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DTE Energy

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September 30, 2021

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

RE: In the matter, on the Commission's own motion, to open a docket for certain regulated electric utilities to file their five-year distribution investment and maintenance plans and for other related, uncontested matters.
MPSC Case No: U-20147

Dear Ms. Felice:

Attached for electronic filing in the above referenced matter is DTE Electric Company's 2021 Distribution Grid Plan Final Report. Also attached is the Proof of Service.

Very truly yours,

Lauren D. Donofrio

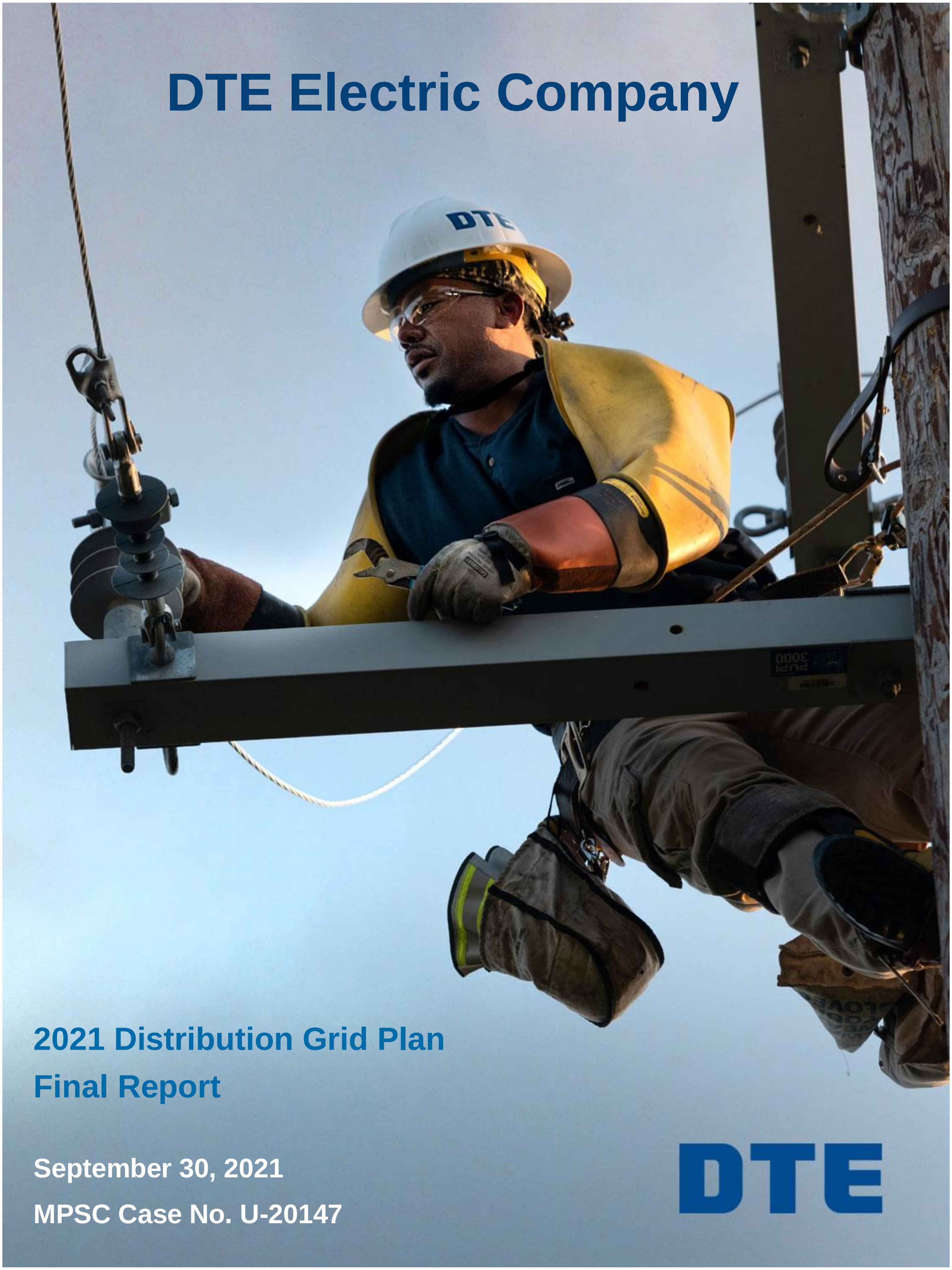
Digitally signed by Lauren D. Donofrio
Date: 2021.09.30 15:47:02 -04'00'

Lauren D. Donofrio

LDD/erb
Enclosure

cc: Service List

DTE Electric Company



2021 Distribution Grid Plan
Final Report

September 30, 2021

MPSC Case No. U-20147

DTE

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1 Executive summary

1.1 Introduction

The energy landscape is changing across the nation, including right here in Michigan. When the groundwork for our company's electric infrastructure system was laid more than a century ago as one of the first in the country, it was built as a one-way distribution system – providing customers the energy required for a much simpler day-to-day life, while also acting as the engine of progress for industry. Our foundation was formed by the Edison Illuminating Co. of Detroit in the late 1880s and has served our customers well through the turn of the century, the rise of the Detroit automotive industry and the Digital Revolution. While what is now known as DTE Energy continued to build and grow the energy infrastructure throughout the 20th century to meet the needs of its customers and the expansion that occurred in each era, portions of our electric infrastructure that are more than 90 years old are still in operation. This aging equipment will be challenged to meet the growing needs of our 2.2 million electric customers across southeast Michigan for the rest of the 21st century. Equipment that has served customers well beyond its expected life, is now incurring costly maintenance and replacement plans and operational constraints that are hindering reliability for our customers.

