road bridge over M10 is severely corroded, with failed cables stuck in place and no spare ducts available for replacement. A failure would place three 24 kV trunk lines serving eight substations, along with two distribution circuits, at risk of an extended outage. This project proposes installing new conduit by boring under M10 and relocating the affected circuits, eliminating the extended outage risk associated with the existing corroded conduit.	0.3	3.0	6.4	5.6	0.03	**15.4**
Trunk 3509 *GPM ranking of 17* This project addresses summer normal and emergency planning-criteria overloads on TRK 3509 that result in load shed. The project replaces identified limiting underground cables to resolve the overloads and prevent future load shedding.	1.8	-	-	-	-	**1.8**
Trunk 4245 *GPM ranking of 105* This is a risk mitigation project driven by the deteriorated condition of the conduit and cable system in the St. Clair Shores/Eastpointe area and a commitment DTE made to MDOT in 2022. The project addresses cable failure risks at the Shores and Savoy substations, which serve customer load.	1.5	5.7	-	-	-	**7.2**

Project	2026	2027	2028	2029	2030	2026-2030 Total
Trunk 4601 *GPM ranking of 104* This project will extend Trunk 4601 to a new 40 kV bus at Bennett station, redesignating the line as Tie 9234. The new TIE line will resolve single-contingency (N-1) voltage planning-criteria violations resulting from the loss of Bennett Transformer 102 or Rush Transformer 101 and provide additional capacity to support future load growth.	-	-	-	1.4	10.4	**11.8**
Trunk 4911 *GPM ranking of 50* This project addresses summer normal and emergency planning-criteria thermal overloads and voltage violations on TRK 4911. It includes construction of a new trunk line, reconfiguration of TRK 4911, and upgrades to limiting overhead conductors and underground cables to resolve all violations while improving reliability, operability, and future load growth capacity.	11.6	12.6	12.2	-	-	**36.4**
Trunk 7386 *BCR of 0.44; GPM ranking of 66* This project addresses summer emergency planning-criteria thermal overloads on TRK 7386 that result in load shed. The project replaces identified limiting overhead conductors and underground cables to resolve the overloads and prevent future load shedding.	0.5	2.8	5.8	1.0	-	**10.1**
Waterman *BCR of 1.43; GPM ranking of 102* The remaining oil breakers at Waterman station have exceeded their service life, with limited spare parts available for maintenance and repairs. This project consolidates the station to enable required breaker replacements and decommissions 24 kV breaker positions that are no longer needed under the proposed reconfiguration.	4.0	6.0	0.5	-	-	**10.5**
Total	**74.8**	**86.8**	**83.7**	**80.0**	**90.0**	**415.2**

The proposed five-year investment portfolio for the Subtransmission Redesign and Rebuild program focuses on mitigating critical system risks and delivering customer value through DTE's structured Annual System Review, BCA, and GPM processes. Consistent with this disciplined planning and prioritization approach, the Company is proposing continued IRM treatment for Subtransmission Redesign and Rebuild investments, as discussed in Section 7.2.1 (Infrastructure Recovery Mechanism).

Long-Term Outlook

Over the long term, the Company will continue to strengthen the subtransmission system through targeted rebuilds, expanded station capacity, and coordinated system planning. These investments are designed to replace aging infrastructure, harden the system against more frequent and intense weather events, and provide the capacity and flexibility needed to support

electrification, DERs, and other emerging customer technologies. As renewable generation expands and conventional generation sources retire, modernized subtransmission infrastructure will play an increasingly important role in accommodating changing power flows and supporting an evolving mix of grid resources. In parallel, continued conversion of the 4.8 kV distribution system will enable the orderly retirement of the associated 24 kV subtransmission system, streamlining system architecture while reducing long-term maintenance and capital requirements. Together, these near- and long-term investments will create a more modern, resilient, and flexible subtransmission system that underpins the reliability, performance, and adaptability of the entire electric grid.

6.3.4 Non-Wire Alternatives

Program Overview

The Commission has defined NWA to mean "[a]n electricity grid investment or project that uses distribution solutions such as distributed energy resources (DER), energy waste reduction (EWR), demand response (DR), and grid software and controls, to defer or replace the need for distribution system upgrades."[153] NWAs can potentially serve as cost-effective alternatives to traditional infrastructure investments and, in some cases, delay or eliminate the need for more costly system upgrades. Since 2018, and in response to subsequent MPSC directives and approvals,[154] DTE has implemented a suite of NWA pilot projects. These pilots use alternative technologies to address circuit- and substation-level loading constraints, with the goal of delaying or offsetting traditional system upgrades. Consistent with the Commission's Order in Case No. U-21534,[155]

Example of mobile battery system

[153] Order dated August 20, 2020 in Case No. U-20147 (page 11), available at https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/068t000000DcfWRAAZ, accessed March 23, 2026.

[154] Order dated May 8, 2020 in Case No. U-20561 (page 112), "the Commission directs DTE Electric to provide, in its next distribution investment and maintenance plan, a robust suite of NWAs that may be evaluated for prudency as possible pilot programs."

[155] Order dated January 23, 2025 in Case No. U-21534 (page 158), "The Commission finds that DTE Electric has begun to incorporate NWA options into the company's grid planning and, thus, is not persuaded that the company should be required to expand its current portfolio of NWA pilots or incorporate NWA solutions into its distribution planning process at this time. Rather, the Commission agrees that DTE Electric should continue to focus on the company's current NWA pilots to obtain results that will better inform the company on how to scale its current NWA pilots."

DTE will continue to focus on the company's current NWA pilots to obtain results that inform scalability, improve screening of suitable applications, and incorporate findings into the Company's planning. DTE's seven NWA pilots are summarized in Exhibit 6.50.

Exhibit 6.50 – Overview of NWA Pilots

NWA Pilot (Start Year)	Project Description	Current Status
O'Shea Power Quality (2018)	• Install a 1 MW/1.1 MWh stationary battery to mitigate potential power quality and high-voltage issues caused by large solar generation and relatively low circuit load	• Stationary battery installed on site • Tested various use cases including solar smoothing and peak shaving
Hancock Station (2019)	• Leverage existing, expanded or new EWR and DR programs to achieve geo-targeted peak reduction at Hancock substation	• Completed in 2021 • Achieved 57 kW of peak reduction • Did not meet the pilot objective
EV Charging Demonstration Project (2020)	• Demonstration of managed charging under controlled environment through partnership with DOE and industry stakeholders to advance EV charging and vehicle-to-everything (V2X) technologies	• Demonstrated charging on first U.S. public wireless charging road at Michigan Central Station in February 2022, and at the American Center for Advanced Mobility in October 2022 • Demonstrated managed charging at Detroit Smart Parking Lab (Bagley) in October 2024 • Vehicle-to-grid (V2G) testing with OEMs continue
Fisher Station (2021)	• Leverage existing, expanded or new EWR and DR programs to achieve geo-targeted peak reduction at Fisher substation	• Completed in 2025 • Achieved 741 kW of peak reduction • Met the pilot objective
Omega Load Relief (2021)	• Deploy two 1 MW/4 MWh mobile battery systems at Omega substation to provide temporary load relief for overloaded trunk lines and potential grow house load • Provide 2 MW peak reduction at Omega substation	• Permanent infrastructure solution completed in 2025 • Mobile battery trailers will be repurposed for other use cases
Port Austin Load Relief (2022)	• Install 500 kW of solar generation and utilize 1 MW/4 MWh mobile battery system to relieve substation loading. • Provide up to 1.5 MW peak reduction at Port Austion substation	• 500 kW solar installed on site • Battery and communication gateway installation is underway • Construction is expected to conclude, with the NWA ready for service by the end of 2026
Veridian Grid Support (2022)	• Install new URD design to support fully electrified neighborhood, equipping every home with solar, battery storage, EV chargers, and electric heat pumps • Install front-of-the-meter (FTM) battery to mitigate grid impact	• New URD design has been installed • FTM battery procurement and installation could not proceed due to space limitations • Advanced metering solutions are being evaluated to assess reactive power impacts

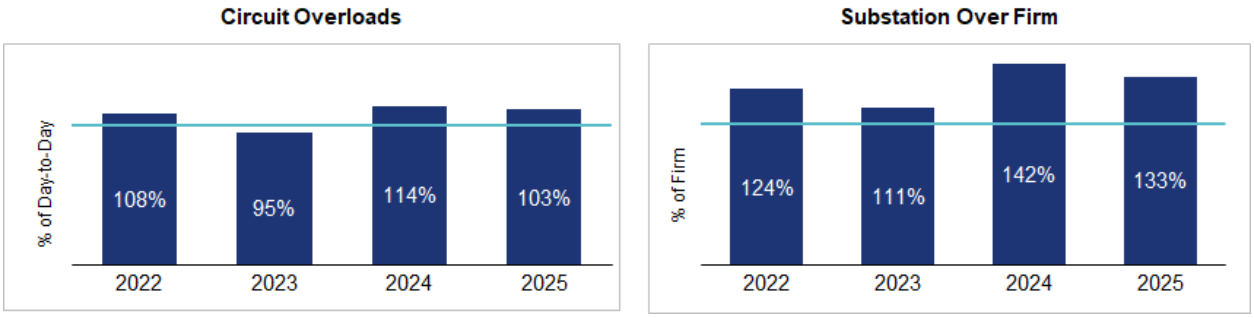
Port Austin Load Relief

The Port Austin substation is a 4.8 kV facility located in the rural northeastern Michigan region known as the "Thumb." It has two distribution circuits that serve just under 2,000 customers. The

Port Austin Load Relief

The Port Austin substation is a 4.8 kV facility located in the rural northeastern Michigan region known as the “Thumb.” It has two distribution circuits that serve just under 2,000 customers. The substation and its circuit serving downtown Port Austin regularly experience overload or over-firm conditions during the summer months due to tourism, seasonal festivals, and special events as illustrated in Exhibit 6.51. Because Port Austin is adjacent to Lake Huron and Thumb Electric’s service territory, low-cost alternatives such as load transfers are not feasible. Since the substation’s load is expected to remain relatively stable, the overload condition during the summer will persist unless corrective measures are taken.

Exhibit 6.51 – Port Austin Loading Issues, 2022-2025



A traditional solution would involve upgrading the existing 4.8 kV substation to a 13.2 kV substation and reconductoring roughly 10 miles of overhead lines to support the higher-voltage system. ISO-down transformers would be installed to serve the remaining portions still operating at 4.8 kV. Overall, this approach would cost at least $15 million and require a multi-year construction effort, typically spanning five to seven years.

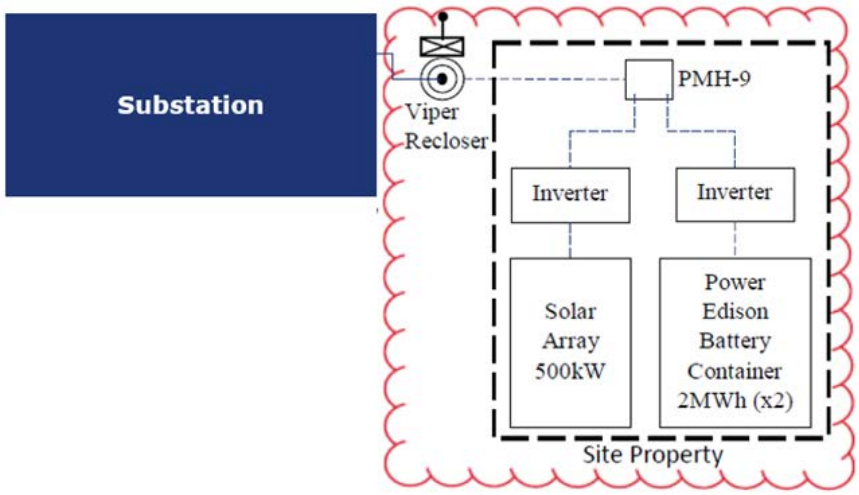
DTE identified the Port Austin loading issue as a good candidate for an NWA pilot based on the following characteristics:

- High cost and long timeline of the alternative
- Limited overload and over-firm condition at the targeted site (a few hours during summer festivities)
- Stable load forecast
- Adequate space for solar and battery installations
- No near-term need for a substation rebuild due to aging infrastructure

As a result, the Company developed an NWA solution to install a 500-kW solar array along with utilizing a 1 MW/4 MWh mobile battery system to provide local energy generation and peak-shifting capability as shown in Exhibit 6.52.

By supplying power during high-demand periods, the combined solar and storage resources would help keep loading on the substation below its firm capacity and maintain circuit demand within day-to-day operating limits, thereby reducing strain on existing infrastructure and deferring the need for costly traditional upgrades.

Exhibit 6.52 – Port Austin NWA Solution



Expected Benefits and Cost-Effectiveness

To evaluate cost-effectiveness, DTE performed a BCA following the analytical framework laid out in the National Standard Practice Manual[156] and Michigan's Jurisdiction Specific Test, approved by the MPSC in 2023.[157] The analysis has monetized the impact categories to the extent possible, and made generous assumptions (i.e., higher values) on the benefit quantification. The Port Austin NWA pilot is estimated to have a BCR of 1.4, demonstrating strong net benefit to customers. The Company expects construction to conclude by the end of 2026 at a total cost of approximately $11.4 million, including the initial cost of the battery trailer. The NWA solution will provide load relief starting in the summer of 2027, and results will be monitored to inform future

[156] National Standard Practice Manual, available at https://www.energy.gov/sites/default/files/2020/10/f79/national-standard-practice-manual.pdf, accessed March 23 2026.

[157] Order dated October 12, 2023 in Case No. U-20898 (page 26), available at https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/0688y00000ACa8IAAT, accessed March 23, 2026.

deployments and analysis. Exhibit 6.53 shows the results of the benefit-cost analysis for Port Austin NWA.

Exhibit 6.53 – Benefit-Cost Analysis for Port Austin NWA Pilot ($ thousands)

Impact Categories	Description	Assumptions	NPV ($ 000)
Total Benefit NPV = $16,221			
Avoided Energy Costs	Reduced energy costs due to solar generation and energy storage arbitrage values	DTE internal energy model run and June 2025 Siemens LMP price forecast	515
Avoided Capacity Costs	Reduced capacity costs due to solar and energy storage capacity values	DTE analysis based on June 2025 Siemens capacity price forecast, and MISO capacity accreditation forecasts	839
Ancillary Service Benefits	Ancillary services provided by energy storage (i.e., regulation, spinning and short-term reserves, ramp capability)	Estimated at 20% of avoided energy costs for battery storage, based on recent market data at Ludington. pumped storage plant	8.4
Avoided Emission Costs	Avoided NOX and SO2 costs due to solar generation	Evolution Market Emission Price Index	0.6
Location Specific Avoided Distribution Costs	Avoided traditional investments for the targeted substation or circuits	Cost of traditional investments, estimated by distribution planning engineers	14,683
Avoided Systemwide T&D Costs	Deferred systemwide T&D costs	$8.24 / kW-year based on DTE's recent IRP filing[158] plus escalation	175
Total Cost NPV = $11,920			
NWA Capital Costs	The upfront investments needed to implement the NWA solution	Actual NWA project cost	11,370
NWA Ongoing Costs	The incremental costs to maintain and operate the solar and battery systems	Lazard 2025 LCOE+ Report	550

As evaluated using the GPM described in Section 5.2.4 (Global Prioritization Model), Port Austin ranked 11th and Veridian ranked 44th among projects and programs considered.[159] Notably, Port Austin ranked first in the overload relief dimension. The Battery Trailer and EV Charging Demonstration projects were not scored because their benefits were outside the scope of the GPM analysis.

[158] Case No. U-21193, Exhibit A-13.2, available at https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/0688y000004qYBJAA2, accessed April 12, 2026.

[159] Port Austin's GPM ranking excludes the cost of the mobile battery trailer, which is redeployable and may be repurposed as needed.

Near-Term Strategy and Investment

Port Austin's characteristics and strong BCR results have helped the Company refine NWA eligibility parameters and more effectively assess each solution's suitability for addressing local area needs. DTE continues to proactively evaluate NWA opportunities during the early stages of project development. Exhibit 6.54 outlines DTE's current NWA screening criteria.

Exhibit 6.54 – DTE's NWA Screening Criteria

Criteria	Description
Project Type	Both load relief and reliability improvement projects
Size and Duration of Customer Load	% of substation over firm (N-1) < 3 MW Circuit day-to-day overload < 3 MW Customer load impacted by outage events < 3 MW Limited duration under abnormal conditions No substantial load growth or reduction expected in the area
Timeline Requirements	No imminent solution needed Can wait for three years or more
Cost of Traditional Investments	Cost of traditional solution alternative > $5 million
Other Alternatives	No lower-cost alternative such as load transfers
Customer Propensity	Number of residential and C&I customers Residential and C&I customer propensity to enroll in utility programs on EWR, DR, managed charging and BTM battery storage
Site Requirements	Adequate space to install battery or solar as FTM solutions No single-banked transformer

While these criteria guide NWA identification, they do not limit the development of potential NWA solutions; unique circumstances may arise that warrant NWA consideration outside of these criteria. Identifying successful projects often requires creativity and site-specific analysis. Through its NWA pilots, DTE has gained valuable knowledge and experience on new technology deployments. Key insights include:

- **R&D and Testing:** As the first-of-its-kind in the country, DTE's mobile battery deployments generated valuable R&D and testing experience. Lessons learned will be shared with other utilities to inform the Company's future projects.
- **No-Regret Investment Decisions:** Mobile batteries can be re-purposed as system conditions change, reducing investment risk.
- **Procurement Risk:** Battery procurement in the 1-8 MWh range requires advanced planning due to limited supplier availability.

- **Vendor Capability:** Standardized, utility-ready power conversion systems for mobile batteries remain a challenge. DTE has worked with multiple vendors in fabrication and will continue monitoring the testing and operations of the systems to collect lessons learned.
- **O&M Risk:** Dedicated field personnel with energy storage expertise are needed to ensure ongoing O&M of NWA technologies, as they tend to have higher failure rates than traditional solutions such as poles and wires.
- **NWA and EV Charging:** The near-term investment plan for NWA includes the EV charging demonstration project, as shown in Exhibit 6.55, which includes evaluation of managed charging, V2G, and integration of chargers with other DER and grid controls, supporting streamlined EV charging installations and new electrification and grid management capabilities.
- **Vehicle Electrification:** EV projects within the Grid Technology category include managed charging, V2G, and integration of chargers with other DER and grid controls, supporting streamlined EV charging installations and new electrification and grid-management capabilities.

Exhibit 6.55 – Investment Plan for NWA, 2026-2030 ($ millions)[160]

NWA	2026	2027	2028	2029	2030	2026 – 2030 Total
NWA: Battery Trailer	0.2	-	-	-	-	**0.2**
NWA: EV Charging Demonstration	1.2	0.7	0.7	0.7	0.7	**3.9**
NWA: Port Austin Load Relief	0.1	0.4	-	-	-	**0.5**
NWA: Veridian	0.8	-	-	-	-	**0.8**
Total	**2.2**	**1.1**	**0.7**	**0.7**	**0.7**	**5.3**

Long-Term Outlook

Looking ahead, DTE expects future NWA projects to involve greater collaboration with external stakeholders, particularly through an expedited pilot process. One potential project under consideration is an Adaptive Network Microgrid (ANM) project to enhance DTE's capabilities in microgrid design, deployment, and grid integration. DTE will seek community and stakeholder input as these future NWA initiatives are developed. The Company continues to be a leader in NWA and microgrid research, publishing papers[161] and presenting at industry conferences and

[160] Totals may not match exactly to the mathematical summation in the table due to rounding of the source data.

[161] Engineering Microgrids Amid the Evolving Electrical Distribution System, available at https://www.mdpi.com/1996-1073/17/19/4764?utm_source=chatgpt.com, accessed March 23, 2026.

seminars. DTE is committed to developing ANM and NWA projects that deliver cost-effective solutions for customers.

6.4 Technology and Automation

Building on physical system redesign, Technology and Automation — the fourth investment pillar — provides the control layer that transforms a stronger grid into a smarter, more responsive one. This section describes six technology investment areas the Company is deploying to coordinate and optimize operations at scale: Distribution Automation, Subtransmission SCADA, Operational Technology, ADMS, Asset Condition Monitoring Technology, and Grid Technology. Together, these capabilities deliver real-time visibility into system conditions, enable automated fault isolation, and accelerate service restoration during outages. By integrating sensing, communications, and advanced control across the grid, Technology and Automation investments support safer, more proactive operations and establish the foundation for a self-healing grid. While the main goal of the Company remains preventing outages, programs within the Technology and Automation pillar provide the tools that enable the system to restore customers in minutes rather than hours.

6.4.1 Distribution Automation

Grid Needs

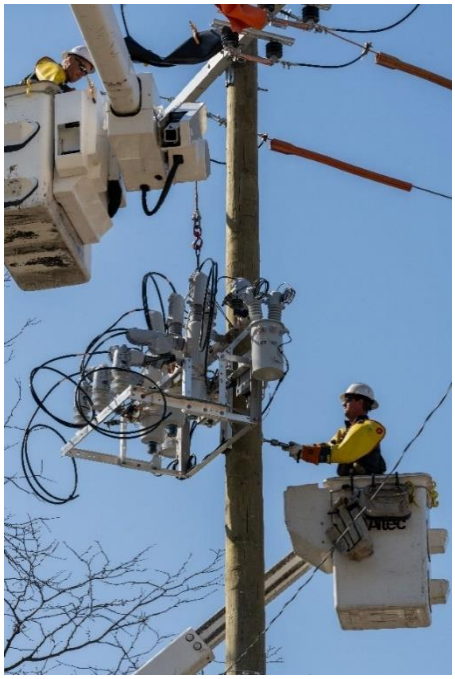
DTE's distribution system has historically relied heavily on manual switching and reactive field response to identify, isolate, and restore outages. This operating model limits real-time visibility and field-level control, constraining the effectiveness of centralized systems and slowing the Company's transition toward predictive, data-driven grid operations. To overcome these limitations, the distribution system must be capable of precise fault isolation, automated sectionalization, and self-healing functionality.

Distribution Automation investments — particularly the deployment of intelligent reclosers — are central to achieving these capabilities and are primarily structured as a safety and restoration program, with reliability and advanced automation benefits that scale incrementally as ADMS capabilities mature. On the 4.8 kV ungrounded delta system, reclosers equipped with ground-hunting logic at substation exits play a critical safety role by rapidly identifying and de-energizing live wire-downs. During outage events, Distribution Automation reclosers can isolate faults closer to their source, preventing substation breakers from opening and limiting interruptions to a smaller portion of the circuit, referred to as sectionalizing. Reclosers also enable automated ties between

circuits, allowing power to be rerouted and further reducing customer impacts. In addition, through communications with the ESOC, reclosers can help pinpoint equipment failures, significantly narrowing down the probable fault location, reducing field patrol time, and accelerating restoration activities.

Collectively, Distribution Automation enables rapid fault detection and isolation, which reduces reliance on manual switching and supports safe, remote restoration actions. These capabilities are foundational to modern grid operations and are necessary to fully leverage ADMS functionality. The Distribution Automation program addresses long-standing operational limitations — such as excessive patrol time and manual switching delays — while delivering measurable safety, reliability, and resiliency benefits across the distribution system.

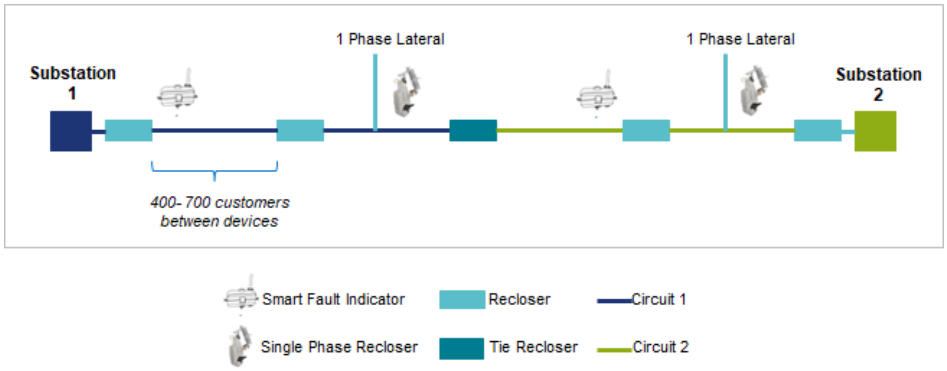
Program Overview and Key Updates



While ADMS provides centralized visibility, analytics, and decision-making, as described in Section 6.4.6 (Advanced Distribution Management Systems), Distribution Automation delivers the field-level capabilities required to execute those decisions in real time. DTE's Distribution Automation program initially focused on deploying intelligent field devices such as automated reclosers and sectionalizing switches. Over time, the program continues to expand into a broader automation ecosystem that includes smart fault indicators, single-phase reclosers, and remote-controlled pole-top switches. This expanded device portfolio enables more granular real-time monitoring and circuit sectionalization, supporting faster and more precise service restoration.

For example, beyond safety reclosers, mid-point and tie-point automation on the 4.8 kV system prepares circuits for future Fault Location, Isolation, and Service Restoration (FLISR) functionality and supports eventual conversion to 13.2 kV. On the 13.2 kV system, automated mid-point and tie reclosers enable effective sectionalization and ADMS-driven service restoration, supplemented by SCADA-enabled devices where enhanced substation visibility is required. The Company strategically segments circuits into optimized customer blocks of roughly 400 to 700 customers, enabling targeted fault isolation, as illustrated in Exhibit 6.56.

Exhibit 6.56 – Distribution Automation Ecosystem Example[162]



DTE continues to incorporate feedback from the Commission and the Audit Report into the design and execution of the Distribution Automation program, with particular emphasis on coordination with planned 4.8 kV Conversions. When selecting circuits for Distribution Automation deployment, the Company considers the timing of future 4.8 kV Conversion projects and defers Distribution Automation investments on circuits planned for conversion within the next five years. If a circuit that has Distribution Automation reclosers installed is subsequently reprioritized for 4.8 kV Conversion, those devices can be redeployed to new locations on the 13.2 kV circuits that better fit the new configuration. In parallel, DTE continues to evaluate emerging device technologies that support cost-effective sectionalization, including single-phase reclosers for single-phase laterals and remote-controlled pole-top switches.

Since development of the initial Distribution Automation program cost estimates, the Company has realized measurable reductions in unit installation costs. Unit costs initially estimated at approximately $137,000 per installation in 2024 declined to approximately $126,000 in subsequent installations, with actual average unit costs of approximately $118,000 achieved by the end of 2025. These reductions reflect improved execution efficiency, including bundled engineering and construction activities, increased contractor familiarity and productivity, and favorable material pricing trends. The realized efficiencies have been incorporated into the updated DA investment profile and contribute to the reduced five-year capital forecast.

Expected Benefits and Cost-Effectiveness

As stated in the most recent General Rate Case Order, “the Commission reaffirms its view that while DA cannot prevent outages, there is significant customer benefit in reducing the number of customers affected by outages and reducing the duration of customer interruptions when they do

[162] Smart Fault Indicators are funded by Distribution Line Sensing and Monitoring as discussed in Section 6.4.5 (Grid Technology).

happen."[163] The impacts shown in Exhibit 6.57 confirm the accuracy of this sentiment, capturing reductions in the number of customers affected and the duration of interruptions. Importantly, these benefits represent a baseline assessment of Distribution Automation value and do not fully reflect the broader set of customer and system benefits expected as Distribution Automation capabilities expand and are further integrated into distribution operations.

Exhibit 6.57 – Customer Benefits of Distribution Automation

Metric	2024	2025	2026[164]
Distribution Automation Reclosers (Cum. Total)	571	1173	1397
Safety-focused Reclosers (Cum. Total)	342	540	614
Reliability-focused Reclosers (Cum. Total)	229	759	783
Customer Interruptions Avoided (CIA; Cum. Total)	9.7K	41.8K	65.4K
Customer Outage Minutes Avoided (CMA; Cum. Total)	3.7M	11.2M	18.0M

DTE partnered with a third-party consultant to estimate the reliability benefits of Distribution Automation investments, as described in Section 5.2.3 (Benefit-Cost Analyses Approach). In response to the Audit Report and Commission's Order in Case No. U-21860, the Distribution Automation BCA was updated to establish dependencies on other reliability-contributing measures, including on-cycle Vegetation Management and PTMM, ensuring that the resulting Distribution Automation benefits are incremental improvements. For Distribution Automation investments, the BCA results serve as a screening and prioritization tool for reliability-driven applications, while safety-driven installations are evaluated separately. The BCA results demonstrate that a portion of Distribution Automation investments are cost-effective and expected to deliver positive net benefits to customers. Additional detail on the analysis, including differences from the prior-year BCA, is provided in Appendix 8.14 (Benefit-Cost Analysis Report).

Distribution Automation ranks third overall in the GPM, reflecting high scores in the Reduce Electrical Hazards, SAIDI, and SAIFI impact dimensions, which underscore its role in improving safety and reliability outcomes. Additional details on the GPM ranking methodology can be found in Section 5.2.4 (Global Prioritization Model).

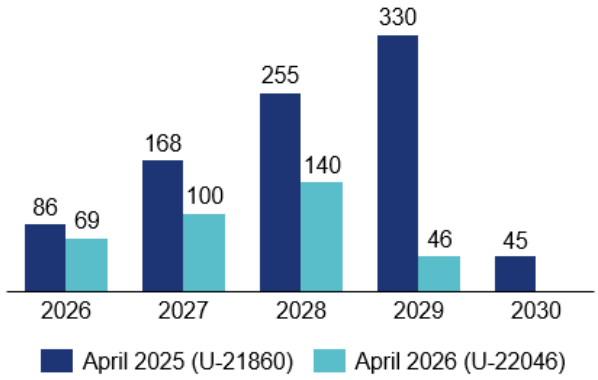
[163] Order dated February 19, 2026 in Case No. U-21860 (page 191), available at https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/068cs00001kHayeAAC, accessed March 24, 2026.

[164] Information presented here represents actual data through March 2026, not an annual projection.

Near-Term Investment

The updated BCA results, together with the cost savings discussed above, support a lower five-year Distribution Automation investment profile than was proposed in the Company's April 2025 General Rate Case filing (Case No. U-21860). As shown in Exhibit 6.58, the total five-year investment has been reduced from approximately $884 million in the prior rate case filing to $355 million in this DSP and Case No. U-22046.

Exhibit 6.58 – Investment Plan for Distribution Automation, April 2025 to April 2026 ($ millions)



Of the $355 million in Distribution Automation investment planned through 2030, approximately $107 million is dedicated to installing safety reclosers on the 4.8 kV system. The five-year investment plan for Distribution Automation, as well as the estimated units, is provided in Exhibit 6.59.

Exhibit 6.59 – Investment Plan and Estimated Units for Distribution Automation, 2026-2030

Distribution Automation	2026	2027	2028	2029	2030	2026 – 2030 Total
Circuits	315	396	517	172	-	**1,400**
Reclosers	560	811	1,138	376	-	**2,885**
Capital ($ millions)	68.9	100.0	140.0	46.0	-	**354.9**

The resulting five-year investment portfolio remains below the level of cost-effective investment identified through the BCA, reflecting the Company's decision to prioritize only the highest-confidence safety and reliability applications, while still delivering meaningful benefits to customers. These refinements directly address the concerns raised in the Audit Report and recent Commission Orders and differentiate the proposed Distribution Automation investments from prior

requests. Accordingly, DTE is requesting Distribution Automation investments for IRM treatment through 2030, as outlined in Section 7.2.1 (Infrastructure Recovery Mechanism).

Long-Term Outlook

Looking ahead, the Distribution Automation program is a key enabler for DTE to meet evolving grid modernization needs by advancing toward a more self-healing grid over time. Distribution Automation investments will also continue to deliver customer-focused reliability improvements while establishing a robust field-level automation foundation. As ADMS capabilities continue to mature, the Company will continue to introduce new device technologies as part of the overall automation ecosystem, including sensors, single-phase reclosers, and SCADA pole-top switches with ubiquitous FLISR capabilities across the electric grid. The deployment of these devices will follow a measured, cost-effective approach that enhances automation performance while maintaining proper prioritization and device application.

6.4.2 Subtransmission SCADA

Grid Needs

The subtransmission system serves as the backbone of the electric grid, supplying power to multiple substations and supporting reliable service across broad geographic areas, which can impact thousands of customers when events do occur, as described in Sections 4.1 (Subtransmission and Distribution System Overview) and 6.3.3 (Subtransmission Redesign and Rebuild). Because each subtransmission circuit feeds one or more distribution substations, these outages have a disproportionately high customer impact. While some segments of the subtransmission system are equipped with automated switching and fault-locating capabilities, other portions continue to rely on manual operation with limited real-time visibility. These disparities constrain operational awareness and flexibility, extend fault isolation and restoration times, and increase reliance on time- and resource-intensive field patrols during abnormal and storm conditions — ultimately prolonging outages and increasing customer impacts.

Although the subtransmission system represents approximately 8% of the Company's total overhead line miles, it has a disproportionately high reliability impact, accounting for approximately 16% of AW SAIFI and 14% of AW SAIDI between January 2025 and February 2026 – roughly twice the impact of the distribution system on a per-line-mile basis. Unlike many distribution outages, which can often be isolated to smaller customer pockets, a single subtransmission fault can result in the complete loss of an entire distribution substation or multiple substations until the fault is located, isolated, and restored. Accordingly, investments that enhance

subtransmission visibility, remote operability, and fault isolation capability represent a highly efficient opportunity to reduce overall customer outage minutes and improve restoration performance.

Currently, DTE's subtransmission system has limited monitoring and switching capability, which hinders speedy restoration of outages that typically impact a much larger number of customers. DTE's investment in Subtransmission SCADA and associated sensing and control technologies is required to address these operational limitations. Expanded real-time monitoring and remote operability across trunk and tie lines enable faster, more precise fault isolation, improved restoration sequencing, and more effective contingency management, thereby reducing CMI. Enhanced SCADA switches also establish a foundation for advanced applications, such as FLISR, and support the safe and reliable integration of growing DERs. Together, these capabilities are essential to modernizing subtransmission operations and ensuring the system can respond dynamically to increasing grid complexity while meeting reliability and resilience targets.

Program Overview

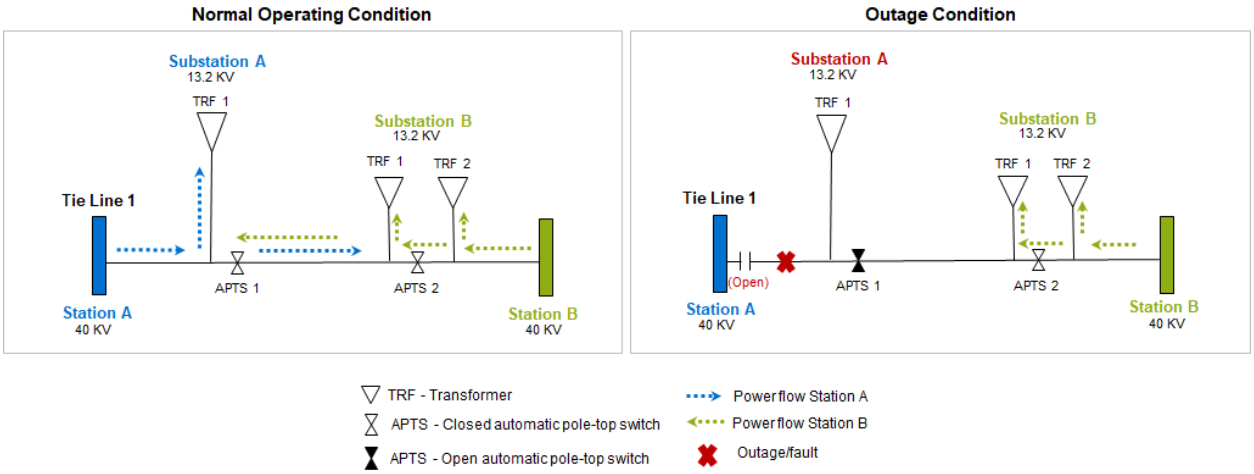
To address these reliability challenges, DTE evaluated the subtransmission system with a focus on outage performance, customer impact, and existing switching capabilities. This evaluation leveraged outage data, circuit topology, and available SCADA devices. Based on this analysis, DTE identified a targeted set of tie lines and trunk lines where incremental SCADA capability would deliver the greatest reliability benefit.

The Subtransmission SCADA program addresses grid needs by expanding deployment of remotely operated switching devices and modern fault-locating sensors across the subtransmission system. These assets strengthen DTE's ability to quickly detect abnormal conditions, isolate faults, and restore service on circuit segments that serve multiple substations. Line-level SCADA devices are designed to operate in coordination with bus section breakers at distribution substations which can enable the automatic throwover of service based on loss of a transformer or subtransmission feed, as described previously in Section 6.3.2 (System Loading).

Exhibit 6.60 illustrates a typical tie line configuration. A tie line is a circuit supplied by two sources (Stations A and B) that feeds one or more distribution substations. Under the normal operating configuration, both Stations will provide the required power to serve Substation A and B. Under an outage condition, as shown in Exhibit 6.60, when a fault occurs between Station A and Substation A Transformer 1 marked by the red "x", the breaker at Station A and APTS 1 operate to isolate the fault, resulting in Substation A Transformer 1 being de-energized until repairs are

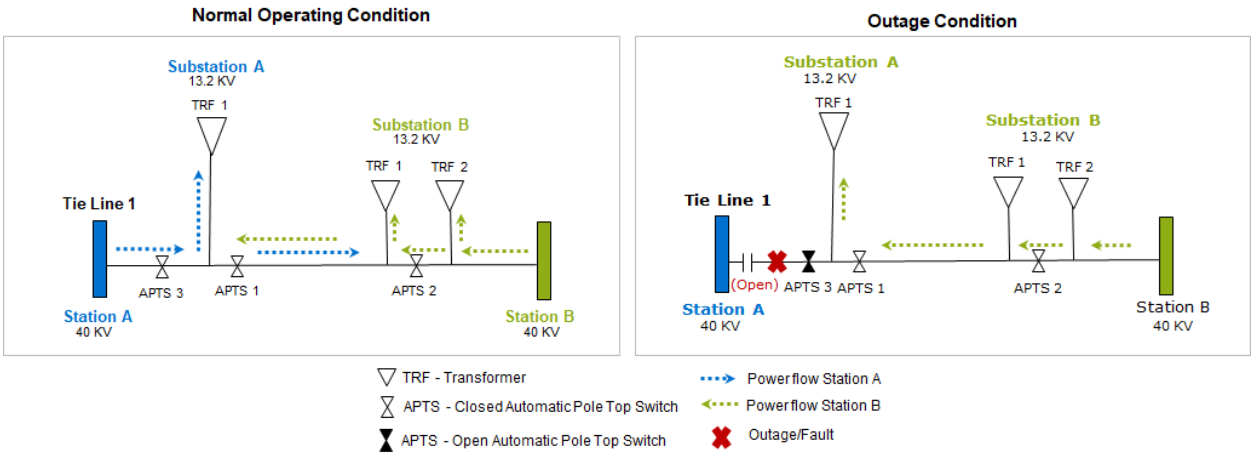
completed. Depending on the scope and scale of the failure or damage, this outage for Substation A could last from hours to longer than a day, while Substation B, including Transformers 1 and 2, remains unaffected by the outage.

Exhibit 6.60 – Tie Line Configuration, Baseline APTS



In this same scenario, Exhibit 6.61 illustrates the much better outcome when an additional APTS (APTS 3) is installed upstream of the single-transformer substation (Substation A Transformer 1). During an outage, the additional APTS enables faster fault isolation and allows both substations to be served by Station B continuously. This configuration reduces customer interruption from the long duration described above to just minutes.

Exhibit 6.61 – Tie Line Configuration with Additional APTS



Program implementation is strategically targeted to locations where additional visibility and sectionalizing provide the greatest operational and customer benefit. This includes deploying SCADA-controlled devices where remote operation materially reduces isolation and restoration

times as well as installing automated switches on high exposure taps and near substations to enhance flexibility during planned and unplanned events. Modern fault indicators are also being installed to improve fault location accuracy and reduce patrol times. All automation enhancements are engineered to align with existing protection schemes, Automatic Throw Over (ATO) configurations, communications infrastructure, and substation standards to ensure safe, reliable, and efficient operations.

Based on these selection criteria, the Company has identified approximately 350 potential locations for inclusion in the program, delivering meaningful reliability improvements while supporting long-term grid modernization. DTE will execute the Subtransmission SCADA program through a phased, multi-year implementation aligned with planned outage windows, available construction resources, and broader system planning objectives. To further improve efficiency and minimize disruption, SCADA deployments will be coordinated with Subtransmission Redesign and Rebuild projects and APTS replacements, delivering multiple upgrades through a sequenced implementation process. Circuit prioritization will be driven by BCA results and informed by planning criteria, operational need, and exposure characteristics, followed by detailed engineering analysis to ensure seamless integration.

Cost-Effectiveness and Near-Term Investment

The Company partnered with a third-party consultant to evaluate Subtransmission SCADA investments using the BCA framework described in Section 5.2.3 (Benefit-Cost Analyses Approach). The results indicate that a significant portion of these investments are cost effective and expected to deliver positive net benefits to customers. Additional detail on the BCA methodology and results is provided in Appendix 8.14 (Benefit-Cost Analysis Report). When evaluated under the GPM, Subtransmission SCADA ranked fourth overall among projects and programs considered, driven by high scores in the SAIDI and SAIFI impact dimensions. Supported by BCA and GPM results, the five-year investment plan and associated units for the Subtransmission SCADA program through 2030 are provided in Exhibit 6.62.

Exhibit 6.62 – Investment Plan and Estimated Units for Subtransmission SCADA, 2026-2030

Subtransmission SCADA	2026	2027	2028	2029	2030	2026 – 2030 Total
SCADA Devices	-	-	12	40	80	**132**
Capital ($ millions)	-	-	6.0	20.0	40.0	**66.0**

DTE's proposed SCADA program targets the greatest customer reliability benefit, avoiding unnecessary installations on circuits that already have effective redundancy or restoration options. This approach allows DTE to significantly reduce the size of outage outcomes and improve restoration speed without over-investing in lower-value locations. Near-term investments will prioritize circuits with the highest historical customer impact, substations lacking effective restoration alternatives, or locations with meaningful opportunity to reduce outage duration.

Long-Term Outlook

Continued investment in Subtransmission SCADA beyond 2030 will be necessary to complete deployment at identified, high-value locations. These investments are prudent and necessary to enable the grid to respond efficiently to both planned and unplanned events. As subtransmission assets continue to age, weather-related stress intensifies, and customers adopt new technologies that introduce increasingly dynamic power flows, the system will require a higher level of operational visibility and controllability to maintain reliable performance. Subtransmission SCADA establishes a foundation for future advanced automation capabilities, including expanded automated restoration and integration with future systemwide FLISR strategies where appropriate.

6.4.3 Operational Technology

Grid Needs

Operational Technology (OT) provides the foundation for how the grid is planned, monitored, and operated in real time. OT encompasses the systems, applications, and field devices that directly model, sense, communicate, and control the grid, integrating operational data across substations, feeder assets, control centers, and enterprise platforms. It differs from traditional utility infrastructure as described in Section 4.2.4 (Technology and Grid Communication Assets). As the grid becomes more complex due to increased DERs, electrification, and increasingly severe weather, legacy tools and manual processes are no longer sufficient. Without modern, scalable OT, DTE's ability to maintain situational awareness, operate the grid safely, respond effectively to outages, and

optimize system performance is constrained. Investment in OT addresses this foundational need by enabling a shift from reactive operations to proactive, data-driven planning and control, supporting safe, reliable, and efficient grid operations today and into the future.

Program Overview and Near-Term Capital Investment

The Company's OT program is organized around five primary investment categories: Distribution Planning, Grid Management, Work Management, Asset Management, and Mobile Technology. Collectively, these investments form an integrated modernization program that supports near-term operational execution while enabling the longer-term transformation of the planning, design, and analytical capabilities needed to manage an increasingly complex grid and meet evolving customer needs.

To manage risk while ensuring value for customers, DTE employs a fast-follower approach to OT investments that emphasizes demonstrated value and maturity over first-mover adoption. This strategy allows the Company to benefit from lessons learned across the industry by deploying technologies that have proven their reliability, scalability, and vendor roadmap stability in real-world utility environments, while avoiding the cost and operational risks associated with early-stage platforms. Additional detail on how OT initiatives are prioritized and selected is provided in Section 5.2.2 (Operational Technology Prioritization Framework). Exhibit 6.63 summarizes DTE's five-year OT capital investment forecast.

Exhibit 6.63 – Operational Technology Capital Investment Forecast, 2026-2030 ($ millions)[165]

Operational Technology	2026	2027	2028	2029	2030	2026 – 2030 Total
Distribution Planning	10.7	19.2	15.0	9.9	14.2	**69.0**
Grid Management	18.6	-	-	5.5	-	**24.1**
Work Management	9.0	9.1	8.4	4.7	3.8	**34.9**
Asset Management	5.5	7.6	7.3	3.7	2.4	**26.5**
Mobile Technology	4.3	5.0	5.1	3.2	5.7	**23.3**
Total	**48.1**	**40.9**	**35.8**	**27.0**	**26.1**	**177.9**

The timing and scale of these investments reflect the Company's current assessment of technology evolution, commercial conditions, and other expectations. As these conditions continue to evolve, future DSP updates will refine the OT investment plan to maintain prudency

[165] Totals may not match exactly to the mathematical summation in the table due to rounding of the source data.

and alignment with system needs. Across all five investment areas, OT investments directly support customer safety and reliability by enhancing real-time situational awareness, improving field execution and workforce effectiveness, strengthening asset data quality and lifecycle management, integrating planning and operations, modernizing grid modeling and analytics, and delivering platforms aligned with evolving cybersecurity, interoperability, and regulatory requirements. Additional information for each OT investment category is provided below.

Distribution Planning

The Distribution Planning category provides engineering and analytical tools to design, model, and simulate the electrical system, evaluating performance, capacity constraints, DER impacts, and long-term capital planning and scenarios. It includes industry-standard planning and design tools (e.g., power-flow and stability studies), capacity tools, interconnection enablement, power-quality analytics, design tool automation, and structural design programs for the entire electric grid. These systems form the analytical foundation of the planning process, enabling accurate forecast scenarios, identification of needs and constraints, and the tools to design the corresponding solutions.

Legacy tools and manual processes supported the grid planning process of the past, but changes in the Company's grid now require an update. They cannot produce timely, granular, and consistent studies across multiple scenarios further complicated by rapid electrification and DER growth. They also cannot maintain data integrity across GIS, planning, and other work systems. Modern planning platforms improve study accuracy and speed, integrate annual 8,760-hour profiles to fully assess DER and NWA opportunities, and align interconnection and hosting-capacity analytics with customer-facing transparency. The alternative of continuing to operate and maintain legacy OT systems for Distribution Planning would result in inconsistent models, slower studies, weaker interconnection compliance, and less defensible, risk-based capital allocations. Specific investments within Distribution Planning, including their use cases and expected benefits, are summarized in Exhibit 6.64.

Exhibit 6.64 – Summary of Distribution Planning OT Investments

Investment	Use Case Description	Implementation Highlights and Customer Benefit
Customer Agreement Processing (CAP) System Replacement	Replaces legacy system for new business agreements with modern workflow automation	• Adds automated routing, DocuSign/OpenText integration, and secure workflows • Reduces processing and wait times
Customer Power Quality Monitoring & Issue Investigation	Detects early signs of equipment or voltage problems to prevent outages	• Introduces real-time waveform analytics and predictive engines to support proactive maintenance and faster restoration
Design Tool Automation	Automates overhead/underground design workflows and ensures compliance with DTE and industry standards	• Integrates tools with GIS and work management, improves design speed and accuracy, and enhances coordination with digital construction workflows
Hosting Capacity Enablement	Improves automation and accuracy of hosting capacity maps for DER siting and transparency	• Automates backend processes, increases update frequency, and enhances customer-facing detail for clearer DER siting guidance
Interconnection Process Enablement	Modernizes customer-facing and internal DER interconnection systems to meet evolving requirements	• Enhances PowerClerk, payment processing, cybersecurity, and automation. • Speeds interconnection approvals and improves customer experience
Load Forecasting & Analytics	Creates 8,760-hour load profiles and supports forecasting, DER impact analysis, and NWA evaluation	• Implements secondary modeling, forecasting modules, scenario modeling, and DER-capable analytics • Enables more accurate capacity planning and DER integration • Enhancements and upgrades to distribution and sub transmission planning tools
Power Quality Analysis Program	Collects, integrates, and analyzes waveform and power-quality event data	• Builds interfaces to SCADA and ADMS, creates a central waveform repository, speeds diagnosis of PQ issues, and supports targeted maintenance
Substation Design Tool Upgrades	Modernizes design tools for overhead, underground, and substation structural analysis	• Provides structural loading and modeling, and facilitates vendor-to-utility designs • Reduces rework and supports accurate, resilient infrastructure design

Over the next five years, Distribution Planning investments are forecasted to be approximately $69.1 million, as shown in Exhibit 6.65.

Exhibit 6.65 – Distribution Planning OT Investment Summary, 2026-2030 ($ millions)[166]

Investments	2026	2027	2028	2029	2030	2026-2030 Total
Customer Agreement Processing (CAP) System Replacement	-	1.9	1.9	-	-	**3.8**
Customer Power Quality Monitoring & Issue Investigation	-	0.9	0.6	-	-	**1.5**
Design Tool Automation	1.2	2.1	1.8	2.4	1.7	**9.2**
Hosting Capacity Enablement	0.4	0.3	0.5	0.4	0.5	**2.1**
Interconnection Process Enablement	2.5	2.7	2.6	2.5	2.5	**12.8**
Load Forecasting & Analytics	5.2	8.3	4.7	3.3	8.2	**29.6**
Power Quality Analysis Program	0.4	0.5	0.4	0.4	0.5	**2.2**
Substation Design Tool Upgrades	1.0	2.5	2.5	1.0	0.8	**7.8**
Total – Distribution Planning	**10.7**	**19.2**	**15.0**	**9.9**	**14.2**	**69.1**

Over the long term, the updated planning tools will support scenario-based probabilistic analysis, integrated grid and DER modeling, automated design workflows, and align with national trends towards advancing distribution planning. As DER complexity, dynamic loads, and automation expand, utilities will face an explosion of possible scenarios, requiring advanced computational models, machine learning, and Agentic AI to manage both simulation and interpretation within practical timeframes and costs. Investment will likely shift toward fully automated planning environments supported by real-time digital twins, more detailed and transient system studies, and tools capable of modeling inverter-based resources and rapid power fluctuations.

Grid Management

Following the transition of ADMS, FLISR, and DERMS to their own investment categories, Grid Management now reflects a more focused portfolio of foundational operational investments. The remaining scope is concentrated on sustaining core grid functions, including telemetry and SCADA data management, AMI network operations, outage management and dispatch systems, and the replacement of aging or unsupported infrastructure. As shown in Exhibit 6.66, these investments support accurate operational visibility, regulatory compliance, and reliable customer restoration, with the majority of investment occurring in 2026. Collectively, the Grid Management category underpins system performance, customer experience, and ongoing operational resilience.

[166] Totals may not match exactly to the mathematical summation in the table due to rounding of the source data.

Exhibit 6.66 – Summary of Grid Management OT Investments

Investment	Use Case Description	Implementation Highlights and Customer Benefit
Automation Configuration and Test Record Database	Replaces an unsupported custom database managing configuration data for 37,000+ relay and SCADA devices	• Automates data entry, ensures NERC CIP compliance, and integrates with asset/work management systems • Improves accuracy, workflow efficiency, and support for DER and modern protection functions
Customer Power Status Visibility Program	Improves AMI communication reliability, outage detection, and customer restoration	• Replaces aging FARs[167], remediates defects, and increases FAR saturation • Improves PON[168] messaging
Distribution SCADA Historian	Provides long-term storage and retrieval of SCADA data to support planning, voltage and loading analysis, and system performance metrics	• Underpins accurate telemetry, operational insights, and improved system performance for customers. • Primary database for all SCADA measurement history
Meter Improvements	Supports replacement of damaged field equipment, expansion of meter lab and validating Next-Gen AMI capabilities	• Enhances meter reliability performance through new AMI features (super-capacitors, Wi-Fi, analytics) • Ensures smooth deployment via software, consulting, and lab testing
Operational Technology and Error-Free Communication	Supports necessary operational tools and customer-facing application enhancements related to outage status	• Funds improvements to outage maps, WISMO, and other critical DO applications • Improves outage visibility, communication accuracy, and customer experience during restoration events
Other Modernize Grid Management	Establishes the AMI Network Operations Center	• Monitors, operates, and optimizes the AMI network that supervises control and data flow from individual meters to the Company's data centers
SOC Phone and Radio Dispatch	Replaces aging hardware and end-of-life software for ESOC's central dispatch system	• Migrates servers, upgrades to AVTEC 5.11, and replaces call recording systems • Maintains compliance, reduces support risk, and improves dispatcher responsiveness for customers

Over the next five years, Grid Management investments are forecasted to total approximately $24.1 million, as shown in Exhibit 6.67.

[167] FAR indicates Field Area Router.
[168] PON indicates Power Outage Notification.

Exhibit 6.67 – Grid Management OT Investment Summary, 2026-2030 ($ millions)[169]

Investments	2026	2027	2028	2029	2030	2026-2030 Total
Automation Configuration and Test Record Database	1.2	-	-	-	-	**1.2**
Customer Power Status Visibility Program	7.8	-	-	-	-	**7.8**
Distribution SCADA Historian	4.7	-	-	5.5	-	**10.2**
Meter Improvements	1.4	-	-	-	-	**1.4**
Operational Technology and Error Free Communication	0.5	-	-	-	-	**0.5**
Other Modernize Grid Management	1.7	-	-	-	-	**1.7**
SOC Phone and Radio Dispatch	1.2	-	-	-	-	**1.2**
Total – Grid Management	**18.6**	**-**	**-**	**5.5**	**-**	**24.1**

Over the long term, Grid Management investments will transition from the foundational deployment phase to predictive, analytics-driven operations and integrated orchestration. The scope will expand toward tighter ADMS/DERMS alignment, feeder-level automation, probabilistic forecasting, and broader sensor deployment. Cybersecurity and interoperability standards will continue to increase, and investment plans will adapt as vendors shift licensing and managed-service models.

Work Management

Work Management enhances the systems and digital tools that support DTE in efficiently planning, scheduling, executing, and documenting field work across the system. It modernizes crew scheduling, mobile work execution, contractor efficiency, vegetation management, customer-driven work, and timekeeping. Collectively, these technologies improve the Company's ability to deploy resources effectively across both emergent and planned work. The Work Management investments aimed at improving overall efficiency and productivity are summarized in Exhibit 6.68.

[169] Totals may not match exactly to the mathematical summation in the table due to rounding of the source data.

Exhibit 6.68 – Summary of Work Management OT Investments

Investment	Use Case Description	Implementation Highlights and Customer Benefit
Digital Construction Management	Replaces manual paperwork and disconnected construction workflows with a unified digital platform	• Connects GIS, Maximo, and design tools. • Improves safety, accuracy, and visibility • Reduces manual errors and supports modernization • Enhances construction updates and resource/material forecasting
External Crew Efficiency	Enhances oversight and productivity of external crews performing trouble work, storm response, and construction	• Integrates URMA with OMS, digitizes approvals, enables real-time crew visibility, and automates reporting • Improves restoration coordination, accountability, and customer reliability
Field Service Management	Standardizes digital workflows for substation crews	• Provides digital work packets, asset details, real-time validation, and offline capability with Maximo/GIS integration • Eliminates paper packets, reduces rework, and improves work quality
Field Work Execution & Workforce Management Enhancements	Supports roster management and crew assignment across planned, emergent, and contractor work	• Automates roster workflows, strengthens compliance tracking, integrates with timekeeping/planning systems, and reduces administrative burden
Mobile Timesheets	Introduces real-time mobile timekeeping for overhead and underground crews to replace manual processes	• Automates validations, integrates payroll and work management, streamlines approvals, and improves compliance • Enhances labor cost accuracy and decreases processing time
Vegetation Management Replatform	Modernizes vegetation scheduling, analytics, contractor oversight, and compliance reporting	• Adds integrated mapping, mobile inspection tools, risk-based planning, and advanced capabilities like LiDAR • Strengthens prioritization and improves reliability for customers

Over the next five years, Work Management investments are forecasted to be approximately $34.9 million, as shown in Exhibit 6.69.

Exhibit 6.69 – Work Management OT Investment Summary, 2026-2030 ($ millions)[170]

Investments	2026	2027	2028	2029	2030	2026-2030 Total
Digital Construction Management	-	2.1	2.2	0.8	0.8	**5.8**
External Crew Efficiency	3.1	3.7	2.2	-	-	**9.0**
Field Service Management	1.3	0.5	-	0.9	-	**2.7**
Field Work Execution & Workforce Management Enhancements	-	-	3.0	3.0	3.0	**9.0**
Mobile Timesheets	1.4	1.3	0.5	-	-	**3.2**
Vegetation Management Replatform	3.2	1.6	0.5	-	-	**5.3**
Total – Work Management	**9.0**	**9.1**	**8.4**	**4.7**	**3.8**	**34.9**

[170] Totals may not match exactly to the mathematical summation in the table due to rounding of the source data.

Over the long term, DTE anticipates Work Management investments to advance from digitization to predictive operations, including AI-driven scheduling, risk- and weather-informed planning, digital twins for resource simulation, and scalable contractor models for peak periods. Rising field workloads, climate-driven storm and vegetation pressures, workforce transitions, and cost control will make integrated digital tools essential.

Asset Management

Asset Management modernizes the data environments and analytical tools used by DTE engineers to assess asset conditions, manage risk, prioritize investments, and maintain grid health. The program integrates enterprise data, engineering models, imagery and LiDAR, field inspections, failure analytics, and long-term forecasting for poles, wires, substations, relays, communications equipment, and grid automation devices. Additional information on the current state of the Company's Asset Management strategy can be found in Section 4.4.1 (Asset Management), and detail on transitioning to more predictive analytics can be found in Section 6.4.4 (Asset Condition Monitoring Technology). Asset Management investments focused on strengthening modeling foundations, imagery and analytics platforms, condition assessment tools, and critical operational infrastructure are summarized in Exhibit 6.70.

Exhibit 6.70 – Summary of Asset Management OT Investments

Investment	Use Case Description	Implementation Highlights & Customer Benefit
Enterprise Service Bus Upgrade	Modernizes integration of middleware supporting real-time data exchange across OMS, AMI, Billing, WFM, and OT/IT systems	• Supports higher data volumes and real-time messaging • Reduces integration failures that impact field and control-room operations • Enhances cybersecurity
ESRI Utility Network Upgrade	Modernizes GIS to an ESRI-supported Utility Network for accurate grid modeling, connectivity, and analytics across planning systems	• Upgrades legacy GIS format and aligns models across systems • Supports advanced load modeling and spatial analytics • Improves data quality and strengthens change control
Telecom & Radio Systems Upgrade	Upgrades mission-critical communication systems for field operations, outage response, and emergency coordination	• Refreshes dispatch hardware, truck radios, voice recording, and satellite backup • Improves audio quality, coverage, interoperability, and cybersecurity • Ensures resilient communication during storms and low coverage events

Over the next five years, Asset Management investments are forecasted to total approximately $26.5 million, as shown in Exhibit 6.71.

Exhibit 6.71 – Asset Management OT Investment Summary, 2026-2030 ($ millions)[171]

Investments	2026	2027	2028	2029	2030	2026-2030 Total
Enterprise Service Bus Upgrade	-	2.1	1.1	1.1	-	**4.3**
ESRI Utility Network Model Upgrade	5.5	5.5	5.5	1.5	-	**18.0**
Telecom & Radio Systems Upgrade	-	-	0.7	1.1	2.4	**4.2**
Total – Asset Management	**5.5**	**7.6**	**7.3**	**3.7**	**2.4**	**26.5**

Over the long term, Asset Management emphasizes predictive analytics, automated inspections, and highly integrated operational data environments, including digital twin models for assets and circuits, automated LiDAR and imagery ingestion with AI-driven detection, and condition-based programs that optimize capital investment. As unified Asset Performance Management platforms mature, investment will be needed to support cloud storage and analytics, and cybersecurity compliance needs are expected to continue to evolve.

Mobile Technology

Mobile Technology supports the efficiency of field personnel with secure, real-time access to work instructions, system data, mobile hardware, and communication tools. It supports storm response, cybersecurity, and daily field productivity by providing real-time field access to accurate work packets, asset information, mapping, photos, safety documentation, and secure communications. Investments in Mobile Technology address the need for modern, reliable, and secure mobile capabilities integrated with the ADMS, GIS, Work Management, and other systems.

[171] Investment for Image Acquisition Platforms and Asset Failure Analytics can be found in Section 6.4.4 (Asset Condition Monitoring Technology).

Legacy or inconsistent devices and applications can impede data quality, slow work, and increase security risk. The near-term Mobile Technology investments are summarized in Exhibit 6.72.

Exhibit 6.72 – Summary of Mobile Technology Investments

Investment	Use Case Description	Implementation Highlights and Customer Benefit
Enhance and Expand Cybersecurity	Scales cybersecurity capabilities as mobile device usage and grid automation increase	• Protects customer data and operational assets and prevents cyber threats to critical infrastructure • Secures field automation and communications • Maintains NERC-CIP compliance as more grid technologies come online
Mobile Equipment Replacement	Replaces frontline tablets and rugged devices on a regular cycle to ensure reliable mobile operations and standardization across teams	• Deploys faster, more durable devices with improved connectivity and battery life • Enhances field efficiency and supports the broader mobile platform ecosystem
Mobile Tools Expansion	Deploys automated job assignments, routing optimization, and priority ranking across mobile tools	• Introduces AI-driven recommendations, mobile accessibility, disaster recovery, and OMS/EDDP integration • Strengthens real-time visibility • Enhances workflows for trouble and planned work

Over the next five years, Mobile Technology investments are forecasted to total approximately $23.3 million, as shown in Exhibit 6.73.

Exhibit 6.73 – Mobile Technology Investment Summary, 2026-2030 ($ millions)[172]

Investments	2026	2027	2028	2029	2030	2026-2030 Total
Enhance and Expand Cybersecurity	1.1	2.0	2.0	2.1	2.1	**9.2**
Mobile Equipment Replacement	1.0	1.0	1.0	1.1	3.6	**7.7**
Mobile Tools Expansion	2.2	2.1	2.1	-	-	**6.3**
Total – Mobile Technology	**4.3**	**5.0**	**5.1**	**3.2**	**5.7**	**23.3**

Long-Term Outlook

Over the long term, DTE expects its OT investments — particularly mobile and field technologies — to continue evolving toward real-time synchronization across ADMS, GIS, and advanced analytics, supported by voice-enabled, sensor-driven workflows, integrated drone imagery, and increasingly robust cybersecurity controls. As emerging vehicle-mounted, robotic, and sensor-

[172] Totals may not match exactly to the mathematical summation in the table due to rounding of the source data.

based systems mature, they may further expand the conditions under which work can be performed safely while capturing higher-quality asset and operational data. While rapid hardware refresh cycles, legacy system integration, and workforce training are expected to remain ongoing challenges, the OT portfolio is deliberately sequenced to balance near-term operational and grid needs with longer-term modernization. This approach ensures the Company sustains today's infrastructure while positioning the grid to take advantage of future capabilities as grid complexity grows. Across planning, operations, and field execution, sustained investment in OT is necessary to support safe and reliable grid operations today and position the system to meet tomorrow's demands — supporting a more resilient, intelligent, and customer-focused system that reduces outage frequency and duration, strengthens cybersecurity, and improves capital efficiency.

6.4.4 Asset Condition Monitoring Technology

Grid Needs

DTE owns and operates more than 1.6 million subtransmission and distribution assets across a geographically diverse service area. Maintaining safe and reliable service depends on understanding asset conditions, degradation mechanisms, and damage resulting from both normal aging and external events. As infrastructure ages and operating conditions become more dynamic, traditional time-based inspection cycles and manual assessments are increasingly insufficient to support proactive asset management.

The challenge extends beyond identifying isolated asset defects. Effective asset condition monitoring requires the consistent collection, interpretation, and long-term retention of condition information across asset classes and locations. Condition data must be standardized, accurately linked to asset records, and retained as part of an asset's lifecycle history to meaningfully inform maintenance, repair, and replacement decisions. Without this structure, condition information remains fragmented and cannot support systemwide prioritization or planning.

These needs become especially critical during major weather events. Within the first couple of hours following a storm, DTE must develop an acute understanding of damage scope, severity, and location to deploy restoration resources efficiently. Access to "as-built" design imagery and asset records improves material ordering accuracy and first-crew efficiency. At the same time, damage and condition information identified during emergency response must be preserved and incorporated into ongoing asset health records rather than treated as event-specific data that is discarded after restoration. All of this must be achieved without increasing burden on field crews, whose responsibilities already include restoration, inspections, and routine operations.

Collectively, these challenges underscore the need for a more proactive, data-driven approach to asset condition monitoring — one that enables earlier detection of deterioration, accelerates damage assessment, and informs long-term asset lifecycle decisions, consistent with the asset management framework described in Section 4.4.1 (Asset Management).

Program Overview

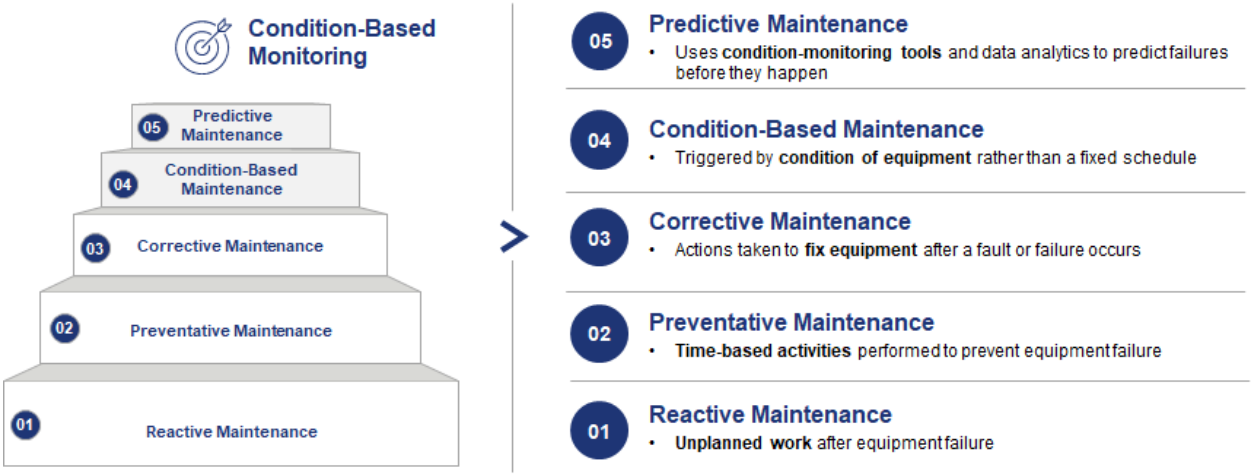
To address evolving system needs, DTE's Asset Management Roadmap establishes a structured strategy for monitoring and assessing the condition and health of electric grid assets, as illustrated in Exhibit 6.74.

Exhibit 6.74 – Asset Management Roadmap

The roadmap advances asset management capabilities from foundational data, governance, and work management controls toward a mature, condition-based and analytics-driven framework that supports proactive outage prevention and sustained reliability. Core elements include implementing condition-based and predictive monitoring through digitized inspections and near-real-time data capture, developing standardized asset health analytics and reporting, strengthening configuration control to ensure accurate system records, formalizing data governance to maintain data integrity, aligning technology solutions with process maturity, and enhancing work management to translate asset condition insights into timely and effective field execution.

DTE is transitioning from reactive and time-based maintenance practices toward condition-based and predictive asset management, in which inspection, maintenance, and replacement decisions are informed by observed asset health rather than fixed schedules or post-failure response. This shift includes expanded use of remote monitoring and a reduced reliance on time-based maintenance to better identify when breakers, relays, and substation transformers require intervention — an approach the Audit Report recognized as supporting improved asset condition monitoring while reducing maintenance costs."[173] As illustrated in Exhibit 6.75, maintenance strategies evolve from reactive maintenance following equipment failures, through preventative and corrective approaches, to condition-based and predictive maintenance enabled by continuous monitoring and analytics. Advancing along this continuum improves reliability, safety, and cost-effectiveness by allowing issues to be identified and addressed before they result in outages, safety risks, or accelerated asset degradation.

Exhibit 6.75 – Progression from Reactive to Predictive Maintenance



DTE's Asset Condition Monitoring Technology program is designed to support this progression by systematically integrating condition data from multiple sources into a unified and scalable framework. The program is organized around two complementary investment categories:

- **Image Acquisition Platforms:** Determines how asset condition data is collected.
- **Asset Failure Analytics:** Converts that data into actionable insight.

[173] Finat Report, Utility Distribution Audit of DTE Energy (page 30), available at https://mipsc.my.site.com/sfc/servlet.shepherd/version/download/068cs00000AyaNpAAJ, accessed April 21, 2026.

Together, these investments connect field observations, automated sensing, and advanced analytics into a centralized asset health ecosystem, enabling a systematic shift from periodic and reactive maintenance toward condition-based and predictive decision-making.

Image Acquisition Platforms

Image Acquisition Platforms[174] encompass the portfolio of technologies used to collect condition data based on asset type, accessibility, and risk profile. These include mobile field tools, automated sensors, and advanced patrol and imaging techniques deployed through foot patrols, vehicles, drones, aircraft, and satellites. Each method is selected to capture condition information appropriate to the asset being evaluated, such as visual imagery, infrared data, LiDAR scans,[175] electrical measurements, and event records.

DTE is equipping field crews with mobile applications that support consistent, structured capture of asset condition information during routine inspections, patrols, and walkdowns. Digital forms, photo documentation, and automated data capture reduce manual effort and ensure findings are directly associated with specific assets. In some cases, image analytics and AI tools can identify assets and observable defects while crews perform other tasks, minimizing rework and improving data quality.

The Company is also deploying automated sensor technologies on or near critical assets where periodic inspections alone are insufficient. These include line, pole, transformer, underground cable, breaker, recloser, capacitor, and regulator sensors, among others. Sensor data supports real-time detection of abnormal conditions as well as long-term trend analysis to inform maintenance and replacement strategies. Many of these deployments are covered throughout various Technology and Automation investments, which are discussed throughout Section 6.4 (Technology and Automation).

Advanced patrol and imaging methods supplement inspection and sensor data by providing additional perspectives on asset conditions. Aerial and satellite imagery, drones, vehicle-mounted cameras, and foot patrols each offer distinct advantages depending on asset location and inspection objectives. Using multiple acquisition methods helps capture conditions that may not be visible from a single vantage point, particularly for overhead assets affected by vegetation, terrain, or access constraints.

[174] Previously named Lidar and Imagery Analysis Platform in MPSC Case No. U-21860.

[175] LiDAR is a remote sensing technology that uses laser pulses to measure distances and create highly accurate 3D representations of vegetation, structures, and assets.

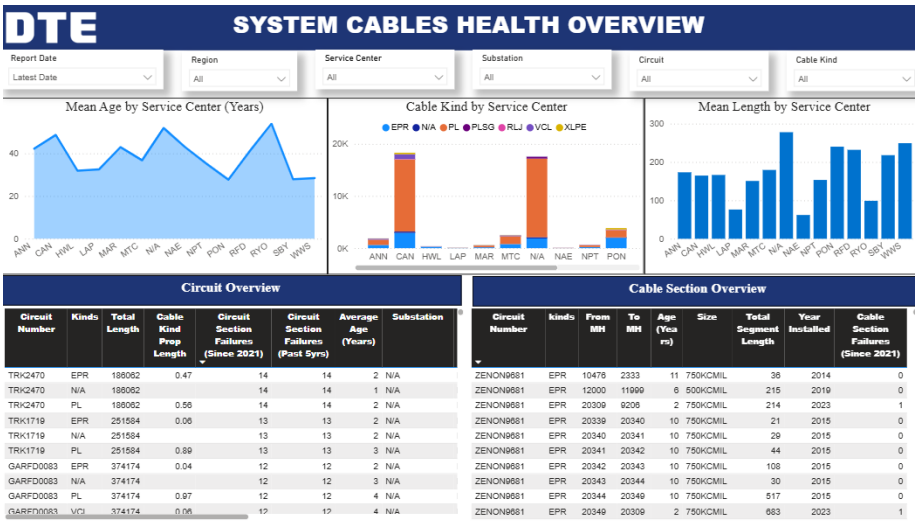
While each technique offers benefits, none is sufficient on its own. Visual imagery is widely available and intuitive but can be affected by lighting, glare, resolution, or lens cleanliness. Infrared technologies identify specific failure modes but require specialized equipment. Aerial imagery and LiDAR provide broad coverage and high-precision geometry but are constrained by flight frequency and weather. Drones offer targeted access but currently require manual operation. A diversified portfolio mitigates these limitations and reduces blind spots inherent in any single method.

Asset Failure Analytics

Asset Failure Analytics focus on transforming collected data into actionable insights. Data from field tools, sensors, patrols, SCADA, and AMI systems are transmitted to centralized platforms that support correlation, analysis, and visualization. DTE employs a combination of internally developed analytics, vendor solutions, and machine-learning and AI techniques to identify degradation patterns, prioritize risks, and support root-cause analysis.

Effective analytics depend on strong data governance and seamless system integration. All condition data is geospatially referenced and linked to accurate asset records through a current GIS model, ensuring consistency and alignment across asset classes. Centralized data storage enables cross-asset analysis and supports the development of dashboards, reports, and visualizations that surface high-priority conditions and summarize asset health trends to inform both operational and planning decisions. Exhibit 6.76 illustrates one such dashboard. Underground cable assets were the first asset class incorporated into this framework, with plans to expand coverage to additional asset classes over time.

Exhibit 6.76 – System Cable Health Dashboard

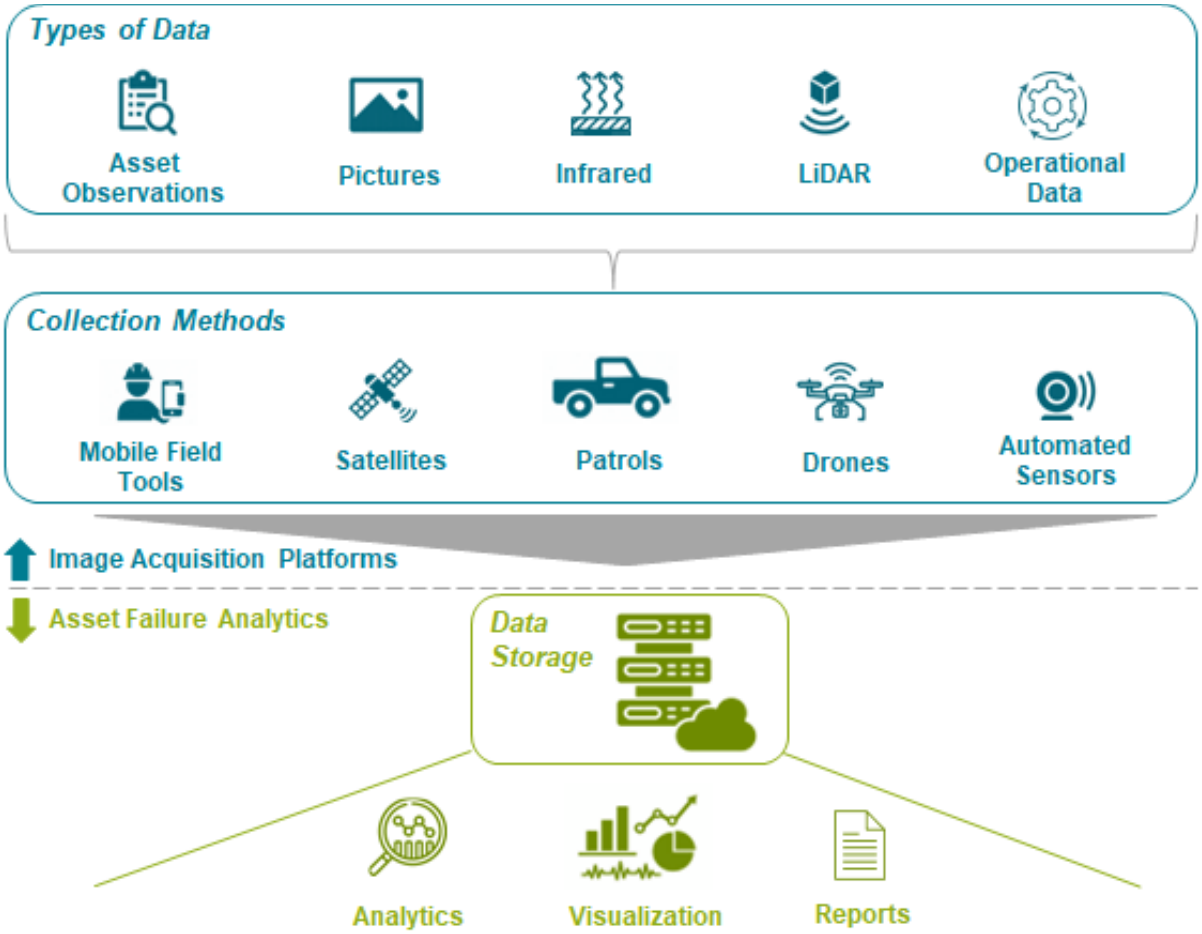


Circuit Number	Kinds	Total Length	Cable Kind Prop Length	Circuit Section Failures (Since 2021)	Circuit Section Failures (Past 5yrs)	Average Age (Years)	Substation
TRK2470	EPR	186062	0.47	14	14	2	N/A
TRK2470	N/A	186062		14	14	1	N/A
TRK2470	PL	186062	0.56	14	14	2	N/A
TRK1719	EPR	251584	0.06	13	13	2	N/A
TRK1719	N/A	251584		13	13	2	N/A
TRK1719	PL	251584	0.89	13	13	3	N/A
GARFD0083	EPR	374174	0.04	12	12	2	N/A
GARFD0083	N/A	374174		12	12	3	N/A
GARFD0083	PL	374174	0.97	12	12	4	N/A
GARFD0083	VCL	374174	0.06	12	12	4	N/A

Circuit Number	kinds	From MH	To MH	Age (Years)	Size	Total Segment Length	Year Installed	Cable Section Failures (Since 2021)
ZENON9681	EPR	10476	2333	11	750KCMIL	36	2014	0
ZENON9681	EPR	12000	11999	6	500KCMIL	215	2019	0
ZENON9681	EPR	20309	9206	2	750KCMIL	214	2023	1
ZENON9681	EPR	20339	20340	10	750KCMIL	21	2015	0
ZENON9681	EPR	20340	20341	10	750KCMIL	29	2015	0
ZENON9681	EPR	20341	20342	10	750KCMIL	44	2015	0
ZENON9681	EPR	20342	20343	10	750KCMIL	108	2015	0
ZENON9681	EPR	20343	20344	10	750KCMIL	30	2015	0
ZENON9681	EPR	20344	20349	10	750KCMIL	517	2015	0
ZENON9681	EPR	20349	20309	2	750KCMIL	683	2023	1

The integrated relationship between Image Acquisition Platforms and Asset Failure Analytics is illustrated in Exhibit 6.77.

Exhibit 6.77 – Asset Condition Monitoring Technology Framework



Expected Benefits and Near-Term Investment

This integrated asset condition monitoring approach enables DTE to deploy a broad range of acquisition technologies while maintaining a consistent, enterprise-level view of asset health. By shifting from fixed-cycle maintenance to condition-based interventions across poles, transformers, conductors, underground cables, and substations, the program improves the precision and timing of maintenance activities. Enhanced defect detection, supported by dashboards and risk maps, reduces patrol time and associated costs while improving the accuracy of asset condition assessments. Together, these capabilities reduce unplanned failures, improve capital prioritization, enhance public and employee safety, and support more consistent reliability performance across the electric grid. The five-year investment plan, totaling $33.4 million, is shown in Exhibit 6.78.

Exhibit 6.78 – Investment Plan for Asset Condition Monitoring Technology, 2026-2030 ($ millions)

Investments	2026	2027	2028	2029	2030	2026-2030 Total
Asset Failure Analytics	1.0	1.0	1.1	1.2	1.4	**5.7**
Image Acquisition Platforms	-	3.6	5.8	12.1	6.2	**27.7**
Total	**1.0**	**4.6**	**6.9**	**13.3**	**7.6**	**33.4**

Long-Term Outlook

Over the long term, continued investment in asset condition monitoring technology supports DTE's progression along the maintenance maturity continuum — from reactive and time-based approaches toward fully condition-based and predictive maintenance. As monitoring coverage expands and analytics capabilities mature, asset condition assessments will increasingly shift from identifying issues after failure to anticipating degradation and intervening earlier in the asset lifecycle. This progression enables maintenance, reinforcement, and replacement decisions to be made with greater confidence and fewer emergency interventions.

By integrating diverse data collection methods with centralized analytics and strong data governance, the asset condition monitoring framework supports earlier identification of risks associated with aging infrastructure and enables proactive mitigation ahead of severe weather events. These capabilities reduce the likelihood of premature failures, improve storm resilience, and allow resources to be deployed more efficiently as system conditions evolve. Over time, this transition to predictive, data-driven asset management strengthens grid reliability, optimizes capital investment, and provides a scalable foundation to manage increasing system complexity while continuing to deliver safe and reliable service to customers.

6.4.5 Grid Technology

Grid Needs

The Company's electrical system is experiencing increased operational complexity driven by growing adoption of DERs and EVs. As discussed throughout Section 6.4 (Technology and Automation), addressing these challenges requires grid modernization technology that enhances sensing, automation, and optimization capabilities to provide real-time visibility to enable more dynamic control and support proactive system management. Grid Technology investments deploy key field devices that underpin the capabilities described above — including controllable capacitors, voltage regulators, SCADA communications equipment, and line sensors — and

support the testing needed to integrate EVs and DERs at scale. These investments are important for improving voltage management and outage detection and restoration while creating a flexible, adaptive grid capable of accommodating emerging technologies.

Program Overview and Expected Benefits

Grid Technology represents a strategic investment category focused on modernizing the electrical system through advanced sensing, automation, optimization, and early testing of emerging capabilities. Together with the investments described throughout Section 6.4 (Technology and Automation), the programs within this category are vital to achieving DTE's long-term vision for a modern, resilient, and intelligent grid.

The Grid Technology portfolio consists of the following seven programs:

- **Conservation Voltage Reduction / Volt-Var Optimization (CVR/VVO):** First piloted in 2022, CVR/VVO reduces peak demand and energy consumption while improving localized voltage management. When paired with ADMS, controllable capacitors, and voltage regulators, circuits can operate at the lower end of the voltage range, increasing DER hosting capacity. The associated generation-resource reduction benefits were highlighted in the Company's IRP.[176] DTE also deploys SCADA-enabled capacitors to proactively replace aging controls on circuits prior to CVR/VVO deployment, improving system efficiency and voltage stability.
- **SCADA Communication Equipment Replacement:** This program replaces end-of-life radio technology used by SCADA devices with modern, IP-based telecommunications technology, consistent with current DTE standards. The scope includes reconfiguring — and where necessary, replacing — SCADA field devices to support communication protocols compatible with the new backhaul, as well as comprehensive testing and end-to-end point-to-point validation. These upgrades improve SCADA system availability and operational situational awareness, enabling the ESOC to more effectively support customers and advance the Company's goal of restoring service within 48 hours following major storm events.
- **Distribution Line Sensing and Monitoring:** As the Company deploys line sensors and fault indicators at strategic locations as part of the Distribution Automation ecosystem, there is a need to evaluate new and emerging line sensor capabilities and use cases to

[176] DTE's 2022 IRP, available at https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/0688y000004qW9sAAE, accessed March 26, 2026.

provide real-time data on outages, voltage, and asset health, improving restoration times and operational decision-making. Investments in this program are to pilot new sensor types and capabilities before they are deployed more broadly.

- **DER Integration[177]:** This program establishes interconnection gateways and hardware DER control platforms to streamline the integration of complex DER and microgrids. It tests new technologies prior to broad deployment, serves as a training platform for engineers, and enables consistent control strategies that will interface with DERMS, reducing future design and engineering costs. As new grid technologies emerge, this program also supports structured evaluation, standards development, and controlled field demonstrations within DTE's training center to ensure compatibility and service continuity prior to broad operational deployment.
- **DER Control:** This program replaces select legacy remote terminal unit (RTU) monitoring devices originally deployed for temporary substation monitoring, as well as non-standard or obsolete control equipment at certain DTE DER locations. These assets will be upgraded to standardized communication gateways and modern SCADA RTU equipment, improving consistency, reliability, and long-term supportability.

Near-Term Investment

From 2026-2030, Grid Technology capital investments total approximately $58.1 million, as shown in Exhibit 6.79 with the largest allocations directed toward the DER Integration and CVR/VVO programs. Near-term investments focus on deploying proven technologies that deliver immediate operational benefits, while continuing to pilot and prepare for future grid capabilities.

Exhibit 6.79 – Investment Plan for Grid Technology, 2026-2030 ($ millions)[178]

Investments	2026	2027	2028	2029	2030	2026-2030 Total
CVR/VVO	2.0	3.0	5.5	6.0	6.0	**22.5**
DER Control	0.3	0.3	0.3	0.3	0.3	**1.5**
DER Integration	5.4	5.1	3.9	2.6	2.6	**19.6**
Distribution Line Sensing and Monitoring	1.0	2.0	2.0	2.0	2.0	**9.0**
SCADA Communications Equipment Replacement	1.1	1.1	1.7	1.7	-	**5.6**
Total	**9.8**	**11.5**	**13.3**	**12.6**	**10.9**	**58.1**

[177] Previously named Grid Edge Insights and New Technology in MPSC Case No. U-21860.
[178] Totals may not match exactly to the mathematical summation in the table due to rounding of the source data.

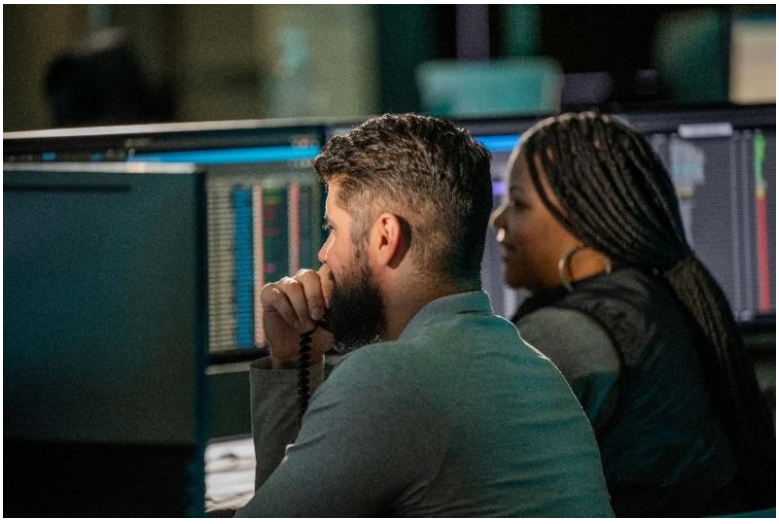
Long-Term Outlook

Grid Technology serves as the foundation for innovation across the electric grid. Through continued investment in advanced sensing, automation, integration platforms, and structured technology evaluation, the Company is building a grid that is more efficient, resilient, and adaptable to future challenges. Over the long term, these capabilities will enable greater adoption of DERs and EVs, support increasingly data-driven grid operations, and enhance reliability, flexibility, and customer value.

6.4.6 Advanced Distribution Management Systems

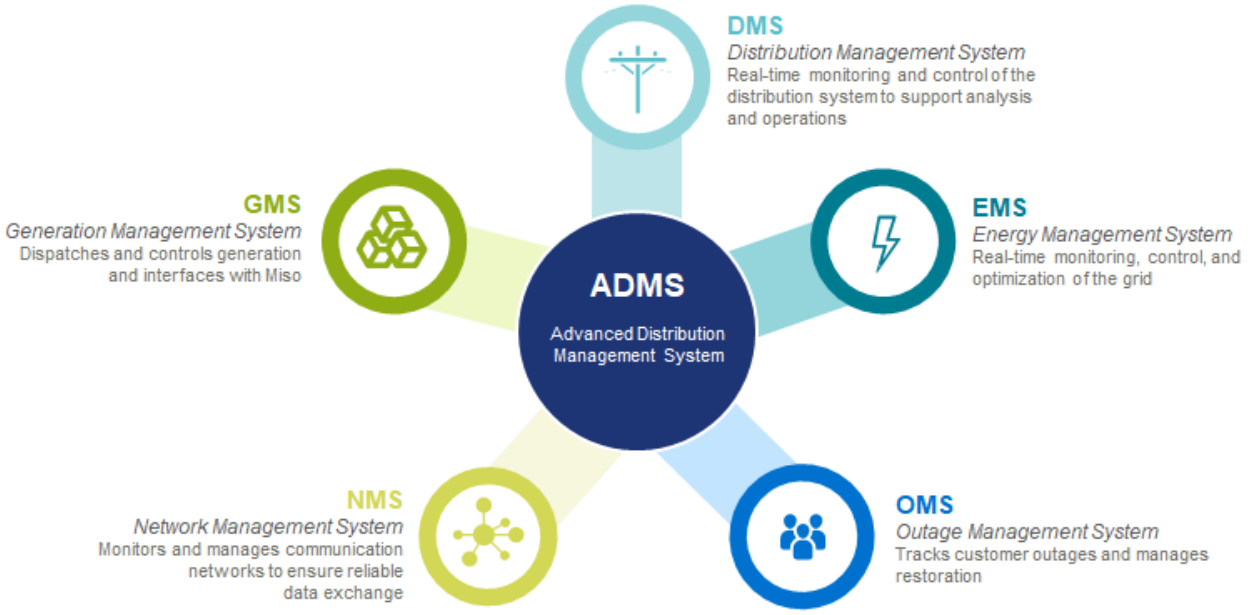
Grid Needs

As the distribution system becomes more complex, operational performance increasingly depends on the Company's ability to integrate data, system models, and workflows across historically siloed platforms. Without this integration, operators must rely on manual processes, fragmented information, and duplicative tools, which limits situational awareness, slows decision-making, and constrains effective response during both normal operations and system events. These challenges are further amplified by growing load, aging infrastructure, more severe weather, and the increasing penetration of EVs and DERs.



At DTE, the ADMS addresses these operational challenges by serving as the central nervous system of the electric grid, coordinating how operational systems work together rather than functioning as isolated platforms. ADMS establishes a common operational framework that supports real-time monitoring, control, and decision-making by aligning network models, authoritative data sources, and clearly defined operational responsibilities. Exhibit 6.80 provides a system-level view of ADMS and its relationship to the operational systems that support the electric grid.

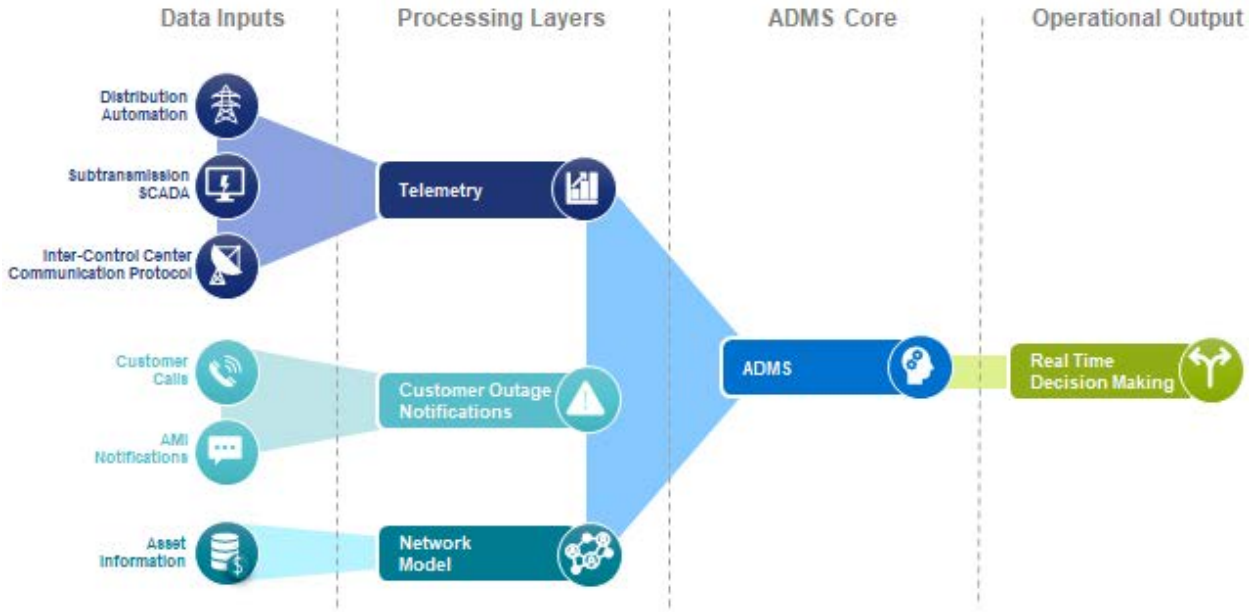
Exhibit 6.80 – Current State ADMS Integrated Operational Architecture



As illustrated, ADMS functions as the central integration platform through which core distribution management capabilities — provided by the Distribution Management System (DMS) and OMS — are coordinated with supporting systems, including the Generation Management System (GMS), Energy Management System (EMS), and Network Management System (NMS). This integrated architecture enables coordinated system operation, supports a shared operational perspective across organizations, and reduces reliance on manual handoffs and standalone tools.

Building on this integration, Exhibit 6.81 illustrates how ADMS brings together real-time telemetry, network models, outage information, and operational workflows into a single operational environment. By consolidating data and processes that were historically distributed across multiple platforms, ADMS transforms system information into actionable operational tools that improve reliability, enhance efficiency, and support high-quality customer service. This environment provides operators with a consistent, shared view of real-time grid conditions and overall system status.

Exhibit 6.81 – Overview of ADMS Integrated Operational Architecture



Through ADMS, operators and dispatchers in the ESOC can monitor real-time grid conditions, coordinate and direct field resources, remotely operate equipment, and safely reroute power to accelerate customer restoration. ADMS also enhances safety through structured switch order management (SOM) capabilities that enforce consistent, verified, and auditable switching processes. Beyond real-time control, ADMS supports feeder-level optimization, automates routine grid functions, and improves asset utilization. As EVs and DERs continue to proliferate, ADMS becomes increasingly critical to managing their operational impacts and coordinating their reliable integration into day-to-day grid operations.

Program Overview and Expected Benefits

Implementing an ADMS is not a one-time event or single-technology deployment, but a multi-year transformation that spans technology, operating processes, and change management. As utilities advance from fragmented, manual operations toward integrated, automated, and optimized distribution operations, they progress through defined stages of operational capability. EPRI formalizes this progression through its ADMS Maturity Model, which outlines five increasingly advanced stages of operational capability, as shown in Exhibit 6.82. The EPRI framework emphasizes that advanced ADMS applications can only be successfully implemented once foundational systems, data quality, and operating practices are firmly in place. As a result, ADMS maturity develops incrementally, with early investments focused on system integration and

situational awareness, followed by progressively higher levels of automation, analytics, and optimization.

Exhibit 6.82 – EPRI ADMS Maturity Model[179]

Level	Characteristics	Focus	Data	Goal
1. Initial	Basic SCADA functionality, manual processes dominate	Reactive operations, minimal integration with other systems	Fragmented, siloed systems with little governance	Establish foundational ADMS capabilities and basic monitoring
2. Managed	Enhanced monitoring and control with some automation	Centralized operations for improved reliability	Improved data quality and integration across systems	Move toward structured processes and better situational awareness
3. Defined	Coordinated control of distributed resources	Advanced applications like Volt/VAR optimization and FLISR	Real-time data exchange and analytics capabilities	Enable proactive grid management and advanced optimization
4. Quantitatively Managed	Predictive analytics and self-healing grid capabilities	Resilience and adaptive operations using forecasting	High-quality, governed data supporting AI-driven decisions	Achieve predictive and adaptive control for reliability and efficiency
5. Leading	Fully integrated ADMS ecosystem with enterprise systems	Industry-leading practices, automation, and resilience strategies	Comprehensive data governance and advanced BI (Business Intelligence)	Deliver a self-optimizing, highly resilient, and sustainable grid

DTE has successfully progressed through Level 1 (Initial) and Level 2 (Managed) of the EPRI ADMS Maturity Model, establishing the foundational capabilities required for advanced distribution operations. These achievements include modernized SCADA, enterprise and operational system integration, and enhanced outage management capabilities. One example of the operational value delivered through Level 2 maturity is the integration of AMI data into the Company's OMS. The use of AMI data, combined with AI-enabled logic, allows momentary outages to be identified and automatically cleared without field response. As a result, DTE experienced a 50% reduction in wasted truck rolls associated with "OK on Arrival" events in 2025, compared to performance under the OMS platform used in 2022. This integration has also enabled automated GIS data corrections, improving the accuracy of the as-operated network model. Exhibit 6.83 summarizes the operational capabilities and integrated systems deployed as part of Level 1 and Level 2 ADMS implementation.

[179] EPRI Data Management Maturity Model, available for purchase at https://www.epri.com/research/products/000000003002028913, accessed March 25, 2026.

Exhibit 6.83 – ADMS Level 1 and Level 2 Operational Capabilities and Integrated Systems

Operational Capabilities and Integrated Systems	Brief Description and Key Benefits
Distribution Topology Processing (DTP)	Maintains real-time feeder connectivity and switching status to support accurate outage analysis and restoration decisions.
Distribution Network Operating Model (DNOM)	Provides an authoritative, real-time network model used for monitoring, analysis, and operational decision-making.
Work Management System	Enables coordination of planned and unplanned work by linking operational needs with field execution.
Geographical Information System (GIS)	Supplies spatially accurate asset and network data to support modeling, visualization, and situational awareness.
SCADA	Delivers real-time telemetry and remote control of field devices to support monitoring, switching, and restoration.
Historian (HIS)	Stores high-resolution operational data to support performance analysis, event review, and continuous improvement.
Trouble Call Management	Aggregates customer outage reports to improve fault location, outage prediction, and response prioritization.
Outage Analysis	Analyzes outage events and system conditions to support faster fault identification and restoration planning.
Crew Dispatch / Management	Supports efficient assignment, tracking, and coordination of field resources during normal and outage conditions.
Outage Reporting / Notification	Provides timely and accurate outage status information to customers and internal stakeholders.
Advanced Metering Infrastructure	Supplies meter-level status and voltage data to enhance outage detection and system visibility.
Customer Information System	Provides customer and premise data to support outage communications and restoration coordination.

Building on this foundation, DTE is now entering Level 3 (Defined) of the EPRI ADMS Maturity Model. This stage is characterized by the deployment of advanced ADMS applications that enable coordinated control, automation, and optimization of the distribution system. Achieving Level 3 requires both vendor platform enhancements and the implementation of advanced operational applications. Accordingly, the Company's ADMS investments are primarily focused on the following five categories:

- **ADMS Enhancements:** The ADMS Enhancements category delivers customer benefits by improving the accuracy, safety, and coordination of outage response and grid operations. An enhanced system model enables clearer outage analysis, stronger alignment between field crews and the ESOC, and more consistent execution of restoration activities. The program also supports the operationalization of SOM, which introduces standardized checks, templates, and workflows that reinforce hazardous energy controls. Together, these enhancements improve employee safety and enable

clearer, more consistent communication of switching and tagging orders, supporting safer and more reliable service restoration for customers.

- **ADMS/GMS Hardware:** This project will replace aging ADMS and GMS hardware infrastructure before vendor support expires in 2027 and 2028, respectively, to ensure continued system supportability, cybersecurity protection, and NERC compliance. Upgrading this platform will modernize and secure operational control platforms to improve grid situational awareness and real-time monitoring. It also positions the grid to support increasing volumes of data and the advanced functionality associated with modern field devices and DERs. It provides the technical foundation necessary to integrate renewables and execute DTE's broader grid modernization strategy. The Company's DER integration strategy is discussed further in Section 4.5 (Distributed Energy Resources and Interconnection Process).
- **ADMS Network Management System (NMS):** NMS integrates data from GIS and other systems to support new ADMS features, providing a unified, real-time view of the electrical system for all ADMS functions. This model also underpins distribution planning tools. Ongoing improvement of the NMS Network Model is foundational for advanced ADMS features like FLISR and critical for OMS accuracy, customer communications, and minimizing unnecessary truck dispatches during outages. Continued investment in NMS will add geospatial intelligence, machine learning automation, and GIS/Maximo integration. It will also improve load analysis, enhance maintenance planning, reduce outage restoration times by approximately five minutes, and improve the customer experience by enabling the Company to provide more accurate information regarding estimated outage restoration times.
- **ADMS: DMS/OMS (Compass) Mobile Tool:** This mobile tool provides the core field functionality required to dispatch, manage, and execute unplanned trouble work for overhead, underground, substation, and primary service operations by integrating directly with ADMS workflows. Through this integration, the tool enables field crews to receive and manage trouble assignments, view real-time system conditions using the as-operated network model, update job status, and coordinate restoration activities with the ESOC. Customers benefit from improved accuracy, coordination, and execution of outage response and restoration activities. While introducing new functionality, the tool also enables DTE to maintain existing operational performance standards, including arrival times for wire-down response under Normal, Gray Sky, and Catastrophic conditions, as well as current dispatch-to-crew timing and cause-code update practices.

- **Fault Location, Isolation, and Service Restoration (FLISR):** FLISR uses data from field devices and system models to identify the likely location of a fault, isolate the affected portion of the system, and automatically restore service to customers outside the impacted area where possible. By centrally coordinating fault identification, isolation, and restoration, FLISR reduces the number of customers affected by outages and supports faster, more consistent restoration. In addition, centralized logic minimizes unnecessary switching operations, particularly on subtransmission devices, compared to local fault-hunting approaches, which helps extend equipment life.

Collectively, these investments will enhance real-time situational awareness, reduce patrol and restoration times, improve coordination between control room operators and field crews, and enable more consistent and repeatable execution of distribution operations through integrated SCADA and AMI visibility.

In addition to the ADMS investments, certain advanced operational capabilities rely on ADMS as the central coordination platform but are discussed elsewhere within this DSP. This includes DERMS, described in Section 6.5.3 (Distributed Energy Resource Management System), which will integrate with ADMS through standardized interfaces to support coordinated DER monitoring and dispatch. As DER adoption increases, DERMS is expected to become an additional integration component within the ADMS architecture, expanding the platform's ability to coordinate distributed resources while maintaining a modular and scalable design. Similarly, voltage control and optimization functionality is enabled through ADMS analytics and coordinated control of SCADA-enabled field devices, with related investments addressed in Section 6.4.5 (Grid Technology).

Near-Term Investment Outlook

Sustained capital investment in ADMS applications is necessary to advance ADMS capabilities in step with rapid changes in grid technology, DER and EV adoption, and customer expectations. Exhibit 6.84 outlines DTE's five-year capital investment plan for ADMS.

Exhibit 6.84 – Investment Plan for ADMS, 2026-2030 ($ millions)[180]

Project	2026	2027	2028	2029	2030	2026-2030 Total
ADMS Enhancements	8.0	15.8	8.6	8.9	7.9	**49.2**
ADMS/GMS Hardware	1.9	5.8	4.3	1.1	0.2	**13.3**
ADMS: Network Management System	2.0	-	-	-	-	**2.0**
ADMS: DMS/OMS (Compass) Mobile Tool	5.3	0.7	-	-	-	**6.0**
FLISR	4.4	6.4	5.4	5.7	-	**21.9**
Total	**21.6**	**28.6**	**18.3**	**15.6**	**8.1**	**92.3**

Long-Term Outlook

Over the long term, ADMS provides a durable operational framework for responding to the fundamental forces reshaping the distribution system, including aging infrastructure, increasingly severe weather, and the integration of customer-adopted technologies. Continued execution of the ADMS roadmap ensures that distribution operations can adapt as assets age, storm impacts intensify, and system complexity increases — without relying on incremental, manual workarounds. By establishing a scalable digital foundation that can evolve with changing system conditions, ADMS supports consistent, reliable operations today while maintaining the flexibility necessary to accommodate future load growth, DER adoption, and evolving operational requirements.

Ongoing advances in Automation Intelligence within ADMS will be critical to realizing the value envisioned in Levels 4 (Quantitatively Managed) and 5 (Leading) of the EPRI ADMS Maturity Model. DTE will continue integrating advanced machine-learning models and AI-enabled agents into the ADMS platform and operator interfaces, expanding decision-support capabilities for ESOC workflows and field execution. By automating routine tasks and lower-complexity decisions currently handled by ESOC System Operators and Power Dispatchers, AI will enable those teams to focus on higher-value system analysis. This shift will strengthen the Company's ability to proactively identify emerging system conditions and deploy resources before customers experience momentary or sustained outages — delivering sustained improvements in reliability, efficiency, and customer service.

[180] Totals may not match exactly to the mathematical summation in the table due to rounding of the source data.

6.5 Grid Edge and Distributed Intelligence

This section introduces Grid Edge and Distributed Intelligence, a new investment pillar in the 2026 DSP that addresses the evolving interface between the electric system and customers' increasingly interconnected technologies. As DERs, EVs, and smart devices continue to proliferate, DTE is advancing three coordinated initiatives to extend visibility, control, and intelligence to the grid edge: Last-Mile Wireless Communications, Next-Gen AMI, and DERMS. Together, these investments enable more proactive system operations and improved customer outcomes. While this pillar reflects a new focus area, it works in concert with DTE's established investment pillars. A well-maintained and hardened physical system provides the foundation for a robust communications backbone, which in turn extends visibility and control to the grid edge and unlocks additional value from automation and redesign. In short, Grid Edge and Distributed Intelligence is where the investment strategy meets the customer — translating a stronger, smarter grid into a more reliable and responsive everyday experience.

6.5.1 Communications Network

Grid Needs

DTE's Field Communications Network (FCN) is a foundational component of grid operations, enabling secure, reliable communication between grid-edge devices and control centers. As the electric grid undergoes rapid transformation driven by increasing demand, renewable energy integration, and customer adoption of DERs, the number of connected devices and the volume of data are growing rapidly. Modern grid initiatives such as grid automation, ADMS, Next-Gen AMI, and DERMS will require connectivity for hundreds of thousands of new grid-edge devices, including reclosers, regulators, capacitors, intelligent electronic devices (IEDs), and advanced meters.

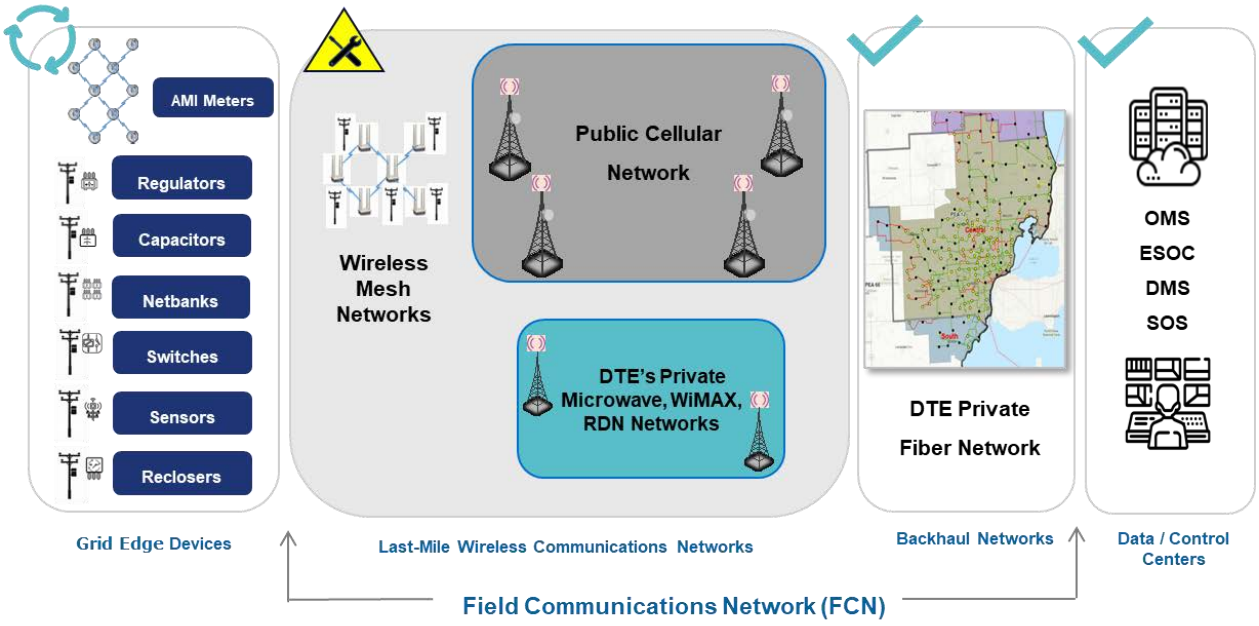
While the current FCN supports existing needs, it faces escalating challenges related to technology obsolescence, capacity constraints, reliability, cybersecurity, operational control, and rising operating costs. Modernizing the FCN — across both the fiber backhaul and the wireless last-mile — is integral to delivering the next generation grid programs and the objectives outlined in this DSP.

Program Overview

DTE's current FCN consists of two primary components as illustrated in Exhibit 6.85:

- **Backhaul Network:** The backhaul network, referred to as Grid Automation Telecommunications, is a private fiber-optic backbone that interconnects critical DTE facilities, including data management systems, substations, towers, and service centers.
- **Last-Mile Wireless Network:** The last-mile network extends connectivity from substations and hubs to grid-edge devices across DTE's service area. Today, this layer depends on a mix of WiMAX,[181] wireless mesh, public cellular, and legacy radio systems.

Exhibit 6.85 – DTE's Current FCN



Grid Automation Telecommunications

DTE is investing in a multi-year grid automation telecommunications initiative to complete a fiber-optic backbone connecting critical Company facilities. The fiber network will be the primary communications platform for SCADA and other critical operational systems and will provide backhaul for next-generation last-mile connectivity. Expanding private fiber reduces reliance on costly leased services, improves cybersecurity measures, mitigates vendor-driven technology retirements, and provides resilient pathways for critical grid communications. It will support high-volume data from asset health sensors, AMI, SCADA systems, and operational field devices,

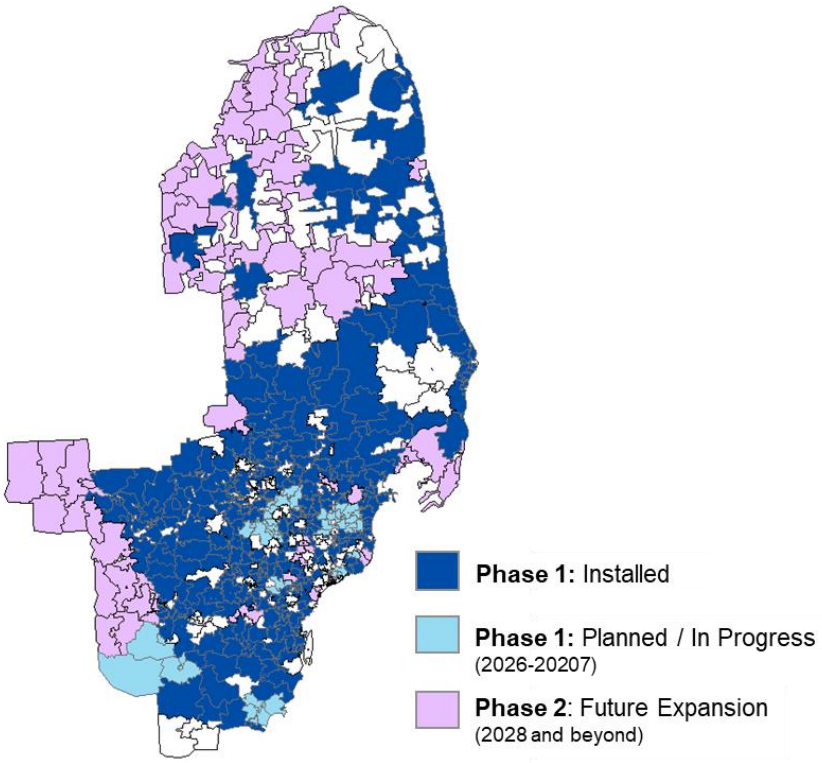
[181] WiMAX (Worldwide Interoperability for Microwave Access) is a wireless broadband technology based on IEEE 802.16 standards that has been used by utilities to support long-range, point-to-multipoint communications with field devices.

delivering information securely to Company data management systems or approved cloud environments for operations, analytics, and planning for many decades to come.

The Company's Grid Automation Telecommunications program will be implemented in two phases and will act as the backhaul for the Last-Mile Wireless Communications system shown in Exhibit 6.86:

- **Phase 1 (through 2028):** Completes fiber routes connecting critical system locations to DTE's data management systems, establishing a systemwide backhaul network. This phase includes installation of fiber infrastructure and associated telecommunications equipment required for data routing, monitoring, and network management.
- **Phase 2 (beginning in 2028):** Extends fiber to the remaining substations based on BCA results, which evaluate the number of SCADA devices transitioned from legacy and end-of-life technologies, the automation assets supported along each route, and the associated reduction in leased-line costs. The BCA results for the Communications Network overall are discussed in more detail later in this section.

Exhibit 6.86 – Grid Automation Telecommunication Phased Implementation of Fiber[182]

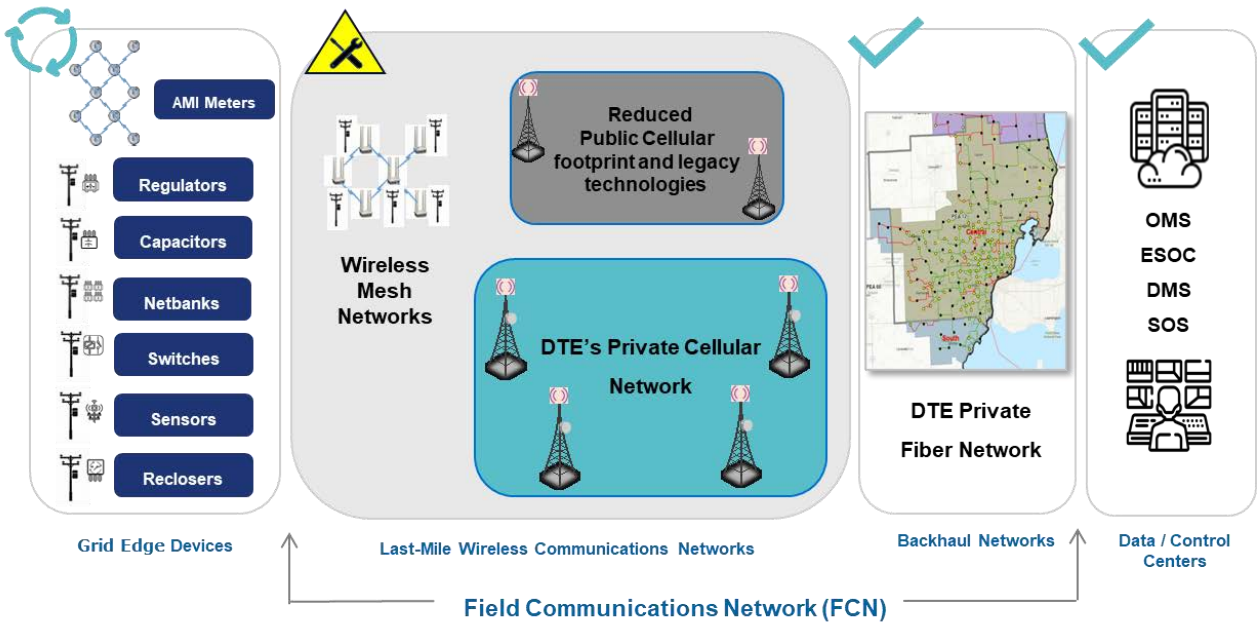


[182] Shading represents the service area of a substation that is connected by fiber. Shading does not imply fiber availability throughout the entire area.

Last-Mile Wireless Communications

To support next-generation grid capabilities, DTE must modernize its last-mile communications network by transitioning away from Radio Data Network (RDN), public cellular, and other legacy technologies. The current mix of systems lacks the performance, scalability, reliability, and cost profile required to support a more automated and data-driven grid, and it is increasingly challenged by interference, network congestion, limited cybersecurity control, carrier-driven technology obsolescence, rising operating costs, and degraded performance during storm events. Following a robust alternatives analysis as described below, the Company will transition toward private cellular-based solutions to establish a secure, high-reliability, cost-effective, utility-controlled communications platform that scales with device growth and aligns with the lifecycle of grid assets. Exhibit 6.87 illustrates the proposed next-generation FCN architecture.

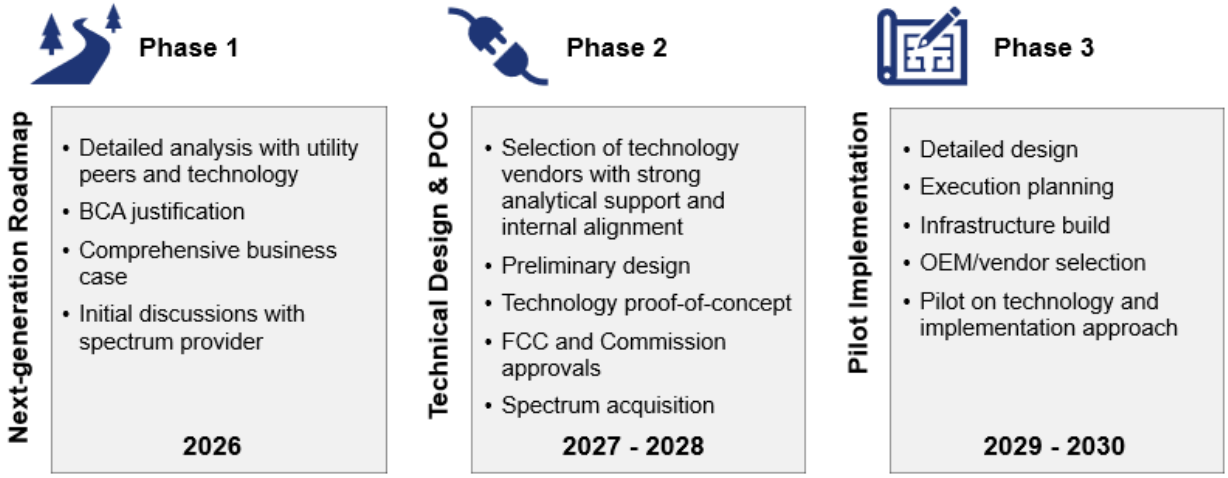
Exhibit 6.87 – DTE's Proposed Next Generation FCN



The program employs a hybrid, multi-technology communications strategy. DTE will deploy a dedicated private cellular network using licensed spectrum to support mission-critical communications, leverage carrier-based public cellular for backup and non-critical applications, and continue to utilize private fiber as the preferred backhaul network. This layered approach enhances system resilience by reducing single points of failure while delivering secure, high-performance, and utility-controlled communications with coverage that can be tailored across the Company's service area. Early phases of the program focus on foundational planning activities,

including spectrum and infrastructure requirements, network architecture, investment profile, implementation schedule, ownership considerations, and potential partnership opportunities. Subsequent phases will include construction of the licensed private cellular network and the systematic transition of device connectivity from public to private cellular. The high-level timeline — from spectrum procurement through pilot implementation — is outlined in Exhibit 6.88.

Exhibit 6.88 – Last-Mile Wireless Communications Roadmap



Last-Mile Alternatives Analysis

DTE engaged with a broad set of peer utilities, industry experts such as EPRI, service and solution vendors, and consultants to develop a comprehensive set of evaluation criteria for Last-Mile Communications technologies. These criteria focus on the technical capabilities required to support mission-critical grid operations and include the following:

- **Bandwidth and Latency:** High-speed, low-latency network performance with predictable and guaranteed service-level agreements to support mission-critical applications without congestion.
- **Reliability:** Enhanced reliability through built-in redundancy and resiliency features that minimize interruptions and support continuous grid operations.
- **Cybersecurity:** A robust, layered cybersecurity architecture that protects against a broad range of threat vectors, including state-sponsored and other malicious actors.

DTE developed a communications requirements matrix for dependent grid programs, shown in Exhibit 6.89, which was used to assess the suitability of alternative solutions against these defined technical criteria.

Exhibit 6.89 – Communications Requirements Matrix by Program

Programs	Requirements			
	Bandwidth	Latency	Reliability	Security
Distribution Automation & Other Modernization Programs	Moderate	Very Low Latency Essential	High	High
Demand Response	Low	High	High	High
AMI (Advanced Metering Infrastructure)	High	Low Latency Essential	Moderate (Multiple Reads)	High
Field Crew Communication	High	Moderate Latency Acceptable	High	High
Substation Communication	Moderate	High Latency Acceptable	High	High
Distributed Energy Resources	High	Moderate Latency Acceptable	High	High
Inter-Utility Communication	High	Moderate Latency Acceptable	High	High

In addition, DTE evaluated alternatives against three essential non-technical considerations:

- **Operational Control:** End-to-end control over maintenance, outage response (including during major storm events), technology and device obsolescence, and implementation of advanced cybersecurity measures.
- **Coverage:** The ability to reliably connect grid-edge devices across the Company's service area without degradation in performance or service quality.
- **Cost:** A lifecycle cost-effective solution that can scale to support the rapidly growing population of grid-edge devices.

DTE evaluated Wi-SUN,[183] satellite broadband, wireless mesh, public cellular, and private cellular technologies against the established evaluation criteria. While certain alternatives may offer discrete advantages, they may not meet the requirement thresholds for other criteria. For example, public cellular presents lower upfront capital costs but entails higher and escalating operating expenses (as shown in Exhibit 6.91), variable performance during network congestion and storm events, limited utility control over cybersecurity, and exposure to carrier-driven technology retirements. The results of the Last-Mile Communications alternatives analysis are summarized in Exhibit 6.90.

[183] Wi-SUN (Wireless Smart Utility Network) is a standards-based wireless mesh technology used to provide secure, large-scale connectivity to IoT devices.

Exhibit 6.90 – Last-Mile Technology Alternatives Evaluation Summary

Technology	Overview	Key Benefits	Primary Issues
WiSUN Alliance	Wireless Smart Utility Network based on IEEE 802.15.4g, supporting AMI and a few select use cases	• Reliable, secure, and self-healing communication • Long-range coverage • Open standards enabling interoperability	• Limited backward compatibility leading to early obsolescence • Operates on licensed-free spectrum, constraining performance (bandwidth, latency) • Hardware upgrades required for newer networks
Satellite Broadband	Satellite broadband services from SpaceX (Starlink) and Amazon (Leo) are available for last-mile networks but face several challenges.	• Ubiquitous coverage, including hard-to-reach areas • High reliability and scalability	• High operating costs • Potential regulations limitations for utility deployment • Higher latency and lower bandwidth than cellular
802.11 Wireless Mesh	The TropOS wireless mesh network currently connects DTE's electric meters and could be used for future grid-edge devices, but it may not be the best fit for DTE for use cases other than electric meters.	• Proven technology and experience at DTE • Self-healing architecture • Works well for meter clusters	• Non-scalable architecture for non-meter use cases or devices that do not support aggregation protocols • High cost to support non-meter edge devices
Public Cellular	Provides a wireless last-mile network option connecting control centers and dispersed grid-edge devices. As a last- mile solution, it bridges the gap from substations, gateways to smart meters, grid sensors, and DER equipment, eliminating the need for laying expensive wired infrastructure for each edge device.	• Scalable with wide coverage • Operational simplicity • Minimal capital investment	• High long-term operating costs at scale • Network congestion risk during emergencies and reliability risk during storms • Limited operational control and scalability • Risks of technology obsolescence and related costs as carriers retire older systems • Limited ability to enforce advanced cybersecurity measures, and increased exposure to sophisticated cyber threats
Private Cellular	Provides a dedicated, utility-owned and managed wireless infrastructure using 4G/LTE technology to provide last-mile wireless communications to grid-edge devices, including DERS, smart meters and grid automation devices. Unlike public cellular, this option is customizable for high security and reliability, allowing utilities to connect to edge devices even in remote areas.	• Significantly lower operating costs • High reliability and scalability • Customizable coverage • Common solution for all field use cases • Full operational control over maintenance and outages, especially during critical storm events • High degree of control on technology and device obsolescence • Full control to enforce advanced cybersecurity measures	• High upfront capital cost • Operational complexity to own and operate a cellular communication network

The Company selected private cellular because it provides a common, future-proof platform to support all grid-edge use cases, including Next-Gen AMI, grid automation, DER integration, and field operations. Although it requires higher upfront capital and the responsibility to own and operate the network, it is the most cost-effective solution overall with licensed spectrum performance, high reliability and scalability, customizable coverage, strong cybersecurity, and full operational control.

Cost-Effectiveness

DTE's preliminary cost analysis further reinforces private cellular as the preferred Last-Mile Wireless Communications standard going forward. A Total Cost of Ownership (TCO) perspective is most appropriate for comparing the alternatives. Over a 40-year horizon, public cellular is projected to cost approximately $2.4 billion to $4.1 billion, driven by per-device carrier fees and varying device forecasts.[184] In contrast, a DTE-owned private cellular network is estimated to cost between $311 million and $473 million over the same period, depending on spectrum selection, as shown in Exhibit 6.91.

Exhibit 6.91 – 40-Year TCO Comparison, Public and Private Cellular ($ millions)

	Public Cellular Cost Range	Private Cellular Cost Range
Capital	-	128 - 290
O&M	2,393 - 4,070	183
Total	**2,393 - 4,070**	**311 - 473**

The key difference is private cellular operating costs do not vary significantly with grid-edge device growth. While this TCO analysis is over a 40-year horizon, the break-even point from the higher upfront capital cost associated with private cellular is much sooner. Depending on grid-edge device growth, the Company is estimating the break-even between private and public cellular to be within nine to 14 years.[185] After this point, public cellular operating costs continue to escalate, while private cellular costs stabilize.

[184] Grid-edge devices include reclosers/switches, load control devices, remote terminal units, voltage regulators, line sensors, capacitor banks, netbanks, meters, radio frequency mesh gateways, street light sensors, manhole monitors, pole sensors, DERs, etc. DTE is forecasting 1.1 million to 1.6 million in grid-edge devices over 40 years.

[185] The payback period is calculated from the first major expenditure (spectrum procurement), excluding minor planning costs. Additional benefits such as improved efficiency and performance are not included; incorporating them would accelerate the break-even estimate.

A BCA was performed on the Last-Mile Wireless Communications solution to evaluate the total 40-year lifecycle costs of public cellular and private cellular alternatives. The analysis compares costs across three scenarios — high growth (1.51 million devices), likely growth (1.31 million devices) and low growth (1.07 million devices). Across all growth scenarios, the Private LTE option results in substantially lower total 40-year lifecycle costs than public cellular, with present-value savings ranging from approximately $3.2 to $4.8 billion. Additional detail on the methodology and results can be found in Appendix 8.14 (Benefit-Cost Analysis Report).

A detailed, DTE-specific cost analysis will be completed during the business case phase, along with a proof-of-concept pilot prior to full-scale investment and deployment.

Near-Term Investment

In the near-term, Grid Automation Telecommunications requires investment of $44 million to advance its two-phased implementation approach, which is designed to optimize investment decisions by balancing cost, system benefits, and long-term operational needs. For Last-Mile Wireless Communications, near-term activities focus on stakeholder engagement, spectrum procurement, detailed network design, planning, and pilot deployments. As shown in Exhibit 6.92, capital investments begin to ramp up in 2028. This phased sequencing allows DTE to establish vendor and partnership agreements, de-risk technology choices through pilots, and prioritize deployment to the highest-value use cases.

Exhibit 6.92 – Investment Plan for Communications Network, 2026-2030 ($ millions)

	2026	2027	2028	2029	2030	2026-2030 Total
Grid Automation Telecommunications	10.0	12.0	12.0	10.0	-	**44.0**
Last-Mile Wireless Communications	-	-	42.0	62.0	56.0	**160.0**
Total	**10.0**	**12.0**	**54.0**	**72.0**	**56.0**	**204.0**

Additionally, Last-Mile Wireless Communications will require approximately $16 million in O&M expenditures to support the stand-up and testing of the private cellular platform, beginning with $4 million in 2028 and increasing to $6 million annually in 2029 and 2030. The investment levels presented in Exhibit 6.92 may vary depending on the licensed spectrum selected and the scale and configuration of the associated radio area network (RAN) infrastructure.

Long-Term Outlook

Wireless communications tower

Over the longer term, the combination of private fiber backhaul through Grid Automation Telecommunications and private cellular for Last-Mile Wireless Communications establishes the foundation of DTE's next-generation FCN. This integrated architecture lowers total long-term costs relative to carrier-based solutions, strengthens cybersecurity and operational control, enhances storm resilience, and enables the advanced grid capabilities required to meet evolving customer expectations and system demands. Completion of the telecommunications backbone will provide engineers, ESOC operators, and system planners with richer, more timely data, improving visibility into real-time grid conditions and performance. These insights support more targeted investments, improved constraint management, and a shift toward condition-based asset replacement. By replacing escalating public cellular operating expenses with durable, rate-based infrastructure aligned with grid asset lifecycles, the next-generation FCN positions the Company to support safe, affordable, reliable, and resilient operations for decades, while serving as a critical enabler of broader grid modernization and the integration of emerging technologies that benefit customers.

6.5.2 Next-Gen AMI and Distributed Intelligence

Grid Needs

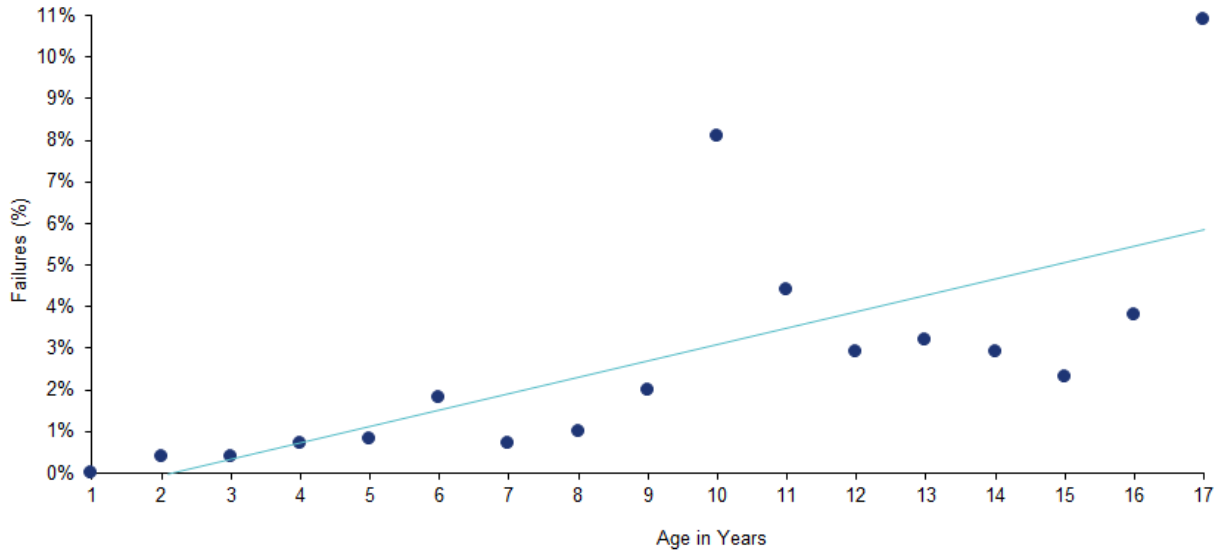
DTE's Advanced Metering Infrastructure (AMI), initially deployed beginning in 2009, has delivered significant customer and operational value, including remote meter reading, remote connect and disconnect capabilities, improved billing timeliness and accuracy, and enhanced outage detection and customer communications. Over time, AMI has evolved from a billing-focused system into a foundational, customer-facing grid asset that improves customers' day-to-day experience with the Company's electric system.

Real-time AMI data provides continuous visibility into customer-level power quality. Interval voltage profiles, sag and swell logs, phase data, and power factor measurements enable faster identification of issues affecting customers and support investigations into asset health, reliability concerns, customer complaints, and damage claims. When integrated with DTE's ADMS and OMS, AMI data improves outage analysis, crew dispatching, and restoration planning. Voltage

readings outside prescribed operating limits are automatically routed to Regional Customer Operations and Voltage Support teams, allowing issues to be quickly isolated to substations, transmission, or customer-side equipment and addressed through structured workflows. Together, these capabilities reduce the duration and impact of service disruptions and support more stable voltage performance for customers. Beyond real-time operations, AMI insights support longer-term distribution planning and grid efficiency initiatives such as CVR/VVO and load allocation analytics. These applications improve system performance, increase grid efficiency, and help moderate energy costs — ultimately benefiting customers through more reliable service and more consistent power quality.

