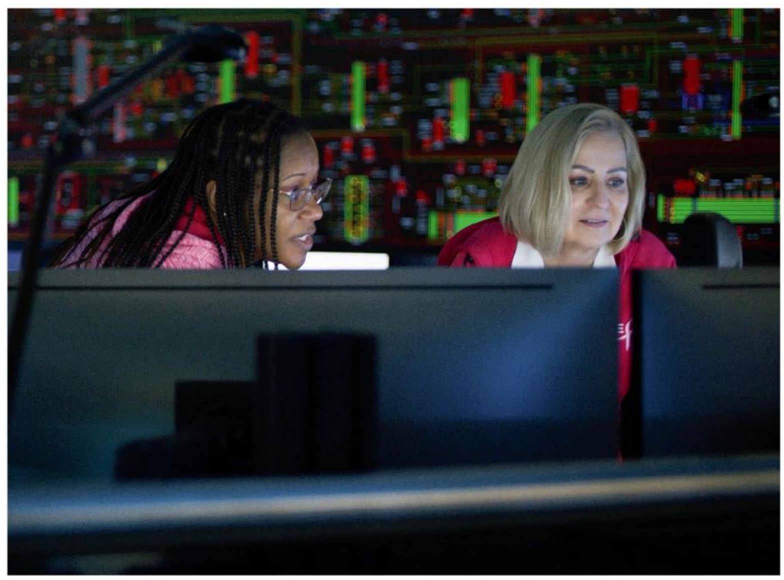
DTE Electric Company



2023 Distribution Grid Plan

September 29, 2023
MPSC Case No. U-20147

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1 Executive Summary

1.1 Introduction

This is a transformational time for Michigan's electrical infrastructure. Nearly a century ago, DTE Electric[1] (DTEE or the Company) developed a grid that met customers' electricity needs when there was far less demand. Since then, the grid has expanded to developing suburbs and rural communities, but the fundamental drivers of grid change, such as load growth, have remained relatively static. That is no longer the case.

Continued investment in the grid is critical to meet the changing needs of customers, including adoption of electric vehicles (EVs), distributed generation (DG) and the evolving ways in which customers are interacting with the grid. In addition, increasingly severe weather and aging infrastructure present challenges to reliability. However, the work that has already been done to create a more resilient grid is showing strong results for our customers.

To meet customer needs into the future and to continue improving reliability, DTEE must strengthen, modernize and transform the grid. DTEE has developed a vision for the future of the grid that is driven by three essential goals:

- Increased reliability and resilience during extreme weather to ensure that the power stays on for customers during ice, snow, heat and high wind events.

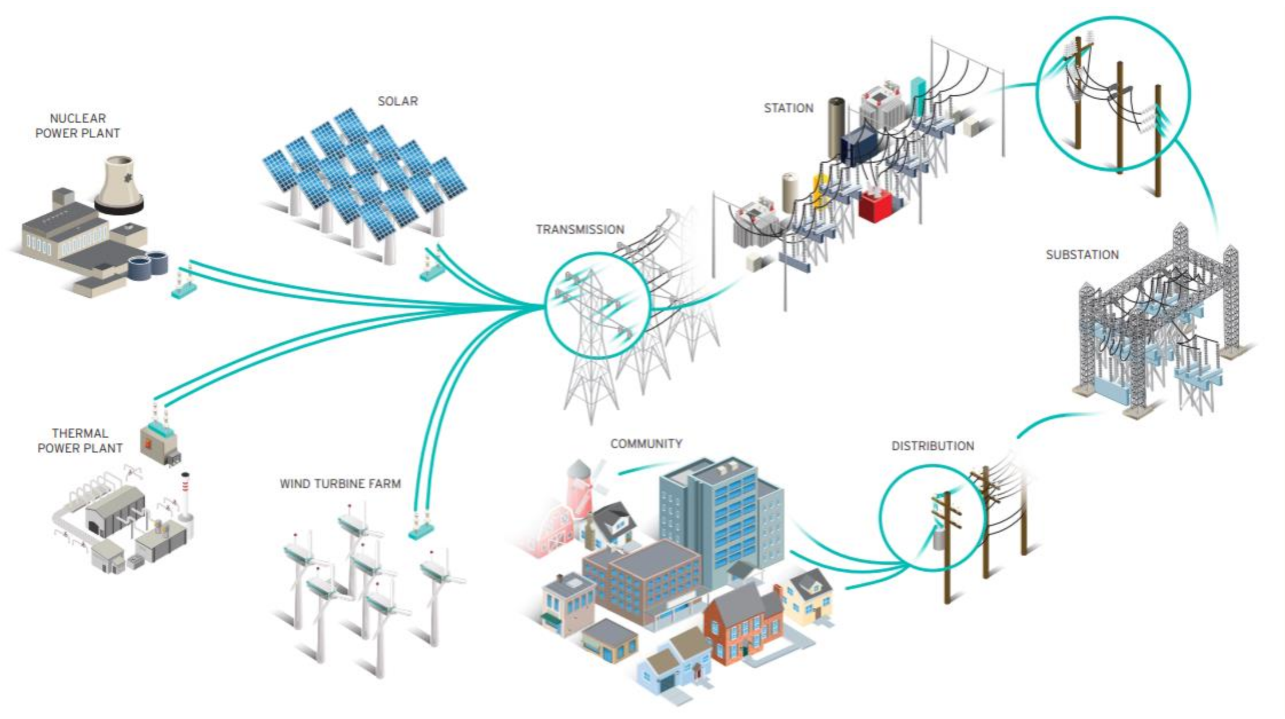
[1] DTE Electric generates, transmits and distributes electricity to 2.3 million customers in southeastern Michigan. DTE Energy, a Detroit-based diversified energy company involved in the development and management of energy-related businesses and services nationwide, is the parent company of DTE Electric.

- Accelerated response to customer outages, driven by a smart grid that supports faster power restorations, identification and de-energization of downed wires and accurate customer restoration estimates.
- Increased grid capacity that accommodates the changing current and future energy needs of all customers.

DTEE's 2023 Distribution Grid Plan (2023 DGP or Plan) was developed to meet these goals while balancing affordability for customers.

1.2 Defining the Electric Grid

To reach customers, power travels from a generation supply resource across transmission lines to DTEE's distribution system. The distribution and subtransmission system are then responsible for delivery to destination points across the Company's 7,600 square-mile service territory. The graphic below provides an overview of how electricity moves across the entire system from generation to delivery.



Power flows to DTEE's subtransmission stations from the transmission system at high voltage, where 230kV and 120kV[2] transformers at the station reduce or "step-down" the voltage to 40kV and 24kV before transmitting it via subtransmission circuits to the distribution substations across the service area. In some cases, larger substations are fed directly from the transmission network and do not use the subtransmission network. The grid is constructed this way because electrical energy is efficiently transmitted at higher voltages to minimize power losses.

DTEE currently operates 783 substations that utilize approximately 1,600 transformers. Transformers at these substations then further step-down the voltage to 13.2kV, 8.3kV, or 4.8kV and disperse it across power lines, or circuits that carry electricity to residential, commercial and industrial customers within communities. A standard single-transformer substation normally serves 1-3 circuits, while a typical two-transformer substation serves 4-8 circuits. Circuits can be constructed overhead or underground or a combination of both. Once the electricity arrives at the customer's location, pole-top or pad-mount transformers step-down the voltage one last time so the power is delivered at a usable voltage for residences or businesses. DTEE's distribution system includes 451,919 transformers in overhead (pole-mounted) or ground (pad-mounted) positions.

DTEE delivers power to customers utilizing 31,000 miles of overhead subtransmission and distribution lines and 14,500 miles of underground lines. A breakdown of the Company's distribution infrastructure is shown in Exhibits 1.2.1 through 1.2.4 below.

Exhibit 1.2.1 DTEE 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	145	49	0	86	1	0	0	0	9
Customer Owned	102	NA	NA	NA	NA	NA	NA	NA	NA
Total	**789**	**293**	**4**	**329**	**31**	**4**	**13**	**3**	**10**

[2] kV stands for kilovolt, or 1000 volts – 120kV is equal to 120,000 volts

Exhibit 1.2.2 DTEE 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**

Exhibit 1.2.3 DTEE Transformers by Voltage Level

Voltage Level	Number of Transformers	kVA Capacity
Substation - Subtransmission	178	13,085,000
Substation - Distribution	1,449	24,093,221
Distribution - Overhead and Pad-mount	451,919	33,078,863
Total	**453,546**	**70,257,084**

Exhibit 1.2.4 DTEE Distribution Circuits by Voltage

Voltage	Number of Circuits	Overhead Miles	Under-ground Miles	Total Miles
13.2 kV	1,269	17,407	11,128	28,535
8.3 kV	13	45	18	63
4.8 kV	1,991	11,096	2,211	13,307
Total	**3,273**	**28,548**	**13,357**	**41,905**

The path electricity travels across the system is subject to interruptions due to a variety of factors (e.g., a tree falling on an overhead electrical line), which can cause outages and potentially dangerous situations for customers and employees. Electrical switches, most commonly breakers or reclosers, are in place at points along the network to recognize and isolate these interruptions (also known as electrical faults) from the rest of the distribution system. These switches allow power to continue flowing to as many customers as possible while restoration is completed for the damaged circuits.

At the distribution substation level, there are large breakers (switches) that interrupt the current flow when a fault is detected to minimize equipment damage and to isolate the faulted equipment from the rest of the system. DTEE has approximately 6,000 breakers on its distribution and subtransmission system.

Downstream from the substation breakers, located on distribution circuits, are reclosers. Reclosers perform like a breaker. When they detect faults, they open and isolate the interruption to a smaller area, impacting fewer customers. Reclosers can prevent the substation breaker from opening, avoiding a larger circuit level outage. Additionally, reclosers can be used to tie two circuits together so that, in the event of an outage, one circuit can provide power to the other. Reclosers have a key role to play in improving reliability and are the foundation of the automation program discussed in Section 10.

DTEE's distribution grid is discussed in greater detail in Section 4 below. The Company's Plan requires investments in each of the various distribution system components in order to achieve DTEE's distribution grid planning objectives (safe, reliable, affordable, clean and accessible), discussed further in Section 2 of this Plan.

1.3 Current Landscape

Aging infrastructure and worsening weather patterns have diminished the performance of DTEE's distribution grid, resulting in more frequent outages for our customers. Many of DTEE's electric grid assets are reaching, or have reached, an advanced age that requires replacement. For example, the 4.8kV system, largely installed between 1940 and 1960, is now 60 to 80 years old. The original sections of the 13.2kV system are 50 to 60 years old and are at, or near, the end of useful life.

Additionally, many of the Company's substations, circuits and "grid edge" assets (i.e., assets nearest to the customer's service site such as distribution transformers, secondary lines, service drops and underground residential distribution (URD) loops) are already experiencing high customer demand in some areas, and are not capable of accommodating the significant increase in demand that is expected to accompany electrification growth. Currently, approximately one-third of the Company's distribution substations have loading constraints, either within the substation or on its circuits. This strain on grid capacity reduces the ability to perform needed maintenance and serve new customers.

Equally important, the strain hampers restoration during outages because customer load is unable to be temporarily shifted to adjacent circuits that are already experiencing loading constraints.

The Company's 2021 Distribution Grid Plan (DGP) outlined DTEE's commitment and detailed plan to continue rebuilding and transforming the distribution grid. The progress on this plan is detailed in Exhibit 1.3.1 below. As part of this progress, DTEE has been proactive in adopting new distribution technology, including the Advanced Distribution Management System (ADMS) which provides a solid foundation on which to build additional grid technologies (discussed in Section 10).

Exhibit 1.3.1 2021 DGP Plan Key Investment Progress

Investment	Progress
Technology and Automation	• Opened the new Electric System Operations Center (eSOC) in 2022 • Launched the Outage Management System (OMS) and Distribution Management System (DMS) components of Advanced Distribution Management System (ADMS) in February 2023
Pole Top Maintenance and Modernization (PTMM)	• Replaced 5,553 poles (2021-2022) through the PTMM program and on track to replace 3,353 poles in 2023
4.8kV Hardening	• Hardened 677 miles of overhead circuits in the city of Detroit and on track to harden 345 additional miles by the end of 2023
Tree Trim	• 80% of the system is now on a five-year tree trimming cycle and the company goal is to be 100% on cycle by the end of 2025
Conversion	• Energized two new 13.2kV substations in the city of Detroit (Corktown Substation and Island View Substation)

The results of recent investments are measurable,[3] but to date have only benefited a fraction of the aged equipment on the electrical system; there's more work to do. These grid improvements are a step in the right direction and DTEE must continue this progress to meet the current and future needs

[3] Tree trimming results are discussed in Section 7 and 4.8kV Hardening program results are found in Section 8.

of our customers. The 2023 DGP builds upon the 2021 DGP, based on learnings realized through implementation of reliability projects, as well as customer and stakeholder feedback.

1.4 Future Drivers of Change

Three external forces are fundamentally shaping the future of the distribution grid:

1. Increasing storm activity: More frequent and extreme storms and other weather events are expected to further impact electric infrastructure.
2. Electrification: As customers move away from carbon-based fuel sources there will be an increased demand for electricity to power EVs, to heating homes and businesses, and to power industrial processes.
3. Distributed Generation (DG)/Distributed Storage (DS): As more customers install solar and battery technology, the grid will be subjected to two-way power flows and the potential for increasing voltage fluctuations.

These three drivers of change are analyzed in Section 3 below to help identify investments that will address the grid needs both today and in the future.

1.5 Investment Plan Summary

Development of the 2023 DGP included incorporating data and learnings from the past two years, integrating updated information into future scenarios and evaluating feedback from customers and other stakeholders. This information drove the DGP strategy, addressing both the short- and long-term safety, reliability and capacity challenges of the distribution system.

Modernizing and strengthening a grid with more than 45,000 miles of overhead and underground circuit miles will take time and sustained investment. In response, DTEE has identified both near- and longer-term initiatives that will improve reliability for our customers. The near-term investments are projected to provide a roughly 60% reduction in customer outage minutes by 2029.

In general, the next five years (2024-2028) of investment focuses on the following overarching goals:

- Stabilize the system with equipment hardening programs to eliminate outages in the face of more frequent and extreme storms.
- Increase the level of automated restorations (smart grid technology) by adding 10,000 reclosers to the system to reduce the size and duration of customer outages.
- Continue to modernize the grid through substation and circuit voltage conversion projects and subtransmission upgrades to improve reliability by replacing end of life equipment; installing the latest automation technology, which will improve safety by eliminating energized wiredowns; and adding capacity for DER and electrification. DTEE's four investment pillars build off the work in the 2021 DGP to facilitate these goals:

1. **Tree Trimming (Section 7):** Historically, two-thirds of the time customers spend without power is due to falling trees and limbs. DTEE has ramped up the Company's tree trimming work over the last five years in response to this challenge. With more than 1,200 tree trimmers[4] and more than an $800 million investment since 2019,[5] the Company has trimmed approximately 25,000 miles of reclaim trees in the last five years – 80% of total system overhead miles of trees. Our goal is to have all 31,000 circuit miles of DTEE's overhead wires fully trimmed to Enhanced Tree Trimming Program (ETTP) specifications and on a five-year trim cycle by the end of 2025. Section 7 of this Plan discusses the company's tree trimming plans and the various improvements made to the program since 2021, including the use of new and specialty equipment to trim trees in areas that pose access challenges, like backyards and alleyways.

2. **Infrastructure Resilience and Hardening (Section 8)**: Replacing and upgrading existing infrastructure – such as poles, crossarms, transformers and substation equipment – continues to improve the safety, reliability and resilience of the electric grid. There are two initiatives within this pillar that will provide significant improvements to reliability. The first initiative is enhancing quality, scope and resources of the Pole Top Maintenance and Modernization (PTMM) Program. The PTMM program involves testing of poles and pole top equipment to determine condition, including the need for replacement. If equipment fails testing, it is replaced with equipment designed to a higher, stronger standard. The

[4] On average – actual number fluctuates seasonally.
[5] $800 from 2019 through 2022.

Company plans to significantly increase the level of investment in this program and has a goal to reach a 10-year cycle time in line with industry standards, dramatically reducing damaged and defective poles and pole top equipment on the system. The second initiative is the completion of the 4.8kV Hardening Program in the city of Detroit in 2026. This program is focused on replacing all poles that fail inspection and all pole top equipment on the 589 miles yet to be hardened within the city. Abandoned arc wire from the former Detroit Public Lighting Department is also removed during this process. Upon completion of the 4.8kV Hardening Program, all overhead circuits in the city of Detroit will be hardened, converted to a higher voltage or in the conversion process. This work will dramatically improve reliability throughout the city of Detroit.

3. **Infrastructure Redesign and Modernization (Section 9)**: One third of DTEE's distribution system was built before 1965 and can no longer meet the growing trend of electrification or customer reliability expectations. The Infrastructure Redesign and Modernization pillar focuses on converting the outdated 4.8kV ungrounded system to a more modern 13.2kV grounded system, improving safety and reliability while providing additional capacity for EVs and DG/DS. Conversion includes rebuilding large portions of the system, and the Company will analyze and consider moving wires underground as part of the process. An investment of more than $500 million into the subtransmission system over the next five years will also eliminate many system loading constraints and provide reliable power for our customers. More details on DTEE's plans to continue implementation of this program are provided in Section 9 of this Plan.

4. **Technology and Automation (Section 10)**: The increasing complexity of the grid requires additional investment; DTEE will invest more than $1.2 billion in smart grid technology, including reclosers, through 2028. A more sophisticated smart grid will provide increased visibility of system conditions to our Electric System Operations Center (ESOC), reduce the size of outages and increase the speed of restoration for customers experiencing outages. Additionally, installing reclosers on the 4.8kV system will improve safety by increasing the ability to detect and de-energize downed wires quickly and remotely. Over the last several years, the groundwork has been laid for the transition to a smart grid. A new, world-class ESOC and the recently launched Outage Management

System (OMS) and Distribution Management System (DMS) components of the Advanced Distribution Management System (ADMS), provide the foundation needed for the installation of equipment that will automatically isolate system damage and reroute power to minimize the scope of outages. The Company plans to fully automate the distribution grid by the end of 2028. The company will also pursue additional Information Technology (IT) and Operational Technology (OT) investments supporting grid management, distribution planning, work management and scheduling, asset management and mobile technology.

These four pillars represent the focus areas that are foundational to improving safety, reliability and building the distribution grid of the future. DTE Electric has invested $5 billion in the electrical grid over the past five years and, over the next five years, plans to invest an additional $9 billion in making it safer and more reliable for customers.

The projects and programs that make up these investment pillars and the implementation of each of the pillar areas were identified after listening to feedback from customers and stakeholders. That feedback included a shift to consider environmental justice (EJ) in DTEE's investment decisions so that projects benefiting our most vulnerable customers are considered in the investment prioritization process. More details on the changes to DTEE's incorporation of EJ in its Global Prioritization Model (GPM) are included in Section 12 of this Plan.

1.6 DGP Methodology

To create the 2023 DGP, DTEE followed the five-step methodology used in the development of the 2021 DGP:

- **Define DTE Objectives**: Review defined objectives from the Company's 2021 DGP and align them to the long-term distribution grid vision (Section 2)

- **Assess Future Drives of Change**: The future drivers of change that are expected to have a significant impact on the distribution grid over the next five to fifteen years were reviewed, including previously identified scenario sign-posts (Section 3)
- **Assess Current State**: Assessing the current grid and its capabilities to determine how well it supports current and future customer demands (Section 4)
- **Determine Gaps to Future State**: Identify future state objectives (Section 5) based on future drivers of change, current state assessments and distribution grid gaps
- **Develop Investment Plan**: Based on those gaps, a five-year investment plan was developed, organized within the four pillars of investment (Sections 6-10). Individual program and project prioritization within the investment plan is done through the Company's Global Prioritization Model (GPM) process (Section 12)

Additionally, customer and stakeholder feedback were integrated into the Plan, including a shift to consider environmental justice (EJ) in DTEE's investment decisions so that projects benefiting our most vulnerable customers are considered in the investment prioritization process. More details on how EJ was incorporated into the GPM are included in Section 12.

2 Planning Objectives

To create a 2023 distribution grid plan aligned to the DTEE vision, the five planning objectives shared across the DTEE organization, including integrated resource planning (IRP) (see Exhibit 2.0.1), were reviewed, with specific references related to the distribution system.

Exhibit 2.0.1 DTEE Organizational Planning Objectives

SAFE
Build, operate and maintain the distribution grid and generation fleet in a manner that ensures public and workforce safety, operational risk management and appropriate fail-safe modes and is compliant with state and federal requirements

RELIABLE AND RESILIENT
Build, operate and maintain the power system within acceptable standards to withstand sudden disturbance or unanticipated failure of elements. Ensure the grid and diverse generation resources are integrated, with secure supply resources, and can quickly recover from high impact, low frequency events

AFFORDABLE
Provide efficient and cost-effective service along with diverse and flexible generation resources by optimizing the system and benefiting all customers

CUSTOMER ACCESSIBILITY AND COMMUNITY FOCUS
Provide flexible and accessible technology and grid options, and information that empowers and engages customers. Provide effective and timely communication with customers and stakeholders. Favor plans that support the diversity of Michigan communities, suppliers and workforce

CLEAN
Build, operate and maintain the resource fleet and grid platforms in an environmentally sustainable manner by achieving low carbon aspirations and clean -energy goals. Provide a grid that facilitates a transition to a decarbonized economy

1. Safe
    a. Reduce/eliminate live wire downs
    b. Reduce equipment failures
2. Reliable and Resilient
    a. Reduce the number of outage events on the system to improve customers experience
    b. Reduce the size and duration of outages to limit the impact on customers
3. Affordable
    a. Maintain and rebuild the system in a cost-effective manner that keeps customer rates affordable
    b. Reduce storm/trouble costs and redirect those funds into system improvements
4. Customer Accessibility and Community Focus
    a. Ensure adequate future capacity on the system to facilitate DER and EV technology
    b. Provide equitable investment in vulnerable communities to reduce electric reliability impact
5. Clean

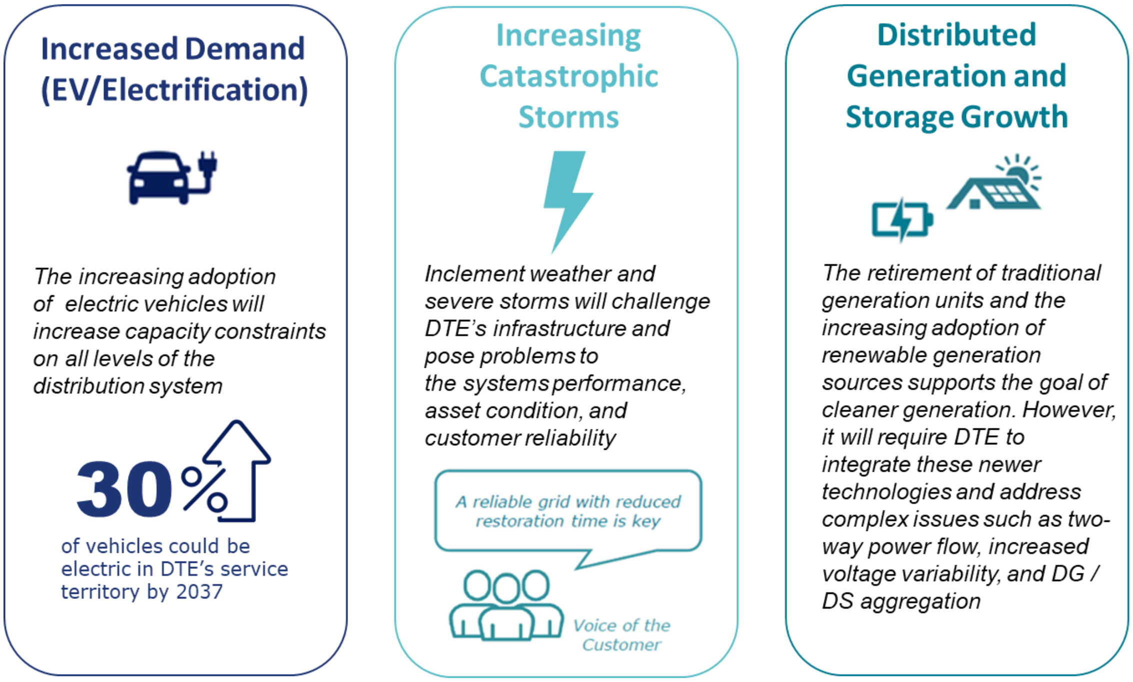
a. Build a robust and reliable distribution grid to facilitate clean generation and transportation electrification technologies

These planning objectives inform the Company's distribution investment decisions, while supporting customer expectations for cleaner and more reliable energy, Michigan's sustainability goals and DTE Electric's corporate goals for clean energy and decarbonization. Each project or program in this plan (detailed in the four strategic investment pillars covered later in the document), aligns to one or more of the planning objectives.

3 Future Drivers of Change

Customer and other stakeholder needs will continue to evolve in the coming decades and will drive a fundamental shift in demands on the electric grid. The key factors driving the grid evolution include electrification of vehicles and buildings, increasing catastrophic storm events driven by more frequent and extreme weather and the growth of Distributed Generation/Distributed Storage (DG/DS) within the distribution system. While these drivers of change pose unique challenges, they also provide DTEE an opportunity to adapt to customers' evolving needs by reshaping the distribution system into a more reliable and resilient grid that provides more value to our customers. These drivers are further detailed in Exhibit 3.0.1 below.

Exhibit 3.0.1 - Future Drivers of Change for the Electric Grid



3.1 Scenario Planning

DTEE began using distribution scenario planning in the 2021 DGP to understand the potential grid impacts caused by EV adoption, increasing extreme weather and Distributed Generation/Distributed Storage (DG/DS) integration. This section describes the updates to the scenario planning process and analysis. As in the 2021 DGP, DTEE has chosen three plausible scenarios to measure against its plans. Each scenario, shown below in Exhibit 3.1.1, represents a unique set of circumstances that have the potential to impact the grid over the next 15 years:

Exhibit 3.1.1 - DTEE Grid Modernization Scenarios

Scenario	Description
Electrification	High electrification of transportation, buildings, and industrial processes
Increasing CAT Storm	Increased frequency and intensity of catastrophic (CAT) storm threats to electric infrastructure
DG/DS	High adoption of distributed generation (DG) solar PV and distributed storage (DS) as batteries behind the meter (BTM)

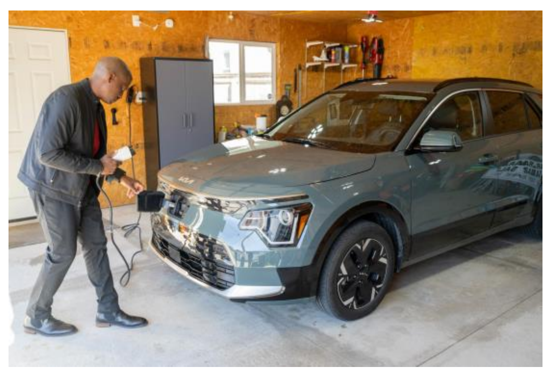
DTEE has identified a directionally plausible forecast specific to each scenario (e.g., increased load from electrification), along with associated grid impacts and signposts. A plausible forecast does not represent DTEE's prediction or specific forecast of the future. The plausible forecast represents a future where the drivers of the scenario experience aggressive growth and have the potential to act as a stress test on the grid. The purpose of a plausible forecast is not to predict with specificity the numerical values of drivers within that scenario, but to provide the Company with an opportunity for analysis, and the chance to study the stresses that each scenario produces on the distribution system. Distribution planning looks for specific types of investments to mitigate specific grid impacts, as opposed to an economic model of optimized solutions. These grid impacts determine future grid needs which are then analyzed in the context of the Distribution System Platform (DSPx) framework discussed below in Section 5. The resulting grid impacts illustrate how a scenario may impact grid infrastructure in its current condition. Signposts are variables that may change over time and are included in each scenario, such as technological innovation or changes in growth, cost or regulatory demands. Signposts are updated as they become known or more data is collected to allow the Company to adjust strategy if there are significant changes to forecasted scenarios.

The approach to scenario development has been updated for the 2023 DGP. A core focus of the update was increasing the alignment between the Integrated Resource Plan (IRP) that was filed in November 2022 and the Distribution Operations (DO) planning processes. To achieve this increased alignment, forecast sensitivities[6] from DTEE's 2022 IRP filing were incorporated as the plausible forecasts for the electrification and DG/DS scenarios and used to determine the associated grid impacts. Along with this change, the Company updated and assessed signposts and key uncertainties to understand how the drivers of each scenario may progress into the future.

The three scenarios used in longer-term distribution planning are different in intent and outputs than the scenarios and sensitivities used in the IRP. IRP scenarios forecast an optimized solution for the forecast inputs, which are typically broad market assumptions like commodity prices, technology costs, load growth and environmental regulations. In contrast, the scenarios developed for long-term distribution planning use a "plausible" forecast that represents a possible future of that discrete scenario. The three discrete scenarios are used to determine a wide range of potential future impacts to the grid, and in turn, identify gaps where grid planning or operational capabilities may need to evolve. By analyzing the grid impacts in each discrete scenario, as opposed to a combined scenario, the overall goal of scenario-based distribution planning is accomplished by identifying investment areas that address grid impacts arising in multiple scenarios. This approach ensures that identified investment areas will be needed even if the grid impacts of one scenario do not materialize or are less than anticipated. This is described in further detail in Section 5, Gaps to the Future State.

3.1.1 Electrification Scenario

The electrification scenario focuses primarily on the electrification of transportation.[7] Under the electrification scenario, the increased movement toward decarbonization assumes a high rate of residential EV adoption and partial electrification of vehicle fleets; these shifts will have the effect of increasing electric system load.



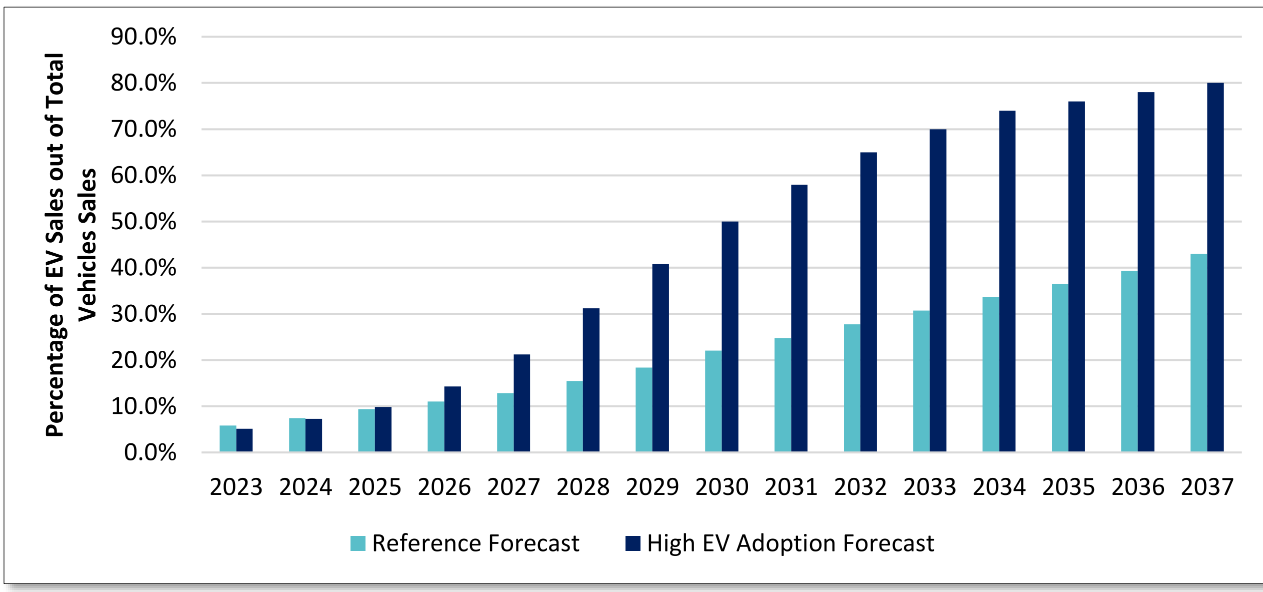
As of December 2022, there were an estimated 31,000 EVs in DTEE's service territory. Automotive industry forecasts are planning for rapid EV sales growth in the coming years, adding pressure on

[6]As described in DTE's 2022 IRP filing, different forecast sensitivities were developed to manage uncertainties and explore a range of higher and lower sales and peak demand levels. The electrification scenario incorporated the stakeholder forecast sensitivity, while the DG /DS scenario used the aggressive customer-owned distributed generation forecast sensitivity.

[7] The electrification of transportation is expected to have a larger impact on the localized grid than the electrification of buildings. For this reason, the electrification scenario is mainly concerned with the increasing adoption of electric vehicles within DTEE's service territory.

the grid's ability to serve the additional load. While the Company believes the 2022 IRP reference forecast[8] is most plausible, a high EV adoption forecast was used for the electrification scenario to stress test the grid impacts if EV growth accelerated more quickly than predicted. In the high EV adoption forecast, light duty EV sales will account for 80% of the light duty[9] vehicle sales by 2037 and total EVs on the road will increase to 2,189,000 in 2037, or 64.4% of the vehicles on the road in DTEE's service territory[10] A more detailed breakdown of projected sales and penetration of light duty EVs is provided below in Exhibits 3.1.1.1 and 3.1.1.2. The EV specific electric consumption will grow to 8,204 GWh by 2037. Projected growth in energy consumption is detailed in Exhibit 3.1.1.3. The high EV adoption forecast is aligned with the MI Healthy Climate Plan and assumes 50% of light-duty vehicle sales, 30% of medium-duty and heavy-duty sales, and 100% of bus sales are electric by 2030.

Exhibit 3.1.1.1 - Light Duty EV Sales as a Percentage of Total Vehicle Sales (2027 – 2037)



[8] The reference forecast from DTE's 2022 IRP filing most closely matches the Company's internal planning assumptions, forecast and goals/aspirations. In the reference forecast, light duty EV sales are expected to be 43.0% of the total vehicle sales by 2037; total EVs' on the road will increase to 1,023,000 in 2037, or 30.1% of the vehicles on the road in DTEE's service territory. The EV specific electric consumption in DTE's service territory will grow from 165 GWh in 2023 to 3,829 GWh in 2037.

[9] EV light duty includes residential home, public L2 and DC fast charging vehicles. EV fleet is exclusively medium and heavy-duty vehicles.

[10] Assumes a base of 3.4 million light duty electric vehicles in DTE's service territory.

Exhibit 3.1.1.2 - Count of EV Light Duty Vehicles with EV Penetration (2027 – 2037)

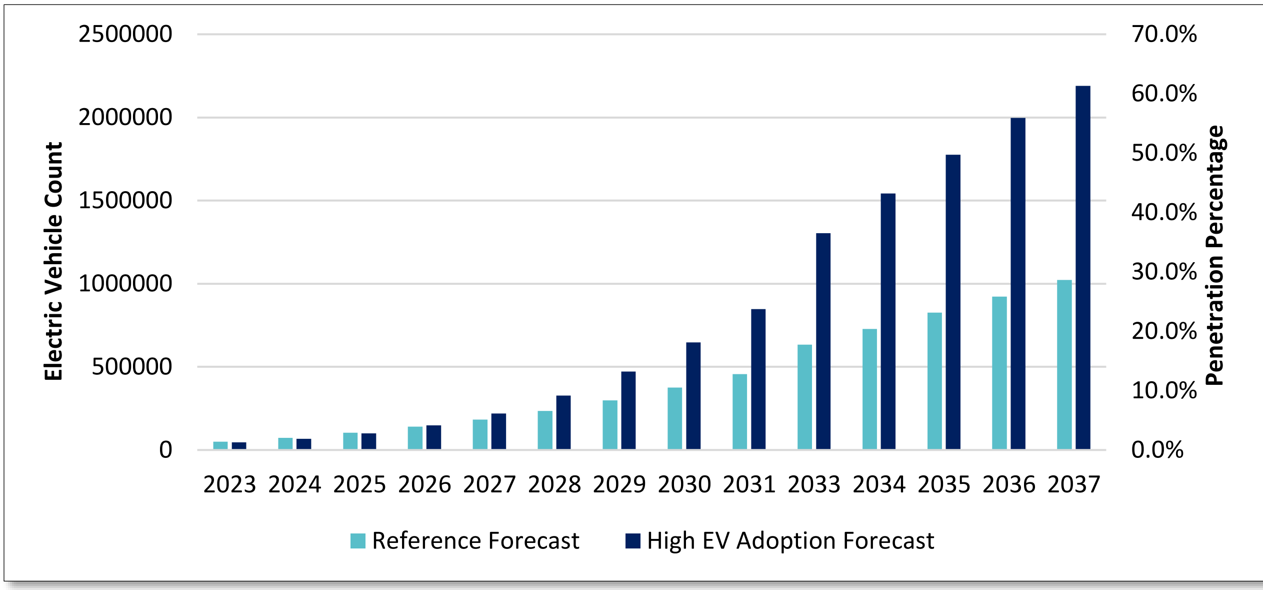
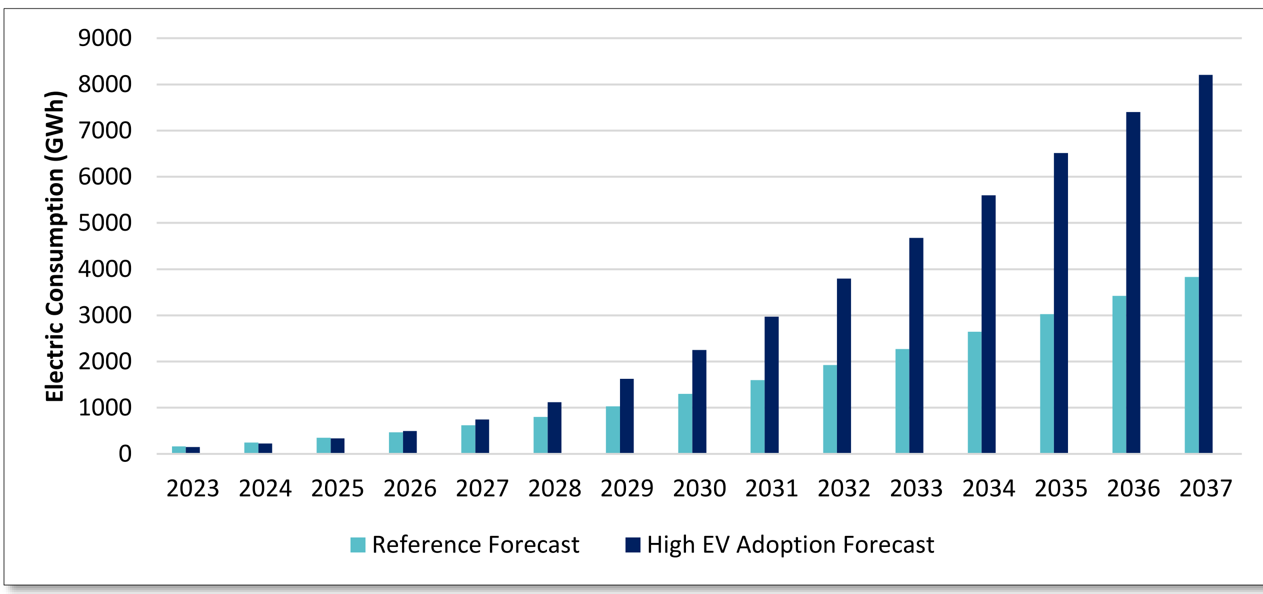


Exhibit 3.1.1.3 - Light Duty Electric Vehicle Energy Consumption (2027 – 2037)



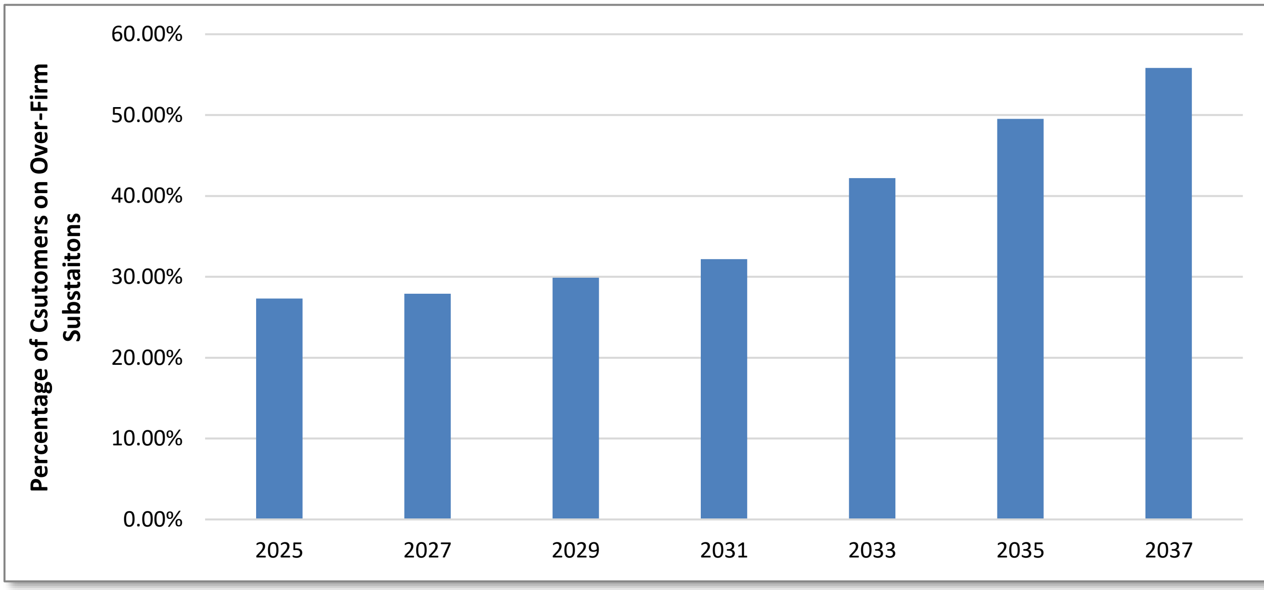
Under the high EV adoption scenario, DTEE's distribution system would face increasing capacity constraints, with some areas seeing higher EV adoptions earlier than other areas. While EVs will increase loading on all levels of the distribution system, the effects of EV adoption will first impact DTEE's grid edge assets, such as underground residential primary (URD) loops, service transformers and the secondary system. This is due, in part, to the tendency of electric vehicles to occur on the system in clusters, which results in high penetrations of EVs in a relatively small geographic area (e.g., neighborhood) or subsection of a circuit. The impact of increased adoption will gradually work upstream to trigger circuit or substation level investments as more neighborhoods on a circuit also adopt EVs. The electrification of EV fleets will also impact circuits and substations, given their substantial and concentrated electric loads. A summary of the high EV adoption load forecasts and percentage of peak load for light duty and fleet electric vehicles is shown in Exhibit 3.1.1.4. Below that, Exhibit 3.1.1.5 shows the portion of total customers on substations that are currently over their firm rating[11] in the high EV adoption forecast.[12]

Exhibit 3.1.1.4 - Electrification Scenario Forecasts of Load Increases (2027 - 2037)

Key Drivers	2027	2032	2037
EV Light Duty	105 MW (0.95% peak)	614 MW (5.35% peak)	1,703 MW (13.7% peak)
EV Fleet	7.4 MW (0.07% peak)	39 MW (0.34% peak)	106 MW (0.86% peak)

[11] The firm rating of a substation is the maximum load the substation can carry under a single contingency condition (e.g., equipment failure at the substation). For more information on substation firm ratings please see Section 5.3.1 – Distribution Load Projects.
[12] Absent any additional investment to support the new load.

Exhibit 3.1.1.5 - Percent of Customers Served by Over-firm Substations in the High EV Adoption Scenario



These additional loads will worsen existing capacity constraints on the distribution system and will require investment, initially to address equipment overloads on grid edge equipment, and with time, to also mitigate impact on the upstream grid equipment, including substations. Substations with limited available capacity will reach or exceed their firm rating, increasing the risk of outages during contingency conditions. For example, an equipment failure may occur at the substation or upstream on the subtransmission system.[13] Increased loading on substations and circuits will restrict the flexibility and resiliency of the grid, as load will not be able to transfer between locations for planned or unplanned work. As electrification-driven load growth continues, existing grid capacity constraints will increase, posing risks of accelerated equipment aging and failures. The impacts of electrification on grid edge assets, expected to occur even under lower levels of electrification, will drive the need for proactive upgrades before widespread equipment overloads and failures can occur. Grid edge equipment upgrades may include replacing service lines, replacing smaller distribution transformer sizes (e.g., 15 or 25 kVA) with a larger size and adding transformers to allow for fewer customers with higher loads per transformer.

[13] DTEE's subtransmission system serves as the vital grid link between the ITC transmission system and the DTEE distribution system. Please see Section 9.2 Subtransmission Redesign and Rebuild Program for more details.

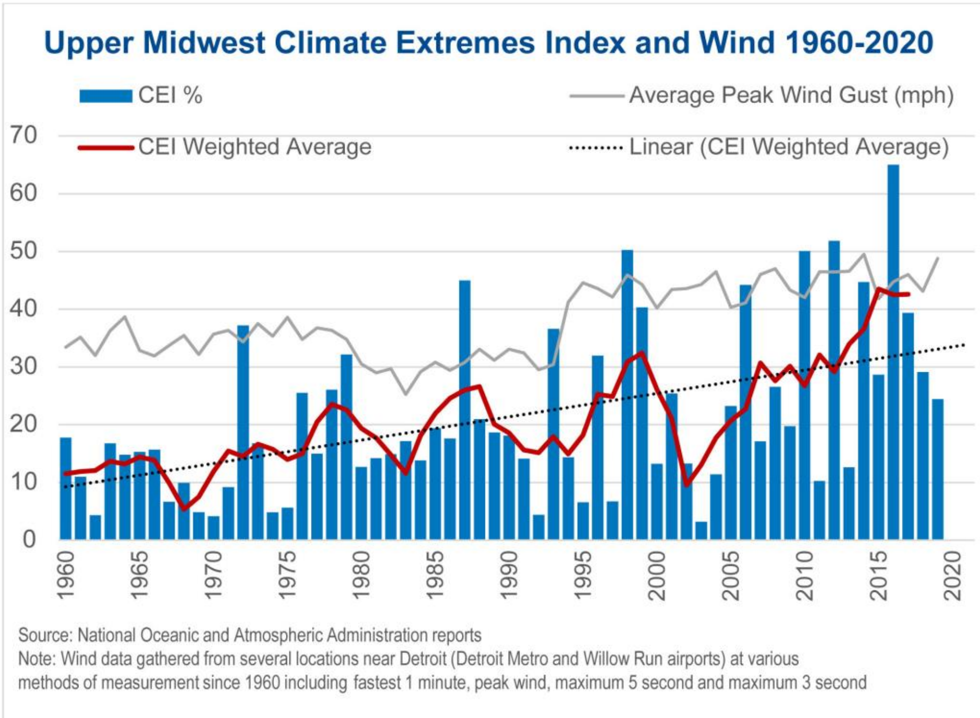
The Company will continue to monitor signposts around electric vehicle growth, charging availability and government legislation. These include the historical rate and magnitude of EV adoption within its service territory, the growth of public EV chargers and EV fleets, and favorable government public policy that supports customer EV adoption. Since the 2021 DGP, the Company has continued to evaluate the status of these signposts and has monitored major developments, such as the ongoing execution of the MI Healthy Climate Plan[14] and the passage of the Infrastructure Investment and Jobs Act (IIJA)[15] and Inflation Reduction Act (IRA).[16]

3.1.2 Increasing Catastrophic Storm Scenario

Climate change is driving an increase in the frequency and severity of extreme weather events across the upper Midwest (Minnesota, Wisconsin, Michigan), a trend recognized by several organizations conducting weather assessments of the region (see Exhibit 3.1.2.1 below). Additionally, the Great Lakes Integrated Sciences & Assessments (GLISA) reports that occurrences of severe storms have increased in the Great Lakes region specifically, and this trend is likely to continue as climate change progresses[17]. DTEE's increasing catastrophic (CAT) storms scenario analyzes the risk to the Company's infrastructure stemming from these weather shifts. The storm scenarios define thresholds for storms to be considered catastrophic, then differentiates those events into two categories: CAT-1 level storms, affecting 5% of the customer base and CAT-2 level storms, affecting 10% or more of the customer base.

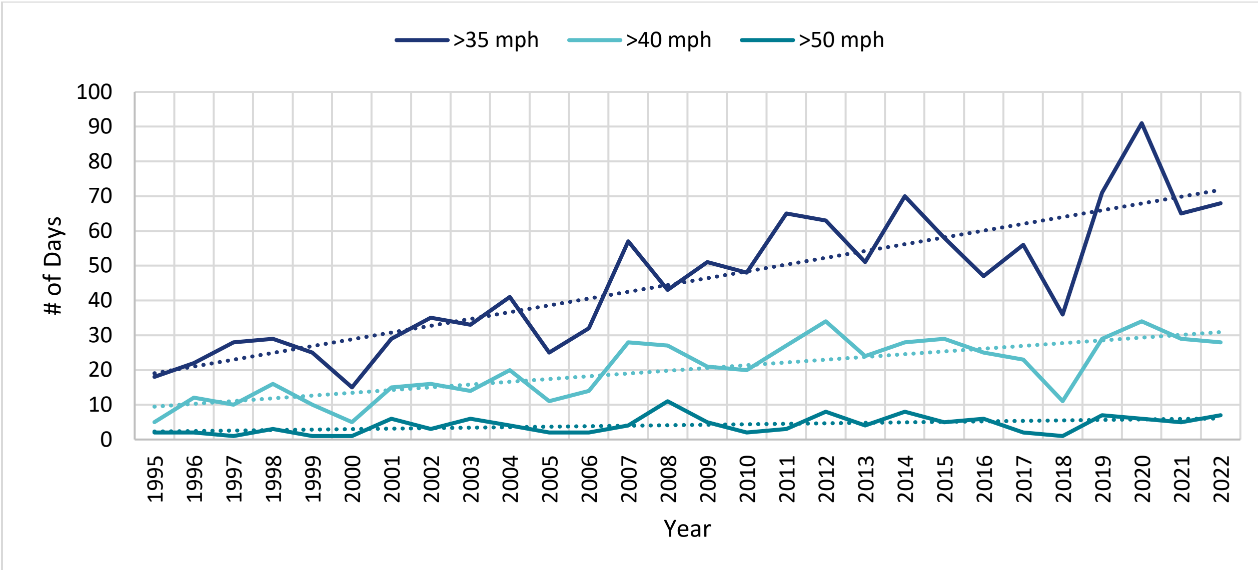
[14] MI Healthy Climate Plan (michigan.gov)
[15] The Bipartisan Infrastructure Law Will Deliver for Michigan | US Department of Transportation
[16] FACT SHEET: One Year In, President Biden's Inflation Reduction Act is Driving Historic Climate Action and Investing in America to Create Good Paying Jobs and Reduce Costs | The White House
[17] Climate Change in the Great Lakes Region References | GLISA (umich.edu)

Exhibit 3.1.2.1 - Upper Midwest Extreme Weather is Increasing in Frequency and Intensity



In Michigan, the 2019 Michigan Hazard Mitigation Plan (MHMP) identified severe winds and ice storms as high-frequency hazards for the regions of Michigan encompassing the DTEE service area. The MHMP further reported an average of 395 annual extreme wind events across Michigan with a future upward risk trend. Within DTEE's service territory, this has been supported by observations on wind gust data from Detroit Metropolitan Airport, shown in Exhibit 3.1.2.2 below.

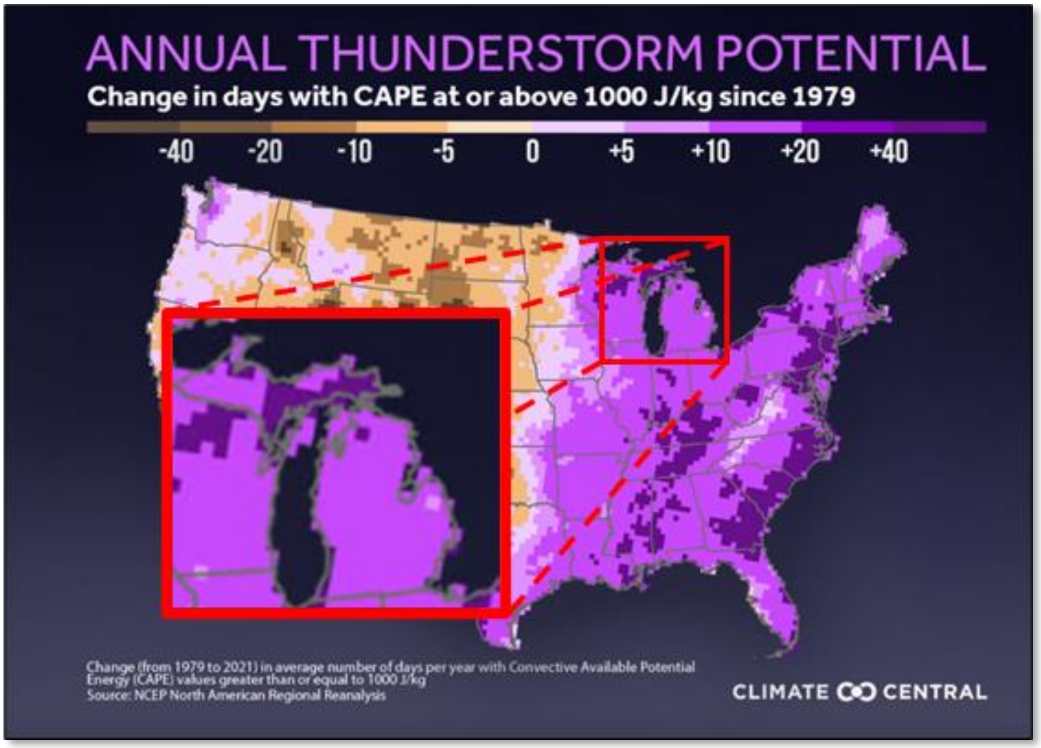
Exhibit 3.1.2.2 - Detroit Metropolitan Airport Wind Gust Data



Another indicator of increasing extreme weather in Michigan is the annual increase in the number of days with higher Convective Available Potential Energy (CAPE), which can be thought of as the amount of energy available for a developing thunderstorm,[18] with higher values translating to greater potential for severe storms.[19] In Michigan, higher CAPE days have become more frequent, as shown below in Exhibit 3.1.2.3**.**

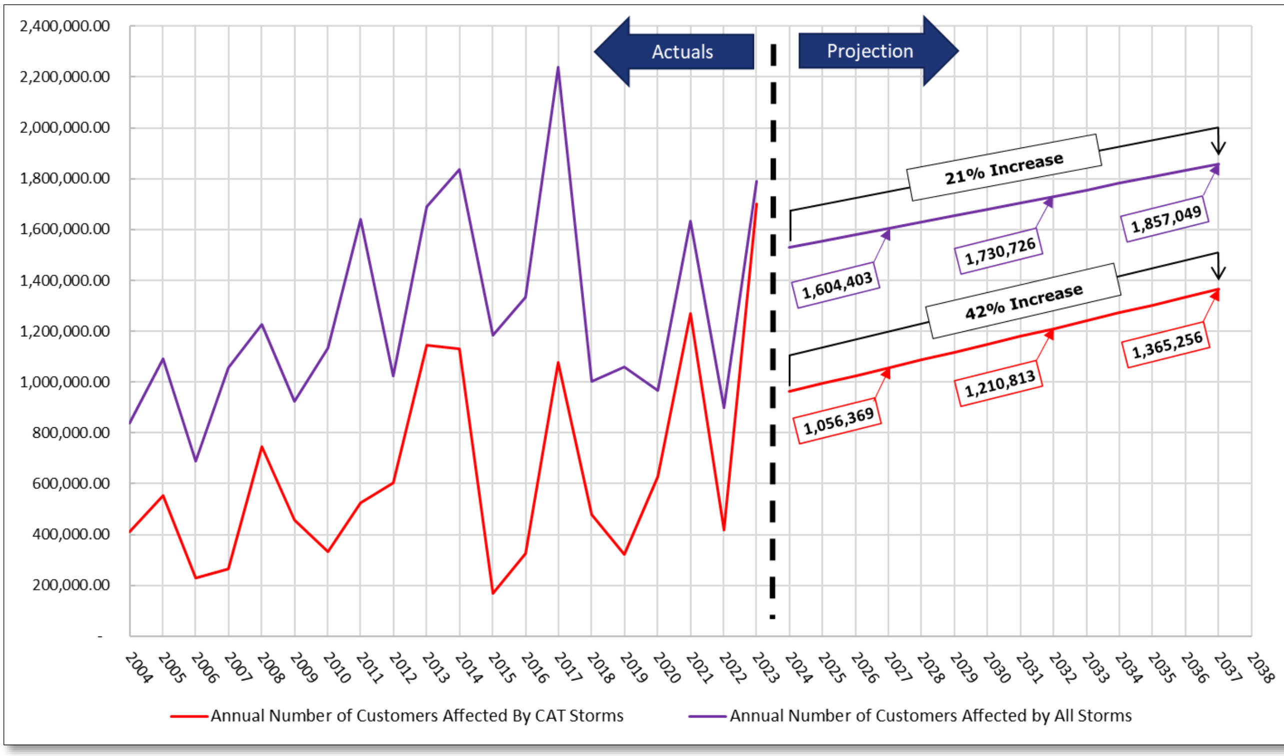
[18] What is Cape? - National Weather Service
[19] Changing Thunderstorm Potential | Climate Central

Exhibit 3.1.2.3 – Higher CAPE Days Have Become More Common in Michigan



There are large uncertainties when projecting extreme weather events due to limitations in existing weather models and inaccurate or missing historical data. Despite this, the trends indicate DTEE's service territory will likely be facing more extreme weather patterns in the future. For the increasing catastrophic storms scenario, the team's plausible forecast was a future where severe weather events increase in intensity. Absent any upgrades to the system, the forecast assumes that the number of customers affected by catastrophic storms will increase, as shown below in Exhibit 3.1.2.4. While the main driver of this forecast is assumed to be the increasing intensity of severe weather, another factor is DTEE's aging and increasingly beyond end-of-life equipment, which is less able to withstand the impacts of severe weather.