Our customers are evolving too, and are more connected than ever, leading to additional grid challenges. Our customers' homes are now "smart" and host dozens of electronic devices that they rely on to give them the information needed to live, work and learn each and every day – thermostat and appliance controls, virtual working and learning platforms, and charging for their electric vehicles. Some of our customers are even generating energy on their own through distributed energy resources (DER) in the form of rooftop solar panels and energy storage. As we look to the future, we expect our customers' dependence on these devices and the information they provide to grow exponentially, which will challenge the current grid – moving it away from a one-way distribution system, to a system that requires a two-way flow that allows customers to send energy and information back into the grid. This evolution requires even more grid technology and integration to ensure the electric reliability that our customers require and deserve.

While our customers are more dependent on technology than ever, we also know that climate change – and its impacts on the energy grid – is one of the defining issues of our era and top of mind for DTE and our customers. DTE Electric (DTEE) is taking bold steps to reduce our company's impacts on climate change by significantly increasing our investments in renewable energy and cutting carbon emissions in half by 2030[1] to reach our goal of net zero carbon emissions by 2050. Michigan's energy landscape is also undergoing a transformation. While the state has formulated new sustainability goals that encourage and enable the electrification of transportation to reduce environmental impact, our customers and communities are looking to us to continue to reduce carbon emissions and deliver energy through a grid that's more reliable and resilient than in the past, a grid that can also handle the increasingly severe weather we are seeing season after season.

In order to deliver the safe, clean, reliable and affordable electricity our customers deserve, DTEE is reexamining the grid infrastructure that is fundamental to supporting these changes. The same innovative vision and planning that went into developing the electric grid in Detroit and the surrounding communities over a century ago is needed today to ensure our grid will support the evolving needs of our customers and our state.

DTEE has made significant progress in upgrading aging infrastructure, accelerating tree trimming efforts, installing modern equipment to detect, prevent and manage outages and improving safety since the filing and implementation of its Distribution Operations Five-Year (2018-2022) Investment and Maintenance Plan with the MPSC in 2018. The results of these strategic investments speak for themselves, as highlighted below. While we are making marked progress where investments have been made, the data on asset conditions and needs, shows significant

[1] Based on a 2005 baseline

additional investment is required to avoid further deterioration and costly reactive spending in order to mitigate outage risks and to prepare for the grid of the future.

- **Grid hardening and modernization:** In areas where grid hardening work is complete, like our Customer Excellence program (which includes a robust program of infrastructure/equipment updates and tree trimming), our customers are seeing a 50-70% improvement in reliability. We want all our customers in Southeast Michigan to experience this level of service from DTEE, so we've developed an accelerated plan for the next five years to ensure we can provide our customers with the safe, reliable and affordable energy they deserve. The continued investment and infrastructure updates outlined in our updated plan will help us realize a 60% improvement in SAIDI, moving us from third quartile in 2020 to first quartile by 2030.

  Modernizing infrastructure will also make the grid more resilient to the increasingly severe weather that is impacting Michigan, helping to significantly reduce reactive costs – a projected $65 million annually by 2025 – and time spent on outages caused by equipment failures and weather. Our experience shows that reactive equipment replacements due to failures can cost up to five times as much as proactive replacement programs.

- **Tree trimming:** Historically, trees cause two-thirds of the time (outage minutes) our customers spend without power. We began our tree trim "surge" to clear the trees farther away from our wires and improve reliability in 2016, when we implemented our Enhanced Tree Trimming Program (ETTP). The data is showing that those circuits that have been trimmed to our new ETTP specification, on average, have 60% fewer outages, shorter outage durations and fewer wire downs and safety hazards. At the beginning of 2018, 23% of our system was trimmed to the ETTP specification. By the end of 2021, 72% of the system will be trimmed to ETTP, including 89% of the city of Detroit. We will continue this "surge" until all of the system has been trimmed to the ETTP by the end of 2025 to meet the industry benchmark five-year ETTP cycle. The ETTP program and maintenance of the required clearances will improve system resilience and provide increased reliability for our entire customer base.

  In addition to the reliability and safety improvements, the Tree Trimming program has been a force for growth within the community. DTEE has implemented two training programs – one at the Vocational Village and Parnall Correctional Facility in Jackson, and a Tree Trimming Academy in Detroit. These programs provide career opportunities for members of the communities we serve.

- **Future technology:** DTEE's Advanced Distribution Management System (ADMS) is a new technology platform that will provide teams across DTEE with a complete and integrated view of multiple energy management systems, allowing DTEE to diagnose problems quicker, leading to faster outage response for our customers. The implementation of the ADMS, which is the foundational platform for our grid modernization efforts, began in 2018 and is being implemented in phases. To date we have completed implementation of the Generation Management System (GMS); the Energy Management System (EMS) to manage the subtransmission system; and connections to the transmission system and Network Management System (NMS) to improve data quality. Over the next several months, DTEE intends to continue implementation of the ADMS with the rollout of the new Outage Management System (OMS) which will improve outage restoration response, along with the first of the Distribution Management System (DMS) components, eMap, which will provide a schematic of the as-operated network model of the electrical system. The remaining ADMS applications are planned for launch in 2022.

  The changes to the grid will also require even more technology investment. The past smart/advanced meter infrastructure (AMI) project is an essential component of a modernized grid, and one that DTEE has already invested in. Other grid enhancements will be needed as part of modernization, including the likely addition of a distributed energy resource management system (DERMS), as well as increased grid sensing and automation technology. Some of the solutions to the grid challenges will include localized new technology, like non-wire alternatives (NWA), and the potential for microgrids. These technologies have the potential to defer traditional utility investments and provide localized solutions to enhance reliability and resiliency.