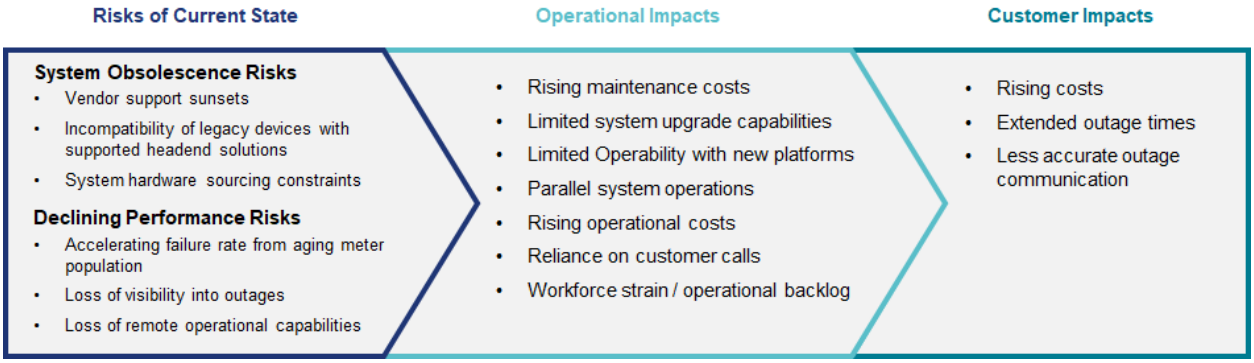
However, the legacy AMI system is now entering the latter portion of its useful life. Most electric meters have an expected useful life of approximately 20 years, and the majority of DTE's meter fleet will reach or exceed that age by 2035. As meters age, failure rates are increasing, as shown in Exhibit 6.93, and the vendor has also confirmed that the annual failure rate for meters older than 20 years is expected to increase. Compounding this risk, as of 2025, approximately 20% of the meter population — roughly 450,000 meters — can no longer receive important firmware updates due to obsolescence, limiting functionality and constraining optimal operation. As a result, these meters cannot receive critical performance improvements, cybersecurity patches, or bug fixes, which increases the likelihood of failures and errors while limiting DTE's ability to maintain reliable, secure, and fully functional service for affected customers.

Exhibit 6.93 – Legacy Meter Failure Rate by Meter Age



Replacing failed meters with legacy hardware is necessary to sustain operations in the near term, but this approach does not address the underlying obsolescence of the AMI platform and is not a viable long-term solution. DTE's legacy meters are incompatible with modern headend systems, and while no formal end-of-life date announcement has been made, the current vendor has indicated it is unable to commit beyond 2030 to supplying legacy meter inventory due to part obsolescence and hardware availability risks. The operational risks and potential customer impacts associated with continued reliance on the current AMI system are summarized in Exhibit 6.94.

Exhibit 6.94 – Obsolescence Risks of Current AMI System



Absent timely action, DTE would be forced into a reactive posture — managing escalating failures, diminishing vendor support, and increasing system exceptions. Over time, this would result in greater manual intervention, rising operating costs, reduced efficiency, and degradation of customer experience, with corresponding pressure on affordability. Further delaying investment further increases the risk of declining system performance, higher sustainment costs, constrained transition options, and ultimately forced, accelerated replacements as vendor support diminishes. Proactive investment in Next-Gen AMI is necessary to manage these risks, preserve existing customer benefits, and enable a seamless transition that sustains and enhances the capabilities customers rely on today.

Program Overview and Expected Benefits

In response to the challenges posed by aging and obsolete AMI meters — and customer expectations for reliable, transparent, and high-quality service — DTE has developed a plan to begin replacing its legacy meter fleet with technologically-advanced devices through the Next-Gen AMI program. The program is intended to mitigate obsolescence risks while preserving and enhancing the customer benefits delivered by today's AMI system, including timely outage information, accurate billing, and consistent voltage performance.

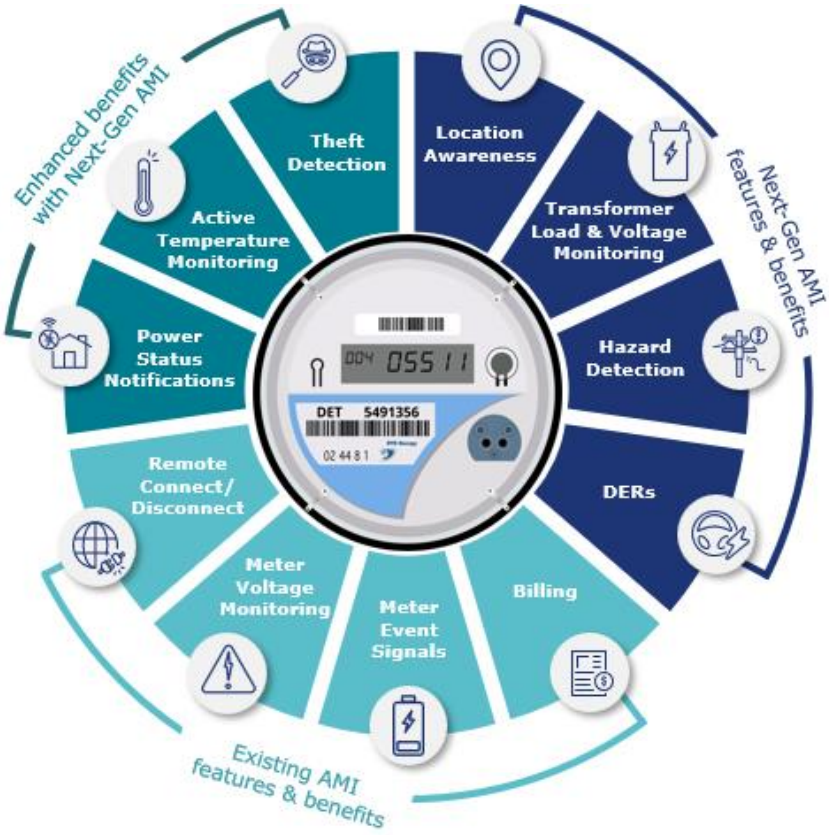
Next-Gen AMI builds on the existing AMI foundation by enabling modern communications, increased bandwidth, a new headend system, and advanced embedded processing at the meter. These enhancements support faster and more precise outage detection, improved power quality monitoring, and greater system responsiveness — directly reducing outage duration, minimizing service disruptions, and improving the overall customer experience. Customers also benefit from improved visibility into their energy usage, more accurate meter data, and support for evolving rate designs and energy programs that provide greater flexibility and choice.

A key advancement enabled by Next-Gen AMI is Distributed Intelligence (DI), which allows meters to communicate with one another and analyze conditions locally at the grid edge. This peer-to-peer capability enables near real-time decision-making without constant reliance on centralized systems, enabling quicker fault isolation and more efficient service restoration following outages or storm events. For customers, this translates into faster recovery, fewer sustained interruptions, and greater resilience during increasingly severe weather. DI also supports integration of customer-owned technologies — such as rooftop solar, EVs, and battery storage — while maintaining grid stability as adoption grows.

In addition, DI and expanded meter capabilities enable more localized voltage management and power quality monitoring, helping maintain customer service within prescribed voltage limits. This reduces the risk of appliance damage, improves the performance of sensitive equipment, and supports a more consistent service experience. The platform also enables advanced functionality such as DER coordination, connectivity modeling, and localized decision-making — capabilities that are increasingly important as customers adopt time-varying rates, participate in DR programs, and engage more dynamically with the grid. These capabilities support emerging regulatory and market requirements, including those associated with FERC Order 2222, discussed in Section 4.5 (Distributed Energy Resources and Interconnection Process).

Next-Gen AMI further enhances situational awareness and field-level insight through expanded or enhanced capabilities such as transformer load monitoring, voltage and power quality monitoring, hazard and tamper detection, location awareness, theft detection, and active temperature management. These improvements support proactive identification and resolution of issues before customers are impacted, reducing repeat outages and improving long-term reliability. Collectively they enable a step-change in operational performance while delivering tangible customer benefits, including improved service reliability, stronger power quality, faster issue resolution, and expanded access to customer energy management tools. The sustained and incremental benefits enabled by Next-Gen AMI are summarized in Exhibit 6.95.

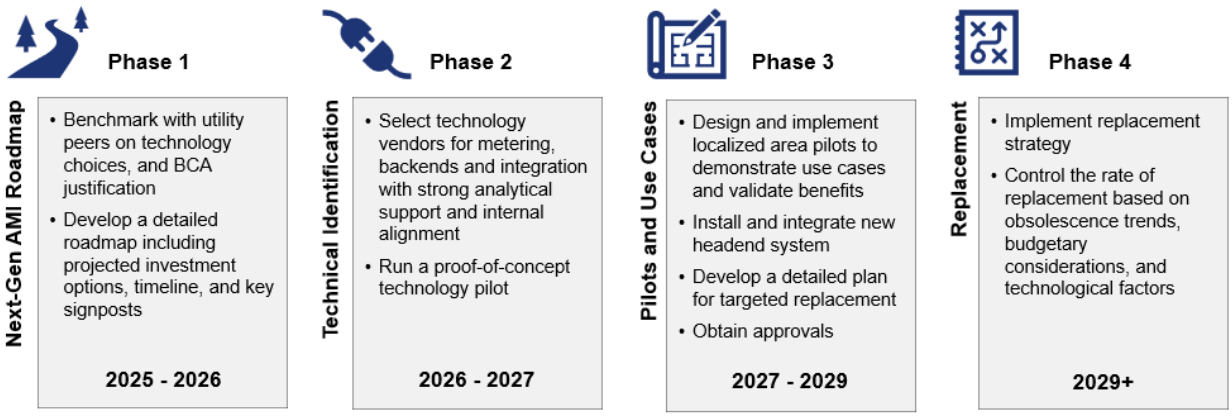
Exhibit 6.95 – Incremental Benefits of Next-Gen AMI



Next-Gen AMI Roadmap and Near-Term Investment

The near-term priority for the Next-Gen AMI program is a structured evaluation designed to reduce uncertainty, validate technology readiness, and inform vendor and platform selection before more significant investment is required, as outlined in Exhibit 6.96.

Exhibit 6.96 – Next-Gen AMI Roadmap



During the initial phases, DTE will complete a BCA, gather market intelligence and issue targeted requests for information (RFIs) to better understand available technologies and vendor capabilities. Technical evaluations — conducted both in laboratory settings and through limited field testing — will assess device performance, interoperability, and alignment with DI requirements. In parallel, early vendor and technology assessments will compare cost structures, performance, cybersecurity posture, and interoperability across potential solutions. This structured approach will enable DTE to identify vendors that best meet its specific needs and to evaluate both single-vendor and multi-vendor solution pathways. These foundational planning activities, planned through 2027, support prudent investment decisions and reduce lifecycle risk associated with long-term technology choices. They facilitate readiness for large-scale deployment by validating key assumptions related to technology maturity, implementation timing, and cost assumptions. Deferring this evaluation phase would result in increased risk of accelerated and potentially more costly investments driven by reactive responses to advanced technology obsolescence and declining system performance.

Beginning in 2027, the program is expected to transition into headend system implementation and integration, communications network deployment, and pilot-scale meter deployment aligned with aging-meter replacement needs and vendor technology maturity. Investment in the communications network, described in detail in Section 6.5.1 (Communications Network), will be strategically sequenced to provide the high bandwidth, low latency, and compatibility required to support Next-Gen AMI meters and the new headend system. The headend platform will be integrated with downstream DTE enterprise systems to support core business operations, enable advanced analytics, and ensure cybersecurity compliance.

Exhibit 6.97 presents the estimated five-year investment required to complete these foundational Next-Gen AMI activities and establish readiness for future wide-scale deployment.

Exhibit 6.97 – Investment Plan for Next-Gen AMI, 2026-2030 ($ millions)

	2026	2027	2028	2029	2030	2026 – 2030 Total
Capital	2.4	2.9	8.3	66.3	74.1	**154**
O&M	2.4	3.8	2.8	4.6	5.3	**18.9**

Long-Term Outlook

Under the current plan, Next-Gen AMI meters are expected to begin replacing legacy meters across all DTE customer classes starting in 2030. Deployment will occur over multiple years, with the pace of meter replacement and associated investments intentionally structured to balance system needs and cost. This phased approach provides flexibility to align deployment with meter end-of-life timing, technology readiness, and evolving customer and regulatory expectations.

Operationally, the transition will include a defined period of dual-system operations, during which DTE will manage both legacy and Next-Gen AMI infrastructure, systems, and processes to ensure continued service reliability and a seamless customer experience. This approach allows DTE to maintain existing functionality while progressively transitioning customers and field operations to the new platform, minimizing disruption and operational risk.

Once fully implemented, Next-Gen AMI will serve as a long-term platform to support an increasingly electrified and decentralized grid. It will enable integration of DERs at scale, improve outage response and power-quality performance, enhance grid resilience in the face of more frequent and severe weather events, and expand customer access to advanced energy management tools. Collectively, these capabilities position DTE to sustainably meet future grid demands while continuing to improve service reliability, service quality, and value for customers.

6.5.3 Distributed Energy Resource Management System

Grid Needs

DTE's distribution system is experiencing rapid growth in DERs, including rooftop solar, battery storage, EVs, and flexible demand technologies. At the current pace of renewable integration, the Company estimates that by 2030 approximately 181 MW of rooftop solar and 38 MW of BTM battery storage will be interconnected on its distribution system.[186] These resources introduce two-way power flows and increased variability in local load and generation — operating conditions not anticipated in the original design of DTE's system.

At the same time, federal regulators have directed utilities to proactively integrate DERs into both system planning and real-time operations. In particular, FERC Orders 841 and 2222 enable DERs and aggregated DER portfolios to participate directly in wholesale markets operated by MISO. Compliance with these requirements and applicable MISO market rules requires utilities to ensure

[186] Based on DTE's latest DER forecast. Today, DTE has approximately 260 MW of company-owned DERs, approximately 260 MW of interconnected customer-owned DERs, and approximately 150 MW of thermostat and interruptible air conditioning programs.

that participation by customer-owned and third-party-managed resources does not compromise distribution system safety or reliability. This includes the ability to identify and enforce distribution-level operating constraints, coordinate dispatch activity, and prevent dual participation across retail and wholesale programs.

As DER penetration increases, DTE faces reduced visibility into real-time system conditions and a growing need to manage interactions between customer-owned devices, aggregations, and utility equipment. Traditional distribution management tools were not designed to monitor or coordinate large numbers of BTM- and third-party-owned resources operating dynamically across distribution circuits. Without modern tools, DER coordination would rely on manual processes that increase operational risk and limit customer and aggregator participation in market programs.

A Distributed Energy Resource Management System (DERMS) addresses these needs by providing the situational awareness, coordination, and control needed to safely integrate DERs, support compliance with federal and regional market requirements, and maintain reliable distribution system operations — while supporting grid stability, optimizing DER utilization, and enabling customer and aggregator participation in regional markets. Exhibit 6.98 summarizes the key drivers for DERMS investment and the capabilities DERMS provides to address those needs.

Exhibit 6.98 – Drivers and Compliance Requirements for DERMS

Driver	Description	Implications to DTE	DERMS Support
FERC Order 2222	• DER aggregation can directly participate in MISO wholesale markets after Jan 1, 2030.	• MISO DER dispatch schedule could cause safety and reliability concerns on distribution systems. • Without oversight, there could be inappropriate dual participation: DERs participating in MISO markets and utility tariffs for the same services.	• Streamlines DER eligibility review to avoid dual participation • Provides DER operational reviews and adjust MISO dispatch schedules when needed • Builds in data-driven measurement and verification
DER Integration	• By 2030, DTE could see 280 MW of rooftop solar and 30 MW of BTM batteries on its system. • Stakeholders are urging DTE to proactively integrate DER into system planning and operations.	• High DER penetration could result in reversed power flow, leading to planning and operational challenges. • DERs, when deployed appropriately, can support bill reduction, traditional investment deferrals (e.g., VPP/NWA) and system resilience (e.g., microgrids).	• Enables unified visibility and control across DTE- and customer-owned DERs • Optimizes DER operations for both market and distribution system support where indicated • Provides valuable DER operational data to advance grid planning and investment

Program Overview and Expected Benefits

A DERMS is a modular software platform that enables monitoring, coordination, and optimization of DERs. It functions as the central communication and control layer for DER-related data exchange, providing DTE's ESOC with visibility into and operational coordination across a broad range of resource types, including DR programs, energy storage, renewable generation, NWAs, and emerging V2G technologies. Resources are managed based on their specific capabilities, operating constraints, and program requirements.

DERMS supports coordination among DTE, aggregators, and MISO by managing operating limits, dispatch signals, and data exchange, while incorporating forecasting tools to anticipate system impacts associated with market activity. MISO has identified specific functional capabilities that distribution utilities must provide to support FERC Order 2222 implementation, and these requirements directly inform the Company's DERMS design and implementation approach. In parallel, updates to interconnection, registration, and planning processes are required to validate DER participation and manage increasing variability in load and generation.

DTE industrial customer solar array and EV chargers

To support scalability and flexibility, DTE's DERMS architecture uses standardized protocols to interface with the ADMS and aggregator platforms. This allows DER dispatch and operational data to be exchanged without requiring ongoing modifications of core ADMS functionality, reducing integration risk and long-term lifecycle costs. Core DERMS functions include resource registration, program assignment, dispatch coordination, performance monitoring, and short-term forecasting, enabling safe DER integration as adoption grows.

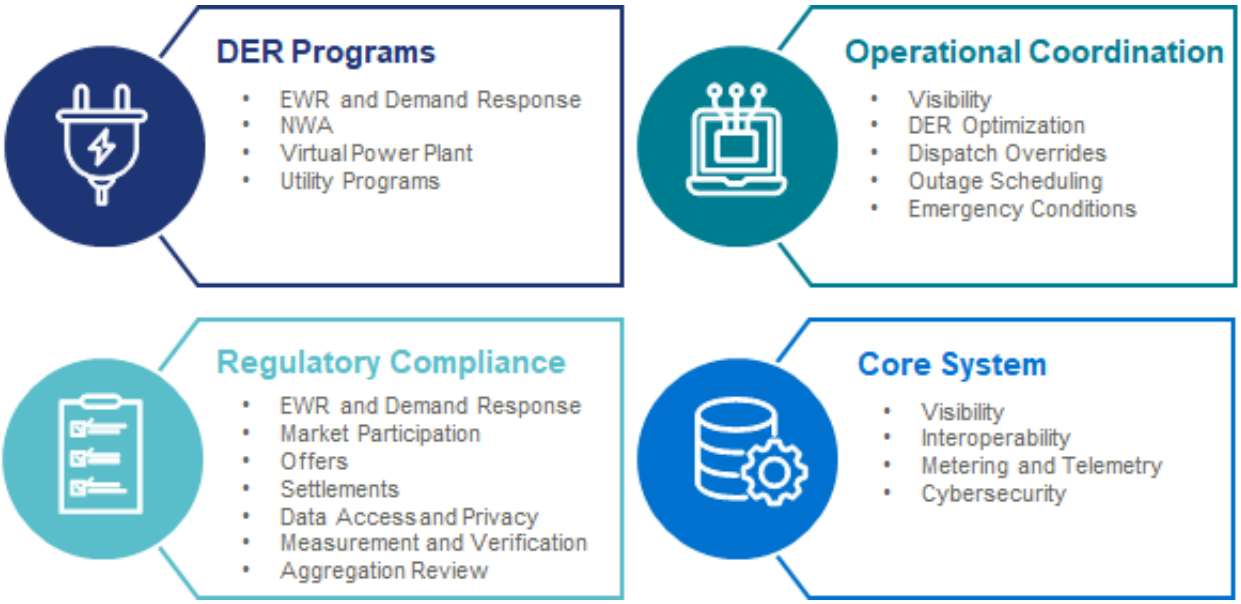
Following good utility practice, DTE's DERMS architecture is organized into three tiers, summarized in Exhibit 6.99, allowing phased implementation while maintaining cybersecurity, interoperability, and operational separation between core utility systems and external parties.

Exhibit 6.99 – DERMS Architecture

Tier	System Name	Primary Role	Primary Interfaces	Key Functions
Tier 1	**Grid DERMS**	Central operational coordination and visibility	ADMS, core business systems, SCADA, MISO, Tier 2	• Integrates with ADMS and core enterprise systems • Forecasting and optimization validated through ADMS power flow • Monitors and controls SCADA-connected DERs • Aligns DER dispatch with outages and shutdowns • Communicates abnormal conditions to MISO and aggregations
Tier 2	**Aggregator DERMS / DER Head End**	Interoperability and secure aggregation layer	Tier 1, Tier 3	• Standardizes communication with aggregators and DER endpoints • Provides cybersecurity isolation for core utility systems • Enables rapid integration of new DER technologies and aggregators • Supports program management and performance validation
Tier 3	**Edge Systems**	Resource-level execution and data exchange	Tier 2, DER devices, third-party DERMS platforms	• Executes dispatch and curtailment commands • Exchanges telemetry and status data • Supports diverse end-use technologies without duplicating aggregator systems

This tiered approach enables DTE to incrementally deploy DERMS capabilities while retaining flexibility in a rapidly evolving DER and market environment. Across all tiers, customer-facing service applications support registration, enrollment, performance tracking, and reporting, ensuring accurate DER data is available for operational and compliance purposes. As summarized in Exhibit 6.100, DERMS delivers integrated benefits across DER program enablement, regulatory compliance, operational coordination, and core system capabilities needed to safely and efficiently support increasing DER adoption and market participation.

Exhibit 6.100 – Benefits of DERMS



DERMS Roadmap and Near-Term Investment

DTE's DERMS strategy prioritizes capabilities required for regulatory compliance and those that increase the efficiency of existing DER and DR operations. Under this approach, DERMS components will be deployed incrementally and scaled based on market participation, regulatory requirements, and forecasted DER growth.

Initial deployment will focus on integrating company-owned DERs not currently connected through SCADA and bringing existing DR programs — such as interruptible air-conditioning and heating — into ADMS-coordinated operations. Subsequent phases will prioritize third-party and aggregator integrations based on MISO market timelines, approved tariff programs, and demonstrated operational readiness. The system will be sized to meet projected needs over the next five years, with periodic reassessment to determine whether expansion or adoption of industry best-practice enhancements is warranted.

The DERMS implementation roadmap begins with an initiation phase in 2026 focused on use-case definition, requirements development, and vendor procurement. Detailed design and system integration activities follow in 2027 through 2028, with testing and operational readiness occurring in late 2028 and early 2029. Deployment, stabilization, and end-to-end testing aligned with MISO's market certification process are expected to conclude with DERMS becoming market-operational in 2030.

DTE's phased implementation approach supports cost-effectiveness by allowing individual components to be upgraded or replaced without modifying the full system, providing scalability and reducing long-term investment risk. It is consistent with approaches taken by peer utilities operating in regions with similar DER growth, wholesale market participation, and regulatory requirements. The investment required to implement a DERMS is provided in Exhibit 6.101.

Exhibit 6.101 – Investment Plan for DERMS, 2026-2030 ($ millions)

	2026	2027	2028	2029	2030	2026 – 2030 Total
Capital	2.8	5.1	3.4	1.5	2.0	**14.8**

Long-Term Investment Outlook

Over the long term, DERMS will play a critical role in addressing increasing DER adoption, increasingly severe weather impacts, and growing capacity constraints on the distribution system. As DER penetration increases, DERMS will enable flexible and efficient integration of customer-owned and third-party resources while maintaining safe and reliable grid operations. Future phases of DERMS investments will focus on expanding customer programs, advancing forecasting and optimization capabilities, and increasing automation of constraint management and coordination between distribution and transmission system operators. Collectively, these capabilities position DTE to meet evolving regulatory requirements and adapt to future changes in the energy landscape while preserving system reliability and supporting customer participation in DER and market programs.

7. Delivering the Distribution System Plan

Chapter 7 outlines the key approaches DTE uses to support the successful execution of its five-year capital plan, along with the regulatory structures that help ensure the Company meets the expectations of customers and the Commission. The chapter is organized into two sections. The first section addresses DTE's execution capabilities, including the PMO's responsibility for delivering capital investment programs and projects, as well as the integrated workforce and material planning models that support forward-looking resource forecasting. It also summarizes the Company's ongoing efforts to pursue external partnerships to support its investment strategy. The second section describes the regulatory mechanisms that promote timely, transparent, and customer-focused improvements — specifically the IRM and PBR structures. Together, these sections conclude the DSP by outlining the path forward for effective plan delivery.

7.1 Execution

This section provides an update on the PMO, resource modeling tools, and external partnership opportunities related to the 2026 DSP.

7.1.1 Project Management Organization

As DTE's capital investment needs continue to grow, the Company has strengthened its ability to deliver programs and projects with greater speed, coordination, and efficiency. In 2023, DTE consolidated its Major Enterprise Projects organization with the Distribution Operations Project Management team to establish the PMO, a dedicated enterprise-wide group focused exclusively on executing programmatic projects in the Company's capital investment portfolio. The PMO leverages disciplined project management practices to deliver critical DSP initiatives, including PTMM, 4.8 kV and 8.3 kV Conversions, Distribution Automation, Subtransmission Redesign and Rebuild, and other essential system upgrades.

Over the past three years, the PMO has continued to evolve to maintain strong alignment across the Company while managing a growing portfolio of complex projects. In 2025, for example, DTE created a dedicated substations group within the PMO to streamline work execution and increase efficiency across substation-related investment categories. This and other organizational enhancements are designed to optimize resources, reduce redundancies, and accelerate project delivery as DTE advances its grid modernization strategy.

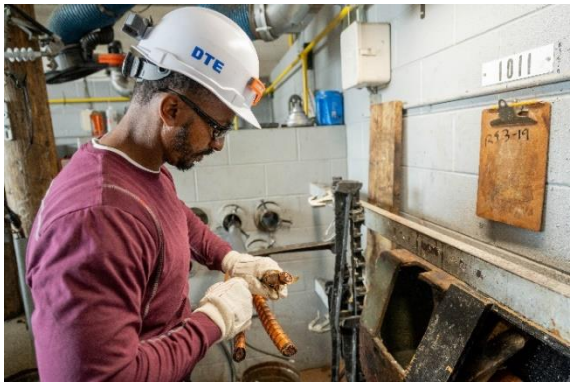
To support execution of an expanding volume of work, the PMO directs resources to effectively deliver capital projects. This includes core functions such as planning and coordination, project controls, and standards governance. Working closely with DO, the PMO has significantly enhanced its ability to scale and has successfully delivered a distribution-related capital portfolio totaling $819 million in 2023, $860 million in 2024, and $841 million in 2025. Looking ahead, the PMO will continue to play a pivotal role in executing the DSP, delivering projects safely, efficiently, and in alignment with the Company's vision for a modern and resilient grid.

7.1.2 Forecasted Workforce and Material Resources

As noted in Section 4.6 (Resource Management), while the Company expects tight supply conditions for key material and qualified labor to continue in the near term, the multi-pronged approaches it has implemented have been effective and have, in large part, mitigated these constraints. The Company is also leveraging the pool of existing expertise within its DO organization to strengthen collaboration with the PMO's contract resources. In parallel, DTE is

taking a broader strategic approach to shoring up core competencies, including engineers, operational and technical support staff, project managers, and field personnel such as linemen, splicers, and other specialized technicians. Additionally, workforce and material requirements are estimated through planning models to ensure adequate staffing levels and timely procurement as the Company executes its DSP.

Workforce Planning



The Company maintains a 10-year integrated workforce plan that defines the technical, skilled-trade, and business support roles needed to execute the full scope of DO work. This integrated approach enables DTE to optimize resources across both daily operations and strategic capital programs — ensuring, for example, that grid and substation operators remain available to maintain safety and system reliability while a dedicated workforce stays focused on long-term strategic projects. It also allows DTE to proactively plan for potential staffing gaps in roles that require multi-year training and qualification pathways.

The long-term plan covers multiple field positions, including overhead linemen, cable pullers, cable splicers, substation operators, and arborists, among many other specialized trades. It also includes technical engineers (including SCADA and other specialties), analysts, schedulers, and administrative staff. This model is refreshed annually and incorporates key inputs that shape DTE's long-term staffing needs, including the Company's capital plan, attrition trends, and new or emerging projects. Leveraging this long-range outlook enables DTE to anticipate workforce needs and proactively align resources with future workload.

Complementing its long-term workforce outlook, the Company also develops a 52-week resource plan to ensure appropriate monthly availability of technical resources throughout the year. This plan forecasts monthly labor-hour requirements for critical skill sets and aligns staffing needs across emergent work, planned work, and the strategic capital investments outlined in the DSP. The output of this planning process serves several important purposes. It provides the scheduling organization with the information needed to develop executable work plans, anticipate overall resource availability, and establish construction schedules that DTE can reliably deliver. The annual forecast also informs the level of contractor resources required across the DO and PMO

organizations to support reliability objectives and execution of strategic investments. For example, the strategic capital forecast intentionally reduces planned work during the summer months to limit operational impacts if crews must be redirected to storm-related restoration activities. These labor projections are shared with union partners and PMO contractors up to a year in advance, enabling them to plan and adjust workforce levels accordingly to maintain resource availability for strategic capital work.

To effectively execute DTE's strategic capital investments, the Company relies not only on field construction and trade resources, but also on a wide range of back-office and business support functions. DTE uses near-term forecasting models to maintain the appropriate level of project oversight and adheres to sound project management practices. The PMO staffing model evaluates non-trade project support roles within its DO work pillar, focusing on needs over the next two years. Each position is forecasted based on the nature of the work, using project-based, dollar-based, or unit-based modeling, to generate accurate, function-specific staffing estimates. Exhibit 7.1 outlines the additional PMO staff required from 2025 through 2027. These roles will be supplemented by contracting partnerships described in Section 4.6 (Resource Management).

Exhibit 7.1 – PMO Incremental Staff Positions

	2025	2026	2027
Project Managers	71	78	88
Project Coordinators	2	4	4
Work Management Specialists	2	7	8

One of the most significant resource gaps identified through DTE's workforce models is in engineering capacity, driven by the increased workload associated with grid modernization. In response, the Company has begun ramping up engineering hiring, with staffing forecasts supporting continued increases over the next several years. In the interim — and in parallel with internal hiring — the Company's engineering needs are being supplemented by contractor support, as outlined in Section 4.6 (Resource Management).

Material Forecasting

DTE also develops multi-year material forecasts to support its Materials Resource Planning (MRP) process. These forecasts rely on five years of historical consumption and spending data, organized by investment area and material type. Using this information, the PMO calculates a

historical spend factor for each material type within each investment category and applies these factors to the investment plan to generate forward-looking material needs.

Once completed, the forecast is provided to the Supply Chain organization for integration into the MRP process, including adjustments to reorder points and the initiation of purchase requisitions based on expected lead times. Additionally, the Company is establishing processes to refine its forecasting approach in response to evolving engineering standards or market conditions. Lastly, the PMO and Supply Chain organizations have collaborated to improve visibility into long-lead equipment (LLE). Throughout the year, both groups review and update LLE duration timelines to ensure project schedules are adjusted accordingly. Project teams receive regular reports identifying when equipment must be ordered so that materials arrive on time and do not delay construction.

7.1.3 External Funding Opportunities Exploration and Grants

On Nov. 15, 2021, the Infrastructure Investment and Jobs Act (IIJA), also known as the Bipartisan Infrastructure Law (BIL), was signed into law. The IIJA authorized approximately $1.2 trillion in funding over five years, with significant emphasis on clean energy, decarbonization, EV infrastructure, grid reliability and resilience, and other critical infrastructure investments. Beginning in 2022, DTE initiated a comprehensive review of IIJA funding opportunities, submitted applications for eligible programs, and supported third-party applicants through outreach and coordination. Since that time, the Company has provided the MPSC with seven biannual updates regarding its IIJA activities in Case No. U-21227, most recently on Dec. 15, 2025.[187]

Although DTE has had several applications selected for potential awards, the Company has been unable to proceed due to conflicts between federal grant terms and DTE's fiduciary obligations. For example, on Oct. 18, 2023, the DOE announced its selection of DTE's adaptive networked microgrid project (Smart Grid Grant) for a potential grant award of approximately $23 million. The Company anticipated finalizing the award agreement in early 2025 and had already identified the personnel and financial resources needed to execute the project. However, during negotiations, DTE became aware of terms and conditions in the grant agreement that conflicted with the Company's obligations under its long-standing financial agreement with its bondholders.

DTE identified the same conflict in connection with the Resilience for States & Tribes (40101d) program and the Energy Storage Demonstration and Validation grant. As a result, on March 11,

[187] MPSC Case No. U-21227 available at https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/068cs00001WqKNuAAN, accessed March 16, 2026.

2025, DTE notified the Department of Environment, Great Lakes, and Energy (EGLE) that it could not proceed with the 40101d award. Similarly, on June 4, 2025, the Company informed the DOE that it was withdrawing its applications for both the Smart Grid Grant (DE-FOA-0002740) and Energy Storage Demonstration and Validation Grant (DE-FOA-0003036) absent a resolution to the conflicting terms.

With the enactment of the Working Families Tax Cut — also known as the One Big Beautiful Bill Act — on July 4, 2025, the federal government established the Energy Dominance Financing (EDF) program, which provides up to $200 billion in loan guarantees for projects that add energy to the grid or enhance reliability. In Q1 2025, DTE received conditional commitments for loan guarantees from the DOE for up to $7.2 billion. The Company is currently engaged in discussions with the DOE's EDF regarding project eligibility and loan terms.

DTE continues to monitor federal and state funding opportunities and explore partnerships that align with its strategic objectives and eligibility requirements. The Company will provide an update of its efforts to obtain external funding in its eighth biannual update to the MPSC in Case No. U-21227, which will be filed on or before June 30, 2026.

7.2 Regulatory Considerations

This section outlines the regulatory mechanisms that promote transparency in the Company's investments as DTE works to deliver meaningful value to its customers.

7.2.1 Infrastructure Recovery Mechanism

The Company traditionally recovered its distribution system investments entirely through the electric rate case process. More recently, an IRM has been utilized to recover a subset of these investments, with accompanying planning, operational, and customer benefits as described below. The remainder of the investments described in this DSP will continue to utilize the rate case process for cost recovery. Additionally, absent IRM approval, the IRM investments described below would also be included in rate cases.

DTE first proposed the IRM in Case No. U-21297 (the 2023 General Rate Case). At its core, the IRM is a cost-recovery mechanism designed to bring greater planning and operational certainty, transparency, and stakeholder engagement to strategic distribution and subtransmission investments. This filing and related rate cases describe the Company's overall investment strategy, and the IRM recovers a portion of these investments. DTE believes the IRM remains an important mechanism and delivers the following key benefits:

- **Program Certainty Ensures Investments are Committed in the Intended Area:** The IRM program provides greater certainty and discipline in the Company's capital allocation for the areas that are defined in the approved IRM programs. This program certainty also enables more effective work planning and coordination and reduces execution risk. In addition, the predictability of IRM-driven capital deployment strengthens the Company's ability to proactively procure equipment and materials, mitigating cost volatility and supply chain constraints. Collectively, these benefits support timely and economic execution in the intended areas for the benefit of customers.
- **Customers Only Pay for Actual Work Completed**: Approved IRM investments must be made within the designated program at the specified amount. If the authorized, program-specific investment levels are not achieved, customers are refunded the difference.
- **Transparency:** The IRM includes program-level investment plans and detailed reconciliations comparing actual spending to planned investment, helping to confirm the Company is delivering the customer value that is expected.
- **Stakeholder Engagement:** Interested parties have the opportunity to review and provide feedback on the IRM Plan through the stakeholder engagement process, fostering a collaborative approach.

The MPSC approved the first two years of the IRM in Case No. U-21297, along with additional reporting and review requirements, stating that "there is value in the company's proposal."[188] In Case No. U-21534, the Commission said it "finds persuasive DTE Electric's argument that the IRM has delivered benefits in terms of certainty in spending on defined distribution programs and increased transparency and outside involvement in the planning and reconciliation process."[189] On this basis, the Commission approved a one-year extension of the IRM to serve as a bridge through 2026 while outcomes from related dockets (e.g., distribution audit and performance-based ratemaking) were pending. The Company subsequently proposed an expanded IRM in Case No. U-21860 which leveraged the findings of the distribution audit. Although the MPSC agreed "that DTE Electric has made progress incorporating the recommendations of the Liberty Audit,"[190] the Commission's Order approved only a one-year extension, with the inclusion of

[188] Order dated December 1, 2023 in Case No. U-21297 (page 289), available at https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/0688y00000At0VBAAZ, accessed March 17, 2026.

[189] Order dated January 23, 2025 in Case No. U-21534 (page 301), available at https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/068cs00000X23rkAAB, accessed March 17, 2026.

[190] Order dated February 19, 2026 in Case No. U-21860 (page 384), available at https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/068cs00001kHayeAAC, accessed March 17, 2026.

PTMM beginning in 2026. In total, approved IRM investment programs from Orders U-21297, U-21534, and U-21860 are shown in Exhibit 7.2.

Exhibit 7.2 – Approved IRM Investment Programs by Year, ($ millions)[191]

Capital Program	2024	2025	2026	2027
4.8 kV Conversions	1.6	185.8	-	-
Subtransmission Redesign & Rebuild	5.5	53.8	53.8	52.5
Breaker Replacement	13.7	12.6	12.6	15.0
URD Replacement	14.6	13.5	13.5	15.0
Distribution Automation	26.4	24.4	68.9	-
PTMM	-	-	200.0	200.0
Total	**61.8**	**290.1**	**348.8**	**282.5**

The Commission did not approve Distribution Automation in the 2027 IRM, noting that it was "further persuaded by the findings of the Liberty Audit" even though it "continues to see benefit in DA investments in improving both safety and reliability."[192] The Audit Report's recommendations focus on clarifying the incremental benefits of Distribution Automation — separate from those associated with keeping Vegetation Management and PTMM on-cycle — and reassessing the appropriate scale of cost-effective Distribution Automation investment using the updated BCA methodology. DTE has incorporated both of those recommendations into its updated Distribution Automation strategy as described in Section 6.4.1 (Distribution Automation).

In its Case No. U-21860 Order, the Commission emphasized that IRM investments must be for established, proven programs, and that any future multi-year IRM extensions must be supported by a comprehensive, well-articulated investment strategy justified by BCAs. The Company believes the 2026 DSP fully satisfies these expectations. Therefore, to build on the key IRM benefits of investment certainty and transparency, and to ensure consistency with the well-defined, value-driven programs in this DSP, DTE proposes a multi-year extension of the IRM in Case No. U-22046. Key updates include:

- Expanding and extending PTMM to progress toward a five-year pole-top and 10-year pole inspection and maintenance cycle, consistent with Audit Report findings and as detailed in Section 6.2.1 (Pole and Pole-Top Maintenance and Modernization).

[191] "Distribution Automation" was authorized as "4.8 kV Circuit Automation" for IRM Years 2024 and 2025.

[192] Order dated February 19, 2026 in Case No. U-21860 (pages 190-191), available at https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/068cs00001kHayeAAC, accessed March 17, 2026.

- Expanding and extending Breaker and URD Replacements and adding System Cable Replacement to proactively address critical aging and failing infrastructure, as detailed in Section 6.2.6 (System Equipment Replacement).
- Expanding and extending Subtransmission Redesign and Rebuild to achieve modern design standards necessary for long-term system resiliency, as detailed in Section 6.3.3 (Subtransmission Redesign and Rebuild).
- Proposing Distribution Automation for IRM treatment to continue to deliver safety and reliability benefits to customers, as detailed in Section 6.4.1 (Distribution Automation).

Exhibit 7.3 summarizes the previously approved IRM investments for 2026 and 2027 in addition to the proposed IRM investments for the remaining years of the five-year DSP timeframe.[193]

Exhibit 7.3 – Five-Year IRM Investment Overview, ($ millions)

Capital Program	2026	2027	2028	2029	2030
Subtransmission Redesign & Rebuild	53.8	52.5	58.0	80.0	90.0
Breaker Replacement	12.6	15.0	20.0	35.0	55.0
URD Replacement	13.5	15.0	20.0	35.0	55.0
System Cable	-	-	31.0	40.0	55.0
Distribution Automation	68.9	100.0	140.0	46.0	-
PTMM	200.0	263.4	376.8	482.6	540.0
Total	**348.8**	**445.9**	**645.8**	**718.6**	**795.0**

Considering prior IRM years, the current year, and the Commission's recent approvals, the IRM continues to provide strong and consistent support for the Company's essential strategic capital investments. The proposed multi-year extension builds on this foundation, facilitating continued reliability improvements, investment transparency, and alignment with Commission expectations.

7.2.2 Performance Metrics

Performance-Based Ratemaking (PBR) is a regulatory approach that links a utility's financial outcomes to its operational performance. This is often done through performance incentive mechanisms, which are typically designed to support broader policy objectives such as improving reliability, advancing energy efficiency and renewable energy, and modernizing the grid. While Michigan is relatively new to formal reliability-focused PBR, similar frameworks have been used in other states for many years.

[193] See Exhibit A-33, Schedule X2, Alternative Investment and In-Service Levels in Case No. U-22046. For 2027, $100M of Distribution Automation investment and $63.4M of PTMM investment are proposed but have not yet been approved.

Michigan's PBR efforts began in 2016, when lawmakers passed Public Act 341 directing the Commission to study PBR. The Commission advanced this effort in May 2020 by issuing an order in Case No. U-20561 directing DTE to submit potential PBR metrics in the Company's next DSP. In response, the Company's 2021 DSP presented a conceptual PBR mechanism centered on SAIDI exMED and CEMI 6.[194]

The Commission expanded this effort in April 2023 by opening Case No. U-21400, which established a "Financial Incentives and Disincentives" workgroup to develop metrics, incentives, and disincentives focused on distribution reliability. After multiple rounds of stakeholder comments and iterative refinements to a straw proposal, the workgroup produced a final straw proposal that the Commission adopted in February 2025. That Order directed DTE to file a PBR proposal aligned with the approved straw proposal, and the Company filed its first PBR plan in Case No. U-21909 in April 2025. In December 2025, the Commission issued an Order approving the settlement agreement in that case.[195,196] Both the filing and the settlement agreement reflect the Commission's adopted straw proposal.

The settlement establishes seven performance metrics covering systemwide reliability, customer restoration speed, and frequent outages. The metrics, weights, and associated incentive and penalty structure are shown in Exhibit 7.4.

Exhibit 7.4 – PBR Metrics, Weights, and Maximum Incentives and Penalties[197]

Metric	Weight (% of Total)	Maximum Incentive / Penalty ($ millions)
SAIDI exMED	15%	1.5
SAIDI All-Weather	15%	1.5
48-hour Catastrophic Storm Restoration	25%	2.5
72-hour Catastrophic Storm Restoration	20%	2.0
24-hour Gray Sky Restoration	10%	1.0
CEMI-4	10%	1.0
Worst Performing Circuits (SAIDI exMED, System Basis)	5%	0.5
Total	**100%**	**10.0**

[194] 2021 Distribution Grid Plan Final Report, available at https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/068t000000Uc0pkAAB, accessed March 17, 2026.

[195] Parties to the settlement include the Company, Staff, the Attorney General, MNSC, the City of Ann Arbor, and ABATE.

[196] Order U-21909 dated December 18, 2025, available at https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/068cs00001XbWwnAAF, accessed March 17, 2026.

[197] The MPSC defines Gray Sky conditions as events in which 1 to less than 10% of the customer base is impacted and Catastrophic conditions as events affecting 10% or more of customers.

The approved incentive mechanism establishes targets, thresholds, and maximums for each metric as shown in Exhibit 7.5 through Exhibit 7.7 below.

Exhibit 7.5 – Targets, Thresholds, and Maximums for SAIDI exMED

SAIDI exMED	2026	2027	2028	2029	2030
Maximum Incentive	107.7	104.6	101.6	98.6	95.6
Incentive Threshold	128.1	125.0	122.0	119.0	116.0
Target/Penalty Threshold	150.0	148.5	147.0	145.4	143.9
Maximum Penalty	170.4	168.9	167.4	165.8	164.3

Exhibit 7.6 – Targets, Thresholds, and Maximums for SAIDI All-Weather

SAIDI All-Weather	2026	2027	2028	2029	2030
Maximum Incentive	237.9	222.4	206.8	191.3	175.7
Incentive Threshold	500.0	484.4	468.9	453.3	437.8
Target/Penalty Threshold	769.8	762.0	754.3	746.5	738.7
Maximum Penalty	1031.9	1024.1	1016.3	1008.6	1000.8

Exhibit 7.7 – Targets, Incentive, and Penalty Ranges for All Other Metrics

Metric	Penalty Range	Target	Incentive Range
48-hour Catastrophic Storm Restoration	≤90%	>90%	>90 to 100%
72-hour Catastrophic Storm Restoration	≤95%	>95%	>95 to 100%
24-hour Gray Sky Restoration	≤90%	>90%	>90 to 100%
CEMI-4	≥6	<6%	0 to <6%
Worst Performing Circuits (SAIDI exMED, System Basis)[198]	*For Penalty:* A circuit is listed in top 10 during the review year and listed in the top 10 in any of the four years prior. *For Incentive:* None of the circuits listed in the top 10 during the review year are listed in the top 10 in any of the four years prior.		

The performance metrics included in the approved PBR mechanism are functioning as intended as they have informed and shaped the Company's DSP planning process. The proposed DSP is designed to support the attainment of the PBR targets set forth by the Commission, meet or exceed the SQRS, and advance the Company's own commitment to fewer and shorter outages. The Company's incident command structure, storm response plan, and storm-related technology and innovation initiatives collectively support achieving the restoration targets as described in

[198] For both Penalty and Incentive: Review Year 2026 shall be compared with years 2023- 2025. Review year 2027 shall be compared with years 2023-2026. Review year 2028 shall be compared to years 2024-2027. Subsequent review years will be compared to the prior three years.

Section 4.4.2 (Weather Event Response and Restoration). In addition, the DSP's strategic investment pillars are structured to preserve recent gains while continuing to drive sustained improvement across the remaining PBR metrics as discussed throughout Chapter 6 (Distribution System Plan Investment Pillars).

DTE's approved PBR Plan is a constructive, forward-looking component of the Company's strategy to provide reliable service to its customers. It reflects thoughtful stakeholder engagement and collaboration through Case Nos. U-21400 and U-21909, and the Company's DSP is fully aligned with — and actively advances — the objectives embedded in the Commission-approved PBR framework. Achievement of the PBR metrics is possible with constructive stakeholder engagement and ongoing approval of the required capital investments.

7.3 Conclusion

DTE's 2026 DSP presents a transparent, data-driven strategic roadmap for planned grid investments from 2026 through 2030. The plan reflects Commission directives related to the Audit Report, SQRS, and PBR, as well as the evolving drivers of electric grid investment — including aging infrastructure and capacity constraints, increasingly severe weather, and customer adoption of DER and other emerging technologies that add operational complexity.

The DSP builds on demonstrated progress from prior investments, strengthens its analytical rigor, and provides greater transparency into the planning and prioritization frameworks used to inform investment decisions. Together, these enhancements strengthen the linkage between proposed investments and customer outcomes. The resulting five pillars of reliability and modernization investment form a cohesive and balanced strategy, designed to work as an integrated portfolio that enables effective work-scope management, coordinates the timing and pacing of capital deployment, and supports efficient delivery of near-term reliability improvements while leveraging specialized expertise for more complex, longer-term grid infrastructure investments.

Recognizing the essential role the Company plays in powering homes, businesses, and communities, DTE submits this plan in support of its continued commitment to meet customers' evolving needs through a modern, resilient electric grid. Through disciplined planning, transparent decision-making, and sustained focus on performance improvement, the Company remains committed to providing safe, reliable, and clean electricity, while balancing affordability with the pace of necessary investments for the customers and communities it serves.

8. Appendix

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8.2 Glossary of Acronyms and Terms

Acronym or Term	Definition
AC	Alternating Current
ACSR	Aluminum Conductor Steel Reinforced
ADMS	Advanced Distribution Management System
AI	Artificial Intelligence
ALA	Area Load Analysis
AMI	Advanced Metering Infrastructure
ANM	Adaptive Network Microgrid
APTS	Automatic Pole-Top Switch
ATO	Automatic Throw Overs
Audit Report	Refers to the MPSC-ordered distribution audit report produced by The Liberty Consulting Group
AW	All-Weather
BCA	Benefit-Cost Analysis
BCR	Benefit-Cost Ratio
BI	Business Intelligence
BIL	Bipartisan Infrastructure Law
BIPOC	Black, Indigenous, and People of Color
BTM	Behind-The-Meter
c/kWh	Cents Per Kilowatt-Hour
C&I	Commercial And Industrial
CAIDI	Customer Average Interruption Duration Index
Catastrophic Condition	In Case No. U-20629, the MPSC defined Catastrophic conditions as events affecting 10% or more of the customer base.
CCRO	Customer Connections, Relocations, and Other
CE	Customer Excellence
CEI	Climate Extremes Index
CELID-n	Customers Experiencing Long Interruption Durations (n=hours)
CEMI-n	Customers Experiencing Multiple Interruptions (n=outages)
CEO	Clean Energy Organizations
CIAC	Contribution in Aid of Construction
CM	Corrective Maintenance
CMA	Customer Outage Minutes Avoided

Acronym or Term	Definition
CMI	Customer Minutes Interrupted
CODI	City of Detroit Infrastructure (Downtown) program
ComEd	Commonwealth Edison
CVR/VVO	Conservation Voltage Reduction / Volt-Var Optimization
DA	Distribution Automation
DAAO	Detroit Area Advocacy Organization
DC	Direct Current
DDO	Distribution Design Order
DER	Distributed Energy Resource
DERMS	Distributed Energy Resource Management System
DG	Distributed Generation
DGA	Dissolved Gas Analysis
DGP	Distribution Grid Plan
DI	Distributed Intelligence
DLBA	Detroit Land Bank Authority
DMS	Distribution Management System
DO	Distribution Operations
DOE	Department of Energy
DPLD	Detroit Public Lighting Department
DR	Demand Response
DSP	Distribution System Plan
DTE	For purposes of this report, DTE refers to DTE Electric Company
EDDP	Everyday Daily Plan
EDF	Energy Dominance Financing
EEI	Edison Electric Institute
EFL	Emergency Field Leader
EJ	Environmental Justice
ELC	Emergency Load Control
ELPC	Environmental Law and Policy Center
EMS	Emergency Management System
EP&R	Emergency Preparedness & Response
EPC	Engineer-Procure-Construct
EPRI	Electric Power Research Institute

Acronym or Term	Definition
ESOC	Electric System Operations Center
ESRI	Refers to Esri, Inc. (GIS platform provider)
ETTP	Enhanced Tree Trimming Program
ETO	Electronic Turnover Cards
EV	Electric Vehicle
EWR	Energy Waste Reduction
exMED	Excluding Major Event Days
FAR	Field Area Router
FCN	Field Communications Network
FEMA	Federal Emergency Management Agency
FERC	Federal Energy Regulatory Commission
FLISR	Fault Location, Isolation, and Service Restoration
FTE	Full-Time Equivalent
FTM	Front-Of-The-Meter
GEE	Generalized Estimating Equations
GIS	Geographical Information System
GLMA	Great Lakes Mutual Assistance
GMS	Generation Management System
GPM	Global Prioritization Model
Gray Sky	In Case No. U-2-629, the MPSC defined Gray Sky conditions as events that impact more than 1% but less than 10% of the customer base.
GWh	Gigawatt-hour
HID	High-Intensity Discharge
IBEW	International Brotherhood of Electrical Workers
IBR	Inverter-Based Resources
IC	Incident Commander
ICE	Interruption Cost Estimate
ICS	Incident Command Structure
IED	Intelligent Electronic Devices
IEEE	Institute of Electrical and Electronics Engineers
IFS	Integrated Forecasting Solution
IIJA	Infrastructure Investment and Jobs Act
IoT	Internet of Things

Acronym or Term	Definition
IRM	Infrastructure Recovery Mechanism
IRP	Integrated Resource Plan
ISO-down	Isolation-Down Areas
ITC	International Transmission Company
Jumpering	Refers to the installation of electrical jumpers — short lengths of conductor or cable that electrically connect two points in the system
kV	Kilovolt
kW	Kilowatt
LCOE	Levelized Cost of Energy
LED	Light-Emitting Diode
LiDAR	Light Detection and Ranging
LLE	Long Lead Equipment
LMM	Linear Mixed Models
MAC EJ	Michigan Advisory Council on Environmental Justice
MED	Major Event Day – defined in IEEE Standard 1366 as any day in which the daily SAIDI exceeds a statistically-derived threshold value
MHMP	Michigan Hazard Mitigation Plan
MIC	Michigan Infrastructure Council
MISO	Midcontinent Independent System Operator
MPSC	Michigan Public Service Commission
MRP	Materials Resource Planning
MW	Megawatt
MWh	Megawatt Hour
MVA	Mega Volt Ampere
Near term or near-term	For purposes of this filing, “near term” refers to the 2026-2030 planning horizon addressed in this DSP
NECA	National Electrical Contractors Association
NERC	North American Electric Reliability Corporation
NESC	National Electric Safety Code
Next-Gen AMI	Next-Generation Advanced Metering Infrastructure
NIMS	National Incident Management System
NMS	Network Management System
NOAA	National Oceanic and Atmospheric Administration
Normal Conditions	In Case No. U-20629, the MPSC defined Normal conditions as those that do not meet the threshold for either Gray Sky or Catastrophic conditions.

Acronym or Term	Definition
NOX	Nitrogen Oxides
NPV	Net Present Value
NRUC	Normal Retirement Unit Change-out
NWA	Non-Wire Alternative
OEM	Original Equipment Manufacturer
OH or OHL	Overhead Line
O&M	Operation and Maintenance
OMS	Outage Management System
OROW	Outside-Of-Right-Of-Way
OT	Operational Technology
PBR	Performance-Based Ratemaking
PM	Preventative Maintenance
PMO	Project Management Organization
PON	Power Outage Notification
PTMM	Pole and Pole-Top Maintenance and Modernization
PTS	Pole-Top Switch
PV	Photovoltaics
PVA	Project Value Analysis
RAN	Radio Area Network
RDN	Radio Data Network
RFI	Request For Information
RIM	Ratepayer Impact Measure
ROW	Right-Of-Way
RTU	Remote Terminal Unit
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SCADA	Supervisory Control and Data Acquisition
SFI	Smart Fault Indicators
SME	Subject Matter Expert
SRIP	Strategic Reliability Improvement Program
SPdM	Substation Predictive Maintenance Inspection
SOC	System Operations Center
SOM	Switch Order Management

Acronym or Term	Definition
SO2	Sulfur Dioxide
Storm	Typically declared when outage volume exceeds 760 active outage events across at least 200 circuits for more than one hour.
STDF	Subtransmission Distribution Facilities
SQRS	Service Quality and Reliability Standard
T&D	Transmission and Distribution
TCO	Total Cost of Ownership
TEP	Transportation Electrification Plan
TRSDs	Trouble Requests for Shutdown
UG	Underground
URD	Underground Residential Distribution
UWUA	Utility Workers Union of America
URMA	Utility Restoration Management Application
V2G	Vehicle-To-Grid
V2X	Vehicle-To-Everything
VLF	Very Low Frequency
VPP	Virtual Power Plant
VVO	Volt/VAR Optimization
WFM	Workforce Management

8.3 Requirement Fulfillment Matrix

Category	DSP Requirement (Order Excerpt Summary)	Order No.	Incorporation into the DSP
High-Level / Filing Framework	Incorporate the MPSC-approved filing guidelines for DSPs.	U-20147 dated 7/10/25 (pp. 18)	**Table of Contents** **Section 2.1** (Distribution System Plan Purpose)
	Ensure DTE's other plans and programs are considered in the DSP.	U-20147 dated 7/10/25 (p. 30)	**Section 4.5.2** (Transportation Electrification Plan) **Section 5.1** (Load Forecasts and Scenario Planning) **Section 7.2.1** (Infrastructure Recovery Mechanism) **Section 7.2.2** (Performance Metrics)
	Include discussion of the feedback provided on the reliability metrics related to financial incentives and disincentives as outlined in Case No. U-21400.	U-21305 dated 6/12/25 (p. 21)	**Section 7.2.2** (Performance Metrics)
	Create a new, individual docket for the next DSP.	U-20147 dated 7/10/25 (p. 30)	**Case No. U-22104**
Outreach	Demonstrate how DTE has engaged interested parties to obtain input, explored ideas and potential solutions, and incorporated findings into plan.	U-20147, Exhibit A dated 7/10/25 (p. 2)	**Section 3.1** (Summary of Pre-Filling Outreach) **Section 3.2** (Summary of Ongoing Outreach Efforts)
	Provide summary of utility customer, community, and local government outreach efforts.	U-20147, Exhibit A dated 7/10/25 (pp. 4)	**Section 3.2** (Summary of Ongoing Outreach Efforts)
	Include approaches to distribution modeling as part of DSP pre-filing outreach.	U-21860 dated 2/19/26 (pp. 119-120)	**Section 3.1** (Summary of Pre-Filing Outreach)
	Develop more concreate planning protocols and guidelines for 4.8 kV Conversions and include as part of pre-filing outreach.	U-21860 dated 2/19/26 (pp. 167)	**Section 3.1** (Summary of Pre-Filing Outreach) **Section 6.3.1** (4.8kV and 8.3kV Conversions)
	Develop more concrete planning protocols and guidelines for 4.8 kV Conversions and include as part of pre-filing outreach.	U-21860 dated 2/19/26 (pp. 167)	**Section 3.1** (Summary of Pre-Filing Outreach) **Section 6.3.1** (4.8kV and 8.3kV Conversions)
Current State	Provide a data-based review of the current and recent historical system characteristics, asset health, and relevant operations to provide basis and context.	U-20147, Exhibit A dated 7/10/25 (pp. 4)	**Chapter 4** (State of the System and Additional DSP Requirements)
	Provide relevant data on system assets to provide basis of planning efforts, including age, condition, location, and voltage characteristics.	U-20147, Exhibit A dated 7/10/25 (pp. 4)	**Section 4.1** (Subtransmission and Distribution System Overview) **Section 4.2** (General Asset Health and Condition)
	Provide a brief discussion or summary of the utility's current operation strategy.	U-20147, Exhibit A dated 7/10/25 (pp. 5)	**Section 4.4** (Operations)
	Provide a summary of Vegetation Management, including maps as applicable.	U-20147, Exhibit A dated 7/10/25 (pp. 5)	**Section 6.1.1** (Vegetation Management) **Section 4.3.5** (Historical Overlay Maps) **Section 5.5** (Planned Investment Overlay Maps)

Category	DSP Requirement (Order Excerpt Summary)	Order No.	Incorporation into the DSP
Safety	Include safety incident information reported under Mich Admin Code R 460.3804.	U-20147 dated 7/10/25 (pp. 22)	**Section 4.3.1** (Grid Safety and Historical Safety Incidents)
	The data shall be compiled from 460.3804 reported incidents for prior three years.	U-20147, Exhibit A dated 7/10/25 (pp. 5)	**Section 4.3.1** (Grid Safety and Historical Safety Incidents) R 460.3804 Accidents; notice to commission. Rule 804. An electric utility or cooperative shall promptly notify the commission of fatalities and serious injuries that are substantially related to the facilities or operations of the facilities.
Rate Case Alignment	Future cost recovery requests in rate cases should align with the projections in DTE's most recent DSP.	U-21305 dated 6/12/25 (pp. 20-21)	**Section 5.3.2** (Forecasted Reliability Benefits) **Appendix 8.13** (Reliability Model Technical Report) **See also Case No. U-22046 Electric Rate Case**
	Ensure alignment between DSP and rate case request.	U-20147 dated 7/10/25 (pp. 20-21)	**Section 2.1** (Distribution System Plan Purpose) **Section 5.3.1** (Forecasted O&M and Capital Investments) **See also General Rate Case No. U-22046**
	Align DSP spending classifications to the rate case.	U-20147, Exhibit A dated 7/10/25 (pp. 3)	**Section 4.3.4** (Historical O&M and Capital Spend) **Section 5.3.1** (Forecasted O&M and Capital Investments) **See also Case No. U-22046 Electric Rate Case**
	Provide customer rate impacts by customer class.	U-20147, Exhibit A dated 7/10/25 (pp. 9)	**Section 5.3.3** (Customer Affordability Analysis) **Appendix 8.12** (Detailed Customer Affordability Analysis)
Historical Performance	Provide maps showing three years of historical investments starting January 2024.	U-20147, Exhibit A dated 7/10/25 (pp. 6)	**Section 4.3.5** (Historical Overlay Maps)
	Use consistent reliability metrics, including industry standard definition of all weather, for comparison across utilities.	U-20147 dated 9/26/2024 (pp. 138)	**Section 4.3.2** (Historical Reliability Metrics) **Section 4.3.3** (Historical Outage Events) **Section 7.2.2** (Performance Metrics) **Appendix 8.5** (Additional Reliability and Outage information)
	Provide five-year historical reliability metrics for AW and exMED conditions.	U-20147, Exhibit A dated 7/10/25 (pp. 4)	**Section 4.3.2** (Historical Reliability Metrics)
	Provide a comparison of actual reliability performance to reliability projections.	U-21305 dated 6/12/25 (pp. 26)	**Section 4.3.2** (Historical Reliability Metrics)
	Provide five-year historical O&M and capital spend by category.	U-20147, Exhibit A dated 7/10/25 (pp. 5)	**Section 4.3.4** (Historical O&M and Capital Spend)
	Provide historical outage events affecting >1% of DTE's customer base, including costs for catastrophic event recovery and maps as applicable.	U-20147, Exhibit A dated 7/10/25 (pp. 5)	**Section 4.3.4** (Historical Outage Events) **Appendix 8.5** (Additional Reliability and Outage Information)

Category	DSP Requirement (Order Excerpt Summary)	Order No.	Incorporation into the DSP
Hosting Capacity	Provide an update on Hosting Capacity maps.	U-20147, Exhibit A dated 7/10/25 (pp. 9)	**Section 4.5.1** (Hosting Capacity Analysis) **Section 6.4.3** (Operational Technology)
Resource Planning	Include SCADA resources in workforce planning model and elaborate on plans for long-term engineering resources in next DSP.	U-21305 dated 6/12/25 (pp. 5-6, 8)	**Section 7.1.2** (Forecasted Workforce and Material Resources)
	Provide a description of any recent historical of ongoing resource challenges.	U-20147, Exhibit A dated 7/10/25 (pp. 6)	**Section 4.6** (Resource Management)
Environmental Justice	Perform EJ analysis by mapping circuits to census tracts and cross-referencing with MiEJScreen tool. Present a comprehensive plan for remaining arc-wire removal.	U-21534 dated 1/23/25 (pp. 103-104)	**Section 4.7** (Environmental Justice Analyses) **Section 6.2.2** (4.8 kV Hardening)
	Evaluate changing demographics over time and incorporate reliability performance for vulnerable communities in DSP.	U-21534 dated 1/23/25 (pp. 124-125)	**Section 4.7** (Environmental Justice Analyses) **Section 5.4** (Environmental Justice in Distribution Planning) **Appendix 8.8** (Environmental Justice Changing Demographic Analysis)
	Incorporate EJ related considerations, including avoiding creating performance disparities.	U-21534 dated 1/23/25 (pp. 444)	**Section 4.7** (Environmental Justice Analyses) **Section 5.4** (Environmental Justice in Distribution Planning) **Appendix 8.6** (Environmental Justice Regression Analysis) **Appendix 8.8** (Environmental Justice Changing Demographics Analysis)
	Work with Staff and other stakeholders to develop a detailed customer demographic and regression analyses.	U-21297 dated 12/1/23 (pp. 352)	**Section 4.7** (Environmental Justice Analyses) **Appendix 8.7** (Environmental Justice Regression Analysis) **Appendix 8.8** (Environmental Justice Changing Demographics)
	Provide comparative reliability analysis for EJ vs. non-EJ communities and percentages of populations participating in low-income programs.	U-20147, Exhibit A dated 7/10/25 (pp. 6)	**Section 4.7** (Environmental Justice Analyses) **Section 5.4** (Environmental Justice in Distribution Planning)
Planning Analyses & Investment Prioritization	Perform project-specific BCA and alternatives analysis for all Subtransmission projects over $10 million.	U-21534 dated 1/23/25 (pp. 133)	**Section 5.2.1** (Alternatives Analyses Process) **Section 5.2.3** (Benefit-Cost Analyses Approach) **Section 6.3.3** (Subtransmission Redesign and Rebuild) **Appendix 8.9** (Alternatives Analyses Project List) **Appendix 8.14** (Benefit-Cost Analysis Report)
	The DSP should include rigorous, realistic BCAs and alternatives analyses instead of only relying on GPM outputs.	U-21305 dated 6/12/25 (pp. 20-21)	**Section 5.2.1** (Alternatives Analyses Process) **Section 5.2.3** (Benefit-Cost Analyses Approach) **Appendix 8.9** (Alternatives Analyses Project List) **Appendix 8.14** (Benefit-Cost Analysis Report)

Category	DSP Requirement (Order Excerpt Summary)	Order No.	Incorporation into the DSP
	Perform project-specific BCA and alternatives analysis for subtransmission projects and how the scaled approach fits with other planned investments and priorities.	U-21305 dated 6/12/25 (pp. 28)	**Section 5.2.1** (Alternatives Analyses Process) **Section 5.2.3** (Benefit-Cost Analyses Approach) **Section 5.2.4** (Global Prioritization Model) **Section 5.2.5** (Prioritization Summary and Results) **Section 6.3.3** (Subtransmission Redesign and Rebuild) **Appendix 8.9** (Alternatives Analyses Project List)
	Perform project-specific BCA and alternatives analysis for conversion projects, including other reliability investments as an alternative to full conversion.	U-21305 dated 6/12/25 (pp. 29-30)	**Section 5.2.1** (Alternatives Analyses Process) **Section 5.2.3** (Benefit-Cost Analyses Approach) **Section 6.3.1** (4.8 kV and 8.3 kV Conversions) **Appendix 8.14** (Benefit-Cost Analysis Report)
	Address climate risks in scenario planning in next DSP.	U-20147 dated 9/26/2024 (pp. 138)	**Section 2.3** (Drivers of Investment) **Section 5.2.3** (Benefit-Cost Analyses Approach) **Section 5.3.4** (Long-Term Investment Outlook) **Appendix 8.14** (Benefit-Cost Analysis Report)
	Include an analysis of the trade-offs between capital and O&M, including tree trimming.	U-21305 dated 6/12/25 (pp. 20-21)	**Section 5.2.4** (Global Prioritization Model) **Section 5.2.2** (Prioritization Summary and Results) **Appendix 8.10** (Complete GPM Rankings)
	Describe circuit-level load forecasting process, including DER impacts. Consider at minimum low and high building and transportation electrification scenarios. Provide certain circuit-level information.	U-20147 dated 7/10/25 (pp. 24)	**Section 5.1** **(Load Forecasts and Scenario Planning)** **See workpapers**
	Compare safety and reliability investments for 4.8 kV system, such as DA, Conversions, and Vegetation Management, so that the prioritization of investments can be more clearly discerned.	U-21305 dated 6/12/25 (pp. 36)	**Section 5.2.4** (Global Prioritization Model) **Section 5.2.5** (Prioritization Summary and Results) **Section 6.1.1** (Vegetation Management) **Section 6.3.1** (4.8 kV and 8.3 kV Conversions) **Section 6.4.1** (Distribution Automation)
Investments / Expenditures and Projected Impacts	Include five-year capital investment and O&M expenditure projections.	U-20147, Exhibit A dated 7/10/25 (pp. 7)	**Section 5.3.1** (Forecasted O&M and Capital Investments) **Chapter 6** (Distribution System Plan Investment Pillars)
	Provide planned investment overlay maps showing year of and two years following DSP.	U-20147, Exhibit A dated 7/10/25 (pp. 7)	**Section 5.5** (Planned Investment Overlay Maps)
	Provide supporting data for charts, tables, and maps.	U-20147, Exhibit A dated 7/10/25 (pp. 3)	**See workpapers**
	Include expected reliability improvements mapped to planned system investments.	U-20147, Exhibit A dated 7/10/25 (pp. 7)	**Section 5.3.2** (Forecasted Reliability Benefits) **Appendix 8.13** (Reliability Model Technical Report)

Category	DSP Requirement (Order Excerpt Summary)	Order No.	Incorporation into the DSP
Investment Pillars	Include an action plan to address the established short-term and long-term challenges and needs.	U-20147, Exhibit A dated 7/10/25 (pp. 6)	**Section 5.3.1** (Forecasted O&M and Capital Investments) **Chapter 6** (Distribution System Plan Investment Pillars)
	Stay on the five-year Vegetation Management cycle while investigating the additional benefits of moving to a four-year cycle.	U-21305 dated 6/12/25 (pp. 17)	**Section 6.1.1** (Vegetation Management)
	Include a plan to address all backlogs as part of the next DSP.	U-21305 dated 6/12/25 (pp. 50)	**Section 6.1.2** (Preventative Maintenance and Inspections) **Section 6.1.3** (Corrective Maintenance)
	Demonstrate progress toward goal of reaching the five- and 10-year PTMM cycles utilizing BCA results.	U-21534 dated 1/23/25 (pp. 108)	**Section 6.2.1** (Pole-Top Maintenance and Modernization) **Section 5.2.3** (Benefit-Cost Analyses Approach)
	Incorporate lessons learned from Undergrounding into improved business case development for future use cases.	U-21534 dated 1/23/25 (pp. 139-140)	**Section 6.2.5** (Undergrounding)
	Develop a realistic, detailed, and actionable plan for when and where cable replacement should occur.	U-21305 dated 6/12/25 (pp. 11)	**Section 4.2.3** (Underground Assets) **Section 5.2.3** (Benefit-Cost Analyses Approach) **Section 6.2.3** (System Equipment Replacement) **Appendix 8.14** (Benefit-Cost Analysis Report)
	Age should not be the sole factor when determining equipment replacement.	U-21305 dated 6/12/25 (pp. 26)	**Section 4.2** (General Asset Health) **Section 6.2.6** (System Equipment Replacement)
	Include findings of cable injection pilot in DSP.	DTE Reply in Case No U-21305 dated 11/15/24 (pp. 17)	**Section 6.2.6** (System Equipment Replacement)
	Continue to focus on current NWA pilots to obtain results that will better inform DTE on how to scale its current NWA pilots.	U-21534 dated 1/23/25 (pp. 158-159)	**Section 6.3.4** (Non-Wire Alternatives)
	Provide a BCA for the Pontiac Conversion and better justify the risks associated with maintaining the status quo.	U-21305 dated 6/12/25 (pp. 33)	**Section 6.3.1** (4.8 kV and 8.3 kV Conversions) **Appendix 8.14** (Benefit-Cost Analysis Report)
	Provide an update on plan to complete the installation of reclosers at the beginning of 4.8 kV circuits for safety benefits.	U-21305 dated 6/12/25 (pp. 31)	**Section 6.4.1** (Distribution Automation)
	Provide an update on DTE's asset management strategy, including efforts to prevent outages from occurring.	U-20147, Exhibit A dated 7/10/25 (pp. 5-6)	**Section 4.4.1** (Asset Management) **Section 6.4.4** (Asset Condition Monitoring Technology)

Category	DSP Requirement (Order Excerpt Summary)	Order No.	Incorporation into the DSP
	Detail DTE's efforts to address ongoing and upcoming distribution technologies.	U-20147, Exhibit A dated 7/10/25 (pp. 8)	**Section 2.3** (Drivers of Investment) **Section 4.5** (Distributed Energy Resources and Interconnection Process) **Section 5.1** (Load Forecasts and Scenario Planning) **Section 6.3.4** (Non-Wire Alternatives) **Section 6.4** (Technology and Automation) **Section 6.5** (Grid Edge and Distributed Intelligence)

8.4 Community Lighting

Community Lighting is a service that provides illumination for public spaces and neighborhoods and operates independently from the broader distribution system. These assets are considered utility-owned lighting infrastructure rather than end use customer connections, and they are governed by distinct tariff provisions, cost recovery mechanisms, and operational requirements compared to traditional distribution service. DTE owns, operates, and maintains approximately 202,000 Community Lighting assets across its service area, serving municipal, commercial, and residential customers. Of these, approximately 168,000 are streetlights, typically located within the public road right-of-way, while the remaining 34,000 consist of outdoor protective lighting installed on residential and commercial private properties. The costs of these lighting assets are directly allocated to lighting customers through four dedicated lighting rates.[199]

Historical Capital and O&M Spend

Historically, Community Lighting investments have fallen into four key categories, classified as either capital or O&M in accordance with standard utility accounting practices:

- **New Business:** Includes customer-initiated requests for new outdoor lighting systems or relocation/removal of existing equipment.
- **Infrastructure Investment:** Includes a suite of preventative maintenance and replacement programs aimed at maintaining safety standards, reducing emergency repairs, and extending asset lives. These programs have included underground-fed post inspections and replacements, post painting, night patrol lighting surveys, underground cable replacement, and wood pole replacement.
- **Outage Restoration:** Includes usage of the KloudGin OMS, a key enhancement initially adopted in 2024. This system enables the Company to track individual light outages, automate work assignments, and improve root cause classification. The system also supports detailed reporting, such as number of outages, average duration for repair, and night patrol results, which were first distributed to participating municipalities in February of last year. During a typical year, the Company responds to approximately 20,000 outage events, using contracted crew resources, and has maintained an average restoration rate of about five days.

[199] Rate Schedules D9 (Outdoor Protective Lighting), E1 (Municipal Street Lighting Rate), E2 (Traffic and Signal Lights), E1.1 (Energy-Only Streetlighting); distribution and power supply costs are recovered as well for load served

- **Light Conversions:** Includes systematically replacing legacy high-intensity discharge (HID) lighting technology with new LED lighting in accordance with Commission directives and federal energy policy.

The five-year historical spend for Community Lighting capital and O&M is shown in Exhibit 8.1 and Exhibit 8.2, respectively. Infrastructure replacements such as post replacements, pole replacements, and underground cable replacements are considered capital expenditures (Infrastructure Investment), while post inspections, post painting, and night patrol surveys are O&M expenses (Preventative Maintenance).

Exhibit 8.1 – Historical Community Lighting Capital Spend, 2021-2025 ($ millions)

Category	2021	2022	2023	2024	2025
New Business	6.9	6.5	8.9	14.5	6.2
Outage Restoration	4.8	7.1	7.1	8.4	14.0
Infrastructure Investment	1.7	3.0	1.9	3.4	3.6
Light Conversions	1.3	0.6	0.3	0.7	1.7
Total	**14.7**	**17.2**	**18.2**	**27.0**	**25.5**

Exhibit 8.2 – Historical Community Lighting O&M Spend, 2021-2025 ($ millions)[200]

Category	2021	2022	2023	2024	2025
Outage Restoration	2.8	2.0	2.0	2.6	2.4
Preventative Maintenance	1.3	0.7	0.2	0.6	0.5
Supervisory and Administration	1.1	1.2	1.2	1.9	1.6
Total	**5.2**	**3.9**	**3.4**	**5.1**	**4.5**

Near-Term Investment Outlook

The Company's five-year strategy focuses on modernizing its outdoor lighting system by adopting a universal, replacement-cost-based rate design and fully transitioning to smart-node lighting controls. Shifting away from wattage-based rate categories ensures long-term flexibility as lighting technologies evolve. This universal framework creates a stable foundation for incorporating future innovations while ensuring fairness and consistency across all customers. To support this modernized structure, the Company is proposing a $20 million system-wide deployment of smart nodes to replace all existing photocells over the next five years. Smart nodes enable real-time

[200] These three O&M spend categories roll up to Streetlighting – 596 FERC account.

monitoring, automated outage detection, remote scheduling and dimming, and energy use visibility, transforming the current reactive lighting system into a proactive, data-driven network. The initiative will begin with a 5,000-unit pilot deployment in 2026, with installations ramping up each subsequent year. Deployment will be coordinated with HID-to-LED conversion projects, routine maintenance cycles that allow aging photocells to be replaced with smart nodes, and all new business installations.

This investment is reasonable and prudent because it improves reliability, reduces long-term operating costs, enhances customer control and transparency, and positions the Company to meet emerging customer needs, including future smart-city applications. The five-year capital and O&M investment strategy for Community Lighting, including the deployment of smart nodes, is summarized in Exhibit 8.3 and

Exhibit 8.4. As explained above, these investments are funded through distinct tariff provisions and cost-recovery mechanisms.

Exhibit 8.3 – Community Lighting Capital Investment Forecast ($ millions)

Category	2026	2027	2028	2029	2030
Outage Restoration (incl. Third-Party Damage Claims)	13.2	13.3	13.4	13.6	13.8
New Business	8.3	8.5	8.8	9.0	9.2
Infrastructure Investment	3.4	3.5	3.5	3.7	3.8
IT Development (incl. Smart Nodes)	1.4	3.8	5.2	5.4	5.6
Light Conversions	1.3	0.5	0.5	0.6	0.7
Total Capital Investment	**27.6**	**29.6**	**31.4**	**32.3**	**33.1**

Exhibit 8.4 – Community Lighting O&M Investment Forecast ($ millions)[201]

Category	2026	2027	2028	2029	2030
Outage Restoration	2.5	2.5	2.5	2.5	2.5
Preventative Maintenance	0.5	0.5	0.6	0.6	0.6
Supervisory & Administration	1.6	1.6	1.7	1.7	1.8
Total	**4.6**	**4.6**	**4.8**	**4.8**	**4.9**

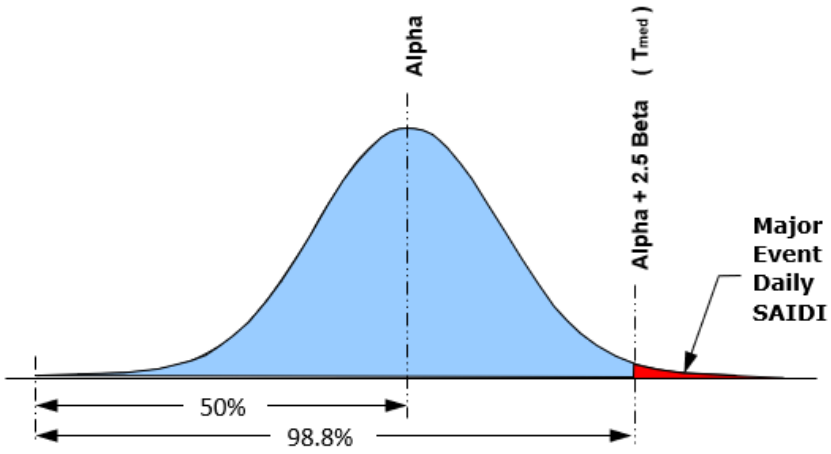
Overall, DTE's strategy demonstrates compliance with regulatory directives while advancing reliability, safety, and efficiency in Community Lighting operations.

[201] These three O&M spend categories roll up to Streetlighting – 596 FERC account.

8.5 Additional Reliability and Outage Information

Applying MED thresholds is essential for accurate reliability metric calculations. DTE adheres to standards set by IEEE,[202] using historical SAIDI outage data to determine these thresholds using the 2.5 Beta (β) method. To establish this threshold, SAIDI-per-day data from the five most recent years is compiled, excluding days with a SAIDI of zero. The natural logarithm of each value is then calculated, followed by computing the mean (α) and standard deviation (β) of these logarithms. The threshold, T_med, is derived as exp(α + 2.5 × β). Any day in the subsequent year with SAIDI greater than T_med is classified as an MED, as illustrated in Exhibit 8.5.

Exhibit 8.5 – Distribution of the Natural Log of Five-Year SAIDI Data

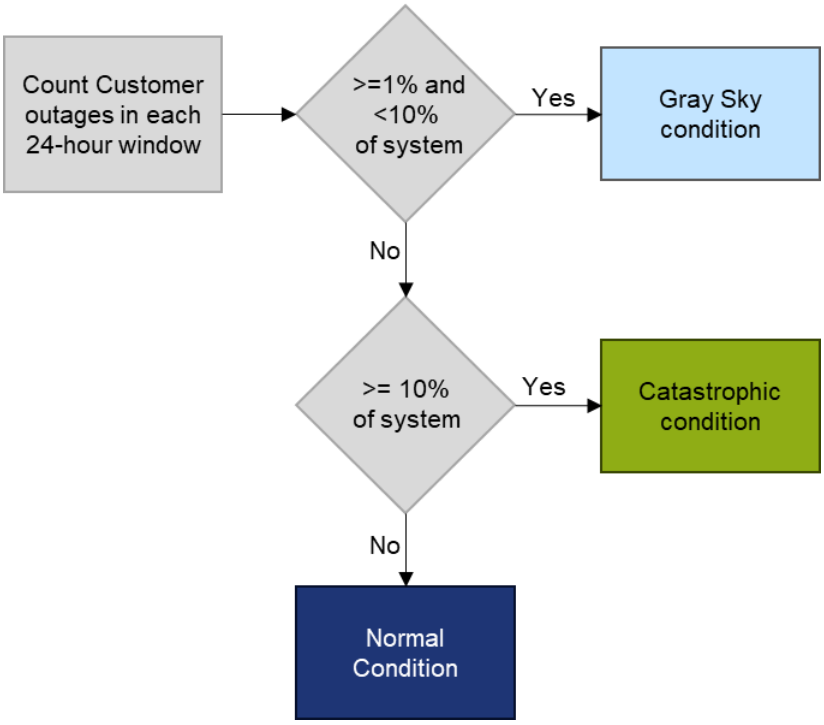


In addition, DTE utilizes a rolling 24-hour methodology to determine Catastrophic and Gray Sky conditions and the customers impacted. Existing regulations and standards organizations, such as IEEE, do not provide specific guidance on identifying Catastrophic conditions within a utility's territory. The MPSC only states that Catastrophic conditions exist when at least 10% of the customer base is affected but does not clarify whether this declaration should begin at the hour the threshold is met or the day it is met. Due to this ambiguity, DTE applies a rolling 24-hour window method to define the Catastrophic condition. This approach is easily auditable and avoids subjective criteria. The categorization process is illustrated in Exhibit 8.6 and as follows:

- If outages affect greater than or equal to 1% but less than 10% of the system's customer base within a 24-hour window, it is classified as a Gray Sky condition.
- If outages affect greater than or equal to 10%, it is classified as a Catastrophic condition.
- Otherwise, it is a Normal condition.

[202] IEEE 1366 - IEEE Guide for Electric Power Distribution Reliability Indices.

Exhibit 8.6 – 24-Hour Window Categorization Process Map



There are 8,760 rolling 24-hour windows in a calendar year based on the start time of each 24-hour window,[203] and each window is evaluated to determine whether it meets Gray Sky or Catastrophic criteria. For example, a window from 2 p.m. one day to 2 p.m. the next day may have 150,000 customers out, indicating a Gray Sky condition event. The next window from 3 p.m. to 3 p.m. may have 250,000 customers out, indicating a Catastrophic condition event, which may extend beyond 24 hours. Event duration is determined by the range of consecutive 24-hour windows in which the number of outages remains within the event bounds. Exhibit 8.7 illustrates how a Gray Sky condition can last more than 24 hours.

Exhibit 8.7 – Example Analysis of 24-Hour Windows

Hourly Start Time	24-Hour End Time	Rolling 24-Hour Outages	% of Customer Base	Metric Category
08/26/2024 13:00	08/27/2024 13:00	18,402	≤1%	Normal
08/26/2024 14:00	08/27/2024 14:00	18,609	≤1%	Normal
08/26/2024 15:00	08/27/2024 15:00	18,571	≤1%	Normal
08/26/2024 16:00	08/27/2024 16:00	14,426	≤1%	Normal

[203] Because the 24-hour window spans midnight, windows ending on the last day of the calendar year will include hours from the first day of the following year.

Hourly Start Time	24-Hour End Time	Rolling 24-Hour Outages	% of Customer Base	Metric Category
08/26/2024 17:00	08/27/2024 17:00	25,670	>1% to ≤ 10%	Gray Sky
08/26/2024 18:00	08/27/2024 18:00	213,445	>1% to ≤ 10%	Gray Sky
08/26/2024 19:00	08/27/2024 19:00	252,418	> 10%	Catastrophic
08/26/2024 20:00	08/27/2024 20:00	254,171	> 10%	Catastrophic
08/26/2024 21:00	08/27/2024 21:00	263,485	> 10%	Catastrophic
08/26/2024 22:00	08/27/2024 22:00	270,080	> 10%	Catastrophic
08/26/2024 23:00	08/27/2024 23:00	278,546	> 10%	Catastrophic

A detailed list of 82 historical Gray Sky outage events from the past five years is provided in Exhibit 8.8.

Exhibit 8.8 – Historical Outage Events for Gray Sky Conditions, 2021-2025

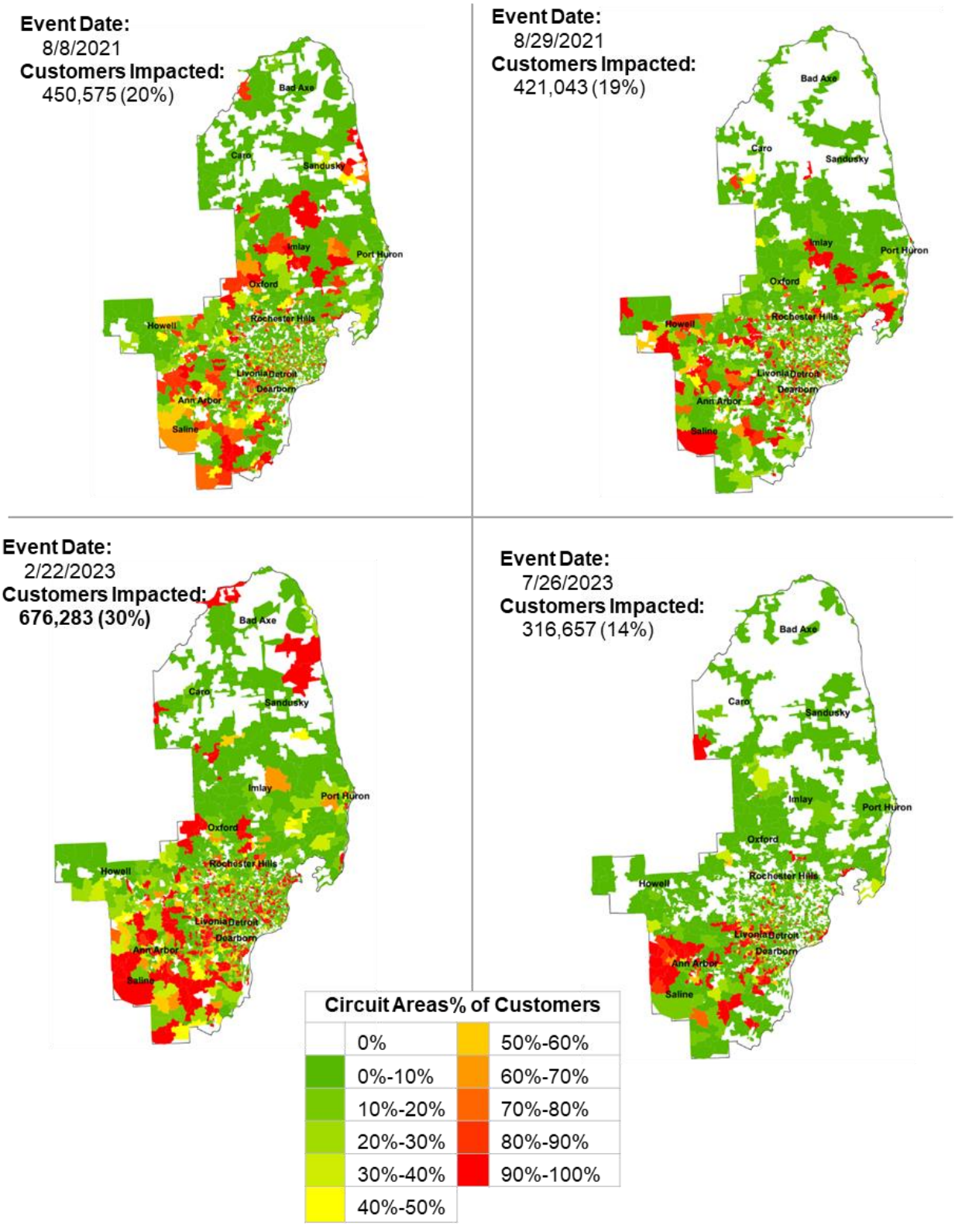
Event Start Date	Event End Date	Unique Number of Customers Impacted	Percentage of Customer Base Affected
03/27/2021	03/29/2021	25,212	1%
05/28/2021	05/30/2021	33,386	2%
06/20/2021	06/23/2021	84,844	3%
06/25/2021	07/02/2021	182,640	8%
07/05/2021	07/13/2021	208,139	9%
07/13/2021	07/18/2021	50,788	2%
07/20/2021	07/23/2021	45,151	2%
07/24/2021	07/28/2021	122,719	6%
07/29/2021	07/31/2021	24,059	1%
08/24/2021	08/27/2021	55,746	3%
08/27/2021	08/29/2021	42,012	2%
08/29/2021	08/31/2021	28,221	1%
09/07/2021	09/10/2021	79,309	4%
09/12/2021	09/17/2021	64,232	3%
09/21/2021	09/28/2021	202,137	9%
10/02/2021	10/05/2021	33,598	2%
11/11/2021	11/13/2021	32,309	1%
12/06/2021	12/07/2021	23,206	1%
12/11/2021	12/15/2021	166,318	8%
12/15/2021	12/18/2021	38,805	2%
02/01/2022	02/03/2022	33,517	2%

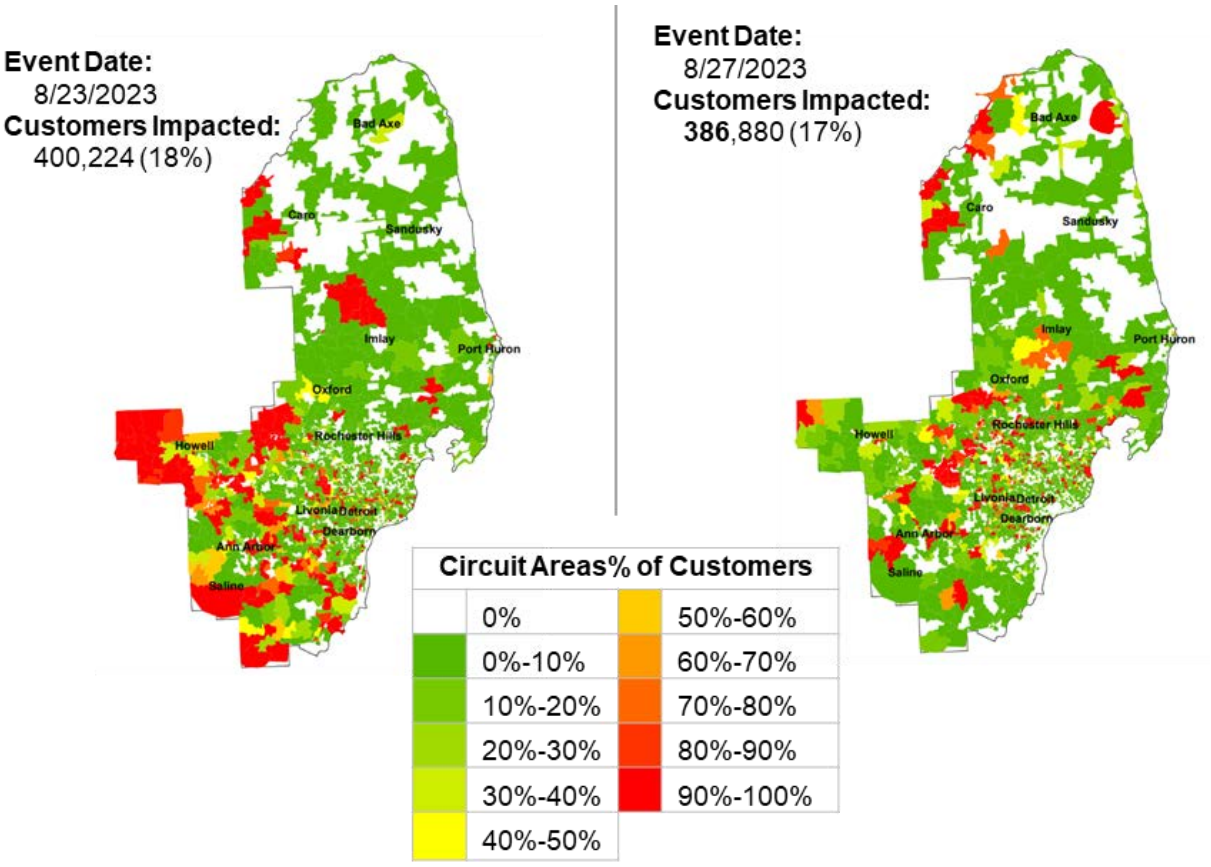
Event Start Date	Event End Date	Unique Number of Customers Impacted	Percentage of Customer Base Affected
03/06/2022	03/07/2022	28,057	1%
03/30/2022	04/01/2022	69,024	3%
04/13/2022	04/15/2022	49,499	2%
05/15/2022	05/18/2022	33,640	2%
05/20/2022	05/22/2022	43,353	2%
05/31/2022	06/04/2022	52,266	2%
06/07/2022	06/07/2022	23,133	1%
06/14/2022	06/19/2022	81,254	4%
06/20/2022	06/24/2022	45,933	2%
07/05/2022	07/08/2022	42,596	2%
07/19/2022	07/22/2022	62,039	3%
07/23/2022	07/26/2022	38,031	2%
08/02/2022	08/06/2022	95,137	4%
08/07/2022	08/11/2022	34,000	2%
09/19/2022	09/22/2022	46,385	2%
11/05/2022	11/08/2022	78,963	4%
12/23/2022	12/25/2022	37,576	2%
01/25/2023	01/27/2023	28,985	1%
02/15/2023	02/18/2023	49,012	2%
03/17/2023	03/19/2023	676,283	1%
03/25/2023	03/27/2023	29,445	2%
05/30/2023	06/01/2023	52,762	2%
06/11/2023	06/13/2023	31,435	1%
06/22/2023	06/24/2023	35,499	2%
06/25/2023	06/28/2023	155,620	7%
07/09/2023	07/11/2023	52,771	2%
07/12/2023	07/15/2023	41,778	2%
07/20/2023	07/23/2023	163,763	8%
09/05/2023	09/07/2023	31,702	1%
01/12/2024	01/16/2024	168,267	7%
04/12/2024	04/13/2024	52,333	2%
04/17/2024	04/18/2024	39,724	2%
05/07/2024	05/12/2024	46,922	2%
05/19/2024	05/23/2024	38,583	2%
05/26/2024	05/28/2024	26,515	1%
06/05/2024	06/07/2024	65,116	3%
06/13/2024	06/16/2024	38,533	2%
06/16/2024	06/23/2024	149,265	7%
07/09/2024	07/11/2024	47,080	2%
07/15/2024	07/17/2024	47,991	2%

Event Start Date	Event End Date	Unique Number of Customers Impacted	Percentage of Customer Base Affected
07/23/2024	07/24/2024	25,587	1%
08/05/2024	08/06/2024	23,060	1%
03/15/2025	03/16/2025	54,666	2%
03/30/2025	04/02/2025	85,557	4%
04/02/2025	04/03/2025	31,881	1%
04/21/2025	04/22/2025	40,953	2%
04/29/2025	04/30/2025	29,190	1%
05/16/2025	05/17/2025	33,513	1%
06/18/2025	06/20/2025	69,403	3%
06/21/2025	06/24/2025	77,072	3%
06/24/2025	06/26/2025	95,421	4%
06/27/2025	06/28/2025	34,421	2%
07/12/2025	07/13/2025	35,454	2%
07/24/2025	07/25/2025	41,522	2%
07/28/2025	07/29/2025	43,271	2%
07/30/2025	07/31/2025	24,002	1%
08/11/2025	08/13/2025	65,497	3%
10/19/2025	10/20/2025	25,555	1%
10/21/2025	10/22/2025	26,885	1%
12/26/2025	12/28/2025	59,798	3%
12/28/2025	12/30/2025	45,862	2%

Exhibit 8.9 includes maps of the six Catastrophic outage events over the last five years, including circuit-level percentages of customers affected.

Exhibit 8.9 – Five-Year Historical Catastrophic Outage Event Maps




Event Date:
8/23/2023
Customers Impacted:
400,224 (18%)
Bad Axe
Caro
Sandusky
Imlay
Port Huron
Oxford
Howell
Rochester Hills
Livonia
Detroit
Dearborn
Ann Arbor
Saline
Event Date:
8/27/2023
Customers Impacted:
386,880 (17%)
Bad Axe
Caro
Sandusky
Imlay
Port Huron
Oxford
Howell
Rochester Hills
Livonia
Detroit
Dearborn
Ann Arbor
Saline
Circuit Areas% of Customers
0%
0%-10%
10%-20%
20%-30%
30%-40%
40%-50%
50%-60%
60%-70%
70%-80%
80%-90%
90%-100%

8.6 Historical Regulatory Financial Alignment

Exhibit 8.10 presents adjustments to the Company's historical O&M expenses to align with FERC accounting, consistent with DTE's rate cases.

Exhibit 8.10 – Overview of Adjustments for FERC Accounting ($ thousands)[204]

	2021	2022	2023	2024	2025
Base	72,550	82,227	67,771	77,221	77,046
Non-Storm Emergent	54,703	69,581	60,163	57,355	72,561
Storm Emergent	75,769	59,921	183,786	59,563	20,061
Preventative Maintenance	7,142	11,332	6,495	11,749	10,618
Vegetation Management	171,659	239,570	169,670	159,193	238,648
PTMM Inspections	-	-	136	625	967
Total Historical O&M Expenses	**381,823**	**462,630**	**488,022**	**365,706**	**419,901**
Adjustments for FERC Accounting					
Distribution Short Term Incentives Net Streetlighting	4,542	5,673	1,666	5,685	7,439
Distribution Long Term Incentives Net Streetlighting	3,199	3,097	2,623	2,276	2,338
Street Lighting, Exhibit A-13, Schedule C5.6, FERC Acct 585 and 596	5,206	3,991	3,405	5,091	4,142
NERC Compliance	6,785	6,194	5,370	4,773	4,744
Public Lighting Department	7,169	7,263	13	0	0
Amortization of Deferred ADMS Costs	0	351	150	1,174	1,174
Environmental Mgmt. & Resources	570	1,835	1,040	533	738
Technical Training	1,340	1,341	1,325	1,316	1,290
Rent	0	0	0	0	2,460
Meter Reading	-1,011	-1,208	-1,212	-1,567	-1,416
Revenue Management & Protection			-1,292	-3,652	-3,821
Primary Services	-688	-619	-368	-355	-229
Vegetation Management - Regulatory Liability	0	-85,769	-3,630	0	0
Corporate Safety	1,152	1,213	501	0	0
Other	8,732	5,053	-1,874	-866	-1,022
Subtotal of Adjustments for FERC Accounting	**36,996**	**-51,585**	**7,715**	**14,407**	**17,838**
Total Distribution Expenses Exhibit A-13, Schedule C5.6 and C5.6.1	**418,819**	**411,044**	**495,737**	**380,113**	**437,739**

[204] Totals may not match exactly to the mathematical summation in the table due to rounding of the source data.

Exhibit 8.11 shows the historical capital investment aligned to the newly created DSP subcategories.

Exhibit 8.11 – Overview of Historical Capital to DSP Subcategories ($ thousands)[205]

Type	Pillar	Type – Pillar - Category	2021	2022	2023	2024	2025
Base	Emergent Replacements						
		Storm	395,286	181,326	273,538	151,799	44,067
		Non-Storm	209,236	263,014	209,356	272,424	415,202
		Substation Reactive	46,008	40,382	41,178	47,816	75,406
	Connections, Relocations and Other						
		Connections and New Load	159,918	191,288	189,593	240,048	263,830
		Relocations	24,113	20,613	37,615	42,907	37,694
		Electric System Equipment	30,471	30,180	27,670	36,276	27,377
		NRUC and Improvement Blankets	20,952	32,851	19,742	23,967	43,979
		General Plant, Tools & Equipment and Miscellaneous	7,445	8,103	6,090	5,633	7,126
		Public Lighting Department Project	19,353	13,440	2,186	(310)	26
Strategic	Resilience and Hardening						
		4.8 kV Hardening	65,794	159,328	130,531	92,266	100,354
		Frequent Outage	23,285	60,067	64,638	53,698	34,019
		Pole and Pole-Top Maintenance and Modernization	31,647	83,934	85,611	66,503	107,678
		Resilience & Restoration Readiness	5,984	15,234	3,706	8,141	1,657
		Substation Risk	8,102	21,596	18,154	47,978	33,578
		System Equipment Replacement	52,338	80,128	78,937	83,504	63,770
		Undergrounding	256	462	3,011	11,360	2,184
	Redesign and Modernization						
		4.8 kV and 8.3 kV Conversion	59,092	104,483	162,104	219,478	238,387
		Non-Wire Alternatives	7,255	10,641	10,509	7,816	4,841
		Subtransmission Redesign & Rebuild	29,785	62,620	98,067	72,223	75,541
		System Loading	4,710	3,648	14,192	24,949	20,076
	Technology and Automation						
		Advanced Distribution Management System	23,681	31,032	12,080	11,902	14,381
		Distribution Automation	3,297	5,506	26,836	51,896	92,238
		Grid Technology	8,274	8,314	10,256	10,119	11,348
		Operational Technology	27,322	51,620	79,113	77,232	34,271
	Grid Edge and Distributed Intelligence						
		Communications Network	10,239	16,328	21,679	21,200	6,810
		Distributed Energy Resource Management System	0	0	0	0	15
	Total		**1,273,843**	**1,496,136**	**1,626,391**	**1,680,825**	**1,755,856**

[205] Totals may not match exactly to the mathematical summation in the table due to rounding of the source data.

8.7 Environmental Justice Regression Analysis

On Dec. 1, 2023, the Commission directed DTE to conduct a detailed evaluation of whether electrical reliability outcomes differ for customers in vulnerable communities. In response, the Company initiated an EJ regression analysis in 2024 in collaboration with Commission Staff and CEO. The objective of this effort was to determine whether a statistically significant relationship exists between EJ scores and reliability performance, as measured by SAIFI and SAIDI, after accounting for circuit level characteristics that influence reliability.

Background on Regression Analysis

At the simplistic level, populations can be compared by examining the difference in averages, as in average income or average reliability. Regression is a more complex statistical technique used to examine how two or more variables relate to one another and to assess the extent to which changes in one or more independent factors may influence a dependent outcome. Within statistical analysis, regression provides a structured means of identifying patterns in the data, quantifying the strength of relationships among variables, and determining whether those relationships are statistically significant. The process begins by defining the two types of variables included in the regression analysis:

1) **Dependent Variable:** Represents the primary outcome that the analysis seeks to measure and predict. For example, SAIFI and SAIDI as the reliability measures for the outcome.
2) **Independent variable(s):** Represent the factors that may influence or affect the dependent outcome. For example, EJ score, circuit voltage, and overhead and underground line-miles.

Once the dependent and independent variables are defined, regression models are applied to assess the relationships among the variables and to determine whether the observed associations are statistically significant. Different regression models may be used depending on the characteristics of the data and the nature of the relationship being evaluated. Selecting an appropriate model is essential to ensure that the analysis is both accurate and suitable for the specific dataset. Different regression models offer varying levels of predictive accuracy, and sometimes more complex models are needed to achieve the desired accuracy. Several factors may influence the selection of a regression model, including:

- **Nature of the Relationship:** Some relationships follow a linear pattern, while others require non-linear modeling approaches.

- **Type of Dependent Variable:** The structure of the outcome variable (e.g., binary versus continuous) may dictate the appropriate model.
- **Number of Independent Variables:** When multiple explanatory variables are included, a multiple linear regression model is appropriate because it allows estimation of a partial association between each independent variable and the dependent variable while holding other factors constant.

Most regression models rely on a set of four key foundational assumptions that ensure the results are valid, unbiased, and suitable for decision making:

1) **Linearity:** The model assumes a linear relationship between the dependent variable and each independent variable, meaning the effect of an independent variable on the outcome is consistent across its range.
2) **Independence:** All observations must be independent of one another. Violations, such as correlated errors or repeated measures on the same unit, can distort estimates and reduce the reliability of statistical tests.
3) **Homoscedasticity:** The variance of the error terms should remain constant across all levels of the independent variables. If the variance changes (heteroscedasticity), the model's estimates may still be unbiased, but the statistical tests become unreliable.
4) **Normality:** The error terms are expected to follow a normal distribution, which is particularly important for hypothesis testing and constructing confidence intervals.

When these assumptions are met, the regression model can accurately characterize relationships among variables and support sound analytical conclusions. When they are not met, the resulting estimates and statistical inferences may be biased or misleading, requiring additional diagnostic testing, model adjustments, or alternative modeling approaches. Careful evaluation of these assumptions is therefore a critical component of any rigorous analytical process and helps ensure that the findings presented are both defensible and methodologically robust.

EJ Regression Analysis Framework

The Company initiated its EJ regression analysis in 2024, working collaboratively with Commission Staff and CEO to establish the analytical framework, refine the underlying hypothesis, and identify the key variables to be included in the study. Through this collaborative process, the parties agreed on the statistical hypothesis to be tested*: Is there a relationship between the EJ score variable and SAIDI or SAIFI after adjusting for other circuit-level characteristics?*

In support of this hypothesis, the parties agreed that SAIFI and SAIDI would serve as the dependent variables representing reliability outcomes, while EJ scores would serve as the proxy for vulnerable communities. The analysis was conducted at the circuit level on a calendar-year basis to determine whether EJ scores are associated with reliability performance after controlling circuit characteristics that may otherwise confound the observed relationships.

Conducting the analysis at the circuit level is appropriate because a circuit's physical construction and geographic characteristics can significantly influence the reliability experienced by customers downstream. These characteristics, such as circuit length, configuration, and environmental exposure are largely independent across circuits. Additionally, when DTE dispatches crews to respond to outages, restoration activities are typically completed on one circuit before crews transition to another. These operational and structural factors directly affect SAIFI and SAIDI, further supporting the use of circuit-level data for this analysis.

To test the hypothesis, the Company performed a series of regression analyses designed to explore the relationship between vulnerable communities and reliability performance. The analytical process consisted of three primary components:

1) **Data Gathering and Processing:** The Company collected, validated, and evaluated circuit-level data, including reliability metrics and circuit characteristics, to ensure the dataset was complete, accurate, and suitable for regression modeling.
2) **Descriptive Statistics (Simple Linear and Non-Linear Regression):** Each variable was examined individually to assess its distribution, identify potential data issues, and determine whether transformations were necessary prior to modeling. This step also included evaluating the univariate relationships between circuit characteristics and reliability metrics from both an AW and exMED perspective.
3) **Multiple Linear and Nonlinear Regression Modeling:** The Company executed several regression models to assess the relationship between EJ scores and reliability performance. These models included:
    - Multiple Linear Regression: AW and exMED SAIFI and SAIDI.
    - Nonlinear Regression: Log-transformed AW and ExMED SAIFI and SAIDI.
    - Complex Nonlinear Regression: Linear Mixed Models (LMM) and Generalized Estimating Equations (GEE) using log-transformed AW and exMED SAIFI and SAIDI.

To evaluate the statistical significance of the EJ score variable within these models, the Company examined the beta coefficient and corresponding p-value. Under the null hypothesis, there is no relationship between EJ scores and reliability metrics; therefore, the expected beta coefficient is zero. A p-value less than 0.05 indicates that the estimated beta coefficient is statistically different from zero, providing evidence to reject the null hypothesis and conclude that a statistically significant relationship exists. Additional details on the circuit characteristics included in the models are provided in the statistical methodology sections below.

Data Gathering

To conduct the regression analysis at the circuit level, the Company assembled the full suite of datasets required for the evaluation, including detailed reliability performance metrics and comprehensive circuit characteristics as shown in Exhibit 8.12. This process involved systematically gathering, validating, and organizing circuit-level reliability data, as well as structural, operational, and geographic attributes that may influence performance outcomes. Together, these inputs established the foundational dataset used to support the regression modeling and the assessment of relationships between circuit features and reliability metrics.

Exhibit 8.12 – Dataset Collected for Regression Analysis at the Circuit Level

Circuit Variable Data Type (2019-2023)	Variable Description
Voltage Level	The voltage of the circuit at the bus level (4.8 kV, 8.3 kV, 13.2 kV)
ISO	Indicator if the circuits have two voltages (ISO down circuits)
Circuit Customer Base	The number of customers fed by each circuit
Overhead/Underground Miles	The number of overhead and underground miles on a circuit
Region	The region in which the circuit is located
Last Vegetation Management Year	Number of years to the given calendar year the circuits were trimmed
Substation Age	Number of years to the given calendar year the substation was commissioned
Reliability Data (circuit level)	Circuit-level AW/exMED SAIFI and AW/exMED SAIDI
Environmental Justice Scores	Weighted average of EJ scores based on percent of residential customers that fall within a census tract

Additional circuit level features were also collected to support the calculation of the characteristics described above. These supplemental inputs ensured that all relevant attributes were accurately represented in the analysis. A comprehensive description of each variable included in the dataset is provided in Appendix 8.6.A.

Data Processing

From the raw data collected, the dataset initially contained 16,226 observations, with each observation representing a unique circuit year. The Company applied the following criteria to preprocess the data:

1) **Customer Count Threshold:** Only circuits serving 100 or more customers in the applicable calendar year were included.[206] After applying this criterion, 11,354 observations remained.
2) **Minimum Overhead Mileage:** Circuits with at least 0.1 overhead miles were retained for analysis. Circuits with minimal overhead mileage are not subject to Vegetation Management activities, and one of the variables included in the model — YearsFromTrim — is directly related to Vegetation Management. In addition, the overhead miles variable is log transformed in the regression models, and this threshold avoids issues associated with taking the logarithm of zero or near zero values. After this step, 10,945 observations remained.
3) **ISO Circuit Identification:** For purposes of defining ISO circuits, only circuits with 80% or more ISO miles were assigned a value of 1 for the IsISO variable.

All observations were required to have complete data for every variable included in the model; no imputation was performed. Several circuits did not have assigned EJ scores,[207] and any observation with missing values for one or more variables was removed. After applying these completeness requirements, the final dataset used for the regression analysis consisted of 10,847 circuit year observations.

Descriptive Statistics

The Company conducted a detailed evaluation of the two dependent variables — SAIFI and SAIDI — under both AW and exMED conditions. As illustrated in the histograms, box plots, and quantile summaries in Appendix 8.6.B, both metrics substantial right skewness in their raw form, which can present challenges for regression analysis. Applying a logarithmic transformation produces

[206] This approach is consistent with the Company's methodology in the annual Power Quality Report (U 16065), the annual Service Quality and Reliability Standards Report (U 12270), and the quarterly Reliability Report, all of which evaluate worst performing circuits using a threshold of more than 100 customers. This threshold helps avoid situations where SAIFI or SAIDI results for circuits with very small customer bases are disproportionately influenced by a single outage event, such as a car accident, an isolated customer interruption, or a transformer outage, which can produce misleading reliability outcomes at the circuit level.

[207] Only circuits with one or more residential customers were assigned EJ scores. There were some census tracts that did not have EJ scores. Furthermore, we mapped 95% of our premises to a census tract. There is still 5% that is not mapped to a census tract prior to this analysis being performed.

distributions that are more symmetric, and bell shaped.[208] For completeness, the analysis includes regression models using both the original SAIFI and SAIDI values and their log-transformed counterparts.[209]

Summary statistics for the independent variables are provided in Exhibit 8.13. For continuous predictors, means, quartiles, and correlation coefficients were used to characterize their distributions and univariate relationships with the dependent variables. For categorical predictors, frequency counts and ANOVA/t tests were applied, with p values reported based on the applicable statistical test. AW and exMED univariate statistics are provided in Exhibit 8.14 and Exhibit 8.15, respectively.

Exhibit 8.13 – Statistic Summary for Independent Variables

Variable Data Type	Category	Number of Observations (N)	Mean (Min/Q1/Q2/Q3/Max)
Bus KV		10,847	
	4.8	6,382	
	8.3	49	
	13.2	4,416	
EJ_CutOFF		10,847	
	0	7,506	
	1	3,341	
IsISO		10,847	
	0	10,793	
	1	54	
Reg		10,847	
	NE	2,279	
	NW	1,920	
	SE	3,880	
	SW	2,768	
Year		10,847	
	2019	2,148	
	2020	2,160	
	2021	2,180	
	2022	2,184	
	2023	2,175	

[208] A small value of 0.01 was added prior to taking the natural log to avoid taking the log of 0. There is no agreed upon constant to be added to avoid taking log of 0. See (Pape, 2022) for a more complete discussion on this topic. As indicated in the paper (Pape, 2022), there may be more advanced techniques to deal with this issue that is beyond the scope of this project. To avoid a left skew issue once the log is taken, we did not want to add too small a constant which led to 0.01 being chosen. Even still, as you can see from the regression plots in the workpapers, this may have caused a small skewness to the left.

[209] In the calculation of TMED (IEEE Power and Energy Society, 2022), IEEE assumes that SAIDI is approximately lognormal at a daily level. This would indicate that at a yearly level, SAIDI is not lognormally distributed as the sum of lognormal is not lognormal (arXiv:1606.07300v2 [, n.d.), (Fenton, 1960). However, (Fenton, 1960) shows that we can approximate a lognormal distribution from the sums of other lognormal given further justification to taking the log for SAIDI.

Variable Data Type	Category	Number of Observations (N)	Mean (Min/Q1/Q2/Q3/Max)
YearsFromTrim		10,847	
	0	4,639	
	1	1,669	
	2	1,548	
	3	1,275	
	4	1,062	
	5	654	
EJScore		10,847	61.8(0/41.1/64.5/84.6/100)
Miles OH		10,847	12.8(0.1/4.6/6.6/11.5/204)
Miles UG		10,847	5.5(0/0.6/1.5/6.2/73)
Log Miles OH		10,847	2(-2.2/1.5/1.9/2.4/5.3)
Log Miles UG		10,847	0.7(-4.6/-0.4/0.4/1.8/4.3)
CIircuitCustBase		10,847	1035.6(100/534/849/1351/4892)
YearsFromSubBuilt		10,847	65.3(4/52/67/76/108)

Exhibit 8.14 – Univariate Statistics All-Weather

				All Weather			All Weather
	Category	N	Mean (Min/Q1/Q2/Q3/Max)	Mean SAIDI / Mean Log SAIDI	P_Value SAIDI / P_Value Log SAIDI	Mean SAIFI / Mean Log SAIFI	P_Value SAIFI / P_Value Log SAIFI
Bus KV		10847			3.73E-02/2.00E-23		1.14E-52/1.50E-80
	4.8	6382		785/5.27		1.16/-0.473	
	8.3	49		563/5.82		1.79/0.346	
	13.2	4416		729/5.64		1.53/-0.015	
EJ_CutOFF		10847			6.46E-01/8.05E-01		3.34E-18/8.41E-11
	0	7506		765/5.43		1.38/-0.231	
	1	3341		753/5.42		1.16/-0.399	
IsISO		10847			5.83E-01/7.41E-03		3.49E-07/6.83E-06
	0	10793		761/5.42		1.31/-0.287	
	1	54		853/6.1		2.17/0.481	
Reg		10847			7.73E-28/1.87E-09		1.42E-31/8.61E-25
	NE	2279		539/5.24		1.35/-0.278	
	NW	1920		734/5.62		1.44/-0.072	
	SE	3880		785/5.42		1.13/-0.43	
	SW	2768		930/5.46		1.45/-0.226	
Year		10847			1.46E-261/1.25E-204		2.05E-41/1.33E-43
	2019	2148		493/5.12		1.3/-0.32	
	2020	2160		347/4.8		1.15/-0.466	
	2021	2180		922/5.76		1.41/-0.194	
	2022	2184		571/5.14		1.13/-0.436	
	2023	2175		1468/6.3		1.57/0.002	
YearsFromTrim		10847			2.71E-07/4.56E-05		2.44E-03/1.06E-04
	0	4639		758/5.39		1.32/-0.282	
	1	1669		713/5.28		1.26/-0.369	
	2	1548		772/5.39		1.23/-0.379	
	3	1275		930/5.6		1.27/-0.311	
	4	1062		914/5.63		1.28/-0.24	
	5	654		716/5.42		1.36/-0.227	
EJScore		10847	61.8(0/41.1/64.5/84.6/100)	761/5.42	r=-0.053 PValue=2.93E-08/r=-0.083 PValue=6.15E-18	1.31/-0.283	r=-0.166 PValue=4.18E-68/r=-0.141 PValue=1.57E-49
Miles OH		10847	12.8(0.1/4.6/6.6/11.5/204)	761/5.42	r=0.08 PValue=6.77E-17/r=0.187 PValue=2.59E-86	1.31/-0.283	r=0.247 PValue=7.34E-150/r=0.242 PValue=1.96E-144
Miles UG		10847	5.5(0/0.6/1.5/6.2/73)	761/5.42	r=-0.012 PValue=2.03E-01/r=0.066 PValue=4.91E-12	1.31/-0.283	r=0.105 PValue=7.82E-28/r=0.128 PValue=8.56E-41
Log Miles OH		10847	2(-2.2/1.5/1.9/2.4/5.3)	761/5.42	r=0.133 PValue=3.86E-44/r=0.316 PValue=3.85E-250	1.31/-0.283	r=0.312 PValue=2.47E-243/r=0.362 PValue=0.00E+00
Log Miles UG		10847	0.7(-4.6/-0.4/0.4/1.8/4.3)	761/5.42	r=-0.014 PValue=1.36E-01/r=0.072 PValue=5.21E-14	1.31/-0.283	r=0.127 PValue=3.94E-40/r=0.148 PValue=6.31E-54
CIircuitCustBase		10847	1035.6(100/534/849/1351/4892)	761/5.42	r=0.002 PValue=7.95E-01/r=0.118 PValue=5.86E-35	1.31/-0.283	r=0.113 PValue=3.52E-32/r=0.168 PValue=1.45E-69
YearsFromSubBuilt		10847	65.3(4/52/67/76/108)	761/5.42	r=0.036 PValue=2.04E-04/r=-0.015 PValue=1.07E-01	1.31/-0.283	r=-0.037 PValue=1.39E-04/r=-0.066 PValue=6.11E-12

Exhibit 8.15 – Univariate Statistics exMED

				ExMED		ExMED	
	Category	N	Mean (Min/Q1/Q2/Q3/Max)	Mean SAIDI / Mean Log SAIDI	P_Value SAIDI / P_Value Log SAIDI	Mean SAIFI / Mean Log SAIFI	P_Value SAIFI / P_Value Log SAIFI
Bus KV		10847			4.75E-12/1.57E-91		3.93E-82/6.19E-129
	4.8	6382		156/3.98		0.77/-0.952	
	8.3	49		309/5.31		1.64/0.266	
	13.2	4416		184/4.59		1.13/-0.366	
EJ_CutOFF		10847			5.69E-04/1.29E-03		1.18E-17/1.75E-11
	0	7506		173/4.27		0.98/-0.653	
	1	3341		156/4.16		0.8/-0.832	
IsISO		10847			1.63E-02/1.36E-04		2.69E-07/2.11E-06
	0	10793		168/4.23		0.92/-0.712	
	1	54		247/5.05		1.61/0.117	
Reg		10847			2.44E-05/2.40E-16		2.05E-34/5.99E-35
	NE	2279		187/4.27		1.02/-0.656	
	NW	1920		172/4.49		1.04/-0.452	
	SE	3880		157/4.12		0.77/-0.891	
	SW	2768		166/4.19		0.98/-0.673	
Year		10847			3.50E-10/4.36E-12		2.11E-12/7.57E-06
	2019	2148		198/4.4		1.05/-0.593	
	2020	2160		164/4.19		0.95/-0.686	
	2021	2180		154/4.12		0.88/-0.792	
	2022	2184		154/4.12		0.9/-0.739	
	2023	2175		172/4.35		0.84/-0.728	
YearsFromTrim		10847			9.33E-05/1.19E-11		1.26E-08/3.20E-10
	0	4639		162/4.2		0.94/-0.697	
	1	1669		159/4.09		0.88/-0.8	
	2	1548		150/4.07		0.85/-0.823	
	3	1275		161/4.15		0.83/-0.838	
	4	1062		161/4.25		0.84/-0.729	
	5	654		181/4.36		0.99/-0.617	
EJScore		10847	61.8(0/41.1/64.5/84.6/100)	168/4.24	r=-0.116 PValue=1.34E-33/r=-0.119 PValue=1.01E-35	0.92/-0.708	r=-0.155 PValue=3.21E-59/r=-0.142 PValue=8.47E-50
Miles OH		10847	12.8(0.1/4.6/6.6/11.5/204)	168/4.24	r=0.193 PValue=3.09E-91/r=0.248 PValue=3.33E-151	0.92/-0.708	r=0.246 PValue=4.29E-149/r=0.254 PValue=2.10E-159
Miles UG		10847	5.5(0/0.6/1.5/6.2/73)	168/4.24	r=0.032 PValue=8.78E-04/r=0.128 PValue=6.52E-41	0.92/-0.708	r=0.117 PValue=3.80E-34/r=0.154 PValue=1.65E-58
Log Miles OH		10847	2(-2.2/1.5/1.9/2.4/5.3)	168/4.24	r=0.223 PValue=5.76E-122/r=0.363 PValue=0.00E+00	0.92/-0.708	r=0.289 PValue=3.51E-207/r=0.355 PValue=1.38e-319
Log Miles UG		10847	0.7(-4.6/-0.4/0.4/1.8/4.3)	168/4.24	r=0.05 PValue=1.86E-07/r=0.147 PValue=2.63E-53	0.92/-0.708	r=0.143 PValue=9.71E-51/r=0.178 PValue=2.69E-78
CircuitCustBase		10847	1035.6(100/534/849/1351/4892)	168/4.24	r=0.014 PValue=1.39E-01/r=0.148 PValue=2.09E-54	0.92/-0.708	r=0.11 PValue=1.10E-30/r=0.176 PValue=1.71E-76
YearsFromSubBuilt		10847	65.3(4/52/67/76/108)	168/4.24	r=-0.005 PValue=5.89E-01/r=-0.084 PValue=2.96E-18	0.92/-0.708	r=-0.065 PValue=1.10E-11/r=-0.098 PValue=1.09E-24

Based on the descriptive statistics, both OH and UG miles appear to be skewed, which is confirmed by the histograms in Appendix 8.6.B. To mitigate the influence of highly leveraged or potentially influential observations, the Company applied a logarithmic transformation to both variables.[210] The correlation with the outcomes were greatly increased for the OH miles when taking logs and slightly increased for the UG miles when taking logs. The variable, OH Miles (and log OH miles), has the highest univariate correlation with all the outcomes of interest, log SAIFI/SAIDI both AW and exMED. More details on the descriptive statistics for the OH and UG miles can be found in Appendix 8.6.B.

From the univariate results, two observations emerge that relate to the hypothesis: 1) The EJ score when treated as a continuous variable is statistically correlated with both log SAIFI and log SAIDI for AW and exMED (the untransformed SAIFI and SAIDI is also negatively correlated with EJ score). The correlation is negative, which indicates that as EJ score increases, log SAIFI and log SAIDI are expected to decrease. 2) When treating the EJ score as a binary variable (categorical) the univariate analysis shows a statistically significant difference in the means, for all metrics except AW SAIDI and AW log SAIDI. For all metrics, the mean in the <80 EJ score was higher than the mean for the ≥80 EJ score group. This corroborates with the univariately results using EJ score as a continuous variable where the higher the EJ score the lower SAIFI and SAIDI across all metrics.

[210] In this case, since some circuits have 0 for the UG we add the same constant as we did for SAIDI and SAIFI (0.01). For OH miles this was not necessary since we already subsetted the data to only include circuits with >= 0.1 OH miles.

When the multivariable regression is run and appropriate confounders are included, the resulting models indicate that the relationships may reverse. After controlling circuit characteristics in the multivariable model, circuits with EJ scores under 80 may demonstrate lower reliability on average, and higher EJ scores may correspond to increases in the reliability metrics. A possible reason for this can be seen in Exhibit 8.16, which looks at the log and untransformed average reliability metrics within quantiles of log OH miles and EJ score group (≥80 and <80). The results shows that the lower EJ score group tended to have higher log OH miles. Within the same quantile of log OH miles, the EJ group with ≥80 had worse reliability than the EJ group with <80. This highlights the necessity to put the correct confounders into the model and not simply rely on univariate relationships.

Exhibit 8.16 – Cross-Tabulation of EJ and Log Metrics

EJ Cut OFF	Quantile LogOH	Count	Mean Log SAIDI AW	Mean Log SAIFI AW	Mean_ Log SAIDI exMED	Mean Log SAIFI exMED	Mean SAIDI AW	Mean SAIFI AW	Mean SAIDI exMED	Mean SAIFI exMED
0	1	702	4.01	-1.220	3.03	-1.580	369	0.70	93	0.52
0	2	605	4.68	-0.790	3.57	-1.200	530	0.94	108	0.67
0	3	603	5.15	-0.529	3.85	-1.050	730	1.03	127	0.70
0	4	632	5.12	-0.497	3.89	-0.987	671	1.09	133	0.74
0	5	596	5.29	-0.428	4.02	-0.925	743	1.15	139	0.77
0	6	617	5.23	-0.421	4.04	-0.848	677	1.14	129	0.79
0	7	729	5.69	-0.040	4.51	-0.452	865	1.46	179	1.02
0	8	910	5.75	0.025	4.56	-0.395	817	1.55	181	1.09
0	9	1027	6.04	0.252	4.84	-0.164	923	1.80	219	1.27
0	10	1084	6.26	0.459	5.22	0.109	1028	2.11	303	1.56
0	11	1	6.02	0.125	5.92	0.086	413	1.12	373	1.08
1	1	382	4.18	-1.120	3.2	-1.460	419	0.82	110	0.62
1	2	481	5.23	-0.502	4.09	-0.872	617	1.05	147	0.77
1	3	481	5.35	-0.441	4.17	-0.851	702	1.09	152	0.77
1	4	451	5.51	-0.393	4.2	-0.850	791	1.13	160	0.78
1	5	490	5.56	-0.381	4.22	-0.852	785	1.09	145	0.72
1	6	468	5.67	-0.269	4.29	-0.748	844	1.21	155	0.81
1	7	355	6.02	-0.003	4.55	-0.523	1050	1.49	203	0.98
1	8	174	5.91	0.067	4.78	-0.315	789	1.56	204	1.13
1	9	59	6.56	0.467	5.01	-0.017	1283	1.94	226	1.27

Multivariable Linear Regression

The Company estimated models for both SAIFI and SAIDI under the AW and exMED frameworks and included specifications using the original (untransformed) metrics in addition to the log transformed versions. In total, 16 regression models were run to capture the full set of analytical scenarios:

- EJ score modeled as a continuous variable and as a categorical variable
- AW and ExMED
- Log transformed and untransformed SAIFI and SAIDI
- SAIFI and SAIDI as dependent variables

The primary hypothesis tested focused on the beta coefficients and p values associated with the EJ variables. Across the eight untransformed models, EJ score treated as a continuous variable did not show a statistically significant relationship at the 0.05 level in any specification except for SAIDI exMED, where the coefficient was −0.267. The results could be interpreted as: “holding all other variables constant, on average, as you increase your EJ score by one unit, we would anticipate a decrease of .267 SAIDI exMED.” The untransformed table results in Exhibit 8.17 show that using EJ score as a categorical variable in all cases the beta coefficient is positive, but not statistically significant the 0.05 level.

Exhibit 8.17 – Multivariate Regression Results, AW and exMED

Table: Multivariable Regression Results AW and ExMED

	Dependent variable:							
	SAIDI_AW		SAIFI_AW		SAIDI_ExMED		SAIFI_ExMED	
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
EJ_CutOFF	47.077		0.054*		5.843		0.042*	
	(29.000)		(0.030)		(5.966)		(0.024)	
AvgMiEJScore		-0.717		-0.001		-0.267**		-0.0002
		(0.607)		(0.001)		(0.125)		(0.0005)
RegNW	394.178***	384.945***	0.197***	0.187***	2.080	-0.144	0.039	0.034
	(37.581)	(37.642)	(0.038)	(0.038)	(7.731)	(7.742)	(0.031)	(0.031)
RegSE	459.460***	486.107***	0.204***	0.233***	37.435***	43.654***	0.072**	0.087***
	(34.211)	(34.418)	(0.035)	(0.035)	(7.038)	(7.079)	(0.028)	(0.028)
RegSW	639.558***	633.509***	0.354***	0.347***	21.370***	20.430***	0.113***	0.108***
	(34.019)	(33.871)	(0.035)	(0.035)	(6.998)	(6.966)	(0.028)	(0.028)
BuskV8.3	-122.668	-56.707	0.883***	0.955***	215.798***	230.491***	1.071***	1.113***
	(168.211)	(167.900)	(0.172)	(0.171)	(34.604)	(34.533)	(0.138)	(0.138)
BuskV13.2	-170.219***	-163.030***	0.176***	0.183***	16.192**	18.586**	0.263***	0.266***
	(37.073)	(37.420)	(0.038)	(0.038)	(7.627)	(7.696)	(0.031)	(0.031)
LogMilesOH	314.230***	304.202***	0.456***	0.445***	73.871***	70.776***	0.308***	0.304***
	(13.948)	(15.226)	(0.014)	(0.016)	(2.869)	(3.132)	(0.011)	(0.013)
LogMilesUG	-19.461	-26.364**	0.006	-0.001	7.017***	5.094*	0.011	0.008
	(12.748)	(13.158)	(0.013)	(0.013)	(2.622)	(2.706)	(0.010)	(0.011)
IsISO	-38.494	-50.224	0.272*	0.260	-14.311	-18.120	0.177	0.173
	(157.685)	(157.892)	(0.161)	(0.161)	(32.439)	(32.474)	(0.130)	(0.130)
YearsFromTrim0	-93.722***	-91.911***	-0.072**	-0.070**	-21.713***	-21.408***	-0.023	-0.022
	(32.787)	(32.777)	(0.033)	(0.033)	(6.745)	(6.741)	(0.027)	(0.027)
YearsFromTrim1	-219.834***	-217.407***	-0.165***	-0.163***	-24.928***	-24.518***	-0.076***	-0.074***
	(33.933)	(33.915)	(0.035)	(0.035)	(6.981)	(6.975)	(0.028)	(0.028)
YearsFromTrim2	-191.579***	-188.951***	-0.205***	-0.202***	-31.798***	-31.330***	-0.098***	-0.096***
	(36.777)	(36.761)	(0.038)	(0.038)	(7.566)	(7.561)	(0.030)	(0.030)
YearsFromTrim3	-68.972*	-67.063*	-0.175***	-0.173***	-23.028***	-22.708***	-0.123***	-0.121***
	(39.546)	(39.537)	(0.040)	(0.040)	(8.135)	(8.132)	(0.033)	(0.033)
YearsFromTrim4	-167.133***	-166.849***	-0.188***	-0.188***	-18.690*	-18.731*	-0.087**	-0.086**
	(48.778)	(48.781)	(0.050)	(0.050)	(10.035)	(10.033)	(0.040)	(0.040)
YearsFromSubBuilt	0.541	0.723	0.004***	0.004***	0.478***	0.522***	0.003***	0.003***
	(0.609)	(0.610)	(0.001)	(0.001)	(0.125)	(0.126)	(0.001)	(0.001)
Year2020	-110.592***	-111.043***	-0.112***	-0.113***	-28.203***	-28.314***	-0.078***	-0.078***
	(34.737)	(34.740)	(0.035)	(0.035)	(7.146)	(7.145)	(0.029)	(0.029)
Year2021	471.916***	470.949***	0.154***	0.152***	-36.852***	-37.085***	-0.151***	-0.151***
	(34.855)	(34.857)	(0.036)	(0.036)	(7.170)	(7.169)	(0.029)	(0.029)
Year2022	130.050***	128.988***	-0.114***	-0.115***	-35.557***	-35.794***	-0.121***	-0.122***
	(35.304)	(35.305)	(0.036)	(0.036)	(7.263)	(7.261)	(0.029)	(0.029)
Year2023	1,037.526***	1,036.313***	0.336***	0.335***	-17.666**	-17.928**	-0.183***	-0.184***
	(35.806)	(35.807)	(0.037)	(0.037)	(7.366)	(7.365)	(0.029)	(0.029)
CircuitCustBase	-0.099***	-0.091***	-0.0001***	-0.0001***	-0.043***	-0.041***	-0.0001***	-0.0001***
	(0.020)	(0.021)	(0.00002)	(0.00002)	(0.004)	(0.004)	(0.00002)	(0.00002)
Constant	-359.619***	-306.359***	0.013	0.068	36.556***	54.195***	0.189***	0.206***
	(63.361)	(73.477)	(0.065)	(0.075)	(13.035)	(15.112)	(0.052)	(0.061)
Observations	10,847	10,847	10,847	10,847	10,847	10,847	10,847	10,847
R^2	0.162	0.162	0.134	0.134	0.072	0.072	0.108	0.107
Adjusted R^2	0.161	0.160	0.132	0.132	0.070	0.071	0.106	0.106
Residual Std. Error (df = 10826)	1,130.402	1,130.466	1.153	1.153	232.546	232.507	0.931	0.931
F Statistic (df = 20; 10826)	104.731***	104.657***	83.689***	83.575***	42.033***	42.228***	65.361***	65.190***
Note:								*p<0.1; **p<0.05; ***p<0.01

In the workpapers, the Company shares the graphs that check some of the regression model assumptions. Several assumptions (linearity, homogeneity of variance, normality of residuals) seem to be violated with the untransformed variables. The sample size is quite large, thus running standard statistical test on residuals (e.g., Shapiro-Wilks or Breusch-Pagan) is generally not recommended as the tests will show violations with our regression assumptions even if none are there.[211] The visual graphs in the workpapers are more telling, with some of the tests included for reference in Appendix 8.6.C. The results from the transformed dependent variables will be discussed after the next section, which provides a brief examination of several technical details that occur when the outcome variable is log transformed in a multivariable regression setting.