Exhibit 3.1.2.4 – The Number of Customers Affected by CAT Storms Is Increasing Each Year



Because of the distribution system's aging equipment, configuration and existing capacity constraints, DTEE's grid is increasingly vulnerable to the impact of extreme weather. Storms can cause widespread outages that disrupt service to customers for extended periods of time, as well as damage equipment, resulting in costly repairs. Compounding forms of extreme weather can exacerbate the negative effects of storms on DTEE's grid infrastructure. For example, periods of high heat can stress the grid, overloading equipment and limiting the ability to transfer customer load to other circuits during outages. As another example, heavy precipitation events can cause flooding, impacting underground equipment and saturating the soil, making trees more likely to uproot and fall into power lines during periods of high winds.

Exhibit 3.1.2.5 - Tree Damage to DTEE Equipment in the Webberville Community (July 26,2023)

In response to the impacts of extreme weather, DTEE will strengthen the distribution grid to enhance system reliability and resiliency. Grid strengthening includes replacing aging overhead equipment with stronger poles, fiberglass crossarms and polymer insulators, as well as developing options such as undergrounding overhead wires.

Signposts that DTEE will continue to monitor in the catastrophic storm scenario include increasing storm severity and frequency; communities implementing resiliency initiatives and projects, including the construction of resilience hubs or community centers that support residents when extreme weather events occur; weather patterns and environmental conditions that increase the likelihood of wildfires; and government policy and initiatives to support resiliency infrastructure projects.

3.1.3 Distributed Generation/Distributed Storage Growth Scenario

The Distributed Generation/Distributed Storage (DG/DS) scenario focuses on the adoption of distributed generation and storage technologies that can reduce customer electricity demand and, in some cases, export power back to the grid. Both DG and DS are classified as subsets of distributed energy resource (DER) technologies by the MPSC,[20] which defines DER as, "source of electric power

[20] MPSC Case U – 20147, August 20th Order, Pg. 11.

and its associated facilities that is connected to a distribution system. DER includes both generators and energy storage technologies capable of exporting active power to a distribution system."

While there is more than one type of DG, customer owned solar photovoltaic (PV) is the most common today. Since 2007, through legacy net metering programs and the more recent distributed generation program,[21] the Company has supported customers in the interconnection of their DER projects. Recently, DTEE increased its DG cap from 1% to 6% of its average in-state peak load for the preceding five calendar years. Technological advances and public policy (e.g., tax credits) have reduced DER costs and payback period, which is expected to drive increased customer adoption. Another force of DER growth is expected to come with the Midcontinent Independent System Operator's (MISO) ongoing implementation of FERC Orders 841 and 2222, which when implemented can provide residential as well as commercial and industrial (C&I) customers an opportunity to participate in the wholesale market. In addition, federal and state grants are expected to provide additional funding for residential and community solar projects.

The Company's 2022 IRP examined multiple DG adoption forecasts, including the "aggressive customer-owned distributed generation" sensitivity,[22] analyzing it for distribution planning purposes as the plausible forecast for residential and small C&I solar PV growth. Along with this forecast, it is expected that ~55%[23] of PV residential solar installations will include a battery energy storage system, potentially resulting in an additional 144 MW of added residential storage capacity through 2037. The plausible forecast is summarized in Exhibit 3.1.3.1 below.

[21] About DTE's Distributed Generation Program

[22] This stakeholder- requested IRP forecast scenario utilized an aggressive assumption for solar photovoltaic adoption, combined with solar system capital costs that were set to align with NREL's 2021 annual technology baseline aggressive scenario. See: https://mi-psc.force.com/sfc/servlet.shepherd/version/download/0688y000004qW9sAAE

[23] From internal DTEE interconnection data. The 55% attachment rate used in the DG/DS scenario matches the highest annual attachment rate observed in the previous three years of DER interconnection data (2020-2022).

Exhibit 3.1.3.1 - DG/DS Scenario Capacity Forecast (2027 – 2037)

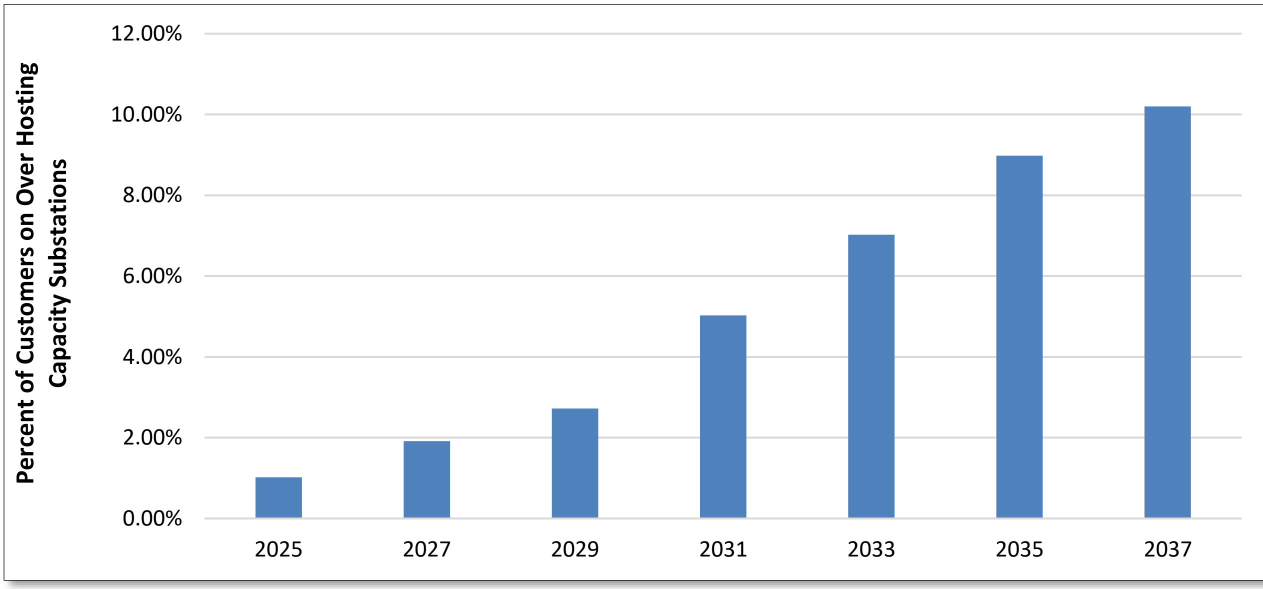
Key Drivers	2027	2032	2037
Solar PV – Residential	107 MW (0.97% peak)	226 MW (2.0% peak)	355 MW (3.1% peak)
Solar PV – Small C&I	74 MW (0.66% peak)	153 MW (1.38% peak)	236 MW (2.0% peak)
Storage – Residential	35.7 MW (0.32% peak)	87.6 MW (0.79% peak)	144 MW (1.26% peak)
Storage – Small C&I	2.6 MW (0.02% peak)	6.5 MW (0.06% peak)	10.5 MW (0.09% peak)

The introduction of DER into the distribution grid may provide an opportunity to gain a variety of distribution grid benefits, such as reduction in distribution system losses, mitigation of overloads and adding ancillary services that improve power quality and voltage regulation. However, since adoption levels are still relatively low in Michigan, quantification of these benefits is not fully understood today. In addition to grid benefits, moderate to high levels of DER can also cause localized grid challenges, including voltage and thermal issues impacting power quality in addition to protective device malfunctions. As customer adoption increases, the Company will continue to study the grid impacts of DER to understand both the benefits and challenges for the distribution system.

The Company will invest in grid communications and controls to support the DER operating benefits, while maintaining the stability and quality of power delivered to all customers. This may include a need to curtail generation at those sites during certain conditions, as well as making other investments in system upgrades. The number of customers on substations where the desired level of installed solar capacity exceeds a substation's hosting capacity[24] limit will likely increase in the future if upgrades are not made to distribution system equipment implemented through the interconnection process (shown below in Exhibit 3.1.3.2).

[24] Hosting capacity is defined as the amount of DER that can be accommodated on a circuit or substation without adversely impacting operational criteria, such as power quality, reliability and safety, under existing grid control and operations and without requiring infrastructure upgrades.

Exhibit 3.1.3.2 - Percentage of Customers on Substations where Installed Solar Capacity Exceeds the Hosting Capacity Limit (2025 – 2037)



The signposts the Company will continue to monitor are those affecting customer adoption, incentives and market participation. These include MISO's ongoing implementation of FERC Order No. 2222, growth of solar and storage installations in the Company's service territory, and any public polices related to DG and storage. Of these indicators being monitored, compliance with MISO's requirements for FERC Order No. 2222 is of special note, as the associated grid implications will be a core driver for a number of technology and automation investments. This includes the Distributed Energy Resource Management System (DERMS) program, interconnection process enhancements, and planning tool upgrades (see Section 10.2 – Operational Technology Roadmap – and Appendix C.2 – Grid Management Investments, DERMS & FERC2222 for more details).

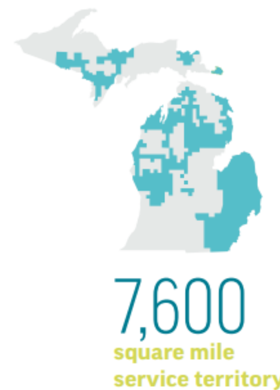
3.1.4 Scenario Impacts

As these scenarios highlight, the future grid will require greater flexibility to quickly respond to changes in load demands, generation and system configurations on the distribution system. The grid will also need to be more robust to withstand more extreme weather predicted in the future. Infrastructure upgrades - such as conversion - will aid the system in accommodating customer DG/ DS adoption and demand growth from electrification. Lastly, more technology will be needed to allow for grid monitoring and control technologies (e.g., ADMS) that can be used by grid operators to ensure system reliability and maintain the quality of power delivered to customers. The current state of the Company's grid will be discussed next in Section 4. Section 5 will revisit the impacts of scenarios in determining the gaps that need to be addressed to improve the system.

4 State of the Grid

4.1 Current Electric System Overview

DTEE's distribution grid includes approximately 31,000 miles of overhead distribution lines and 14,500 miles of underground distribution lines. Its service territory encompasses 7,600 square miles and includes approximately 2.3 million residential, commercial and industrial customers. DTEE's electrical grid consists of six voltage levels: 120kV, 40kV, 24kV, 13.2kV, 8.3kV and 4.8kV. Maps depicting the distribution and subtransmission voltages across the service territory can be found in Exhibit A.1. in Appendix A.



As many of DTEE's distribution assets have been in operation for several decades, a significant portion of the distribution system's equipment is reaching, or has exceeded, the typical industry lifespan, resulting in a higher occurrence of outage events when compared to peer utilities. Older equipment may have deteriorated due to long exposure to the elements, but in many cases this equipment was also built to less resilient standards of the past. Certain areas of the distribution system are in locations difficult to access such as backyards or wooded areas. Distribution lines in abandoned alleyways are particularly challenging to access, causing delays in restoration efforts and complicating equipment maintenance. Additionally, the electric system faces limitations on capacity in some areas, which at times present difficulties in accommodating new customer loads. The Company has seen a growing number of outages, particularly during extreme weather. Redesign and modernization will improve reliability and help to meet the evolving demands of today's energy landscape.

4.1.1 Subtransmission System Voltages

DTEE's subtransmission system consists of three voltages: 24kV, 40kV and a limited amount of 120kV, which supplies customer-dedicated substations. The subtransmission system steps down the transmission voltage for delivery to distribution and industrial substations. The 24kV segments of the system were built to serve the 4.8kV sections of DTEE's distribution system but do not align with modern standards; however, the newer 40kV lines are being constructed to meet industry standards. Similar to distribution equipment, much of the subtransmission equipment is approaching or is beyond typical industry lifespans. Maintenance access to sections of the overhead subtransmission lines is regularly impeded by obstacles such as wooded areas and railroads, often delaying restoration after a failure. Load constraints on the subtransmission system limit operational flexibility, creating delays to shutdowns needed for equipment maintenance and for prepping the system to accommodate new loads. These factors could lead to increased failures, resulting in the loss of redundancy, or in some cases to large, sustained outages. Section 9.2 further discusses the current state of the subtransmission system, including challenges and limitations as well as the strategies and investments to mitigate these issues.

4.1.2 Distribution System Voltages

DTEE's initial distribution system voltage was 4.8kV, which remains in active use today. The system was designed as an ungrounded delta configuration and banked secondary standard. Ungrounded delta configuration means that in order for a trip device to operate on the system, two of the high-power lines need to touch each other to create a fault the devices can see, in contrast to higher voltage grounded systems. In a banked secondary configuration, multiple transformers are interconnected to provide power to a small area of customers. This system has its strengths in resiliency, however, due to its ungrounded design, fault locating can be challenging and may complicate restoration efforts. Delta configuration is a design from the early 1900s. In most neighborhoods, the 4.8kV system was constructed as overhead rear-lot poles and wires, which was aesthetically preferable to front-lot construction. Right-of-way 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, preventing DTEE trucks from accessing the poles and wires. Consequently, the limited access significantly increased the time to locate and repair trouble on the 4.8kV system and increased the time required to perform tree trimming and maintenance work.

In the 1960s, DTEE began installing a 13.2kV distribution voltage. The 13.2kV system is a newer, grounded system with increased reliability. Because the system is a grounded configuration, the 13.2kV system can more easily accommodate automation technology when compared to the 4.8kV system. Additionally, the 13.2kV system is typically constructed to provide better access to locate and repair trouble.[25] These key differences between the two systems mean average restoration time for an outage on the 4.8kV system is 70% longer than on the 13.2kV system. Other key reliability and operability advantages of the 13.2kV compared to the 4.8kV system are summarized below:

- The 4.8kV system has smaller conductors (wires), which are weaker in strength compared to those the on 13.2kV system
- Due to the voltage, a 4.8kV circuit has lower capacity and can only accommodate ~40% of the customers serviced by a 13.2kV circuit
- The 4.8kV system can have more significant voltage drops than the 13.2kV system due to higher impedance, making the 4.8kV circuits more susceptible to dropping below acceptable voltage limits
- Unlike the 13.2kV system, the 4.8kV system is an ungrounded delta configuration, making detection, location and protection of single-phase downed wires challenging

4.2 Reliability

DTEE customers expect and deserve reliable service. To better serve customer needs, DTEE has made reliability one of the core planning objectives. Measuring reliability performance helps drive operational performance improvement, prioritizes strategic investments and validates that those investments are delivering the intended benefits.

[25] The 13.2kV system is usually built along roadways which allows for easy access from bucket trucks.

4.2.1 SAIFI, SAIDI, and CAIDI

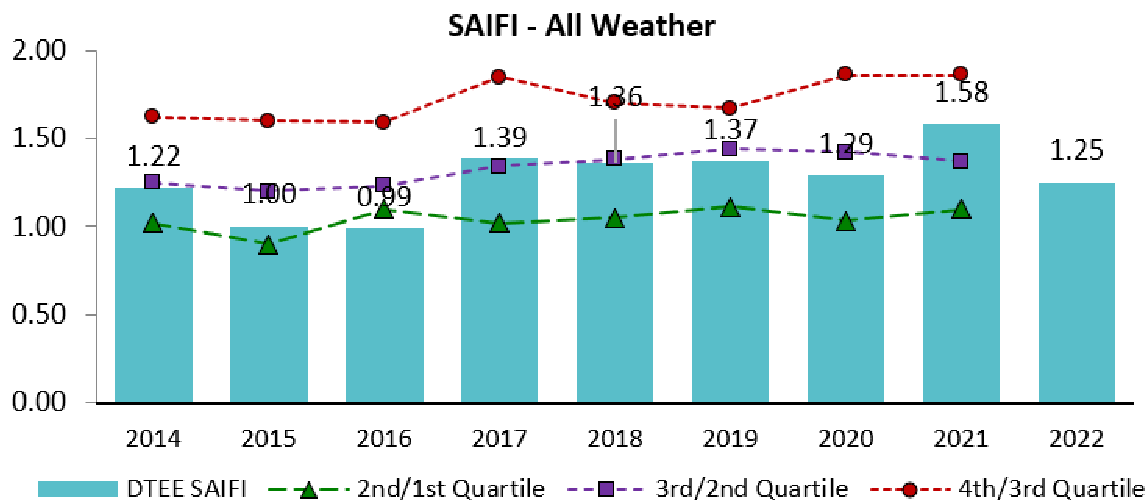
DTEE measures overall system reliability using the indices System Average Interruption Frequency Index (SAIFI), System Average Interruption Duration Index and Customer Average Interruption Duration Index (CAIDI). These three metrics are reliability performance indicators defined in IEEE Standard 1366 and summarized in Exhibit A.2 in Appendix A. These indices are typically calculated in two ways: 1) All-Weather conditions, and 2) excluding Major Event Days (MEDs). An MED is any 24-hour period in which there is a significant statistical difference in daily SAIDI; the calculation details are in IEEE Standard 1366.[26] Excluding MEDs gives a clearer picture of day-to-day system performance and customer experience absent significant weather events, which are highly variable from year to year.

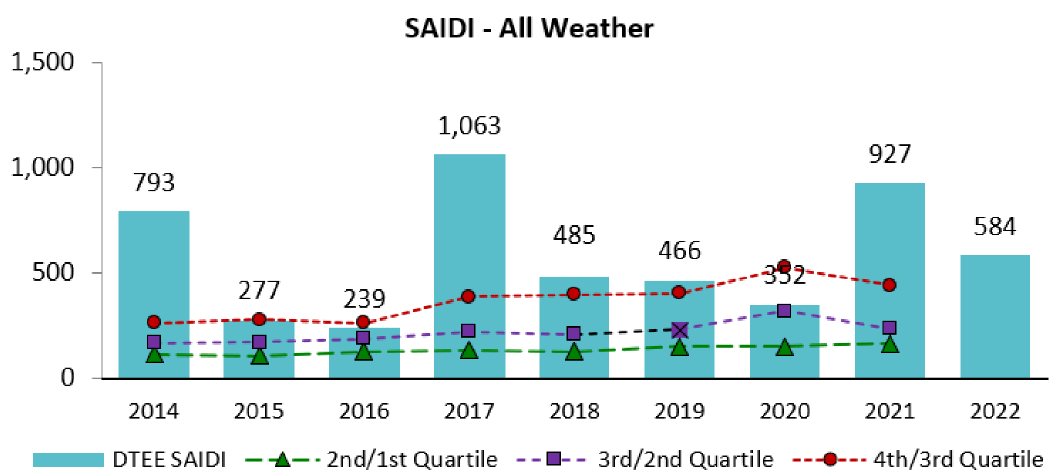
In addition to the IEEE standard indices, DTEE also tracks reliability performance under various weather-related conditions: catastrophic storms, non-catastrophic storms and excluding storms. Analyzing these stratifications allows better insight into reliability performance, root causes of customer outages and the remediations needed to improve performance under different conditions. Reliability data in these various weather conditions can be seen in Exhibits A.3 - A.6 in Appendix A.

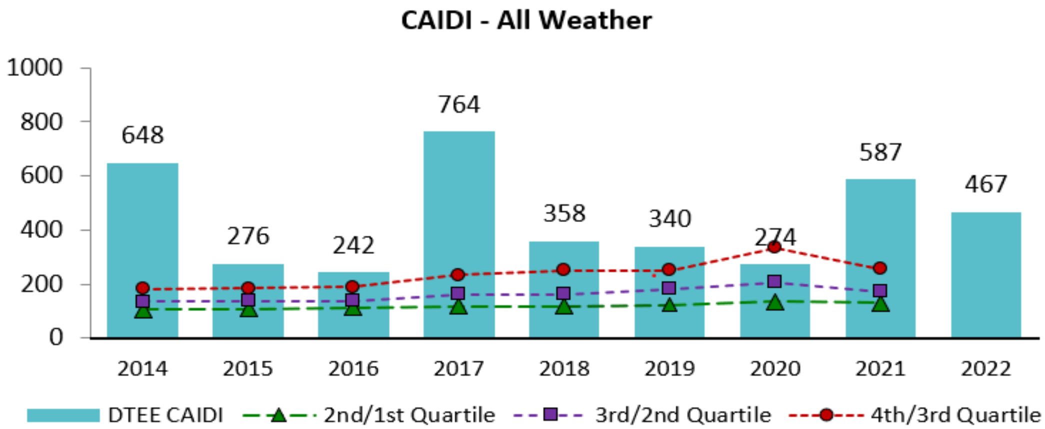
Exhibit 4.2.1.1 below shows reliability statistics over the last nine years for All-Weather indices. Over this span, DTEE has consistently been in the second and third quartile for SAIFI, and primarily in the fourth quartile for SAIDI and CAIDI.

[26] Microsoft PowerPoint - Without video IEEE 1366- Reliability Indices 2-2019.pptx

Exhibit 4.2.1.1 Reliability Statistics - All Weather







4.2.2 Causes of Interruptions

The Company analyses what causes interruptions to DTEE's electric distribution system to address primary outage drivers and improve reliability. Exhibits 4.2.2.1 through 4.2.2.3 found below illustrate the percentage contribution to customer minutes of interruption, customer interruptions and outage events by cause. Tree/wind interference is the leading cause of DTEE's customer minutes of interruption (SAIDI) and number of customer interruptions (SAIFI). Tree/wind is also the leading cause of outage events (within DTEE's Outage Management System) on the DTEE system. Equipment failures are the second leading cause of the SAIFI outage events on the DTEE system.

Exhibit 4.2.2.1 5-Year Average Customer Minutes of Interruption by Cause (SAIDI)

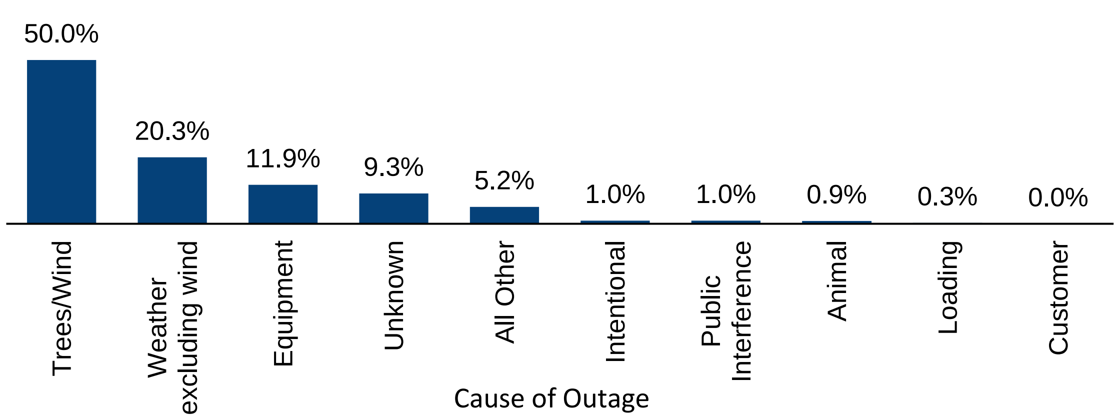


Exhibit 4.2.2.2 5-Year Average Customer Interruptions by Cause (SAIFI)

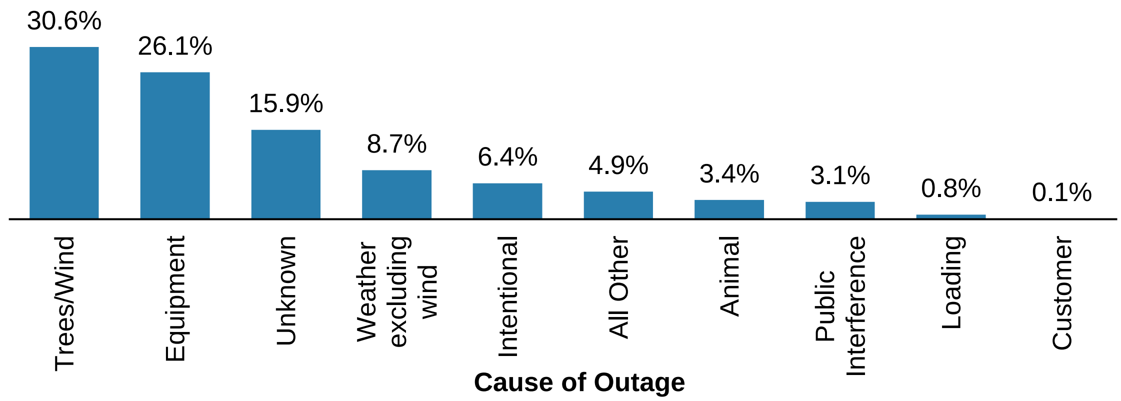
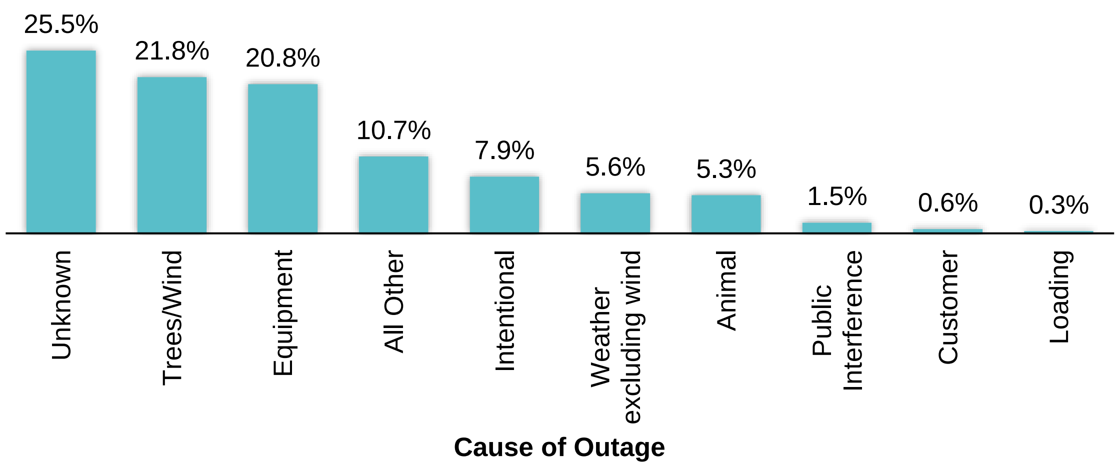


Exhibit 4.2.2.3 Five-Year Average Outage Events by Cause



Note: Equipment includes substation, underground and overhead equipment, and hardware

4.3 Distribution System Assets

4.3.1 Distribution System Asset Overview

There are 18 assets that have the greatest potential impact on customer reliability. The average age, range of ages and life expectancy for the 18 asset classes are summarized in Exhibit 4.3.1.1. The life expectancy is based on manufacturer recommendations, industry benchmarks, EPRI (Electric Power Research Institute) Industry Database, NEETRAC (National Electric Energy Testing, Research & Applications Center) Asset Survival Plots and DTEE's data. Age can become a significant factor when replacement parts become unavailable or, in specific cases, where asset health deteriorates sharply with age. However, DTEE also uses annual health assessments to evaluate its assets. The criteria for each asset were described in detail in Section 8 of the 2021 DGP and the risk factors have not changed since then. Sections 4.4.2-4.4.8 provide a detailed description for eight key asset classes. Additional detailed descriptions can be found in the 2021 DGP on pages 148-203.

Exhibit 4.3.1.1 Asset Age Summary

Asset (Section)	DTE Electric Age Range (Years)	DTE Electric Average Age (Years)	Life Expectancy (Years)	% of Asset Class at or Beyond End of Life
Substation Power Transformers (4.4.3)	0-99	43	40-45	49%
Network Bank Transformers	0 – 85+	46	20 - 30	91%
Circuit Breakers (4.4.4)	0 – 90	41	30 – 40	60%
Circuit Switchers	0 – 36	19	NA	NA
Relays	0-60+	33	15-50	NA
Switchgear	0 – 70	40	40	55%
Poles (4.4.5)	0-90+	46	40-50	50%[27]
Three-phase Reclosers (4.4.6)	0-34	10	20	10%
SCADA (Supervisory Control and Data Acquisition) Pole Top Switches	0-31	15	20	38.5%

[27] This number was calculated using 50 years as the number for expected end of life of poles.

40 kV Automatic Pole Top Switches	0-50+	21	40	35%
Overhead Capacitors	Oldest: 25+	NA	20	NA
Overhead Regulators	Oldest: 25+	NA	20	NA
System Cable (4.4.7)	0 – 100+	49	20 – 40	64%
Underground Residential Distribution (URD) Cable (4.4.8)	0 – 60+	26	40	23.6%
Manholes	1-100+	78	Varies based on construction and field conditions	NA
Advanced Metering Infrastructure (AMI meters)	0-13	6.5	20	0%

4.3.2 Substation Power Transformers

DTEE has approximately 1,600 substation power transformers connecting the transmission system (120kV) to the subtransmission system (40kV and 24kV) and to the distribution system (4.8kV, 8.3kV, and 13.2kV). The average age of substation power transformers is approximately 43 years. The Company has averaged over 15 power transformer failures per year over the past five years, including units that were identified[28] and proactively replaced before failure. Bushings, load tap changers and winding insulation breakdown account for approximately 65% of the failures. The

[28] Based on results from routine inspection and Dissolved Gas Analysis (DGA).

average age of transformers at the time of failure is approximately 48 years. Failures of substation power transformers can cause outages on multiple circuits simultaneously. Substation power transformer failures can also reduce system redundancy effectively increasing outage risk to customers for extended periods, sometimes impacting thousands of customers. Approximately 49% of substation power transformers are at or beyond expected useful life.

4.3.3 Circuit Breakers

A circuit breaker is an electrical switch that isolates faults on substation equipment, buses and circuits. Its basic function is to interrupt current flow after a fault is detected to minimize equipment damage due to high fault currents and to isolate the faulted asset from the electrical system. DTEE has approximately 6,000 breakers on the electrical distribution and subtransmission systems. This number is a mixture of oil, air magnetic, gas and vacuum breakers. Currently, 60% of all breakers are beyond expected useful life and 53% are candidates for replacement based on the findings in the asset health assessment. Included in this 53% are approximately 2,090 oil-filled breakers that require replacement due to a combination of multiple risk factors associated with that equipment, such as the environmental concerns of possible leaks. A failure of a circuit breaker can cause outages on multiple circuits and reduce system redundancy for an extended period during repairs. Depending on the extent of the failure and possible adjacent collateral damage, thousands of customers could be impacted for an extended duration. More information on breaker replacements can be found in Section 8.3.3.

4.3.4 Poles and Pole Top Equipment

DTEE owns more than one million distribution and subtransmission poles. In addition, DTEE has assets attached to nearly 200,000 poles owned by other utilities (e.g., Comcast, AT&T). The average pole age in the DTEE system is approximately 46 years. The useful life expectancy of a pole is 40 years for wood pine poles and 50 years for wood cedar poles, though the actual useful life can vary based on field conditions. Currently, 50% of poles in DTEE's system are at or beyond end-of-life.

Poles can fail for a variety of reasons, including vehicle strikes, damage from trees and branches and icing or wind loads above the design standard. As poles age they weaken and become more susceptible to failure.

Pole top hardware can also fail as equipment ages. That hardware includes cutouts, slack span sleeves, blackburn hot taps, ground wires, arresters, cross-arm parts, transformer parts, insulators, primary line sag, guy wire components, spacer blocks, neutrals on secondary taps and secondary equipment.

4.3.5 Three-phase Reclosers

An overhead three-phase recloser is a sectionalizing device that is installed at key points on overhead circuits. It acts like a circuit breaker by opening if high current is detected due to a downstream fault, such as a tree branch across two phases. Reclosers localize the fault to the circuit section beyond the recloser (downstream of the recloser), leaving customers intact on the remainder of the circuit (upstream of the recloser). Unlike a fuse that will open and stay open, a recloser is designed to automatically attempt to reclose several times to restore the downstream customers if the fault has cleared. The open and reclose cycle allows a temporary fault, such as a small falling tree limb, to clear from the circuit and 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 can be programmed to automatically back feed parts of a circuit in the event of a power outage. Modern, three-phase reclosers offer remote functionality that can be utilized as part of a loop scheme. At a circuit level, loop schemes facilitate automation by transferring power into adjacent sections of the circuits when an outage is detected. Loop schemes are currently installed on approximately 5.5% of distribution circuits. Loop schemes are standard for all new or converted circuits. Efforts are currently underway to automate specific aspects of the 4.8 kV system where possible, and these efforts are discussed in section 10.1.

DTEE has a preventive maintenance program for overhead three-phase reclosers. Reclosers failing preventative maintenance inspection or failing in service are replaced or repaired. The average age of the three-phase reclosers is 10 years, and approximately 10% of three-phase reclosers are at or beyond expected useful life.

4.3.6 System Cable

DTEE's distribution and subtransmission system has over 3,000 miles of underground system cable. System cable is large diameter cable surrounded by insulation that is typically installed in conduit and requires manholes or switch cabinets approximately every 100 to 800 feet, depending on the cable type and path. Manholes and switch cabinets provide locations where sections of cable can be pulled through the conduit and spliced together. System cable provides higher storm resiliency than overhead lines; however, the cost and time to install, repair or replace is much greater. The increased time to repair/replace system cable makes it imperative that redundancies are maintained, such that when a cable fails, its load can be shifted to another power source (often another system cable) to avoid a long duration customer outage. System cable is especially useful to route multiple circuits through a small, congested area (e.g., entrances and exits of a substation).

Exhibit A.7 in Appendix A illustrates five of the six major types of underground system cable installed in DTEE's distribution system. Exhibit 4.3.6.1 below shows the types, quantities, average age and life expectancy of system cables in the DTEE system. The average life expectancy of system cables is 40 years or less, although actual useful life varies depending on cable type and field conditions. System cable is a critical component for both the subtransmission and distribution systems. A cable failure reduces system redundancy and resiliency and can interrupt many customers for an extended period. Of DTEE's system cable, 64% is at or beyond end-of-life and 28% has been assessed as high-risk of failure. Information on system cable replacements can be found in section 8.3.2.

Exhibit 4.3.6.1 Underground System Cable Ages and Life Expectancy

Cable Type	PILC	EPR	VCL	Gas	XLPE Post 1990 (Tree retardant)	XLPE Pre 1990 (Non-tree retardant)	BUYTL
Miles	2,219	707	114	49	50	59	7
% of Total Population	69%	22%	4%	2%	2%	2%	0%

Average age	52	15	61	55	20	37	53
Life Expectancy	40	35	40	40	40	25	20

4.3.7 Underground Residential Distribution (URD) Cable

Underground Residential Distribution (URD) is a specific type of cable designed and used in underground residential applications on the Company's secondary electric system. URD consists of small-diameter cable surrounded by polyethylene insulation, which is either directly buried or installed inside conduit into the ground. Since URD is buried underground, it is not exposed to above ground tree-related or other overhead-related outages. However, it is more expensive to install and repair than overhead lines. Underground cable failures are less frequent but take a long time to repair or replace. DTEE is currently evaluating options to underground portions of circuits to improve reliability for customers. The average age of DTEE URD cable is 26 years. DTEE currently has 2,682 miles of URD cable, or 23.6%, that is ready for replacement. Information on underground residential distribution (URD) cable replacement can be found in Section 8.3.2.

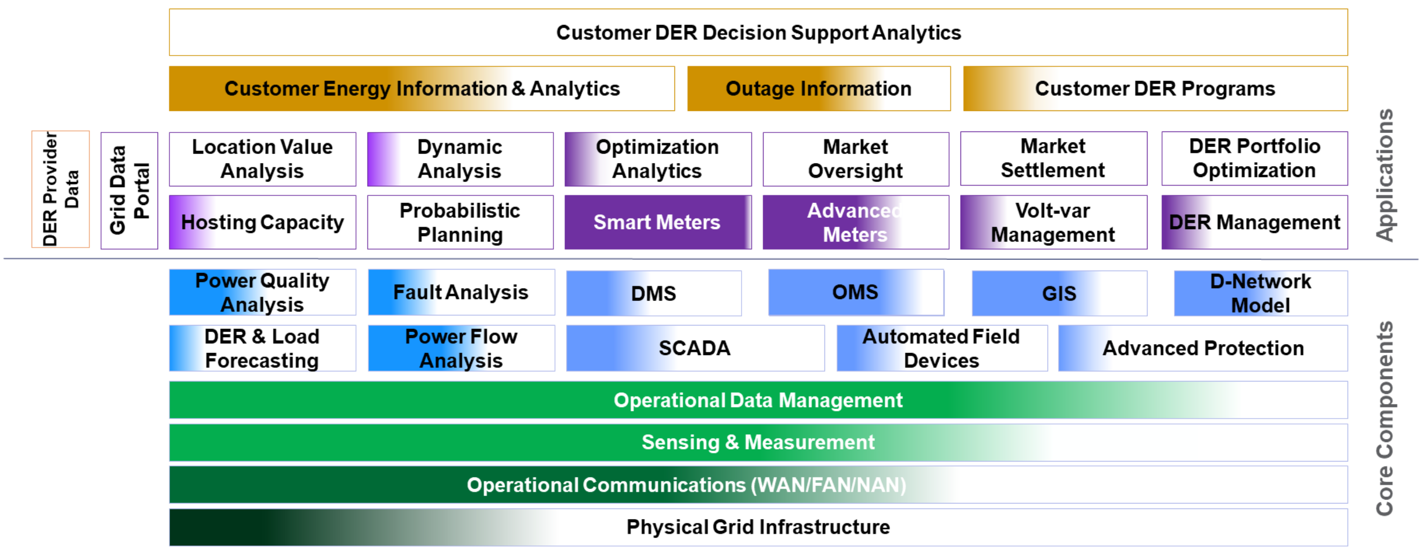
4.3.8 Small Wire

Small wire is identified by the wire gauges #8, #6 and #4. These wire sizes are no longer used for new installations. Small wire is of concern due to its weaker mechanical strength, causing it to break more easily when tree branches fall on it. To improve reliability, new wire specifications provide strengths that are two- to three-times stronger than small wire sizes. There is no standalone proactive replacement program for small wire. However, small wire replacement is performed during other capital work to support load growth, conversion and consolidation, or reliability improvements.

5 Gaps to Future State

After reviewing the scenario analysis discussed in Section 3, and assessing current state infrastructure in Section 4, the Company leveraged the United States Department of Energy Distribution System Platform Initiative (DSPx) framework to help determine where gaps exist between the grid in place today and the future grid needed to serve customers. The DSPx framework segments planning and operational technologies in order to clearly display the progress the Company has made in each area and those where investment is most needed. The figure below is adapted from Volume 3 of the DSPx framework and has been included to conceptually show the status of DTEE's core grid modernization platform and application layers. The more color a bar has, the more advanced DTEE is in that area; large amounts of white space indicate a gap that needs to be closed.

Exhibit 5.0.1: DTEE Grid Modernization Status



Reference U.S. Department of Energy Modern Distribution Grid Project Volume 3 Figure 8: https://gridarchitecture.pnnl.gov/modern-grid-distribution-project.aspx

Using the DSPx framework in conjunction with the scenario analysis discussed in Section 3, further highlights current state gaps as well as potential future system gaps. As investments are weighed against each other, an indicator of the most valuable investments is the ability to address grid needs for multiple scenarios. For example, a physical grid infrastructure investment in voltage conversion will create capacity required in the electrification scenario, increase resilience by modernizing and hardening equipment benefiting the CAT storm scenario and increase hosting capacity necessary to support the DG/DS scenario.

For simplicity, DTEE has summarized the gaps to future state that were derived from this analysis into four categories:

1) Physical Grid Infrastructure
2) Observability and Controls
3) Analytics and Computing Platforms
4) Communications

5.1 Physical Grid Infrastructure

Physical grid infrastructure is by far the largest investment gap identified (by size of investment required) and is foundational to meeting all future grid needs. Much of the current infrastructure is old and failing in ever-increasing amounts, making the system particularly susceptible to extreme weather impacts. Capacity constraints at both the circuit and substation levels will restrict the ability to: (1) add new customers and new load forecast from electrification, (2) accommodate the voltage fluctuations caused by DER, and (3) limit current and future ability to reroute power during outages. Based on DTEE's 2022 area load analysis, approximately one-third of distribution substations currently have loading constraints, either within the substation or on its circuits. These capacity concerns are particularly problematic on the 4.8kV system where the lower voltage is limiting.

Additionally, fault locating can be challenging on the 4.8 kV system and the limited ability to utilize circuit automation on the system can complicate restoration efforts. The 4.8kV infrastructure is also the oldest on the system. While not the only factor, aging equipment can increase the probability and severity of failure resulting in customer outages and the need for emergency equipment replacements and repair.

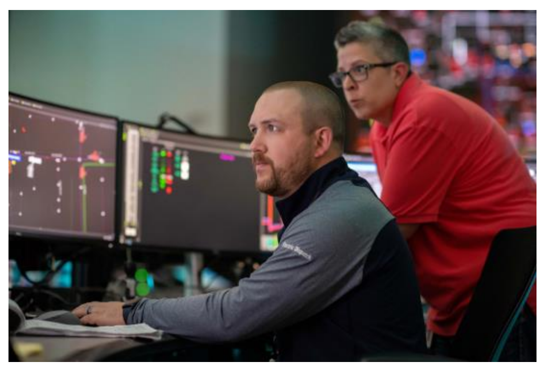
Solving this gap will not be easy or quick. It will take sustained investment in voltage conversion and infrastructure replacement programs including overhead, underground and substation equipment. Lastly, new capacity will need to be added to accommodate future load demands. Increased capacity will need to primarily come from conversion work and 13.2kV substation/circuit expansions, while a smaller part of the solution set will be load offsets from customer DER and/or energy conservation.

More information on Physical Grid infrastructure Investments can be found in Section 8 - Infrastructure Resilience and Hardening and Section 9 - Infrastructure Redesign and Modernization.

5.2 Observability and Controls

The Company's electric distribution grid requires increases to both remote observability and control of the assets operating on the system. Benefits of observability and control include:

- **Automating the Grid**: Automated technology to control switching devices to reconfigure the grid during outages, enabling remote restoration that will be particularly beneficial during extreme weather events
- **Understanding Problems:** The ability of system operators to understand in real time when and where outages occurred and what current system restoration options are available
- **Monitoring Distribution:** Monitoring of system attributes such as voltage, current and harmonics – information needed to maintain a stable electric grid while managing large volumes of DER and the impacts of electrification
- **Coordinating Resources:** Work with certain DER assets (e.g. DER aggregations, energy storage, utility owned solar facilities) to maintain system integrity and reliability



Increasing the number of DER on the Company's system creates a need for enhanced, granular monitoring and sensing capabilities because DER interacts with the grid in fundamentally different ways than most current generation assets. Consequently, the impact of DER on the grid will need to be managed carefully. Everyday grid operations such as power quality management will become more dynamic as customers adopt DER and transportation is electrified, resulting in a wider range of less predictable loading conditions.

Storms will further threaten grid reliability and increase outage volumes unless effective control schemes are able to both sectionalize the grid and transfer load to adjacent circuits.

Increasing control capabilities to adapt to these unique, and at times overlapping, impacts support DTEE's safety and reliability priorities and will assist the Company in integrating more DER into its distribution system.

More information on Observability and Controls investments can be found in Sections 10.1 - Grid Automation and 10.2.1 -Grid Management Investments.

5.3 Analytics & Computing Platforms

Investments in observability and controls will provide the Company with increased volumes of associated data. It is important to have the capability to quickly and efficiently process this data while maintaining its quality. This is accomplished through investments in analytics and computing platforms that can ensure the quality and processing of large amounts of data to enable fast, informed decisions. DTEE has made significant progress in improving its analytics and computing platforms in recent years and recognizes that even more work will be required to keep pace with the increasing volumes of data available.

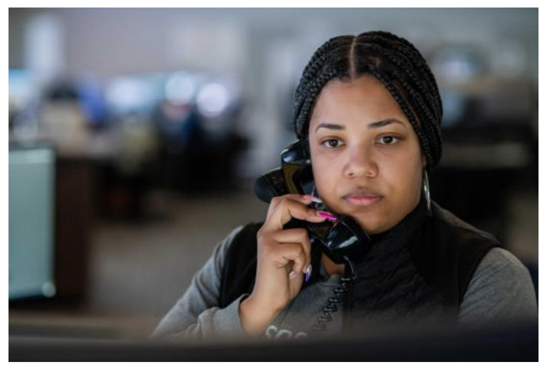
Accurate distribution system models and loading data will become increasingly important as planners work to forecast areas of DG/DS and EV adoption, as well as identifying distribution abnormalities well in advance of when they occur. Uncertainties surrounding consumer EV charging patterns will further complicate planning and forecasting efforts. The grid impacts associated with electrification, DER and increasing storms will require expanded data collection and an advanced analytics platform to assist the Company with complex decisions relating to planning and operating the grid.

For more information on analytics and computing platforms investments see Section 10.2.2 -10.2.5.

5.4 Communications

Communications technology is required to support the observability and control technology discussed in Section 5.2. This technology will enable data generated from smart grid devices to move between the equipment in the field and the ESOC. The current communications architecture must be enhanced to meet the throughput, latency and reliability standards that a modern grid requires.

Grid automation is needed to improve grid resiliency during extreme weather events; this automation requires communications infrastructure enhancements. Additionally, as DER and electrification growth occur, the number of connected devices and associated volumes of data that must be sent securely and in near-real time will also increase. While the Company has made headway with its telecommunications investments to date, many of the older assets within the current telecommunications architecture are incompatible with modern systems and incapable of handling the data requirements necessary to support DER growth. The Company's radio-based communications system, for example, was not initially designed to support large volumes of data and many areas of DTEE's service territory lack high-bandwidth communications. The Company has also had to adapt to several external regulatory changes from the FCC. The FCC spectrum reallocation has negatively impacted utility communications on wireless point-to-point and point-to-multi-point systems, as has the phase out of 3G cellular networks, which is the basis for the current AMI architecture.



DTEE is also susceptible to network blackouts caused by using leased Internet Service Providers and leased Cellular Service Providers that do not build their networks with the same level of resilience that the electric grid requires. This has resulted in a strategic shift in recent years to build networks privately owned and maintained by DTEE to enable the Company to securely control and operate reliable telecommunication systems.

To close these communication infrastructure gaps, additional privately owned tiered telecommunications systems are needed, including deploying fiber with enough coverage to support critical sites such as data centers, service centers, power plants, substations and renewables sites. In addition to fiber deployments, wireless point-to-point and point-to-multi-point systems will be needed to supplement telecommunications needs to intelligent edge devices such as AMI meters. This tiered telecommunications system design will place emphasis on system redundancy and resiliency, allowing the Company to better operate during outages on the communications network as well as the electrical system.

For more information on communications investments see Section 10.1 - Grid Automation.

6 Distribution Investment Strategy

DTEE's investment strategy will transform the grid and deliver significant benefits to customers, including improved reliability, reduced system risk, increased capacity to serve current and future load and enhanced capabilities to integrate the technologies that customers are adopting. Overall, the Company plans to invest $5.8 billion in strategic capital and almost $600 million in tree trimming across the five-year period described in this plan. DTEE has organized these strategic investments in the grid into the following four pillars, which the Company has used since the filing of the 2018 distribution plan:

- Tree Trimming
- Infrastructure Resilience and Harding
- Infrastructure Redesign and Modernization
- Technology and Automation

Each of these four pillars is designed to address grid needs identified through the scenario planning process described in Sections 3 through 5. The projects that receive the highest score in the Company's Global Prioritization Model (GPM), and therefore are assessed as having the highest impact, are prioritized for investment.

6.1 DGP Investment Summary and Impact on Reliability

Rebuilding and modernizing the electric grid is identified as the most important investment need in Section 5. Several factors contributed to this determination. First, much of the current infrastructure is at or beyond expected useful life and susceptible to failure, particularly when exposed to extreme weather. Second, approximately one-third of the physical grid has some form of load constraint on the subtransmission, substation or circuit level. Third, parts of the grid, specifically the 4.8kV distribution system, were designed in a configuration that has resulted in both safety and technological challenges. Three of the four pillars focus on improving the physical grid:

- **Tree Trimming (Section 7) –** The Tree Trimming investment includes both an enhanced specification to improve the impact of trimming trees, and a surge to bring the entire system on-cycle to this enhanced specification. Bringing the system on-cycle and maintaining that cycle is critical to minimizing the impact trees have on the physical grid infrastructure, particularly during extreme weather.
- **Infrastructure Resilience & Hardening (Section 8) –** Projects and programs in this pillar are focused on replacing aging infrastructure to improve grid reliability and resilience in the short term. This pillar addresses the overhead system through programs such as Pole Top Maintenance and Modernization and 4.8kV Hardening. Substations and the underground system are improved through system equipment replacement programs.
- **Infrastructure Redesign & Modernization (Section 9) –** This pillar includes projects which make more fundamental improvements to the electrical system and are focused on the longer term, such as conversion of the 4.8kV system to 13.2kV and upgrades of the subtransmission system to increase system capacity. These investments address longer-term grid needs as they replace aging infrastructure, relieve load constraints and convert the 4.8kV system to a modern grounded system at a higher voltage.

Section 5 also identified investment needs in the areas of Observability and Controls; Analytics and Computing Platforms; and Communications. Investments to support operating the grid more efficiently and closing these gaps are found in the fourth pillar.

- **Technology and Automation (Section 10) –** These programs and projects include investments to automate the entire distribution system and build out the telecommunications infrastructure to enable communication with widely deployed smart grid devices. Additional investments are earmarked for an operational technology roadmap that will enable integration of DER into the Company's system and enhance distribution planning processes, allowing the Company to forecast grid needs as customers adopt new technologies. Advanced technology and automation on the grid not only improves reliability but is also a key factor in enabling greater customer accessibilty to the grid.

Over the next five years, DTEE will invest $5.8 billion in strategic capital programs and projects. This level of investment will deliver improved reliability, reduced reactive cost and increased capacity to serve current and future load with reduced system risk.

The overall investment levels are shown in Exhibit 6.1.1, with more detail by pillar and program shown in Exhibit 6.1.2. These investments represent all of the capital investments.

Exhibit 6.1.1 Projected DTEE Five-Year Distribution Grid Plan Investments

Category		Capital Investments ($ Millions)					
		2024	2025	2026	2027	2028	5-Year Total
Base Capital	Emergent Replacements (Reactive Trouble and Storm Capital)	$415	$399	$368	$348	$345	$1,877
	Customer Connections, Relocations and Others	$282	$295	$314	$334	$355	$1,580
Strategic Capital Programs (details in Exhibit 6.1.2)		$906	$995	$1,134	$1,302	$1,485	$5,821
Total Capital Investments		$1,603	$1,689	$1,816	$1,985	$2,185	$9,278

Exhibit 6.1.2 5-Year Investment Per Pillar with Most Significant Investment for Each

Pillar	5-Year Pillar Investment 2024–2028 (Millions)	Largest Investment Area	5-Year Program Investment 2024-2028 (Millions)
Tree Trimming	$573	Enhanced Tree Trimming Program	$573
Infrastructure Resilience and Hardening	$1,639	Pole and Pole Top Maintenance and Modernization	$773
Infrastructure Redesign and Modernization	$2,537	4.8kV Conversion and Consolidation (including CODI)	$1,498
Technology and Automation	$1,645	Grid Automation	$1,192

6.1.1 Investment Impact on Reliability

The investments detailed in the 2023 Distribution Grid Plan will provide significant customer benefits including improved safety as well as better reliability and resiliency during normal conditions and severe weather. These investments will also improve the operability of the distribution system, including the ability to accommodate new loads.

The investments in 2024-2028 detailed in the four pillars will significantly reduce the frequency (SAIFI) and duration (SAIDI) of customer outages. While the entire portfolio of strategic investments is needed to improve the grid, the primary drivers of reliability improvement over the next five years are the tree trimming program, pole top maintenance and modernization and automating the distribution system. Reliability projections are shown in Exhibits 6.1.1.1 and 6.1.1.2 and are shown through 2029 as the first full calendar year post 2028 investments. In summary:

- By 2029, All-weather SAIDI is projected to improve by 64% in normal weather,[29] improving from a fourth quartile baseline to second quartile performance. In addition to the projected average SAIDI, the range between all-weather SAIDI in favorable and unfavorable weather years is projected to decrease, primarily due to the impacts of the automation program, which will reduce the size of outage events.
- All-weather SAIFI during normal weather is projected to improve by 27% and achieve first quartile performance in 2029.

[29] A normal weather year typically has a quantity of Major Event Days (MEDs) that is close or equal to the average of the last ten years. DTE has experienced eight MEDs on average per year over the last ten years. There are exceptions, like the March 2017 windstorm, that can have only 1-2 MEDs but have an outsized impact on reliability metrics.

Exhibit 6.1.1.1 System All Weather SAIDI

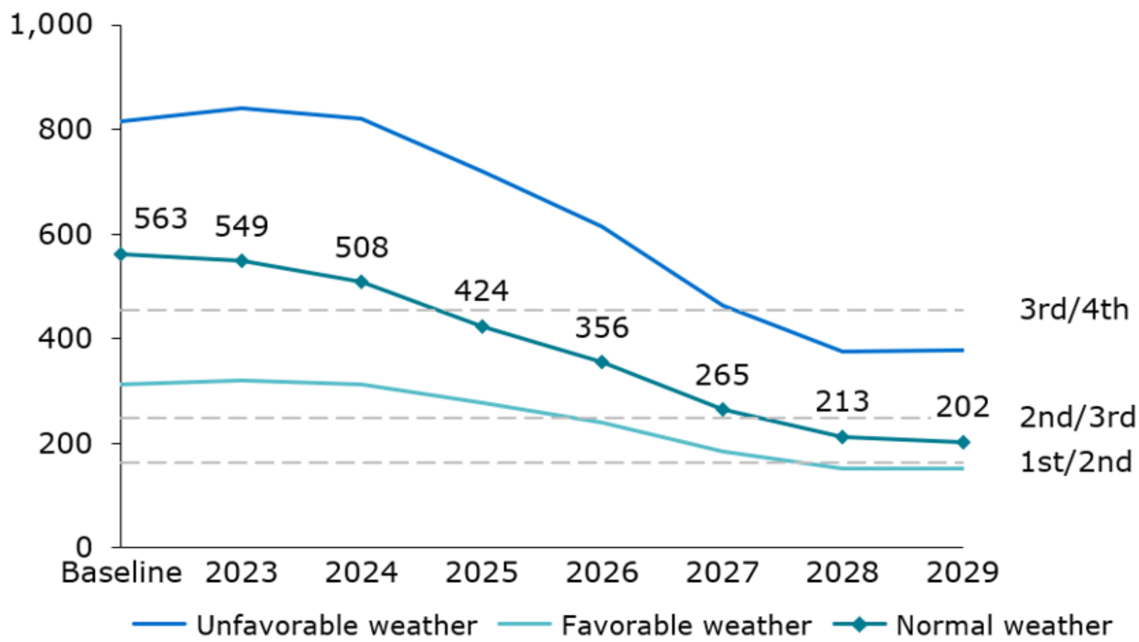
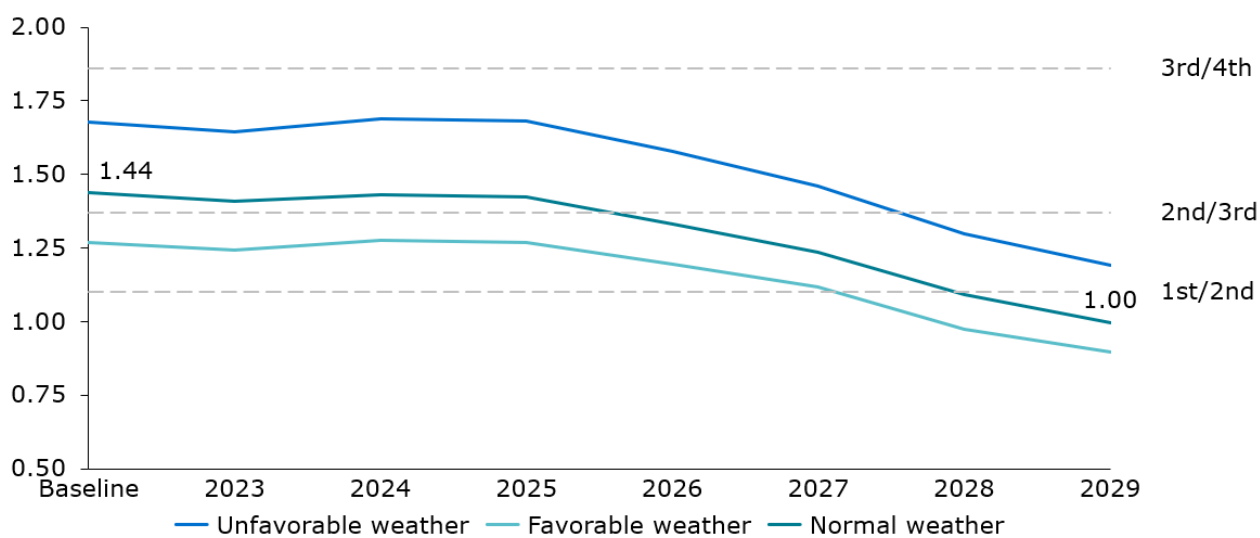


Exhibit 6.1.1.2 All Weather SAIFI



These reliability projections are based on a new reliability model and methodology the Company has updated since the filing of the 2021 DGP. This methodology uses a circuit level reliability projection to model investment impacts and to generate a system level projection. More details on the methodology, as well as projections for non-MED reliability metrics care shown in Exhibit A.3 in Appendix A.

7 Pillar: Tree Trimming

Maintaining sufficient tree clearance from electrical equipment and lines is critical to ensuring safe and reliable power for customers. At present, nearly two-thirds of all outage minutes experienced (storm and non-storm) by DTEE customers are caused by trees damaging power equipment.