- **Electric ESOC:** In June 2019, construction began on DTEE's new Electric System Operations Center (ESOC) at the Company's downtown Detroit headquarter complex. The completion of the facility in the fourth quarter of 2021, will allow for co-location of dispatchers and system operators who utilize the new ADMS, which will lead to improved management of significant system disruptions and quicker response time for our customers. The facility includes electronic displays and improved console designs to meet dispatcher and operator needs, while enhancing situational awareness, and improving safety and reliability of the electric grid for our customers.

- **Infrastructure redesign to support economic growth:** Our customers have increasing demands of the electric grid as they look to new areas to live and grow their businesses and communities, while moving more of their lives and operations toward electrification. Since the filing of DTEE's 2018 five-year distribution grid plan, we have started the planning for and are in the early phases of construction for new substations and the conversion of circuit miles to higher voltage levels. These projects, once complete, will support economic growth, customer demand and improve reliability for the customers and communities we serve in areas like Almont, Ann Arbor, Detroit, Dexter, Northville, Shelby Township and Van Buren. These projects will allow us to add about 700 MW of additional capacity to the distribution grid – enough to power 180,000 residential homes or 110,000 electric vehicles – that will accommodate new load that will flex and grow with customers' expectations for the grid of the future.

Customers, both residential and commercial, are moving toward electrification of their vehicles, and we'll be able to support this demand as well as growth from areas like economic and community development projects. For example, as part of the City of Detroit Infrastructure (CODI) program, DTEE began construction on a new 13.2 kV Corktown substation in 2021, with plans to energize it in the first quarter of 2022. Meeting this schedule will accommodate significant new customer load as part of economic development activities planned in Detroit's Corktown area. In addition, it enables the future conversion and transfer of load from nearby lower voltage Kent and Gibson substations, which will allow for the decommissioning of these aging substations. DTEE's new Distribution Grid Plan builds on the 2018 plan and establishes the foundation for near-term change in DTEE's distribution system for the next five years, as well as a more transformative vision for future improvements to the grid over the next 10-15 years. This transformation will significantly improve reliability and resilience for our customers and increase the ability to effectively integrate new clean energy technologies such as electric vehicles, rooftop and large-scale solar, and batteries.

We have taken a strategic approach to prioritize and sequence investments, evaluate alternatives, and have included a Performance Based Regulation (PBR) proposal in this plan to ensure progress and transparency in measuring positive impacts for our customers. Our PBR proposal will be included in DTEE's next rate case.

DTEE began its planning efforts by reviewing the MPSC goals, and then developed planning objectives across our company, building on the planning principles that were used to guide our recent integrated resource planning. Five planning objectives were defined, which are described below.

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

The planning objectives provide guidance and support for the four strategic pillars in our investment strategy.

Pillar	Program / Project Examples
 **Infrastructure Resilience and Hardening**	• 4.8kV Hardening program • Asset replacement programs stemming from engineering asset condition assessments • Pole and pole top maintenance and modernization (PTMM)
 **Infrastructure Redesign**	• Conversion of 4.8kV system • Major subtransmission upgrade and redesign projects • System loading projects
 **Technology and Automation**	• Advanced Distribution Management System (ADMS) • Construction of a new Electric System Operations Center (ESOC) and launch operations in 2021 • Distribution Automation – installation of remote monitoring and grid control devices
 **Tree Trimming**	• Enhanced Tree Trim Program (ETTP)

These planning objectives and investment pillars align to the long-term strategic shift planned by both the electric utility industry and DTEE. These objectives support our customers' expectations for cleaner and more reliable energy, the state of Michigan's sustainability goals, and the DTE Energy corporate goals for clean energy and decarbonization.

Knowing that our customers' requirements of the grid of the future are much more complex than in the past, DTEE took a different approach to developing the five-year plan and longer-term vision for the distribution grid. Starting with the planning objectives above, the Company worked with an external consultant, ICF, to develop three scenarios. Each scenario is distinct from the others and reflects plausible future outcomes. Although the future will likely blend elements from each scenario, examining the grid impacts of the three distinct scenarios supports an understanding of the constraints on our existing distribution and subtransmission system and provides guidance on required future investments.

Scenario	Description	Implications
Electrification Scenario	High electrification of transportation, buildings, and industrial processes	Distribution overloads begin to occur at 2% adoption on quite a few substations
Increasing CAT Storm Scenario	Increased catastrophic (CAT) storm frequency and intensity threat to aging grid reliability	Current system loading and designs flexibility will be further challenged
DG/DS Scenario	High adoption of distributed generation (DG) solar PV and distributed storage (DS) behind the meter (BTM)	Distribution voltage, thermal and protection issues will increasingly arise at relatively low adoption levels DTEE Needs a DER operational & control strategy for DER, Including MISO coordination

The conclusions of the scenario analysis, grid impacts and modernization needs identified that in order to modernize and absorb the impacts of electrification, storms and DERs, there will need to be an increase in grid investment. While these future grid impacts will present challenges, they also provide DTEE with a great opportunity to rebuild and modernize the distribution system into a more reliable and resilient grid that better serves our customers and other stakeholders.

DTEE used the four pillars and the scenario-based planning to develop a strategic five-year capital investment level of $7 billion. While this is a significant investment, the results mean DTEE will be able to provide a safer, more resilient and robust system for our customers. The cost of inaction to customers and DTEE, particularly in situations of long-duration outages, is much greater. These costs aren't always quantifiable on energy bills, because they include the experiential burden incurred by our customers every time they are impacted by an outage event. These impacts are important when considering tradeoffs of affordability, as vulnerable customers may be the greatest impacted if we do not take more aggressive steps to invest in the distribution grid to make it more reliable and resilient in the future.

The plan is guided by our objectives of providing safe, clean and reliable electricity to our customers that is affordable and accessible to all. We also fully embrace the Commission's view that distribution planning should relate to a "core objective of 'customer needs' that binds everything together."[2] Our customers are at the heart of our plans for a modern and more resilient

[2] MPSC August 20, 2020 order, Docket No. 20147, at p. 40.

grid. This is why DTEE reached out to our customers and other stakeholders to gain feedback through multiple channels to listen to their concerns and gain input on their perceptions of DTE as a company overall, the electric reliability they currently experience and their expectations for the grid of the future.