Technical Context on Log Transformation

The standard multivariable regression models the relationship between an outcome/dependent variable, Y_i, and a set of p covariates/predictors/independent/explanatory variables $X_i \in R^p$through the following formula (where i is a record in a dataset of n records):

$$Y_i = X_i^t \beta + \epsilon_i$$

Where $\epsilon_i \sim N(0, \sigma^2), \beta \in R^p, \epsilon_i \perp \epsilon_j \; i \neq j, \; 1 \leq i \leq n,$ (i.i.d normal random variables with mean 0 and variance σ^2). To interpret the j^{th} β coefficient, β_j, we can look at the difference between the following expectations:

$$E[Y|X_{(j-)} = x_{(j-)}, X_j = x_j + 1] - Y|X_{(j-)} = x_{(j-)}, X_j = x_j] = \beta_j$$

Where $X_{(j-)} = (X_1, \dots, X_{j-1}, X_{j+1}, \dots, X_p)$ and $x_{(j-)} = (x_1, \dots, x_{(j-1)}, x_{(j+1)}, \dots, x_p)$.

Thus, the interpretation of β_j is the expected change in your outcome variable, Y, for a one unit increase in your independent variable, X_j, holding all other independent variables the same (or constant). To obtain a point estimate for a given set of predictors, the following approach may be used: $E[Y|X = x] = x^t \hat{\beta}$. Where $\hat{\beta}$ is the estimator of β from the regression model. When applying the log transformation to Y and then running the regression model, the model becomes: $\log Y = X^t \beta + \epsilon$ which implies $Y = \mathrm{e}^{X^t \beta + \epsilon}$ or $Y \sim lognormal(X^t \beta, \sigma^2)$. The mean of Y (which is well known and easy to derive) is: $E[Y] = \mathrm{e}^{X^t \beta + \frac{\sigma^2}{2}}$. As a very important note, $\mathrm{e}^{\mathrm{E}[\log Y]} = e^{X^t \beta} \neq$

[211] This is why the R function does not allow sample sizes > 5000 when using the Shapiro-Wilks test. Some discussion on this can be found (Weisberg, 1982).

$e^{X^t\beta+\frac{\sigma^2}{2}} = E[Y]$. This is due to Jensen's inequality that states that if f is a convex function, you have $f(E[X]) \leq E[f(X)]$ this relationship is illustrated here where f is the exponential function that maps the independent variables, X, to Y. This becomes important when predicting and interpreting the results from a multivariable regression that uses a $\log$ transformed outcome. In statistics this is often referred to as the retransformation problem. See (Duan, 1983) , (Rainey, 2017) and (More, 2022) for more details. The point estimate for $\log(Y|X = x)$ is given by $E[\log(Y|X = x)] = x^t\,\beta$ which is estimated using $x^t\,\hat{\beta}$. When estimating original scale of Y it is tempting to simply exponentiate each side yielding $e^{E[\log(Y|X\,=\,x)]} = e^{x^t\,\beta}$. However, this is not equivalent to $E[e^{\log(Y|X=x)}] = E[Y|X = x] = e^{x^t\,\beta}E[e^{\epsilon}]$=$e^{x^t\,\beta}e^{\frac{\sigma^2}{2}}$ which is typically the quantity of interest. There are several methods of estimating $e^{x^t\,\beta}e^{\frac{\sigma^2}{2}}$. One common way is to substitute for β, $\hat{\beta}$ and for σ^2 the MSE (mean square error) from the regression output. This method of approach is known as the "normal method". (Duan, 1983) proposed a non-parametric estimator for an unknown distribution of ϵ which is $E[h(\epsilon)] = \frac{1}{n}\sum_{\{i=1\}}^{\{n\}} h(r_i)$ where r_i are the residuals from the regression $(Y_i - X_i^t\hat{\beta})$. This is called the smearing estimator. In this case, the

estimator would be $e^{X_i^t\,\hat{\beta}}\frac{1}{n}\sum_{\{i=1\}}^{\{n\}} e^{r_i}$. Similarly, care must be taken when interpreting the meaning of the betas from the regression. The interpretation of $\beta_j$is the expected difference in $\log Y$, for a one unit increase in this independent variable, X_j, holding all other independent variables the same (or constant).

$$E[\log(Y|X_{(j-)} = x_{(j-)}, X_j = x_j + 1)] - E[\log(Y|X_{(j-)} = x_{(j-)}, X_j = x_j)] = \beta_j$$

We are interested in the interpretation of the relationship between the independent variables and the original scale of the reliability metrics not the log-transformed metrics. $\frac{E[\mathrm{Y}|\mathrm{X}_{(\mathrm{j}-)}, X_j = x_j + 1]}{E[\mathrm{Y}|\mathrm{X}_{(\mathrm{j}-)}, X_j = x_j]} = e^{\beta_j}$. If $\beta_j \geq 0$, subtract one from it and multiply it by 100. The interpretation is "holding all the other variables constant, on average as you increase X_j by one unit, the percent change in the mean of Y will be $100 * \left(e^{\beta_j} - 1\right)\%$ ***higher***. If $\beta_j < 0$ subtract it from one and multiply it by 100. The interpretation is "holding all the other variables constant, on average as this increase x_j by one unit, the percent change in Y will be $100 * \left(1 - e^{\beta_j}\right)\%$ ***lower***. Once the regression has been run substitute the unknown $\beta_j$with $\widehat{\beta_j}$.

Since the main interest is on the statistical significance of the βs for EJ scores and the directional relationship of the βs with respect to reliability, focus will be on the direction of the βs and associated p-values.

Log Transformed Results

The results from the eight regressions run from log transforming the reliability metrics are presented in Exhibit 8.6.7. The variables seem to be more explanatory as can be indicated with the much higher R^2statistic. In addition, in all the models the EJ score variables are statistically significant and directionally, tell the same story.

The beta coefficient in the AW Log SAIDI model for this variable was .273 using the EJ score as a categorical variable. The standard interpretation is as follows "holding all the other variables constant, on average, the percent change in the mean of AW SAIDI for the circuits with EJ score 80 or more compared with the circuits with EJ score less than 80, will be $(e^{.273} - 1) * 100$ or 31% *higher.*" Similarly, for AW SAIFI the interpretation would be $(e^{.131} - 1) * 100$ or 14% *higher,* similar results are observed for the exMED metrics. Using EJ score as a continuous EJ score variable, the beta coefficient for AW SAIDI was .004. The interpretation is as follows, "holding all the other variables constant, on average as EJ score is increased by one unit, the percent change in the mean of AW SAIDI for the circuits will be $(1 - e^{.004}) * 100$ or 0.4% *higher*".

It is important to note that the direction of the betas for the independent variables that are significant at the 0.05 level to test if they fit the expected relationship. In the workpapers and Appendix 8.6.C, there are graphs of the residuals and some statistical tests used to check to see if the regression assumptions were met. Looking at the graphs of the residuals, they demonstrate that for the most part, the regression assumptions seem to be met. It is common in a Q-Q plot to have deviations from normality at the tails. However, there is some left skewness in the residual plots. This is a biproduct of adding a small constant to avoid taking log of 0 as described above. However, for log SAIFI, there are some severe deviations. Furthermore, the constant variance assumption (homogeneity of variance) may be violated for all the models. This makes sense in the dataset. Circuit reliability information between one year and the next would be more informative than to another circuit's reliability. This is true because there are circuit characteristics that may drive reliability that were not conditioned on in this dataset. The physical construction (e.g., number of reclosers) and geo location (e.g., tree density) of the circuit can contain valuable information that were not investigated for this study. This can cause data from one calendar year to the next within a circuit to be more informative than a completely different circuit. In the next

section, the Company ran a more complex regression model that attempts to handle this issue. For SAIFI, it is not entirely clear from the residual plots that other regression assumptions are met. The distribution of SAIFI or log SAIFI may simply not follow a normal distribution conditioning on the variables in the dataset.

Exhibit 8.18 – Multivariable Regression Results for log AW and Log ExMED

Table: Multivariable Regression Results for log AW and log ExMED

	Dependent variable:							
	LogSAIDI_AW		LogSAIFI_AW		LogSAIDI_ExMED		LogSAIFI_ExMED	LogSAIDI_ExMED
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
EJ_CutOFF	0.273***		0.131***		0.254***		0.164***	
	(0.042)		(0.029)		(0.037)		(0.030)	
AvgMiEJScore		0.004***		0.002***		0.004***		0.004***
		(0.001)		(0.001)		(0.001)		(0.001)
RegNW	0.652***	0.650***	0.310***	0.309***	0.317***	0.317***	0.234***	0.317***
	(0.054)	(0.055)	(0.038)	(0.038)	(0.048)	(0.048)	(0.039)	(0.048)
RegSE	0.823***	0.839***	0.340***	0.347***	0.501***	0.509***	0.261***	0.509***
	(0.050)	(0.050)	(0.034)	(0.035)	(0.044)	(0.044)	(0.036)	(0.044)
RegSW	0.723***	0.697***	0.344***	0.332***	0.285***	0.261***	0.223***	0.261***
	(0.049)	(0.049)	(0.034)	(0.034)	(0.043)	(0.043)	(0.035)	(0.043)
BuskV8.3	0.722***	0.795***	0.971***	1.004***	1.516***	1.569***	1.347***	1.569***
	(0.244)	(0.243)	(0.169)	(0.169)	(0.215)	(0.214)	(0.175)	(0.214)
BuskV13.2	0.167***	0.137**	0.247***	0.232***	0.429***	0.398***	0.411***	0.398***
	(0.054)	(0.054)	(0.037)	(0.038)	(0.047)	(0.048)	(0.039)	(0.048)
LogMilesOH	0.804***	0.834***	0.527***	0.542***	0.692***	0.724***	0.497***	0.724***
	(0.020)	(0.022)	(0.014)	(0.015)	(0.018)	(0.019)	(0.015)	(0.019)
LogMilesUG	-0.054***	-0.043**	-0.018	-0.013	0.001	0.014	-0.005	0.014
	(0.018)	(0.019)	(0.013)	(0.013)	(0.016)	(0.017)	(0.013)	(0.017)
IsISO	-0.128	-0.084	0.095	0.116	-0.117	-0.071	0.075	-0.071
	(0.228)	(0.229)	(0.159)	(0.159)	(0.201)	(0.202)	(0.164)	(0.202)
YearsFromTrim0	-0.187***	-0.180***	-0.086***	-0.083**	-0.167***	-0.161***	-0.064*	-0.161***
	(0.048)	(0.048)	(0.033)	(0.033)	(0.042)	(0.042)	(0.034)	(0.042)
YearsFromTrim1	-0.400***	-0.391***	-0.206***	-0.202***	-0.281***	-0.273***	-0.162***	-0.273***
	(0.049)	(0.049)	(0.034)	(0.034)	(0.043)	(0.043)	(0.035)	(0.043)
YearsFromTrim2	-0.333***	-0.325***	-0.224***	-0.220***	-0.287***	-0.279***	-0.173***	-0.279***
	(0.053)	(0.053)	(0.037)	(0.037)	(0.047)	(0.047)	(0.038)	(0.047)
YearsFromTrim3	-0.171***	-0.164***	-0.173***	-0.170***	-0.226***	-0.220***	-0.196***	-0.220***
	(0.057)	(0.057)	(0.040)	(0.040)	(0.050)	(0.051)	(0.041)	(0.051)
YearsFromTrim4	-0.198***	-0.192***	-0.116**	-0.113**	-0.102	-0.097	-0.064	-0.097
	(0.071)	(0.071)	(0.049)	(0.049)	(0.062)	(0.062)	(0.051)	(0.062)
YearsFromSubBuilt	0.002***	0.002***	0.002***	0.002***	0.002**	0.002**	0.002***	0.002**
	(0.001)	(0.001)	(0.001)	(0.001)	(0.001)	(0.001)	(0.001)	(0.001)
Year2020	-0.261***	-0.261***	-0.115***	-0.115***	-0.168***	-0.168***	-0.070*	-0.168***
	(0.050)	(0.050)	(0.035)	(0.035)	(0.044)	(0.044)	(0.036)	(0.044)
Year2021	0.707***	0.706***	0.168***	0.168***	-0.214***	-0.214***	-0.164***	-0.214***
	(0.051)	(0.051)	(0.035)	(0.035)	(0.044)	(0.045)	(0.036)	(0.045)
Year2022	0.102**	0.101**	-0.064*	-0.064*	-0.204***	-0.205***	-0.102***	-0.205***
	(0.051)	(0.051)	(0.036)	(0.036)	(0.045)	(0.045)	(0.037)	(0.045)
Year2023	1.278***	1.276***	0.379***	0.378***	0.032	0.030	-0.090**	0.030
	(0.052)	(0.052)	(0.036)	(0.036)	(0.046)	(0.046)	(0.037)	(0.046)
CircuitCustBase	-0.0001***	-0.0001***	-0.00005**	-0.0001***	-0.0002***	-0.0002***	-0.0001***	-0.0002***
	(0.00003)	(0.00003)	(0.00002)	(0.00002)	(0.00003)	(0.00003)	(0.00002)	(0.00003)
Constant	2.818***	2.602***	-1.832***	-1.939***	2.547***	2.321***	-2.046***	2.321***
	(0.092)	(0.107)	(0.064)	(0.074)	(0.081)	(0.094)	(0.066)	(0.094)
Observations	10,847	10,847	10,847	10,847	10,847	10,847	10,847	10,847
R^2	0.222	0.221	0.173	0.172	0.170	0.169	0.157	0.169
Adjusted R^2	0.221	0.219	0.171	0.171	0.168	0.167	0.156	0.167
Residual Std. Error (df = 10826)	1.638	1.639	1.138	1.139	1.443	1.444	1.178	1.444
F Statistic (df = 20; 10826)	154.472***	153.310***	113.211***	112.719***	110.894***	110.009***	101.062***	110.009***

Note: *p<0.1; **p<0.05; ***p<0.01

Longitudinal Panel Data

In the previous section, DTE ran the following types of models: YearsFromSubBuilt

$$LogSAIDI_i = \beta_0 + \beta_1 YearsFromSubBuilt_i + \beta_2 RegNW_i + \beta_3 EJ_CutOFF_i + \cdots + \epsilon_i$$

where each circuit year combination would be a row in the dataset and "i" in the above model would be a number from 1-10,847 as there were 10,847 datapoints. One of the assumptions of regression is that $\epsilon_i \sim N(0, \sigma)$ where the model estimates σ and σ is a single number. Meaning, the variance is constant no matter what circuit year is being evaluated. Another assumption is that $\epsilon_i \perp \epsilon_j$ when $i \neq j$ meaning the data is completely independent of each other. From the prior section an intuitive reason was mentioned for why that may not be the case here. The data is longitudinal (or panel data), meaning, the Company is measuring circuits over time and would anticipate circuits from one year to be correlated with itself in another year. In this section, the Company tests it formally with several models. The models that handle longitudinal data fall into one of two classes: marginal models and conditional models. The research question is slightly different for these models.

Marginal models look to answer how EJ scores are related to reliability across all circuits. When using marginal models, it is not the effect of EJ scores on individual circuits that is of interest, but rather the overall population level relationship. Modeling differences among individual circuits is not the focus; instead, attention is placed on identifying the general relationship. Under an untransformed model, the interpretation becomes: "On average, across all circuits, a one-unit increase in EJ score is associated with an improvement or worsening in reliability of X." This reflects the expected population level impact of EJ scores but does not describe how the effect varies from one circuit to another.

Conditional models look to answer how EJ scores affect reliability within each circuit accounting for differences between circuits. Each circuit has unique, unobserved characteristics (e.g., configuration, geographic location, etc.). Some circuits may naturally perform better or worse than others due to unobserved factors. These differences will be modeled using random effects, meaning the effect of EJ is estimated while accounting for circuit-specific differences. The interpretation becomes, "For a given circuit, increasing EJ score by one unit improves/worsens reliability by X amount." This framing places emphasis on within-circuit effects, rather than overall population trends.

Exhibit 8.19 – Marginal Versus Conditional Models

Model	Focus	What It Explains	Example Interpretation
Conditional	Circuit- specific effects	Individual circuit variability and vulnerability impact	"Vulnerable circuits have, on average, 5% lower reliability, considering circuit-specific characteristics and inherent differences."
Marginal	Overall trend across circuits, ignoring circuit- specific variability.	Overall trend across circuits, ignoring circuit-specific variability	"Vulnerable circuits are 5% less reliable than non-vulnerable ones across all years, controlling for circuit characteristics."

The first to be considered is a conditional model called Linear Mixed Model (LMM). This is a mixed effects model:

$$LogSAIDI_{ij} = \beta_0 + \beta_1 YearsSinceCommission_{ij} + \beta_2 RegNW_i + \beta_3 EJ_{CutOFF_i} + \beta_4 2020Year_{ij} + \cdots + \alpha_i + \epsilon_{ij}$$

Where "i" ranges from 1-2,193, the number of unique circuits, and $j \in \{2020,2021,2022,2023\}$ (2019 was the reference year), referring to the calendar year. Linear mixed models allow for an unbalanced design so if a circuit only has data for a subset of those years, those data points could still be used. Here, $\alpha \sim N(0,\tau)$ and is independent from $\epsilon \sim N(0,\sigma)$. As before, $\epsilon_i \perp \epsilon_j$. This model is called the random intercept model. However, in a fixed effects model, all time-invariant differences between circuits are removed to focus purely on within-circuit variation over time. However, the primary interest is the EJ score variable and how it relates to reliability. EJ score (for this dataset) was time-invariant as EJ score does not change year to year.[212] Thus, the fixed effects (FE) model would not address the original hypothesis (after demeaning, the EJ score variable is removed). However, an FE model was run to validate one of the assumptions of LMM. Specifically, one of the assumptions is that the random effects are uncorrelated with the independent variables (the fixed effects). The Hausman test was performed to test this assumption which compares the differences between the beta coefficients from each model. The second model to be considered was a marginal model called Generalized Estimating Equations (GEE). GEE focuses on estimating the marginal effects of the covariates averaging the effects across the entire population. It accounts for correlations between observations without explicitly modeling the random effects. The primary goal of GEE is to estimate the population-average effects, which means the beta coefficients reflect how a covariate influences the average outcome

[212] In this case, the EJ score remained constant for each circuit throughout the five years.

for the population. Since the random effects themselves are not estimated (rather the correlation structure of the data is used to adjust the standard errors), GEE provides population-level estimates that are robust to the within-cluster correlation.

The GEE model assumes the following:

$$LogSAIDI_{ij} = \mu_{ij} + \epsilon_{ij}$$

Where Y_{ij} is the response variable for the i-th observation in the j-th cluster and μ_{ij} is the expected value of Y_{ij}, which is models as $\mu_{ij} = \beta_0 + \beta_1 RegNW_i + \beta_1 EJ_{CutOFF_i} + \beta_3 2020Year_{ij} + \cdots$ where β is the vector of population-averaged coefficients (the fixed effects). The GEE approach focuses on the marginal distribution of the outcome, which is the average outcome for the entire population (ignoring random effects). GEE estimates β by solving the following equation:

$$\sum_{\{i=1\}}^{\{n\}} \frac{\partial \mu_{ij}}{\partial \beta}^{t} V^{-1}[Y_{ij} - \mu_{ij}] = 0$$

Where V is the working covariance matrix of the observations which accounts for the correlation structure (such as exchangeable, autoregression, etc.) and $\frac{\partial \mu_{ij}}{\partial \beta}$ is the derivative of the mean function with respect to the regression coefficients. The choice of working correlation structure specified does not impact the consistency of the parameter estimates but can possibly impact the efficiency (lower variance) of the parameter estimates. The Company ran GEE using an exchangeable structure (compound symmetry) which assumes a constant correlation between all-time points within a subject. This is what's assumed with the LMM random intercept model. Due to the law of iterated expectations, the population mean of the outcome is the same as the mean of the conditional expectations $E[Y|X] = E[E[Y|X, \mu]]$. So, in the untransformed model, for GEE it is:

$$E\left[Y_{ij}|X_{ij}\right] = X_{ij}\beta$$

and for LMM it is:

$$E\left[Y_{ij}|X_{ij}\right] = E[E[Y_{ij}|X_{ij}, \alpha_i]] = E[X_{ij}\beta + \alpha_i|X_{ij}] = X_{ij}\beta$$

since the random effects are assumed to be uncorrelated with the fixed effects $E\left[\alpha_i|X_{ij}\right] = E[\alpha_i] = 0$ by assumption. By law of iterated expectations, the effects of X in the LMM which is conditional

on the random intercepts is equivalent to the average effect of X across the population which is what GEE is estimating. With a log transformation, practically, people just exponentiate the beta and interpret it in a similar way as last section. When condition is applied on a specific circuit, the intercept is $\beta_0 + \alpha_i$ for circuit "i" allowing to capture the potential correlation within a circuits data. The necessity of this model will be formally evaluated by examining the τ parameter estimated in the model. If τ is statistically different than 0, this may indicate that this model is more appropriate for the dataset as opposed to the model in the previous section. A couple of notes before presenting the results. The standard linear mixed model in the lme4 package in R does not provide p-values. The author did not want to display the p-values as the standard way p-values are calculated using the T tests and F test may not be appropriate (this relates to the degrees of freedom, see (Bates D. , n.d.) for more details on this). There are several options that were used instead. The first option used was the lmerTest package that overloads the functions in the lme4 package (Kuznetsova, 2017). The p-values provided for the fixed effects consider some of the lme4 author's concern. The Company also provided profile likelihood confidence intervals on the betas and random effects (Bates D. M., 2015). Lastly, a parametric bootstrap was performed in which the data were resampled 1,000 times to obtain bootstrapped confidence intervals for both the fixed and random effects (T. Kubokawa, 2012). It should be noted that when the parametric bootstrap is used, the variance parameter is tested at the boundary of the parameter space (because variance cannot fall below zero). As a result, a value of zero will not be obtained in the confidence interval, even though that is the value being tested. This differs from the profile likelihood approach, under which a value of zero can indeed be obtained. However, the point estimate and associated confidence intervals indicate that inclusion of the random effects structure is warranted from the profile likelihood approach. The result from the AW log SAIDI model using EJ as a continuous predictor is displayed. It is observed that in all cases, the τ parameter is bounded away from 0 in all the models. This indicates that considering the circuits within group correlation is favorable compared with the independence model. The interpretation of the coefficients is the same for this model, and the Company will ignore Jensen's inequality here. In the R code, DTE provides an example on how to do this adjustment. The model assumptions for the marginal model, GEE, and the conditional model, LMM, are displayed in Exhibit 8.20.

Exhibit 8.20 – Assumptions of GEE versus LMM

Step	LMM (Random Effects)	GEE (Population-Averaged)
Linearity Check	plot(fitted(lmm_model), resid(lmm_model))	Not required
Normality of Residuals	hist(resid(lmm_model)) + qqnorm(resid(lmm_model))	Not required
Homoscedasticity	plot(fitted(lmm_model), resid(lmm_model))	Not required
Random Effects Validity	phtest(fe_model, lmm_model)	Not applicable
Correlation Structure	Not applicable	QIC(gee_indep, gee_exch, gee_ar1)

There is a performance package in R that graphically checks several of the assumptions at once. The regression plots for the linear mixed model are in the workpapers.

Linear Mixed Model Results

For the model below, the coefficient for the continuous EJ variable is interpreted as follows: "When all other variables are held constant, a one-unit increase in EJ score is associated, on average for a given circuit, with a percent change in the mean of AW SAIDI of $(1 - e^{.00419}) * 100$ or 0.42% higher."

See the interpretation for the GEE model example later in this section. As expected, the point estimate (beta coefficients) is close to the independent model. The main reason for running this model is for the confidence intervals and p-value correction for potentially correlated data. The results show that the EJ score variables are significant in all models. The overall results are almost identical to the model run in the previous section. Looking at the regression plots, it appears that the regression assumptions seem to hold better for SAIDI than SAIFI.

Exhibit 8.21 – LMER Log for SAIDI (AW Log SAIDI EJ Continuous)

	Estimate	P value from LMER	Profile Likelihood		Parametric Bootstrap	
			2.50%	97.50%	2.50%	97.50%
Tau	5.33E-01		4.84E-01	5.74E-01	4.86E-01	5.75E-01
Sigma	1.55E+00		1.53E+00	1.57E+00	1.53E+00	1.57E+00
(Intercept)	2.62E+00	3.33E-90	2.37E+00	2.86E+00	2.37E+00	2.88E+00
AvgMiEJScore	4.19E-03	6.19E-05	2.15E-03	6.24E-03	2.12E-03	6.31E-03
RegNW	6.53E-01	3.01E-23	5.26E-01	7.80E-01	5.27E-01	7.70E-01
RegSE	8.41E-01	1.30E-43	7.25E-01	9.58E-01	7.19E-01	9.55E-01
RegSW	6.99E-01	5.49E-32	5.85E-01	8.13E-01	5.82E-01	8.08E-01
BuskV8.3	7.97E-01	5.62E-03	2.35E-01	1.36E+00	2.00E-01	1.35E+00
BuskV13.2	1.43E-01	2.62E-02	1.73E-02	2.69E-01	1.03E-02	2.71E-01
LogMilesOH	8.29E-01	9.85E-184	7.78E-01	8.80E-01	7.72E-01	8.78E-01

	Estimate	P value from LMER	Profile Likelihood		Parametric Bootstrap	
LogMilesUG	-4.59E-02	4.20E-02	-9.00E-02	-1.76E-03	-9.48E-02	-2.91E-03
IsISO	-7.99E-02	7.69E-01	-6.12E-01	4.53E-01	-6.49E-01	3.95E-01
YearsFromTrim0	-1.95E-01	5.08E-05	-2.88E-01	-1.00E-01	-2.94E-01	-9.77E-02
YearsFromTrim1	-4.03E-01	6.58E-16	-5.00E-01	-3.05E-01	-5.00E-01	-3.01E-01
YearsFromTrim2	-3.27E-01	1.71E-09	-4.33E-01	-2.21E-01	-4.27E-01	-2.19E-01
YearsFromTrim3	-1.72E-01	3.16E-03	-2.87E-01	-5.80E-02	-2.94E-01	-5.67E-02
YearsFromTrim4	-1.79E-01	1.24E-02	-3.19E-01	-3.89E-02	-3.16E-01	-3.21E-02
YearsFromSubBuilt	2.36E-03	2.51E-02	3.01E-04	4.41E-03	3.06E-04	4.30E-03
Year2020	-2.59E-01	5.76E-08	-3.53E-01	-1.66E-01	-3.60E-01	-1.72E-01
Year2021	7.09E-01	1.13E-48	6.15E-01	8.03E-01	6.15E-01	8.06E-01
Year2022	1.04E-01	3.43E-02	7.66E-03	1.99E-01	3.11E-03	1.99E-01
Year2023	1.28E+00	6.53E-141	1.18E+00	1.38E+00	1.18E+00	1.38E+00
CircuitCustBase	-1.23E-04	5.47E-04	-1.93E-04	-5.36E-05	-1.90E-04	-5.22E-05

The remaining seven Linear Mixed Models can be found in Appendix 8.6.D, as well as the results from a few of the Hausman test on some of the models. In all cases, there was a significant difference between the fixed effects and mixed effects model. While a small p-value from the Hausman test indicates a statical preference for the FE model, in large datasets, even trivial differences can become statistically significant as discussed above. Furthermore, as explained above, the EJ score variable is time-invariant, so a FE model would not allow the hypothesis of interest to be addressed. The results from the GEE model were found to be essentially the same. It should also be noted that attention is being directed specifically toward the EJ score variable. Since EJ score is a “between group” or time-invariant variable, the interpretation of the counterfactual (a circuit can’t lower or raise its EJ score if EJ score doesn’t change in the dataset by circuit) is unobserved because the random intercept is a latent variable. To address this issue, the interpretation must be given as the response for two different circuits that happen to share the same value for the unobserved random effects. See (Garrett M. Fitzmaurice, 2011) for more details.

GEE Results

The GEE model for log AW SAIDI using EJ as a continuous variable is displayed in Exhibit 8.22. The remaining seven GEE models are provided in Appendix 8.6.D. For the model below, the interpretation of the coefficient for the EJ continuous variable is: “holding all the other variables constant, on average across all circuits, as the EJ score is increased by one unit, the percent

change in all-weather SAIDI for the circuits will be $(1 - e^{.0043}) * 100$ or 0.43% higher." The results in this case are essentially identical to those obtained from the linear mixed model.

Exhibit 8.22 – GEE Log SAIDI Regressed on MiEJScore and Other Circuit Variables

```
Call:
geeglm(formula = LogSAIDI_AW ~ AvgMiEJScore + Reg + BuskV + LogMilesOH +
    LogMilesUG + IsISO + YearsFromTrim + YearsFromSubBuilt +
    Year + CircuitCustBase, data = DataFinal, id = CircuitIDRandomized,
    corstr = "exchangeable")

 Coefficients:
                   Estimate   Std.err   Wald Pr(>|W|)
(Intercept)        2.60e+00  1.18e-01 489.20  < 2e-16 ***
AvgMiEJScore       4.30e-03  9.45e-04  20.73  5.3e-06 ***
RegNW              6.50e-01  5.10e-02 162.68  < 2e-16 ***
RegSE              8.39e-01  5.14e-02 266.93  < 2e-16 ***
RegSW              6.97e-01  4.95e-02 197.87  < 2e-16 ***
BuskV8.3           7.95e-01  1.81e-01  19.37  1.1e-05 ***
BuskV13.2          1.37e-01  5.38e-02   6.51  0.01075 *
LogMilesOH         8.34e-01  2.67e-02 976.00  < 2e-16 ***
LogMilesUG        -4.33e-02  2.00e-02   4.71  0.02996 *
IsISO             -8.38e-02  1.58e-01   0.28  0.59698
YearsFromTrim0    -1.80e-01  4.90e-02  13.48  0.00024 ***
YearsFromTrim1    -3.91e-01  4.92e-02  63.30  1.8e-15 ***
YearsFromTrim2    -3.25e-01  5.36e-02  36.69  1.4e-09 ***
YearsFromTrim3    -1.64e-01  5.79e-02   8.04  0.00458 **
YearsFromTrim4    -1.92e-01  6.62e-02   8.44  0.00367 **
YearsFromSubBuilt  2.34e-03  8.58e-04   7.43  0.00642 **
Year2020          -2.61e-01  4.94e-02  27.88  1.3e-07 ***
Year2021           7.06e-01  5.11e-02 191.12  < 2e-16 ***
Year2022           1.01e-01  5.21e-02   3.73  0.05330 .
Year2023           1.28e+00  5.10e-02 626.20  < 2e-16 ***
CircuitCustBase   -1.23e-04  2.79e-05  19.48  1.0e-05 ***
---
Signif. codes:  0 '***' 0.001 '**' 0.01 '*' 0.05 '.' 0.1 ' ' 1

Correlation structure = exchangeable
Estimated Scale Parameters:

            Estimate Std.err
(Intercept)     2.68  0.0484
  Link = identity

Estimated Correlation Parameters:
      Estimate Std.err
alpha        0       0
Number of clusters:   10847  Maximum cluster size: 1
```

Conclusion

In the simplest analysis, a comparison of the average reliability of vulnerable and non-vulnerable communities, vulnerable communities had better reliability. To look at a more complex analysis, the Company developed and ran several different models to assess the statistical relationship between vulnerable communities and electrical reliability. Statistically significant differences were observed between circuits with a higher than 80 EJ score compared with circuits with a lower than 80 EJ score. Specifically, after controlling circuit characteristics, circuits with higher than 80 EJ scores tend to have worse reliability both in terms of log SAIDI and in terms of log SAIFI for AW and exMED metrics even though the univariate results suggested the opposite pattern. The overhead miles variable explained most of the variation found in the model in terms of the R square statistics and univariately was the most correlated with the outcomes.

When the two EJ groups of < 80 compared with ≥80 were compared, circuits with EJ scores below 80 were found to have more OH miles. As a result, the OH miles variable was confounding the relationship between reliability and EJ scores. When looking at EJ scores on a spectrum, as a continuous variable, the results were a similar story to the EJ score as a categorical variable. It is important to note that when running SAIFI and SAIDI without taking logs, the findings differed. The EJ score as a categorical variable was not shown to be statistically significant in any models, and when using EJ score as a continuous variable, it was only significant in one model (SAIDI exMED) where the relationship was like the univariate analysis (higher EJ scores associated with better SAIDI exMED performance).

As noted earlier, several potential regression assumption violations appear to arise when SAIDI and SAIFI are modeled without transformation, largely due to the strong right skewness of the data. From the model diagnostics, greater confidence can be placed in the SAIDI results than in the SAIFI results. SAIFI tends to follow a more complex distribution, and some regression assumptions may remain violated even after log transformation. In the literature, there is some evidence that SAIDI may follow normal behavior patterns; however, no literature has been identified that describes the distribution of SAIFI.

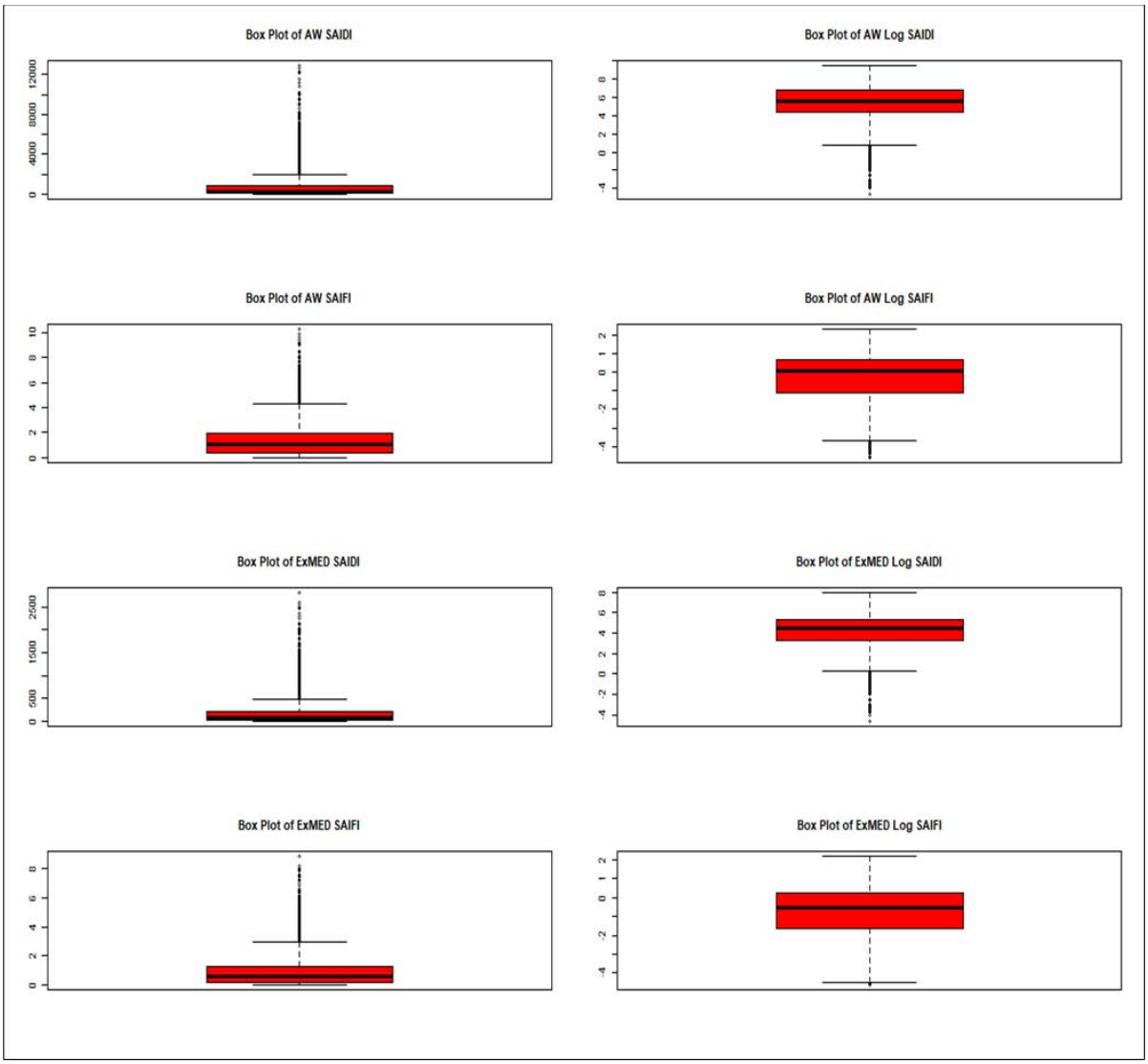
Appendix 8.6.A – Data Directory

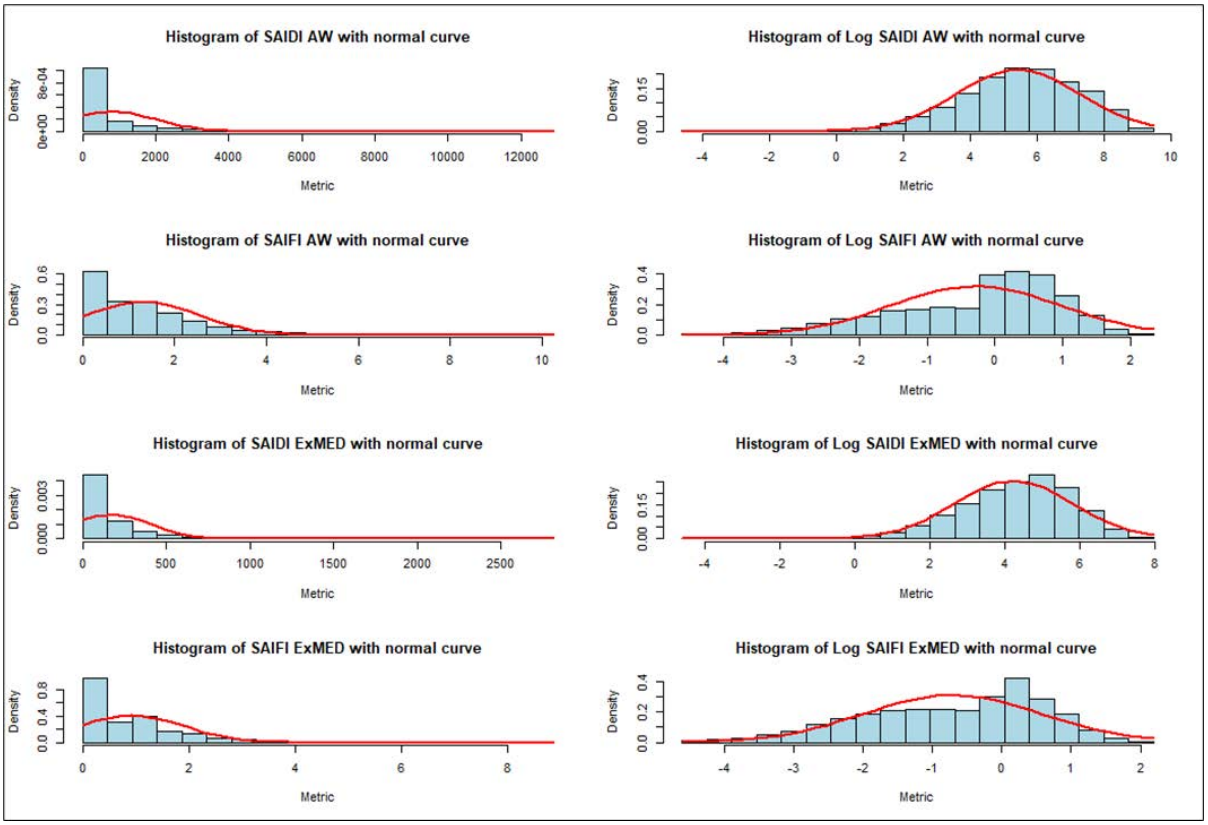
Variable Name	Brief Description	Possible Values it Can Take	Categorical/ Continuous	File
AvgMiEJScore	weighted average of EJ scores based on percent of residential customers that fall within a census tracts. Each census tract has an EJ score. So for example, if census tract 1 has an EJ score of 50 and census tract 2 has an EJ score of 60 than if a circuit has 100 residential customers with 30 in census tract 1 and 70 in census tract 2 the Avg MiEJ Score = $\frac{30}{100} * 50 + \frac{70}{100} * 60 = 57$	0-100	Continuous	RegressionRaw.csv
BuskV	Voltage distribution for the circuit	13.2, 4.8 or 8.3	Categorical	RegressionRaw.csv
CircuitCustBase	Total number of customers served for the circuit (for a given year).	Natural number	Continuous	RegressionRaw.csv
CircuitIDRandomized	Randomized ID for a circuit	Natural number	Categorical	RegressionRaw.csv
EJ_CutOFF	Circuit with AvgMiEJScore of >= 80 take the value of 1. 0 otherwise.	1 or 0	Categorical	Calculated variable in R
IsISO	Indicator if circuit is an ISO circuit. Takes the value of 1 if the percentage of ISO_MILES are >= .8 of the circuit total miles	1 or 0	Categorical	Calculated variable in R
ISO_Percent	Percent of ISO miles for the circuit	Non-negative real number between 0 and 1	Continuous	RegressionRaw.csv
MilesOH	Number of overhead miles for the circuit	Non-negative real number	Continuous	RegressionRaw.csv
MilesUG	Number of underground miles for the circuit	Non-negative real number	Continuous	RegressionRaw.csv
Reg	Region the circuit is located in.	NE, NW, SE, SW	Categorical	RegressionRaw.csv
SAIDI_AW / SAIDI_exMED	Total number of minutes from sustained outages (outages >= 5 minutes) the customers were out of power for that circuit (for a given year) divided by the customer base for that circuit (for a given year). AW = All Weather metric. ExMED excludes any major events days	Non-negative real number	Continuous	RegressionRaw.csv

Variable Name	Brief Description	Possible Values it Can Take	Categorical/ Continuous	File
	defines in (IEEE Power and Energy Society, 2022)			
SAIFI_AW / SAIFI_ExMED	Total number of sustained outages (outages >= 5 minutes) the customers were out of power for that circuit (for a given year) divided by the customer base for that circuit (for a given year). AW = All Weather metric. ExMED excludes any major events days defines in (IEEE Power and Energy Society, 2022)	Non-negative real number	Continuous	RegressionRaw.csv
Year	Calendar year of interest.	Whole number from 2019-2023	Continuous	RegressionRaw.csv
YearsFromSubBuilt	Number of years since the substation was commissioned. Year - SubstationYearsS2	Whole number 0-108	Continuous	RegressionRaw.csv
YearsFromTrim	Number of years have passed since a circuits last Tree Trim from DTEs ETTP Tree Trim program. Cycle is every 5 years therefore value is capped at 5. Circuits never trimmed receive the value of 5. Reference category was “5”.	Whole number from 0-5	Categorical	RegressionRaw.csv

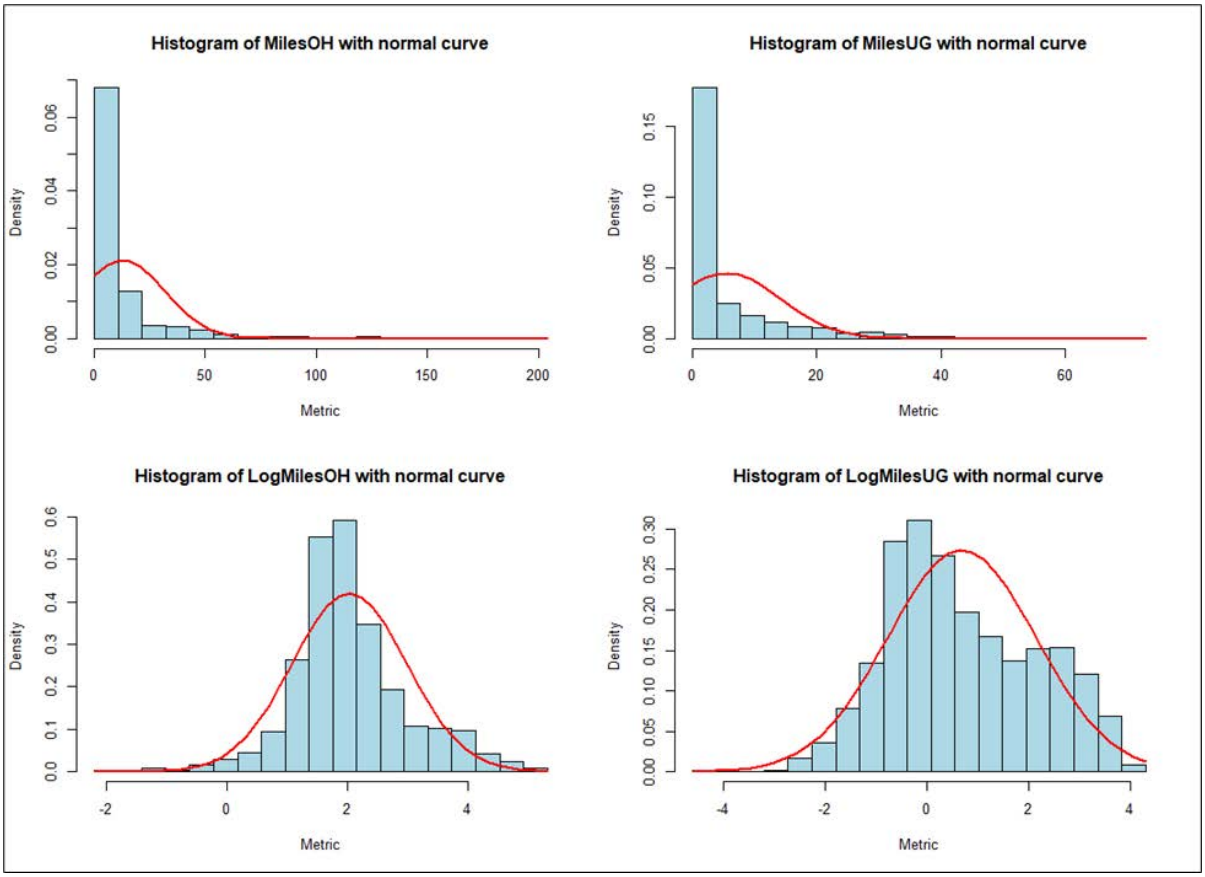
Appendix 8.6.B – Descriptive Statistics of the Dependent Variables

Percentile	SAIDI AW	SAIFI AW	Log SAIDI AW	Log SAIFI AW	SAIDI ExMED	SAIFI ExMED	Log SAIDI ExMED	Log SAIFI ExMED
0%	0.000	0.000	-4.605	-4.605	0.000	0.000	-4.605	-4.605
1%	1.312	0.015	0.279	-3.700	0.647	0.010	-0.421	-3.927
2%	3.402	0.027	1.227	-3.296	1.714	0.019	0.544	-3.528
3%	5.468	0.038	1.701	-3.026	2.876	0.026	1.060	-3.311
4%	7.523	0.048	2.019	-2.840	3.757	0.033	1.326	-3.137
5%	9.462	0.058	2.248	-2.685	4.574	0.040	1.523	-3.002
6%	11.583	0.069	2.450	-2.544	5.528	0.047	1.712	-2.873
7%	13.520	0.078	2.605	-2.435	6.400	0.053	1.858	-2.766
8%	16.195	0.087	2.785	-2.337	7.373	0.059	1.999	-2.681
9%	19.204	0.096	2.956	-2.243	8.237	0.065	2.110	-2.593
10%	21.899	0.106	3.087	-2.151	9.331	0.071	2.234	-2.511
20%	53.689	0.236	3.983	-1.402	20.843	0.140	3.038	-1.895
30%	101.440	0.434	4.620	-0.813	36.166	0.234	3.588	-1.411
40%	167.228	0.771	5.119	-0.248	55.967	0.374	4.025	-0.957
50%	261.059	1.050	5.565	0.058	83.641	0.596	4.427	-0.501
60%	403.048	1.276	5.999	0.252	120.883	0.950	4.795	-0.041
70%	649.925	1.660	6.477	0.513	173.759	1.152	5.158	0.150
80%	1143.268	2.118	7.042	0.755	254.939	1.523	5.541	0.427
90%	2281.369	2.906	7.733	1.070	418.532	2.162	6.037	0.776
91%	2443.488	3.020	7.801	1.109	450.559	2.260	6.111	0.820
92%	2596.182	3.158	7.862	1.153	474.171	2.379	6.162	0.871
93%	2791.039	3.312	7.934	1.201	515.576	2.512	6.245	0.925
94%	3036.107	3.489	8.018	1.253	557.624	2.645	6.324	0.976
95%	3323.806	3.720	8.109	1.316	602.788	2.811	6.402	1.037
96%	3714.606	3.976	8.220	1.383	687.333	3.020	6.533	1.108
97%	4096.603	4.314	8.318	1.464	780.265	3.294	6.660	1.195
98%	4766.759	4.803	8.469	1.571	923.142	3.795	6.828	1.336
99%	5789.974	5.635	8.664	1.731	1165.604	4.547	7.061	1.517
100%	12893.993	10.250	9.465	2.328	2815.470	8.869	7.943	2.184


Box Plot of AW SAIDI
0
4000
8000
12000
Box Plot of AW Log SAIDI
-4
-2
0
2
4
6
8
Box Plot of AW SAIFI
0
2
4
6
8
10
Box Plot of AW Log SAIFI
-4
-2
0
1
2
Box Plot of ExMED SAIDI
0
500
1500
2500
Box Plot of ExMED Log SAIDI
-4
-2
0
2
4
6
8
Box Plot of ExMED SAIFI
0
2
4
6
8
Box Plot of ExMED Log SAIFI
-4
-2
0
1
2


Histogram of SAIDI AW with normal curve
Density
0e+00
8e-04
0
2000
4000
6000
8000
10000
12000
Metric
Histogram of Log SAIDI AW with normal curve
Density
0.00
0.15
-4
-2
0
2
4
6
8
10
Metric
Histogram of SAIFI AW with normal curve
Density
0.0
0.3
0.6
0
2
4
6
8
10
Metric
Histogram of Log SAIFI AW with normal curve
Density
0.0
0.2
0.4
-4
-3
-2
-1
0
1
2
Metric
Histogram of SAIDI ExMED with normal curve
Density
0.000
0.003
0
500
1000
1500
2000
2500
Metric
Histogram of Log SAIDI ExMED with normal curve
Density
0.00
0.15
-4
-2
0
2
4
6
8
Metric
Histogram of SAIFI ExMED with normal curve
Density
0.0
0.4
0.8
0
2
4
6
8
Metric
Histogram of Log SAIFI ExMED with normal curve
Density
0.0
0.2
0.4
-4
-3
-2
-1
0
1
2
Metric

Details on the descriptive statistics for the OH and UG miles variables:



Appendix 8.6.C – Constant Variance Assumptions

Model	P Value from Breusch-Pagan
Log SAIDI (AW/exMED) with EJ as continuous predictor	p = < 2.22e-16
Log SAIDI (AW/exMED) with EJ as categorical predictor	p = < 2.22e-16
Log SAIFI (AW/exMED) with EJ as continuous predictor	p = < 2.22e-16
Log SAIFI (AW/exMED) with EJ as categorical predictor	p = < 2.22e-16

Model	P value from Breusch-Pagan
SAIDI (AW/exMED) with EJ as continuous predictor	p = < 2.22e-16
SAIDI (AW/exMED) with EJ as categorical predictor	p = < 2.22e-16
SAIFI (AW/exMED) with EJ as continuous predictor	p = < 2.22e-16
SAIFI (AW/exMED) with EJ as categorical predictor	p = < 2.22e-16

Appendix 8.6.D – AW Log SAIDI Categorical

	AW Log SAIDI EJ Categorical					
	Estimate	P value fr	Profile Likelihood		Paremetric Bootstrap	
			2.50%	97.50%	2.50%	97.50%
Tau	0.529137		0.479606	0.570301	0.480839565	0.57228
Sigma	1.550595		1.527029	1.573241	1.528386925	1.575711
(Intercept)	2.823764	3.4E-137	2.615375	3.032037	2.628764874	3.01873
EJ_CutOFF	2.71E-01	6.47E-08	1.73E-01	3.68E-01	1.74E-01	3.68E-01
RegNW	0.655827	1.34E-23	0.529237	0.782369	0.530003459	0.778629
RegSE	0.824444	9.7E-43	0.709339	0.939539	0.704165326	0.941149
RegSW	0.725003	4.25E-34	0.610538	0.839445	0.600485979	0.839001
BuskV8.3	0.722022	0.01205	0.160192	1.2839	0.18212622	1.295662
BuskV13.2	0.171928	0.007028	0.047283	0.296475	0.042567522	0.299357
LogMilesOH	0.800862	3.7E-200	0.754119	0.847655	0.755835905	0.847328
LogMilesUG	-0.05567	0.010844	-0.09834	-0.01296	-0.100156599	-0.01066
IsISO	-0.12298	0.650364	-0.65342	0.407418	-0.642678928	0.398043
YearsFromTrim0	-0.20006	3.07E-05	-0.29389	-0.10598	-0.293546823	-0.11003
YearsFromTrim1	-0.41009	2.01E-16	-0.50749	-0.31249	-0.505709327	-0.31266
YearsFromTrim2	-0.33412	7.47E-10	-0.44026	-0.22794	-0.444198057	-0.23436
YearsFromTrim3	-0.17858	0.002219	-0.29277	-0.06425	-0.297779918	-0.06331
YearsFromTrim4	-0.18443	0.009974	-0.32464	-0.04441	-0.321390722	-0.04303
YearsFromSubBuilt	0.002312	0.027174	0.000267	0.004358	0.000365817	0.004434
Year2020	-0.25963	5.61E-08	-0.35323	-0.16607	-0.349102393	-0.16299
Year2021	0.708823	1.07E-48	0.614675	0.802919	0.614724543	0.807303
Year2022	0.104408	0.03276	0.008588	0.200164	0.002742218	0.201093
Year2023	1.279922	2.9E-141	1.182455	1.377335	1.181506232	1.378015
CircuitCustBase	-9.8E-05	0.004255	-0.00017	-3.1E-05	-0.000166749	-3E-05

	AW Log SAIFI EJ Continuous					
	Estimate	P value from LMER	Profile Likelihood		Paremetric Bootstrap	
			2.50%	97.50%	2.50%	97.50%
Tau	3.60E-01		3.25E-01	3.89E-01	3.27E-01	3.89E-01
Sigma	1.08E+00		1.06E+00	1.10E+00	1.07E+00	1.10E+00
(Intercept)	-1.93E+00	5.11E-102	-2.10E+00	-1.76E+00	-2.10E+00	-1.75E+00
AvgMiEJScore	**2.04E-03**	**4.62E-03**	**6.34E-04**	**3.45E-03**	**6.09E-04**	**3.47E-03**
RegNW	3.11E-01	4.94E-12	2.24E-01	3.99E-01	2.24E-01	3.98E-01
RegSE	3.49E-01	2.65E-17	2.69E-01	4.29E-01	2.69E-01	4.36E-01
RegSW	3.34E-01	2.06E-16	2.55E-01	4.12E-01	2.58E-01	4.18E-01
BuskV8.3	1.01E+00	3.73E-07	6.23E-01	1.40E+00	6.50E-01	1.42E+00
BuskV13.2	2.36E-01	1.26E-07	1.49E-01	3.22E-01	1.54E-01	3.24E-01
LogMilesOH	5.40E-01	7.33E-167	5.05E-01	5.75E-01	5.03E-01	5.77E-01
LogMilesUG	-1.43E-02	3.59E-01	-4.47E-02	1.62E-02	-4.49E-02	1.68E-02
IsISO	1.17E-01	5.35E-01	-2.50E-01	4.84E-01	-2.47E-01	4.68E-01
YearsFromTrim0	-9.24E-02	5.63E-03	-1.58E-01	-2.70E-02	-1.57E-01	-2.50E-02
YearsFromTrim1	-2.09E-01	1.71E-09	-2.76E-01	-1.41E-01	-2.77E-01	-1.46E-01
YearsFromTrim2	-2.21E-01	4.63E-09	-2.95E-01	-1.47E-01	-2.96E-01	-1.48E-01
YearsFromTrim3	-1.73E-01	1.94E-05	-2.53E-01	-9.39E-02	-2.55E-01	-9.38E-02
YearsFromTrim4	-1.01E-01	4.28E-02	-1.98E-01	-3.50E-03	-1.90E-01	-8.23E-03
YearsFromSubBuilt	2.30E-03	1.55E-03	8.79E-04	3.71E-03	7.60E-04	3.82E-03
Year2020	-1.15E-01	5.84E-04	-1.80E-01	-4.93E-02	-1.81E-01	-4.82E-02
Year2021	1.69E-01	4.64E-07	1.03E-01	2.34E-01	1.08E-01	2.34E-01
Year2022	-6.35E-02	6.25E-02	-1.30E-01	3.25E-03	-1.28E-01	1.17E-03
Year2023	3.79E-01	1.17E-27	3.11E-01	4.47E-01	3.17E-01	4.46E-01
CircuitCustBase	-5.93E-05	1.56E-02	-1.07E-04	-1.14E-05	-1.09E-04	-1.05E-05

AW Log SAIFI EJ Categorical						
	Estimate	P value from LMER	Profile Likelihood		Paremetric Bootstrap	
			2.50%	97.50%	2.50%	97.50%
Tau	3.59E-01		3.24E-01	3.88E-01	3.24E-01	3.87E-01
Sigma	1.08E+00		1.06E+00	1.10E+00	1.06E+00	1.10E+00
(Intercept	-1.83E+00	1.57E-122	-1.97E+00	-1.69E+00	-1.96E+00	-1.69E+00
EJ_CutOFI	**1.30E-01**	**1.68E-04**	**6.25E-02**	**1.97E-01**	**6.11E-02**	**1.95E-01**
RegNW	3.12E-01	3.66E-12	2.25E-01	4.00E-01	2.26E-01	3.98E-01
RegSE	3.42E-01	7.29E-17	2.62E-01	4.21E-01	2.65E-01	4.23E-01
RegSW	3.46E-01	2.02E-17	2.67E-01	4.25E-01	2.69E-01	4.26E-01
BuskV8.3	9.75E-01	9.40E-07	5.87E-01	1.36E+00	6.09E-01	1.35E+00
BuskV13.2	2.49E-01	1.59E-08	1.63E-01	3.35E-01	1.72E-01	3.36E-01
LogMilesC	5.26E-01	2.87E-184	4.93E-01	5.58E-01	4.92E-01	5.56E-01
LogMilesU	-1.91E-02	2.04E-01	-4.86E-02	1.03E-02	-4.98E-02	9.92E-03
IsISO	9.56E-02	6.10E-01	-2.70E-01	4.62E-01	-2.74E-01	4.31E-01
YearsFrom	-9.50E-02	4.39E-03	-1.60E-01	-2.96E-02	-1.59E-01	-2.84E-02
YearsFrom	-2.12E-01	9.26E-10	-2.80E-01	-1.44E-01	-2.76E-01	-1.43E-01
YearsFrom	-2.24E-01	2.68E-09	-2.98E-01	-1.51E-01	-2.93E-01	-1.51E-01
YearsFrom	-1.76E-01	1.38E-05	-2.56E-01	-9.69E-02	-2.55E-01	-9.86E-02
YearsFrom	-1.03E-01	3.76E-02	-2.01E-01	-6.12E-03	-2.00E-01	-2.92E-03
YearsFrom	2.28E-03	1.63E-03	8.66E-04	3.69E-03	8.23E-04	3.60E-03
Year2020	-1.15E-01	5.77E-04	-1.80E-01	-4.94E-02	-1.81E-01	-5.30E-02
Year2021	1.69E-01	4.60E-07	1.03E-01	2.35E-01	1.05E-01	2.30E-01
Year2022	-6.30E-02	6.43E-02	-1.30E-01	3.68E-03	-1.28E-01	4.64E-03
Year2023	3.80E-01	9.35E-28	3.12E-01	4.47E-01	3.13E-01	4.47E-01
CircuitCus	-4.72E-05	4.70E-02	-9.36E-05	-7.61E-07	-9.41E-05	2.09E-06

ExMED Log SAIDI EJ Continuous						
	Estimate	P value fr	Profile Likelihood		Paremetric Bootstrap	
			2.50%	97.50%	2.50%	97.50%
Tau	4.52E-01		4.84E-01	5.74E-01	4.09E-01	4.90E-01
Sigma	1.37E+00		1.53E+00	1.57E+00	1.35E+00	1.39E+00
(Intercept	2.33E+00	8.35E-94	2.37E+00	2.86E+00	2.12E+00	2.56E+00
AvgMiEJS(	**4.34E-03**	**1.99E-06**	**2.15E-03**	**6.24E-03**	**2.54E-03**	**6.07E-03**
RegNW	3.19E-01	1.92E-08	5.26E-01	7.80E-01	2.04E-01	4.33E-01
RegSE	5.13E-01	1.20E-22	7.25E-01	9.58E-01	4.16E-01	6.09E-01
RegSW	2.64E-01	2.33E-07	5.85E-01	8.13E-01	1.65E-01	3.72E-01
BuskV8.3	1.56E+00	5.16E-10	2.35E-01	1.36E+00	1.07E+00	2.03E+00
BuskV13.2	3.99E-01	1.62E-12	1.73E-02	2.69E-01	2.93E-01	5.11E-01
LogMilesC	7.21E-01	5.95E-183	7.78E-01	8.80E-01	6.76E-01	7.64E-01
LogMilesL	1.28E-02	5.17E-01	-9.00E-02	-1.76E-03	-2.47E-02	4.88E-02
IsISO	-6.51E-02	7.84E-01	-6.12E-01	4.53E-01	-5.12E-01	4.37E-01
YearsFrom	-1.73E-01	4.19E-05	-2.88E-01	-1.00E-01	-2.57E-01	-9.52E-02
YearsFrom	-2.87E-01	6.79E-11	-5.00E-01	-3.05E-01	-3.78E-01	-1.99E-01
YearsFrom	-2.82E-01	3.85E-09	-4.33E-01	-2.21E-01	-3.75E-01	-1.93E-01
YearsFrom	-2.27E-01	9.82E-06	-2.87E-01	-5.80E-02	-3.33E-01	-1.27E-01
YearsFrom	-9.18E-02	1.46E-01	-3.19E-01	-3.89E-02	-2.18E-01	3.37E-02
YearsFrom	1.81E-03	4.86E-02	3.01E-04	4.41E-03	-3.44E-05	3.54E-03
Year2020	-1.67E-01	8.10E-05	-3.53E-01	-1.66E-01	-2.51E-01	-8.24E-02
Year2021	-2.13E-01	5.52E-07	6.15E-01	8.03E-01	-2.92E-01	-1.28E-01
Year2022	-2.03E-01	2.56E-06	7.66E-03	1.99E-01	-2.90E-01	-1.18E-01
Year2023	3.24E-02	4.62E-01	1.18E+00	1.38E+00	-4.92E-02	1.15E-01
CircuitCus	-1.85E-04	3.03E-09	-1.93E-04	-5.36E-05	-2.48E-04	-1.28E-04

ExMED Log SAIDI EJ Categorical						
	Estimate	P value fr	Profile Likelihood		Paremetric Bootstrap	
			2.50%	97.50%	2.50%	97.50%
Tau	4.49E-01		4.04E-01	4.86E-01	4.04E-01	4.84E-01
Sigma	1.37E+00		1.35E+00	1.39E+00	1.35E+00	1.39E+00
(Intercept	2.55E+00	7.92E-146	2.37E+00	2.73E+00	2.36E+00	2.74E+00
EJ_CutOFF	2.53E-01	6.81E-09	1.68E-01	3.38E-01	1.64E-01	3.38E-01
RegNW	3.19E-01	1.71E-08	2.09E-01	4.30E-01	2.10E-01	4.27E-01
RegSE	5.04E-01	2.76E-22	4.03E-01	6.04E-01	4.04E-01	6.02E-01
RegSW	2.88E-01	1.90E-08	1.88E-01	3.88E-01	1.82E-01	3.86E-01
BuskV8.3	1.51E+00	1.98E-09	1.02E+00	2.00E+00	1.01E+00	1.98E+00
BuskV13.2	4.29E-01	1.64E-14	3.21E-01	5.38E-01	3.18E-01	5.36E-01
LogMilesC	6.90E-01	2.65E-196	6.49E-01	7.31E-01	6.49E-01	7.32E-01
LogMilesU	1.13E-03	9.53E-01	-3.61E-02	3.83E-02	-3.61E-02	3.63E-02
IsISO	-1.11E-01	6.39E-01	-5.73E-01	3.51E-01	-5.58E-01	3.76E-01
YearsFrom	-1.78E-01	2.46E-05	-2.61E-01	-9.55E-02	-2.63E-01	-9.20E-02
YearsFrom	-2.93E-01	2.49E-11	-3.79E-01	-2.07E-01	-3.81E-01	-2.10E-01
YearsFrom	-2.88E-01	1.67E-09	-3.81E-01	-1.95E-01	-3.77E-01	-1.90E-01
YearsFrom	-2.33E-01	5.80E-06	-3.34E-01	-1.32E-01	-3.29E-01	-1.32E-01
YearsFrom	-9.68E-02	1.25E-01	-2.20E-01	2.66E-02	-2.19E-01	2.10E-02
YearsFrom	1.82E-03	4.65E-02	3.33E-05	3.60E-03	4.60E-05	3.62E-03
Year2020	-1.67E-01	7.83E-05	-2.50E-01	-8.42E-02	-2.57E-01	-8.11E-02
Year2021	-2.13E-01	5.38E-07	-2.96E-01	-1.30E-01	-2.99E-01	-1.27E-01
Year2022	-2.03E-01	2.74E-06	-2.88E-01	-1.18E-01	-2.91E-01	-1.24E-01
Year2023	3.35E-02	4.47E-01	-5.27E-02	1.20E-01	-5.77E-02	1.22E-01
CircuitCus	-1.58E-04	1.55E-07	-2.17E-04	-9.92E-05	-2.16E-04	-9.81E-05

	ExMED Log SAIFI EJ Continuous					
	Estimate	P value from LMER	Profile Likelihood		Paremetric Bootstrap	
			2.50%	97.50%	2.50%	97.50%
Tau	3.54E-01		3.17E-01	3.85E-01	3.18E-01	3.86E-01
Sigma	1.12E+00		1.11E+00	1.14E+00	1.11E+00	1.14E+00
(Intercept)	-2.18E+00	7.65E-122	-2.35E+00	-2.01E+00	-2.35E+00	-2.01E+00
AvgMiEJScore	**2.69E-03**	**2.54E-04**	**1.26E-03**	**4.13E-03**	**1.26E-03**	**4.08E-03**
RegNW	2.35E-01	3.09E-07	1.45E-01	3.24E-01	1.49E-01	3.23E-01
RegSE	2.70E-01	1.34E-10	1.88E-01	3.51E-01	1.86E-01	3.52E-01
RegSW	2.09E-01	4.07E-07	1.29E-01	2.89E-01	1.25E-01	2.90E-01
BuskV8.3	1.39E+00	8.07E-12	9.96E-01	1.79E+00	9.94E-01	1.78E+00
BuskV13.2	3.94E-01	6.73E-18	3.06E-01	4.83E-01	3.06E-01	4.83E-01
LogMilesOH	5.15E-01	2.29E-148	4.79E-01	5.51E-01	4.76E-01	5.49E-01
LogMilesUG	8.14E-04	9.59E-01	-3.02E-02	3.19E-02	-3.19E-02	2.93E-02
IsISO	1.04E-01	5.89E-01	-2.71E-01	4.78E-01	-2.62E-01	4.86E-01
YearsFromTrim0	-6.78E-02	4.95E-02	-1.35E-01	-1.25E-04	-1.34E-01	1.50E-03
YearsFromTrim1	-1.62E-01	6.05E-06	-2.32E-01	-9.19E-02	-2.30E-01	-9.36E-02
YearsFromTrim2	-1.67E-01	1.75E-05	-2.44E-01	-9.12E-02	-2.44E-01	-8.95E-02
YearsFromTrim3	-1.91E-01	5.11E-06	-2.74E-01	-1.09E-01	-2.76E-01	-1.13E-01
YearsFromTrim4	-5.11E-02	3.21E-01	-1.52E-01	4.96E-02	-1.48E-01	4.46E-02
YearsFromSubBuilt	2.33E-03	1.69E-03	8.79E-04	3.77E-03	7.85E-04	3.74E-03
Year2020	-6.92E-02	4.58E-02	-1.37E-01	-1.34E-03	-1.37E-01	-1.51E-03
Year2021	-1.64E-01	2.52E-06	-2.32E-01	-9.58E-02	-2.30E-01	-9.77E-02
Year2022	-1.03E-01	3.77E-03	-1.72E-01	-3.32E-02	-1.66E-01	-2.96E-02
Year2023	-9.07E-02	1.18E-02	-1.61E-01	-2.02E-02	-1.64E-01	-2.12E-02
CircuitCustBase	-8.58E-05	6.31E-04	-1.35E-04	-3.68E-05	-1.31E-04	-3.41E-05

ExMED Log SAIFI EJ Categorical						
	Estimate	P value from LMER	Profile Likelihood		Paremetric Bootstrap	
			2.50%	97.50%	2.50%	97.50%
Tau	3.52E-01		3.15E-01	3.83E-01	3.17E-01	3.84E-01
Sigma	1.12E+00		1.11E+00	1.14E+00	1.11E+00	1.14E+00
(Intercept	-2.04E+00	1.77E-143	-2.19E+00	-1.90E+00	-2.20E+00	-1.90E+00
EJ_CutOFF	**1.63E-01**	**3.72E-06**	**9.43E-02**	**2.32E-01**	**9.86E-02**	**2.32E-01**
RegNW	2.35E-01	2.65E-07	1.46E-01	3.24E-01	1.45E-01	3.26E-01
RegSE	2.62E-01	3.03E-10	1.81E-01	3.43E-01	1.78E-01	3.44E-01
RegSW	2.24E-01	5.89E-08	1.44E-01	3.05E-01	1.43E-01	3.06E-01
BuskV8.3	1.35E+00	3.04E-11	9.56E-01	1.75E+00	9.62E-01	1.74E+00
BuskV13.2	4.13E-01	8.02E-20	3.25E-01	5.01E-01	3.28E-01	5.08E-01
LogMilesC	4.96E-01	2.94E-161	4.63E-01	5.29E-01	4.60E-01	5.30E-01
LogMilesU	-6.10E-03	6.92E-01	-3.62E-02	2.40E-02	-3.61E-02	2.25E-02
IsISO	7.55E-02	6.93E-01	-2.98E-01	4.49E-01	-2.95E-01	4.51E-01
YearsFrom	-7.12E-02	3.92E-02	-1.39E-01	-3.52E-03	-1.36E-01	-6.43E-04
YearsFrom	-1.66E-01	3.39E-06	-2.37E-01	-9.63E-02	-2.42E-01	-9.66E-02
YearsFrom	-1.72E-01	1.06E-05	-2.48E-01	-9.55E-02	-2.49E-01	-9.80E-02
YearsFrom	-1.95E-01	3.29E-06	-2.77E-01	-1.13E-01	-2.85E-01	-1.07E-01
YearsFrom	-5.44E-02	2.91E-01	-1.55E-01	4.63E-02	-1.55E-01	3.73E-02
YearsFrom	2.32E-03	1.67E-03	8.79E-04	3.76E-03	9.91E-04	3.84E-03
Year2020	-6.94E-02	4.53E-02	-1.37E-01	-1.50E-03	-1.35E-01	-3.99E-03
Year2021	-1.64E-01	2.50E-06	-2.32E-01	-9.58E-02	-2.32E-01	-9.94E-02
Year2022	-1.02E-01	3.94E-03	-1.72E-01	-3.28E-02	-1.76E-01	-3.14E-02
Year2023	-9.00E-02	1.25E-02	-1.61E-01	-1.94E-02	-1.64E-01	-2.25E-02
CircuitCus	-6.94E-05	4.26E-03	-1.17E-04	-2.20E-05	-1.18E-04	-2.25E-05

Below are the results from the Hausman test for two of our models. As can be seen, the p-value is very small, indicating that a statistical difference between the two models is present and that the endogeneity assumption of the random effects may be violated. It should be noted that the test compares only the time-varying coefficients, despite the code suggesting that time-invariant features were included in the fixed-effects model. Those features are simply set to zero by the model.

```
> fe_model_Log_AW_Factor_SAIDI <- plm(LogSAIDI_AW~EJ_CutOFF+Reg+BuskV+ LogMilesOH  + LogMilesUG +IsISO +YearsFromTrim+ YearsFromSubBuilt+Year+CircuitCustBase,
+                 data = DataFinal,
+                 index = c("CircuitIDRandomized", "Year"),
+                 model = "within")
> lmm_model_Log_AW_Factor_SAIDI <- plm(LogSAIDI_AW~EJ_CutOFF+Reg+BuskV+ LogMilesOH  + LogMilesUG +IsISO +YearsFromTrim+ YearsFromSubBuilt+Year+CircuitCustBase,
+                 data = DataFinal,
+                 index = c("CircuitIDRandomized", "Year"),
+                 model = "random")
> phtest(fe_model_Log_AW_Factor_SAIDI, lmm_model_Log_AW_Factor_SAIDI)

        Hausman Test

data:  LogSAIDI_AW ~ EJ_CutOFF + Reg + BuskV + LogMilesOH + LogMilesUG +  ...
chisq = 50, df = 12, p-value = 1e-06
alternative hypothesis: one model is inconsistent

>
> fe_model_Log_AW_Con_SAIDI <- plm(LogSAIDI_AW~AvgMiEJScore+Reg+BuskV+ LogMilesOH  + LogMilesUG +IsISO +YearsFromTrim+ YearsFromSubBuilt+Year+CircuitCustBase,
+                                  data = DataFinal,
+                                  index = c("CircuitIDRandomized", "Year"),
+                                  model = "within")
> lmm_model_Log_AW_Con_SAIDI <- plm(LogSAIDI_AW~AvgMiEJScore+Reg+BuskV+ LogMilesOH  + LogMilesUG +IsISO +YearsFromTrim+ YearsFromSubBuilt+Year+CircuitCustBase,
+                                   data = DataFinal,
+                                   index = c("CircuitIDRandomized", "Year"),
+                                   model = "random")
> phtest(fe_model_Log_AW_Con_SAIDI, lmm_model_Log_AW_Con_SAIDI)

        Hausman Test

data:  LogSAIDI_AW ~ AvgMiEJScore + Reg + BuskV + LogMilesOH + LogMilesUG +  ...
chisq = 53, df = 12, p-value = 4e-07
alternative hypothesis: one model is inconsistent
```

Below are the results from the other 7 GEE models:

AW Log SAIDI EJ Categorical

```
Call:
geeglm(formula = LogSAIDI_AW ~ EJ_CutOFF + Reg + BuskV + LogMilesOH
    LogMilesUG + IsISO + YearsFromTrim + YearsFromSubBuilt +
    Year + CircuitCustBase, data = DataFinal, id = CircuitIDRandomi
    corstr = "exchangeable")

 Coefficients:
                  Estimate   Std.err    Wald Pr(>|W|)
(Intercept)       2.82e+00  9.60e-02  862.12  < 2e-16 ***
EJ_CutOFF         2.73e-01  4.41e-02   38.14  6.6e-10 ***
RegNW             6.52e-01  5.05e-02  166.75  < 2e-16 ***
RegSE             8.23e-01  5.20e-02  250.32  < 2e-16 ***
RegSW             7.23e-01  4.97e-02  211.83  < 2e-16 ***
BuskV8.3          7.22e-01  1.81e-01   15.98  6.4e-05 ***
BuskV13.2         1.67e-01  5.29e-02    9.95  0.00161 **
LogMilesOH        8.04e-01  2.35e-02 1165.84  < 2e-16 ***
LogMilesUG       -5.40e-02  1.91e-02    8.03  0.00461 **
IsISO            -1.28e-01  1.58e-01    0.65  0.42039
YearsFromTrim0   -1.87e-01  4.91e-02   14.47  0.00014 ***
YearsFromTrim1   -4.00e-01  4.93e-02   66.04  4.4e-16 ***
YearsFromTrim2   -3.33e-01  5.36e-02   38.69  5.0e-10 ***
YearsFromTrim3   -1.71e-01  5.77e-02    8.79  0.00302 **
YearsFromTrim4   -1.98e-01  6.61e-02    8.95  0.00277 **
YearsFromSubBuilt 2.31e-03  8.51e-04    7.35  0.00670 **
Year2020         -2.61e-01  4.93e-02   27.99  1.2e-07 ***
Year2021          7.07e-01  5.11e-02  191.20  < 2e-16 ***
Year2022          1.02e-01  5.20e-02    3.83  0.05044 .
Year2023          1.28e+00  5.09e-02  629.50  < 2e-16 ***
CircuitCustBase  -9.71e-05  2.68e-05   13.11  0.00029 ***
---
Signif. codes:  0 ‘***’ 0.001 ‘**’ 0.01 ‘*’ 0.05 ‘.’ 0.1 ‘ ’ 1

Correlation structure = exchangeable
Estimated Scale Parameters:

            Estimate Std.err
(Intercept)     2.68  0.0484
  Link = identity

Estimated Correlation Parameters:
      Estimate Std.err
alpha        0       0
Number of clusters:   10847  Maximum cluster size: 1
```

AW Log SAIFI EJ Continuous

```
Call:
geeglm(formula = LogSAIFI_AW ~ AvgMiEJScore + Reg + BuskV + LogMilesOH +
    LogMilesUG + IsISO + YearsFromTrim + YearsFromSubBuilt +
    Year + CircuitCustBase, data = DataFinal, id = CircuitIDRandomized,
    corstr = "exchangeable")

 Coefficients:
                   Estimate   Std.err    Wald Pr(>|W|)
(Intercept)       -1.94e+00  8.01e-02  585.13  < 2e-16 ***
AvgMiEJScore       2.11e-03  6.39e-04   10.94  0.00094 ***
RegNW              3.09e-01  3.68e-02   70.28  < 2e-16 ***
RegSE              3.47e-01  3.63e-02   91.43  < 2e-16 ***
RegSW              3.32e-01  3.52e-02   88.81  < 2e-16 ***
BuskV8.3           1.00e+00  1.34e-01   56.47  5.7e-14 ***
BuskV13.2          2.32e-01  3.83e-02   36.63  1.4e-09 ***
LogMilesOH         5.42e-01  1.71e-02 1000.42  < 2e-16 ***
LogMilesUG        -1.26e-02  1.39e-02    0.82  0.36541
IsISO              1.16e-01  1.18e-01    0.98  0.32177
YearsFromTrim0    -8.30e-02  3.33e-02    6.21  0.01270 *
YearsFromTrim1    -2.02e-01  3.48e-02   33.63  6.7e-09 ***
YearsFromTrim2    -2.20e-01  3.71e-02   35.04  3.2e-09 ***
YearsFromTrim3    -1.70e-01  4.01e-02   17.98  2.2e-05 ***
YearsFromTrim4    -1.13e-01  4.64e-02    5.97  0.01459 *
YearsFromSubBuilt  2.29e-03  6.08e-04   14.16  0.00017 ***
Year2020          -1.15e-01  3.61e-02   10.21  0.00140 **
Year2021           1.68e-01  3.56e-02   22.30  2.3e-06 ***
Year2022          -6.45e-02  3.65e-02    3.12  0.07751 .
Year2023           3.78e-01  3.57e-02  112.23  < 2e-16 ***
CircuitCustBase   -5.97e-05  1.99e-05    8.95  0.00277 **
---
Signif. codes:  0 ‘***’ 0.001 ‘**’ 0.01 ‘*’ 0.05 ‘.’ 0.1 ‘ ’ 1

Correlation structure = exchangeable
Estimated Scale Parameters:

            Estimate Std.err
(Intercept)     1.29  0.0167
  Link = identity

Estimated Correlation Parameters:
      Estimate Std.err
alpha        0       0
Number of clusters:   10847  Maximum cluster size: 1
```

AW Log SAIFI EJ Continuous

```
Call:
geeglm(formula = LogSAIFI_AW ~ EJ_CutOFF + Reg + BuskV + LogMilesOH +
    LogMilesUG + IsISO + YearsFromTrim + YearsFromSubBuilt +
    Year + CircuitCustBase, data = DataFinal, id = CircuitIDRandomized,
    corstr = "exchangeable")

 Coefficients:
                   Estimate   Std.err     Wald Pr(>|W|)
(Intercept)       -1.83e+00  6.72e-02  743.03  < 2e-16 ***
EJ_CutOFF          1.31e-01  3.02e-02   18.80  1.5e-05 ***
RegNW              3.10e-01  3.67e-02   71.37  < 2e-16 ***
RegSE              3.40e-01  3.64e-02   87.40  < 2e-16 ***
RegSW              3.44e-01  3.53e-02   95.25  < 2e-16 ***
BuskV8.3           9.71e-01  1.34e-01   52.64  4.0e-13 ***
BuskV13.2          2.47e-01  3.77e-02   42.69  6.4e-11 ***
LogMilesOH         5.27e-01  1.52e-02 1202.29  < 2e-16 ***
LogMilesUG        -1.80e-02  1.33e-02    1.82  0.17686
IsISO              9.48e-02  1.17e-01    0.66  0.41652
YearsFromTrim0    -8.63e-02  3.34e-02    6.69  0.00970 **
YearsFromTrim1    -2.06e-01  3.49e-02   35.01  3.3e-09 ***
YearsFromTrim2    -2.24e-01  3.71e-02   36.37  1.6e-09 ***
YearsFromTrim3    -1.73e-01  4.01e-02   18.70  1.5e-05 ***
YearsFromTrim4    -1.16e-01  4.64e-02    6.25  0.01244 *
YearsFromSubBuilt  2.28e-03  6.05e-04   14.21  0.00016 ***
Year2020          -1.15e-01  3.61e-02   10.23  0.00138 **
Year2021           1.68e-01  3.56e-02   22.32  2.3e-06 ***
Year2022          -6.40e-02  3.65e-02    3.07  0.07995 .
Year2023           3.79e-01  3.57e-02  112.80  < 2e-16 ***
CircuitCustBase   -4.66e-05  1.91e-05    5.96  0.01464 *
---
Signif. codes:  0 ‘***’ 0.001 ‘**’ 0.01 ‘*’ 0.05 ‘.’ 0.1 ‘ ’ 1

Correlation structure = exchangeable
Estimated Scale Parameters:

            Estimate Std.err
(Intercept)     1.29  0.0167
  Link = identity

Estimated Correlation Parameters:
      Estimate Std.err
alpha        0       0
Number of clusters:   10847  Maximum cluster size: 1
```

AW Log SAIFI EJ Categorical

```
Call:
geeglm(formula = LogSAIDI_ExMED ~ AvgMiEJScore + Reg + BuskV +
    LogMilesOH + LogMilesUG + IsISO + YearsFromTrim + YearsFromSubBuilt +
    Year + CircuitCustBase, data = DataFinal, id = CircuitIDRandomized,
    corstr = "exchangeable")

 Coefficients:
                  Estimate   Std.err   Wald Pr(>|W|)
(Intercept)       2.32e+00  1.06e-01 477.09  < 2e-16 ***
AvgMiEJScore      4.42e-03  8.47e-04  27.20  1.8e-07 ***
RegNW             3.17e-01  4.54e-02  48.83  2.8e-12 ***
RegSE             5.09e-01  4.52e-02 127.06  < 2e-16 ***
RegSW             2.61e-01  4.42e-02  34.92  3.4e-09 ***
BuskV8.3          1.57e+00  1.89e-01  69.18  < 2e-16 ***
BuskV13.2         3.98e-01  4.78e-02  69.25  < 2e-16 ***
LogMilesOH        7.24e-01  2.45e-02 876.51  < 2e-16 ***
LogMilesUG        1.37e-02  1.77e-02   0.60  0.43852
IsISO            -7.11e-02  1.58e-01   0.20  0.65218
YearsFromTrim0   -1.61e-01  4.27e-02  14.21  0.00016 ***
YearsFromTrim1   -2.73e-01  4.46e-02  37.53  9.0e-10 ***
YearsFromTrim2   -2.79e-01  4.68e-02  35.66  2.4e-09 ***
YearsFromTrim3   -2.20e-01  4.96e-02  19.63  9.4e-06 ***
YearsFromTrim4   -9.73e-02  5.89e-02   2.73  0.09863 .
YearsFromSubBuilt 1.79e-03  7.73e-04   5.37  0.02052 *
Year2020         -1.68e-01  4.59e-02  13.42  0.00025 ***
Year2021         -2.14e-01  4.55e-02  22.16  2.5e-06 ***
Year2022         -2.05e-01  4.60e-02  19.88  8.3e-06 ***
Year2023          3.05e-02  4.46e-02   0.47  0.49429
CircuitCustBase  -1.86e-04  2.52e-05  54.50  1.6e-13 ***
---
Signif. codes:  0 ‘***’ 0.001 ‘**’ 0.01 ‘*’ 0.05 ‘.’ 0.1 ‘ ’ 1

Correlation structure = exchangeable
Estimated Scale Parameters:

            Estimate Std.err
(Intercept)     2.08  0.0412
  Link = identity

Estimated Correlation Parameters:
      Estimate Std.err
alpha        0       0
Number of clusters:   10847  Maximum cluster size: 1
```

exMED Log SAIDI EJ Categorical

```
Call:
geeglm(formula = LogSAIDI_ExMED ~ EJ_CutOFF + Reg + BuskV + LogMilesOH +
    LogMilesUG + IsISO + YearsFromTrim + YearsFromSubBuilt +
    Year + CircuitCustBase, data = DataFinal, id = CircuitIDRandomized,
    corstr = "exchangeable")

 Coefficients:
                  Estimate   Std.err    Wald Pr(>|W|)
(Intercept)       2.55e+00  8.65e-02  867.06  < 2e-16 ***
EJ_CutOFF         2.54e-01  3.95e-02   41.56  1.1e-10 ***
RegNW             3.17e-01  4.50e-02   49.58  1.9e-12 ***
RegSE             5.01e-01  4.58e-02  119.55  < 2e-16 ***
RegSW             2.85e-01  4.44e-02   41.26  1.3e-10 ***
BuskV8.3          1.52e+00  1.89e-01   64.57  8.9e-16 ***
BuskV13.2         4.29e-01  4.69e-02   83.70  < 2e-16 ***
LogMilesOH        6.92e-01  2.15e-02 1040.70  < 2e-16 ***
LogMilesUG        1.37e-03  1.69e-02    0.01  0.93517
IsISO            -1.17e-01  1.55e-01    0.58  0.44789
YearsFromTrim0   -1.67e-01  4.28e-02   15.27  9.3e-05 ***
YearsFromTrim1   -2.81e-01  4.47e-02   39.68  3.0e-10 ***
YearsFromTrim2   -2.87e-01  4.68e-02   37.59  8.7e-10 ***
YearsFromTrim3   -2.26e-01  4.96e-02   20.83  5.0e-06 ***
YearsFromTrim4   -1.02e-01  5.89e-02    3.02  0.08215 .
YearsFromSubBuilt 1.81e-03  7.68e-04    5.56  0.01839 *
Year2020         -1.68e-01  4.58e-02   13.48  0.00024 ***
Year2021         -2.14e-01  4.55e-02   22.17  2.5e-06 ***
Year2022         -2.04e-01  4.60e-02   19.71  9.0e-06 ***
Year2023          3.18e-02  4.45e-02    0.51  0.47500
CircuitCustBase  -1.58e-04  2.41e-05   42.86  5.9e-11 ***
---
Signif. codes:  0 ‘***’ 0.001 ‘**’ 0.01 ‘*’ 0.05 ‘.’ 0.1 ‘ ’ 1

Correlation structure = exchangeable
Estimated Scale Parameters:

            Estimate Std.err
(Intercept)     2.08  0.0412
  Link = identity

Estimated Correlation Parameters:
      Estimate Std.err
alpha        0       0
Number of clusters:   10847  Maximum cluster size: 1
```

exMED Log SAIFI EJ Continuous

```
Call:
geeglm(formula = LogSAIFI_ExMED ~ AvgMiEJScore + Reg + BuskV +
    LogMilesOH + LogMilesUG + IsISO + YearsFromTrim + YearsFromSubBuilt +
    Year + CircuitCustBase, data = DataFinal, id = CircuitIDRandomized,
    corstr = "exchangeable")

 Coefficients:
                  Estimate   Std.err   Wald Pr(>|W|)
(Intercept)      -2.19e+00  8.22e-02 707.20  < 2e-16 ***
AvgMiEJScore      2.76e-03  6.64e-04  17.26  3.3e-05 ***
RegNW             2.33e-01  3.82e-02  37.32  1.0e-09 ***
RegSE             2.68e-01  3.70e-02  52.39  4.6e-13 ***
RegSW             2.07e-01  3.62e-02  32.77  1.0e-08 ***
BuskV8.3          1.38e+00  1.34e-01 106.48  < 2e-16 ***
BuskV13.2         3.92e-01  3.98e-02  96.99  < 2e-16 ***
LogMilesOH        5.17e-01  1.75e-02 875.29  < 2e-16 ***
LogMilesUG        1.93e-03  1.43e-02   0.02  0.89274
IsISO             1.03e-01  1.38e-01   0.56  0.45458
YearsFromTrim0   -5.98e-02  3.45e-02   3.01  0.08276 .
YearsFromTrim1   -1.56e-01  3.64e-02  18.49  1.7e-05 ***
YearsFromTrim2   -1.68e-01  3.86e-02  19.00  1.3e-05 ***
YearsFromTrim3   -1.92e-01  4.11e-02  21.71  3.2e-06 ***
YearsFromTrim4   -6.05e-02  4.83e-02   1.57  0.21057
YearsFromSubBuilt 2.31e-03  6.33e-04  13.27  0.00027 ***
Year2020         -7.00e-02  3.68e-02   3.62  0.05722 .
Year2021         -1.64e-01  3.71e-02  19.68  9.2e-06 ***
Year2022         -1.03e-01  3.74e-02   7.59  0.00588 **
Year2023         -9.12e-02  3.68e-02   6.13  0.01329 *
CircuitCustBase  -8.63e-05  2.09e-05  17.03  3.7e-05 ***
---
Signif. codes:  0 '***' 0.001 '**' 0.01 '*' 0.05 '.' 0.1 ' ' 1

Correlation structure = exchangeable
Estimated Scale Parameters:

            Estimate Std.err
(Intercept)     1.39  0.0159
  Link = identity

Estimated Correlation Parameters:
      Estimate Std.err
alpha        0       0
Number of clusters:   10847  Maximum cluster size: 1
```

exMED Log SAIFI EJ Categorical

```
Call:
geeglm(formula = LogSAIFI_ExMED ~ EJ_CutOFF + Reg + BuskV + LogMilesOH +
    LogMilesUG + IsISO + YearsFromTrim + YearsFromSubBuilt +
    Year + CircuitCustBase, data = DataFinal, id = CircuitIDRandomized,
    corstr = "exchangeable")

 Coefficients:
                  Estimate   Std.err    Wald Pr(>|W|)
(Intercept)      -2.045977  0.068886  882.15  < 2e-16 ***
EJ_CutOFF         0.164108  0.031267   27.55  1.5e-07 ***
RegNW             0.233611  0.038037   37.72  8.2e-10 ***
RegSE             0.261126  0.037144   49.42  2.1e-12 ***
RegSW             0.222792  0.036320   37.63  8.6e-10 ***
BuskV8.3          1.347135  0.134514  100.30  < 2e-16 ***
BuskV13.2         0.411158  0.039202  110.00  < 2e-16 ***
LogMilesOH        0.496833  0.015433 1036.34  < 2e-16 ***
LogMilesUG       -0.005500  0.013712    0.16  0.68835
IsISO             0.074548  0.136502    0.30  0.58498
YearsFromTrim0   -0.063747  0.034469    3.42  0.06440 .
YearsFromTrim1   -0.161724  0.036390   19.75  8.8e-06 ***
YearsFromTrim2   -0.173197  0.038606   20.13  7.2e-06 ***
YearsFromTrim3   -0.195862  0.041168   22.64  2.0e-06 ***
YearsFromTrim4   -0.063699  0.048274    1.74  0.18700
YearsFromSubBuilt  0.002308  0.000630   13.43  0.00025 ***
Year2020         -0.070048  0.036775    3.63  0.05681 .
Year2021         -0.164435  0.037061   19.69  9.1e-06 ***
Year2022         -0.102344  0.037373    7.50  0.00617 **
Year2023         -0.090252  0.036801    6.01  0.01419 *
CircuitCustBase  -0.000069  0.000020   11.87  0.00057 ***
---
Signif. codes:  0 ‘***’ 0.001 ‘**’ 0.01 ‘*’ 0.05 ‘.’ 0.1 ‘ ’ 1

Correlation structure = exchangeable
Estimated Scale Parameters:

            Estimate Std.err
(Intercept)     1.39  0.0158
  Link = identity

Estimated Correlation Parameters:
      Estimate Std.err
alpha        0       0
Number of clusters:   10847  Maximum cluster size: 1
```

Exhibit 8.6.E – Bibliography

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8.8 Environmental Justice Changing Demographic Analysis

The changing demographic analysis presents a statistically rigorous comparison of selected census tract–level demographic and socioeconomic metrics derived from the American Community Survey (ACS) 5-year estimates for 2015–2019 and 2020–2024.

Census tracts were classified using the Michigan Environmental Justice Screen percentile score (MiEJScorePL) (Michigan Department of Environment, Great Lakes, and Energy, 2023). Tracts with MiEJScorePL ≥ 80 were designated vulnerable, and those with MiEJScorePL < 80 were designated non-vulnerable.

The analysis evaluates:

1) Temporal changes within vulnerable and non-vulnerable groups
2) Differences between groups at each time point
3) Difference-in-differences (interaction between time and vulnerability status)
4) Tract-level changes across time
5) Statistical reliability using design-consistent variance estimation
6) Multiple testing adjustments using False Discovery Rate (FDR) procedures

Variance estimation relies on ACS 5-year Variance Replicate Estimate Tables constructed using Successive Difference Replication (SDR) (U.S. Census Bureau, 2024). Replicate-based estimation preserves the complex survey design, including stratification, clustering, and unequal weighting.

To address multiplicity at the tract level, both the Benjamini–Hochberg (BH) procedure (Benjamini & Hochberg, Controlling the false discovery rate: A practical and powerful approach to multiple testing, 1995) and the more conservative Benjamini–Yekutieli (BY) procedure (Benjamini & Yekutieli, The control of the false discovery rate in multiple testing under dependency, 2001) are reported.To address multiplicity at the tract level, both the Benjamini–Hochberg (BH) procedure and the more conservative Benjamini–Yekutieli (BY) procedure are reported. The objective of this study is statistical evaluation.

Background on Changing Demographic Analysis

This analysis investigates statistically significant changes in selected census tract–level socioeconomic indicators between the 2015–2019 and 2020–2024 American Community Survey (ACS) 5-year estimates. In addition to tract-level statistical comparisons, each census tract was classified into one of two groups, either vulnerable or non-vulnerable, based on its Michigan

Environmental Justice Screen percentile score (MiEJScorePL). Throughout this document, “EJ score” refers specifically to MiEJScorePL. The EJ score is a composite indicator designed to quantify environmental and social vulnerability at the census tract level. Tracts with MiEJScorePL values greater than or equal to 80 are classified as vulnerable, while those with scores below 80 are classified as non-vulnerable. These classifications are used consistently throughout the analysis.

Details regarding the definition and construction of MiEJScorePL are available through the Michigan Department of Environment, Great Lakes, and Energy (EGLE) (Michigan Department of Environment, Great Lakes, and Energy, n.d.). Additional preprocessing details are provided in the Data Gathering and Preprocessing section.

The study compares these two groups across multiple demographic and socioeconomic metrics over time. The analysis focuses on the magnitude of observed changes, associated uncertainty, and statistical reliability. The primary objective is to provide an objective and reproducible statistical assessment while remaining within the bounds of methodological expertise. Accordingly, the report emphasizes statistical rigor and does not extend to policy interpretation.

The motivation for this analysis arises from discussions associated with Case No. U-21534, in which DTE Electric was requested to evaluate demographic changes over time. Specific analytical considerations were discussed with DAAO/CEO during a virtual meeting on January 16, 2026, with additional clarifications provided via subsequent correspondence. DAAO recommended the use of American Community Survey (ACS) data to evaluate demographic and socioeconomic variables.

The ACS is an ongoing survey administered by the U.S. Census Bureau that produces annual and multi-year estimates of demographic, economic, and housing characteristics. Five-year estimates combine data across five consecutive survey years, thereby increasing statistical reliability for smaller geographic areas such as census tracts.

The ACS publishes both one-year and five-year estimates. The five-year estimates were selected for the following reasons:

1) One-year estimates are not available at the census tract level.
2) Five-year estimates provide improved statistical reliability for small populations due to larger effective sample sizes and reduced margins of error (U.S. Census Bureau, 2020).

3) Variance replicate tables are not available for 1-year estimates, limiting the ability to conduct design-consistent variance estimation. See the Variance Replicates Methodology section for additional discussion.

The most recent available ACS five-year dataset is the 2020–2024 release. This dataset was compared to the 2015–2019 release to avoid overlapping survey years, thereby preserving sampling independence assumption used in variance estimation (Beaghen & Weidman, 2008). Details on how to compare surveys from different years are discussed on the website: https://www.census.gov/programs-surveys/acs/guidance/comparing-acs-data.html. Additional discussion of this assumption is provided in the Assumptions section.

The primary statistical comparison evaluates temporal changes in the following tract-level and group-level metrics:

- Percentage of Black or African American population
- Percentage of households not receiving public assistance
- Percentage of individuals below the federal poverty line
- Percentage of black, indigenous, and people of color (BIPOC) population

All metrics are defined as ratios of ACS population or household estimates. Detailed construction methods are provided in the Metrics section.

For each metric and each tract, the null hypothesis is:

$$H_0: p_{2015–2019} = p_{2020–2024}$$

That is, there is no statistically significant difference between the two ACS five-year estimates.

Data Gathering and Preprocessing

Environmental Justice (MiEJScreen Score): MiEJScreen overall scores (MiEJScorePL) for 2010 census tracts were obtained from the Michigan Department of Environment, Great Lakes, and Energy (EGLE) open data portal (Michigan Department of Environment, Great Lakes, and Energy, n.d.). The dataset provides Environmental Justice (EJ) composite scores for all 2010 census tracts in the state of Michigan.

The downloaded dataset includes multiple variables. The primary fields used in this analysis are:

- **GEOID:** 2010 census tract identifier
- **MiEJScorePL:** percentile rank of the EJ score, scaled 0–100

The raw MiEJScore is converted by EGLE into MiEJScorePL, which represents the statewide percentile ranking of each tract's EJ score relative to all Michigan census tracts.

An MiEJScorePL value of 80 indicates that the tract is at or above the 80th percentile of EJ scores statewide. Under the full statewide distribution, approximately 20 percent of tracts have MiEJScorePL ≥ 80. However, this percentile interpretation applies only to the statewide population of tracts.

Because this analysis is restricted to census tracts located within DTE Electric's service territory, the percentile distribution within that subset does not necessarily follow an 80/20 split. While it would be possible to recalibrate percentile rankings relative to the DTE-only subset, the original statewide MiEJScorePL values were retained for classification consistency.

Census tracts were therefore classified as and shown in Exhibit 8.23:

- **Vulnerable:** MiEJScorePL ≥ 80
- **Non-vulnerable:** MiEJScorePL < 80

Exhibit 8.23 – Distribution of Census Tracts in DTE Territory

	Total	Percentage
Vulnerable Census Tracts (>= 80)	483	33%
Non-Vulnerable Census Tracts (< 80)	988	67%
Total	**1,471**	**100%**

As expected, the distribution within DTE territory does not mirror the statewide 80/20 percentile interpretation.

DTE Census Tract Mapping

To determine which 2010, census tracts fall within DTE Electric's service territory, a geospatial matching procedure was implemented.

Step 1: Extract Transformer Coordinates

Distinct latitude and longitude coordinates for DTE transformers were queried from Databricks. Geographic bounds corresponding to the state of Michigan were applied to exclude clearly invalid coordinate entries. This filtering reduces the likelihood of including erroneously geocoded assets outside Michigan.

Step 2: Census Tract Boundary Files

2010 census tract boundary shapefiles for Michigan were obtained from the U.S. Census Bureau TIGER/Line repository: https://www2.census.gov/geo/tiger/TIGER2010/TRACT/2010/tl_2010_26_tract10.zip.

These shapefiles define the geographic boundaries required to spatially assign transformer coordinates to census tracts.

Step 3: Spatial Join

Using R (RStudio), transformer latitude/longitude coordinates were spatially joined to 2010 census tract polygons. Each transformer was assigned to the census tract polygon containing its coordinates.

Step 4: Identification of DTE Tracts

Unique census tract GEOIDs containing at least one DTE transformer were retained.

The final analytic tract file was constructed by merging:

- **MiEJscreenScore.csv** (statewide EJ scores)
- **CensusTractsDTE.csv** (tracts with DTE transformers)

The merge was performed using the script: CreateFinalEJTable.R

Results:

- Census tracts identified in DTE territory: 1472
- Census tracts with MiEJ scores statewide: 2767
- Successfully matched tracts: 1471

One tract (GEOID 26115990000) was identified in DTE territory but did not have a corresponding MiEJScorePL value in the EGLE dataset.

Accordingly, the final analytic file FinalEJTable.csv contains 1,471 census tracts.

Variance Replicate Estimate files

Variance estimation relied on the American Community Survey (ACS) 5-year Variance Replicate Estimate Tables (U.S. Census Bureau, 2024). These files provide 80 replicate estimates

constructed using Successive Difference Replication (SDR) methodology and shown in Exhibit 8.24.

Table definitions and shells were obtained from official ACS technical documentation https://www.census.gov/programs-surveys/acs/technical-documentation/table-shells.html.

Exhibit 8.24 – Replicate Table Extraction

Table Id	Universe	Table Title	Orders Used in Table	Order Description from Detailed Shell Table
B19057	Households	Public Assistance Income in the Past 12 Months for Households	1,2	B19057_001: Total B19057_002: With public assistance income
B17001	Population for whom poverty status is determined	Poverty Status in the Past 12 Months by Sex by Age	1,2	B17001_001: Total B17001_002: Income in the past 12 months below poverty level
B03002	Total population	Hispanic or Latino Origin by Race	1,3	B03002_001: Total B03002_003: White alone
B02009	Black or African American alone or in combination with one or more other races	Black or African American Alone or in Combination with One or More Other Races	1	B02009_001: Total

All replicate files were downloaded directly from the Census Bureau replicate estimate repository https://www2.census.gov/programs-surveys/acs/replicate_estimates.

Methodology

Metrics: The BIPOC metric was calculated using table id B03002. The B03002_001 (order 1) part of the table provides the total population and the B03002_003 (order 3) part of the table provides the count of the white population alone. The BIPOC for year, j, at a census tract, i, was calculated as:

$$\frac{B03002^{j}_{001}(i) - B03002^{j}_{003}(i)}{B03002^{j}_{001}(i)}$$

At a census tract level, the null and alternative hypothesis are:

$$H_0: \frac{B03002^{2024}_{001}(i) - B03002^{2024}_{003}(i)}{B03002^{2024}_{001}(i)} - \frac{B03002^{2019}_{001}(i) - B03002^{2019}_{003}(i)}{B03002^{2019}_{001}(i)} = 0$$

$$H_1: \frac{B03002_{001}^{2024}(i) - B03002_{003}^{2024}(i)}{B03002_{001}^{2024}(i)} - \frac{B03002_{001}^{2019}(i) - B03002_{003}^{2019}(i)}{B03002_{001}^{2019}(i)} \neq 0$$

At the group level (testing whether there is a statistically significant difference in the percentage of BIPOC within that group between 2024 and 2019) we looked at the following hypothesis:

$$H_0: \frac{\sum_{i\in\mathcal{T}_g} B03002_{001}^{2024}(i) - \sum_{i\in\mathcal{T}_g} B03002_{003}^{2024}(i)}{\sum_{i\in\mathcal{T}_g} B03002_{001}^{2024}(i)} - \frac{\sum_{i\in\mathcal{T}_g} B03002_{001}^{2019}(i) - \sum_{i\in\mathcal{T}_g} B03002_{003}^{2019}(i)}{\sum_{i\in\mathcal{T}_g} B03002_{001}^{2019}(i)} = 0$$

$$H_1: \frac{\sum_{i\in\mathcal{T}_g} B03002_{001}^{2024}(i) - \sum_{i\in\mathcal{T}_g} B03002_{003}^{2024}(i)}{\sum_{i\in\mathcal{T}_g} B03002_{001}^{2024}(i)} - \frac{\sum_{i\in\mathcal{T}_g} B03002_{001}^{2019}(i) - \sum_{i\in\mathcal{T}_g} B03002_{003}^{2019}(i)}{\sum_{i\in\mathcal{T}_g} B03002_{001}^{2019}(i)} \neq 0$$

for the set of tracts $\mathcal{T}_g$ (group $g \in \{vulnerable, non-vulnerable\}$). At the census tract level, you have over a thousand hypotheses, one for each census tract. Thus, the classic multiple testing comes into play. See the Multiple Testing section below for more details on this. At the group level no such adjustment is necessary as there are only two hypotheses, one for each group. In addition to the above hypothesis, we also tested several other hypotheses:

- Whether, under the null hypothesis, the difference between 2024 and 2019 was at *least* 1% different. This was done at a group level and at a census tract level.
- Whether the difference in the vulnerable group between 2024 and 2019 was statistically different than the difference in the non-vulnerable group. This hypothesis allows us to test that if both groups happen to change, the change in one group is more significant than the other. We additionally tested whether the difference-in-differences exceeded 1 percentage point.

Here is an example of how to set up the hypothesis for a range of values under the null.

$$H_0: \left|\frac{B03002_{001}^{2024}(i) - B03002_{003}^{2024}(i)}{B03002_{001}^{2024}(i)} - \frac{B03002_{001}^{2019}(i) - B03002_{003}^{2019}(i)}{B03002_{001}^{2019}(i)}\right| \leq .01$$

$$H_1: \left|\frac{B03002_{001}^{2024}(i) - B03002_{003}^{2024}(i)}{B03002_{001}^{2024}(i)} - \frac{B03002_{001}^{2019}(i) - B03002_{003}^{2019}(i)}{B03002_{001}^{2019}(i)}\right| > .01$$

In the later sections we will go through in detail the test statistics and distributional assumptions made to test the above hypothesis. We will go through the other metrics in less detail below. However, as in the BIPOC metric, all listed hypotheses were tested for all metrics listed below.

The public assistance metric or the way the testing was done which was lack of public assistance was calculated using the B19057 table. The B19057_001 contains the total for that universe (see table shells section) and the B19057_002 are the counts without public assistance.

$$H_0: \frac{\mathrm{B19057}_{002}^{2024}(i)}{\mathrm{B19057}_{001}^{2024}(i)} - \frac{\mathrm{B19057}_{002}^{2019}(i)}{\mathrm{B19057}_{001}^{2019}(i)} =$$

$$H_1: \frac{\mathrm{B19057}_{002}^{2024}(i)}{\mathrm{B19057}_{001}^{2024}(i)} - \frac{\mathrm{B19057}_{002}^{2019}(i)}{\mathrm{B19057}_{001}^{2019}(i)} \neq 0$$

The poverty metric was calculated using the B17001 table. The B17001_001 contains the total for that universe (see table shells section) and the B17001_002 are the counts whose income in the past 12 months below poverty level.

$$H_0: \frac{\mathrm{B17001}_{002}^{2024}(i)}{\mathrm{B17001}_{001}^{2024}(i)} - \frac{\mathrm{B17001}_{002}^{2019}(i)}{\mathrm{B17001}_{001}^{2019}(i)} = 0 H_1: \frac{\mathrm{B17001}_{002}^{2024}(i)}{\mathrm{B17001}_{001}^{2024}(i)} - \frac{\mathrm{B17001}_{002}^{2019}(i)}{\mathrm{B17001}_{001}^{2019}(i)} \neq 0$$

The black population metric was calculated using the B02009 and B03002 tables. The B02009_001 contains the counts of individuals who identified as Black or African American alone or in combination with one or more other races.

$$H_0: \frac{\mathrm{B02009}_{001}^{2024}(i)}{\mathrm{B03002}_{001}^{2024}(i)} - \frac{\mathrm{B02009}_{001}^{2019}(i)}{\mathrm{B03002}_{001}^{2019}(i)} = 0$$

$$H_1: \frac{\mathrm{B02009}_{001}^{2024}(i)}{\mathrm{B03002}_{001}^{2024}(i)} - \frac{\mathrm{B02009}_{001}^{2019}(i)}{\mathrm{B03002}_{001}^{2019}(i)} \neq 0$$

We interpret that this is a subset of the B03002_001 total. Meaning the population in B03002_001 contains B02009_001. Every unit in B03002_001had the chance of being in B02009_001 so the proportion makes sense. The variance replicates approach would be valid in this case even though the numerator and denominator come from different tables.

Variance Replicates Methodology

To test the above hypothesis, we need to make distributional assumptions under the null hypothesis. Without loss of generality, we will use the poverty metric as an example. For a given census tract i, the published statistics, $\mathrm{B17001}_{002}^{2024}(i)$, is the estimate of the count of whose

income in the past 12 months below poverty level in census tract i. Along with the estimate, the ACS publishes a 90% confidence margin of error (MOE). The MOE is based on the calculation of the variance using the Variance Replicate Estimate Table. Dividing the MOE by 1.645 yields the standard error. This is because $P(Z \leq 1.645) = .95\ where\ Z \sim N(0,1)$ so for 90% confidence you get: $P(-1.645 \leq Z \leq 1.645) = .9$. The assumption is that the estimators are asymptotically normal with standard error MOE/1.645. The ACS describe in detail how they derive those estimates. See (Estimates, n.d.) ACS, n.d., chapter 12 of (Rico, 2024) and (Webinar, n.d.) for more details. In most cases, the variance is calculated using the replicate-based methodology known as successive difference replication (SDR) that considers the sample design and estimation procedures. "Beginning with the 2010–2014 5-year data, the ACS has published the Variance Replicate Estimate Table package, which allows advanced users to calculate variances, standard errors, and margins of error using replicate estimates. This allows us to calculate the standard error of our ratio:

$$\frac{\mathrm{B17001}_{002}^{2024}(i)}{\mathrm{B17001}_{001}^{2024}(i)}$$

The variance replicates tables provide eighty replicate estimates constructed using Successive Difference Replication (SDR) techniques. These replicates reflect the full ACS sampling design, including stratification, clustering, and unequal weights. Replicate-based variances capture covariance terms that are ignored by analytic approximations (U.S. Census Bureau, 2024). We should note that in all the approximation methods listed (ACS, n.d.), (Approximation, n.d.) the covariance is assumed to be 0 between estimates *except* in the case of proportion. Since we are dealing with a proportion, it would be remiss if we did not discuss that case in some detail. For a general ratio, $R = \frac{A}{B}$ the standard error of R is given by:

$$SE(R) = \frac{1}{B}\sqrt{(SE(A)^2 + R^2 SE(B)^2)}$$

while for a proportion (which is a type of ratio where $A \subset B$), $P = \frac{A}{B}$

$$SE(P) = \frac{1}{B}\sqrt{(SE(A)^2 - P^2 SE(B)^2)}$$

These formulas come from (ACS, n.d.), (Approximation, n.d.). The motivation behind these comes from the delta method or Taylor expansion around (A, B) where we treat the ratio as a function of the two.

$$R = f(A,B) = \frac{A}{B}$$

If

$$A \sim N(\mu_A, \sigma_A^2) \text{and } B \sim N(\mu_B, \sigma_B^2)$$

we have

$$\begin{pmatrix} \mathrm{A} - \mu_A \\ \mathrm{B} - \mu_B \end{pmatrix} \xrightarrow{d} N(0, \Sigma)$$

Where $\Sigma = \begin{bmatrix} \sigma_A^2 & \sigma_{\mathrm{AB}} \\ \sigma_{\mathrm{AB}} & \sigma_B^2 \end{bmatrix}$ the variance covariance matrix. We can derive the distribution of $(f(A,B) - f(\mu_A, \mu_B))$ by looking at the first order Taylor expansion.

$$(f(A,B) - f(\mu_A, \mu_B)) \approx \nabla f^{\top} \begin{pmatrix} \mathrm{A} - \mu_A \\ \mathrm{B} - \mu_B \end{pmatrix}$$

Where ∇f is the gradient vector. In this case, the partial derivative with respect to A is $\frac{1}{B}$ and the partial derivative with respect to B is $-\frac{A}{B^2}$. So $\nabla f = \begin{pmatrix} \frac{1}{B} \\ -\frac{A}{B^2} \end{pmatrix}$. The $\mathrm{Var}(f) \approx \nabla f^{\top} \Sigma \nabla f$ so you have

$$\mathrm{Var}(f) = \left(\frac{1}{B}, -\frac{A}{B^2}\right) \begin{bmatrix} \sigma_A^2 & \sigma_{\mathrm{AB}} \\ \sigma_{\mathrm{AB}} & \sigma_B^2 \end{bmatrix} \begin{pmatrix} \frac{1}{B} \\ -\frac{A}{B^2} \end{pmatrix} = \frac{1}{B^2}[\sigma_A^2 + R^2\sigma_B^2 - 2R\sigma_{\mathrm{AB}}]$$

In the case of a general ratio, they assume $\sigma_{\mathrm{AB}} = 0$ and you get $\sqrt{(\mathrm{V}(f)} = \frac{1}{B}\sqrt{(}\, SE(A)^2 + R^2 SE(B)^2)$ where $SE(A) = \sigma_{\mathrm{A}}, SE(B) = \sigma_{\mathrm{B}}$. This is the independence assumption used in the approximation methods (for jointly normal random variables covariance of 0 implies independence). However, in the case of proportions, they use $\frac{1}{B}\sqrt{(SE(A)^2 - P^2 SE(B)^2)}$ which means $P^2\sigma_B^2 - 2P\sigma_{\mathrm{AB}} = P^2\sigma_B^2$.

This implies that $\sigma_{\mathrm{AB}} = P\sigma_B^2$. We believe they model this covariance is parametrically. For a proportion:

$$\hat{p} = A/B,$$

ACS assumes asymptotically:

- B estimates total population.
- A estimates subgroup.
- Conditional on B, A behaves like Binomial(B, p)

So:

$$A = pB + \varepsilon, Var(\varepsilon \mid B) = p(1-p)B$$

and

$$Cov(B, \varepsilon) = 0$$

From this:

$$Cov(A, B) = Cov(pB + \varepsilon, B) = pVar(B)$$

Even though ACS accounts for covariance, a concern is that it assumes a *specific stochastic model* that is only approximately true under ideal conditions. This means that the covariance structure used in ACS analytic approximations is model-based, not design-based. In addition, while analytic Taylor linearization formulas assume a specific variance structure, replicate weights empirically capture the full sampling design, including clustering, stratification, and calibration adjustments. When testing at a group level, there are no formulas that account for geography aggregation. Meaning when we perform the analysis on a group level we are summing across geographies (census tracts) and not allowing for covariance between them. Replicate methods avoid model-based variance assumptions and instead approximate sampling variance empirically under the survey design.

They empirically estimate the variance from the eighty replicates under the actual survey design. For these reasons, replicate-based variance estimation is preferred when available. We still provide the approximation formulas as well at the census tracts level but not the group level in the results. Group-level estimates were constructed using replicate weights aggregated across tracts, preserving design-consistent variance estimation. Providing the approximation method at the group level would require summing up hundreds of variances without accounting for any covariances. In the worked examples document (Approximation, n.d.) they show why adding even some variances without accounting for covariances can lead to bias. The main reason we provide the approximation at a census tract level is because there are cases where the variance replicates methodology is not available. See next section for more details on this.

Census Tracts without Meaningful Variance Replicates

We excluded from the group-level comparisons any census tracts that do not vary with their variance replicate estimates. This can occur when the estimate is zero for a count estimate or if the percentage is 100%. These are edge cases and ACS does not use variance replicates estimates to estimate the variance in these cases. When ACS estimates equal zero or 100%, replicate values may also be identical across all replicates, producing zero estimated variance. This does not imply true certainty but rather reflects limitations of published summary tables. Such estimates systematically understate sampling uncertainty. For zero counts and extreme proportions, the Census Bureau applies analytic methods based on Poisson or normal approximations and scaling constants (approximately 2.3) to construct 90% confidence intervals; see chapter 12 here for more details (Rico, 2024). These approaches assume independent Poisson sampling and constant variance-to-mean ratios. Replicate methods incorporate all sources of sampling variability and allow valid estimation of variances for derived statistics and aggregated geographies. They avoid parametric assumptions and preserve design effects. Boundary truncation further reduces nominal coverage probabilities, resulting in confidence intervals that do not achieve their stated confidence levels. This analysis retains only estimates for which variance replicate tables are available and exhibit non-zero variability. Estimates derived solely from boundary approximation methods are excluded in the group analysis. This ensures that all reported inference is based on design-consistent uncertainty measures. However, when displaying the results using the approximation method, we include all census tracts where applicable. The approximation method backs out the standard error from the ACS published MOE. This means in the approximation method it will include the 0 or 100 percent estimates. However, the main results of our analysis will focus on the variance replicate approaches. Including the approximation method was done as more of a robustness check. However, we do not account for census tracts that have zero counts in total for those metrics (meaning zero in the denominator).

Statistical Testing via P-values

Using Poverty as an example, recall that the quantity of interest we are testing is.

$$\frac{\mathrm{B17001}_{002}^{2024}}{\mathrm{B17001}_{001}^{2024}} - \frac{\mathrm{B17001}_{002}^{2019}}{\mathrm{B17001}_{001}^{2019}}$$

From the section above we described using the variance replicate method (or approximating method) to get the standard error of $\frac{\mathrm{B17001}_{002}^{2024}}{\mathrm{B17001}_{001}^{2024}}$ and $\frac{\mathrm{B17001}_{002}^{2019}}{\mathrm{B17001}_{001}^{2019}}$, SE_{2024}, SE_{2019} respectively. What we say here applies to both the group level and the census tract level.

Let $Z = \frac{\frac{\mathrm{B17001}_{002}^{2024}}{\mathrm{B17001}_{001}^{2024}} - \frac{\mathrm{B17001}_{002}^{2019}}{\mathrm{B17001}_{001}^{2019}}}{\sqrt{(SE_{2024}^2 + SE_{2019}^2)}}$

We will assume under the null hypothesis that $Z \sim N(0,1)$ (asymptotically). We require independence between non-overlapping survey years. We discussed the normality assumption in the previous section. The independence assumption is discussed in more detail in the Assumption section below. The above Z statistic is for testing a single valued null hypothesis not a composite null.

$$\frac{\mathrm{B17001}_{002}^{2024}}{\mathrm{B17001}_{001}^{2024}} - \frac{\mathrm{B17001}_{002}^{2019}}{\mathrm{B17001}_{001}^{2019}} = 0$$

Later in this section we will adjust this when testing the null hypothesis that $\frac{\mathrm{B17001}_{002}^{2024}}{\mathrm{B17001}_{001}^{2024}} - \frac{\mathrm{B17001}_{002}^{2019}}{\mathrm{B17001}_{001}^{2019}} \leq 0.01$.

The p-value, p, is defined as:

$$p = 2[1 - \Phi(|Z|)]$$

where Φ is the C.D.F of the standard normal. When comparing within groups or between vulnerable and non-vulnerable groups, we will investigate if the $p < .05$. At the census tract level, adjustment to this p value is necessary. See the Multiple Testing section below.

Let $\delta = \frac{\mathrm{B17001}_{002}^{2024}}{\mathrm{B17001}_{001}^{2024}} - \frac{\mathrm{B17001}_{002}^{2019}}{\mathrm{B17001}_{001}^{2019}}$

When testing $|\delta| \leq 0.01$ the p value is defined as:

$$p = \sup_{|\delta| \leq 0.01} P_{\delta}(\text{test statistic} \geq \text{observed}).$$

Let $Z^* = \max\left(0, \frac{|\delta| - 0.01}{\sqrt{(SE_{2024}^2 + SE_{2019}^2)}}\right)$

This works out to

$$p = 2[1-\Phi(|Z^*|)]$$

The intuition is any realized difference δ, where $|\delta| \leq 0.01$, you want to set Z^* to 0 (under the null hypothesis the difference is less than or equal to 0.01). The p value in that case is just one, analogous to a single null hypothesis if you observe a $\delta = 0$.

Multiple Testing

Due to the many census tracts, we end up with many p-values, one for each tract. An adjustment needs to be made for multiple testing. The multiple testing problem can be described as follows:

Suppose you test:

$$H_1, H_2, \dots, H_m$$

simultaneously.

Let:

- V= number of false rejections
- R= total number of rejections
- m_0= number of true null hypotheses

Without correction, if each test is at level $\alpha = 0.05$ (0.05 is standard but other alphas can be chosen), then:

$$\mathbb{E}[V] \approx 0.05 m_0$$

So, with over a thousand tests, false positives are almost guaranteed. The question then becomes: what error criterion do we want to control?

- Family-Wise Error Rate (FWER)
- False Discovery Rate (FDR)

We will provide a brief overview of each and conclude with the choice that we used for this analysis.

The Family-Wise Error Rate is:

$$\text{FWER} = \mathbb{P}(V \geq 1)$$

This is the probability of making at least one false discovery**.** This is a strong criterion. If FWER ≤ 0.05, then in 95% of experiments (meaning if you repeat the m hypothesis many times), you make zero Type I errors.

Interpretation

- Treats any false positive as catastrophic
- One mistake ruins the entire "family" of tests (hence the "family" in Family-Wise Error Rate)

This is extremely conservative when m is large. An example of this is the Bonferroni correction.

Reject H_i if:

$$p_i \leq \frac{\alpha}{m}$$

Where p_i is the p-value from the H_i hypothesis. So, for example, if you have one thousand census tracts ($m = 1000$) and you are looking for significance at an $\alpha = 0.05$ you would require a p-value less than 0.00005. This is equivalent to adjusting the p-values by a factor of 1000, $p_{adjusted} = m * p_i \leq \alpha$. Very few hypotheses would get rejected using this procedure which is why this is known to have poor power. Power can be described as the ability to reject the null hypothesis when the null hypothesis is false. There are other corrections that are used for FWER like Holm-Bonferroni, which is an improvement over the Bonferroni correction (better power) (Holm, 1979). Still, the power is much lower compared to False Discovery Rate.

The False Discovery Rate is:

$$\text{FDR} = \mathbb{E}\left[\frac{V}{R \vee 1}\right]$$

where $R \vee 1 = \max(R, 1)$ (we want to avoid any divide by zero issue). This is the expected proportion of false discoveries among those you call significant.

Key difference:

- Allows false positives
- Controls their fraction, not their existence

- FWER controls the chance of any mistake
- FDR controls the expected proportion of mistakes

If FDR ≤ 0.05 then on average, no more than 5% of your discoveries declared are false.

There are two procedures we will discuss for FDR:

- Benjamini–Hochberg (BH)
- Benjamini–Yekutieli (BY)

BH procedure (Benjamini & Hochberg, Controlling the false discovery rate: A practical and powerful approach to multiple testing, 1995):

Given p-values $p_1, \dots, p_m$:

1. Sort:

$$p_{(1)} \leq p_{(2)} \leq \cdots \leq p_{(m)}$$

2. Find

$$\hat{k} = \max\{k: p_{(k)} \leq \frac{k}{m}\alpha\}$$

3. Reject all hypotheses with

$$p_i \leq p_{(\hat{k})}$$

The BH adjusted p-values are:

$$\text{BH-adjusted } p_{(i)} = \min\left(\frac{m}{i}\, p_{(i)}, 1\right)$$

- This is the “raw” BH formula.
- Then we apply monotonicity correction: make sure the adjusted p-values are non-decreasing from smallest to largest.

You can then compare the $\mathrm{BH} - \mathrm{adjusted}\, p_{(i)}$ with any α level of choice. In the results sections we will show for $\alpha = 0.05$. However, in the backup files and tables in the appendix we provide the BH-adjusted $p_{(i)}$ as well if someone wants to test at a different α level. This is what the R function

p.adjust(p_values, method="BH") returns**:** a numeric vector same length as input, with the BH-adjusted p-values in the original order.

Interpretation:

- Each adjusted p-value is the smallest FDR level at which you would reject that hypothesis
- To reject at FDR level α, just do: p.adjust(p_values, method = "BH") <= α.
- For the validity of the BH procedure as a method of FDR, the assumptions are that the hypothesis tests are either:
  - Independent
  - Positive dependence (PRDS) (weaker condition than independence)

Because dependence structure across tracts is unknown and may include arbitrary dependence due to survey design, we report both BH and the more conservative BY procedure. As a diagnostic assessment of the dependency across census tracts, we used the variance replicates tables to help construct pairwise correlation between the census tracts statistics. Using poverty as an example we retrieved eighty values for each census difference in poverty ratios (which is the hypothesis we are testing). $R \in \{1, \dots, 80\}$:

$$\frac{\mathrm{B17001}_{002}^{2024}(i)^R}{\mathrm{B17001}_{001}^{2024}(i)^R} - \frac{\mathrm{B17001}_{002}^{2019}(i)^R}{\mathrm{B17001}_{001}^{2019}(i)^R}$$

For each census tract i, let

$$D_i = \frac{\mathrm{B17001}_{002}^{2024}(i)}{\mathrm{B17001}_{001}^{2024}(i)} - \frac{\mathrm{B17001}_{002}^{2019}(i)}{\mathrm{B17001}_{001}^{2019}(i)}$$

denote the estimated difference in the tract-level proportion of interest.

Using the ACS replicate weights, we compute 80 replicate estimates of this difference:

$$D_i^{(1)}, \dots, D_i^{(80)}$$

Thus, for each tract i, we have the vector

$$D_i^{(1:80)} = (D_i^{(1)}, \dots, D_i^{(80)})$$

For two tracts $i$and j, we estimate their sampling-design-induced correlation as

$$\widehat{\mathrm{Cor}}(D_i, D_j) = \frac{\sum_{r=1}^{80} \left(D_i^{(r)} - \bar{D}_i\right)\left(D_j^{(r)} - \bar{D}_j\right)}{\sqrt{\sum_{r=1}^{80} (D_i^{(r)} - \bar{D}_i)^2}\sqrt{\sum_{r=1}^{80} (D_j^{(r)} - \bar{D}_j)^2}}$$

where the Pearson correlation is computed across the 80 replicate estimates.

Constructing this quantity for all pairs of tracts yields a $m \times m$ matrix where entry (i, j)estimates the correlation between tract-level difference estimators under the ACS sampling design.

Importantly:

- These correlations arise from the shared survey design and replicating weighting structure.
- They do not represent population-level correlation between true demographic changes.
- They quantify dependence between test statistics, which is directly relevant for multiple testing procedures.

PRDS is a technical condition implying that large values of one test statistic do not decrease the likelihood of large values of others. A mixed-sign correlation structure does not establish violation of PRDS, but it weakens confidence in assuming classical positive dependence. Therefore, if the dependence structure were strongly positively dependent, we would expect a predominance of positive correlations. Empirically, however, we observe that half of the pairwise correlations are negative across several metrics. This suggests that the dependence structure is mixed sign and not uniformly positively dependent. This finding does not formally prove violation of PRDS, as PRDS is a stronger distributional condition than pairwise nonnegativity. However, it indicates that the dependence structure is complex and not obviously aligned with classical positive dependence assumptions.

For this reason, we report on both:

- BH-adjusted p-values (valid under independence or PRDS)
- Benjamini–Yekutieli (BY) adjusted p-values (valid under arbitrary dependence)

The BY procedure provides a conservative robustness check when dependence structure is uncertain.

BY procedure (Benjamini & Yekutieli, The control of the false discovery rate in multiple testing under dependency, 2001):

Define the harmonic constant:

$$c(m) = \sum_{i=1}^{m} \frac{1}{i}$$

Then $\mathrm{BY} - \mathrm{adjusted}\ p_{(i)}$ are:

$$\text{BY-adjusted } p_{(i)} = \min\left(\frac{m}{i} * c(m)\ {}^{*}p_{(i)}, 1\right)$$

So, the same as BH just multiplied by $c(m)$. In R you can just run the same function just change the method to BY: p.adjust(pvals, method = "BY"). To summarize:

- BH controls FDR under independence or PRDS
- BY controls FDR under arbitrary dependence
- BY is valid regardless of sign or structure of correlation

We provide both the BY and BH adjusted p-values in the csv files and display the results in the results section and appendix.

Assumptions

We used non-overlapping years for the analysis as recommended by the (Michael Beaghen, 2008), (data, n.d.). “Since estimates for non-overlapping years are nearly independent, a very good approximation to the variance for a difference between non-overlapping estimates is just the sum of the variances of the two estimates.” (Michael Beaghen, 2008). Statistical analysis between overlapping surveys would have to account for covariance between the calculated metrics. The 2015–2019 and 2020–2024 periods do not share sample years. However, they may share underlying population structure. ACS five-year samples are drawn independently each year. Non-overlapping five-year periods are only approximately sampling independent. So, the independence assumption is sampling independence, not population independence. However, the ACS does not publish covariance between survey years and shows worked examples where the covariance is assumed to be zero for overlapping periods (Data, 2011). Along with the independent assumption there are several other assumptions when using the ACS data:

- Asymptotic normality of ratio estimators
- Validity of SDR variance estimators

Limitations

Census Tract GEOID from 2010 to 2020: The final EJ Table had 1471 census tracts (2010). Some of the census tracts from 2010 were split into multiple census tracts in 2020 and some of the census tracts were merged into a single census tract in 2020. More information on the relationship files between the two can be found here:

https://www.census.gov/geographies/reference-files/2020/geo/relationship-files.html#tract

and you can download Michigan census tract relationship file here:

https://www2.census.gov/geo/docs/maps-data/data/rel2020/tract/tab20_tract20_tract10_st26.txt.

The file provides the mapping between the 2020 to 2010 census tracts. Information on the columns of the csv file are here: https://www.census.gov/programs-surveys/geography/technical-documentation/records-layout/2020-census-block-record-layout.html . We only use census tracts that share the same GEOID between the year 2020 and 2010. Using the land area, we see that over 94.5% of all census tracts with the same GEOID overlapped in more than 99% of the land area. This means that more than 99% of the 2020 census tract GEOID land area was in the same 2010 census tract GEOID area and that more than 99% of the 2010 census tract GEOID land area was in the same 2020 census tract GEOID area. Because over 94% of GEOIDs exhibit >99% area overlap, tract-level comparisons are unlikely to reflect boundary artifacts.

Exhibit 8.25 – Census Tracts with same GEOID

Greater than	#Census Tracts Satisfying	#Census Tracts Failed	%Satisfied
99%	2340	135	94.5%
95%	2442	33	98.7%
90%	2462	13	99.5%
80%	2471	4	99.8%

There are other ways of viewing census tract overlaps other than land area. There are websites (not from the census bureau) that attempt to use algorithms to not only match the overlap in terms of land mass but also in terms of population. The NATIONAL HISTORICAL GEOGRAPHIC INFORMATION SYSTEM is one such website https://www.nhgis.org/geographic-crosswalks . For this analysis, only census tracts that share the same GEOID were used for comparison purposes between 2024 five-year ACS and 2019 five-year ACS. Our robust test was using the land area

overlap between the two and we were satisfied after looking at the results from the table above. We decided that any GEOID that was the same from 2020 to 2010 can be treated as the same geographic area and compared accordingly. While it may be possible to calibrate census tracts that were merged or split by attempting a percentage breakdown, we did not investigate this and simply only used those with the same GEOIDs.

Results

Preprocessing: The results of preprocessing the data for use of the variance replicate methodology are shown in Exhibit 8.26:

Exhibit 8.26 – Results of Preprocessing Data

Variance Replicates walkdown	Black Population	Poverty	No Public Assistance	BIPOC
Census Tracts (2010) in DTE Territory with EJ scores	1471	1471	1471	1471
2024 Estimates for Census	1321	1321	1321	1321
2024 Zero Estimates	1275	1309	1309	1304
2024 100 percent Estimates	1274	1307	1178	1302
Census Tracts (2010) in DTE Territory	1471	1471	1471	1471
2019 Estimates for Census	1471	1471	1471	1471
2019 Zero Estimates	1428	1458	1459	1447
2019 100 percent Estimates	1419	1456	1259	1445
Final Dataset (Intersection of 2024 and 2019 census tracts)	1246	1305	1030	1293

The final row in the table above shows the census tracts used for that metric. The results of preprocessing for the approximation method are shown in Exhibit 8.27.

Exhibit 8.27 – Results of Preprocessing using Approximation Method

Approximation Method	Black Population	Poverty	No Public Assistance	BIPOC
Census Tracts (2010) in DTE Territory with EJ scores	1471	1471	1471	1471
2024 Estimates for Census	1312	1311	1309	1312
2019 Estimates for Census	1463	1462	1459	1463
Intersection of 2024 and 2019 census tracts	1312	1311	1309	1312
Final Dataset (positive standard error, no division by 0s)	**1312**	**1310**	**1275**	**1311**

For most metrics we do not gain many more census tracts using the approximation method as opposed to the variance replicates method. For the “No Public Assistance” metric the gain is more substantial.

Group level results

Below are the results of testing within groups if there were statistically significant changes between the 2024 percentage and the 2019 percentages. The results below are rounded and not listed in percentage format. An example on how to read the table is as follows:

The BIPOC Vulnerable group had 391 census tracts, the estimated percentage of BIPOC in 2024 was 68% and the estimated percentage of BIPOC in 2019 was 67%. This difference was 1% and the p-value was 0.0000315, so significant at an 0.05 alpha level. The p-value testing whether the difference was greater than or equal to 1 percent was .38. Group level results are shown in Exhibit 8.28.