DTEE has taken deliberate action against tree interference by trimming to an enhanced specification known as the Enhanced Tree Trimming Program, or ETTP, since 2016. The ETTP is designed to reclaim right of ways, remove or reduce vegetation hazards from distribution infrastructure and properly define trim specifications for vegetation encroachment.

7.1 Methodology of Impact Analysis

DTEE created a control group of non-ETTP circuits to compare against ETTP circuits across four tree-related metrics: outage events, customers interrupted, customer-minutes interrupted and wire down events. The control group is used to negate the effects that weather and system variations could introduce into the performance metrics as both groups generally experience the same conditions each year. Performance is measured over the first four years post-ETTP work by calculating the percentage improvement between each year and the average of the three years prior to the work. The same methodology is used for the control group. The two groups are then compared to determine the relative difference of the ETTP group versus the control group.

7.2 Results: Consistent Improvement Across All Metrics

Below are results for the metrics measured in the impact analysis. These numbers indicate significant reductions in outage events resulting in improvements to ETTP circuit reliability, underscoring the effectiveness of reducing tree-related issues to enhance overall system performance.

7.2.1 Metric 1: Outage Events

First-year performance results indicate a significant reduction (62.1%) in tree-related outage events. Data for several years of the program can be examined in Exhibit 7.2.1.1 below.

Exhibit 7.2.1.1 Tree-Related Outage Event Difference: ETTP vs. Non-ETTP Circuits

Years Post-Trim	1	2	3	4
Number of Dist. Circuits ETTP-Trimmed	1,549	1,228	754	298
Change in Outage Events for ETTP Circuits	-27.3%	-15.2%	+9.4%	+36.7%
Change in Outage Events for Non-ETTP Circuits	+34.8%	+53.4%	+60.5%	+77.3%
Difference in Number of Outage Events	-62.1%	-68.6%	-51.1%	-40.6%

7.2.2 Metric 2: Customers Interrupted

Tree-related customer interruptions were reduced in each year for the ETTP-trimmed circuits with a 66.3% reduction after the first year. Additional data is available in Exhibit 7.2.2.1. below.

Exhibit 7.2.2.1 Tree-Related Customer Interruption Difference: ETTP vs. Non-ETTP Circuits

Years Post-Trim	1	2	3	4
Number of Dist. Circuits ETTP-Trimmed	1,549	1,228	754	298
Change in Customer Interruptions for ETTP Circuits	-46.7%	-44.8%	-38.9%	-24.6%
Change in Customer Interruptions for Non-ETTP Circuits	+19.6%	+31.8%	+25.7%	+27.8%

Difference in Number of Customer Interruptions	-66.3%	-76.6%	-64.6%	-52.4%

7.2.3 Metric 3: Customer Minutes Interrupted

Customer minutes interrupted showed a reduction for all years, with a 59.1% decrease after the first year. Additional data is available in Exhibit 7.2.3.1. below.

Exhibit 7.2.3.1 Tree-Related Customer Minutes Interrupted Difference: ETTP vs. Non-ETTP Circuits

Years Post-Trim	1	2	3	4
Number of Dist. Circuits ETTP-Trimmed	1,549	1,228	754	298
Change in Customer Minutes Interrupted for ETTP Circuits	-51.8%	-37.3%	-25.9%	-32.8%
Change in Customer Minutes Interrupted for Non-ETTP Circuits	+7.3%	+25.0%	-12.3%	-6.4%
Difference in Number of Customer Minutes Interrupted	-59.1%	-62.3%	-13.6%	-26.4%

7.2.4 Metric 4: Wire Down Events

Tree-related wire down events decreased in all years of measurement, with a 53.0% reduction in the first year. Further data is available in Exhibit 7.2.4.1. below.

Exhibit 7.2.4.1 Tree-Related Wire Down Events Difference: ETTP vs. Non-ETTP Circuits

Years Post-Trim	1	2	3	4
Number of Dist. Circuits ETTP-Trimmed	1,549	1,228	754	298
Change in Wire Down Events for ETTP Circuits	-61.2%	-63.7%	-56.2%	-38.2%
Change in Wire Down Events for Non-ETTP Circuits	-8.2%	-3.7%	-17.3%	-29.5%

Difference in Number of Wire Down Events	-53.0%	-60.0%	-38.9%	-8.7%

7.3 Learning-based Improvements to Tree Trimming

DTEE has made several significant improvements to its tree trimming practices since the beginning of ETTP in the areas of scheduling, herbicide and efficiency in the field.

7.3.1 Scheduling

Tree trimming supports several workstreams (e.g., maintenance, trouble, and capital trimming) and DTEE has dedicated a team to improve the scheduling of these workstreams across the board. In the past, prioritizing and scheduling was disaggregated and often took place at the service center level. Currently, the tree trim scheduling team is developing an integrated scheduling tool that monitors all workstreams in a centralized manner, enabling the Company to schedule with the efficiency required for both customer and construction projects while staying on schedule with annual maintenance trimming.

7.3.2 An Industry-best Herbicide Program

Since 2018, the Company has used treatments instead of physical removal of vegetation from right-of-ways. DTEE's herbicide program includes foliar and basal herbicide treatments as well as a dormant stem treatment. These applications help control tree species with the potential to grow into electrical wires and reduce the cost of maintenance trimming by decreasing tree density over time. As tree density and brush height decrease, the electrical system will experience fewer tree-related outages and the right-of-way will become more accessible for overhead crews, allowing them to more quickly find and repair damaged wire or broken equipment.

7.3.3 Improved Efficiency Through Innovative Equipment

DTEE has partnered with its tree trim contractors on new ways to improve efficiency through innovative equipment, piloting of new equipment and utilization of specialty equipment in backyard areas and alleyways.

- **Boom-mounted Saw Pilot**: This new, insulated saw (one of only two in the world) allows for use in the energized zone near the wires. These saws can safely and quickly remove large tree branches without the need for climbing and rigging, saving significant amounts of time, improving safety and reducing the number of trimmers needed to accomplish the work.
- **Specialty Equipment in Backyard Areas and Alleyways:** By using mechanical mowers, contractors can clear brush and small trees, creating access for bucket equipment and making tree removal easier and less expensive. DTEE continues to actively investigate methods to eliminate manual labor through the use of specialized equipment to further enhance overall efficiency and productivity. For example, DTEE is exploring the opportunity to use cranes for tree removal. Cranes can allow for easier and safer tree removal, specifically when dealing with trees over electrical wires.

7.4 On-Cycle – Risk-Based Modeling

As the Tree Trim Program enters the final years of the surge (2024-2025), the Company is dedicated to continuing to find program improvements. One enhancement is identifying optimal cycle lengths for individual circuits through the implementation of new technology tailored to meet the unique needs of each circuit. DTEE is currently developing a risk-based, variable-cycle model that will leverage Light Detection and Ranging (LiDAR) data and internal data sources to help identify optimal trim cycles and high-risk areas. This model will allow the Company to improve its maintenance trimming cycle to be more targeted than the current five-year standard for distribution circuits. Adjusting cycle-lengths will improve trimming efficiencies and reliability benefits for customers.

After the surge is complete, DTEE will be able to implement its risk-based model, having established a standardized five-year cycle baseline for the entire service territory. During this interim phase, DTEE will have the opportunity to validate the model outputs and pilot its findings for trim cycles. This model's introduction into annual planning is intended to maintain the system reliability enhancements achieved during the surge while gaining efficiencies and improving outcomes with a risk-based cycle.

7.5 Accessing the Local Workforce Through Growth and Outreach

DTEE primarily utilizes five contract tree trimming companies to supply an average of approximately 1,200 workers needed to execute the annual tree trim plan. Assuming average storm volume, this same supply of contractors will be essential to maintain through the end of surge. Currently, there are not enough qualified local tree trimmers to complete the surge program and maintain on-cycle trimming, so DTEE must hire crews from outside of its service territory to supplement the local workforce.

The Company's long-term plan is to create an adequate number of local, qualified tree trimmers and to eliminate the need to hire non-local crews. Having local tree trimmers available provides immediate support for storm trouble, supplies workers properly trained on the local vegetation management program and is more cost effective.

Since 2020, DTEE has supported two pilot initiatives aimed at increasing the local tree trimmer workforce and creating more employment opportunities for residents.

- **Pre-Woodsman Training Program (Pilot)** The Company has partnered with the city of Detroit, IBEW Local 17, Focus Hope, and its tree trimming contractors to develop and implement a training program to help generate qualified tree trimmers. The pilot academy was established within the city of Detroit to support accessibility for resident candidates and to encourage them to prepare for work as woodsmen. As of September 2023, the training program has graduated 148 candidates, 40% of which are Detroit residents.

- **Parnall Correctional Facility Outreach Program (Pilot)** DTEE has implemented a training program for tree trimming at the Vocational Village within the Parnall Correctional Facility in Jackson. This program was developed to allow returning citizens to directly enter the apprenticeship program upon leaving the correctional system. In selecting applicants, the Vocational Village administration placed significant emphasis on the individual's county of residence to ensure a reasonable commute to work once released. Graduates are paired with jobs upon completion of the program.

7.6 Conclusion

The Tree Trimming Program is one of the most important and impactful pillars in furthering the Company's commitment to improving system reliability and safety. The program has demonstrated significant decreases in system risk (specifically wire downs) and increases in reliability (fewer and shorter outages). Through completion of the surge and implementation of innovative risk-based modeling, DTEE will continue to yield proven reliability and safety improvements.

8 Pillar: Infrastructure Resilience and Hardening (Capital Replacement Programs)

DTEE is experiencing increasing challenges from its aging infrastructure and faces the need to upgrade and rebuild much of its equipment and facilities. The 2023 American Society of Civil Engineering (ASCE) report scored Michigan a cumulative C-, grouping it among states most in need of infrastructure investments. Among the fourteen categories ASCE analyzed, such as bridges, roads, schools and energy, Michigan received a D rating in Energy infrastructure[30] . Demographic trends are mostly responsible for this situation. Michigan industrialized in the late 1800s and early 1900s and thereafter experienced robust population growth until the 1960s. As a result, much of its infrastructure (including DTEE's) was built during that period. Flat to declining population for the state and its major cities over the past 50 years made it financially challenging for government entities and utilities to replace this aging infrastructure. In response, DTEE focused on maintaining its existing distribution assets in a cost-effective manner in recent decades, expanding the distribution system when needed to meet demand, but leaving aged equipment in place to achieve affordability targets for its customers.

Replacement of this infrastructure can no longer be prudently deferred as these assets are now at, or nearing, the end of their useful life. Equipment manufacturers provide useful life expectations for their equipment representing the number of years a piece of equipment is expected to operate before it becomes unreliable and uneconomical to keep in service. Assets which meet or exceed their useful life fail more often and present safety and affordability concerns to customers as outage frequency and expenditures for reactive maintenance increase. It is critical that DTEE accelerates investment

[30] Report-2023-MI-IRC-Final-WEB.pdf (infrastructurereportcard.org)

into its Infrastructure Resilience and Hardening pillar to ensure its distribution system meets customer expectations for safety, reliability, power capacity and quality. Ramping up the Pole Top Maintenance and Modernization Program (PTMM) to make the grid more reliable, completing the 4.8kV Hardening program to improve safety and increase storm resiliency, and replacing aging, defective, obsolete, and otherwise at-risk infrastructure are all key parts of the strategy to improve service for customers.

The gaps assessment utilizing the DSPx framework discussed in Section 5 makes it clear that the foundation of the electrical grid is the physical grid infrastructure (e.g., poles). To improve the foundation of the DTEE electric grid, the Infrastructure Resilience and Hardening pillar focuses investments on the replacement of equipment that fails inspection; is defective and prone to premature failure; is at or nearing end of useful life; or is obsolete with limited availability of spare replacement parts. Investments in this program include a range of equipment replacements from poles and pole-top equipment to breakers and underground cable. Replacing this equipment is critical to ensuring the distribution system meets customer expectations for safety and reliability. For reference, Section 9 of the Company's 2021 DGP[31] provides more detailed descriptions of capital replacement programs within the Infrastructure Resilience and Hardening pillar. The 2023 DGP report will highlight the major equipment types that support the distribution system and make up the largest portion of the investment in this pillar. Each of these equipment types has a replacement program with dedicated investment. Many of these programs, such as subtransmission disconnect switch replacement, will continue beyond 2028 due to the volume of equipment needing to be replaced or as additional issues or reliability needs are identified, and replacement is warranted.

8.1 Pole and Pole-Top Maintenance and Modernization Program (PTMM)

Approximately 70% of DTEE's infrastructure is overhead, and overhead equipment failures cause nearly 25% of all outages that customers experience. Poles and pole-top equipment are some of the most important and visible parts of the subtransmission and distribution grid, and are continually exposed to harsh conditions (e.g., ice, heat,

[31] DTEE 2021 Distribution Grid Plan - [068t000000Uc0pkAAB (site.com)]

rain, lightning, sunlight and wind), causing them to degrade and weaken over time.

DTEE's Pole and Pole-Top Maintenance and Modernization Program (PTMM) inspects overhead circuits for poles and pole-top equipment that fail inspection and replaces them with modern equivalents with better materials that are more durable and reliable. Poles younger than 20 years are visually inspected for structural integrity and poles older than 20 years undergo rigorous physical testing that includes treatments to prevent decay (Exhibit 8.1.1). Poles that fail inspection are replaced with new poles of a higher class which are as much as two-times stronger at groundline and 20% better at withstanding high winds when compared to the poles being replaced. Pole tops are inspected to identify defective equipment (including wooden crossarms, porcelain cutouts and porcelain insulators) and any component that fails inspection is replaced with stronger fiberglass crossarms, polymer cutouts, and polymer insulators which have five to six times more mechanical strength than their wooden and porcelain counterparts (Exhibit 8.1.3). This new pole-top equipment is made of stronger materials, experiences less deterioration from weather elements, and can better withstand increasing storms and wind gusts, resulting in fewer equipment failures and customer outages.

DTEE's PTMM Program has received significant enhancements over recent years, including improving both pole testing and pole top inspections. These changes were made after benchmarking other Northeast and Midwest utility practices (Exhibit 8.1.2), reviewing the U.S. Department of Agriculture's Rural Utility Services (RUS) bulletin ("1730-121 USDA Rural Utility Service Wood Pole Inspection and Maintenance"), and conducting internal reviews of the Company's pole failure performance. The Company adopted physical testing for poles 20 years and older after reviewing the above sources, reviewing its own pole performance, and determining that below-grade pole decay has rarely been seen on poles installed less than 20 years ago. DTEE reviews these specifications bi-annually and makes changes as appropriate based on internal performance analysis and industry best practices.

Enhanced PTMM inspections have resulted in a two to three time increase in identification of poles that fail inspection and pole top equipment locations that need to be remediated on a per circuit mile basis. Because the PTMM program scope has grown over the last 12 months, the Company lacks specific performance data for reliability improvement from the improved PTMM program. The Company estimates a 30% reduction of multiple customer outage events in the first year post PTMM after analyzing performance from Customer Excellence[32] and 4.8kV Hardening performance. Because the number of pole replacements and overhead assets the PTMM program is remediating has increased, the Company is confident that the benefit to customers will be in the 30% improvement range and could in fact be higher in future years. The Company will continue to analyze this program, including the before and after reliability and wire down performance of circuits, and update its reliability improvement assumptions accordingly as more circuits are completed with the new PTMM standards.

DTEE's goal is to inspect poles on a 10-year cycle per the industry guidance discussed above as well as the MPSC Staff's recommendation in their "Utility Pole Inspection Investigation Staff Report" dated November 20, 2009. Over the next five years, to ensure testing and maintenance of the entire system in a timely manner, the Company plans to ramp up the PTMM Program to achieve this goal DTEE plans to increase its investments in the PTMM Program as a key lever to reduce overhead equipment-related failures and drive reliability improvements, reduce reactive and storm expenditures and improve the safety of the system by reducing wire downs.

[32] The Customer Excellence (CE) program provides rapid solutions to small pockets of customers experiencing poor reliability on a circuit.

Exhibit 8.1.1 Pole Testing

Equipment	Rural Utility Services (RUS)	DTEE Specification
Pole	Physical testing on all poles 10+ years old	Physical testing on all poles 20+ years old

Exhibit 8.1.2 Utility Pole Benchmarking

	Company 1 Northeast	Company 2 Northeast	Company 3 Midwest	Company 4 Midwest
Inspection Practices	4-year pole and pole top inspection program	5-year pole and pole top visual inspection program	10-year pole test program 5-year visual inspection including pole top	10-year pole test program 5-year visual inspection including pole top

Exhibit 8.1.3 Pole Top Equipment Specifications

Equipment	Construction Specification (2019-Current)
Crossarms	Fiberglass crossarms (5x stronger, 60-year lifespan)
Insulators	Polymer insulator (6x stronger, longer lasting)
Cut-outs	Polymer cut-outs (6x stronger, longer lasting)

The PTMM Program modernized 1,562 circuit miles, replaced 4,537 poles and performed approximately 92,000 inspections in 2022. It is anticipated that the PTMM 2023 workplan will replace poles and pole-top equipment on approximately 1,000 circuit miles and replace approximately 3,300 poles (which includes eliminating the pre-2022 condemned pole backlog).

Exhibit 8.1.4 below shows that DTEE plans to invest $773 million over the next five years in the PTMM Program. The 4.8kV Hardening Program miles inspected are included in this table because the program also performs pole and pole top inspections to the same standard, and its work scope does not include the same circuits as the PTMM Program. PTMM is a standard utility industry program, and this program will continue indefinitely beyond the five-year span detailed in this grid plan.

Exhibit 8.1.4 Pole and Pole Top Program Future Investment

	2024	2025	2026	2027	2028	2024-2028 Total
PTMM Investment Projection ($ millions)	$121	$121	$151	$192	$188	$773
Miles Inspected on PTMM	1,604	1,604	2,043	2,651	2,651	10,553
Miles Inspected on 4.8kV Hardening	145	296	154	-	-	595

8.2 4.8kV Hardening Program

The 4.8kV system built in Detroit and the surrounding communities, is the oldest part of DTEE's distribution network. Due to age and condition, these segments have a ~3.6 times higher volume of trouble events per circuit mile than non-Detroit areas. Additionally, there is a parallel electric system and a public lighting system in the city of Detroit that was built by the Detroit Public Lighting Department (DPLD) that is no longer being used and needs to be removed. This DPLD system includes arc wire, which is highly susceptible to wire downs and represents a public and employee safety hazard, co-located with DTEE's electric grid. The Company created the 4.8kV Hardening Program after receiving an order from the MPSC in Case No. U-18484 to develop a plan to address the DPLD arc wire.

The need to remove the arc wire, combined with the age and condition of the electric grid in the city of Detroit, has rendered general maintenance practices insufficient to achieve the safety and reliability results needed. In response, DTEE created its 4.8kV Hardening Program in 2018 to aggressively improve and upgrade the city of Detroit overhead infrastructure. The program delivers near-term, cost-effective results that improve public safety and address frequent outages through extensive system upgrades. The scope of the 4.8kV Hardening Program includes:

- Removing Detroit Public Lighting Department (DPLD) arc wire and distribution wire from Company-owned equipment and ensuring the remaining Company wires are left in a safe configuration
- Testing of all utility poles that have Company equipment attached; replacing or reinforcing as needed
- Replacing wooden crossarms with fiberglass crossarms and removing service lines to abandoned properties
- Trimming trees, as required, to support construction activities
- Performing any additional necessary work as dictated by field conditions
- Removing primary conductor in sparsely populated areas (deconductoring)

8.2.1 Results of the 4.8kV Hardening Program

The 4.8kV Hardening Program has hardened 1,464 miles between 2018-2023, including 475 miles in 2022, and plans for 345 miles in 2023. The program will have removed approximately 695 miles of arc wire (roughly 50% of the total co-located with DTEE equipment) from 2018-2023 including 224 miles in 2022 and plans to remove 173 additional miles in 2023.

Exhibit 8.2.1.1 4.8kV Circuit Miles Hardened

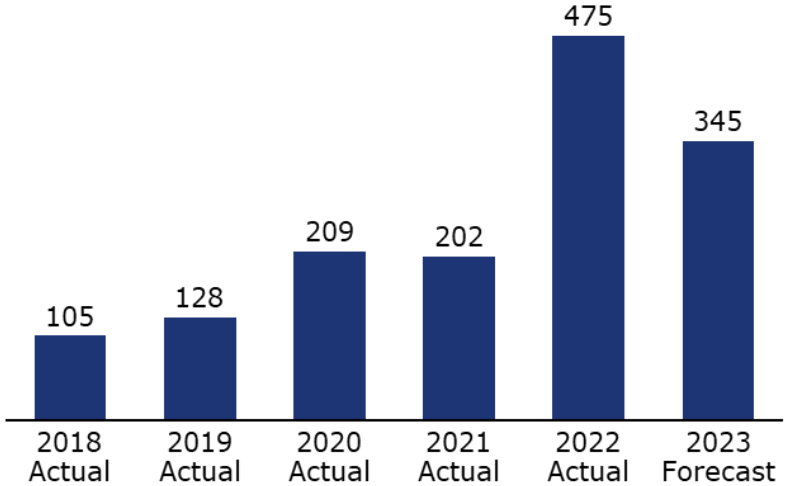
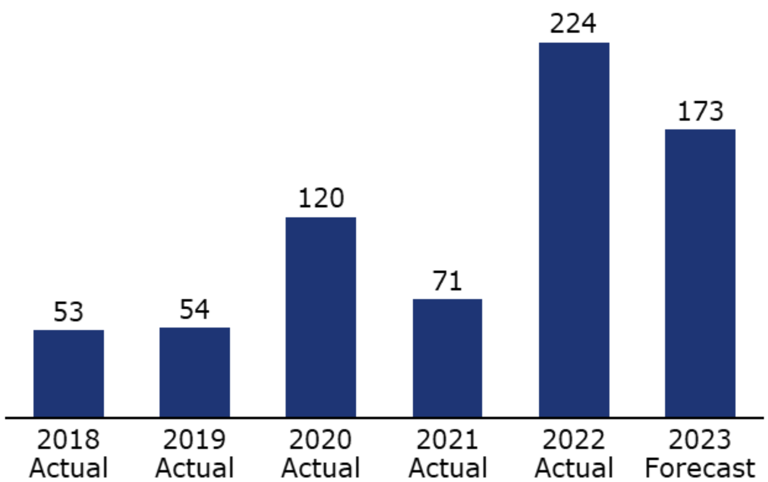


Exhibit 8.2.1.2 4.8kV Miles of Arc Wire Removed

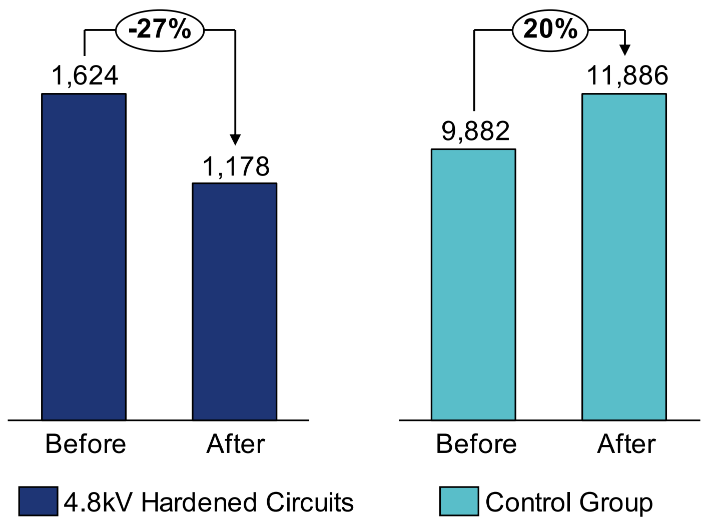


The program hardened approximately 183 circuits in the city of Detroit and surrounding areas through year-end 2022. The 144,222 customers impacted by these improvements represent nearly half of all DTEE's Detroit customers.

As a result of these investments, customers have seen noticeable improvements in the safety and reliability of the circuits they depend upon. When compared to a control group[33] of similar unhardened circuits, the 4.8kV circuits that were hardened experienced:

- a net 47% improvement in number of wire downs:

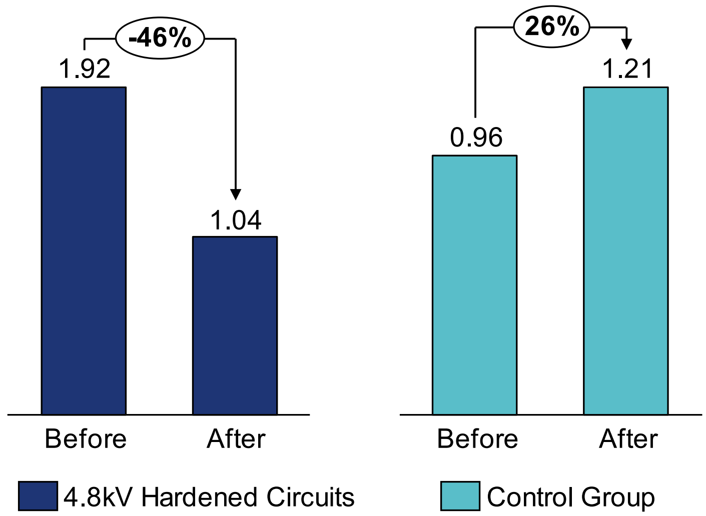
Exhibit 8.2.1.3 Wire Downs Before and After Hardening



- A net 72% reduction in All-Weather SAIFI:

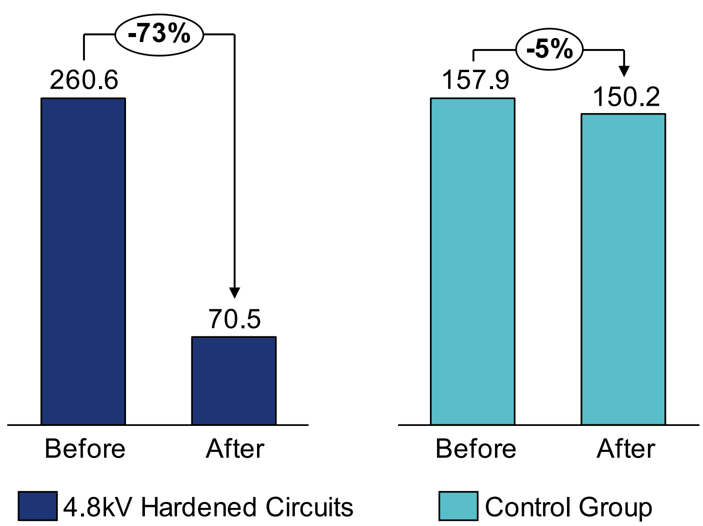
[33] A control group is used to negate the impacts of weather variation.

Exhibit 8.2.1.4 All-Weather SAIFI Before and After Hardening



- A net 68% improvement in SAIDI Ex-MEDs:

Exhibit 8.2.1.5 SAIDI Ex-MEDs Before and After Hardening



8.2.2. 4.8kV Hardening Technical Conference

On March 22, 2023, the Company hosted a technical conference sponsored by the MPSC Staff[34]. The meeting was organized to discuss opportunities to improve the safety and resiliency of the 4.8kV system, as well as options to address the remaining DPLD arc wire. The conference examined:

a) The benefits the 4.8kV Hardening Program has provided thus far
b) 4.8kV Hardening Program alternatives: Several options were presented, including new alternatives consistent with the MPSC Order in case U-20836:
   i. Arc Wire Removal
   ii. Pre-Conversion
   iii. Conversion
   iv. Microgrids

Exhibit 8.2.2.1 4.8KV Hardening Alternatives

Program	Avg. Cost per Mile	Wire Down Reduction	SAIFI Reduction	SAIDI Reduction
Arc Wire Only	$191k	-13%	-22%	-36%
4.8kV Hardening	$353k	-26%	-44%	-72%
Pre-Conversion	$1.7M	-90%	-85%	-85%
Conversion	$2.7M	-90%	-85%	-85%
Microgrids	$14.6M	-90%	-95%	-95%

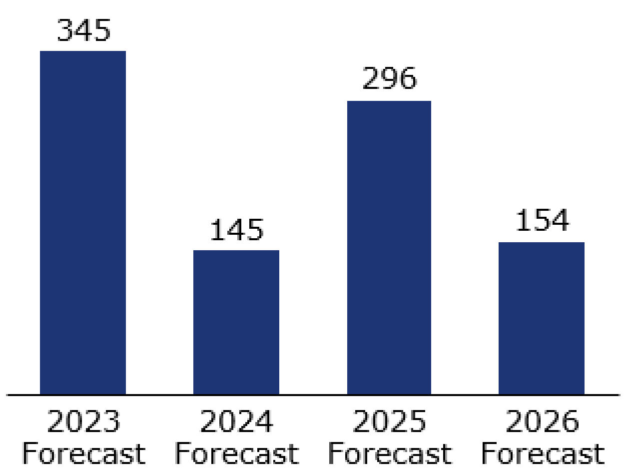
Analysis of Hardening alternatives and feedback from staff and stakeholders during the technical conference supports the Company's conclusion that the 4.8kV Hardening remains a cost-effective solution to quickly deliver safety and reliability improvements to customers in the Detroit area.

[34] DTE Electric 4.8kV Technical Conference - DTE Electric 4.8kV Technical Conference (michigan.gov)

8.2.3 Future of the 4.8kV Hardening Program

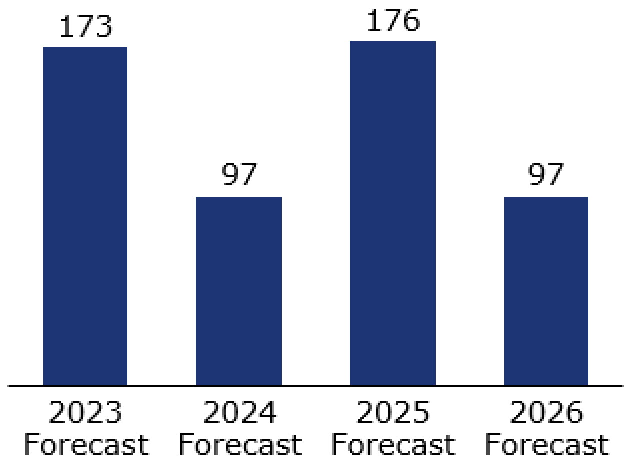
An estimated 550 miles of DPLD arc wire co-located with DTEE equipment will remain after year-end 2023. The 4.8kV Hardening Program plans to harden an additional 595 miles from 2024-2026 for a combined total of 2,059 miles from 2018-2026. The program also plans to remove an estimated 370 additional miles of arc wire from 2024-2026 for a combined total of approximately 1,065 miles removed, representing an estimated 86% of all arc wire collocated with DTEE equipment.[35] Upon completion of the 4.8kV Hardening Program in 2026, almost every pole will have been tested as well as having new cross arms and pole top equipment, which will provide customers with proven safety and reliability improvements.

Exhibit 8.2.3.1 Forecasted Circuit Miles Hardened



[35] Remaining collocated arc wire will be removed through 4.8kV conversion projects.

Exhibit 8.2.3.2 Forecasted Miles of Arc Wire Removed



8.3 System Equipment Replacement

System equipment plays a vital role in delivering electricity to customers, isolating and locating faults, and maintaining proper voltages and power quality on the electric system. For the system to operate as designed, this equipment should be not only functional, but in good condition physically and operationally. To optimize the consistency and reliability of these assets for our customers, DTEE uses an asset health analysis to routinely monitor and prioritize investments in replacement programs and identify the equipment that requires replacement. While some equipment replacements are integrated into circuit conversion projects, other assets such as those tied to the 13.2kV, 24kV, and 40kV are addressed through a separate replacement program for aged or defective equipment.

Over the next five years, DTEE plans to invest $365 million in multiple distribution equipment categories. Exhibit 8.3.3.1 details the equipment asset types, quantities planned for replacement by year and projected investment needs over the next five years. A select group of these programs are discussed in the Section below.

Additional background on these assets can be found in Section 8: Asset Health Assessment on pages 151-210 of the 2021 DGP.

8.3.1 Overhead System Equipment

Automatic Pole-Top Switches (APTS): The function of the APTS is to sectionalize, isolate or connect portions of the subtransmission system. Failure of one of these switches has the potential to interrupt thousands of customers or result in significant operational constraints. There are 120 APTS in total that need to be replaced and, 69 of these will be replaced over the next five years.

SCADA (Supervisory Control and Data Acquisition) Pole-Top Devices: SCADA replacement targets two of the equipment types that have experienced high rates of failure – Eaton Form 3 reclosers and Bridges pole-top switches (PTS). Failure of these devices will result in reduced system operability and can cause customer interruptions at a circuit level.

An overhead three-phase recloser is a sectionalizing device that is located at key points on overhead distribution circuits. It acts like a circuit breaker, opening under detection of high current due to a downstream fault, such as a tree branch across two phases. A distribution SCADA PTS allows the System Operations Center (ESOC) to remotely reconfigure the grid to restore customers by isolating faults and/or transferring load to adjacent circuits during both planned and unplanned outages.

The program will replace 154 of these devices over the next five years.

Steel Pole Highway Crossings: DTEE equipment has been subject to incidents that resulted in the collapse of overhead freeway or highway crossing power equipment. This program was developed to replace wood poles with steel poles at these crossings as part of a multi-year program that is expected to replace and rebuild 53 crossings over the next five years.

8.3.2 Underground System Equipment

System Cable: System cable is a specific type of cable designed and used for underground distribution and subtransmission on the Company's primary electric system. System cable consists of large diameter cable surrounded by insulation, and it is installed underground in vaults and ducts between manholes. Sixty-four percent of system cable, or approximately 2,050 miles, is at or near the end of useful life, and 28% is a candidate for replacement based on the findings in the asset health assessment. Approximately 70 miles of system cable are planned for replacement over the next 5 years. DTEE is increasingly concerned about the level of failure-risk posed by the age and condition of system cable because of the impact a system cable failure has on the overall system. When system cable fails, it reduces the level of redundancy of the grid and increases the risk of long duration customer outages.

Underground Residential Distribution Cable (URD): URD is a specific type of cable designed for underground residential use on the Company's secondary electric system. URD consists of small diameter cable surrounded by polyethylene insulation and is either directly buried into the ground or installed inside conduit. Because underground repairs can take significant amounts of time to fix, URD systems are often (but not always) looped so there are two paths to feed customers in case one cable fails. Forty-one percent of URD cables (about 4,500 miles) are candidates for replacement based on findings of the Company's asset health assessment, and 320 miles will be replaced over the next five years. Currently, the system averages approximately 1,000 URD failures per year, creating potential for extended outages when concurrent failures occur on the same URD loop.

8.3.3 Substation Equipment

Breakers: A circuit breaker is an electrical switch designed to isolate faults that occur on substation equipment, buses or circuit positions. Its basic function is to interrupt current flow after a fault is detected to minimize equipment damage due to high fault currents and to isolate the faulted asset from the electrical system. A failure of a circuit breaker can cause outages on multiple circuits and could reduce system redundancy for an extended period during repairs. Depending on the extent of the failure, and possible adjacent collateral damage, thousands of customers could be impacted for an extended duration. The Company has approximately 6,000 breakers on the electrical distribution and subtransmission systems. Sixty percent of all breakers are beyond expected useful life and 53% of all breakers are candidates for replacement based on the findings in the asset health assessment. Current plans are to replace 167 breakers over the next 5 years. To the extent possible, breaker replacements are coordinated with other capital or maintenance work to reduce costs and minimize the overall time the equipment is out of service. In most cases, breaker replacements include relay replacements to make the breaker SCADA controllable and to increase the penetration rate of substation remote monitoring and control capability. This is expected to bring significant customer benefits from improved substation operability.

Substation Regulators: Regulators are used to maintain voltages within a normal range. Replacement will allow for proper voltage regulation and avoid out-of-range voltages that damage customer equipment or cause reliability problems. Fifteen units will be replaced in the next five years.

Subtransmission Disconnect Switches: Subtransmission disconnect switches are used to manually sectionalize and provide isolation points on the electrical system for operational or maintenance purposes. Failures of disconnect switches during operation, when operators attempt to open or close a disconnect manually, can lead to safety hazards, reduced system operability, and force additional equipment to be taken out of service to allow critical work to continue. One hundred and three subtransmission disconnect switches will be replaced in the next 5 years.

Circuit Switchers: Circuit switchers connect the transmission system (120kV) and the subtransmission system (40kV) to the primary side of a substation power transformer. The purpose of the circuit switchers is to protect substation equipment from damage caused by excess fault current. It is a smaller, less expensive alternative to a circuit breaker. Thirty circuit switchers will be replaced over the next 5 years. Switchers identified for replacement are prioritized based on risk of failure and inadequate equipment sizing.

Batteries and Chargers: DC Systems including batteries and chargers are used to provide reliable power to trip equipment during fault conditions. Failure of these systems would result in significantly longer duration faults, greater damage to equipment, larger outages and increased hazards due to the inability to clear faults. To maintain proper operating conditions at substations, batteries and chargers must be replaced when they reach end-of-life.

Exhibit 8.3.3.1 System Equipment Replacement Programs

	Investment ($M) and Quantity by year					
System Equipment	**2024**	**2025**	**2026**	**2027**	**2028**	**2024-2028**
Subtransmission OH Bypass for PTS Maintenance	-	-	$1.5	$1.5	$1.5	$4.5
units	-	-	*2*	*2*	*2*	*10*
40 kV Automatic Pole Top Switch	$5.0	$5.0	$5.8	$5.8	$5.8	$27.3
units	*12*	*12*	*15*	*15*	*15*	*69*
Steel Pole Highway Crossings	$5.0	$5.0	$5.0	$5.0	$5.0	$25
units	9	8	12	12	12	53
Disconnects	$3.0	$3.0	$3.0	$3.0	$3.0	$15.0
units	*22*	*22*	*21*	*20*	*18*	*103*
Switchers	$1.9	$1.9	$1.9	$1.9	$1.9	$9.5
units	*6*	*6*	*6*	*6*	*6*	*30*
Breaker	$14.3	$15.0	15.0	15.0	15.0	$74.3
units	*35*	*36*	*33*	*32*	*31*	*167*
System Cable	$21.4	$20.1	$20.0	$20.0	$20.0	$101.5
miles	*17*	*17*	*17*	*17*	*17*	*85*
URD	$15	$15	$15	$15	$15	$75
miles	*70*	*67*	*64*	*61*	*58*	*320*
SCADA Pole Top Device	$1.8	$2.0	$2.3	$2.6	$5.2	$13.9
units	*22*	*24*	*26*	*28*	*54*	*154*
Substation Regulators	$0.8	$0.8	$0.8	$0.8	$0.9	$4.2
units	*3*	*3*	*3*	*3*	*3*	*15*
Batteries and Chargers	$2.5	$3.0	$3.0	$3.0	$3.0	$14.6
units	*75*	*89*	*74*	*74*	*74*	*386*

8.4 Major Event Risk

Major event risk considers the likelihood and impact of the complete loss of a substation, which can impact a significant number of customers (thousands) for an extended duration (a couple of days). Risk is greatest when there is a combination of at-risk assets and the inability to transfer load when a failure does occur.

DTEE developed the major event risk model to identify areas of the system that are least resilient to a large failure at a substation. The model quantifies the relative substation outage risk scores and is used to help prioritize capital investment required to reduce this risk. Reduction in major event risk is one of the impact dimensions of the Global Prioritization Model (GPM) described in Section 12.1

Since the beginning of 2022, DTEE has experienced 96 major events on the system. These events have caused loss of power for anywhere from a few hundred customers to over 10,000 customers. One example of a major event in 2023 occurred at Snover substation, a single transformer, two circuit substation. The single substation transformer failed, resulting in loss of load for all customers served from the substation. The load of the circuits could not be transferred to neighboring circuits due to the configuration of adjacent DTEE circuits and because the other adjacent circuits are owned by other electric providers. The Company's short-term solution was to deploy portable distributed generators to serve the load of the two circuits. The medium-term solution required the Company to install a portable substation while permanent repairs were made at Snover substation. This example highlights both the significant challenges to addressing a major event failure and the important role the mobile fleet program plays in restoration of service to customers.

8.5 Programs to Address Major Event Risk

The major event risk model provides a framework for DTEE to measure risk reduction resulting from investments. There are four targeted investment areas to reduce major event risk: underground and substation equipment replacement, substation risk projects, station upgrades and the mobile fleet program, which are described below.

Underground and substation equipment replacement (discussed in more detail Section 4.3)

Replacement of at-risk cables and breakers both at substations and on the subtransmission system provides risk reduction by reducing the probability of failure of key substation equipment.

Substation risk projects

Projects in this category generally replace aging, at-risk equipment to reduce the probability of a failure. The most common substation risk project is switchgear replacement. Switchgear is a term for an enclosure with breakers, relays and wiring. A breaker or cable failure in a switchgear can take out multiple circuits at once. Projects target at-risk switchgear with known modes of failure to reduce the risk of a major outage. Projects are prioritized where deployment of mobile fleet assets is limited and cannot restore the entire substation load; in other words, customers will be out for more than 24 hours in the event of a failure. Other projects in this category include the Flood Defense Program, which targets substations that may be prone to flooding due to their location and installs equipment such as pumps to avoid equipment damage from water.

Station upgrade projects

This program focuses on relays and at-risk breakers at subtransmission facilities which convert voltage from transmission levels to our 24kV or 40kV subtransmission voltages. Failures on our subtransmission system have the potential to cause outages to one or more entire substations. Proactive replacement of these assets reduces long-term emergent costs associated with these equipment failures and reduces the risk of large outages.

Mobile Fleet Program

These investments expand the fleet of mobile generation, including portable generators, portable switchgear, portable substations, portable ISO equipment, portable poles, energy storage trailers and the controls that allow these assets wo work together cohesively during planned and emergency events. These tools offer multiple operational benefits including decreasing restoration time for substation load that can’t be feed from adjacent substations/circuits, supporting substations on a single contingency[36] to avoid outages, and providing the ability to facilitate the repairs of the failed equipment inside the substation while customers remain energized. Mobile distribution equipment is

[36] A single equipment failure will cause a large substation outage.

also used to support customers during planned work. Exhibit 8.5.1 shows a portable substation and mobile generator which are part of the fleet.

Exhibit 8.5.1 Portable Substation and Mobile Generator

In addition to the investments above targeted at reducing major event risk, investments in the Infrastructure Redesign and Modernization pillar (see Section 9) will also reduce major event risk by both replacing aging at-risk equipment and adding capacity to the system to enable load transfers so that single failures do not create large customer outages. For example:

- 4.8kV conversions – provide increased capacity and allow for decommissioning of aging substation equipment.
- Subtransmission redesign – station upgrades involve the installation of larger transformers, capacitor banks and associated equipment that will provide additional capacity.

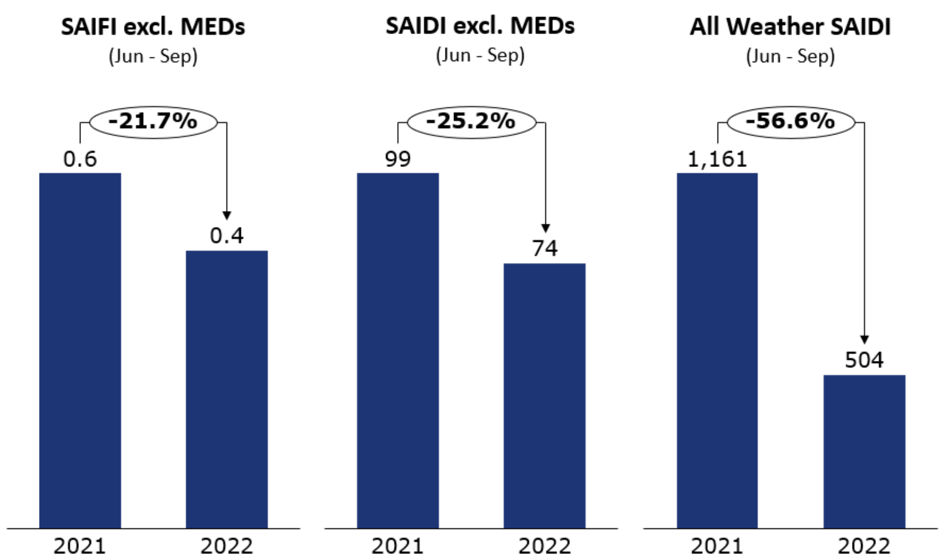
8.6 Short Cycle Maintenance Programs for Poor Reliability Circuits

While DTEE has multiple comprehensive equipment maintenance and replacement programs, these programs must plan their work far in advance to ensure proper planning and execution. The Company's electric distribution grid is vast with over 30,000 overhead circuit miles. At times, circuits or isolated pockets on circuits experience reliability or power quality issues that need to be addressed but are not on the current year's plan for the Company's larger and more comprehensive programs. Short cycle maintenance programs provide regional engineers with the flexibility to quickly identify the root causes of these issues and to create custom solutions for the affected customers and communities.

DTEE has two primary short cycle maintenance programs for poor reliability circuits: Customer Excellence (CE), and Frequent Outage (CEMI).

These two programs have recently undergone a change in how their work is selected and prioritized. In 2021, after experiencing a period of historic summer storms, the Company created a new process called Pre-Storm Season Strengthening (PS3) to identify circuits with characteristics that make them prone to failure during storms. Circuits identified through this process are assigned to each of the Company's programs and our short cycle maintenance programs now receive their work plans from this circuit evaluation process. PS3 circuits that were assigned to CE and Frequent Outage (CEMI) saw significant improvements in SAIDI and SAIFI during summer storm months in 2022 as shown below.

Exhibit 8.6.1 CE & CEMI Pre-Storm Strengthening Reliability Improvements



8.6.1 Customer Excellence Program (CE)

The CE program was established to provide rapid solutions to small pockets of customers experiencing poor reliability. These customers are identified as experiencing four sustained outages (SAIFI > 4.0), or nine momentary outages (MAIFI > 9.0) per year. The prioritization method for the CE program relies on Advanced Metering Infrastructure (AMI) data to identify these customers on a rolling 12-month basis to address issues more rapidly than other programs which rely on the annual analysis of reliability events. In addition to reliability event data, the prioritization also includes an evaluation of time passed since the area's last tree trim was completed, any other near-term planned work on the circuits, and customer complaints.

Upon identification of a circuit that meets the CE prioritization criteria, the Company conducts a field patrol to understand both equipment and tree conditions. After the patrol, the scope of work is developed for both equipment-related and tree-related problems. In addition to the defective equipment replacements and tree trimming, the scope of work also includes checking operating equipment to ensure it is functioning properly, conducting fault studies to ensure fuses are properly sized, and installing additional equipment, such as reclosing devices and animal guards, to prevent future outages. The Company also performs CE work on pockets of its subtransmission system that are experiencing reliability issues. On average, the solutions require investments between $60,000 and $80,000 per circuit to implement.

The Customer Excellence Program will continue beyond five years, though it may decline in investment levels over time as the Company's more comprehensive programs are executed and the grid is brought to an improved operating state.

8.6.2 Frequent Outage Program (CEMI)

The Frequent Outage Program, also known as CEMI (Customers Experiencing Multiple Interruptions), performs improvements to either portions of a circuit (customer pockets), or entire circuits as appropriate. The primary distinctions between the CE and the CEMI programs are that circuits are normally selected for the CEMI program based on three-year average circuit SAIDI and SAIFI performance, MPSC complaints, and regional expertise on customer needs. In addition, the scope of work performed under the CEMI program is more comprehensive, and typically requires investments between $250,000 and $300,000 per circuit to implement.

Frequent Outage Programs (CEMI) will continue beyond five years, though they are likely to decline in investment levels over time as the Company's more comprehensive programs are executed and the grid is brought to an improved operating state.

9 Pillar: Infrastructure Redesign and Modernization

Infrastructure Redesign and Modernization is the investment pillar that supports the long-term grid investments in DTEE's 2023 Distribution Grid Plan. The goals of the projects and investments in this pillar are to enhance safety, reliability and resiliency, and add capacity. These projects include elimination of loading constraints, redesign and rebuild of the subtransmission system, and conversion and consolidation of the 4.8 kV and 8.3 kV systems to the higher 13.2 kV distribution voltage level.

As identified in Section 5.1, the lack of capacity on significant portions of DTEE's distribution and subtransmission systems must be addressed to provide operational redundancy, which is a key element for improving reliability and resiliency. Adding capacity will also accommodate customers' increasing adoption of DER and EVs. This section provides a detailed description for each of the infrastructure redesign projects planned for the next five years. This area of redesign and modernization is expected to grow in importance as DTEE continues to focus on the grid of the future and the role of increased electrification and DER.

9.1 Distribution Load Relief Projects

Assessment of customer load and available capacity at the system, substation and circuit levels is necessary to ensure that sufficient distribution system capacity exists to serve demand. This assessment also helps to identify potential constraints and impact on individual pieces of equipment. Beyond the existing loading conditions, there are areas within the system where the peak load is expected to increase as a result of load from new customers, increased load from existing customers, including increased electrification load, or customers relocating geographically from one area of the system to another. In some areas, existing load conditions have prevented DTEE from supporting new load requests or doing so within customer requested timeframes. It is critical for the Company to identify expected capacity needs well in advance of the expected load increase to complete planning, siting, permitting, ordering of long lead time equipment, and construction of necessary infrastructure in time to provide the expected service and associated reliability to customers.

Capacity needs are reviewed from two grid conditions: normal state and contingency state. The normal state exists when all equipment and components are in service and operating as designed. The contingency state describes the localized grid condition that exists when there is a temporary planned equipment shutdown, the loss/failure of a component of the electric power system (e.g., subtransmission line), or the loss/ failure of individual equipment (e.g., transformer, system cable, or breaker). Under contingency conditions, equipment in the rest of the system often sees an increase in load to compensate for the out-of-service equipment, therefore requiring additional capacity above what is needed for the normal state. Exhibit B.1.1 in Appendix B displays diagrams depicting normal state and contingency state at a substation.

Under the two capacity states, most components and equipment are rated for day-to-day operation and emergency operation. These ratings are calculated to support the viability of an asset throughout its expected useful life. Operating equipment above its designated ratings can in some cases cause immediate failure or accelerate end-of-life.

- The **day-to-day** rating (for normal state conditions) is the load level that the equipment can be operated at to achieve its expected life span.
- The **emergency** rating (for contingency state conditions) is typically higher than the day-to-day rating and indicates the load level at which the equipment can operate for short periods of time. Operating at the emergency rating can add stress to the equipment and shorten its lifespan. If a piece of equipment exceeds its emergency rating, equipment failure may occur, and DTEE’s System Operations Center takes steps to transfer or shed load.
- Substations also have a **firm** rating, which is the maximum load the substation can carry under a single contingency condition and is based on the lowest emergency rating of all the substation equipment that is required to serve the load. Note that it is possible to operate a substation over firm in a normal configuration without damaging equipment, provided it is configured to interrupt power and outage customers for any failure of the incoming feed or

within the substation, and restoration of customer load is restricted until all repairs have been completed.

- Circuits are operated under a Distribution Design Order (DDO) limit, a specific form of a distribution standard intended to maintain system capacity and operational flexibility. For example, the DDO rating for 13.2kV circuits is 8MVA, whereas a typical emergency rating is approximately 12 MVA. These DDO ratings allow for serving half of an adjacent circuit in the event of an outage while still remaining under the emergency rating for that circuit. The DDO limit is comparable to the Rural Utilities Service Standards, which are issued and maintained by the United States Department of Agriculture (USDA), which require system planning to account for planned and emergency load shifting. These are the minimum standards required for Rural Co-operatives to receive USDA financial assistance for projects and provide for ensuring capacity for switching as a baseline standard.

To ensure that expected load growth can be served within the equipment ratings, DTEE's distribution planning engineers conduct annual Area Load Analyses (ALA). These analyses include a review of past loading data and known new loads, verification of equipment ratings and substation firm ratings, system conditions and configurations, and input from large customers and municipal officials about potential development. Based on DTEE's 2022 ALA study, approximately one-third of distribution substations have some level of loading constraints, either within the substation or on their circuits. There are two major impacts of operating substations over their firm rating. The first limitation, during high loading periods, normally the summer season, occurs when an equipment failure in a substation that is over firm can lead to a customer outage until the equipment is repaired, load is jumpered to a neighboring substation, or another mitigation plan is enacted such as deploying a mobile generator. In some areas of the distribution grid with limited capacity, the option of transferring load to an adjacent substation may not be available. The second limitation is that substations over firm have limited capacity for new load. Under a scenario with increased electrification, capacity constraints are expected to get more severe over time. In addition, it can take several years to resolve loading issues if a new substation and circuits are needed to provide relief.

For areas experiencing loading constraints, capital investment projects are developed to add or upgrade overhead or underground lines, expand or build new substation capacity, or both. A strategic load relief project is often the result of a combination of general load growth, specific customer connection requests, aging infrastructure replacement and reliability improvement needs. Some strategic load relief projects, such as building a new substation, may have the added benefits of mitigating substation risk at neighboring substations and improving overall reliability for the area.

9.1.1 Load Relief Prioritization

To address the approximately one-third of DTEE's distribution substations that have loading constraints, DTEE's engineering team assesses loading constraints and criticality to develop priorities and projects to eliminate the loading issues. These projects are then input into DTEE's Global Prioritization Model as part of the Company's capital planning process.

This load relief prioritization methodology has been enhanced in recent years and is now based on five variables including distribution circuits exceeding Distribution Design Order (DDO) limits:

- **Substation equipment overload** (peak load nearing or exceeding substation equipment day-to-day ratings or nearing substation equipment emergency ratings) — The limiting element is often a substation transformer or regulator, but it can sometimes be other secondary equipment at the substation such as conductor, system cable, bus bar, or breaker. A score is given to substations based on the ratio of load to rating with the highest score representing the most severe overload condition.
- **Substation Over Firm** (peak load exceeding substation firm rating under contingency conditions) – A score is given to substations that experience varying degrees of megavolt-amperes (MVA) load over their firm ratings. Under contingency conditions, any load over a substation's firm rating represents customers that cannot be served by that substation.
- **Circuit equipment overload** (peak load exceeding circuit equipment day-to-day ratings or exceeding circuit equipment emergency ratings) - The limiting element for distribution circuits is often the underground cable exiting the substation, but it can also be other equipment such as reclosers or overhead conductors. A score is given to each circuit based on the ratio of load to rating with the highest score representing the most severe overload condition. A circuit also receives a score if the distribution transformers on the circuit are exceeding their day-to-day rating. The circuit scores are then summed for each substation.
- **Strong load growth prospect** – The overall score given to a substation is increased if the substation has known load growth.

- **Circuit over DDO** – A score is given to substations with circuits that exceed the Distribution Design Orders (DDOs), which is 8MVA for 13.2kV circuits and 3MVA for 4.8kV circuits. While operating within these standards is important to provide flexibility and improve restoration options, the scoring for the Circuit over DDO dimension is given less weight than other loading constraints.

The final priority ranking of distribution load relief is a combination of the previously stated five variables. Exhibit 9.1.1.1 lists the highest ranked substations based on this methodology with checkmarks indicating applicable variables. Engineering reviews the constraints and develops projects to eliminate the loading issues.

Exhibit 9.1.1.1 Top 25 Highest Ranked Load Relief Substations Overview

Index	Substation	Voltage (kV)	Community	Substation Equipment Overload	Substation Over Firm	Circuit Equipment Overload	Strong Load Growth Prospect	Circuits over DDO	Project Planned
1	St. Antoine	13.2	Detroit			✓	✓	✓	✓
2	Alfred	13.2	Detroit			✓	✓	✓	✓
3	Garfield	4.8	Detroit			✓	✓	✓	✓
4	Cato	13.2	Detroit			✓	✓	✓	✓
5	Temple	13.2	Detroit			✓	✓	✓	✓
6	Madison	4.8	Detroit			✓	✓	✓	✓
7	Jewell	13.2	Washington	✓	✓	✓	✓	✓	✓
8	Walker	4.8	Detroit			✓	✓	✓	✓
9	Cody	13.2	South Lyon		✓	✓	✓	✓	✓
10	Hawthorne	4.8	Dearborn Heights		✓	✓		✓	✓
11	Cato	4.8	Detroit			✓	✓	✓	✓
12	Amsterdam	4.8	Detroit			✓	✓	✓	✓
13	Daly	4.8	Dearborn Heights	✓	✓	✓		✓	✓

Index	Substation	Voltage (kV)	Community	Substation Equipment Overload	Substation Over Firm	Circuit Equipment Overload	Strong Load Growth Prospect	Circuits over DDO	Project Planned
14	Roseville	4.8	Roseville	✓	✓	✓		✓	✓
15	Howard	4.8	Detroit			✓	✓	✓	✓
16	Golf	13.2	Macomb		✓	✓		✓	✓
17	Cypress	13.2	Marysville	✓	✓	✓	✓	✓	✓
18	Utica	4.8	Utica		✓	✓		✓	✓
19	Shaw	4.8	Imlay City	✓	✓	✓			✓
20	Slater	4.8	Brockway	✓	✓	✓		✓	✓
21	Wixom	13.2	Wixom		✓	✓	✓	✓	✓
22	Grayling	13.2	Shelby		✓		✓	✓	✓
23	Boyne	13.2	Macomb		✓	✓	✓	✓	✓
24	Snover	4.8	Snover	✓	✓	✓			✓
25	Goodison	13.2	Oakland Twp		✓	✓	✓	✓	✓

9.1.2 Consideration of Non-Wire Alternatives

To resolve the substation loading constraints described earlier, typical investments include conversion of a 4.8kV substation to higher voltage, or a substation loading project for an overloaded 13.2kV substation. In addition to these standard projects, which often take 5 or more years to engineer and construct, DTEE continues to investigate non-wire alternatives (NWAs) through the implementation and analysis of a set of NWA pilot projects. NWA projects use a set of technologies that include solar energy, battery storage, and geo-targeted energy waste reduction and demand response (EWR/DR). NWA projects in some circumstances can provide targeted load relief to the electrical system in the short or even longer-term. To determine which load relief grid needs are candidates, DTEE has developed a screening process which reviews the specific factors including the project type, magnitude and timeline for the needed load relief, availability of contingencies, and cost of alternatives (specifically traditional alternatives). The screening process also takes into account the location of the site to evaluate if there is available space to implement NWA solution. If a substation or distribution circuit is identified as a potential candidate for NWA through the screening process, planning engineers work with technology and EWR/DR experts to evaluate detailed designs.