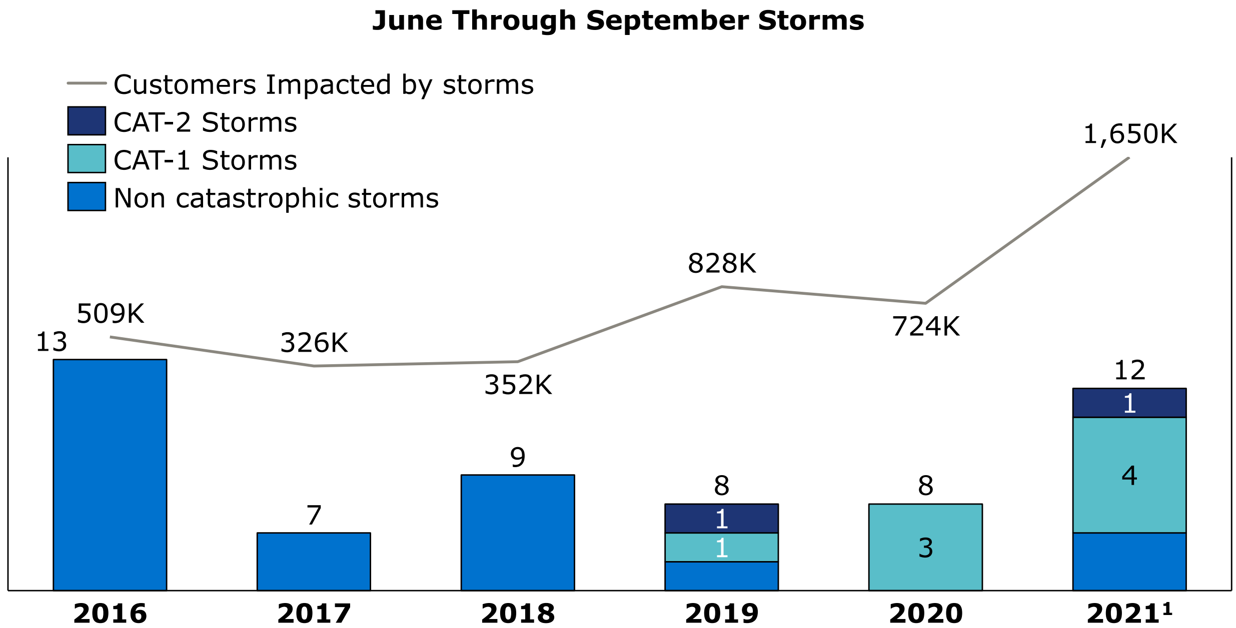
Almost all stakeholders told DTEE that this transition to a modernized grid must be done, and it must be done equitably. Our customers told us, and we agree, that this investment must be structured in a way that is fair and just for all customers. DTEE will continue to look for efficient ways to work and keep bills affordable for all while we upgrade and strengthen our infrastructure – a long-term investment that will improve the quality of power customers in all communities receive.

The DTEE DGP is not the end of the distribution planning process, rather it is just a step on the journey to a modernized grid. This report lays out a detailed five-year investment plan and a 10- to 15- year vision for the grid. It also identifies the next steps in the process, the continuing work that is required for the longer-term vision to become a reality.

Change can be daunting and modernizing the grid for our customers will present challenges as well as opportunities along the way. We are confident that by listening to our customers and other stakeholders, employing the talent of our employees and partners, and applying our skills in project management and continuous improvement, we will build an efficient modernized grid. We are committed to bringing about the ingenuity that went into developing the electric grid in Detroit and surrounding communities over 100 years ago, in order to build and operate a clean, affordable, reliable, resilient, and accessible grid that will support the evolving needs of our customers and our state well into the future.

1.2 Severe Weather of Summer 2021 and the impact on the DGP

During the summer of 2021, DTEE's customers, communities, and employees distinctly felt the impact of severe weather on the electrical system. From mid-June through mid-September, DTEE experienced twelve storms (roughly defined as weather impacting at least 25,000 customers), including four CAT-1 storms (110,000 customers impacted), and one CAT-2 storm (220,000 or more customers impacted). The storm which started on August 9th impacted almost 500,000 customers and was one of the largest storms in company history. The combination of frequency and intensity of severe weather, and impact on the system was unprecedented. A summary of the 2021 storms in comparison with recent years is shown below.



The weather patterns in Southeast Michigan during this period reflect the challenges faced by the distribution system. During two different storms, the area experienced rainfall in excess of 4 inches over a 48-hour period. There were at least five confirmed tornados, and wind gusts during the August 10th storm approached 75 miles per hour, while winds during three other storms exceeded 60 miles per hour.

For every storm this summer, DTEE followed the storm restoration process described in Section 7.3.2. This process included ramp-up planning (using weather forecasts to prepare for potential outages in advance of the weather system entering the area) and requesting additional resources from other areas to assist with the restoration effort. Over the eleven storms experienced this summer, nearly 5,500 mutual assistance line workers aided in the restoration effort, including over 1,500 who worked during the August CAT-2 storm.

Due to the frequency of storms, a specific challenge this summer was the post-storm recovery phase. The storm restoration efforts include making temporary repairs in order to provide power to customers as quickly is possible. In the weeks following a severe storm, crews go back to these temporary repairs and make permanent repairs or replacements. This summer, the time between completing restoration for one storm and the beginning of another storm averaged less than five days. This did not give the crews enough time to make the permanent repairs or replacements needed and left some areas of the system vulnerable to repeat outages.