Exhibit 8.28 – Group Level Results

Metric	Group	N	2024	2019	Difference	P_Value	P_Value 1Percent
BIPOC	Vulnerable	391	0.68	0.67	0.01	3.15E-05	3.80E-01
	Non-Vulnerable	902	0.22	0.18	0.04	1.61E-214	4.35E-124
No Public Assistance	Vulnerable	372	0.95	0.96	-0.01	9.12E-05	1.00E+00
	Non-Vulnerable	658	0.97	0.98	-0.01	5.10E-16	1.00E+00
Black Population	Vulnerable	400	0.56	0.57	-0.01	7.31E-04	1.00E+00
	Non-Vulnerable	846	0.10	0.09	0.01	1.92E-23	1.60E-01
Poverty	Vulnerable	405	0.27	0.29	-0.02	3.12E-06	5.73E-03
	Non-Vulnerable	900	0.09	0.09	0.00	7.82E-01	1.00E+00

The test below evaluates whether the temporal change differs between vulnerable and non-vulnerable tracts.

Exhibit 8.29 shows equivalent testing, whether the differences in the vulnerable and non-vulnerable groups in 2024 are statistically different than the differences in the vulnerable and non-vulnerable groups in 2019.

(Non-Vulnerable_2024- Non-Vulnerable_2019) -(Vulnerable_2024- Vulnerable_2019)

= (Non-Vulnerable_2024- Vulnerable_2024) -(Non-Vulnerable_2019- Vulnerable_2019)

Exhibit 8.29 – Temporal Changes between Vulnerable and Non-Vulnerable Tracts

	2024Diff	2019Diff	DiffOfDiff	P_Value	P_Value_1Percent
BIPOC	0.46	0.48	-0.029	2.19E-13	1.80E-06
Poverty	0.18	0.21	-0.025	5.94E-06	6.57E-03
Black Population	0.46	0.48	-0.022	8.96E-09	2.10E-03
No Public Assistance	-0.03	-0.02	-0.003	2.41E-01	1.00E+00

Census Tract Level Results using Variance Replicate Methodology

Both the BH and BY adjusted p-values are provided for the census tracts. As mentioned above, to indicate whether the assumption of BH was satisfied (Positive correlation or independence between the statistics), the correlation matrix was constructed between census tracts for each metric. Exhibit 8.30 shows that around half the correlations between census tracts were negative which may call into question if BH assumptions were satisfied. To reiterate, BY allows for arbitrary dependency between the hypothesis tests, but comes with a cost of lower power.

Exhibit 8.30 – Correlations between Census Tracts

Metric	Mean Correlation	Percent Negative Correlation
Poverty	-2.73E-05	49.99%
BIPOC	-4.62E-04	50.25%
No Public Assistance	1.21E-04	49.97%
Black Population	-4.49E-04	50.16%

Exhibit 8.31 are the counts of the census tracts that were statistically significant at the 0.05 alpha level. Taking the BIPOC Non-Vulnerable census tracts as an example:

Seven census tracts were statistically significant using the BH adjusted p-values at the 0.05 level. One was statistically significant using BY. 3 were statistically significantly different by more than 1 percent difference using BH. 1 was statistically significant by more than 1 percent difference using BY.

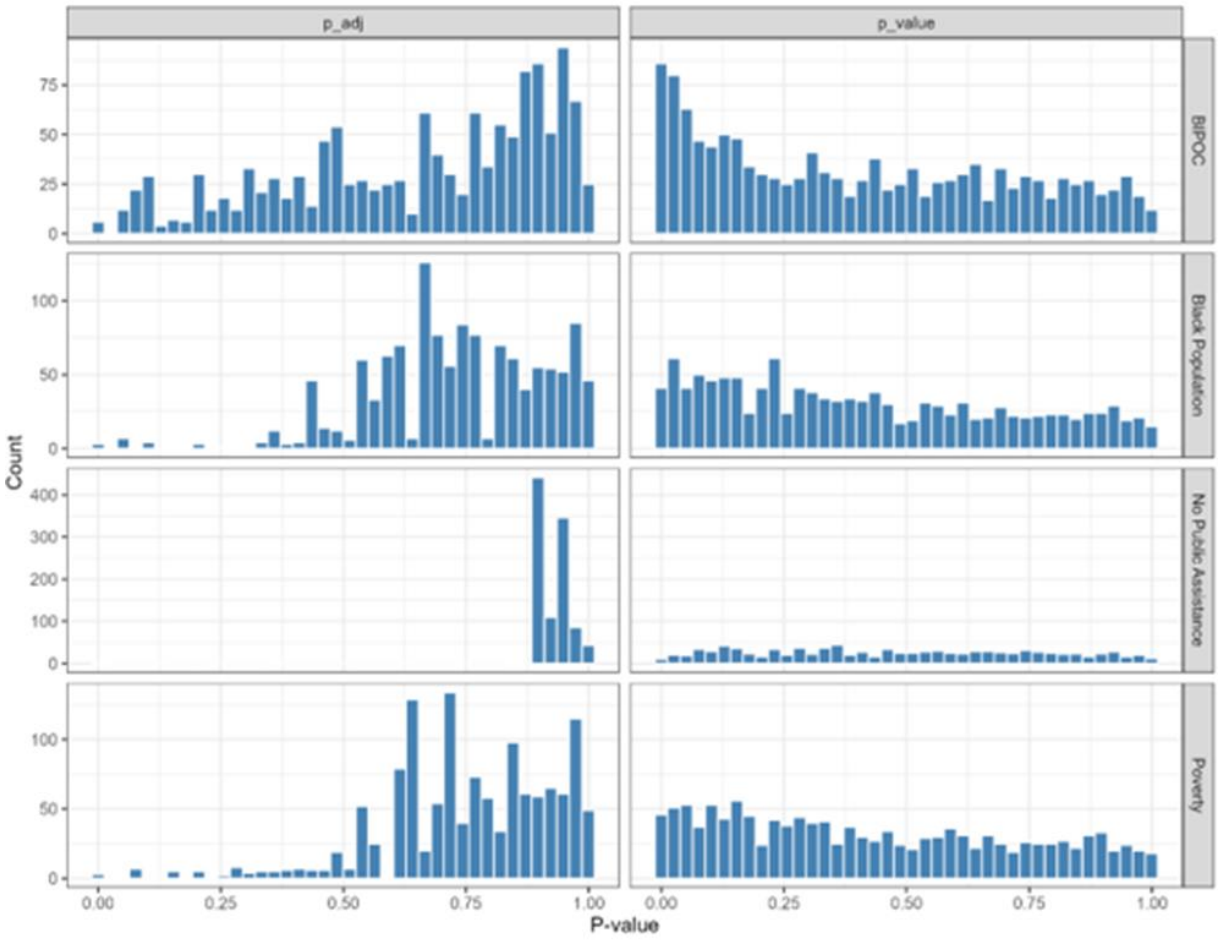
Exhibit 8.31 – Census Tracts Significant at 0.05 Alpha Level

	Group	BH	BY	BH_1%	BY_1%
Black Population	Non-Vulnerable	**5**	**2**	**1**	**1**
	Vulnerable	**4**	**1**	**1**	**0**

BIPOC	Non-Vulnerable	**7**	**1**	**3**	**1**
	Vulnerable	**6**	**1**	**3**	**1**
No Public Assistance	Non-Vulnerable	**0**	**0**	**0**	**0**
	Vulnerable	**1**	**1**	**1**	**1**
Poverty	Non-Vulnerable	**1**	**0**	**1**	**0**
	Vulnerable	**3**	**2**	**3**	**2**

These percentages are based on the overlap of land between the 2010 and 2020 census tracts. See the Limitations section above. As expected, they are all close to 100 percent as the same GEOID is used. You can see from the p-value histogram below the importance of using FDR. Under the global null hypothesis, the p-values are supposed to follow a uniform distribution. However, you can see the skew around 0 indicating that there are indeed census tracts statistically different from 2024 to 2019. Exhibit 8.32 illustrates the shift towards 1 after the adjustment.

Exhibit 8.32 – Distribution of Raw and FDR-Adjusted P-Values



The Q-Q plot of the p-values indicates these deviations as well in Exhibit 8.33.

Exhibit 8.33 – Q-Q Plots of P-Values

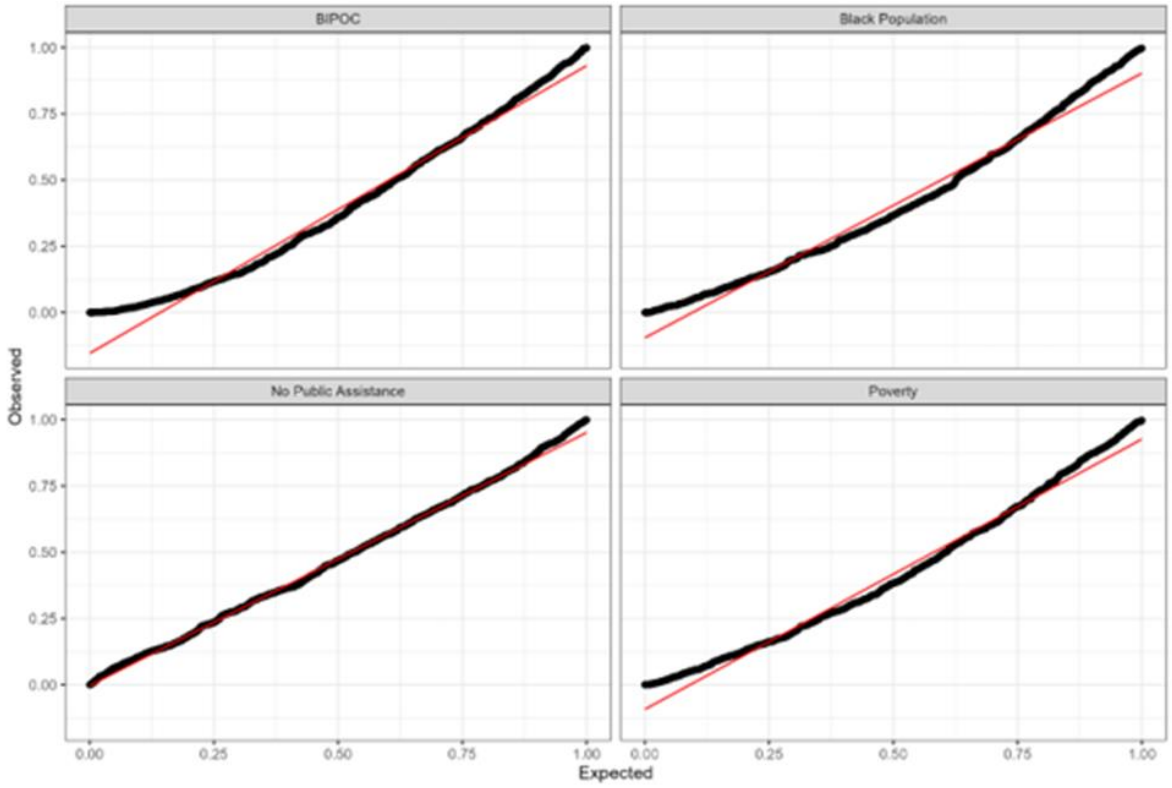


Exhibit 8.34 and Exhibit 8.35 display the BIPOC census tracts that showed statistical difference between 2024 and 2019 using BH. The maps for the other metrics are in Appendix 8.7.B.

Exhibit 8.34 – Significant Census Tract Changes in BIPOC

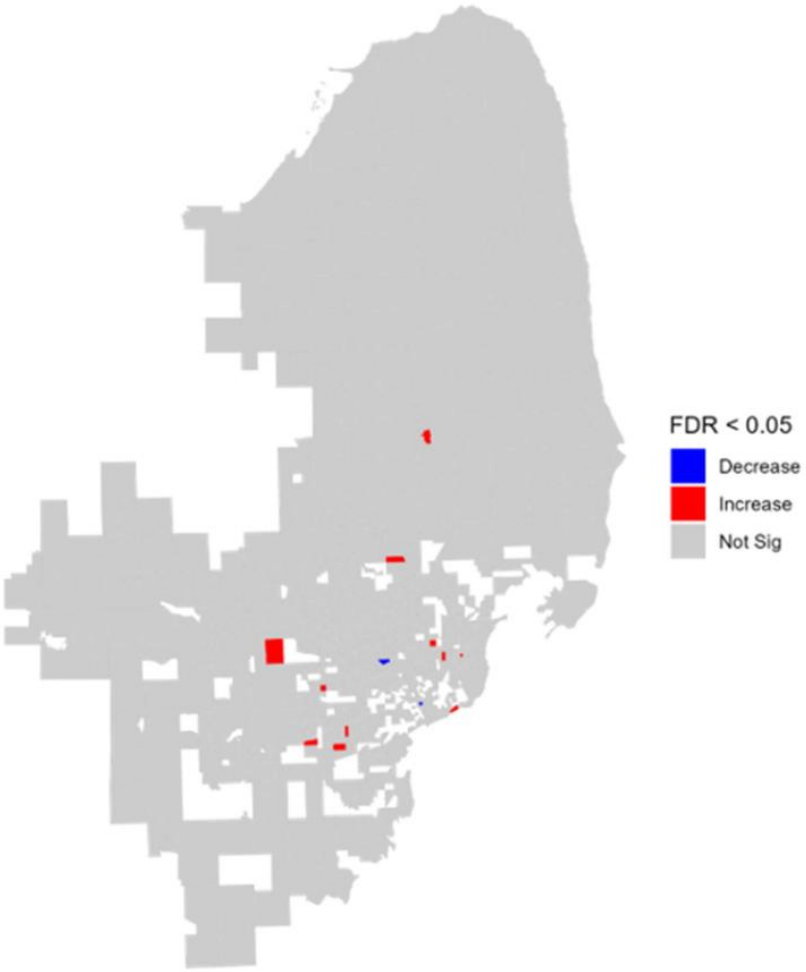
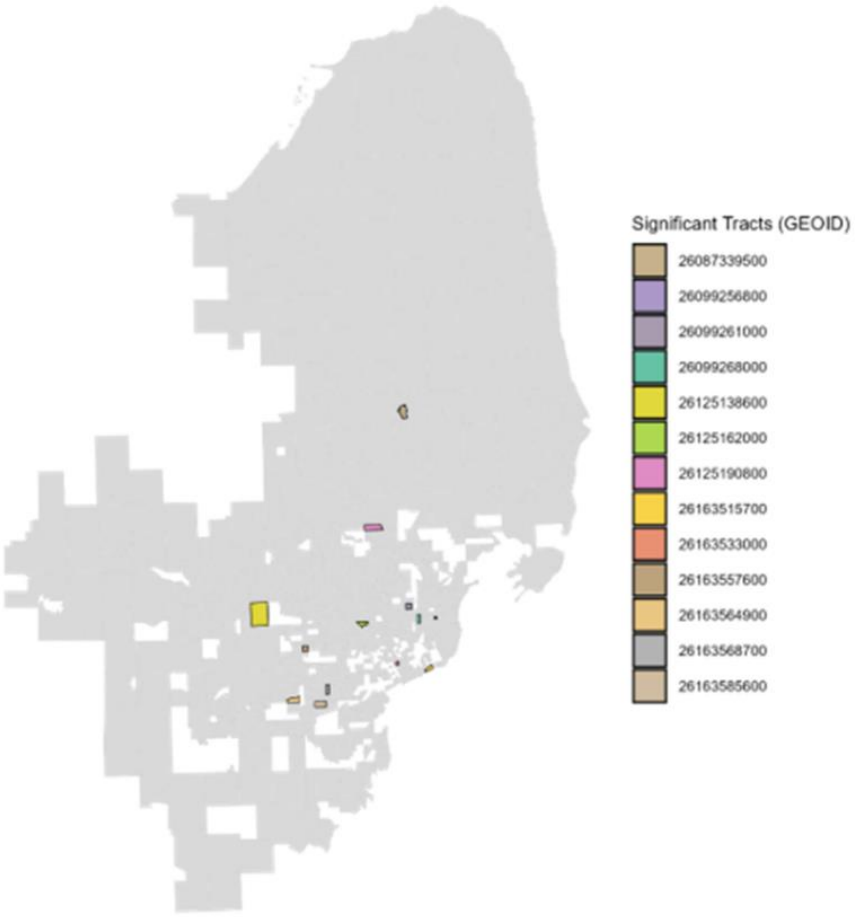


Exhibit 8.35 – FDR Significant Census Tracts: BIPOC



Census Tract Level Results using the Approximation Method

The counts of the census tracts, in Exhibit 8.36, are statistically significant at the 0.05 alpha level using the approximation method. This means that all census tracts were tested using this method. The interpretation is identical to the table in the above section.

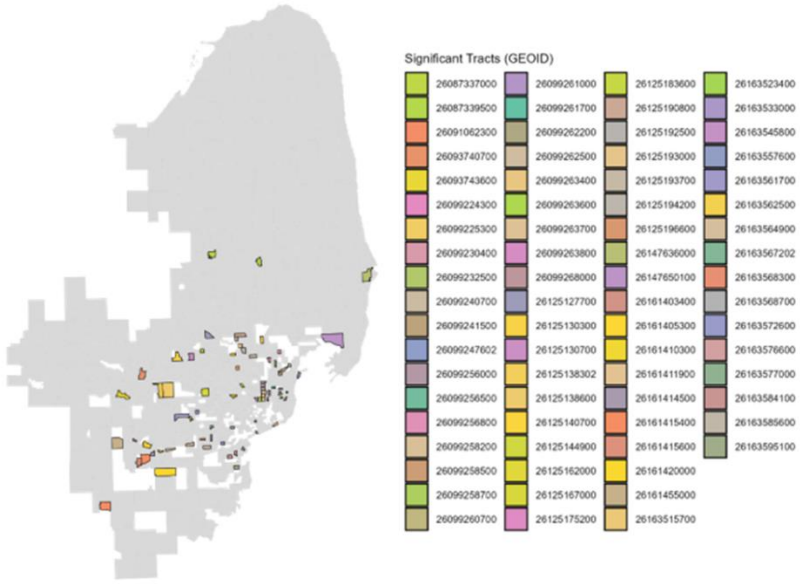
Exhibit 8.36 – Census Tracts Significant at 0.05 Alpha Level

	Group	BH	BY	BH_1%	BY_1%
Black Population	Non-Vulnerable	3	2	2	1
	Vulnerable	8	5	7	2
BIPOC	Non-Vulnerable	54	21	41	19
	Vulnerable	19	7	13	7
No Public Assistance	Non-Vulnerable	7	4	1	1
	Vulnerable	3	2	2	2
Poverty	Non-Vulnerable	1	0	1	0

	Group	BH	BY	BH_1%	BY_1%
	Vulnerable	5	5	5	5

Exhibit 8.37 is the map of the BIPOC census tracts that were statistically significant using BH. More census tracts were considered statistically significant using the approximation method. Especially in the BIPOC metric. However, as explained above, we posit the variance replicate approach provides a sounder statistical analysis. The tradeoff is that some census tracts could not be included in the variance replicate methodology.

Exhibit 8.37 – BIPOC Census Tracts using BH



Conclusion

This study provides a rigorous framework for looking at changes to population characteristics over time, by comparing ACS tract-level estimates across time using variance replicate weights and FDR adjustment. The methodology supports reproducible and transparent inference while maintaining disciplinary boundaries. From the results, there is statistical evidence of shifts in percentages based on the metrics we investigated among some of the census tracts. There is statistical evidence that at a group level, both the vulnerable and non-vulnerable group had small changes over time. Due to the substantial number of census tracts within each group, we were able to detect even small shifts in the metrics. While statistically detectable changes exist, the practical significance is not actionable from an investment prioritization perspective. More graphs, charts, and tables are in the workpapers.

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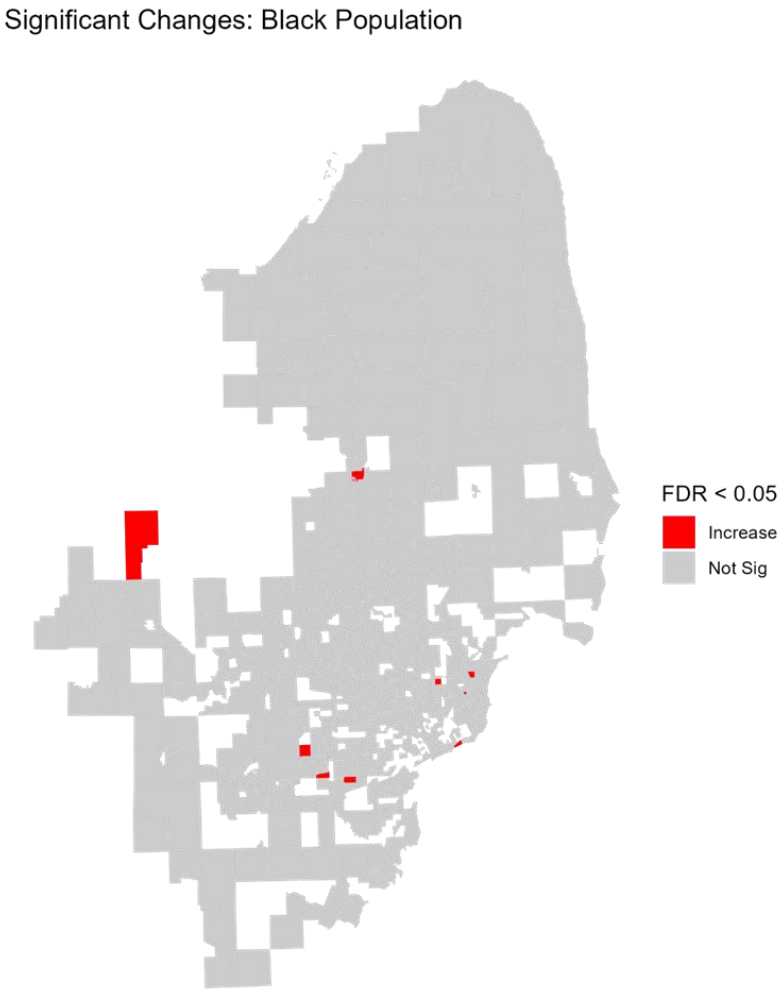
Appendix 8.7.A

Table of the census tracts are statistically significant using variance replicate methodology is below.

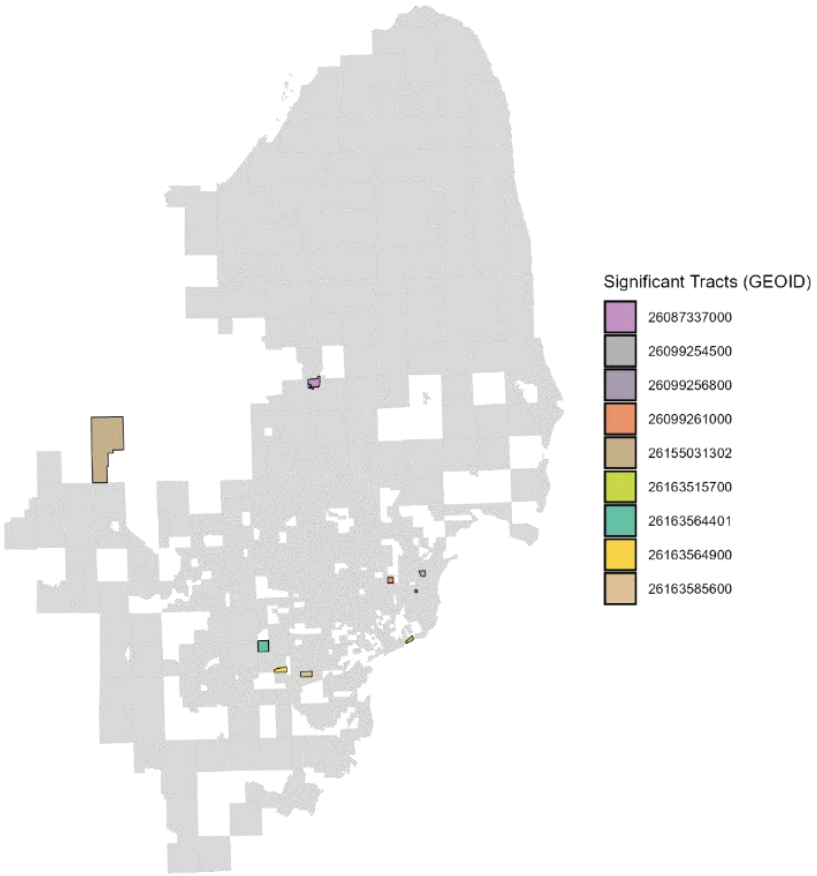
GEOID	Metric	2024 Population Estimate	Estimate	p_ value	p_ adj_BH	p_adj_BY	Percentage Overlap 2010	Percentage Overlap 2020	EJ Score
26099261000	BIPOC	4679	28%	3.39E-06	2.19E-03	1.70E-02	100.00%	100.00%	77.3
26163515700	BIPOC	3277	23%	1.90E-06	2.19E-03	1.70E-02	100.00%	100.00%	89.2
26125162000	BIPOC	3975	-25%	1.85E-05	7.96E-03	6.16E-02	98.31%	100.00%	81.4
26099268000	BIPOC	5912	30%	3.93E-05	9.80E-03	7.58E-02	100.00%	100.00%	87.6
26125138600	BIPOC	3761	24%	3.46E-05	9.80E-03	7.58E-02	100.00%	99.99%	32.7
26163568700	BIPOC	3786	38%	4.55E-05	9.80E-03	7.58E-02	99.64%	100.00%	76.6
26163557600	BIPOC	2877	15%	2.24E-04	4.13E-02	3.20E-01	99.97%	100.00%	43.4
26087339500	BIPOC	3721	18%	3.83E-04	4.51E-02	3.49E-01	99.55%	94.64%	39.3
26125190800	BIPOC	3548	15%	3.71E-04	4.51E-02	3.49E-01	100.00%	100.00%	20.9
26163564900	BIPOC	2284	26%	3.22E-04	4.51E-02	3.49E-01	100.00%	100.00%	83.1
26163585600	BIPOC	4128	13%	3.21E-04	4.51E-02	3.49E-01	100.00%	100.00%	77.8
26099256800	BIPOC	1599	28%	4.66E-04	4.87E-02	3.77E-01	100.00%	100.00%	80.8
26163533000	BIPOC	1567	-22%	4.89E-04	4.87E-02	3.77E-01	100.00%	99.94%	98.3
26087337000	Black Population	3537	15%	4.13E-07	5.15E-04	3.97E-03	98.91%	95.80%	57.1
26163515700	Black Population	3277	23%	7.40E-06	4.61E-03	3.55E-02	100.00%	100.00%	89.2
26163564401	Black Population	7199	7%	1.30E-05	5.41E-03	4.17E-02	100.00%	99.96%	27.7
26155031302	Black Population	3918	4%	1.39E-04	4.32E-02	3.32E-01	100.00%	100.00%	18
26099254500	Black Population	4216	12%	2.47E-04	4.41E-02	3.39E-01	100.00%	100.00%	80.1
26163564900	Black Population	2284	24%	2.16E-04	4.41E-02	3.39E-01	100.00%	100.00%	83.1
26163585600	Black Population	4128	16%	2.06E-04	4.41E-02	3.39E-01	100.00%	100.00%	77.8
26099256800	Black Population	1599	28%	2.97E-04	4.63E-02	3.57E-01	100.00%	100.00%	80.8
26099261000	Black Population	4679	20%	3.44E-04	4.77E-02	3.67E-01	100.00%	100.00%	77.3
26163531300	No Public Assistance	1236	-25%	2.57E-07	2.65E-04	1.99E-03	100.00%	100.00%	84.9
26099262400	Poverty	3525	-32%	6.28E-07	5.14E-04	3.99E-03	100.00%	99.75%	92.2
26163555300	Poverty	3087	-22%	7.88E-07	5.14E-04	3.99E-03	100.00%	100.00%	89.8
26163573701	Poverty	1787	-33%	1.81E-05	7.87E-03	6.10E-02	100.00%	100.00%	75.7
26163503600	Poverty	1560	37%	3.97E-05	1.29E-02	1.00E-01	100.00%	100.00%	88.5

Appendix 8.7.B

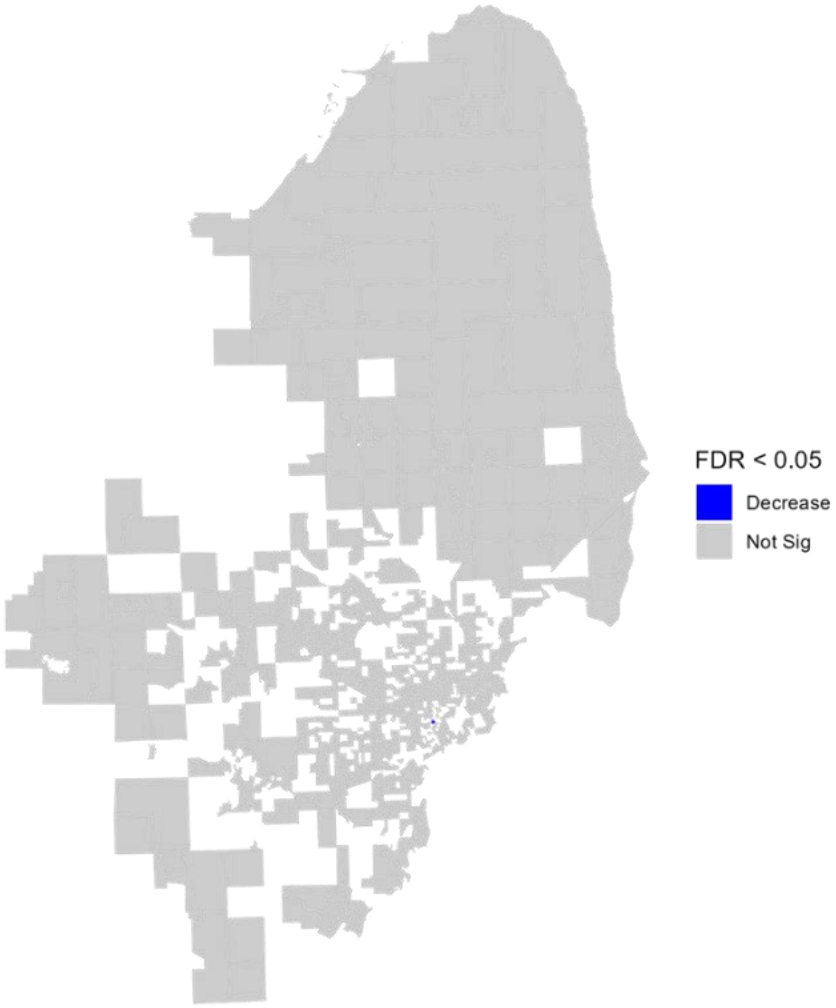
Maps for the other metrics for census tracts showed statistically significant use of the variance replicate methodology.



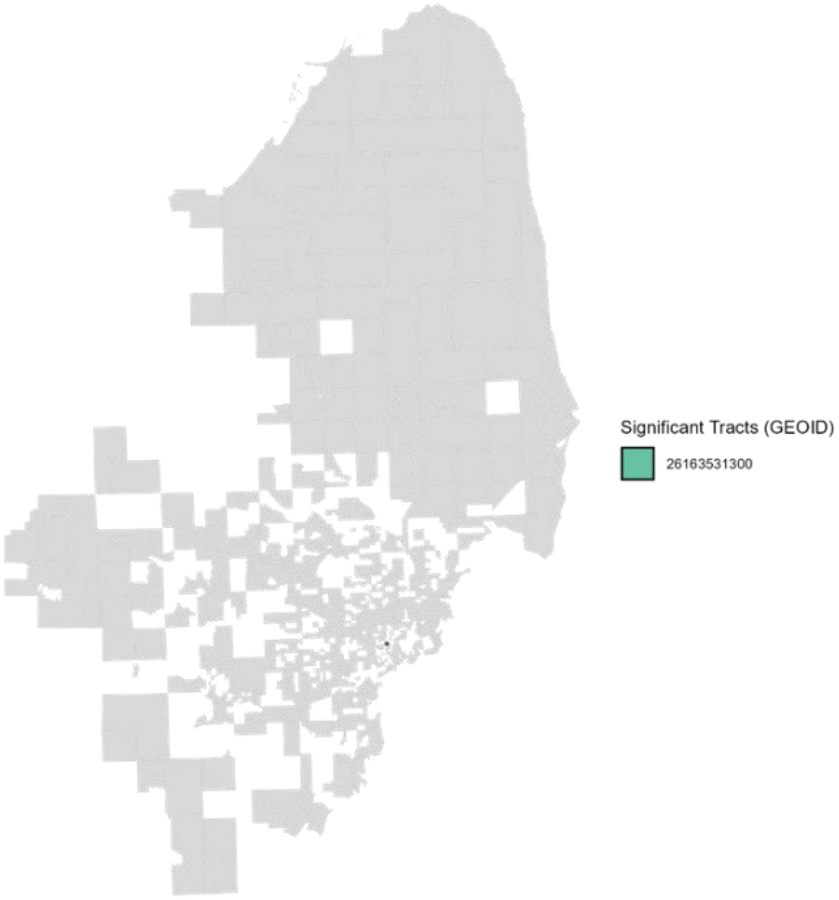
FDR-Significant Census Tracts: Black Population

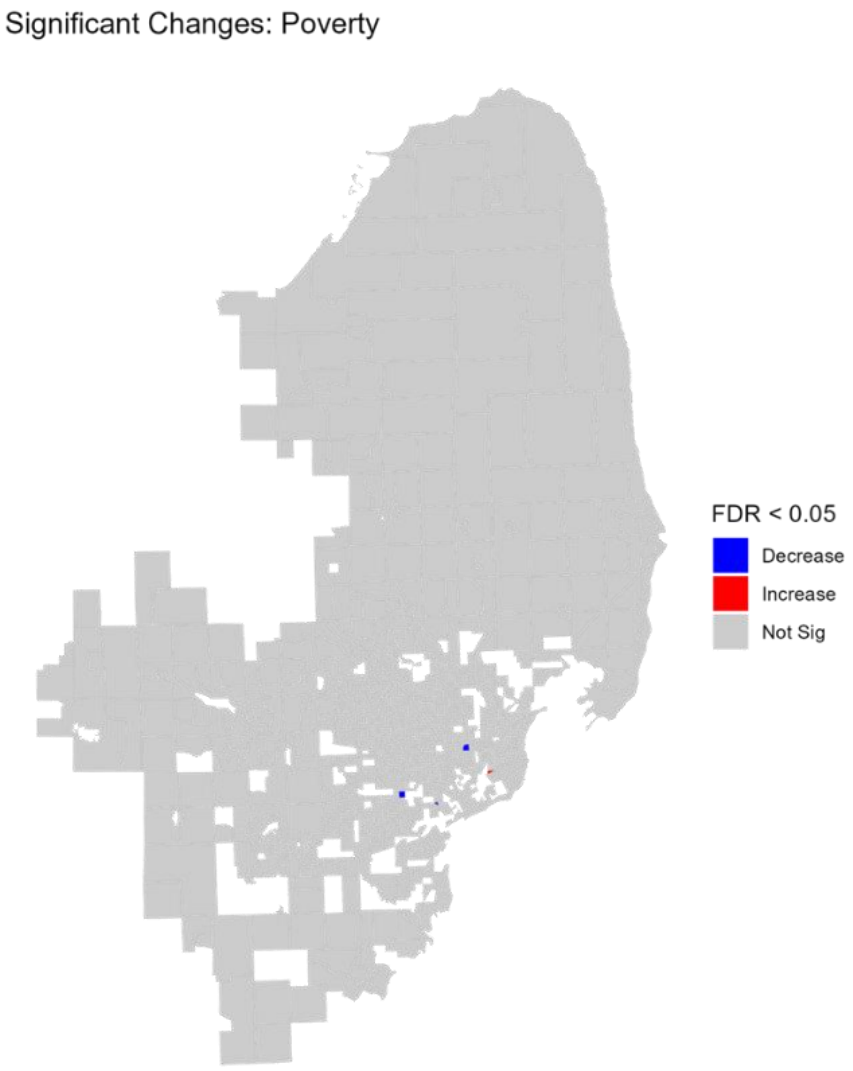


Significant Changes: No Public Assistance

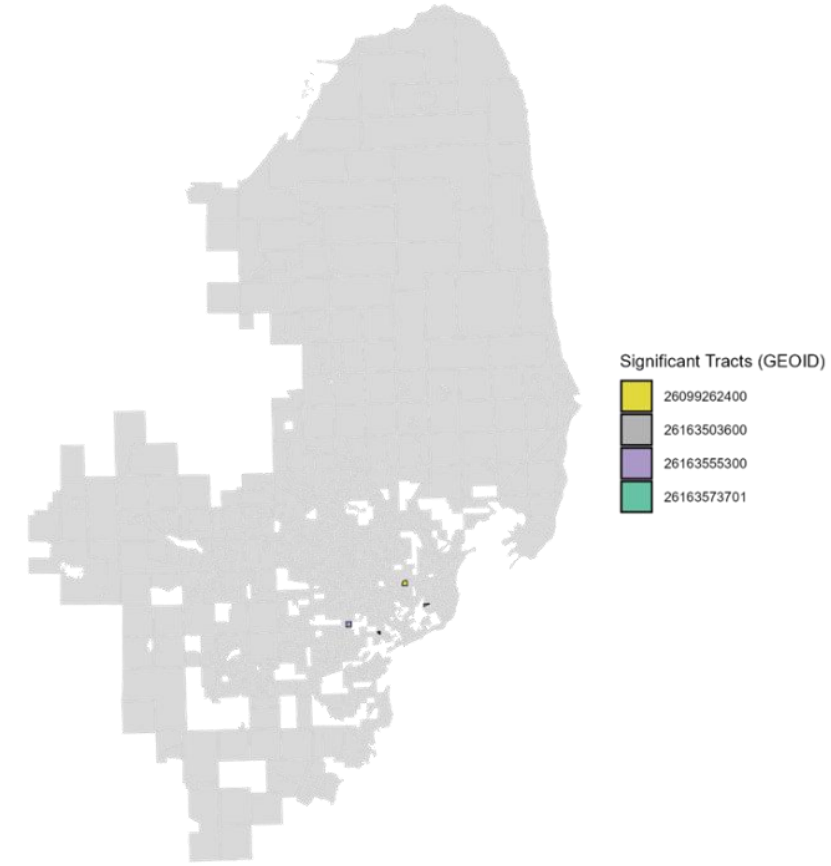


FDR-Significant Census Tracts: No Public Assistance



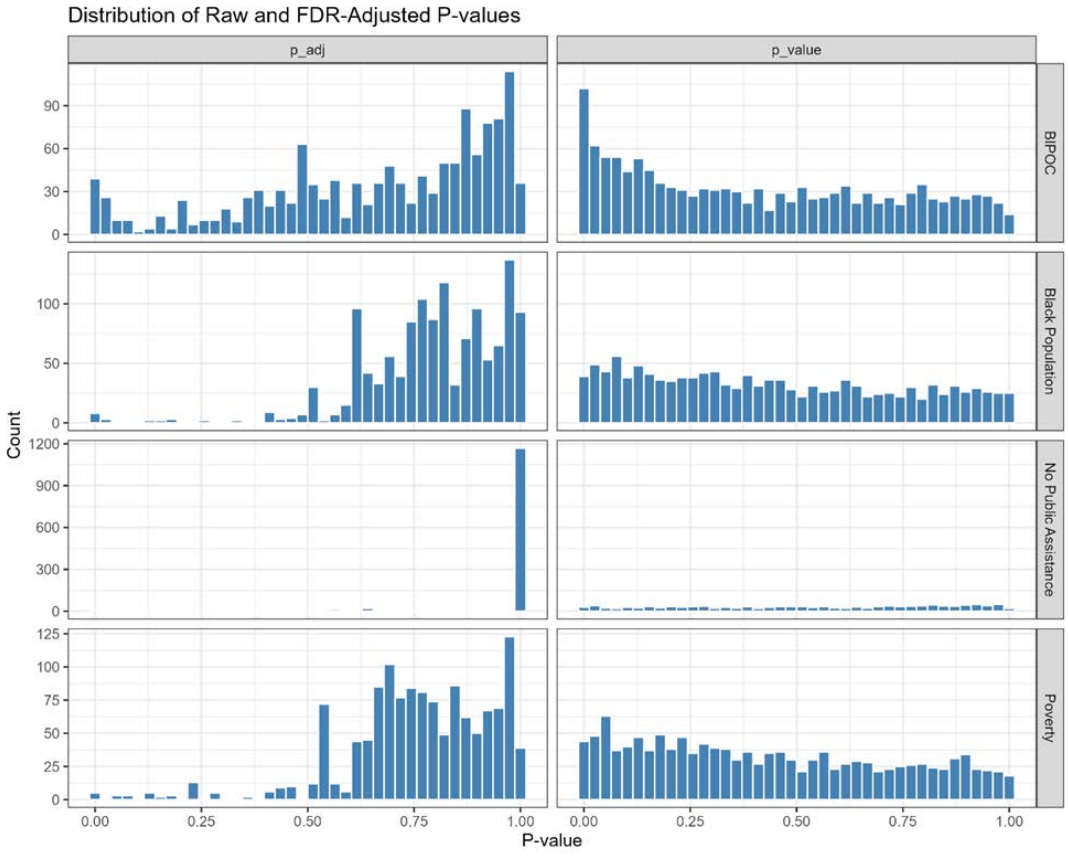

Significant Changes: Poverty
FDR < 0.05
Decrease
Increase
Not Sig

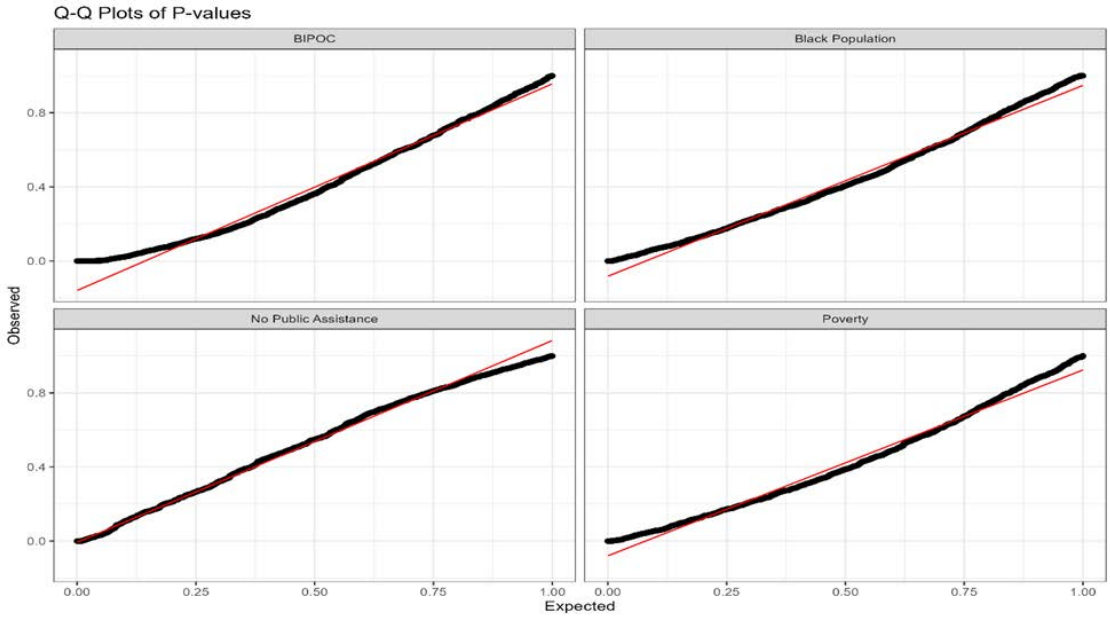
FDR-Significant Census Tracts: Poverty



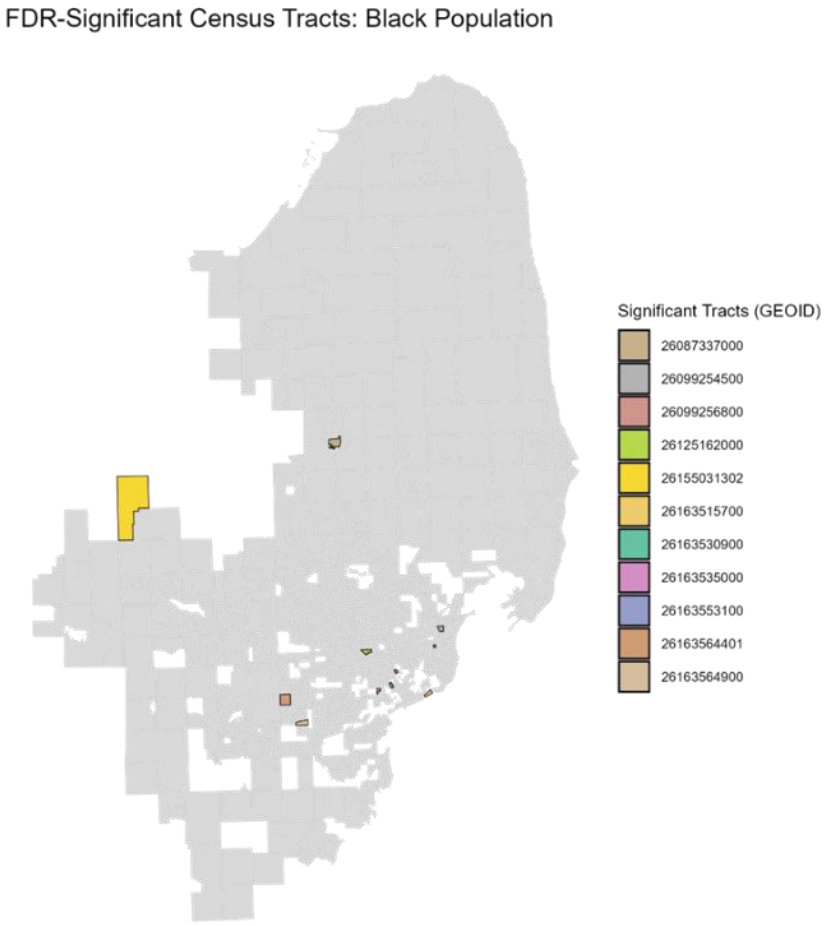
Appendix 8.7.C

P-value histogram and Q-Q plots for the approximation method.

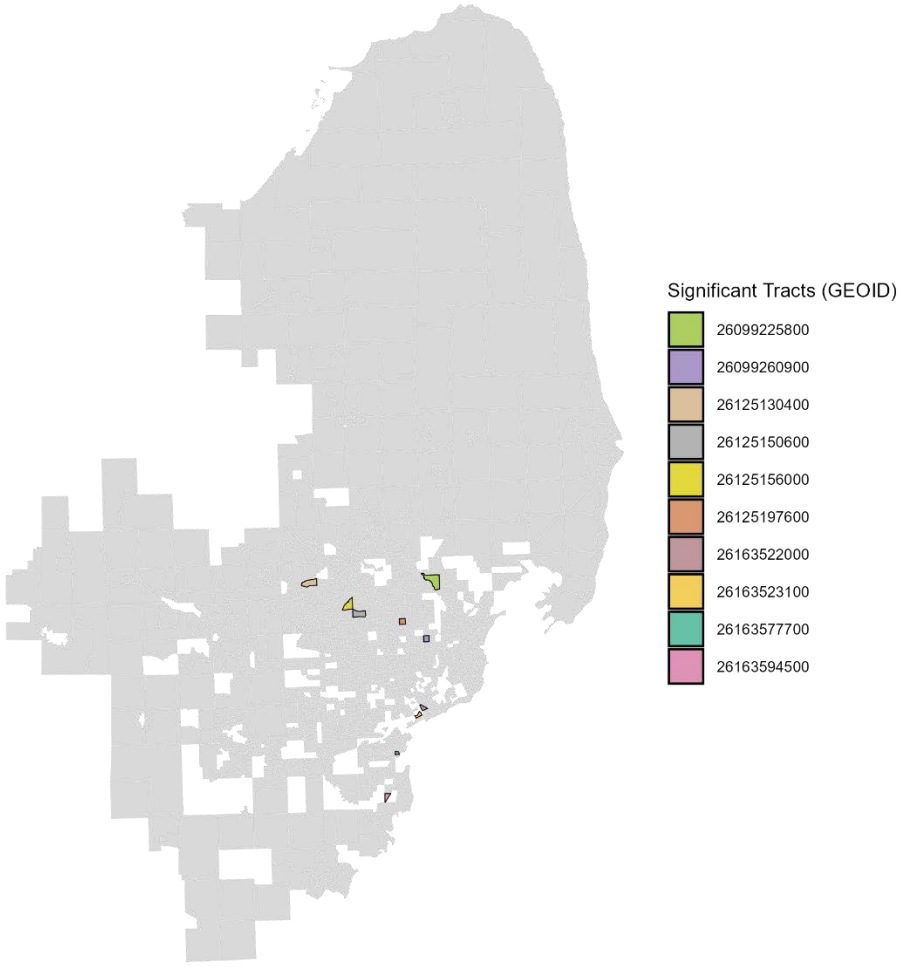




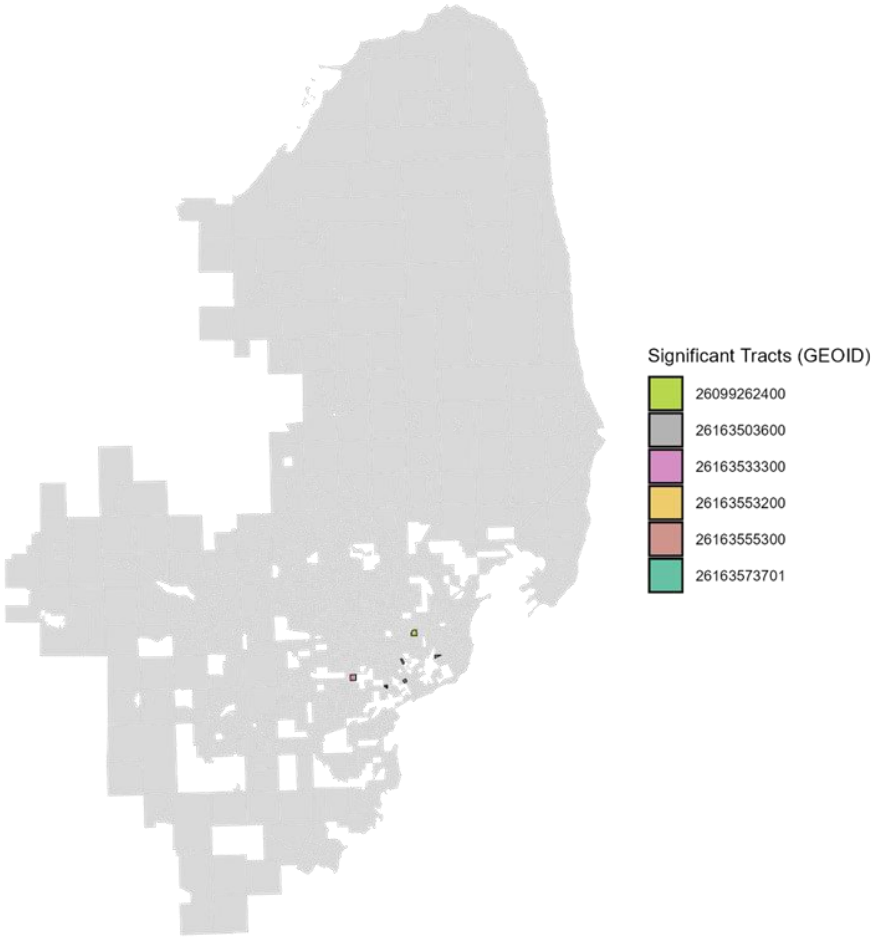
Appendix 8.7.D



FDR-Significant Census Tracts: No Public Assistance



FDR-Significant Census Tracts: Poverty



8.9 Alternatives Analyses Project List

	Alternative Analysis Project List
1	Subtransmission: Cortland Station Expansion
2	Subtransmission Redesign & Rebuild: Tie 4104 North
3	Subtransmission Redesign & Rebuild: Tie 7504
4	Subtransmission Redesign & Rebuild: Tie 3205
5	Subtransmission Redesign & Rebuild: Trunk 2455
6	Subtransmission Redesign & Rebuild: Maxwell Cable Replacement
7	CODI: Garfield Network Upgrade
8	CODI: Kent/Gibson Conversion
9	CODI: Howard Conversion
10	4.8 kV CC: I-94 Substation and Circuit Conversion (Promenade)
11	4.8 kV CC: Hawthorne Relief and Circuit Conversion
12	4.8 kV CC: Belleville Substation and Circuit Conversion
13	4.8 kV CC: Ann Arbor AC Network Conversion
14	4.8 kV CC: Pittsfield Substation and Circuit Conversion
15	4.8 kV CC: Hemlock Decommissioning and Circuit Conversion
16	4.8 kV CC: Hilton Circuit Conversion Phase 2
17	8.3 kV CC: Wheeler
18	4.8 kV CC: New Baltimore
19	System Loading: Brown City
20	System Loading: Richmond/Armada
21	System Loading: Spokane/Seneca
22	System Loading: Cody
23	System Loading: Grenada
24	System Loading: Wixom
25	System Loading: Goodison
26	System Loading: Lark/Spruce
27	System Loading: Otsego/Capac/Shaw

Project — Station Upgrade: Cortland Station Expansion

Due to current space constraints at Cortland Station, it is not possible to perform work on existing Transformers 1 & 2. This initiative is to expand the station footprint and replace existing Transformers with (2) new 120-24kV Transformers.

Project is NOT suitable for a NWA solution.

	Proposed Solution	Alternative 1	Alternative 2	Alternative 3
Brief Description	Replace 2 station transformers Install 6 circuit switchers Replace 600 feet of cable, install 600 ft of conduit. ITC to relocate transmission equipment to new station across the street to allow space for DTE equipment replacements.	Replace Cortland Transformer 101 and Transformer 102 and relocate on new DTE property purchased across the street from Cortland station. Existing transmission equipment at Cortland station would be utilized.	Replace Cortland Transformer 101 and Transformer 102 and relocate on new DTE property purchased across the street from Cortland station. ITC equipment would be installed on new DTE property with a straight bus configuration.	Decommission Cortland station and serve load from trunklines out of Frisbie station. Install new 24kV trunk lines from Frisbie to Cortland Install 2 conduits from Frisbie to Cortland (2 conduits x 3.1 miles) Install 16 cables from Frisbie to Cortland (16 cables x 3.1 miles) Install 12 breakers and 12 disconnects and 12 relay panels.
If constructable, provide high-level estimate.	$19 million	n/a – not constructable	n/a – not constructable	~$165 million; not including cost to decommission equipment at Cortland Station
What benefits does the alternative provide?	Replacing at risk transformers at Cortland and eliminating the risk of a widespread outage in the event of a transformer failure.	Replacing at risk transformers at Cortland and eliminating the risk of a widespread outage in the event of a transformer failure.	Replacing at risk transformers at Cortland and eliminating the risk of a widespread outage in the event of a transformer failure.	Decommissioning at risk transformers at Cortland and eliminating the risk of a widespread outage in the event of a transformer failure.
Why was this solution not selected?	N/A - Selected	ITC rejected this proposal due to relaying issues.	ITC rejected this proposal because straight bus no longer meets ITC's new standards.	N-1 and N-1-1 thermal and voltage violations were identified utilizing PSSE load flow analysis on Frisbie 120-24kV transformers and trunk lines with the new configuration.

Project — Subtransmission Redesign & Rebuild: Tie 4104 North

This project will reconductor the poor performing section of TIE4104 and relocate the circuit out of deep right of way to improve customer reliability. TIE4104 has deteriorated conductor and end of life poles resulting in equipment failure. The existing route of TIE4104 is in deep right of way which is susceptible to tree interference and leads to increased outage duration due to inaccessibility.

Project is NOT suitable for a NWA solution.

	Proposed Solution	Alternative 1	Alternative 2	Alternative 3
Brief Description	Install 18.83 miles of new OH, remove 17.27 miles of existing OH, replace 16.3 miles of distribution underbuilt, install 2.65 of new distribution underbuilt, upgrade substation.	Install 17.3 miles of new OH, remove 17.27 miles of existing OH, replace 5.6 miles of distribution overbuilt, upgrade substation.	Install 20.00 miles of new OH, remove 17.27 miles of existing OH, replace 11.3 miles of distribution underbuilt, upgrade substation.	Rebuild 17.27 miles of TIE4104 in place, rebuild 7 miles of distribution underbuilt.
If constructable, provide high-level estimate.	$59 million	$46 million	$49 million	$63 million
What benefits does the alternative provide?	TIE4104 experiences frequent outages and wire-down safety risks due to deteriorated 3/0 ACSR conductor, aging poles (84% beyond useful life), and a deep right-of-way that drives tree interference and long restoration times. The project will improve reliability and safety by upgrading to 636 AL conductor, replacing end-of-life wood poles with steel, and relocating the line to a truck-accessible route.	TIE4104 experiences frequent outages and wire-down safety risks due to deteriorated 3/0 ACSR conductor, aging poles (84% beyond useful life), and a deep right-of-way that drives tree interference and long restoration times. The project will improve reliability and safety by upgrading to 636 AL conductor, replacing end-of-life wood poles with steel, and relocating the line to a truck-accessible route.	Reduce sustained outages on TIE4104 by eliminating wire-down safety risks, upgrading deteriorated conductor to 636 AL, and replacing end-of-life wood poles with steel poles.	Reduce sustained outages on TIE4104 by eliminating wire-down safety risks, upgrading deteriorated conductor to 636 AL, and replacing end-of-life wood poles with steel poles.
Why was this solution not selected?	N/A - Selected	North section of this route is in dense residential area. The longest distance that would require Thumb Electric colocation More forested wetland areas More parcels impacted by tree removal for construction.	Longest 40 KV route A section of road is unimproved and may cause accessibility issues to steel poles.	This solution does not relocate the circuit out of Deep Right of Way and Railroad Easement. TIE 4104 would still be exposed to tree interference and would have poor accessibility for maintenance in the future. Steel poles can also not be utilized in non-truck accessible locations.

Project — Subtransmission Redesign & Rebuild: Tie 7504

This project will rebuild and relocate TIE7504 to improve customer reliability and address low voltage violations. TIE7504 has experienced frequent outages resulting in escalated customer complaints. The majority of the TIE7504 infrastructure is beyond life expectancy. The existing route of TIE7504 goes through deep right of way which is susceptible to tree interference and leads to increased outage duration due to inaccessibility.

Project is NOT suitable for a NWA solution.

	Proposed Solution	Alternative 1
Brief Description	HIGH LEVEL SCOPE OF WORK • Replace 12.2 miles of Subtransmission overhead conductor • Install 4 miles of new Subtransmission overhead conductor • Replace 5 pole top switches • Install 1 capacitor • Replace 2 breakers • Replace 2 relay panels • Replace 2 disconnects	HIGH LEVEL SCOPE OF WORK: Build 120-40kV station and reconductor TIE7504 • Replace 12.2 miles of Subtransmission overhead conductor • Install 4 miles of new Subtransmission overhead conductor • Replace 5 pole top switches • Replace 2 breakers • Replace 2 relay panels • Replace 2 disconnects • Install 11.5 mile 120kV line extension • Install 2 120kV buses • Install 4, 120kV breakers • Install 1, 120/40kV TRF
If constructable, provide high-level estimate.	$45.6 million	$66.2 million
What benefits does the alternative provide?	Reliability Capacity Operability	Reliability Capacity Operability
Why was this solution not selected?	N/A - Selected	Cost to implement greatly exceeds the proposed solution.

Project — Subtransmission Redesign & Rebuild: Tie 3205

This project will rebuild and relocate TIE3205 to improve customer reliability. TIE3205 has experienced frequent outages resulting in escalated customer complaints. The majority of the TIE3205 infrastructure is beyond life expectancy. The existing route of TIE3205 is in deep right of way which is susceptible to tree interference and leads to increased outage duration due to inaccessibility.

Project is NOT suitable for a NWA solution.

	Proposed Solution	Alternative 1
Brief Description	HIGH LEVEL SCOPE OF WORK • Replace 1 breaker • Replace 2 disconnects • Replace 1 relay panel • Install 28.8 miles of overhead conductor • Remove 25.6 miles of overhead conductor • Install 6 pole top switches • Remove 8 pole top switches	HIGH LEVEL SCOPE OF WORK: Reconductor TIE3205 in place • Replace 1 breaker • Replace 2 disconnects • Replace 1 relay panel • Install 27.6 miles of overhead conductor • Remove 27.6 miles of overhead conductor • Install 8 pole top switches • Remove 8 pole top switches
If constructable, provide high-level estimate.	$75.9 million	$75.4 million
What benefits does the alternative provide?	Reliability, aging Infrastructure, tree interference, and truck accessibility/outage duration	Reliability and aging infrastructure
Why was this solution not selected?	N/A - Selected	This solution was not selected as it does not relocate the circuit from deep right of way which reduces total tree exposure by 24 miles as well as time to patrol, repair and restore if an event takes place.

Project — Subtransmission Redesign & Rebuild: Maxwell Cable Replacement

DTE intends to replace the 120 kV pipe type cables as a proactive measure for a critical facility following multiple 2017 and 2025 cable failures. The existing pair of 120kV gas filled cables are beyond life expectancy (50+ years), the cable type is out of date, requires constant maintenance and extensive amount of shutdown time to restore.

Project is NOT suitable for a NWA solution.

	Proposed Solution	Alternative 1
Brief Description	Replace underground cables and conduit.	Build new DTE substation along with cable replacement.
If constructable, provide high-level estimate.	$7.73 million	$22.4 million + land acquisition cost
What benefits does the alternative provide?	Equipment failure, maintenance, and reliability	Equipment failure, maintenance, Operational flexibility and reliability
Why was this solution not selected?	N/A - Selected	Cost and timeline to benefit ratio.

Project — Subtransmission Redesign & Rebuild: Trunk 2455

The conduit in the 8 Mile Rd bridge crossing over M-10 is corroded and cables have become stuck in the conduit after failures occurred. There are no spare ducts in this conduit to install new cable if another failure occurs and the failed cable is unable to be removed and replaced. Three 24kV trunklines (impacting 8 substations) and two distribution circuits are at risk for an extended outage if a cable failure were to occur. New conduit is being proposed, boring under M-10 to replace this corroded conduit system. The three 24kV trunklines and two distribution circuits can then be relocated into the new conduit, eliminating the risk for an extended outage due to cable failure in the corroded conduit.

Project is NOT suitable for a NWA solution.

	Proposed Solution	Alternative 1	Alternative 2
Brief Description	Evaluate pulling out stuck cables then utilizing new conduit lining process to repair corroded ducts. Then iteratively relocate cables to lined ducts and continue lining all the corroded ducts in the bridge.	Install conduit in the bridge north of the existing conduit.	Re-route circuits overhead to bypass corroded conduit.
If constructable, provide high-level estimate.	$15.6 million	n/a – not constructable	n/a – not constructable
What benefits does the alternative provide?	Reliability: The conduit crossing M-10 at 8 Mile Road is corroded causing cables to become stuck in the ducts. Eight substations are at risk of losing one of their subtransmission feeds if a cable failure occurs. Eliminate the potential for an extended outage and potential load loss due to cable failure in the existing damaged conduit.	There were no benefits as MDOT rejected the proposal.	There were no benefits as this was not achievable.
Why was this solution not selected?	N/A - Selected	MDOT rejected this proposal as it would require structural modifications to the bridge to make room for the conduit installation.	There are not enough possible overhead routes to re-route all the circuits overhead and abandon the conduit.

Project — CODI: Garfield Network Upgrade

The Garfield project is part of the City of Detroit Infrastructure (CODI) plan, which addresses load demand and aging infrastructure. Garfield substation is to be decommissioned and its circuits converted to nearby 13.2kV substations.

NWA analysis performed - is NOT a candidate.

	Proposed Solution	Alternative 1	Alternative 2	Alternative 3
Brief Description	• Consolidate & Convert 4.8 kV ~35 miles of overhead into 13.2 kV • Consolidate & Convert 4.8 kV ~28 miles of underground into 13.2 kV • Decommission and Remove Garfield substation and circuits • Decommission 24 kV assets feeding Garfield substation	Only upgrade Garfield ACNWK • Replace ~8 miles of Garfield ACNWK backbone with 500EPR cable • Replace (83) netbank transformers	• Transfer 4.8 kV OH/underground GARFD Power Line and Distribution circuits/Primary Service customers to nearby 4.8 FRISB/PULFD circuits • Decommission and remove GARFD substation and circuits • Decommission 24 kV assets feeding GARFD substation • Transfer GARFD ACNWK system to nearby AMSTR ACNWK system	Consolidate and Convert circuits to nearby existing 13.2kV substations and install ISO down transformers • Consolidate & Convert ~15 miles of 4.8kV overhead into 13.2kV • Consolidate & Convert ~19 miles of 4.8kV all UG circuits (incl T.O.) into 13.2kV • Install ~(10)1MVA Iso-banks • Install ~ (6) 2500kVA ISO step down transformers and transfer 4.8 kV underground Garfield Power Line circuits/Primary Service customers to nearby 13.2kV circuits • Decommission and Remove (1) 4.8kV substation • Transfer all Garfield ACNWK system to AMSTR 4.8kV ACNWK System
If constructable, provide high-level estimate.	$288 million	$108 million	n/a – not constructable	n/a – not constructable
What benefits does the alternative provide?	•New 13.2 KV substation increases load capacity •Addresses Operability by providing capacity relief, improves restoration pathways through installation of more open points and deployment of smart sectionalizing equipment •Provides significant reliability improvement, as it will replace all aging assets/equipment/infrastructure in the system and substation • Enables SCADA on the ACNWK netbanks	• Replaces limited backbone system cable on the ACNWK system • Enables SCADA on the ACNWK netbanks • Marginally increases capacity on the ACNWK System	Load is transferred off Garfield substation onto Frisbie/Pulford substations, allowing the decommissioning of Garfield substation and 24 kV assets feeding Howard.	Load is transferred off Garfield substation onto nearby 13.2kV substation, allowing the decommissioning of Garfield substation and 24 kV assets feeding Garfield.
Why was this solution not selected?	N/A - Selected	•Does not address 24kV system •Limited impact to stranded load •Limited impact on SAIDI gap •Does not enable larger (>0.8MVA) non-network customers to connect •Expanding the 4.8 kV system does not address safety/reliability concerns	Frisbie/Pulford are 4.8 kV substations and will also be decommissioned in the future. Frisbie/Pulford substation loading is limited on the 24kV lines.	•Does not address small-copper conductor •Does not address ungrounded wire downs •Limited impact to stranded load •Limited impact on SAIDI gap •Large number of iso-banks impractical to install in urban areas •This option is not practical for urban residential dense areas with a large amount of small conductor

Project — CODI: Kent/Gibson Conversion

The Kent/Gibson Conversion project is part of the greater City of Detroit Infrastructure (CODI) which was implemented to serve new load and address aging assets. This project will help serve load along the West Detroit Riverfront currently can't be served reliably with the 4.8kV infrastructure. The project will utilize the newly built 13.2kV Corktown substation to convert and consolidate the 4.8kV in the area to 13.2kV.

NWA analysis performed - is NOT a candidate.

	Proposed Solution	Alternative 1	Alternative 2
Brief Description	• Consolidate, pre-convert & convert (6) KENT4.8kV circuits to CORKT13.2kV • Consolidate, pre-convert & convert (8) GIBSN 4.8kV circuits to CORKT13.2kV • Consolidate, pre-convert & convert (1) SCOTN 4.8kV circuits to CORKT13.2kV • Consolidate, pre-convert & convert (3) HOWRD 4.8kV circuits to CORKT13.2kV • Convert (17) primary customer from 4.8 kV to 13.2 kV • Decommission 8 miles of 4.8 kV cable • Remove (8) 4.8 kV breakers and decommission Kent substation • Remove (11) 4.8 kV breakers and decommission Gibson substation • Decommission 16 miles of 24kV cables and equipment	4.8kV Substation Capacity Upgrade • Install or upgrade power transformers at Kent & Gibson Substation	Source Conversions w/ISO Down • Utilize existing 120-13.2kV Corktown Substation to consolidate & convert ~16 miles of 4.8kV overhead into 13.2kV • Consolidate & Convert ~8 miles of 4.8kV underground cable into 13.2kV • Install ~50 ISO Transformers • Decommission 8 miles of 4.8 kV cable • Remove (8) 4.8 kV breakers and decommission Kent substation • Remove (11) 4.8 kV breakers and decommission Gibson substation • Decommission 16 miles of 24kV cables and equipment
If constructable, provide high-level estimate.	$107 million	n/a – not constructable	n/a – not constructable
What benefits does the alternative provide?	• Automation • Protection • Addresses loading concerns due to the resurgence of the area • Safety, Capacity, Reliability, Operability	Increases capacity at the substation level.	• Less Preconversion miles, will save overall cost • Backbones will be preconverted and equipped with protective devices • Even though the substation Capacity increases, it is limited at each ISO transformer
Why was this solution not selected?	N/A - Selected	• Space limitations at existing substation footprints • The 24kV system also has capacity constraint	• Large number of iso-banks impractical to install in urban areas • Does not address small-copper conductor • Does not address ungrounded wire downs • Limited impact to stranded load • Limited impact on SAIDI gap

Project — CODI: Howard Conversion

The CODI: Howard Conversion Project is part of the City of Detroit Infrastructure (CODI) plan, which addresses known reliability issues, system operability, and aging infrastructure. Howard substation power lines and network feeders are to be decommissioned and converted to nearby 13.2kV substations. After all load is removed from Howard substation, the substation and its 24 kV primary feeders are to be decommissioned. Howard substation overhead distribution circuits will be converted as part of the CODI: Kent/Gibson project.

NWA analysis performed - is NOT a candidate.

	Proposed Solution	Alternative 1	Alternative 2	Alternative 3
Brief Description	•Consolidate & Convert 4.8 kV ~32.11 miles of underground into 13.2 kV •Decommission and Remove Howard substation and circuits •Decommission 24 kV assets feeding Howard substation	Install or upgrade power transformer(s) at Howard substation	• Transfer 4.8 kV underground Howard Power Line circuits/Primary Service customers to nearby 4.8 kV Madison circuits • Decommission and remove Howard substation and circuits • Decommission 24 kV assets feeding Howard substation • Transfer Howard ACNWK system to nearby Madison ACNWK system	• Install ~ () 2500kVA ISO step down transformers and transfer 4.8 kV underground Howard Power Line circuits/Primary Service customers to nearby 13.2kV circuits • Decommission and remove Howard substation and circuits • Decommission 24 kV assets feeding Howard substation • Transfer Howard ACNWK system to nearby Madison ACNWK system
If constructable, provide high-level estimate.	$116-120 million	n/a – not constructable	n/a – not constructable	n/a – not constructable
What benefits does the alternative provide?	Removes 4.8 kV circuits and transfers load to 13.2 kV system. Decommission aging 4.8 kV assets. 13.2 kV system will have increased load capacity for existing load and future developments.	Replaces aging infrastructure at Howard substation. Expanded substations increase load capacity of the substation.	Load is transferred off of Howard substation onto Madison substation, allowing the decommissioning of Howard substation and 24 kV assets feeding Howard.	Load is transferred off of Howard substation onto nearby 13.2kV substation, allowing the decommissioning of Howard substation and 24 kV assets feeding Howard.
Why was this solution not selected?	N/A - Selected	No room to expand Howard substation. The substation is enclosed in a building. Howard substation is 4.8 kV. DTE is working to convert the 4.8 kV delta system to 13.2 kV. Increasing capacity at a substation level doesn't benefit the Howard ACNWK system.	Madison is a 4.8 kV substation and will also be decommissioned in the future. Madison substation loading is limited on the 24kV lines.	No physical room to install 2500kVA ISO padmounted transformers in the dense area of Detroit's Financial District. Loading will also be limited by the ISO padmount transformers as well.

Project — 4.8 kV CC: I-94 Substation and Circuit Conversion (Promenade)

This project will construct a new 120/13.2kV Class A Substation to relieve existing overloads, improve reliability, operability and increase capacity in the I-94 Industrial Park region which serves approximately 9,000 customers.Additional load from the I-94 Industrial Park region cannot be reliably served by the 4.8kV infrastructure at Lambert, Lynch and Pulford substations, which are over 80 years old. This initiative will convert, consolidate, and decommission (3) 4.8kV substations, their associated circuits, and decommission a significant amount of 4.8kV & 24kV infrastructure.

NWA analysis performed - is NOT a candidate.

	Proposed Solution	Alternative 1
Brief Description	Construct a new 120-13.2kV substation named Promenade • Construct 1.6 miles of 15-5" conduit • Install (20) 3-way manholes • Convert existing 4.8kV circuits and transfer to new 13.2kV circuits (over 100 miles of overhead) • Decommission existing system cable • Decommission Pulford, Lynch, and Lambert substations • Decommission eight 24kV trunk lines	Install ISO down transformers (just source conversion) • Consolidate & Convert ~60 miles of 4.8kV overhead into 13.2kV • Install ~(20) 1MVA Iso-banks • Decommission and Remove (2) 4.8kV substations
If constructable, provide high-level estimate.	$295 million	n/a – not constructable
What benefits does the alternative provide?	Substation area encompasses the emerging I-94 Industrial Corridor, potential for major industrial Load Growth • Addresses old age infrastructure • Decreases SAIDI • Increases capacity • Decommission (2) 24-4.8kV substations • Decommission 24kV	• Minimal impact on SAIDI • Decommission (2) 24-4.8kV substations • Decommission 24kV • least costly
Why was this solution not selected?	N/A - Selected	• Does not address old, aging infrastructure • Capacity is limited by ISO transformers

Project — 4.8 kV CC: Hawthorne Relief and Circuit Conversion

Hawthorne Project is a critical investment needed to address growing capacity constraints, aging infrastructure, and system configuration limitations affecting the Daly, Glendale, Hawthorne, and related substations. These substations collectively serve over thirty thousand customers and form a major structural backbone of DTE's distribution system in Redford, Dearborn, Westland and surrounding areas. Years of load growth, combined with equipment operating beyond design limits, have diminished the system's ability to reliably serve customers, respond to contingencies, and maintain safe operating conditions. Without targeted investment, these conditions are projected to worsen, resulting in increased customer outages, higher safety risks, and diminished operational flexibility. The project focuses on expanding the 13.2kV Mallard substation to relieve existing 4800V overloads and support future load growth, improving system reliability and operability by converting approximately 92 miles of 4.8kV overhead infrastructure from multiple substations while installing protective equipment and enabling loop schemes, and reducing stress on overloaded substations and circuits to enhance overall performance and resilience.

NWA analysis performed - is NOT a candidate.

	Proposed Solution	Alternative 1	Alternative 2
Brief Description	Expand existing 120-13.2kV Class A Mallard Substation - Consolidate & Convert about 88 miles of 4.8kV overhead into 13.2kV - Consolidate & Convert ~2 miles of 4.8kV all UG circuits (mostly T.O.) into 13.2kV - Decommission and Remove (2) 4.8kV substations	Expand existing 120-13.2kV Class A Mallard Substation - Consolidate & Convert ~59 miles of 4.8kV overhead into 13.2kV - Consolidate & Convert ~2 miles of 4.8kV all UG circuits (incl T.O.) into 13.2kV - Install ~(20)1MVA Iso-banks - Decommission and Remove (2) 4.8kV substations	Install or upgrade power transformer at 4.8 kV substations (DALY and HAWTH) - At Hawthorne substation replace (2) existing smaller 20MVA transformers with (2) bigger 40MVA transformers - At Daly substation replace a 10 MVA and a 20MVA existing transformers with (2) bigger 40MVA transformers
If constructable, provide high-level estimate.	$200-250 million	$175-200 million	n/a – not constructable
What benefits does the alternative provide?	This solution addresses capacity constraints and aging infrastructure in the area. It provides capacity relief, improves restoration pathways through installation of more open points and deployment of smart sectionalizing equipment.	Addresses loading concerns in the area. It provides limited impact on reliability and limited jumpering options.	Partially addresses system loadability, is not feasible to execute due to space.
Why was this solution not selected?	N/A - Selected	This solution was not selected because of the following - Does not address small-copper conductor - Does not address ungrounded wire downs - Limited impact to stranded load - Limited impact on SAIDI gap - Large number of iso-banks impractical to install in urban areas	This solution was rejected because of the following: - Does not address 24kV system - Limited impact to stranded load - Limited impact on SAIDI gap - Not feasible due to space limitations

Project — 4.8 kV CC: Belleville Substation and Circuit Conversion

Belleville Substation's 4.8kV switchgear failed in 2022. It was decommissioned and removed. The remaining 4.8kV infrastructure was reconfigured into two load carrying circuits. This project will convert, consolidate, and decommission the remaining 4.8kV side of the existing BELVL Class 'T" substation as well as the 2, 4.8kV, circuits it currently serves. The converted equipment as well as BELVL's existing 13.2kV side will be combined to form a new 120/13.2kV Class 'R' Substation. This project will relieve capacity issues and improve reliability, safety and operability in the Belleville Area, which serves approximately 4,100 customers.

NWA analysis performed - is NOT a candidate.

	Proposed Solution	Alternative 1	Alternative 2	Alternative 3
Brief Description	Construct a new 40/13.2kV Class R substation - Convert existing 4.8kV BELVL circuits - Transfer load to surrounding infrastructure -Install new 13.2kV transformer - Decommission 4.8kV side of BELVL Substation - Transfer load back on to BELVL and reconfigure new circuits - Replace existing 13.2kV transformer	4.8kV circuit conversion - Convert existing 4.8kV BELVL circuits - Transfer to surrounding infrastructure/substations - Decommission 4.8kV side of BELVL Substation	Construct a new 40/13.2kV Class T substation - Convert existing 4.8kV BELVL circuits - Transfer load to surrounding infrastructure -Install new 13.2kV transformer - Decommission 4.8kV side of BELVL Substation - Transfer load back on to BELVL and reconfigure new circuits - Replace existing 13.2kV transformer	Class A Belleville Substation - Convert existing 4.8kV BELVL circuits - Transfer load to surrounding infrastructure -Install new 13.2kV transformer - Decommission 4.8kV side of BELVL Substation - Transfer load back on to BELVL, reconfigure new circuits, and install PDC - Replace existing 13.2kV transformer
If constructable, provide high-level estimate.	$25 million	n/a – not constructable	$29 million	$35 million
What benefits does the alternative provide?	Safety: • The newly converted BELVL circuits will be 13.2KV grounded wye Reliability: • 5 year average All Weather SAIDI is projected to be reduced by up to 90% Capacity/Loadbility: • BELVL 13.2kV sub will be ~40% of Firm upon initiative completion • Additional capacity available for new business/customers Operability: • All BELVL 13.2kV circuits will be under the 8 MVA DDO limit • All 13.2kV circuits will be fully automated with loop schemes and automatic pole top switches, as well as full fault protection (fusing, sectionalizing, reclosing) • Newly converted 13.2kV circuits will be able to communicated and transfer load between the surrounding infrastructure (SUMTR, DAYTN, existing BELVL 13.2kV)	Safety: • The newly converted BELVL circuits will be 13.2KV grounded wye Reliability: • 5 year average All Weather SAIDI is projected to be reduced by up to 90% Operability: • All 13.2kV circuits will be fully automated with loop schemes and automatic pole top switches, as well as full fault protection (fusing, sectionalizing, reclosing) • Newly converted 13.2kV circuits will be able to communicated and transfer load between the surrounding infrastructure (SUMTR, DAYTN, existing BELVL 13.2kV)	Safety: • The newly converted BELVL circuits will be 13.2KV grounded wye Reliability: • 5 year average All Weather SAIDI is projected to be reduced by up to 90% Capacity/Loadbility: • BELVL 13.2kV sub will be under Firm upon initiative completion • Additional capacity available for new business/customers Operability: • All BELVL 13.2kV circuits will be under the 8 MVA DDO limit • All 13.2kV circuits will be fully automated with loop schemes and automatic pole top switches, as well as full fault protection (fusing, sectionalizing, reclosing) • Newly converted 13.2kV circuits will be able to communicated and transfer load between the surrounding infrastructure (SUMTR, DAYTN, existing BELVL 13.2kV)	Safety: • The newly converted BELVL circuits will be 13.2KV grounded wye Reliability: • 5 year average All Weather SAIDI is projected to be reduced by up to 90% Capacity/Loadbility: • BELVL 13.2kV sub will be under of Firm upon initiative completion • Additional capacity available for new business/customers Operability: • All BELVL 13.2kV circuits will be under the 8 MVA DDO limit • All 13.2kV circuits will be fully automated with loop schemes and automatic pole top switches, as well as full fault protection (fusing, sectionalizing, reclosing) • Newly converted 13.2kV circuits will be able to communicated and transfer load between the surrounding infrastructure (SUMTR, DAYTN, existing BELVL 13.2kV)
Why was this solution not selected?	N/A - Selected	- Does not relieve capacity drivers and would bring surrounding infrastructure over DTE's DDO rating of 8MVA - New equipment and conversion would increase operability/communication between circuits but the increase in loading would severely limit load transfers between the surrounding circuits - No additional capacity for future load growth	- Limited substation reliability, as compared to the class R, with similar cost	- Largest increase and capacity with the most number of options in terms of new circuits. However, it is the most costly and the area in which it would be installed is not expecting large amounts of load growth in the near future.

Project — 4.8kV CC: Ann Arbor AC Network Conversion

The AC network system consists of network feeders, network transformer bank assemblies and network secondary conductors. The system is designed to eliminate service interruptions due to the failure of primary feed. DTE is developing plans to convert the Ann Arbor AC network from 4.8kV to 13.2kV. The City of Ann Arbor has issued an ordinance geared towards increasing use of electric vehicles and electric heating which would increase demand in Ann Arbor and has a goal to be carbon neutral by 2030. The existing electrical infrastructure is not able to accommodate this expected load growth. This project will replace AC Network pedestals and netbank transformers. It will also upgrade an existing substation from 40-4.8kV to 40-13.2kV, by converting circuits and transferring them to adjacent substations.

NWA analysis performed - is NOT a candidate.

	Proposed Solution	Alternative 1
Brief Description	**Upgrade Hoover Substation** 40-4.8kV to 40-13.2kV TRFs: (2) 15/20/25 MVA PDC: (1) 9-POS Establish conduit and cable Establish OH circuits and sectionalizing Pre-convert and convert 9 Hoover Circuits Pre-convert and convert 3 Burton AC Network Feeders	**Build New 40-13.2kV Substation** TRFs: (2) 15/20/25 MVA PDC: (1) 9-POS Purchase Property Establish 40kV feeds Establish conduit and cable Pre-convert and convert 3 Burton AC Network Feeders
If constructable, provide high-level estimate.	$108 million	n/a – not constructable
What benefits does the alternative provide?	• Provide sufficient capacity to serve growing Ann Arbor downtown • Provides a new source for the 13.2kV AC Network • Reduce network cable failures and improve manhole safety • Decommission aging infrastructure and reduce major event risk • Increase protection for the distribution system • Enhance grid technology and automation • Reduce new customer connection timeframe and cost • Decommission Charlotte Substation	• Provides the ability to construct the new source without having to wait for circuit conversions. • Provides a new 13.2kV source for the AC Network
Why was this solution not selected?	N/A - Selected	• No available properties within the proximity of the AC Network • Purchasing of existing properties can lead to extended project timelines due to public pushback and re-zoning.

Project — 4.8kV CC: Pittsfield Substation and Circuit Conversion

This project will construct a new 40-13.2kV substation to relieve existing overloads through load transfers, providing additional capacity for future project load growth in the PITTS, WLVRN, and CROWN 13.2kV substation areas, which serves 33,000 customers. This area has already completed load transfers for capacity relief; however, MOS requests continue to grow and there is expected general load growth with Ann Arbor's electrification and Hub expansion goals. In addition, this initiative will convert, consolidate, and decommission an aging 4.8kV substation and its associated circuits while addressing safety, reliability and operability issues in the area.

NWA analysis performed - is NOT a candidate.

	Proposed Solution	Alternative 1	Alternative 2
Brief Description	New 40-13.2kV Substation at PITTS	Crown Substation Transformer and PDC Replacement	Purchase new substation property between Wolverine and Crown Substations
If constructable, provide high-level estimate.	~ $78 million	~$85 million	~$100 million
What benefits does the alternative provide?	Safety Reliability Operability Capacity	Safety Reliability Operability Capacity	Safety Reliability Operability Capacity
Why was this solution not selected?	N/A - Selected	Rejected due to distance away from load center of Pittsfield Township. The increased distance would result in much higher costs.	Rejected due to distance away from load center of Pittsfield Township. The increased distance would result in much higher costs. Requirement to purchase new land for substation.

Project — 4.8kV CC: Hemlock Decommissioning and Circuit Conversion

This project will construct a new 40/13.2kV Class A Substation to relieve existing overloads, improve reliability, operability and increase capacity in the Ann Arbor Area which serves approximately 33,000 customers. This area has already completed load transfers for capacity relief; however, bringing 13.2kV into the downtown Ann Arbor area will allow for additional capacity relief for future load growth expectations due to Ann Arbor's electrification efforts, Hub expansion goals and steady increases in MOS requests in the area. This project will convert, consolidate, and decommission (1) 4.8kV substation, its associated circuits and decommission a significant amount of 4.8kV infrastructure.

NWA analysis performed - is NOT a candidate.

	Proposed Solution	Alternative 1	Alternative 2
Brief Description	**Upgrade Hemlock Substation** • Offload HEMLK 4.8kV substation by converting and consolidating circuits • Transfer total load onto neighboring circuits and (2) STDFs • Establish conduit and cable • Establish OH circuits • Decommission substation • Build new 40-13.2kV Class A substation • TRFS: (2) 15/20/25MVA • PDC: (1) 9-POS • Establish sectionalizing and loop schemes	**Build new 40-13.2kV Substation** • Purchase property between HEMLK and JAKSN substations • TRFS: (2) 15/20/25MVA • PDC: (1) 9-POS • Establish conduit and cable • Establish OH circuits and sectionalizing • Complete conversions in Ann Arbor Area	**Convert neighboring 4.8kV iso-pockets** • Convert neighboring 4.8kV iso-pockets on 13.2kV circuits (SPRUC, PDMNT).
If constructable, provide high-level estimate.	$120 million	n/a – not constructable	n/a – not constructable
What benefits does the alternative provide?	Bringing 13.2kV into the downtown Ann Arbor area allows for capacity relief and replacement of aging 4.8kV infrastructure, improving safety and operability. This option will relieve existing overloads, improve reliability, operability and increase capacity.	Increase capacity and bring 13.2kV into the downtown Ann Arbor area.	Allows for the replacement of aging 4.8kV infrastructure, improving safety and operability. Improves load jumpering capabilities in the area.
Why was this solution not selected?	N/A - Selected	Property acquisition had been attempted in the area between HEMLK and JAKSN substations but was not adopted due to cost and limited availability of land.	Conversions of 4.8kV iso-pockets needed to complete load transfers during HEMLK project onto neighboring 13.2kV circuits (SPRUC, PDMNT) were addressed as part of the iso-conversion program. Completing conversions on only these iso-pockets would not have addressed lack of capacity and the need to bring 13.2kV into the downtown Ann Arbor area.

Project — 4.8 kV CC: Hilton Road Circuit Conversion Phase 2

This project is the continuation of a capacity project to relieve the overloaded FERND & HAZPK substations, and the area continues to be of high interest for large economic development requests. Other dirvers are poor reliability and operability in the area as well as the aged existing 24kV and 4.8kV equipment. This project will expand an existing 120kV-13.2kV Class A Substation (HLTRD) to increase capacity and improve reliability, operability in the Ferndale, Pleasant Ridge, Royal Oak Township, Oak Park and Hazel Park area currently served by (3) 4.8kV substations (FERND, WDSID, HAZPK) serving over 14,000 customer and will decommission (3) 4.8kV substations, their associated circuits, and a significant amount of 24kV infrastructure.

NWA analysis performed - is NOT a candidate.

	Proposed Solution	Alternative 1
Brief Description	Consolidate/Convert & Decommission FERND, WDSID and HAZPK Substations • Expand HLTRD substation • Consolidate & Convert ~ 95.6miles of 4.8kV overhead to 13.2kV fed from HLTRD substation • Decommission 24kV lines • Decommission FERND, WDSID and HAZPK substations	Consolidate/Convert & Decommission FERND, WDSID and HAZPK Substations - Source Conversion with ISO Downs • Expand HLTRD substation • Consolidate & Convert ~63.7miles of 4.8kV overhead to 13.2kV fed from HLTRD substation • Install ~(34) 1MVA Iso-banks • Decommission 24kV lines • Decommission FERND, WDSID and HAZPK substations
If constructable, provide high-level estimate.	$324.4 million	n/a – not constructable
What benefits does the alternative provide?	• 5 year average All Weather SAIDI would expect to be reduced by 80% • Decommission 24kV lines • Decommission FERND, WDSID and HAZPK Substations	• Decommission 24kV lines • Decommission FERND, WDSID and HAZPK Substations
Why was this solution not selected?	N/A - Selected	• Limits jumpering opportunities in highly treed areas • Reduced reliability benefits

Project — 8.3 kV CC: Infrastructure to support decommission of (8.3KV) sub - Pontiac OH (Wheeler)

This project will upgrade 120/13.2kV Class A Substation to relieve failing, obsolete five substations, improve reliability, operability and increase capacity in the Pontiac Area which serves approximately 13,000 customers. This project will convert, consolidate, and decommission (4) 8.3kV and (1) 13.2kV substations, their associated circuits, and a significant amount of 8.3kV infrastructure. The project will enhance safety, reliability, operability, and capacity.

NWA analysis performed - is NOT a candidate.

	Proposed Solution	Alternative 1	Alternative 2
Brief Description	• Purchased property. • Extend (1.4 miles) conduit. • Extend (14 miles) cable. • Replace (33.4 miles) overhead. • Rebuild 120-13.2kV substation. • Convert (33.4 miles) to 13.2kV • Decommission five substations.	• Purchased property. • Extend (4.9 miles) conduit. • Extend (19.1 miles) cable. • Replace (39.5 miles) overhead. • Build 40-13.2kV substation. • Convert (33.4 miles) to 13.2kV • Decommission five substations.	Rebuild / Upgrade existing facilities
If constructable, provide high-level estimate.	$43.5 million	$68 million	n/a – not constructable
What benefits does the alternative provide?	Aging, failing, At-Risk infrastructure. Safety, Reliability, Operability, Capacity	Aging, failing, At-Risk infrastructure. Safety, Reliability, Operability, Capacity	The site permits expansion to rebuild/upgrade the existing facility.
Why was this solution not selected?	N/A - Selected	Significant additional scope, budget, schedule, labor resources.	Inadequate equipment operational clearances / site footprints.

Project — 4.8kV CC: New Baltimore

This project will construct a new 40-13.2kV Class A Substation to relieve existing overloads, improve reliability, operability, and increase capacity in the New Baltimore Area which serves approximately 5.700 customers. This area has had load transfers for capacity relief onto JACOB in the past and the 40-13.2kV Class R substation at NBALT has been loaded over firm for several years. This project will first fully convert all NBALT 4.8kV load and fully decommission both the 40-4.8kV Class E and 40-13.2kV Class R substation at NBALT for a new 40-13.2kV Class A with an increased capacity. This initiative also provides circuit balancing for JACOB.

NWA analysis performed - is NOT a candidate.

	Proposed Solution	Alternative 1	Alternative 2
Brief Description	Replace existing 40-13.2kV and 40-4.8kV Class R and E substations at NBALT with a new 40-13.2kV Class A substation at existing site with increased capacity	Replace existing 40-13.2kV and 40-4.8kV Class R and E substations at NBALT with a new 40-13.2kV Class R-R substation at existing site with increased capacity	Purchase new property to build a 40-13.2kV Class R-R/A Substation
If constructable, provide high-level estimate.	$75 million	$70 million	$66 million
What benefits does the alternative provide?	-Full conversion of 4.8kV Island -Over Firm on 13.2kV NBALT -JACOB circuit balancing -System loading and conversion	-Full conversion of 4.8kV Island -Over Firm on 13.2kV NBALT -JACOB circuit balancing -System loading and conversion	-Full conversion of 4.8kV Island -Over Firm on 13.2kV NBALT -System loading and conversion
Why was this solution not selected?	N/A - Selected	-Circuit count limited to four	-Difficult to find property -No JACOB benefits.

Project — System Loading: Brown City

This project will construct a new 40-13.2kV Class T substation and rebuild an existing 40-13.2kV Class T and 40-4.8kV Class E to relieve existing overloads, improve reliability, operability and increase capacity in the Marlette and Brown City Area which serves approximately 4,880 customers. The area has multiple substations with long overhead miles that limit jumpering capabilities, resulting in the potential for customers to be stranded. Voltage class differences in the area leave multiple substations islanded, furthering the potential for stranded customers.

NWA analysis performed - is NOT a candidate.

	Proposed Solution	Alternative 1	Alternative 2	Alternative 3
Brief Description	Construct a new Class T at BENET station. Rebuild MARLT 4.8kV Class E and MARLT 13.2kV Class T as a new MARLT 13.2kV Class R. Transfer load from TCOMA, BRCTY, and SHAW to BENET. Decommission BRCTY substation.	Construct a new Class T at BENET station. Upgrade TCOMA from a 5MVA transformer to a 10/12.5MVA transformer. Transfer load from TCOMA, BRCTY, MARLT, and SHAW to BENET. Decommission BRCTY substation.	Construct a new Class T at BENET station. Transfer load from TCOMA, BRCTY, MARLT, and SHAW to BENET. Decommission BRCTY substation.	Construct a new Class T at a new property. Transfer load from TCOMA, CAPAC, and SHAW to the new substation.
If constructable, provide high-level estimate.	~$124 million	~$78.2 million	n/a – not constructable	n/a – not constructable
What benefits does the alternative provide?	This project avoids property purchase (Alternative 3). This project addresses loading concerns and non-standard configuration of MARLT substations.	This alternate is cheaper than the selected solution due to scope but does not satisfy 4.8 kV rebuild, which would increase capacity and operability. This project avoids property purchase (Alternative 3).	Cheapest solution of all alternatives considered. This project avoids property purchase (Alternative 3).	Extends DTE's property portfolio.
Why was this solution not selected?	N/A - Selected	Proposed solution would not address all the MARLT drivers.	Proposed solution would not address all the MARLT drivers. BENET alone would not offer the capacity relief to decommission the islanded BRCTY substation.	Proposed solution would not address all the MARLT drivers. The cost of a new property is an unnecessary cost that can be negated with the other proposed solutions.

Project — System Loading: Richmond/Armada

This project will construct a new 40/13.2kV Class A Substation to relieve existing overloads, improve reliability, operability and increase capacity in the Richmond Area which serves approximately 13,000 customers. This area has already completed some load transfers for capacity relief and reliability has remained poor even after Tree Trim has been completed. This project will convert, consolidate, and decommission (2) 4.8kV substations, their associated circuits, and decommission a significant amount of 4.8kV infrastructure.

NWA analysis performed - is NOT a candidate.

	Proposed Solution	Alternative 1	Alternative 2
Brief Description	**Build New Class 'A' 2-transformer substation** 40-13.2kV TRFs: (2) 15/20/25MVA PDC: (1) 9-POS (2) Circuit Switcher Establish conduit and cable Establish OH circuits and sectionalizing	**Install a new class A substation at new GRAMER station**	**Build New Class 'A' 2-transformer substation (Full Conversion)** 40-13.2kV TRFs: (2) 15/20/25MVA PDC: (1) 9-POS (2) Circuit Switcher Establish conduit and cable Establish OH circuits and sectionalizing
If constructable, provide high-level estimate.	~$96 million	n/a – not constructable	~$120 million
What benefits does the alternative provide?	*Safety:* • RICHM and ARMAD are 4.8kV ungrounded systems which causes a higher safety risk in an event of a wire-down • RICHM has aging substation infrastructure with a high risk of failure. *Reliability:* • The 4.8kV switchgear at Richmond substation was installed in 1956 and is the only oil filled truck type outdoor switchgear remaining on the DTE system. The breakers along with the CTs have no spare parts available. *Capacity:* Constraints on the system. *Operability:* • Armada has limited jumpering options so when the substation needs maintenance, a portable substation is required to pick up the load.	- Richmond (RICHM) are 40kV-4.8kV class A and 40kV-13.2kV class T substations; both built in 1956 -High Risk 4.8kV vintage switchgear installed in 1956; last oil filled truck type outdoor switchgear left on DTE's system - TRANS 3 has oil filled High Speed Ground Switch (HSGS)	*Safety:* • RICHM and ARMAD are 4.8kV ungrounded systems which causes a higher safety risk in an event of a wire-down • RICHM has aging substation infrastructure with a high risk of failure. *Reliability:* • The 4.8kV switchgear at Richmond substation was installed in 1956 and is the only oil filled truck type outdoor switchgear remaining on the DTE system. The breakers along with the CTs have no spare parts available. *Capacity* Constraints on the system. *Operability:* • Armada has limited jumpering options so when the substation needs maintenance, a portable substation is required to pick up the load.
Why was this solution not selected?	N/A - Selected	- Does not provide as many benefits as upgrading the existing RICHM substation - The station site is ~3.5 miles from the existing RICHM substation, which is away from load center and would require more reconductoring work and more OH exposure - Substations to the south are VICTOR and NHAVN and there are no overloads or strong drivers are these substations	- not selected due to the large amount of OH work that would be required - not selected due to the high cost of this project with limited budget

Project — System Loading: Spokane/Seneca

This project will expand SPKNE substation to relieve existing overloads through load-transfers and provide additional capacity for future projected load growth in the SPKNE and SENCA 13.2kV substation areas, which serves customers.

NWA analysis performed - is NOT a candidate.

	Proposed Solution	Alternative 1	Alternative 2
Brief Description	- Expand Spokane Substation to 3 transformers class 'A' substation. - Extend 3.5 miles of conduit - Establish 3 circuits -Transfer 17.3 MVA from Seneca to Spokane Substation	-Expand Seneca Substation to 3 transformers 2 switchgear class 'A' substation. -Expand Spokane Substation to 3 transformers 2 switchgear class 'A' substation. - Extend 1.5 miles of conduit - Establish 2 new circuits	- Property Acquisition - Build new 2 transformer 1 switchgear class "A" substation - Extend 3 miles of conduit - Install 12 miles of cable - Establish 7 new circuits - Install 12 manual Pole Top Switches - Transfer 17.3 MVA from Seneca Substation - Transfer 18.9 MVA from Spokane Substation
If constructable, provide high-level estimate.	$45 million	n/a – not constructable	$90 million
What benefits does the alternative provide?	System loading: Addresses loading concerns at Spokane and Seneca Substations by increasing the capacity at both substations.	System Loading: Addresses loading concerns at Spokane and Seneca Substations by increasing the capacity at both substations.	System Loading: Addresses loading concerns at Spokane and Seneca Substations by increasing the capacity at both substations.
Why was this solution not selected?	N/A - Selected	This alternative cannot be implemented since Seneca Substation is a walled substation and cannot be expanded.	While this alternative addresses the loading and capacity concerns at both substations, it is double the cost and scope of the solution we are implementing. This alternative is dependent on property acquisition which is both costly and difficult in this area.

Project — System Loading: Cody

This project will expand the existing 120-13.2kV CODY Class T Substation to a Class A. This will increase the firm rating from 39.6MVA to ~60MVA and have additional circuit positions to create more distribution circuits. This will help relieve existing circuit loads through load transfers and provide additional capacity for future load growth in Lyon Twp for residential and electrification. The new circuits will split the CODY circuits, which reduces customer count and outages per circuit. Additionally, operability improves as there are more circuits and each circuit has less load and customers than today's configuration.

NWA analysis performed - is NOT a candidate.

	Proposed Solution	Alternative 1	Alternative 2
Brief Description	Expand CODY substation from Class TT to Class A 120-13.2kV Upgrade TRFs: (2) 15/20/25MVA to (2) 24/32/40MVA PDC: (1) 12-POS Establish conduit and cable Establish OH circuits and sectionalizing	Build New Class 'A' 2-transformer substation Purchase new property 40-13.2kV TRFs: (2) 15/20/25MVA PDC: (1) 9-POS Establish conduit and cable Establish OH circuits and sectionalizing	Use neighboring substations to transfer load.
If constructable, provide high-level estimate.	$64 million	$58.4 million	n/a – not constructable
What benefits does the alternative provide?	Capacity: *Substation:* • Future Peak % of Firm after initiative: 70% Circuit: • 0 circuits will be over the DD Rating after initiative *Operability:* • 1/6 of circuits over DDO after project. The 1 circuit over DDO will have less load on circuit compared to today and will still be below DD. *Other:* • Automatic loop schemes will be installed in initiative to help support reliability in the area. "	Helps create more capacity and operability in the area, but depending on new property location, it may not necessarily help all of CODY substation area.	Neighboring substations are already overloaded, making this option not obtainable.
Why was this solution not selected?	N/A - Selected	- Approximately the same cost - Cost varies in what property cost is and the location of the property. It could mean more or less conduit/cable. -Industrial zoned parcels in the area are close to CODY and some are covered with wetlands. - CODY is at the center of all 4 existing CODY circuits, which makes it easier to split each one if needed in the future. - Would need to acquire new property, which would require: - New primary feed extensions	- Surrounding substations and circuits are too heavily loaded

Project — System Loading: Grenada

This project will construct a new 40/13.2kV Class A Substation to replace the existing substation. It will relieve existing overloads, improve reliability, operability and increase capacity in the Superior Township/Ann Arbor area. The new substation will serve approximately 2,000 customers. This project will also convert, consolidate, and decommission (1) 4.8kV substation and its associated circuits, and decommission a significant amount of 4.8kV infrastructure.

NWA analysis performed - is NOT a candidate.

	Proposed Solution	Alternative 1	Alternative 2	Alternative 3
Brief Description	**Construct a new 40/13.2kV Class A Substation** -Replace existing Grenada Substation -Transfer and decommission Prospect Substation	**Upgrading/Converting PROSP Substation** - Convert existing 4.8kV PROSP circuits - Build new 13.2kV PROSP Substation	**Construct New Substation** - Obtain property in Superior township - Build new 13.2kV Substation - Reconfigure/Transfer load from surrounding substations to new substation	**Upgrade Wolverine Substation** - Install additional transformer and PDC - Reconfigure surrounding circuits to provide load relief
If constructable, provide high-level estimate.	$47.5 million	n/a – not constructable	n/a – not constructable	n/a – not constructable
What benefits does the alternative provide?	*Safety:* • The newly converted PROSP circuits will be 13.2KV grounded wye *Reliability:* • 5 year average All Weather SAIDI is projected to be reduced by 88% *Capacity/Loadbility:* • GRENA 13.2kV sub will be ~55% of Firm upon initiative completion, which will also support surrounding substation decomissioning/convertion work on substations such as PROSP and PRICE *Operability:* • All GRENA 13.2kV circuits will be under the 8 MVA DDO limit • All 13.2kV circuits will be fully automated with loop schemes and automatic pole top switches, as well as full fault protection (fusing, sectionalizing, reclosing) • Newly converted 13.2kV circuits will be able to communicate and transfer load between the surrounding infrastructure	*Safety:* • Newly Converted PROSP will be 13.2kV grounded wye *Reliability:* • 5 year average All Weather SAIDI is projected to be reduced by 88% *Capacity/Loadbility:* • New PROSP 13.2kV would bring a substantial amount of capacity to the surrounding area • Excess capacity can be used to bring Grenada Significantly under Firm, start conversion work at PRICE, and potentially provide some load relief to WLVRN as well *Operability:* • All Grenada and Prospect circuit would be under the 8MVA DDO limit • All 13.2kV circuits will be fully automated with loop schemes and automatic pole top switches, as well as full fault protection (fusing, sectionalizing, reclosing) • Newly converted 13.2kV circuits will be able to communicate and transfer load between the surrounding infrastructure	*Safety:* • The newly converted PROSP circuits will be 13.2KV grounded wye *Reliability:* • 5 year average All Weather SAIDI is projected to be reduced by 88% *Capacity/Loadbility:* • GRENA 13.2kV will be brought under firm upon initiative completion and new substation will also support surrounding substation decomissioning/convertion work on substations such as PROSP and PRICE *Operability:* • All 13.2kV cirucits will be under the 8 MVA DDO limit • All 13.2kV circuits will be fully automated with loop schemes and automatic pole top switches, as well as full fault protection (fusing, sectionalizing, reclosing) • Newly converted 13.2kV cirucits will be able to communicate and transfer load between the surrounding infrastructure	*Capacity/Loadbility:* • GRENA 13.2kV will be brought under firm upon initiative completion and upgrades *Operability:* • All 13.2kV circuits will be under the 8 MVA DDO limit • All 13.2kV circuits will be fully automated with loop schemes and automatic pole top switches, as well as full fault protection (fusing, sectionalizing, reclosing)
Why was this solution not selected?	N/A - Selected	- No room at existing PROSP site to rebuild next to existing substation - All surrounding substations are near firm and unable to take PROSP load during an upgrade - Overhead conductor span over Frain Lake unable to support larger wire sizes which would result in costly circuit construction to reroute Prospects main backbone.	Surrounding properties were analyzed as potential prospects for a new substation. However, all fell into the following categories: - Inability to pull enough new circuits and reconfigure the existing infrastructure to support the surrounding area - Significant distance from 40kV lines which are costly to construct and would require significant new build	-Wolverine is already a Class 'A' Substation and does not have room on site for additional equipment - Unable to convert and provide load relief to Prospect substation

Project — System Loading: Wixom

This project will expand the existing 120-13.2kV WIXOM Class A Substation with 2 TRFs and 1 PDC with 3 TRFs and 2 PDCs. This will increase the firm rating from 61.3MVA to ~120MVA and have additional circuit positions to create more distribution circuits. This will help relieve existing circuit overloads through load transfers and provide additional capacity for future load growth in Wixom and Novi for industrial, commercial, residential, and electrification. WIXOM substation is in the industrial zone of the city of Wixom. There are many existing industrial customers and new industrial/commercial MOS requests. The new circuits will split the WIXOM circuits, which reduces customer count and outages per circuit. Additionally, operability improves as there are more circuits, and each circuit has less load and customers than today's configuration.

NWA analysis performed - is NOT a candidate.

	Proposed Solution	Alternative 1	Alternative 2
Brief Description	Expand WIXOM substation from Class 2 TRFs and 1 PDC to 3 TRFs and 2 PDCs 120-13.2kV Install a 3rd 24/32/40MVA TRF Install an additional 12-POS PDC Replace existing 12-POS PDC Establish conduit and cable Establish OH circuits and sectionalizing	Build New Class 'A' 2-transformer substation Purchase new property 120-13.2kV TRFs: (2) 24/32/40MVA PDC: (1) 12-POS Establish conduit and cable Establish OH circuits and sectionalizing	Use neighboring substations to transfer load.
If constructable, provide high-level estimate.	$55 million	$65.9 million	n/a – not constructable
What benefits does the alternative provide?	*Capacity:* *Substation:* • Future Peak % of Firm after initiative: 56% Circuit: • 0 circuits will be over the DD Rating after initiative *Operability:* • 1/11 of circuits over DDO after project *Other:* • Automatic loop schemes will be installed in initiative to help support reliability in the area. 78% SAIDI decrease after initiative. • Reconfiguring and reducing number of cables to mitigate risk and increase circuit DD and EM ratings after initiative. • Replacing existing near end of life PDC with modern PDC equipped with SCADA	Helps create more capacity and operability in the area, but depending on new property location, it may not necessarily help all of WIXOM substation area	Neighboring substations are already overloaded, making this option not obtainable.
Why was this solution not selected?	N/A - Selected	- Would need to purchase new property which may only help a certain part of WIXOM substation/circuits. - Would need to extend 120kV to new property - Existing WIXOM substation is in the center of the city of WIXOM and all the industrial load	- Surrounding substations and circuits are too heavily loaded - Surrounding substations are very distant from city of WIXOM concentrated industrial load, which may cause voltage issues and new issues to existing customers

Project — System Loading: Goodison

This project will construct a new 40-13.2kV Class A Substation to relieve existing overloads through load transfers and provide additional capacity for future load growth in Oakland Charter Twp for residential and electrification. The new substation, Paint Creek (PNTCK), will split the GODSN circuits and COLRD9100, which reduces customer count and outages per circuit. Additionally, operability improves as there are more circuits, and each circuit has less load and customers than today's configuration.

NWA analysis performed - is NOT a candidate.

	Proposed Solution	Alternative 1	Alternative 2
Brief Description	Build New Class 'A' two-transformer substation Operating voltage: 40-13.2 kV Transformers: (2) 15/20/25 MVA Power distribution center: (1) 9-POS -Establish conduit and cable. -Establish OH circuits and sectionalizing.	Build New Class 'A' three-transformer substation Operating voltage: 40-13.2 kV Transformers: (3) 15/20/25 MVA Power distribution center: (2) 9-POS -Establish conduit and cable. -Establish OH circuits and sectionalizing.	Expand existing Goodison class 'R' substation to class 'A' substation Operating voltage: 40-13.2 kV Transformer: (1) 15/20/25 MVA Power distribution center: (1) 9-POS -Establish conduit and cable. -Establish OH circuits and sectionalizing.
If constructable, provide high-level estimate.	$56 million	$65-80million	n/a – not constructable
What benefits does the alternative provide?	-Increases area capacity to support current and future load growth for 15+ years. -Relieves load off of GODSN and COLRD substation and circuits. -Leaves two spare positions for additional circuits.	-Increases area capacity to support current and future load growth for 25+ years. -Relieves load off of GODSN and COLRD substation and circuits. -Leaves eight spare positions for additional circuits.	-Increases substation capacity to support current and future load growth for 15+ years. -Relieves load off of GODSN and COLRD substation and circuits. -Leaves two spare positions for additional circuits.
Why was this solution not selected?	N/A - Selected	-More costly. -Selected project leaves the option for additional substation expansion as load growth materializes.	Not enough footprint to expand and inability to procure adjacent property.

Project — System Loading: Lark/Spruce

This project will construct a new 120-13.2kV Class R substation at Lark to relieve existing overloads through load transfers, providing additional capacity for projected load growth in the Dexter Ann Arbor area, which serves approximately 10,000 customers. This area has had multiple MOS requests recently alongside general load growth leading to limited capacity to serve new business requests and expected load growth in the immediate future. Alongside the introduction of new 13.2kV capacity, this initiative will improve the operability in the Spruce 13.2kV substation area.

NWA analysis performed - is NOT a candidate.

	Proposed Solution	Alternative 1	Alternative 2
Brief Description	Substation Expansion at LARK	Building a new substation at an alternate location or new property	Installing a third transformer at SPRUC
If constructable, provide high-level estimate.	~$33 million	~$40 million	n/a – not constructable
What benefits does the alternative provide?	-Capacity, operability, reliability, and safety	-Capacity, operability, reliability, and safety	Limited space, expansion work beyond current configuration.
Why was this solution not selected?	N/A - Selected	There was a lack of available property in the area due to this being a rural and heavily treed area. This would have risk of required major tree trim and PTMM at an alternate site. Another significant consideration was the cost of buying a new property and additional site preparation, which was high when compared to using available property for expansion instead.	This solution would require major reconfiguration or expansion work at the SPRUC substation property. There would be a very high cost associated with this work. There is very limited space and proper clearance to install another transformer at SPRUC.

Project — System Loading: Otsego/Capac/Shaw

This project will consist of the Load Transfer from OTSGO DC762 to MIDAS DC8298 and CAPAC DC8013 to MIDAS DC8715 in order to relieve existing overloads and improve operability. This project will consist of reconductoring Overhead Conductor OTSGO 8762 and MIDAS DC8013 and approximately 1 mile of 40kV Conductor on TIE 9303.

NWA analysis performed - is NOT a candidate.

	Proposed Solution	Alternative 1
Brief Description	1- Transfer Load from OTSGO to MIDAS to Relief OTSGO Sub. 2- Transfer Load from CAPAC to MIDAS to Relief CAPAC Sub.	Build New Class 'R' 2-transformer substation 120-13.2kV TRFs: (2) 15/20/25MVA PDC: (1) 9-POS Establish conduit and cable Establish OH circuits and sectionalizing
If constructable, provide high-level estimate.	~$21 million	~$70 million
What benefits does the alternative provide?	-Reliefs Load off of OTSGO and CAPAC Substation and Circuits -Prepares for future load growth -Allows jumpering Capabilities -Establish Loop schemes	- Circuits would follow our DOO 13.2 KV NORMAL CIRCUIT LOADING - Creates more capacity on both OTSGO and CAPAC - Allows jumpering, validates current invalid jumpering points - Brings both substation below our DD Ratings
Why was this solution not selected?	N/A - Selected	- not selected due to the large amount of OH work that would be required - not selected due to the high cost of this project with limited budget

8.10 Complete GPM Rankings

GPM Rank	Description	GPM Impact Dimensions									Total Score
		Reduce Electrical Hazards	Overload Relief	Capacity Relief	Major Event Risk	SAIDI	SAIFI	O&M Avoidance	Capital Avoidance	Investment in EJ communities	
1	Preventative Maintenance: Breakers	-	-	-	-	619	732	-	1,308	1.26	3,357
2	Preventative Maintenance: 40 kV Pole Top Switch	-	-	-	-	741	1,339	-	-	1.26	2,625
3	Distribution Automation	1,779	-	-	-	227	64	-	-	1.26	2,612
4	Substransmission SCADA	-	-	-	-	280	680	-	-	1.26	1,212
5	CODI: Charlotte Network Upgrade	594	-	10	2	-	-	-	-	1.83	1,108
6	Preventative Maintenance: Distribution Remote Devices	-	-	-	-	564	236	-	-	1.26	1,009
7	Vegetation Management	328	-	-	-	320	43	56	24	1.26	973
8	Preventative Maintenance: OH Capacitor and Regulator Controls	-	-	-	-	-	-	506	206	1.26	899
9	Preventative Maintenance: URD Transformers	629	-	-	-	-	-	-	-	1.26	794
10	4.8 kV Hardening	281	-	-	-	54	9	26	11	1.87	714
11	NWA: Port Austin Load Relief	11	607	45	-	10	1	7	2	1	683
12	40 kV: Automatic Pole-Top Switch	-	-	-	-	131	364	-	-	1.26	625
13	Substation Risk: Seville	-	126	63	397	-	-	-	-	1	586
14	Subtransmission Redesign & Rebuild: Sandusky Transformer 101 Breaker	-	275	296	-	-	-	-	-	1	571
15	CODI: Amsterdam Conversion Initiative	274	11	9	2	3	1	7	1	1.83	564
16	CODI: Garfield Network Upgrade	227	28	19	1	3	1	21	3	1.82	551
17	Subtransmission Redesign & Rebuild: Trunk 3509	-	290	195	24	-	-	-	-	1.05	532
18	CODI: Alfred Substation Expansion	-	203	87	-	-	-	-	-	1.81	525
19	Pole and Pole Top Maintenance and Modernization (PTMM)	34	-	-	-	172	21	129	52	1.26	515
20	Frequent Outage Program (CEMI)	25	-	-	-	200	93	45	19	1.26	483
21	Cable Replacement Program	-	-	-	50	10	1	-	295	1.26	450
22	CODI: Targeted Network Secondary Cable Replacement	300	-	-	-	-	-	-	-	1.48	443
23	Subtransmission Redesign & Rebuild: Trunk 4266	-	-	230	128	-	-	-	-	1.16	416
24	4.8 kV CC: Zenon Substation and Circuit Conversion - Phase 2	72	29	6	3	18	4	69	13	1.89	407
25	8.3 kV CC: Pontiac Overhead/Underground Conversion	66	-	3	61	22	6	60	14	1.7	391
26	CODI: Howard Conversion	204	56	12	2	0	0	1	0	1.4	385
27	4.8 kV CC: I-94 Substation and Circuit Conversion (Promenade)	76	8	8	2	13	2	71	15	1.96	384
28	4.8 kV CC: Hawthorne Relief and Circuit Conversion	115	13	7	12	51	8	109	22	1.11	375
29	Subtransmission Redesign & Rebuild: Hurst	-	116	250	-	-	-	-	-	1	366

30	4.8 kV CC: Grosse Pointe Substation and Circuit Conversion - South	80	-	5	10	26	4	86	18	1.52	347
31	Substation Risk: Chestnut	-	-	-	204	-	-	-	-	1.68	342
32	Subtransmission Redesign & Rebuild: Bernard	-	331	-	-	-	-	-	-	1	331
33	URD Replacement Program	-	-	-	-	136	12	57	25	1.26	290
34	System Loading: Otsego/Capac/Shaw	-	133	104	-	7	3	36	4	1	287
35	Substation Risk: Hood	-	279	-	-	-	-	-	-	1	279
36	4.8 kV CC: Calla Circuit Conversion and Phase 2	26	-	184	-	14	3	45	5	1	277
37	CODI: Kent/Gibson Conversion	46	17	11	7	10	3	57	9	1.72	274
38	4.8 kV CC Barber Substation and Circuit Conversion	61	4	23	0	19	4	39	12	1.64	265
39	Substation Risk: Belleville Switchgear Decommission	-	-	-	258	-	-	-	-	1	258
40	Subtransmission Redesign & Rebuild: Badax Transformer 102 Addition	-	79	170	-	-	-	-	-	1	249
41	4.8 kV CC: Birmingham Decommissioning and Circuit Conversion	69	27	14	42	18	4	56	12	1	242
42	CODI: Islandview Substation	48	4	4	4	9	2	39	7	1.95	229
43	4.8 kV CC: Melvindale	49	-	1	4	26	2	43	9	1.68	224
44	NWA: Veridian	65	-	21	-	50	5	66	14	1	221
45	4.8 kV CC: Hilton Substation and Circuit Conversion	58	3	5	9	20	2	54	11	1.33	216
46	4.8 kV CC: SCOTN	-	-	-	4	-	-	122	-	1.7	214
47	4.8 kV CC: ISO Conversion Program	55	-	-	-	36	6	41	11	1.4	209
48	Substation Risk: Apache	-	-	-	198	-	-	-	-	1	198
49	Breaker Replacement Program	-	-	-	12	6	3	13	116	1.26	190
50	Subtransmission Redesign & Rebuild: Trunk 4911	1	111	39	-	8	2	23	3	1	187
51	SCADA Pole-Top Device Replacement	-	-	-	-	105	44	-	-	1.26	187
52	System Loading: Wixom	-	32	53	98	1	0	3	0	1	187
53	Subtransmission Redesign & Rebuild: Boyne	7	-	104	-	9	2	15	3	1.32	186
54	System Loading: Richmond/Armada	11	46	28	46	6	2	37	3	1	180
55	System Loading: Cody	3	63	71	-	10	2	18	3	1	170
56	Substation Risk: Savage Switchgear Replacement	-	-	-	166	-	-	-	-	1	166
57	4.8 kV CC: Hemlock Decommissioning and Circuit Conversion	52	7	7	3	44	5	36	9	1	163
58	4.8 kV CC: Unionville DC 301 B1 Conversion	51	-	-	-	13	5	72	15	1	155
59	4.8 kV CC: Pittsfield Substation and Circuit Conversion	46	-	4	21	30	5	38	8	1	153
60	4.8 kV CC: Belleville Substation and Circuit Conversion	20	-	49	54	3	0	22	3	1	152
61	4.8 kV CC: Ann Arbor AC Network Conversion	40	36	13	7	14	2	27	7	1	147
62	System Loading: Brown City	15	54	32	-	5	2	31	5	1	144
63	4.8 kV CC: White Lake Decommissioning and Circuit Conversion	20	40	31	9	12	2	21	4	1	140
64	CODI: Midtown Substation Expansion	-	-	85	-	-	-	-	-	1.61	137
65	4.8 kV CC: Buckler Circuit Conversion	58	-	-	1	11	2	49	11	1	131
66	Subtransmission Redesign & Rebuild: Trunk 7386	-	-	114	-	-	-	-	-	1.06	121
67	System Loading: Kings Pointe	1	52	52	-	1	0	1	0	1.07	115
68	Pilot: Strategic and Service Undergrounding	31	-	-	-	10	2	32	6	1.39	112

69	System Loading: Port Sanilac	22	25	10	0	24	5	17	5	1	107
70	System Loading: Grenada	13	-	30	27	9	1	22	3	1	106
71	Substation Risk: Lancaster	-	-	-	104	-	-	-	-	1	104
72	Subtransmission Redesign & Rebuild: Tie 3416	-	-	92	-	-	-	9	-	1	101
73	Subtransmission Redesign & Rebuild: Trunk 2308	-	-	47	-	5	2	26	3	1.22	100
74	Subtransmission Redesign & Rebuild: Tie 1473 Reconductor	19	-	-	-	19	2	51	3	1	95
75	4.8 kV CC: New Baltimore	15	-	34	10	7	2	20	5	1	93
76	System Loading: Spokane/Seneca	-	-	57	36	-	-	-	-	1	92
77	Frequent Outage: Wolfhill	-	-	-	39	9	1	38	4	1	92
78	NWA: Fisher Load Relief	-	-	58	-	14	2	7	2	1.07	87
79	System Loading: Mohican	18	-	28	-	7	2	28	5	1	87
80	Substation Risk: McGraw	-	26	13	2	-	-	-	-	1.97	82
81	Substation Risk: Sterling	-	-	10	71	0	0	1	0	1	82
82	System Loading: Lark/Spruce	4	-	26	-	15	1	24	3	1	73
83	Subtransmission Redesign & Rebuild: Tie 810	4	14	24	-	3	1	23	2	1	70
84	4.8 kV CC: Fairgrove	22	-	-	-	11	2	28	4	1	67
85	System Loading: Goodison	-	14	34	-	6	1	9	2	1	65
86	Subtransmission Redesign & Rebuild: Pigeon Area Improvement	-	20	22	1	0	0	16	0	1	59
87	Small Wire Replacement Program	10	-	-	-	19	3	6	3	1.26	51
88	Station Upgrade: Navarre	-	-	-	24	-	-	-	-	1.97	48
89	CODI: CATO Substation Expansion	-	-	18	10	-	-	-	-	1.58	44
90	4.8 kV CC: Pinegrove Substation Relocation and Conversion	12	-	-	6	5	1	9	2	1.18	42
91	4.8 kV CC: Almont Relief and Circuit Conversion (Midas)	10	-	6	2	8	1	9	3	1	40
92	Subtransmission Redesign & Rebuild: Tie 3205	7	-	-	-	7	1	21	2	1	38
93	Subtransmission Redesign & Rebuild: Cortland Station Expansion	-	-	-	18	-	-	-	-	1.94	34
94	4.8 kV CC: Rochester Decommissioning and Tienken Relief	9	6	3	2	6	1	5	1	1	32
95	Subtransmission Redesign & Rebuild: Tie 6602	-	-	-	-	3	1	27	1	1	32
96	Subtransmission Redesign & Rebuild: Tie 4105	4	-	-	-	4	2	19	1	1	30
97	Subtransmission Redesign & Rebuild: Tie 7504	4	-	-	-	1	0	21	1	1	28
98	Subtransmission Redesign & Rebuild: Tie 4104	3	-	-	-	2	1	16	1	1	23
99	Station Upgrade: Lincoln	-	-	-	21	-	-	-	-	1	21
100	Substation Risk: Drexel	-	-	13	6	-	-	-	-	1	19
101	Subtransmission Redesign & Rebuild: Trunk 2455	-	-	-	8	-	-	-	-	1.89	16
102	Subtransmission Redesign & Rebuild: Waterman	-	-	-	7	-	-	-	-	1.62	12
103	Subtransmission Redesign & Rebuild: Kennett	-	-	-	-	-	-	11	-	1	11
104	Subtransmission Redesign & Rebuild: Trunk 4601	-	-	-	-	-	-	8	-	1	8
105	Subtransmission Redesign & Rebuild: Trunk 4245	-	-	-	6	-	-	-	-	1.14	6
106	Subtransmission Redesign & Rebuild: Imlay Rebuild	-	-	-	-	-	-	4	-	1	4
107	Subtransmission Redesign & Rebuild: French Landing	-	-	-	2	-	-	-	-	1.09	2
108	Ann Arbor System Improvements	-	-	-	1	-	-	-	-	1	1

109	DER Control	-	-	-	-	-	-	-	-	1	-
109	Subtransmission Redesign & Rebuild: DETWS	-	-	-	-	-	-	-	-	1	-
109	4.8 kV CC: Camden Decommissioning	-	-	-	-	-	-	-	-	1.47	-
109	Substation Risk: Waterman	-	-	-	-	-	-	-	-	1	-
109	Subtransmission Redesign & Rebuild: DUNN Station	-	-	-	-	-	-	-	-	1	-
109	Pontiac Vaults	-	-	-	-	-	-	-	-	1	-
109	NWA: Battery Trailer	-	-	-	-	-	-	-	-	1	-
109	Substation Risk: Flood Defense Program	-	-	-	-	-	-	-	-	1.86	-
109	TCHPP Switchyard Upgrades	-	-	-	-	-	-	-	-	1	-
109	Subtransmission Redesign & Rebuild: Tempest Phase II	-	-	-	-	-	-	-	-	1	-
109	Disconnect and Switcher Replacement	-	-	-	-	-	-	-	-	1.26	-
109	Station Upgrade: 120kV Relays Upgrade for ITC Projects	-	-	-	-	-	-	-	-	1.26	-
109	Steel Pole Highway Crossings	-	-	-	-	-	-	-	-	1.26	-
109	Batteries and Chargers Replacement Program	-	-	-	-	-	-	-	-	1.26	-
109	Substation Regulator Replacement	-	-	-	-	-	-	-	-	1.26	-
109	Subtransmission Redesign & Rebuild: Reverse Power Relay Scheme Program	-	-	-	-	-	-	-	-	1.26	-
109	Subtransmission Redesign & Rebuild: Transformer High Side Protection Program	-	-	-	-	-	-	-	-	1.26	-
109	NWA: EV Charging Demonstration	-	-	-	-	-	-	-	-	1.26	-

8.11 Mapping Investments to Grid Needs

To provide a high-level view and clearly link investment programs to identified grid needs, DTE provides a supplemental summary of grid needs in Exhibit 8.38, along with a summary of how the Company's investment programs across the five pillars address those needs in Exhibit 8.39.

Exhibit 8.38 – Summary of Grid Needs

High-Level Grid Need	Description
Replacing Aging Infrastructure	A significant portion of subtransmission and distribution system assets are operating beyond their expected service life, increasing the likelihood of equipment failures, maintenance costs, and unplanned outages.
Capacity Constraints	Certain substations and distribution circuits are approaching thermal or load limits, restricting system flexibility and increasing the need for upgrades to support growing and shifting demand.
Cost Efficiency Needs	Investment strategies must balance reliability, safety, and modernization needs while managing cost impacts and ensuring that ratepayer resources are used efficiently.
Energized Wire-Downs and Safety Risks	Downed wires, arc faults, and other field hazards create significant public safety risks and require technology, process, and equipment improvements to prevent, detect, and respond to dangerous conditions.
Localized Overload and Load Uncertainty	Rapid, uneven adoption of new technologies (e.g., EV clusters, DERs, electrification) is creating localized overloads and unpredictable loading patterns that traditional planning tools were not built to forecast precisely. Rooftop solar, battery storage, EV charging, and microgrids introduce reverse power flow, voltage variability, and protection coordination issues that legacy circuits were not engineered to manage.
Maintenance Backlogs	A combination of aging assets and limited access windows has resulted in deferred maintenance, which continues to increase over time and elevates overall reliability risk.
Obsolete System Designs	Older circuit layouts, protection schemes, and legacy configurations limit automation, hinder fault isolation, and restrict the integration of modern technologies.
Operational Flexibility Limitations	A lack of sectionalizing, automation, backfeed capability, and system visibility limits the ability to respond quickly to outages, perform switching, and optimize grid operations on both the subtransmission and distribution systems.
Reliability Challenges	Recurring outage patterns, equipment failure trends, and circuit topology constraints reduce system reliability in certain areas, requiring targeted interventions.
Technology and Data Gaps	Inconsistent data quality, limited field telemetry, and outdated monitoring tools reduce situational awareness and constrain data-driven planning and operational decisions.
Vegetation Around Infrastructure	Vegetation growth near circuits and equipment creates a persistent risk of contact-related outages, asset damage, and public safety hazards, especially during severe weather events.
Weather-Driven Risk and Climate Vulnerability	Increasing frequency and intensity of storms, heat events, and extreme weather expose system weaknesses, increasing outage durations and stressing assets that were not designed for modern climate patterns.

Exhibit 8.39 – Investment Categories Mapped to Grid Needs

Investment Categories	Grid Needs											
	Replacing Aging Infrastructure	Capacity Constraints	Cost Efficiency Needs	Energized Downed Wire and Safety Risks	Localized Overload and Load Uncertainty	Maintenance Backlogs	Obsolete System Designs	Operational Flexibility Limitations	Reliability Challenges	Technology and Data Gaps	Vegetation Around Infrastructure	Weather-Driven Risk and Climate Vulnerability
Vegetation and System Maintenance												
Vegetation Management				X		X			X		X	X
Preventative Maintenance and Inspections	X					X			X			X
Corrective Maintenance	X					X		X	X			X
Resilience and Hardening												
Pole and Pole-Top Maintenance and Modernization	X		X	X		X		X	X		X	X
4.8kV Hardening	X		X	X		X	X		X		X	X
Frequent Outage	X			X					X			X
Small Wire Replacement	X	X		X	X		X		X		X	X
Undergrounding	X	X	X	X					X		X	X
System Equipment Replacement	X	X				X			X			X
Substation Risk	X	X				X	X	X	X			X
Restoration Readiness and Customer Resilience				X					X			X
Redesign and Modernization												
4.8kV and 8.3kV Conversions	X	X	X	X		X	X	X	X	X	X	X
System Loading		X			X			X				X
Subtransmission Redesign and Rebuild	X	X				X	X	X	X	X	X	X
Non-Wire Alternatives		X	X		X							
Technology and Automation												
Distribution Automation	X		X	X			X	X	X	X		X
Subtransmission SCADA	X		X					X	X	X		X
Operational Technology								X		X		
Asset Condition Monitoring Technology	X					X				X		
Grid Technology				X	X		X			X		
Advanced Distribution Management System				X	X			X		X		
Grid Edge and Distributed Intelligence												
Communication Network				X	X			X		X		
Next-Gen AMI and Distributed Intelligence			X		X					X		
Distributed Energy Resource Management System		X			X			X		X		

8.12 Detailed Customer Affordability Analysis

Exhibit 8.40 – Average Impact of DSP on Residential Customer Rates ($M)

Line No.	Residential Customer Class	Source/Calculation		2026	2027	2028	2029	2030
1	Class Revenue Requirement ($M)	U-21860	3,172					
2	Class Revenue Requirement Projection ($M)[213]	Growth Rate	3.00%	3,172	3,268	3,366	3,467	3,571
3								
4	Distribution COSS Allocation (%)	U-21860	60.30%	60.30%	60.30%	60.30%	60.30%	60.30%
5								
6	Incremental Capital Revenue Requirement of DSP ($M)	Calculated based on DSP[214]		0	44	156	305	472
7								
8	Class Allocation of Incremental Revenue Requirement ($M)	Line 6 x Line 4		0	27	94	184	285
9								
10	Sales Forecast (GWh)	U-22046, Ex A-15, Sch E1[215]		15,377	15,471	15,551	15,556	15,558
11								
12	*Projected Rate After Inflation*	Line 2 / Line 10		20.63	21.12	21.64	22.28	22.95
13	*Projected DSP Rate Impact*	Line 8 / Line 10		0.00	0.17	0.60	1.18	1.83
14	*Total Projected Rate*	Line 12 + Line 13		20.63	21.29	22.24	23.46	24.78

[213] Excludes PSCR factor and securitization charges.
[214] Strategic capital net of reductions to emergent capital.
[215] 2026 sales from U-21860 ordered rate design, all other years from U-22046.

Exhibit 8.41 – Average Impact of DSP on Commercial Customer Rates ($M)

Line No.	Commercial Customer Class	Source/Calculation		2026	2027	2028	2029	2030
1	Class Revenue Requirement ($M)	U-21860	1,604					
2	Class Revenue Requirement Projection ($M)[216]	Growth Rate	3.00%	1,604	1,652	1,701	1,753	1,805
3								
4	Distribution COSS Allocation (%)	U-21860	27.09%	27.09%	27.09%	27.09%	27.09%	27.09%
5								
6	Incremental Capital Revenue Requirement of DSP ($M)	Calculated based on DSP[217]		0	44	156	305	472
7								
8	Class Allocation of Incremental Revenue Requirement ($M)	Line 6 x Line 4		0	12	42	83	128
9								
10	Sales Forecast (GWh)	U-22046, Ex A-15, Sch E1[218]		10,785	10,943	11,036	11,086	11,142
11								
12	*Projected Rate After Inflation*	Line 2 / Line 10		14.87	15.09	15.42	15.81	16.20
13	*Projected DSP Rate Impact*	Line 8 / Line 10		0.00	0.11	0.38	0.74	1.15
14	*Total Projected Rate*	Line 12 + Line 13		14.87	15.20	15.80	16.55	17.35

[216] Excludes PSCR factor and securitization charges.

[217] Strategic capital net of reductions to emergent capital.

[218] 2026 sales from U-21860 ordered rate design, all other years from U-22046.