DTEE first identified a set of NWA projects in the 2021 Distribution Grid Plan, each addressing different opportunities and challenges of specific NWA technologies. Currently, these projects are in various stages of engineering, design and construction. Early lessons learned from the NWA projects have reinforced the importance of developing standard designs and creating operations and maintenance instructions for the new equipment during the pilots. As an example, the standardization of the site plans and procedures when combined with the flexible mobile battery trailer systems developed from the Omega project is promising a much more efficient deployment at Port Austin and other future sites. Also, planning for increased lead times caused by vendor driven variability in equipment, software, and availability of parts due to global supply chain issues is critical to meeting schedules with new technology. Finally, existing EWR and DR programs, with additional marketing and outreach, show higher levels of customer engagement than expected or experienced with less targeted efforts.

Further detail on these projects is discussed in Section 10.1 Grid Automation. Once the projects are implemented, learnings will be collected from these and other utility projects, and DTEE will leverage these learnings to continue to refine its criteria, develop new tools, and advance the overall process for pursuing NWAs as part of the distribution planning process. The summary of NWA project learnings will be included in the 2025 DGP.

9.1.3 Projects to Address Distribution Loading

The projects including scope of work that are planned to address load relief for the highest ranked substations are listed in Exhibit B.1.2 in Appendix B. In addition to the highest ranked substations, there are other planned projects addressing load relief along with additional project drivers. These projects are shown in Exhibit B.1.3 in Appendix B. The projects that provide load relief typically include building or expanding substations, replacing substation transformers or other equipment, and establishing new distribution circuits to take load from existing overloading circuits and substation areas.

The projected costs and timeline for load relief projects are shown in Exhibit B.1.4 in Appendix B. This exhibit excludes the CODI and 4.8 kV conversion projects that provide load relief, as the projected investment for those projects is listed in 4.8 kV Conversions, Exhibit 9.3.5.1. DTEE has based the cost and timeline estimates for the identified projects on the best knowledge and information known today.

The identified load relief projects are planned based on DTEE's current assessments of area load growth and system loading conditions. Future area load growth is constantly evolving due to changes in general economic trends, utilization of demand response and energy efficiency measures, and changing customer trends such as adoption of EVs. Despite changing market dynamics, DTEE has a solid fundamental understanding of load growth in the near term and has a strong track record of forecast accuracy. Adoption of emerging technologies, specifically the adoption of electric vehicles, will surely bring complexity to the forecast. To address this, DTEE is developing forecasting tools to provide insight into system requirements at the feeder-level. These solutions will monitor adoption of emerging technologies and forecast their impact on load on an hourly basis across the system. More information on planning and forecasting tools can be found in Section 10.2 Operational Technology Roadmap.

Based on current planned projects, DTEE estimates the annual capital investment on load relief projects as shown in Exhibit 9.1.3.1.

Exhibit 9.1.3.1 Projected Load Relief Capital Investment

	2024	2025	2026	2027	2028	Total Investment 2024-2028
Load Relief Capital Investment ($ million)	$47	$75	$59	$100	$100	$381

9.2 Subtransmission Redesign and Rebuild Program

The subtransmission system serves as a vital grid link between the ITC transmission system and the DTEE distribution system. A station is a facility where high voltage from the transmission system is stepped down to 24kV, 40kV, or 120kV subtransmission voltage. 120kV radial lines that serve general purpose substations are transmission lines owned by the ITC (International Transmission Company). DTEE owns 120kV subtransmission radial lines that serve customer dedicated substations. The 24kV system primarily serves 4.8kV substations and as the 4.8kV system is converted to higher system voltage, much of the 24kV subtransmission system will be eliminated. The subtransmission system is designed to provide redundant sources to distribution substations, which then directly serve circuits and customers. This redundancy provides continuity of service to customers even during a planned or unplanned equipment outage, also known as a contingency situation. DTEE's subtransmission includes both radial and network elements. The radial configuration, called a trunk line, has one source station and can feed one or multiple distribution substations. The network configuration, called a tie line, has multiple source stations and can feed multiple distribution substations. Exhibits 9.2.1 and 9.2.2 below illustrate a trunk line and a tie line.

Exhibit 9.2.1 – Trunk Line Diagram Example (Radial)

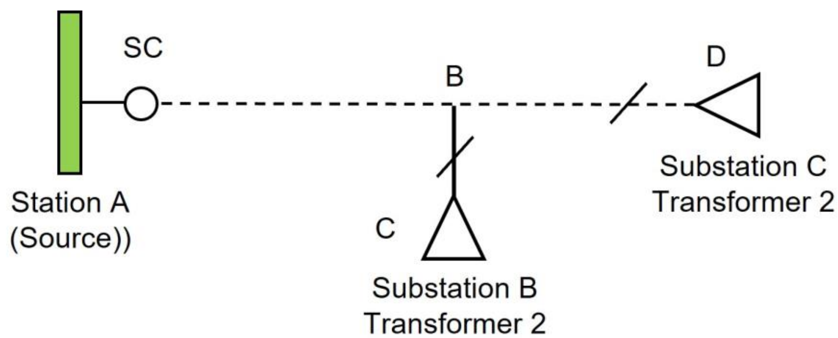
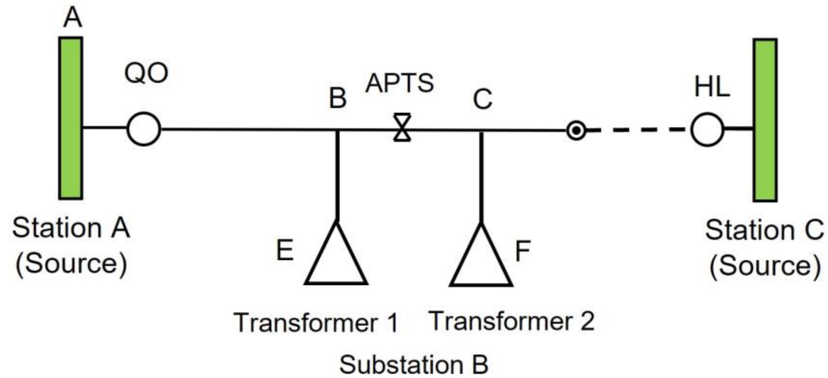


Exhibit 9.2.2 – Tie Line Diagram Example (Network)



The subtransmission system has automation built into the design by utilizing a coordinated system of automatic pole top switches (APTS) as discussed in Section 8.3.1, and line section breakers on the networked tie lines to isolate faults and maintain service to customers in single contingency failure situations. For example, a fault originating on one end of a tie line could be isolated by an APTS opening between that fault and the other parts of the line. The majority of the tie line would remain energized, as well as the substations and distribution customers it serves, minimizing or eliminating the disruption to customers. The entire 40kV APTS population is considered for replacement as part of the APTS capital replacement program (Section 8.3.1) to address high failure rates and unavailable spare parts for early vintages.

As the subtransmission circuits can serve multiple substations in sequence or parallel configuration, an outage event on the subtransmission system can impact tens of thousands of customers, particularly in an area with limited redundancy due to compacity constraints. Furthermore, subtransmission outages typically require the deployment of costly mobile generation or portable substations (Section 8.5) to restore customers in the short term, because permanent solutions often take an extended period of time to implement. Exhibit 9.2.3 below shows key statistics of the subtransmission system.

Exhibit 9.2.3 DTEE Subtransmission Circuits

Voltage	Number of Circuits	Overhead Miles	Underground Miles	Total Miles
120 kV	68	59	8	67
40 kV	326	2,353	466	2,819
24 kV	242	177	732	909
Total	636	2,589	1,206	3,795

As discussed earlier in Section 3, the combination of aging infrastructure, increasingly severe weather events, and loading constraints contribute to an increased frequency of failures, potential for large, sustained outages when failures do occur, and difficulties in accommodating long term localized customer load growth. The Company's subtransmission strategy is structured to improve the reliability, safety, efficiency and system capacity of the subtransmission system in both the near and long-term.

9.2.1 Subtransmission Strategy

The Company has a four-part strategy to improve the reliability performance, safety, efficiency, and capacity of the subtransmission system. These four parts are:

1. Improve reliability in the near-term through the PTMM program by bringing the subtransmission overhead circuits on-cycle within this program.
2. Increase automation on the subtransmission by completing the replacement of the 40kV APTS devices as discussed in Section 8.3.1
3. Redesign and rebuild sections of the subtransmission to updated standards to improve reliability, safety, and efficiency and increase capacity where it's currently constrained or where there is strong customer load growth, as well as increase automatic restoration and truck accessibility.
4. Decommission the 24kV system as part of a collaboration with the distribution planning teams and the 4.8kV conversion strategy.

9.2.2 Scope of Subtransmission Redesign and Rebuild Projects

Projects which redesign and rebuild the subtransmission system will dramatically improve safety, reliability, operability, and increase capacity by upgrading stations and rebuilding overhead and underground subtransmission circuits.

Station upgrades involve the installation of large transformers, capacitor banks and associated equipment that will provide additional capacity, redundancy and voltage support. Overhead subtranmission work includes replacement of aged wooden poles with new and strengthened steel poles, porcelain insulators with polymer clamp top insulators, and small diameter aging conductors with larger, stronger conductors which leads to improved safety by reducing downed wires. The current overhead subtransmission conductor standards used in replacement projects are designed to be capable of withstanding winds up to 90mph and include conductor with approximately twice the strength of existing conductors to more easily withstand impacts from trees. In addition to greater strength, the larger conductor will also provide significantly more capacity on each circuit. It will also reduce the magnitude of voltage drop over long distances on the system, which reduces grid efficiency, and can result in power quality issues for our customers.

Underground subtransmission work involves replacing or upgrading cables that are at-risk or overloaded.

Rebuilding the subtransmission system will reduce both the frequency and impact of failures. In addition to the reliability benefits, these rebuilt and redesigned areas of the subtransmission system will support area load growth for existing and new customers along with the ability to support DER interconnections. As the generation profile is expected to change with the integration of more renewables coupled with the retirement of fossil plants, improvements to the subtransmission system will support the changing power flows on the system.

9.2.3 Subtransmission Prioritization

DTEE considers six criteria when prioritizing the subtransmission redesign and rebuild projects. The first four criteria are part of what are called planning criteria violations. A planning criteria violation means that in either normal state or single contingency state, the system does not have adequate capacity to serve the existing load without exceeding equipment ratings or voltage standards. The six criteria are listed in Exhibit 9.2.3.1 below, along with definitions for each criterion.

Exhibit 9.2.3.1 Criteria to Prioritize Subtransmission Redesign and Rebuild Projects

Subtransmission Criteria	Definition
Load Loss for Single Contingency	Total load that will be shed in certain conditions when a subtransmission line can no longer support the substation and does not have a back-up
Load over Emergency Rating for Single Contingency	Load in excess of the emergency rating of a subtransmission line during a contingency event (i.e., outage)
Load over Day to Day Rating, Normal Conditions	Load in excess of the rating of a subtransmission line during normal conditions
Voltage Violation	Voltage drop on a subtransmission line exceeds standards when it is not in its normal configuration (i.e., due to an outage)
Strong Load Growth Prospect	Subtransmission lines that are predicted to experience load growth
Reliability	History of outages or equipment failures on the subtransmission circuit

The Company evaluates system loading on an annual basis and ranks the planning criteria violations based on severity (refer to Section 10.2.2 for further information on planning and forecasting tools). Projects are then identified to alleviate the constraints of the limiting elements on the system. The scope of the projects and future subtransmission system configuration is designed to accommodate expected load growth for a specific area and is influenced by distribution system plans to construct new and retire aged substations. These distribution plans provide the necessary input to ensure the scope of the subtransmission projects will meet the long-term need of customers. In addition to planning criteria violations and future distribution system plans, the Subtransmission Planning Engineering group also closely monitors the reliability of the system and identifies circuits which have had repeated reliability issues. Once these poor reliability circuits are identified, the outages are analyzed to determine the most effective project to improve reliability performance. The project plans are developed to improve reliability based on the locations of the existing lines and the areas in which outages have occurred. While these projects improve reliability, safety improvements are also made by replacing aged conductors which reduces wire down events and provides increased capacity with the larger wires.

Consistent with other strategic projects and programs, Subtransmission rebuild and redesign projects are evaluated and prioritized using the GPM. Specifically, the criteria used to prioritize subtransmission projects listed above are included in the GPM impact dimensions which are discussed in Section 12.1. Planning criteria violations and potential for strong load growth are included in the Overload Relief and Capacity Relief dimensions, while reliability improvements are factored into the SAIDI and SAIFI. Projects which provide a higher level of benefits, such as amount of load relief accomplished, per dollar invested will receive higher GPM scores and be prioritized in the investment plan. Exhibit 9.2.3.2 lists the highest ranked 25 subtransmission rebuild and redesign projects.

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Exhibit 9.2.3.2 Highest Ranked 25 Subtransmission Load Relief Project Dimensions Overview

Index	Project	Community	Load Loss for Single Contingency	Load over Allowable Emergency Rating for Single Contingency	Load over Day to Day Rating	Strong Load Growth Prospect	Voltage Violation
1	Tie 3416	Elkton, Pigeon	✓	✓	✓	✓	✓
2	Trunk 7105	Southfield	✓	✓	✓		
3	Trunk 4217	Grosse Pointe Harper Woods, Detroit	✓	✓	✓		
4	Tie 3705	Dundee			✓		✓
5	Boyne	Macomb, Harrison, Clinton, Mt. Clemens, Chesterfield, New Baltimore	✓	✓		✓	
6	Bad Axe Transformer 102 Addition	Bad Axe	✓	✓			✓
7	Hurst	Hartland	✓				✓
8	Trunk 3509	Royal Oak		✓	✓		
9	Sandusky Transformer 101 Breaker	Sandusky			✓		
10	Tie 810 Gramer	Lenox	✓	✓		✓	✓

Index	Project	Community	Load Loss for Single Contingency	Load over Allowable Emergency Rating for Single Contingency	Load over Day to Day Rating	Strong Load Growth Prospect	Voltage Violation
11	Trunk 4601	Burlington, Burnside, Marlette	✓			✓	✓
12	Trunk 4245	Eastpointe	✓				
13	Tie 7504	Novesta	✓			✓	✓
14	Derby	Vassar	✓			✓	✓
15	Tie 6907	Rochester Hills	✓			✓	
16	Pigeon Area	Unionville, Sebewing, Kilmanagh, Pigeon, Bayport, Caseville, Kinde, Port Austin	✓				✓
17	Trunk 4911	Lenox, Chesterfield, New Baltimore, Ira	✓				
18	Trunk 7386	Madison Heights, Warren	✓				
19	Trunk 3508	Troy	✓				
20	Trunk 3546	Royal Oak	✓				
21	Trunk 328	Detroit	✓				
22	Trunk 362	Detroit	✓				
23	Tie 4105	Lexington, Croswell					✓

Index	Project	Community	Load Loss for Single Contingency	Load over Allowable Emergency Rating for Single Contingency	Load over Day to Day Rating	Strong Load Growth Prospect	Voltage Violation
24	Oak Beach Capacitor	Port Austin					✓
25	Trunk 1444	Monroe					✓

9.2.4 Subtransmission Projects and Programs

The portfolio of over 60 projects listed in Appendix B includes investments focused on improving the subtransmission system and improving grid reliability and operability. Exhibit B.2.1 in the Appendix lists the local community and scope of work for the identified subtransmission redesign and rebuild projects. Exhibit B.2.2 in the Appendix lists the projected costs and timeline for the projects.

Given the current state of the subtransmission assets and their critical role in grid reliability and capacity, DTEE plans to continue to increase the investment in the subtransmission system in future years, with the pace of that growth influenced by the signposts that materialize for the scenarios discussed in the Grid Modernization Process (Section 3), specifically the Electrification and DG/DS scenarios which could cause additional circuits on the subtransmission system to violate planning criteria. Additionally, as the Company continues to evaluate the impact of potential peaker retirements on the distribution system, future subtransmission projects will be developed to mitigate those impacts.

Exhibit 9.2.4.1 shows the yearly projected investment level for the Subtransmission Redesign and Rebuild program.

Exhibit 9.2.4.1 Projected Subtransmission Redesign and Rebuild Capital Investment

	2024	2025	2026	2027	2028	Total Investment 2024-2028
Subtransmission Redesign and Rebuild Capital Investment ($ million)	$100	$100	$108	$108	$108	$524

9.2.5 Impact of Peaking Generation on the Distribution System

At the end or edge of the larger grid, the electrical distribution system is dependent on a robust upstream transmission system and generation fleet to ensure consistent reliable power is available to all customers. The current electric grid, as it exists today, was designed in concert with generation resources to provide the necessary capacity and redundancy to support power delivery to customers. Generation resources can serve different functions for the electric grid based on their operating characteristics and physical location.

The generation peaker fleet plays a key role in supporting the reliability and operability of the distribution grid. Peaker generation resources have the ability to go from offline to full load within minutes to meet emergent system demand providing grid edge local capacity and voltage support during planned and unplanned outages on the distribution system. The peaker generation units are utilized during planned outages to provide local system support in the event of any system issues or unexpected power flows. This support is critical to execute the necessary shutdowns needed to perform routine maintenance and replacements on equipment while minimizing customer interruptions. The generation peaker fleet also supports necessary system upgrade projects that support the current and future needs of customers.

In some circumstances, peaker generation units also provide an ability to restore service to customers during a storm or other unplanned outage events before the grid can be fully restored to normal operating conditions. For example, peakers are utilized to mitigate equipment overloads and low voltage issues on the distribution system during events such as a storm, system equipment failure, and performing routine maintenance on the system. During routine maintenance on a transmission (120kV) line or subtransmission (40kV) line, peakers can be utilized in the event of next contingency loss of another piece of 120kV or 40kV equipment. In the case of next contingency, peakers could be put in service and used as necessary to support the system and prevent cascading outages. Without peaker support, and until distribution system mitigations can be developed and constructed, the Company's ability to serve pockets of customers during adverse system conditions may be negatively impacted.

DTEE is in the process of conducting the analysis of peaking generation, specifically peakers in alignment with the Integrated Resource Plan (IRP) 2023 settlement.[37] DTEE maintains operating procedures documenting the system load conditions and equipment shutdowns that trigger the use of localized peaking generators. During these known conditions, local generation resources such as peakers provide key functions including: (1) supplying additional power, (2) temporarily helping to support distribution system demands, and (3) minimizing potential overloads and voltage drops. If not mitigated through targeted projects, the retirement of peaking units may produce reliability issues and low voltage violations during both planned and unplanned outages. Since these units would be unavailable to support the distribution and transmission systems; to accommodate the loss of peaker benefits projects such as reconducting, or system reconfiguration will likely be required to minimize the risk of distribution system failure during adverse system conditions. A detailed peaker retirement analysis is underway to identify mitigation projects likely to be considered in the distribution planning process (i.e., conversions, subtransmission upgrades) and future DGPs.

9.3 4.8kV Conversion

9.3.1 Background on the 4.8kV System

DTEE's 4.8kV system design and configuration date back to the original construction of the Company's distribution system. Background information and characteristics of the 4.8kV system are described in detail in Section 4.1.

The age, configuration, and loading on the 4.8kV system pose safety, operational, and reliability challenges. Overhead, underground and substation equipment often exceed industry expected lifespan which can result in increased equipment outages. The 4.8kV system contains wire which is weaker in strength than current higher standard wires. The ungrounded configuration of the 4.8kV system makes detecting, locating, and protecting downed wires challenging.

[37] MPSC Order dated July 26, 2023 in Case No. U-21193 - S T A T E O F M I C H I G A N (force.com)

The 4.8kV and higher voltage systems are capable of accommodating electric vehicles (EVs) and DER. However, in areas where the 4.8kV system is near capacity, increased loads at the grid edge, such as adoption of EVs, can both thermally overload conductors and create significant voltage drops. Conversion to a higher voltage introduces more system capacity to handle future electrification by increasing conductor size and reducing voltage drop while also improving reliability.

A summary of the 4.8kV system as compared to the 13.2kV system is shown in the two tables below. The tables below also include statistics on the 8.3kV system which is discussed further in Section 9.3.7.

Exhibit 9.3.1.1 General Purpose Substations by Low Side kV

Substation Type	Total Number of Substations	Number of Substations by Low Side kV			
		4.8	8.3	13.2	4.8 and 13.2
General Purpose	542	244	4	243	30

Exhibit 9.3.1.2 DTEE Distribution Circuits – Line Miles by Line Voltage

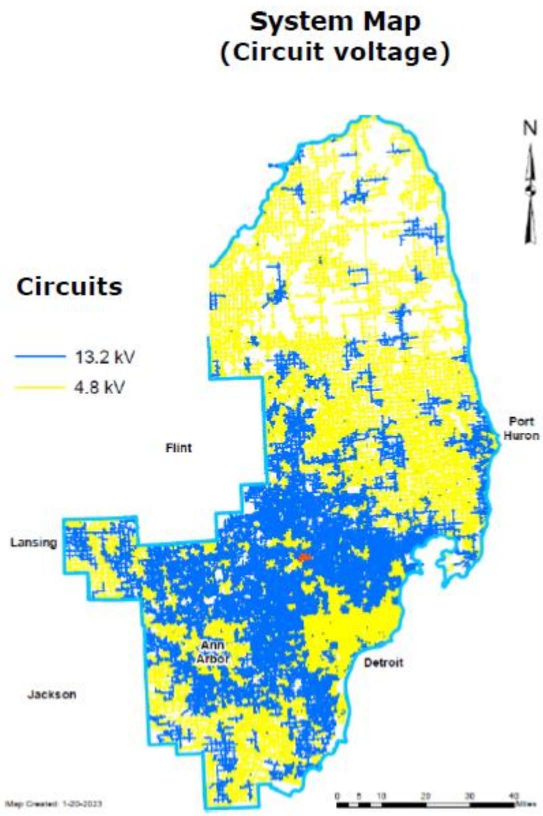
Bus Voltage	Number of Circuits	Overhead Miles			Underground			Total Miles	Total Customers
		13.2 kV	8.3 kV	4.8 kV	13.2 kV	8.3 kV	4.8 kV		
13.2 kV	1,269	11,796	16	5,596	10,710	1	417	28,535	1,030,999
8.3 kV	13	0	45	0	1	18	0	63	8,202
4.8 kV	1,991	31	0	11,064	274	0	1,937	13,307	1,213,025
Total	**3,273**	**11,828**	**60**	**16,660**	**10,985**	**18**	**2,354**	**41,905**	**2,252,226**

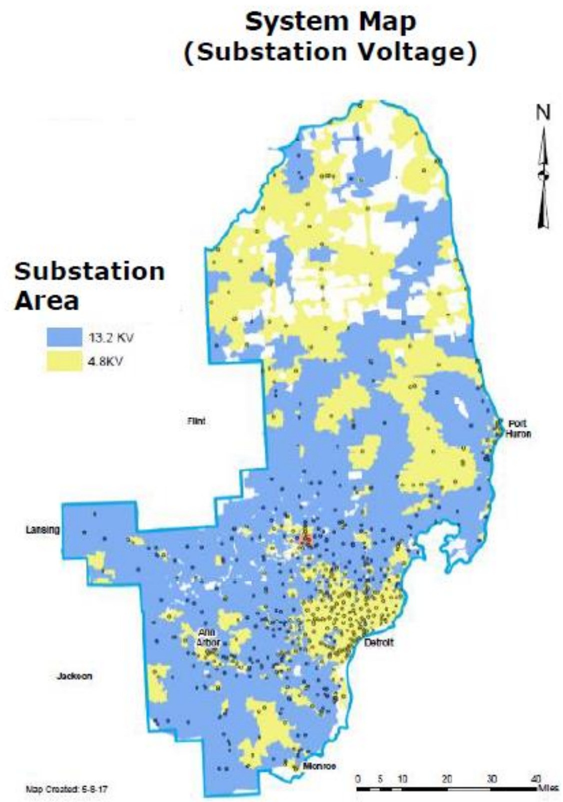
As the Exhibits above indicate, there are approximately 16,700 miles of overhead 4.8kV circuits on the DTEE system. Over 11,000 miles are served from a 4.8kV substation, and over 5,500 miles are served from 13.2kV substations. The 5,500 miles of 4.8kV overhead circuit served by 13.2kV substations are referred to as isolation down (ISO Down) areas and are created when step-down transformers are installed on 13.2kV circuits to lower the voltage to 4.8kV to serve the circuit downstream. In most cases the 4.8kV circuit is the original circuit infrastructure and the 13.2kV circuit and substation feeding it were rebuilt to alleviate a loading constraint.

The maps below show the 4.8kV system in yellow at both a substation/bus level and a line mile level (which includes the ISO downs). Comparing the two, significant areas on the western, southwestern and Thumb area are ISO down areas as they are yellow in the left map, and blue in the right map. Geographically, approximately 2,000 miles, or 12.5%, of the 4.8kV circuitry is located within the City of Detroit. The remaining 4.8kV is located across the entire service territory from the northern thumb region all the way to the southern territory in Monroe County.

The voltage map for DTEE’s distribution system is shown in Exhibit 9.3.1.3 below.

Exhibit 9.3.1.3 DTEE Distribution Voltage Map





9.3.2 Strategies to Address the 4.8kV System

As described earlier the 4.8kV system is aged and has challenges related to reliability, capacity, and the safety of ungrounded downed wires. In the near-term, DTEE is addressing many of these challenges through the Hardening program discussed in Section 8.2, the Pole Top Maintenance and Modernization (PTMM) program discussed in Section 8.1, and Automation discussed in Section 10. In the longer-term, phasing out the 4.8kV system is an integral part of DTEE's grid modernization strategy.

The conversion and consolidation projects will bring multi-faceted benefits of safety improvements, load relief, risk reduction, reliability improvements, technology modernization and cost reduction. The conversion program offers several customer benefits:

- Relieves current load constraints and provides capacity for future load growth, including electrification load and accommodation of DER
- Provides transformational reliability and safety improvements such as an 90% reduction in customer minute interruptions, wire downs, and trouble events
- Allows for the decommissioning of aging equipment which will lead to improved reliability and lower emergent maintenance costs
- Typically converting 4.8kV substations allows for a single 13.2kV substation to serve the customers on 2 to 4 older substations. This consolidation will reduce the amount of substation equipment and system cable that needs to be maintained. Converting and consolidating 4.8kV circuits and substations also allows for the decommissioning and removal of the aged 4.8kV substation equipment, and distribution and subtransmission underground cables
- Converted areas will be rebuilt to the latest automation standards, which will enable the use of FLISR (see Section 10.2), and dramatically improve restoration times which will lower emergent costs.

9.3.3 Investments to Convert the 4.8kV System

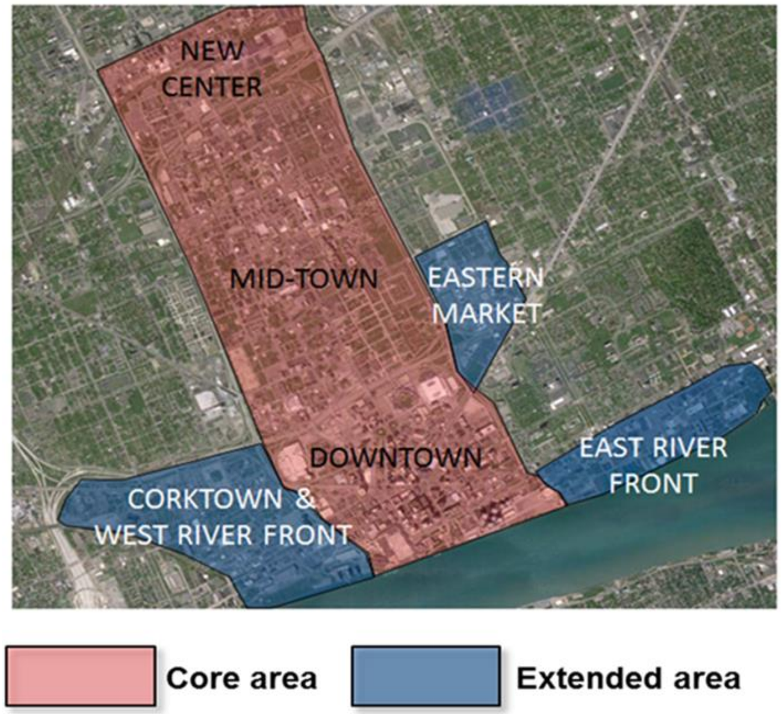
Investments to convert the 4.8kV system can be divided into three groups: City of Detroit (CODI) projects, 4.8kV conversion projects, and the 4.8kV isolation down (ISO) area conversions.

CODI Program

CODI is a subset of the overall 4.8kV conversion strategy targeted in the city of Detroit. Electrical system infrastructure in the city of Detroit dates back to the early 20th century and a significant portion of it is at end-of-life. A resurgence of development in the greater downtown Detroit area in recent years has resulted in increased loading on the aged, often end-of-life assets. The downtown CODI program is different from other conversion and consolidation projects due to the presence of a large amount of underground system cable and secondary network cable running under streets and through manholes, adding to the complexity of operating, maintaining, and upgrading this part of the system. The substation and circuit upgrades must be sequenced and conducted in a robust, multi-year program.

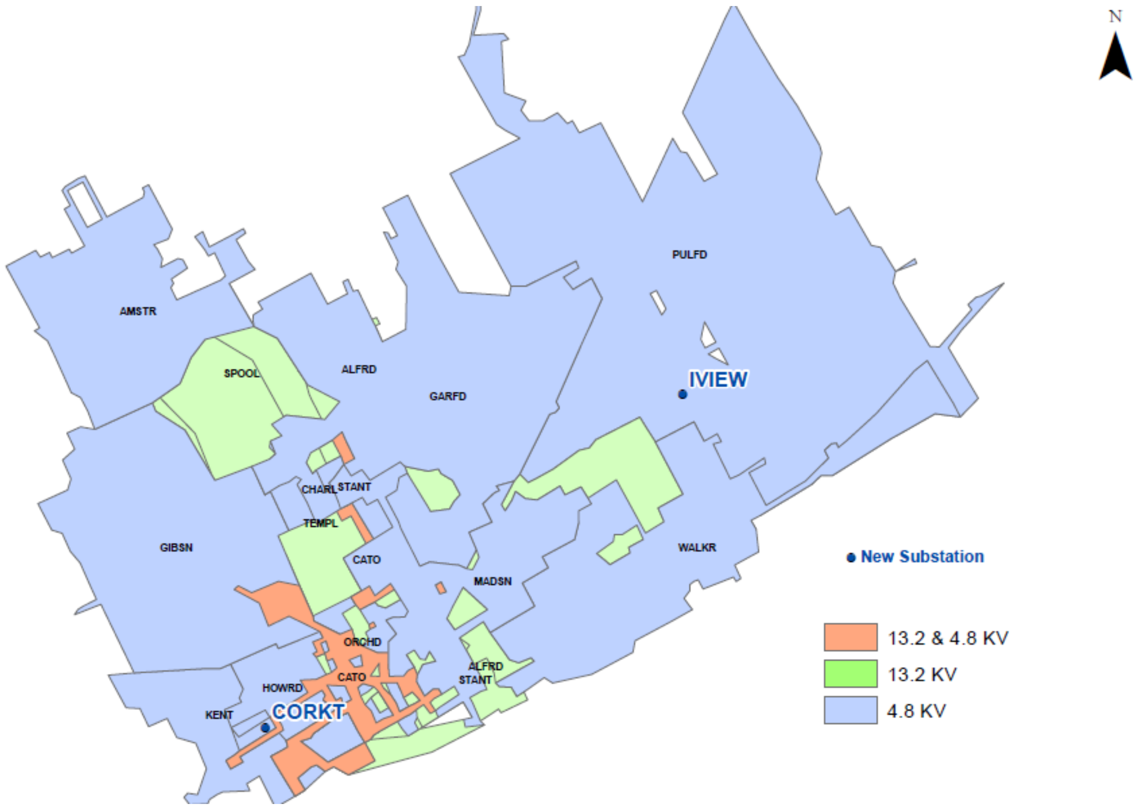
The Exhibit below shows the areas of Detroit that are being addressed by the CODI program, which includes a core area from Downtown to the Midtown and New Center areas and an extended area including Eastern Market, Corktown, and the West and East Riverfronts. There are approximately 31,800 customers served in this area including 27,486 residential, 4,299 commercial, and 15 industrial customers. The area also includes several hospitals, universities, and large sports and entertainment venues.

Exhibit 9.3.3.1 Downtown City of Detroit Infrastructure (CODI) Scope Area



The Downtown CODI program consists of 13 projects including the targeted network secondary cable replacement program. Exhibit 9.3.3.2 illustrates the substation areas for the CODI program which is expected to be complete by the end of 2035.

Exhibit 9.3.3.2 CODI Program Substation Areas



4.8kV Conversion Projects

This category includes conversion of all 4.8kV circuits served by 4.8kV substations outside of the geographic CODI area.

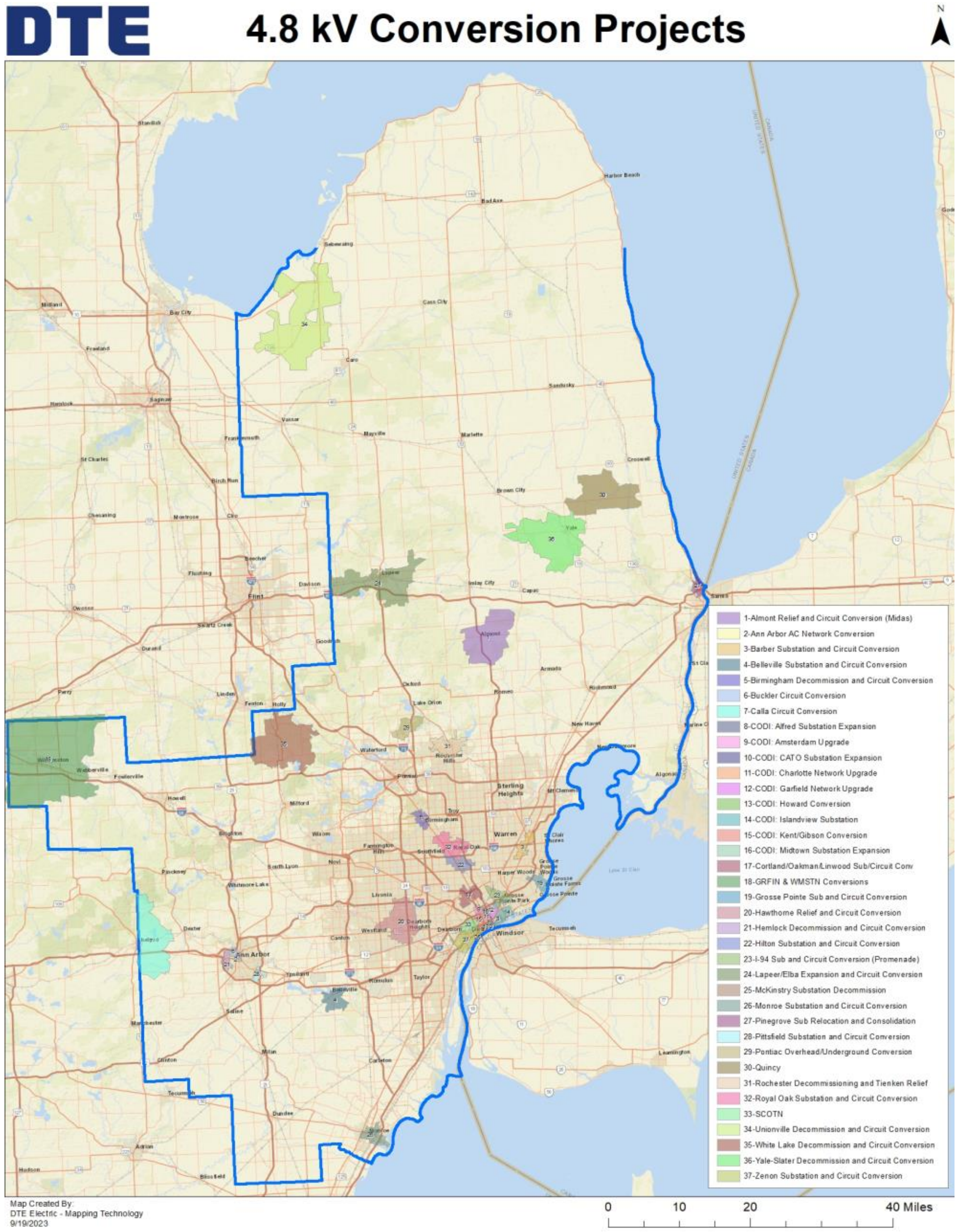
The work performed as part of a 4.8kV Conversion includes:

- Building new 13.2kV substations or upgrading existing 13.2kV substations to absorb 4.8kV substation load.
- Installing controls and automation in the substations and circuits to our latest design standards
- Reconfiguring circuits and establishing new jumpering points.
- Completing overhead pre-conversion work including rebuilding pole tops, replacing poles and transformers as needed, and installing neutral wire.

- Rebuilding underground infrastructure.
- Reconductoring overhead lines as needed based on modern standards and new circuit configurations.
- Establishing new distribution circuits from new, upgraded, or existing 13.2kV substations.
- Reconfiguring circuits and establishing new jumpering points.
- Converting and transferring the load off the 4.8kV substations to the 13.2kV substations.
- Decommissioning of aging 4.8kV substations and associated subtransmission infrastructure

Exhibit 9.3.3.3 provides a map to illustrate the locations of the 4.8 kV Conversion and Consolidation projects.

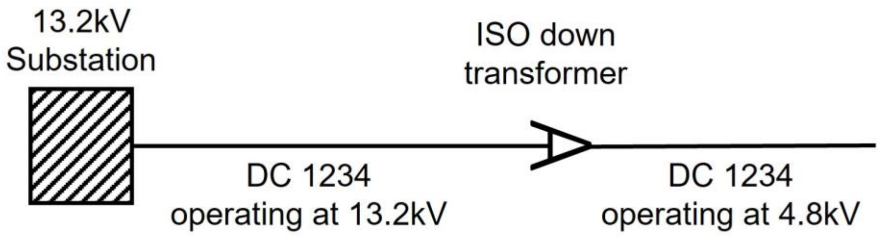
Exhibit 9.3.3.3 4.8kV Conversion Map



4.8kV ISO down area conversions

As described above, the Company operates some circuits as ISO downs, 4.8kV circuits that are fed from a 13.2kV substation. On these circuits the higher voltage is stepped down to 4.8kV by a transformer and the rest of the circuit downstream of that transformer operates in a 4.8kV delta configuration. Exhibit 9.3.3.4 illustrates a circuit with an ISO down area.

Exhibit 9.3.3.4 – ISO Down Circuit



There are ISO downs on more than 400 circuits on the system. Exhibit 9.3.3.5 below provides the number of circuits with ISO downs, the number of customers served in an ISO down area, and the number of overhead and underground miles within the ISO down areas.

Exhibit 9.3.3.5 Number of Circuits with ISO Downs and Miles of 4.8kV

	Number of Circuits	Number of Customers	Miles Overhead Wire	Miles Underground Wire
4.8kV ISO Downs	432	142,335	5,596	417

The portion of circuit operating at 4.8kV in an ISO down area has the same characteristics of 4.8kV circuits fed from a 4.8kV substation including the same reliability, capacity, safety, and operational flexibility challenges. As part of DTEE's long term vision to convert the 4.8kV system, converting the ISO down areas to a higher voltage will also be required.

The work required as part of a 4.8kV ISO down conversion includes:

- Installing controls and automation on the circuits
- Completing overhead pre-conversion work including rebuilding pole tops, replacing poles and transformers as needed, and installing neutral wire
- Rebuilding underground infrastructure as needed
- Reconductoring overhead lines as needed

- Reconfiguring circuits and establishing new jumpering points
- Removing ISO down transformers

9.3.4 Prioritization of Conversion Projects

Prioritization of near-term conversion projects

Conversion and consolidation projects provide many benefits including safety improvements, load relief, risk reductions, reliability improvements, technology modernization and cost reduction. While other investments such as PTMM (detailed in Section 8.1 and the 4.8kV Hardening program (detailed in Section 8.2) can provide many of these benefits, converting the 4.8kV system is the strategy used to address load constraints, replace the aging substation equipment and change the configuration from an ungrounded system to a grounded system.

Approximately one third of the system has some form of loading constraint on substations, circuits, or equipment (Section 9.1 discussed the impacts of operating under loading constraints). Since conversion of the 4.8kV system addresses capacity constraints and aging substation equipment, the primary factors considered when developing conversion projects are:

- Substation firm rating
- Circuit overloads
- Wire downs per overhead mile
- Substation risk ranking

Consistent with other strategic projects and programs, 4.8kV conversion projects are evaluated and prioritized using the GPM, which takes into account the factors above, in addition to reliability improvements and investment in EJ communities. While these criteria initially prioritize substations for conversion, other criteria are also considered when developing and proposing a project. For example, adjacent substations are evaluated for inclusion, the feed for the new substation is considered and property for the new or expanded substation must be available and acquired.

Prioritization criteria – ISO downs

The 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. Without the need to consider substation factors, the following become the driving factors of 4.8kV ISO down conversions:

- Safety (wire down reduction)
- Reliability (customer minute interruptions)
- Costs (avoided O&M and capital)

9.3.5 4.8kV Conversion Plan for 2024-2028

Exhibit 9.3.5.1 Projected 4.8kV Conversion Capital Investment

Project/Program ($ millions)	2024	2025	2026	2027	2028	Total Investment 2024-2028
CODI	$95	$126	$148	$119	$90	$579
4.8kV Conversions	$66	$66	$185	$243	$310	$869
4.8kV ISO down Area Conversions	$10	$10	$10	$10	$10	$50

9.3.6 4.8kV Conversion Plan for 2029 and Beyond

The challenges of the 4.8kV system, including age, configuration, and loading have been described in detail in this section and in Sections 4 and 5. These challenges are likely to increase based on the impact analysis of the scenarios discussed in Section 3. As the 4.8kV system will be less and less likely to meet customer needs over the coming decades, the Company has developed an aspirational goal to convert all the lower voltage (4.8kV and 8.3kV) circuits and substations by 2040. This effort will be significant and complex. Even after the investments outlined in this DGP there will still be nearly 16,000 overhead miles of 4.8kV distribution circuits and over 200 4.8kV substations remaining. The investment needed to completely convert the 4.8kV system to a higher voltage is estimated at $20-25 billion in 2023 dollars, using current labor, material and productivity assumptions. Approximately $3 to $4 billion of this investment includes conversion of the ISO down circuits which already have 13.2kV substations feeding them.

The Company has begun developing a long-term plan for conversion to outline the sequence of projects to come after the timeline of this DGP. The highest priority investments after 2028 will be investments needed to complete projects that were started in the later years of this plan. For example, as most large conversion projects require multiple years from engineering to completion of construction, projects started in 2026-2028 will continue past the 5-year timeframe in the DGP. Based on current project estimates, $1 billion of investment is needed to complete these projects, including completing the entire scope of all CODI projects.

Looking beyond projects included in this DGP, the next set of 4.8kV substations and circuits slated for conversion will be driven by loading and load relief needs. The company has used the components of the GPM that rank load and capacity constraints on the distribution system and identified the highest ranked 25 substations based on the GPM dimensions of 'Overload Relief' and 'Capacity Constraints' which consider the six metrics listed in Exhibit 9.3.6.1 below. More information on the GPM metrics will be discussed in Section 12.1 – Investment Selection Methodology.

Exhibit 9.3.6.1 – GPM dimensions related to distribution system load relief

Overload Relief	Capacity Expansion
• Substation equipment over day-to-day • Circuit over day-to-day	• Substation over firm (today) • Substation over firm (2035) • Strong near-term load growth • Circuit over design order (DDO)

Given the potential timeframe of when these projects would be started, cost estimates and project scope should be considered preliminary. High level characteristics of the projects to address the next 25 4.8kV substations with the highest load constraints are provided in Exhibit 9.3.6.2 below. As was described in Section 9.3.2, a typical conversion project includes multiple substations based on the higher capacity of a single 13.2kV substation compared to the capacity of a 4.8kV substation. The scope of work therefore includes 24 adjacent substations to the targeted overloaded substations in order to fully realize the benefits of the higher capacity, including reducing the amount of aging equipment on the system.

Exhibit 9.3.6.2 – Conversion Projects to Address 25 4.8kV Substations with Highest Loading Constraints

Total 4.8kV Substations	49 (25 based on loading constraints and 24 adjacent substations)
Estimated cost	$4 billion
Overhead miles	2,400
Substation % over firm (today, average)	112%
Substations with circuit loading constraints	34
Average All-weather SAIDI	479 (4^{th} quartile)
% of customers in EJ communities	32%

Based on the current state of the substations above, conversion projects will provide substantial load relief, reliability and safety improvements with a significant share of the investments impacting customers in EJ communities.

Within this group of conversion projects, the GPM will be used to prioritize the sequencing of projects. It should be noted that for planning for projects starting in 2029 and beyond, prioritization and sequencing will be an iterative process. The GPM metrics include the output from the integrated forecasting tools that will enhance planning capabilities and incorporate additional data, such as propensity for adoption of EVs and DER and hourly load shapes, into the current substation loading profiles (refer to Section 10.2.2 for detailed information on planning and forecasting tools). In addition, the pace at which electrification develops will further impact which substations are subject to the most significant loading constraints.

In addition to the projects to convert circuits fed by 4.8kV substations, the Company will increase investments to convert the 4.8kV ISO areas to achieve the aspiration of converting the entire system. Based on current estimates, the Company would need to invest approximately $320M per year from 2029-2040 to convert the approximately 5,500 ISO down miles. Circuits for ISO down conversion will be prioritized based on safety (wire downs), reliability and avoided trouble costs, as was also described in Section 9.3.4.

The total conversion of the 4.8kV system will provide a modernized grid for our customers and will provide transformational benefits of improved safety, reliability and relief of loading constraints. Designing the distribution system with sufficient capacity will increase operational flexibility, increase resiliency, and ensure that increased customer demands for the adoption of new technologies can be met by the grid.

9.3.7 Pontiac 8.3kV Conversion

DTEE did not construct the 8.3kV system that serves the City of Pontiac. Located within DTEE's service territory, it was acquired from CMS Energy in the 1980s. The 8.3kV system is served by four substations: Bartlett, Paddock, Rapid Street, and Stockwell, and their 18 distribution circuits.

Unlike the 13.2kV system, contingency options are limited for the 8.3kV system. Because the 8.3kV system is an island surrounded by the 13.2kV system, it is impossible to transfer load from 8.3kV circuits to neighboring facilities. This results in a high risk for stranded load in the event of an 8.3kV substation outage event.

Adding to the operational challenges, replacement parts are no longer available for 8.3kV breakers and other substation equipment due to their obsolescence. Non-standard clearances require substation shutdowns for operations and maintenance. This leads to extended customer interruptions during outage events and leaves the system in an abnormal state for extended periods of time if any 8.3kV equipment fails. In addition, crews must be trained to operate and maintain the 8.3kV system, adding to training and operation and maintenance costs.

Meanwhile, the City of Pontiac has gradually increased in load in the past 7 years.

The plan to address the 8.3kV system has been developed, starting with the upgrading of the system vaults. The original underground vaults were a safety hazard, with live front equipment and often insufficient arc flash distances. This work will be completed in 2023. The circuit conversion work involves conversion and transfer to circuits out of Catalina substation with the remainder to be converted and transferred to circuits out of a new substation adjacent to the existing Wheeler substation site. For the conversions to take place, services in Pontiac fed through 8.3kV rated underground equipment will need to be upgraded. This effort will require replacement of customer-owned switchgear, fuses, transformers, and cables rated at less than 15kV class.

As a result of the project, all four 8.3kV substations, Bartlett, Rapid Street, Paddock and Stockwell will be decommissioned by 2029. In addition, the Wheeler substation upgrade will enable load to be transferred off Bloomfield Substation. This will allow Bloomfield Substation to be decommissioned, thus taking its at-risk switchgear out of service. Exhibit 9.3.7.1 provides a summary of the project capital investment for the next 5 years.

Exhibit 9.3.7.1 Pontiac 8.3 kV Conversion Capital Investment

Project ($ millions)	2024	2025	2026	2027	2028	2024-2028 Total
Pontiac 8.3 kV Conversion	$19	$31	$29	$18	$18	$114

9.4 Undergrounding

Background

As discussed in Section 3.1.2, DTEE is planning for a future that will likely include an increase in storm frequency and severity. In the face of the resulting outages, customers and other stakeholders have increasingly asked, “why not put the lines underground?” As noted in Section 14.1 on customer engagement, recent customer research of over 4,000 customers indicated a specific interest in improving reliability by burying lines underground. Since the 1970s, new construction of subdivisions and other projects (as possible) have required installation of underground lines, resulting in well over 30% of the current DTEE system running underground. In recent years, DTEE has been developing small pilot projects to move existing overhead infrastructure underground. As the company works towards undergrounding as a viable and economic option to overhead construction, it will be worked into the strategy for circuit conversions. The company is committed to continuing to mature its capability in Undergrounding the overhead infrastructure and lower the cost so that significant portions of our system can be relocated underground.

Undergrounding will be implemented in a manner that balances reliability and other longer-term benefits of underground infrastructure with the initial cost of installation. The Company has recently completed one project, Appoline, and additional projects are being developed. The

Company is planning to develop projects with varying scopes to test different construction and outreach methodologies. This includes partnering with the DTE Gas Company to find synergies in areas of joint underground construction, executing both urban and rural undergrounding to determine benefit and cost differences, and working with customers to determine the most effective outreach strategy. Additional completed projects will help identify pathways to reducing project costs, while also providing more data points for use in evaluating overall total cost over time of underground infrastructure vs. similarly situated overhead assets. The projects will incorporate benchmarking of other utility underground construction practices, develop solutions for complexities including obtaining customer agreements, develop cost-saving practices, and complete a comprehensive long-term or life cycle cost analysis of underground vs overhead infrastructure. When supported by the expected results of the projects, undergrounding as a project option would be applied to areas based on several factors including recent reliability, downed wires, and maintenance costs. Due to the forecasted costs for undergrounding subtransmission and distribution backbone lines, the company is not currently pursuing a program to address these lines but instead evaluating the undergrounding of single-phase lateral infrastructure and services primarily serving residential customers. As pilots are developed, the Company will present them to the Commission, as requested in Order U-20836, with analysis of the "benefit/cost of the proposed undergrounding pilot compares to that of other solutions the company is currently employing to enhance the reliability of the distribution system".

The Company has a unique opportunity to align the Undergrounding program with the 4.8kV conversion program, where significant overhead rebuild would otherwise be occurring. When evaluating the economics of undergrounding a target area, cost used in analysis would be the incremental cost to underground versus the cost to rebuild the overhead. The analysis will also include consideration of life cycle cost of overhead vs underground construction, including potentially reduced costs for underground construction maintenance over time, including eliminating the tree trim costs for overhead as an example. It is anticipated that when considering the lifecycle cost of undergrounding, these assets will offer opportunities to cost effectively underground a significant portion of rear-lot overhead laterals and services when converting circuits.

Appoline Pilot

History and Status

DTEE began an undergrounding project in 2018 on the Appoline DC 1346 circuit. The intent of this project was to move rear-lot overhead infrastructure to rear-lot Underground Residential Distribution (URD). The goals of this project were to determine actual installation costs, understand customer acceptance, and determine opportunities to improve cost and construction efficiency in subsequent pilots. This project includes approximately 61 residential customers on two city blocks in Detroit. The scope of the project includes the installation of a looped URD system with approximately 1,300 feet of primary conductor, six transformers, and underground services to residences. When the underground equipment is completed and functional, the overhead infrastructure will be removed.

At the time of this filing, 47 of the 61 customers have already transferred to the URD Loop. Transfer of the remaining customers should be completed by the end of October 2023 with retirement of the electrical equipment on the rear-lot poles being completed by the end of November 2023.

Appoline Pilot Lessons Learned

From the Appoline pilot, the Company gained valuable experience in undergrounding existing overhead infrastructure and recorded two key learnings: rear-lot URD poses significant challenges, and early customer engagement and agreements prior to construction are critical to the success of the project. Before installation work could begin, the overhead infrastructure located in rear alleyways required extensive vegetation and debris removal. The cost and time required for these activities will be considered when developing any future rear-lot undergrounding projects. Another significant challenge impacting the schedule of this project was difficulty in contacting the homeowners, often landlords instead of resident homeowners, to obtain the approvals required to modify the electric service attachments to their homes. After limited success using several mailings and door hangers, the Company has continued using door-to-door customer outreach, which has shown improved results. Nonetheless, reaching all property owners has been a challenge that requires addressing in future undergrounding projects.

As the Appoline pilot comes to a full conclusion, the Company will produce the requested report from U-20836 regarding the benefit/cost analysis (BCA), alternatives evaluated, and its plans for incorporating Undergrounding further into the distribution grid plan.

Benchmarking

The Company participated in a benchmarking exercise on Undergrounding with over ten peer utilities to determine the optimum infrastructure configuration and construction methods that balance reliability, cost, constructability and customer engagement when relocating infrastructure. The results overwhelmingly concluded that front-lot URD is the best option over other locating the URD in the rear. Front-lot URD provides the best customer experience for both reliability and aesthetics. Additionally, DTEE's benchmarking found that the peer utilities will complete easement acquisition and gain any necessary customer agreements prior to executing such a project. Significant cost savings were realized by Utilities that executed their Undergrounding program at high volumes and scale, having benefitted from economies of scale and productivity. The peer utilities assess target projects by evaluating the NPV over the life cycle of the asset, reliability benefit economics, and construction costs.

Another area of benchmarking explored the reasons why peer utilities are executing their Undergrounding programs. The Company found that the rationale for peer programs varied across the country, but almost all focus exclusively on single phase lateral overhead due to higher costs of undergrounding three phase and backbone with higher voltages. These higher costs are driven by higher building construction specifications, including cement reinforced duct banks.

Key lessons learned from benchmarking efforts on how to improve efficiency of execution include the importance of streamlined contracting for design, customer outreach, construction, and utilizing public right-of-way. The greatest challenge identified by other utilities for other configuration options was community acceptance once the project was already underway. To further develop the Company's experience in Undergrounding, DTEE is incorporating peer utility best practices for improving the cost efficiency of the work that may be applied more broadly across system and infrastructure improvement plans.

The benefit of Undergrounding is primarily the avoidance of outages in the impacted area caused by trees, wind, and public contact. However, customers are still vulnerable to outages from damage that occurs upstream from the undergrounded portion of their circuit or substation. In large storm situations, there is an additional restoration time benefit to the entire customer population as resources will not be required to address downed wire and outage jobs on undergrounded infrastructure.

Next Steps

The Company is developing and plans to execute additional projects to gain information on expected costs and construction efficiencies. These projects will involve a mix of geography (suburban, rural) and will incorporate lessons learned from benchmarking peer utilities to develop a more cost competitive Undergrounding program. Additionally, the Company is refining its Total Cost of Ownership (TCO) model for these projects and will incorporate Undergrounding into the 4.8kV Conversion program as an option for rebuilding overhead infrastructure. Another area the Company will explore is identifying segments of high Tree Trimming and other maintenance cost segments of overhead infrastructure that would be good candidates for undergrounding.

Davison/Buffalo Charles Project

The Company plans to use the lessons learned from the Appoline project and Benchmarking to implement a new project in the City of Detroit. The scope of this project will be to replace roughly 3 miles of overhead infrastructure with underground infrastructure in the area of E. McNichols and E. Davison (Davison and Buffalo Charles neighborhoods). This area was chosen in partnership with the City of Detroit and DTE Gas. In addition to the area being a focus for some of the City of Detroit's near-term revitalization plans, there are also cost and execution benefits for implementing Undergrounding in this area. First, DTE Gas is performing gas main replacement in the area, and cost and other construction synergies are expected from collaboration between the two utilities, both of which will be using directional boring to complete their work. The combination work will also minimize the time for construction disturbance for customers, when compared to coming in before or after gas main renewal has occurred. Additionally, this area has considerable Detroit Land Bank Authority and City-owned properties where the City/Land Bank has agreed to allow easements for transformer placement.

For this project, the Company expects to remove approximately 160 poles, 2.8 miles of overhead conductor, 51 overhead transformers, 3.5 miles of secondary, and 0.7 miles of PLD primary. This infrastructure will be replaced with 4.3 miles of underground primary cable, 3.3 miles of underground secondary cable, 9.5 miles of underground service cable, 60 underground transformers, 147 handholes, 459 junction boxes on houses, and 11.7 miles of conduit. Junction boxes are utilized so that customers are not required to relocate their interior electric wiring in order to receive the new underground service, previously fed from above their home. The area also has a lower customer density than previously completed or proposed projects, which is expected to further reduce costs.