Near-term changes due to 2021 Summer Storms

DTEE acknowledges that the frequency and intensity of storms over the summer caused frustration and hardship for many customers. With 1.65 million customers impacted by storms, many were without power during multiple storms, and many were without power for an extended duration. Operating a safe and reliable grid is a primary goal of distribution planning, which is reflected by our Planning Objectives, which consider Safe and Reliable two of the critical factors by which we prioritize investments. While the draft DGP filed in August included a robust plan to improve storm resilience, DTEE has augmented some of the short-term investments in the DGP to address opportunities identified during the storms, and to accelerate key programs to improve reliability for our customers more quickly. Key initiatives as a result of summer storm activity are:

- **Tree Trimming:** The tree trimming surge is being accelerated and $70 million of investments are being pulled ahead into the next few years. The impact of this change is that the 'surge' will be completed by the end of 2024, a year ahead of the original schedule. Once the surge is complete, the entire system will be trimmed to the latest specifications. This additional investment is being done without impact to customer rates. More details on the Tree Trimming program are found in Section 9.
- **Frequent Outage**: Due to the frequency of storms and the total number of customers impacted by storm, there are areas of the system that experienced multiple outages. To improve the reliability in these areas, the frequent outage program has increased investment levels by $10 million in 2021 and $20 million in 2022.
- **Customer Communication:** A frequent source of frustration from DTEE's customers during the summer storms was the inaccurate information about outage status provided to customers through DTEE channels (Outage Center website and DTE Energy Mobile app). Some customers were told that their power had been restored when it had not. Other customers received inaccurate restoration estimates. In order to improve the quality and accuracy of the information customers received during the restoration process, additional technology projects are being implemented to align data across multiple sources of information and ensure that customers get accurate, error-free information during the restoration process.
- **Strategic Undergrounding:** The draft DGP outlined an approach to strategically underground equipment in areas where 1) it operationally makes sense and 2) the investments are cost-effective. In this final DGP filing, DTEE has made progress in

identifying a potential circuit for an undergrounding pilot, which will help DTEE to understand customer acceptance, drive down costs if the program expands, and ensures that a strategic undergrounding option is cost-effective and affordable for our customers.

- **Outage credits:** DTEE fundamentally understands that outages have an economic impact on our customers. For example, one of the tools DTEE uses to value strategic investments is the Lawrence Berkeley National Laboratory (LBNL) ICE calculator, which estimates the economic costs of outages on customers. This tool has been used in past rate cases and is described in Section 6 on the benefit cost approach to prioritization. Due to the impacts of the storms this summer, DTEE increased the credits paid to customers who experienced frequent or lengthy outages, including proactively paying a $100 credit to customers who remained without power until Monday August 16th during the CAT-2 storm.[3]

DGP and planning for storm resilience

DTEE's approach to distribution planning in the DGP incorporated the need to make the grid more reliable and resilient across multiple phases of the planning process. The overall grid modernization process is described in Section 3 and starts with identifying our customers' needs. As part of this initial process DTEE engaged with stakeholders and with customers through focus groups. Throughout these conversations DTEE listened to what was important to customers – a grid that provides reliable electric services even in the face of severe weather. These experiences helped affirm the importance of two of the core DTEE Electric Planning Objectives - Safe and Reliable.

To develop a near-term plan and long-term vision for the distribution system, the Company introduced scenario-based planning as a tool to provide insight into potential future outcomes and to inform the investment strategy. DTEE developed three distinct scenarios to identify trends likely to impact the grid over the next 15 years. Consistent with the 2019 Michigan Statewide Energy Assessment (SEA) and Michigan Hazard Mitigation Plan (MHMP), DTEE developed a scenario which considered increasing frequency of catastrophic-level storms. This scenario is based on the potential for climate change to increase the threat and type of severe weather that DTEE's infrastructure will be subject to, particularly if there are changes in the form of extreme heat, flooding, severe winds, tornados, or other weather patterns. The scenario planning process also

[3] The voluntary $100 credit was not in lieu of, but rather was in addition to any payments made under R460.744, R460.745, or R460.746.

acknowledged that much of the current infrastructure is at or near end of life, including poles, URD, system cable, and substation breakers.

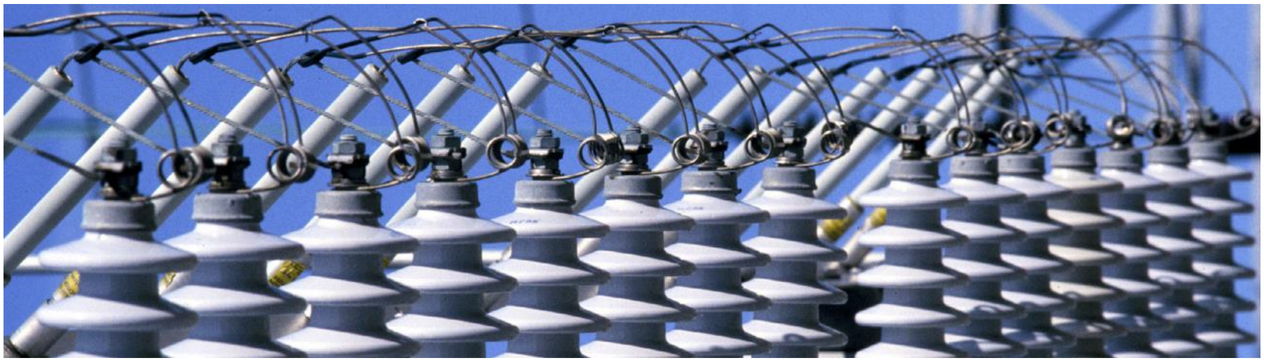
The combination of the customer needs, the current state of the system, and a potential future scenario with more severe weather threats helped inform both the 5-year near-term investment plan and a longer-term trajectory to develop a system that is robust and resilient.