Exhibit 8.42 – Average Impact of DSP on Industrial Customer Rates ($M)

Line No.	Industrial Customer Class	Source/Calculation		2026	2027	2028	2029	2030
1	Class Revenue Requirement ($M)	U-21860	1,230					
2	Class Revenue Requirement Projection ($M)[219]	Growth Rate	3.00%	1,230	1,266	1,304	1,344	1,384
3								
4	Distribution COSS Allocation (%)	U-21860	9.92%	9.92%	9.92%	9.92%	9.92%	9.92%
5								
6	Incremental Capital Revenue Requirement of DSP ($M)	Calculated based on DSP[220]		0	44	156	305	472
7								
8	Class Allocation of Incremental Revenue Requirement ($M)	Line 6 x Line 4		0	4	15	30	47
9								
10	Sales Forecast (GWh)	U-22046, Ex A-15, Sch E1[221]		17,978	17,945	17,944	17,922	17,917
11								
12	*Projected Rate After Inflation*	Line 2 / Line 10		6.84	7.06	7.27	7.50	7.72
13	*Projected DSP Rate Impact*	Line 8 / Line 10		0.00	0.02	0.09	0.17	0.26
14	*Total Projected Rate*	Line 12 + Line 13		6.84	7.08	7.36	7.67	7.99

[219] Excludes PSCR factor and securitization charges.

[220] Strategic capital net of reductions to emergent capital.

[221] 2026 sales from U-21860 ordered rate design, all other years from U-22046.

Exhibit 8.43 – Average Impact of DSP on Other Customer Rates ($M)

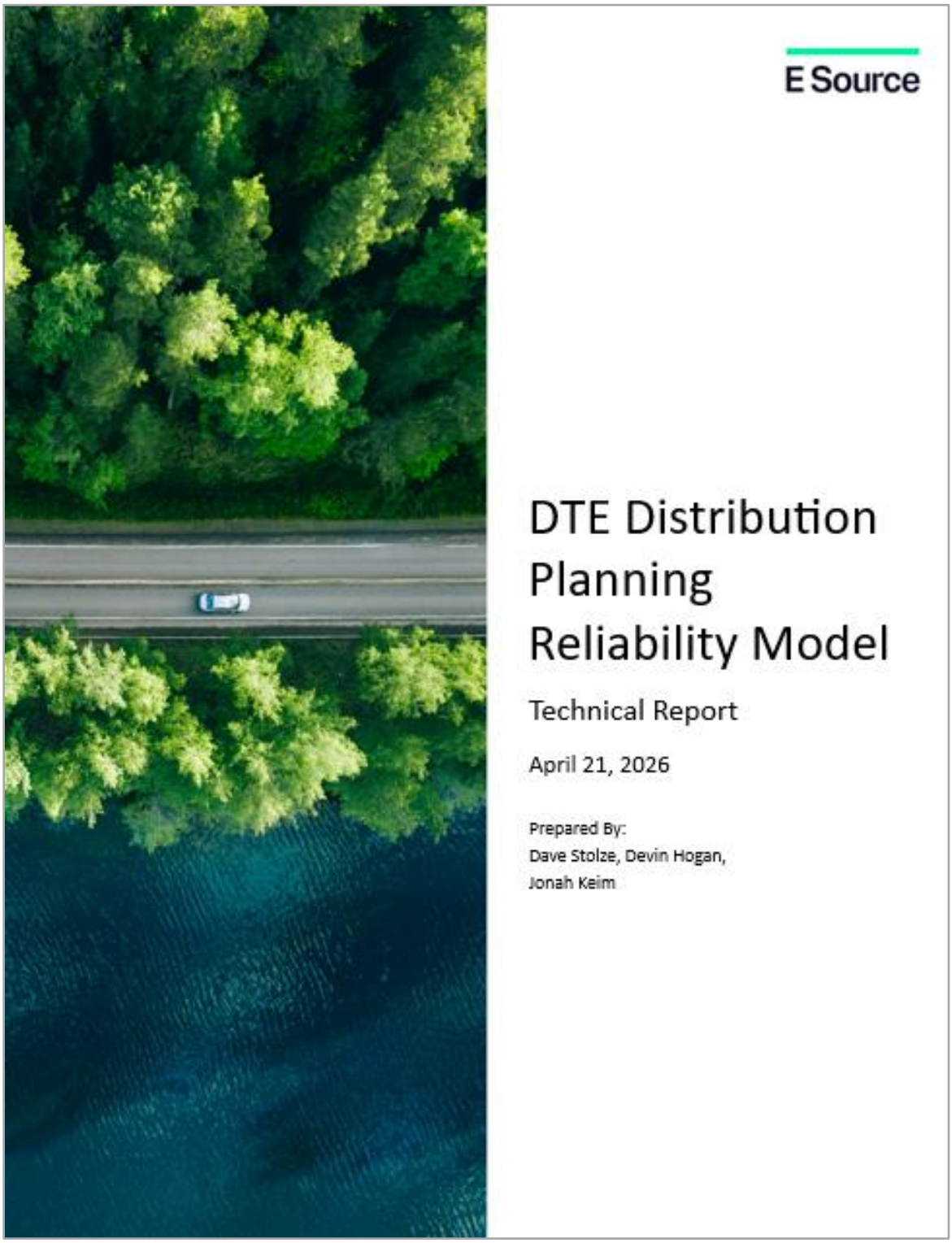
Line No.	Other Customer Class	Source/Calculation		2026	2027	2028	2029	2030
1	Class Revenue Requirement ($M)	U-21860	91					
2	Class Revenue Requirement Projection ($M)[222]	Growth Rate	3.00%	91	94	97	99	102
3								
4	Distribution COSS Allocation (%)	U-21860	2.69%	2.69%	2.69%	2.69%	2.69%	2.69%
5								
6	Incremental Capital Revenue Requirement of DSP ($M)	Calculated based on DSP[223]		0	45	156	306	475
7								
8	Class Allocation of Incremental Revenue Requirement ($M)	Line 6 x Line 4		0	1	4	8	13
9								
10	Sales Forecast (GWh)	U-22046, Ex A-15, Sch E1[224]		214	181	181	180	180
11								
12	*Projected Rate After Inflation*	Line 2 / Line 10		42.50	51.68	53.47	55.20	56.92
13	*Projected DSP Rate Impact*	Line 8 / Line 10		0.00	0.66	2.33	4.58	7.10
14	*Total Projected Rate*	Line 12 + Line 13		42.50	52.34	55.80	59.78	64.02

[222] Excludes PSCR factor and securitization charges.

[223] Strategic capital net of reductions to emergent capital.

[224] 2026 sales from U-21860 ordered rate design, all other years from U-22046.

8.13 Reliability Model Technical Report[225]



[225] The DTE Distribution Planning Reliability Model Technical Report was prepared by E Source and retains its original, report-specific page numbering shown in the footer. DSP page numbers, also shown in the footer, reflect the pagination of the consolidated filing and do not correspond to the report's internal numbering.

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Executive Summary

DTE Electric's 2026 Distribution System Plan (DSP) details the long-term investment roadmap for distribution, substation, and subtransmission systems to improve reliability and meet evolving customer expectations and regulatory requirements. DTE Electric partnered with E Source to conduct a five-year retrospective analysis and forecast of power reliability performance specific to DTE Electric's distribution and subtransmission systems and investment plan. The forecasting analyses aim to evaluate whether, and to what degree, DTE Electric's proposed investment programs will improve power reliability as quantified by key performance metrics over the next five years and under three weather scenarios.

The retrospective analyses revealed key insights that are pertinent to prioritizing reliability investments and forecasting future investment and mitigation outcomes. Statistical models were used to estimate outage counts, Customer Interruptions (CI) per outage and Customer Average Interruption Duration Index (CAIDI) based on covariates specific to DTE Electric's distribution, substation, and subtransmission networks over the past five years.

The annual rates of outage events were greatest on distribution overhead and underground circuits, in contrast to subtransmission circuits and substations. Overall, the three most influential covariates in the statistical models were (1) lagged rates of outages during mild weather over the preceding 12 months; (2) the count of elevated and extreme weather days per month; and (3) LiDAR and imagery derived estimates of tree cover. All three of these covariates positively influenced the rates of outage events across the network. The most influential covariate predicting CAIDI was count of concurrent outage events (outages occurring within the same region and year), which demonstrated a strong positive impact on CAIDI. Therefore, higher counts of elevated and extreme weather days simultaneously increased both the frequency and duration of outages, leading to a compounding increase in Customer Minutes Interrupted (CMI).

Predictions from statistical models were used to derive composite measures of annual System Average Interruption Frequency Index (SAIFI) and System Average Interruption Duration Index (SAIDI) by operating region, which showed moderate goodness of fit with the historical actuals under a cross-validation test (R^2: SAIFI 0.49, SAIDI 0.57).

The retrospective statistical models were used in collaboration with DTE Electric to forecast five-year reliability outcomes, assuming (1) zero mitigation investments; and (2) DTE Electric's Distribution System Plan. The following reliability programs were included in DTE Electric's Distribution System Plan:

- Vegetation Management
- Pole and Pole-Top Maintenance and Modernization (PTMM)
- Distribution Automation
- 4.8 kV Circuit Hardening
- 4.8 kV Conversion Projects
- Undergrounding
- Small Wire Replacement
- Substation Equipment Replacement
- Underground Residential Distribution (URD) Cable Replacement

Overall, DTE Electric's investment strategy was forecast to improve SAIFI from 1.26 given current system state to 1.07 in 2030, and to improve SAIDI from 352 to 262 by 2030. Besides SAIFI and SAIDI, which are composite indices, associated input measures for outage events, CI per outage, and CAIDI were also predicted and reported. These estimates assume a typical weather scenario as defined by the average yearly count of elevated and extreme weather days DTE Electric has observed from 2018–2025.

The most influential mitigation programs on DTE Electric's reliability performance were Vegetation Management, PTMM, and Distribution Automation. Together these three programs combined to contribute 96.4% of the total SAIFI benefit and 96.1% of the total SAIDI benefit. The majority of SAIFI and SAIDI benefits forecast across the network were attributed to investments in DTE Electric's overhead and underground distribution circuits.

1. Introduction

To meet evolving customer needs and continue improving safety and electric reliability, DTE Electric is focused on strengthening, modernizing, and transforming its grid. DTE Electric's 2026 Distribution System Plan (DSP) details the investment roadmap for DTE Electric's substation, subtransmission and distribution systems, collectively referred to as the electric grid, through 2030 along with a longer-term outlook. The 2026 DSP provides an updated and comprehensive view of the state of the electric grid and incorporates feedback from the Michigan Public Service Commission (MPSC)-ordered distribution audit performed by Liberty Consulting Group in 2024. This feedback was used to help guide cost-effective investments essential to improving grid safety, reliability, and modernization—all integral to supporting economic prosperity in the communities DTE Electric serves. The project supports DTE Electric's 2026 DSP through a five-year retrospective analysis and forecast of electric grid reliability performance. The analyses evaluates whether, and to what degree, DTE Electric's proposed investment programs will improve power reliability as measured by key performance metrics over the next five years.

SAIDI and SAIFI forecasts or targets are often established using a normalized five-year average of historical reliability performance, excluding Major Event Days (IEEE, 2022). This approach does not direct account for the effects of infrastructure and environmental conditions, such as tree conditions or severe weather. The retrospective analyses herein aim to develop statistical models for outage counts and outage impacts, including CI and CAIDI, using infrastructure and environmental conditions that are specific to DTE Electric's distribution, substation and subtransmission networks over the past five years.

The objectives of the retrospective analysis are to:

- Conduct retrospective statistical analyses of DTE Electric's power outage event data given local environmental and infrastructure conditions between 2021 and 2025.
- Develop statistical models to predict the count of power outage events given covariates for conductor and device characteristics, tree conditions, and historical outage trends.
- Develop statistical models to predict the CI per outage event for each circuit or substation given covariates for customers downstream and historical CI per outage event.
- Develop statistical models to predict CAIDI given covariates for co-occurring outages (outage count per region-year), region and network.
- Predict estimates of SAIFI and SAIDI from the statistical models above to forecast future reliability performance outcomes given DTE Electric's planned electric grid reliability investment program.

The objectives of the five-year power reliability forecast are to:

- Forecast annual outage events, SAIFI, and SAIDI given a baseline (zero-investment) scenario assuming DTE Electric does not implement any reliability investment mitigations under three weather severity scenarios.
- Forecast annual outage events, SAIFI and SAIDI assuming DTE Electric implements currently planned investments (reliability investment scenario) that include 10 mitigation programs under three weather severity scenarios.
- Quantify the annual differences in outage events, SAIFI, and SAIDI forecasts given the zero-investment scenario and the reliability investment scenario (i.e., predict reliability benefits).

2. Retrospective Reliability Analysis

2.1 Methods

Statistical models were developed to relate historical outage event data (2021–2025) with infrastructure and environmental conditions for DTE Electric's distribution circuits, subtransmission circuits, and substations. Specifically, these datasets were used to estimate models to predict the (1) count of outage events; (2) count of CI per outage; and (3) average restoration time per customer interruption (CAIDI). Predictions from these three models were then used to calculate estimates of SAIDI and SAIFI and to forecast future reliability performance outcomes assuming DTE Electric's planned reliability investment program (Section 3. Reliability Performance Forecasting).

A summary of the historic outage event data used in the retrospective analysis is detailed in Table 1. The sampling period for overhead and underground distribution circuits was 55 months and the sampling period for subtransmission circuits and substations was 35 months. Subtransmission and substations had shorter sampling periods due to limited availability of outage data prior to February 2023. Distribution circuit outage events captured between February and June 2023 were excluded due to known inconsistencies in outage data capture associated with a re-configuration of DTE Electric's Advanced Distribution Management System (ADMS). The dataset was cleaned to include sustained outages defined by infrastructure and environmental cause-type conditions (Appendix A). Less than 2% of the outage events and less than 6% of DTE Electric's systemwide circuits (0.01% of circuit miles) were deemed as outliers and removed from analysis. These removals predominantly targeted short circuits, which could bias parameter estimation.

Table 1. Summary of historical data utilized for retrospective analysis after outlier filtering

Network System	Count of Circuits and Substations	Outage Events (n)	Outage Event Sampling Period
Overhead Distribution Circuits	2,582 (45,889 miles)	323,445	Jan. 2021–Dec. 2025 (55 months)*
Underground Distribution Circuits	2,735 (16,053 miles)	74,656	Jan. 2021–Dec. 2025 (55 months)*
Subtransmission Circuits	590 (3,884 miles)	655	Feb. 2023–Dec. 2025 (35 months)
Substations	577	688	Feb. 2023–Dec. 2025 (35 months)

Notes: Distribution network includes secondary conductors. Substations exclude wind parks, single customer or customer-owned substations. Outage events captured between February and June 2023 were excluded due to configuration of DTE's ADMS.

Count of Outage Events

DTE Electric's outage event data was treated as counts and statistical models were estimated using generalized linear models (GLMs) (McCullagh & Nelder, 1989) following a spatiotemporal design. Specifically, the counts of outage events were tallied by four circuit and substation networks (spatial sampling units) and by month and year (temporal sampling units). The four circuit and substation networks included: overhead distribution circuits, underground distribution circuits, subtransmission circuits, and substations (Table 2).

Table 2. Summary of circuit-month outage event counts across the four networks evaluated

Network System	Sampling Units (n)*	Range (Outage Count)	Mean (Outage Count)	Variance (Outage Count)
Overhead Distribution Circuits	274,780	0-131	1.45	8.87
Underground Distribution Circuits	148,148	0-65	.50	1.90
Subtransmission Circuits	20,639	0-11	.03	.05
Substations	42,070	0-8	.02	.03

*Count of circuit or substation units multiplied by the number of sampling months in each dataset

Statistical count models were estimated using maximum likelihood with the final model form and covariates selected using Bayesian Information Criterion (Schwarz, 1978). Both negative binomial and Poisson model forms (McCullagh & Nelder, 1989) were considered in the analysis of the counts because the larger than one mean to variance ratios in Table 2 indicated potentially over-dispersed count data. Hurdle and zero-inflated models were further evaluated recognizing the potential for zero-inflated counts (Cameron & Trivedi, 2013). The outage event counts were heavily skewed within each of the four networks (Table 2). As expected, a negative binomial model form best accounted for the overdispersion across all networks evaluated. For brevity, results are detailed specific to the hurdle (negative binomial) and negative binomial model forms.

A description of the key covariates considered in the analyses of the outage event data is detailed in Table 3. Continuous covariates were centered around the mean and scaled by the standard deviation to improve model convergence and parameter estimation and interpretation. Additional methods for generating geospatial covariates are in Appendix B.

Table 3. Overview of key covariates used in the estimation of outage event count models

Covariate Name	Network System	Description
Conductor Length	Overhead Distribution, Underground Distribution, Subtransmission	Total measured conductor length derived from geospatial mapping
Conductor Voltage	Overhead Distribution, Subtransmission	Proportion of each major voltage level (secondary, 4.8kV, 8.3kV, 13.2kV, 24kV, 40kV, 120kV)
Conductor Material	Overhead Distribution, Underground Distribution, Subtransmission	Proportion of each major conductor material type (ACSR, APEC, copper)
Phase Configuration	Overhead Distribution	Proportion of conductor configured as multi (2- or 3-phase) or single (1-phase)
Device Count by Type	Substation	Total count of devices (fuses, switches, transformers, dynamic protective devices, voltage regulators) contained within a substation
Infrastructure Age	All Networks	Estimated years since install derived from structures or build records
Region	All Networks	Operating region (NW, NE, SE, SW)
Severe Weather Days per Month	All Networks	Count of days the network experienced elevated or extreme conditions resulting in elevated outage counts
Outage Fidelity	All Networks	Count of unplanned outages (per mile of conductor) measured across the preceding 12-, 24-, 36-months on non-inflated weather days (not elevated or extreme weather event days)
Season	All Networks	Sine and cosine curves for day of year (Julian date)
Tree Exposure	Overhead Distribution, Subtransmission	Distance of conductor (miles) exposed to an over-strike by adjacent trees

The count of inflated outage event days in each month was used as an indicator of exposure to severe weather events. Specifically, the daily count of sustained outage events was calculated across the entirety of the 2021–2025 study period specific to DTE Electric's system. Days of inflated outage counts were classified as elevated (outage counts from the 95th – 99th percentile of the distribution) or extreme (outage count greater than the 99th percentile) (Figure 1). As a final step, the dates of inflated outage counts were cross-referenced with reported weather events and observational surface station weather data to confirm consilience (Figure 2).

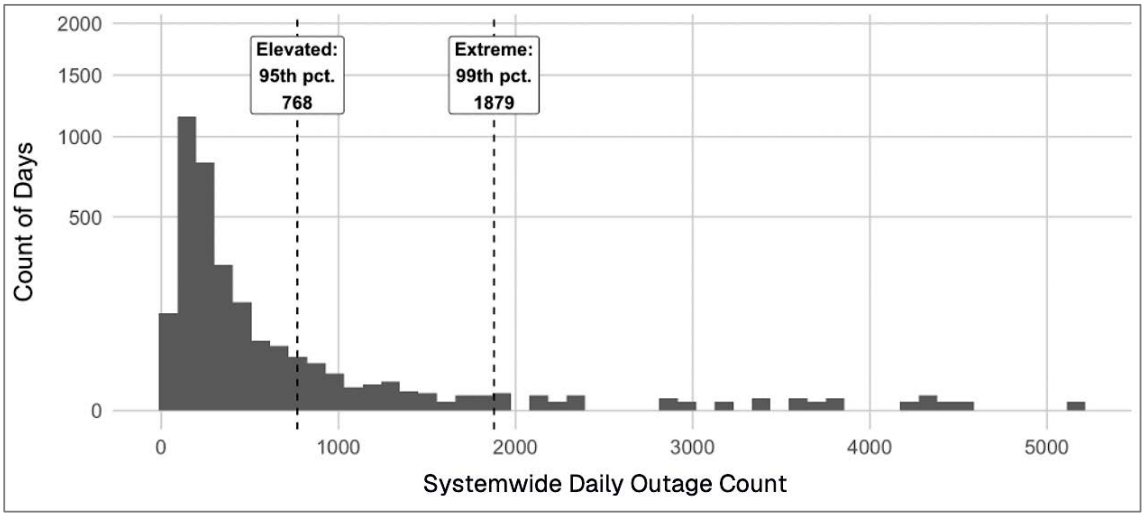

Figure 1. Distribution of daily outage counts used to identify elevated and extreme impact thresholds

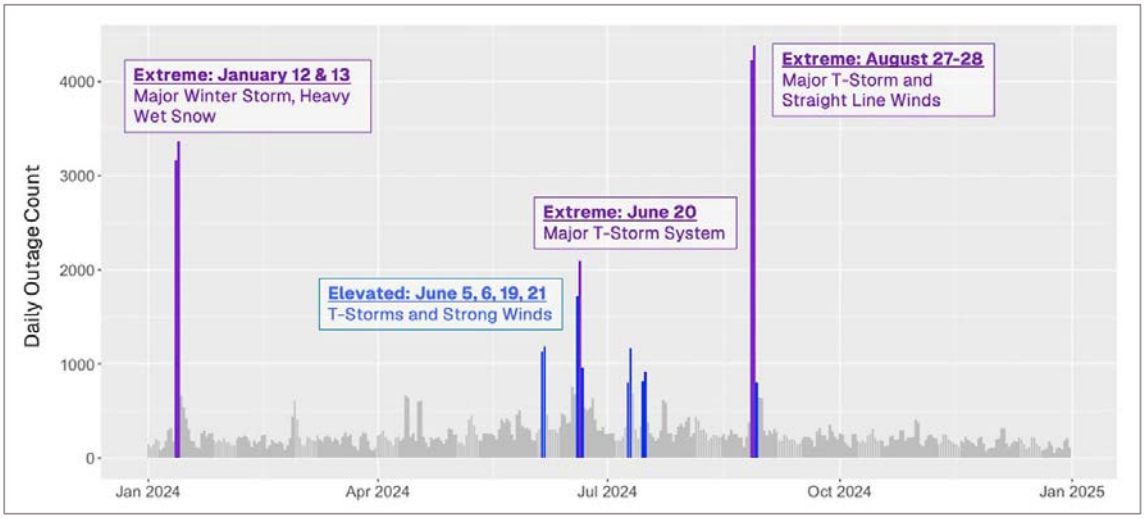

Figure 2. Sample of identified elevated or extreme weather days based on daily outage counts

Outage Event Outcomes and Reliability Performance Metrics

CI was recorded for each outage event over the extent of historical records. Where historical outage and CI data were available, the forecast CI per outage was calculated as the historical mean CI per outage per substation and circuit by network (subtransmission, overhead primary, overhead secondary, or underground). For circuits and substations with insufficient historical records, the forecast CI per outage was calculated as the mean value across that network for substations, subtransmission, overhead secondary, and underground outages. For overhead primary outages, in the case of insufficient historical records, the forecast CI per outage was calculated as the historical mean proportion of circuit customers interrupted per primary overhead outage multiplied by the current circuit customer count. This method ensured that a CI per outage estimate given up to date customer configuration would be provided specific to each circuit and substation when forecasting.

CAIDI was measured over the extent of historical records and was aggregated to region (spatial unit) and year (temporal unit) to allow for analysis. A Gaussian linear regression was fit to estimate minutes per customer interruption given count of yearly outages and operating region (Fisher, 1922).

Estimates of key reliability performance metrics were derived given the predictions from the estimated outage event models as inputs. Specifically, estimates of CI, CMI, SAIFI, and SAIDI were derived using the functions detailed in Table 4.

Table 4. Functions used to calculate performance metrics

Reliability Performance Metric	Acronym	Function
Customer Interruptions	CI	Outage Event Count × CI per Outage Event
Customer Minutes Interrupted	CMI	Outage Event Count × CI per Outage Event × CAIDI
System Average Interruption Frequency Index	SAIFI	CI / Total customers on electric system per year
System Average Interruption Duration Index	SAIDI	CMI / Total customers on electric system per year

Goodness of Fit Evaluations

Goodness of fit estimations were conducted using R-squared (McCullagh & Nelder, 1989). A cross validation (goodness of fit) test was conducted by iteratively (1) selecting a random 75% of the spatial (circuits, substations) and temporal (month) units for model estimation; and (2) evaluating goodness of fit using the remaining 25% of the dataset. Goodness of fit

tests were also conducted at higher level resolutions by aggregating and summing both the known (truth) and the predicted values among nested space and time intervals (e.g., circuits to system, months to years). This approach enabled goodness of fit to be explored at resolutions pertinent to those of the forecasting evaluation.

2.2 Results

2.2.1 Outage Count Models

The relationship between circuit miles and outage counts was fixed with a slope of one (exposure term) among each of the three circuit models: overhead distribution circuits, underground distribution circuits, and subtransmission circuits. This enabled the circuit count models to be interpreted as a rate: outage events per mile of circuit. The substation model was estimated as the count of outages per month by substation.

Overhead Distribution Circuit Outage Model

The best fit model for estimating overhead distribution outages took the form of a negative binomial count model. The scaled parameter estimates for the covariates included in the best fit model are provided in Table 5.

Table 5. Parameter estimates of the best fit distribution overhead circuit outage count model

Covariate	Scaled Coefficient	Standard Error
Intercept	-2.372	0.006
Outage Fidelity	0.729	0.004
Conductor Voltage [Secondary]	0.310	0.009
Elevated Weather Days	0.262	0.003
Extreme Weather Days	0.210	0.003
Conductor Voltage [13.2kV]	-0.057	0.004
Tree Exposure	0.046	0.003

Notes: All covariates are significant at P<0.001. Scaled parameter estimate interpretation: (1) larger absolute parameter estimates indicate greater relative importance in the model; (2) the direction of the relationship with the rate of outage counts is provided by a positive or negative parameter estimate. The Negative Binomial overdispersion parameter estimate was 0.936.

Goodness of fit for the overhead distribution outage count model revealed strong performance based on R-squared cross validation tests conducted at circuit-year resolution (R^2: 0.67; range: 0.60-0.71). Outage fidelity was the most influential covariate in the best fit model. This relationship revealed that the rate of outage events per month was positively related to the count of outages each circuit had experienced per mile on non-weather days in the previous 12-month period. After controlling for outage fidelity, the rates of outage events were positively correlated to secondary conductor (relative to primary conductor), the

counts of elevated and extreme weather days in each month, and the miles each circuit is exposed to tree cover. Outage event rates were reduced on primary conductor with increased presence of 13.2 kV conductor (as secondary lines do not have 13.2 kV conductor). The counts of elevated and extreme weather days per month were moderately correlated (Pearson correlation: 0.41), but both weather covariates revealed positive relationships with outage count rates. Otherwise, all other covariates had low correlation (absolute Pearson correlation <0.1).

Underground Distribution Circuit Outage Model

The best fit model for estimating underground distribution outages took the form of a negative binomial count model. The scaled parameter estimates for the covariates included in the best fit model are provided in Table 6.

Table 6. Parameter estimates of the best fit distribution underground circuit outage count model

Covariate	Scaled Coefficient	Standard Error
Intercept	-2.737	0.006
Outage Fidelity	0.811	0.006
Elevated Weather Days	0.257	0.005
Extreme Weather Days	0.140	0.005

Notes: All covariates are significant at P<0.001. Scaled parameter estimate interpretation: (1) larger absolute parameter estimates indicate greater relative importance in the model; (2) the direction of the relationship with the rate of outage counts is provided by a positive or negative parameter estimate. The Negative Binomial overdispersion parameter estimate was 1.133.

Goodness of fit for the underground distribution outage count model revealed strong performance based on R-squared cross validation tests conducted at circuit-year resolution (R^2: 0.81; range: 0.78-0.84). The best fit outage count model for underground circuits contained only three covariates. Like the overhead distribution outage model, outage fidelity was the most influential covariate in the model for underground circuits. Otherwise, the rates of outages on underground circuits were positively correlated with the counts of both elevated and extreme weather days per month. It is presumed that risers from overhead to underground infrastructure provide the greatest correlation between severe weather and the rates of underground circuit outages.

Subtransmission Circuit Outage Model

The best fit model for estimating subtransmission circuit outages took the form of a hurdle, negative binomial, count model. The scaled model parameters generally showed greater effect sizes (greater importance) on the probability (of an outage event) side of the model, relative to the zero-truncated count side of the hurdle model. This is not surprising given the

negligible abundance of counts greater than one in the dataset (>95.5% of the monthly outage counts were zero and one counts). The parameter estimates in the best fit hurdle model are provided in Table 7.

Table 7. Parameter estimates of the best fit subtransmission circuit outage count model

Covariate	Scaled Coefficient	Standard Error
Zero-truncated outage count model		
Intercept	-4.318	0.127
Elevated + Extreme Weather Days	0.174	0.072
Outage Fidelity	0.160	0.079
Probability of an outage event model		
Intercept	-6.44	0.060
Conductor Voltage [120 kV]	-1.393	0.384
Outage Fidelity	0.297	0.039
Extreme Weather Days	0.251	0.043
Tree Exposure	0.246	0.043
Elevated Weather Days	0.227	0.046

Notes: All covariates are significant at P<0.001. Scaled parameter estimate interpretation: (1) larger absolute parameter estimates indicate greater relative importance in the model; (2) the direction of the relationship with the rate of outage counts is provided by a positive or negative parameter estimate.

The probability of an outage event was reduced on 120 kV lines, which was the most influential covariate in the model based on the magnitude of the scaled parameter estimates. The probability of an outage event was otherwise positively correlated with outage fidelity, the amount of tree cover, and elevated and severe weather days. The zero-truncated count model showed that the rates of outage counts increased positively with both outage fidelity and the number of elevated and extreme weather days per month. Overall, the subtransmission and distribution circuit outage models consistently included significant effects for outage fidelity, tree cover, and severe weather covariates.

Less than 0.3% of the total outage events in the dataset occurred on subtransmission circuits between February 2023 and December 2025. The small sample size of the captured outage events (intensities), comprising approximately 225 outage events across 590 circuits every year, and the highly zero-inflated distribution, comprising >99% of the counts, made the effort challenging to fit the count models on subtransmission circuits. As a result, the

goodness of fit for the subtransmission count model revealed poor performance based on the R-squared cross validation tests conducted at the circuit and year levels (R^2: 0.33; range: 0.27-0.43) relative to the models for distribution circuits. Despite low R-squared values when predicting outage counts, the probability side of the model had an area under the curve (AUC) performance of 0.79, which demonstrated strong predictive performance at differentiating zero and greater than zero counts. The probability model can be used to prioritize times and conditions wherein subtransmission outages are most likely to occur.

Substation Outage Model

The best fit model for estimating substation outages took the form of a hurdle, negative binomial, count model. The scaled model parameters generally showed greater effect sizes (greater importance) on the probability (of an outage event) side of the model, relative to the zero-truncated count side of the hurdle model. Like the results for subtransmission circuit outages, this was not surprising given the negligible frequency of counts greater than one in the dataset (>99.7% of the monthly outage counts were zero and one counts). The parameter estimates in the best fit hurdle model are provided in Table 8.

Table 8. Parameter estimates of the best fit substation circuit outage count model

Covariate	Scaled Coefficient	Standard Error
Zero-truncated outage count model		
Intercept	-0.882	0.152
Outage Fidelity	0.528	0.167
Season (cosine curve)	-0.198	0.080
Season (sine curve)	-0.163	0.074
Probability of an outage event model		
Intercept	-7.037	0.239
Substation Age > 17 Years	1.823	0.231
Proportion Dynamic Protective Devices	0.925	0.047
Outage Fidelity	0.568	0.101
Device Count	0.286	0.034
Season (sine x cosine curve)	0.258	0.072
Season (cosine curve)	-0.214	0.048
Elevated + Extreme Weather Days	0.197	0.045

Notes: All covariates are significant at P<0.001. Scaled parameter estimate interpretation: (1) larger absolute parameter estimates indicate greater relative importance in the model; (2) the direction of the relationship with the rate of outage counts is provided by a positive or negative parameter estimate.

Based on the scaled parameter estimates, the most influential covariates in estimating the count of substation outages were substation age (>17 years) and the proportion of dynamic protective devices in the substation. Both covariates were positively correlated with the

probability of at least one outage event at a substation. The probability of an outage event was also positively related with outage fidelity, substation device count, and the counts of elevated and severe weather days per month. Covariates for outage fidelity and season occurred in both the probability of an outage event and zero-truncated outage count components of the hurdle model. The influence of the season covariates in the hurdle model for substations indicated that outages occur with greatest frequency during peak summer and are lowest in November and December of the calendar year.

Less than 0.3% of the total outage events in the dataset occurred on substations between February 2023 and December 2025 (i.e., >99% of the outage events occurred on distribution circuits). The small sample size of outage events (intensities) captured (approximately 240 outage events across 1,202 substations every year), and the highly, zero-inflated distribution (>99.5% of the counts), made it challenging to fit the count models for DTE Electric's substations. The goodness of fit for the substation count model revealed weak performance based on the R-squared cross validation tests conducted at the substation and year levels (R^2: 0.13; range: 0.12-0.23). The probability side of the model had an area under the cure (AUC) performance of 0.84, which demonstrated strong predictive performance at differentiating zero and greater than one counts. The probability model can be used to prioritize times and conditions wherein subtransmission outages are most likely to occur.

2.2.2 Outage Event Outcomes and Reliability Performance Metrics

Customers Interrupted per Outage Event

Customer interruptions per outage varied by network as shown in Figure 3. Subtransmission and substation outages demonstrated significantly higher (2,223 and 2,402 medians, respectively) customer interruption per outage. This was anticipated, as these networks typically support multiple circuits downstream that may be interrupted by a single outage. Primary distribution network outages were observed to interrupt a lower count of customers per interruption (21 median).

Overhead secondary and underground yielded the lowest customer interruptions per outage, with the majority (87% and 64%, respectively) interrupting only a single customer.

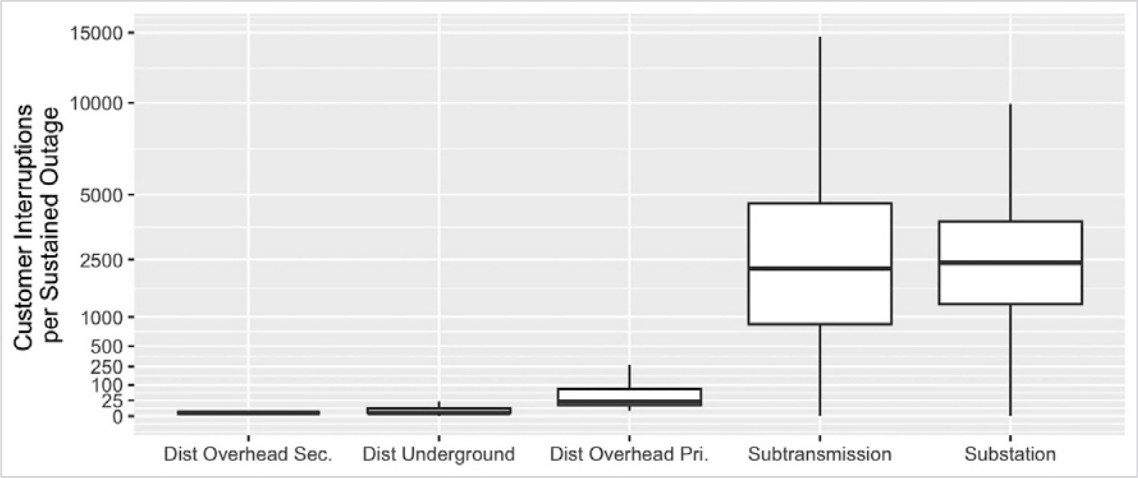

Figure 3. Customer interruptions per outage per modeled network over study window

Minutes per Customer Interruption (CAIDI)

CAIDI had minimal variation by network (Figure 4). On average, substation outages had the lowest mean minutes per customer interruption, and secondary distribution overhead circuits the longest. Outage minutes per customer interruption varied widely, showing significant overlap across networks.

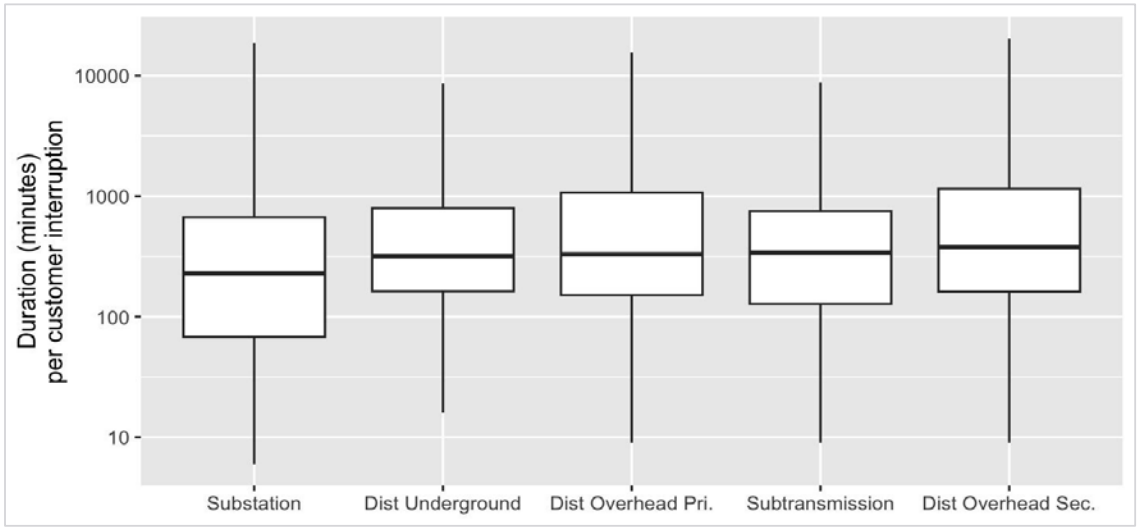

Figure 4. Minutes per customer interruption per modeled network over study window

A model was estimated to predict the CAIDI at region-month resolution. The best fit model for estimating CAIDI took the form of a linear Gaussian regression model. The parameter estimates of the final best fit linear model are provided in Table 9. CAIDI increased markedly

as concurrent outage count increased within month, and the intercept and slope of the relationship varied by region (Figure 5). The goodness of fit for the CAIDI model revealed strong performance based on the R-squared cross validation tests conducted by operational region (R^2: 0.62).

Table 9. Parameter estimates for the best fit minutes per customer interruption model

Covariate	**Scaled Coefficient**	**Standard Error**
Intercept	448.00	23.49
Outage Count x SW	350.56	45.93
Outage Count x NW	312.65	63.98
Outage Count x NE	167.16	50.66
Outage Count x SE	155.24	27.01

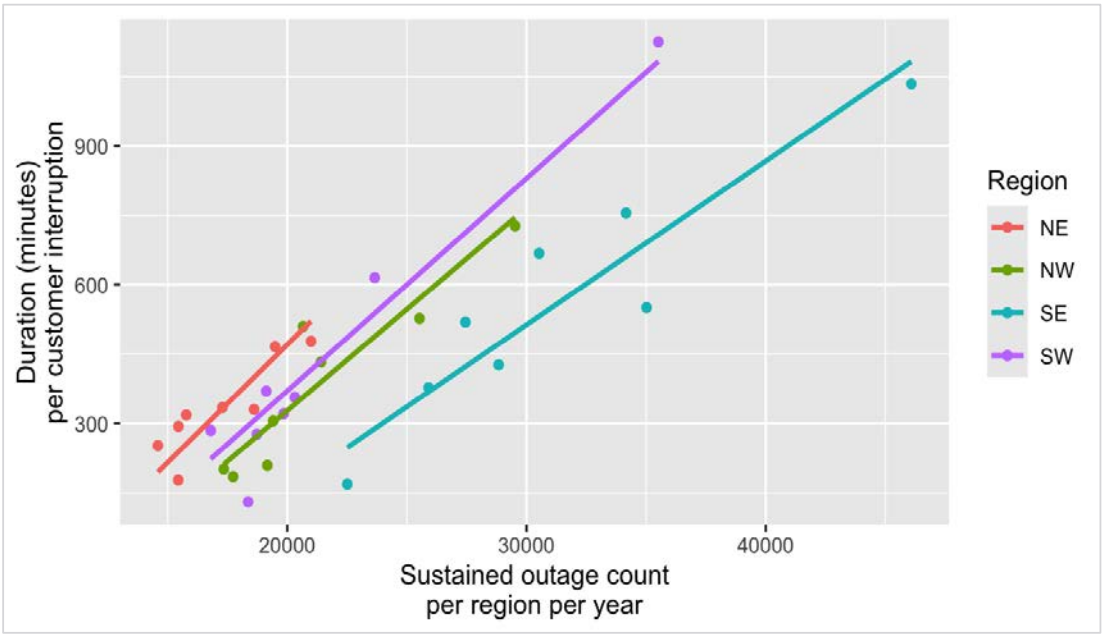

Figure 5. Minutes per customer interruption vs concurrent outages within same year and region

SAIDI and SAIFI Reliability Performance Models

DTE Electric employs composite measures of reliability performance to measure the outcomes of investment programs. Composite metrics such as SAIFI and SAIDI integrate across root reliability mechanisms, such as outage frequency, customers interrupted per outage event, and minutes per customer interrupted. SAIFI and SAIDI are typically aggregated across DTE Electric's operational regions or the full system to measure overall system reliability performance.

Predicted estimates of key reliability performance metrics were derived given the predictions from the estimated outage event models as inputs. Actual (from the cleaned retrospective dataset) and model predicted measures of DTE Electric's SAIFI and SAIDI reliability performance between 2024 and 2025 are provided in Table 10.

Table 10. DTE Electric's cross-validation observed and predicted SAIDI and SAIFI by region and year

KPI	**System SAIFI Contribution Actual (Prediction)**		**System SAIDI Contribution Actual (Prediction)**	
Year	2024	2025	2024	2025
NE	0.294 (0.372)	0.274 (0.324)	98 (139)	48 (82)
NW	0.351 (0.331)	0.339 (0.283)	153 (113)	64 (60)
SE	0.255 (0.200)	0.227 (0.165)	108 (77)	38 (30)
SW	0.334 (0.352)	0.316 (0.288)	118 (110)	41 (40)
Systemwide	1.250 (1.260)	1.162 (1.060)	483 (439)	192 (191)

Notes: The model predictions of SAIFI and SAIDI are provided in brackets. The measures include reliability performance across DTE Electric's distribution circuits, subtransmission circuits and substations. The model evaluations were conducted across a broader range of years for DTE Electric's distribution circuits (2021–2025).

The model-based predictions of SAIDI and SAIFI demonstrated reasonable goodness of fit with the actuals by region and year (R^2: SAIFI 0.49, SAIDI 0.57). At a systemwide level, the model predictions were even stronger. These results were pertinent to the efficacy of the models for predicting SAIDI and SAIFI monitoring metrics, which were the key metrics used to forecast the overall reliability performance outcomes of DTE Electric's reliability investment plan in Section 3.

3. Reliability Performance Forecasting

3.1 Methods

Two reliability performance scenarios were forecast across DTE Electric's distribution, subtransmission and substation network from 2026–2030: a baseline (zero-investment) scenario with no mitigation works and a reliability investment scenario with planned mitigation works. Each scenario was simulated under three weather conditions (mild, typical and severe). The reliability benefit of the investment scenario was calculated by taking the difference in the predicted SAIFI and SAIDI between the zero-investment scenario and the reliability investment scenario.

Scenario Forecasting Procedures

The following steps were employed sequentially to run five-year reliability forecasts for each mitigation scenario. The reliability investment scenario incorporated calculation across all seven steps below. In contrast, the zero-investment scenario did not assume any mitigation program benefits (Step 3) or automation program benefits (Step 5).

1. **Yearly Outage Prediction:** Using the outage count models detailed above, the following metrics were predicted (as relevant) specific to each active (customer-serving in 2026) circuit and substation on the DTE Electric network (distribution, subtransmission, and substation): overhead distribution outage count, underground distribution outage count, subtransmission outage count, and substation outage count. Predictions were generated for a five-year period under each of three weather scenarios.
2. **Outage Program Benefits Applied**: The assumed reliability benefits of each program were provided by DTE Electric (U-22046 Kryscynski Exh A-23 Sch M7 Reliability Model Output). The program benefits represent a % reduction to outage count based on the program deployed and years since deployment. The benefits were applied in sequence to the outage count forecast for each circuit-year. In the year a program deployment is planned, 50% of the benefit of the program to that circuit or substation was applied (assumes mid-year completion of work).
3. **Outage Degradation Applied**: To capture the impact of network degradation, DTE Electric provided an 8% annual degradation rate of circuits and a 2% annual degradation rate of substations. The degradation factors estimate the annual increase in outage events due to aging assets in the absence of reliability programs. The degradation rates were applied to all outages (excluding planned and public interference) on substations and primary overhead, underground, and subtransmission circuits that did not currently have degradation captured through an applied program benefit assumption. If a circuit had a program benefit applied that

included a degradation effect (Vegetation Management, PTMM, Conversion, or Hardening), no additional degradation was applied.

4. **Customer Interruption Predictions**: Using the customer interruption per outage models detailed above, the following metrics were predicted (as relevant) specific to each active circuit and substation on the DTE Electric network: CI per primary outage, CI per secondary outage, CI per underground outage, CI per subtransmission outage, and CI per substation outage. Each of these predictions was multiplied by the relevant outage count prediction to produce a forecast CI related to primary, secondary, underground, subtransmission, or substation interruptions. These individual CI forecasts were summed per circuit or substation to produce a total CI forecast per year.
5. **CAIDI Predictions:** Using the model detailed above, a CAIDI prediction was generated per year at the region-level for distribution circuits. The average CAIDI prediction per year across the four regions was used for each subtransmission circuit and substation in the forecast. The total forecast CI for each circuit or substation was multiplied by the CAIDI prediction to provide a yearly CMI forecast.
6. **Automation Benefits Applied**: To capture the benefit of automation in the forecast, the assumed effects of automation completed in or before a specific forecast year were applied as a % reduction to the total forecast CI and CMI (unique benefits provided) for each treated circuit.
7. **SAIFI/SAIDI Forecasting:** The yearly forecast CI and CMI from the process above were divided by system customer count as of 2026 (2,284,019) to yield a SAIFI and SAIDI value for each year in the forecast window.

3.1.1 Investment Scenario Mitigation Programs

The following nine mitigation programs, detailed in DTE Electric's 2026 Distribution System Plan (DSP), were integrated within the investment scenario for simulation:

- **4.8 kV Conversion Projects:** Conversion of 4.8 kV circuits to 13.2 kV standard
- **Distribution Automation:** Distribution automation involving sectionalizing, building new ties, or automating existing ties
- **Undergrounding:** Burying primary overhead distribution conductor
- **Small Wire Replacement:** Comprehensive rebuild of small wire conductor on primary distribution
- **Vegetation Management:** Removing limbs within a 15-foot radius and vegetation underneath conductor
- **4.8 kV Circuit Hardening:** Replacing and reinforcing pole infrastructure, conducting tree trimming, and removing unnecessary lines
- **Pole and Pole-Top Maintenance and Modernization (PTMM):** Testing and replacing of poles and pole-top equipment

- **Substation Equipment Replacement:** Replacement of various substation devices
- **Underground Residential Distribution (URD) Cable Replacement:** Upgrading underground cable infrastructure

The schedule of programs as components of the investment scenario is summarized in Table 11. The modeled programs do not represent the comprehensive investment plan, as only select projects were included for some programs. The results of the investment scenario were forecast through 2030.

Table 11. Counts of modeled program deployments (circuits and substations) by year

Program Name	2026	2027	2028	2029	2030
Vegetation Management	578	455	560	607	709
PTMM	135	217	188	365	343
Distribution Automation	155	157	196	68	0
4.8 kV Hardening	96	12	0	0	0
4.8 kV Conversion	6	18	17	4	18
URD Cable Replacement	68	10	0	0	0
Small Wire Replacement	2	1	0	0	0
Undergrounding	1	1	0	0	0
Substation Equipment Replacement	6	1	0	0	0

Specific assumptions, including effect sizes and methods, were provided by DTE to forecast the expected impact—outage events, CI or CMI reduction—per circuit or substation for each mitigation program. The benefits were applied to the forecasts based on the affected networks, the type of reliability measures that could be affected, and the extent completed, such as miles of conductor or count of devices upgraded. Benefits were provided either as a single value that was applied in perpetuity or as a degrading benefit over a defined number of years. For all programs, it was assumed that in the year a project was completed, circuits would receive half of the expected year one benefit.

The benefits of previously completed work were inherently captured in the forecast because recent reliability performance contributed to the predictions. To fully capture the residual benefits of projects recently completed in 2025, 50% of the program benefit was assumed to be captured, and the additional 50% benefit was applied to the future forecasts. For both historical and planned work, program benefits were applied directly to the relevant reliability mechanism for that program—outages, CI or CMI—ensuring that a benefit applied

to outages could yield a non-equal benefit to CI and CMI. Figure 6 illustrates the forecasting process and inputs provided by E Source and DTE.

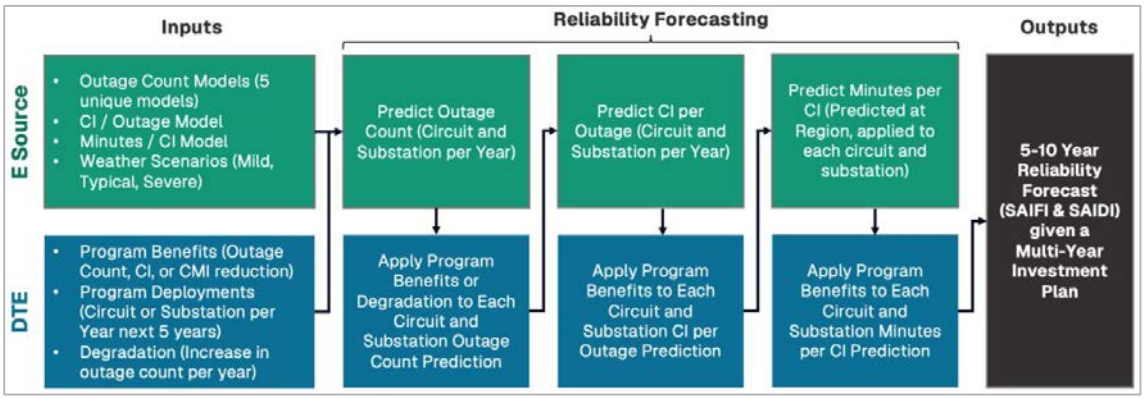

Figure 6. Illustration of reliability forecasting process using program benefit assumptions

3.1.2 Weather Scenarios Evaluated

Mild, typical and severe weather scenarios were simulated by predicting the outage models given different counts of elevated and extreme weather days. The typical weather scenario was calculated as the average annual counts of elevated and extreme weather days since 2018, excluding 2023 (Table 12). The mild and severe scenarios represented the historical years on record with the least and most elevated and extreme weather days.

Table 12. Count of severe weather days simulated under mild, typical and severe weather scenarios

Weather Scenario	Reference Years	Elevated Weather Days	Extreme Weather Days
Mild	2025	11	0
Typical	7-Year Average	15	3
Severe	2021	35	5

3.2 Results

The zero-investment scenario and investment scenario were simulated under mild, typical and severe weather for a total of six reliability forecasts. These scenarios were evaluated to understand expected system performance and expected benefits of the planned reliability investments. The forecasts are presented using SAIFI and SAIDI, which were calculated using the 2026 customer count of 2,284,019.

3.2.1 Baseline (Zero-Investment) Scenario

The zero-investment scenario forecast showed that without future investment SAIFI (as predicted by models detailed in Section 2.2.2) was predicted to increase 18.3% over the next five years from 1.26 (1.11–1.71) in 2026 given current system state to 1.49 (1.30–2.02) in 2030 (Figure 7). SAIDI was predicted to increase 43.2% over the next five years from 352 (211–884) in 2026 to 504 (317–1,208) in 2030. Tabular results of this forecast are provided in Appendix Table C1.

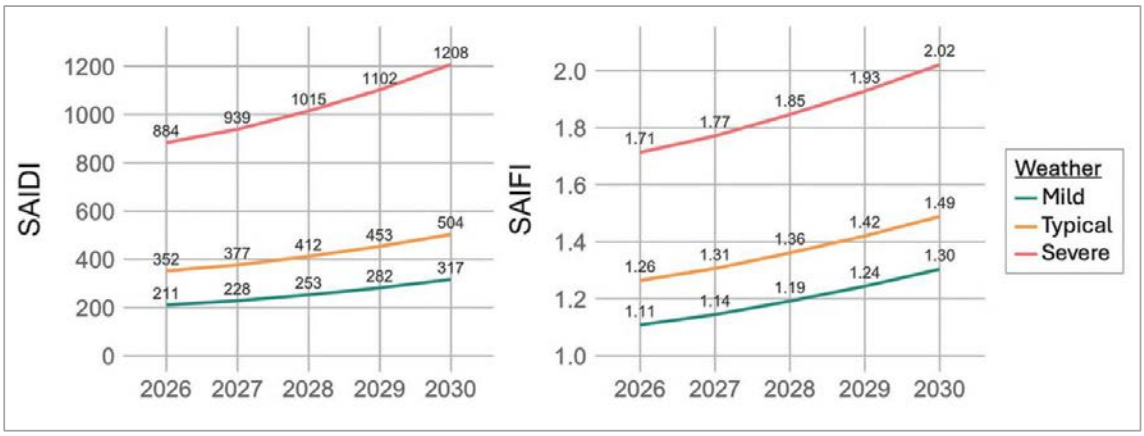

Figure 7. Forecast SAIDI and SAIFI by weather scenario given zero-investment scenario

Without reliability investment, the greatest proportional increases in reliability metrics were forecast on the subtransmission network, with SAIFI increasing by 0.025 (29%) and SAIDI increasing by 13.3 (56%) over the next five years (Figure 8). The greatest total increases in reliability metrics were forecast on the distribution network, with SAIFI increasing by 0.193 (17%) and SAIDI increasing by 132.9 (43%). Substation SAIFI was forecast to increase by 0.005 (8%) and SAIDI was forecast to increase by 5.7 (31%). Tabular results of this forecast are provided in Appendix Table C2.

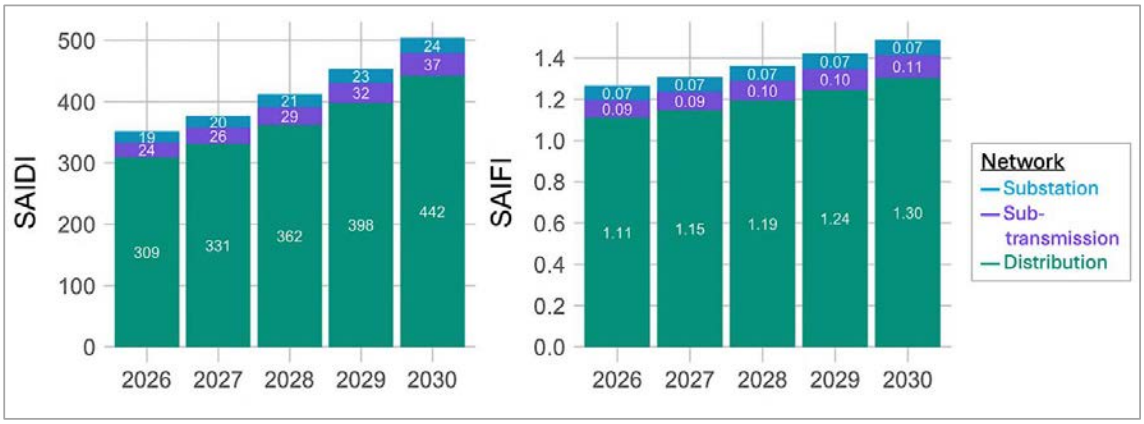

Figure 8. Forecast SAIDI and SAIFI by network given zero-investment scenario

3.2.2 Reliability Investment Scenario

The reliability investment scenario was forecast between 2026 and 2030 in alignment with DTE Electric's five-year reliability investment plan. The investment scenario forecast predicted that SAIFI and SAIDI were expected to decrease markedly over the next five years. SAIFI was predicted to decrease 15.1% from 1.26 (1.11 – 1.71) in 2026 given current system state to 1.07 (0.94 – 1.45) in 2030 (Figure 9). SAIDI was predicted to decrease 25.4% from 352 (211 – 884) in 2026 to 262 (151 – 683) in 2030. Tabular results of this forecast are provided in Appendix Table C3.

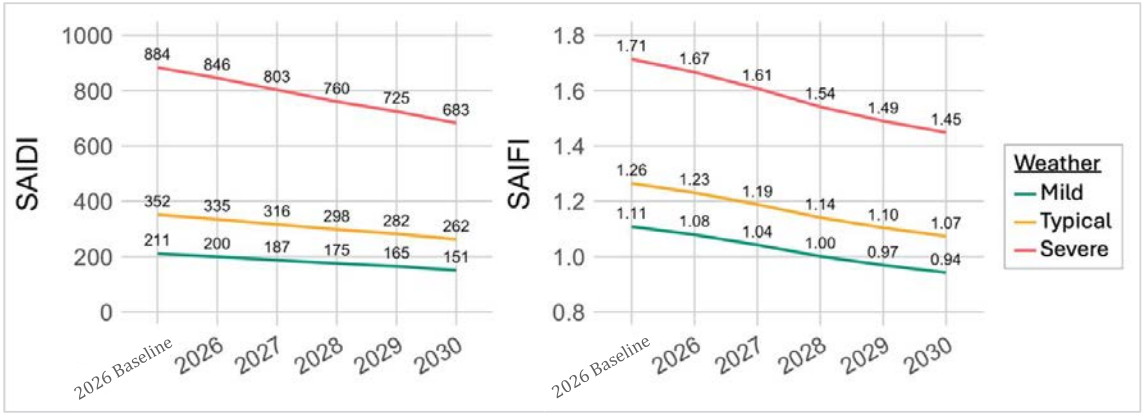

Figure 9. Forecast SAIDI and SAIFI by weather scenario given modeled reliability investment

Compared to the zero-investment scenario, the planned investments would result in a difference of 0.42 (0.36 – 0.57) SAIFI in 2030 (Table 13). SAIDI in 2030 was predicted to benefit 242 (166 – 525) from the planned investments.

Table 13. Forecast SAIDI and SAIFI difference between baseline and reliability investment scenarios over 5 years

KPI	Weather Scenario	2026	2027	2028	2029	2030
SAIFI	Mild	0.03	0.10	0.19	0.28	0.36
	Typical	0.03	0.12	0.22	0.32	0.41
	Severe	0.05	0.16	0.30	0.44	0.57
SAIDI	Mild	11	41	77	117	166
	Typical	17	61	114	171	241
	Severe	38	136	254	378	525

With reliability investment, the greatest impacts (proportionally and by magnitude) were forecast on the distribution network, with SAIFI decreasing by 0.196 (17.6%) and SAIDI decreasing by 85.5 (27.6%) over the next five years (Figure 10). Combined subtransmission and substation SAIFI was forecast to remain generally consistent or slightly increase, while SAIDI was forecast to decrease by 4.0 (9.3%). Within the distribution network, the greatest impacts were forecast on the overhead primary network (30% decrease in SAIDI), followed by the underground network (23% decrease in SAIDI). Overhead secondary SAIFI was forecast to have 0% change; however, SAIDI was forecast to decrease by 11%. Tabular results of this forecast are provided in Appendix Table C4.

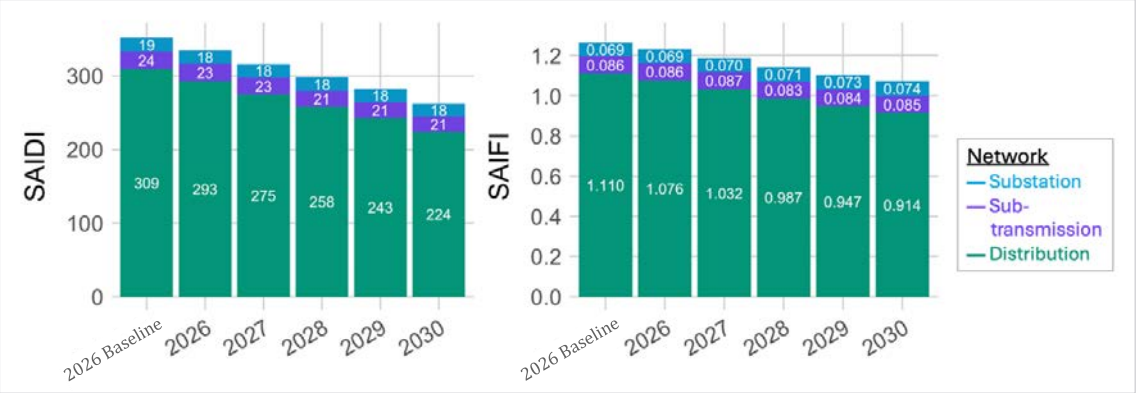

Figure 10. Forecast SAIDI and SAIFI by network given modeled reliability investment

For both SAIDI and SAIFI benefit the most influential mitigation programs were Vegetation Management, PTMM, and Distribution Automation. This reflects that these three programs (1) have relatively large magnitude effects compared to the other programs; and (2) are widely and abundantly scheduled for deployment across the system over the next five years.

The planned program with the greatest expected impact on CI and CMI over the period of investment (2026–2030) was Vegetation Management, followed by PTMM and Distribution Automation (Table 14). Expected program benefits vary year-over-year based on the schedule of deployments; as such the impact is provided as a five-year sum rather than an annual average. Program benefits by year are provided in Appendix D.

Table 14. Cumulative five-year outage, CI, and CMI reduction per program

Program	**Five-year Total Outage Benefit**	**Five-year Total CI Benefit**	**Five-year Total CMI Benefit**
Vegetation Management	12,791	1,237,759	822,273,828
PTMM	11,104	878,919	672,287,851
Automation	0	867,104	263,598,463
Conversion	502	41,507	30,154,456
Hardening	740	56,019	28,690,568
URD Cable Replacement	199	11,388	10,735,100
Small Wire Rebuild	25	2,723	1,604,730
Undergrounding	7	814	583,115
Substation Equipment Replacement*	<1	25	7,583

* Substation equipment replacement CI and CMI benefits based on probability of a single outage occurring

4. Key Insights and Conclusions

4.1 Retrospective Analysis

The retrospective data analyses of DTE Electric's reliability performance on distribution circuits, subtransmission circuits and substations evaluated power reliability data captured between 2021 and 2025. The analyses revealed key insights that are pertinent to prioritizing and conducting reliability management works, and to forecasting future mitigation outcomes. Key reliability performance insights from the retrospective analyses were as follows.

The overall rates of outage events evaluated across the system were greatest on distribution overhead circuits (0.24 outages per mile per month on average) followed by distribution underground circuits (0.12 outages per mile per month on average). In contrast, the average monthly rate of outage events on subtransmission circuits and at substations was <.01 outages per conductor mile or device respectively. The statistical analyses indicated that, on average, there was less than one outage event per year per subtransmission circuit or substation given the condition-based covariates. Based on the scaled parameter estimates, the three most influential mechanisms influencing the rates of outage events were weather conditions, typical-weather outage fidelity, and tree conditions.

Elevated and extreme weather event days were important covariates for predicting outages on overhead distribution circuits. The ability to capture and estimate outage event rates given variable weather scenarios is accordingly important to reliability performance forecasting. The retrospective models, which include covariates for elevated and extreme weather days, enabled predictions to be forecast for DTE Electric's reliability investment plan assuming variable levels of weather severity.

Lagged rates of non-weather event outage fidelity over the past 12 months were a significant predictor of the rates of outages across all network systems. Circuits that revealed greater rates of non-weather event outage rates (outages per circuit mile) experienced greater intensities of outages in future months. Evidence suggests that this covariate is relevant to prioritizing outage mitigations, and to evaluating system outage performance. Mitigations that can curb the rates of non-weather events outages are likely to lead to long term improvement in reliability.

The tree cover covariate was important for estimating the rates of outage events on overhead distribution and subtransmission circuits. Evidence in the retrospective data indicated that mitigations aimed at specifically reducing the abundance of tree to conductor overstrike across DTE Electric overhead circuits would improve reliability performance by reducing the abundance of outage events.

Outage event outcomes, including customer interruptions and CAIDI, were evaluated. Customer interruptions were significantly elevated on subtransmission circuits and substations relative to overhead primary distribution lines (1,076 and 793 customer interruptions on average, respectively). Outages from underground and secondary distribution circuits tended to impact even fewer customers. CAIDI was found to increase significantly as concurrent outage counts increase, which was an especially prominent condition associated with storm event days.

Composite predictions of annual SAIDI and SAIFI at system-wide and regional resolutions showed a moderate goodness of fit with the historical actuals (0.57 and 0.49 regional R^2, respectively). These metrics are employed to monitor the efficacy of DTE Electric's reliability performance and are key to the forecasting of DTE Electric's reliability performance outcomes.

4.2 Reliability Forecasting

The reliability forecasts generated for the distribution, subtransmission, and substation networks predicted annual SAIFI and SAIDI outcomes from 2026 to 2030. Key takeaways from the forecast were as follows.

The overall SAIFI of the network was forecast to improve from 1.26 in 2026 given current system state to 1.07 in 2030 given DTE Electric's investment strategy, assuming the typical weather scenario. The overall SAIDI of the network was forecast to improve from 352 in 2026 to 262 in 2030. The overall benefit to typical network reliability would be a decrease of 0.19 SAIFI and 90 SAIDI minutes by 2030.

The projected SAIFI and SAIDI can range markedly due to annual variations in weather severity. The predictions of mild and severe weather employed the five-year retrospective reliability data analyses and associated models specific to DTE Electric's system. It is highly unlikely that DTE Electric would experience consecutive years of low or high weather severity over a five-year period. For this reason, the cumulative outcomes of the high and low weather scenarios should be interpreted as extreme bounds. The typical weather scenario is a more probable outcome when considering cumulative outcomes across the five-year forecast window.

Most of the reliability improvement to DTE Electric's system SAIFI was attributed to the distribution network, with a projected reduction of 17.7% by 2030. The benefit to subtransmission SAIFI was predicted to comprise a smaller overall reduction of 1.0%. Secondary overhead SAIFI was assumed to be unaffected by DTE Electric's investment scenario. The substation network was the only network where SAIFI was predicted to increase (+7.9%).

The largest proportional reduction to annual SAIDI was on the distribution network, with a projected reduction of 27.5% by 2030. SAIDI reductions were expected across all networks resulting from lower CAIDI. The largest contributor to reduced CAIDI was the reduction of co-occurring outage events (per region-month), which predominantly resulted from mitigations related to outage prevention (especially during elevated and extreme weather days).

For both SAIDI and SAIFI benefit, the most influential mitigation programs were Vegetation Management, PTMM, and Distribution Automation. Combined, these three programs contributed 96.4% of the total SAIFI benefit and 96.1% of the total SAIDI benefit across DTE Electric's reliability investment scenario. These results show that these three programs: (1) have relatively large magnitude effects compared to the other programs; and (2) are widely and abundantly scheduled for deployment across the system over the next five years.

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U-22046 Kryscynski Exh A-23 Sch M7 Reliability Model Output

Appendix A – Outage Filtering and Classification Logic

Outage models were fit using DTE Electric's historical outage data from 2021-2025. Outages were cleaned and filtered according to the exclusion criteria detailed in Appendix Table A1.

Table A1. Summary of outage filtering exclusions (percentages are relative to all outages).

Exclusion Criteria	Outages Excluded
Excluded Cause Code ("CANC", "COMP", "COMPLETE", "OTHERUTIL", "OTHER UTILITY EQUIP", "FOREIGN UTILITY EQUIPMENT")	5,098 (0.7%)
Excluded Subtype ("SLO", "TT", "COLLECT", "OPL")	479 (0.07%)
Non-Customer Circuits	11,726 (1.6%)
Transmission Outages	10 (.<01%)

Outages were classified as distribution, subtransmission, or substation using the "Outage Category" field. Distribution outages were attributed to overhead or underground and to primary or secondary infrastructure. Outages were classified as underground if the "Subtype Name" field contained "underground". Outages were classified as secondary if the "Event Subtype" indicated a secondary issue ("ONELEG", "SDXL", or "XCURR"), the outage impacted only 1 or 2 customers, or the outage impacted 5 or less customers and rolled up to a transformer but was not a transformer device failure.

Appendix B – Geospatial Covariate Methods

E Source augmented each circuit with geospatial imagery and sensor data. Remote sensing data for topography and modeled tree canopies were collected, processed and used to construct topographic indices (slope, aspect, elevation, etc.) and vegetation conditions (canopy locations, heights and areas) within a 40-meter buffer around the DTE Electric distribution, subtransmission and substation network. Using modeled tree cover and heights and spatially cleaned network conductor, tree-conductor strike calculations were performed to quantify the potential tree impact on conductor lines as a measure of vegetation risk (Figure B1). Strike and accessibility metrics were aggregated to span, segment and circuit resolutions to allow for analysis at multiple scales and project specific circuit filtering logic.

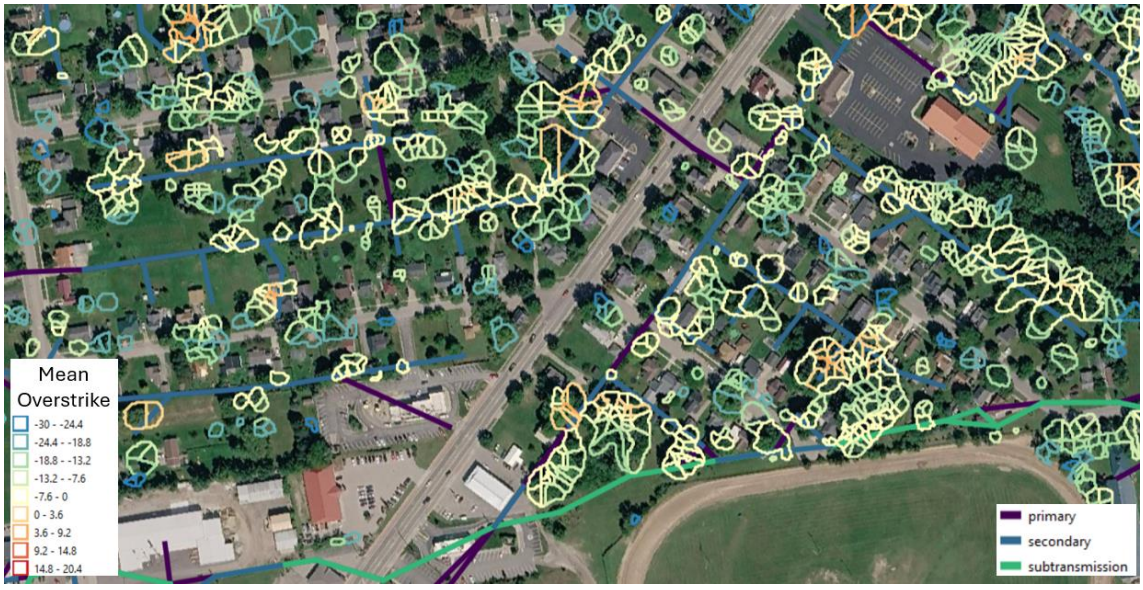

Figure B1. Illustration of canopy strike metric (canopy height - 3D distance to span). Negative numbers indicate tree heights too low to overstrike the conductor lines. Positive numbers indicate potential overstrike.

Appendix C – Yearly Forecast Values

Table C1. Five-year SAIFI and SAIDI forecast with zero reliability investment by Weather Scenario.

KPI	Weather Scenario	2026	2027	2028	2029	2030
SAIFI	Mild	1.11	1.14	1.19	1.24	1.30
	Typical	1.26	1.31	1.36	1.42	1.49
	Severe	1.71	1.77	1.85	1.93	2.02
SAIDI	Mild	211	228	253	282	317
	Typical	352	377	412	453	504
	Severe	884	939	1015	1102	1208

Table C2. Five-year SAIFI and SAIDI forecast with zero reliability investment by Network.

KPI	Network	2026	2027	2028	2029	2030
SAIFI	Distribution	1.11	1.15	1.19	1.24	1.30
	Subtransmission	0.09	0.09	0.10	0.10	0.11
	Substation	0.07	0.07	0.07	0.07	0.07
SAIDI	Distribution	309	331	362	398	442
	Subtransmission	24	26	29	32	37
	Substation	19	20	21	23	24

Table C3. Five-year SAIFI and SAIDI forecast with modeled reliability investment by Weather Scenario.

KPI	Weather Scenario	2026	2027	2028	2029	2030
SAIFI	Mild	1.08	1.04	1.00	0.97	0.94
	Typical	1.23	1.19	1.14	1.10	1.07

	Severe	1.67	1.61	1.54	1.49	1.45
SAIDI	Mild	200	187	175	165	151
	Typical	335	316	298	282	262
	Severe	846	803	760	725	683

Table C4. Five-year SAIFI and SAIDI forecast with modeled reliability investment by Network.

KPI	Network	2026	2027	2028	2029	2030
SAIFI	Distribution	1.08	1.03	0.99	0.95	0.91
	Subtransmission	0.09	0.09	0.08	0.08	0.09
	Substation	0.07	0.07	0.07	0.07	0.07
SAIDI	Distribution	293	275	258	243	224
	Subtransmission	23	23	21	21	21
	Substation	18	18	18	18	18

Appendix D – Yearly Forecast Program Benefits

Table D1. 2026-2030 outage reduction per program, ranked by 2030 benefit.

Program	2026 Outage Benefit	2027 Outage Benefit	2028 Outage Benefit	2029 Outage Benefit	2030 Outage Benefit
Vegetation Management	215.64	1,115.22	2,291.69	3,609.14	5,559.60
PTMM	199.01	805.54	1,757.40	3,175.71	5,166.86
Conversion	14.43	44.09	85.88	132.48	225.28
Hardening	60.22	133.41	157.56	178.74	210.12
URD Cable Replacement	19.14	41.06	44.35	46.25	48.81
Small Wire Rebuild	1.94	4.89	5.95	6.19	6.36
Undergrounding	0.49	1.42	1.93	1.97	2.02
Substation Equip. Replacement	0.00	0.01	0.01	0.01	0.01
Automation	0.00	0.00	0.00	0.00	0.00

Table D2. 2026-2030 CI reduction per program, ranked by 2030 benefit.

Program	2026 CI Benefit	2027 CI Benefit	2028 CI Benefit	2029 CI Benefit	2030 CI Benefit
Vegetation Management	19,543	111,091	233,653	354,360	519,111
PTMM	15,644	63,577	140,424	250,096	409,177
Automation	35,466	97,906	180,946	261,132	291,654
Conversion	1,528	3,925	7,208	10,391	18,455
Hardening	4,519	10,168	12,049	13,516	15,767
URD Cable Replacement	1,087	2,344	2,535	2,638	2,784
Small Wire Rebuild	207	526	643	666	680
Undergrounding	58	153	196	201	206
Substation Equip. Replacement	3	5	6	6	6

Table D3. 2026-2030 CMI reduction per program, ranked by 2030 benefit.

Program	2026 CMI Benefit	2027 CMI Benefit	2028 CMI Benefit	2029 CMI Benefit	2030 CMI Benefit
Vegetation Management	13,980,603	70,014,721	146,992,622	232,918,404	358,367,478
PTMM	12,298,680	47,335,940	104,130,436	190,132,340	318,390,455
Automation	9,706,035	27,522,282	52,743,426	79,673,427	93,953,293
Conversion	1,036,877	2,738,291	5,198,161	7,737,962	13,443,164
Hardening	2,142,736	4,906,885	6,068,691	7,049,800	8,522,456
URD Cable Replacement	933,734	2,070,280	2,341,214	2,554,197	2,835,674
Small Wire Rebuild	103,836	283,254	372,760	405,782	439,098
Undergrounding	35,885	100,906	138,325	147,968	160,031
Substation Equip. Replacement	729	1,540	1,646	1,765	1,904

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8.14 Benefit-Cost Analysis Report[226]

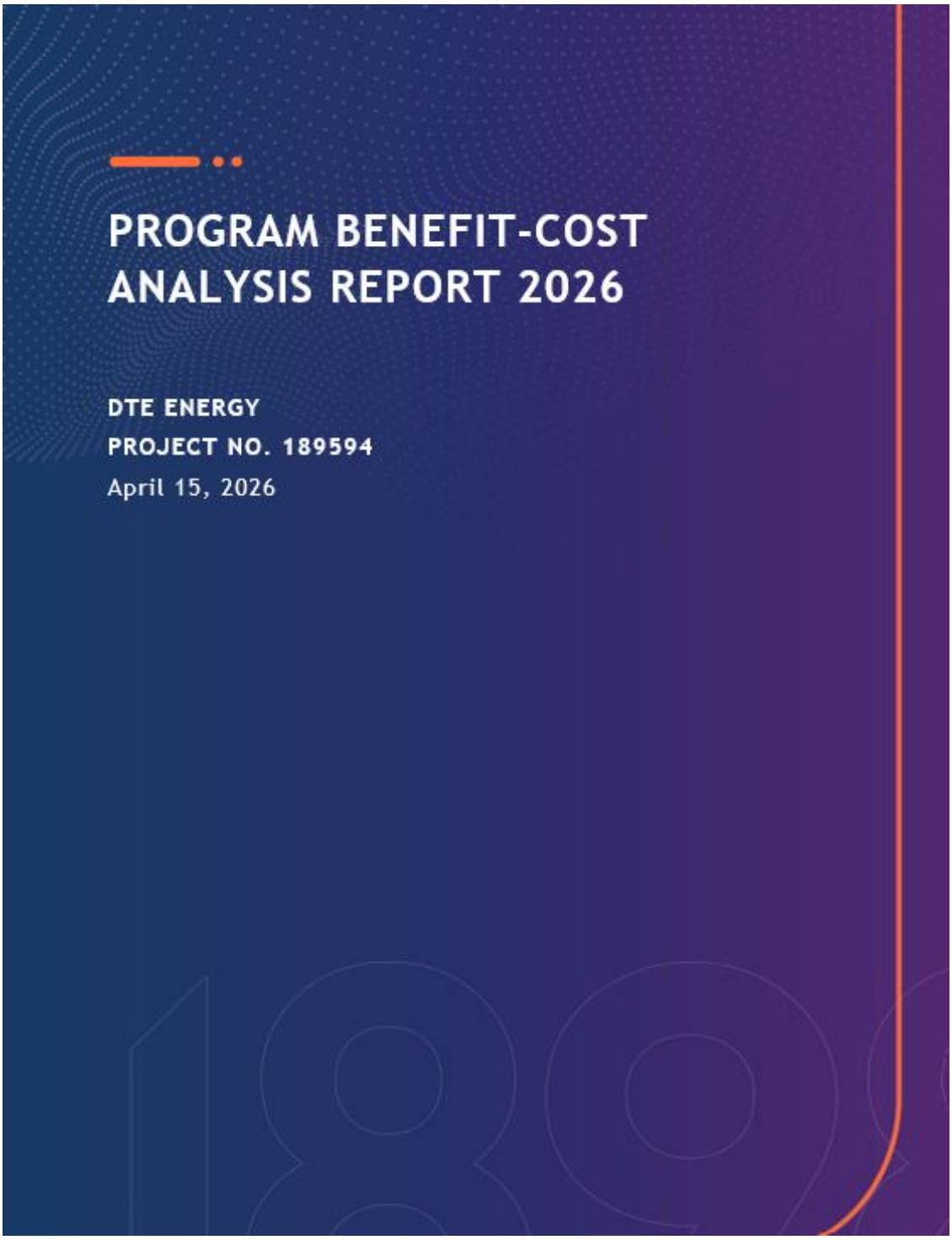

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TABLE OF ACRONYMS

Acronym	Term/Phrase/Name
ADMS	Advanced Distribution Management System
AMI	Advanced Metering Infrastructure
APTS	Automatic Pole Top Switch
ATO	Automatic Throwover
BCA	Benefit-Cost Analysis
BCR	Benefit-Cost Ratio
CDF	Customer Damage Functions
CEMI	Customers Experiencing Multiple Interruptions
C&I	Commercial & Industrial
CI	Customers Interrupted
CIS	Customer Information System
CMI	Customer Minutes Interrupted
$CMI	Monetized Customer Minutes Interrupted
CODI	City of Detroit Infrastructure
DA	Distribution Automation
DOE	Department of Energy
ELC	Emergency Load Control
ESOC	Electric System Operations Center
GIS	Geographic Information System
ICE	Interruption Cost Estimator
ISO	Isolation
MED	Major Event Day
OMS	Outage Management System
PTMM	Pole and Pole Top Maintenance & Modernization
ROW	Right-of-Way

Acronym	Term/Phrase/Name
SCADA	Supervisory Control and Data Acquisition
URD	Underground Residential Distribution

1.0 Executive Summary

DTE Electric (DTE) engaged 1898 & Co., the advisory and technology consulting arm of Burns & McDonnell, to perform a Benefit-Cost Analysis (BCA) for multiple investment programs included within DTE's rate case filing. The programs include:

1. Pole and Pole Top Maintenance & Modernization (PTMM)
2. Small Wire Replacement Program
3. URD Replacement Program
4. Cable Replacement Program
5. Breaker Replacement Program
6. Subtransmission SCADA
7. Distribution Automation (DA)
8. Communication Network
9. Subtransmission Redesign and Rebuild
10. 4.8 kV & 8.3 kV Conversion Programs

The evaluation also supported the selection of investment activities by using Benefit-Cost Ratios (BCRs) for investment activities across the programs. 1898 & Co. used a resilience, reliability, and risk-based planning approach to perform the Benefit-Cost Analysis of investment activities by using the Integrated Resilience, Reliability, and Risk Investment Model developed by 1898 & Co. The key objectives for the Integrated Resilience, Reliability, and Risk Investment Model are to:

- Quantify the improvement expected for individual investment activities and programs, specifically estimating benefits from a customer-centric perspective, avoided future costs to repair or replace assets and value of reduction in customer outages,
- Demonstrate the expected improvement in the number and duration of customer outages for programs, and
- Identify and prioritize investments with the highest quantified benefit per dollar invested into the system.

1898 & Co.'s Integrated Resilience, Reliability, and Risk Investment Model uses a data-driven, decision-making methodology utilizing sophisticated algorithms to calculate the resilience, reliability, and risk mitigation benefit of investments by identifying the expected range of reduced duration and frequency of customer outages, measured as Customer Minutes Interrupted (CMI), and reduced outage restoration costs. The Benefit-Cost approach and model utilized by 1898 & Co. support the identification of investments that provide the most benefit to DTE's customers. Utilizing the Benefit-Cost Analysis as a decision-making tool for investments in the electric delivery system helps provide confidence that investments are justified from a customer-centric perspective and the overall level of investment for each program is appropriate.

This report outlines the data (Sections 2.0 and 3.0) and methodology (Section 4.0) 1898 & Co. used to perform the Benefit-Cost Analysis for the programs outlined above. The report also includes results (Section 5.0) from the Benefit-Cost Analysis at both program and investment-activity levels. Throughout this report, investment activity refers to a specific scope of work designed to produce resilience, reliability, and/or risk-mitigation benefits for some collection of assets on the electric delivery system. Depending upon the program and type of investment, an investment activity can be at the individual-asset, protection-zone, subtransmission-line, circuit, or substation level. Finally, the report includes 1898 & Co.'s conclusions for these programs based on the Benefit-Cost Analysis (Section 1.4). The following sub-sections provide a summary of the key sections of this report.

1.1 Key Updates from the 2025 to 2026 Benefit-Cost Analysis

Multiple changes have been made for the 2026 analysis. Key changes include both the expansion of programs analyzed and the approach to quantifying benefits and impacts for replacing infrastructure. In the 2025 Benefit-Cost Analysis (BCA), three programs and two pilot projects were analyzed as listed below:

- PTMM
- Distribution Automation
- Grid Automation Telecommunications
- Spruce strategic undergrounding pilot project

- Attica strategic undergrounding pilot project

For the 2026 Benefit-Cost Analysis, the analysis was expanded to the 10 programs listed above. In addition to the increase in the number of programs analyzed the following changes for benefits modeling and key inputs were also incorporated:

1) Resiliency modeling for the impact of storms on DTE assets (Section 3.0 and Section 4.3),
2) Updated analysis on the PTMM pole inspection reject rates (Section 2.6),
3) Quantification of benefits from customer outages by moving from the ICE 1.0 to ICE 2.0 calculator (Section 4.2),
4) Integrated sequence of programs that model benefits by starting with Vegetation Management, then PTMM, and accounting for DA last (Section 4.7), and
5) Adjusted approach to the Grid Automation Telecommunication to a least-cost comparison between two potential long-term future states, public cellular compared to private cellular supported by fiber backhaul (Section 5.8).

As a minor update, unit costs for PTMM and Distribution Automation were also provided by DTE. The 2026 Benefit-Cost Analysis (BCA) represents a substantial evolution from the 2025 analysis, in scope, inputs, and modeling methods. The 2025 analysis focused on three programs and two underground pilot projects and primarily evaluated reliability and risk reduction using a deterministic, circuit-level framework. In contrast, the 2026 Benefit-Cost Analysis expands the analysis to a comprehensive portfolio of distribution and subtransmission programs and adopts a fully integrated, system-level modeling approach. This expanded scope results in a significantly larger asset base being evaluated and introduces a broader range of investment categories, including additional replacement and modernization programs that were not considered in the prior analysis.

1.1.1 Resilience Modeling Updates

A key distinction between the 2025 and 2026 BCA is the treatment of resilience events. While the 2025 analysis incorporated the general risk of weather events, it did

not explicitly model the impact of the specific major weather events that impact DTE's territory. The 2026 evaluation introduces a formal resilience modeling framework that leverages historical NOAA data, outage records, and Monte Carlo simulation techniques to quantify the effects of high-impact, low-probability storm events. This addition materially changes the benefit estimation through a more granular analysis on the likelihood and consequence of varying storm types.

1.1.2 PTMM Updates

From the 2025 analysis, system-wide, PTMM groundline inspection program spending of approximately $1.66 billion yielded a Benefit-Cost Ratio (BCR) of 1.69. Meanwhile, the pole-top program spending of approximately $709 million yielded a BCR of 2.76. Taken together, the two programs totaled nearly $2.4 billion in investment. A key observation from the 2025 analysis was that $2.3 billion or 97% of PTMM investment, over both programs, produced positive benefits. These economic benefits were primarily from avoided outage costs and reduced restoration expenses, little of which were attributed to extreme weather events due to the modeling approach of the 2025 analysis. So, the 2025 analysis demonstrated clear net benefits for the PTMM programs while, at the same time, likely underestimating the overall magnitude of the Resilience, Reliability, & Risk Benefits available in the presence of extreme weather events.

In contrast, the 2026 analysis reflects an increase in both capital investment and monetized benefits, fundamentally improving the BCR of the PTMM programs. Total investment requirements increase, with the groundline program increasing to approximately $2.97 billion and the pole-top program increasing to approximately $853.3 million. In the 2026 analysis, $2.86 billion or 96.3% of the groundline investment had a BCR ≥ 0.9. For the pole-top program, $827.5 million or 97% of the investment had a BCR ≥ 0.9. The investment increases result, primarily, from a combination of higher inspection defect rates and higher unit costs. The unit costs for the 2026 analysis are higher due to inflation, and the consideration of more available granular unit cost data based on actual program construction such as cable poles, poles with line transformers and poles without street access.

The groundline program's BCR increases to a system-wide weighted value of 2.62, while the pole-top BCR increases to a system-wide weighted value of 4.64. That is, the 2026 PTMM-program analysis identified substantially more economic benefit than was apparent from the 2025 analysis. Key to the increase in economic benefit was the inclusion of resilience-based benefits associated with mitigating the effects of major weather events. By considering these weather events (outlined in Section 4.3), this 2026 analysis captured the benefits of avoiding long-duration outages, which have very high customer consequences. Consideration of these consequences, expressed as the monetized cost of customer minutes interrupted (CMI), increased the calculated costs of outages, and the benefits of avoiding them.

1.1.3 ICE Calculator Updates

Lawrence Berkeley National Laboratory and Resource Innovations, Inc. started the "ICE 2.0 Initiative" in 2021 with the goal of updating the interruption cost calculator (ICE) to reflect advancements in the societal use of electronic devices, in-home life-saving medical devices, and other technologies, including a higher number of people working from home. The ICE initiative is being released in various phases and for each phase of the "ICE 2.0 Initiative" more surveys of customers will be used to update the cost of interruption. The ICE calculator is being released in phases based on different surveys collected from utilities across different regions of the United States and is aggregated based on all regions collected. Phase 1 was released in May 2025, and phase 2 was released in late February 2026. Additional updates are also expected over the coming years, which could include more regionally focused results as opposed to averages of the respondents regardless of location. While phase 2 was released before the filing of this application, the release timing of late February 2026 was too late to incorporate into the Benefit-Cost Analysis. As such, this analysis is based on the phase 1 release, ICE 2.0. The phase 2 release is classified as ICE 2.2. The following includes a summary of the differences between ICE 1.0, 2.0 and 2.2. More detailed comparisons are provided in Section 4.2.

The valuation of customer outage impacts differs between the 2025 and 2026 BCA due to the transition from the ICE 1.0 to ICE 2.0 calculator (phase 1). The updated ICE 2.0 calculator incorporates more recent and consistent survey data than ICE 1.0, as well as more detailed data regarding commercial and industrial customers. This change has altered the monetization of outage durations and customer classes. In comparing the impact of the ICE 1.0 calculator utilized in the 2025 analysis to the ICE 2.0 (phase 1) calculator for the 2026 analysis, 1898 & Co. utilized information from the developers of the ICE tool as well as cost of interruption analysis for DTE's customers. The following provides a high level overview of the impacts of moving from ICE 1.0 to 2.0:

- Residential Customers: the cost of interruption values across a range of outage durations are very similar. For outages less than 1 hr, ICE 2.0 is less than ICE 1.0, however, for outages longer than 1 hour, ICE 2.0 is slightly higher than ICE 1.0 with the values being nearly the same at 12 hours and greater.
- Non-Residential Customers: the cost of interruption values for DTE's system is lower for ICE 2.0 compared to ICE 1.0 for all outage durations. The difference is not constant across outage durations. For outage durations of 120 minutes or less, ICE 2.0 is approximately 20 percent lower than ICE 1.0 for DTE's system. For outages greater than 480 minutes, ICE 2.0 is approximately 60 percent lower than ICE 1.0.

With the recent release of phase 2 of the ICE calculator, known as ICE 2.2, the value of the loss of service for residential and non-residential (C&I) customers have been updated based on expanded survey data. The impact of the change from ICE 2.0 to ICE 2.2 for residential customers shows a minor decrease (ICE 2.2 is approximately 2 percent lower than ICE 2.0) while the C&I customers change is notable. For DTE's system, ICE 2.2 is approximately 50 percent higher than ICE 2.0 for outage durations less than 480 minutes. For longer duration outages, over 24 hours, ICE 2.2 is approximately 25 percent higher than ICE 2.0. This demonstrates that the phase 2 release (ICE 2.2) would have a significant impact on the value of outages in the analysis. For many programs the key benefit stream is avoided customer outages.

Based on this information, 1898 & Co. considers the BCA results to be conservative, especially for programs where the benefits are mainly avoided customer outages and focused on circuit backbones where these C&I customers typically are served from.

It is also useful to understand the comparison of ICE 2.2 and ICE 1.0 for the C&I customers on DTE's system. 1898 & Co. observed the following when comparing the outage cost results between the two calculators:

- ICE 2.2 is approximately 25 percent higher than ICE 1.0 for outage durations less than 120 minutes
- ICE 2.2 and ICE 1.0 are approximately equal in customer impacts for 240 minute outage duration
- ICE 2.2 is significantly lower than ICE 1.0 for outage durations of 480 minutes or more ranging from approximately 40 percent to 55 percent lower than ICE 1.0.

Even as the ICE Calculator evolves through successive phases, it remains a valid and credible tool for estimating the economic cost of power interruptions because its updates reflect improvements in data quality, sample size, and model specification, not a change in the fundamental methodology. The transition to ICE 2.2 incorporates a larger and geographically diverse set of customer surveys, as well as additional explanatory variables that capture how different customer characteristics influence outage costs.

Importantly, these updates were necessary because ICE 1.0 was based on survey data collected between 1989 and 2012, using independently designed studies with inconsistent methodologies and limited geographic representation. Over time, changes in electricity use, such as increased digital dependence, automation, and work-from-home trends, have altered how customers experience and value reliability.

The enhancements in ICE 2.0 and 2.2 are therefore expected to shift estimated outage values, such as increases in certain non-residential interruption costs, not because the tool is less reliable, but because it is reflecting current customer behavior and economic conditions. The core framework of the ICE Calculator which uses statistically derived Customer Damage Functions (CDFs) that are based on

empirical survey data, remains consistent across versions, which helps provide continuity and comparability.

Overall, the ICE Calculator should be viewed as a living, data-driven model. Its periodic updates strengthen its validity by keeping outage cost estimates current, representative, and analytically robust, which is essential for utility planning, reliability investment decisions, and regulatory analysis.

1.1.4 Integrated Sequence of Programs Modeling Approach

The Integrated Sequence of Programs Modeling Approach applies a defined sequencing of programs to reflect how multiple investments interact on the same portions of the electric system and to avoid double-counting benefits. Because several programs can affect the same outage mechanisms, 1898 & Co. did not evaluate each program in isolation and fully independent. Instead, the modeling framework evaluates programs in a logical sequence such that the benefits attributed to each program reflect only the incremental improvement associated with that investment after preceding programs are considered.

Under that sequencing, the modeling first reflects the effect of vegetation management, then evaluates PTMM, and then evaluates Distribution Automation. This order is important because vegetation management, PTMM, and DA can each affect outage frequency and outage impact on the same circuits. For example, vegetation management may reduce the likelihood of tree-related outages, PTMM may reduce failures associated with aging pole infrastructure, and DA may reduce the number of customers interrupted when an outage occurs. By sequencing the analysis in that manner, the PTMM BCA is evaluated on a system that already reflects the impact of vegetation management, and the DA BCA is evaluated on a system that already reflects both vegetation management and PTMM. As a result, the benefits shown for DA represent the remaining incremental benefits after those preceding investments are taken into account.

This sequencing makes the Integrated BCA more conservative and more representative of how the programs work together in practice. It allows 1898 & Co. to evaluate

multiple programs within a single integrated framework while providing greater confidence that the quantified benefits are not overstated. In that respect, the sequencing is a key part of the integrated modeling approach and helps support a more accurate comparison of program-level and investment-level benefits across DTE's portfolio. It should be noted that if the sequencing is changed, the BCA for an investment activity on a circuit would change and could potentially drive different decision-making. For instance, DA may not be beneficial to include on a circuit since vegetation management and PTMM provide significant improvement to vegetation and equipment based outages. If the vegetation management program is significantly altered, it may now be beneficial to add DA to that circuit. DTE should continue to evaluate whether investment decisions regarding these programs change when the activities of other programs are modified.

1.1.5 Grid Automation Telecommunication Updates

The Grid Automation Telecommunications BCA was refined from 2025 to 2026. In the 2025 analysis, 1898 & Co. evaluated a broader set of global telecommunications scenarios, including the current communications system, Public Cellular and Private Cellular under both current-capacity and expanded-use-case conditions, with the purpose of identifying the preferred long-term system-wide or "North Star" solution and evaluating specific fiber investments based on that preferred solution.

In the 2026 BCA, the approach was refined to a direct least-cost comparison between two primary long-term alternatives: Public Cellular and Private Cellular supported by fiber backhaul. The updated analysis evaluated those alternatives under High, Likely, and Low device-growth scenarios and excluded Distribution Automation benefits so the communications evaluation would isolate network-related costs and avoided costs. The conclusion was similar to the 2025 analysis: the private communications solution continued to be the preferred long-term strategy because it produced the lower life-cycle cost and better supports future grid modernization needs.

In the 2026 analysis the fundamental approach to performing the BCA for fiber routes remained aligned with the 2025 BCA. The 2026 results show that the fiber route investments support the broader "North Star" strategy, in that most route-level

investments are economically supportive of the Private Cellular/Fiber platform while also enabling the longer-term expansion of grid communications capabilities across the system.

1.1.6 Distribution Automation Updates Impact Overview

The modeling approach used for the 2025 BCA was leveraged for the 2026 BCA, and the approach did not materially impact the results for the 2026 BCA. However, key inputs such as the ICE calculator and program sequencing did have a significant impact on the Distribution Automation (DA) BCA. Both changes represent shifts towards a more conservative modeling approach, thus reducing the monetized benefits available when considering deploying DA solutions.

In the 2025 BCA, the total investment was estimated at approximately $1.03 billion, with an aggregate Benefit-Cost ratio (BCR) of 3.56. Approximately $830 million or 80.6% of the investment showed benefits in excess of costs. These results reflect a modeling approach in which DA benefits were evaluated largely in isolation, with limited interaction effects from other programs explicitly incorporated into the baseline. Additionally, the 2025 analysis utilized ICE 1.0 for the monetization of customer outages. As Section 1.1.3 describes the change from ICE 1.0 to ICE 2.0 is impactful for C&I customers. Avoided C&I outages are a major benefit stream for distribution automation since most of these customers are directly served from circuit backbones that DA is designed to improve.

In contrast, the 2026 analysis shows a materially different Resilience, Reliability, and Risk BCR profile for the DA program. The total investment decreases to approximately $868 million, and the aggregate BCR is reduced to approximately 1.37, with $380M or 43.8% of the investment producing benefits with a BCR ≥ 0.9. The aggregate BCR for deploying this program on circuits where the BCR ≥ 0.9 is 2.71.

The ICE calculator's valuation of C&I customers and the assumption that vegetation management and PTMM occur before DA reduce the Avoided CMI$ that can be attributed to the DA program. In addition, the Benefit-Cost Analysis for this program

needs additional context for investment decision purposes, mainly the conservative nature of the analysis:

- It is rooted in historical outage data and does not consider the full universe of weather events captured in the Resilience modeling approach, therefore, future outages could be higher than what is currently considered.
- It assumes a fuse blowing protection strategy instead of fuse saving. Because of this the avoided outages of this program are underrepresented.
- It does not capture many indirect benefits of the DA programs (e.g., more crews' time made available for restoration from faster line patrol and failure identification, and avoiding manual switching operations to adjacent circuits and substations, etc.)
- The discounted cash flow is only applied to the first 20 years of the recloser asset life, which generates lower present value of the benefits than taking the entire asset life of reclosers (30 years) into the analysis.
- A conservative customer outage economic cost valuation from ICE 2.0. As Section 1.1.3 notes, the C&I benefits could be underestimated by as much as 50 percent. Given the mix of customers on backbones, utilizing the ICE 2.2 calculator could significantly increase the benefits on DA projects. 1898 & Co. estimates that it could increase these benefits by 25 to 40 percent for many circuits.

While the DA program's level of investment quantified benefits decreased from 2025 to 2026, the analysis in both years shows that investing in distribution automation is significantly beneficial for DTE's customers. As this program matures and the evaluation approach is enhanced to account for the conservative nature of the evaluation described above, 1898 & Co. expects the level of investment for this program to expand for the benefit of DTE customers.

1.2 Resilience, Reliability, and Risk-Based Planning Approach

1898 & Co. utilized a resilience, reliability, and risk-based planning approach to identify and prioritize potential investments and perform a Benefit-Cost Analysis to

support the investment justification for the investment programs outlined above. The planning approach utilizes a suite of planning models and the Integrated Resilience, Reliability, & Risk Investment Model developed by 1898 & Co. For the purposes of this evaluation, resilience, reliability, and risk benefits for investment activities are estimated from a customer-centric perspective. The customer benefits are shown in terms of the following:

1. Decrease in utility restoration costs; and
2. Decrease in the number of customers impacted and in the duration of the overall outages, calculated as CMI and monetizing the CMI.

From these benefit streams, the model calculates the resilience, reliability, and risk BCR for each investment activity, circuit, substation (where appropriate), and program.

$$Resilience, Reliability, \& \, Risk \, BCR = \frac{Lifecycle \, PV \, Avoided \, Reactive \, Costs + Lifecyle \, PV \, Avoided \, \$CMI}{Lifecyle \, PV \, of \, Investment}$$

The Resilience, Reliability, & Risk BCR, as used in this analysis, is a single value that represents complex modeling of resiliency and reliability failure modes (including Major Event Day type outages), infrastructure vulnerability, infrastructure rebuild costs, and other financial factors to provide a robust and reliable measure to evaluate individual investments from a quantified customer benefit perspective.

This single value, Resilience, Reliability, & Risk BCR, for each circuit, substation, and program level constitutes a sophisticated multi-factored analysis. The results of this evaluation are measured at the circuit and/or substation level to align with DTE's execution approach. The Resilience, Reliability, & Risk BCR incorporates the following factors for each investment activity associated with each program:

Resiliency & Reliability Failure Modes & Events

- Range of resiliency events.
- Frequency of those resiliency events.
- Location of events by county.

- The expected asset-level probability of failure is based on expected equipment lives and types of failures.
- Expected Impact to customers, customer minutes interrupted, is based on historical customer impacts.
- The decrease in customer outage impacts for DA is directly estimated from historical outage records.

Infrastructure Vulnerability

- Number of assets within each investment activity.
- Age of the assets within each investment activity and their expected lives.
- Known equipment original design vulnerabilities (e.g., Cellon-treated poles).
- Vegetation density around each span of conductor.
- Number of downstream customers impacted for each investment activity.
- Types of customers (residential, commercial & industrial (C&I) grouped into 20 different bins based on usage) for each investment activity; and
- The accessibility of the infrastructure in terms of street access.

Infrastructure Rebuild Costs

- The investment needed to mitigate the resilience, reliability, and risk events, including:
  - Type of assets,
  - Number of assets, and
  - Location of the assets (rear lot/front lot).

Financial Factors

- Discounted cash flow methodology over the life-cycle of the infrastructure, shown in Table 4-1.
- The Interruption Cost Estimator (ICE) 2.0, phase 1, calculator (see Section 4.2) to evaluate the cost of an outage for the range of customer types and outage durations.

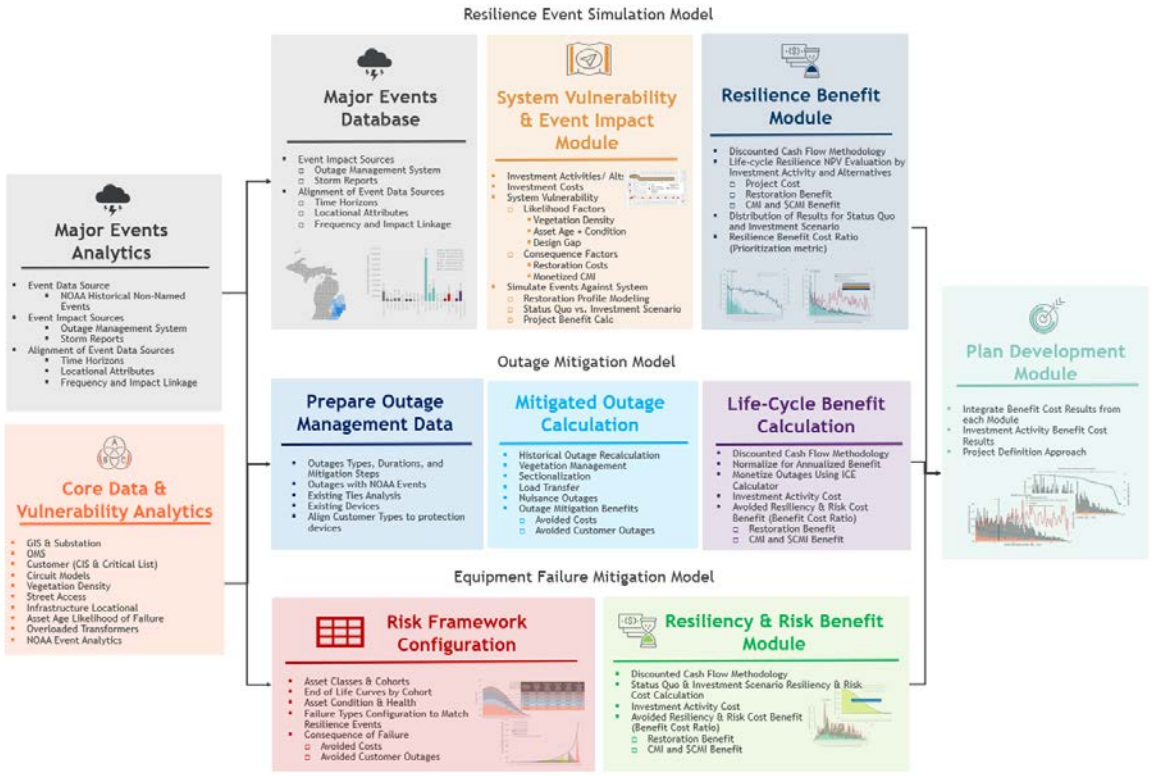
1898 & Co. has carefully integrated all these factors within each model to estimate benefits objectively, consistently, and precisely for each investment activity. This

approach makes the BCR value a robust and reliable measure to help understand the justification for investment activities. This multi-factored and quantified benefit metric provides confidence that investments will provide benefits in excess of costs for customers. This value is thus an appropriate metric to guide investment selection and justification on the DTE system.

The Resilience, Reliability, & Risk BCR captures many, but not all, benefit streams. The above list illustrates the breadth of factors quantified in the BCR assessment. However, 1898 & Co. recognizes that other difficult-to-quantify risk factors also influence investment selection and prioritization. Key qualitative factors include safety, areas of lower performance (e.g., Customers Experiencing Multiple Interruptions or CEMI), and cyber-security risks, including the risk that new regulations require additional cyber-security investment. To account for qualitative benefits that are not directly quantified in a BCR, 1898 & Co. uses a BCR ≥ 0.9 threshold for justification of investment. The Resilience, Reliability, & Risk BCR is an important tool for justifying investments. However, other, less-quantifiable, factors must also be considered. Integrating quantitative and qualitative assessments provides a more powerful decision-making tool for utility investments.

Figure 1-1 provides an overview of the Integrated Resilience, Reliability, & Risk Investment Model utilized within the DTE Benefit-Cost Analysis. The Integrated Resilience, Reliability, & Risk Investment Model employs a data-driven, decision-making methodology using sophisticated algorithms to calculate the resilience, reliability, and risk benefits for each potential investment activity that makes up each program.

Figure 1-1: Integrated Resilience, Reliability, & Risk Investment Model



The model first includes foundational data, including DTE's asset registers and equipment characteristics, which are used to determine the unique vulnerabilities of DTE's system. This information feeds the rest of the model.

The model includes two analytics models (Outage Mitigation Model and Equipment Failure Mitigation Model). Each analytics model estimates the expected avoided costs and avoided customer outages. Each analytics model was designed to estimate the resilience, reliability, and risk benefits of investments based on the available data, asset types, benefit streams, and failure types. This is further discussed in Section 4.0.

Finally, the model includes a plan development module that integrates the Benefit-Cost results from each analytics model and incorporates investment activity bundling approaches to support DTE's implementation planning. The output of this module is a list of investment activities that can help inform DTE's development of an executable plan.

1.3 Benefit-Cost Analysis Results Summary

Table 1-1 provides a summary of the Benefit-Cost Analysis (BCA) results for each of the programs evaluated by 1898 & Co at the program level. The table presents a high-level comparison of total benefits, total investment, and the cost-effectiveness of activities across the programs evaluated. Additional detail regarding each program is provided in Section 5.0.

Table 1-1: BCA Analysis Summary By Program[1]

Program	Total Benefits	Total Investment	Total Benefits **BCR ≥ 0.9**	Total Investment **BCR ≥ 0.9**	% of Investment with BCR ≥ 0.9	Weighted BCR of Activities **BCR ≥ 0.9**
PTMM Groundline	$7.77B	$2.97B	$7.7B	$2.86B	96.3%	2.69
PTMM Pole Top	$3.96B	$853.3M	$3.94B	$827.48M	97%	4.76
Small Wire Replacement	$5.67B	$5.25B	$4.58B	$2.39B	45.5%	2.09
Breaker Replacement	$1.58B	$2.29B	$967.21M	$857.27M	37.4%	1.13
URD Replacement	$1.54B	$3.63B	$447.55M	$420.58M	11.6%	1.06
Cable Replacement	$4.93B	$8.06B	$1.33B	$1.22B	15.1%	1.09
Subtransmission SCADA	$1.28B	$161.87M	$1.27B	$93.61M	57.8%	13.52
Distribution Automation	$1.19B	$868.46M	$1.03B	$380.14M	43.8%	2.71

The Communication Network program is an enabling, system-wide investment evaluated using a least-cost framework rather than a traditional benefit attribution approach. Reported benefits represent avoided life cycle costs relative to continued reliance on Public Cellular services, not direct reliability or operational benefits. Under the likely device growth scenario the total investment is $6.9 billion with a BCR

[1] All values are presented in life-cycle net present value 2026 dollars.

of 1.58. The results for High and Low device growth scenarios are presented in the Communication Network section 5.8.

The Subtransmission Redesign and Rebuild projects evaluated by 1898 & Co. represent a total investment of approximately $405 million. The results indicate that several projects provide strong quantified reliability and resilience benefits, while others address important capacity, operability, and safety needs that are not fully captured in the quantitative BCA. The 4.8 kV and 8.3 kV conversion projects represent a total investment of approximately $2.9 billion. For these programs, the analysis indicates that a majority of projects provide strong, quantified reliability and resilience benefits, while others provide value from improvements in operations, safety, and load-serving capability.

1.4 Conclusions

The results of the 2026 Benefit-Cost Analysis show that the evaluated programs include a substantial set of investments that are supported by quantified resilience, reliability, and risk-reduction benefits. The Integrated Resilience, Reliability, and Risk Investment Model used for this evaluation applied a consistent, data-driven framework to assess the customer and system benefits associated with distribution, subtransmission, substation, and communication network assets. The analysis quantified avoided customer outage impacts and avoided restoration-related costs and compared those benefits to the required investment on a program and project basis. The following summarizes the conclusions of the Benefit-Cost Analysis for the programs evaluated by 1898 & Co.:

- The resilience, reliability, and risk BCR value is a robust and reliable measure to help understand the justification for investment activities. This multi-factored and quantified benefit metric provides confidence that investments will provide benefits in excess of costs for customers. Additionally, the Benefit-Cost Analysis is comprehensive, consistent, customer-centric, data-driven, and practical.

- When compared to the previous 2025 BCA, the 2026 BCA expands both the scope of programs evaluated and includes additional modeling enhancements. Specifically, it incorporates additional asset and outage data, applies updated interruption cost assumptions from ICE calculator 2.0, updates the unit costs of assets in previous programs, and introduces resilience-event simulation to capture the consequences of various weather events. The addition of the resilience model to the 2026 BCA improves the ability of the analysis to reflect the actual performance risks facing DTE's system and provides a robust basis for identifying investments that are expected to provide meaningful customer value.
- The 2026 BCA is enhanced through the incorporation of storm and resiliency modeling. Unlike the prior analysis, the 2026 BCA evaluates the impact of **various weather events on DTE's system** by using historical NOAA weather data, DTE outage records, and simulation of future weather-event outcomes. The evaluation showed that nearly 80 percent of all historical customer minutes interrupted (CMI) directly mapped to an observed weather event. This addition allows the analysis to better capture the customer and system consequences of severe events, including long-duration outages and restoration challenges, and better quantifies the value of investments that reduce infrastructure vulnerability, improve system performance during weather events, and strengthens overall grid resilience.
- The Pole and Pole Top Maintenance & Modernization program, similar to the conclusions from the 2025 BCA, is beneficial for DTE Electric customers and provides a significant opportunity to improve resiliency, improve reliability and manage safety risks on the system. The modeling shows that over 96 percent of the potential investment for the distribution system has a BCR ≥ 0.9.
- The Small Wire Replacement program identified targeted circuits where benefits can be gained from improving the resilience and reliability of DTE Electric's overhead distribution system through targeted rebuilds of protection zones that contain qualifying small wire. The BCA shows that this program is beneficial for

DTE customers with nearly $2.4 billion of investment with a BCR ≥ 0.9 and an average BCR of 2.09.

- For the Breaker Replacement, URD Replacement, and Cable Replacement programs, the modeling was used to evaluate the benefits of proactively replacing aging and higher-risk infrastructure by estimating avoided customer outage impacts and avoided reactive restoration costs over the life of the assets. This is particularly important for system cable, which often serves dense load areas, critical infrastructure, and other high-impact customers where failures can be difficult to locate, labor-intensive to repair, and disruptive for long durations. The modeling identified specific parts of the system for potential investment that would benefit DTE customers, with nearly $2.5 billion of investment across the three programs with a BCR ≥ 0.9. In addition, each of these programs provide qualitative benefits not fully captured in the quantified BCA, including improved operability and maintainability, reduced safety exposure from reactive repairs, improved fault-clearing performance, and reduced risk of broader equipment damage or hazardous failure events.
- The Subtransmission SCADA Program demonstrated significant opportunity for customer value at specific locations where additional switching capability can improve the performance of DTE's subtransmission system. The subtransmission system serves as the critical link between the transmission network and the distribution substations that ultimately serve customers, and it is designed to provide redundancy through trunk and tie line configurations. By adding SCADA-enabled Automatic Pole-Top Switches, DTE can better isolate faults, leverage existing system redundancy, reduce outage duration, and lessen the customer impacts of high-consequence subtransmission outages. In that respect, the program supports both improved reliability and improved operational flexibility on a portion of the system where outages can affect large numbers of downstream customers.

The DA Program continues to provide meaningful customer value by reducing the impact of outages through increased sectionalization and automated switching on

DTE's distribution system. The 2026 BCA shows that the program remains beneficial and can materially reduce customer outage impacts. Relative to the prior analysis, however, the quantified Benefit-Cost results are lower due primarily to two factors: the transition from the ICE 1.0 to ICE 2.0 calculator, which reduces the monetized value of non-residential outages, and the integrated sequence of modeling assumption that vegetation management and PTMM have occurred before DA benefits are evaluated, which reduces the remaining incremental benefit available to the DA program. When considering the level of investment into this program, the conservative nature of the evaluation, and the expected changes with ICE 2.2, the benefits of this program could increase by 25 to 40 percent for most circuits. As this program matures and the evaluation approach is enhanced to account for the conservative nature of the evaluation described above, 1898 & Co. expects the level of investment for this program to expand for the benefit of DTE customers.

- The Subtransmission Redesign and Rebuild Program and the 4.8 kV and 8.3 kV Conversion Programs include critical projects that address aging infrastructure, improve switching and restoration capability, strengthen system operability, and support future load growth. Many of the projects have proven to be cost effective by the monetized BCRs alone. Yet all the projects analyzed provide important tangible, qualitative benefits to DTE customers.
    - For the Subtransmission Redesign and Rebuild Program specifically, those additional benefits include improved operational flexibility, greater ability to isolate faults and transfer load including N-1 contingency events, improved maintainability, reduced exposure to vegetation-related outages where facilities are relocated to more accessible corridors, enhanced crew safety, and reduced risk of catastrophic equipment failures on backbone facilities that can interrupt service to large portions of the system. In that respect, these projects should not be viewed solely through their quantified BCR results, because they also support DTE Electric's obligation to provide safe, reliable, operable, and resilient electric service.

  - For the 4.8 kV and 8.3 kV Conversion Programs, additional qualitative benefits include improved public and worker safety through the reduction of risks associated with aging legacy equipment and downed energized conductors, simplification and standardization of system operations and maintenance, improved voltage performance and capacity, and enhanced ability to accommodate future load growth, electrification, and distributed energy resources. In that respect, these projects should not be viewed solely through their quantified BCR results, because they also support DTE's obligation to provide safe, reliable, operable, and resilient electric service.

- The Communication Network analysis supports a clear long-term strategic direction. The evaluation indicates that a Private Cellular solution supported by fiber backhaul represents the lowest life-cycle cost communications strategy relative to reliance on Public Cellular service. This conclusion is consistent across the modeled growth scenarios and reflects the long-term cost advantage of utility-managed communications infrastructure when compared to large, recurring carrier fees, risk in sharing the network with the general public, and replacement cycles that are out of DTE's control. The fiber routes analyzed to support communications infrastructure serves as a critical foundational component of this strategy by providing high-capacity, low-latency, and highly reliable backhaul connectivity between substations, communication nodes, and control centers. In addition to the quantified cost advantage, this strategy positions DTE to support future grid modernization requirements through a more scalable, secure, and operationally aligned communications platform.
- Many of the programs will benefit all DTE customers. The nature of the many of the programs is widespread across the entire DTE system. The avoided reactive and investments costs are shared by all distribution customers. Additionally, distribution customers will experience fewer storm outages from both direct and indirect factors. Direct benefits are realized by those customers whose infrastructure is located directly downstream of the resiliency investment. Indirect benefits are realized by all distribution customers since

storm restoration crews will be able to rebuild the system quicker because less infrastructure will fail.

- The investment benefits are conservative. First, the use of the ICE Calculator is conservative as the BCA utilizes the ICE 2.0 calculator. A recent update to the calculator, ICE 2.2, shows the cost of interruptions for DTE's C&I customers is approximately 50 percent higher for most outage durations. Second, the quantified evaluation only considers direct benefits to events and does not factor in the indirect benefits from lower overall storm restoration durations. Third, the quantified benefit-cost assessment has carefully included the full cost of implementing investments; however, the full level of benefits has not been captured. Specifically, the evaluation has not incorporated qualitative benefits associated with safety, mitigating cyber risk, or service improvement in areas of lower performance where quantified benefits are not in excess of cost.

Overall, the 2026 BCA concludes that DTE's proposed set of programs and investment levels include investments that are both economically justified and strategically aligned with long-term system needs. While not all individual projects yield quantified benefits above a BCR ≥ 0.9, the combined portfolio, supported by both quantitative results and qualitative considerations, provides substantial value to customers through improved reliability, reduced outage impacts, enhanced safety, increased system resilience and enhanced system operability to meet customer expectations, future load growth and DER integration, while maintaining or reducing customer costs.

2.0 Core Data and Analytics

The resilience, reliability, and risk-based planning approach and methodology is data-driven. This section outlines the core data sets and base algorithms employed within the Integrated Resilience, Reliability, & Risk Investment Model. A connectivity model is established that allows for the linkage of the foundational data sets: Geographical Information System (GIS), Outage Management System (OMS) and Customer Information data. Additionally, the connectivity model builds on the foundational data set asset-level attribute understanding by utilizing models that:

1) estimate conductor level vegetation density,
2) determine age of assets,
3) analyze pole inspection rejection rates, and
4) determine accessibility of assets for the entirety of the system.

The 1898 & Co. analytics engine then transforms the data connectivity model into the data model needed to perform the risk and reliability analytics.

2.1 Asset Base

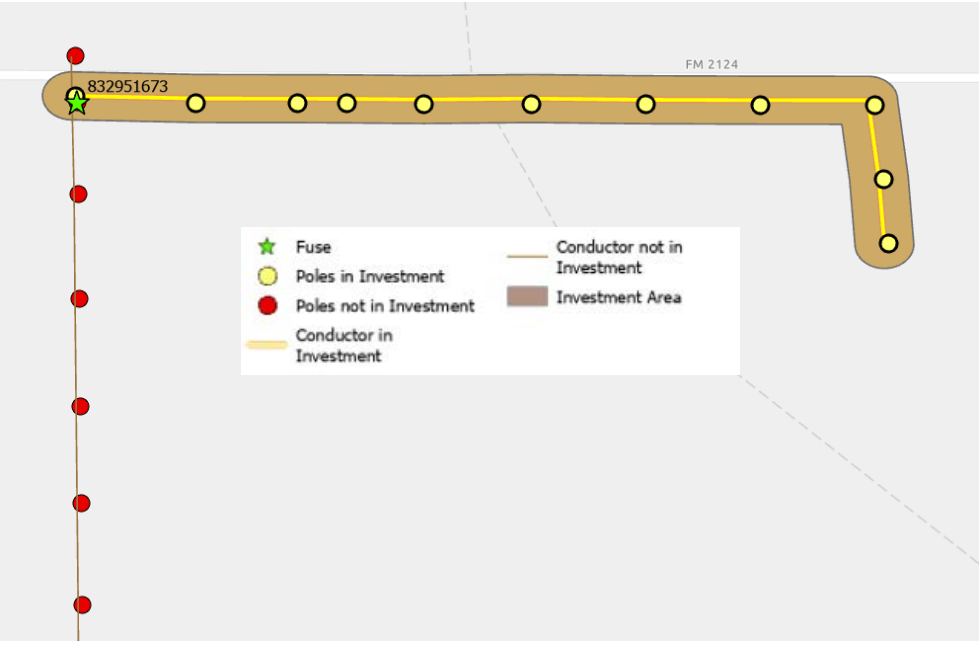
This section describes the asset foundation used in the model, including the GIS-based system inventory, the linkage of assets to protection zones, and the overall scale of the distribution, subtransmission, and substation assets evaluated. Establishing this asset base is a critical step in the bottom-up methodology because it defines the physical system being analyzed and creates the structure needed to connect asset condition, failure consequences, and customer impacts. The following subsections summarize how assets were identified, organized, and mapped within the modeling framework.

2.1.1 GIS Data

GIS provides the list of circuit assets in DTE's system and how they are connected to each other. Since the planning approach is fundamentally a bottom-up asset management methodology, it starts with the asset data, then rolls all the assets up to protection zones (a collection of assets that directly impact customers), and

protection zones to circuits and substations. The relationship between assets and protection zones is illustrated in Figure 2-1 below.

Figure 2-1: Asset to Protection Zone Relationship



In alignment with this methodology, 1898 & Co. utilized the connectivity within DTE's GIS and distribution circuit models to link each distribution voltage asset to a lateral (typically a fuse protection device) or feeder (typically a breaker or recloser protection device) to establish discrete protection zones. The asset to protection zone linkage is foundational to the 1898 & Co. modeling approach. Each protection zone includes a set of assets that service downstream customers from the protection device. If any assets in the protection zone were to fail, all the downstream customers would be impacted. This allows for the direct alignment between assets and customers.

2.1.2 Distribution, Subtransmission, and Substation Asset Base

Through this approach, 1898 & Co. was able to use the asset-level information and map it to over 89,000 protection zones on the system where applicable. By organizing the analysis at the protection-zone level, the model can directly connect asset condition and performance to potential customer impacts, which supports a detailed system evaluation. Table 2-1 below displays the assets that were mapped and

analyzed in 1898's analysis. The substation asset base includes key information such as equipment type, position within the substation, asset age, and other supporting attributes.

Table 2-1: **DTE's Mapped Asset Base Used in BCA**

Asset Type	Units	Value
OH Distribution Primary Conductor	[miles]	28,111
OH Subtransmission Primary Conductor	[miles]	2,572
System Cable	[miles]	2,456
URD Cable	[miles]	10,656
Distribution Mainline Poles (Breaker/Recloser)	[count]	257,206
Distribution Lateral Poles (Fuse)	[count]	603,287
Subtransmission Poles	[count]	84,925
Substation Breaker[2]	[count]	5,228

2.2 Outage Management System

The OMS includes detailed outage information by cause code for each protection between January 1, 2007, to Dec. 31, 2025. DTE provided this dataset, which includes outage causes, durations, CI, CMI, dates, and locations for over 1,000,000 outage events.

As with most utility outage management system records, DTE's OMS data contains some limitations in completeness and consistency, including instances where outage causes or device types were not identified or recorded. Based on 1898 & Co.'s experience reviewing outage management system data across many electric utilities, these types of data limitations are common and are influenced by field conditions, business processes, and historical recording practices. 1898 & Co. observed that DTE's outage data quality has generally improved over time, with more recent records demonstrating greater completeness and consistency than older records. 1898 & Co.

[2] Includes both breakers and substation reclosers.

determined that the OMS data was sufficient for use in the Integrated Resilience, Reliability, & Risk Investment Model.

The Integrated Resilience, Reliability, & Risk Investment Model utilized this information to understand the historical weather-related outages for the various distribution laterals and feeders on the system. The OMS data is utilized by the Outage Mitigation Risk & Resilience model to identify outages that can be mitigated by investments in distribution automation. It is also used to understand failure types and restoration times utilized in the Equipment Failure Mitigation Modeling approach.

2.3 Customer Information Data

DTE provided customer count and customer type information with relational links to the GIS and OMS databases. This data enabled 1898 & Co. to identify the count and type of customers that would be impacted by a failure in each distribution protection zone and subtransmission circuit. The customers served by each substation were also established by using connectivity from the distribution circuit to the substation protection device (breaker or substation recloser). In cases where customers could not be linked to substations through direct relationships, unmatched customers were allocated within each substation to the remaining distribution circuit-protecting devices.

This data allowed the Integrated Resilience, Reliability, & Risk Model to link the number and type of customers impacted to each distribution protection device, circuit, and substation. This customer information is used with the estimated event and failure duration to estimate the CMI for each investment activity, which is then monetized using the ICE Calculator (see Section 4.2). This is foundational for the customer-centric Benefit-Cost assessment.

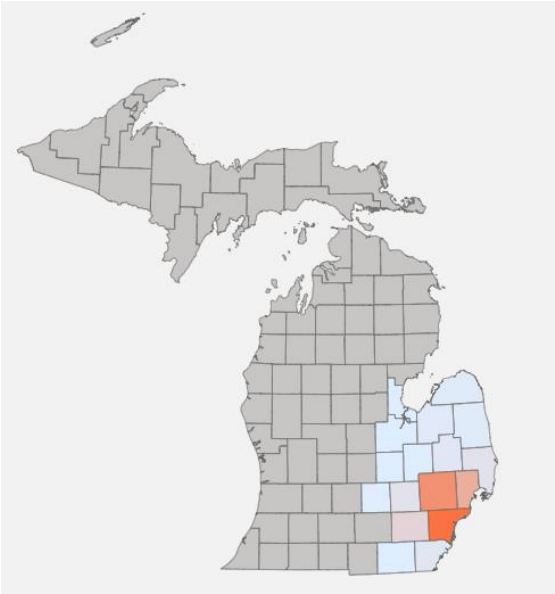
The tables and figures below provide a summary of the customers across DTE's system that 1898 & Co. mapped to assets for this analysis. Table 2-2 shows the total mapped customer count by type, and Figure 2-2 shows a geospatial representation of customer locations across the DTE service area. These customers were derived from our mapping using CYME models and customer-to-protection device ID linkages, with protection devices subsequently mapped to system assets; as a result, some

customers are not included due to gaps or inconsistencies in these linkages. The figure shows a heavy representation of customers in the Detroit metropolitan area, including Wayne, Oakland, and Macomb counties.

Table 2-2: **DTE's Mapped System**-wide Metered Customer Breakdown

Customer Type	Customer Count	Percentage
Residential Customers	2,049,796	91.56%
Commercial & Industrial Customers	189,007	8.44%
Total	2,238,803	100.0%

Figure 2-2: Relative Customer Count Across DTE's System



As described in Section 2.1.1, the approach organized distribution assets at the protection zone level. For each protection zone, 1898 & Co. identified the number and type of downstream customers that would be impacted by a failure within that protection zone, based on the database relationships described above.

The following figures present the distribution of customer counts and types across all circuits (Figure 2-3), distribution protection zones (Mainline Zones in Figure 2-4 and Lateral Zones in Figure 2-5), and substations (Figure 2-6).

Figure 2-3: Metered Customer Count and Type by Distribution Circuit

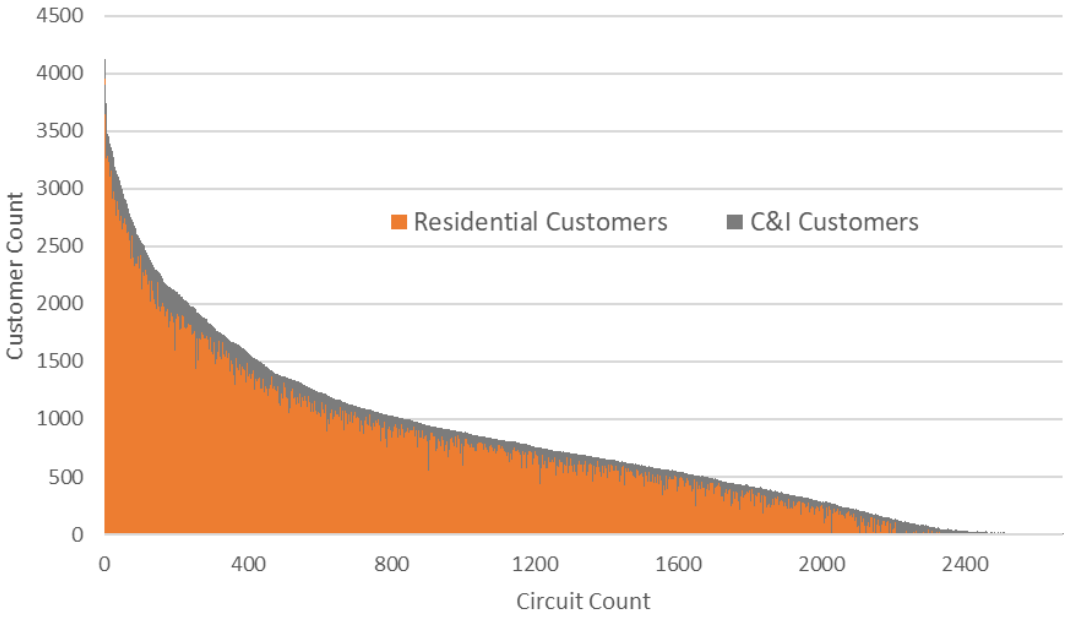
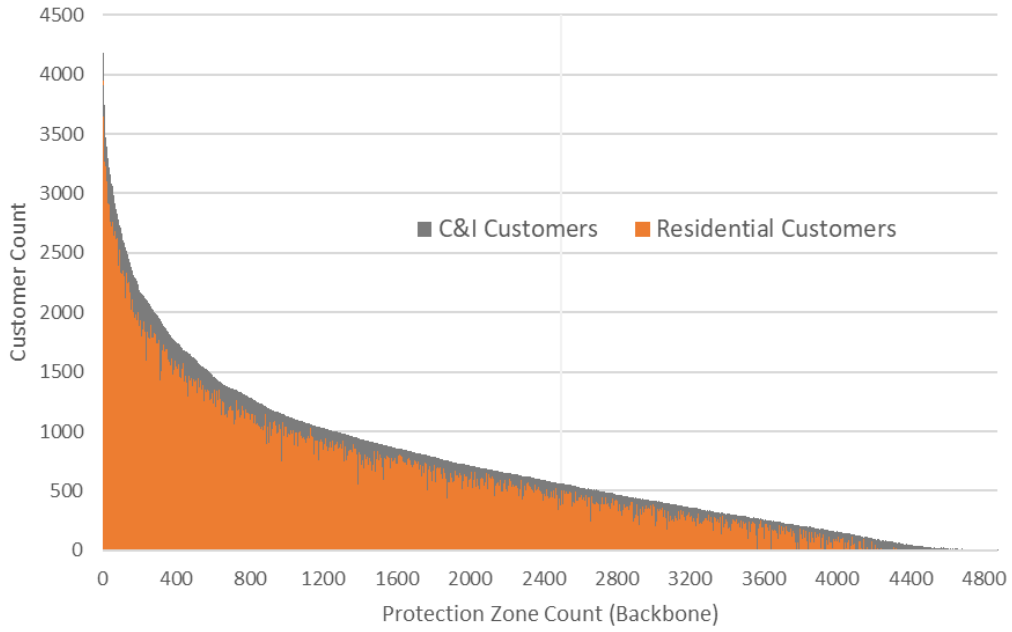


Figure 2-4: Metered Customer Count and Type for Distribution Mainline[3] Protection Zones



[3] Includes breaker and mainline recloser protection devices.