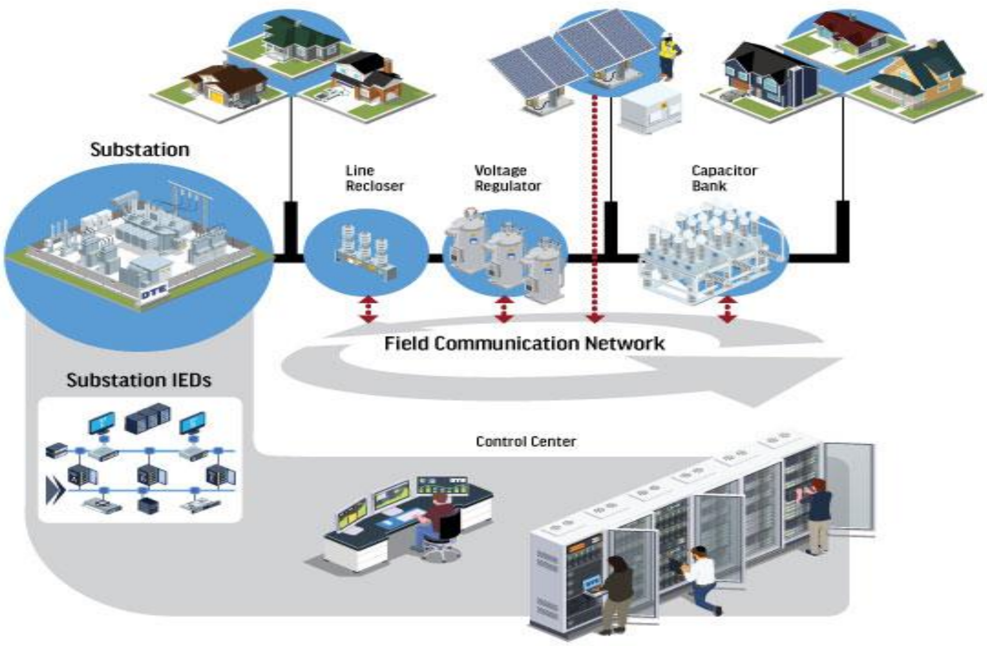
At the time of this filing, construction is scheduled to begin in October 2023 and will continue throughout 2024.

10 Pillar: Technology & Automation

New technology is improving the way modern electric grids operate, resulting in improved reliability, performance, and safety. This technology also provides new opportunities to improve operations in ways that benefit customers, such as the ability to automatically isolate outages to limit the number of impacted customers and to provide real-time visibility into circuit and substation loading needed to accommodate increasing numbers of DG/DS and EVs (described in Section 3 above). Implementing new information technology (IT) and operational technology (OT) will streamline and optimize the Company's planning while also improving safety and productivity. These investments form the core of this investment pillar.

A modern distribution system overview, shown in Exhibit 10.0.1 below, shows key distribution automation tools such as line reclosers,[38] voltage regulators,[39] capacitor banks,[40] substation intelligent electronic devices (IED).[41] These systems and tools support the Electric System Control Center (ESOC),[42] providing the data input to grid management tools such as the Advanced Distribution Management System (ADMS)[43] that are essential to modern operations.

Exhibit 10.0.1: Modern Distribution Overview



[38] Reclosers are devices on the distribution grid that automatically detect and interrupt transient faults.
[39] Voltage regulators are devices on the distribution grid that regulate and maintain voltage within a set standard.
[40] Capacitor banks are electrical devices on the distribution grid that store large electrical energy charges and are used for conditioning the flow of energy.
[41] Intelligent electronic devices (IED) are devices that integrate multi-processors with the capability to receive or send data or control from or to an external source.
[42] ESOC is the most critical facility in Distribution Operations. Personnel in the ESOC operate the Company's subtransmission and distribution system in southeast Michigan, and support generation operations. With state-of-the-art technology like ADMS and an electronic display board of the transmission, subtransmission and distribution networks, these personnel monitor alarms and system conditions, and direct field personnel to operate electrical equipment for routine switching needed for outage restoration, maintenance, and other planned activities.
[43] ADMS is an advanced operating technology platform that is essential to the Company's grid modernization efforts to improve system reliability and operational efficiency. It is comprised of five components that will substantially improve DTE Electric's ability to manage the flow of electricity from the point of generation to the point of delivery, to monitor the condition of the grid, to safely operate it, and to respond to emergency conditions and outages more quickly.

The Company is well positioned to utilize modern distribution system technology, including automation, because of foundational investments in DTEE's world-class ESOC, Alternative System Operations Center (ASOC),[44] and the ADMS. These three investments provide the necessary foundation for the Company to develop, deploy, and control a broad range of new technologies to improve reliability for customers by reducing the number of sustained outages and shortening others, as well as supporting the changes that are coming as part of grid modernization.

Supporting a focus on improving storm restoration efficiency, the 2023 distribution grid plan for the Technology and Automation pillar includes an acceleration of investments in distribution automation. Distribution automation describes a group of field assets such as reclosers, switches, capacitors, and sensors capable of monitoring and controlling the distribution system and supporting grid edge technologies like DER and NWA applications. Distribution automation helps customers in three important ways. First, when an outage occurs (from a tree, animal intrusion, public interference, etc.), automation can reduce the overall number of customers affected by "sectionalizing" the event to a smaller area. Second, devices used for automation can report back information to the Company's ESOC that allows the grid management system to determine the location of the equipment failure down to a few feet, significantly reducing the patrol time required by DTEE's field crews and shortening duration of the outage. And third, while crews are in route to the outage, the Company's system operators can remotely control automation devices in the field from the control center, routing power from other areas further reducing the customers affected and shortening restoration time. On circuits where this technology is installed, DTEE can reduce the number of customers affected by an outage and reduce restoration time. Estimated outage minute reductions of roughly 50% are expected when connections to other circuits allow automated reconfiguration, and 25% when reconfiguration is not practical due to system design constraints. These reductions assume existing circuit automation is not present on a circuit and that there are not any other factors limiting automated restoration such as multiple damage locations, damage on adjacent circuits or loading constraints preventing transfer.

[44]ASOC, the new backup SOC (System Operation Center), will have the appropriate square footage required to co-locate necessary personnel, and will have the appropriate mechanical and electrical system redundancies as the ESOC. In addition, the new ASOC will also be outfitted with the same ADMS technology (including a video wall) as the new ESOC, for seamless operations during the transition between facilities.

In addition to investments in grid automation, DTEE's Operational technology roadmap outlines ongoing IT and OT investments in five investment areas. The roadmap focuses on technology tools within the Technology & Automation pillar. Investments within the roadmap support grid management, distribution plan, work management and scheduling, asset management, and mobile technology. These investments focus on establishing new capabilities and enhancing existing capabilities that will improve safety, reliability, and affordability for customers. Categories of investment within the Technology & Automation pillar are summarized below:

Technology and Automation Investments

Grid Automation

Grid Automation is focused on the physical infrastructure needed to support a modern distribution grid. Investments in reclosers to improve safety and reliability, capacitors and voltage regulation for CVR/VVO, as well as infrastructure to support NWA, EVs, and grid telecommunications. This section also includes initial investments in updating the AMI systems.

Operational Technology roadmap

- **Grid management**

  Grid management includes Operational Technology investments that enable the Company to monitor, control and optimize the operation of grid automation investments. These projects include the full suite of ADMS distribution management applications, including outage response, fault location and service restoration (FLISR), and advanced control toolsets. and will enable distribution operators to model the real time state of the electrical system and manage the distribution network, monitor and control the power system, manage planned and unplanned outages, and analyze and optimize the quality and reliability of the network. These investments also include the platforms that enable the management of DER such as the DERMS (Distributed Energy Resource Management System).

- **Distribution planning**

  Distribution planning encompasses all technology dimensions needed for distribution planning, design, specification, modeling, forecasting and the analytics of associated data. This area accounts for systems and engineering tools needed to perform modelling functions accurately and effectively for distribution planning activities and investments. These investments also support streamlining the customer interconnections process and include investments in hosting capacity mapping.

- **Work management and scheduling**

  A work management system is technology that provides a set of management tools that are used to manage labor, materials, and scheduling in the completion of work. The work management system manages both planned and unplanned work, includes work order creation, resource scheduling, and work execution for DTEE employees, vendors, and third-party crews. The system encompasses job planning, labor, material, tools, and services for both larger, complex work efforts and smaller, short-term jobs. Upon completion, work is audited and verified in the system to reconcile time capture and payment.

- **Asset management**

  Asset Management systems allow the Company to manage assets to minimize the total cost of ownership while maintaining high equipment service levels. The systems include managing operational data about assets and as well as the appropriate algorithms to process that data to determine if maintenance or replacement needs to be initiated. These technologies help manage the full lifecycle of an asset, including engineering. maintenance, and financial management. DO's primary asset management systems are IBM Maximo (with industry solutions) and ESRI ArcGIS.

- **Mobile technology**

  Mobility technology allows for field teams collecting and distributing data at the point of activity through mobile devices. Mobile investments include both purchase of required devices and new and existing applications that are engineered for mobile access and usage. Types of applications that rely on mobile communication include work dispatch, work execution, forms digitization, location tracking, route navigation, field analytics and secure file sharing.

Technology and Automation is a wide-ranging environment. The use of the DOE DSPx (Department of Energy Next Generation Distribution System Platform) framework,[45] discussed in Section 5, facilitates a broad understanding of the critical automation and technology components of the future grid and how they integrate.

DTEE is ramping up the deployment of technology and automation investments throughout 2023. As devices are installed, customers served by those circuits will see immediate benefits; complete deployment is expected to take five to six years. The following sections detail the Company's plan to deploy these new technologies and demonstrate how it will improve electric service and reliability for DTEE's 2.3 million electric customers. Throughout this section larger programs and projects will be highlighted and associated with gaps they close within the larger framework.

10.1 Grid Automation

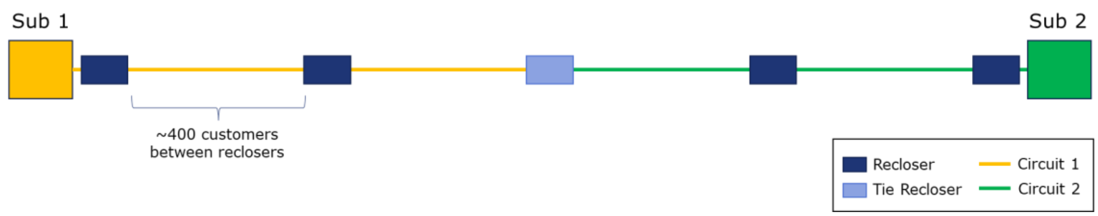
Automation devices provide situational awareness about faults and other distribution system issues and help quickly identify and isolate the problem. Increasing the number of automated devices will provide improved detection of down wires and abnormal system conditions so issues can be automatically or remotely isolated, improving safety. Automated devices provide reliability benefits through targeted isolation of outages which reduce the number of customers initially impacted as well as reduce the duration of outages for those impacted by allowing automated or remote partial restoration through switching operations. Automated devices, paired with SCADA, provide the Company real-time data on voltage, current, fault analysis, and other data points and deliver the data to the ADMS. This provides control room operators and dispatchers with real-time system information and conditions. Increased situational awareness also helps crews locate outages and restore the system more quickly.

The long-term use of automation calls for the deployment of SCADA, automated field devices, and fault analysis tools. The DSPx model calls out substation and distribution SCADA and makes note of protective and switching devices, such as reclosers and voltage control devices such as capacitor banks. Consistent with this, DTEE has established standards that newly constructed and rebuilt portions of the distribution systems have SCADA enabled substation breakers, three phase reclosers[46] and capacitor controls. New circuits will also be constructed with SCADA

[45] PNNL: Grid Architecture - Modern Distribution Grid Project, https://gridarchitecture.pnnl.gov/modern-grid-distribution-project.aspx, retrieved on (09/01/2023).
[46] For circuits serving more than 400 customers.

enabled tie points between circuits allowing for automated or remote restoration of undamaged sections. Standards also require the use of digital relays and communications protocols in alignment with advanced protection requirements. These standards ensure that investments made through system loading and conversion programs are consistent with enabling a modern electrical grid. As Fault Location, Isolation and Service Restoration (FLISR) advances, additional devices (e.g., reclosers, sensors, etc.) will be deployed in the field to close the gaps in grid sensing and control.

Exhibit 10.1.1: Automation Program – Retrofit Circuit Example



To achieve the benefits of automation more rapidly, the Company plans to retrofit the existing infrastructure. Retrofitting automation will be considerably faster than waiting to apply new standards to rebuild projects. This work will require bringing the existing distribution system to the retrofit specification shown in Exhibit 10.1.1. The retrofit effort will require the installation of over 10,000 distribution line reclosers as well as upgrading many switching and tie points to facilitate the ability to quickly restore customers before repairs are completed. This program will be focused on installation and automation of most of the existing 4.8kV and 13.2kV system to the retrofit specification, installing ground detection on the 4.8kv system that is retrofitted, and building switching points to enable restoration from multiple sources using automation. The tables below (Exhibit 10.1.2 and Exhibit 10.1.3) summarize the key investments and projected timelines for the grid automation section.

Exhibit 10.1.2: Key Investment Highlights for Grid Automation

Key Investment	Use Case	Implementation Highlight	DSPx Objective
Grid Automation	Establish SCADA control, automation and ground identification and isolation	Reduce sustained circuit outages, minimize the size of outages, reduce crew patrol time and operating time to speed restoration, minimize impacts of system grounds	Physical Grid Infrastructure, Sensing & Measurement, Automated Field Devices, SCADA
Grid Telecommunications program	Install fiber backbone communications to substations and advanced wireless mesh	Increased communication bandwidth and resiliency to support new grid automation devices, DER, field workers, advanced metering, including analysis and optimization of data, leading to better overall utility coordination for day-to-day operations and during storm	Operational Communications
CVR/VVO	Conservation Voltage Reduction and Volt Var Optimization. Install new SCADA enabled capacitors and replace existing capacitor controls to coordinate with substation voltage regulators to reduce system voltage and fluctuations	Reduce system losses, increase system efficiency and improve system voltage and power quality	Physical Grid Infrastructure, Sensing & Measurement, Automated Field Devices, SCADA, Volt-Var Management
Capacitor Placement and Control Program	Optimizing location of capacitors on circuits and replacing end of life controls	Improve system efficiency and voltage	Physical Grid Infrastructure that Improves sensing and measurement of reactive power through automated field devices that can be controlled by volt-var management
NWA Projects	Non-Wire Alternative demonstrations for energy storage, energy efficiency, demand	Enable more DER integration and create methods for future programs and NWA integration	Customer DER programs, DER Management, Advanced Protection,

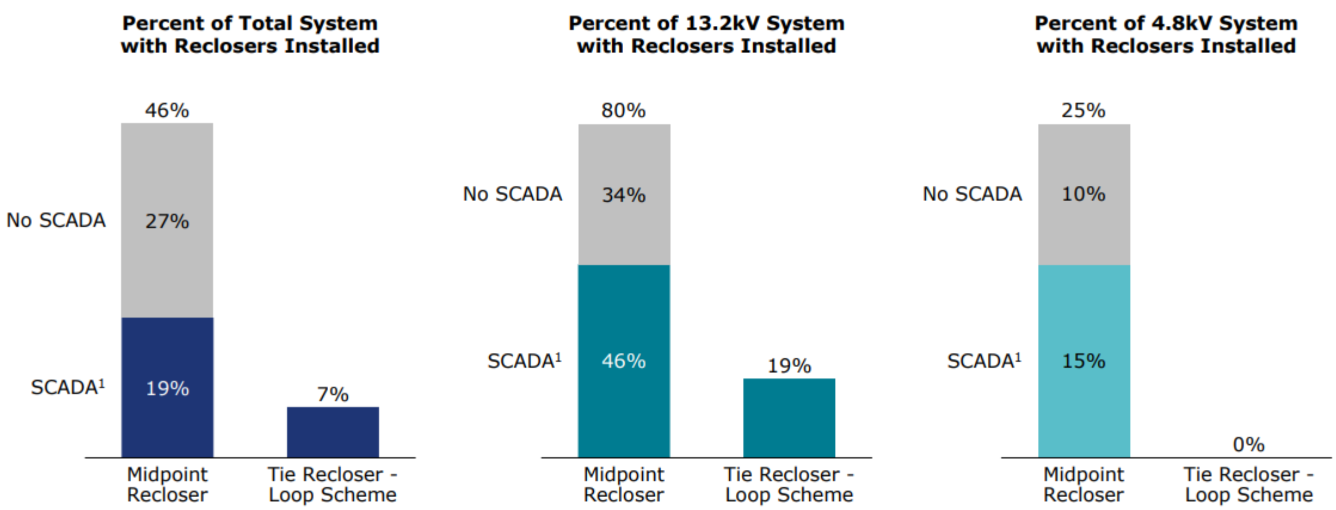
	response and integration of DER and microgrids		Physical Grid Infrastructure
Grid Edge Enablement Program	Interconnection gateways, DER controls coordination and microgrid controls, DER testing and training facility	Consistent and optimized controls and communications to streamline DER interconnection integration. Test new DER capabilities and their grid interaction prior to wide-scale deployment while also serving as a training platform	Support safe and reliable transition to clean, distributed energy resources, enables Customer DER programs, DER Management, Operational Communications, cybersecurity and Advanced Protection
Vehicle Electrification Projects	EV managed charging, Vehicle to Grid, Charger integration with other DER and grid controls	Streamline EV charging installations, Enable new capabilities for electrification and grid management.	DER Management, Vehicle to Grid and Electrification
URD Fault Indicators	Facilitate URD restoration and minimize time field crews would need to troubleshoot outage	Reduce crew patrol time, and provide faster restoration time	Physical Infrastructure, Sensing & Measurement
New Technology Evaluation Program	Assess new grid assets and technology for use on the DTEE system. Test and approve compatible equipment and develop work practices and procedures	Incorporate emerging technology into grid automation and construction to improve efficiency and reliability	Evaluate and test new Automated Field Devices and Physical Grid Infrastructure and develop standards and work practices

Exhibit 10.1.3: Key Investment and Timeline for Grid Automation

Key Investment (in millions)	2024	2025	2026	2027	2028
Grid Automation	$61.6	$162.6	$190.6	$308.6	$469
Grid Automation Telecommunications Program	$16.9	$15.0	$13.8	$12.5	$11.0
CVR/VVO Program	$5.0	$5.0	$5.0	$5.0	$5.0
Capacitor Placement and Control Program	-	$5.6	-	-	-
NWA Projects	$14.5	$1.3	$0.3	-	-

Grid Edge Enablement Program	$5.5	$4.2	$4.2	$3.0	$2.8
Vehicle Electrification Projects	$2.9	$1.0	$0.8	$0.8	$0.5
URD Fault Indicators	$3	$3	$3	$3	$3
New Technology Evaluation Program	$1.2	$1.0	$1.0	$1.0	$1.0
Line Sensors	$0.5	-	-	-	-
Large/Medium Sized DER Monitoring and Control	$0.3	$0.3	$0.3	$0.3	$0.3
Total	**$111.4**	**$199**	**$219**	**$334.2**	**$492.6**

Exhibit 10.1.4: Percent of Reclosers Installed on DTEE's System



10.1.1 Grid Automation Program

Grid Automation on 13.2kV circuits has multiple objectives including: 100% SCADA monitoring and control of overhead distribution circuits, SCADA control of existing circuit reclosers, the addition of new automation reclosers to reduce the potential impact of outages and SCADA control of existing circuit tie points. The program has a goal of reviewing and updating all 1264 circuits using reclosers and other automation devices. The reliability impact of this distribution automation work is expected to be significant. As an example, a 2016 DOE study[47] showing reductions in customer minutes interrupted 17- 55% when compared to the same circuit before automation, with DTEE expecting results in the range of 25-50% depending on the conditions found at each circuit.

Grid Automation on 4.8kV circuits is very similar to the 13.2kV with the inclusion of an additional objective to establish ground detection and isolation. The 4.8kV cannot identify or isolate energized down wire as reliably as the grounded 13.2kV system, resulting in wire downs that can remain energized and pose a hazard to the public. To address this consideration, all 4.8kV circuits not identified for conversion within the next five years will get an automation device installed near the start of the overhead portion of the circuit that is able to identify and isolate down wires. This program is expected to update 1,945 circuits over the 2024-2028 period. While the safety benefits of the program are substantial, the reliability benefits would be slightly reduced when compared to the 13.2kV automation program as new outage events would be introduced when isolating down wire that currently are only interrupted during repairs.

The Grid Automation program also includes building new line extensions, replacing small wire, and adding or replacing voltage control equipment to enable new circuit connection points and bidirectional flow to be established. The circuit connection portion of the program addresses the gap that approximately 40% of existing circuits do not have connections with adjacent circuits that would allow the Company to transfer and restore customers during trouble. This program would also install SCADA enabled devices at the tie point between circuits to allow automatic or remote execution of switching to restore customers. This program would continue past 2028 with a focus on looking at circuits that need additional work to establish and automated switching points.

The overall Grid Automation program is expected to continuously increase throughout the 2024-2028 period as capacity to deploy devices increases with the program investing more than $1 billion over the 5-year period. The program is key to achieving the long term SAIDI reduction objectives and captures many of key core components highlighted in the DSPx model.

[47] Distribution Automation: Results from the Smart Grid Investment Grant Program (energy.gov), https://www.energy.gov/sites/prod/files/2016/11/f34/Distribution%20Automation%20Summary%20Report_09-29-16.pdf, retrieved on (09/01/2023).

Grid Automation Telecommunications Program

In addition to the automation devices themselves, a modern electrical distribution system demands a secure, highly reliable communications network that connects those devices, relaying information between the field and ESOC. Grid Telecommunications covers the operational communications portion of the physical core components within the DSPx framework. As installation of automation and other field devices continue to increase, investment to expand the company's fiber and mesh networks[48] is necessary to ensure secure and reliable communication with company data centers, substations, distribution network, automation devices and metering infrastructure as well as emerging DER installations. The current and planned network technology landscapes are shown below (Exhibit 10.1.1.1 and Exhibit 10.1.1.2) and highlight the connections and communications paths between these key components.

[48] A mesh network allows a network to have multiple pathways between network nodes that adjust automatically to conditions to allow for efficient and resilient routing of data to and from devices.

Exhibit 10.1.5.1: DTEE Current Network Technology Landscape

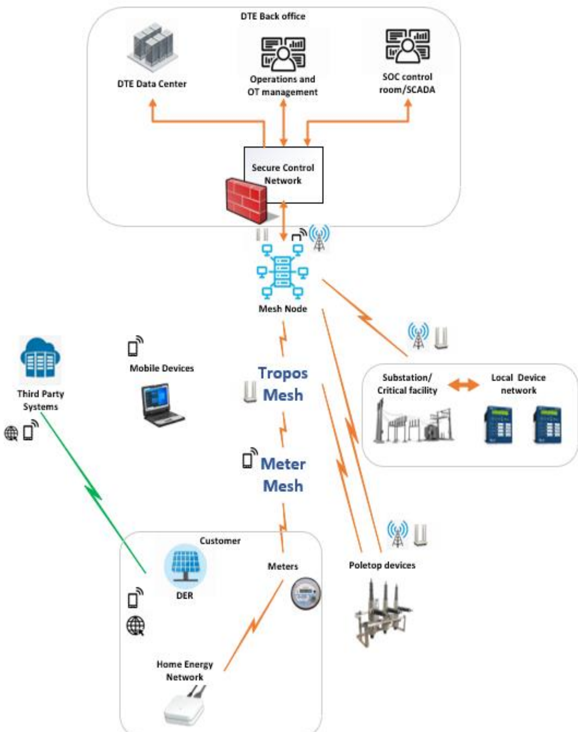
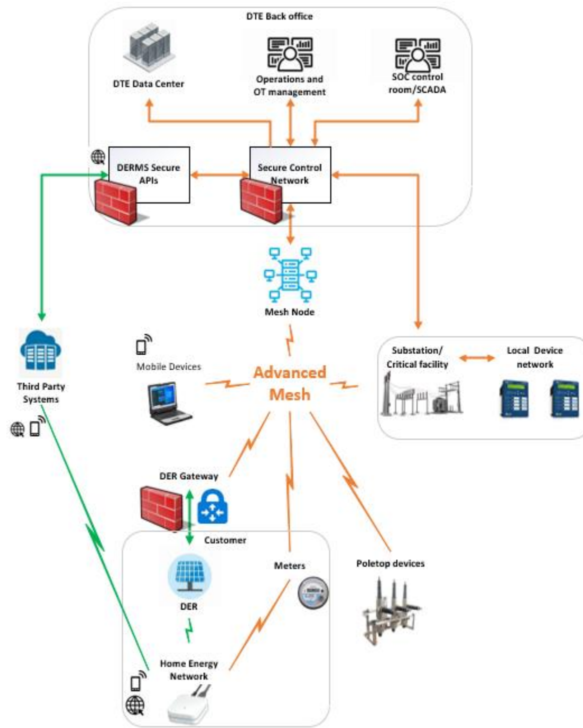


Exhibit 10.1.5.2: DTEE Future Network Technology Landscape



To date, more than 250 miles of new Company-owned fiber has been installed with a focus on connecting critical facilities such as data centers, service centers, power plants, substations, and other grid assets including metering communications towers. Many of the remaining routes will be coordinated with 40kV rebuilds to provide construction synergies and follow new truck accessible right of way. The program is also coordinated with the conversion and consolidation plan and automation plan to provide appropriate backhaul solutions to areas and minimize rework due to changing circuit configurations. Substantial completion of fiber installation is expected by 2028.

Between 2024 and 2028 fiber routers will be installed to complete fiber loops and provide communications to end points. This work will include installing communication poles, fiber entrances and taps along installed routes to make final connections into substations and support the advanced mesh network deployment with additional mesh nodes. The diagram also shows how other investments such as the DER gateway incorporate customer information into the communications network.

Asset tracking tools that provide updated information on the status of the communications network and troubleshooting will be enhanced as the fiber system is brought online. Visualization and analysis tools will be implemented to allow planning and operations to view the status and location of communication assets in real time. This includes integration of telecom monitoring software telemetry and the mapping system to provide real time visualization of network status and performance. Later investments will focus on supporting the advanced mesh network including anticipated licensing costs for dedicated frequencies.

CVR/VVO Program (Conservation Voltage Reduction / Volt-Var Optimization)

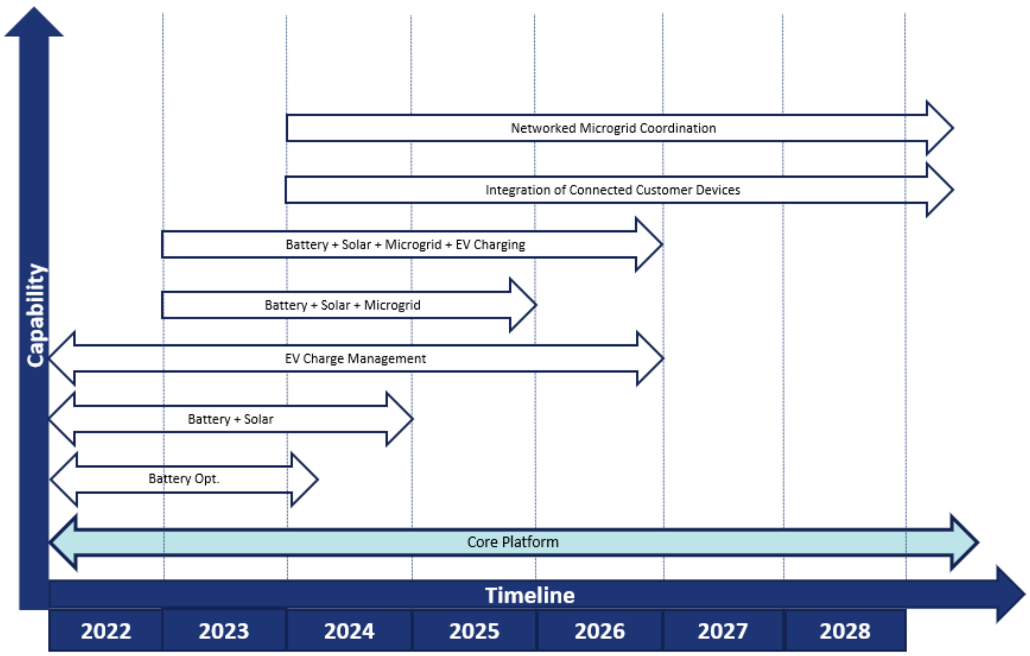
CVR/VVO was piloted in 2022 and the benefits to generation resource reduction were highlighted in the 2023 Integrated Resource Plan. In addition to the benefits of peak and energy reduction achieved with CVR/VVO, the program also provides more localized grid benefits including better voltage management and increased capability to support DER. Paired with the ADMS, controllable capacitors and voltage regulators installed by the program enable circuits to operate reliably in the lower portion of the allowable voltage range. This reduces energy consumption and allows more DER to be installed before high voltage concerns would arise. The capacitor placement and control program will be coordinated with the CVR/VVO program to replace aging capacitor controls on circuits in advance of CVR/VVO deployment. Details around these programs can be found in the Appendix Section C.1 - Grid Automation Investments.

NWA Projects

Non wire Alternative projects were discussed in more detail in the prior 2021 Distribution Grid plan, however, there have been some updates to the approach to NWA and DER integration. A key aspect of the Company's approach to NWAs is to have a consistent set of functionalities and controls. The initial NWA focus on single functions such as using battery storage for peak shaving or managing a battery with solar for smoothing. More advanced projects start to combine these functions together for further optimization and with microgrid capabilities, culminating in coordinated microgrids that implement some or all the optimization functions. The most advanced

NWA projects build on each other and integrate more functionalities such as combining energy storage management, solar management and EV charge management with monitoring and control of customer devices. Exhibit 10.1.1.3 below depicts the Company's levels of maturity and functionality for NWAs.

Exhibit 10.1.1.3: NWA Maturity and Functionality



Grid Edge Enablement, and Vehicle Electrification

The Grid Edge Enablement program and Vehicle Electrification Projects are implementing the functions and processes to enable DER and EVs to integrate with the grid so that these assets can be controlled by the utility to optimize the distribution system of the future. A key aspect of these programs is to coordinate the controls with grid automation devices and the ADMS applications to increase the value of DER and potentially minimize future investment. A standardized Interconnection Gateway (discussed in more detail in the Appendix C.1 Section - Grid Automation Investments) allows more software functions to be added to the gateway core platform, so that future projects benefit from a standardized approach in both controls design and processes.

The vision is to have a consistent hardware and software platform with modular functions that can be enabled as a project needs them. This allows for consistency of implementation, which can be communicated to customers early, and greatly reduces design and engineering costs once functions have been integrated.

AMI Future Planning

Advanced Metering Infrastructure (AMI) remains central to many of the Company's ongoing and upcoming capital investments. Originally designed and implemented to address real world customer challenges with billing accuracy and overall efficiency, DTEE implemented AMI to eliminate meter reading errors, reduce instances of estimated billing, and move away from manual meter reading. Over the last 14 years, DTEE has systematically executed to achieve those goals and as a result now has an industry-class system that delivers on those important customer-based outcomes.

In addition to these traditional use cases, supporting improved customer reliability has become critically important. AMI can help with many reliability efforts including locating system damage, determining what repairs are needed, determining each customer's power status, and reducing how often power is interrupted. These processes rely heavily on the AMI systems, which were not initially developed and implemented to deliver reliability benefits. While the Company continues to find ways to use the AMI system better, DTEE has reached the point where the future of AMI needs to be addressed to meet the reliability needs discussed above. It is essential that the AMI system of the future meet several criteria:

- Capable of different types of architecture because the Company now requires a design that can deliver reliable, near-real-time sensing of power status down to the meter level rather than simple historical meter usage information after the fact. Power status information would also require the ability to detect open neutrals.
- More resilient and fault tolerant so the AMI system can be used for operations in addition to using it for static billing, which was the original design basis.
- More flexible in its capabilities to allow for the use of different tariffs, and more specific time of day rates for various uses of energy.
- Capable of supporting new use cases including DERs, which requires more complex metering configurations to accurately separate generation, storage, and load and provide near-real-

time reads to inform the ADMS tools of important electrical grid variations due to EV charging, vehicle to grid support, energy shifting with storage, weather-dependent generation and active control schemes used by customers and third-party aggregators. New advanced meters may be able to provide control and submetering of separate connections at the same meter box which would greatly improve the management of DERs, EV charging, and demand response of large residential loads.

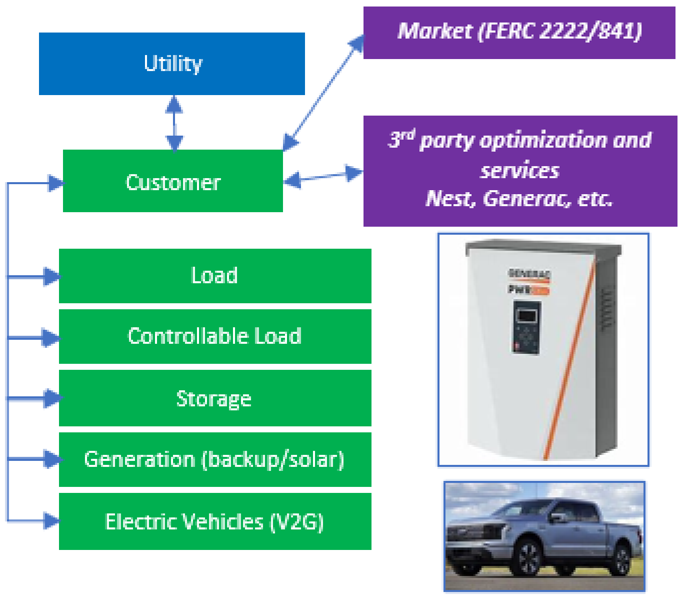
10.2 Operational Technology Roadmap

While the Grid Automation program forms the cornerstone of technology investments over the next five years, there are multiple other important investments being made which make up the Operational Technology roadmap; these are summarized in the investment area sections below. Within each section, we have also highlighted the investments and timing along with the corresponding applications and components of the DSPx model.

10.2.1 Grid Management Investments

Changes in customer capabilities such as controllable load, demand response, energy efficiency, on site generation, storage, electrification of HVAC and vehicles, vehicle to grid and microgrid technologies create needs for advanced grid management technologies. The diagram below (Exhibit 10.2.1.1) shows the various commercially available DER options to customers. In addition, these grid management technologies need to coordinate with advanced inverter and storage control modes that can produce or consume real and reactive power and impact gird performance. Individual DER in the field will need to be enabled to fully support this effort to unlock the benefits.

Exhibit 10.2.1.1: DER Options Commercially Available to Customers



Communication to end point devices and between end point devices is increasingly important as capacity margins decrease and less traditional stability is provided by central generating resources and variable power generation. The distribution system needs to be built for coordinated bi-directional power flow. Resources directly connected to the grid can include generation or storage and can have the potential to work as non-wire alternatives. To be able to provide Midcontinent Independent System Operator (MISO) requested grid services,[49] the assets need to be able to coordinate with other grid controls and other DER and have predictable behavior and interfaces. Operating and Planning processes also need to incorporate the capabilities of this new technology. These fundamental changes in customer capabilities form the basis for investment in DERMS (Distributed Energy Resource Management System) and enhancements to the ADMS, as the system used to manage the distribution grid, and to support coordination with DER.

[49]State of Common Grid Services Definition, retrieved on (09/21/2023), https://eta-publications.lbl.gov/sites/default/files/gmlc_state_of_grid_services_report.12.12.22.pdf

Objectives

- Visibility and control of the system
- Integration of Distributed Energy Resources
- Compliance to market and regulatory requirements
- Efficient management of automation assets and configurations

Key Investments

Exhibit 10.2.1.2: Key Investment Highlights for Grid Management

Key Investment	Use Case Description	Implementation Highlight and Customer Benefit	DSPx Objective
ASOC	Includes electronic displays and software/hardware that meet dispatcher and operator needs and mimic the current ESOC standards	Allows for a fully functioning, alternate location to carry-on the activities of the current Headquarters ESOC seamlessly, in the event of an emergency	Distribution Management System, Outage Management System
ADMS Enhancements	Enhance the integration, performance and capabilities of the ADMS	More efficient restoration and planned work coordination.	Enhances and further integrates components of the ADMS such as Real Time Power Flow Analysis, Distribution Management System, Outage Management System and Distribution Network model
EFC/PPS Storm Enhancements	Continue to improve customer outage status communications and storm response technology	More accurate outage status and restoration communications to customers and improved storm response systems	Outage Information
Meter Improvements	Improve meter situational awareness and use of energization as an outage management tool	Reduce improve outage estimates and communication, reduce okay on arrivals and improve dispatch of correct crew type	Advanced meters and Smart Meters, Operational Communications Outage Information

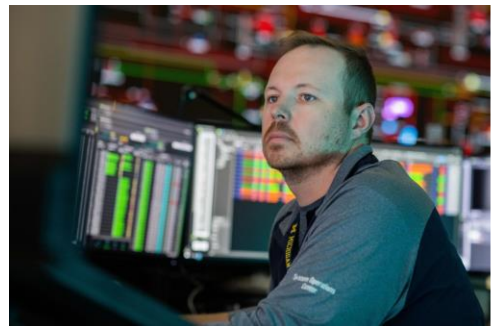
FLISR	Fault Location, Isolation and Service Restoration in ADMS	Minimize the scope of an outage through fault location and automated switching and optimizing restoration	DMS, Fault Analysis, SCADA, Automated Field Devices
DERMS Program	Distributed Energy Resource Management System provides interfaces for ADMS to communicate with DER, aggregations and market programs.	Optimize the dispatch of DER and offer new DER programs, integrate more DER into the system and improve the reliability of the grid	DER Portfolio Optimization, DER Management, Customer DER programs
Cyber security tools Program	Establish standardized tools, hardware and practices for maintaining cyber security at all points of the network	Harden the grid against cyberthreats	Cybersecurity of the operational communications network, Automated field devices, customer DER and interactions with DER Provider systems
Automation Configuration Database Project	Database for storage of relay and automated device settings. Replace existing database with an industry standard. Purchase new test sets that can automate settings and test management	Increase efficiency and accuracy of automation equipment installation and maintenance	Supports Operational data management for configurations and settings of SCADA, Automated field Devices and Advanced Protection

Exhibit 10.2.1.3: Key Investment and Timeline for Grid Management

Key Investment (in millions)	2024	2025	2026	2027	2028
ASOC	$3.9	-	-	-	-
ADMS Enhancements	$7.0	$7.0	$7.0	$7.0	$7.0
EFC/PPS Storm Enhancements	$5.6	$1.4	$1.4	$1.1	$0.4
Meter Improvements	$1.4	$1.4	$1.4	$2.8	$2.8
Microwave End of Life	$0.5	$0.5	$0.5	$0.5	$0.5
FLISR	$7.4	$6.4	$6.4	$6.4	$5.9
DERMS Program	-	$1.5	$2.8	$2.8	$2.8
Cyber Security Tools Program	$0.8	$0.8	$0.5	$0.5	$0.5

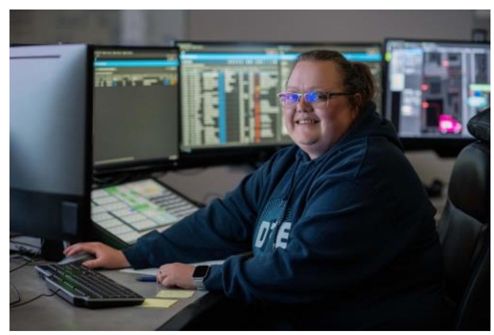
Automation Configuration Database Project	$1.4	$3.2	$3.2	-	-
Other Grid Management	$2.2	$3.5	$1.7	$1.4	$1.4
Total	**$30.2**	**$25.7**	**$24.9**	**$22.5**	**$21.3**

10.2.1.1 ASOC



ASOC is located inside the Waterford Service Center and is comprised of approximately 16,300 square feet with back-up generation and double redundancy for wireless and internet capabilities.

Construction on the Waterford Service Center in Waterford, Michigan, began in November 2022. The construction portion of the ASOC buildout will be completed in December of 2023, and completion of the furniture, fixtures and finishes as well as the technological fit out of the space will continue into 2024 for approximately 4-6 months. The ASOC is expected to achieve full NERC certification in 3rd quarter of 2024.



The design of both the ESOC and the ASOC is based on extensive benchmarking with many top tier utilities and industry experts. This facility includes electronic displays and software/hardware that meet dispatcher and operator needs and mimic the current ESOC standards. This will allow for a fully functioning, alternate location to carry-on the activities of the current Headquarters ESOC seamlessly, in the event of an emergency, as well as provide for the future training/re-training and testing of Emergency System Operation Centers employees. This will improve the resiliency of the system by providing redundancy.

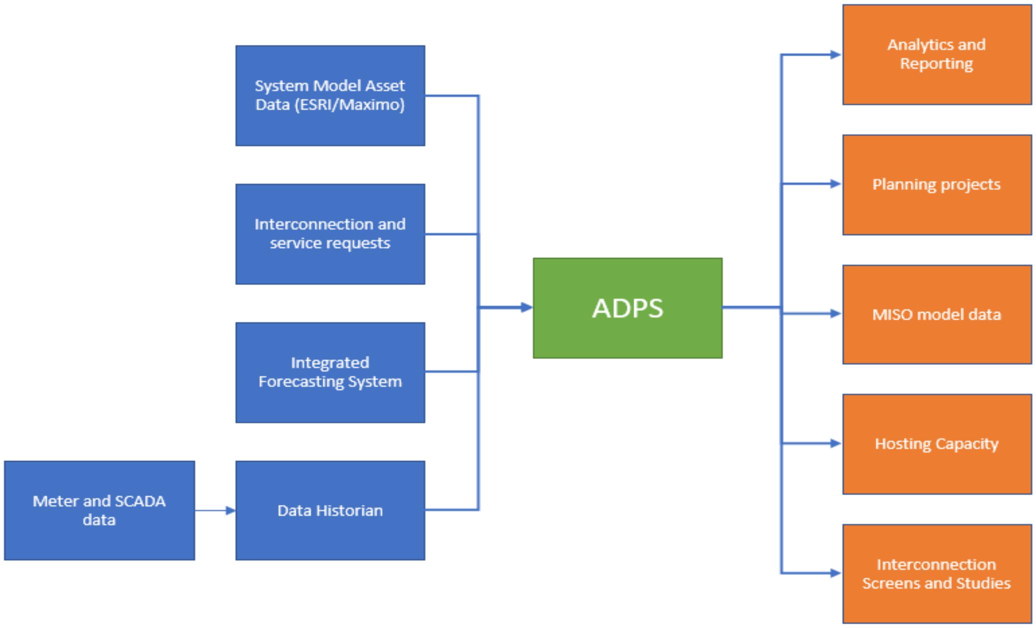
10.2.1.2 Core Grid Management

Primary control of the distribution system is through the ADMS (Advanced Distribution Management System). The OMS (Outage Management System) and DMS (Distribution Management System) portions of the ADMS system were deployed in February of 2023 and will continue to receive upgrades and enhancements throughout the 2024-2028 period as evolving customer trends and demands on the grid require them. The key area of investment over this period will be the activation and expansion of FLISR (Fault Locating and Isolation with Service Restoration). The ADMS FLISR application will be used to automatically determine the location of a fault and recommend and execute switching operations, restoring power quickly to those not directly impacted by a fault. FLISR is a key complement to the larger automation program, as it enhances the value of the distribution automation devices being deployed in the distribution automation section of the report.

10.2.2 Distribution Planning Investments

The Advanced Distribution Planning System (ADPS) is the name for a suite of planning tools that work together to model and plan distribution system investments discussed in this Distribution Grid Plan. Investments incorporate enhancements to existing tools, new tools, and interfaces to allow more frequent and accurate modeling of the distribution system and planned changes. ADPS is made up of a number of core components including CYME, Power Runner, SEEQ and PSSE. These individual tools are used by planning engineers in modeling grid impacts. The ADPS system is tied directly to the automation strategy as it implements the planning toolsets used to evaluate system loading and reliability benefits of automation installations. The longer-term investments in this category will support the grid modeling needed for the expected increased penetration of DER. This section addresses the investments in Hosting capacity, Interconnection processing, Distribution planning, Power Quality analysis, DER and load forecasting and power flow analysis.

Exhibit 10.2.2.1: General Configuration of the Advanced Distribution Planning System



Drivers (DER, MISO, AFS, FERC2222)

A roadmap for planning tool investments has been established to align with multiple regulatory requirements and the availability of more complex DER functionality that creates a need for more complex modelling and simulation of the electrical system and requires upgrades to planning tools. Traditional distribution planning has been focused on a single point in time for each year, the annual peak load. However, as DER become more common and dispersed throughout the distribution grid, the day to day and hourly variability of load and generation needs to be modelled to ensure the system is designed to reliably handle the variability in grid load and other characteristics.

Recent MPSC changes to the interconnection rules introduced screening criteria requiring utilities to perform rapid studies of circuit and line segment level minimum loading analysis. Future MISO modelling requirements through MOD-32 require studies to be done on gross load rather than net load, and disaggregation of all distribution DER by type of generation, voltage control mode, and dynamic models for distribution DER aligned to the transmission nodes in the MISO model.

FERC 2222 will require additional validation studies for distribution and aggregated DER that is seeking market participation and periodic restudy to validate that circuit operating criteria is not violated. In addition to the modelling tools themselves, investments are needed to properly contextualize the data for stakeholders while maintaining the security of the grid data and Critical Energy Infrastructure Information (CEII).

Peak loading and reliability analysis will continue to be a critical aspect of project planning for all projects, as it identifies times of maximum load current and areas that may experience low voltage and how circuits will be operated to improve reliability. This functionality is complicated by incorporating new DER which may mask the actual peak load or change how the system must be operated. Interconnection studies typically identify times of minimum or reverse power flow and high voltage as well as the impacts to the grid and are critical for complying with the interconnection and system modelling processes to ensure grid stability. DER in the form of storage requires analysis of available energy to charge and the ability for the circuit to handle the discharge. This analysis requires a more granular load allocation at the hourly level. Grid upgrades, customer loads, and DER interconnections simulations need to be coordinated and sequenced according to their construction schedules to ensure that the grid remains reliable during these significant changes.

With these complexities introduced through DER integration, the system design tools that perform studies for capital projects and operational verification need to be upgraded to incorporate forecasts, DER variability, time dependent loading and multi scenario analysis, and increased integration between distribution planning tools and subtransmission and transmission modelling. All these factors are considered and addressed in the ADPS investments. More details are provided in the Distribution Planning Investments Section-Appendix C.3.

Objectives

- Efficient grid simulation tools that incorporate DER and NWA analysis
- Multi scenario analysis and forecasting
- Regulatory compliance for interconnection and FERC rules
- Streamlined design tools that facilitate standards

Key Investments

Exhibit 10.2.2.2: Key Investment Highlights for Distribution Planning

Key Investment	Use Case Description	Implementation highlight and Customer Benefit	DSPx Objective
Network Management System (NMS) Phase 2	Management of GIS, asset and system model data for use by the ADMS and System Planning tools	Improved cohesion of utility data systems; enhanced accuracy of distribution model improves all functions that are essential to safe and effective planning, monitoring, and operation of the electrical grid	Operational Data Management, Distribution Network model
Load Allocation Analytics	Data consolidation and analytics platform that integrates hourly SCADA loading information, AMI loading and load forecast data into a single analytics and reporting engine that can be used by other operational and planning tools and distribution system programs	Improved accuracy of system loading models improves results of distribution planning analysis leading to better project designs and more efficient investment of capital system improvements.	DER & Load Forecasting, Operational and Data Management, Locational Value Analysis
CYME Enhancements Program	Distribution planning tool enhancements to incorporate power runner data to perform hourly multi scenario analysis for DER and system improvements	More accurate distribution system planning leading to optimized distribution system capital investments, more integration of DER, Storage, Non-Wire Alternatives and being prepared for electrification.	Power Quality Analysis, Fault Analysis, Power Flow analysis, Probabilistic Planning, Locational Value Analysis
Forecasting and Propensity Analysis Program	Analysis tools to create locational forecast scenarios for DER and electrification adoption, integrate with system load forecasting and feed this data to planning tools	Improved mid to long range scenarios to evaluate distribution planning projects against to better optimize capital investments.	DER & Load Forecasting, DER Portfolio Optimization, Probabilistic Planning

Interconnections Process Enablement Program	Improvements to Interconnection tools and processes, Compliance requirements for State and Federal Interconnection programs	Streamlined interconnection application, screening, and study	DER Management, Customer DER Programs, Customer DER Decision Support Analytics
Hosting Capacity Program	Enhancements to publicly accessible Hosting Capacity data resolution, updates and inclusion of Loading capacity	Improved customer access to system data relevant to new DER and load integration	Hosting Capacity, Customer DER Decision Support Analytics, Grid Data Portal, DER provider Data
Sub transmission planning Program	Sub transmission planning tool enhancements integrate distribution system and DER data and keep compliant with MISO modeling requirements	More accurate sub transmission system planning leading to optimized system capital investments and system resiliency planning, more integration of DER, Storage, Non-Wire Alternatives and being prepared for electrification	Power Quality Analysis, Fault Analysis, Power Flow analysis, Probabilistic Planning, Locational Value Analysis, Dynamic Analysis
Power Quality Analysis Program	Tools to improve the collection, processing and analysis of faults, grid disturbances and power quality events	Improved detection of grid anomalies and root cause analysis of outages and failures will help identify future outage risks, eventually leading to incipient failure detection and proactive measures to mitigate or prevent outages where possible	Power Quality Analysis, Fault Analysis, Dynamic Analysis
Substation and Structural Design Program	Structural and CAD Design tool enhancements to improve design accuracy, efficiency, standardization, and compliance	More efficient and timely design of capital investment projects	Supports engineering, design, and Implementation of Physical grid Infrastructure

Exhibit 10.2.2.3: Key Investment and Timeline for Distribution Planning

Key Investment (in millions)	2024	2025	2026	2027	2028
NMS Phase 2	$1.6	$2.8	$2.1	$1.5	-
Load Allocation Analytics	$2.2	$1.0	$2.0	$2.5	$0.8
CYME Enhancement program	$1.3	$1.5	$1.5	$1.5	$1.5
Forecasting and propensity analysis Program	$0.2	$1.8	$0.7	$0.4	$1.5
Interconnections process enablement Program	$1.9	$1.7	$1.7	$1.8	$1.5
Hosting Capacity Program	$0.5	$0.3	$0.4	$0.3	$0.5
Sub transmission planning Program	$0.4	$0.3	$0.3	$0.3	$0.3
Power Quality Analysis Program	$0.4	$0.5	$0.4	$0.5	$0.4
Substation and structural design Program	$1.9	$1.2	$1.5	$0.8	$0.5
Other Distribution Planning	$1.6	$2.2	$0.5	-	-
Total	**$12.0**	**$13.3**	**$11.1**	**$9.6**	**$7.0**

10.2.3 Work Management and Scheduling Investments

As DTEE increases investments in its distribution grid and focuses on automation, the higher workload and job complexity will require the company to advance its work management systems and processes. The work management process includes scheduled and unscheduled work, work order creation, resource scheduling, and tracking work execution for employees, vendors and third-party crews. Work management tools also include job planning, labor, material, tools and services for both large, complex work efforts and smaller, short-term jobs. Upon completion, work must be audited and verified for payment purposes.

Objectives

- Visibility into the status of work as it moves through the planning, scheduling and execution pipeline

- Awareness of crew and contract resource availability on a weekly and daily basis
- Schedule optimization and prioritization
- Ensure all time worked is properly applied to jobs
- Ability for all resources executing work to access electronic job information and electronically verify completion

Key Investments

Exhibit 10.2.3.1: Key Investment Highlights for Work Management and Scheduling

Key Investments	Use Case Description	Implementation highlight and Customer Benefit	DSPx Objective
DO Maximo Transformation	Implementing a separate Maximo environment for DO to support DTEE-specific processes and optimizations	Increased operational efficiency with planned work will lead to faster modernization of the grid	Operational Data Management, management of Physical Grid Infrastructure and Distribution Network Model information
Enhance Maximo capabilities and processes	Optimizing Maximo for electric distribution operations and work management	Increased operational efficiency with planned work will lead to faster modernization of the grid	Operational Data Management, management of Physical Grid Infrastructure and Distribution Network Model information, Scheduling of Physical Grid Infrastructure
Substation Reporting and Process Enhancements	Expand integration to include crew work data within Maximo	Improved productivity will maintain service affordability	Operational Data Management
Primary Service Orders Replatform	Replatform the technology that supports processes that serve primary customers	Faster restoration outcomes for primary customers	Operational Data Management, Distribution Network Model and GIS
External Crew Efficiency	Collect and process work time and associated data from external crews performing work for DTEE	Streamlined crew tracking will reduce administrative costs associated with this work and maintain service affordability	Operational Data Management

Exhibit 10.2.3.2: Key Investment and Timeline for Work Management and Scheduling

Key Investment (in millions)	2024	2025	2026	2027	2028
DO Maximo Transformation	$4.2	$7.0	$7.0	$7.0	-
Enhance Maximo capabilities and processes	-	$0.8	$1.1	$1.4	$2.1
Substation reporting and process enhancements	$0.4	-	-	-	-
Primary Service Orders Replatform	$2.0	$4.1	$1.1	-	-
External Crew Efficiency	$2.0	$0.8	-	-	-
Other Work Mgmt & Scheduling	$1.4	$1.0	$0.6	-	-
Total	**$10.0**	**$13.7**	**$9.8**	**$8.4**	**$2.1**

10.2.4 Asset Management Investments

Managing the electric grid relies heavily on maintaining and replacing distribution assets, thereby requiring systems that can effectively manage this critical function. The overall goal of effectively managing assets is to minimize the total cost of ownership and operations while delivering desired service levels. This includes maintaining access to accurate digital data about the asset, algorithms to process and analyze data, and a visual context of an asset's location and condition.

Objectives

- Ability to manage asset processes online or offline, regardless of wireless connectivity
- Improved timeliness of asset updates from the field and support for map-centric asset management
- Ability to track labor, materials, and tools charges by all asset types and linear measures
- Increased presence and frequency of asset assessments to better monitor asset health
- Modernization of asset tracking through mobile technology, including health and location monitoring.

Key Investments

Exhibit 10.2.4.1: Key Investment Highlights for Asset Management

Key Investment	Use Case Description	Implementation Highlight and Customer Benefit	DSPx Objective
ESRI ArcGIS updates	Update and rearchitect ArcGIS system to eliminate redundancies	Streamlined architecture reduces overall cost of ownership and improves management of operational data	Operational Data Management, GIS
ESRI Utility Network Proof of Concept	Assessment and pilot of ESRI utility Network Model conversion and its impacts	Prepare for a successful transition to the Utility Data Model	Operational Data Management, GIS, Distribution Network Model
ESRI Map Data Conflation	Accurate positioning of GIS data to geo located coordinates and spatial data sets	More accurate right of way, maps, asset locations design to enable more efficiency in capital improvements	Operational Data Management, GIS, Distribution Network Model
ESRI Utility Network Conversion	Conversion of the ESRI database to the industry standard Utility Network Model and associated tools and processes	Improvements in data structures and management that more accurately reflects the electrical and physical systems of the grid and the change management processes for installing, maintaining and removing assets enabling much more efficiency updates to the ADMS and system planning tools and data interchange of system model information	Operational Data Management, GIS, Distribution Network Model
ESRI Field Tool Integration	Filed data capture of As Built designs, asset status and as found conditions	Improved accuracy of distribution system model, asset condition and field markup increases the efficiency and accuracy of all of the ADMS and planning and design tools leading to greater efficiency	Operational Data Management, GIS, field Capture of Physical Grid Infrastructure changes, Distribution Network Model

		of capital investment and trouble resolution	
Asset Assessment Frequency	Real time assessment of asset health	More targeted identification of assets that might need maintenance or replacement	Operational Data Management, Asset management of Physical Grid Infrastructure
Systematic Tracking of Rotatable Assets	Tracking rotatable assets and tools through their lifecycle using RFID	More effective maintenance of rotatable assets	Operational Data Management

Exhibit 10.2.4.2: Key Investment and Timeline for Asset Management

Key Investment (in millions)	2024	2025	2026	2027	2028
ESRI ArcGIS updates	-	$0.6	-	$1.1	$0.6
ESRI Utility Network Proof of Concept	$1.1	-	-	-	-
ESRI Map Data Conflation	$0.3	$2.2	$1.4	$1.4	$1.1
ESRI Utility Network Conversion	-	-	$4.2	$4.2	$5.6
ESRI Field Tool Integration	-	-	-	$2.8	$2.1
Asset assessment frequency	-	-	$0.4	-	-
Systematic Tracking of Rotatable Assets	-	$0.6	-	-	-
Total	**$1.4**	**$3.4**	**$6.0**	**$9.5**	**$9.4**

10.2.5 Mobile Technology Investments

The goal of mobile technology investments is to create seamless transitions between on-line and off-line operations and provide integrated communication, including workflows, between the control room, field leaders, field crews, and supporting organizations. Mobile capabilities include both devices and applications that are engineered for mobile access and usage. Applications include dispatch, work execution and forms digitization, location tracking, route navigation, analytics and secure file sharing.

Objectives

- Enhance daily work through mobile tools that provide timely and accurate information, as well as allow quick and easy capture of critical data in the field (including photos, markups, and videos)
- Enable point-of-activity applications that increase worker and leader time in the field
- Deploy optimized, task-based applications and mobile access to all intra-company systems and documents
- Improve time tracking of field workers work execution
- Modernize field crew tools and technologies to gain efficiencies through reduced manual effort, improved data quality, and accelerated customer service, including faster restoration and improved reliability

Key Investments

Exhibit 10.2.5.1: Key Investment Highlights for Mobile Technology

Key Investment	Use Case Description	Implementation Highlight and Customer Benefit	DSPx Objective
Mobile Tools Expansion	Expand tools that allow workers to execute their work completely from the point of activity	Improved efficiency through point-of-activity data transactions; increased employee engagement; centralized operational data through system integrations	Operational Data Management
Maintain Compliance	Ensure compliance with regulatory and industry mandates and requirements	Continued compliance with all relevant mandates around the use of operational, customer, and payment data	Operational Data Management

	related to the use of operational data		
Enhance and Expand Cybersecurity	Maintain cybersecure technologies that remain safe against the expanding threat landscape	Heightened security vigilance maintains security and integrity of customer and operational data	Operational Data Management
Mobile Equipment Replacement	Replace end-of-life mobile hardware used by field workers	Field workers that can execute work from the field without interruption	Operational Data Management

Exhibit 10.2.5.2: Key Investment and Timeline for Mobile Technology

Key Investment (in millions)	2024	2025	2026	2027	2028
Mobile Tools Expansion	$1.1	$0.8	$0.7	$1.1	$1.1
Compass Mobile Tool	$1.6	-	-	-	-
Maintain Compliance	$0.6	$0.6	$1.1	$0.6	$0.4
Enhance and Expand Cybersecurity	$0.8	$0.8	$0.8	$0.8	$0.8
Mobile Equipment Replacement	$2.8	$2.8	$1.4	$4.2	$7.0
Other Mobile Technology	$1.3	$0.8	$1.1	$1.0	$1.0
Total	$8.2	$5.8	$5.1	$7.7	$10.3

11 Summary of Investment Plan

The overall investment levels are shown in Exhibit 11.0.1, with more detail by pillar and program shown in Exhibit 11.0.2. These investments represent all capital investments, and the two key maintenance programs (tree trimming and preventive maintenance).