Specifically, DTEE's 5-year plan includes significant investments in projects and programs that will improve reliability to achieve 2nd quartile All-Weather reliability performance by 2025. Investments in tree trimming, 4.8kV hardening, pole top maintenance and modernization (PTMM), and increased penetration of substation and circuit Automation, on top of benefits of increased situational awareness from the ADMS project, will reduce both the frequency and duration of outages. These programs will upgrade large areas of the system over the next 5-years by reducing tree-related outages and replacing aging overhead equipment with stronger poles, fiberglass crossarms, and polymer insulators which all have increased strength in the face of inclement weather.

The longer-term plan also addresses reliability and resiliency by rebuilding the grid more completely through programs such as the 4.8kV conversion program and subtransmission rebuild and redesign program. These programs will continue to fully rebuild circuits to our latest, more reliable and resilient standard. For example, DTEE constructs all new circuits to National Electric Safety Code (NESC) Grade B construction standards for all new overhead construction. While other utilities still build to Grade C construction, Grade B construction standards allow the electrical system to withstand higher ice accumulation and wind speeds.

DTEE's planning process created a robust strategic investment portfolio that transforms the grid into a system that will provide what our customers are asking for – a reliable and resilient grid that can withstand both current weather and a future with more severe and frequent weather.

2 Stakeholder engagement and input



2.1 Stakeholder engagement

At the heart of the electric grid is our customers. Their input is essential to our planning and grid analysis, so DTEE reached out to our customers and other stakeholders to receive their direct feedback about their perceptions of DTE and how they and their constituents feel about the electric reliability they receive. Third-party research companies were engaged to help conduct open access webinars, customer focus group sessions and one-on-one conversations with state and community leaders in order to gain broad input from all stakeholders through proven research methods. This voice of the customer research was conducted from November 2020 through July 2021.

This summer, our customers and other stakeholders have also been providing more informal feedback about the impact of the season's severe weather on the electric grid. We've been listening and conversing with them through multiple channels, including regular federal, state and local stakeholder meetings; meetings with community partners; and interactions with customers at Community Vans in impacted neighborhoods.

2.1.1 Customer focus groups

DTEE invited a cross section of residential and commercial customers to participate in multiple Zoom-based qualitative focus group discussions to provide insights used to inform the Distribution Grid Plan. The customer focus groups participants were randomly selected from customer data samples based on income, geography and recent levels of reliability. These sessions were held in April and May with the intention of gaining feedback on the following:

- Perceptions of DTEE's current grid reliability
- Awareness of positive or negative trends to that reliability
- Anticipated trends in terms of electricity usage at a household- or business-level over the next five years
- Support for grid improvement (and willingness to fund actions that do more than maintain status quo)

Four key themes were consistent throughout the discussions – energy usage, perceptions of DTEE, reactions to grid benefits and equity.

Energy usage

Both residential and commercial customers felt their energy usage has been fairly consistent for the past five years. Lifestyle or domicile changes were noted as drivers of increased usage among residential customers.

However, expectations for future usage varied between residential and commercial customers. Most residential customers anticipated their future energy usage will stay consistent over the next five years. The remainder anticipated their usage would increase due to continued expanded use of personal electronics and potentially an electric vehicle.

Commercial customers, on the other hand, expected an increase in usage due to requiring more electrical-intensive appliances. Businesses that expected their electrical usage to stay consistent over the next five years were often those that have recently taken action to become more energy efficient, with the intention that those savings will offset any potential rise in usage.

Regardless of their personal usage, both residential and commercial customers consistently expected regional electrical use to increase over the next ten years, driven by personal electronics and technology advancements – particularly electric vehicles (EV).

When it comes to electric vehicles (EV), virtually no residential customer who participated in the focus group sessions anticipated adopting an EV within the next ten years. On the contrary, commercial customers recognized that electric vehicles will become the dominant type of vehicle for the future.

“Our cars are over ten years old, but I think the way the world is going, we may not be able to buy a non-electric vehicle…” –Residential Customer

Current perceptions of DTEE

At the time the focus groups were conducted, in spring of 2021, prior to the summer’s storm events, perceptions of DTEE were fairly positive in terms of reliability, innovation and environmental stewardship. As demonstrated across participants in each focus group, most customers’ views of DTEE are driven almost exclusively by personal reliability experiences.

Customers found it almost impossible to talk about DTEE’s performance or infrastructure activities on a regional or company-wide level because they simply don’t pay that much attention to DTEE unless activities/updates specifically impact their home and reliability. Residential customers’ confidence in DTEE’s ability to meet future demand was highly correlated to the company’s ability to provide that customer’s household with reliable power right now. Commercial customers tended to take a more regional view about reliability and were often more cognizant of issues in parts of the gird that may not affect their account directly.

Both residential and commercial customers cited the lack of visible, or specifically identifiable, maintenance or upgrades to the electrical grid as evidence that DTEE does not aggressively maintain or upgrade its distribution grid. They didn’t know what they should be looking for other than the presence of DTEE work trucks or crews in their area doing “something.” To the customer, visible presence equals maintenance.

“We’re in the dark, literally, about what DTE is doing to make improvement. They are, but is should be visible to the customer. We see the trucks and sometimes see the tree trimming, but there’s no bigger picture for us.”
– Residential Customer

Recognizing that they may be missing DTEE’s activities when it comes to maintenance and infrastructure upgrades, 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 actually taking place, even if they don't personally see the work happening.

"I don't have any concerns. When we flip the switch, the lights go on, and it's always been like that. I think DTE is generally very responsive. I'm a satisfied customer."
– Commercial Customer

Reactions to grid modernization benefits

Before talking about specific changes to the distribution grid, residential respondents were given an "off-the-shelf" overview of what the electric industry anticipates over the next ten years via a video produced by the Edison Electric Institute. Commercial respondents were given a visual overview (two diagrams highlighting the difference between a traditional and advanced grid), as well as a list of benefits to enhance clarity and further drive the discussion.