Figure 2-5: Metered Customer Count and Type for Distribution Lateral[4] Protection Zones

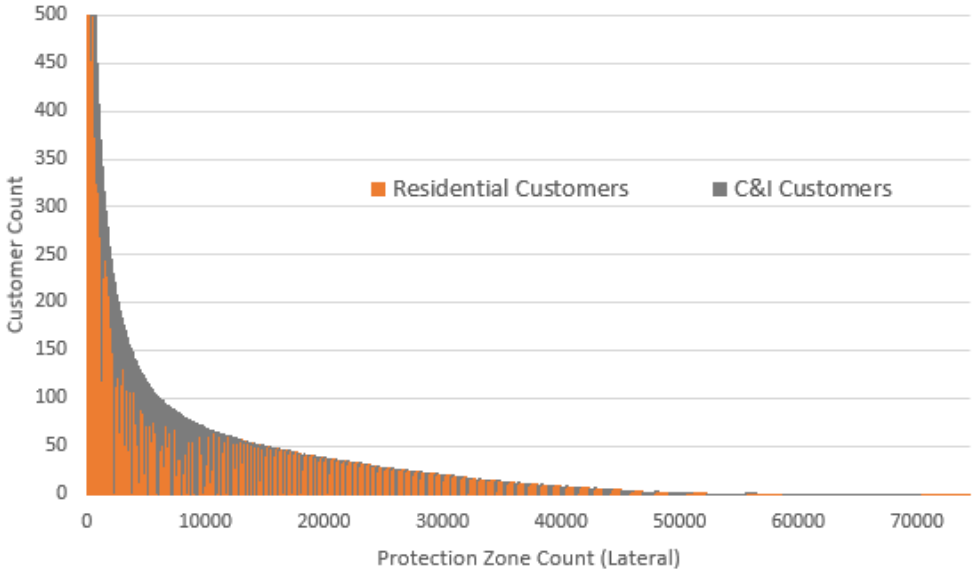
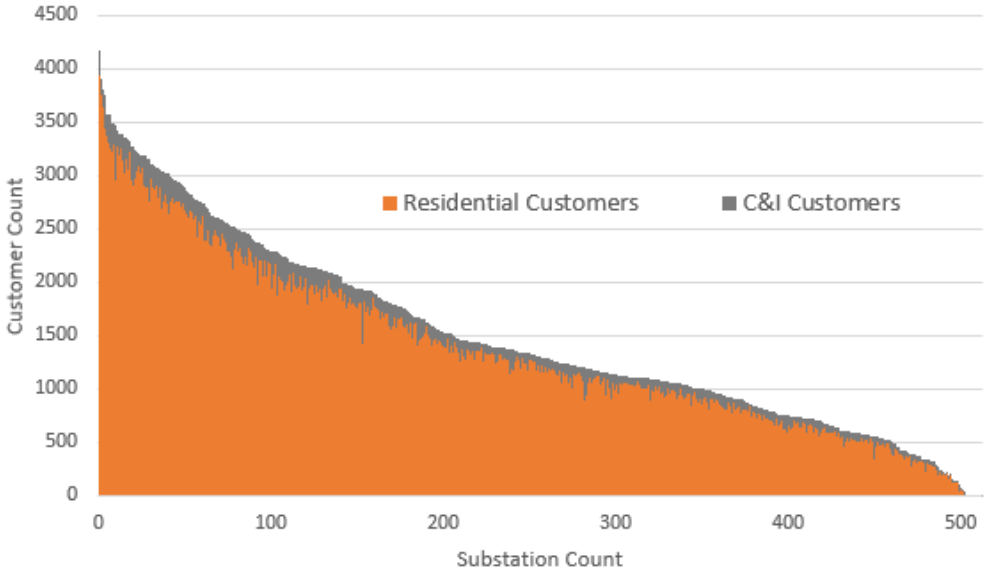


Figure 2-6: Metered Customer Count and Type for Substations



[4] Fuse or Lateral Recloser Protection devices

2.4 Vegetation Density

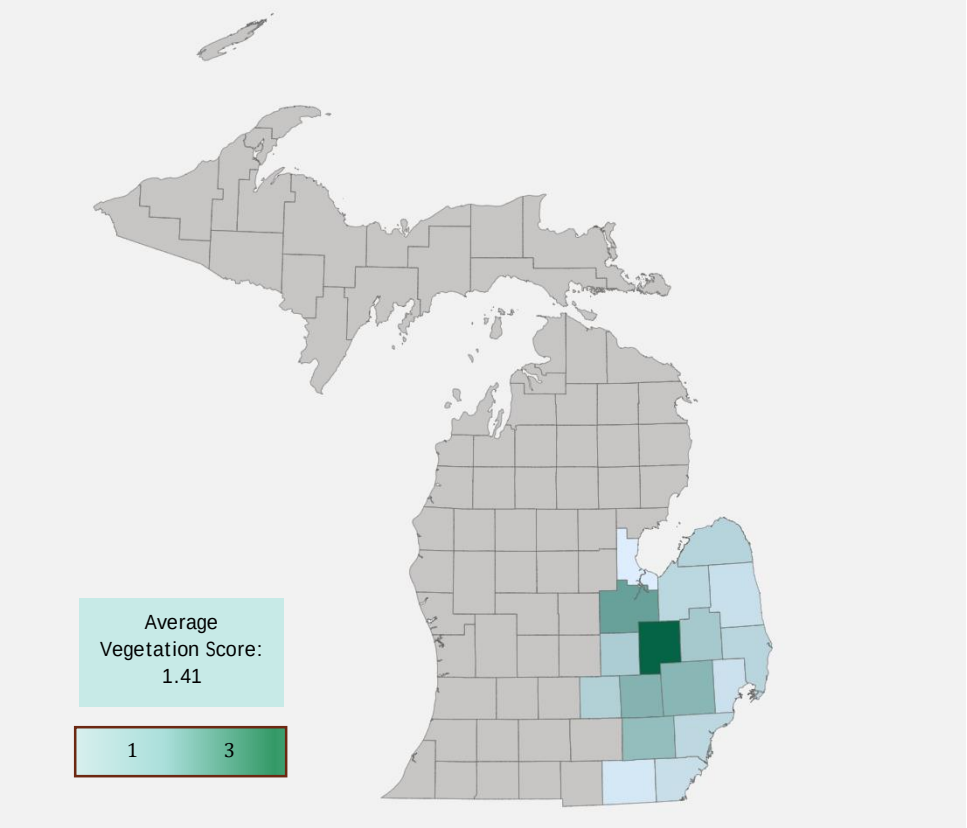
The vegetation density for each overhead conductor is a core data point for identifying and prioritizing investment for circuit assets. Poles that are in high vegetation areas are subject to more life-cycle stresses over their life-cycle than poles in low vegetation areas. The life-cycle stresses impact the expected life and increase the likelihood that poles or pole tops may fail. The Integrated Resilience, Reliability, and Risk Model estimates the vegetation density around each distribution overhead conductor. The model utilizes satellite tree-canopy data to calculate the percentage of vegetation for 30-meter by 30-meter (900 square-meter) areas across the entire DTE system. The 900 square-meter area is indicative of the vegetation density on the system from a major storm perspective. For each of the approximately 1 million spans of conductor on DTE's system, a vegetation density is assigned based on the 900-square-meter area(s) the conductor spans through. The evaluation only considers the space that is 20 feet on either side of the conductor.

Figure 2-7 illustrates vegetation density for distribution primary assets mapped geospatially across county sections. To support comparison across the system, the modeled vegetation density values were converted to a vegetation density score on a scale of 1 to 5, where higher scores indicate greater vegetation exposure. Scores were assigned based on the underlying vegetation density percentage as follows:

1) 0% to 20% corresponds to a score of 1,
2) 20% to 40% corresponds to a score of 2,
3) 40% to 60% corresponds to a score of 3,
4) 60% to 80% corresponds to a score of 4, and
5) 80% to 100% corresponds to a score of 5.

On the map, darker shading indicates a higher vegetation density score and therefore a higher relative level of vegetation exposure, while lighter shading indicates lower vegetation density scores. As shown in the figure, the highest vegetation density scores are concentrated in a limited number of county sections, while much of the system falls within lower-scoring ranges.

Figure 2-7: **Average Vegetation Density Across DTE's System**



2.5 Asset Age

As assets age, they lose some of their original design strength and capability. For example, aged poles, when all else is equal, will fail at lower dynamic load levels than poles with their original design strength. The same concept applies to other overhead, underground, and substation assets. To account for this effect, the 1898 & Co. analysis utilized industry-standard survivor curves together with each asset class's expected average service life and each specific asset's age to estimate the age-based likelihood of failure. Asset ages were extracted from DTE's enterprise data systems for each asset class.

Table 2-3 summarizes the system average age end of life for the major asset classes included in the analysis. This comparison provides a system-level view of how the average age of each asset class relates to its expected life and helps illustrate which asset groups are, on average, closer to later-life condition states. This information

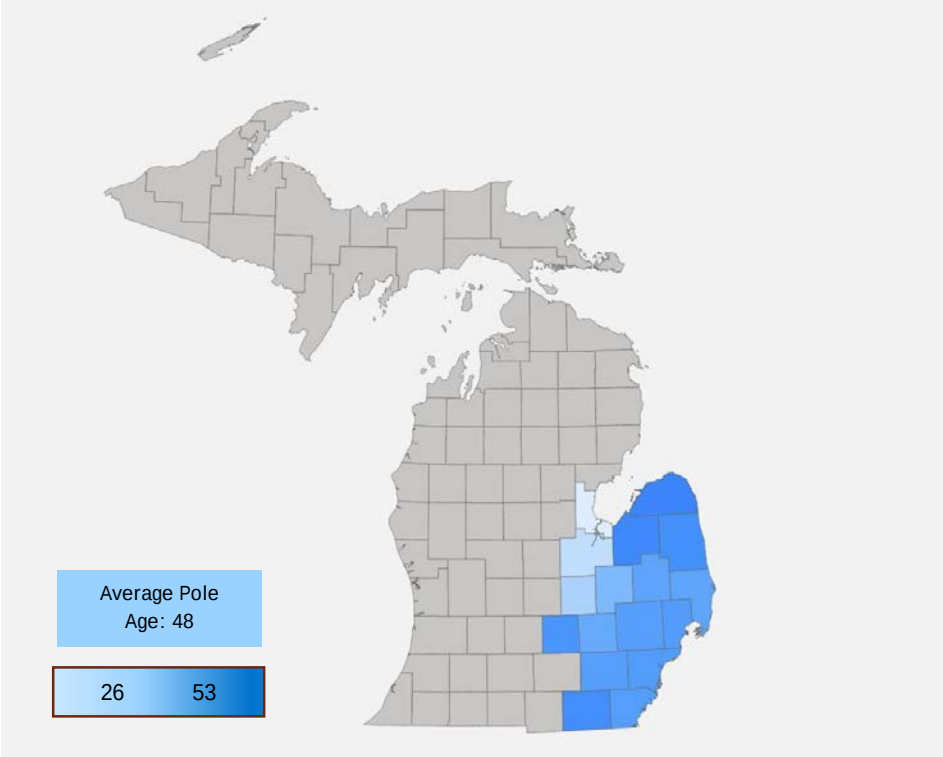
provides important context for how age-related vulnerability was incorporated into the failure modeling.

Table 2-3: DTE System Average Age

Asset Type	System Average Age
OH Distribution Primary Conductor	55
OH Subtransmission Primary Conductor	55
System Cable	53
URD Cable	27
Distribution Poles	48
Subtransmission Poles	46
Breakers	51
Substation Reclosers	43

Figure 2-8 illustrates the geographic distribution of average distribution primary pole age across DTE's service territory. While Table 2-3 provides a system-level summary, this figure shows how pole age varies spatially across the service area and highlights areas with relatively older or younger pole populations. This geographic view provides additional context for understanding how age-related vulnerability differs across the system. The heat map reflects the average age of distribution primary poles within each county, rather than the age of the oldest pole in each county. As shown, pole ages vary across the system, with the lowest county-level average pole age equal to 26 years and the highest county-level average pole age equal to 53 years.

Figure 2-8: DTE's Distribution Primary County Average Pole Age



2.6 Pole and Pole-Top Maintenance & Modernization Failure Rate Analysis

Pole inspections play a crucial role in maintaining the reliability and resilience of the power grid. Inspections help utilities understand whether or not poles can withstand environmental factors, including extreme weather conditions. This proactive, inspection-based approach enhances the overall resilience and reliability of the power grid, reducing the likelihood of service interruptions and improving the continuous delivery of reliable electricity to communities.

2.6.1 Background & Program Description

This failure-rate analysis was a continuation of work from the previous 2025 rate case. In the previous effort, 1898 & Co., in collaboration with DTE, developed a spreadsheet-based tool that produced circuit-level, PTMM-failure rate results by grouping assets into broad cohorts.

In this subsequent analysis, 1898 & Co. developed a more-granular, asset-level approach, derived from the more-detailed and more-recent inspection results that

DTE provided. Both theoretical and empirical evidence indicated a strong relationship between an asset's age and its probability of failure. This analysis disregarded any inspection result for which an asset age could not be determined.

2.6.1.1 Ground Line Inspection Program

As with the overall population of poles across the DTE system, the great majority of inspected poles were 90 years old or younger. For this analysis, 1898 & Co. developed groundline probability-of-failure (POF) rates after excluding inspection results for the small number of poles that were more than 90 years old at the time of inspection. When applying the POF rates to the full population of DTE poles, 1898 & Co. assumed that the failure rate for a 90-year-old pole was suitable for all poles older than 90 years.

2.6.1.2 Pole-Top Inspection Program

The more-recent pole-top-inspection results included no age data for the pole tops. Therefore, the pole-top-failure rate development relied upon the age of each pole top's associated pole.

2.6.2 Groundline and Pole-top Asset Evaluation

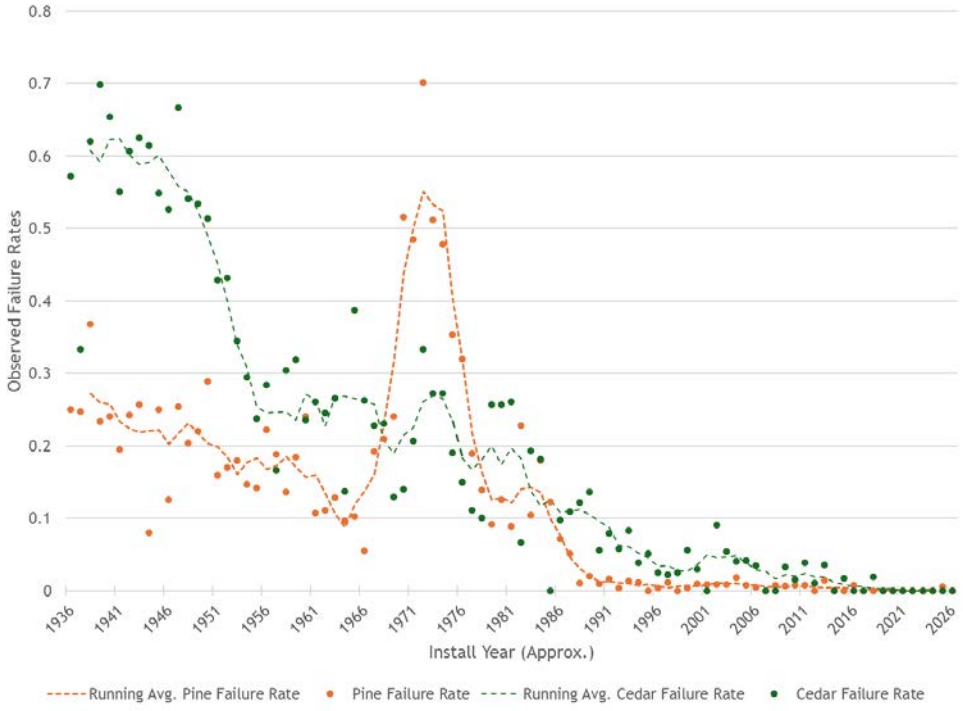
This section provides background on the asset data and an evaluation of the inspection results, beginning with the groundline inspections for the poles.

2.6.2.1 Groundline

In the evaluation, age was a strong predictor of pole failure. However, wood type was also a strong predictor. Based on DTE system data, 99% of the wood poles were either pine or cedar. Figure 2-9 illustrates the observed inspection failure rates for pine and cedar poles, with dots representing single-year rates and dashed lines representing failure rates over a five-year rolling window. The figure indicates that:

- Failure rates tended to be higher for older poles, compared to younger poles,
- Failure rates tended to be higher for cedar poles, compared to pine poles,
- There was a large increase in pine-pole failures rates among those poles installed during (approximately) the 1970s.

Figure 2-9: Groundline Inspection Failure Rates



2.6.2.2 Cellon Treatment

For this evaluation, DTE provided background information to enable better understanding of the large increase in pine-pole groundline-inspection failures among those poles installed during the 1970s. Over a long period of time, DTE (like many other utilities) had installed pine poles treated with Cellon for the purpose of extending the life of the poles. The greatest share of these Cellon-treated poles had installation years in and around the 1970s. Based on indications from DTE and the failure rate observations, it appeared that Cellon-treated, pine poles failed inspection at a higher rate than did non-Cellon-treated, pine poles.

2.6.2.3 Pole Tops

Figure 2-10 illustrates the observed pole top inspection failures, with dots representing individual-year failure rates and the dashed line representing a rolling five-year average. Unlike with the groundline inspections, the pole top failure rates did not, in general, decrease steadily with decreasing pole age. Instead, the pole top failure rates exhibited three ranges, each with a seemingly distinct failure-rate trend. Those ranges were, approximately:

1. Pole tops on poles installed before 1950.
2. Pole tops on poles installed between 1950 and 2009.
3. Pole tops on poles installed after 2009.

When considering Figure 2-10, possible explanations, though not fully explored, for these ranges include:

- Poles installed before 1950 generally had low pole top failure rates. This is likely because the original pole tops installed with these poles had previously failed and, therefore, the poles had newer, younger, replacement pole tops.
- Poles installed between 1950 and 2009 generally had a steady increase in pole top failures with increasing pole age, since the pole tops were standard across that range of pole-install dates and few poles had received replacement pole tops.
- Poles installed after 2009 generally had a very low pole top failure rate. This is likely due to the age and design basis of these younger poles and pole tops.

Figure 2-10: Pole Top Inspection Failure Rates

2.6.3 Analysis Method and Results

To model and evaluate the inspection-based failure of poles over time, 1898 & Co. developed POF models using logistic regression. A key application of logistic regression is predicting the probability of some binary outcome, based on certain input conditions. The binary outcome for this analysis was inspection pass-or-fail, while the input conditions were pole age and other factors described later in this section.

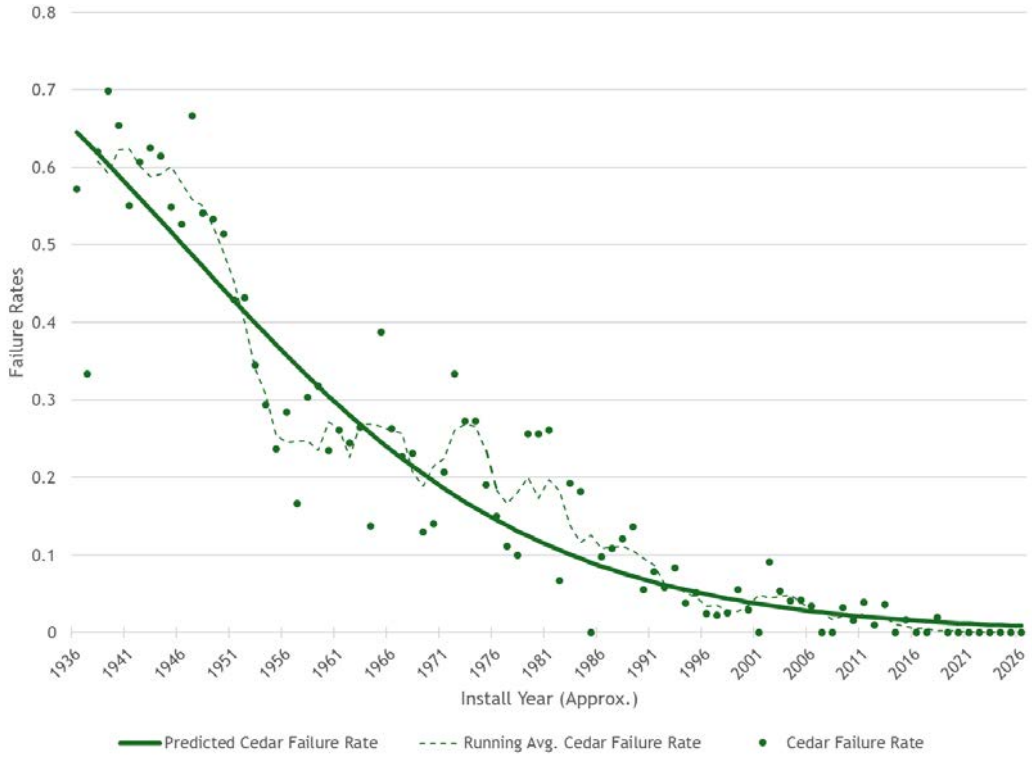
2.6.3.1 Groundline

This section describes the POF development for cedar poles and then for pine poles.

Cedar Pole POF Development

For the simple, cedar-pole case, pole age was the only input condition. The logistic regression produced a smooth POF curve that decreased from a 65% failure rate for poles installed in 1936 to a less than 1% failure rate for poles installed in 2026. As expected, the POF curve closely followed the observed failure rates. Figure 2-11 shows the predicted failure rate curve for cedar poles, along with the observed rates shown previously in Figure 2-9.

Figure 2-11: Cedar Pole Predicted Failure Rate

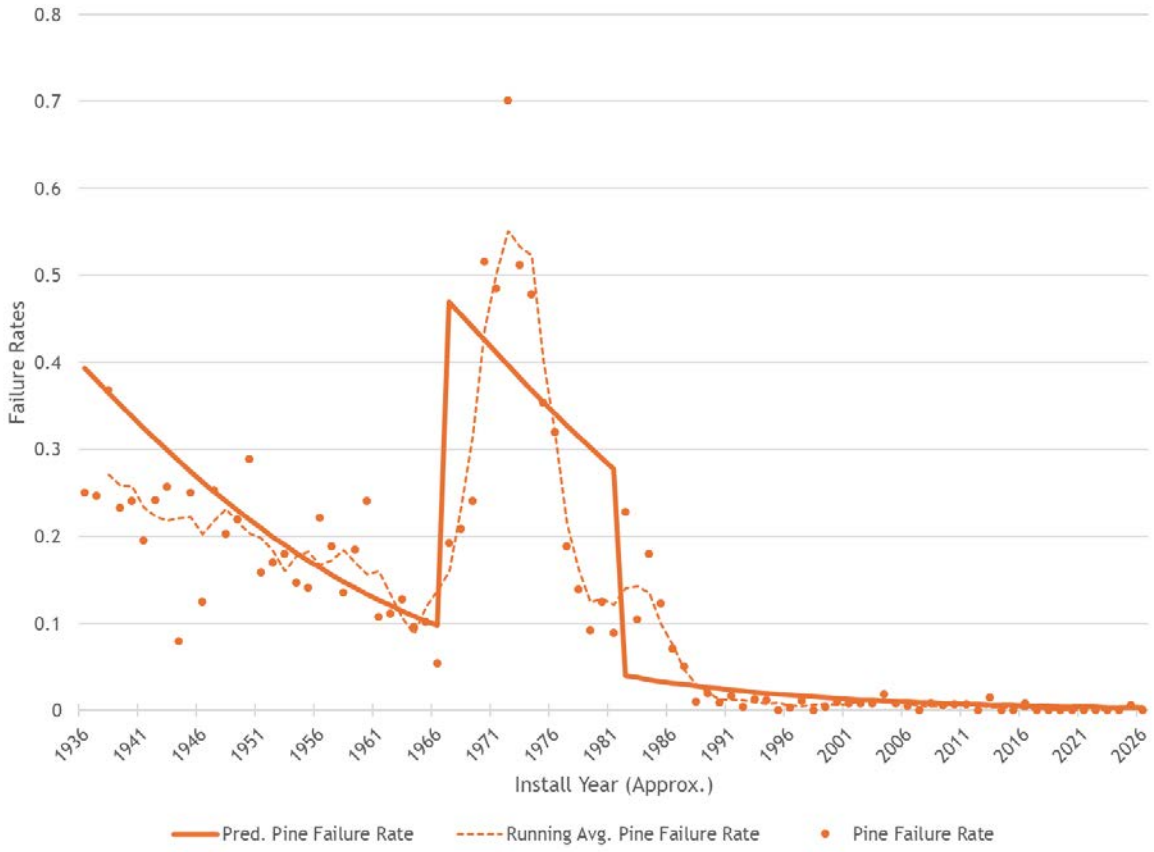


Pine Pole POF Development

The elevated observed-failure rate for pine poles installed in and around the 1970s required the introduction of a second input condition for the pine-pole regression. The second input was a binary value to indicate whether the pole's install year fell within a period of high Cellon-pole installation. Figure 2-12 shows the predicted failure rate curve for pine poles, along with the observed rates previously shown in Figure 2-9.

The pine-pole POF curve can be thought of as a single continuous curve, with the middle portion shifted upward to account for the increased failures among Cellon-treated poles.

Figure 2-12: Pine Pole Predicted Failure Rate



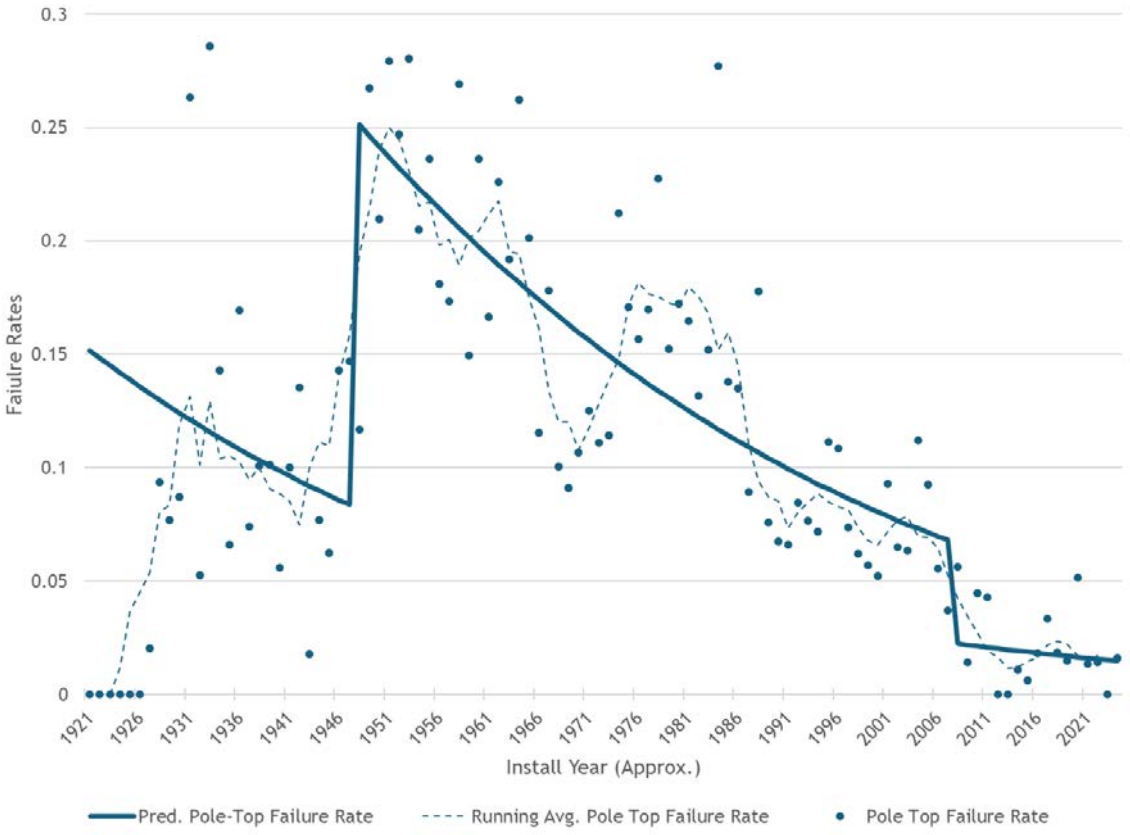
2.6.3.2 Pole Top

Previous sections detailed the difficulties associated with predicting pole top failures using pole age. Despite those difficulties, the available data supported POF development for pole tops after separating the pole tops into three groups based on the associated pole age. Recall these groups were:

- Pole tops attached to poles installed before 1950.
- Pole tops attached to poles installed between 1950 and 2009.
- Pole tops attached to poles installed after 2009.

Figure 2-13 shows the predicted pole top failure rates, with the observed rates previously shown in Figure 2-10.

Figure 2-13: Pole Top Predicted Failure Rate



2.6.4 PTMM Failure Rate Analysis Conclusions

This analysis produced data-driven POF curves that enabled the estimation of PTMM program costs and benefits, which are explained further in Section 5.1 below. In general, each curve exhibited the expected relationship between asset age and physical failure, with older assets failing at a higher rate than younger assets. Where this relationship did not hold, such as with Cellon-treated poles, there was a clear explanation for the divergence. The following subsections provide an overall assessment of the analysis insights.

2.6.4.1 Groundline

The cedar pole failures, and the resulting POF curve, demonstrated a straight-forward relationship between pole age and inspection failures. The older the pole, the higher the failure rate.

The pine pole failure and POF curves were more complex than the corresponding cedar curves, to account for the increased incidence of Cellon-treated, pine poles in and around the 1970s.

2.6.4.2 Pole Top

The pole top failures, and the resulting POF curve, had three distinct sections based on the install date of the associated pole: pre-1950 install date, 1950-2009 install date and post-2009 install date.

The relatively lower pole top inspection failures for the pre-1950 poles seemed likely to stem from many of those oldest poles having previously received new pole tops, leaving many pole tops younger than their associated poles.

The relatively lower pole top inspection failures for the post-2009 poles seemed likely to stem from a change to pole top standard in recent years. New poles likely had better, stronger pole tops than their older counterparts.

2.7 Accessibility

The ability of work crews to access an asset has an impact on the duration of the outage and the cost to restore that part of the system. For example, rear-lot structures take much longer and cost more to restore than front-lot structures. To take differences in accessibility into account, 1898 & Co. performed a geospatial analysis of each structure against a data set of roads. Structures within a certain distance of the road were designated as having roadside access, while others were designated as in the deep right-of-way (ROW). These designations were considered when calculating restoration activity costs in the Integrated Resilience, Reliability, & Risk Investment Model. Based on this analysis, approximately 48% of DTE's poles have street access.

3.0 Major Events Impacting DTE's System

This section reviews the historical major weather-based resiliency events that have impacted DTE's electric service area and customers. The range of resiliency events that impacted the DTE's distribution system are from January 1, 1998, through September 30, 2025, as documented by NOAA. At the time this analysis was performed, the complete data for 2025 was not available from NOAA.

This information serves as the basis for understanding the expected frequency of similar resiliency events in the future. The results of the analysis performed by 1898 & Co. help correlate the NOAA event database with DTE's historical outage records which serve as the basis for understanding the customer impact of each resiliency event. Finally, this section concludes with a prioritization of weather events based on resilience risk.

3.1 NOAA Events

The database includes weather events (e.g., thunderstorms, ice storms) from 1998 through September 30, 2025. This database helped identify the resiliency events impacting the DTE service area and the expected frequency of different resiliency events.

The NOAA database records events at the county level. 1898 & Co. mined this data for all counties in DTE's service area. Table 3-1 lists the weather-based events contained in the database and provides definitions for each.

Table 3-1: Extreme Weather Resiliency Events[5]

No.	Resiliency Event Type	Resiliency Event	Definition
1	Storm	Thunderstorm Wind	Winds, arising from convection (occurring within 30 minutes of lightning being observed or detected), with speeds of at least 50 knots (58 mph), or winds of any speed (non-severe thunderstorm winds below 50 knots) producing a fatality, injury, or damage.
2		Lightning	A sudden electrical discharge from a thunderstorm, resulting in fatality, injury, and/or damage.
3		High Wind	Sustained non-convective winds of 35 knots (40 mph) or greater lasting for 1 hour or longer, or gusts of 50 knots (58 mph) or greater for any duration (or otherwise locally/regionally defined).
4		Hail	Hail is defined as frozen precipitation in the form of balls or irregular lumps of ice. Hail of any size may be reported, in hundredths of an inch, although the smallest measure in the hail conversion table is 0.25 inches. This report uses "Hail" to refer to hail that occurs not in connection with a winter-weather event and not during the months of December, January, and February.
5	Flooding	Flood	Any high flow, overflow, or inundation by water which causes damage.
6		Flash Flood	A life-threatening, rapid rise of water into a normally dry area beginning within minutes to multiple hours of the causative event (e.g., intense rainfall, dam failure, ice jam). Six inches or more of swiftly moving water flowing over a road or bridge posing a threat to life or property is one of many suggested guidelines for determining if an event was a Flash Flood.
7	Tornado	Tornado	A violently rotating column of air, extending to or from a cumuliform cloud or underneath a cumuliform cloud, to the ground, and often (but not always) visible as a condensation funnel.
8	Winter	Winter Storm	A winter weather event that has more than one significant hazard (i.e., heavy snow and blowing snow; snow and ice; snow and sleet; sleet and ice; or snow, sleet and ice) and meets or exceeds locally/regionally defined 12 and/or 24-hour warning criteria for at least one of the precipitation elements.
9		Heavy Snow	Snow accumulation meeting or exceeding locally/regionally defined 12 and/or 24-hour warning criteria. This could mean values such as 4, 6, or 8 inches or more in less than 12 hours or less; or 6, 8, or 10 inches in 24 hours or less.
10		Winter Weather	A winter precipitation event that causes a death, injury, or a significant impact to commerce or transportation, but does not meet locally/regionally defined warning criteria. A Winter Weather event could result from one or more winter precipitation types (snow, or blowing/drifting snow, or freezing rain/drizzle).
11		Ice Storm	Ice accretion meeting or exceeding locally/regionally defined warning criteria (typical value is 1/4 or 1/2 inch or more).
12		Blizzard	A winter storm which produces the following conditions for three (3) consecutive hours or longer: (1) sustained winds or frequent gusts 30 knots (35 mph) or greater, and (2) falling and/or blowing snow reducing visibility frequently to less than 1/4 mile

[5] Strassberg, G., & D. Murphy, J. (2021). *NATIONAL WEATHER SERVICE INSTRUCTION 10-1605*. https://www.nws.noaa.gov/directives/sym/pd01016005curr.pdf.

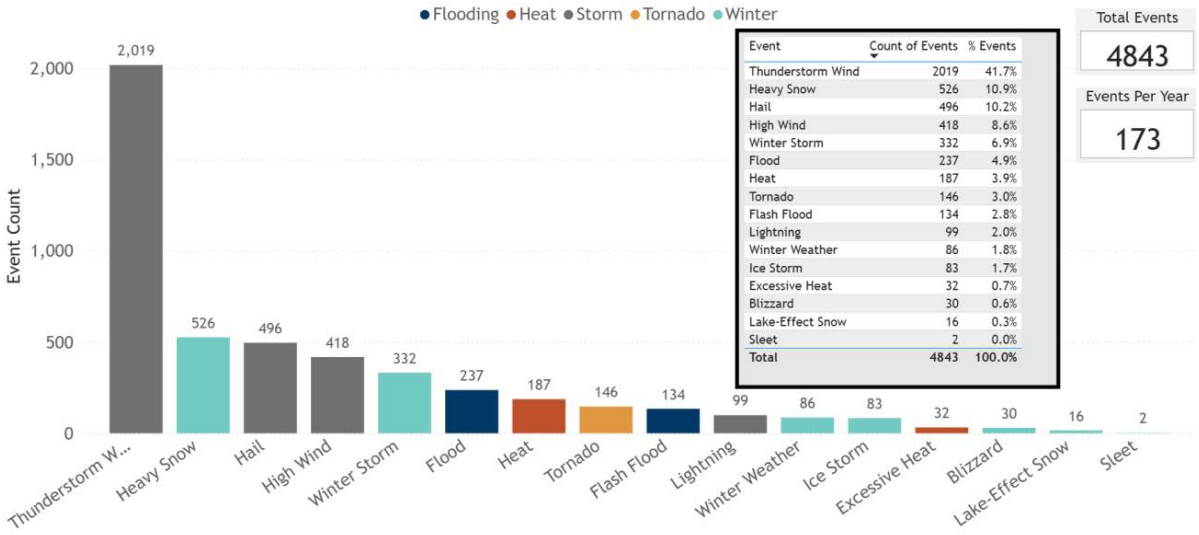
13		Lake Effect Snow	Convective snow bands that occur in the lee of large bodies of water (e.g., the Great Lakes or the Great Salt Lake), when relatively cold air flows over warm water. In extreme cases, snowfall rates of several inches per hour and thunder and lightning may occur. Lake-effect snow accumulations meet or exceed locally defined 12 and/or 24 hour warning criteria (typical values of 6 to 8 inches within 12 hours or 8 to 10 inches within 24 hours).
14		Sleet	Sleet accumulations meeting or exceeding locally/regionally defined warning criteria (typical value is 1/2 inch or more).
15	Heat	Excessive Heat	Excessive Heat results from a combination of high temperatures (well above normal) and high humidity. An Excessive Heat event occurs and is reported in Storm Data whenever heat index values exceed locally/regionally established excessive heat warning thresholds.
16		Heat	A period of heat resulting from the combination of high temperatures (above normal) and relative humidity. A Heat event occurs and is reported in Storm Data whenever heat index values meet or exceed locally/regionally established advisory thresholds.

For this analysis, 1898 & Co. excluded drought events from the analysis since their durations are extremely long making the outage correlation challenging with a reasonable degree of certainty. Additionally, wildfire is not covered in the 1898 & Co. report.

Figure 3-1 and Figure 3-2 show the summary results from the NOAA database of storms to impact the DTE service area from 1998 to September 30, 2025. At the time this analysis was performed using a partial year dataset for 2025 as the complete data was not available from NOAA. These figures include 5 different event categories that summarize 16 different event types as shown in Table 3-1. The chart shows a wide diversity of events impacting DTE's customers. From the NOAA records, 4,843 weather-based resiliency events have affected the DTE service area since 1998, averaging 173 events per year. The most common event category is the Storm category, with Thunderstorm Wind events accounting for 2,019 events equating to 42% of total events. It is important to note that lightning-related outages are primarily represented within the "Thunderstorm Wind" category due to the way NOAA classifies severe weather events. Because lightning typically occurs alongside convective storm activity that meets wind event criteria, it is grouped under this

broader classification rather than being reported separately. This information is the basis for estimating the future frequency of resiliency events that will impact DTE's service area and customers. Figure 3-2 shows the resiliency event count for DTE's service area broken down by year and event type beginning in 1998 for all 4,843 events.

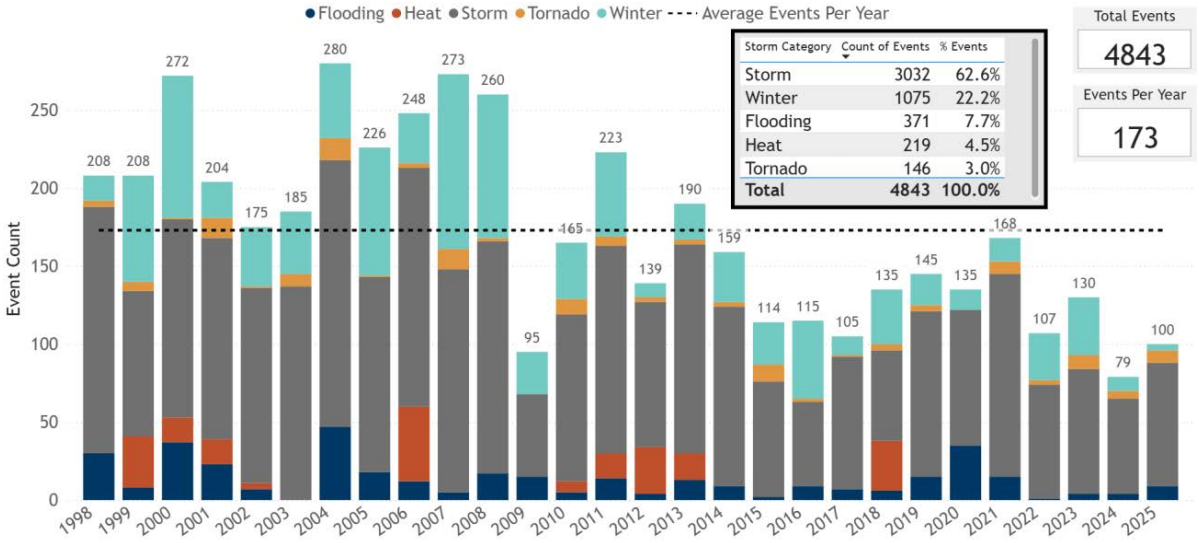
Figure 3-1: Extreme Weather Events in DTE's Service Area (1998- September 30, 2025)[6]



Event	Count of Events	% Events
Thunderstorm Wind	2019	41.7%
Heavy Snow	526	10.9%
Hail	496	10.2%
High Wind	418	8.6%
Winter Storm	332	6.9%
Flood	237	4.9%
Heat	187	3.9%
Tornado	146	3.0%
Flash Flood	134	2.8%
Lightning	99	2.0%
Winter Weather	86	1.8%
Ice Storm	83	1.7%
Excessive Heat	32	0.7%
Blizzard	30	0.6%
Lake-Effect Snow	16	0.3%
Sleet	2	0.0%
Total	4843	100.0%

[6] Ncei. (n.d.). *Storm Events Database | National Centers for Environmental Information*. https://www.ncdc.noaa.gov/stormevents/ with analysis by 1898 & Co.

Figure 3-2: Count of Weather-Based Resiliency Events for DTE's System by Year[7]

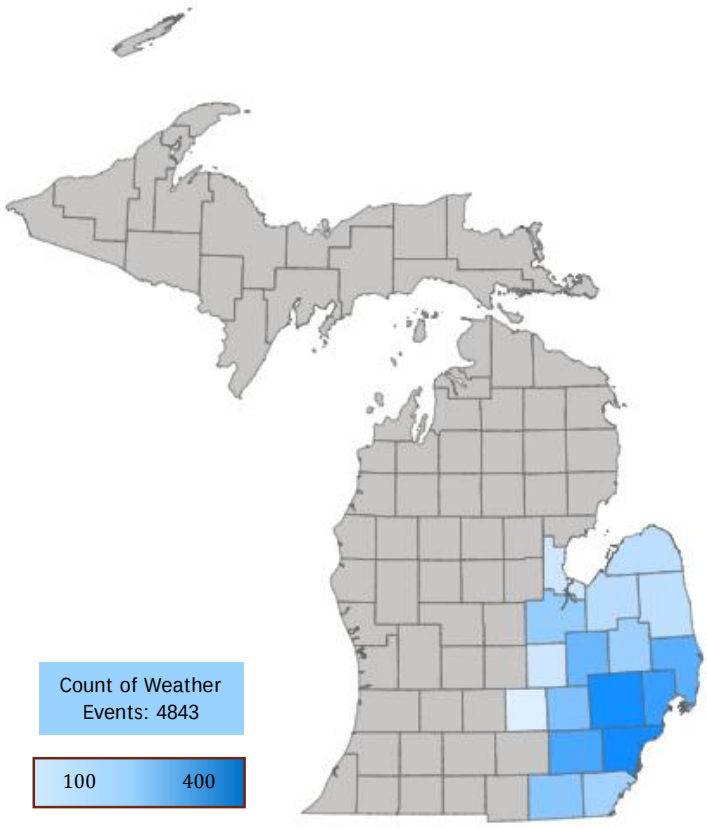


This figure shows a wide range of events occurring over the years. Storm events account for the highest percentage of events to impact the DTE service area at 62.6%.

1898 & Co. utilized NOAA data to organize historical events by county across DTE's service area. Figure 3-3 provides an overview of the counties that intersect DTE's service area with the color gradient showing counties with more events in dark blue and counties with less events in light blue. It is at this level that 1898 & Co. captured each resiliency event.

[7] *Id*. with analysis by 1898 & Co.

Figure 3-3: DTE Service Area Counties with NOAA Recorded Storms



3.2 NOAA Events and Outage Records

The previous section provided foundational information to understand the range of resiliency-event types that impact the DTE service area, where those resiliency events tend to occur within the DTE service area, and the number of resiliency events. This information provides insights into resiliency-event frequency. This section includes an assessment of the impact of these events. 1898 & Co. conducted a correlation analysis between the NOAA event data and DTE's historical outage records to perform that assessment.

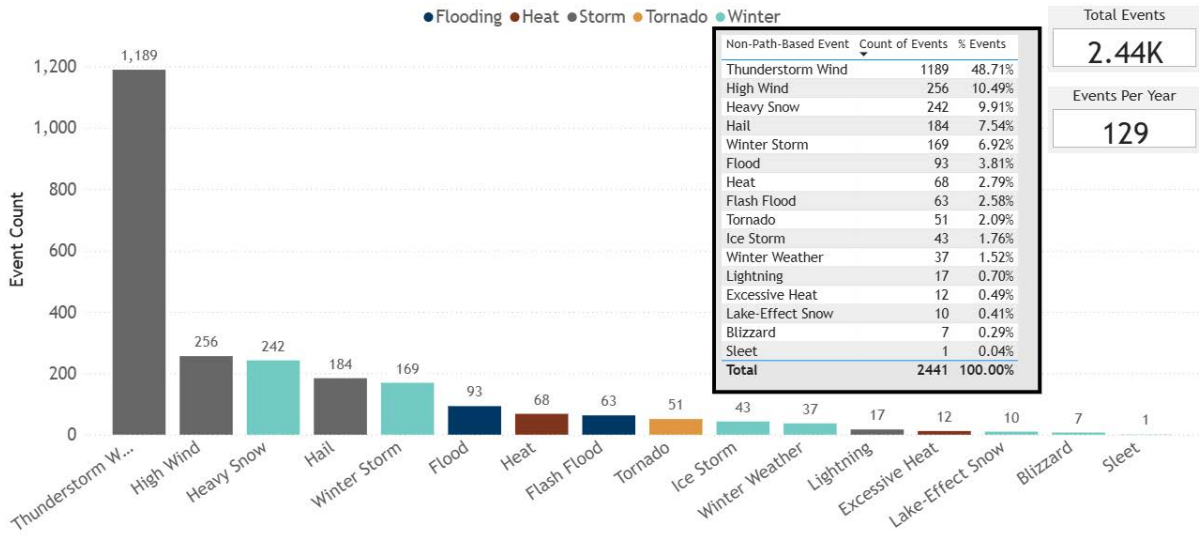
As noted above, this evaluation excludes wildfire and drought events. From 2007 through September 30, 2025, 1898 & Co. correlated events in NOAA to DTE's outage records based on time stamps from both data sets. 1898 & Co. selected 2007 as the earliest year to utilize from DTE's historical outage records, and September 30, 2025,

as the latest year for which complete NOAA event data is available at the time of the study. This correlation allows customer outages to be directly linked to specific resiliency events to assess how the system performed during an individual event. To capture weather events not included in the NOAA database, 1898 & Co. analyzed DTE's outage records. 1898 & Co. identified days with more than thirty outages caused by "Weather" or "Lightning." By classifying these days as distinct weather events, 1898 & Co. added 364 events to the analysis, to more accurately supplement the existing NOAA data based on DTE's observed outage data.

3.2.1 Weather Events from 2007 to September 30, 2025

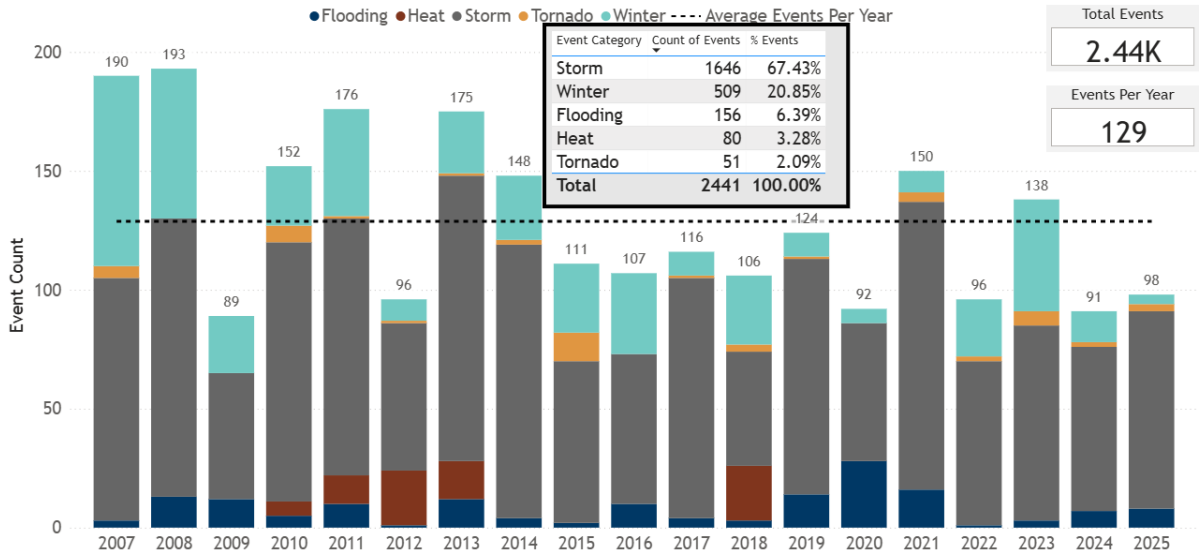
1898 & Co. identified over 2,441 weather events, as defined by NOAA, where an outage was recorded in DTE's OMS. Figure 3-4 shows the type of events that 1898 & Co. mapped to DTE's OMS records over this period from 2007 to September 30, 2025. Figure 3-5 shows the same information summarized by major weather category and by year.

Figure 3-4: Weather **Events Identified in DTE's Outage Records** (2007-September 30, 2025)[8]



Non-Path-Based Event	Count of Events	% Events
Thunderstorm Wind	1189	48.71%
High Wind	256	10.49%
Heavy Snow	242	9.91%
Hail	184	7.54%
Winter Storm	169	6.92%
Flood	93	3.81%
Heat	68	2.79%
Flash Flood	63	2.58%
Tornado	51	2.09%
Ice Storm	43	1.76%
Winter Weather	37	1.52%
Lightning	17	0.70%
Excessive Heat	12	0.49%
Lake-Effect Snow	10	0.41%
Blizzard	7	0.29%
Sleet	1	0.04%
Total	**2441**	**100.00%**

Figure 3-5: Weather Summary Events by Year Identified in DTE**'s Outage Records** (2007-September 30, 2025)[9]



Event Category	Count of Events	% Events
Storm	1646	67.43%
Winter	509	20.85%
Flooding	156	6.39%
Heat	80	3.28%
Tornado	51	2.09%
Total	**2441**	**100.00%**

[8] *Id*. with analysis by 1898 & Co.
[9] *Id*. with analysis by 1898 & Co.

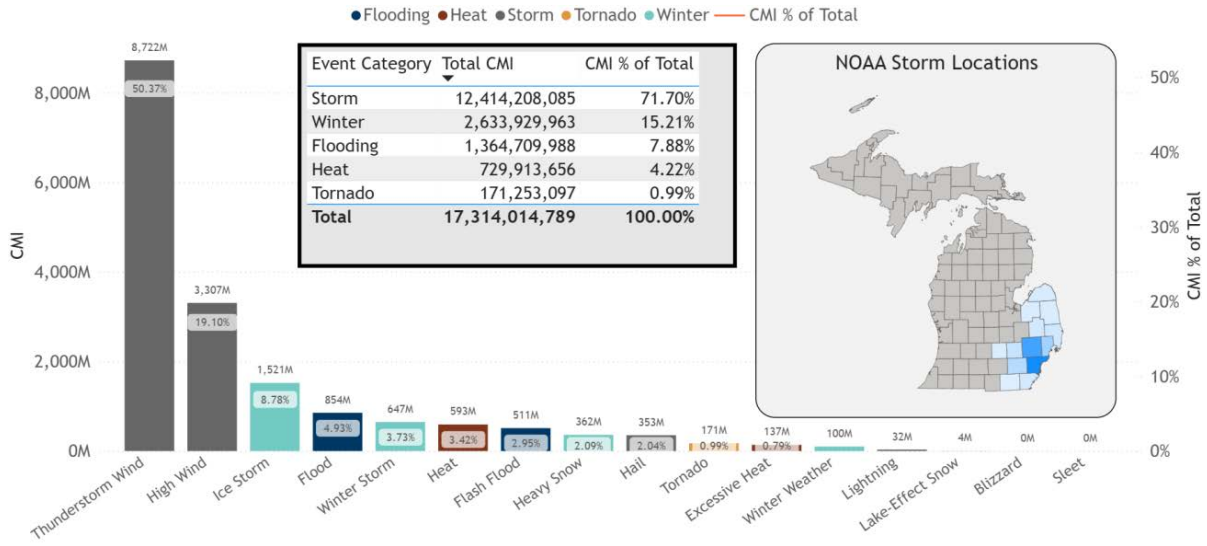
3.2.2 Weather Events and Customer Minutes Interrupted

Between 2007 and September 30, 2025, DTE recorded approximately 21.8 billion Customer Minutes Interrupted (CMI) from outages. An analysis by 1898 & Co. found that a large majority of these interruptions happened during inclement weather.

The analysis linked 16.3 billion CMI, about 74% of the total, to 2,077 severe weather events documented in the NOAA Storm Database. An additional 918 million CMI, or 5.3%, were also attributed to weather as identified by 1898 & Co. when analyzing the DTE outage records. These were identified by finding days with more than thirty outages coded as "Weather" or "Lightning" in DTE's OMS system, which added 364 weather events not recorded by NOAA. This brings the total of weather events identified to 2,441 as shown in Figure 3-4.

Combining these findings, a total of 17.3 billion CMI, or 79.3% of all outages, occurred during inclement weather events. The remaining 4.5 billion CMI (20.7%) happened during "blue-sky" days. Figure 3-6 shows the mapped CMI for each event type.

Figure 3-6: Mapped CMI to OMS and Weather Events (2007 to September 30, 2025)



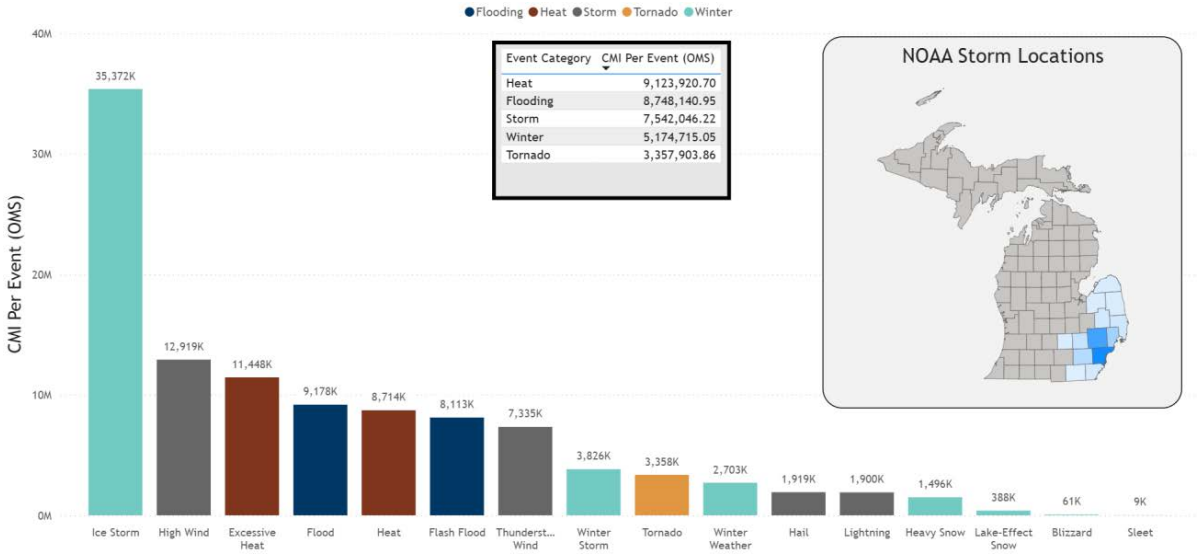
This data illustrates the significant contributions of major weather events to customer outages and the need for resilience investment to mitigate these impacts. The figures above show the following:

1) Two event types below account for nearly 70% of the mapped CMI:
   - Thunderstorm Wind events are the most impactful, with 50.37% of the mapped CMI.
   - High Wind events account for another 19.10%.
2) Seven of the remaining fourteen event types collectively account for an additional 27.94% of the mapped CMI. These seven event types are Ice Storm (8.78%), Flood (4.93%), Winter Storm (3.73%), Heat (3.42%), Flash Flood (2.95%), Heavy Snow (2.09%) and Hail (2.04%).
3) The remaining seven event types account for less than 1% each of all mapped CMI. These are Tornado, Excessive Heat, Winter Weather, Lightning, Lake-Effect Snow, Blizzard and Sleet. Collectively, these account for less than 3% of all CMI.

3.2.3 Customer Minutes Interrupted Per Event

Figure 3-7 shows the historical average CMI per event for each event type. These results are derived by taking the CMI from Figure 3-6 and dividing by the number of events from Figure 3-4. These values serve as the basis to understand the consequence of individual events on the system.

Figure 3-7: CMI Per Event



While Figure 3-7 shows the average CMI per Event over the 2007 through 2025 (through September) time period, Figure 3-8, Figure 3-9, and Figure 3-10 provide a more detailed summary of the CMI per event by year for Thunderstorm Wind, High Wind, and Ice Storm categories, the three highest ranking event types by CMI. These figures demonstrate the significant uncertainty in event impacts. For the top portion of the graph showing the bar chart and line, the blue line represents the total CMI attributed to the storm category for a specific year aligning to the right side of the Y-axis. The bars show the total average CMI per event by year aligned with the left side of the Y-axis. The bottom portion of the graph shows the total count of events linked to the DTE OMS for each year. The figures below show that event impacts, from a CMI perspective, have a wide distribution from year to year.

Figure 3-8: Sum of CMI, Annual CMI Per Event, and Count of OMS Events - Thunderstorm Wind

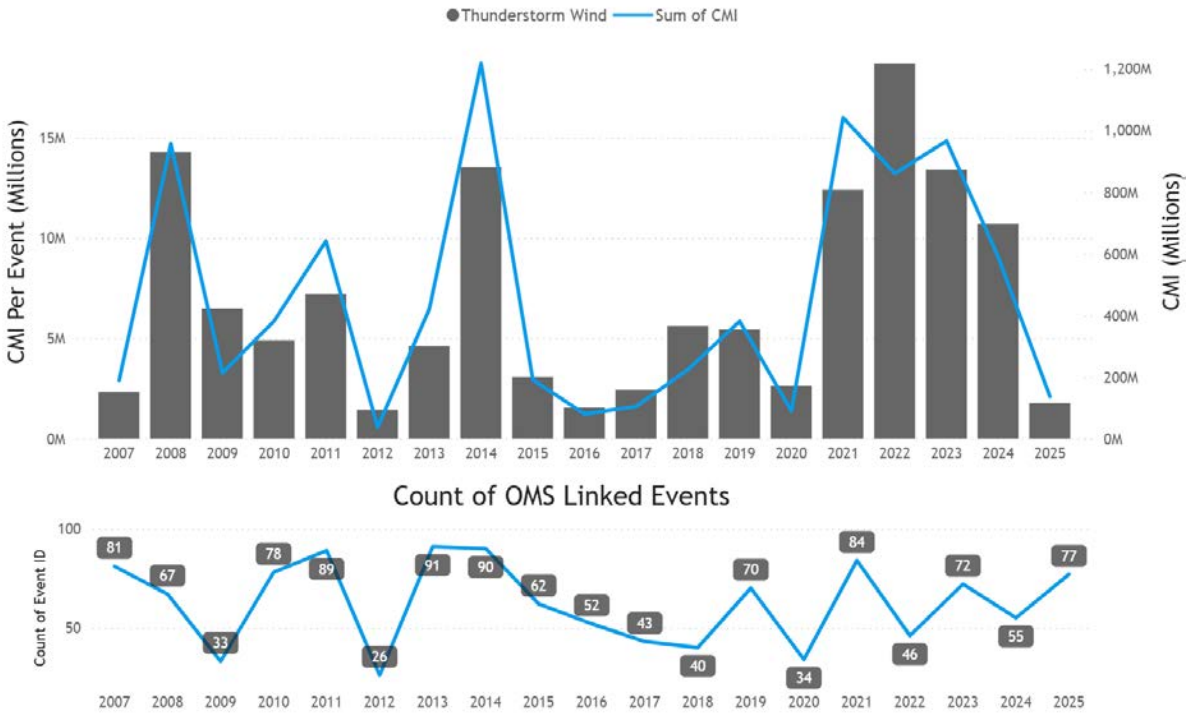


Figure 3-9: Sum of CMI, Annual CMI Per Event, and Count of OMS Events - High Wind

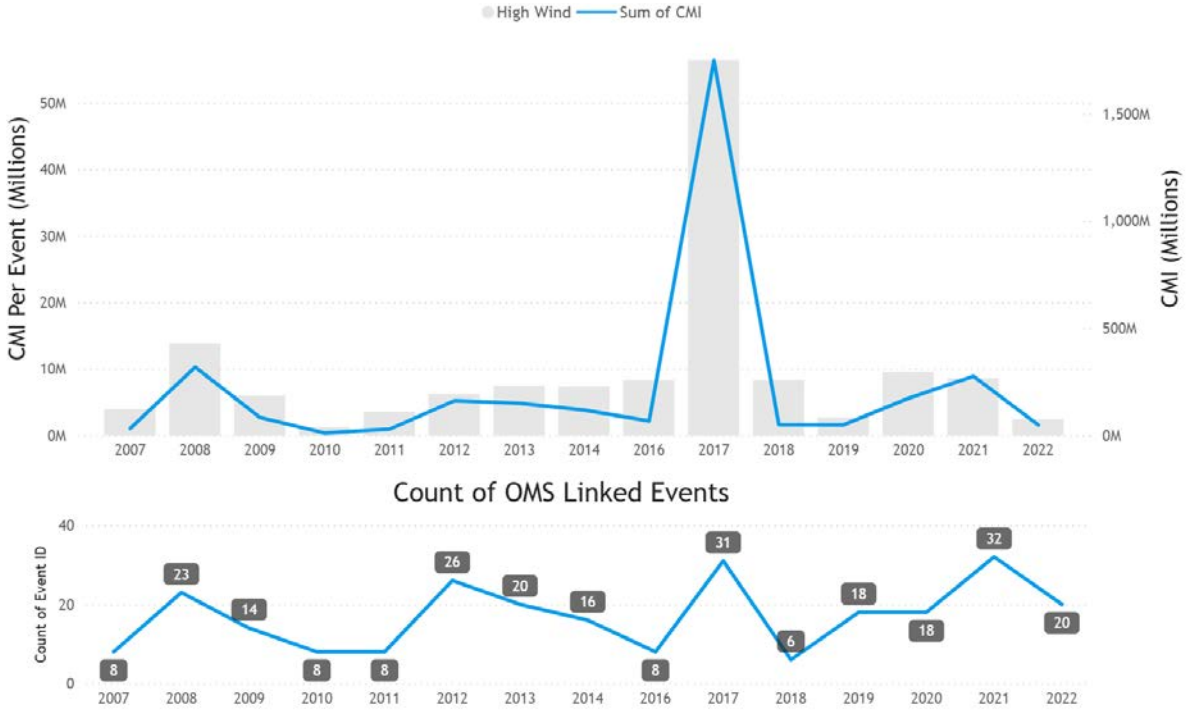
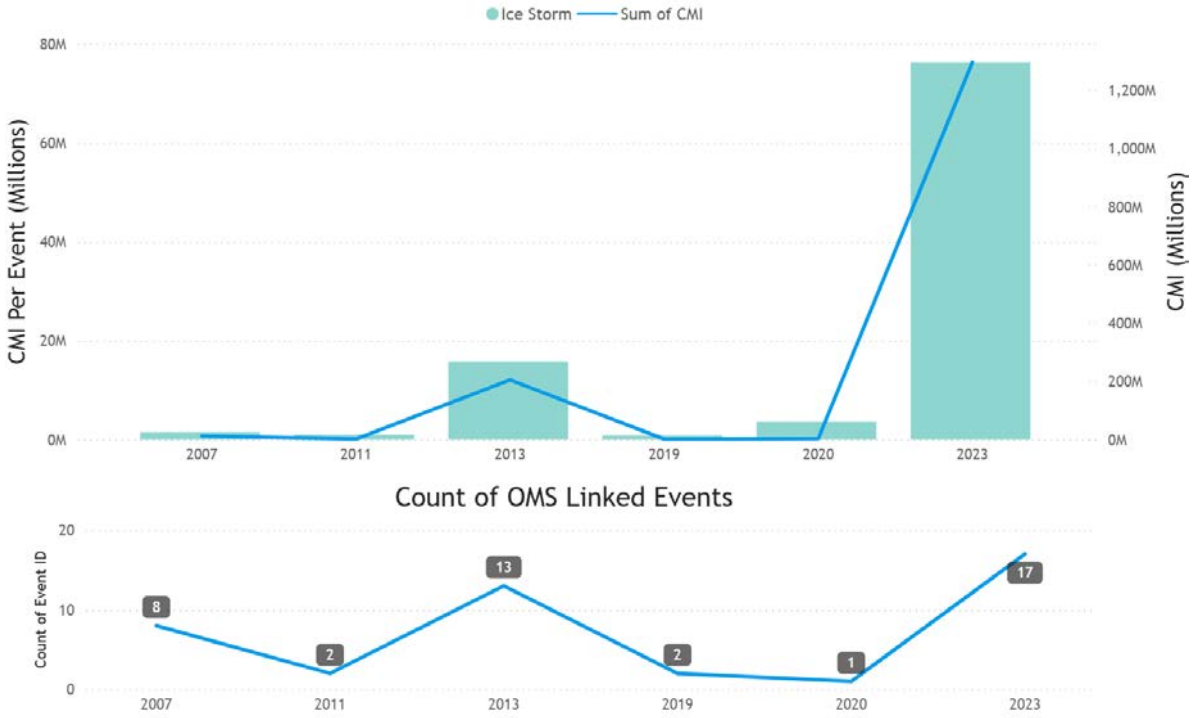


Figure 3-10: Sum of CMI, Annual CMI Per Event, and Count of OMS Events - Ice Storm



3.3 Event Impact Summary

Table 3-2 provides a summary of the resiliency events evaluated by 1898 & Co. that impacted DTE customers. The table includes the events discussed in Section 3.2. Table 3-2 ranks the quantified event types based on their Average Events Per Year (Event Frequency) and the CMI Per Event (Event Impact). The Average Annual CMI is calculated by taking the average number of events per year and multiplying it by the CMI per event. The average number of events per year is from 2007 to September 30, 2025, based on the weather data.

The table shows that Thunderstorm Wind is the main resiliency event impacting customers. Its estimated annual average CMI of approximately 460 million is substantially higher than that of the second-ranked event, High Wind, which has an

annual average CMI of approximately 174 million. Thunderstorm Wind ranks first in event frequency and in CMI per event (event impact).

Ice Storm events occur infrequently, with an average of 2.3 per year, but their severe consequences result in the event impact ranking of 1. Conversely, Thunderstorm Wind events happen far more often, with an average of 63 per year. This high frequency is what drives their top position for the Event Impact rank despite having a lower CMI for each individual event.

Overall, the results show that while Ice Storm has the most significant single-event impact and Thunderstorm Wind occurs most frequently, it is Thunderstorm Wind that has the most significant overall effect on customers. Its combination of the largest

annual average CMI and the highest number of yearly events clearly demonstrates its outsized influence on system resiliency.

The information in Table 3-2 is the core event data utilized within the Integrated Resilience, Reliability, & Risk Investment Model to estimate the quantified benefits of resilience investments across the system. This is discussed in the next section.

Table 3-2: Prioritization of Resiliency Events

Event Category	Event Type	Average Events Per Year (OMS)	CMI Per Event (OMS)	Annual Average CMI (OMS)	Event Frequency	Event Impact Rank
Storm	Thunderstorm Wind	62.58	7,335,309	459,035,897	1	7
Storm	High Wind	13.47	12,918,684	174,062,271	2	2
Winter	Heavy Snow	12.74	1,495,666	19,050,062	3	13
Storm	Hail	9.68	1,918,667	18,580,774	4	11
Winter	Winter Storm	8.89	3,826,181	34,032,869	5	8
Flooding	Flood	4.89	9,178,460	44,926,145	6	4
Heat	Heat	3.58	8,713,799	31,186,227	7	5
Flooding	Flash Flood	3.32	8,112,908	26,900,696	8	6
Tornado	Tornado	2.68	3,357,904	9,013,321	9	9
Winter	Ice Storm	2.26	35,372,384	80,053,290	10	1
Winter	Winter Weather	1.95	2,703,375	5,264,468	11	10
Storm	Lightning	0.89	1,900,481	1,700,431	12	12
Heat	Excessive Heat	0.63	11,447,945	7,230,281	13	3
Winter	Lake-Effect Snow	0.53	388,333	204,386	14	14
Winter	Blizzard	0.37	60,601	22,327	15	15
Winter	Sleet	0.05	9,348	492	16	16

4.0 Benefits Modeling Approach

1898 & Co. utilized a resilience, reliability, and risk-based planning approach to identify, prioritize, and perform a Benefit-Cost Analysis to support the investment justification for the investment programs outlined above. The planning approach utilizes a suite of planning models and the Integrated Resilience, Reliability, & Risk Investment Model developed by 1898 & Co. For the purposes of this evaluation, resilience, reliability, and risk benefits for investment activities are estimated from a customer-centric perspective. The customer benefits are shown in terms of the:

1. Decrease in utility restoration costs; and
2. Decrease in the number of customers impacted and the duration of the overall outage, calculated as CMI and monetizing the CMI.

From these benefit streams, the model calculates the resilience, reliability, and risk BCR for each investment activity, circuit, substation (where appropriate) and program.

$$Resilience, Reliability, \& \ Risk \ BCR = \frac{Lifecycle \ PV \ Avoided \ Costs + Lifecyle \ PV \ Avoided \ \$CMI}{Lifecyle \ Investment}$$

The Resilience, Reliability, & Risk BCR, as used in this analysis, is a single value that represents complex modeling of resiliency and reliability failure modes (including Major Event Day type outages), infrastructure vulnerability, infrastructure rebuild costs, and other financial factors to provide a robust and reliable measure to evaluate individual investments from a quantified customer benefit perspective.

This single value, Resilience, Reliability, & Risk BCR, for each circuit, substation, and program level constitutes a sophisticated multi-factored analysis. The results of this evaluation are measured at the circuit and/or substation level to align with DTE's execution approach. The Resilience, Reliability, & Risk BCR incorporates the following factors for each investment activity for each program:

Resiliency & Reliability Failure Modes & Events

- Range of resiliency events.

- Frequency of those resiliency events.
- Location of events by county.
- The expected asset-level probability of failure (POF) is based on expected equipment lives and types of failures.
- Expected Impact to customers, customer minutes interrupted (CMI), is based on historical customer impacts.
- The decrease in customer outage impacts for DA is directly estimated from historical outage records.

Infrastructure Vulnerability

- Number of assets within each investment activity.
- Age of the assets within each investment activity and their expected lives.
- Known equipment original design vulnerabilities (*e.g.*, Cellon-treated poles)
- Vegetation density around each span of conductor.
- Number of downstream customers impacted for each investment activity.
- Types of customers (residential, commercial & industrial (C&I) based on usage into 20 different groups) for each investment activity.
- The accessibility of the infrastructure in terms of street access.

Infrastructure Rebuild Costs

- The investment needed to mitigate the resilience, reliability, and risk events, including:
  - Type of assets.
  - Number of assets.
  - Location of the assets (rear lot/front lot).

Financial Factors

- Discounted cash flow methodology over the life-cycle of the infrastructure, shown in Table 4-1: Economic Assumptions
- The Interruption Cost Estimator (ICE) calculator (see Section 4.2) to evaluate the cost of an outage for the range of customer types and outage durations.

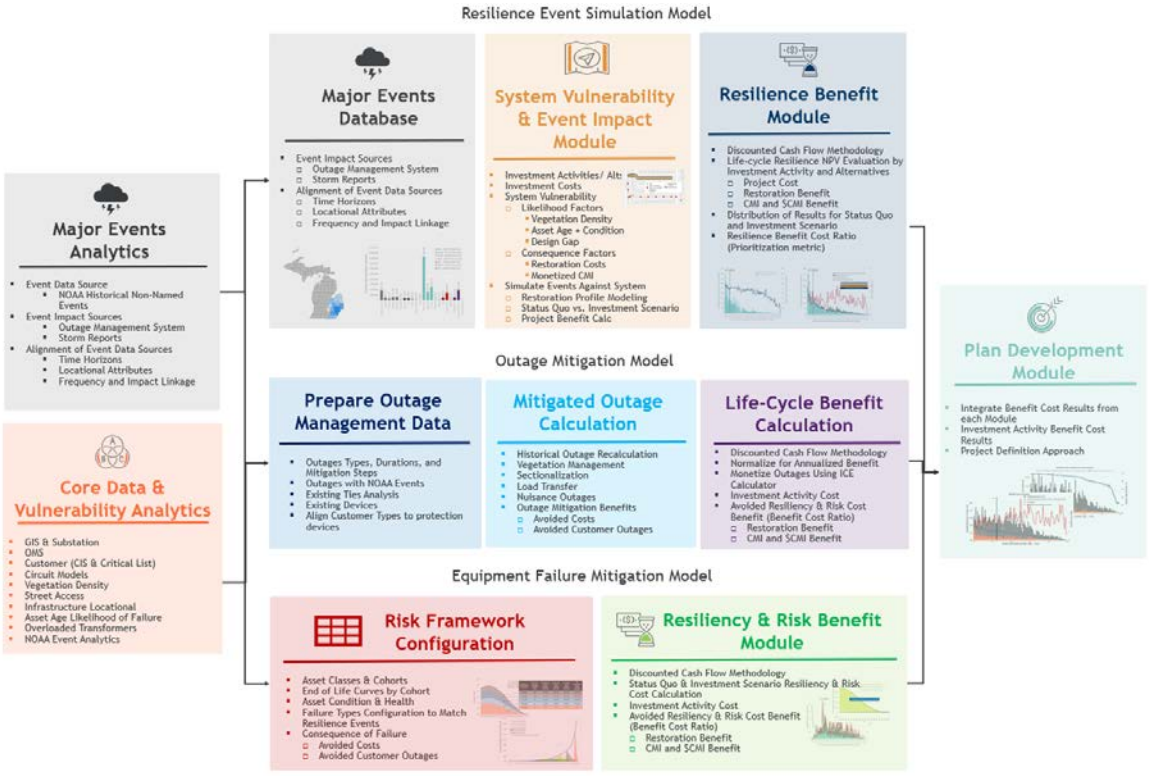
1898 & Co. has carefully integrated all these factors within each model to estimate benefits objectively, consistently, and precisely for each investment activity. This approach makes the Benefit-Cost ratio (BCR) value a robust and reliable measure to help understand the justification for investment activities. This multi-factored and quantified metric provides confidence that investments will provide benefits in excess of costs for customers. Therefore, the BCR value is an appropriate metric to guide investment selection and prioritization on the DTE system.

While the Resilience, Reliability, & Risk BCR incorporates many factors, it does not capture all benefit streams. The list above shows that the BCR incorporates most of the objective factors within the quantified benefits assessment. 1898 & Co. recognizes that more difficult-to-quantify risk factors have not been incorporated into the evaluation. Key factors are safety, areas of lower performance (e.g. Customers Experiencing Multiple Interruptions or CEMI), and cyber-security risks, including the risk that new regulations require additional cyber-security investment.

The Resilience, Reliability, & Risk BCR should be utilized as an important tool in prioritizing and selecting investments in concert with other criteria that incorporate benefits streams not included within the quantified evaluation as described above. Incorporating quantitative and qualitative assessments together is a powerful decision-making tool for utility investments.

The Integrated Resilience, Reliability, & Risk Investment Model employs a data-driven decision-making methodology using sophisticated algorithms to calculate the resilience, reliability, and risk benefits for each potential investment activity that makes up each program. Figure 4-1 provides an overview of the Integrated Resilience, Reliability, & Risk Investment Model utilized within the DTE Benefit-Cost Analysis.

Figure 4-1: Integrated Resilience, Reliability, & Risk Investment Model



The model first includes foundational data. These inputs include core data and vulnerability analytics, such as DTE's asset registers, equipment characteristics, GIS and substation data, outage history, distribution circuit models, and other asset-level information used to assess the specific vulnerabilities of DTE's system. Additional detail on these inputs is provided in Section 2.0.

The model also incorporates major storm event data, including historical storm and event information used to characterize major event risks and simulate future weather events. Additional information on the major events data is provided in Section 3.0.

The model includes three analytics models (Resilience Event Simulation Model, Outage Mitigation Model, and Equipment Failure Mitigation Model). Each of these analytics models estimates the expected avoided costs and avoided customer outages. Each analytics model was designed to estimate the resilience, reliability, and risk benefits of different investments based on the available data, asset types, benefit streams, and

failure types. The sub-sections below provide additional detail on each of the analytics models that estimate benefits.

4.1 General Assumptions

As noted above, the Resilience, Reliability, and Risk Investment Model uses a discounted cash flow methodology for the Benefit-Cost Analysis. Table 4-1 provides an overview of the assumptions used within the Benefit-Cost Analysis.

Table 4-1: Economic Assumptions

Assumption Description	Units	Value
Analysis Period: PTMM	Years	50
Analysis Period: Small Wire Replacement Program	Years	50
Analysis Period: URD Replacement Program	Years	50
Analysis Period: Cable Replacement Program	Years	50
Analysis Period: Breaker Replacement Program	Years	50
Analysis Period: Subtransmission SCADA	Years	40
Analysis Period: Distribution Automation	Years	20
Analysis Period: Communication Network	Years	40
Analysis Period: Subtransmission Redesign and Rebuild	Years	50
Analysis Period: 4.8 kV & 8.3 kV Conversion	Years	50
Escalation Rate	%	2.5%
Discount Rate	%	6.5%
Carrier Fees Escalation Rate	%	2.5%

4.2 ICE Calculator

One of the key assumptions for the Benefit-Cost Analysis (BCA) is the value for the cost of an outage. To monetize the cost of an outage, 1898 & Co. utilizes the Interruption Cost Estimator (ICE) Calculator 2.0, Phase 1 results. While phase 2 was released before the filing of this application, the release timing of late February 2026 was too late to incorporate into the Benefit-Cost Analysis. As such, this analysis is based on the phase 1 release, ICE 2.0. This report does include a review of the key differences between ICE 1.0, 2.0, and 2.2 for the DTE system further below.

The ICE Calculator is an electric reliability planning tool that was originally developed by Freeman, Sullivan & Co. and Lawrence Berkeley National Laboratory (Berkeley Labs). This tool is designed for electric reliability planners at utilities, government organizations, and other entities that are interested in estimating interruption costs and/or the benefits associated with reliability improvements in the United States.

The original version of the ICE calculator, referred to as ICE 1.0, was developed from 15 customer-interruption surveys conducted by 10 electric utilities from 1989 to 2012. The value of interruption costs in the calculator was based on customer surveys, yielding 34 data sets totaling over 105,000 observations from 1989 to 2012. The dataset included over 44,000 medium- to large-C&I customers, 27,000 small C&I customers, and 34,000 residential customers. The surveys collected were evaluated by two approaches:

4) Willingness-to-pay (WTP) surveys for residential customers:
   Residential respondents were asked how much they would be willing to pay to avoid a hypothetical power interruption. This approach captures both direct financial losses and intangible impacts such as inconvenience or discomfort.
5) Direct cost measurement for commercial and industrial customers:
   Businesses were asked to estimate the monetary losses they would experience during an outage. These costs could include lost production, lost sales, equipment restart costs, spoiled materials, and additional labor required to recover from the interruption.

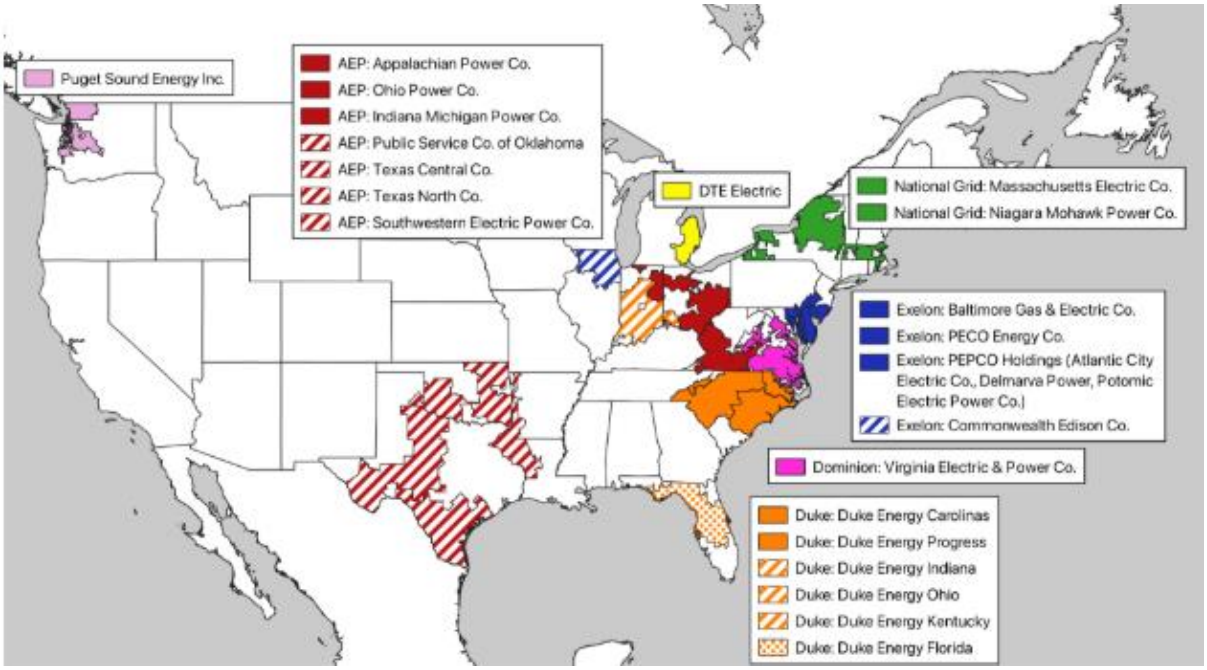
From the surveys, a statistical model for Customer Damage Functions (CDF) to estimate the cost of an outage was created for three different customer classes:

6) Residential customers
7) Small non-residential customers
8) Medium and large non-residential customers

Over time, the developers of the ICE calculator noted significant advancements in the societal use of electronic devices, in-home life-saving medical devices, and other technologies, including a higher number of people working from home. With most

surveys completed before these advancements, Lawrence Berkeley National Labs and Resource Innovations launched the "ICE 2.0 Initiative". The initiative was planned as a national survey comprised of multiple utilities to refresh the underlying survey data in ICE 1.0. To achieve the goal of updating surveys, Berkeley Labs contracted with electric utility sponsors to conduct updated interruption cost surveys that are statistically representative of each utility's customers. These updates are being performed in phases and Figure 4-2, created by Berkeley Labs, shows the electric utilities involved in the phase 1 update of ICE 2.0.

Figure 4-2: ICE 2.0 Phase 1 Utilities[10]



In addition to the support of the sponsoring utilities, Berkeley Labs also received input from the following organizations:

1. U.S. Department of Energy (U.S. DOE)
2. National Association of Regulatory Utility Commissioners (NARUC)
3. National Association of State Utility Consumer Advocates (NASUCA)
4. Energy Offices (NASEO)
5. Edison Electric Institute (EEI)

[10] (Lawrence Berkeley National Laboratory and Resource Innovations, 2025)

6. American Public Power Association (APPA)
7. National Rural Electric Cooperative Association (NRECA)
8. Electric Power Research Institute (EPRI)

4.2.1 ICE 1.0 Compared to 2.0

ICE 2.0 was developed to modernize the interruption cost estimation framework, improve data quality and consistency, and produce more reliable outage cost estimates for utility planning and regulatory analysis. Table 4-2 below highlights the difference between ICE 1.0 and 2.0:

Table 4-2: Summary of Differences between ICE 2.0 and 1.0[11]

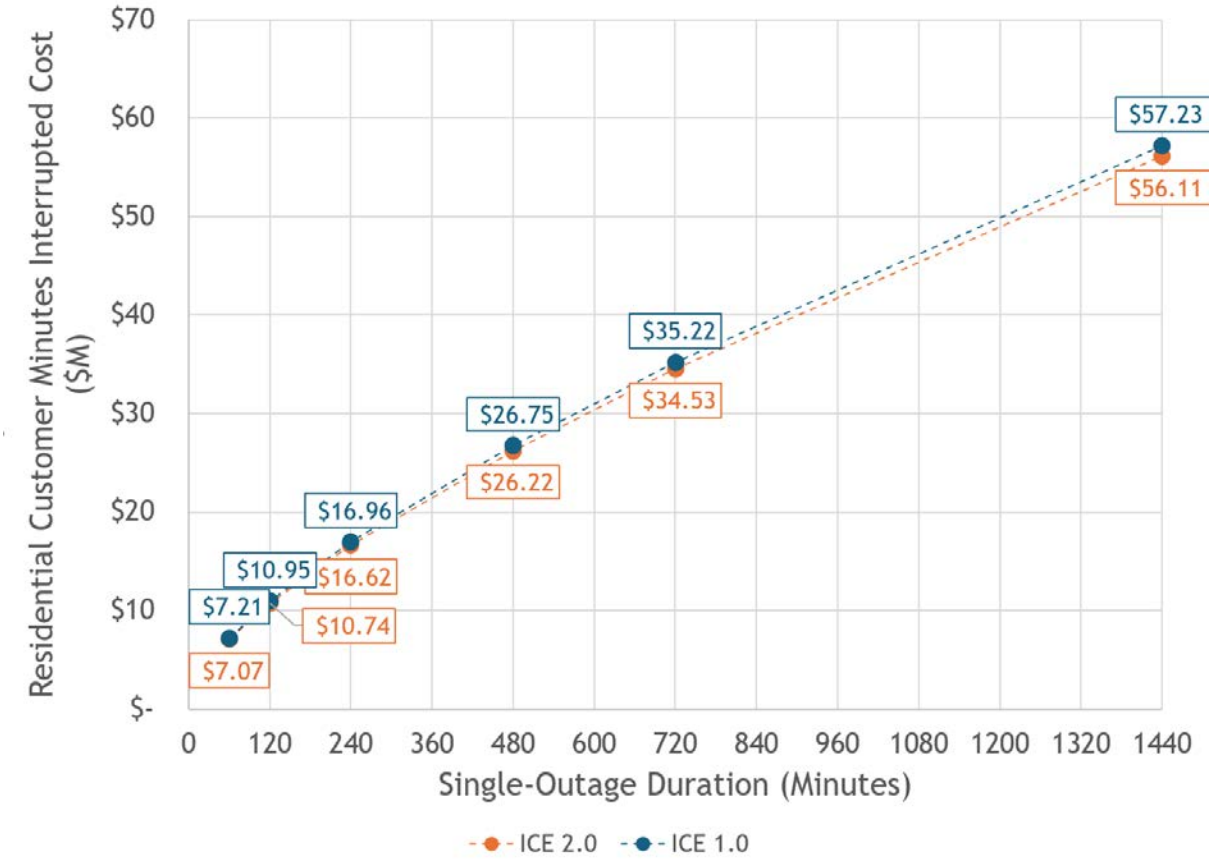
Category	ICE Calculator 1.0	ICE Calculator 2.0
Initial Release	Developed in 2009	Updated and released in 2025
Developers	Lawrence Berkeley National Laboratory and Freeman, Sullivan & Co.	Lawrence Berkeley National Laboratory and Resource Innovations
Purpose	Estimate economic costs of power interruptions for different customer classes	Updated national tool to provide more accurate and representative estimates of outage costs
Survey Years Used	Surveys conducted 1989–2012	Surveys conducted 2022–2024
Number of Survey Efforts	15 independent surveys	11 coordinated surveys (Phase 1)
Utility Coverage	10 utility service territories	24 utility service territories in Phase 1
Geographic Coverage	Primarily Western and Southeastern U.S.	Eastern and Midwestern U.S. and Pacific Northwest, with additional phases expanding coverage
Survey Administration	Surveys conducted independently by utilities with different methodologies	Surveys conducted in a coordinated national effort with identical survey instruments
Survey Questions	Varied questions across surveys	Standardized and consistent questions across all surveys
Interruption Durations Considered	Varied by survey, generally limited to 12 hours or less	Standardized durations: momentary, 2 hours, 8 hours, and 24 hours
Residential Valuation Method	Willingness-to-pay approach	Updated one-and-one-half-bound dichotomous choice (OHDC) willingness-to-pay method
Non-Residential Valuation Method	Direct cost estimation by businesses	Updated direct cost estimation with improved modeling
Customer Damage Functions (CDFs)	**Three models:** residential, small non-residential, medium/large non-residential	**Two models:** residential and non-residential
Model Structure	Two-part econometric models for each customer class	Improved econometric models including generalized linear model (GLM) and probit approaches
Additional Variables Considered	Limited variables such as duration, usage, income, and industry	Expanded variables including backup generation, work-from-home prevalence, industry type, and advance warning
Data Consistency	Data collected with different survey designs and sampling methods	Consistent sampling and survey methodology across utilities
Objective of Update	Provide first national estimate of outage costs	Provide more modern, statistically robust, and nationally representative estimates of outage costs

To understand the impacts of switching from ICE 1.0 in the 2025 BCA to ICE 2.0 in the 2026 BCA, 1898 & Co. compared CDF values for different outage durations. Figure 4-3 shows the difference between ICE 1.0 and 2.0 for the outage value for DTE residential customers for different duration outages. The blue line shows ICE 1.0 values, and the orange line shows ICE 2.0 values. For residential customers, power outages are valued

[11] (Lawrence Berkeley National Laboratory and Resource Innovations, 2025)

slightly lower with ICE 2.0 than with ICE 1.0, making the difference between the curves largely negligible.

Figure 4-3: Comparison of ICE 1.0 and 2.0 for the Value of an Outage for DTE Residential Customers



To understand the potential impact on the value of lost load and the associated benefits of different-duration interruptions for non-residential (C&I) customers between ICE 1.0 and 2.0, 1898 & Co. used DTE's C&I metered customer base and historical annual kWh usage to compare the cost of an outage over a 24-hour period. Figure 4-4 and Table 4-3 compare the difference in the cost of interruption between ICE 1.0 and 2.0, assuming all non-residential customers experience an outage of the designated duration. This approach was utilized since the cost of an interruption is based on kWh usage.

Figure 4-4: Comparison of ICE 1.0 and 2.0 for the Value of an Outage for DTE Non-Residential Customers

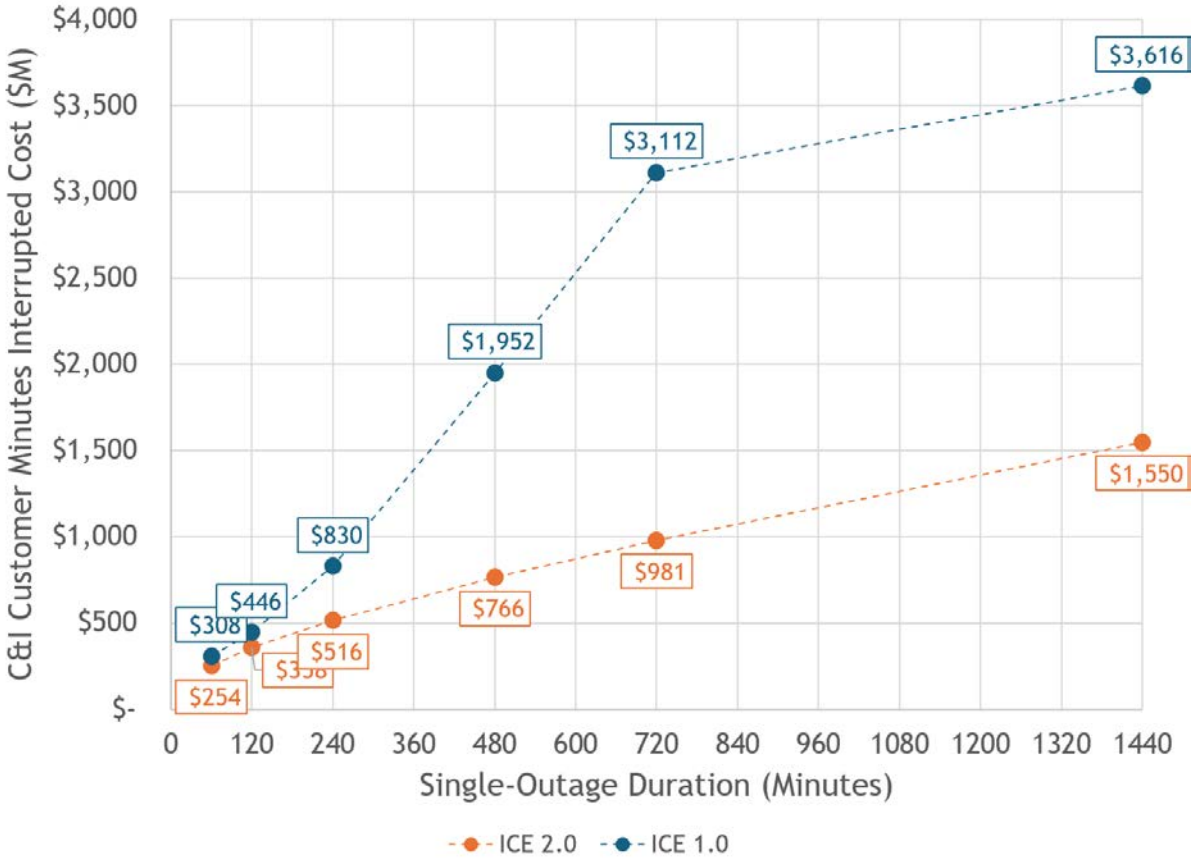


Table 4-3: Difference in cost of interruption between ICE 1.0 and 2.0 for DTE non-residential customers

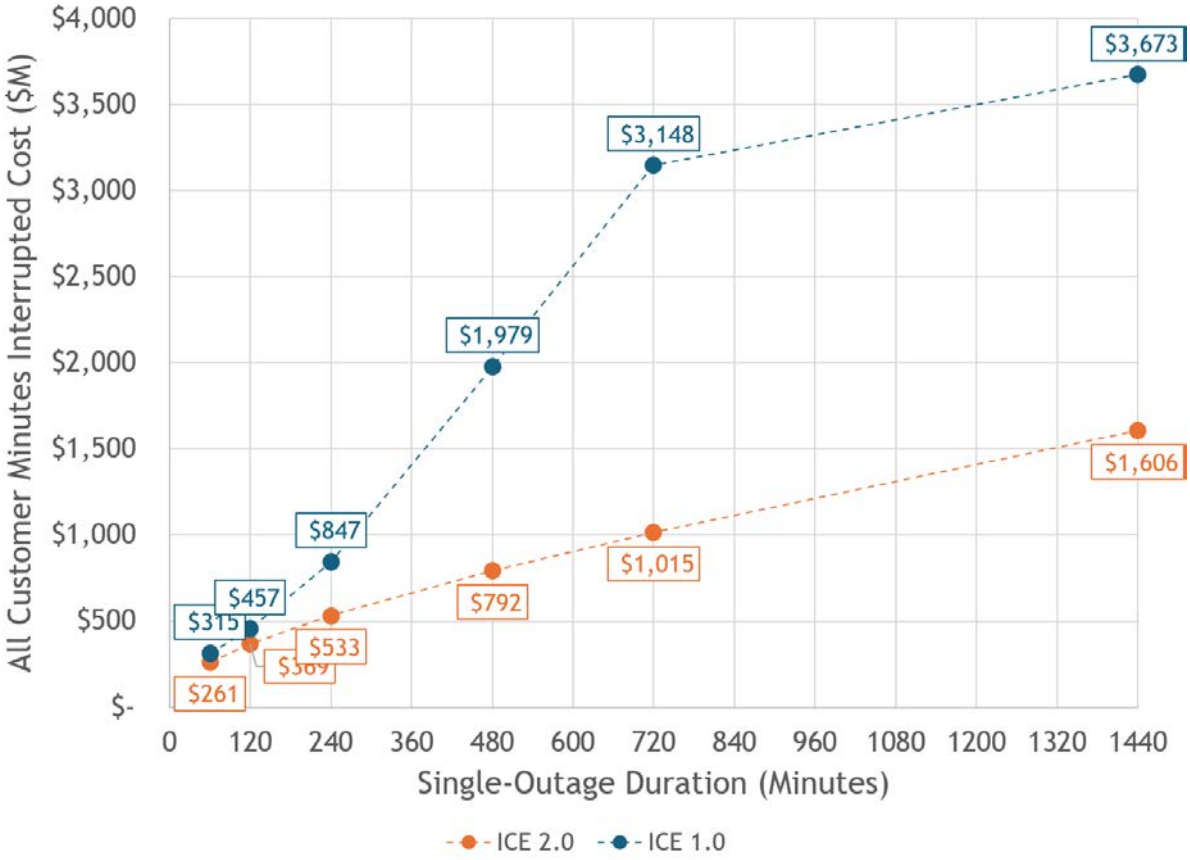
Outage Duration (Minutes)	Estimated Customer Cost ($M)		
	ICE 2.0	ICE 1.0	Delta Between 2.0 and 1.0
60	$253.99	$308.01	-18%
120	$358.25	$446.18	-20%
240	$516.14	$829.71	-38%
480	$765.77	$1,952.37	-61%
720	$980.91	$3,112.33	-68%
1440	$1,549.79	$3,616.09	-57%

In general, 1898 & Co. identified less monetized CMI benefits related to the cost of interruption by shifting from ICE 1.0 to 2.0. Berkeley Labs notes that interruption costs for non-residential customers are comparable for shorter-duration outages, but that ICE 2.0 estimates are 50-75% lower than ICE 1.0 for interruptions lasting more than 10 hours.[12] As can be seen in Table 4-3, the decrease in value for non-residential customers between ICE 1.0 and 2.0 is in line with the expected reduction in value as described by Berkeley Labs.

Figure 4-5 provides the comparison in the difference between ICE 1.0, shown in the blue line, and ICE 2.0, shown in the orange line, for all DTE customers over different outage durations. The chart demonstrated that the primary difference in the cost of an outage is driven by the non-residential customers. Section 4.2.3 includes a similar comparison analysis with ICE 2.2.

[12] (Lawrence Berkeley National Laboratory and Resource Innovations, 2025)

Figure 4-5: Difference in Cost of Interruption between ICE 1.0 and 2.0 for Residential and Non-residential DTE customers



4.2.2 C&I Customer Clustering Approach

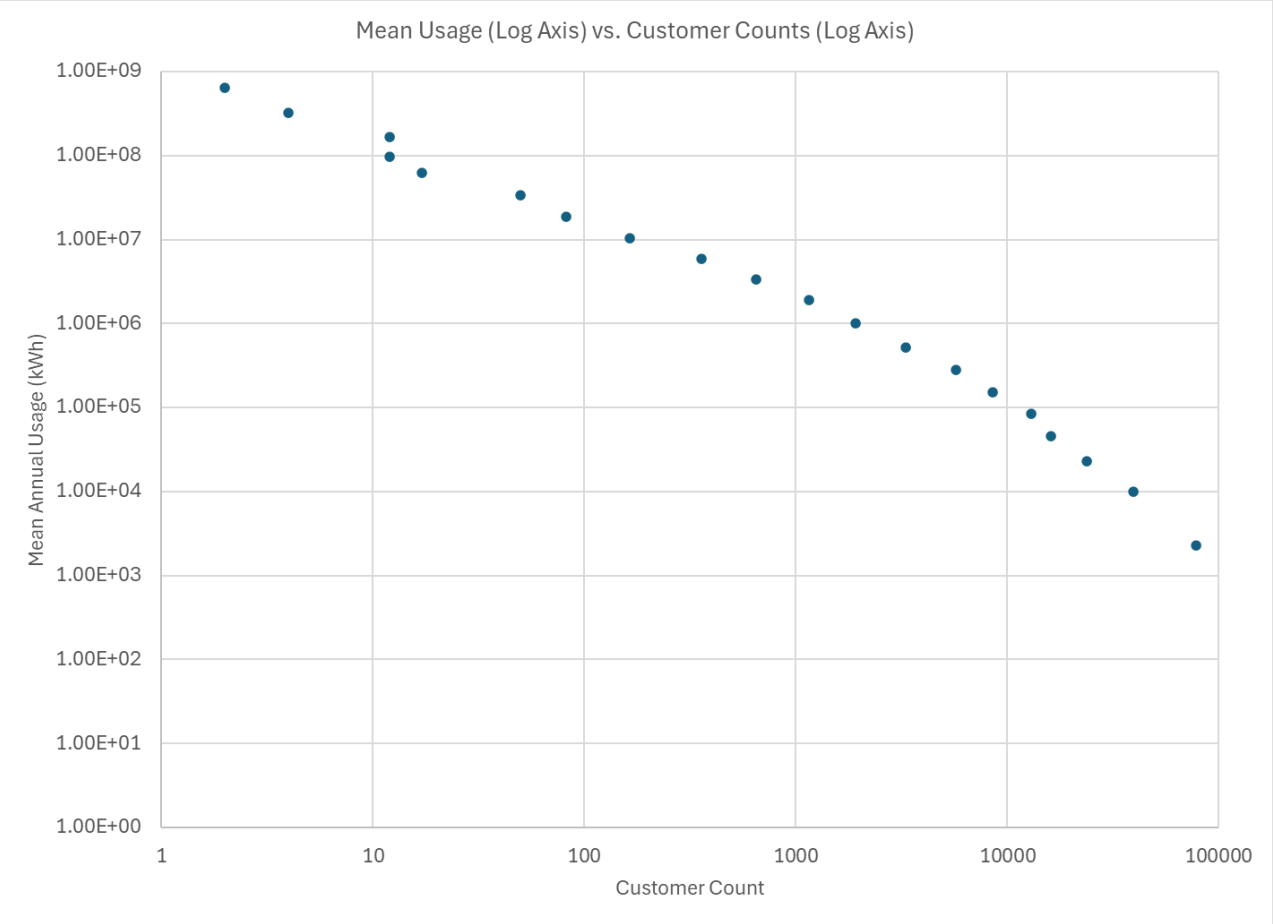
As described above, the ICE Calculator 2.0 defines the cost of an outage for a C&I customer based on the customer's annual kWh usage. DTE provided 1898 & Co. with each C&I customer's annual kWh usage for 2024, and 1898 & Co. utilized this data to map customers to an appropriate annual usage value.

Conceptually, the updated ICE Calculator could enable the consideration of each individual C&I customer's annual usage in evaluating outages. Taking this approach would require significant computational effort and increased modeling complexity to extract values for each customer for each outage duration. For these reasons, 1898 & Co. used a clustering approach to group DTE's C&I customers into representative, relatively homogeneous clusters.

After statistically evaluating options for the number of C&I clusters, 1898 & Co. determined that 20 clusters provided sufficient granularity for evaluating the cost of non-residential outages. This number of clusters represents a reasonable balance between accurately capturing variation in customer usage and maintaining a manageable number of groups for analysis.

1898 & Co. developed the groups by applying k-means clustering to the C&I customer annual kWh usage values for 2024. This clustering approach produced the groups shown in Figure 4-6. In this scatterplot, each dot represents a C&I customer group. The x-axis provides the number of customers within the customer cluster, while the y-axis provides the group's appropriate annual usage value. Given the large ranges for customer count and annual usage, the graph's axes are shown on a logarithmic scale.

Figure 4-6: Results of Clustering C&I Customer Annual kWh Usage



For each of these 20 customer groups, 1898 & Co. extracted non-residential cost of interruption values based on the customer group annual usage and various outage durations from the ICE 2.0 estimator.

4.2.3 Phase 2 of ICE Calculator 2.0 (ICE Calculator 2.2)

On February 26, 2026, Berkeley Labs released Phase 2 of the ICE calculator, referred to as ICE 2.2. This phase expanded the survey results to include more utilities and a larger number of responses. With each new phase of the ICE calculator, the cost of interruption values are updated to reflect additional survey data.

With the addition of the new survey information collected for ICE 2.2, Berkeley Labs updated the customer damage functions to produce new results for the cost of interruption in ICE 2.2. Table 4-4 provides a comparison that Berkeley Labs compiled outlining the estimated differences in the cost of interruption between residential and non-residential customers between ICE 2.0 and ICE 2.2.

Table 4-4: Difference in cost per event between ICE 2.0 and ICE 2.2[13]

Duration of Interruption Event	Residential Cost per Event: % Change Relative to ICE 2.0	Non-residential Cost per Event: % Change Relative to ICE 2.0
2 hours	-2%	+19%
8 hours	-2%	+18%
24 hours	-2%	+4%

As shown in Table 4-4, the difference between the cost of interruption per event is small for residential customers and is estimated to be on average 2% less in value for ICE 2.2. However, for non-residential customers the cost of interruption for longer

[13] (Updates to the Interruption Cost Estimate (ICE) Calculator: Key Differences Between Version 2.0 and 2.2, February 2026)

duration outages has been increased by 19% and 18% for a 2 and 8 hour outage respectively in ICE 2.2.

To understand how the updates to phase 2 of the ICE calculator (ICE 2.2) will impact the cost of service interruption for DTE customers, 1898 & Co. calculated the monetized CMI for different duration outages using the DTE customer base. The results of this analysis are shown in Figure 4-7:. As shown in Figure 4-7:, the ICE 2.2 values are higher than both ICE 2.0 and 1.0 for 2 hour outages and less. At 4 hours, the cost of an outage for ICE 1.0 and 2.2 are close in value. For outages longer than 4 hours, ICE 2.2 is lower than ICE 1.0 but higher in value when compared to ICE 2.0

Figure 4-7: Comparison of ICE 1.0, 2.0, and 2.2 for DTE Customers

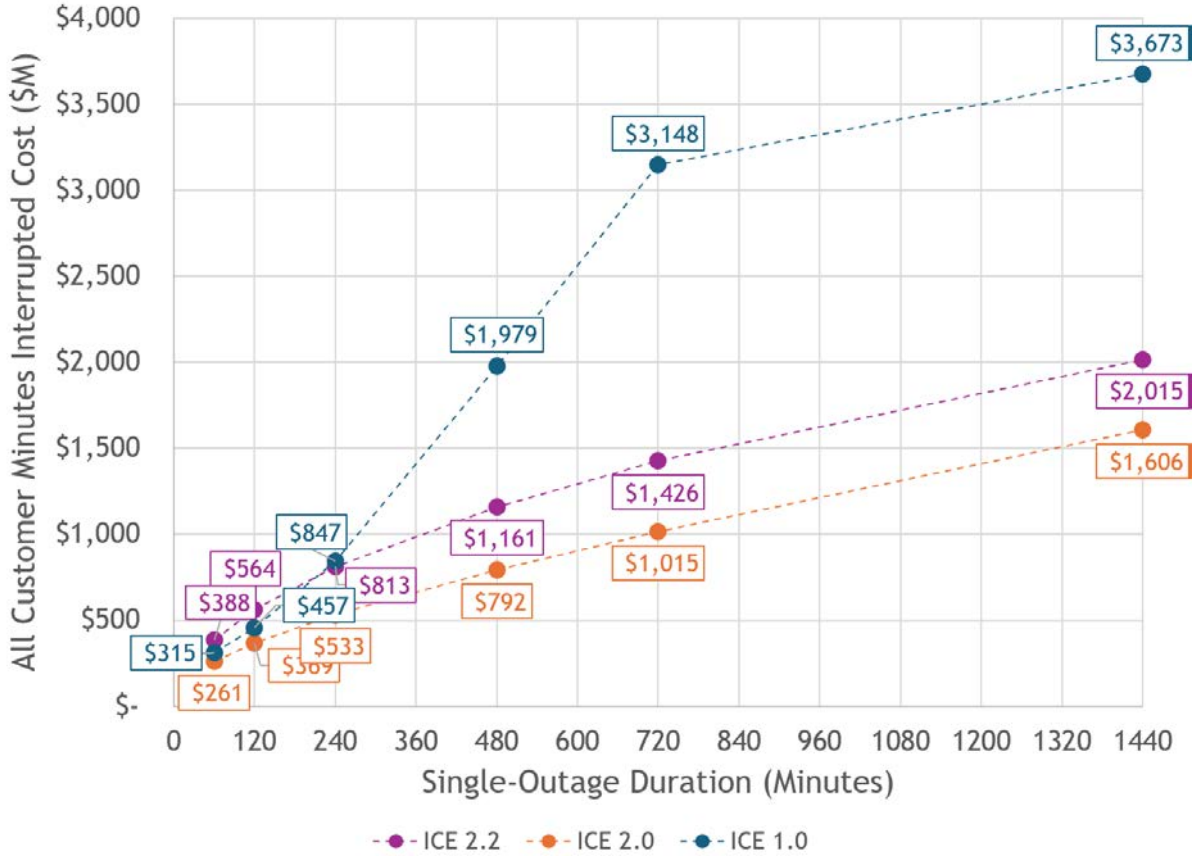


Table 4-5 below compares the difference in the cost of an outage for different durations between ICE 2.2 and 2.0. This shows that ICE 2.2 for the DTE customer profile is anywhere from 25% to 53% higher across the different durations. Of

important note is that outages less than 2 hours are roughly 50% higher in value when using ICE 2.2.

Table 4-5: Difference in cost of interruption between ICE 2.0 and 2.2 for DTE customers

Outage Duration (Minutes)	Estimated Customer Cost ($M)		
	ICE 2.2	ICE 2.0	Delta Between 2.0 and 2.2
60	$387.83	$261.06	49%
120	$564.02	$368.99	53%
240	$812.82	$532.76	53%
480	$1161.49	$791.99	47%
720	$1426.08	$1015.44	40%
1440	$2014.63	$1605.90	25%

Due to the large increase in the value of longer duration of outages for DTE customers, 1898 & Co. estimates that there is potential to increase available benefits when using ICE 2.2 across the DTE programs. In other words, the increased value of an outage for DTE customers could improve the available benefits and the BCRs for all the investment programs discussed in this report. This will be especially true for the DA program as all benefits for this program are related to avoiding customer restoration minutes. For the 2026 analysis, the DA program is receiving reduced benefits due to the change from ICE 1.0 to 2.0 and the Integrated Sequence of Programs explained in section 4.7.1. For the DA program, the use of ICE 2.2 is expected to increase the benefits available to this program which will increase the amount of beneficial investment for DA.

4.3 Resilience and Risk-Based Planning Approach

In the last decade, the frequency and impact of major weather events have grown significantly across the United States. Hurricanes have struck Florida and the Gulf Coast, nor'easters have battered the East Coast, polar vortexes and ice storms have

swept through the Midwest and mountain regions. At the same time, the customer expectations for the availability of the grid have increased dramatically over the last several decades. Decades ago, grid outages were seen as an inconvenience for customers. Today, these outages can cause real economic harm and stress, and even put society's most vulnerable at risk, due to the widespread use of life-saving electronic equipment in people's homes. Additionally, today's society is far more integrated than in the past. The recent supply-chain disruptions following the global pandemic have revealed how interconnected our society and global economy have become. Compounding this challenge is the expected trend towards more dependence on the grid with the acceleration of electrification in applications, such as home heating, oil and gas activity, commercial fleet electrification, and electric vehicle adoption, to name a few. More than ever, today's customers demand that the electric grid be consistently available.

One of the most essential actions electric utilities can take to prepare for major weather events is to make the electric grid more resilient. When the grid can better withstand the impacts of events, everyone benefits. A resilient grid will allow businesses and families to save money because they can get back on their feet more quickly. Proactive investment in grid resilience will also enable utilities to design integrated programs to address all phases of resilience, reducing event-related restoration costs and outage times.

This section of the report outlines a conceptual framework for understanding grid resilience. 1898 & Co. applied the resilience modeling benefit assessment framework to the following DTE programs:

1) PTMM,
2) Small Wire Replacement Program,
3) Subtransmission SCADA,
4) Subtransmission Redesign and Rebuild, and
5) 4.8 kV and 8.3 kV Conversion.

4.3.1 Resilience Definition

The Merriam-Webster dictionary defines resilience as:

1. The capability of a strained body to recover its size and shape after deformation caused especially by compressive stress.
2. An ability to recover from or adjust easily to misfortune or change.[14]

Merriam-Webster elaborates on the definition:

> In physics, resilience is the ability of an elastic material (such as rubber or animal tissue) to absorb energy (such as from a blow) and release that energy as it springs back to its original shape. The recovery that occurs in this phenomenon can be viewed as analogous to a person's ability to bounce back from a jarring setback.[15]

These definitions provide a conceptual understanding of resilience, but additional exploration is needed to understand the term in the context of electric power systems specifically. While the industry has general agreement around the major elements of resilience, the definitions are not identical. Other definitions of resilience from grid stakeholders are:

- IEEE PES PES-TR83 Report—Resilience Framework, Methods, and Metrics for the Electricity Sector: The ability to protect against and recover from any event that would significantly impact the grid.
- CIGRE WG C4.47: Power system resilience is the ability to limit the extent, severity, and duration of system degradation following an extreme event.
- FERC: The ability to withstand and reduce the magnitude and/or duration of disruptive events, which includes the capability to anticipate, absorb, adapt to, and/or rapidly recover from such events.
- DOE: The ability of a power system and its components to withstand and adapt to disruptions and rapidly recover from them.

In a 2013 paper, the National Association of Regulatory Utility Commissioners offered its own definition of resilience in a manner that is simple and easy to understand:

[14] Resilience. (n.d.). Merriam-Webster Dictionary. https://www.merriam-webster.com/dictionary/resilience.
[15] *Id.*

> Robustness and recovery characteristics of utility infrastructure operations, which avoid or minimize interruptions of service during an extraordinary and hazardous event. In other words, it is the gear, the people and the way the people operate the gear immediately before, during and after a bad day that keeps everything going and minimizes the scale and duration of any interruptions.[16]

Before that, the National Infrastructure Advisory Council provided a definition that is often quoted. It states that resilience is:

> The ability to reduce the magnitude and/or duration of disruptive events. The effectiveness of a resilient infrastructure or enterprise depends upon its ability to anticipate, absorb, adapt to, and/or rapidly recover from a potentially disruptive event.[17]

The National Infrastructure Advisory Council definition includes a system's ability to absorb and adapt. Argonne National Laboratory also used these important characteristics in its state and social resilience work. They were also incorporated into Pacific Northwest National Laboratory's work on the resilience impacts of transactive energy systems. The Argonne National Laboratory approach can be used to break resilience into four phases that also align with the National Association of Regulatory Utility Commissioners' elegantly simple description—the difference being that Argonne National Laboratory explicitly includes the ability of the system to recognize and mitigate potential failures before they happen. These four phases are described below:

[16] Keogh, M., Cody Christina, & NARUC Grants & Research. (2013). Resilience in Regulated Utilities. In *https://pubs.naruc.org/pub/536F07E4-2354-D714-5153-7A80198A436D#:~:text=Resilience%20%2Fri%CB%88zily%C9%99ns%2F%20noun%2C%20regulatory,an%20extraordinary%20and%20hazardous%20event*. The National Association of Regulatory Utility Commissioners.
[17] Bush Wes, Grayson Margaret, Berkeley III, A., & Thompson John. (2009). CRITICAL INFRASTRUCTURE RESILIENCE FINAL REPORT AND RECOMMENDATIONS. In *https://www.cisa.gov/sites/default/files/publications/niac-critical-infrastructure-resilience-final-report-09-08-09-508.pdf*. NATIONAL INFRASTRUCTURE ADVISORY COUNCIL.

- Prepare (Before)
  The grid is running normally, but the system and its operators are preparing for potential disruptions.
- Mitigate (Before)
  The grid resists and absorbs the event until, if unsuccessful, the event causes a disruption.
- Respond (During)
  The grid responds to the immediate and cascading impacts of the event. The system is in a state of flux, and fixes are being made while new impacts are felt. This stage is largely reactionary (even if using prepared actions).
- Recover (After)
  The state of flux is over, and the grid is stabilized at low functionality. Enough is known about the current and desired (normal) states to create and initiate a plan to restore normal operations.[18]

The definitions of resilience quoted above can be used to form a conceptual framework to better understand and evaluate initiatives to improve grid resilience. This framework is discussed in the following subsection.

4.3.2 Resilience Conceptual Framework

The Resilience Conceptual Framework provided the foundation for resilience-benefit definition and evaluation within the modeling approach. The resilience of a utility system is a function of many factors; however, the two main factors are:

1) the frequency and types of weather events that impact the system, and
2) the vulnerability characteristics of the infrastructure in the system.

For the first factor, more-frequent and more-intense weather events will make grid resilience more challenging. For the second factor, the unique vulnerability

[18] Argonne National Laboratory. (n.d.). *Resilience Measurement Index: An Indicator of Critical Infrastructure Resilience*. https://publications.anl.gov/anlpubs/2013/07/76797.pdf.

characteristics of a utility's system will change the overall outcome of failure in the face of specific weather events.

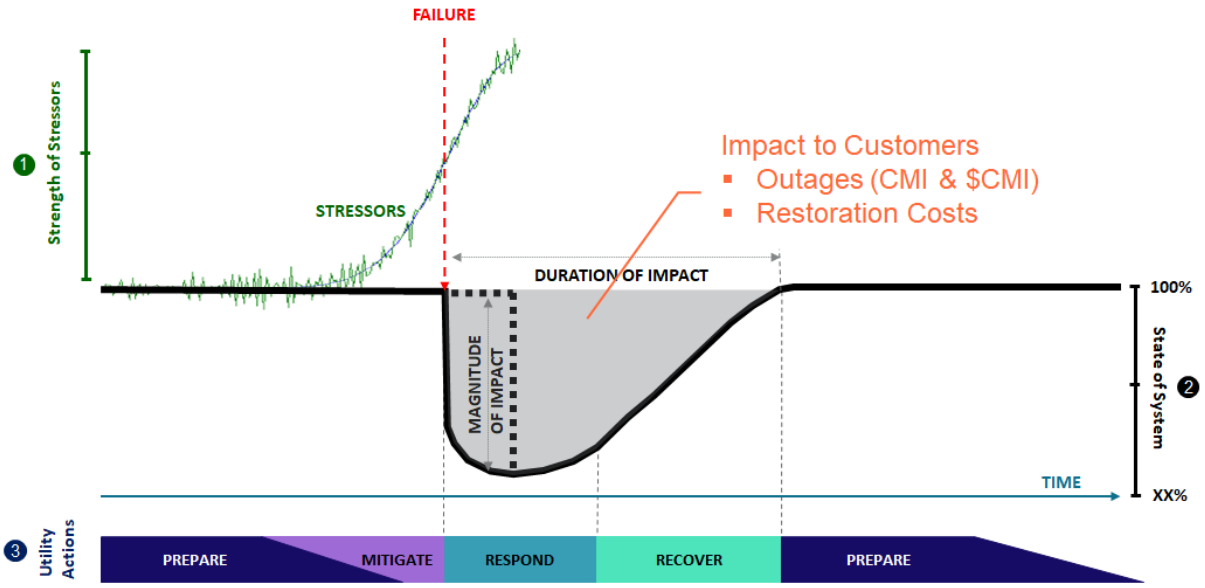
When combined, weather events and system vulnerabilities provide additional challenges for grid resilience. Individual weather events, by their nature, are unpredictable and do not impact an area uniformly. Grid stakeholders could be "lucky" or "unlucky" depending on how the risks posed by a weather event impact the grid. For instance, the electrical system will respond differently to a thunderstorm with pockets of high wind that impact an older, vegetation-dense neighborhood compared to a similar thunderstorm that impacts a newer, suburban neighborhood with underground distribution assets. In the first instance, such a localized thunderstorm may cause significant outages, while having only minimal impact in the second instance, even though the two neighborhoods might be very close in proximity. These two factors, events and vulnerabilities, profoundly impact a grid's measured resilience.

Figure 4-8 presents the Resilience Conceptual Framework that underpinned the modeling approach. As described above, resilience is driven by two primary factors: the frequency and severity of the weather events affecting the system and the vulnerability characteristics of the infrastructure that make up the system. The figure shows how these two factors interact to produce system failures and customer impacts when weather-related stressors exceed the strength of the existing system. The figure also illustrates how utility actions, including preparation, mitigation, response, and recovery, affect the extent of those customer impacts, specifically their magnitude and duration.

Finally, the figure shows that resilience-related investment activities can improve system performance by reducing the severity of these impacts. Depending on the type of investment activity, resilience value may be created by helping the system better withstand major event stressors, reducing the magnitude of the service disruption after failure occurs, or shortening the time required to recover and return to normal operating conditions. As a result, the benefit of resilience-related investment activity

stems from reduced outage consequences and reduced restoration-related costs over the life of the infrastructure.

Figure 4-8: Resilience Conceptual Framework



4.3.3 Resilience Model Overview

The Resilience Event Simulation model estimated the benefits of investment activities, such as asset replacements and inspections, which reduce the impacts of major weather and resilience events on the distribution system. It is based on the resilience conceptual framework described above. The model utilized a resilience-based planning approach to simulate how the DTE system would perform under a wide range of future weather events and to quantify the benefits of investment activities that improve system performance during those events. The modeling framework incorporated historical weather event data, weather-event simulation, system-vulnerability characteristics, and asset-level investment assumptions to evaluate how investments changed outage outcomes and restoration performance under stressed conditions.

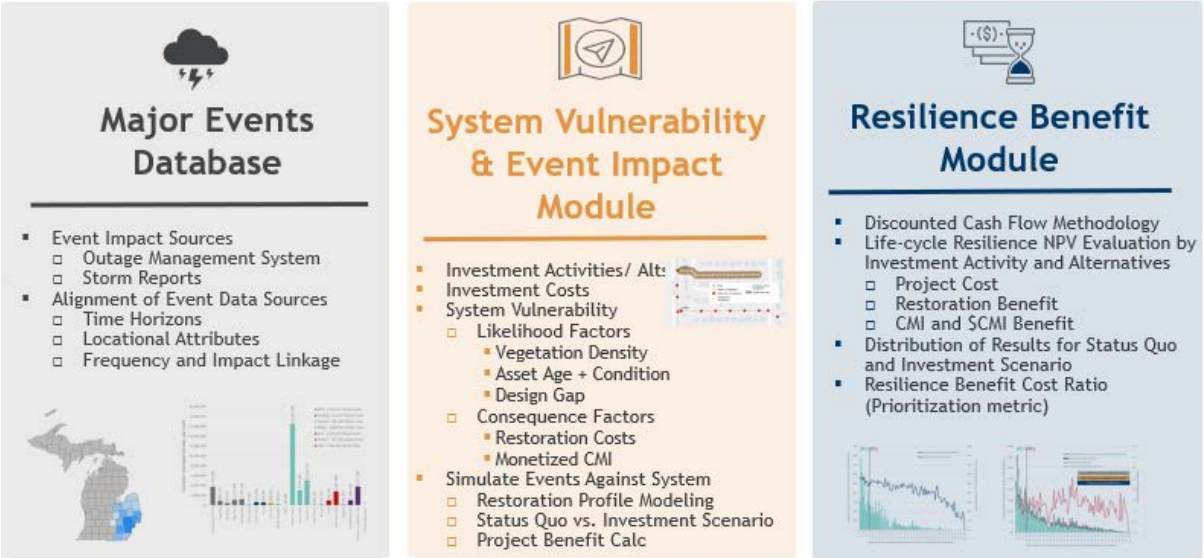
The approach calculated resilience-related benefits for each investment activity (protection-zone or similar element of the system) in each of two scenarios. The first

is a Status Quo scenario in which no proactive investment activity occurred, and the protection zone continued to operate as previously constructed. The second is an Investment scenario in which a proposed, proactive investment activity occurred, such as a rebuild or inspection with equipment replacements and upgrades. For each scenario, the model estimated the distribution of weather-event-induced outcomes, including the resulting customer outages, outage durations, restoration costs, and other resilience-related consequences. The benefits of the investment activity are the differences in outcomes between the Status Quo and Investment scenarios, measured as the avoided resilience consequences attributable to the investment.

Within the modeling framework, the Resilience Event Simulation Model estimated the weather-event-related benefits of investment activities. These benefits are calculated using simulated, future weather events and asset-level representations of system performance or vulnerabilities under stress. When investment activities also provided blue-sky (that is, non-weather-event-related) benefits, such as reduced equipment failure risk under normal operating conditions, the weather-event-related benefits described here were combined with the blue-sky benefits derived from the Equipment Failure Mitigation Model, as described in Section 4.4.

Figure 4-9 provides an overview of the Resilience Event Simulation Model used to calculate the restoration cost reduction and the CMI reduction (the benefits) of resilience-related investment activities. The model has three primary components: the Major Events Database, the System Vulnerability & Event Impact Module, and the Resilience Benefit Module. Collectively, these components integrated weather-event data, system-vulnerability characteristics, and investment activity assumptions to quantify the resilience benefits provided by the evaluated investment activities. The following three sections describe each component in greater detail.

Figure 4-9: Resilience Event Simulation Model



4.3.3.1 Major Events Database

Since an investment activity's associated reduction in restoration costs and CMI depended on the frequency and severity of future weather events that will impact the DTE service area, the Resilience Event Simulation Model begins by developing a "universe" of major weather events that could impact DTE's service area. The Major Event Database provided a high-level, expected impact on the system from each of the NOAA-defined, major weather events. The major events database included the following information:

- Weather Event Type,
- Frequency of the event, for each county section of DTE's service area,
- Average impact, in CMI terms, for each event based on historical outage records.

In developing the database, 1898 & Co. utilized historical weather event information from NOAA's weather event database (1998-2025) and DTE's historical outage records (2007-2025) to ascertain the frequency and impact of events, as outlined in Section 3.0.

4.3.3.2 System Vulnerability & Event Impact Module

The System Vulnerability & Event Impact Module developed a list of potential resilience-related investment activities, their costs, and their effectiveness in mitigating weather-event-related costs. The evaluation comprehensively evaluated multiple investment activities, e.g., overhead rebuilds, pole and pole-top inspections, across nearly the entire system. Investment activities were defined and evaluated at the protection zone (or similar) level. The module also estimated the costs of each resilience-related investment activity.

The module evaluated the impact of major weather events on the system. Specifically, it identified, from an asset-centric perspective, that each protection zone's likelihood of experiencing a failure during each of the weather events included in the Major Events Database. This protection-zone-level likelihood was based largely on asset types, quantities, and ages, along with other condition information, e.g., vegetation density. This reflects the primary driver of protection-zone failures during weather events; wind blows vegetation (and other debris) into assets, placing additional stress on assets, leading to individual structure and then protection-zone failures.

The module estimated the restoration costs associated with the specific failures and calculated the CMI impact. The model calculated weather-event restoration costs using asset-level, planned-replacement costs scaled to reflect the additional costs associated with reactive replacement. The cost scalars were based on historical weather-event data, expected inventory constraints, and the anticipated blend of DTE and non-DTE crews required for the various asset types and weather events. For each weather event, asset-level restoration costs were aggregated up to the protection-zone (or similar) level. Recall that, for the distribution system, investment activities were organized at the protection zone level.

The module calculated the expected duration of an outage using a restoration curve that identified the overall length of an outage based on the total number of protection zones experiencing the outage. The greater the number of protection

zones experiencing the outage, the longer the overall outage duration. After identifying the overall outage duration, individual-protection-zone outage durations were assigned, with higher-priority zones (i.e., those with more customers and those higher in the electrical hierarchy) receiving shorter durations and lower-priority zones receiving longer durations. In the Investment scenario, outages had shorter durations, when compared to outage durations in the Status Quo scenario. In the Investment scenario, investment activities reduced the number of protection zones experiencing an outage due to an individual weather event, leading to shorter overall outage durations and correspondingly shorter protection-zone-outage durations.

A protection zone's outage duration was then multiplied by the zone's numbers and types of affected customers to obtain a CMI value for the outage. Finally, the CMI for each combination of protection zone, scenario and weather event was monetized using the ICE Calculator values corresponding to the outage duration and customer types.

At this point, the module calculated storm restoration and CMI costs for each protection zone (or similar), in both the Status Quo and the Investment scenarios, for each of the NOAA-derived weather events. The difference between an investment activity's weather-event Status Quo and Investment costs was the benefit of the activity in the presence of that weather event. The module's final output was this collection of weather- and investment-activity-specific Status Quo and Investment scenario costs.

In summary, the System Vulnerability & Event Impact Module utilized a robust and sophisticated set of data and algorithms to model the benefits of each resilience investment activity in the presence of each weather event.

4.3.3.3 Resilience Benefit Module

The benefits of resilience investment activities were driven by the frequency, type and location of future weather events. Each weather-event type had a range of potential likelihoods and consequences. For this reason, the Resilience Benefit Module employed Monte Carlo simulation. The Monte Carlo simulation randomly generated

weather events to impact the DTE service area over a number of 50-year weather futures. These random weather events were based on the weather-event frequencies from the Major Event Database. Recall that the database contained the historical record of weather events that have impacted the DTE service area in the past and, therefore, could be expected to impact the service area in the future. The Monte Carlo simulation considered each county individually, generating that county's future weather events based on that county's historical record.

For each randomly generated weather event in each of the weather futures, the Resilience Benefit Module determined the benefits generated by individual investment activities associated with each protection zone (or similar system element) that would have been affected by the weather event. Recall that the benefit of an investment activity was the difference between the associated protection zone's Status Quo scenario costs and its Investment scenario costs.

The Resilience Benefit Module incorporated a discounted cash flow methodology to aggregate the costs and benefits for each investment activity over each weather future's 50-year time horizon. This reflected that future avoided costs are less valuable than the current avoided costs.

Finally, the module consolidated results from the individual weather futures to produce a single, statistical expectation of each investment activity's cost and benefit values. This consolidation captured values from an expected, a high and an extreme weather future, i.e., the 50th, 75th and 95th percentile weather futures. Among the three futures, the majority of the emphasis went to the expected future, while the least emphasis went to the extreme. These key cost and benefit values were utilized within the Plan Development Module to provide a comprehensive, customer-centric, value-driven assessment.

4.4 Equipment Failure Mitigation Modeling Approach

The Equipment Failure Mitigation modeling approach calculates the benefits of replacing existing infrastructure. It utilizes a resilience, reliability, and risk-based planning approach to forecast the probability-weighted consequence of failure for a range of failure types. The failure types are based on how assets fail over their life-

cycle, including inspection-based failures. Consequences are estimated for a range of factors but fall into two main categories:

1) The first category is avoided reactive costs, also called restoration benefits. These are costs avoided by the utility through the replacement of an existing asset, thereby avoiding any remaining material costs of failure associated with the remaining lifespan of that asset.
2) The second category is customer-based outages. This category is the monetization of customer outages in the event of an asset failure based on the ICE calculator described in Section 4.2 above.

The approach calculates each asset's life-cycle reactive 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, comparing the avoided resilience, reliability, and risk life-cycle costs of the Investment scenario to the same costs of the Status Quo scenario.

The equipment failure mitigation modeling approach was the sole model used to evaluate the BCA for the following programs:

1) URD Replacement
2) Cable Replacement, and
3) Breaker Replacement

The model was also used to estimate the non-weather event portion of benefits for the following programs:

1. PTMM
2. Small Wire Replacement Program
3. Subtransmission Redesign and Rebuild, and
4. 4.8 kV and 8.3 kV Conversion Programs

For these investments, the weather-related benefits were estimated using the Resilience Modeling Approach (Section 4.3). The non-weather-related benefits, derived from the Equipment Failure Mitigation Model, and the weather event benefits, derived from the Resilience Model, are then combined and normalized as described in Section 4.7. The Communication network BCA leveraged the Probability of Survival approach to analyze replacement of edge devices. The following sub-sections outline the Equipment Failure Mitigation Modeling Approach in further detail. A 40-year-old oil distribution breaker is used as an illustrative example in the approach to demonstrate benefit calculations.

4.4.1 Probability of Surviving

Many of the asset classes on DTE's system are typically replaced before failure-causing outages. This replacement is because the consequence of failure typically exceeds utilities' risk tolerance levels, especially safety risks. For this reason, utilities actively inspect the assets, perform testing, and collect real-time condition information. When assets exceed a condition tolerance, they are proactively replaced based on detailed engineering evaluations, budgeting considerations, and prioritization of needs.

End-of-Life curves can be utilized to approximate the probability of an asset not surviving over time. Each asset class modeled was assigned an Iowa Survivor Curve inside the Equipment Failure Mitigation Model. Figure 4-10 shows an example End-of-Life (Iowa Survivor Curve) for oil distribution circuit breakers. These breakers are expected to have an average service life of 45 years, as modeled. Figure 4-11 shows the approach to calculate the annual probability of not surviving for a 40-year-old oil distribution circuit breaker asset.