Exhibit 11.0.1 Projected Distribution Grid Plan Investments

		$ Millions					
Category		2024	2025	2026	2027	2028	5-Year Total
Capital Investments ($ Millions)							
Base Capital	Emergent Replacements (Reactive Trouble and Storm Capital)	$415	$399	$368	$348	$345	$1,877
Base Capital	Customer Connections, Relocations and Others	$282	$295	$314	$334	$355	$1,580
Strategic Capital Programs (details in Exhibit 11.0.2)		$906	$995	$1,134	$1,302	$1,485	$5,821
Total Capital Investments		**$1,603**	**$1,689**	**$1,816**	**$1,985**	**$2,185**	**$9,278**
Maintenance Programs ($ Millions)							
Tree Trimming		$123	$140	$101	$103	$106	$573
Preventive Maintenance		$10	$10	$10	$10	$10	$50

Exhibit 11.0.2 Projected Distribution Grid Plan Investments (Sorted by Reference Section Number)

Programs	$ Millions						Reference Section #
	2024	2025	2026	2027	2028	5-Year Total	
Infrastructure Resilience & Hardening							
Pole and Pole Top Maintenance and Modernization	$121	$121	$151	$192	$188	$773	8.1

4.8 kV Hardening	$80	$95	$54	-	-	$229	8.2
4.8 kV Automatic Pole Top Switch (APTS)	$5	$5	$7	$7	$7	$32	8.3.1
SCADA Pole Top Device	$2	$2	$2	$3	$5	$14	8.3.1
Steel Pole Highway Crossings	$3	$5	$5	$5	$5	$25	8.3.1
System Cable Replacement	$21	$20	$20	$20	$20	$102	8.3.2
Underground Residential Distribution (URD) Cable	$15	$15	$15	$15	$15	$75	8.3.2
Subtransmission Disconnect Switches	$3	$3	$3	$3	$3	$15	8.3.3
Circuit Switchers	$2	$2	$2	$2	$2	$10	8.3.3
Circuit Breakers	$14	$15	$15	$15	$15	$74	8.3.3
Substation Regulators	$1	$1	$1	$1	$1	$4	8.3.3
Batteries & Chargers	$3	$3	$3	$3	$3	$15	8.3.3
Substation Outage Risk	$51	$2	$6	$17	$17	$92	8.5
Station Upgrades	$5	$9	$14	$8	$4	$40	8.5
Mobile Fleet	$5	$2	$2	$2	$2	$12	8.5
Frequent Outage (CEMI) including Circuit Renewal	$48	$20	$20	$20	$20	$128	8.6
Infrastructure Redesign & Modernization							
System Loading	$47	$75	$59	$100	$100	$381	9.1
Subtransmission Redesign & Rebuild	$100	$100	$108	$108	$108	$524	9.2
4.8 kV Conversion and Consolidation	$76	$76	$195	$253	$320	$919	9.3

City of Detroit Infrastructure (CODI)	$95	$126	$148	$119	$90	$579	9.3
8.3 kV Conversion and Consolidation	$19	$31	$29	$18	$18	$114	9.3.7
Strategic Undergrounding	$15	$5	-	-	-	$20	9.4
Technology & Automation							
Grid Automation	$62	$163	$191	$309	$469	$1,192	10.1
Grid Automation Telecommunications	$17	$15	$14	$13	$11	$69	10.1
CVR/VVO	$5	$5	$5	$5	$5	$25	10.1
Capacitor Replacement and Control Program	-	$6	-	-	-	$6	10.1
NWA Projects	$15	$1	$0	-	-	$16	10.1
Grid Edge Enablement program	$6	$4	$4	$3	$3	$20	10.1
Vehicle Electrification Projects	$3	$1	$1	$1	$1	$6	10.1
Line Sensors	$1					$1	10.1
URD Fault Indicators	$3	$3	$3	$3	$3	$15	10.1
Large/Medium Sized DER Monitoring and Control	$0	$0	$0	$0	$0	$2	10.1
New Technology Evaluation Program	$1	$1	$1	$1	$1	$5	10.1
Grid Management	$30	$26	$25	$23	$21	$125	10.2.1
Distribution Planning	$12	$13	$11	$10	$7	$53	10.2.2
Work Management and Scheduling	$10	$14	$10	$8	$2	$44	10.2.3
Asset Management	$1	$3	$6	$10	$9	$30	10.2.4
Mobile Technology	$8	$6	$5	$8	$10	$37	10.2.5

12 Work Prioritization

12.1 Investment Selection Methodology

A robust method to evaluate and prioritize investments in the electric grid is fundamental to developing an investment plan that delivers the most benefit for customers. The gaps to future state were discussed in Section 5, and the investments that will help close those gaps are discussed in Sections 7 through 10. The investment needed to fully close these gaps is substantial and will require investments beyond the timeline of this DGP. The goal of the Company's investment selection methodology is to evaluate programs and projects and prioritize the funding of investments which deliver the broadest set of benefits to our customers and improvements to our grid within our capital portfolio.

The DSPx framework describes some of the challenges of evaluating traditional grid investments. The first challenge is that grid investments often provide multiple benefits, which can be impossible to disaggregate. For example, converting an overhead circuit to a higher voltage will provide increased capacity, improved safety and better reliability. A new substation, particularly one which replaces an older substation, will reduce the risk of a major substation outage, provide capacity for new load and reduction of emergent costs. Both types of projects deliver multiple interconnected benefits as part of the investment. The second challenge is that most of these benefits, such as safety, reliability and risk, cannot be easily or appropriately translated into a dollar amount. These two challenges to quantifying project benefits are referred to as "joint and interdependent benefits." To prioritize investments with joint and interdependent benefits, a simple analysis comparing costs to benefits cannot be undertaken. Rather, the GPM is based on an economic evaluation method known as "best-fit, most-reasonable cost."

DTEE has used this method to prioritize investments since the Global Prioritization Model (GPM) was developed in 2018. The most recent update of the GPM measures ten separate benefits that projects and programs deliver to customers. Each benefit is called an 'impact dimension,' and each impact dimension has one or more drivers which are measured to quantify a benefit. Projects and programs are given scores in each dimension (generally ranging from 0 to 100) based on the amount of expected benefit divided by the total investment (in most cases). Projects that deliver more benefits per dollar invested will receive higher scores in that dimension. The score in each dimension is multiplied by a weighting factor for that dimension. The weighting factors enhance the scores of projects that provide benefits in core reliability and safety. The dimension scores are added together to provide a total project or program score. The projects and programs with the higher scores provide more benefits and are prioritized for implementation. This method results in a portfolio where projects that deliver the most value improving safety, reliability, and load relief, are prioritized for earlier investment. The list of impact dimensions and weightings are shown in Exhibit 12.1.1 below.

Exhibit 12.1.1 Global Prioritization Model Impact Dimension

Impact Dimension	Drivers	Weight
Reduce Electrical Hazards	• Reduction in wire down events • Reduction in secondary network cable manhole events	3
Overload Relief	• Elimination of overloaded equipment	
SAIDI	• Reduction in duration of outage events	
SAIFI	• Reduction in frequency of outage events	
Regulatory Compliance	• MPSC staff's recommendation (March 30, 2010 report) on utilities' pole inspection program • Docket U-12270 – Service restoration under normal conditions within 8 hours • Docket U-12270 – Service restoration under catastrophic conditions within 60 hours	2

	• Docket U-12270 – Service restoration under all conditions within 36 hours • Docket U-12270 – Same circuit repetitive interruption of fewer than five within a 12-month period	
Major Event Risk	• Reduction in extensive substation outage events that lead to a large amount of stranded load for more than 24 hours	
Capacity Relief	• Elimination of system capacity constraints	
Investment in EJ Communities	• Percent of customers impacted by investment in EJ communities	
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	

The Company has made four enhancements to the GPM model based on input from stakeholders and the Commission, and in line with the enhancements that were discussed in the 2021 DGP.

1) The impact dimension which was previously named “Load Relief” has been divided into “Overload relief” and “Capacity relief.” The former addresses equipment which is overloaded under normal conditions. Capacity relief addresses substations operating over firm and many of the planning criteria on the subtransmission system. This dimension also incorporates the 15-year loading forecast that will more fully incorporate potential customer adoption of new technologies such as EVs and DER.
2) The impact dimension of “SAIFI” was added to complement SAIDI, and account for reduction in frequency of outages as well the overall importance of improved reliability.
3) “Investment in EJ communities” was added to formally incorporate prioritization of EJ communities into the investment planning process
4) The weighting of dimensions was simplified and changed from a 10-point scale to a 3-point scale.

The intent of these changes is to more fully account for the grid benefits that many of the investments bring to our customers, to incorporate feedback heard about the GPM, and to simplify the framework. These updates to the GPM were presented at the DGP Technical Conference on August 31, 2023.

12.1.1 Interruption Cost Estimate (ICE) Calculator 2.0 and the Value of Reliability

As discussed above, many of the benefits which grid investments deliver are quantifiably but not easily translated into monetary terms. Reliability improvements fall into this category. One commonly used method to value reliability is the ICE calculator, which was developed by Lawrence Berkeley National Laboratory (LBNL). In the 2021 DGP, the company discussed many of the limitations of this version of the ICE calculator.

To provide more meaningful results quantifying the value of reliability, LBNL is developing the second iteration of the calculator, ICE 2.0. DTEE is a sponsoring utility for the development of this updated tool. As a sponsor, LBNL and DTEE are currently surveying DTEE customers across residential, commercial, and industrial segments, to quantify what economic impact outages have of them. This work will close gaps from the first ICE tool, which relied on decades old data and did not have a significant sample of Midwest customers or customers living in colder climates. The updated tool is expected to be released in 2024.

12.2 Environmental Justice

Environmental justice (EJ) is an evolving planning principle within DTEE's DGP.[50] DTEE established its commitment to EJ communities when first addressing them in the development of the 2021 DGP and then in the 2022 Integrated Resource Plan (IRP). Since then, the Company has taken measures to further incorporate EJ into distribution planning and continues to increase the meaningful engagement of customers within its vulnerable communities. The desire for this consideration of EJ was expressed clearly in the feedback DTEE collected from customers, leaders within vulnerable communities, and other stakeholders.

12.2.1 Identifying and Investing in Vulnerable Communities

The Company first began working on the concept of EJ in distribution planning with the 2021 DGP filing. Since the publication of that plan, the State of Michigan published the MiEJScreen tool,[51]

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[50] Under the MI Healthy Climate Plan, environmental justice is defined 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 See MI Healthy Climate Plan: https://www.michigan.gov/egle/-/media/Project/Websites/egle/Documents/Offices/OCE/MI-Healthy-Climate-Plan.pdf?rev=d13f4adc2b1d45909bd708cafccbfffa&hash=99437BF2709B9B3471D16FC1EC692588,accessed September 5, 2023:

[51] MiEJScreen: Environmental Justice Screening Tool (DRAFT) (michigan.gov)

which the Company now uses to identify vulnerable communities within the electric service territory. DTEE defines vulnerable communities as those with a composite MiEJScreen score at or above the 80th percentile. There are 483 census tracts in DTEE's service territory that meet this definition. These 483 census tracts represent 29% of the total census tracts in DTEE's service area and account for approximately 550,000 residential customers. By leveraging the census tract-specific EJ scores provided by the MiEJScreen tool, DTEE has been able to map reliability and investment projects and programs relative to where the most vulnerable customers reside.

Through this mapping, the Company is able to create a geographic representation of reliability data across the Company's service territory. Using the residential customer meters that are matched to census tracts, DTEE associated 2022 reliability data for SAIDI and SAIFI by census tract and grouped the data into DTEE reliability quartiles, with first quartile customers (shown below in green) experiencing the best reliability, and fourth quartile customers (shown below in red) experiencing the worst reliability. See Exhibit 12.2.1., Exhibit 12.2.1.2, Exhibit 12.2.1.3, and Exhibit 12.2.1.4 for maps with systemwide 2022 reliability quartile for vulnerable census tracts within DTEE service territory.

Exhibit 12.2.1.1 2022 All Weather SAIDI by Census Tract for DTE Electric (Full Electric Service Area)

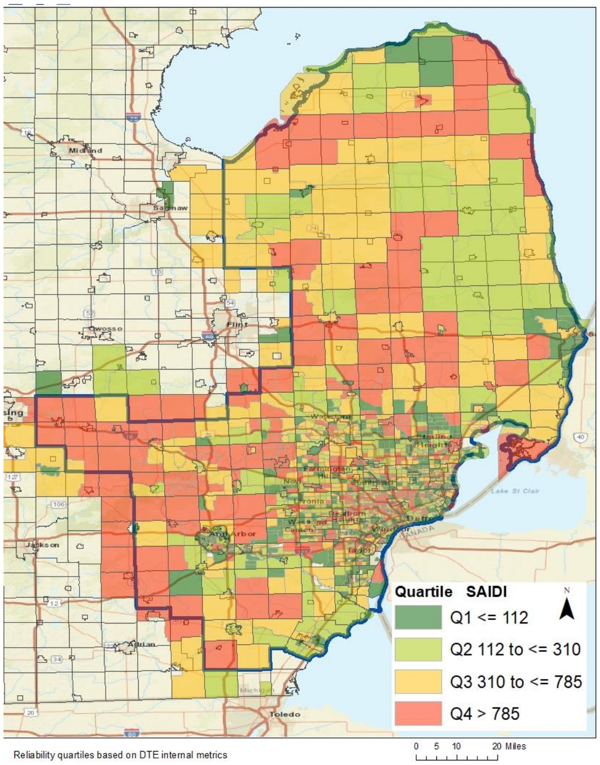


Exhibit 12.2.1.2 2022 All Weather SAIDI for Vulnerable Census Tracts with MiEJ Score of 80% to 100%

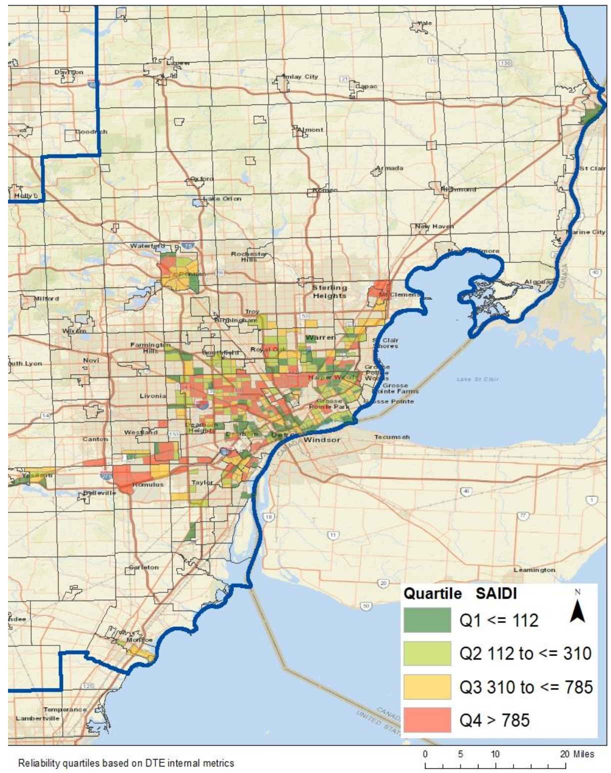


Exhibit 12.2.1.3 2022 All Weather SAIDI by Census Tract for DTE Electric (Metro Detroit Area)

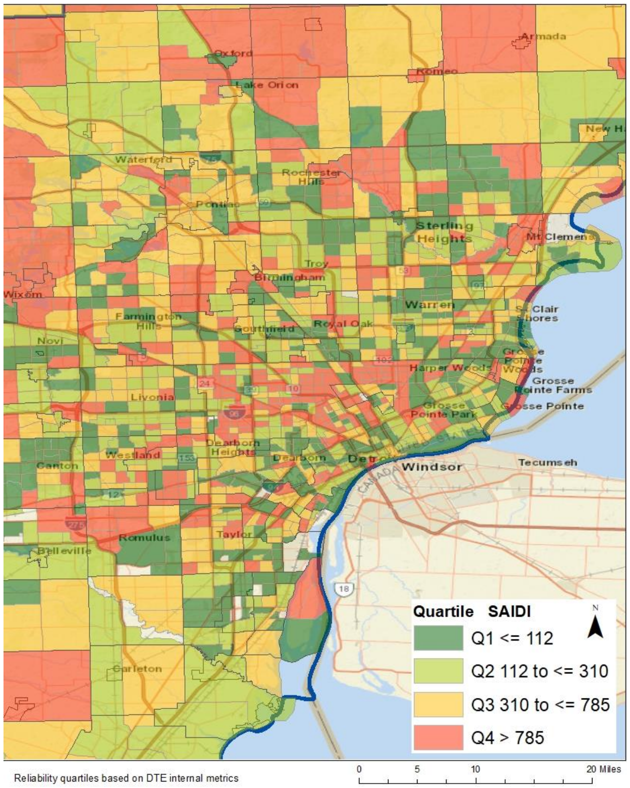
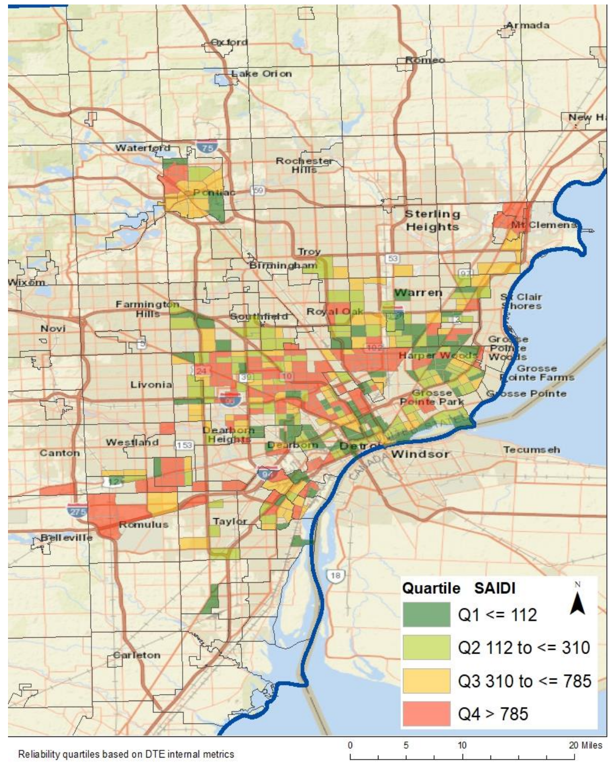


Exhibit 12.2.1.4 2022 All Weather SAIDI for Vulnerable Census Tracts with MiEJ Score of 80% to 100% (Metro Detroit Area)



The Company conducted analysis to evaluate the reliability performance of census tracts in the vulnerable communities compared to the rest of the DTE Electric. The analysis of reliability performance in DTEE's vulnerable communities demonstrates that the investments the Company has focused on vulnerable communities, in particular the City of Detroit, have resulted in improved reliability. The 483 census tracts have a range of performance that spans from first quartile to fourth quartile reliability performance in years 2020 through 2022 for SAIDI and SAIFI compared to the systemwide levels (see Exhibit 12.2.1.5). In addition, the Company conducted an analysis of its investment programs to assess how they are reaching vulnerable communities as shown in Exhibit 12.2.1.6. This analysis demonstrates that the Company has made significant distribution investments in its vulnerable communities in the past five years and plans to continue that investment into the future.

Exhibit 12.2.1.5 Reliability Performance of Vulnerable Census Tracts (MiEJ Score of 80% to 100%) Versus System Average

	2020	2021	2022
All weather SAIFI vulnerable communities	1.06	1.30	1.12
All weather SAIFI system average	1.29	1.58	1.25
Ex-MED SAIFI vulnerable communities	0.81	0.75	0.81
Ex-MED SAIFI system average	1.01	0.92	0.98
All weather SAIDI vulnerable communities	356	823	732
All weather SAIDI system average	352	927	584
Ex-MED SAIDI vulnerable communities	134	116	130
Ex-MED SAIDI system average	142	136	146

(green)	Over performing system average
(red)	Under performing system average
(white)	System average

Exhibit 12.2.1.6 Investments in Vulnerable Communities (Census Tracts with MiEJ Score of 80% to 100%)

Investment Program	% Of Investment in Vulnerable Communities	
	(2018 – 2022)	(2023-2026)
Conversion	75%	86%
4.8kV Hardening	89%	93%
Tree Trim	30%	14%[52]

In addition to these studies, in Order U-20836 dated September 18, 2022, the Commission requested that DTEE work with Staff and interested stakeholders to conduct a study examining the impacts of both socioeconomic data analysis and more comprehensive analysis of alternatives for the 4.8 kV system within the Company's metro Detroit fiber loop.

Further discussion of the study including study results is included in Appendix E.

12.2.2 Engaging Vulnerable Communities in Distribution Planning

DTEE has been engaging customers in its vulnerable communities on the topic of distribution planning. Conversations with community members generated key themes, including:

- A desire to understand reliability performance at the local community level and compared to other communities
- How the investment programs identified in the DGP will translate into investment plans at the local level
- Timing of local investments
- Reliability improvement expected from investments

To continue these conversations, DTEE is keeping lines of communication open through direct conversations via meetings with block clubs, homeowners associations (HOAs), and resident meetings and with community leaders from faith-based organizations, social services agencies,

[52] Tree Trim has not finalized the circuits to be trimmed in 2024 and beyond.

advocacy organizations, and others. Detailed discussion of DTEE's overall engagement plan can be found in Section 14.2, Community Engagement.

12.2.3 Environmental Justice Plan and Actions

While DTEE is proud of the progress made to support vulnerable communities, the Company recognizes there will be ongoing efforts to ensure that the vulnerable communities continue to see improvements. Building on the 2021 DGP, the Company developed three key EJ objectives for the 2023 DGP:

1. Incorporate EJ considerations in investment decisions by including an EJ component in the Global Prioritization Model (GPM)
2. Improve system performance for vulnerable communities with the worst reliability through our investment programs (Tree Trim, PTMM, Conversion, Customer Excellence and 4.8kV Hardening)
3. Provide support to vulnerable customers experiencing outages during storms through community outreach efforts

Update Global Prioritization Model: For the 2023 DGP, EJ is now incorporated into the updated GPM model see Section 12.1. Exhibit 12.2.1 illustrates the addition of "Investment in EJ communities" as a new GPM impact dimension. All other criteria being equal, projects in vulnerable communities will have a higher GPM score and will therefore be prioritized over other projects with a similar GPM score based on the other impact dimensions. This will ensure that vulnerable communities are specifically considered in the prioritization process.

Improve System Performance: DTEE has identified 191 circuits in vulnerable communities which fall in the fourth quartile for reliability performance based on a five-year historic average. As shown in Exhibit 12.2.3.1, about 1/3 of the fourth quartile reliability circuits have already had a recent reliability investment and 2/3 of the circuits are planned to be addressed in 2023-2026 investment programs.

Exhibit 12.2.3.1 Investment of Circuits in EJ Communities that Falls in the 4th Reliability Quartile

Investment Category	191 total circuits in EJ communities fall within the 4th reliability quartile	
	68 circuits had work completed 2018-2022	123 circuits have work planned 2023-2026
Conversion	1	11
4.8kV Hardening	49	88
Tree Trim	12	20
Subtransmission Upgrades	1	0
CEMI Program	5	0
Technology and Automation	0	4

Outage Response: DTEE continues to evolve outage response strategies supporting customers with considerations of impacts in vulnerable communities. Our storm response initiatives ensure relief is provided to vulnerable communities by deploying community vans with essential supplies, supporting warming and cooling centers, in vulnerable communities, performing safety checks at the homes of senior customers and by ensuring there is clear and consistent communication to all affected customers and community leaders during a storm event.

Conclusion

DTE Electric has made progress and plans to further evolve considerations of Environmental Justice in distribution planning over time, ensuring that the most vulnerable communities continue to see improvements. The Company will proactively monitor the progress of the ongoing and planned work in the EJ communities for reliability improvements and continue collaborating with customers and other stakeholders. Additionally, DTEE is joining forces with the MPSC and other stakeholders on potential Infrastructure Investment and Jobs Act (IIJA) grant opportunities to fund infrastructure-related programs to benefit vulnerable communities in alignment with the Biden

Administration's Justice40 initiative.[53] The Company's current efforts to secure IIJA grants are further described in Section 16.

12.3 Tying Investments to Performance

Given the increase in capital investment needed to meet its grid performance goals, the Company acknowledges that stakeholders broadly desire greater utility accountability and a closer linkage between investments and performance. Specifically, the Company has identified two specific areas where utility accountability could be increased:

- In executing capital investments consistent with established plans and Commission orders
- To deliver targeted performance related to improved safety, reliability, and resiliency, while also preparing for a future that has increased Electric Vehicles (EVs), Distributed Generation / Distributed Storage, and other Distributed Energy Resources (DER)

The Company highlights that two efforts are underway, outside of this DGP filing, that have the objective of increasing utility accountability in these two areas. These are described in greater detail in the following sections, but at a high level those two efforts are:

- Performance Based Ratemaking (PBR) – In its April 24, 2023, Order in Case No. U-21400 (April 2023 Order), the Commission launched a "Financial Incentives and Disincentives" workgroup to explore the application of PBR and the appropriate use of financial penalties and rewards, and subsequently issued an order seeking comments on a PBR straw proposal for utilities.
- Infrastructure Recovery Mechanism (IRM) – In pending Case No. U-21297, the Company has proposed an IRM covering a portion of its strategic distribution capital investment; among other things, the proposed IRM would help ensure the Company makes investments consistent with its capital plans deemed prudent by the Commission.

[53] The White House, Justice40: A Whole-of-Government Initiative, available at: Justice40 Initiative | Environmental Justice | The White House, accessed January 14, 2023.

12.3.1 Performance Based Ratemaking (PBR)

The Company defines PBR as an approach to utility regulation that creates a stronger connection between a utility's financial outcomes and its performance. By more closely linking financial outcomes with performance outcomes, a utility is more strongly incentivized to achieve targeted performance.

The Company maintains its position that it remains open to PBR, potentially including the use of financial penalties and rewards tied to performance. However, given the recent guidance provided by the Commission discussed below, the Company has not included a specific PBR proposal in this DGP.

While PBR has been a topic of discussion within the State of Michigan since at least 2016, it was directly linked to the Company's Distribution Grid Plan (DGP) through the Commission's May 8, 2020 Order in Case No. U-20561 when the Commission directed:

> "As part of its distribution investment and maintenance plan to be filed in 2021 in Case No. U-20147, the Commission directs DTE Electric to include proposed PBR elements with reasonable metrics tied to utility financial performance, improvement targets, and timelines for achievement." (page 106)

In that order, the Commission provided additional guidance on what the Company should consider when preparing its PBR proposal.

In compliance with the May 2020 Order, the Company filed its "2021 Distribution Grid Plan Final Report" (Case No. U-20147) on September 30, 2021. This filing included a discussion on PBR. More specifically, the Company proposed two near-term actions:

- The submission of a new standalone annual PBR report that would include new distribution performance metrics and expanded context and discussion of metric performance.
- The establishment of financial incentives and penalties associated with two reliability metrics.[54]

[54] The Company noted in the 2021 DGP that "actual implementation of reliability metrics with financial incentives would follow an Order in a contested case subsequent to this case. Thus, it is expected that the metrics, targets, triggers and

In its July 1, 2022 filing in Case No. U-20147 (July 2022 Filing) the Company communicated its intent to suspend the filing of its proposed annual PBR report, citing in part a lack of Commission guidance on the Company's proposed PBR construct at the time and a desire for opportunities to "…further engage the Commission, Staff and interested stakeholders around its PBR proposal…" (page 2).

In its September 8, 2022 Order in Case No. U-20147 (September 2022 Order), the Commission provided the following guidance in response to the Company's and other utilities' PBR proposals contained within their respective distribution investment plans:

> …the Commission finds what was submitted by the utilities in their distribution plans to be insufficient to address the issue of financial incentives and penalties at this time. (MPSC 2022, 71)

Subsequently, through its April 24, 2023 Order in Case No. U-21400, the Commission launched a "Financial Incentives and Disincentives" workgroup. Notably, the Commission provided the following guidance related to the focus of the workgroup in that order:

> … an initial focus of the Financial Incentives and Disincentives workgroup shall include developing appropriate metrics relating to reliability including, but not limited to, SAIDI (including and excluding MEDs), SAIFI, CEMI, CAIDI, and resilience, including, but not limited to, downed wire response and the frequency and duration of outages during extreme weather, and shall use the recently updated Service Quality rules as a baseline. (MPSC 2023, 12)

and

> "Beyond this primary focus on distribution reliability and safety, the workgroup shall also consider challenges around the readiness of utility distribution grids to effectively accommodate and leverage the increasing and further anticipated growth of distributed generation, EVs, and other DERs." (12)

and

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maximum amounts, as well as the accounting treatment, would be addressed through a specific proposal by DTEE in a contested case prior to implementation."

> "After developing metrics around distribution performance, the workgroup shall explore rate structures and the methods by which incentives and disincentives may be applied." (12)

In a subsequent order issued on August 30, 2023, in that case, the Commission released its PBR "straw proposal" and sought comments from interested stakeholders. The Company provided its comments on September 22, 2023, and continues to be fully engaged in the workgroup.

12.3.2 Infrastructure Recovery Mechanism (IRM)

The Company defines an IRM as a regulatory tool that (1) provides customer protections in the event of utility underinvestment, and (2) allows a utility to recover the costs associated with certain capital investments made on behalf of its customers between rate cases. IRMs typically have a clearly defined duration, size, and scope such that the utility is limited to specific investments it can make under an IRM.

In pending Case No. U-21297, the Company has proposed an IRM focused on strategic distribution capital investments critical to customer safety, reliability, and resiliency. As discussed by Company Witness Foley in pending Case No. U-21297, the Company defined three main objectives of its proposed IRM:

> "…the Company seeks to achieve the following through its proposed Distribution IRM:
>
> - Increased accountability for the Company to fully execute its strategic investments critical to customer safety, reliability and resiliency deemed appropriate by the Commission;
> - Increased transparency into the Company's investment plans and timelines, and the execution of those plans, beyond the projected test year typically assessed during a general rate case; and
> - Increased opportunities for Michigan Public Service Commission Staff (Staff) to review and provide input on the Company's distribution investment plans." (Foley direct testimony; 7)

Importantly, under the Company's proposed IRM, any underinvestment by the Company would result in a return to customers. In this way the Company would be held accountable for making investments consistent with the Commission's approval of the IRM.

While a Commission order related to the IRM is forthcoming, the Company believes that both IRMs and PBR can be constructive tools to increase accountability for the Company to execute its planned capital investments and deliver on the performance improvements it is targeting through those investments.

13 Executing the Distribution Grid Plan

The scope and scale of the DGP will require significant effort and focus from DTEE to consistently achieve the targets laid out in this document. It will take expertise in engineering, procurement, project management, and construction. DTEE has anticipated these challenges and has been taking steps to address them.

13.1 Project Management Organization

As the scale of investment in the electrical grid has increased over the past several years, DTEE has taken steps along the way to grow its capital execution capabilities. Those increasing capabilities have delivered an improvement in strategic capital execution, including investing over $350M into strategic capital investment programs in 2021, investing a record amount of strategic capital in 2022 of $720M and a 2023 forecast exceeding $800M.

The most recent step in the growth of organizational capabilities occurred in the summer of 2023, when DTEE merged the Major Enterprise Projects organization with the Distribution Operations Projects team to form the Project Management Organization, a team solely focused on the execution of strategic investment programs.

This balanced organization is formed around the investment pillars to support grid voltage conversion work: subtransmission system rebuilds, PTMM, 4.8kv hardening, and all other critical investment work. The organization also contains the necessary support resources to execute the growing levels of project work, including planning & coordination functions, controls and standards.

13.2 Workforce Planning

DTEE uses an integrated planning approach, taking into consideration worked planned in the Distribution Grid plan as well as work identified in the annual capital planning cycle. These inputs are fed into a workforce planning model that provides annual resource demand for the next 10 years. The model breaks down projects into the labor resources required to execute the work, including frontline labor such as linemen, splicers and substation journeymen, as well as engineers, designers and project managers.

These forecasts are then used to aid the organization in key decision making to help fill those demands. Some of the workforce will be hired and trained as full-time employees through the Department of Labor certified apprenticeship programs for linemen, splicers, substation maintenance journeymen and planners (designers).

DTEE also works 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. This collaboration trains future workforce for all manner of distribution electrical work including overhead lines, cable splicing, substations and URD. Through these joint training efforts, DTEE has been able to increase the size of its on-property contract workforce by over 25% since the beginning of 2022. DTEE is also hiring a growing number of engineers, project managers, and technicians to support the increasing workload. While DTEE hires experienced employees, it also brings in interns or co-ops and provides them with significant on the job training and coaching throughout their time with the Company. These employees often go on to take full-time roles within the Company or return to DTEE later in their careers.

DTEE has also grown its partnerships with several engineering and design firms, with significant portions of the detailed design work now being completed by these firms. These partnerships have led to several contracting models being utilized to complete work, including the use of Owner's Engineer and EPC (engineer-procure-construct). The work in the last two years has increased overall capacity, as well as expanded understanding of how to grow to the scale of the execution portfolio. DTEE envisions bidding multi-year master service agreements for EPC type work in the areas of "repeatable" investments, such as subtransmission rebuilds, URD replacement, and 4.8kV conversions.

13.3 Material and Equipment Planning

With the establishment of the new PMO organization, DTEE is expanding its material forecasting model. The DGP and annual capital planning processes are used to build forecasts for all key equipment necessary to execute grid plans – everything from poles, wires, and line hardware to substation transformers, and smart grid equipment.

DTEE has developed longer-term agreements with two key suppliers for the supply of line hardware materials (crossarms, insulators, wire, etc.). To support these agreements, vendors are taking specific steps to increase their capacity. The material forecasting model has also allowed negotiation of guaranteed production slots for key long lead equipment.

The capital investments outlined in this distribution grid plan make it essential to evolve DTEE's procurement and supply chain practices. The difficulty of securing materials due to nationwide shortages over the past few years further emphasizes the need for flexible and resilient strategies. The Company will stabilize and expand supply chain capabilities and improve inventory management.

- **Expanding supply chain capabilities:** Increasing resources in procurement and warehousing will enable efficient sourcing and storage of materials and equipment. In addition, a dedicated Quality Management Department is in development that will ensure rigorous assessment and control of vendors and materials. Key objectives of this department include:
    - Assessing current and potential vendors: evaluate existing and potential vendors of engineered materials to ensure reliability and quality

- Supplier Quality Manual (SQM) development: Develop an SQM to establish clear quality expectations and standards for suppliers
- Expanding quality audits: Regular quality audits will verify compliance with established standards

- **Improving inventory management:** For long lead time items critical to project success, negotiations will take place with key suppliers to secure guaranteed production slots. Strategic and tactical forecasting demand meetings will take place to track spending patterns and plan inventory accordingly. To minimize lead time risk and mitigate inflationary pressures, the Company will proactively procure materials for future years.

Conclusion

DTEE's focused efforts on improving the execution of its capital programs have driven significant results in the last two years. The additional work in the creation of the PMO, workforce planning, and material planning provide a secure path to deliver on the increasing demands for upgrades to the electrical grid in the coming years.

14 Storm Response

14.1 Mutual Assistance

DTEE understands that losing power for any reason is difficult for customers, especially at times of adverse weather when there is a high volume of outages and restoration may take longer. Storms that cause outages typically have high winds, but rain, icing, and other factors can also have significant impact on the electric grid. To prepare for these instances, DTEE has a robust and comprehensive process that normally starts 48-hours ahead of expected weather impact and continues until the final customer has been restored.

DTEE is constantly monitoring weather and watching storms evolve. When a storm or other weather event is predicted, and even before the weather impact, DTEE performs scenario planning around the predicted weather, its potential outage impact on customers, and restoration duration. This analysis, led by the Incident Commander, Operations Chief, and Mutual Assistance (MA) Manager, gauges the local availability of restoration resources and allows for the strategic prestaging of additional outside labor resources, if needed, ahead of the weather. This strategy, learned from benchmarking of other utilities impacted by hurricane recovery, can reduce customer restoration time.

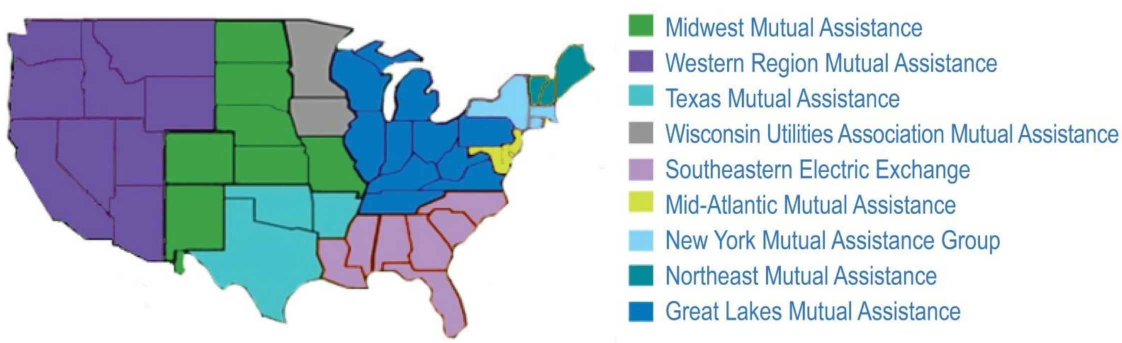
After DTEE's service territory has been impacted by the predicted weather system, the MA Manager again coordinates with the Operations Chief to gather initial reports from the field about the extent and location of damage to feed into the development of the Planning Scenario and Mutual Assistance Resource Plan. The Operations Chief, Logistics Chief, and MA Manager utilize this information to make a recommendation to the Incident Commander detailing the number and type of additional mutual assistance crews that should be requested.

Once the need for additional crews has been identified, DTEE has two options for engaging these resource pools.

1. Traditional Foreign Crews Through Mutual Assistance

DTEE is a member of Great Lakes Mutual Assistance (GLMA) program as part of the Midwest Regional Mutual Assistance Group (RMAG). GLMA group members are neighboring utilities around the Great Lakes area that are signatories to the EEI Mutual Aid Agreement. Once the need for foreign resources is established, a call will be conducted with all member utilities to discuss crew needs and availability across the entire region. Member utilities can choose to either release or hold their restoration resources depending on the expected weather or damage in their specific service territory. Most often this is a reactionary exercise that follows the known impact of the weather; utilities very often hold their resources until the local impact is fully understood. Once released, the restoration crews will travel to southeast Michigan to begin restoration efforts. Should there be not enough crews to meet the demand, DTEE will engage other Regional Mutual Assistance Groups (RMAG) in the United States and Canada. A map of the mutual assistance groups within the United States is shown in Exhibit 14.1.1.

Exhibit 14.1.1 Mutual Assistance Groups within the United States



Map showing the seven mutual assistance group regions in the system of sharing resources to restore power in the U.S. Michigan is in the Great Lakes region.
Edison Energy Institute

2. Non-Traditional Foreign Resources

Starting ahead of the 2020 Storm Season, DTEE began to investigate alternatives for acquiring foreign crews to assist with storm restoration. To support this goal to expand restoration resources, DTEE identified contractors within the Midwest that are not tied directly to GLMA utilities. These contractors can move quickly and do not require permission from parent/host utilities before they're allowed to send crews to our service territory for assistance with customer restoration. These contract crews can be in DTEE's service territory typically anywhere from 4 – 12 hours from the time of the request and will stay until they are no longer needed.

In addition to these resources, DTEE has entered into contractual agreements with many Michigan-based electric utility contractors that do not perform work on DTEE's property day-to-day. These "Local Foreign" contractors make up to approximately 200 additional restoration resources that can be quickly mobilized to support customer restoration.

Additionally, DTEE has retained a Michigan based multi-state lineman company in a Right of First Refusal contract giving DTEE access to over 200 line workers before any other utility in the country. Between the non-utility-based contractors, Local Foreign, and the Right of First Refusal crews, DTEE is positioned to bring in, and have working, up to 500 crews (1800 FTEs) within 12-16 hours of a weather event.

14.2 Wire Down Response

DTEE has a robust wire down it employs in response to downed wires that utilizes technology, people, and process as discussed below.

Technology

DTEE has developed several technology tools to help quickly mitigate downed wires that could threaten the public following a weather event. DTEE has developed an internal auto-dispatching tool (Chatbot) to speed up the response time of Public Protection resources to locations of reported wire down. The tool directly dispatches the closest available member of the Public Protection Program to the location of the highest priority wire down. Since the Company is working to address reported wire downs from the public, the wire could be an actual electric wire down, a joint use cable such as telecom, or in some cases no wire or cable is actually down.

Once the Public Protection team has arrived and confirmed that an electric wire is down, the Chatbot will take them through a list of questions that prompt them to tape/secure the site and report any information that will be pertinent to the line crews who follow. After completing these questions and securing the hazard, the Public Protection crew will text the Chatbot to receive their dispatch orders for the next closest, highest priority, wire-down event. The implementation of this

Chatbot has improved the dispatch time of Public Protection resources since its implementation in 2021.

People

To support the Public Protection Program, DTE Electric has engaged the entire DTE Energy employee team to recruit, train, and equip more storm resources for securing downed wires, and other storm process roles. Every member of the Public Protection team receives extensive training including mentored storm work. Once graduated from the training program, a Public Protection team member will be able to safely and effectively secure downed wires in the field, making the grid safer for the public. DTEE has successfully trained over 500 non-DO resources from throughout the entire DTE Energy enterprise to support this initiative.

Process

The Public Protection Program helps to make wire down events safer by taping off and securing the hazard to help the public avoid dangerous areas. To perform this function, public protection team members require consumable equipment that can run out in the middle of performing this function. Starting in 2023 DTEE has deployed materials to local warehouses and locations across the entire service territory. This helps to respond to wire down events more quickly by allowing support teams that start from across southeast Michigan to resupply more easily.

14.3 Singles Damage Assessment

After the 2021 Storm Season, DTEE started a new Damage Assessment program to speed up the restoration of small and single customer outages, which in most cases are repaired at the tail end of storm restoration. Key to this strategy is targeting small customer outages (typically fewer than 10 customers reported out of power along an entire distribution circuit) for assessment earlier in the restoration process. This program, Singles Damage Assessment (SDA) is a best-in-class program that has been shown to improve the restoration speed of small outages by approximately 14%. Once DTEE has entered Storm Response, SDA will be activated to begin the assessment and preflight of any single customer outage or any outage that is below the level of a transformer device, typically fewer than 10 customers.

The entire circuit patrol is not normally required to resolve these smaller outages, so teams are dispatched directly to the location of the reported trouble. After the SDA team arrives at the location, they will assess the outage conditions, identify resources and materials required, alert the nearby customers of any safety concerns and secure any downed wires. DTEE has access to additional non-lineman resources that can assist with this type of restoration, depending on the degree and location of damage. By better assessing the damage up front, DTEE can identify the correct resources earlier, and perform customer restoration more quickly. When DTEE can perform restoration without an Overhead Lines Crew, not only can the customer be restored more quickly but the linemen can be allocated to other jobs that do require their specific skillset.

The SDA program also helps to identify Ok-On-Arrival sites where the reported hazard causing the outage has been cleared or problem may have existed for only a moment. When a weather event comes through the service territory, overhead wires can contact trees, animals (birds and squirrels), and other wires. While these hazards can cause flickering lights or outages, over a multiple day restoration effort, they sometimes can clear themselves without any actual restoration work.

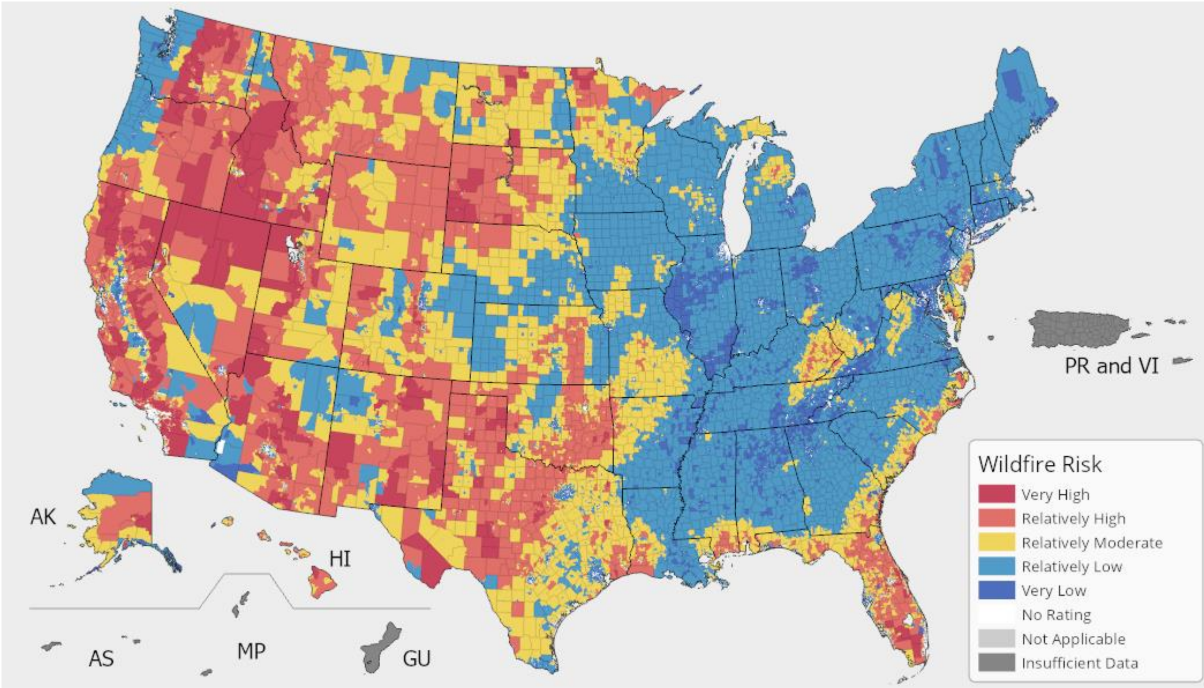
SDA helps to identify these locations where power has already been automatically restored or temporary problems cleared, and DTEE will not need to send an additional restoration resource to the site. By reducing and pre-flighting these Ok-On-Arrival events, the overall storm restoration process is more efficient, and DTEE can better allocate their resources to the sustained outages that require them.

14.4 Wildfire Mitigation Approach

The risk for wildfires exists in Southeast Michigan but is significantly lower than other parts of the country. While Michigan has experienced a few wildfires in recent years, nearly all of them have occurred in Northern Lower Michigan and the Upper Peninsula.

The graphic below published by Federal Emergency Management Agency (FEMA)[55] shows that the DTE Electric service area is classified as being at *Relatively Low* or *Very Low* Wildfire Risk. These are the two lowest risk categories.

[55] Wildfire risk map by Federal Emergency Management Agency (FEMA) - Wildfire | National Risk Index (fema.gov), accessed September 23, 2023



While the wildfire risk in DTEE's service territory is low, many of the Company's planned investments in the distribution system and its storm response processes described above are intended to mitigate risks posed by downed wires, including fires. Specifically, PTMM, 4.8kV Hardening, 4.8kV conversion, and tree trimming will all prevent downed wires. Additionally, the installation of viper reclosers in the grid automation program described in section 10.1, is intended to decrease the risk of adverse impact from downed wires.

Additionally, the DTEE System Operations Center (SOC) has established real time processes that enable the control room to take quick action to de-energize DTE Electric equipment during emergent field conditions. This de-energization is accomplished either remotely via the SCADA control system, or through field resource actions when the emergent information is conveyed to the SOC control room.

14.5 Storm Estimates and Power Status

In addition to concerns about outage frequency and duration, customer feedback on outages has increasingly focused on DTEE's need to improve the timely and accurate communication on their outage status and restoration estimate. The Error Free Communication (EFC) program is designed to ensure that customers experience quality communication throughout the duration of an outage. Feedback indicates that customers want to better understand their outage, including a clear and correct estimate of restoration, as well as the cause of the outage. Customers also want to have confidence in their restoration notice, knowing that when DTEE informs them the power is back on the outage is truly over.

Several factors contribute to the Company's ability to provide a quality communications experience for customers during an outage. Timely and accurate communication with meters at customer locations, resilient backend systems that use data to determine the power status at a residence (Outage Management System [OMS], Customer Management System [CRM]), and systems that communicate with customers must all work seamlessly in concert to support consumers notifications. DTEE is making investments in its Automated Metering Infrastructure (AMI) system that specifically improve the quality and timeliness of collecting and utilizing the AMI data. The greater the volume and quality of the data collected, the better the system(s) will perform, and this expanded pool of data will allow DTEE to better model outage events within the OMS, delivering a more accurate prediction of outage magnitude (cause, size, extent of damage). Accurate prediction is key to restoring power as safely and quickly as possible, including initiating and maintaining communications with customers about their event.

DTEE made significant progress this year in improving the resilience of its digital communication. In past storms, customers and communities have reported issues with being able to consistently reach DTEE. In response the Company made aggressive corrections, and in the most recent weather events all systems performed well.

The EFC program continues to improve the accuracy and timeliness of outage communications. Timely, accurate restoration estimates for customers remain a significant area of focus. While estimate accuracy still needs to be improved, DTEE is investing in additional communication technologies to improve its score, rigorously testing improvements and measuring efficacy to ensure better communication with customers during outages.

15 Base Capital

Base capital refers to the investments associated with work activities that DTEE performs as part of the normal business of serving our customers. These activities include restoration of customers after a storm or equipment failure, connection of new customers, and the relocation of existing assets.

Base capital is divided into two major categories: 1) emergent replacements, and 2) connections, relocations, and other.

15.1 Emergent Replacements

Emergent replacements are those necessitated by damage or failure on the system and are reactive, rather than proactive, but nonetheless essential to maintain safety and reliable operation of the system. There are three types of emergent expenditures: Storm, Non-Storm, and Substation Reactive.

15.1.1 Emergent Replacement – Storm

This category includes investments required to perform repairs of the overhead and underground distribution and subtransmission systems for damage which occurs during storms. Expenditures are made to replace damaged equipment which caused power outages our customers or created a hazard. DTEE defines a storm as 760 outages events affecting at least 200 circuits. Equipment examples include poles, crossarms, and conductors, among other assets.

15.1.2 Emergent Replacement – Non-Storm

This category includes investments required to perform repairs of the overhead and underground distribution and subtransmission systems for damage during non-storm conditions. The “non-storm” description does not imply that these events are not caused by whether such as thunderstorms and high winds. It simply means that there were not enough outages for “storm” conditions to be declared, as defined in Section 16.1.1. Failures in the non-storm category can also include failures from public interference, age-related equipment failures and more. Equipment examples include poles, crossarms and conductors, among other assets.

15.1.3 Emergent Replacement – Substation Reactive

This category includes investments required to perform emergency replacement work for substation equipment. DTEE makes these expenditures to replace broken or failed equipment that either led to customer outages, created a risk of customer outages, created a hazard, or impacted the operability of the electrical system. Equipment examples include breakers, substation transformers, and substation reclosers. Additionally, substation reactive includes expenditures made to non-electrical equipment necessary to operate the substation, maintain security, and reduce hazards. An examples of non-electrical substation reactive expenditures include fence/gate repairs mandated by NERC security protocol and replacing HVAC heating to remove condensation to mitigate equipment corrosion.

Exhibit 15.1.3.1 Emergent Replacements Investment ($ Millions)

Category	2024	2025	2026	2027	2028	5-Year Total
Emergent Replacements	$415	$399	$368	$348	$345	$1,877

15.2 Connections, Relocations and Other

The connections, relocations and other investment category is further broken down in to five major sub-categories: Connections and New Load; Relocations; Electric System Equipment; NRUC and

Improvement Blankets and General Plant, Tools & Equipment and Miscellaneous. Exhibit 15.2.1 provides the connections, relocations and other investment for 2024-2028

Exhibit 15.2.1 Connections, Relocations and Other Investment ($ Millions)

Category	2024	2025	2026	2027	2028	5-Year Total
Connections, Relocations and Other	$282	$295	$314	$334	$355	$1,580

15.2.1 Connection and New Load

The Connections and New Load sub-category investments are divided into two categories: Small Load Growth projects & Customer Connections, and New Business projects.

Small Load Growth & Customer Connections projects are projects required to serve new load, customer connections, or an upgrade needed to address a limited level of loading issues on the electric system. Projects in this category are typically less than $500,000 to complete and are developed and executed by distribution regional service centers. Activities to support these customer needs may include reconductoring lines, minor expansions to a substation, or transferring load to provide load relief. Other typical projects in this sub-category include installing additional overhead and underground lines to provide service to small commercial businesses or housing developments. Small Load Growth & Customer Connections projects are often requested by customers and can carry a customer contribution in aid of construction (CIAC) cost wherein the customer pays an allocated cost of new service depending on the requested load and service requirements.

New Business investment projects are larger customer-driven projects, more than $500,000, and require a central engineering approach to design and implementation. Like Small Load Growth and Customer Connections, these are projects required to serve new load, connections or to address loading issues, but are on a larger scale. Activities to support customer new business needs often include installing additional overhead and underground lines or upgrading or building new substations to provide services to large commercial or industrial customers. As with Customer Connections, New Business projects are often requested by customers and can include a CIAC cost, where the customer may be responsible for an allocated cost of system upgrades, depending on the existing system conditions, the requested load, and the impact to the electrical system.

These investments connect new customers, support area load growth for both existing and new customers, enable economic growth, and ultimately support customers.

15.2.2 Relocation

Relocation projects are requests from customers or municipalities and other governmental entities, including the Michigan Department of Transportation, to relocate existing DTEE facilities. These requests are typically related to construction activities in specific geographic areas, including the modification of roadways, bridges, water mains, public sanitation, alleys or other customer activities.

DTEE facilities being relocated could include overhead lines and poles, or underground lines and pad-mount transformers, or possibly substations and system cable. With expected federal investment driving investments in municipal infrastructure, it's expected that these types of projects will become more frequent in the coming decade.

These investments can enable economic growth, meet customer needs, are required by regulation, or at the request of municipalities. Similar to Customer Connections and New Business, some projects requested by customers or municipalities include a CIAC cost wherein the requester pays for part of the costs of relocating DTEE assets.

15.2.3 Electric System Equipment

DTEE maintains an inventory of critical spare equipment in order to support both emergent replacements and planned projects. The Electric System Equipment sub-category of investment includes investments in equipment, particularly long lead time items, to provide proper inventory levels of major electric system equipment. Equipment purchased under this sub-category includes substation transformers, distribution transformers, regulators, and meters, among other items.

These investments provide inventory to help serve customer needs in a timely fashion, so that urgent work is not slowed down due to a need for critical equipment.

15.2.4 NRUC and Improvement Blankets

There are three subcategories that make up the NRUC and Improvement Blankets: (1) System Improvements, (2) Normal Retirement Unit Change-out (NRUC), and (30 Operation Technologies.

System Improvement projects are small projects managed by regional operations to immediately address customer issues, reliability, and complaints. These are projects that do not require extended planning and design and do not exceed $350,000.

NRUC consists of projects to perform scheduled work that replaces assets (pole top switches, reclosers, capacitors, and regulators) determined to be end-of-life. These assets are inspected by overhead linemen or power quality technicians to determine if they are end-of-life.

Operational Technologies consists of the infrastructure and associated applications that support the AMI platform and data. This also covers annual work in testing new meter types, designing and installing configurations, replacing communications equipment, and testing changes for new equipment.

15.2.5 General Plant, Tools & Equipment, and Miscellaneous

General Plant, Tools & Equipment and Miscellaneous includes the tools and replacement tools required for linemen and splicers to perform their work, and test equipment used by engineers and technicians. In addition, this sub-category includes substation physical security investments.

These expenditures ensure that DTEE work crews are equipped for their day-to-day field work. Examples of items included in General Plant, Tools & Equipment and Miscellaneous include: very low frequency (VLF) trucks used to test cables at frequencies between 0.02 and 0.1 Hz, DC hi-potential testers (Hippoters) used to test insulation on cable, breakers, transformers, etc., oil processing trailers, insulated screwdrivers, pencil tip soldering iron and other tools and equipment.

15.2.6 Other Known Major Projects

DTEE supports some grid work that is outside of the more typical categories already described in this plan. The Blue Water Bridge Plaza expansion project is a large relocation project example where DTEE is leveraging the required relocation project to begin the 4.8kV to 13.2kV conversion effort in the Port Huron area.

To build the new Blue Water Bridge customs plaza, the Michigan Department of Transportation (MDOT) requested that DTEE relocate all its facilities outside the expanded plaza footprint. This requires construction of a new electrical substation (‘Neon’) to replace the existing substation (‘Pinegrove’) which resides in the future plaza footprint. The new substation will be built to current 13.2kV standards, replacing the existing 4.8kV site, fulfilling the needs of the relocation while delivering increased reliability and capacity to our customers. DTEE agreed to a joint venture with MDOT wherein MDOT would pay a portion of the cost to relocate DTEE facilities. The project is expected to be completed by the end of 2026.