Initial reactions to the smart grid varied by customer type. Residential customers were open to the need for maintenance and modernization of today's grid but were less excited about the more "intelligent" elements of a smart grid – largely because the majority did not anticipate widescale adoption of distributed generation resources in the next ten years. Not surprisingly, initial reactions from commercial customers suggest they were more open to the need for modernization but were more immediately concerned about the cost implications and potential bill increases.

Across both customer groups, even among those who were enthusiastic about a grid overhaul, it wasn't until they were made aware of the risks associated with not modernizing the grid that customers ultimately saw enough value in grid modernization that they would be willing to pay more to modernize and ensure continued reliability.

"I think you would do yourself a disservice if you didn't have holistic conversation about both the positives and the negatives [of improving the grid] and you need to find a path in the middle. Yes, you pay a little more, but you improve [the grid].
– Commercial Customer

Equity

The issue of equity surfaced spontaneously in every residential discussion group, often at different times and focused on different aspects of the grid plan.

One equity concern was the potential inability of lower-income households to pay for an increase in their electric costs. A second concern was whether industrial customers would be paying their fair share of the modernization, or whether they would benefit off the backs of residential customers. A third concern was making sure the new grid was built out in a way that did not benefit more affluent areas first. On the contrary, equity was rarely an issue raised in the business group sessions.

"I could absorb the cost, but I'd like to see [grid improvements] be balanced across all walks of life and make sure that everyone has equal access to power."
– Residential Customer

The report for the customer focus groups is included in Appendix VII – Customer Focus Groups.

2.1.2 Community leader engagement

DTEE engaged 35 influential community leaders from our electric service territory to gather feedback on their constituents' energy usage and anticipated needs over the next five to 15 years. These leaders included community activists, community services organizations, faith-based leaders, and elected and non-elected public sector officials. Each leader was asked to speak on behalf of their constituents and discuss their views on the roles DTEE and energy play for their community members. Interviewees were provided a brief overview of DTEE's Distribution Grid Plan and were asked to provide initial reactions to help inform the final plan.

Findings from leader interviews focused on their constituents' current electricity usage, perceptions of DTEE, reactions to the grid plan and anticipated benefits to their constituents.

Current electricity usage

Most stakeholders believe their constituent's energy usage is average or above average, almost none responded with below average. Stakeholders were led to this conclusion for several reasons, including constituents living in older homes that are less energy efficient, and constituents having larger families requiring more energy. Community leaders from more affluent areas also cited a growing number of electric vehicles in their neighborhoods. There were mixed responses on how energy usage has shifted over the last year due to the pandemic, but most believed that residential usage has increased, although less so in areas where the digital divide is still prevalent. Usage among businesses, however, is believed to have decreased due to the pandemic shutdown.

Overall, there is consensus that there will be increased demand for energy in the next five to 15 years, with beliefs that the top contributing factors to increases in usage include:

- Heavier reliance on technology, particularly as televisions and other devices continue to remain a significant source of home entertainment and work from home options are expanded.
- Economic growth in various neighborhoods, including increased housing stock, businesses, and energy drainers like indoor agriculture.

In anticipation of greater usage, affordability and sustainability are top of mind for community leaders. There is significant concern around affordability, especially given the current economic situation brought on by COVID-19. There was also sentiment that energy affordability impacts the State of Michigan's ability to attract businesses

Current perceptions of DTEE

DTEE is seen as an increasingly reliable service provider. Recent winters seem to be milder, so outages are not as top of mind. New substations and tree-trimming are helping to decrease outages and durations. Natural gas and nuclear power plants will help retain reliability as more coal plants are closed.

Community leaders flagged that reliability is only a major issue for customers during an outage. Many of these customers experience outages during severe weather, which they see as a factor outside of DTEE's control. Certain neighborhoods continue to have reliability issues due to infrastructure, but many areas have been addressed.

Overall, DTEE is not seen as a leader in innovation, in part due to community leaders' lack of awareness. There was some recognition that work is likely being done, but most stakeholders could not speak to it personally, or if they could, they felt their constituents could not. Most thought that DTEE could do more to communicate what it is doing relative to preparing for the future of energy, particularly in light of rapidly changing technologies.

While innovation was viewed as movement toward clean energy by many community leaders, others identified an opportunity for DTEE to innovate relative to affordability. Innovation is not only making technological advances to produce cleaner energy, but also determining how it can be done in an affordable and equitable manner. Community leaders believe that DTEE has an opportunity to develop innovative business models and policy solutions to continue as a leader among utilities. Concern was also expressed around the accessibility of clean energy technologies to Detroiters.

Reactions to DTEE's grid plan

While all community leaders had a positive reaction to the high-level summary of the grid plan, there was hesitation on taking a firm stance without additional information and hearing from company leadership. Components of the plan, particularly tree trimming, were welcomed by stakeholders at large. Stakeholders were interested in learning more details about the plan, including:

- How plant retirements will be addressed in terms of capacity.
- How the increasing use of electric transportation fits into the plan.
- How battery technologies fit into the plan in terms of renewable energy.
- How the land use required for solar energy be managed.
- How technology be incorporated into customer issue reporting.
- The extent that underground lines rather than overhead lines are being considered.

Flagging the technical nature of the language used was common, as was the lack of specificity around why each action is necessary. Stakeholders hope to see more "straight talk" language from DTEE that clearly outlines the costs and benefits of upgrading the grid and moving to a cleaner energy future. It is important to note that community leaders were provided with only a one-slide summary of key components of the plan during the interviews.