Figure 4-10: Example Survivor Curve for Oil Distribution Circuit Breakers

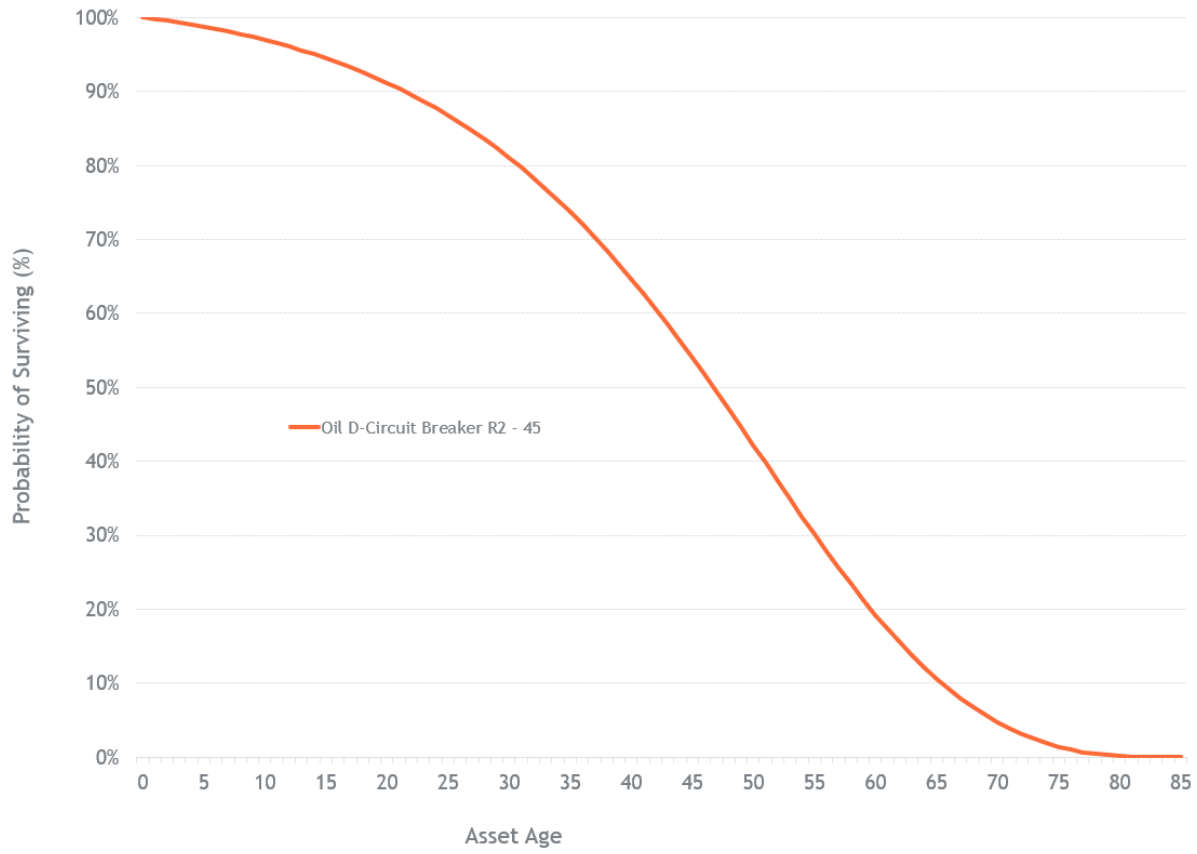
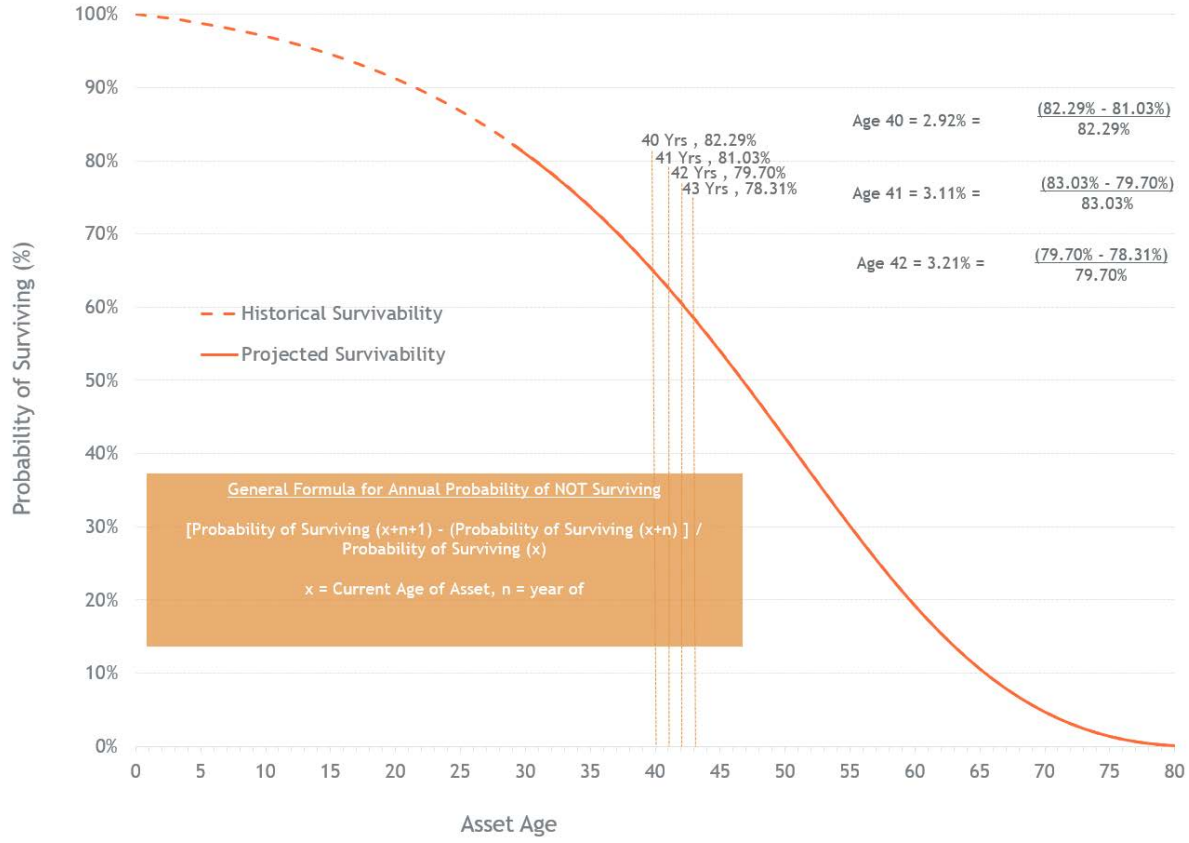


Figure 4-11: Annual Probability of Not Surviving Example - Oil Distribution Circuit Breaker



The survivor curves allow for the calculation of the annual probability of an asset not surviving over time. The curves produce a probability density function where the total probability is 100%. The curves are then used to forecast the probability of an asset not surviving at the asset's age. Figure 4-12 shows the annual probability of not surviving for a range of ages for an oil distribution circuit breaker based on the mathematical approach shown in Figure 4-11. The figure illustrates that, as assets get older, the 100% probability of not surviving each successive year is distributed over fewer years, thereby increasing the annual probability of failure for older assets.

Figure 4-12: Survivor Curves to Annual Probability of Not Surviving Profiles for Oil Distribution Breakers

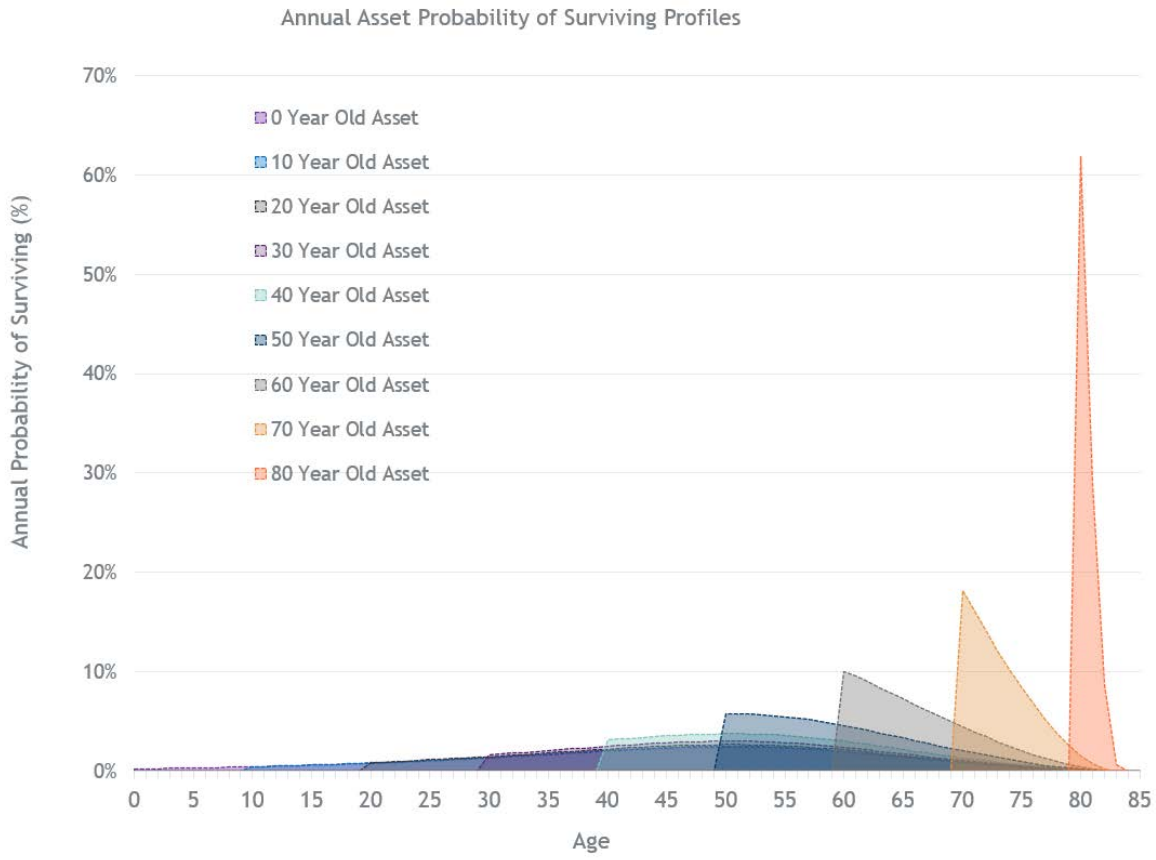


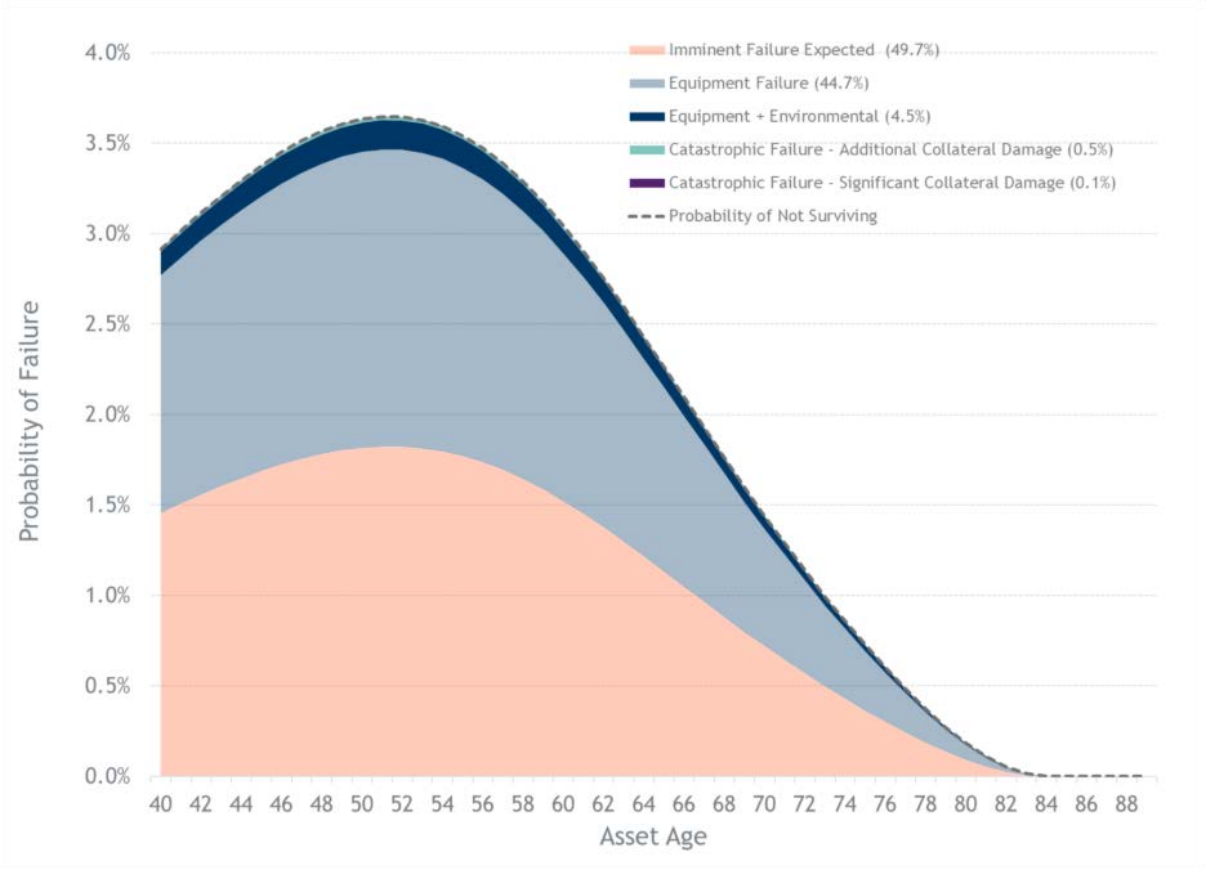
Figure 4-12 also shows the probability of not surviving at each age (Probability of Not Surviving at Age X). Each asset class survivor curve produces different representative failure rate profiles as an asset ages. Using the assigned survivor curve, the Equipment Failure Mitigation model calculates the probability of not surviving for each asset included in the evaluation.

4.4.2 Failure Types and Probability of Failure

The previous section, Section 4.4.1, described the approach to forecast an asset's annual probability of not surviving over time. Assets regularly fail to survive a year for a wide range of reasons. For example, a breaker may be replaced due to a failed inspection or after a catastrophic failure. 1898 & Co. has developed a library of failure type profiles for T&D infrastructure assets. That library is codified within the

Equipment Failure Analytics Engine, a proprietary and confidential software developed by 1898 & Co. Figure 4-13 illustrates the probability of failure profile for each failure type of an example 40-year-old oil distribution circuit breaker.

Figure 4-13: Failure Types and Probability of Failure for 40-Year-Old Oil Distribution Breaker



For oil distribution circuit breakers, the most common expected failure type is imminent failure expected, where the breaker's condition (known through inspections and testing) does not meet the utility's risk tolerance. As the figure shows, this failure type makes up approximately 50% of how the oil circuit breaker is expected to fail.

4.4.3 Consequence of Failure

For each failure type, the risk framework library inside of the Equipment Failure Mitigation Model includes a range of consequence types based on expected impact

should the asset fail. Table 4-6 shows the range of consequence types evaluated, the asset classes that they apply to, and the avoided cost type. The framework puts a monetary value to each of these consequence factors.

Table 4-6: Consequence Types and Asset Class

Consequence	Avoided Cost Type	Circuit Assets	Substation Assets
Customer Outages	Customer Outage	✓	✓
Equipment Failure Costs	Reactive	✓	✓
Oil Spill Remediation	Reactive	✗	✓
Collateral Damage	Reactive	✗	✓

4.4.3.1 Customer Outage Impact

One of the main consequences of failure across all asset classes is the impact on customers. When assets fail, the protection schemes activate to protect the system against fault currents, limiting customer outages to zones of protection. These protective interventions cause customer outages for the time it takes to restore the system. The relationship between assets and customers was established for all circuit assets as outlined in Section 2.3 above.

For each asset and failure type, the expected duration of the outage was estimated based on typical restoration times. For example, the expected duration to replace a breaker during a typical equipment failure is approximately 1 hour, since crews are likely to be readily available and the replacement work is straightforward. The duration of a catastrophic event is longer, as the potential damage to the breaker itself can require more effort from crews to remove, clean up, and replace. The outage duration for a catastrophic event is estimated at approximately 4 hours for breakers. Based on the expected duration of each failure type for each asset and expected customers impacted (Section 2.3), while also accounting for customer type, the approach calculates the risk-weighted CMI for each asset. This risk-weighted CMI is monetized using the ICE Calculator (see Section 4.2) to estimate each asset's risk-weighted $CMI over time.

4.4.3.2 Equipment Failure Costs

When assets fail before being proactively replaced, it creates an urgency to repair or replace the asset to minimize the impact on the customer. The level of urgency is generally proportional to the failure types outlined in Figure 4-14 below. This urgency results in a level of effort that is not without cost. These additional costs are captured under the category of equipment failure costs. The magnitude of these costs is different depending on the failure type. Crews are generally available during "normal operations" (non-storm) failure types, but capital efficiencies are lost as the mobilization is generally for one asset. During the various weather events or catastrophic failure types, overtime is generally authorized to restore electric power as soon as possible. During these impactful events, crews from neighboring utilities are often utilized to minimize the impact to the customer. These costs can be significant. For these types of events, it is not uncommon for the cost of replacement to be more than double the cost of proactive replacement. Equipment Failure costs were estimated for all asset categories and all failure types. Combined with the annual probability for each failure type, these values are used to calculate the failure cost profiles for all assets.

4.4.3.3 Oil Spill Remediation Costs

Oil is a vital fluid for the functioning of specific substation assets (e.g. oil-filled breakers). The new equipment standard for circuit breaker insulation is gas or vacuum, depending on voltage class. While rare, oil-filled breaker assets can fail with consequences that include significant oil leaks or oil spattering over a sizeable area. This risk increases as the asset ages. Should an asset fail where oil is not contained, the oil spills must be addressed through remediation. The higher the asset capacity rating, the larger the potential remediation costs (i.e., more oil for insulation purposes).

Oil spill remediation costs were probabilistically factored into the analysis for oil-filled breakers. The approach assumed replacement of oil-filled breakers with a vacuum circuit breaker, eliminating oil remediation risk altogether. The resilience, reliability, and risk benefits are twofold: first, decreasing the condition-based age for

the asset; and second, eliminating oil spill risk.

4.4.3.4 Collateral Damage

Substations are an area of high energy transfer. High energy in combination with an asset failure can result in a catastrophic failure that may result in fire or explosion, especially with arcing. The fire or explosion is generally not contained to the asset that failed. The result is collateral damage to other assets within the substation and, in rare circumstances, property outside the substation's boundary. These collateral damage costs can vary significantly from thousands to millions of dollars. As assets age, the probability of this type of failure increases. While statistically rare, these high to extreme costs are factored into the analysis for substation assets.

4.4.4 Status Quo Resilience, Reliability, & Risk Profile

As discussed above, the evaluation calculates the resilience, reliability, & risk cost profile over time for two scenarios, the Status Quo Scenario, and the Investment Scenario. The Status Quo scenario assumes the asset is not proactively replaced and could incur risk costs over time. To calculate the Status Quo Resilience, Reliability, & Risk costs over time, the probability of failure for each failure type is multiplied by the cost consequence for each failure type. Figure 4-14 depicts this approach for a 40-year-old oil distribution breaker example with approximately 1,500 customers downstream. The figure shows the number of residential and C&I customers for this example. Figure 4-15 and Figure 4-16 show the Status Quo Resilience, Reliability, & Risk costs for reactive and restoration costs and customer outage costs, respectively. The profiles are based on multiplying the probabilities of failure in Figure 4-14 by the economic consequence values and applying the escalation and discount rate from above. Figure 4-15 and Figure 4-16 each depict the percentage of total costs for each failure type. Figure 4-17 is the sum of Figure 4-15 and Figure 4-16 for each year, and shows the total resilience, reliability, & risk costs for the 40-year-old oil distribution breaker.

Figure 4-14: Status Quo Resilience, Reliability, & Risk Calculation 40-Year-Old Oil Distribution Breaker

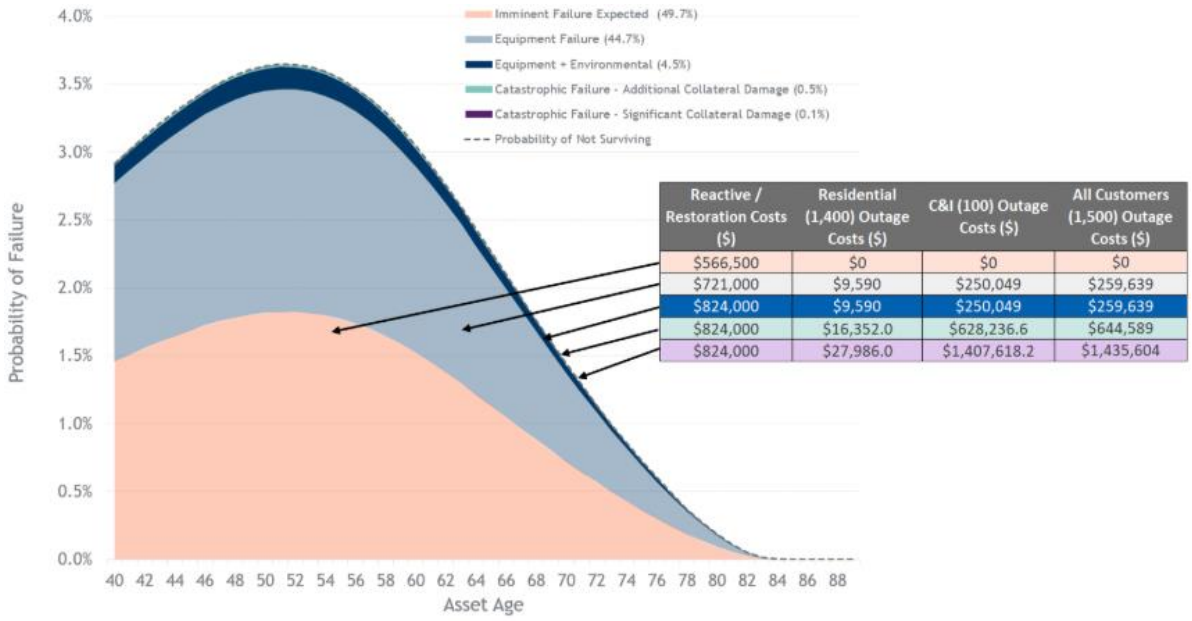


Figure 4-15: Status Quo Reactive Costs Profile - 40-Year-Old Oil Distribution Breaker [Present Value $]

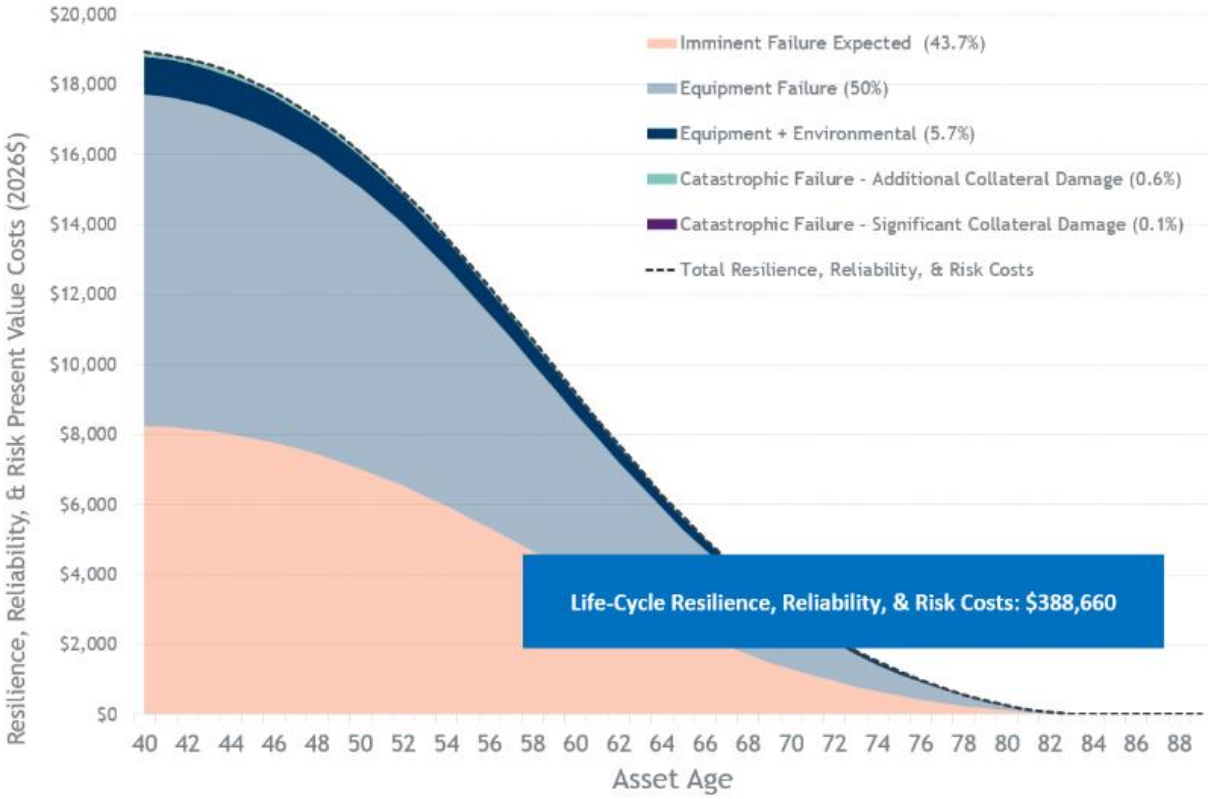


Figure 4-16: Status Quo Customer Costs Profile - 40-Year-Old Oil Distribution Breaker [Present Value $]

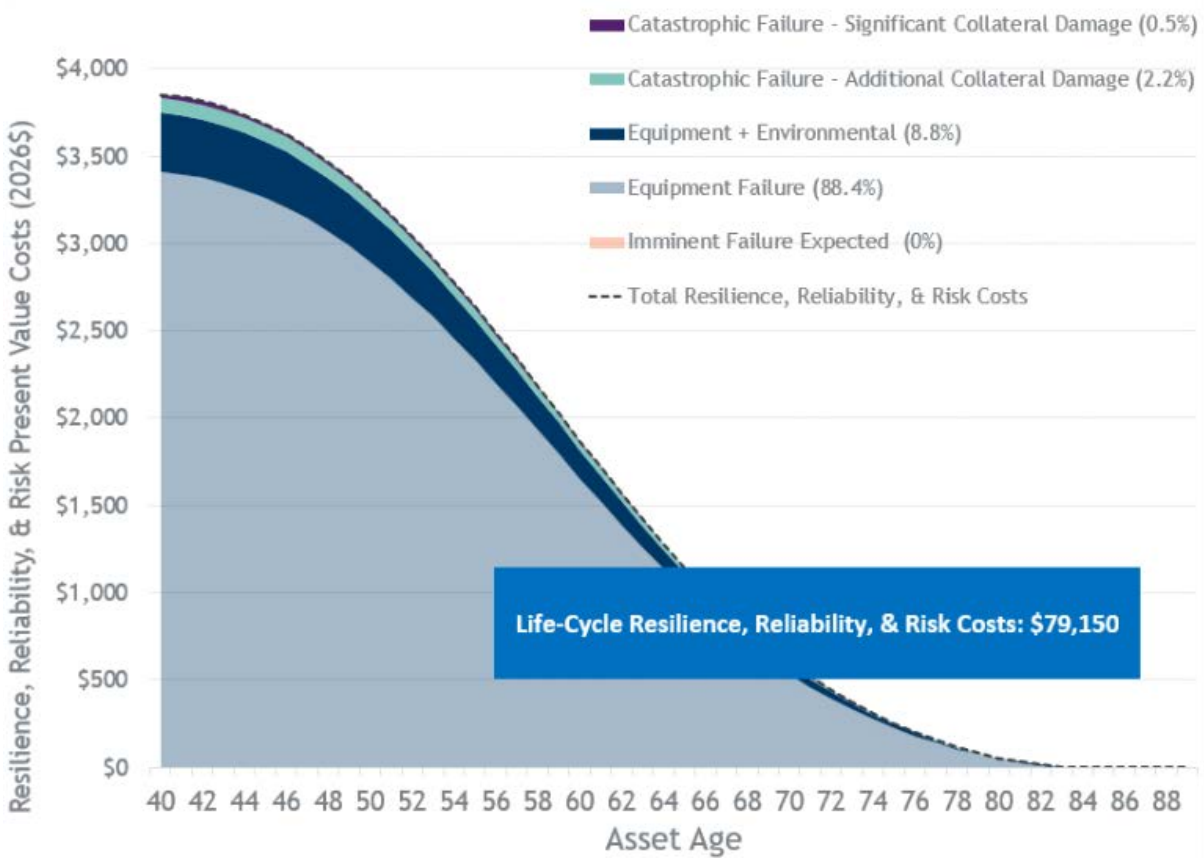
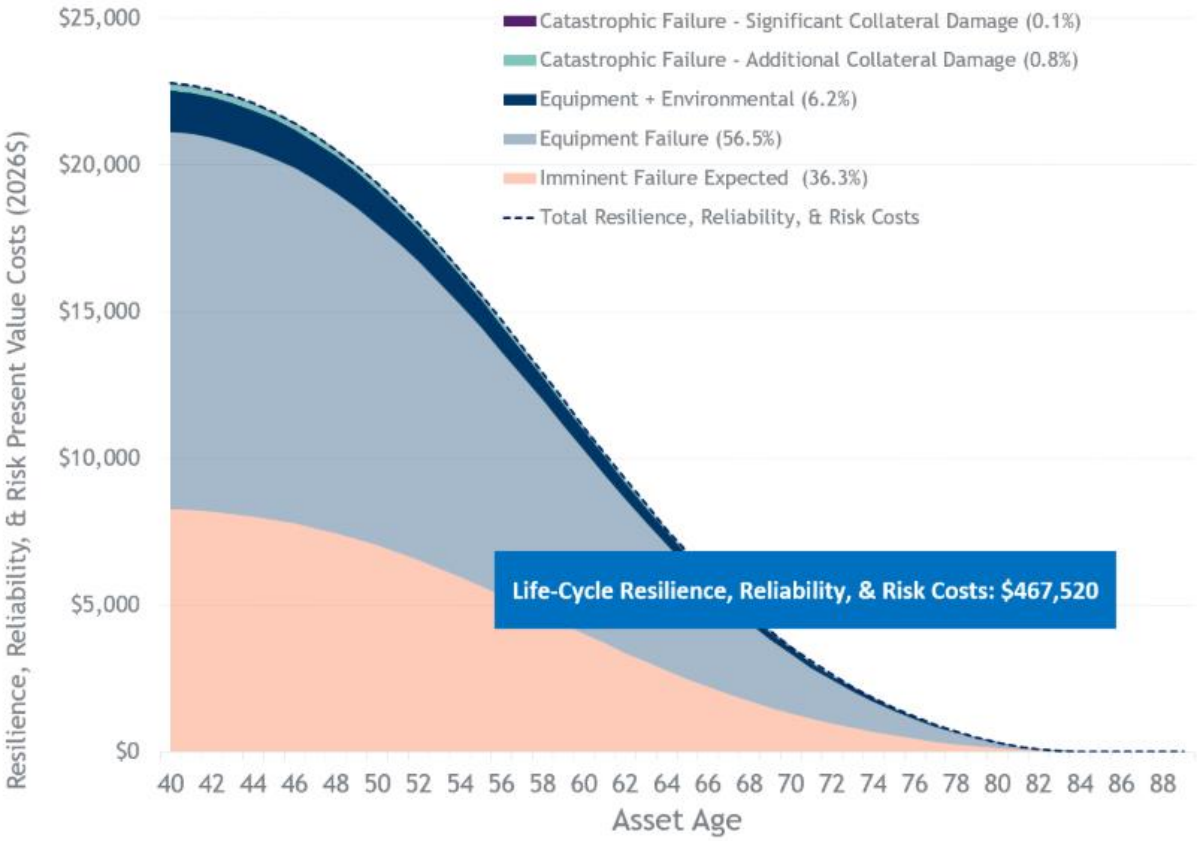


Figure 4-17: Status Quo Total Costs Profile - 40-Year-Old Oil Distribution Breaker [Present Value $]



4.4.5 Avoided Resilience, Reliability, & Risk Cost-Benefit Calculation

The second scenario evaluated for each asset is the Investment Scenario. This scenario assumes the asset is replaced. By replacing the asset, the near-term failure probabilities decrease since the asset is now 0 years old. In some cases, the failure types change with the replacement, such as wood cross arms that are replaced with fiberglass cross arms. The avoided resilience, reliability, & risk benefit for infrastructure upgrades is the difference between the Status Quo and Investment scenarios.

Figure 4-18 and Figure 4-19 show the failure probabilities of the Status Quo and Investment scenarios for the example 40-year-old oil distribution breaker. Over the next 50 years, for the 40-year-old oil distribution breaker, there is a 99% probability of not surviving. If the oil distribution breaker is replaced, there is approximately a

34% probability of not surviving over the same 50-year time horizon. The figures also show the life-cycle probabilities for each failure type.

Figure 4-18: Status Quo Probability of Failure Profiles

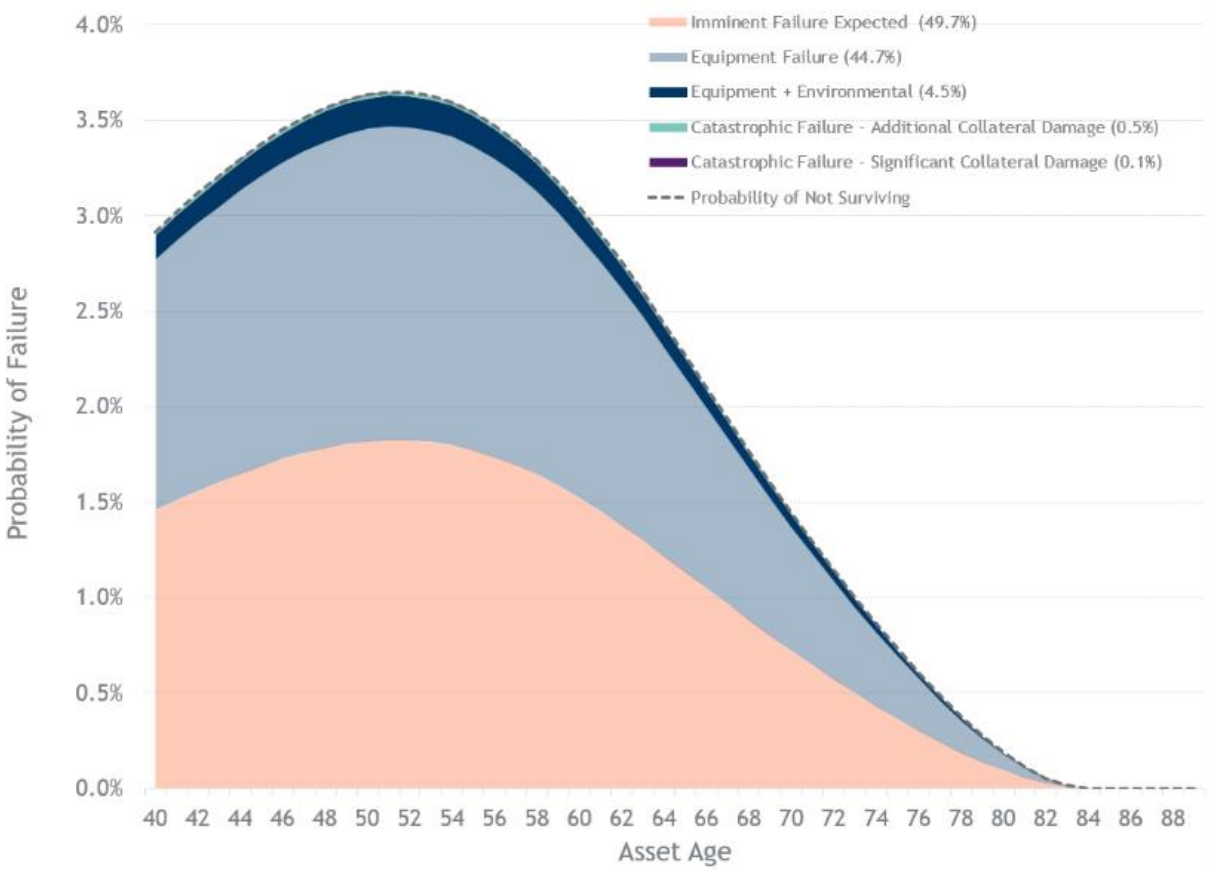


Figure 4-19: Investment Scenario Probability of Failure Profiles

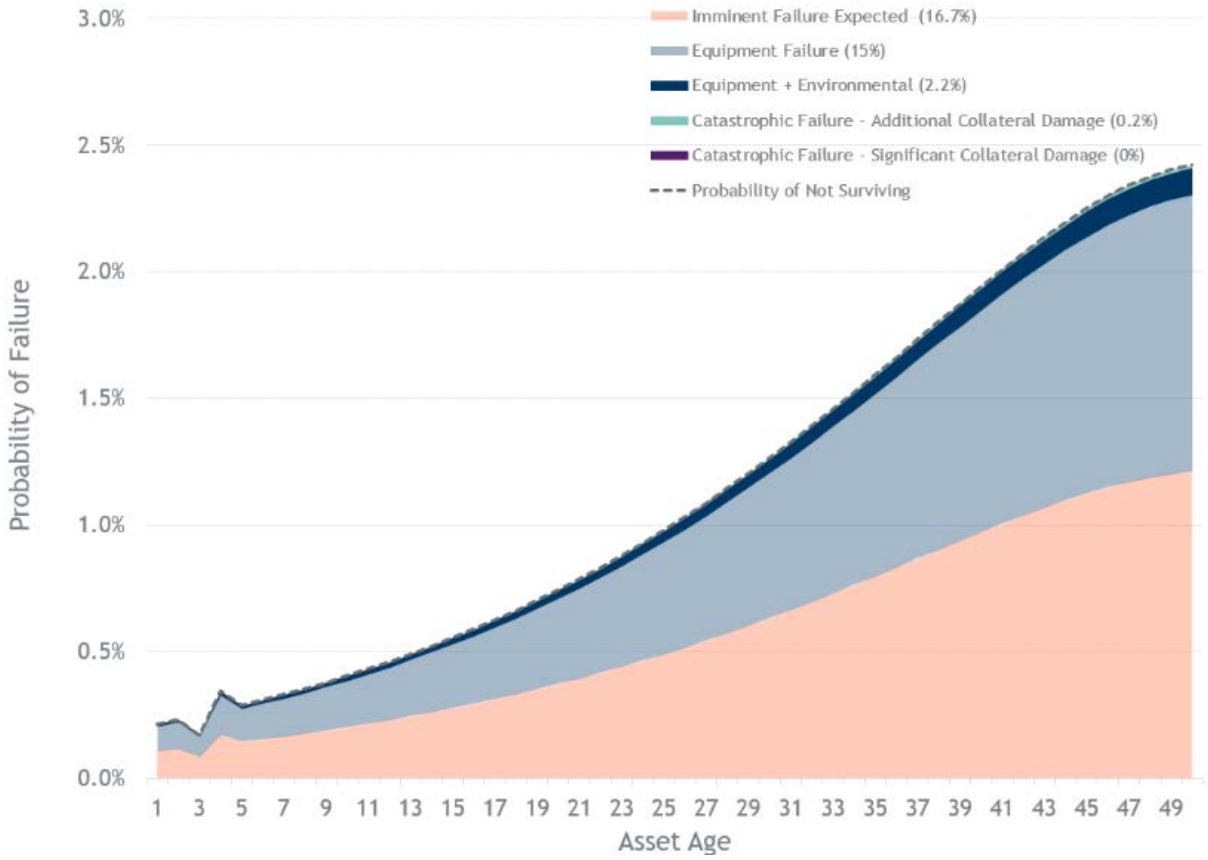


Figure 4-20 and Figure 4-21 show the companion resilience, reliability, and risk cost profiles for the Status Quo and Investment scenarios. Figure 4-22 shows the total values from Figure 4-20 and Figure 4-21 and the annual difference (Status Quo minus Investment). The annual difference is the avoided annual costs for replacing the 40-year-old oil distribution breaker. The life cycle avoided cost benefit is approximately $308,840 (present value dollars) for replacing the oil distribution breaker. If the breaker were younger, the annual avoided costs would turn negative sooner and make the project less beneficial.

Figure 4-20: Status Quo Resilience, Reliability, & Risk Cost Profiles [Present Value $]

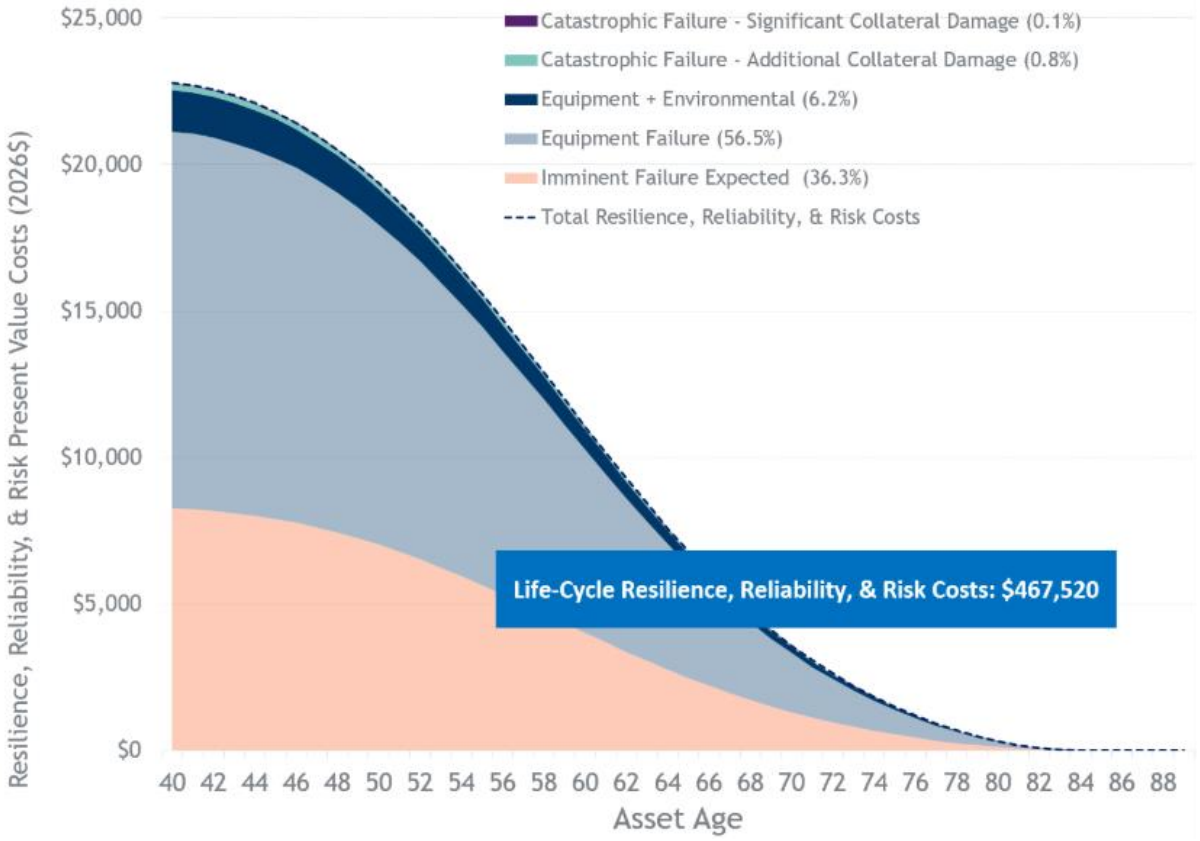


Figure 4-21: Investment Scenario Resilience, Reliability, & Risk Cost Profiles [Present Value $]

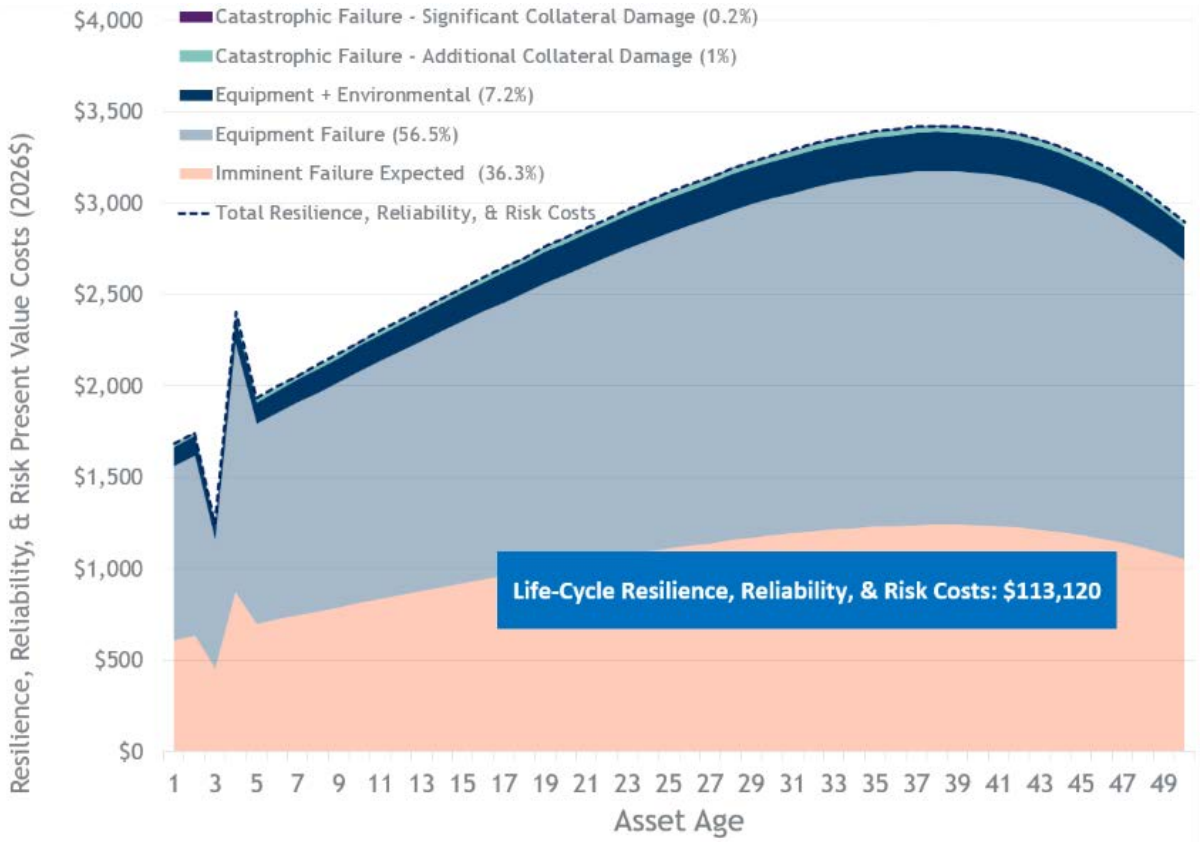
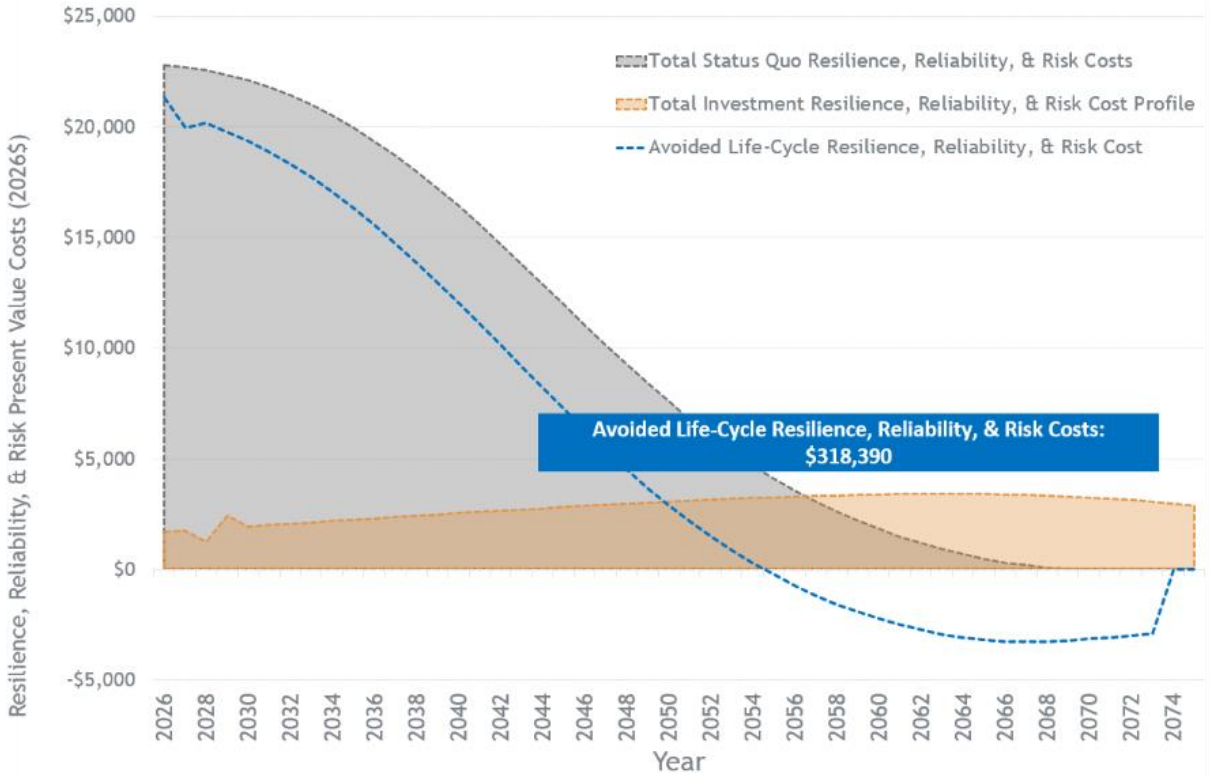


Figure 4-22: Avoided Resilience, Reliability, & Risk Cost-Benefit [Present Value $]



4.5 Outage Mitigation Modeling Approach

The outage mitigation modeling approach calculates the benefits of proposed investments by recalculating historical outage events as if the proposed investments were already in place. The approach is intentionally conservative in that it is grounded in historical outage data and only credits benefits for outages recorded in utility's historical data, instead of considering a full universe of the weather events or climate risk future, as discussed in Section 4.3 Resilience and Risk-Based Planning Approach.

For each outage, the model compares two scenarios. The first is a Status Quo scenario reflecting observed outage performance. The second is the Investment scenario, in which the proposed investments are assumed to be in place. The benefit of the investment is the difference between the two scenarios, measured as avoided

customer minutes interrupted. These avoided outage impacts are monetized using the ICE Calculator based on the customer types affected.

The life-cycle present value of avoided customer outages is calculated by applying escalation and discount rates over the life of the investment. This produces a life-cycle present value of benefits that can be directly compared to investment cost through the Benefit-Cost ratio (BCR).

This approach is used for quantifying benefits of the DA program and evaluates the benefits of the following investment activities:

1. Sectionalization
2. Automate Existing Ties
3. Build New Ties

The following sub-sections describe this modeling approach in further detail.

4.5.1 Prepare OMS Data and Customer Types

As discussed above, the outage mitigation modeling benefit approach is data centric. The core data used for this analysis is the historical outage records provided by DTE (described in Section 2.2). To better represent the current system state, the analysis leverages the most recent 5 years (2021-2025) of DTE's 19 years of outage records. The recent OMS data reflects customer experience under the current configuration of the distribution system, including manual and automated switching capabilities, current crew response practices, and recent investments that impact reliability such as vegetation management and PTMM.

This approach conservatively assumes that future outages will be similar to those observed in the past 5 years. The quantified benefits may understate future outage risk because they are grounded in historical outage data. As a result, they do not account for the possibility of more severe future outages driven by increasing climate risk or extreme weather events in the future.

The analysis leveraged the cause descriptions, device type, and system of the outage for identifying the outages that can be mitigated by investments in distribution

automation. Identifying which outages can be mitigated by DA (and which outages cannot) provides confidence that benefits are not overstated.

As described in Section 2.3, DTE provided customer-type information with database ties to DTE's GIS and OMS. Using this information, 1898 & Co. linked the type of customers impacted on each of the outages in the OMS. This data allows for the monetization of outages using the ICE calculator to evaluate the economic impact of customer outages for different customer types.

4.5.2 Mitigated Outage Calculations

This section outlines the general approach to re-calculating the outage records to quantify customer benefit. The DA program has impact on customer outages in two major ways:

1. Sectionalization
2. Automate Existing Ties & Build New Ties

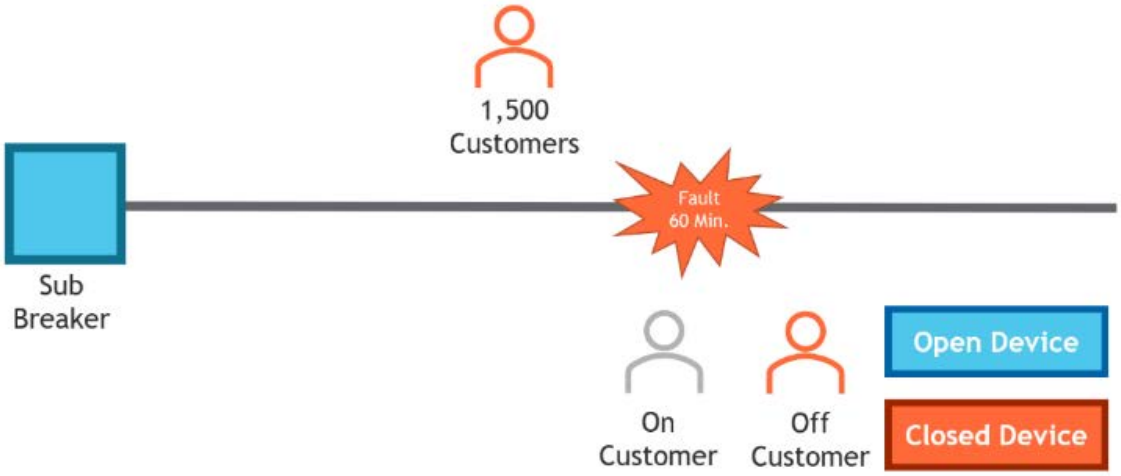
4.5.2.1 Sectionalization

1898 & Co. calculated the benefits associated with investing in reclosers to increase the sectionalization of distribution circuits across DTE's system. By increasing the sectionalization of a circuit, the customer impact from outages can be mitigated by isolating outage-causing faults using a recloser instead of a breaker or further upstream device. The model recalculates the outage assuming that sectionalizing reclosers had been in place and uses the ICE calculator to monetize the new customer outage impact.

The model identifies outages on the mainline of the circuit (not on fused laterals or the secondary system) that are candidates for sectionalization improvement from adding reclosers. The model assumes that secondary and lateral outages do not benefit from adding a sectionalizing recloser. However, DTE uses a "fuse-saving" protection philosophy, and some lateral outages may in practice avoid a sustained interruption. The benefits of avoiding a sustained outage on laterals and the associated avoided truck roll are not quantified in the model.

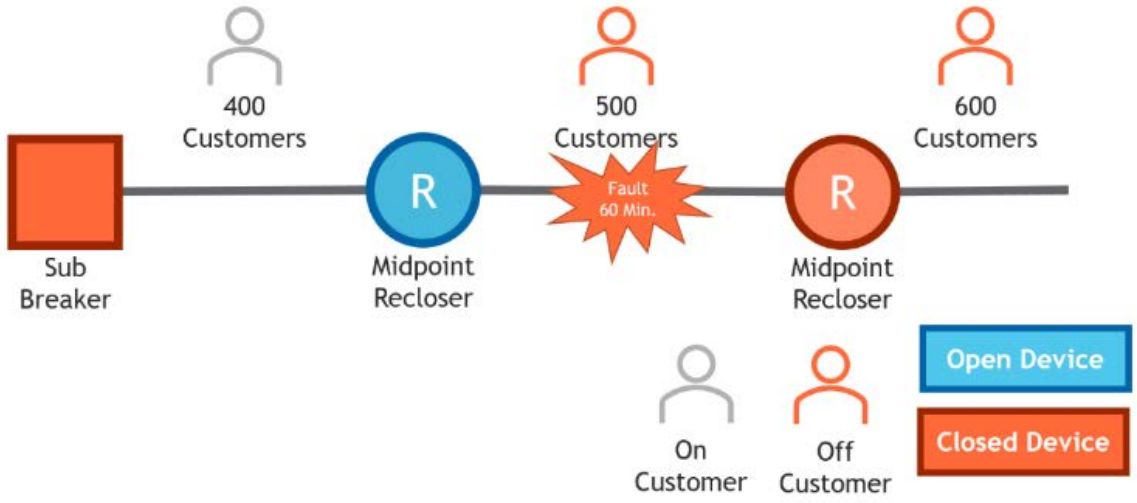
Figure 4-23 and Figure 4-24 represent a simplified diagram of a circuit before and after investing in sectionalization. Without sectionalizing reclosers, a fault on the mainline of the circuit requires the breaker to operate, and all 1,500 customers downstream from the breaker experience an outage. In this example, crews take 60 minutes to identify the outage location, clear the outage, and restore power. 1,500 CI for 60 minutes results in 90,000 CMI for the event.

Figure 4-23: Simplified Outage Example without Sectionalizing Reclosers



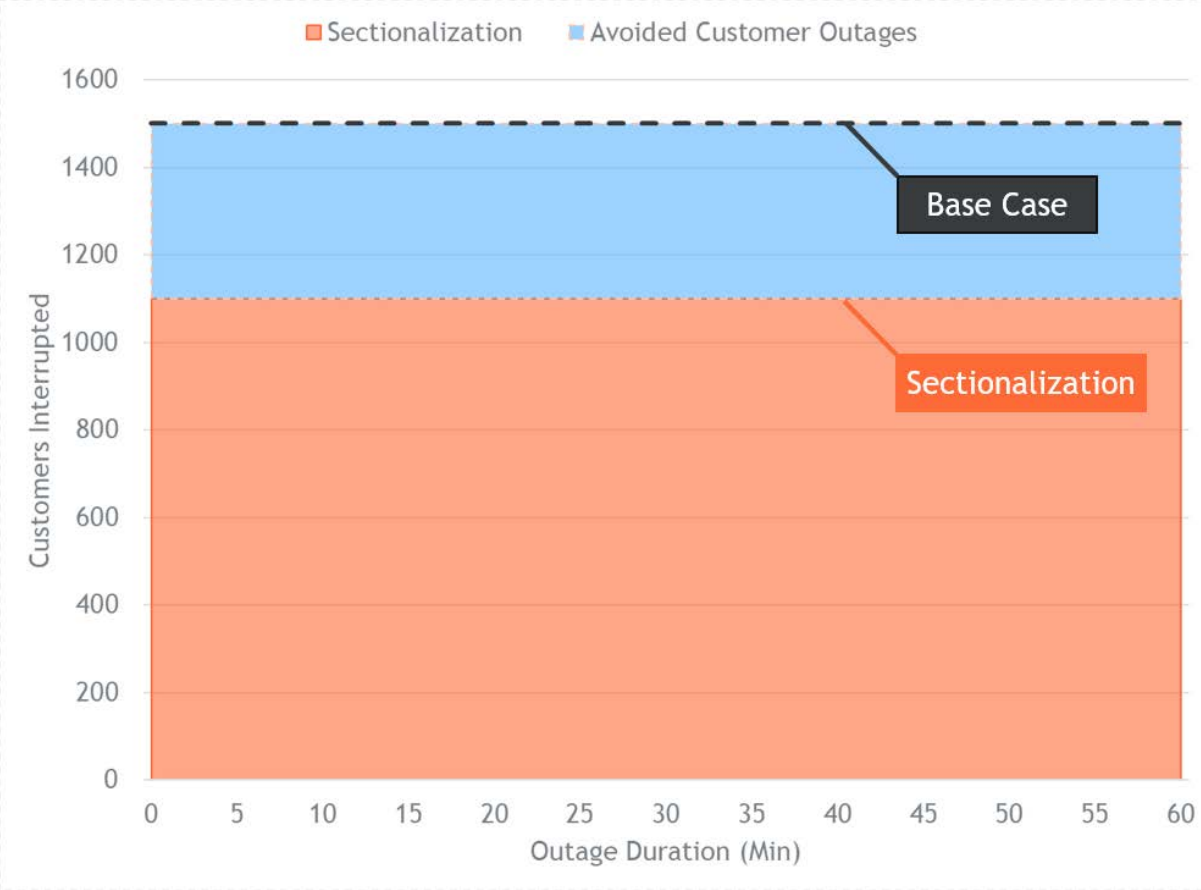
In the investment scenario for sectionalizing reclosers, shown below, a recloser isolates the fault. Due to the sectionalization afforded by the midpoint recloser, the 400 customers upstream of the recloser do not experience an outage. Only 1,100 customers are impacted in this scenario, with a resulting CMI of 66,000 (1,100 CI x 60 minutes). While there is likely improved response speed due to the known locations of the reclosing devices, the model conservatively assumes the job duration will remain the same as in the Status Quo scenario. Additionally, the model takes a weighted average of the CI to account for the fact that some faults will continue to occur upstream of any new reclosers and result in a breaker operation.

Figure 4-24: Simplified Outage Example with Investment in Sectionalizing Reclosers



The figure below shows the avoided CMI between the two scenarios. The blue section represents the avoided customer outages, which represents the customer benefit due to sectionalization. This avoided CMI is monetized using the ICE Calculator, which drives the customer benefits from investing in sectionalization.

Figure 4-25: Example of Sectionalization Benefit



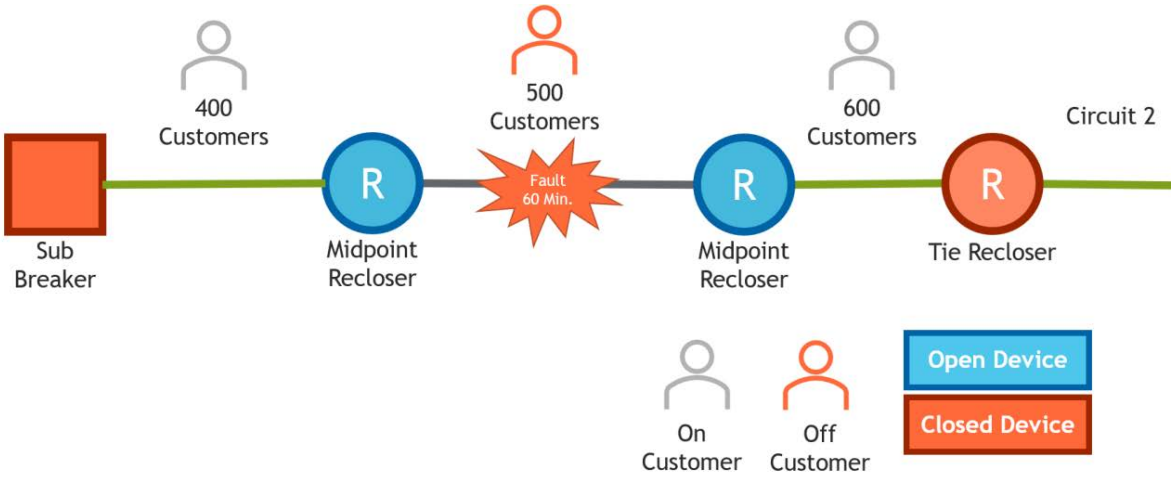
4.5.2.2 Automate Existing and Build New Ties

1898 & Co.'s Outage Mitigation Model assesses the benefits of investing in automated ties, necessary communication systems, and new tie construction to improve system flexibility and outage recovery. Based on the mapping of new devices to the OMS, 1898 & Co. recalculated the impact of mainline outages assuming the new customer count in each sectionalization pod and transferring customers not within the faulted pod to the adjacent circuit.

Figure 4-26 shows a simplified example of a circuit with reclosers added to support an Automate Ties scheme. This example represents the same 60-minute outage that occurs on a feeder with 1,500 customers downstream of the substation breaker. In this example, the fault is detected by the most upstream recloser, which operates and disconnects the 1,100 customers downstream of it. As a result of investment in

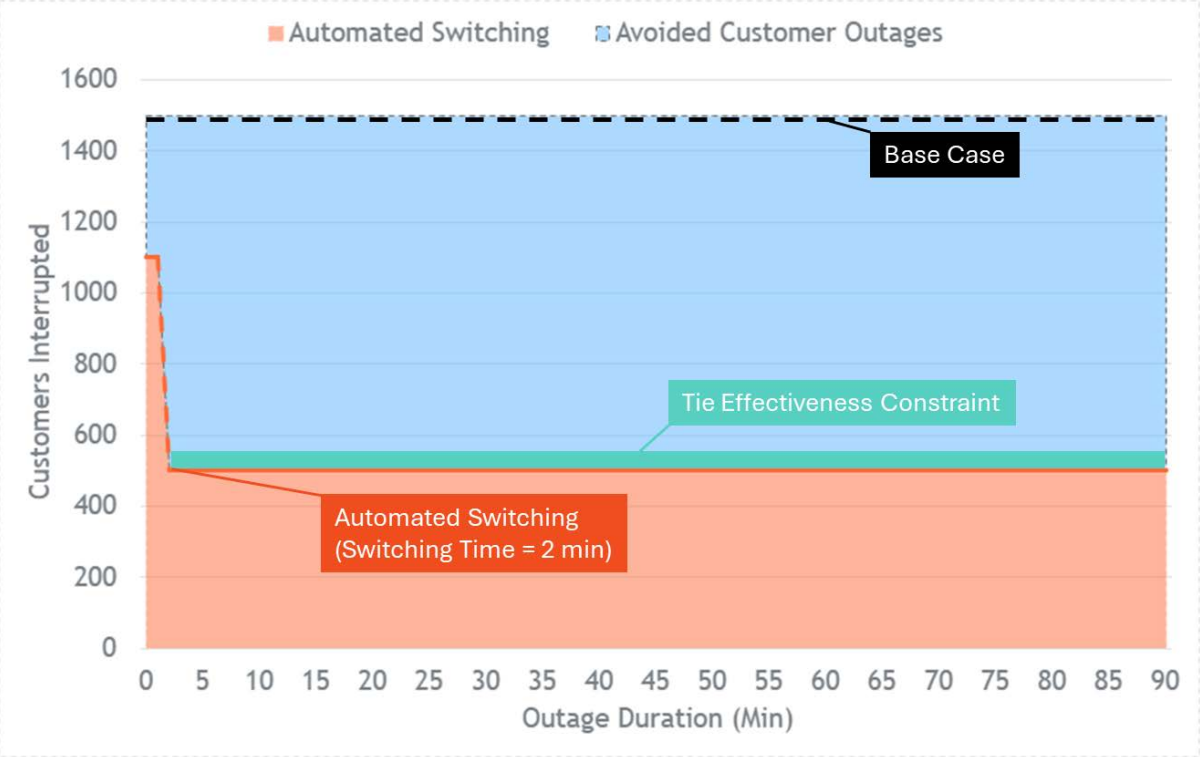
automated ties, the sectionalizing recloser downstream of the fault opens, and the tie recloser to an adjacent circuit closes. This allows the pod of customers downstream of the faulted pod to only experience a momentary outage and be restored within the automated switching time.

Figure 4-26: Simplified Diagram of Circuit with Automate Ties Scheme



It should be noted that the original number of customers impacted, and the duration of the entire outage is the same. The difference is in the ability to restore customers through automating ties rather than manual back feeding. Figure 4-27 below shows the avoided CMI resulting from investment in sectionalization and an automated tie recloser. The ability to automate ties substantially decreases the overall CMI in this example. The black dotted line represents the CMI without any Distribution Automation Program investment. The orange dotted line represents the CMI assuming distribution automation was fully effective.

Figure 4-27: Mainline Outage Profile with Sectionalization and Automated Tie



During major events, these investments may not operate if the supporting infrastructure (*e.g.*, tie lines and neighboring circuits or substations) is impacted. Additionally, during non-major event days, loading or thermal constraints may prevent the automated tie transfer from operating. The analysis applies MED and non-MED effectiveness to conservatively estimate the impact of these factors. The effectiveness of automating ties is shown below in Table 4-7. The impact of the tie effectiveness to the avoided CMI calculations is shown in the teal color shown in Figure 4-27.

Table 4-7: Constraints on Tie Effectiveness

Non-MED Automated Feeder Switching Effectiveness	MED Automated Feeder Switching Effectiveness
95%	80%

By integrating both automated ties and new tie construction into the analysis, the model provides a comprehensive assessment of how enhanced circuit connectivity can

improve system resilience and reliability. These investments create more opportunities for rerouting power, reducing outage duration, and ultimately lowering CMI across the system.

4.5.3 Normalization, Monetization, and Lifecycle Benefits Calculation

The mitigated outage improvement was normalized to a single year, averaging any significant year-to-year variations on outage types, outage causes, and circuits. The annualized value was then monetized using the ICE Calculator (detailed in Section 4.2) and customer profile for each outage. Applying escalation, a discount rate, and a 20-year expected useful life for the investments, the life-cycle benefit was calculated for each outage event and rolled up to the circuit level.

4.6 Qualitative Approach

The previous sections have outlined the methods used to quantify the benefits of specific investments within the Benefit-Cost Analysis framework. However, it is difficult to fully capture and monetize every factor that may influence an investment decision. As a result, qualitative considerations remain an important part of the overall evaluation. In general, these qualitative considerations fall into the following categories:

- Economic stability and attractiveness,
- Customer anxiety,
- Bolstering performance for lower performing areas (i.e. Customers Experiencing Multiple Interruptions) and disadvantaged communities.
- Safety and security,
- Capacity expansion to meet customer needs and improve operability and constructability including contingency (N-1)

Reliability and resilience investments support economic activity by helping businesses operate more consistently and making communities more attractive to residents and employers. These investments can also reduce customer anxiety and hardship associated with frequent or prolonged outages, particularly for customers who may

already face greater vulnerability during service interruptions. In addition, investments that improve service in lower-performing areas may provide equity-related benefits by helping address localized reliability concerns and improving outcomes for communities that have historically experienced a greater burden of outages. While these benefits are generally recognized as valid considerations in investment planning, they are inherently difficult to quantify directly and were therefore not monetized within 1898 & Co.'s modeling approach.

Safety and security considerations represent another important category of qualitative benefits. Many of the evaluated investments reduce safety risks to both the general public and DTE employees by lowering the likelihood of equipment failure, minimizing hazardous operating conditions, reducing exposure during restoration activities, or improving the ability to respond during major events. Certain investments may also provide broader security or system hardening benefits by improving the system's ability to withstand disruptive conditions. Although these safety- and security-related benefits are important, they are difficult to monetize in a manner that is sufficiently robust and consistent for direct inclusion in the BCR framework. Accordingly, 1898 & Co.'s quantitative evaluation does not directly include separate safety mitigation benefit streams.

Capacity expansion is an important factor in planning for future load and DER growth and enhancing system operability. Performing investments that expand capacity, such as voltage conversion projects and subtransmission redesign and rebuilds, enable the DTE system to reliably and efficiently serve customers now and into the future. These projects are an important part of meeting DTE planning criteria to deliver safe and reliable power. Additionally, investments that improve system capacity benefit the electric grid by reducing system complexity, which improves efficiency during construction work, and mitigating loading impact that can reduce asset life during peak load in the summer.

For this reason, the BCR should be interpreted as a decision-support metric rather than as the sole determinant of whether an investment is warranted. The BCR incorporates a substantial range of quantified benefit streams, but it does not capture

all relevant planning considerations. Therefore, when reviewing results, 1898 & Co. balances the quantified Benefit-Cost outcomes with important unquantified considerations, including safety risk mitigation, customer impacts, and broader strategic or equity-related objectives. As a result, an investment with a BCR ≥ 0.9 is appropriate where significant unquantified benefits are present and where those considerations materially support the investment rationale.

4.7 Model Integration and Calibration

1898 & Co.'s Integrated Resilience, Reliability, & Risk Investment Model incorporates the suite of benefit modeling approaches described above. These modeling approaches work together to create a data-driven and comprehensive BCA framework for evaluating a range of investment programs.

When evaluating multiple investments within the same area of the electric system, it is important to consider interactions among programs. The modeling framework evaluates investment programs in a defined sequence to reflect how multiple investments interact to avoid overstating benefits.

While each modeling approach is validated independently, the integrated suite of models is also calibrated to historical outage data to demonstrate that the framework produces results consistent with recent system reliability. This calibration shows that the Integrated Resilience, Reliability, & Risk Investment Model is grounded in reality and reliable for decision making.

4.7.1 Integrated Sequence of Programs

1898 & Co. conducted BCAs for multiple DTE investment programs. Because these programs affect the same infrastructure and outage mechanisms, the integrated modeling approach evaluates them to avoid attributing the same reliability benefits to multiple programs (i.e., to avoid double-counting benefits).

Electric systems experience a range of reliability challenges, and multiple investment programs can influence the same outage events. For example, a branch contacting an overhead line may cause a fault that results in a customer outage. Several investment programs can affect the likelihood or impact of this event. Vegetation Management

may reduce the likelihood of contact, PTMM may improve the condition and resilience of the infrastructure, and Distribution Automation may reduce the number of customers affected by automatically transferring load.

To account for these interactions, the modeling framework applies a defined sequence for incorporating investment programs. Under this approach, each program is evaluated relative to a baseline that reflects previously modeled investments. This approach allows the benefits attributed to each program to reflect only the incremental reliability improvements associated with that investment.

The modeling framework evaluates the benefits of programs by considering that there is a reduction in outages to account for vegetation management being performed before the BCR of PTMM or DA projects are calculated. The analysis identified outages likely to be avoided by vegetation management (wind- and tree-related) and applied reductions using the estimated tree-trimming effectiveness provided by DTE, for example, a 44% reduction in year 1 after tree trim and declining as years go on. This analysis considered circuits that have had recent investment in vegetation management and did not adjust those outages, as the CMI baseline reflects vegetation management investment.

The PTMM BCA is modeled using the Equipment Failure Mitigation and Resilience models and calibrated so that the Status Quo CMI reflects expected system performance under ongoing vegetation management activities. By utilizing this process, the PTMM evaluation does not attribute benefits already associated with Vegetation Management.

Similarly, the Distribution Automation BCA uses a Status Quo CMI baseline that incorporates expected reduction in benefits from DTE's vegetation management and the improvements analyzed in the PTMM program. As a result, the benefits estimated for Distribution Automation represent incremental improvements beyond those already captured by the preceding programs.

4.7.2 Integrated Model Calibration

The 1898 & Co. Resilience, Reliability, & Risk planning approach considers the broad range of stressors and failure types affecting DTE's overhead and underground systems. To capture this complexity, the analysis integrates the Equipment Failure Mitigation Modeling Approach described in Section 4.4 with the Resilience Modeling Approach described in Section 4.3. Together, these approaches provide a comprehensive view of system risk and expected reliability performance.

This integrated approach is particularly important because electric system reliability is driven by both day-to-day equipment-related outages and larger weather-related outage events. For PTMM, the Equipment Failure Mitigation Modeling Approach represents non-storm-related failures, including blue-sky equipment failures and other asset-driven outage mechanisms. Similarly for PTMM, the Resilience Modeling Approach captures weather-related outages, including major events that can cause significant customer interruption. By combining these approaches, the integrated model captures both routine reliability performance and the effects of storm-related events.

To calibrate the integrated model, 1898 & Co. compared modeled annual Customer Interruptions (CI) and Customer Minutes Interrupted (CMI) to historical outage performance derived from five years of DTE OMS data. The large quantity of historical outage data for distribution system overhead and underground assets allowed for a direct-comparison approach to distribution-system calibration. The limited availability of historical outage data for the subtransmission and substation systems required alternative calibration approaches. For instance, subtransmission-asset failure rates were calibrated to the failure rates for comparable distribution assets, while subtransmission outage durations were calibrated using duration frameworks derived from subtransmission architectures and the available outage data.

For calibration purposes, 1898 & Co. used the five-year average historical CI and CMI as the baseline for expected system performance. Modeled annual CI and CMI results were then compared to these historical values to evaluate how well the integrated framework reproduces observed reliability performance. This approach provides a

practical basis for assessing whether the model produces results consistent with recent system experience and supports the use of the framework in evaluating the incremental benefits of proposed investments.

To distinguish between weather-related and non-weather-related outages, 1898 & Co. separated outage events using an intersection of outage dates from OMS and historical NOAA weather event dates. This allowed the calibration to align non-storm equipment-related outage performance with the Equipment Failure Mitigation Modeling Approach and storm-period outage performance with the Resilience Modeling Approach. In addition, cause code information was used, where appropriate, to align specific model components with observed outage mechanisms.

The calibration process focused primarily on two categories of model inputs: (1) the likelihood that a given failure mechanism results in a customer outage, and (2) the duration of the resulting outage. These calibration levers materially influence modeled CI and CMI and were adjusted within reasonable bounds to better reflect observed system performance over the historical period.

This calibration provides confidence that the integrated modeling framework produces reasonable estimates of customer interruption frequency and duration and does not systematically overstate reliability benefits. As a result, the model provides an appropriate basis for evaluating the relative reliability, resilience, and risk reduction benefits of the investment programs analyzed in this report

5.0 Program Benefit-Cost Analysis Results

This section includes the Benefit-Cost Analysis (BCA) results for each of the programs evaluated by 1898 & Co. The programs analyzed are listed below:

1. Pole and Pole Top Maintenance & Modernization (PTMM)
2. Small Wire Replacement Program
3. URD Replacement Program
4. Cable Replacement Program
5. Breaker Replacement Program
6. Subtransmission SCADA
7. Distribution Automation (DA)
8. Communication Network
9. Subtransmission Redesign and Rebuild
10. 4.8 kV and 8.3 kV Conversion

Assets associated with the Subtransmission Redesign and Rebuild Program and the 4.8 kV and 8.3 kV Conversion Program were excluded from the analyses of the other evaluated programs. Each program section includes important background information, the approach to estimating investment activities and costs, quantified Benefit-Cost results, and qualitative considerations. Lastly, each section outlines how the data outlined in Section 2.0 and 3.0 and benefits modeling approach from Section 4.0 were utilized to estimate costs and benefits.

5.1 PTMM Program

This section includes the Benefit-Cost methodology and results for the PTMM program. The section contains background information on the program and the approach 1898 & Co. utilized to estimate the number and costs of poles and pole tops for replacement. The section also includes the Benefit-Cost results of the program and outlines additional factors for consideration. 1898 & Co. performed a comprehensive Benefit-Cost Analysis across the entire DTE system using the Resilience Event Simulation Model outlined in Section 4.3 and Equipment Failure Mitigation Model methodology outlined in Section 4.4 above. The PTMM program includes two sub-inspection

programs: Groundline Poles and Pole Tops. The Benefit-Cost Analysis was performed for each program separately. A detailed explanation of the inspection program and pole and pole-top reject rate analysis can be found in Section 2.6.

5.1.1 Background & Program Description

Pole inspections play a crucial role in maintaining the reliability and resilience of the power grid. Inspections help understand if utility poles can withstand environmental factors, including extreme weather conditions. This proactive approach enhances the overall resilience and reliability of the power grid, reducing the likelihood of service interruptions and improving the continuous delivery of reliable electricity to communities.

Inspections also contribute to the efficient management of utility assets by enabling early detection of issues, allowing utilities to plan and prioritize maintenance and replacement activities effectively. Utilities can reduce long-term costs and extend the lifespan of utility poles by allocating resources most efficiently. This proactive maintenance strategy supports the sustainable management of utility infrastructure. Regular inspections of utility poles are vital for identifying and addressing structural weaknesses, such as rot, insect damage, and mechanical failures. These weaknesses can compromise the stability of utility poles, posing significant risks of pole collapses. Such incidents can lead to power outages, property damage, and potential injuries. By conducting thorough inspections, utilities can mitigate these risks, ensuring the safety of both the infrastructure and the public.

DTE has enhanced its groundline and pole top inspections to proactively replace aging and defective assets on its system over the past several years. DTE has started planning for 10-year and 5-year cycles for groundline and pole top inspections, respectively. This PTMM Benefit-Cost Analysis has been enhanced to evaluate benefits at the protection zone level for distribution primary, with results then aggregated to the substation level, and at the circuit level for subtransmission, consistent with DTE's execution approach for the program. This refined approach improves the linkage between individual assets, their failure mechanisms, and the customers impacted, while still supporting substation-level planning and decision-making.

While the BCA considered two separate PTMM programs, one groundline and one pole top, Section 5.1.2 begins by describing an overarching groundline-and-pole-top PTMM approach before detailing the individual inspection programs. These individual programs have separate evaluations to reduce the risk of double-counting benefits with the different cycle lengths.

5.1.2 Estimating Investment Activities and Cost

This section outlines the systematic approach employed by 1898 & Co. to identify investment activities for the programs and estimate their expected costs. It begins with an overarching approach to evaluating a consolidated groundline-and-pole-top PTMM program before diverging to discuss the individual programs.

The core element of an overarching PTMM program is the inspection of the pole groundline and top. To model that inspection, the approach treated the overarching inspection as a sequence of decisions and tasks, beginning with the groundline inspection and concluding, as needed, with the pole top inspection.

1. Groundline Inspection
    a. If the pole was less than 10 years old, then no groundline inspection (or pole top inspection) was needed, and no cost was incurred.
    b. If the pole was at least 10 years old, then it received a visual inspection, with an associated cost.
    c. If the pole was at least 20 years old, then it received a second, physical inspection with an additional associated cost.
    d. If the pole failed a visual or a physical groundline inspection, then the inspection results designated the pole for either replacement or for reinforcement, i.e., trussing. Each of the two alternatives had an additional cost.
2. Pole Top Inspection
    a. If the pole failed inspection and was designated for replacement, then the pole top was replaced with the pole. There was no need for pole top inspection, but there was a cost associated with replacing the pole top.

b. If the pole was at least 10 years old and was not designated for replacement, then the pole top received a visual inspection, the cost for which was included in the pole inspection cost.
c. If the pole top failed inspection, then the pole top was replaced with an associated replacement cost.

The following sub-sections provide the approach utilized to identify investment activities and estimate their cost. The groundline-only and pole top-only inspection programs had overlapping elements, so the sum of the groundline-only and pole top-only inspection programs will exceed the cost for an overarching inspection program.

5.1.2.1 Program 1: Groundline Pole Inspection Program

- Investment Activity Identification: 1898 & Co. utilized the GIS data to identify the number of poles on each circuit. These circuits included subtransmission and primary distribution. The expected number of poles to be replaced was based on the age of the pole and the expected reject rate (see Section 2.6). 1898 & Co. utilized the age data from the GIS to estimate pole age (see Section 2.5). Using the historical rejection rates, both non-restorable and restorable, from previous groundline inspections (see Section 2.6), poles were given a probability of failure due to inspection. Based on these rejection rates and specific poles and their ages on each circuit, 1898 & Co. estimated the number of poles expected to fail inspection on each circuit.
- Investment Activity Cost Estimation: The cost to inspect a circuit was based on the number of poles on the circuit and on the average inspection cost per circuit. DTE provided the unit cost for inspection. 1898 & Co. assigned a visual or physical inspection cost for each pole, depending on DTE's inspection standards. These costs were then aggregated to the substation level to determine the distribution PTMM cost and to the circuit level to determine the subtransmission PTMM cost. DTE also provided unit costs to replace poles and to restore poles. 1898 & Co estimated the pole inspection costs by circuit by multiplying each pole's probability of failure (POF) for each rejection type, reject requiring replacement or restoration reject, by these unit costs. The

sum of all the probability-weighted rejection rates and costs for all the poles on the circuit provided the total circuit costs.

5.1.2.2 Program 2: Pole Top Maintenance Program

- Investment Activity Identification: Investment activities for this program follow the same process as the Groundline Pole Inspection Program above. The differences are that this program only looks at pole tops and uses a different set of rejection rates derived from pole top-specific historical inspection data.
- Investment Activity Cost Estimation: Like the activity identification above, the cost estimation for the Pole Top Maintenance Program follows the same process as the Groundline Pole Inspection Program. The only difference is that pole tops will only have a visual inspection cost and no physical inspection cost.

5.1.3 Quantitative Benefit-Cost Results

The following four subsections include the Benefit-Cost results for the Groundline and Pole Top Inspection Programs. 1898 & Co. evaluated this program and sub-programs comprehensively across the entire DTE distribution and subtransmission overhead systems, mapping poles to the upstream protection device to provide a granular linkage of the customers impacted if the pole were to fail. The evaluation organized the benefits and costs of this program at the substation level for distribution and circuit level for subtransmission circuits in alignment with DTE's execution approach for the program and sub-programs. This section includes the quantified benefit results from the analytics models described in Section 4.3 and 4.4. These results assume that:

1) Vegetation management has occurred on all circuits.
2) No Distribution Automation investment activities are occurring on the DTE system.

For ease of representing this level of information, the quantified benefit results are shown on a percentile ranking basis. The ranking is based on the Resilience, Reliability, & Risk BCR.

5.1.3.1 Distribution Groundline Pole Inspection Program

Figure 5-1 includes the expected avoided customer outage benefits for the Distribution PTMM Groundline Program. The figure illustrates the absolute benefit in CMI and the percentage improvement. The figure also includes which substation percentiles have a quantified BCR ≥ 0.9. As the figure shows, approximately 83% of the substation percentile bins shown have quantified benefits with a BCR ≥ 0.9. For these investment activities, the evaluation shows an average expected improvement in CMI of approximately 48%, ranging from 44% to 61%, in the percentile ranking view.

Figure 5-1: Distribution PTMM Groundline Inspection Avoided Customer Outage Benefit

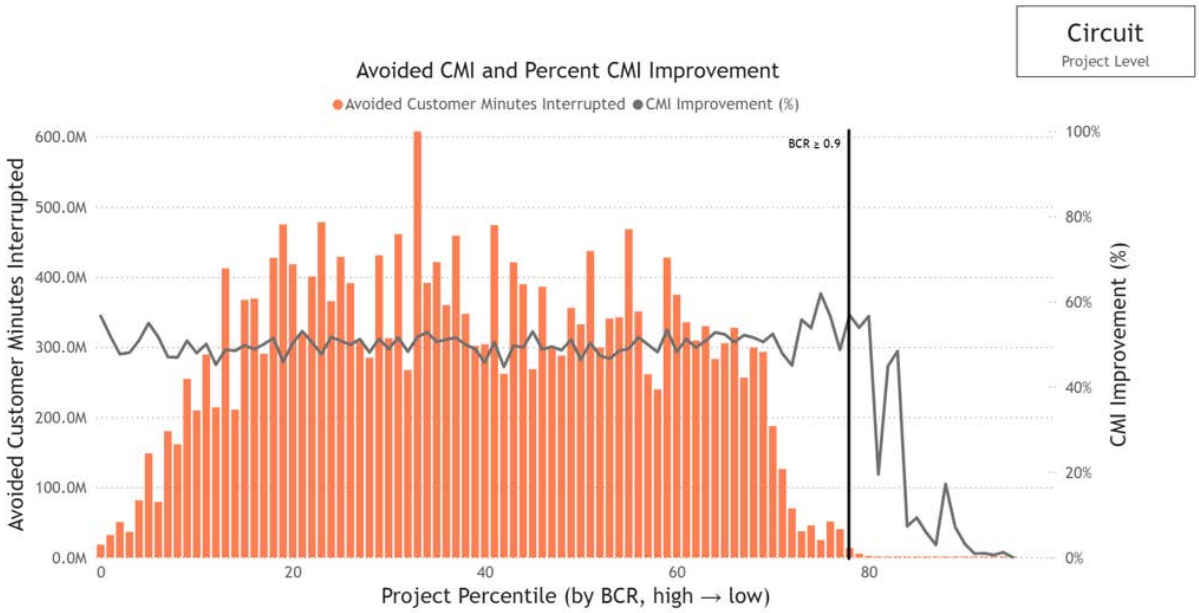


Figure 5-2 uses the CMI benefits shown in Figure 5-1 and applies the ICE Calculator (see Section 4.2) to show monetized CMI, along with the avoided restoration costs for projects at the substation level. It is important to note that the application of the ICE Calculator incorporates the various customer types into the evaluation. This figure shows the total monetized resilience and risk benefits of this program. As the figure shows, most of the quantified benefits are from avoided customer outages. The figure

also includes the expected improvement in monetized customer outages and restoration costs. The substation percentiles with a BCR ≥ 0.9 show an improvement in monetized customer outages of 30% on average, ranging from 23% to 35%, and 46% on average for restoration costs, ranging from 40% to 54%, in the percentile ranking view.

Figure 5-2: Distribution PTMM Groundline Inspection Program Benefits Summary

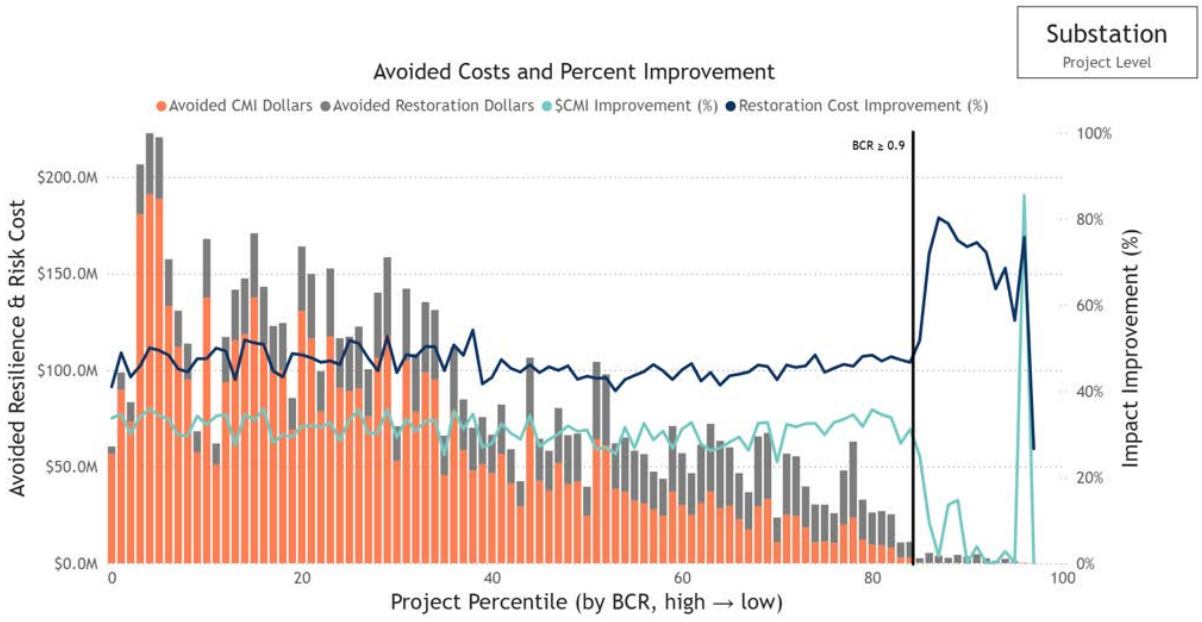
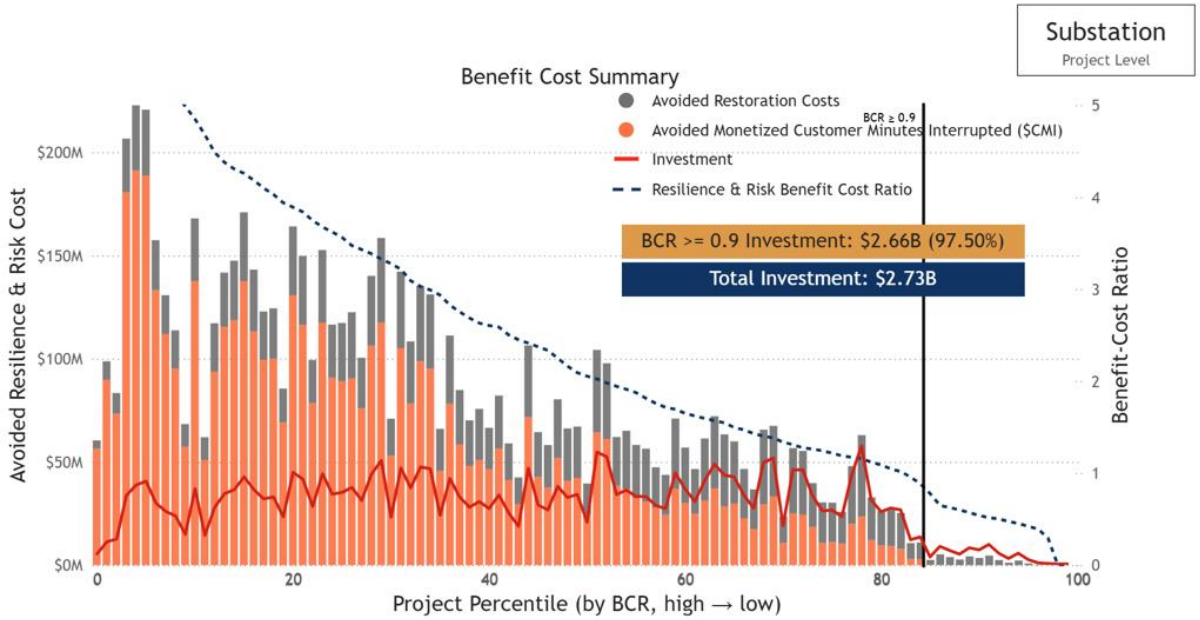


Figure 5-3 takes the benefit results from Figure 5-2 and layers in the expected resiliency investment for each substation to show the Resilience, Reliability, & Risk BCR. Figure 5-3 shows that if this program were applied to the entire DTE distribution system, the overall investment level would be approximately $2.73 billion. The weighted BCR for deploying this program across the entire system is 2.72. The figure shows that approximately $2.66 billion, or 97.5% of the total investment, has a BCR ≥ 0.9. The weighted BCR for deploying this program only on circuits where the BCR ≥ 0.9 is 2.77.

Figure 5-3: Distribution PTMM Groundline Inspection Program BCR Summary



5.1.3.2 *Distribution Pole Top Maintenance Program*

Figure 5-4 includes the expected avoided customer outage benefits for the distribution PTMM pole-top inspection program. The figure consists of the absolute benefit in CMI and the percentage improvement. The figure also includes which substation percentiles have quantified benefits. As the figure shows, approximately 85% of the substation percentiles have quantified benefits with a BCR ≥ 0.9. For these investment activities, the evaluation shows an expected improvement in CMI of approximately 21%, ranging from 15% to 30%, in the percentile ranking view.

Figure 5-4: Distribution PTMM Pole Top Inspection Avoided Customer Outage Benefit

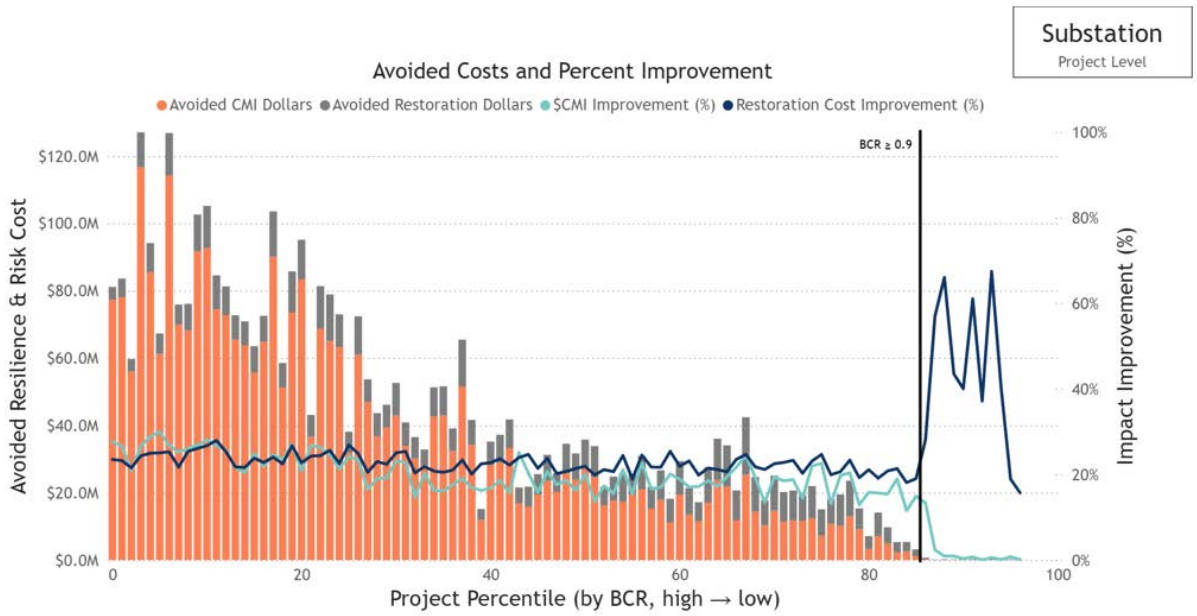


Figure 5-5 takes the CMI benefits from Figure 5-4 and applies the ICE Calculator (see Section 4.2) to monetize the outages and add the avoided restoration costs for each substation. It is important to note that the application of the ICE Calculator incorporates the various customer types into the evaluation. This figure shows the total monetized resilience and risk benefits of this program. Figure 5-5 illustrates that most of the quantified benefits are from avoided customer outages. The figure also includes the expected improvement in monetized customer outages and restoration costs. The substations with a BCR ≥ 0.9 show an improvement in monetized customer outages of 21% on average, ranging from 13% to 30%, and 24% for restoration costs, ranging from 18% to 27%, in the percentile ranking view.

Figure 5-5: Distribution PTMM Pole Top Program Benefits Summary

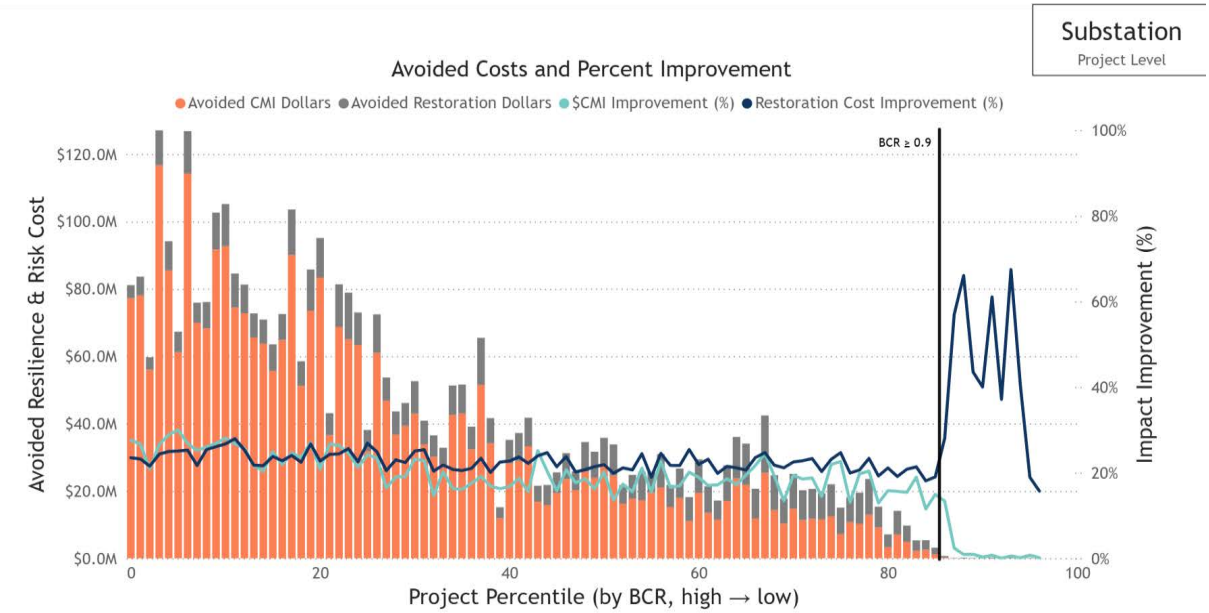
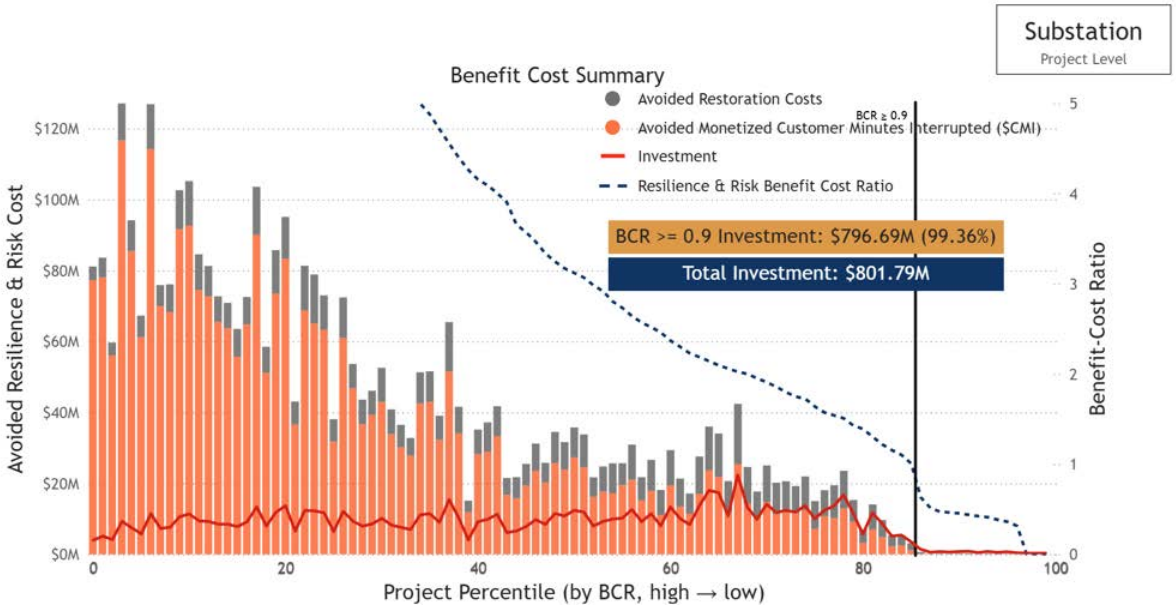


Figure 5-6 takes the benefit results from Figure 5-5 and layers in the expected investment for each substation to show the Resilience, Reliability, & Risk BCR. As the figure shows, if this program were applied to the entire DTE distribution system, the overall investment level would be approximately $801.79 million. The weighted BCR for deploying this program is 4.78. The figure shows that approximately $796.69 million, or 99.36% of the total investment, has a BCR ≥ 0.9. The weighted BCR for deploying this program only on circuits where the BCR ≥ 0.9 is 4.81.

Figure 5-6: Distribution PTMM Pole Top Inspection Program BCR Summary



5.1.3.3 Subtransmission Groundline Pole Inspection Program

Figure 5-7 includes the expected avoided customer outage benefits for the subtransmission PTMM groundline program. The figure illustrates the absolute benefit in CMI and the percentage improvement. The figure also includes which circuit percentiles have quantified benefits with a BCR ≥ 0.9. As the figure shows, approximately 76% of the circuit percentiles shown have a BCR ≥ 0.9. For these circuit percentiles, the evaluation shows an average expected improvement in CMI of approximately 63%, ranging from 21% to 81%, in the percentile ranking view.

Figure 5-7: Subtransmission PTMM Groundline Inspection Avoided Customer Outage Benefit

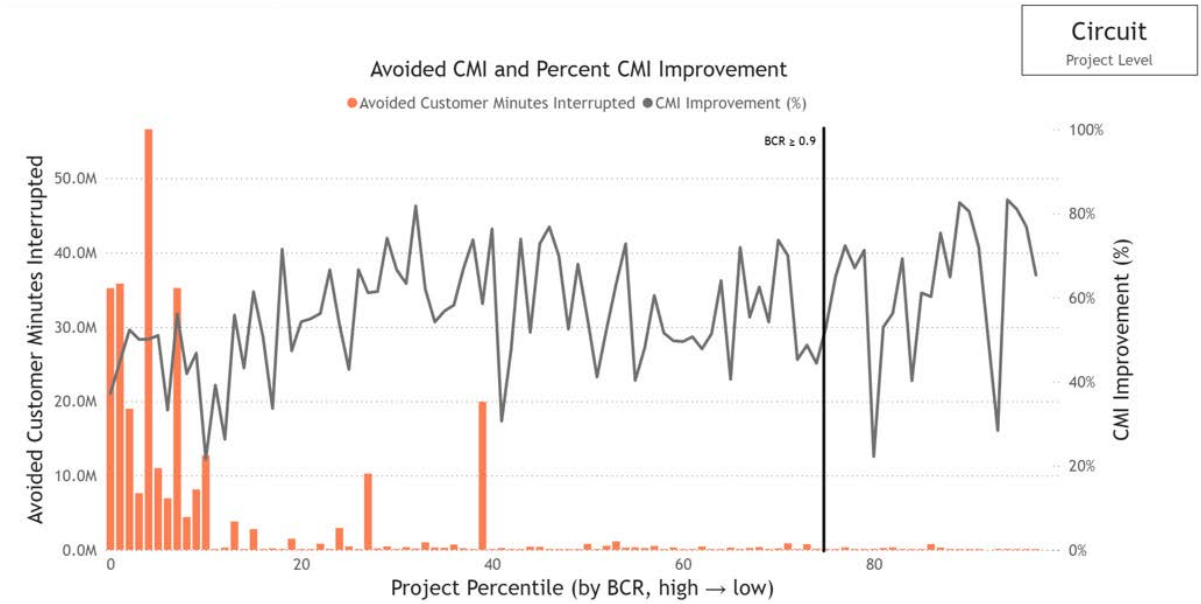


Figure 5-8 takes the CMI benefits from Figure 5-7 and applies the ICE Calculator (see Section 4.2) to monetize the outages and adds the avoided restoration costs for each circuit. It is important to note that the application of the ICE Calculator incorporates the various customer types into the evaluation. This figure shows the total monetized resilience and risk benefits of this program. The figure also includes the expected improvement in monetized customer outages and restoration costs. The circuits with a BCR ≥ 0.9 show an improvement in monetized customer outages of 25% on average, ranging from 7% to 87%, and 51% on average for restoration costs, ranging from 33% to 63%, in the percentile ranking view.

Figure 5-8: Subtransmission PTMM Groundline Inspection Program Benefits Summary

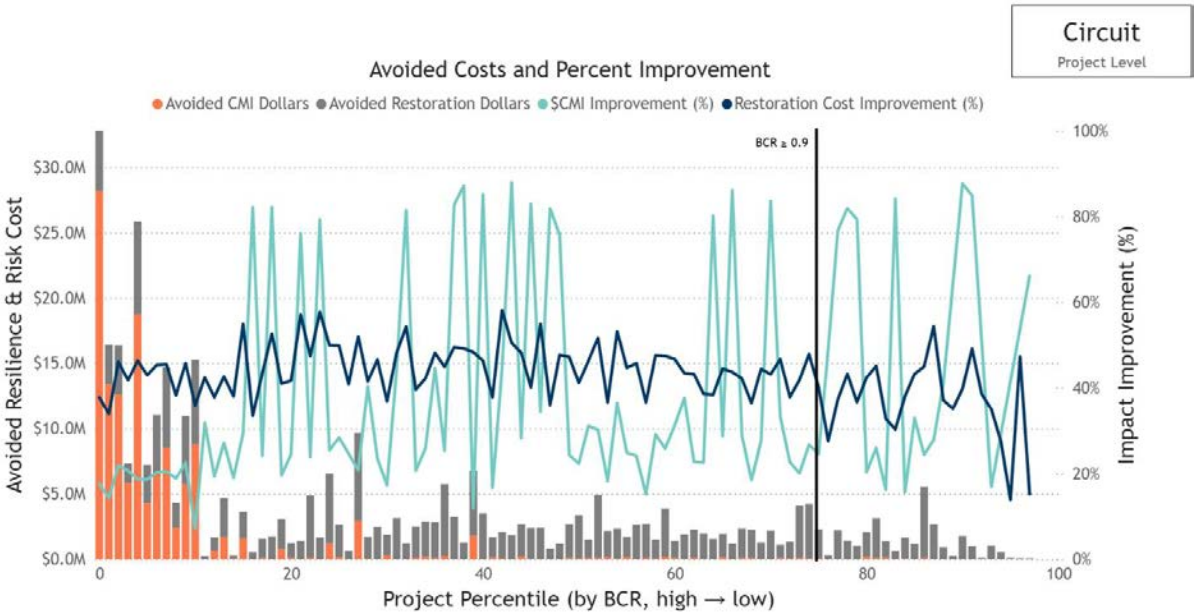
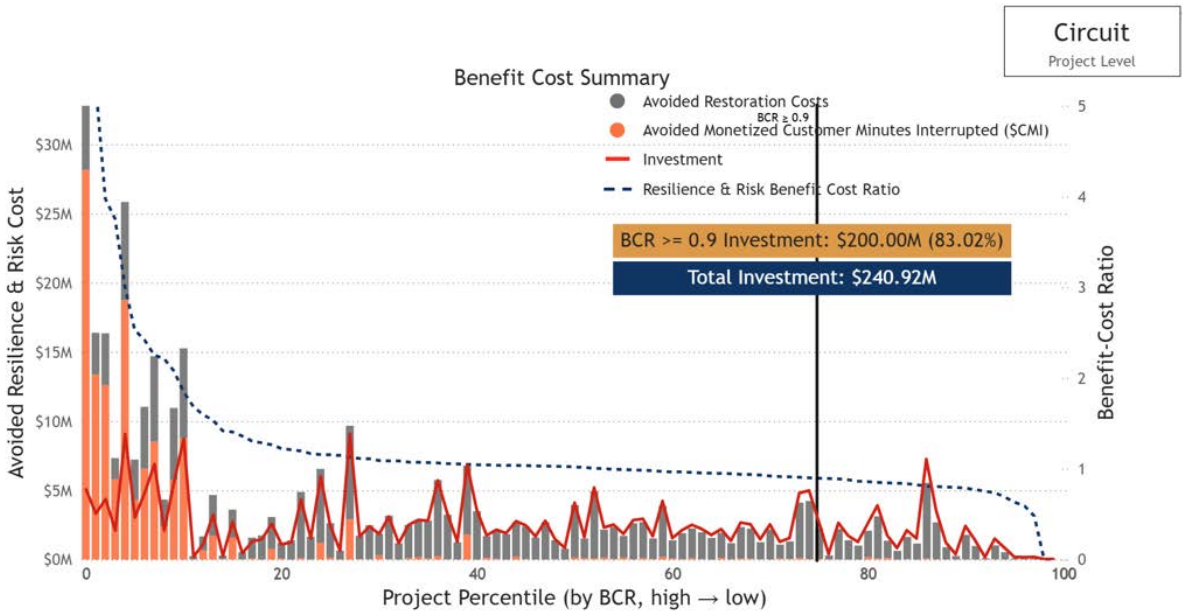


Figure 5-9 takes the benefit results from Figure 5-8 and layers in the expected resiliency investment for each circuit to show the Resilience, Reliability, & Risk BCR. Figure 5-9 depicts that if this program were applied to the entire DTE system, the overall investment level would be approximately $240.92 million. The weighted BCR for deploying this program across the entire system is 1.47. The figure shows that approximately $200 million, or 83% of the total investment level, has a BCR ≥ 0.9. The weighted BCR for deploying this program is only on circuits where the BCR ≥ 0.9 is 1.6.

Figure 5-9: Subtransmission PTMM Groundline Inspection Program BCR Summary



5.1.3.4 Subtransmission Pole Top Maintenance Program

Figure 5-10 includes the expected avoided customer outage benefits for the subtransmission PTMM pole-top inspection program. The figure consists of the absolute benefit in CMI and the percentage improvement. As the figure shows, approximately 49% of the circuit percentiles have quantified BCR ≥ 0.9. For these investment activities, the evaluation shows an expected improvement in CMI of approximately 34%, ranging from 4% to 86%, in the percentile ranking view.

Figure 5-10: Subtransmission PTMM Pole Top Inspection Avoided Customer Outage Benefit

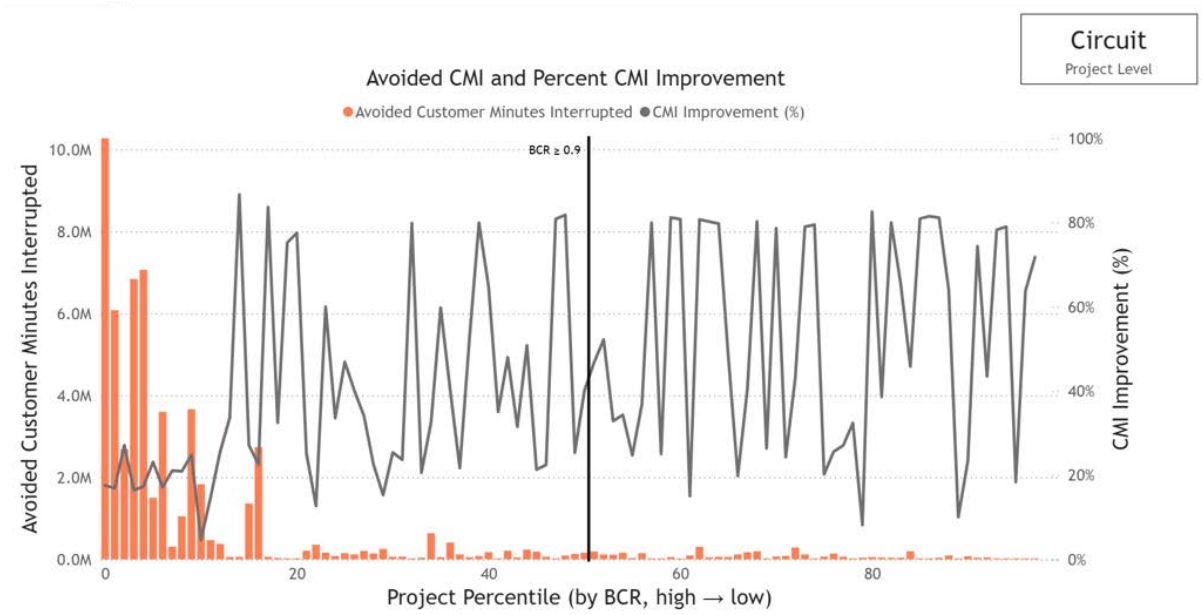


Figure 5-11 takes the CMI benefits from Figure 5-10 and applies the ICE Calculator (see Section 4.2) to monetize the outages and add the avoided restoration costs for each circuit. It is important to note that the application of the ICE Calculator incorporates the various customer types into the evaluation. This figure shows the total monetized resilience and risk benefits of this program. Figure 5-11 illustrates that most of the quantified benefits are from avoided customer outages. The figure also includes the expected improvement in monetized customer outages and restoration costs. The circuits with a BCR ≥ 0.9 show an improvement in monetized customer outages of 28% on average, ranging from 4% to 91%, and 13% for restoration costs, ranging from 7% to 20%, in the percentile ranking view.

Figure 5-11: Subtransmission PTMM Pole Top Program Benefits Summary

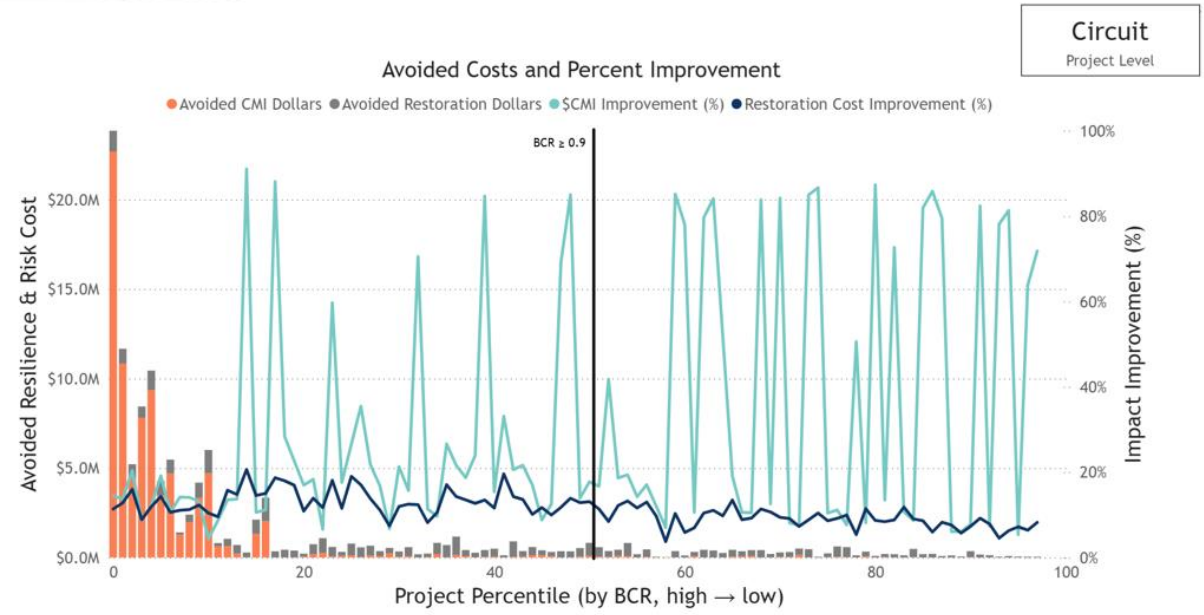
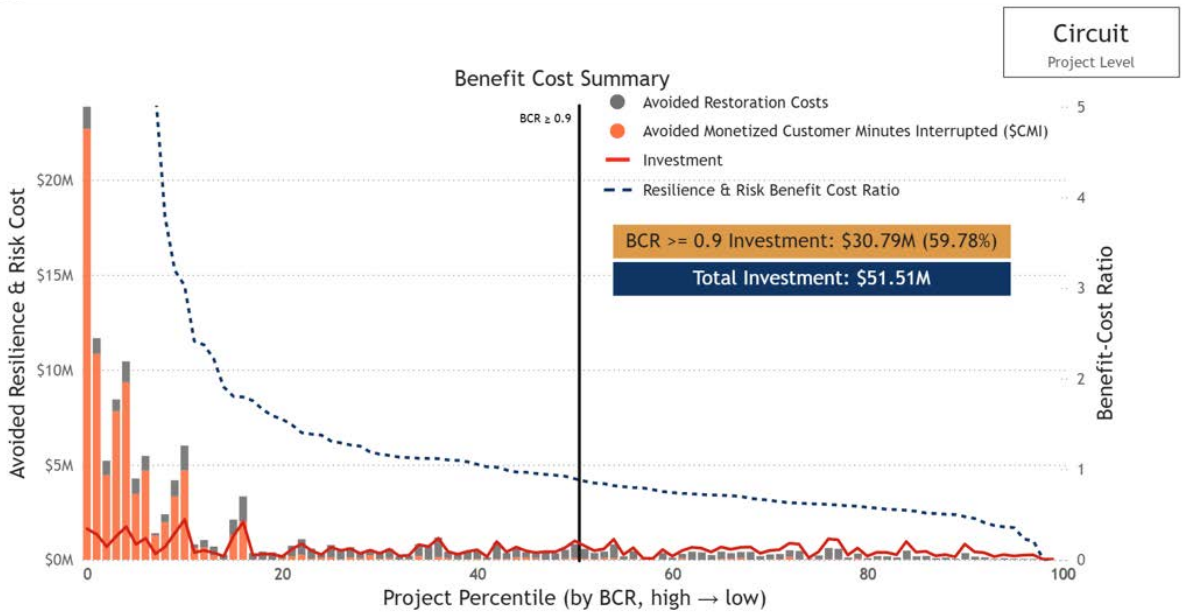


Figure 5-12 takes the benefit results from Figure 5-11 and layers in the expected investment for each circuit to show the Resilience, Reliability, & Risk BCR. As the figure shows, if this program were applied to the entire DTE distribution system, the overall investment level would be approximately $51.51 million. The weighted BCR for deploying this program is 2.37. The figure shows that approximately $30.79 million, or 59.78% of the total investment, has a BCR ≥ 0.9. The weighted BCR for deploying this program only on circuits where the BCR ≥ 0.9 is 3.52.

Figure 5-12: Subtransmission PTMM Pole Top Inspection Program BCR Summary



5.1.4 Qualitative Additional Benefits of the Program

The previous sections have outlined the results from quantifying the benefits of specific investments. As discussed, it is difficult to fully capture and quantify all the factors that go into every investment decision. For the PTMM program, a key benefit stream not included in the quantified Benefit-Cost Analysis is mitigating safety risks. Pole and pole-top failures expose the public to safety hazards. Additionally, there are benefits to DTE crews in not having to replace failed equipment reactively. One of the failure types included in the quantitative evaluation was equipment failures during weather events. In this scenario, crews replace failed pole infrastructure following major events. This can be in extreme cold or wet conditions, with infrastructure replacements occurring at all hours of the day, including in the dark. This program would mitigate the failures during these events and minimize the safety risk exposure to DTE crews. Given the safety risk exposure, inspection-based programs like PTMM are appropriate for the sole purpose of mitigating safety risks. As such, while the PTMM investment has quantified benefits for customers, the qualitative safety risk mitigation benefits further justify this investment.

5.2 Small Wire Replacement Program

This section includes the Benefit-Cost methodology and results for the Small Wire Replacement Program. The section provides background information on the program, describes the approach 1898 & Co. utilized to identify investment activities and estimate project costs, and summarizes the resulting Benefit-Cost findings. The section also outlines additional factors for consideration when interpreting the results.

1898 & Co. performed the Benefit-Cost Analysis using the Resilience Event Simulation Model outlined in Section 4.3 and the Equipment Failure Mitigation Model methodology outlined in Section 4.4. Consistent with the broader modeling framework, benefits were evaluated at the protection zone level and then aggregated to the circuit level for planning and decision-making purposes.

5.2.1 Background & Program Description

The Small Wire Replacement Program is intended to improve the resilience and reliability of DTE's distribution primary overhead system through targeted rebuilds within a project's protection zone. The program focuses on replacing distribution primary overhead conductor and associated assets in areas where existing conductor characteristics indicate a higher likelihood of failure, reduced performance under stress, or the need for modernization. By proactively rebuilding these sections, DTE can reduce future outage risk, improve system performance under both blue-sky and weather event conditions, and support more effective long-term asset management.

Small wire is generally more vulnerable to failure under loading and vegetation interaction than larger conductor. As a result, targeted replacement of small wire can improve the ability of the system to withstand stressors and reduce the likelihood of customer outages. The program also provides an opportunity to replace other associated assets within the protection zone, such as pole tops, older poles, and applicable line transformers, where those assets are included as part of the rebuild scope. This allows the program to address asset conditions in a more integrated manner and better align investment activities with the expected configuration of the rebuilt line segment.

Under this evaluation, projects were defined at the protection zone level and aggregated to the circuit level. Each project reflects a targeted rebuild of distribution primary overhead assets within the protection zone based on the program inclusion criteria. Any section containing qualifying small wire was identified for inclusion in the program. This approach supports a more granular evaluation of investment needs and improves the relationship between the assets included in the rebuild, the failures avoided, and the customers impacted.

5.2.2 Estimating Investment Activities and Cost

This section outlines the systematic approach used by 1898 & Co. to identify investment activities for the Small Wire Replacement Program and estimate their expected costs. The analysis begins at the protection zone level, where each investment activity is evaluated based on the assets located within the zone and the applicable program inclusion criteria. If any section within a protection zone contains qualifying small wire, the entire protection zone is identified for inclusion in the Small Wire Replacement Program. The associated costs are then estimated at the protection zone level and aggregated at the circuit level for comparison and planning purposes.

The core element of the program is the targeted rebuild of distribution primary overhead assets within the protection zone. To identify candidate projects, the modeling approach first evaluates conductor sections within each protection zone against the program's small wire criteria. The criteria includes the following wire sizes:

1) 1/0 aluminum single-phase conductor
2) 2 or 6 copper single-phase conductor
3) 1/0 aluminum two-phase 4.8 kV/8.3 kV conductor
4) 2 or 6 copper two-phase 4.8 kV/8.3 kV conductor

If any conductor section within the protection zone meets one or more of these criteria, the protection zone is classified as a small wire project and the rebuild scope is developed for the entire protection zone.

After a protection zone is identified for inclusion, the model determines the assets to be included in the rebuild across that full protection zone. All pole top components within the protection zone are included. Poles are included when their age exceeds 40 years. Line transformers with a voltage below 13.2kV are included for replacement with dual transformers, but this does not imply conversion. As these protection zones have already been selected to contain small wire, all conductor within them is included. Together, these assumptions define the investment activities and project scope used to estimate project cost for each protection zone.

Once the included assets are identified, project costs are estimated using the applicable unit cost assumptions for each asset class. These costs are then combined at the protection zone level to form the total project cost for each candidate investment. The resulting project definitions and costs serve as inputs to the modeling framework used to estimate the resilience, reliability, and risk reduction benefits of the program. Evaluating the program at the protection zone level improves the linkage between the assets included in the rebuild, the failures avoided, and the customers impacted, while aggregation to the circuit level maintains consistency with broader planning and portfolio evaluation.

5.2.3 Quantitative Benefit-Cost Results

1898 & Co. evaluated this program comprehensively across DTE's distribution overhead system. The evaluation organized the benefits and costs of this program at the circuit level in alignment with DTE's execution approach for the program. This section includes the quantified benefit results from the analytics models described in Section 4.3 and Section 4.4. These results assume that:

1) Benefits from vegetation management are accounted for, and
2) Distribution Automation investment activities have not occurred on the DTE system.

The quantified benefits results for this program were aggregated to the circuit level in alignment with the execution approach intended by DTE for this program. For ease of representing this level of information, the quantified benefit results are shown on a

percentile ranking basis. The ranking is based on the Resilience, Reliability, & Risk BCR.

Figure 5-13 includes the expected avoided customer outage benefits for the Small Wire Replacement Program. The figure consists of the absolute benefit in CMI and the percentage improvement. As the figure shows, approximately 35% of the circuits shown in the percentiles have quantified benefits with a BCR ≥ 0.9. For these circuits, the evaluation shows an average expected improvement in CMI of approximately 83%, ranging from 81% to 86%, in the percentile ranking view.

Figure 5-13: Small Wire Replacement Program Avoided Customer Outage Benefit

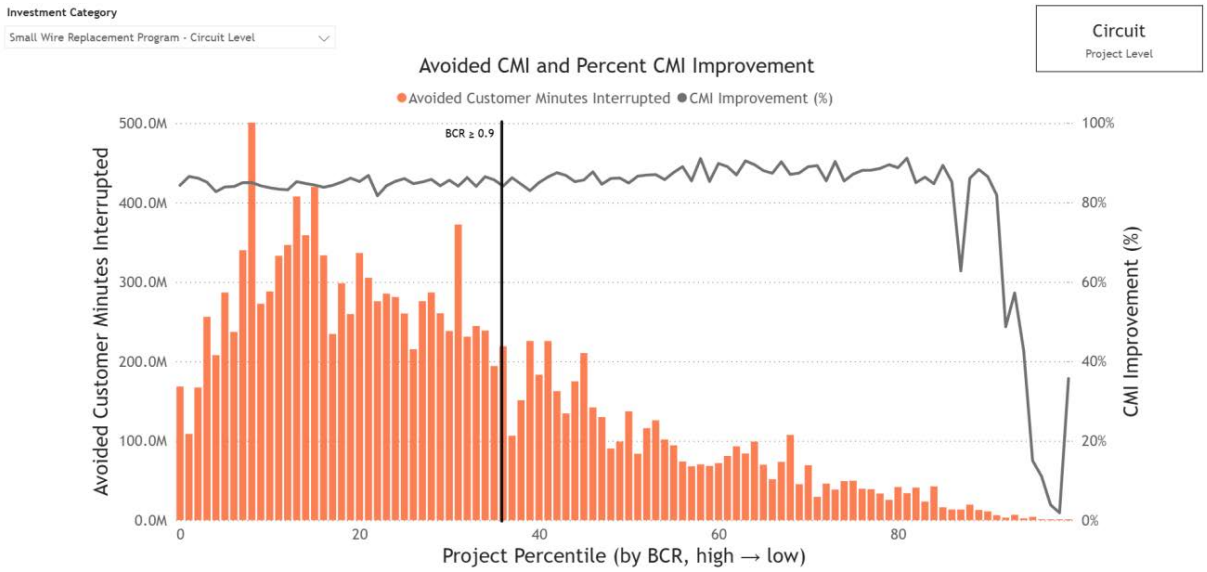


Figure 5-14 takes the CMI benefits from Figure 5-13 and applies the ICE Calculator (see Section 4.2) to monetize the outages and adds the avoided restoration costs for each circuit. It is important to note that the application of the ICE Calculator incorporates the various customer types into the evaluation. This figure shows the total monetized resilience and risk benefits of this program. The figure also includes the expected improvement in monetized customer outages and restoration costs. The circuits with a BCR ≥ 0.9 show an improvement in monetized customer outages of 84% on average, ranging from 82% to 86%, and 85% on average for restoration costs, ranging from 82% to 87%, in the percentile ranking view.

Figure 5-14: Small Wire Replacement Program Benefits Summary

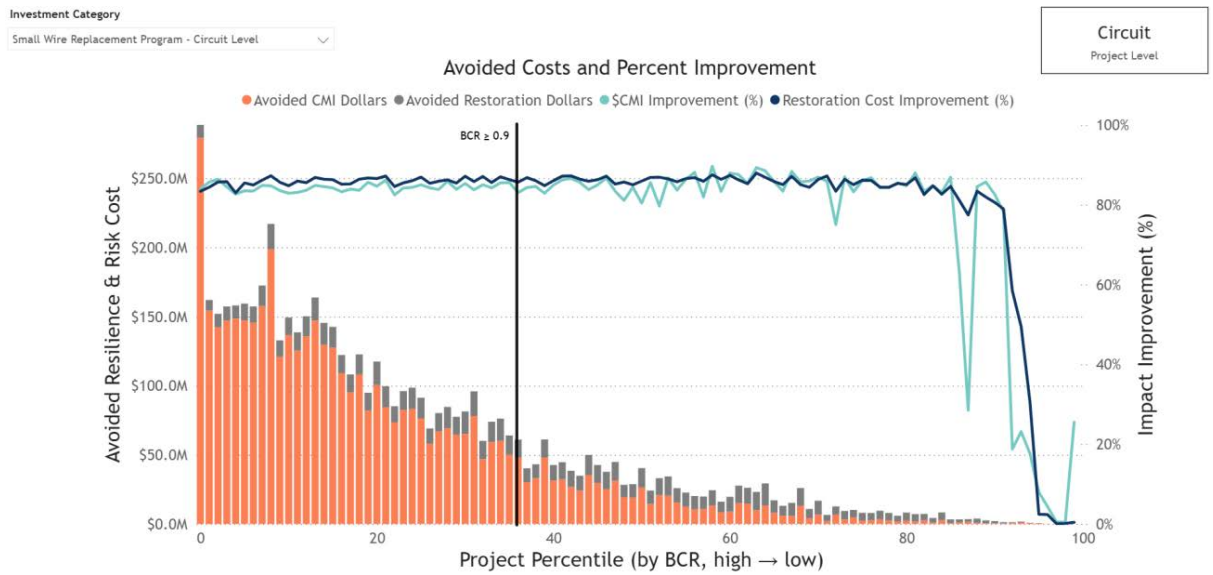
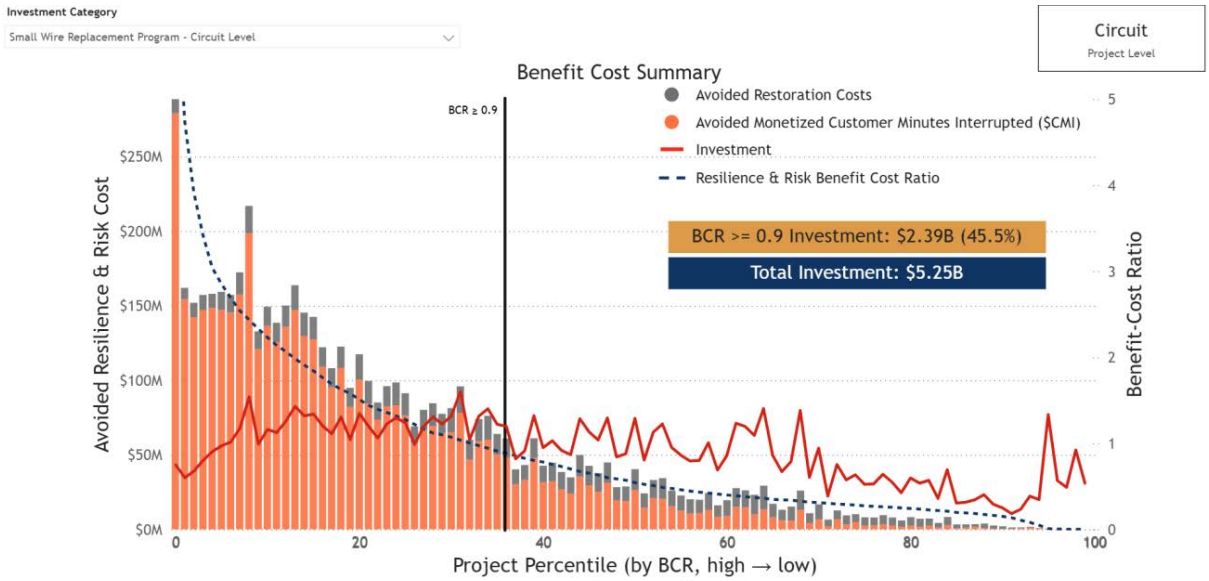


Figure 5-15 takes the benefit results from Figure 5-14 and layers in the expected resiliency investment for each circuit to show the Resilience, Reliability, & Risk BCR. As the figure shows, if this program were applied to the entire DTE system, the overall investment level would be approximately $5.25 billion. The weighted BCR for deploying this program across the entire system is 1.08. The figure shows that approximately $2.39 billion, or 45.5% of the total investment level, has a BCR ≥ 0.9. The weighted BCR for deploying this program on circuits where the BCR ≥ 0.9 is 2.09.

Figure 5-15: Small Wire Replacement Program BCR Summary



5.2.4 Qualitative Additional Benefits of the Program

The previous sections have outlined the results from quantifying the benefits of specific investments. As discussed, it is difficult to fully capture and quantify all the factors that go into every investment decision. For the Small Wire Replacement Program, an important set of benefits not fully reflected in the quantified Benefit-Cost Analysis relates to operational, safety, and system hardening considerations associated with proactively rebuilding small wire sections of the distribution primary overhead system.

Small wire is generally more vulnerable to failure under loading and vegetation interaction than more robust conductor configurations. As a result, proactively replacing small wire can provide qualitative benefits beyond those directly captured in the modeled resilience, reliability, and risk benefit streams. These benefits include reducing exposure to conductor-related safety hazards for the public and improving the overall operability and maintainability of the system. When small wire fails, repairs often must be performed reactively, potentially during major events, at night, or under extreme weather conditions. By reducing the frequency of these reactive replacement activities, the program can help reduce safety risk exposure for DTE crews and improve restoration working conditions.

The program may also provide broader system benefits that are difficult to quantify directly. Rebuilding protection zones that contain small wire can improve standardization of conductor configurations, reduce maintenance complexity, improve system capacity, and support more durable long-term system performance. In addition, these projects may improve service in localized areas that have historically experienced poorer reliability or greater exposure to storm and vegetation-related impacts. Accordingly, while the quantitative BCR results provide an important decision-making metric, the qualitative safety, operational, and system hardening benefits of the Small Wire Replacement Program may further support investment in projects that strengthen the distribution primary overhead system.