15.2.7 Transportation Electrification Plan

After four years of executing on its EV pilots under the Charging Forward umbrella, DTEE is transitioning to longer-term programming by developing a comprehensive Transportation Electrification Plan (TEP) that will detail its EV strategy, programs, and investment through 2028 and be published by year end. DTEE forecasts over 300,000 EVs in its service territory by 2028 up from nearly 40,000 today. To support this level of EV adoption, approximately 270,000 additional chargers are needed in single family homes, multi-unit dwellings, fleet depots, workplaces and public areas between through 2028.[56]

Although the final TEP is still in development, regardless of what incentives for charger deployment are ultimately proposed and approved, customers will request new or upgraded service connections from DTEE to install the additional chargers. Based on historical work order analysis and cost data from Roland Berger’s global database, approximately $189 million of distribution investment will be needed on the utility side of the meter to connect the chargers required to support EV adoption through 2028. From this same analysis, DTEE estimates that it will be responsible for approximately 85% of that investment cost, and the balance will come from customers’ contribution in aid of construction (CIAC). Therefore, the total DTEE portion of the required distribution investment, $161 million, has been included in the new customer connection portion of the budget.

[56] A detailed study was performed leveraging Roland Berger and their global EV database and automotive experience. The model output is based on assumptions for the number of vehicles served by each charger in a segment (e.g., from one EV for a single-family home to 200 EVs for a public fast charger) as well as the power levels (e.g., 12-150 kilowatts).

16 IIJA Distribution Grid Activity

On November 15, 2021, President Biden signed the Infrastructure Investment and Jobs Act or Bipartisan Infrastructure Law (the “IIJA” or the “BIL”), a once-in-a-generation opportunity to invest in the Nation's infrastructure, competitiveness, and communities.

Over the past year and a half, DTE has applied for IIJA grants as well as analyzed, performed outreach, and supported third party applicants. DTE has applied for three grants and plans to apply for an upcoming request for proposal in grid resilience and innovation areas to bring additional investment into Michigan.

1. Smart Grid Grants (40107)

On March 17, 2023, DTE filed for a $23M grant for a project to construct two sets of adaptive networked microgrids to Grid Resilience and Innovation Partnerships (GRIP) topic area 2 grant. These microgrids will be networked to increase flexibility and reduce the number of outages for area residents. As of mid-September 2023, DTE has yet to be notified on the award of the grant.

2. Grid Resilience Grants (40101c)

On April 6, 2023, DTE filed for a $100M grant to GRIP topic area 1 for a project to: (1) expand an existing substation by adding a third 13.2kV transformer and converting the 4.8kV equipment to operate at 13.2kV, (2) rebuild 145 miles of 4.8kV overhead distribution circuits, (3) decommission two other substations by transferring their load to the newly expanded substation, and (4) install an EV Charging. As of mid-September 2023, DTE has yet to be notified on the award of the grant.

3. Grid Innovation Program (40103b)

On May 19, 2023, EGLE proposed an innovative large-scale public-private partnership to implement a shared remote sensing solution that leverages light detection and ranging (LiDAR) to create a geospatial “digital twin” of Michigan’s geography. DTE is a subrecipient and financial partner to the application. As of mid-September 2023, EGLE has yet to be notified on the award of the grant.

4. Resilience for States & Tribes (40101d)

In May 2023, the EGLE submitted a $14.9M application for Preventing Outages and Enhancing the Resilience of the Electric Grid. EGLE was awarded on July 6, 2023. Next, EGLE will issue a Request for Proposal (RFP) for eligible entities to apply for a portion of the funding. The Company looks forward to the release of the State’s RFP and submitting an application that best aligns to the program scope and budget.

16.1 Actions and On-going Activities

DTEE will continue to actively pursue applicable grant opportunities that benefit its customers, support the Company’s decarbonization objectives, improve the distribution grid reliability and resiliency, and support the state’s progress towards meeting its climate goals. Progress is shared biannually in MPSC Case U-21227.[57]

[57] Case: U-21227 (site.com)

17 Stakeholder Engagement

DTEE has ongoing outreach and regular engagement with customers and stakeholders that includes issues related to the distribution grid to both communicate updates and listen to feedback. For example, the Company sends out a newsletter to elected officials, local leaders and community partners to provide critical information during severe weather events and works with municipalities and customers to communicate upcoming infrastructure projects happening in their communities. In addition to these regular efforts, DTEE conducts targeted initiatives in alignment with the Company's DGP and other regulatory filings with the MPSC. For example, in preparation for the Company's last DGP in 2021, DTEE conducted research with customers and other stakeholders to receive direct feedback about their perceptions of the Company and how they feel about the electric reliability they receive. DTEE also received comments from customers on issues related to the distribution grid through the Voice of the Customer research conducted in preparation of the 2022 Clean Vision Integrated Resource Plan. While this research was targeted to solicit feedback on electric generation issues, concerns were noted from participants regarding the duration of outages and inconsistency in reliability across DTE Electric's service territory.

In preparation for the 2023 DGP, DTEE built upon these prior initiatives and learnings to dive deeper and gain additional insights from customers, communities, and technical stakeholders. DTEE appreciates the feedback the Company has received, as well as the time various stakeholders took to provide their perspectives and views. The Company recognizes that distribution planning is an iterative process and looks forward to continuing to listen to customers and other stakeholders and incorporating their sentiments into ongoing distribution planning efforts.

17.1 Customer Engagement

The Company is listening to the perspectives and concerns offered by customers through direct communication channels as well as external venues. This information from customers is an essential component of DTEE's distribution planning and communication processes. Through prior customer research, the Company learned that customers felt DTEE does not aggressively maintain or upgrade its distribution grid because of a lack of visible upgrades and maintenance. Many residential customers suggested that DTEE regularly communicate to them with infrastructure updates that represent modernization/improved reliability in their immediate communities so they better understand what is taking place, even if they may not personally see the work happening. Based on this feedback, DTEE enhanced its customer communications by developing a reliability-focused Empowering MI blog site[58] and is sending out targeted emails to let customers know about distribution work happening in their area. In addition, DTEE has developed the Electric Reliability Improvements Map (Exhibits 14.1.1 and 14.1.2) to provide customers with information on near-term reliability improvement projects in the areas of tree trimming, strengthening power lines, utility poles maintenance, rapid response, and modernizing and rebuilding the grid.[59] The Map is available on the Company's website[60] and allows users to navigate through DTEE's entire service territory or search a specific address or place.

[58] https://empoweringmichigan.com/category/your-neighborhood/reliability-work-updates/

[59] Maps show investments and improvements the Company is making through 2023. Planned work boundaries are approximate and may not represent the exact extent of the work. Accessed August 16, 2023.

[60] https://dte.maps.arcgis.com/apps/webappviewer/index.html?id=5d9dc2eb124445618959ce788086e00e#

Exhibit 17.1.1 Electric Reliability Improvement Map (DTE Service Territory)

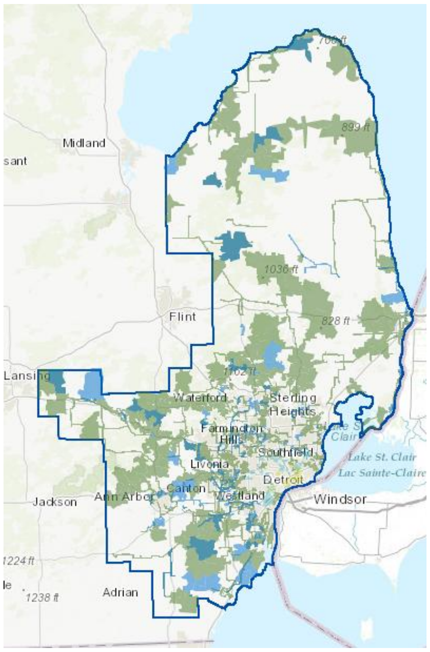
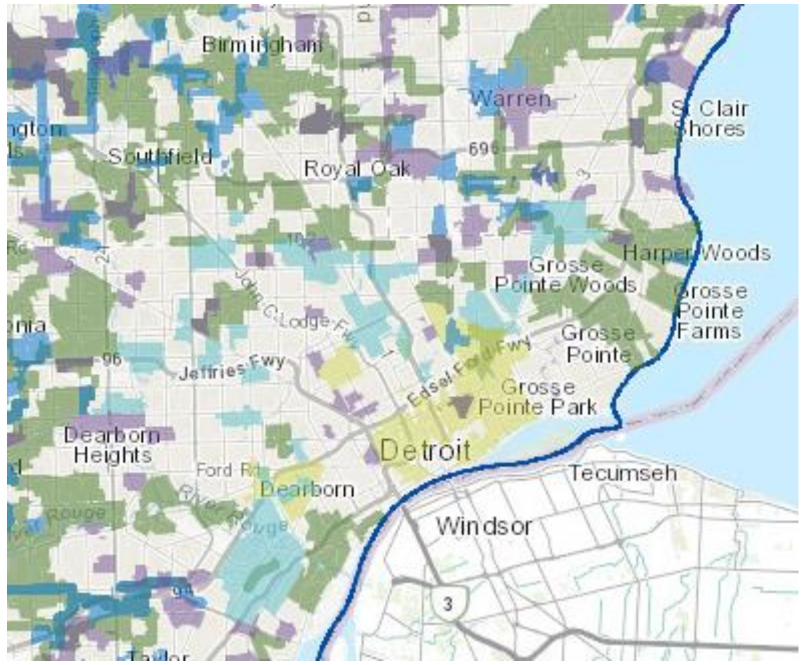


Exhibit 17.1.2 Electric Reliability Improvement Map (Metro Detroit)



■	**Tree Trimming**	Tree limbs and branches are responsible for nearly 70% of the time our customers spend without power. That's why we're surging our efforts to trim overgrown trees in your neighborhood to keep you safe and the energy grid reliable.
■	**Strengthen Power Lines**	We're upgrading and strengthening power lines to ensure the electric system in your neighborhood is more resilient and reliable.
■	**Utility Poles Maintenance**	We're inspecting and repairing utility poles and replacing cross arms and other pole top equipment to ensure our system delivers the power you need when you need it.
■	**Rapid Response**	Tree trimming and pole top equipment repairs/replacements to quickly improve reliability in communities experiencing emergent issues in between planned maintenance schedules.
■	**Modernizing & Rebuilding the Grid**	Modernizing electrical substation equipment, as well as the underground and overhead infrastructure that delivers power to you, including replacing poles and wiring. Tree trimming will be completed, as necessary, in advance of pole replacements.

DTEE has also been listening to the concerns raised by customers at recent Legislative and Commission-led events. In March 2023, the MPSC held three townhalls to give Michiganders, including DTEE customers, a chance to share directly with state regulators their experiences during and after the February and March 2023 ice storms. Key themes raised by attendees include:

- Frustration over frequency and duration of outages
- Dissatisfaction with electric rate increases
- Desire for clean energy resources, including rooftop solar
- Challenges reaching energy provider via phone and imprecise communications regarding outages/restoration efforts
- Discontent with outage credit compensation

Similar sentiment was shared at a June community event in Detroit as part of the Michigan House Energy Reliability, Resilience and Accountability Task Force's listening tour. In addition, DTEE also regularly tracks customer complaints submitted to the MPSC regarding the Company's distribution operations. Through August 2023, the highest number of distribution-related complaints were related to frequency and duration of outages, and restoration estimate times during an outage. DTEE works directly with customers to address these issues.

The Company understands the frustrations customers experience because of outages. The proven investments highlighted in this plan will reduce the number and duration of outages during these severe weather events. Additional information on how DTEE is addressing customer feedback from the February ice storms is in Appendix D.

Building on these key themes and findings from prior customer outreach, DTEE conducted additional research to better understand customers' awareness and attitudes toward the Company's distribution planning efforts. A third-party research company surveyed more than 4,300 residential customers throughout DTEE's service territory through an online questionnaire.

Through this research, the Company learned:

- Most respondents (55%) had seen or heard something pertaining to DTEE's efforts to improve the grid prior to taking the survey
- Most respondents (61%) preferred to receive updates on the plan via email; the DTE Energy website (39%) and bill inserts (35%) were also popular methods of communication

- Most respondents found all four key pillars of the DGP to be a high priority,[61] and there was a particular interest in burying lines underground to improve reliability
- Respondents were sensitive to the plan's impact on increasing their electric bill[62]
- Most respondents (52%) who contacted DTEE regarding an outage in the past six months rated the effectiveness of the complaint process as a 6 or lower (on a 0-10 scale)

Based on these research findings, the Company's enhanced customer communications appear to be a step in the right direction to increase customers' awareness of the work DTEE is doing to improve distribution reliability and resiliency. Customers agree that the four key pillars of focus and investment should be high priorities, and the Company should continue to balance the need for these significant investments with customer affordability. Finally, the Company knows it has more work to do to improve the quality of customer communications and resolution of complaints during outages.

17.2 Community Engagement

DTEE has heard from customers, community leaders and technical stakeholders that equity and environmental justice are important issues that should be considered in distribution planning. As outlined in Section 12 of this report, DTEE has taken several measures to incorporate this feedback. In addition, a key component of environmental justice is meaningful involvement. As such, the Company seeks to deepen its outreach and engagement with vulnerable communities leveraging the analysis of reliability performance in vulnerable communities (described in Section 12) to identify and target engagements with stakeholders in these vulnerable communities. During these discussions, the Company is informing community members of its planned distribution investments, how its distribution planning process is integrating equity and environmental justice and listening to better understand the communities' sentiments related to distribution issues.

[61] Percentage of respondents that rated each pillar as a very high / high priority: rebuilding significant portions of the grid, 88%; upgrading existing electric distribution infrastructure, 83%; trimming trees, 73%; transitioning to a smart grid, 72%.

[62] 47% of respondents reported their opinion of DTEE would be somewhat / much worse if their monthly electric bill increased by less than $10 per month to cover the cost of the plan.

In addition, the Company is continuously reaching out and listening to its communities through multiple channels, including regular meetings with federal, state and local representatives; meetings with community leaders from faith-based institutions, social service agencies, advocacy organizations and others who represent the DTEE customer base; community stakeholder surveys; and interactions with community members at District meetings in Detroit, informal neighborhood gatherings and DTEE Community Van deployments during storm recovery.

During these conversations, community members have been receptive to DTEE's four-point plan, and the variety of solutions being implemented. There is a desire to understand the reliability performance of the local community and how that compares to other communities. In addition, communities want to understand how the overarching investment programs identified in the DGP will translate into investment plans at the local level, when that investment is expected to take place, and the reliability improvements that can be expected after the plans have been implemented. DTEE looks forward to maintaining a dialogue with its communities and further understanding the communities' sentiments toward distribution issues. While DTEE reports reliability performance data with the MPSC on a quarterly basis,[63] the Company is developing ways to share this information with the community. In addition, to better address community members' desire for localized information about DTEE's investments, the Company is exploring enhanced ways to effectively communicate plans for improving reliability.

17.3 Technical Stakeholder Engagement

Technical stakeholders include parties that participated in the Company's 2021 DGP technical conferences or expressed interest in participating in the 2023 technical conferences by signing up for the MPSC's email distribution list. DTEE held two virtual technical conferences in preparation of this DGP. The first conference, held in March 2023, was focused on the 4.8kV electric distribution system and had over 200 participants. The second conference, held in August 2023, previewed key topics from the 2023 DGP with stakeholders and had over 180 participants. Both events were hosted and moderated

[63] https://www.michigan.gov/mpsc/consumer/electricity/distribution-system-reliability-metrics

by the MPSC and included a question-and-answer segment. The agendas, presentations, conference recordings and follow-up responses to questions are all available on the Commission's websites.[64,65] In addition, DTEE developed a dedicated DGP email address to maintain regular engagement with technical stakeholders on distribution planning.

[64] https://www.michigan.gov/mpsc/consumer/electricity/dte-electric-4-8kv-technical-conference
[65] https://www.michigan.gov/mpsc/commission/events/2023/08/31/dte-distribution-grid-plan-technical-conference

Appendices

Appendix A State of the Grid

Exhibit A.1 DTEE Distribution System

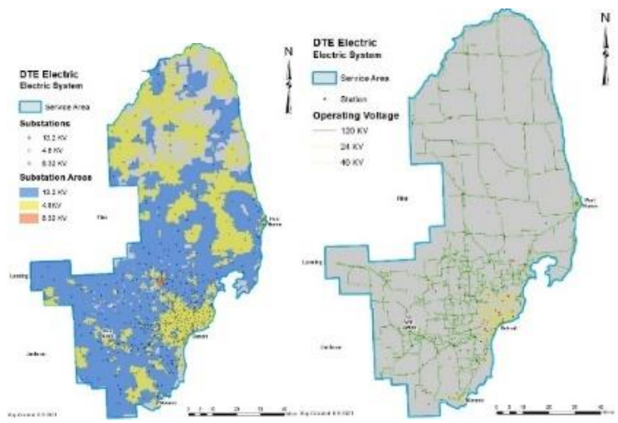
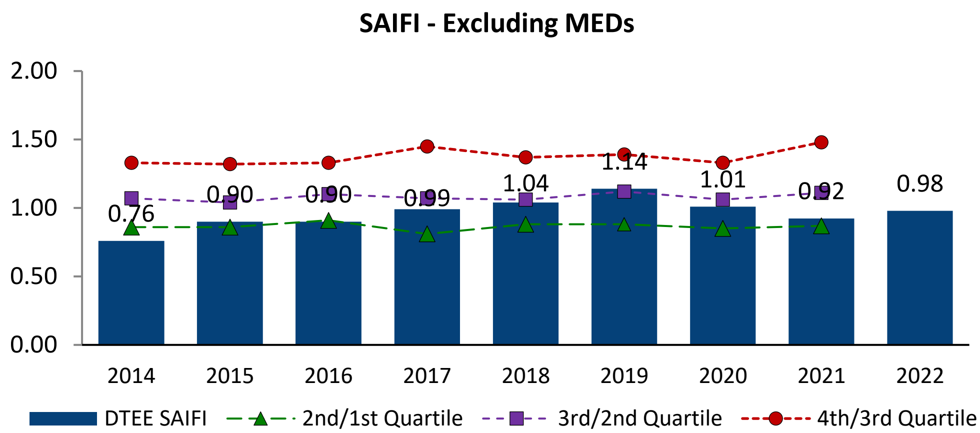
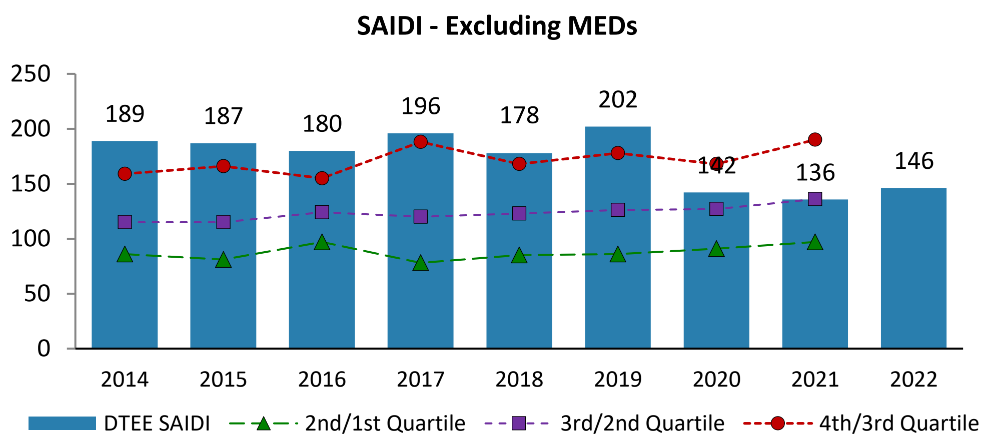


Exhibit A.2 Reliability Indices Definitions

Index	Full Name	Calculation
SAIFI	System Average Interruption Frequency Index	Total number of customer interruptions divided by the number of customers served
SAIDI	System Average Interruption Duration Index	Total minutes of interruption divided by the number of customers served
CAIDI	Customer Average Interruption Duration Index	Total minutes of interruption divided by the total number of customer interruptions

Exhibit A.3 Reliability Statistics - Excluding MEDs





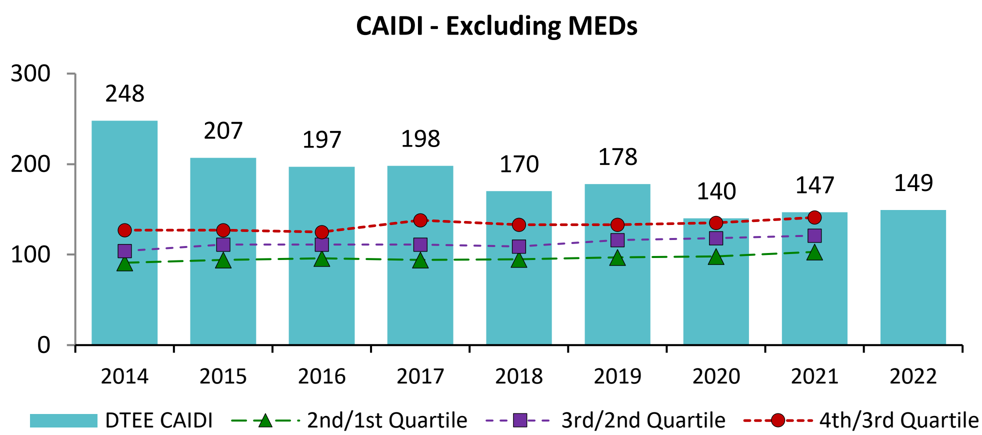


Exhibit A.4 Reliability Statistics - Catastrophic Storms (DTEE Definition)

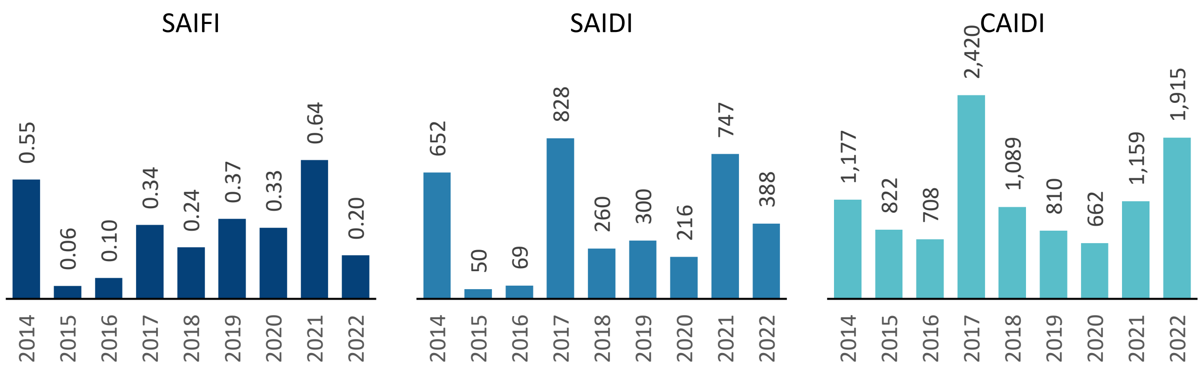


Exhibit A.5 Reliability Statistics – Non-catastrophic Storms (DTEE Definition)

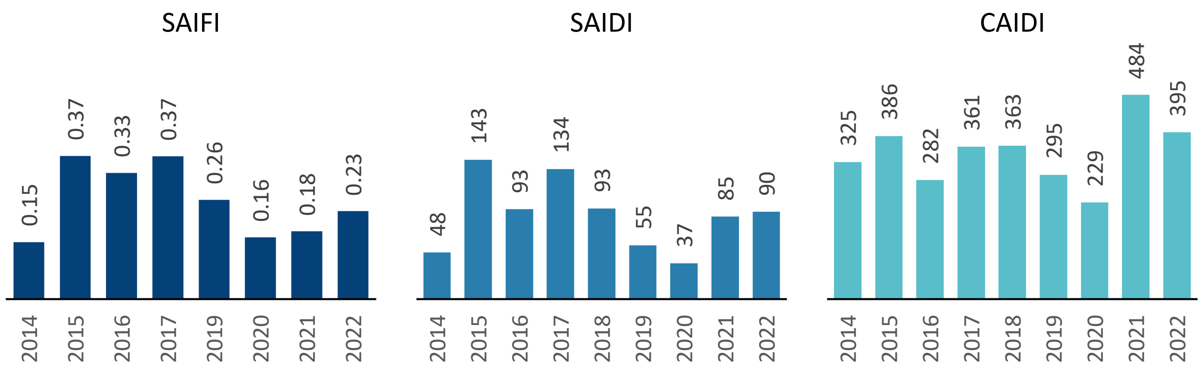


Exhibit A.6 Reliability Statistics - Excluding All Storms

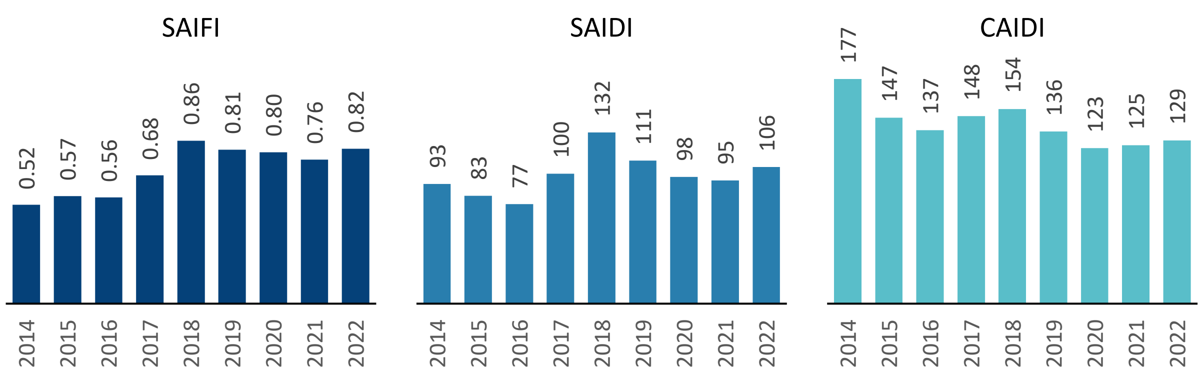
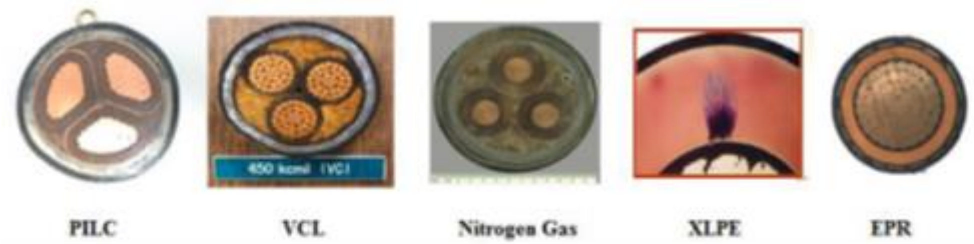


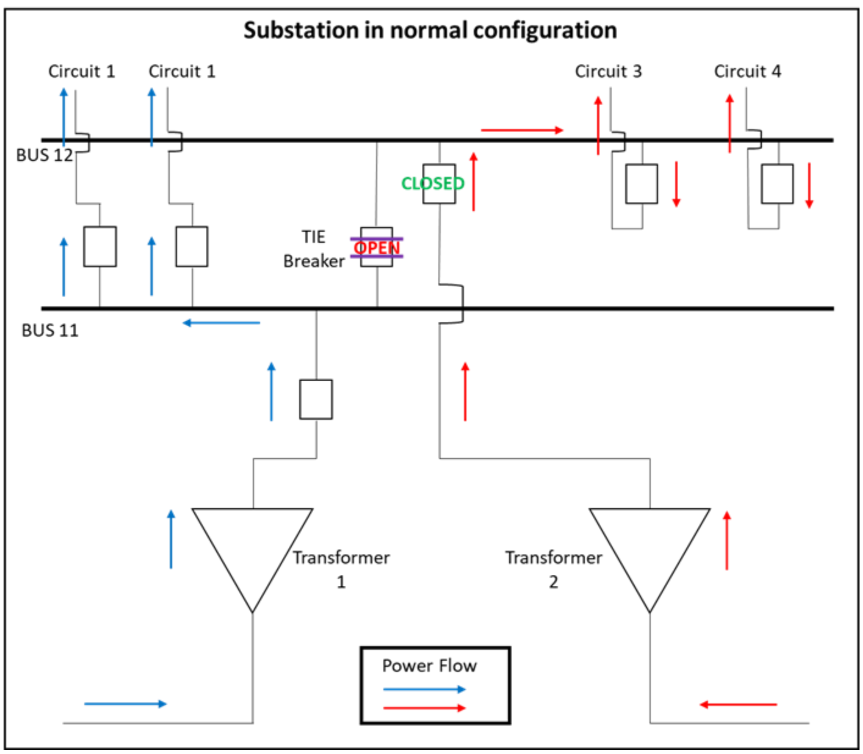
Exhibit A.7 Underground System Cable Types



Appendix B Infrastructure Redesign and Modernization

Appendix B.1 Distribution Load Relief Diagram and Tables

Exhibit B.1.1 Substation in Normal and Contingency States



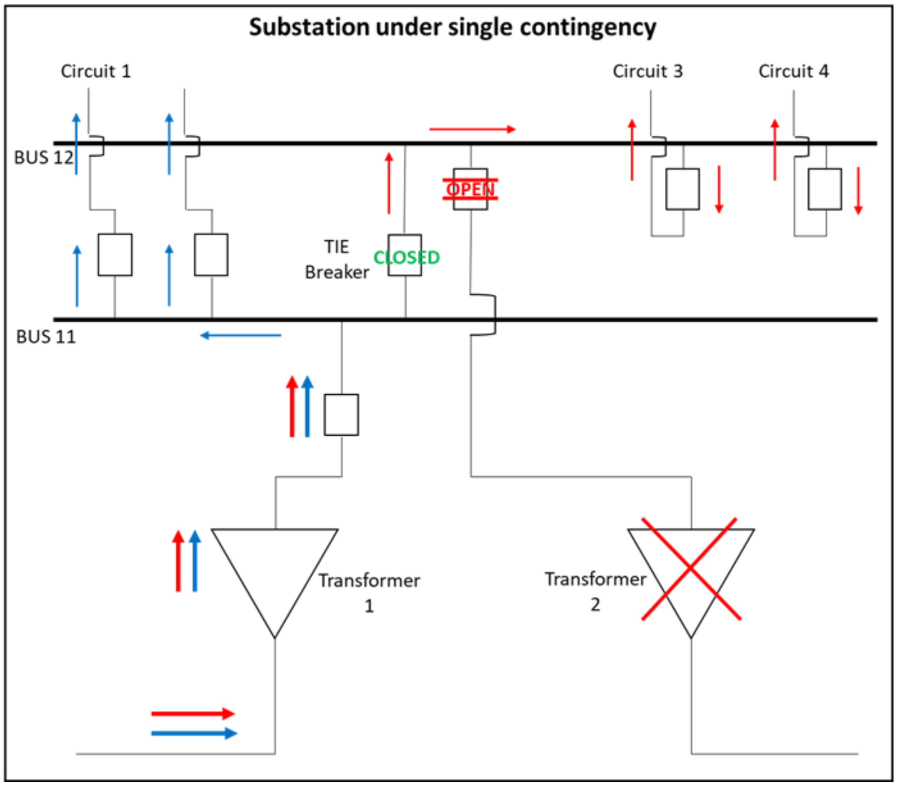


Exhibit B.1.2 Top 25 Highest Ranked Load Relief Substations – Project Summary

Index	Substation	Community	Project and Scope of Work
1	St. Antoine	Detroit	CODI – Alfred Expansion: Expand 13.2 kV Alfred substation
2	Alfred	Detroit	CODI – Alfred Expansion: Expand 13.2 kV Alfred substation
3	Garfield	Detroit	CODI – Garfield Network Conversion: • Rebuild 36 miles of network feeder cable • Replace or remove 78 netbank transformers • Convert 24 miles of overhead • Convert and consolidate the circuits to 13.2 kV fed by Stone Pool substation • Remove 4.8 kV and 24 kV cable and decommission Garfield substation
4	Cato (13.2)	Detroit	CODI – Cato Substation Expansion: Expand 13.2 kV Cato substation

Index	Substation	Community	Project and Scope of Work
5	Temple	Detroit	CODI – Midtown Expansion: Expand 13.2 kV Midtown substation
6	Madison	Detroit	CODI - Madison Conversion: • Rebuild 31 miles of network feeder cable • Rebuild 30 miles of system cable • Replace or remove 92 netbank transformers • Convert three miles of overhead • Convert and consolidate the circuits to 13.2 kV fed by Temple substation • Decommission Madison substation
7	Jewell	Washington	System Loading: Jewell: • Build a new 13.2 kV substation • Build 6 miles of underground conduit and install 8 miles of underground cable • Establish 4 new distribution circuits to accommodate load transfers from Jewell circuits • Convert and transfer about 11 miles of overhead line from Washington and decommission Washington 4.8 kV substation
8	Walker	Detroit	CODI – Islandview Substation and Walker Conversion: • Construct new 13.2 kV Islandview substation • Convert 32 existing 4.8 kV circuits from Walker and Pulford • Decommission Walker substation • Decommission aging 24kV cables and infrastructure
9	Cody	South Lyon	System Loading: Cody: • Expand Cody substation • Establish 4 new circuits • Install 8 miles of underground conduit and 17 miles of underground cable • Reconductor 7.5 miles of overhead line
10	Hawthorne	Dearborn Heights	4.8 kV Conversion: Hawthorne Relief and Circuit Conversion:

Index	Substation	Community	Project and Scope of Work
			• Extend overhead from Mallard distribution circuits and convert 4.8 kV areas out of Glendale and Hawthorne • Upgrade Biltmore 13.2 kV substation and establish 3 new distribution circuits • Replace switchgear at Villa substation • Expand Mallard substation and build two new general purpose substations to convert and remove load from Hawthorne, Glendale, Villa, and Daly substations
11	Cato (4.8)	Detroit	CODI – Cato/Orchard Conversion (Cato portion): • Rebuild 17 miles of system cable • Convert and consolidate the circuits to 13.2 kV fed by Temple substation • Decommission Cato 4.8 kV substation
12	Amsterdam	Detroit	CODI – Amsterdam Conversion: • Rebuild 12.3 miles of network feeder cable • Rebuild 50 miles of radial powerline system cable • Replace or remove 60 netbank transformers • Convert seven miles of overhead from 4.8kV to 13.2kV • Convert and consolidate the circuits to 13.2 kV fed by Stone Pool substation • Decommission Amsterdam substation
13	Daly	Dearborn Heights	Load relief will be provided by the 4.8 kV Conversion: Hawthorne Relief and Circuit Conversion project, see Index #10
14	Roseville	Roseville	4.8 kV Barber Substation and Circuit Conversion: • Build new 13.2 kV Barber substation • Convert 20 miles of 4.8kV to 13.2kV • Reconductor 3 miles of 3 phase 13.2kV • Install 1 mile of new 13.2kV conductor • Decommission Bunert substation
15	Howard	Detroit	CODI – Howard Conversion: • Rebuild 6 miles of network feeder cable • Rebuild 12 miles of system cable

Index	Substation	Community	Project and Scope of Work
			• Replace or remove 89 netbank transformers • Convert three miles of overhead • Convert and consolidate the circuits to 13.2 kV fed by Corktown, St. Antoine, Cato, and Temple substations • Decommission Howard substation
16	Golf	Macomb	<u>System Loading: Kings Point</u> • Build new 13.2 kV Kings Point substation • Install 13 miles of system cable to establish the new 8 load carrying circuits and one throwover circuit • Reconductor 5 miles of overhead • Convert 3 miles • Install conduit and cable to establish 2 new circuits out of Golf substation
17	Cypress	Marysville	Load relief will be provided by completion of new industrial substation
18	Utica	Utica	Load relief will be provided by transfers between Utica circuits
19	Shaw	Imlay City	<u>System Loading: Brown City:</u> • Install new 13.2 kV substation at Bennett Station • Replace transformers at Marlette substation • Convert and transfer about 38.5 miles of Tacoma, Marlette, Brown City, and Shaw circuits to 13.2 kV • Decommission Brown City Substation
20	Slater	Brockway	<u>4.8 kV CC: Yale-Slater Decommissioning and Circuit Conversion:</u> • Build new 13.2 kV substation • Reconductor and convert 5.6 miles of single phase to three phase • Reconductor and Convert 25 miles of 4.8kV to 13.2kV

Index	Substation	Community	Project and Scope of Work
21	Wixom	Wixom	System Loading: Wixom: • Add a third transformer at Wixom substation • Replace existing switchgear with two 12-position switchgear • Build multiple miles of underground cable, conduit, and overhead lines)
22	Grayling	Shelby	Load relief will be provided by the construction of new Sigma substation as part of a new business and load growth projects
23	Boyne	Macomb	Load relief will be provided by the System Loading: Kings Point project, see Index #16
24	Snover	Snover	Load relief will be provided by a load transfer to an adjacent substation and circuit
25	Goodison	Oakland Twp	System Loading: Goodison: • Construct a new 13.2 kV substation • Establish two new distribution circuits to relieve load from Goodison • Install underground conduit and cable to connect to existing circuits • Reconductor 1.4 miles of overhead line and extend 2 miles of overhead

Exhibit B.1.3 Additional Load Relief Projects

Substation(s) / Location	Community	Project and Scope of Work
Berlin	Berlin Twp	System Loading: Berlin: Upgrade Berlin substation and split existing distribution circuit
Diamond	Dexter	System Loading: Diamond: Replace transformer #2 and upgrade substation equipment

Substation(s) / Location	Community	Project and Scope of Work
Disco	Sterling Heights	System Loading: Disco: Install 3 miles of underground cable and establish two new circuits out of Bronco substation to provide load relief to Disco substation and circuits
Globe	Vassar	System Loading: Globe Replace the existing transformer at Globe substation with a larger unit
Grenada	Ann Arbor	System Loading: Grenada • Build new 13.2 kV substation • Rebuild existing Grenada circuits and one circuit out of Wolverine substation • Convert and transfer load from adjacent Prospect substation and circuits
Lark/Spruce	Ann Arbor	System Loading: Lark/Spruce • Build new 13.2 kV substation • Split one Spruce circuit into two new Lark circuits • Reconductor almost 6 miles of overhead
Macomb	Clinton Twp	System Loading: Macomb Substation • Expand Macomb substation • Establish 4 new distribution circuits to relieve load from Macomb and adjacent substations and circuits
Malta	Sterling Heights	System Loading: Malta Circuits Establish three new distribution circuits at Malta to relieve load of existing circuits
Mayville	Mayville, Clifford	System Loading: Mayville • Build new pad-mounted 13.2 kV subtransmission distribution facility (STDF) • Convert and transfer load from Mayville and Clifford circuits
New Baltimore/Chesterfield	New Baltimore, Chesterfield	System Loading: New Baltimore/Chesterfield • Build a new 13.2 kV substation and upgrade New Baltimore substation

Substation(s) / Location	Community	Project and Scope of Work
		• Establish 5 new distribution circuits including 1.5 miles of underground cable installation and rebuilding 4 miles of overhead distribution • Rebuild 8 miles of overhead 40 kV line
Otsego/Capac	Imlay Twp	System Loading: Otsego/Capac • Build new 13.2 kV substation • Establish two new circuits to relieve 13 MVA of load from Otsego and Capac substations and circuits
Port Hope	Rubicon Twp	System Loading: Port Hope • Build new 13.2 kV subtransmission distribution facility (STDF) • Reconductor one mile of overhead • Transfer all Port Hope load to new STDF and decommission Port Hope
Port Sanilac	Port Sanilac	System Loading: Port Sanilac • Build new 13.2 kV substation • Convert and transfer load from Port Sanilac and Foster circuits • Decommission Port Sanilac substation
Richmond/Armada	Richmond, Armada	System Loading: Richmond/Armada • Upgrade Richmond substation • Transfer existing Richmond and Armada load • Decommission 4.8 kV sides of Richmond and Armada substations
Spokane/Seneca	Rochester Hills	System Loading: Spokane/Seneca Expand Spokane substation and establish 7 new distribution circuits to relieve Spokane and Seneca
Sterling	Sterling Heights	System Loading: Sterling Expand Sterling substation and establish three new distribution circuits
Tahoe	Novi	System Loading: Tahoe: Expand Tahoe substation and establish new distribution circuit

Exhibit B.1.4 Projected Costs and Timeline for Load Relief Projects

Project	2024	2025	2026	2027	2028	2024-2028 Cost Estimate ($ million)
System Loading: Jewell						$23
System Loading: Cody						$31
System Loading: Kings Point						$29
System Loading: Brown City						$17
System Loading: Wixom						$29
System Loading: Goodison						$18
System Loading: Berlin						$5
System Loading: Diamond						$4
System Loading: Disco						$5
System Loading: Globe						$3
System Loading: Grenada						$39
System Loading: Lark/Spruce						$13
System Loading: Macomb Substation						$15
System Loading: Malta Circuits						$1
System Loading: Mayville						$15
System Loading: New Baltimore/Chesterfield						$14
System Loading: Otsego/Capac						$11
System Loading: Port Hope						$3

Project	2024	2025	2026	2027	2028	2024-2028 Cost Estimate ($ million)
System Loading: Port Sanilac						$26
System Loading: Richmond/Armada						$32
System Loading: Spokane/Seneca						$31
System Loading: Sterling						$11
System Loading: Tahoe						$8

Appendix B.2 Subtransmission Tables

Exhibit B.2.1 Subtransmission Projects Summary

Project Name	Community	Scope
Subtransmission Redesign and Rebuild Projects		
Badax Transformer 102 Addition	Bad Axe	• Expand Badax station by installing a new 40kV bus with additional positions and new transformer
Bernard	Wales Twp.	• Install a capacitor at Bernard substation
Boyne	Macomb	• Expand Boyne station • Install 1.5 miles of new conduit and 40kV underground cable • Install 2.5 miles of new 40kV overhead lines • Reconductor overhead and underground on two trunk lines
Carpenter	Milan	• Install a capacitor at Carpenter station

Project Name	Community	Scope
		• TIE 1568 – reconductor 6.1 miles of 40kV overhead and distribution underbuild • TIE 3705 – reconductor 6.5 miles of 40kV overhead and distribution underbuild
Custer Republic	Monroe	• Decommission transformer at Republic • Decommission and reconfigure trunk lines • Replace relay panels at Custer station
Derby	Vassar	• Install two new transformers and associated equipment
Detroit Waste Water Maxwell Cable Replacement	Detroit	• Replace over 4,500 feet of underground cable • Replace over 4,500 feet of conduit
Hurst	Howell	• Expand Hurst station
Imlay Rebuild	Imlay City	• Expand Otsego station • Decommission & remove 40kV busses and associated equipment at Imlay • Reconfigure tie lines by installing underground cable and overhead lines
Kennett	Pontiac	• Complete decommission and equipment removal at Kennett substation
Mohican	Marysville	• Complete decommission and equipment removal at Mohican substation
Oak Beach Capacitor	Port Austin	• Install a capacitor at Oak Beach substation

Project Name	Community	Scope
		• Install 40kV cap bank switcher with associated below grade and relaying equipment
Pigeon Area Improvement	Unionville, Sebawing, Kilmanagh, Pigeon, Bayport, Caseville, Kinde, Port Austin	• Expand Oliver station • Decommission 40kV equipment at Pigeon station • Extend conduit and cable on five tie lines • Extend 40kV overhead on four tie lines
Praxair	River Rouge	• Upgrade equipment at Praxair substation to resolve operating concerns
Reverse Power Relay Scheme Program	Multiple	• Upgrade relays, relay panels at various stations
Sandusky Station Rebuild	Sandusky	• Expand and rebuild Sandusky station and substation
Sandusky Transformer 101 Breaker	Sandusky	• Replace existing Transformer 101 secondary disconnect switch and associated equipment
Small Projects & Reserve	Various	• Complete necessary work to address small overload issues
STPS6	Snover	• Remove unused overhead subtransmission lines and associated equipment from former STPS6 site
Tempest Phase II	Pontiac	• Rebuild Tempest substation to current standards
Thumb Electric Fault Isolation	Kinde, Watertown, Ubly, Owendale, Millington	• Replace five 40kV pole top switches with new automatic pole top switches to support shutdowns and future maintenance

Project Name	Community	Scope
Tie 1423	Monroe	• Reconductor 17 miles of 40kV overhead lines and distribution underbuild and relocate out of deep right-of-way • Replace oil breakers at Rockwood and Custer stations
Tie 1473	Sumpter, Augusta, London, and Exeter Twps, Maybee, Raisinville	• Reconductor 17 miles of 40kV overhead lines and distribution underbuild and relocate out of deep right-of-way
Tie 3205	Pigeon, Caseville, Oak Beach, Port Austin	• Install 28.8 miles of new 40kV overhead lines • Reconductor .7 miles of existing 40kV overhead lines • Decommission and remove 24.9 miles of existing overhead 40kV lines
Tie 3416	Bad Axe	• Replace trainers at Badax and Sullivan substations • Replace 1.6 miles of 40kV overhead lines and 1.6 miles of distribution underbuild
Tie 3705	Dundee	• Reconductor 1 mile of 40kV overhead lines • Upgrade relays at Carpenter station
Tie 4104 North	Sherman, Sand Beach	• Reconductor .02 miles of overhead 40kV lines and 16.4 miles of distribution underbuild • Reconductor 5.1 miles of distribution underbuild • Install 18.9 miles of new 40kV overhead lines and 2.8 miles of distribution underbuild

Project Name	Community	Scope
		• Decommission 17.3 miles of overhead 40kV lines • Upgrade Talbot station • Upgrade relaying and sectionalizing
Tie 4105	Lexington, Croswell, Port Sanilac, Applegate, Carsonville	• Reconductor 36 miles of overhead 40kV lines and 19.2 miles of distribution underbuild and relocate out of deep right-of-way
Tie 5208	Milan, Belleville	• Remove 9.7 miles of overhead conductor • Install 14 miles of new 40kV overhead conductor • Replace oil breaker at Carpenter station
Tie 6147	Milford Charter Twp	• Replace 5.7 miles of overhead 40kV lines
Tie 6602	Lima Twp	• Remove 3.75 miles of overhead 40kV lines • Install 3.95 miles of new overhead 40kV lines
Tie 6907	Rochester Hills	• Reconfigure Tie 6907 and Trunk 6941 • Install 1,700 feet of overhead conductor
Tie 7504	Novesta	• Reconductor 12.2 miles, install 4 miles, and remove 4 miles of overhead 40kV lines • Reconductor 2.7 miles of distribution underbuild • Install capacitor at Wilmot station and replace breakers and associated equipment
Tie 810 (Gramer)	Lenox	• Build new Gramer station • Reconfigure existing tie and trunk lines

Project Name	Community	Scope
		• Install 11 miles of 40kV overhead lines • Reconductor 16 miles of 40kV overhead lines • Decommission 5 miles of 40kV overhead lines
Trunk 0359	Detroit, Taylor	• Replace 517 feet of 24kV underground cable and associated equipment
Trunk 1444	Monroe	• Install capacitor at Trinity substation
Trunk 2308	Macomb	• Rebuild 2.9 miles of overhead 40kV lines and distribution underbuild
Trunk 2419	Detroit	• Replace .3 miles of underground cable
Trunk 2448	Detroit	• Replace ~3 miles of underground cable
Trunk 2455	Detroit	• Install 1,000 feet of conduit with 4 new manholes • Install 2,000 feet of 40kV underground cable • Install 2,000 feet of 15kV underground cable • Remove 4.8 miles of underground cable
Trunk 328	Detroit	• Replace 3.4 miles of underground cable
Trunk 3508	Troy	• Replace 2.8 miles of underground cable
Trunk 3509	Troy	• Install new position at Troy station to create new trunk line to relieve Trunk 3509
Trunk 3546	Troy, Birmingham, Royal Oak	• Install .9 miles of conduit • Replace 2.9 miles of underground cable

Project Name	Community	Scope
Trunk 362	Detroit	• Replace 3.3 miles of underground cable
Trunk 4217	Grosse Pointe, Harper Woods, Detroit	• Replace 2.1 miles of underground cable and associated station work • Install new 40kV breaker and associated equipment at Erin station • Replace Vernier substation transformer 3 secondary breaker and cable terminations
Trunk 4245	Eastpointe	• Install 3,000 feet of new conduit • Install 17,500 feet of new underground cable • Remove 17,500 feet of existing underground cable
Trunk 4266	Eastpointe	• Replace 2.5 miles of underground cable • Replace oil breakers at Erin and Savoy stations
Trunk 4601	Burlington, Burnside, Marlette	• Expand Bennett station by installing a new bus and associated equipment • Install 11.1 miles of new 40kV overhead lines
Trunk 4911	Lenox	• Trunk 4911 – reconductor 12.4 miles of 40kV overhead lines and move to road right-of-way • Expand Victor station and install cable and conduit and 3.6 miles of 40kV overhead to establish new Trunk 4950 • Trunk 4962 – relocate 1 mile of 40kV overhead lines
Trunk 7105	Southfield	• Expand Southfield station by installing a new position with associated equipment

Project Name	Community	Scope
		• Install 1.53 miles of new cable for new trunk line
Trunk 7150	Southfield	• Replace 21,775 feet of underground 40kV cable
Trunk 7386	Madison Heights, Warren	• Upgrade ~5,500 feet of underground cable • Install ~2,611 feet of new conduit
Waterman	Detroit	• Consolidate at decommission breaker positions at Waterman station
Other Subtransmission Investment Projects		
Ann Arbor system Improvements	Ann Arbor	• Construct 2 new substations and 5 miles of 120kV lines • Reconfigure subtransmission tie lines and trunk lines
Station Upgrade: Cortland Station Expansion	Highland Park	• Purchase property adjacent to Cortland station and expand the station
Subtransmission Breaker Short Circuit Violations	Multiple	• Install reactors or replace breakers at multiple stations
Transformer High Side Protection Program	Various	• Install high side switching devices on 19 subtransmission and distribution transformers located at 15 different stations • Eight of these transformers will also require relocation and/or replacement due to space constraints at their current sites
TCHPP (Trenton Channel Power Plant) Switchyard Upgrades	Trenton	• Upgrade Trenton Channel switchyard to current standards

Exhibit B.2.2 Projected Investment and Timeline for Subtransmission Projects

	$ Millions					
Project	**2024**	**2025**	**2026**	**2027**	**2028**	**Total Investment 2024-2028**
Badax Transformer 102 Addition						$9
Bernard						$1
Boyne						$0
Carpenter						$8
Custer Republic						$2
Derby						$9
Detroit Waste Water Maxwell Cable Replacement						$2
Hurst						$4
Imlay Rebuild						$2
Kennett						$1
Mohican						$1
Oak Beach Capacitor						$1
Pigeon Area Improvement						$47
Praxair						$3
Reverse Power Relay Scheme Program						$4
Sandusky Station Rebuild						$1
Sandusky Transformer 101 Breaker						$4

Small Projects & Reserve						$3
STPS6						$0
Tempest Phase II						$8
Thumb Electric Fault Isolation						$1
Tie 1423						$3
Tie 1473						$2
Tie 3205						$54
Tie 3416						$5
Tie 3705						$9
Tie 4104 North						$37
Tie 4105						$30
Tie 5208						$5
Tie 6147						$0
Tie 6602						$5
Tie 6907						$2
Tie 7504						$32
Tie 810 (Gramer)						$49
Trunk 0359						$0
Trunk 1444						$1
Trunk 2308						$6

Trunk 2419						$1
Trunk 2448						$3
Trunk 2455						$4
Trunk 328						$4
Trunk 3508						$4
Trunk 3509						$2
Trunk 3546						$7
Trunk 362						$4
Trunk 4217						$7
Trunk 4245						$16
Trunk 4266						$9
Trunk 4601						$33
Trunk 4911						$23
Trunk 7105						$2
Trunk 7150						$2
Trunk 7386						$5
Waterman						$3
Ann Arbor system Improvements						$14
Station Upgrade: Cortland Station Expansion						$7
Subtransmission Breaker Short Circuit Violations						$1

Transformer High Side Protection Program						$22
TCHPP (Trenton Channel Power Plant) Switchyard Upgrades						$2

Appendix B.3 Conversion Tables

Exhibit B.3.1 4.8 kV Conversion Projects

Project	Community	Drivers	Scope of Work
Almont Relief and Circuit Conversion	Almont Twp	• Provide load relief at Almont substation • Replace aging infrastructure • Increase jumpering capability	• Build a new 13.2kV substation • Transfer Almont load to new substation, converting to 13.2kV • Reconductor 15-16 miles of overhead backbone • Establish new jumpering points • Decommission Almont substation
Ann Arbor AC Network Conversion	Ann Arbor	• Address aging infrastructure • Provide capacity for new growth	• Install new underground conduit and cable including secondary cable • Replace existing netbank transformers with dual voltage netbank transformers
Barber Substation and Circuit Conversion	Roseville, Warren, Eastpointe	• Provide load relief • Provide capacity for new load growth • Address aging infrastructure • Increase jumpering capability	• Install a new 13.2kV substation • Convert and transfer load to new substation • Decommission Bunert substation

Belleville Substation	Belleville	• Address aging infrastructure • Provide jumpering capability • Provide capacity for new load growth	• Install a new 13.2kV transformer and replace Transformer 3 with a new 13.2kV transformer • Rebuild and convert over 10 miles of overhead to 13.2kV • Create new jumpering points with adjacent substations
Birmingham Decommissioning and Circuit Conversion	Birmingham, Bloomfield Hills	• Substation outage risk for Birmingham substation • Provide capacity for new load growth • Address aging infrastructure	• Transfer Birmingham load to adjacent substation • Rebuild Birmingham substation to new 13.2kV substation • Convert and transfer load from Birmingham and Quarton Road substations to new substation • Decommission Quarton Road substation
Buckler Circuit Conversion	Ann Arbor	• Provide load relief and capacity needs for downtown Ann Arbor • Increase jumpering capability	• Transfer remaining circuits from Argo to Buckler substation, converting them to 13.2kV
Calla Circuit Conversion Phase 2	Dexter	• Provide load relief to Diamond substation and capacity needs for Dexter • Increase jumpering capability	• Rebuild 4.8kV Diamond circuits to 13.2kV and transfer to Calla substation
Cortland / Oakman / Linwood Consolidation	Detroit	• Reduce trouble events and O&M expenses by decommissioning two aging, underutilized 4.8kV substations	• Consolidate 4.8kV Oakman and Linwood into 4.8kV Cortland substation to decommission aging substation equipment and system cable

Griffin and Williamston 4.8kV ISO Conversions	Webberville, Williamston	• Address aging overhead infrastructure	• Convert 13.6 miles of overhead from 4.8kV to 13.2kV and remove three ISO down transformers
Grosse Pointe Substation and Circuit Conversion	Grosse Pointe, Eastpointe, Detroit	• Provide capacity for new load growth • Address aging infrastructure	• Install a new 13.2kV substation • Convert and transfer load from Vernier, Wayburn, Grosse Pointe and Denver substations • Decommission Wayburn, Grosse Pointe and Denver substations
Hawthorne Relief and Circuit Conversion	Dearborn Heights	• Provide load relief • Address aging infrastructure • Provide capacity for new growth	• Extend overhead from Mallard distribution circuits and convert 4.8 kV areas out of Glendale and Hawthorne • Upgrade Biltmore 13.2 kV substation and establish 3 new distribution circuits • Replace switchgear at Villa substation • Expand Mallard substation and build two new substations to convert and remove load from Hawthorne, Glendale, Villa, and Daly substations
Hemlock Decommissioning and Circuit Conversion	Ann Arbor	• Provide capacity for new load growth • Address aging infrastructure • Provide load relief	• Install STDF (Subtransmission Distribution Facility) and transfer load from Hemlock substation. • Rebuild Hemlock as a new 13.2kV substation • Install new 13.2kV substation • Convert and transfer load to new substation

			•
Hilton Circuit Conversion Phase 2	Ferndale, Oak Park	• Provide capacity for new load growth • Address aging infrastructure	• Expand Hlton Road substation • Convert and transfer load from Ferndale, Hazel Park and Woodside substations to expanded Hilton Road substation • Decommission Hazel Park, Ferndale and Woodside substations and 24kV trunk lines out of Lincoln station
I-94 Substation and Circuit Conversion (Promenade)	Detroit	• Replace aging infrastructure • Reduce trouble events and O&M expenses • Provide capacity to emerging businesses such as I-94 industrial park	• Construct a new 13.2kV substation • Convert existing 4.8kV circuits from Lynch, Lambert and Pulford • Decommission Lynch, Lambert and Pulford substations • Decommission trunk lines
Lapeer-Elba Expansion and Circuit Conversion (Apollo)	Lapeer, Elba Twp	• Provide load relief • Replace aging infrastructure • Increase jumpering capability	• Build a new 13.2kV Apollo substation • Convert and consolidate 4.8kV circuits from Elba and Lapeer substations to 13.2kV • Decommission the 4.8kV portion of Lapeer substation • Decommission Elba and 40kV tap to substation • Transfer a portion of Hunter's Creek to new substation to improve reliability
McKinstry Substation Decommission	Detroit	• Decommission substation as all load has been transferred to	• McKinstry substation will be decommissioned and all equipment removed.

		Zenon or West End substations due to the Gordie Howe International Bridge project	
Monroe Substation and Circuit Conversion	Monroe	• Address aging infrastructure • Provide load relief • Provide capacity for new growth	• Construct a new 13.2kV substation • Convert and transfer load from Front and Roosevelt substations to the new 13.2kV substation • Decommission Front and Roosevelt substations
Pine Grove Substation Relocation and Conversion	Port Huron	• Substation needs to be relocated due to bridge plaza expansion	• Construct a new 13.2kV substation • Re-route subtransmission lines to feed new substation • Convert and transfer all load from Pine Grove substation • Decommission Pine Grove substation
Pittsfield Substation and Circuit Conversion	Ann Arbor, Ypsilanti	• Provide capacity for new load growth • Address aging infrastructure • Provide load relief	• Install a new 13.2kV substation • Convert and transfer load from Pittsfield to new substation • Decommission Pittsfield substation
Quincy Conversion	Yale	Aging wood foundation supporting transformer at Quincy substation	• Construct new pad-mount substation • Convert 3 miles of overhead and install ISO-down transformers • Transfer load from Quincy to new pad-mount • Decommission Quincy substation
Rochester Decommissioning	Rochester Hills	• Address aging infrastructure	• Construct a new 13.2kV substation

and Tienken Relief		• Provide load relief • Provide jumpering capability • Provide capacity for new load growth	• Convert and transfer load from Rochester and Tienken substations to the new 13.2kV substation • Decommission Rochester substation
Royal Oak Substation and Circuit Conversion	Royal Oak	• Reduce customer interruptions with increased protection • Provide capacity for new load growth	• Construct a new 13.2kV substation • Convert existing 4.8kV circuits from Whittier and Webster substations to new substation • Convert and transfer 4.8kV Lincoln load to 13.2kV side of Whittier substation • Decommission 4.8kV Whittier, Webster and Lincoln substations
Scotten Circuit Consolidation	Detroit	• Increase jumpering capability	• Decommission and consolidate three circuits at Scotten substation
Unionville DC 301 B1 Conversion – resolve voltage problems	Unionville	• Increase motor start capabilities in the area that will reduce flicker	• Convert a portion of the circuit to 13.2kV, relocate regulators and capacitors on the circuit
Unionville Decommissioning and Circuit Conversion	Unionville	• Provide load relief • Provide capacity for new load growth • Address aging infrastructure • Provide jumpering capability	• Install a new 13.2kV substation at existing Randolph Station • Reconductor 16 miles of overhead line • Convert and transfer load from Unionville and Fairgrove to the new 13.2kV substation • Decommission Unionville substation
White Lake Decommission and Circuit Conversion	White Lake	• Provide load relief • Replace aging infrastructure	• Build a new 13.2kV substation with four load carrying circuits

		• Allows for jumpering (existing 4.8kV is islanded – surrounded by 13.2kV) • Provide capacity for new load growth	• Convert and transfer load from White Lake substation and a portion of Clyde substation • Establish new jumpering points • Decommission White Lake substation
Yale-Slater Decommissioning and Circuit Conversion	Yale	• Address aging infrastructure • Provide capacity for new load growth • Increase jumpering capability	• Construct new 13.2kV substation • Reconductor, convert and transfer load from Slater and Yale substations to new 13.2kV substation • Decommission Slater and Yale substations
Zenon Circuit Conversion Phase 2	Detroit	• Addresses aging infrastructure • Provide jumpering capability • Provide capacity for new growth	• Expand Zenon Substation • Convert and transfer load from Scotten and Westend substations • Decommission Scotten and Westend substations

Exhibit B.3.2 Projected Costs and Timeline for 4.8 kV Conversion Projects

Project	$ Millions					
	2024	2025	2026	2027	2028	Cumulative 2024-2028 Investment
Almont Relief and Circuit Conversion						$1
Ann Arbor AC Network Conversion						$34
Barber Substation and Circuit Conversion						$17
Belleville Substation						$11
Birmingham Decommissioning and Circuit Conversion						$27
Buckler Circuit Conversion						$4
Calla Circuit Conversion Phase 2						$9
Cortland / Oakman / Linwood Consolidation						$1
Griffin and Williamston 4.8kV ISO Conversions						$13
Grosse Pointe Substation and Circuit Conversion						$52
Hawthorne Relief and Circuit Conversion						$62
Hemlock Decommissioning and Circuit Conversion						$58
Hilton Circuit Conversion Phase 2						$82
I-94 Substation and Circuit Conversion (Promenade)						$140
Lapeer-Elba Expansion and Circuit Conversion (Apollo)						$27
McKinstry Substation Decommission						$2
Monroe Substation and Circuit Conversion						$2
Pine Grove Substation Relocation and Conversion						$24
Pittsfield Substation and Circuit Conversion						$60
Quincy Conversion						$0

Rochester Decommissioning and Tienken Relief						$20
Royal Oak Substation and Circuit Conversion						$34
Scotten Circuit Consolidation						$2
Unionville DC 301 B1 Conversion – resolve voltage problems						$1
Unionville Decommissioning and Circuit Conversion						$13
White Lake Decommission and Circuit Conversion						$40
Yale-Slater Decommissioning and Circuit Conversion						$47
Zenon Circuit Conversion Phase 2						$85

Appendix C Technology and Automation

Appendix C.1 Grid Automation Investments

Technical Training Center DER lab

The Technical Training Center (TTC) DER lab is DTEE's location to test and validate technology and processes before deployment to the system and validate NWA controls and approaches. The TTC DER lab co-locates the training center of excellence to allow for field and engineering input on new technology with infrastructure to test interactions of technology and compatibility of operating practices. Hardware in the loop simulation of controls and grid models coupled with real time networking and cyber security testing allows complex control schemes to be tested thoroughly before deployment on a specific project using the actual control hardware.

The testbed also allows testing and training of DER systems available to customers to determine how control modes function, interactions between devices and test cyber security and integration. Further, the DER Lab allows the development of inspection and commissioning procedures and safety training, pilot documentation for installation of initial units in the grid and working with manufacturers on issues that are found in testing to reduce issues that DTEE must resolve. In a recent case, the DER Lab staff found an issue in the wiring of a popular inverter and worked with the manufacturer to change the installation manual and provide instructions to Michigan solar installers. This specific inverter has been mis-connected by developers in more than 50 installations in DTEE's grid since its introduction in early 2023 and these installations had to be corrected to avoid improper operation and safety issues for DTEE personnel and the customers.

Gateways & Grid edge services

As DER sites become more capable, the functions the devices can perform are moving from passive to active management. Most existing inverters have initial settings applied at installation with no intent to change them dynamically, advanced inverters can be actively controlled in real time and have their settings updated to adapt to changes to the grid configuration. The mechanism to provide this real time change management and coordination can be done through a grid edge gateway device that is installed alongside the DER.

While simple DER may be able to operate independently, when multiple DER need to coordinate, they may not all be able to communicate the same protocol or have the same capabilities. and A gateway can provide this point of coordination. This is especially useful in distribution microgrids where multiple devices may need to coordinate to reconfigure the microgrid state or boundaries and may not be all owned by the same party or be at the same location.

Grid edge gateways are needed at the interface point between customer resources and utility resources to act as a security and control coordination point. Grid edge gateways communicate with both the customer DER(s) and the utility SCADA/DERMS systems and provide a cyber security firewall and intrusion detection capability to allow necessary communications to flow between the utility and the DER.

Gateways provide many functions including cyber security, centralized management, anomaly detection, coordination of resources, protocol conversion, deconfliction of control commands, sitewide optimizations, and alarming and event logging. Gateways initially are being deployed as part of real time SCADA controls for large DER such as solar and wind parks but will become increasingly necessary to coordinate distribution microgrids and Non-Wire alternatives.

Currently gateways are collections of off the shelf hardware that are packaged into control cabinets, longer-term dedicated gateway devices that perform the communications, cyber security, control and optimization functions. The gateways being utilized implement Open FMB (Open Field Message Bus) as a standardized and interoperable data exchange framework and an application suite called Open DSO which has been demonstrated by several utilities to be able to provide DER and microgrid coordination and has the ability to have modular optimization and protocol adapters using cyber security best practices. Gateways are becoming standardized through IEEE1547.10 which defines the behavior and function of gateways. Eventually certified third party gateways may be available that allow for utility applications to be securely loaded onto them.

Load and Electric Vehicle managed charging

Transportation electrification will be highly dependent on the ability to manage vehicle charging loads, anticipate peak demands, and implement programs to incentivize off peak usage. While programs and incentives are developing, this program is focused on technical integrations to the Company's control systems to ensure cyber security and reliable integration of electrified transportation.

This program also includes fast charger modeling and assessments that plan for the impact of high-powered chargers and characterization of dense electrified transportation loads including power quality metering and analysis at several sites in the service territory. These investments support multiple demonstration implementations including electrification of public transportation and fleets and DTEE's truck stop of the future project in Redford that is a partnership with Daimler Trucks.

Managed charging technology and communications standardization and integration are specific focuses of the program. This includes the DOE supported EVs-at-RISC technology demonstration program to create a reference architecture and implementation for cyber secure managed charging using interoperable protocols. This project is in partnership with Idaho National Labs (INL), Oakridge National Laboratory (ORNL) and other partners and demonstrates utilizing advanced security approaches such as zero trust and advanced firewalls to provide a reference framework for distribution scale charge management. The project will be demonstrating capabilities in the Corktown area through 2025. This program also includes demonstrations of digital, policy-based program management that implement digital contracts to the DER. Longer term, several projects with secondary use and repackaging of transportation storage for grid reuse will be undertaken as batteries become available. Vehicle to Grid (V2G) and vehicle to load integrations to the interconnection process including communications integration to allow management are being investigated and demonstrated.

New Technology evaluation

As new automation and grid hardware is brought online, use of a rigorous and standardized process for evaluation, testing, and documenting the technology implementation is employed. This project includes field demonstrations and training center implementation of technology before it is made broadly available into standard designs and use.

CVR/VVO

The initial CVR/VVO program pilot was completed in 2022 and the program was paused for 2023. The program achieved the expected results, but it was identified that the method implemented resulted in an unsatisfactory number of Load Tap Changer (LTC) operations and a more optimized method such as the ADMS VVC capability needed to be used instead. In late 2023, an RFP will be conducted for measurement and verification, reporting, and consulting that will be an ongoing aspect of the program until these functions can be fully automated in house. In 2024, the CVR/VVO program will be restarted, the initial work will be to complete field construction of jobs that were planned in 2022 but put on hold. The remaining budget will be used to replace a substantial number of capacitor controls on circuits ahead of substation work. These capacitor controls will reduce operation of the LTC by substituting operation of the capacitor bank for fine voltage adjustment and transient voltage issues. The ADMS VVC module will be enabled to control all suitably configured capacitor and voltage regulation devices on the system and CVR will be enabled where all work on a substation bus is completed. The approach allows the ADMS CVR module to optimize the system voltage continuously in any location where voltage control devices are located. The CVR module will be enabled where substation LTC control and field installation of capacitors has been completed.

From 2025 onward the program will focus on replacement of 100% of all poletop capacitor and regulator controllers with SCADA enabled controls, analyzing all circuits for appropriate capacitor and regulator placement, moving and supplementing capacitor placement where needed. The capacitor control replacement will have an added value of providing sensing capability at each location which will be used by the ADMS. This will be done while maintaining a low, but sustainable schedule of substation LTC upgrades each year that allows for appropriate coordination and shutdowns. Substation LTC control upgrades to support CVR/VVO functionality will be built into design standards and replacements. This will result in a wider deployment of smaller initial benefits because most circuits will be optimized with the pole top devices alone, but this will allow for increased visibility into the system response to VVO through the ADMS and get critical data back to planning tools to verify CVR opportunities. This work will be coordinated with 4.8KV conversion and replacement and the circuit automation programs to ensure that device is placed where needed. The program will also investigate the use of circuit capacitors as part of the optimization and alternatives to large station capacitors. Pole top regulator SCADA controls and smart inverter controls will also be added to the program over the next 5 years. Additional work in the program will include development of sufficient tracking algorithms, analysis and reporting to measure benefits vs expected results and improvements to internal planning tools to allow CVR/VVO to continue to be operated as circuits change due to load changes, circuit reconfiguration and DER installations.

Appendix C.2 Grid Management Investments

DERMS & FERC2222

The Distributed Energy Resource Management System (DERMs) is composed of five major functions which will be implanted as part of this investment:

- Program assignment with end point Registration/deregistration
- Interfaces between the ADMS and aggregator/end point systems/APIs
- Dispatch optimization
- Program compliance
- Short term DER forecasting for load and supply

The initial deployment of DERMs will be to integrate all Company owned DER that is not connected through SCADA as well as all existing DR programs and systems such as Interruptible air conditioning and heating to the ADMS. Once these integrations are done, major third-party integrations will be prioritized depending on the implementation of market aggregators, FERC2222, or tariff programs.

The company will begin by selecting a DERMs vendor with deployment of an initial DERMs system.This initial system will be sized to cover expected DERMs needs for the next five years which is anticipated to control active DER endpoints along with a substantial amount of the customer base in DR end points. Afterwards, or as needed, reevaluation of the market space will be made to determine if the system will continue to be expanded or if substantial improvements in the industry have been made in DERMs capabilities. Adjustments to this plan will be made as needed to comply with State and Federal requirements and programs.

Distribution System Operator Support tools (DSO) include dynamic analysis, optimization analysis of DER, portfolio optimization, management of customer DER programs, short term forecasting, Locational Value Analysis, and linkages to the Generation Management System (GMS) for market functions such as oversight, will be evaluated. These functions will be served by a combination of DERMs, enhancements to Power runner, and tools yet to be identified as the maturity of commercially available toolsets improves.

FERC841/2222 Coordination

While compliance for MISO requirements and process is several years out, some of the foundational investments in this space have long implementation times and require augmenting and reworking many existing processes. Investments in preparing for implementation have already started in cases where there is a high degree of certainty that the functionality is needed. Tools will be needed to support the control room in identifying constraints that are created by market participating entities on distribution circuits and aggregations and the associated communications needed with all of the affected entities.

Tools will also be needed to inform the system supervisor of the impact of operating decisions in constraining market participants and aggregations and of the constraints that aggregations that are responding to market actions. These tools will need to evaluate short term planning horizons of a few minutes to a few weeks to allow for appropriate notifications and constraint identification.

Process changes will be required to support the coordination and notification processes. Control process and signals will be developed to inform participants and aggregators of system constraints, shutdowns, and maintenance. Short term forecasting and prediction tools will need to be integrated into the process to anticipate possible power flow changes from market and aggregator operations.

Enhancements to the interconnection process will be made to allow for compliance to the program registration and validation requirements that are required by MISO. Enhancements in planning processes and tools will be made to perform the appropriate studies and scenarios that will be created by more load and generation volatility.

Cyber security and SCADA tool server

This program establishes work practices, substation hardware specifications, and back-end software to implement cyber security policies in an auditable and efficient manner, utilizing Subnet solutions on the SCADA tool servers to provide cyber security interface for patching, firmware updates, password updates and security auditing. This program also establishes standards for new networked substations and includes cyber security consulting and best practices benchmarking as well as security testing.

Prior years of project implemented SCADA tool servers in both the Downtown and Ann Arbor data centers. Ongoing work includes (1) implementation of interfaces to SCADA tools including power quality metering tools such as Honeywell Connexo and Schneider PME to the PI historian, (2) interfaces between cybersecurity and vendor specific asset management tools for field devices that are part of the cyber security and settings management programs.

Automation Configuration and Testing database

This project replaces in-house developed software with a vendor-supported and industry standard system to provide a single source of protection and automation settings data, as well and a consistent interface for automation device change management, auditing, and lookup of settings. Automated interface with test equipment to facilitate test data collection and record keeping, as well as interfaces to asset management and network management data will allow SCADA, ADMS, and planning tools to have the most up-to-date data. This project also enables the use of advanced automated test sets for technicians to streamline testing. Remote access through SCADA tool servers to validate settings will also be enabled.

Appendix C.3 Distribution Planning Investments

Load Allocation Analytics Program

Power Runner is a software tool designed to incorporate AMI, SCADA, and forecast data into one data set of historical and future hourly intervals to serve the requirements of the planning tools for load allocation and data for analysis.

Power Runner requires interfaces to many data systems including the data lake, NMS, SCADA (DOPI), AMI (AMIPI), and Power Quality Metering (Schneider PME and Honeywell Connexo). Power runner will be used to improve data quality by identifying gaps in meter and SCADA data and inconsistencies that can then be fed back to the NMS for correction. Power Runner will be integrated with the ADMS 'as switched model' to provide an accurate historical record of the state of the system down to the customer meter level and validate automation performance. Power Runner will provide short term forecast information and incorporate long term forecast data and scenarios from corporate load forecasting for use in planning simulations. Power Runner will be used to update and automate the ALA and TLA processes and assess system losses, DR and DER program compliance, and validate forecast data. Enhancements to DOPI and AMIPI systems to support Power Runner automation and performance will be included. Data analysis tools from SEEQ to do time series data science analysis and scripted automation of historical trend analysis are also planned to be interfaced to Power Runner.

CYME enhancements Program, Advanced Project Manager and Dynamic Data pull and reporting

The CYME planning tool will be enhanced by acquiring new modules and working with the vendor on the product roadmap that is shared by other utilities to support evolving needs in grid planning. The CYME system will be upgraded on a regular schedule to incorporate new vendor functionality as it becomes available.

The CYME dynamic data pull module will be implemented to collect information from Power Runner. This will allow studies to select specific time periods for analysis or do an 8760 analysis of an entire year. CYME server will be implemented to offload studies that will run for a long time to a central server that can implement GPU and machine learning optimizations and reduce the time to run studies and scenarios. CYME Advanced Project Manager will be implemented and integrated with Maximo to allow each workorder to be linked to the electrical system model changes and the start and end date of the work to be simulated allowing a comprehensive schedule of system upgrades, load additions, and interconnections to be studied across multiple years and alert the engineer if a schedule change will adversely impact the reliability or loading of a circuit. The CYME gateway will be enhanced to pick up additional data from the Asset and GIS systems and further automate the network model validation processes including incorporating the sub transmission and substation models and AC network and the linkage to PSSE models.

CYME will be integrated with the interconnections processing tool PowerClerk to improve screening and study, and automate common validations and checks such as system fault current, voltage min and max, short circuit current, phase imbalance, jumpering, and loop scheme validation. Integration of CYME with Maximo CUs will allow for more accurate engineering estimates and updates. Integration of LIDAR data into CYME reliability analysis will refine SAIFI, SAIDI, CAIDI improvement analysis for project changes. Interfaces from CYME to PSSE will be developed to meet MOD-32 modeling requirements and to coordinate model updates between the distribution and sub transmission and transmission. Automations will be developed to streamline and automate modeling and scenario setup.

A single system to track future customer load additions and changes, interconnections, and their configurations will be created to feed the ADPS and allow for scenario analysis. A single system to track customer program participation, tariff and market participation will be developed to allow the planning tools to update scenario assumptions on DER utilization, DR responses and validate requirements for programs and FERC 2222. Enhanced reporting for the engineering teams will be provided to consolidate the very large amounts of data produced by the new planning tools and scenario analysis to identify limits, constraints, and areas for more focused study.

Forecasting and propensity analysis Program

Use case specific forecasting and propensity tools will be evaluated and it is likely that a combination of the IFS forecasting scenarios and specific technology propensity tools will be integrated to develop the specific scenarios that the ADPS will use. These tools need to not only inform the potential adoption scenarios of various technologies in both time and location, but also be able to provide the base parameters to allow the power flow simulations to incorporate the specifics of each technology and control methods.

The propensity and forecasting solution will need to create useful and practical scenarios and bounds for the ADPS tool to process. Anticipated models that are needed will include, but are not limited to, weather models, home and commercial energy usage models, HVAC electrification, EV charging adoption, managed charging models, solar adoption, energy storage mode analysis, vehicle to grid and industrial, and fleet electrification models. Energy storage specifically needs specialized analysis because of the need to charge and discharge the storage without violating constraints and the limited duration of energy storage requires a time series analysis across many different usage cycles.

Advanced machine learning will be needed to identify scenarios that represent the right boundaries to study in order to reduce the computational needs as well as the amount of analysis that is needed to validate and review the scenarios.

Power Runner will be integrated with the Itron Metrix forecast outputs created by the load forecasting team. This will provide consistency for the feeder level forecasting that will be used for scenario analysis in ADPS/CYME. Power Runner will also supply the cleansed SCADA data from PI to the Itron Metrix forecasting solution and provide reporting on the deltas between SCADA, AMI and forecasting for further data analysis. Power runner will be enhanced to provide short range forecasting (<1 month) that can be used for study of switching and planning coordination of shutdowns.

In the next 5 years the combination of ADPS and Power Runner will be used to bring Integrated resource planning and distribution planning closer with the longer-term goal of reaching a suite of tools that allows for Integrated Distribution Modelling (IDM).

Interconnections Process Enablement Program

The MPSC released final interconnection rules under U-20890 and is has open proceedings on U—21117 interconnection rules and procedures. There are several short- and longer-term investments to meet compliance with these orders and to improve efficiencies of the new interconnection processes. Compliance with new interconnection rules, automating to improve efficiency, and processing time are major portions of the Operational Technology investment in this program; the program also includes engineering consulting and benchmarking support through EPRI and other vendors on industry best practices, customer facing design and interconnection study process enhancements and tools updates.

The updates to the interconnection rules drive investments in two key exiting tools for interconnection processing, PowerClerk and its integration into SAP commerce cloud. PowerClerk is an online application system for interconnection used by the Company and many other utilities to support interconnection applications and tracking and processing, including digital signatures of documents. At the end of 2022 the Company completed the integration between PowerClerk and Commerce cloud. This integration provided several benefits to customers and to the efficiency of the interconnection process: first, the integration allowed for single sign on so that Power Clerk applicants, both customers and contractors, are able to use a DTEE login, and second, it enabled electronic payment of interconnection fees and automatic creation of internal orders top post the payment against. This greatly reduced the number of physical checks the company received for interconnections and for those applications paid for electronically, eliminated a significant amount of time waiting for mail delivery and check processing. The new rules implement several changes that require upgrades to this system. Fees and fee calculations have changed, new interconnection statuses have been added that require tracking, and several new sub processes were added, such as pre application, that require new software development and testing to meet the requirements. Further enhancements are also planned to incorporate changes to data and model collection during the application and study process to implement updates to MISO Affected System Study process (AFS), and to capture appropriate data to aggregate into yearly planning models at MISO.

Initial Investments will be made in PowerClerk to adopt the new processes, filters and process steps including timelines and reporting requirements to support fast track, non-export and study tracks, and the new pre-application process. In commerce cloud, interfaces to adopt the new payment structures and process steps will be created. PowerClerk enhancements will be made to support updated reporting and timeline tracking requirements from the new rules as well as enhancements to the DTE website interconnection pages to provide required information, documentation, and procedures. Improvements will be made to the registration system to allow for self-registration of installers, and Business-to-Business customers. Payment will be expanded to cover the new pre-application process as well as study fees. Additional integrations will be added between PowerClerk and the GIS system to allow for completed projects to be automatically added to the mapping system, replacing a manual process today and to support reporting and modeling on pending applications. Additional work will be done in SAP to facilitate adding appropriate transaction codes for different program and meter configurations.

Additional investments will be made to facilitate the screening of interconnections and the study of interconnections. Some of the core system modelling investments are covered in the prior section, but specific integration will be made with the planning tools and PowerClerk to implement automation of the interconnection screens where possible as the screening process in many cases requires a fault or power flow study to get the correct location specific data. The automation will be designed to capture the information from the application and application, insert the interconnection into a temporary study of the current and known future changes to the configuration of the system and then apply the appropriate automated calculation and then return the results to PowerClerk reporting for inclusion into the interconnection technical review package. For studies, a significant amount of time is needed to prepare the study data package and investments into automating the generation of the study and study scenarios from the applicant's data will be made to streamline processing timelines and effort. As other aspects of the ADPS platform are completed, this study automation can be further expanded to run common models and incorporate future grid changes and forecast scenarios into the model runs automatically. Longer term automation of study result interpretation and study reports will be targeted to further streamline the process. Initial investments may include decision support for the interconnection engineer on screening and study results to recommend if additional study is needed or if the results are sufficient to move the project forward.

Another area of investment will be in processes and tools to validate program and tariff compliance for DER. This will not only function as a mechanism to validate customer compliance to specific program and tariff requirements but also provide a continuous program auditing capability to detect gaps in the process before they have any impacts to customers. Some of these compliance functions will be implemented in Power Runner enhancements. Future enhancements may include machine learning algorithms, the use of other supplementary data sets and advanced pattern analysis, especially where storage or other power control systems are used, and meter data alone may be insufficient to determine the driving factors behind the behavior of the DER.

Enhancements will be needed to support FERC2222 implementation. Investments will be made in the application intake process which will be implemented into Powerclerk as a separate program that will provide a linkage between the market participation request and the interconnection while allowing each to proceed according to their appropriate compliance processes. There will also be required validation studies as part of the process that will be automated where possible to maintain the ability to meet timelines. Additionally, investment will be made in integration of load modifying and demand response resources into the modeling process and interconnection process which will impact studies, hosting capacity and scenario planning during peak and light loading conditions. Finally, necessary reporting and coordination functions will be integrated as identified when MISO releases their procedural requirements over the next few years.

One potential area of increased efficiency in the interconnection process is to utilize machine learning algorithms to evaluate interconnection requests. A large amount of the time spent analyzing the request is comparing the application information to the supporting information such as the one line and site plan. While final review by an interconnection engineer is likely in the case of complex systems, validation and consistency checking of more straightforward systems may be able to benefit from machine learning analysis to identify inconsistencies or missing elements. The identification process will be integrated into the PowerClerk application process right after application submission to identify issues as soon as possible in the process so that feedback can be provided to applicants.

Another area of planned investment is in web portals and website enhancements that provide customers additional information and data access on DER integration specific to their location and use case to provide decision support. These tools will be coordinated with other customer decision support analytics for rates and programs to help guide customers to energy efficient solutions and bill savings. These investments are still being investigated.

In the next few years, as Interconnections become more common, work will be undertaken to merge the new service, method of service, and interconnection process into a single workflow. This transition will occur over several years in multiple steps and all of the investments for this transition have not been completely quantified, however, it is likely that much of the work done on interconnection processing will be used to enhance new service processing. As an example, given the rapid pace of vehicle to grid (V2G) development for electric vehicles, PowerClerk will be used to capture applications for bi-directional capable chargers, and to facilitate support of future bi-directional charging in the ADMS, DERMS, and in the circuit analysis.

Hosting capacity Program

In the Commission's June 30th, 2023, Grid Integration Study Report, recommendations were made regarding hosting capacity. These recommendations will benefit directly from investments in the Advanced Distribution Planning System, which are foundational data sources for improved hosting capacity calculations and visualizations.

The initial scope includes improving data availability and map capabilities to provide greater accessibility and interactivity while maintaining security of critical infrastructure and customer information. This work also includes implementing capacity map visualizations and vocabulary to provide consistency of communication about hosting capacity data. Other areas of investment in this program are automating hosting capacity through use of toolkits to improve the frequency of hosting capacity updates and hosting capacity tools for load and distributed generation to allow for visualization of the grid's ability to incorporate additional load and generation.

The commission requested enhancements to hosting capacity for DER as well the creation of a loading capacity map during workshops in 2022, and in the MIPower grid report. Specific requirements may come out of future working groups. An initial loading capacity map is being developed with a public release planned for late 2023. The loading capacity map will be updated once a year based on the annual planning cycle. Internal enhancements to streamline the update process and incorporate specific study data will be ongoing. Enhancements to the hosting capacity and loading capacity maps to increase frequency of updates and increase detail of data will be directly dependent on completion of the ADPS scope. There is currently no specific timeline for public facing enhancements. With integration of CYME and EPRI drive, more granular hosting capacity data can be generated in both high penetration areas, and those that have undergone detailed study. Research in Hosting capacity methods is ongoing, especially in how to integrate storage, power controls, and bi-directional EV charging and this will drive future investment in this area.

Hosting capacity investments are composed mostly of the visualization and presentation of the data that will be derived from the other investments in Advanced Distribution Planning System study tools.

Sub transmission modelling Program

Modeling the interface between the distribution and transmission systems is a critical aspect of operational and reliability planning. This analysis uses different tools than the distribution circuits primarily due to requirements in modeling the bidirectional power flow on the sub transmission tie line system and incorporating DTEE assets into the transmission model maintained by MISO for reliability studies and interconnection process compliance. Several investments in enhancements in this area are required to maintain compliance and to facilitate system planning and investment.

TSAT is required to validate customer defined models and verify modelling and study information for transmission affected systems. TSAT is a tool new to DTEE and many of the vendors that do MISO modelling but is required to generate models for MISO planning scenarios and to incorporate specific customer DER models. PSSE enhancements following requirements from MISO and MOD-32 to produce new model scenarios and synchronize study information with ADMS and CYME will also be part of this program. Scripting will be created to initially allow CYME to roll up distribution connected DER and properly reference between the models to meet the requirements of affected system studies and yearly model updates.

Longer-term there will be a need to merge the distribution models and transmission models to be able to execute more complex multi scenario analysis and wide area optimization. The full scope of these integrations is still being evaluated, but likely will include integrations between IRP planning tools, transmission modeling tools, and distribution modelling tools to create an Integrated Distribution Modeling system.

Power Quality analysis Program

This project includes the identification and purchase of a power quality tool that can collect power quality information from the SCADA tool servers, line sensors, and other meters and correlate events based on time and system impact. Analysis of voltage swells, sags, harmonics, flicker, and waveform events with predictive analytics to identify event precursors and forensic analysis tools to apply sequence of events and precise time stamp synchronization for failure analysis are all functionalities that will be considered when selecting the toolset. Visualization tools to map events and trends over time and on a spatial and schematic view of the system and to generate heat maps to identify patterns and related events. The initial scope is to utilize Schneider PME as the storage and visualization tool for users and then later to integrate machine learning to analyze waveforms against known failure modes and event patterns and identify incipient faults or failures and help troubleshoot outage and power quality events. PSCAD is a detailed power modeling tool that allows for study of harmonic interactions, dynamic response, high frequency transients, and detailed analysis of abnormal power quality events. Additional licenses will be required as more DER require modelling and have interactions with grid equipment that will need to be assessed for upgrades.

Substation and structural Design tools Program

The MicroStation CAD tools will be enhanced with the integration of MicroStation design libraries with Maximo Compatible Units and Bill of material generation to reduce manual work and validate accurate material orders. Additional features include (1) 3D CAD design that allows for automatic evaluation of clearances and conflicts and rapid generation of different cross sections, plans, and views; (2) automatic wire routing and schematic validation; (3) ca comprehensive document and version management system for design revisions and print creation; and 4) incorporation of metadata into design library to allow for analysis of material requirements.

PLSCAD is used for individual engineered poles and overhead structures where additional structural calculations are needed where structural design requires detailed mechanical analysis such as in critical crossings or constrained spaces where guy wires cannot be used and is an advanced CAD tool to do specific modelling on engineered poles and specific structure designs.

Spidacalc is used for all pole designs to ensure that the poles are meeting design standards for Grade B construction. Enhancements to the Spidacalc tool are used by planners to calculate the appropriate design for poles. Licensing for structural design tools like RISA3D is also anticipated. RISA3D is an advanced mechanical and civil design tool to validate structure loading for substations and below grade structures. Bluebeam is another tool that will need investment as it provides print mark up, collaboration and red lining, at a significant savings in engineering and field labor time, freeing those resources to take on the backlog of other work.

One area of new investment will be in LIDAR and spatial assessment tools which includes evaluating and selecting a tool set that allows for incorporation of LIDAR data into planning tools and assessing clearances to vegetation, ROW/easement, truck accessibility, Line sag, risk of vegetation impact to lines and structures, identification of joint use changes, and pole loading changes from design, identifying equipment configuration and pole top arrangement, equipment identification, and contributing to asset health assessments. Additionally, the ability to incorporate photographic and event information into the geospatial toolset to provide a single location for viewing spatially located images and data will be investigated.

Appendix D Stakeholder Engagement

Exhibit D.1 Key Themes from Customer Feedback (February 2023 Ice Storm)

Key Themes from Customer Feedback regarding February 2023 Ice Storms	DTEE's Plan to Address Customer Feedback
Frustration over frequency and duration of outages	DTEE plans to invest $9 billion in grid improvements over the next five years by focusing on the four key areas the Company knows make a significant difference in reliability – tree trimming, infrastructure resilience and hardening, infrastructure modernization, and technology and automation. Each of these investment programs is detailed in this plan.
Dissatisfaction with electric rate increases	Upgrading the grid to a 21st century standard requires the investments outlined in this plan. Specifically, Section 6 contains information on the benefits that can be expected from the proposed level of investment. The Company intends to remain transparent in how those investments are made, which is executed through the rate case process in coordination with the MPSC and participating stakeholders.
Desire for clean energy resources, including rooftop solar	DTEE's proposed investments to upgrade the grid will support additional capacity for clean energy resources, like electric vehicles, rooftop solar and other distributed energy resources. In addition, Section 3 contains a distributed generation/distributed storage growth scenario.[66]
Challenges reaching energy provider via phone and imprecise communications	DTEE's customers deserve as clear and as accurate of communications as possible and they deserve to be able to

[66] Separate from the DGP, DTEE's approved Integrated Resource Plan settlement agreement (U-21193) includes an increase in the DG cap from 1% to 6%.
https://mi-psc.force.com/sfc/servlet.shepherd/version/download/0688y000008puPjAAI

regarding outages/restoration efforts	contact the Company easily. Reference new Section 15.5 on outage/restoration estimates.
Discontent with outage credit compensation	Michigan's Service Quality and Reliability Standards for Electric Distribution System rules establish a bill credit for customers. Michigan is one of a select few states in the country with these customer credits. Due to the widespread impact of the February ice storm, DTEE voluntarily applied an outage credit for qualifying customers. In March 2023, the MPSC made this credit automatic for qualifying customers.[67]

Appendix E Detroit Targeted Study

On September 18, 2022 the MSPC requested a case study of the impacts of socioeconomic data analysis and comprehensive analysis of alternatives for the 4.8kV system within the geographic area of Detroit bounded by DTEE's fiber loop. Expectations of the study included generating insights on how to best support service reliability for customers within the boundary, as well as to inform DTEE's broader efforts to increase reliability for customers within its surrounding vulnerable communities. DTEE completed the study and shared results with stakeholders at the August 2023 Technical Conference.

Appendix E.1 Area of Analysis

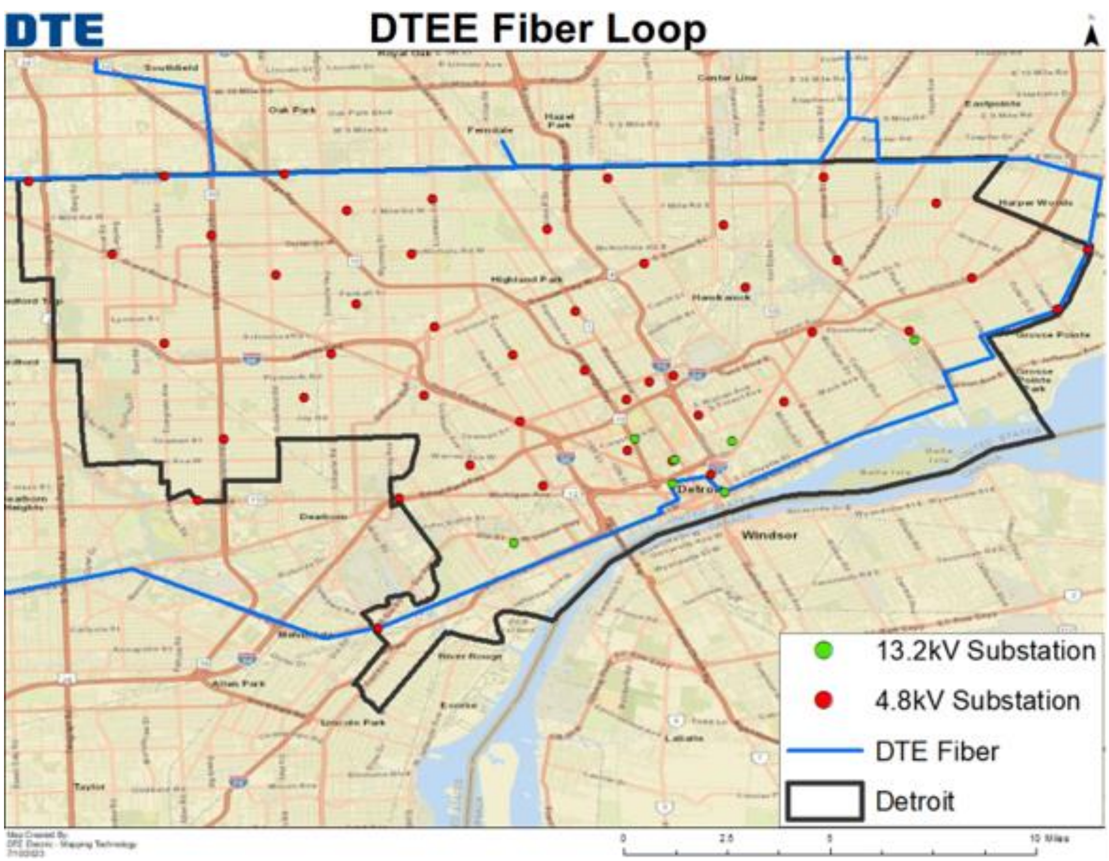
The geographic area examined in the study was the city of Detroit territory bounded by the DTEE telecommunications fiber loop. The scope of the analysis was the 4.8KV system within this boundary, consisting of forty-five 4.8KV substations and eight 13.2kV substations. The map in Exhibit E.1.1 illustrates the study area and identifies the forty-five 4.8KV and eight 13.2KV substations. The study area only included substations that were strictly contained within the study territory. The study encompassed 2,107 miles of overhead circuits and equipment, 622 miles of underground circuits and equipment, and 267,366 customers.

Substations outside of the city limits were excluded even if they were in the fiber loop. However, all circuits that originate from the substations within the study area were included even if they extended beyond the city of Detroit boundary. This is because the 4.8KV system was assessed

[67] See MPSC final order in Case U-20629.
https://mi-psc.force.com/sfc/servlet.shepherd/version/download/0688y000007IzfgAAC

at the substation level, and it is necessary to include all the circuits originating from a substation to determine the condition of the substation.

Exhibit E.1.1 DTEE Fiber Loop (Detroit)



Appendix E.2 Methodology for Evaluating Substations

To measure substation performance, metrics were identified for evaluating each of the 4.8KV substations in the study. Then, a score for each metric was used to indicate the performance of a single substation relative to all other substations in DTEE's electric grid. The following four metrics were utilized to provide a directional picture of the overall condition of each of the substations in the study; the metrics selected for the study are consistent with how DTEE measures the performance of its overall system.

- **The substation MiEJScreen tool score:** The substation's Environmental Justice Score calculation leveraged the state of Michigan MiEJScreen score assigned to each census tract. All customers in a single tract were assigned the same EJ score. The circuit EJ score was first determined using a weighted average as a calculation of the individual scores of customers on that circuit. Then the Substation EJ score was determined using a weighted average calculation of individual scores of circuits that roll up to each substation. A high EJ score indicates that customers served by that substation experience a higher pollution burden and vulnerability when compared to those served by substations with a lower score. Each substation with an EJ score of 80% or greater was defined as a vulnerable community substation.

- **Wire Down Exposure (Safety) -** The Substation Wire Down Exposure (Safety) metric evaluates the safety risk associated with each station. The metric is calculated by dividing the total number of wire downs over a 5-year period by the number of overhead miles and then multiplying by the total number of customers served. Substations with only underground circuits were omitted from this calculation. A substation with a low customer count has a lower safety risk than another substation with a similar wire down density, but a higher customer count. Substations with a Wire Down Exposure in the fourth quartile, relative to all DTEE substations, were considered for a safety mitigation solution.
- **Reliability-** The Substation Reliability metric is measured using a 5-year average of System Average Interruption Duration Index (SAIDI). Substations with a Reliability in the 4^{th} quartile, relative to all DTEE substations, were considered for a reliability mitigation solution.
- **Capacity-** The Substation Capacity metric is a measure of the electrical demand that a substation can accommodate. This was calculated by dividing the substation 2022 Peak MVA by the substation firm rating, or the maximum amount of electricity that a substation can supply under a single contingency without damage to the equipment. Substations with a capacity over 100% were considered for a capacity mitigation solution in this study.

Collection and assessment of these metrics provided a comprehensive framework for measuring the physical and socioeconomical conditions of customers within the fiber loop territory as well as the means to evaluate them against other substations in the DTEE service territories.

Appendix E.3 Findings

The above analysis identifies points where the metrics indicate that a mitigation solution is needed for each of the 4.8KV substations in the study. DTEE leverages a range of solutions to address

Wire Down Exposure, Reliability, and Capacity concerns. Exhibit E.3.1 summarizes the various solutions that can be implemented along with their relevant use case, cost, and complexity.

Exhibit E.3.1 Solution Options

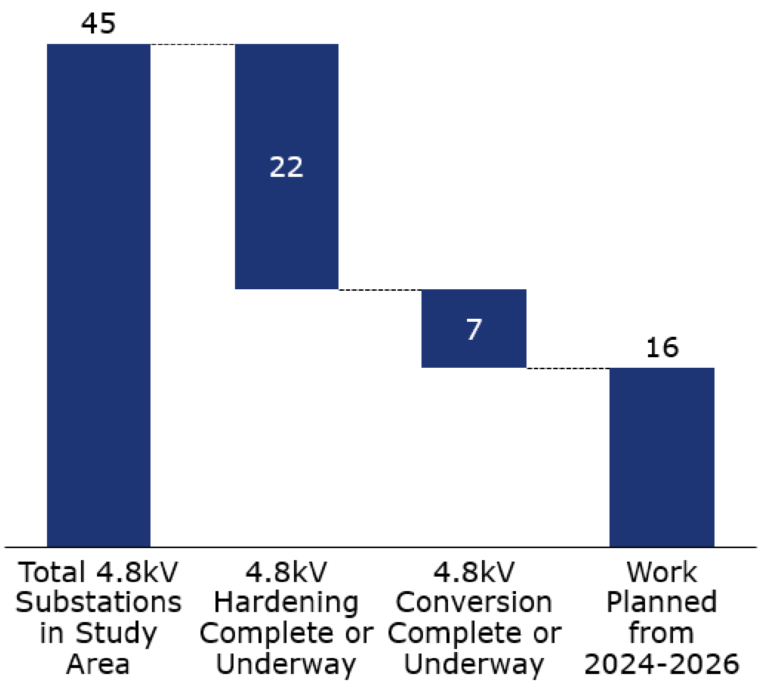
	Improved Safety/ Wire downs	Improved Reliability	Increased Capacity	Use case	Cost Level	Execution Complexity
Tree Trimming	◔	◑	○	Improve reliability/safety if area is off-cycle	Low	Low
4.8kV Hardening	◑	◕	○	Improve reliability and safety, remove arc wire	Medium	Low
Conversion	●	●	●	Relieve capacity constraint and provide significant safety/reliability improvements	High	High
Microgrids + Pre-conversion	●	●	◑	Potential to provide highest reliability and resiliency	Very High	Very High
DERs & Storage	○	◔	◑	Small/moderate load relief	Medium	Medium
Energy Efficiency	○	○	◔	Small load relief	Low	Medium

Hardening, Conversion, or Microgrids + Pre-conversion are the best safety mitigation solutions. Tree Trimming of off-cycle circuits, Hardening, Conversion, and Microgrids + Pre-conversion will yield the most effective results for improving reliability. DERs & Storage and Energy Efficiency are most effective for addressing capacity challenges. The biggest challenges for the 4.8 KV substations in the study area are safety and reliability. The Tree Trimming program has a goal to reach a 5-year cycle by 2025, after which Tree Trimming of these circuits will be critical for maintaining the benefits incurred, but it will not yield additional reliability or safety benefit for on-cycle circuits. Therefore, the best solutions to implement to yield additional reliability and safety benefits are Hardening, conversion, or Microgrids +Pre-conversion. Of the substations evaluated by the study, only one (DENVR) was over capacity, but DERs & Storage was not a viable solution in this case as the capacity needed is greater than 3 MVA.

Appendix E.3.1 Completed and Planned Work

DTEE has actively worked in the Detroit Targeted study area over the past several years under its capital investment programs. the Company will continue to address the needs within the study territory through its strategy for future investment. Subsequently, twenty-nine of the forty-five 4.8KV substations in the study area have capital work that is either already completed or is in progress. An additional sixteen have capital work that is planned from 2024 to 2026. Exhibit E.3.1.1 summarizes the status of capital work for 4.8KV substations in the fiber loop.

Exhibit E.3.1.1 Capital Work Plan 16.5.2 Targeted Study Findings



Conclusion

DTEE is actively investing to enable a reliable and resilient grid for the vulnerable communities in its service territory. Investigation of the 4.8kV system in the Detroit Targeted Study provided key insights on challenges the grid faces when servicing customers within the study area. DTEE's past and future planned capital investment, along with the proposed solutions set for each substation, address the needs of the 4.8KV system in the Detroit Targeted Study territory. The Company will proactively monitor the progress of the ongoing and planned work in the study area for reliability improvements and continue collaborating with stakeholders to identify potential opportunities on how to best support the customers in this area.

Appendix F Top 50 Strategic Capital Programs and Projects Based on GPM

Rank	Capital Program/Project
1	Pole and Pole Top Hardware (PTMM)
2	4.8 kV Circuit Automation
3	Automation: 13.2kV Circuit Distribution
4	CODI: Charlotte Network Upgrade
5	4.8 kV CC: ISO Conversion Program
6	Substation Risk: Apache
7	4.8 kV Hardening
8	4.8 kV CC: Buckler Circuit Conversion
9	4.8kV CC: Barber Substation and Circuit Conversion
10	CODI: Garfield Network Upgrade
11	Subtransmission Redesign & Rebuild: Bernard
12	Subtransmission Redesign & Rebuild: Trunk 4217
13	Subtransmission Redesign & Rebuild: Tie 6907
14	Subtransmission Redesign & Rebuild: TIE6147
15	Subtransmission Redesign & Rebuild: Boyne
16	Substation Risk: Chestnut
17	4.8 kV CC: Hawthorne Relief and Circuit Conversion

18	Frequent Outage Program (CEMI)
19	4.8 kV CC: Zenon Circuit Conversion Phase 2
20	CODI: Howard Conversion
21	Subtransmission Redesign & Rebuild: Trunk 3509
22	4.8 kV CC: Grosse Pointe Substation and Circuit Conversion
23	URD Replacement Program
24	Cable Replacement Program
25	4.8 kV CC: Belleville Substation and Circuit Conversion
26	Subtransmission Redesign & Rebuild: Sandusky Transformer 101 Breaker
27	8.3 kV CC: Pontiac Overhead Conversion
28	Subtransmission Redesign & Rebuild: Trunk 3508
29	Breaker Replacement Program
30	System Loading: Otsego/Capac/Shaw
31	4.8 kV CC: Monroe Substation and Circuit Conversion
32	System Loading: Brown City
33	Subtransmission Redesign & Rebuild: Trunk 2419
34	4.8 kV CC: Birmingham Decommissioning and Circuit Conversion
35	Subtransmission Redesign & Rebuild: Badax Transformer 102 Addition
36	Subtransmission Redesign & Rebuild - Carpenter
37	System Loading: Macomb/Golf

38	4.8kV CC: Hemlock Decommissioning and Circuit Conversion
39	System Loading: Richmond/Armada
40	System Loading: Jewell
41	Substation Risk: Savage
42	Subtransmission Redesign & Rebuild: Tie 6602
43	Subtransmission Redesign & Rebuild: Tie 4105
44	4.8 kV CC: Lapeer - Elba Expansion and Circuit Conversion (Apollo)
45	Subtransmission Redesign & Rebuild: Trunk 362
46	CODI: Amsterdam Upgrade
47	Subtransmission Redesign & Rebuild: Thumb Electric Fault Isolation
48	Subtransmission Redesign & Rebuild: Trunk 328
49	Subtransmission Redesign & Rebuild: Derby
50	System Loading: Globe

Appendix G Distribution Plan Requirements

Category	Distribution Plan Requirement (MPSC Order text)	Order /Date Page	Incorporation into the DGP
Reliability Metrics	The Commission is seeking future distribution plans to include: Expected measurable improvements resulting from the proposed distribution investments Benchmark reliability performance measures, such as SAIDI, SAIFI, CAIDI and CEMI against peer companies in the industry and identify areas of improvement	U-20147 2022-09-08 (p69)	Section 4 State of the Grid – charts show historic and forecasted improvements. Additional information is included in Appendix A
	The Commission adopts the recommendation by AEE/EIBC for the utilities to “construct SAIDI, SAIFI, and CAIDI statistics with and without major events instead of using the MED construct	U-20147 2022-09-08 (p70)	Appendix A.3 shows reliability metric charts excluding MED
	The Commission has requested information about how and, by how much, the Company’s hardening and tree trimming work is expected to improve reliability	U-20147 2022-09-08 (p69)	Tree Trim, Hardening, Reliability model sections (6) - point to the charts & tables in these sections
Energy and Environmental Justice	The Commission acknowledges the company’s commitment to develop a comprehensive environmental justice plan for its distribution system considering the reliability of service in communities identified by the MiEJScreen tool, and continued efforts to work with the Staff to provide data at a more granular level. Therefore, in future rate cases and distribution plans, DTE Electric shall “include future analyses, like overlay maps, charts, graphs, and other displays, that provide a visual or data informed understanding C19of more holistic impacts of electric infrastructure investments on customer communities.”	U-20836 2022-11-18 (p463)	EJ plan, analysis, and charts are included in Section 12

Investment Prioritization and Pilot Requirement	In either future rate case or next distribution plan, submit targeted strategic undergrounding pilot proposals using the objective criteria for pilots set forth in Case No. U-20645	U-20147 2022-09-08 (p73-74)	Undergrounding approach, pilots, and projects are discussed in Section 9.4
	The Commission is seeking more information on the distribution system conversion plans (i.e., more information on upgrades, ranking, where to start, undergrounding plans already in process, etc.)	U-20147 2022-09-08 (p73-74)	Section 9.3 discusses the Company's plans for conversion in detail
	The Commission is seeking a comparison of tradeoffs between grid hardening, undergrounding, and upgrading/converting, using appropriate BCA tests to determine the most reasonable and prudent path forward for various circumstances	U-20147 2022-09-08 (p72-73)	Current cost benefit approach discussion included in Section 12.1. The grid hardening discussion included in Section 8.2
	The Commission is adopting the Staff's recommendations in the May 27, 2022, comments on guidance for future plans. The Commission is requesting the following: -Problem description, goals, and possible solutions determined through community and third-party engagement, -Summarize full set of alternatives analyzed before determining the selected solution, Desired utility learnings or system outcomes, -Identification of investment locations overlayed with socioeconomic context, such as the MiEJScreen information, and electric distribution system information (4.8kV, 13.2kV, substation type and density, etc.).	U-20147 2022-09-08 (p74-75)	The information requested here could be found in: - Project summaries (rate case) - Stakeholder Engagement Section 17 - EJ Section 12.2
Performance Based Regulation	The Commission highlighted that utilities provided insufficient information to address the issue of financial incentives and penalties. In this regard, a MI Power Grid	U-20147 2022-09-08 (p71)	The Company's activity in this area is discussed in Section 12.3.1

	order is expected to be issued at the end of this year and additional guidance will be provided		
	The Commission cannot stress enough its expectation that DTE Electric will invest the amounts approved for strategic capital improvements and not shift them to other categories such as emergent replacement and other reactive spending. As such, the Commission may be willing to consider a long-term investment recovery mechanism (similar to the IRM for the gas Main Renewal Program first approved in the April 16, 2013 order in Case No. U-16999) to ensure that the spending included in rates for strategic capital improvements— including the ultimate conversion of DTE Electric's distribution grid—is spent for these purposes, and to provide greater long-term certainty on recovery of reasonable and prudent costs related to these strategic distribution grid investments. The Commission expects that DTE Electric will include in any such proposal a full description of costs and benefits, as well as associated timelines.	U-20836 2022-11-18 (p76 - 77)	IRM Section (12.3.2)
Benefit Cost Analysis	The Commission is seeking information on the utilities' investment programs, including benefit costs analyses (BCAs) in order to gauge the most reasonable and prudent paths for improving reliability	U-20147 2022-09-08 (p73-74)	Section 12.1 discusses the current cost benefit approach (GPM)
4.8kV Studies and Investments	The Commission also finds the Staff's request for DTE Electric to work with the Staff and interested stakeholders to develop "a case study on the impact of socioeconomic data analysis and more comprehensive analysis of alternatives for the 4.8 kV system within the Company's metro Detroit fiber loop" to be reasonable. The Commission directs DTE Electric to file this study in a future rate case or distribution plan, informed by stakeholder input and reflecting the learnings derived from the technical conference(s) detailed above	U-20836 2022-11-18 (p463 & 92 - 93)	Appendix E include the Company's Detroit Targeted Study in detail

	Include in next DGP a detailed description of plans regarding grid hardening and conversion including timelines and technical conference learnings	U-20836 2022-11-18	Detail plans for Hardening and Conversion are discussed in detail in Section 8.2 and 9.3 respectively

Table of Exhibits

Glossary

ADMS	Advanced Distribution Management System
ALA	Area Load Analysis
AMI	Advanced Metering Infrastructure
APTS	Automatic Pole Top Switch
C&I	Commercial and Industrial
CAIDI	Customer Average Interruption Duration Index
Capacity	Amount of electrical demand that a single piece or group of electrical equipment can deliver based on safety and preservation of the asset
CELIDt	Customers Experiencing Long Interruption Durations of t hours or more
CEMIn	Customers Experiencing Multiple Interruptions of n or more
CHP	Combined Heat and Power
CODI	City of Detroit Infrastructure (Downtown)
Customer 360	DTEE's customer information and billing system
DDO	Distribution Design Orders
DDS	Distribution Design Standards
DER	Distributed Energy Resource
DERMS	Distributed Energy Resource Management Systems
DG	Distributed Generation
DGA	Dissolved Gas Analysis
DO	Distribution Operations Organization of DTE Electric Company
DOE	Department of Energy
DS	Distributed Storage

DTEE DTE Electric Company

EEI Edison Electric Institute

E-ISAC Electricity Information Sharing and Analysis Center

EMS Emergency Management System

EPR Ethylene Propylene Rubber

EPRI Electric Power Research Institute

ESOC Electric System Operations Center

ETTP Enhanced Tree Trimming Program

FLISR Fault Location, Isolation and Service Restoration

Gas Breaker Circuit breaker where the interrupting arc quenching is done with compressed gas

Gas Cable Underground cable which requires pressurized gas to maintain the insulation integrity

GIS Geographical Information System

ICS Incident Command System

IEEE Institute of Electrical and Electronics Engineers

ISO Isolation transformer

Industrial Control System

A general term that encompasses several types of control systems and associated instrumentation used in industrial production technology, including supervisory control and data acquisition (njjnhg) systems, distribution management systems (DMS), and other smaller control system configurations often found in the industrial sectors and critical infrastructure

IRP Integrated Resource Planning

Line losses Electrical power loss resulting from an electric current passing through a resistive element (e.g., conductor)

Jumpering Point	A location on a distribution circuit in proximity to a second distribution circuit where the two can be electrically tied together
Line Sensors	Devices installed on distribution circuits that provide load and fault data
Manhole	An underground structure for cable pulling and splicing
MED	Major Event Day - defined in IEEE Standard 1366 as any day in which the fdaily SAIDI exceeds a threshold value
MPSC	Michigan Public Service Commission
NDAS	Network Database and Applications Support
NEETRAC	National Electric Energy Testing, Research and Applications Center
NERC	North American Electric Reliability Corporation
NERC CIP	North American Electric Reliability Corporation Critical Infrastructure Protection
NESC	National Electric Safety Code
Netbank	Distribution network design used in heavy-load-density city areas which provides high reliability
Oil Breaker	Circuit breaker where the interrupting arc quenching is done in oil
O&M	Operation and Maintenance
OMS	Outage Management System
Overload	Electrical demand that exceeds the electrical capacity to serve
PCB	Polychlorinated biphenyl - now considered an environmental contaminant
PERT	Power Equipment and Relay Testing
PI	Data collection software
PILC	Paper in Lead Cable - refers to the type of insulation/jacket on an underground cable
PM	Preventative maintenance - routine scheduled maintenance based on time or number of operations

PON	Power Outage Notification
Primary	Any part of the electrical system energized at 4.8 kV, 8.3 kV, or 13.2 kV
PSSE	Data modeling software
PTMM	Pole Top Maintenance and Modernization
PTS	Pole Top Switch
RBR	Restore Before Repair. It is the practice that customers (load) are transferred to adjacent circuits or substations to restore power before repair can be completed on the failed section of the circuit
Recloser	Sectionalizing device which opens upon detection of fault current
Redundancy	Ability to continue to serve in the event of a contingency condition
Relay	Electrical switch used to initiate operations of other electrical equipment
ReliabilityFirst	One of the eight regional entities that are responsible for ensuring the reliability of the North American bulk power system under Federal Energy Regulatory Commission approved delegation agreements with the North American Electric Reliability Corporation, pursuant to the Energy Policy Act of 2005. DTEE's service territory is in ReliabilityFirst region
RM	Reactive maintenance resulting from a mis operation or malfunction
ROW	Right-of-Way
RTU	Remote Terminal Unit that sends or receives telemetry data to or from a master control
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SCADA	Supervisory Control and Data Acquisition
Secondary	Any part of the electrical system energized at 120/240 volts
Service	The conductor / cable and equipment that connects a customer to the electrical system

SFI	Smart Fault Indicators
STDF	Subtransmission Distribution Facility
Stranded load	Under contingency conditions, electrical demand that cannot be readily served through available jumpering or mobile generation
Subtransmission	Any part of the electrical system energized at 24 kV, 40 kV, 120 kV, or higher
Substation	A facility of the electrical power grid that allows for the connection and/or switching of circuits and/or the transformation of voltage from one level to another
TARA	Data modeling software
Through Fault	A fault occurring on the secondary side of a power transformer which may damage the insulation of the transformer
TIE (Tie line)	A subtransmission circuit that interconnects two or more substations with power flow normally from any of the substations
TRK (Trunk line)	A radial subtransmission circuit with power flow normally in one direction to serve substation or individual customer loads at 24 kV or 40 kV
TR-XLPE cable	Tree retardant cross-linked polyethylene - refers to the type of insulation on an underground cable
URD	Underground Residential Distribution
Vacuum Breaker	Circuit breaker where the interrupting arc quenching is done in a vacuum
Vault	An underground structure for cable pulling and splicing that also contains power equipment such as transformers and switches
VCL Cable	Varnished Cambric Lead - refers to the type of insulation/jacket on an underground cable
XLPE cable	Cross-linked polyethylene - refers to the type of insulation on an underground cable