5.3 Breaker Replacement Program

This section includes the Benefit-Cost methodology and results for the Breaker Replacement Program. The section contains background information on the program and the approach used to estimate the number and costs of substation breakers and reclosers included in the analysis. The section also includes the program's Benefit-Cost results and outlines additional factors for consideration. The Breaker Replacement Program focuses on the replacement of aging breakers and substation reclosers that protect distribution circuits and help isolate faults within substations.

Additional information describing the substation asset base and the customer connectivity approach used in this analysis is provided in Section 2.1.2.

5.3.1 Background & Program Description

Substations serve as the heart of the electrical power system, acting as the central hub where electricity is transformed, protected, and routed from the transmission and subtransmission networks to distribution circuits that deliver power to customers. Within each substation, critical assets such as breakers and substation reclosers play an important role in isolating faults and maintaining the safe and reliable flow of electricity to distribution circuits and ultimately to customers. Because substations contain key protection equipment in a single location, failures of these devices can interrupt service to large portions of the distribution system, resulting in widespread

customer outages. Maintaining and monitoring these protection assets is therefore essential to supporting safe, reliable, and resilient grid operations.

Effective management of substation protection assets requires utilities to understand the age, configuration, and operational role of the equipment that supports these facilities. As breakers and substation reclosers age, the probability of failure increases, which can lead to equipment damage or extended service interruptions. Proactive planning and replacement of aging protection equipment enables utilities to reduce operational risk while also ensuring substations continue to perform their critical role in providing electricity to customers.

This program introduces substation equipment replacement modeling to evaluate the customer benefits associated with substation breakers and reclosers. The analysis establishes connectivity between these protection devices, the distribution circuits they serve, and the customers ultimately impacted by their operation. By linking breakers and substation reclosers to distribution circuits and customer counts, the analysis enables a more accurate evaluation of reliability benefits and customer impacts associated with substation protection investments.

5.3.2 Estimating Investment Activities and Cost

The analysis begins by identifying the population of breakers and substation reclosers using the substation asset register provided by DTE.

Investment costs for breaker and substation recloser replacements were developed using planning-level cost estimates provided by DTE. These estimates reflect the typical scope of work required to replace substation protection equipment.

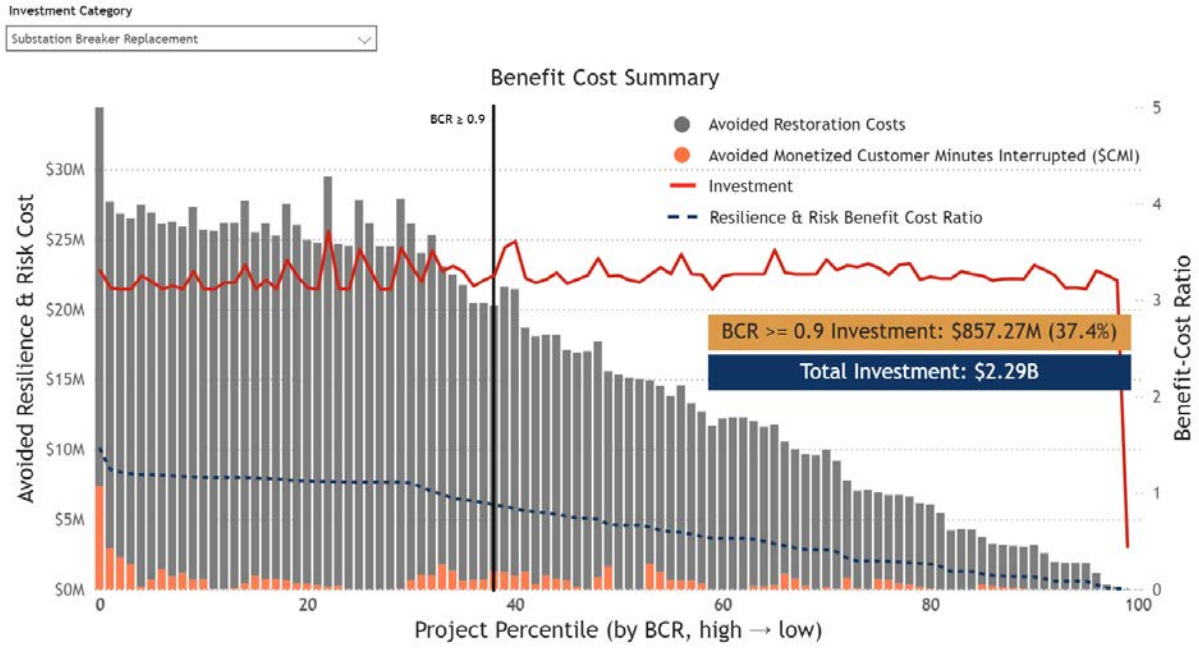
5.3.3 Quantitative Benefit-Cost Results

This section includes the quantified benefit results from the analytics models described in Section 4.4. 1898 & Co. evaluated the breaker replacement program, linking each breaker and substation recloser to the downstream distribution circuits and customers they protect. This connectivity enables a granular assessment of the reliability benefits associated with proactively replacing aging substation equipment. The evaluation organizes benefits and costs at the asset level. Quantified benefit

results reflect only the impacts of breaker and substation recloser replacement. To support comparison across projects with varying sizes and customer counts, results are presented on a percentile ranking basis using the BCR as the ranking metric. The results are shown in Figure 5-16.

As Figure 5-16 depicts, if this program were applied to the entire DTE distribution system, the overall investment level would be approximately $2.29 billion. The weighted BCR for deploying this program across the entire system is 0.69. The figure shows that approximately $857.27 million, or 37.4% of the total investment level, has a BCR ≥ 0.9. The weighted BCR for deploying this program is only on circuits where the BCR ≥ 0.9 and is 1.13.

Figure 5-16: Substation Breakers Benefit-Cost Analysis Summary



5.3.4 Qualitative Additional Benefits of the Program

The previous sections outlined the results from quantifying the benefits associated with specific investments. As discussed, it is difficult to fully capture and quantify all the factors that go into every investment decision. For the Breaker Replacement Program, several important operational and safety benefits are not fully captured in the quantified Benefit-Cost Analysis.

Breakers and substation reclosers serve as critical protective devices that quickly isolate faults and prevent fault current from propagating through the electrical system. If a breaker fails to operate as intended, high fault currents may continue flowing through substation and distribution equipment, potentially causing extensive damage to transformers, conductors, and other connected infrastructure. Modern replacement breakers are typically designed to operate more quickly and consistently, enabling faster fault clearing that limits the duration of fault currents on the system. By interrupting faults more rapidly, these devices reduce the thermal and mechanical stress placed on connected equipment, lowering the risk of widespread equipment damage.

In addition to equipment damage, sustained fault conditions can increase the likelihood of arc flash events, fires, or explosions due to the high energy present in the system. These conditions can pose significant safety risks to substation personnel and operations staff who may be working in or responding to events at the facility. Proactive replacement of aging breakers helps reduce the likelihood of faults.

Breaker replacement programs may also coincide with upgrades to modern protection and control systems, allowing utilities to improve protection coordination and ensure faults are detected and isolated more effectively across the system. These operational and safety improvements represent meaningful benefits of the Breaker Replacement Program that are not reflected in the quantified Benefit-Cost results.

5.4 URD Replacement Program

This section includes the Benefit-Cost methodology and results for the Underground Residential Distribution (URD) Replacement Program. The section provides background information on the program, describes the approach 1898 & Co. utilized to identify investment activities and estimate project costs, and summarizes the resulting Benefit-Cost findings. The section also outlines additional factors for consideration when interpreting the results. 1898 & Co. performed the Benefit-Cost Analysis using the Equipment Failure Mitigation Model methodology outlined in Section 4.4.

5.4.1 Background & Program Description

The URD Replacement Program is intended to improve the reliability and long-term performance of the DTE underground residential distribution system through the proactive replacement of aging underground cable. URD cable is a smaller-diameter, polyethylene-insulated conductor used primarily in underground residential areas on the distribution system. These cables are typically either directly buried or installed in conduit. Since URD cable is located below ground, it avoids many of the outage drivers that affect overhead facilities, such as vegetation contact, wind loading, and other weather-related impacts.

URD cable is generally more costly and labor-intensive to install, locate, and repair than overhead construction. Although failures may occur less frequently than for comparable overhead assets, they can be more difficult to identify, more time-consuming to repair, and more disruptive to customers when they occur. As a result, underground cable failures can still create meaningful reliability and restoration challenges, particularly as the cable population ages.

The URD Replacement Program reflects both the need to address aging underground infrastructure and the need for sustained reinvestment to support long-term reliability in underground residential areas. By proactively replacing older or higher-risk URD cable segments, DTE can reduce future failure risk, avoid reactive repair activities, and support more effective long-term asset management.

5.4.2 Estimating Investment Activities and Cost

URD replacement investments were included in this analysis to evaluate the reliability benefits associated with proactively replacing underground residential distribution cable on the secondary system. Incorporating URD assets into the Benefit-Cost Analysis (BCA) allows the model to quantify how replacement of higher-risk URD cable segments can reduce outage frequency and duration for residential customers.

The analysis begins by identifying the population of URD cable using DTE GIS information. This dataset includes attributes such as installation year, cable type, installation method, direct buried or conduit, and associated residential circuits. For

purposes of the analysis, cable installed in 1985 or earlier is assumed to be non-tree-retardant. Using the population asset characteristics identified in the DTE provided data, the model identifies the applicable URD cable segments and estimates the replacement activity evaluated within the planning horizon.

Investment costs for URD cable replacement were developed using unit cost estimates provided by DTE. These estimates reflect the typical scope of work required to replace URD cable, including the expected construction approach and associated installation practices. The resulting replacement quantities and costs serve as inputs to the Equipment Failure Mitigation Model used to estimate the reliability benefits of the program.

5.4.3 Quantitative Benefit-Cost Results

1898 & Co. evaluated this program comprehensively across DTE's underground residential distribution cable. The evaluation organized the benefits and costs of this program at the protection zone level. This section includes the quantified benefit results from the Equipment Failure Mitigation Model described in Section 4.4.

The quantified benefits results for this program were aggregated to the protection zone level. For ease of representing this level of information, the quantified benefit results are shown on a percentile ranking basis. The ranking is based on the BCR.

Figure 5-17 includes the expected avoided customer outage benefits for the URD Replacement program. The figure consists of the absolute benefit in CMI and the percentage improvement. The figure also includes which protection zones have a quantified BCR ≥ 0.9. As the figure shows, approximately 12% of the protection zone percentiles have a BCR ≥ 0.9. For these protection zone percentiles, the evaluation shows an average expected improvement in CMI of approximately 96%, ranging from 94% to 97%, in the percentile ranking view.

Figure 5-17: URD Replacement Program Avoided Customer Outage Benefit

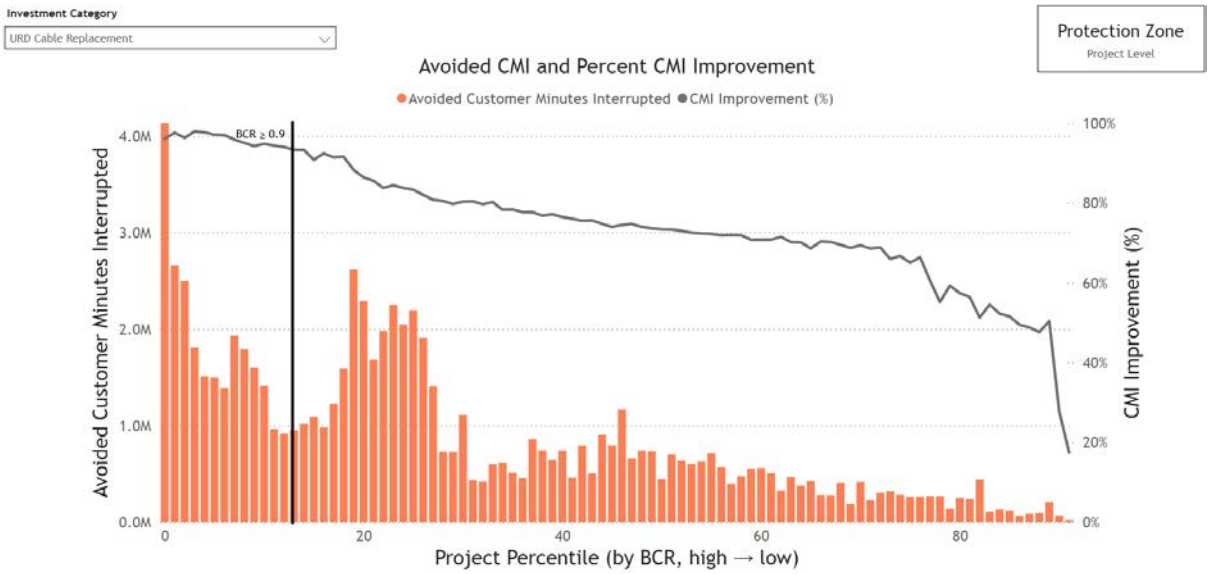


Figure 5-18 takes the CMI benefits from Figure 5-17 and applies the ICE Calculator (see Section 4.2) to monetize the outages and adds the avoided restoration costs for each circuit. It is important to note that the application of the ICE Calculator incorporates the various customer types into the evaluation. This figure shows the total monetized resilience and risk benefits of this program. The figure also includes the expected improvement in monetized customer outages and restoration costs. The protection zones with a BCR ≥ 0.9 show an improvement in monetized customer outages of 96% on average, ranging from 95% to 98%, and 97% on average for restoration costs, ranging from 96% to 99%, in the percentile ranking view.

Figure 5-18: URD Replacement Program Benefits Summary

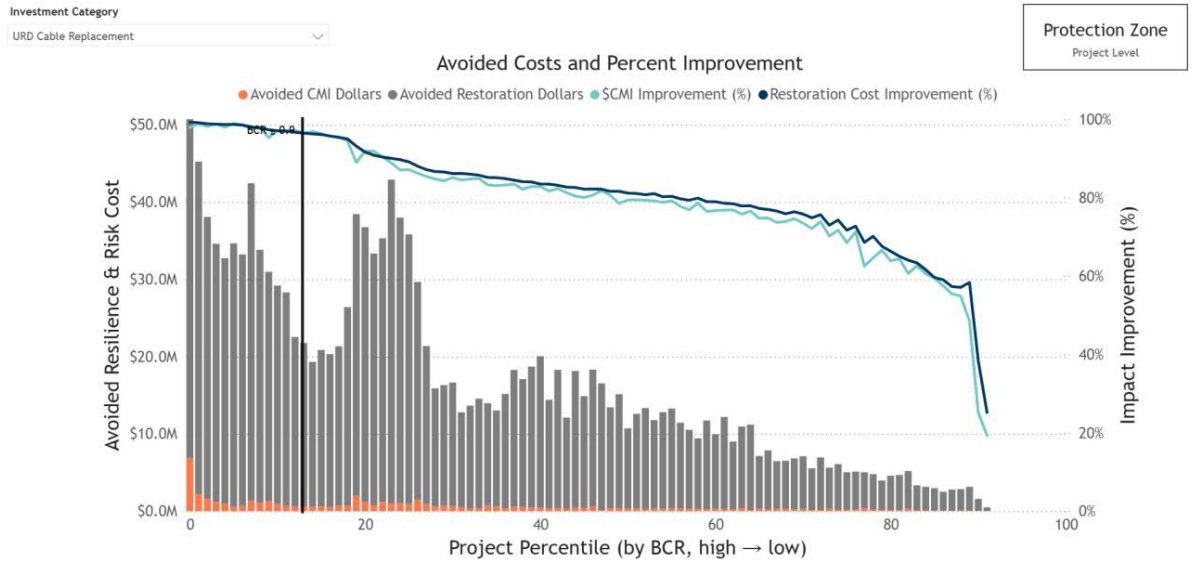
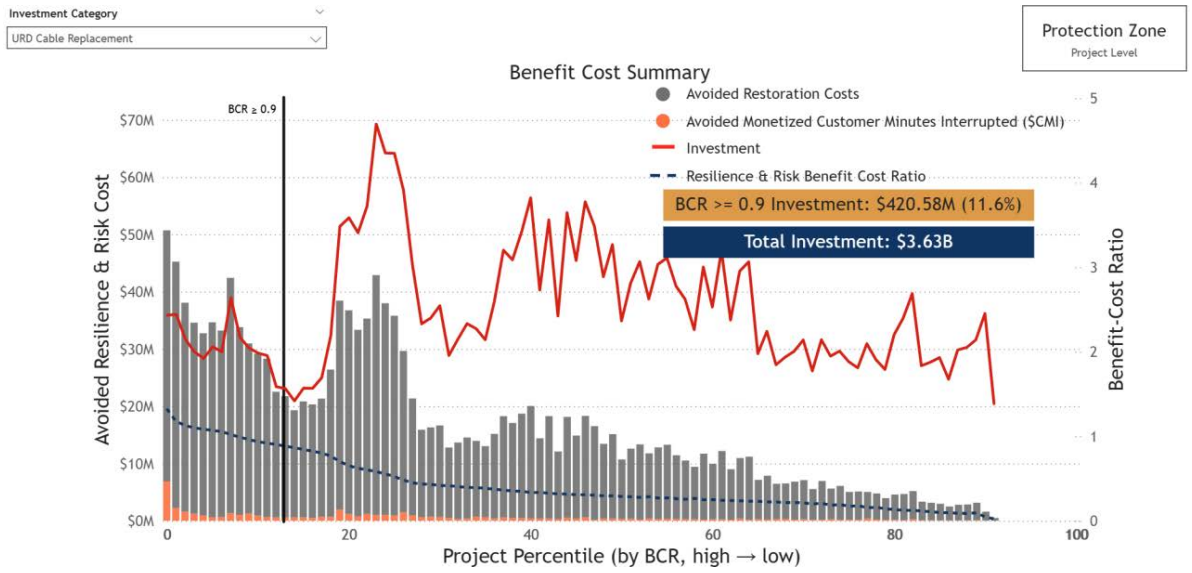


Figure 5-19 takes the benefit results from Figure 5-18 and layers in the expected investment for each circuit to show the BCR. As the figure shows, if this program were applied to the entire DTE system, the overall investment level would be approximately $3.63 billion. The weighted BCR for deploying this program across the entire system is 0.69. The figure shows that approximately $420.58 million, or 11.6% of the total investment level, has a BCR ≥ 0.9. The weighted BCR for deploying this program is only on circuits where the BCR ≥ 0.9 is 1.06.

Figure 5-19: URD Replacement Program BCR Summary



5.4.4 Qualitative Additional Benefits of the Program

The previous sections have outlined the results from quantifying the benefits of specific investments. As discussed, it is difficult to fully capture and quantify all the factors that go into every investment decision. For the URD Replacement Program, a key set of benefits not fully reflected in the quantified Benefit-Cost Analysis relates to operational, customer, and safety considerations associated with proactively replacing underground residential cable.

Although URD cable is generally less exposed to common overhead outage drivers such as vegetation contact and weather-related damage, failures can be difficult to identify, locate, and repair when they occur. As a result, underground cable failures can be particularly disruptive to customers and can require more complex restoration activities than comparable overhead repairs. Proactively replacing higher-risk URD cable segments can therefore provide qualitative benefits beyond those directly captured in the modeled reliability benefit streams.

The program may also provide important customer and community benefits that are difficult to monetize directly. Because underground cable failures can take longer to isolate and repair, proactive replacement can help reduce the customer frustration, inconvenience, and uncertainty associated with extended residential outages. In addition, the program can improve the long-term operability and maintainability of the underground residential system by reducing the need for reactive repairs and supporting a more planned approach to asset replacement.

There are also safety-related benefits associated with reducing reactive underground repair work. Repairs to failed underground cable may require excavation, fault locating, and work in challenging field conditions, sometimes during periods of heightened customer impact or adverse weather. By reducing the frequency of these reactive activities, the URD Replacement Program can help reduce safety exposure for DTE crews and contractors while also improving the efficiency and predictability of restoration work. As such, while the quantitative evaluation captures the direct

reliability benefits of the program, the qualitative operational, customer, and safety benefits further support the value of continued investment in URD cable replacement.

5.5 Cable Replacement Program

This section includes the Benefit-Cost methodology and results for the Cable Replacement Program. The section provides background information on the program, describes the approach 1898 & Co. utilized to identify investment activities and estimate project costs, and summarizes the resulting Benefit-Cost findings. The section also outlines additional factors for consideration when interpreting the results. 1898 & Co. performed the Benefit-Cost Analysis using the Equipment Failure Mitigation Model methodology outlined in Section 4.4 above.

5.5.1 Background & Program Description

The Cable Replacement Program is intended to improve the reliability and long-term performance of the DTE underground distribution and subtransmission system through the proactive replacement of system cable. System cable is a large diameter, insulated conductor typically installed in conduit, with manholes, vaults, or switch cabinets located at intervals along the route to allow crews to pull cable through the conduit system and splice segments together. This configuration supports the operation of underground facilities in areas where overhead construction is not practical or where multiple circuits must pass through constrained corridors, such as approaches to substations, dense urban areas, and other critical portions of the system. In many cases, system cable also serves downtown customers, major public venues, critical infrastructure, or links substations to overhead circuits.

Because system cable is installed underground, it is generally less exposed to common overhead outage drivers such as vegetation contact, wind, and other weather-related impacts. This can provide important resilience and reliability advantages relative to overhead construction. At the same time, underground system cable is significantly more complex and costly to install, locate, repair, and replace. When failures occur, restoration activities can be labor intensive and time consuming, often requiring specialized construction methods and coordination to access the failed section.

For this reason, system cable plays an important role in the overall operation and reliability of the underground network, particularly in locations where redundancy and alternate sourcing are needed to limit customer impacts during an outage. Because these assets often serve dense load areas, critical facilities, and highly visible community locations, system cable failures can result in broader customer and community impacts than a typical overhead outage. When a system cable failure occurs, the ability to transfer load to an alternate source can help reduce the duration and extent of outages. Accordingly, the Cable Replacement Program reflects the need for continued reinvestment in underground infrastructure to maintain long-term reliability, reduce future failure risk, and support more effective long-term asset management in critical underground portions of the system.

5.5.2 Estimating Investment Activities and Cost

System cable replacement investments were incorporated into this analysis to evaluate the reliability benefits associated with proactively replacing underground system cable across DTE's distribution and subtransmission networks. Including these assets in the Benefit-Cost framework allows the model to quantify how replacement of higher-risk system cable segments can reduce failure risk, improve restoration performance, and mitigate the potential for larger customer interruptions where underground system cable serves as a critical part of the network configuration.

The analysis begins by identifying the population of system cable segments using DTE's underground asset inventory. This dataset includes key asset attributes such as cable type, installation year, voltage, and associated circuit or substation connections. As part of the modeling assumptions, cable installed in 1991 or earlier is assumed to be non-tree-retardant. Using this asset population and related characteristics, the model identifies the applicable system cable segments to be included in the program and estimates the associated replacement activity over the planning horizon.

Investment costs for system cable replacement were developed using planning-level cost estimates provided by DTE. These estimates reflect the typical scope of work required to replace underground system cable, including the expected construction

approach and associated installation practices. The resulting replacement quantities and costs were then used as inputs to the Equipment Failure Mitigation Model to estimate the reliability benefits associated with the program.

5.5.3 Quantitative Benefit-Cost Results

1898 & Co. evaluated this program comprehensively across DTE's underground distribution and subtransmission system cable. The evaluation organized the benefits and costs of this program at the circuit level. This section includes the quantified benefit results from the Equipment Failure Mitigation Model described in Section 4.4.

The quantified benefits results for this program were aggregated to the circuit level. For ease of representing this level of information, the quantified benefit results are shown on a percentile ranking basis. The ranking is based on the BCR.

Figure 5-20 includes the expected avoided customer outage benefits for the Cable Replacement program. The figure consists of the absolute benefit in CMI and the percentage improvement. As the figure shows, approximately 28% of the circuit percentiles have a BCR ≥ 0.9. For these circuit percentiles, the evaluation shows an average expected improvement in CMI of approximately 96%, ranging from 92% to 98%, in the percentile ranking view.

Figure 5-20: System Cable Program Avoided Customer Outage Benefit

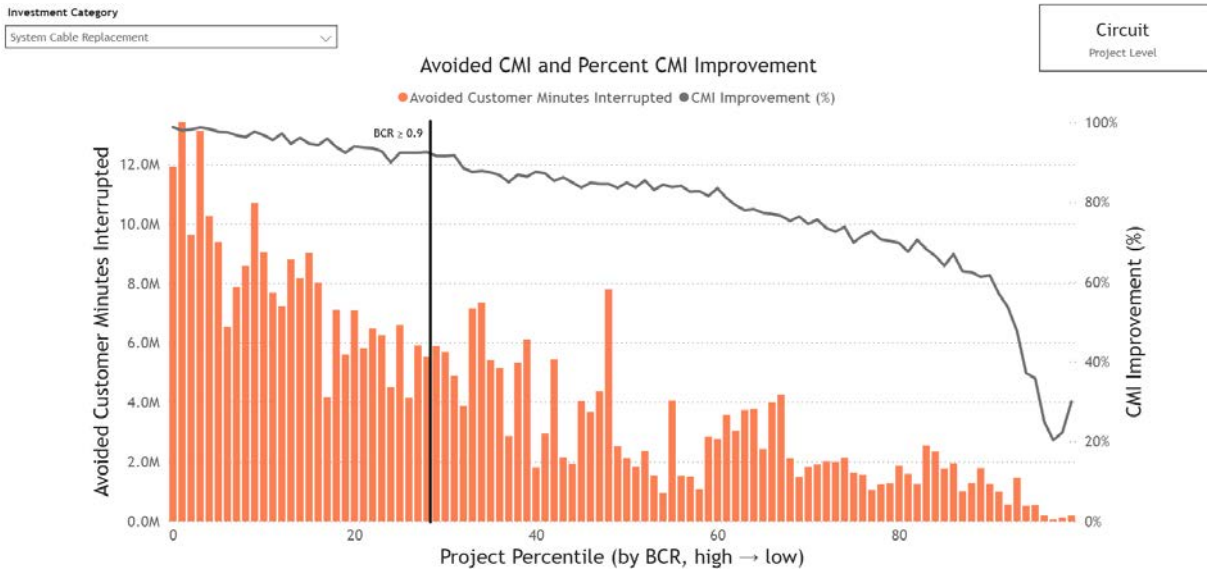


Figure 5-21 takes the CMI benefits shown in Figure 5-20 and applies the ICE Calculator (see Section 4.2) to monetize the outages and adds the avoided restoration costs for each circuit. It is important to note that the application of the ICE Calculator incorporates the various customer types into the evaluation. This figure shows the total monetized resilience and risk benefits of this program. The figure also includes the expected improvement in monetized customer outages and restoration costs. The circuits with a BCR ≥ 0.9 show an improvement in monetized customer outages of 98% on average, ranging from 96% to 99%, and 97% on average for restoration costs, ranging from 96% to 98%, in the percentile ranking view.

Figure 5-21: System Cable Replacement Program Benefits Summary

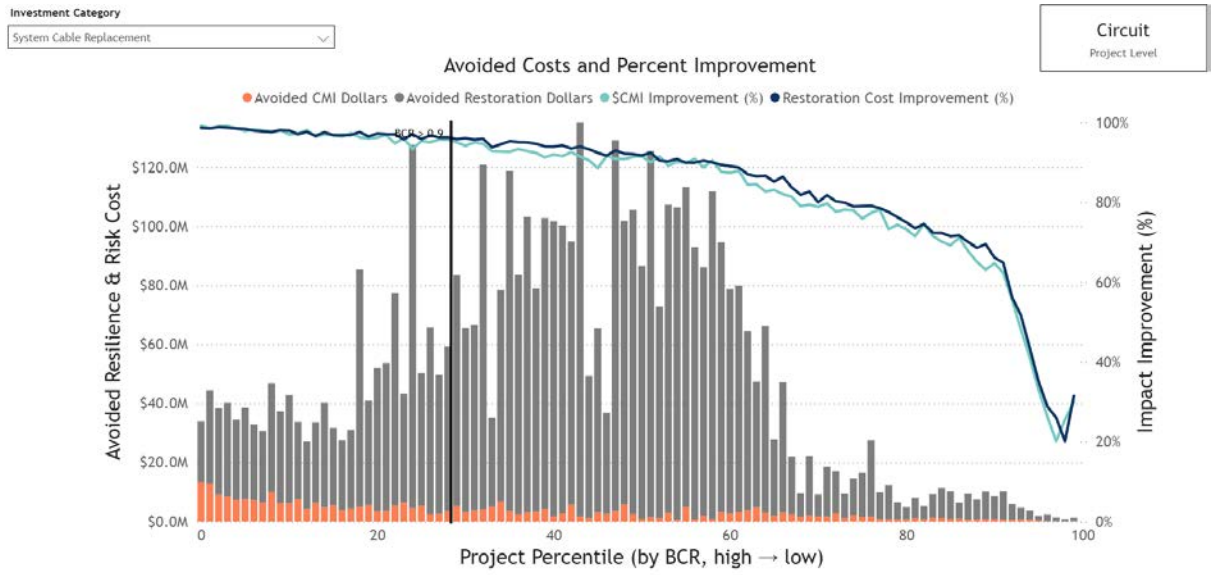
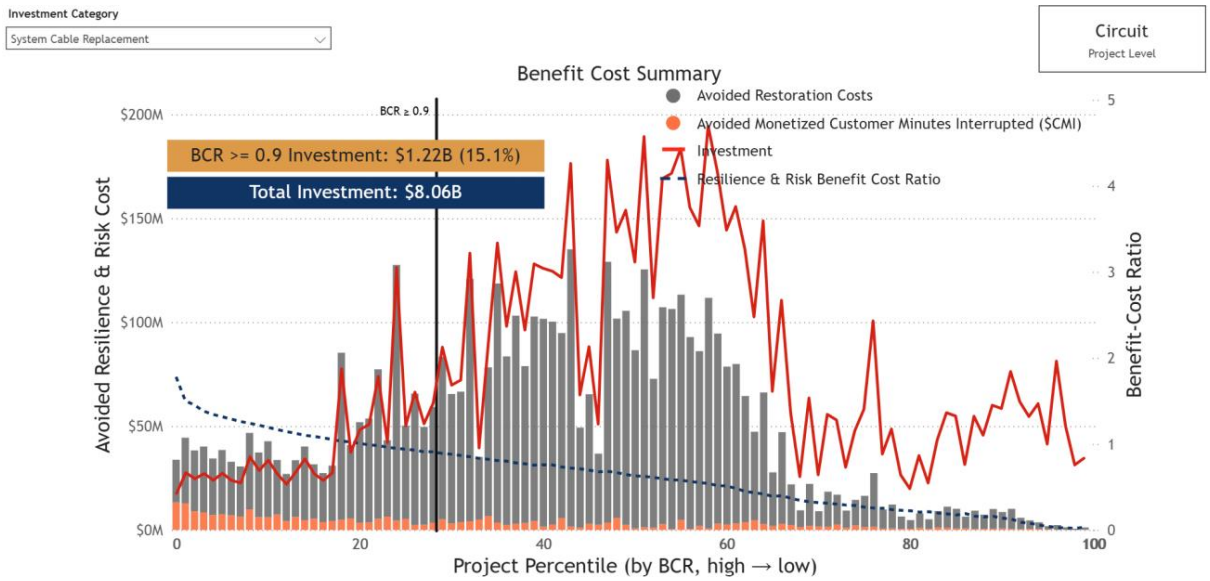


Figure 5-22 takes the benefit results shown in Figure 5-21 and layers in the expected investment for each circuit to show the BCR. As Figure 5-22 shows, if this program were applied to the entire DTE system, the overall investment level would be approximately $8.06 billion. The weighted BCR for deploying this program across the entire system is 0.61. The figure shows that approximately $1.22 billion, or 15.1% of the total investment level, has a BCR ≥ 0.9. The weighted BCR for deploying this program only on circuits where the BCR ≥ 0.9 is 1.09.

Figure 5-22: System Cable Replacement Program BCR Summary



5.5.4 Qualitative Additional Benefits of the Program

The previous sections have outlined the results from quantifying the benefits of specific investments. As discussed, it is difficult to fully capture and quantify all the factors that go into every investment decision. For the Cable Replacement Program, a key set of benefits not fully reflected in the quantified Benefit-Cost Analysis relates to operational, customer, and safety considerations associated with proactively replacing underground cable.

Although system cable is generally less exposed to common overhead outage drivers such as vegetation contact and weather-related damage, failures can be difficult to identify, locate, and repair when they occur. System cable is a large-diameter cable that is a critical part of the distribution and subtransmission system and supports grid redundancy and resiliency. When failures occur on system cable service can be disrupted to many DTE customers for long durations as it requires more complex restoration activities than comparable overhead repairs. Additionally, system cable also serves downtown districts and major public venues where outage impacts can have greater societal impacts.

Proactively replacing higher-risk system cable segments can therefore provide qualitative benefits beyond those directly captured in the modeled reliability benefit streams.

The program may also provide important customer and community benefits that are difficult to monetize directly. Since the failure of system cable takes longer to isolate and repair, impacts many DTE residential and C&I customers, and reduces system redundancy when out of service, proactive replacement helps reduce the customer frustration, inconvenience, and uncertainty associated with extended outages. In addition, the program can improve the long-term operability and maintainability of the underground system by reducing the need for reactive repairs and supporting a more planned approach to asset replacement.

There are also safety-related benefits associated with reducing reactive underground repair work. Repairs to failed underground cables may require excavation, work in challenging field conditions, and repairs during periods of heightened customer impact or adverse weather. By reducing the frequency of these reactive activities, the Cable Replacement Program can help reduce safety exposure for DTE crews and contractors while also improving the efficiency and predictability of restoration work. As such, while the quantitative evaluation captures the direct reliability benefits of the program, the qualitative operational, customer, and safety benefits further support the value of continued investment in system cable replacement.

5.6 Subtransmission SCADA

This section includes the subtransmission SCADA program's Benefit-Cost methodology and results. The section includes background information on the program and the approach 1898 & Co. utilized to estimate the cost to enable subtransmission SCADA on the system. The section also includes the program's Benefit-Cost results and outlines additional factors for consideration.

1898 & Co. performed a Benefit-Cost Analysis across the applicable DTE subtransmission system using the Resilience Model methodology outlined in Section 4.3 above. The evaluation quantified the reliability, resilience, and risk-reduction

benefits of placing Automatic Pole Top Switches (APTS) on the different trunk (TRK) and tie (TIE) lines of the DTE subtransmission system.

5.6.1 Background & Program Description

The DTE subtransmission system serves as a critical link between the ITC transmission system and the DTE distribution system and is used to supply power to customer-dedicated substations across the DTE service area. Due to the critical role the subtransmission network plays in moving power across the DTE system and serving customers, the system is designed to provide redundant sources of power to distribution substations and circuits that directly serve customers. This redundancy helps provide service to customers during planned outages or during contingency situations such as unplanned equipment outages.

To enable supporting contingency situations the subtransmission circuits are configured as either a trunk (TRK) line or a tie (TIE) line. Trunk lines are configured to provide power as a radial circuit having one source station that can feed one or more distribution substations. The tie line is a network configured circuit and can have multiple source stations that can feed multiple distribution substations. Examples of trunk and tie lines are provided in Figure 5-23 and Figure 5-24. As shown in the figures, the DTE subtransmission system is configured to provide redundancy during outage events. For trunk lines, affected transformers that are serving customers can sometimes be switched to different trunk lines (Figure 5-23). For tie lines, faults can be isolated through switching and transformers can continue to serve customers from one of the two stations serving the tie line (Figure 5-24).

In addition to the redundancy of the subtransmission circuits, each substation can also be configured with redundancy and reliability schemes. For example, the substation may be configured with an Automatic Throwover (ATO) and/or an Emergency Load Control scheme. As shown in Figure 5-23, substation B has two transformers, an ATO scheme, and an ELC scheme in place. If a fault on TRK line 1 caused the customers served by transformer 1 to lose power, the ATO can activate and shift (throwover) customers served by transformer 1 to transformer 2. However, if the demand of

moving customers exceeds the capacity of transformer 2 the ELC scheme could block the throwover from occurring.

Figure 5-23: Example Trunk Line Configuration

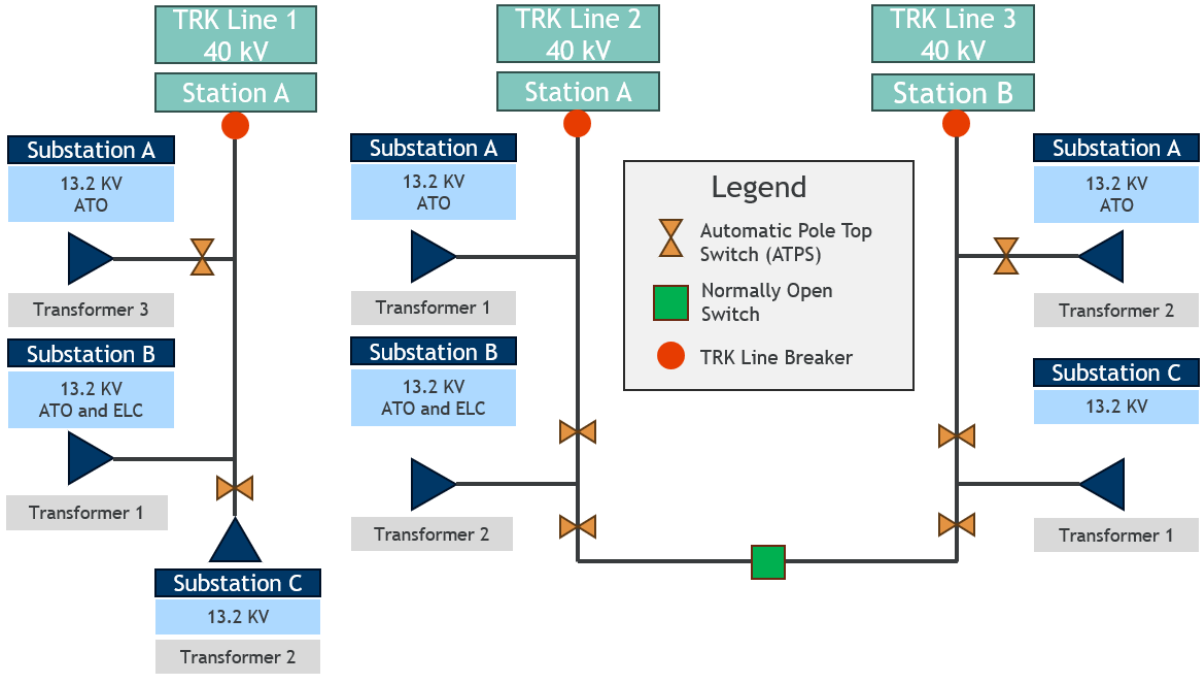
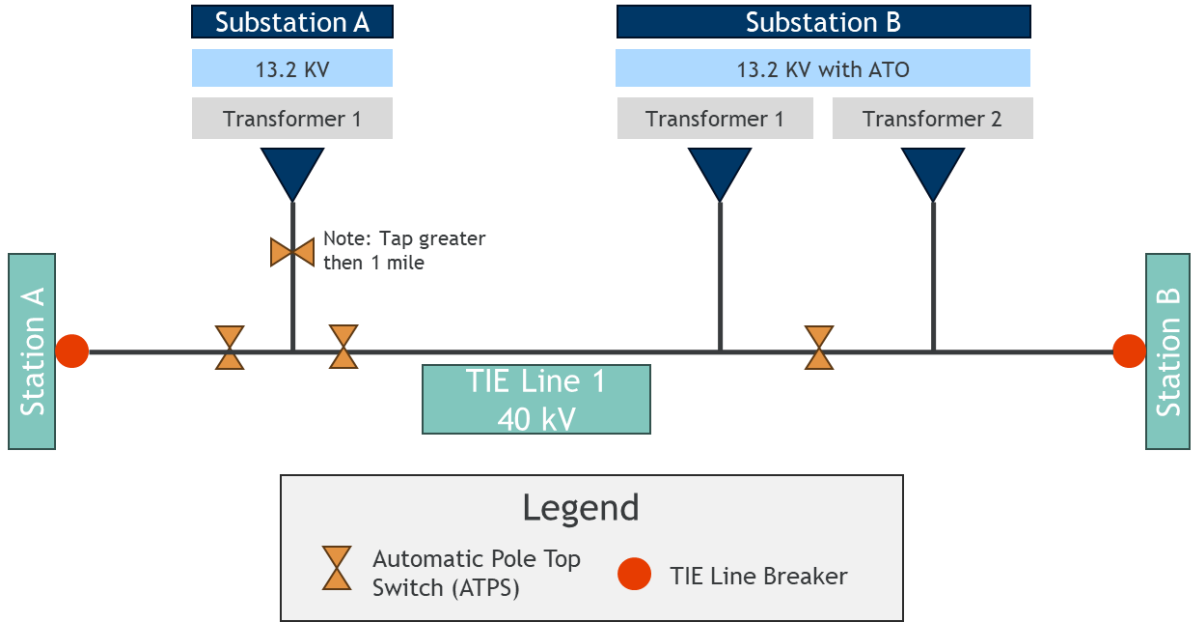


Figure 5-24: Example Tie Line Configuration



Additionally, if a fault occurs on a trunk or tie line for a single transformer substation, such as substation A in Figure 5-24, switches need to be in place to minimize customer impact and leverage the redundancy of the subtransmission system.

To build upon and improve on the benefits of the redundancy in the subtransmission system, outages can be reduced and mitigated through the deployment of a coordinated system of switches known as Automatic Pole Top Switches (APTS). Using APTS allows the subtransmission system to sectionalize and isolate faults while maintaining service to customers in single contingency failure events. For example, a fault on a tie line can be isolated by opening a strategically placed APTS, allowing a single source, on one side of the fault, to continue serving customers.

As can be seen in Figure 5-23 and Figure 5-24, the subtransmission system serves multiple substations and transformers that in total can serve thousands of DTE customers. Faults on the subtransmission system can lead to longer restoration times, when APTS are not present, causing interruption of service to thousands of DTE customers. This creates the opportunity to gain benefits through the deployment of SCADA enabled APTS which can leverage the redundancy of the subtransmission through the automatic isolation of faults on the subtransmission system.

5.6.2 Estimating Investment Activities and Cost

This section outlines the systematic approach used by 1898 & Co. to identify investment activities for the program and estimate their expected costs. In this analysis, 1898 & Co. performed a system-wide, rules-based analysis to evaluate both the number of APTS to add and the trunk and tie lines to which to add them.

DTE provided substation-level indicators to identify locations with Automatic Throwover (ATO) schemes, Emergency Load Control (ELC) schemes, and stations operating at or above 90 percent of firm rating. DTE also provided data identifying trunk and tie lines and the number of customers served by each. Using these inputs, the analysis applied a rules-based framework to estimate the total APTS required to support these operating conditions across the system. Existing DTE APTS were then

incorporated by subtracting the estimated existing APTS from the rules-based necessary APTS quantities to calculate the incremental APTS needed.

A high-level overview of the general rules applied to determine APTS count is outlined below:

TRUNK Lines:

1) For single transformer substations, add APTS to isolate faults downstream of that substation tap.
2) For multiple transformer substations, which exceed 90% of the transformer firm rating, place APTS to isolate faults downstream of that substation tap. As an example, see substation B on TRK line 1 in Figure 5-23
3) For trunk lines with a normally open point and serving at least one substation exceeding 90% of its firm rating, place APTS to create a tie to an adjacent circuit. This enables restoration of that substation without relying on the automatic throwover (ATO) as that can result in the Emergency Load Control (ELC) scheme operating and the potential loss of customers. As an example, placement of APTS on both sides of the substation transformer tap as shown at substation B in Figure 5-23
4) If a substation served from a trunk line has a tap that exceeds one mile, place an APTS. This supports reducing risk of outage exposure and potential voltage violations. As an example, see substation A on TRK line 3 in Figure 5-23

TIE Lines:

1) For a single transformer substation served, apply APTS to both sides of the tap to the substation. As an example, see substation A in Figure 5-24.
2) For a multiple transformer substation with an automatic throwover (ATO) place an APTS between the transformer taps. As an example, see substation B in Figure 5-24.

3) If a substation served from a tie line has a tap that exceeds one mile, place an APTS. This supports reducing risk of outage exposure and potential voltage violations. As an example, see substation A in Figure 5-24.

Because existing APTS information is available at the subtransmission line level, specific switch locations were not evaluated in this planning-level assessment. Therefore, the model distributes existing APTS across the substations associated with each trunk or tie line. This approach can produce fractional existing APTS values at the substation level and, as a result, fractional incremental APTS requirements. Further engineering review would be needed to determine the optimal switch placement and the exact mix of trunk versus tie-line installations for individual projects; however, for purposes of this planning-level assessment, the proportional allocation approach provides a reasonable system-level estimate of incremental APTS needs and associated investment. The next section provides the quantitative Benefit-Cost results for the analysis.

5.6.3 Quantitative Benefit-Cost Results

To evaluate the benefits of implementing APTS, 1898 & Co. used the resiliency model to evaluate weather-event-induced failures of subtransmission assets, which can result in customer outages. The model then evaluated the outage-reduction benefits available from deployment of additional APTS on the subtransmission system. The benefit evaluation considered subtransmission and substation configurations capable of reducing the duration of individual outages, though not the number of such outages.

The DTE OMS records contained only a small number of subtransmission-system outages, which limited the ability to directly determine subtransmission-system-asset probability of failure (POF) rates. Therefore, 1898 & Co. considered subtransmission-pole and pole-top failures to be similar in nature to distribution pole and pole-top failures. The analysis assigned to each subtransmission asset the probability of failure (POF) values of the corresponding distribution asset. For example, a Class 3

subtransmission pole received the POF values calculated for a Class 3 distribution pole. When considering the impact of a weather event on an entire subtransmission trunk or tie line, the failure of any single asset on the line (i.e., pole or pole top) would result in a subtransmission line outage. Therefore, the subtransmission line's POF for a particular weather event was equal to the probability that one-or-more of the line's assets (i.e., pole or pole top) failed during the weather event.

Since subtransmission SCADA investment activities did not include asset replacements, a subtransmission line's investment (INV) POFs (one per weather event type) were assumed to be the same as its status quo (SQ) POFs. Given the limited data available about historical subtransmission outages and the redundancy in the design of both subtransmission circuits and the substations those circuits serve, this analysis assumed that without installing APTS (i.e., under the status quo case), a subtransmission outage's duration was 45 minutes. In this SQ case, each of these outages had the potential to impact thousands of customers. After installing subtransmission SCADA, (i.e., under the INV case), each subtransmission outage's duration was assumed to be 5 minutes.

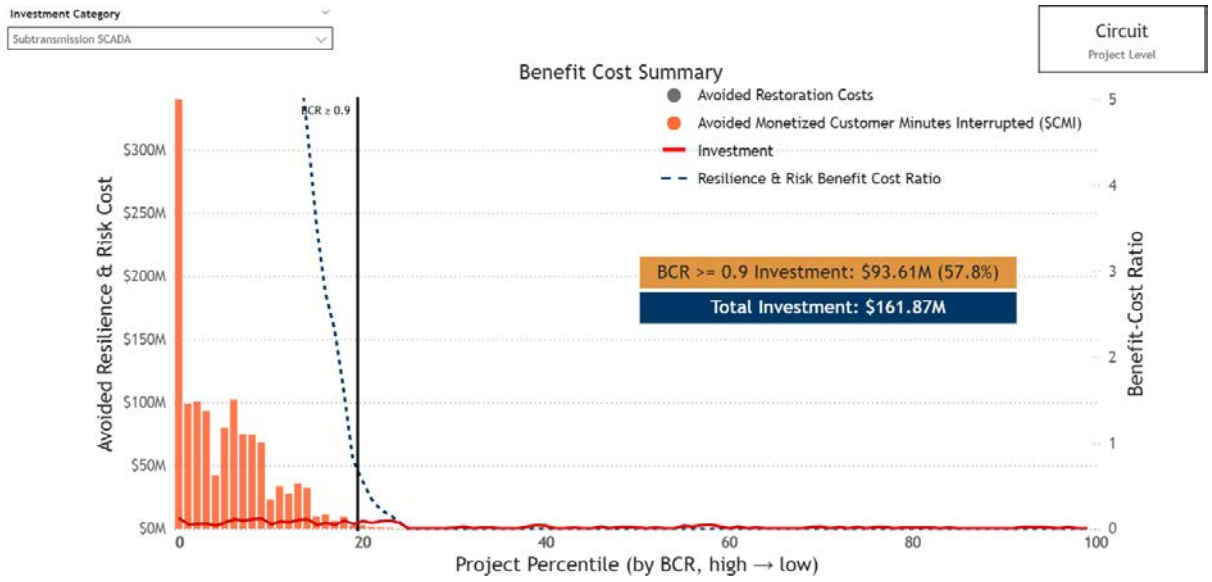
Given these assumptions, a subtransmission line's SQ customer minutes interrupted (CMI) for a failure equaled the 45-minute duration multiplied by the number of customers impacted. Similarly, the subtransmission line's INV CMI (that is the CMI after the SCADA investment activity) for a failure equaled the 5-minute duration multiplied by the customer count. CMI-cost calculations applied ICE calculator values to the outage durations using the customer quantities by type. The number of customers without power during a subtransmission outage was based on the number of customers served by those substations fed by the particular trunk or tie line. The customer-outage calculation also considered potential outage reductions due to substation ATO and/or ELC schemes, which can mitigate outages downstream of a transformer by shifting or shedding load.

Existing APTS switches were also considered in the analysis. 1898 & Co. identified existing APTS using GIS-based connectivity information and incorporated those switches into the calculation of the incremental investment needed. In cases where

existing APTS were already present, only the additional switches needed beyond the existing configuration were attributed to the investment activity. To reflect this in the benefits analysis, outage-reduction benefits were scaled based on the share of total APTS that were incremental rather than already in place. This approach was intended to recognize that existing system automation may already provide a portion of the outage mitigation benefit.

The results shown in Figure 5-25 consider the quantity of APTS, the benefits received by reducing customer interruptions, and the costs of placing APTS. The total investment cost was based on adding 352 new APTS switches across both trunk and tie lines based on the rules outlined in 5.6.2. Of the potential $161.87M of investment in subtransmission SCADA, $93.61M or 57.8% of total investment has a BCR ≥ 0.9. This analysis demonstrates the potential for specific parts of the DTE system to receive strong benefits from the deployment of APTS.

Figure 5-25: Subtransmission SCADA BCR Summary



5.6.4 Qualitative Additional Benefits of the Program

There are additional benefits associated with investment in the Subtransmission SCADA Program that 1898 & Co. did not monetize in this analysis. These include potential benefits in capacity or load constrained areas of the DTE system, where faster fault isolation and service restoration may help reduce operational challenges

and improve system flexibility during outage conditions. The program can also provide important safety benefits by reducing the time required to identify, isolate, and restore faults, which can reduce field exposure for crews and support a more controlled restoration process.

Additional switches and included sensors provide visibility into system events, better granularity on fault locations, and minimize the amount of time to patrol circuits to find a fault. For example, APTS installed at connection points between circuits can enable remote operations to quickly restore customers during an outage. This is currently done by crews in the field, which is known as restore before repair, and delays their ability to go directly to the damage and begin repairs. Both of these field restoration practices will receive benefit from installing APTS as the time that customers experience an outage will be reduced.

5.7 Distribution Automation

This section includes the distribution automation program's Benefit-Cost methodology and results. The section includes background information on the program and the approach 1898 & Co. utilized to estimate the scope and cost to enable distribution automation on the system. The section also includes the program's Benefit-Cost results and outlines additional factors for consideration. 1898 & Co. performed a comprehensive Benefit-Cost Analysis across the entire DTE system using the Outage Mitigation Modeling methodology outlined in Section 4.5. The analysis was performed across three different investment alternatives: Sectionalization, Automating Existing Ties, and Building New Ties.

5.7.1 Background & Program Description

Every year DTE customers experience thousands of outages, disrupting homes, businesses, and critical services. The system saw approximately 8 billion Customer Minutes Interrupted (CMI) and 15 million Customer Interruptions (CI) over the past five years, with outages lasting an average of 525 minutes per event, according to OMS data. These disruptions impact daily life and challenge long-term system resilience, reliability, and safety. These outages stem from a wide range of system stressors and

equipment failures; as a result, directly addressing each cause can require significant investment. Distribution Automation (DA) offers a cost-effective solution to improve outcomes by reducing the impact of outages when they occur. While DA does not prevent faults from happening, it provides the important capability to reduce the customer impacts across a wide range of outage types.

Recognizing DA's meaningful ability to improve the customer experience, DTE is continuing to invest in these capabilities through a two-part DA program. DTE's DA program has two sub-programs. The first sub-program is targeted toward safety risk mitigation. For the 4.8 kV distribution system, events may occur where the existing substation protection does not identify a fault current and appropriately lockout. In these instances, there can be live-wire situations, which can create serious safety concerns. The first sub-program includes installing a recloser immediately outside the substation to address this safety risk. The BCA provided by 1898 & Co. does not include costs and benefits for the investment activities within this safety-focused sub-program.

Instead, the BCA represents the costs and benefits of the second sub-program, which targets improvement of reliability. This sub-program includes investment in smart and connected protection devices to increase sectionalization and enable automated switching, minimizing the impact to customers from disruptive events.

A unique aspect of implementing DA across DTE's system is the presence of multiple voltage levels across circuits, leading to the identification of hybrid circuits that operate at more than one voltage. To account for these complexities, 1898 & Co. collaborated with DTE to develop a structured decision matrix framework to guide the classification and analysis of these circuits.

1898 & Co. leveraged Geographic Information System (GIS) and Outage Management System (OMS) data to establish a study foundation, further enabling investment recommendations that align with system constraints and operational feasibility. The following sections detail the methodology and key results from this analysis.

5.7.2 Estimating Investment Activities and Cost

This section outlines the systematic approach employed by 1898 & Co. to identify investment activities for the program and estimate their expected costs. As discussed in Section 4.5, the evaluation considers three scenarios for distribution automation investments, each with their respective cost components. The following provides the approach employed by 1898 & Co. and DTE to estimate each of the three cost components (if any) for deploying distribution automation across the DTE system:

- Sectionalization: This investment includes adding sectionalizing reclosers to isolate outage-causing faults. 1898 & Co. evaluated each circuit's current state to identify the number of reclosers to include on each circuit. This involved identifying circuits with existing reclosers and SCADA. 1898 & Co. worked with DTE to establish which existing reclosers needed replacements and which ones could be leveraged for automation (Form 6). For 13.2kV circuits without SCADA, 1898 & Co. calculated costs for a recloser outside the station to provide necessary communications support for distribution automation schemes. For the reliability-focused recloser deployment, a decision matrix was used to determine the number of sectionalizing reclosers that could be added, adhering to the maximum thresholds set by DTE for each circuit. The following includes an overview of the decision matrix:
    - For 4.8 kV circuits with fewer than 400 customers, no sectionalizing reclosers were assigned. Circuits with 400+ customers received 2.5 sectionalizing reclosers, estimated to create 2 sectionalized pods. Because of the complexity of the 4.8kV circuit ring configurations, more than one sectionalizing recloser is required to create an isolated section. Based on the unique configuration of each circuit, the number of reclosers required may vary, but it is typically 2 or 3. Therefore, this analysis used a system-wide assumption of 2.5
    - For 13.2 kV and 8.3 kV circuits, those with fewer than 400 customers were not assigned any sectionalizing reclosers. Circuits with more than 400 customers received a number of midpoint reclosers equal to the

total number of customers on the circuit divided by 400 minus 1. The approach rounded down and placed a cap of five reclosers per circuit. DTE provided the cost per recloser, including device placement and ongoing maintenance. Based on this and the number of reclosers for each circuit, 1898 & Co. estimated the cost for recloser deployments for each circuit.

- Automate Existing Ties: This investment enables the automated transfer of customers between circuits. Utilizing GIS data, 1898 & Co. identified manual tie switch locations between circuits of the same voltage for potential locations for upgrading to a tie recloser. Based on sectionalized pod counts and potential tie locations, 1898 & Co. estimated the number of manual tie switches to convert to automated reclosers for each circuit.
- Build New Ties: This investment involves constructing new tie lines for circuits that do not have an existing tie point. 1898 & Co. estimated the scope of adding new tie lines to circuits that do not have existing tie points. Utilizing geospatial analytics and GIS data, 1898 & Co. identified the shortest connection distance between two circuits and applied routing factors to estimate the amount of new tie construction. 1898 & Co. takes a conservative approach in estimating tie line distance by using the Manhattan distance method. While 1898 & Co.'s geospatial analysis identifies two points that are close together, the model does not assume the distance is "as the crow flies" (i.e., the shortest straight-line connection). To provide a more realistic estimate of construction distance, the model assumes the route forms a right angle between the two connection points and travels along these perpendicular segments for the calculation of tie length and cost.

  The routing factor is applied as follows:

$$Estimated\ Tie\ Line\ Distance = \sqrt{2} \times Shortest\ Connection\ Distance$$

  This approach reasonably approximates the additional routing distance that may occur due to roadway alignments, right-of-way constraints, terrain, and other physical barriers, while maintaining a conservative estimate of tie

construction scope and cost. Based on install costs per mile from DTE, 1898 & Co. estimated the cost to add new tie lines to each circuit that did not have existing tie points.

5.7.3 Quantitative Benefit-Cost Results

This section presents the quantified benefits of the Distribution Automation Program that leverages the Outage Mitigation Modeling approach outlined in Section 4.5. 1898 & Co. comprehensively evaluated distribution circuits across DTE's distribution system. Circuits with fewer than 400 total customers are not eligible for distribution automation in accordance with DTE operational guidelines. Out of 2,640 distribution circuits identified with customers in GIS, 1,838 circuits were eligible for investment based on the customer count minimum. This exclusion of smaller circuits ensures that DA investments are targeted toward areas likely to produce the most customer benefit.

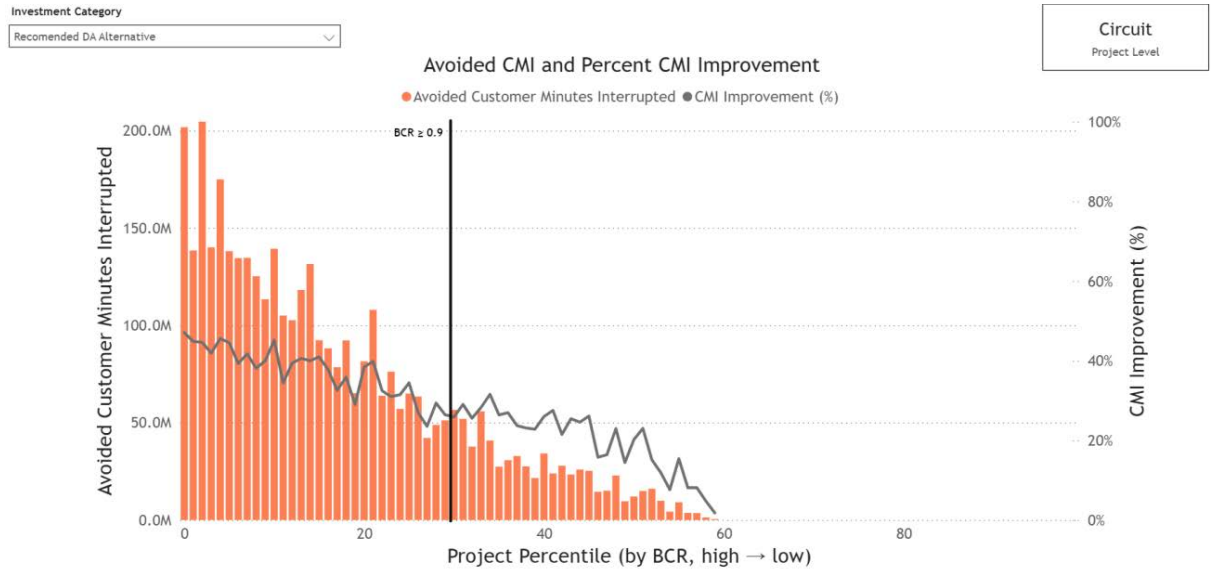
As discussed above, the evaluation considered three scenarios: Sectionalization only, Automating Existing Ties, and Building New Tie Lines. 1898 & Co. leveraged the Benefit-Cost Analysis to identify the recommended alternative from these three, specifically selecting the most mature scenario with a Benefit-Cost Ratio (BCR) greater than 1.0 for each circuit. This allows the analysis to select the alternative that maximizes customer benefits while aligning with system constraints and investment feasibility. The Benefit-Cost Analysis results below are based on the recommended scenario.

As outlined in Section 4.5 above, the benefits were measured in terms of avoided customer outages. To provide a clear representation, results are displayed as a percentile ranking based on the Resilience, Reliability, & Risk Benefit-Cost Ratio (BCR) at the circuit level (highest to lowest). Figure 5-26 illustrates the expected benefits of avoiding customer outages from the Distribution Automation Program. The figure includes each circuit's recommended distribution automation scenario from either the Sectionalization, Automate Existing Ties, or Build New Ties option.

The figure includes the absolute benefit in Customer Minutes Interrupted (CMI) from the decrease in normalized historical outage records, the percentage improvement in CMI, and the circuits where quantified benefits exceed costs. Approximately 29% of the 2,640 circuits have a BCR ≥ 0.9. For these circuits, the evaluation indicates an expected improvement in CMI of approximately 38% ranging from 23% to 47% in the percentile ranking view.

Beyond the circuits with BCR ≥ 0.9, an additional 31% of circuits produce some level of CMI reduction to customers. While these investments are not justified by the quantitative BCA alone, some are likely to prove to be beneficial to customers when also considering the safety benefits and other benefits not quantified within the model. These findings demonstrate strong potential for targeted distribution automation investments to minimize outage impacts and improve reliability for DTE customers.

Figure 5-26: Distribution Automation Program Avoided Customer Outage Benefit



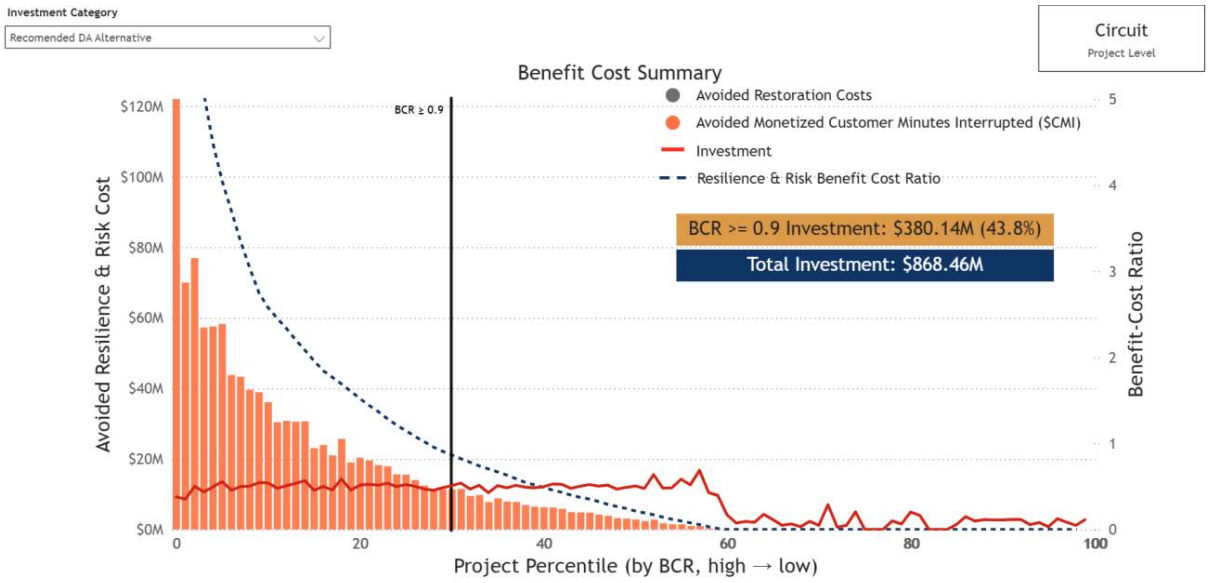
When reviewing Figure 5-26, it is important to note that the modeling approach is fundamentally conservative when calculating CMI improvement. When reviewing the BCR summary, it is important to note that the items listed below demonstrate the conservatism embedded in the approach:

- The model conservatively assumes that the duration of time required for a crew to deal with an outage event (find the outage location, equipment repair, restore power) is the same with or without DA investment. However, with SCADA sectionalizing reclosers, there is likely better visibility into fault locations, which will speed up the time it takes for a crew to find the outage.
- This approach conservatively does not account for the possibility of more severe future outages driven by increasing climate risk or extreme weather events outside the 2021-2025 study period. The quantified benefits may understate future outage risk because they are grounded in historical outage data.
- The value of outages for C&I customers is likely underestimated due to the use of ICE 2.0. Incorporating the most recent ICE Calculator results (which were published after this BCA had been performed), would likely produce greater benefits for these customers. This is described in Section 4.2.
- The BCA does not currently reflect the protection coordination between recloser and downstream fuses that is applied by DTE. DTE implements a fuse saving coordination that allows for the reclosers to clear a momentary fault on the line before a fuse blows open and results in a permanent outage to customers until a crew can replace it. The BCA currently does not reflect fuse saving coordination between protective devices that inherently prevents more sustained outages and is conservative in the benefits modeled.
- The analysis uses a 20-year model length for the discounted cash flow, meaning that an investment in DA is estimated to produce benefits for customers for the next 20 years. This assumption is conservative, as it is likely that the reclosers will last longer than 20 years and continue producing benefits for customers. Benefits after 20 years have not been quantified in the BCA.
- The model assumes that DTE has already made investments in PTMM and Vegetation Management. As a result, the benefits presented reflect the remaining value available to Distribution Automation (DA) after the impacts of those programs have been realized. This is discussed further in Section 4.7.1.

- The quantified benefits do not include reductions in the DTE's reactive costs. The reduction of crew hours spent due to DA's improvement of the restoration process are not quantified. In general, the better visibility and control that SCADA devices provide will likely reduce DTE's reactive costs. Further, reclosers can clear faults through their reclosing action, and as a result crews don't need to deploy to isolate and clear the fault
-

Figure 5-27 takes the CMI benefits from Figure 5-26 and applies the ICE Calculator (see Section 4.2) to monetize the outages and include the expected investment for each circuit to show the BCR. If this program were applied to the entire DTE distribution system, the overall investment level would be approximately $868.46 million. The weighted BCR for this program is 1.37. The figure shows that $380.14 million, or 43.8% of the total investment have a BCR ≥ 0.9. The weighted BCR for deploying this program only on circuits where BCR ≥ 0.9 is 2.71.

Figure 5-27: Distribution Automation Program BCR Summary



5.7.4 Qualitative Benefits and Costs

While the quantified Benefit-Cost Analysis demonstrates benefits to customers, there

are qualitative aspects that the BCA did not capture. Improvements to safety and the restoration process were not captured in the quantitative BCA, but have meaningful impact to both customers and the utility.

The quantified Benefit-Cost evaluation described above only included investments for reliability improvement. As noted above, this program also focuses on deploying reclosers outside of 4.8 kV substations at the station cable pole to minimize the risks of live wire. 1898 & Co. supported DTE in identifying circuits to deploy reclosers on the 4.8 kV system for this purpose. Other parts of DTE's filing include the specific scope and cost of this part of the program. Given the historical frequency of these types of faults that are not identified by the current protection scheme, this investment is justified in mitigating this risk to the general public.

The quantified BCA also does not consider DA's potential to improve the restoration process. DTE's current practice during outage restoration is to restore customers before repairing the failed infrastructure. With distribution automation, the reclosers will perform the outage restoration, rather than crews performing the manual switching. In addition to identifying outages more quickly, crews will save time from performing the manual switching, allowing them to focus more of their time on infrastructure repairs, decreasing outage times. These improvements in crew efficiency are not quantified in the BCA, but they have the potential to reduce outage durations and increase crew availability.

Following equipment repairs, energizing the system is currently done manually by crews. In the case of mainline outages, this requires crews to re-engage the substation breaker to reenergize the circuit. This causes outage times to be higher as the crews need to drive back to the substation. With distribution automation, system re-energizing can be done more quickly. This decrease has not been incorporated into these CMI benefits making the analysis conservative. The impact to the restoration process is especially valuable during major event days and catastrophic events, when crew availability is constrained.

In light of the conservative analysis, the importance of DTE's restoration process, and

the importance of reducing safety risk, investments in distribution automation are well justified.

5.8 Communication Network

This section presents an updated Benefit-Cost Analysis (BCA) of long-term communication network solutions for DTE. The goal is to identify a system-wide "North Star" communications strategy that delivers the greatest value to DTE's customers while supporting the grid's future operational needs and, based on that "North Star", evaluate near-term investments in fiber installation. In 2025, an initial analysis evaluated multiple scenarios for modernizing DTE's grid communications. Since that time, DTE's planning assumptions and strategic objectives have continued to evolve.

This 2026 update focuses on a direct comparison between two primary alternatives: continuing to use Public Cellular networks versus deploying a representative Private Cellular communications solution supported by fiber backhaul. The evaluation covers High, Likely, and Low connected device growth scenarios and excludes Distribution Automation (DA) program benefits in order to isolate communication network-related costs and cost avoidance.

Across all scenarios, the Private Cellular alternative results in lower total life-cycle costs than the Public Cellular approach, yielding a strong positive Benefit-Cost ratio (BCR). This analysis demonstrates that in present value terms, for every $1.00 invested in a Private Cellular network, DTE and its customers avoid roughly $1.56 to $1.61 in costs that would occur under the Public Cellular option. These quantified results reflect typical lifetime cost characteristics of private cellular communications solutions and are complemented by qualitative benefits related to reliability, cybersecurity, and operational flexibility, which are discussed later in this report.

Over a 40-year period, this translates to present-value savings on the order of $3 to $5 billion (depending on future device growth). These savings mainly stem from eliminating recurring carrier fees and avoiding forced mid-life equipment

replacements. They also provide a clear justification for pursuing a Private Cellular network as the "North Star" communications strategy.

5.8.1 Introduction and Background

This section provides an introduction, background, and context for the communication network analysis completed by 1898 & Co.

5.8.1.1 The Need for a Modern Communication Network

A modern, high-capacity, private communication network is essential for DTE to operate the electric grid efficiently, reliably, and securely. Advanced grid devices (smart sensors, automated switches, smart meters, etc.) require real-time connectivity to coordinate actions and improve power delivery. This connectivity enables immediate detection of problems (outages, equipment failures) and supports rapid, remote interventions to maintain service or restore power. It also underpins emerging capabilities like distributed energy resource management and detailed grid analytics.

DTE's current communication network infrastructure includes fiber-optic links and microwave radios on backbone routes, leased circuits in some areas, and TropOS-based wireless mesh networks supporting certain field communications. TropOS-based wireless mesh is effective for backhauling smart meter clusters via cell relays; however, it is not economically scalable for providing direct connectivity to a rapidly growing population of grid-edge devices. As device density increases, deploying dedicated TropOS nodes for each additional asset would result in prohibitive capital and operational costs, limiting its suitability as a long-term solution for expanded grid automation.

In summary, DTE's existing telecom network, while serviceable in the past, is now a bottleneck for grid modernization. Without an upgrade, DTE could face rising costs to keep outdated systems running, and the network would inhibit deployment of new technologies that could improve reliability and efficiency. This situation drives the need to invest in a unified, modern communications platform that can scale with

increasing data demands, connect a growing number of field devices, and meet stricter reliability and security standards – all in a cost-effective manner.

5.8.1.2 Purpose of the BCA and the "North Star" Strategy

The purpose of this BCA is to guide DTE in selecting a long-term, system-wide communication network strategy with the lowest life-cycle cost and greatest strategic value. Rather than focusing on individual projects or regions, this analysis establishes a clear system-wide direction – a "North Star" – for DTE's grid communications. With a defined end-state solution in mind, DTE can evaluate individual incremental investment (e.g., connecting a new substation or replacing a device) to align with the "North Star" plan, avoiding piecemeal fixes that might later become stranded or require rework.

In the 2025 analysis, multiple scenarios were examined including continued reliance on the legacy TropOS system, expanded use of public cellular, and building a private network under various grid use cases. That analysis concluded that the legacy platform was unsustainable and that a new communications strategy was needed for the long-term. It also indicated that building a Private Cellular network, supplemented by fiber, was the most cost-effective path when considering system-wide needs.

This 2026 BCA update builds on those findings with refined assumptions and focus:

- Direct Comparison - Public vs. Private: The analysis now centers on a binary choice between Public Cellular and Private Cellular. It eliminates intermediate or hybrid scenarios, providing a clear head-to-head evaluation of the two primary alternatives. Each is assessed over a 40-year horizon to capture the full life-cycle costs including initial capital, ongoing operations, and replacement cycles.
- Device Growth Scenarios: To account for uncertainty in the pace of grid modernization, three scenarios are modeled for the total number of connected field devices: High, Likely, and Low. These roughly correspond to reaching ~1.51 million, ~1.31 million, and ~1.07 million devices system-wide,

respectively. This represents a significant expansion from the ~100,000 devices considered in the 2025 analysis. Evaluating this broader range enhances the evaluation to understand if the recommended strategy remains robust whether device deployment accelerates or progresses more gradually in the coming decades.

- Exclusion of DA Program Benefits: Unlike the 2025 analysis, the 2026 BCA does not include reliability benefits from the Distribution Automation program in the communication network evaluation. In 2025, certain DA-driven outage reductions were factored into some scenarios. For clarity, the updated BCA treats the communication network purely as an enabling investment and measures its value by comparing costs (i.e., lowest cost and best fit justification method) rather than by assigning it direct reliability benefits. This way, the comparison between Public and Private communication options is straightforward and not conflated with other grid programs.

By taking this approach, the 2026 analysis provides a transparent view of the long-term financial and strategic trade-offs between relying on public carrier networks versus deploying a Private Cellular communications capability. The goal is that DTE's decision is informed by a holistic understanding of the full cost of each option and its alignment with DTE's mission to deliver safe, reliable and affordable energy.

5.8.1.3 Unique Aspects of Telecommunications Investments

Communication networks in a utility context have some unique characteristics that influence how their costs and benefits should be evaluated:

- Enabling Infrastructure (Indirect Benefits): A telecom network is an enabling investment. It provides the foundation for other grid projects such as DA, advanced metering, and distributed energy integration, to generate their benefits. It does not directly reduce outages or improve power quality on its own. Therefore, telecom BCAs rely on a "least-cost" (indirect benefit) analysis. We compare alternative ways to provide the required communications service and identify which has the lower 40-year cost. The 'benefit' of the cheaper option is the cost avoided by not choosing the more expensive option. This is

different from other project BCA discussed in this report, where one might quantify direct benefits like fewer outages or operational savings – here, the value is in cost reduction and risk avoidance.

- Re-Investment Risk - Importance of a Long-Term Plan: Telecom technologies evolve rapidly. If DTE were to invest in a short-term solution that isn't aligned with the eventual long-term strategy, it might have to replace that solution prematurely, effectively incurring costs twice. For example, expanding the TropOS radio system or signing a short-term cellular contract might seem economical now, but if DTE later commits to a different technology, those expenditures could be wasted. Thus, establishing a long-term preferred solution up front is critical. The 2025 study explored various "end states" to mitigate this risk, and this 2026 analysis reaffirms a clear end-state, such that ongoing investments can build toward a consistent goal.
- System-Wide vs. Local Optimization: The chosen system-wide strategy will guide most investments, but DTE acknowledges that local conditions vary. While the Private Cellular with fiber backhaul strategy may be optimal overall, there could be isolated cases, such as a remote location, where a different approach is temporarily more cost-effective. Local deviations can be evaluated on a case-by-case basis, but the overall strategy supports that any exceptions are made consciously and minimally. The BCA's primary role is to set the global optimum; it's understood that localized decisions will be revisited as necessary, especially for unique outliers, all while keeping the "North Star" in view.
- Sunk Costs in Private Infrastructure: Investing in a private communications infrastructure involves significant upfront costs that benefit the entire system. For example, core network equipment or a fiber route that connects multiple substations. Once those costs are incurred, they are sunk for the purposes of evaluating incremental decisions. While a localized comparison might show that a single small substation is cheaper to connect via cellular than via fiber, that equation changes if fiber is already running past that site as part of the broader network. In the 2025 analysis, when system-level costs

were allocated down to individual investments, it was clear that after the backbone is built, adding most individual substations to the private network costs very little extra and is financially attractive. Therefore, the system-wide BCA provides the umbrella justification, and localized analyses that consider only incremental costs (not re-counting sunk costs) to decide the best method for each site.

These factors frame the analysis approach (detailed in Section 5.8.4) and the interpretation of results. In essence, two pathways are being compared for critical underlying infrastructure, with an emphasis on which pathway minimizes long-term costs and risks for DTE customers. The communication network value is realized through enabling other functions and this BCA is about achieving that capability in the least-cost way possible.

5.8.2 Solution Alternatives

DTE's communication network decision involves two fundamentally different approaches, each with its own cost and risk profile: continued reliance on Public Cellular networks and deployment of a Private Cellular communications solution with fiber backhaul. Each approach is described in the following sections.

5.8.2.1 Public Cellular Network

The Public Cellular alternative means using commercial wireless carrier networks to meet DTE's grid communication needs. Under this approach, each field device, such as a recloser controller, line sensor, or meter, communicates via a subscription to the carrier's network. DTE would transition devices from legacy systems to cellular communication as those systems age out, leveraging the carriers' existing infrastructure rather than building its own.

Short-Term Pros: By using public networks, DTE can avoid large upfront capital investments in communication infrastructure. Device connectivity can be added on a pay-as-you-go basis: as new devices are deployed or old ones replaced, DTE would equip them with cellular modems and activate service plans. The carriers provide

wide-area coverage and ongoing technology upgrades, which means DTE doesn't have to purchase and install much network equipment itself initially.

Long-Term Cons and Risks: The apparent simplicity and low upfront cost of the public approach come with significant long-term costs and operational risks:

- Perpetual Carrier Fees: The Public Cellular model incurs recurring subscription fees for every device, every year. Over a multi-decade period, these fees accumulate to very large totals. They also scale linearly with system growth – if the number of connected devices doubles, the annual fees roughly double. This creates a rising cost curve that never stabilizes, since each new device adds a permanent new expense line.
- Obsolescence-Driven Replacements: Perhaps the biggest hidden cost is the impact of carrier technology transitions on device life. Public carriers periodically upgrade their networks (e.g., moving from 4G to 5G) and decommission older technologies. When a carrier shuts down an old network generation, any DTE devices using that technology must be replaced or upgraded to remain operational, even if those devices are only at mid-life. In practical terms, devices that might physically last 15-20 years could require replacement or upgrade in about 10 years due to technology changes. These obsolescence-driven replacements are in addition to the regular end-of-life (EOL) replacements that would occur at the 15-20 year mark; effectively, the Public Cellular strategy can force a doubling of replacement cycles, meaning many devices are bought twice over a 20-year span. This is a major incremental cost and logistical burden that does not exist in a private cellular scenario. The BCA explicitly models these obsolescence cycles as a separate cost category for the public cellular option.
- External Control and Uncertainty: By using a public network, DTE gives up a measure of control over a critical operational resource. Service terms, coverage quality, and pricing are determined by the carrier. While DTE can negotiate contracts, it ultimately cannot dictate the carrier's technology roadmap or pricing strategies. This introduces long-term cost uncertainty. For

example, data rates could increase faster than general inflation, or new fee structures might arise. Operationally, during major events, such as storms or emergencies, the carrier's network could be congested with public traffic, potentially compromising the performance of DTE's grid control signals when they are most needed. Additionally, relying on a public network means that cybersecurity controls and responses are partially in the carrier's hands, which can complicate compliance with utility-specific security standards.

In summary, while the Public Cellular alternative provides a near-term, low-capital way to meet communication needs, it carries significant long-term financial costs and operational risks. The cost to "rent" network services from carriers grows continuously with the system and includes hidden costs like technology refreshes. These factors make the public strategy more expensive and less within DTE's control over the long haul.

5.8.2.2 Private Cellular Network with Fiber Backhaul

The Private Cellular alternative reflects deployment of a dedicated cellular communications capability designed to support utility grid operations, with fiber backhaul providing high-capacity connectivity between access sites, substations, and control centers. The analysis evaluates representative infrastructure and operating cost characteristics typical of private cellular solutions, without assuming a specific spectrum band, licensing approach, or ownership model.

Upfront Investments: Unlike the public option, the Private Cellular strategy requires upfront capital investment:

- Network Infrastructure Build-Out: The network cost assumptions used in this analysis are intended to be representative of a private cellular deployment suitable for wide-area utility communications, including radio access equipment, core network functionality, and supporting infrastructure. These assumptions are used solely for the purpose of estimating typical lifetime costs and do not reflect a final design decision regarding spectrum selection or network configuration. The model assumes that major capital outlays for the

private network would begin in 2028, with the majority of capital spending complete by 2032.

- Fiber Backhaul Expansion: To support a Private Cellular network, fiber-optic cables are crucial for connecting radio towers and substations to the utility's control centers and to each other. DTE plans to expand its fiber network between 2026 and 2032 such that all key sites (including nearly all substations) have a high-capacity, low-latency connection. This fiber network not only carries cellular traffic, but also strengthens the utility's overall communications backbone (e.g., for relaying protection signals or other non-cellular data).
- Device Equipment Updates: In preparation for and during the Private Cellular rollout, DTE will replace or retrofit a large number of field devices with cellular-capable communication modules. The migration of devices onto the new network is projected to start in earnest by 2033 (once the infrastructure is ready) and proceed through the 2030s.

Long-Term Cost Structure: After this build-out, the cost profile of the Private Cellular network becomes favorable:

- Minimal Recurring Costs per Device: There are no carrier subscription fees for each device. Once the network exists, adding a new device involves only the one-time cost of the device's communications module and a negligible increase in the network's operating expense. In practical terms, the marginal cost of connecting each additional device is very low, since the network can accommodate growth without proportionally increasing cost. This stands in contrast to the Public model, where each device brings a new monthly bill.
- Controlled Replacement Cycles: Under a private cellular operating model, technology upgrades can be aligned with DTE's own schedule. Devices can remain in service for their full natural life (often 15–20 years) without being retired early due to network changes. This means the Private Cellular scenario largely avoids the kind of mid-life, obsolescence-driven

replacements for the Public option. In the financial model, no additional 10-year forced replacements were modeled in the Private scenario.

Operational Benefits: Beyond cost, a private network offers control and performance benefits:

- Dedicated Reliability: Key sites are equipped with backup power and redundant links, and critical communication paths can be engineered to meet utility reliability standards which are often higher than commercial communication network standards. During grid emergencies, the private network will carry only utility traffic, and it remains available for real-time operations even if public networks are jammed. DTE can also implement quality of service (QoS) settings to ensure that the most critical data, such as protective relay signals, are never delayed or dropped.
- Security and Compliance: A Private Cellular network is a closed, private system. DTE can enforce end-to-end encryption, strong authentication, and continuous monitoring tailored to the utility's cyber security requirements. The network can be isolated from public internet access, reducing cyber risk. This approach aligns well with regulatory expectations (e.g., NERC CIP standards) that critical control systems be secure and under the utility's direct oversight. DTE's security team can manage the network's defenses directly, without needing to rely on a third-party provider's policies or incident response.
- Flexibility and Scalability: The Private Cellular network can be upgraded or expanded as needed. DTE can increase capacity (through spectrum enhancements or additional sites) if usage grows, and it can incorporate new technologies when they mature and provide clear value. This can be done on DTE's own timetable, balancing cost and benefits. In contrast, under the public approach DTE would be subject to the carrier's upgrade timeline regardless of its own readiness. The ability to scale the private network inexpensively means that as DTE's grid evolves with more

automation, more sensors, and new control schemes, the communication network will not be a limiting factor or a cost-prohibitive hurdle.

Summary of Private Cellular: The Private Cellular option requires upfront planning and capital, but it transitions DTE from paying indefinitely for leased public network services to a dedicated communications platform. Over time, the investment is paid back through avoided fees and greater operational efficiencies. It positions DTE with a communications platform that is resilient, secure, and economically scalable for the foreseeable future.

5.8.3 Benefit-Cost Analysis Methodology

This BCA evaluates the full life-cycle cost of two telecommunications alternatives: Public Cellular and Private Cellular. The analysis calculates the present value of all costs incurred between 2026 and 2072, beginning with the start of capital expenditures for the Private Cellular network. This includes early investments in fiber deployment starting in 2026 and major infrastructure build-out occurring through 2032. The present value of all costs is calculated for each option to determine which is more economical in the long run. All cash flows are discounted to 2026 using a 6.50% discount rate, and an annual cost escalation of 2.50% is assumed for future costs.

The analysis treats the Public Cellular scenario as the baseline. The "benefit" of the Private Cellular scenario is the set of costs avoided by not following the Public Cellular path. This approach frames the decision as a least-cost problem, appropriate for an enabling infrastructure investment. If Private Cellular can provide the required communication service at lower life-cycle cost, then it yields a positive net benefit equal to the avoided costs of the more expensive public option.

5.8.3.1 Analysis Timeline and Comparison Basis

Analysis Period (2026-2072): The model assumes that Private Cellular network construction will take place primarily between 2028 and 2032, with fiber deployment beginning earlier in 2026 and continuing in parallel. By 2033, a substantial portion of spend would have happened and Private Cellular network is expected to be in service

and able to start supporting DTE's field devices. The comparison between Public and Private scenarios is structured to reflect equivalent service delivery between 2033-2072, while still accounting for all relevant costs incurred during the build-out phase (beginning in 2026) in the present value calculations.

Transition Period Considerations: Beginning in 2033, as DTE initiates the migration of existing field devices from Public Cellular to the Private Cellular network, the Private scenario incurs overlapping costs; namely, continued carrier fees for devices not yet transitioned. 1898 & Co. included these overlapping costs in the Private scenario cash flow for a fair comparison.

This approach holds the scope of service constant for each scenario during the comparison period; the variables are how they achieve it and at what cost.

5.8.3.2 Key Cost Components and Assumptions

The BCA model includes several major cost elements. Each one is outlined below:

- Edge Device Investments and Replacements: This includes costs for deploying new communication-enabled field devices and replacing them over time.
  - Device Inventory & Unit Costs: DTE provided a detailed inventory of existing field devices that rely on communications, with counts by type, and the expected average cost to replace or upgrade each device type.
  - Natural End-of-Life (EOL) Cycle: We assume most field devices have a useful life of 20 years. Using device age profiles, 1898 & Co. applied end-of-life curves to model when devices would be retired due to normal aging or wear-out. This spreads replacements over the 40-year span instead of all at once. Under both scenarios, devices would undergo these regular EOL replacements.
  - Obsolescence-Driven Replacements: In the Public Cellular scenario, devices face an additional replacement cycle around every 10 years on average, driven purely by carrier technology transitions. For example, the shutdown of 3G or 4G networks forcing upgrades to 4G or 5G.
    These obsolescence-driven replacements are in addition to the 20-year EOL

replacements. The model explicitly includes this by assuming an effective 10-year communication lifespan for devices on the public network. This effectively doubles the number of replacements for each device over 40 years (e.g., a device might be replaced at year 10 due to obsolescence and again at year 20 for true end-of-life). In the Public scenario, to avoid double counting, the model treats obsolescence-driven replacements as incremental to the natural replacement cycle. In the Private Cellular scenario, this incremental obsolescence cost is set to zero, reflecting the assumption that a private cellular network would help avoid premature device retirements. Additionally, in the Private Cellular scenario, 1898 & Co. assumed no forced mid-life replacements. Devices are retired at the end of their natural life, with technology upgrades managed to coincide with those cycles. This key difference eliminates a major cost category in the Private scenario.

- Carrier Service Fees: For each device on a public network, DTE must pay ongoing carrier fees (for data plans or connectivity). DTE provided current per-device annual fees for various device types. In our model, these fees are applied to every active device in the Public scenario for each year, growing as the number of devices grows. 1898 & Co. assumed an escalation of 2.5% per year on fee rates (matching general inflation). Carrier fees are a dominant cost in the Public scenario's long-term profile, and they do not decline over time or with scale. More devices always mean proportionally more fees. In the Private Cellular scenario, these fees are almost eliminated after the transition period, since most devices will use the private network. Note that a very small number of specialty connections might still use public networks due to unique circumstances, but these have been assumed to be negligible in cost.
  - Private Cellular Network Infrastructure Costs: DTE provided an estimate of capital investments for building and expanding the private network:
    - Spectrum Acquisition and Core Network: This includes securing suitable spectrum (a dedicated frequency band) and deploying a

dedicated cellular core. These costs occur early (2028-2029) and are necessary for network launch.

- Fiber Routes and Substation Links: About 29 main fiber route projects were analyzed to fill additional gaps in the existing fiber network. 1898 & Co. included the costs of constructing these routes (which typically span between clusters of substations) between 2026 and 2032, as well as the costs to install fiber "last-mile" connections and networking gear at each substation. Fiber not only carries cellular traffic but also strengthens DTE's capacity to handle other communications (e.g., protective relaying, high-speed data transfers) independent of third-party telecom providers.
- In the Public Cellular scenario, the primary O&M costs are embedded in the carrier fees (since the carrier operates the network). DTE's internal O&M is minimal beyond managing contracts and perhaps some integration equipment.
- In the Private Cellular scenario, there are O&M costs to run the network - including staffing for network operations, maintenance of tower sites (e.g., inspections, repairs), updating network software, and maintaining the fiber plant. These cost estimates provided by DTE are included in the model and contribute to the annual expenses of the Private scenario.

All cost elements are summed over the 2026-2072 timeline including build-out years and then discounted to 2026 to compare the total present values of each alternative. The difference between them (Public minus Private) represents the net savings or "benefit" of choosing the Private Cellular path. The following section presents the results of this analysis.

5.8.4 System-Wide "North Star" Benefit-Cost Results

To evaluate the long-term financial implications of each communication network strategy, the 2026 BCA assessed the total life-cycle costs of the Public Cellular and Private Cellular over 2026-2072 study period. This analysis provides a comprehensive

view of the cumulative capital, operational, and replacement costs associated with each option, enabling a direct comparison of their economic performance under varying grid modernization scenarios.

5.8.4.1 Total Life-Cycle Costs

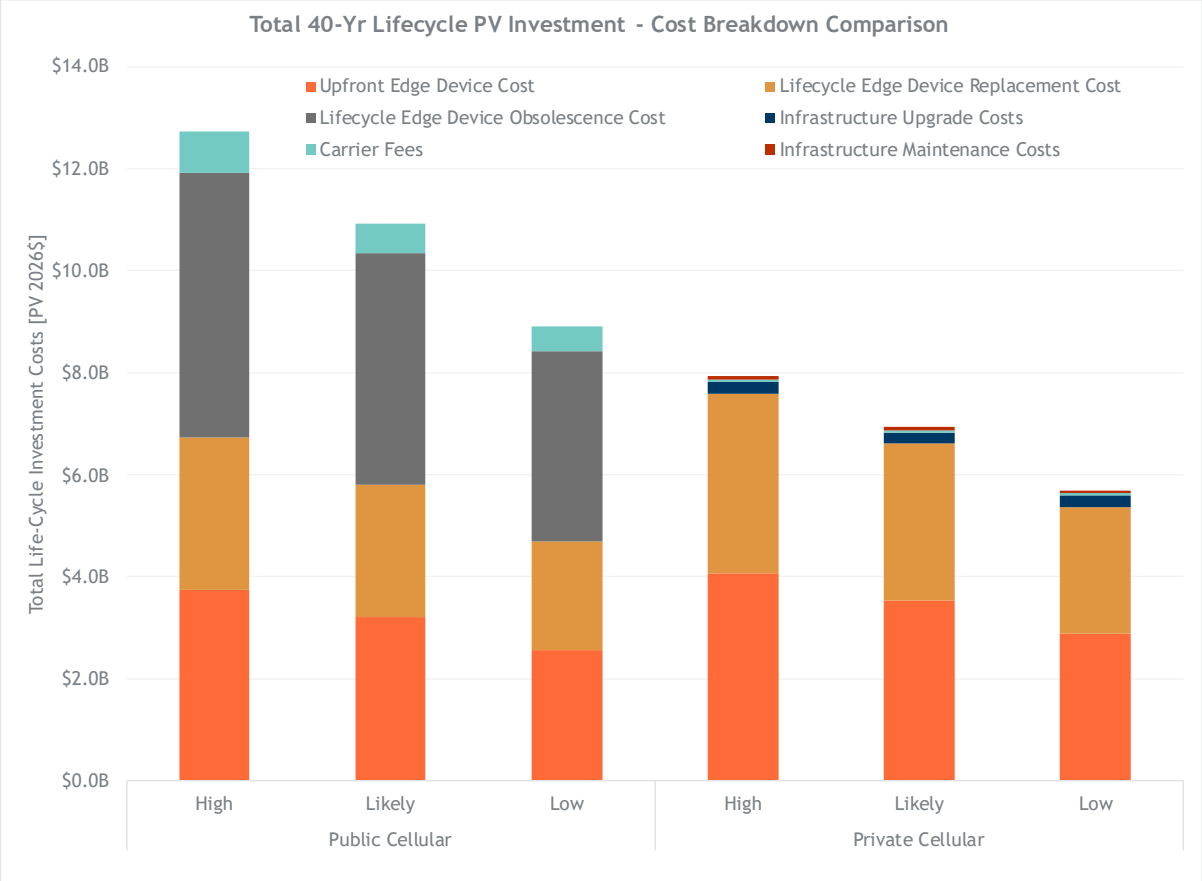
For each device growth scenario (High, Likely, Low), 1898 & Co. calculated the total life-cycle cost of each alternative, in present value terms (2026 dollars):

- Public Cellular - Total Life-Cycle Cost (Present Value, PV):
  - High Growth (1.51M devices): $12.73 billion
  - Likely Growth (1.31M devices): $10.92 billion
  - Low Growth (1.07M devices): $8.90 billion
- Private Cellular - Total Life-Cycle Cost (Present Value, PV):
  - High Growth (1.51M devices): $7.93 billion
  - Likely Growth (1.31M devices): $6.93 billion
  - Low Growth (1.07M devices): $5.69 billion

In every scenario, the Private Cellular alternative remains significantly lower-cost over the full life cycle. The resulting present-value cost advantage of Private Cellular is approximately $4.8 billion in the High case, $4.0 billion in the Likely case, and $3.2 billion in the Low case.

The cost advantage of Private Cellular is more pronounced at higher device counts. This is because the Public scenario costs, especially carrier fees and obsolescence-driven replacements, scale almost directly with the number of devices. Whereas the Private scenario costs plateau after the initial build-out since additional devices add very little incremental cost. The result is that as the grid becomes more connected, moving from Low to High device growth, the gap between the two scenarios' costs widens in favor of Private Cellular. Figure 5-28 shows the comparison of the public cellular and Private Cellular present values side by side.

Figure 5-28: 40-Year Present Value Cost Breakdown: Public vs. Private (for each scenario)



5.8.4.2 *Cost Breakdown and Drivers*

To illustrate why the Private Cellular option is cheaper, the life-cycle costs are broken into key components for the Likely scenario (nominally 1.31M devices) in Table 5-1 below. The patterns are similar in High and Low cases.

Table 5-1: Life-Cycle Cost Breakdown (Likely Scenario, PV 2026$)

Cost Category (PV)	Public Cellular (Million)	Private Cellular (Million)
Upfront Device Investments (Initial wave)	$3,200 M	$3,538 M
Lifecycle Device Replacements (EOL)	$2,599 M	$3,067 M
Obsolescence-Driven Replacements	$4,533 M	$0 M
Network Infrastructure Build-Out (Private Cellular)	$0 M	$227 M
Carrier Service Fees (Recurring)	$590 M	$41 M
Network O&M (Infrastructure Ops)	$0 M	$54 M
Total Present Value Cost (2026$)	$10,922 M	$6,927 M

Summary of this breakdown is outlined below:

- Obsolescence-Driven Replacements (Public Only): In the Public Cellular PV total (~$10.9 billion), about $4.5 billion, roughly 40%, is due to obsolescence-driven device replacements. These are the mid-life (≈10-year) replacements required to keep up with carrier changes, incremental over the standard end-of-life replacements. The Private Cellular column shows $0 for this category, highlighting a huge cost avoidance: in the Private case, devices are not replaced in 10 years just for network reasons; they are utilized for their 20-year life.
- Carrier Fees vs. Network O&M: The costs in the Private scenario (network O&M of ~$54 million PV and a residual $41 million in carrier fees during the overlap period) are a small fraction of the over half a billion dollars (PV) in carrier fees under the Public scenario. In nominal terms, the Public scenario would involve paying several million dollars every year to carriers, for a total that dwarfs the ongoing cost of a private network.
- Device Costs: Both scenarios involve significant investment in field devices over the 40-year study period, including initial deployment and subsequent replacements. The Private Cellular scenario shows a somewhat higher present

value of device costs upfront because it assumes deployment of new cellular-compatible devices, whereas the Public scenario begins with approximately 111k existing devices already in service. The Public scenario can therefore defer a portion of initial replacements relative to Private Cellular. However, once obsolescence-driven replacements are incorporated, the Public scenario ultimately replaces a greater number of devices over time.

- **"Infrastructure" vs. "No Infrastructure":** The Private scenario incurs about $227 million PV in infrastructure costs (towers, fiber, spectrum) that the Public scenario avoids. However, this network infrastructure investment leads to much greater cost avoidance in later years, resulting in a strong net-positive outcome.

5.8.4.3 Benefit-Cost Ratio

Using the totals above, the Benefit-Cost Ratio (BCR) for choosing Private Cellular can be calculated for each scenario. The BCR is the ratio of the avoided cost (Public minus Private) to the Private Cellular investment cost:

- High scenario: BCR ≈ 1.61 (Avoided cost $4.80B vs. Private Cellular cost $7.93B)
- Likely scenario: BCR ≈ 1.58 (Avoided cost $4.00B vs. Private Cellular cost $6.93B)
- Low scenario: BCR ≈ 1.56 (Avoided cost $3.21B vs. Private Cellular cost $5.69B)

All BCRs are above 1.0, indicating a financially favorable investment under a wide range of futures. The Likely case BCR of 1.58 means that in present value terms, the Private Cellular strategy returns about $1.58 in avoided costs for every $1.00 spent. Even in the Low case (slow growth), it's roughly $1.56 back per $1.00 and in the High case it's about $1.61 back per $1.00.

5.8.4.4 *Summary of Key Quantitative Insights*

The quantitative analysis clearly demonstrates:

- The private cellular scenario is the preferred solution as it is the least-cost alternative for all device count scenarios.
- The larger the scale of the grid communications (more devices/data), the greater the savings with Private Cellular, since the costs do not grow linearly with device count whereas Public costs do.
- A significant portion of the Public scenario cost is attributable to carrier fees and forced early replacements, elements the Private scenario avoids.
- The financial case holds even if grid modernization is slower (Low scenario) or if discount rate or other factors change moderately. For instance, even a scenario with the low device growth still yielded a BCR of 1.56.

The next section examines the economic outcome at a more granular level (individual substation connections and fiber routes), reinforcing that this strategy is sound not just in aggregate but in its implementation details. Qualitative drivers and other strategic considerations area also address below.

5.8.5 Substation & Fiber Route Benefit-Cost Results

To check if the recommended strategy makes sense not only system-wide but also at a granular level, the analysis examined the economics of connecting individual substations and fiber routes under the Private Cellular strategy. DTE's 2026 plan analyzes 29 new fiber route projects to provide connectivity to its 602 distribution substations. These projects supplement those already constructed or currently underway, and some routes will serve multiple substations. Each substation or route can be evaluated with its own BCA, considering the local costs to extend fiber or wireless coverage and the local benefits (primarily avoided carrier fees and avoided legacy system costs for that substation's devices).

1898 & Co. performed this cost allocation of the global costs to each of the substations and fiber routes for two scenarios to understand the preferred alternative, Private or Public cellular, for each individual component. The first was to

allocate all costs to each substation and fiber route, the second was to exclude 'sunk' costs in the allocation. In the case of this BCA, the sunk costs for cost allocation purposes are the cost of towers and spectrum. It is appropriate to exclude these costs when considered individual investments.

Updated 2026 Substation BCA Results: Even under the more conservative assumptions of the 2026 analysis (with no DA benefits, etc.), most substations are economically justified to connect to the private network. Below is a summary of substation-level BCR (BCR > 1 means Private Cellular solution is lower cost than the Public Cellular alternative) outcomes across the scenarios:

Table 5-2: Substation Benefit-Cost Analysis Summary

Substation BCR	High (602 subs)	Likely (602 subs)	Low (602 subs)
BCR ≥ 0.9	470 substations	458 substations	454 substations
BCR ≥ 0.9 (Sunk Cost Excluded)	497 substations	495 substations	491 substations

In the Likely scenario, 458 out of 602 substations (approximately 75%) show a BCR of 0.9 or higher on an individual basis. This indicates that connecting those substations to the Private Cellular with fiber network yields a positive net financial return over the analysis period when considering their specific costs and avoided costs.

When system-wide sunk costs are excluded, the number of substations meeting this threshold increases to 495 in the Likely scenario, demonstrating that the Private Cellular solution is even more economically favorable when evaluated on an incremental, location-specific basis.

An additional 12 substations fall just below break-even (BCR between 0.8 and 0.9); these are typically locations with higher fiber costs or lower device counts, but they are close to achieving positive economics. A further 36 substations show partial benefits (BCR between 0 and 0.8). The remaining 96 substations were not allocated any communication-dependent benefits in the model due to limited available data. As

a result, neither the Public nor Private scenario was modeled to provide quantifiable benefits at locations and are therefore excluded from the economic comparison.

Updated 2026 Fiber Route BCA Results: The fiber routes are groupings of substation connections (each route ties a set of substations into the network). Evaluating at this aggregate level (which is often how projects would be executed) also shows robust results.

Table 5-3: Fiber Routes Benefit-Cost Analysis Summary

Fiber Route BCR	High (29 routes)	Likely (29 routes)	Low (29 routes)
BCR ≥ 0.9	19 routes	19 routes	18 routes
BCR ≥ 0.9 (Sunk Cost Excluded)	29 routes	28 routes	26 routes

In the Likely scenario, 19 of the 29 fiber route projects have a BCR of 0.9 or higher, indicating strong net economic value. When sunk costs are excluded, nearly all fiber routes exceed the BCR ≥ 0.9 threshold, underscoring that route-level economics improve materially once system-wide investments are removed from individual project evaluations.

The remaining routes all show positive benefits, with 3 routes falling in the 0.8-0.9 BCR range and 7 routes in the 0-0.8 range. No fiber route shows a zero benefit. Every planned route carries some of the communications load and thus provides some avoided cost. The routes with lower BCRs usually serve areas with fewer devices or longer distances, but they often still need to be built for network topology reasons (to reach remote pockets). These lower-return routes are relatively few, with all routes showing some benefits.

Furthermore, these results do not account for strategic value of network redundancy or future use on those routes. They strictly look at currently anticipated device-driven benefits, making them conservative.

From a system planning perspective, the updated analysis confirms that DTE's planned fiber build-out and substation connections under the Private Cellular strategy remain economically sound:

- A substantial percentage of the total substation investment, by number of sites, is either breakeven or net positive, with results strengthening further when system-wide sunk costs are excluded.
- All 29 fiber routes provide value, and about two-thirds of them in the Likely case have clear net benefits (BCR ≥ 0.9). The remaining routes still contribute to the overall strategy (for completeness of the network) and have partial cost recovery through avoided expenses. When system-wide sunk costs are excluded, nearly all fiber routes exceed the BCR ≥ 0.9 threshold, indicating even stronger route-level economics.

It's also worth noting that these results are slightly conservative. They do not include potential operational benefits of having fiber at every substation, such as improved protection schemes or future applications, and they assume no DA reliability benefits. If even a small fraction of the qualitative benefits (e.g., faster restoration in storm events due to more reliable comms) were monetized, many of the borderline cases would likely tip to BCR ≥ 0.9. However, even without those considerations, the local-level economics are strong.

The 2026 substation and fiber route analysis reinforces that the Private Cellular/fiber strategy is not only optimal for the system but also justified when drilling down to individual projects. Each project is either clearly beneficial or strategically necessary as part of the broader network roll-out. This local perspective provides additional assurance that the chosen path will create value for customers at every level of implementation.

In conclusion, transitioning to a Private Cellular/fiber communication network is the recommended long-term strategy for DTE and its customers. It provides the lowest life-cycle cost solution, avoids the pitfalls of vendor dependency and forced upgrades, and establishes a robust foundation for the grid's ongoing modernization.

5.8.6 Qualitative Benefits and Strategic Considerations

While the numbers make a strong case for the Private Cellular strategy, there are additional qualitative benefits that bolster it as the prudent long-term choice for DTE:

- Reliability and Resilience: With a private network, DTE can design its communication network to utility-grade reliability standards. This includes robust backup power at communication sites, redundant paths (e.g., fiber loops) for critical links, and coverage focused on grid asset locations (not population centers). During major storms or emergencies, when public cellular networks often experience congestion or outages, the private network would continue to function solely for DTE's operations. This dedicated capacity means, for example, that automated restoration commands and damage assessment data can flow unimpeded even if cellular phone service for the public is overloaded. The result is faster outage response and a more robust grid during crises. These reliability improvements, while not explicitly monetized in the BCA, are invaluable in fulfilling DTE's service obligations.
- Cybersecurity and Compliance: With a private, closed network, DTE significantly reduces cybersecurity risks. Communications with substations and field devices can be kept off the public internet and confined to DTE-controlled infrastructure. This 'air gap' and control over network access make it much harder for malicious actors to infiltrate or disrupt critical systems. Public carrier networks, in contrast, connect millions of users and rely on broadly shared infrastructure and protocols, creating a larger attack surface and potential vulnerabilities outside of DTE's direct control. A private network aligns with regulatory trends (e.g., NERC CIP standards) that favor isolating key grid control systems on secure, utility-run circuits. Adopting Private Cellular now anticipates future compliance requirements and avoids the risk that DTE would be forced for security reasons to migrate off public networks later (at possibly great expense).

- Cost Predictability and Control: The Private Cellular model converts variable costs into fixed costs. This contrasts with the Public model, where costs remain variable (per device) and subject to market forces. Utilities and regulators generally prefer cost stability. Through a private cellular deployment supported through long-term arrangements, DTE avoids the risk of sudden carrier fee increases or changes in terms of carrier fees. Any technological upgrades on the private network can be planned and budgeted internally, rather than reacting to an external mandate (which might come at an inconvenient time financially). This control also means DTE can improve the timing of investments – for example, deciding to implement a 5G upgrade when equipment costs have come down and a genuine need exists, rather than when a carrier decides to pursue it for competitive consumer reasons.
- Scalability and Future Innovation: The analysis showed that as device counts go up, the private network's relative advantage grows. This implies that the more DTE modernizes and digitizes its grid, the more value a private network provides. Importantly, a private network enables future use cases at low marginal cost. If DTE in 10 years wants to add thousands of distributed energy resource controllers or support a network of EV charging stations with grid management signals, or deploy advanced sensors on every transformer, the communications cost to do so on the Private Cellular would be minimal. That encourages innovation and adoption of beneficial technologies. In the Public scenario, each new use case would come with a hefty new communications bill (potentially tipping some projects from feasible to infeasible due to ongoing costs). Thus, choosing Private Cellular not only saves money on current forecasts, but removes a potential barrier to future grid innovations – it's an investment in optionality. The communication network capacity can be seen as an abundant resource that DTE owns, ready to be used in whatever way it provides value to customers, without needing a business case for each MB of data.

Beyond the clear numerical savings, the Private Cellular network is a strategic enabler. It provides DTE with a higher reliability communications backbone, better

security postures, stable and lower long-term costs, and the flexibility to support the grid's evolution. These benefits are difficult to quantify but have profound implications for the success of DTE's grid modernization and the quality of service experienced by customers.

5.9 Subtransmission Redesign and Rebuild

1898 & Co. performed a Benefit-Cost Analysis of the subtransmission projects provided by DTE using the Resiliency Model and Equipment Failure Mitigation Model methodology outlined in Section 4.3 and Section 4.4. The evaluation quantified the reliability, resilience, and risk-reduction benefits of replacing and reconfiguring aging subtransmission infrastructure. Assets associated with these projects were evaluated separately and were not included in the analyses for the other evaluated programs.

5.9.1 Background & Program Description

The subtransmission system serves as a critical link between the transmission and distribution networks. Subtransmission circuits deliver power from the bulk electric system to distribution substations that serve customers throughout the DTE service territory. Because these circuits supply multiple substations and distribution feeders, failures on subtransmission infrastructure can impact large portions of the electric system.

Several areas of the DTE subtransmission system include infrastructure that is approaching or exceeding its expected service life. Aging conductors, poles, and station equipment increase the likelihood of failures that can result in outages and complex restoration efforts. Additionally, some portions of the system are experiencing capacity constraints or operational limitations that restrict maintenance activities or limit the ability to transfer load during outages.

The Subtransmission Redesign and Rebuild Program addresses these challenges by modernizing portions of the subtransmission network. Projects within this program typically include reconductoring existing lines, replacing aging structures, upgrading station equipment, installing switching devices, and improving circuit configurations to enhance system performance.

Several projects also improve accessibility and maintainability by relocating circuits from deep right-of-way to more accessible corridors. These improvements reduce exposure to vegetation-related outages and enhance a crew's ability to perform maintenance and restoration activities.

5.9.2 Estimating Investment Activities and Cost

This section outlines the systematic approach 1898 & Co. employed to identify the investment activities associated with the Subtransmission Redesign and Rebuild Program and estimate their expected costs.

DTE provided a list of projects for evaluation as part of the Benefit-Cost Analysis. In total, 12 projects were provided for evaluation in the Subtransmission Redesign and Rebuild Program. Each project was provided in a project-level scoping document containing detailed information regarding the proposed work. This information included the circuits or substations where the work would occur, the quantities of infrastructure to be replaced, retired, or installed, and the estimated cost of each project.

1898 & Co. reviewed the scoping information provided by DTE and developed a process to translate the proposed project scopes into asset-level investment activities that could be evaluated within the Benefit-Cost modeling framework.

Using the circuits, substations, and equipment descriptions included in the project scopes, 1898 & Co. applied a set of rules to identify the specific assets associated with each project. These rules mapped project-scope information to assets in DTE's GIS and Maximo asset management system.

Where project scopes included quantities such as miles of conductor replacement or counts of equipment replacement, these quantities were used to identify the specific assets included in the evaluation. By identifying assets at this level of granularity, the evaluation improves the relationship between the infrastructure being replaced, the likelihood of equipment failures, and the customers impacted by those failures.

The expected cost of each project was based on the project-level cost estimates provided by DTE as part of the project scoping documentation. DTE also provided unit

cost assumptions, which were incorporated into the modeling of investment activities to estimate the risk and resilience benefits associated with the projects.

For purposes of the Benefit-Cost Analysis, DTE's total project costs were compared with the quantified risk and resilience benefits associated with replacing or reconfiguring the infrastructure.

5.9.3 Quantitative Benefit-Cost Results

1898 & Co. evaluated the benefits of the Subtransmission Redesign and Rebuild Program using the analytics models described in Section 4.3 and 4.4. The evaluation quantified the reliability, resilience, and risk reduction benefits associated with replacing aging subtransmission infrastructure.

Subtransmission assets serve as critical backbone infrastructure for the electric system. Failures on these assets can interrupt service to multiple downstream substations and distribution circuits. Proactively replacing aging infrastructure reduces the likelihood of these failures and the associated customer outages.

The analysis estimated avoided restoration costs and reductions in Customer Minutes Interrupted (CMI) associated with lowering the probability of equipment failures. The avoided outage impacts were monetized using the ICE Calculator described in Section 4.2. In addition to avoided outage costs, the evaluation incorporated avoided restoration costs associated with repair activities following equipment failures.

Table 5-5 includes a high-level description of each project, the resulting Resilience, Reliability, & Risk BCR, and the primary benefit drivers associated with the investment. Using the legend in Table 5-4, the table identifies whether each project's benefits are associated with avoided restoration costs, avoided customer minutes interrupted (CMI), capacity, operability, and safety. This summary provides additional context for understanding how the quantified BCA results align with the underlying drivers for each project. The evaluated projects represent a total investment of approximately $405 million. These results indicate that several projects deliver strong, quantified reliability and resilience benefits relative to their investment costs. Other projects produce more modest quantified benefits but may still provide

important improvements in system reliability, operations, and safety that are not fully captured in the quantitative evaluation.

Table 5-4: Benefit Drivers

Driver	Indicator
Avoided Restoration Costs	
Avoided Customer Outages (CMI)	
Capacity	
Operability	
Safety	

Table 5-5: Subtransmission Redesign and Rebuild Projects Description and Drivers

Project Name	Project Description	BCR	Benefit Drivers (Monetized and Captured by BCR)	Benefit Drivers (Non-monetized)
Subtransmission Redesign & Rebuild: Waterman	Bus consolidation project at Waterman Substation consisting of: • Remove 15 breakers • Remove 11 relay panels • Replace 5 breakers • Replace 1 relay panel • Remove 5 reactors • Replace approximately 1,500 feet of subtransmission cable	1.43		
Subtransmission Redesign & Rebuild: Tie 7504	• Replace 12.2 miles of Subtransmission overhead conductor on Tie 7504 • Install 4 miles of new Subtransmission overhead conductor on Tie 7504 to reroute out of deep right of way • Replace 3 pole top switches • Install 1 40kV capacitor bank at Wilmont substation • Replace 1 breaker, 2 disconnects, 1 relay panel at Wilmont Substation • Replace 1 breaker, 2 disconnects, 1 relay panel at Arrowhead Substation	0.94		
Subtransmission Redesign & Rebuild: Tie 3205	• Replace 1 breaker, 2 disconnects, 1 relay panel at Port Austin • Install 28.8 miles of overhead conductor on Tie 3205 and relocate circuit out of	0.62		

	deep right of way • Remove 25.6 miles of overhead conductor on Tie 3205 • Install 6 pole top switches • Remove 8 pole top switches			
Subtransmission Redesign & Rebuild: Tie 4104	• Replace 18 miles of overhead conductor on Tie 4104 • Install 4 miles of new subtransmission overhead conductor on Tie 4104 to reroute out of deep right of way • Replace 18 miles of distribution under-build conductor and associated equipment • Install 2 Automatic Pole Top Switches • Replace 3 manual pole top switches • Install 1 circuit switcher and replace control house and relaying at Talbot substation	0.59		
Subtransmission Redesign & Rebuild: Trunk 2455	• Install 1000 feet of conduit and 4 manholes • Remove 200 feet of conduit • Install 14,000 feet of subtransmission cable • Install 4,000 feet of distribution cable • Remove 7,700 feet of subtransmission cable • Remove 2,200 feet of distribution cable	0.53		
Subtransmission Redesign & Rebuild: Pigeon Area Improvement	• Install (1) new station and decommission and remove existing station equipment on existing substation property • Decommission and remove existing station equipment at (1) existing station • Replace (2) breakers • Reconfigure (5) subtransmission tie lines	0.52		
Subtransmission Redesign & Rebuild: Trunk 7386	• Replace 2 miles of cable on Trunk 7386 • Install .5 miles of conduit • Reconductor ~1 mile of 3/0 ACSR with new 40kV 636 AL SW-ACSR • Remove pothead and install new cable terminations at Chestnut Station • Replace one cable pole and cable termination	0.44		
Subtransmission Redesign & Rebuild: Imlay Rebuild	• Purchase substation property • Build (1) new class B substation on new property, substation to be named Borland. • Reconfigure subtransmission lines, install 1 mile of conduit, new cable poles, and 3.5 miles of 40kV overhead • Convert subtransmission exists at Otsego from overhead to underground • Decommission class B substation at Imlay • Upgrade relaying at Hunter's Creek and Yale substation	0.32		
Subtransmission Redesign &	Reconfigure Cortland substation:	0.22		

Rebuild: Cortland Station Expansion	• ITC will relocate 120kV equipment to across the street property • Replace 2 station transformers • Install 6 circuit switchers • Replace 600 feet of cable, install 600 ft of conduit			
Subtransmission Redesign & Rebuild: Transformer High Side Protection Program	• Install high side switching devices, circuit switches or breakers on 22 subtransmission and distribution transformers at 16 different stations • Replace or relocate ten of those transformers due to space constraints	0.22		
Subtransmission Redesign & Rebuild: Hurst	Expansion at Hurst substation to consist of: • Install 1 station transformer • Install 1 circuit switcher • Install 1 breaker • Install 1 disconnect • Install 1 relay panel	N/A		
Subtransmission Redesign & Rebuild: Trunk 4601	Expansion at Benet substation to consist of: • Install 1 station bus • Install 3 breakers • Install 6 station disconnects • Install 4 relay panels Extension of Trunk 4601 line to consist of: • Install 11.1 mile of overhead construction	N/A		

Note: Certain projects primarily involve installing new infrastructure. Because the quantitative BCA is designed to evaluate the benefits of replacing or retiring existing at-risk assets, monetized benefits were not captured for these projects. These investments may still provide important capacity and operability benefits.

5.9.4 Qualitative Additional Benefits of the Program

The previous sections have outlined the results from quantifying the benefits of specific investments. As discussed above in Section 4.6, it is difficult to fully capture and quantify all the factors that go into every investment decision. For the Subtransmission Redesign and Rebuild Program, several additional qualitative benefits further support the proposed investments.

First, these projects improve the operational flexibility of the electric system. Upgrading aging infrastructure and modernizing subtransmission configurations improve system operators' ability to isolate faults, transfer load between substations, and perform maintenance activities without significantly impacting customers. In several areas of the system, existing infrastructure limits the ability to perform

maintenance or operational switching due to legacy equipment or constrained system configurations. Modernizing these facilities improves system operability and reduces the operational risks associated with maintaining the electric system.

Second, replacing aging subtransmission infrastructure improves safety for both utility personnel and the public. Aging conductors, poles, breakers, and station equipment can pose safety risks when failures occur unexpectedly. Proactively replacing this infrastructure reduces the likelihood of catastrophic equipment failures and improves the safety of field crews who maintain and operate the system.

Finally, the subtransmission network is a critical component in providing service to DTE customers. When an outage occurs on the subtransmission system, it could affect thousands of DTE customers; for this reason, the system is designed to provide N-1 redundancy to reduce impacts. DTE has a duty to serve customers safely and reliably, and these investments support long-term system planning objectives by increasing system capacity and strengthening the backbone of the electric grid. Modernized subtransmission infrastructure enhances the system's ability to accommodate load growth and distributed energy resources (DERs) and provides redundancy to reduce the impact of service disruption to customers.

While the quantitative analysis demonstrates that many of these investments provide measurable reliability and resilience benefits to customers, the additional qualitative benefits described above further support the value of the Subtransmission Redesign and Rebuild Program.

5.10 4.8 kV & 8.3 kV Conversion

1898 & Co. performed a Benefit-Cost Analysis of the conversion projects provided by DTE using the Resiliency Model and Equipment Failure Mitigation Model methodology outlined in Section 4.3 and Section 4.4 above. The evaluation quantified the reliability, resilience, and risk reduction benefits associated with converting legacy voltage circuits and replacing aging infrastructure. Assets associated with these projects were evaluated separately and were not included in the analyses for the other evaluated programs.

5.10.1 Background & Program Description

The DTE Electric distribution system includes several areas that continue to operate at legacy voltage levels, including 4.8 kV and 8.3 kV systems. Much of this infrastructure was constructed several decades ago and includes equipment that is approaching the end of its service life.

Lower-voltage distribution systems generally have lower capacity and less operational flexibility than higher-voltage distribution systems. In addition, many of these legacy systems operate as electrical islands with limited ability to transfer load to neighboring circuits. These operational constraints can make it more difficult to perform maintenance activities, restore service during outage events, and accommodate increasing customer demand.

Several of the projects included in this program address aging substations and distribution and subtransmission infrastructure that are approaching or exceeding their expected service life. In some cases, substations serving these systems were constructed many decades ago and contain equipment for which replacement parts are increasingly difficult to obtain. Other projects address capacity constraints associated with growing customer demand.

The 4.8 kV and 8.3 kV Conversion Programs address these challenges by modernizing portions of the distribution network and converting legacy systems to 13.2 kV operation. These projects may include constructing new substations, expanding or upgrading existing substations, converting overhead and underground circuits to higher voltage levels, consolidating circuits to a single substation, replacing aging transformers and cables, and installing modern switching and automation equipment.

By converting these legacy systems to higher-voltage distribution configurations, the program improves circuit capacity, enhances operational flexibility, and supports the long-term reliability and resilience of the electric distribution system.

5.10.2 Estimating Investment Activities and Cost

The process used to identify investment activities and estimate costs for the voltage conversion projects follows the same methodology described above for the Subtransmission Redesign and Rebuild Program.

DTE provided project-level scoping documentation describing the circuits involved, the quantities of infrastructure to be converted, replaced, or retired, and the estimated project costs. These scopes were reviewed by 1898 & Co. and translated into asset-level investment activities using the GIS and Maximo datasets provided by DTE.

Assets associated with each project were identified based on the circuits, substations, and equipment types described in the project scope. Where project scopes specified quantities such as miles of conductor replacement or counts of equipment replacement, these quantities were used to determine the specific assets included in the evaluation.

The expected cost of each project was based on the project-level cost estimates provided by DTE as part of the project scoping documentation. DTE also provided unit cost assumptions, which were incorporated into the modeling of investment activities to estimate the reliability and resilience benefits associated with the projects.

For purposes of the Benefit-Cost Analysis, DTE's total project costs were compared with the quantified reliability and resilience benefits associated with replacing or upgrading the infrastructure.

5.10.3 Quantitative Benefit-Cost Results

1898 & Co. evaluated the benefits of the 4.8 kV and 8.3 kV Conversion Programs using the analytics models described in Section 4.3 and 4.4. The evaluation quantified the expected reduction in equipment failure risk associated with replacing or retiring aging infrastructure and converting legacy voltage circuits.

By replacing aging infrastructure, increasing circuit operating voltage, and installing sectionalizing and automation devices, the program reduces the likelihood of equipment failures and improves circuit performance. These improvements reduce

the frequency and duration of customer outages and can also reduce outage duration by improving fault isolation, enabling load transfers, and supporting more efficient service restoration.

The analysis estimated avoided customer interruptions and reductions in CMI associated with the proposed investments. The avoided outage impacts were monetized using the ICE Calculator described in Section 4.2. In addition to avoided outage costs, the evaluation incorporated avoided restoration costs associated with emergency repairs following equipment failures.

Table 5-7 includes a high-level description of each project, the resulting Resilience, Reliability, & Risk BCR, and the primary benefit drivers associated with the investment. Using the legend in Table 5-6, Table 5-7 identifies whether each project's benefits are associated with avoided restoration costs, avoided customer minutes interrupted (CMI), capacity, operability, and safety. This summary provides additional context for understanding how the quantified BCA results align with the underlying drivers for each project. The evaluated projects represent a total investment of approximately $2.9 billion. These results indicate that a majority of the projects deliver strong, quantified reliability and resilience benefits relative to their investment costs. Other projects produce more modest quantified benefits but may still provide important improvements in system reliability, operations, capacity, and safety that are not fully captured in the quantitative evaluation.

Table 5-6: Benefit Drivers

Driver	Indicator
Avoided Restoration Costs	
Avoided Customer Outages (CMI)	
Capacity	
Operability	
Safety	

Table 5-7: 4.8 kV & 8.3 kV Conversion and CODI Project Descriptions and Drivers

Project Name	Project Description	BCR	Benefit Drivers (Monetized and Captured by BCR)	Benefit Drivers (Non-monetized)
CODI: Kent/Gibson Conversion - Kent Decommissioning	• Consolidate, pre-convert & convert (6) KENT4.8kV circuits to CORKT13.2kV • Consolidate, pre-convert & convert (8) GIBSN 4.8kV circuits to CORKT13.2kV • Consolidate, pre-convert & convert (2) SCOTN 4.8kV circuits to CORKT13.2kV • Consolidate, pre-convert & convert (3) HOWRD 4.8kV circuits to CORKT13.2kV • Convert (17) primary customer from 4.8 kV to 13.2 kV • Decommission 8 miles of 4.8 kV cable • Remove (8) 4.8 kV breakers and decommission Kent substation • Remove (11) 4.8 kV breakers and decommission Gibson substation • Decommission 16 miles of 24kV cables and equipment	2.51		
8.3 kV CC: Pontiac Overhead Conversion	• Purchase property. • Extend (1.4 miles) conduit. • Extend (14 miles) cable. • Replace (33.4 miles) overhead. • Rebuild 120-13.2kV Wheeler substation. • Convert (33.4 miles) to 13.2kV • Decommission five substations - Bartlett, Paddock, Stockwell, Rapid Street, Bloomfield.	2.3		
4.8 kV CC: Zenon Substation and Circuit Conversion	• Establish (6) new ZENON 13.2kV circuits from existing 13.2kV power delivery center and convert 4.8kV power delivery center at ZENON • Pre-convert & convert 144 miles of 4.8kV overhead to 13.2kV • Install 3 miles of conduit • Install 17 miles of system cable • Convert or ISO down (70) primary service customers • Replace two transformers at ZENON substation • Install a third 24/32/40 MVA	2.28		

	transformer at ZENON substation • Install third transformer, second PDC, and third cap bank at Corktown substation • Decommission SCOTN substation and 24kV trunk lines • Decommission WSEND substation and 24kV trunk lines			
4.8 kV CC: I-94 Substation and Circuit Conversion (Promenade)	• Construct a new 120-13.2kV substation named Promenade • Install new conduit and manholes for new circuits • Install new cable for new circuits • Convert existing 4.8kV circuits and transfer to new 13.2kV circuits (over 100 miles of overhead) • Decommission existing system cable • Decommission Pulford, Lynch, and Lambert substations • Decommission eight 24kV trunk lines	2.15		
4.8 kV CC: Calla Circuit Conversion and Phase 2	• Build (1/5) mile of overhead to establish new backbone connection • Rebuild, pre-convert and convert approximately 11 miles of overhead conductor to 13.2kV • Remove (1/2) mile of overhead infrastructure and install (3/4) mile of new overhead infrastructure in road right-of-way • Establish jumpering points and load relief to adjacent DIMND circuit	1.61		
CODI: Howard Conversion	• Install (41) new netbank transformers • Decommission (6) network feeders and their substation positions/breakers • Decommission (9) feeder section switches • Replace or remove 38 netbank transformers and structures • Install (4) 3-way 600A feeder section switches and (8) 2-way 200A feeder section switches • Install (9) 3-way manholes and (1) 2-way manhole • Construct over 14,400 feet of conduit • Construct ~43,560' of new AC	1.5		

	network system cable • Decommission (16) 4.8 kV power lines • Decommission (16) breakers and positions • Decommission (27) miles of 4.8 kV cable • Rebuild (12) miles of radial power line system cable • Convert (26) primary customers to 13.2 kV • Convert and consolidate the circuits to 13.2 kV fed by Corktown, Temple, St. Antoine, and Cat substations • Decommission (5) 24 kV Cable Lines - TRK 787T-B, TRK 709T-B, TRK 753T-B, TRK 764T-B, TRK 775T-E • Decommission Howard Substation			
4.8 kV CC: Ann Arbor AC Network Conversion	• Pre-convert all Hoover circuits • Convert and Transfer Hoover Circuits to neighboring substations • Upgrade Hoover Substation from 40-4.8kV to 40-13.2kV Substation • Build and commission new 40-13.2kV Class A substation with 5 load carrying circuits	1.31		
4.8 kV CC: Belleville Substation and Circuit Conversion	• Pre-convert all Belleville 4.8kV circuits • Upgrade Belleville 13.2kV Substation from Class 'T' to a Class 'R' • Commission a second 13.2kV Belleville circuit • Convert and transfer all Belleville 4.8kV circuits	1.3		
4.8 kV CC: Grosse Pointe South Substation and Circuit Conversion	• Procure substation property • Build new Class A 120/13.2 kV substation named Conner • Convert and consolidate VERNR and WAYBN circuits (273 overhead 4.8kV miles) • Install 3000 ft of conduit and 6000 ft of cable • Decommission WAYBN and DENVR substations	1.27		
CODI: Garfield Network Upgrade	• Convert and consolidate circuits fed by Stone Pool, Midtown, Alfred, Detroit substations • Decommission (4) 24 kV lines -	1.24		

	TRK1809 , TRK1815, TRK 1820 & TRK1834 • Decommission Garfield Substation			
4.8 kV CC: Hilton Substation and Circuit Conversion	• Expand Hilton Road Substation so that it has 3 transformers and 2 PDCs • Convert 100% of circuits from FERND, HAZPK, and WDSID substations and transfer to Hilton Road Substation • Decommission FERND, HAZPK, and WDSID substations	1.15		
4.8 kV CC: Pittsfield Substation and Circuit Conversion	• Reconductor (26.9) miles of overhead conductor • Replace (272) overhead transformers • Replace (225) underground transformers • Install (2.9) miles of cable • Install (0.9) miles of conduit • Commission (1) new 40-13.2kV substation and (4) new load-carrying circuits • Decommission (1) 40-4.8kV substation and (.5) mile of system cable	0.83		
4.8 kV CC: Hawthorne Relief and Circuit Conversion	• Purchase property for substation • Expand Mallard substation • Convert and/or consolidate (15) circuits • Decommission Daly substation	0.71		
8.3 kV CC: Pontiac Underground Conversion	• Pre-convert (5) circuits	0.69		
4.8 kV CC: Hemlock Decommissioning and Circuit Conversion	• Replace (30) miles of overhead conductor • Pre-convert and convert 4.8kV area to 13.2kV • Decommission (1) 40-4.8kV substation and remove (1/2) mile of system cable • Install (1) new 40-13.2kV substation, install 2 miles of system conduit, and 3 miles of system cable • Commission 4 new distribution circuits and 1 throwover circuit	0.57		
4.8 kV CC: White Lake Decommissioning and Circuit Conversion	• Installing (1) 40-13.2kV substation, substation to be named Meadowlake • Installing (2) miles of system conduit • Installing (4) miles of system	0.53		

	cable • Convert area to 13.2kV • Decommission 40-4.8kV White Lake substation			
4.8 kV CC: Barber Substation and Circuit Conversion	• Purchase 1 new parcel of property • Install 1 new substation, to be named Ten Mile • Install 7300 ft of conduit for the new TENMI circuits • Convert 53.4 miles of overhead 4.8kV conductor • Decommission Bunert substation	0.43		
4.8 kV CC: New Baltimore	• Purchase substation property • Build new class A substation at New Baltimore • Decommission Class R and Class E substations at New Baltimore	0.40		
4.8 kV CC: Rochester Decommissioning and Tienken Relief	• Acquiring property • Installing (1) 120-13.2kV substation, substation name not identified yet. • Installing (3) miles of system conduit • Installing (16) miles of system cable • Removing (1.46) miles of system cable • Converting area to 13.2kV • Building (0.1) miles of overhead conductor • Installing (10) pole top switches • Installing (18) viper reclosers • Decommissioning Tienken40-13.2kV substation	0.28		

5.10.4 Qualitative Additional Benefits of the Program

The previous sections have outlined the results from quantifying the benefits of specific investments. As discussed above in Section 4.6, it is difficult to fully capture and quantify all the factors that go into every investment decision. For the 4.8 kV and 8.3 kV Conversion Programs, several additional qualitative benefits further support the proposed investments.

First, these projects improve the safety of the electric distribution system. Many of the existing 4.8 kV and 8.3 kV systems include aging infrastructure and legacy

equipment that are increasingly difficult to maintain and repair. For portions of the legacy 4.8 kV delta system, downed conductors may remain energized, creating an elevated public safety risk. In addition, portions of the 8.3 kV system include aging underground cable and vault infrastructure that can increase the complexity and risk associated with inspection, maintenance, and restoration work. Converting these systems to modern distribution voltage standards reduces the likelihood of equipment failures and helps mitigate safety risks associated with aging assets and wire-down events.

Second, the program simplifies system operations and maintenance. Legacy voltage systems often require specialized equipment and operating practices. Converting these systems to a higher voltage standard allows DTE to standardize equipment and operating practices across the system, improving operational efficiency and reducing long-term maintenance challenges.

Third, these projects improve the distribution system's ability to accommodate future load growth and electrification. Higher-voltage distribution systems offer greater capacity and improved voltage performance than legacy systems. These improvements help the electric system support future economic development and evolving customer energy needs.

Finally, many projects in this program enable the retirement of aging substations and infrastructure approaching the end of their useful life. Replacing these facilities with modern infrastructure improves the overall reliability and resilience of the electric distribution system. DTE has a duty to serve customers safely and reliably, and these investments support long-term system planning objectives by increasing system capacity and strengthening the backbone of the electric grid.

While the quantitative analysis demonstrates measurable risk and resilience benefits associated with these investments, the qualitative benefits described above further support the value of the 4.8 kV and 8.3 kV Conversion Program.

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2026 Distribution System Plan Workpapers

All 2026 Distribution System Plan ("DSP") workpapers are incorporated by reference herein and are made available for review to Staff and parties to Case Nos. U-20147, U-21860, and U-22046 via hyperlink. The workpapers are accessible at the following location:

Public

Home - U-22104 2026 Distribution System Plan

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of **DTE ELECTRIC COMPANY**'s submission of its Distribution System Plan pursuant to the Commission's Order in Case No. U-20147.	)))))	Case No. U-22104

PROOF OF SERVICE

CAITLIN D. MYERS states that on April 28, 2026, she served a copy of DTE Electric Company's Distribution System Plan Report in the above caption matter, via electronic mail, upon the persons listed on the attached service list.

Caitlin D. Myers

Digitally signed by Caitlin D. Myers
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