Stakeholders hope to see their community businesses and constituencies play a role in the conversation to green energy. Concerns were expressed about people of color being able to participate in potential job opportunities that would be made available. Other significant questions were around alternative energy sources and adequately addressing capacity needs in certain geographic areas.

Anticipated benefits to constituents

There was general knowledge that tree trimming and preventative maintenance would make service more reliable. While needed to avoid outages, community leaders relayed that customers are often unhappy with tree trimming due to the appearance of trees or reduction of shade on the property. Keeping up with demand while “going green” is a key priority for community leaders, and they understand that updating grid infrastructure will allow for the transition to more renewables without sacrificing reliability.

Community leader concerns

Community leaders identified two key concerns if DTEE does not invest in the grid:

- The inability to advance toward net zero and a cleaner energy future; and
- The inability to provide reliable service in the face of extreme weather, the popularization of electric vehicles, and growing demand for renewable energy sources.

Additionally, it was considered that without a modern electric grid, Michigan is at risk of being passed over for investments and economic growth. Leaders stated that many residents are unaware of the ripple effect an unreliable grid will cause, not only for themselves at home, but for the region in terms of business, tourism, and attracting residents. There was sentiment that our state’s economy will increasingly be linked to the availability of reliable service, and electric vehicle charging stations.

The negative effects of failing to invest in the electric grid were highlighted as the most persuasive arguments for investment. The threat of decreased reliability and decreased opportunity for renewable energy were top motivators for supporting investments. The added benefits of having a modern electric grid were persuasive as well, but not to the same extent as facing the reality of what would happen without an updated grid.

There is serious hesitation around increasing electric rates to fund grid modernization. While there is consensus that updates are needed, the full burden falling on residents is in question. Several respondents indicated that there was no argument to convince residents, particularly low-income families, that a rate increase is warranted. Community leaders warned of the impacts rate increases have on vulnerable populations. There is a call for policy solutions to help DTEE make investments in the grid in an equitable way. A sliding rate scale, a base fee + usage costs, and bill caps were discussed as potential solutions. The need for energy efficiency in older homes, often owned by senior citizens and low-income populations, was also repeatedly flagged. A role for the federal and state governments, as well as DTEE's internal policies, were mentioned when discussing the transition of infrastructure. Finally, it was mentioned that municipalities might be willing to share costs with DTEE in cases where capacity and reliability are significant issues.

Stakeholders are interested in easy-to-understand information and access to data for themselves and their constituents. Many stakeholders have an interest in understanding DTEE's work around innovation and environmental stewardship. Community leaders believe residents will be more favorable toward DTEE and understanding of rate increases if they feel engaged and knowledgeable about what is happening and why. Understanding the bigger picture will be key for leaders and customers alike.

The report for the community leader engagement discussions is included in Appendix VIII – Community leader engagement.

2.1.3 Technical stakeholder engagement

DTEE reached out to stakeholders who had intervened in recent cases and invited them to attend a series of webinars. These webinars introduced the distribution grid plan development process, provided progress on the plan development and solicited input on the plan. The webinars ranged from 90 minutes to two hours, and were held November 19, 2020, and June 18 and July 29, 2021. Invitations to the first webinar were sent by email from the Company using a list of intervenors. The latter two sessions were also advertised in collaboration with the MPSC Staff using the Licensing and Regulatory Affairs (LARA) alert process. Additionally, stakeholders who have been active in recent cases and participants in the first webinar were invited to an individual discussion. Ten of these discussions were held between March and June 2021.

In general, the stakeholders were interested and engaged in DTEE's distribution planning process. Common themes and questions from these discussions, along with guidance on where DTEE addressed the feedback is shown in Exhibit 2.1.3.1 below.

Exhibit 2.1.3.1 Feedback from Individual DGP Stakeholder Discussions

Common Questions	DGP Section where question is addressed
Scenario planning – How do the scenarios interact, what are the underlying assumptions, and what happens when multiple scenarios come to fruition?	Section 3 – The scenarios and scenario planning process are described in detail in this section.
Energy and environmental justice – How is DTEE addressing these issues in the DGP?	Section 2.2 – DTEE's approach to address energy and environmental justice is described here.
Availability of granular data – Can more granular data on system performance be shared?	As part of the energy and environmental justice approach, DTEE plans to overlay reliability with census-tract level data. More detail on the approach is found in both Section 2.2 and Section 15 – Performance Based Rate Making.
Undergrounding to improve resilience – Has DTEE considered this approach to improve customer reliability and resiliency?	Section 11.6 – Strategic Undergrounding. DTEE is developing pilot circuits and areas for targeted undergrounding
Ability of the grid to incorporate DERs – Linked to the scenario planning effort, how much DER does the grid have capacity for and where are the constraints?	Section 4.5 describes the Hosting Capacity Analysis pilot, with results expected by the end of 2021.
DER control strategy – How is DTEE evaluating centralized vs. localized control of DERs?	Section 12.8 describes the DER control strategy developed to meet system and regulatory needs.
Cybersecurity - Given some recent cyber security incidents, how is DTEE preparing the grid to be more resilient to potential threats?	DTEE has a cross-functional team engaged in upgrading and preparing the grid for any potential threats. Details that can be shared are discussed in Section 16.3
NWA pilots – Will the pilots proposed address concerns beyond capacity, and is there any consideration of using NWAs to facilitate customer connections in overloaded areas?	Section 12.7 contains details on a suite of NWA pilots, which primarily focus on capacity constraints and incorporating new technologies. Rapid deployment of utility scale batteries is being explored in one pilot to relieve loading constraints.

2.1.4 Feedback on the Draft DGP Filing

The Draft DGP was filed and became available on the U-20147 docket on August 2nd, 2021. During the period between the draft and final filings, DTEE received feedback from stakeholders through both filed comments in the docket, written comments sent directly to DTEE, and a series of individual discussion to solicit feedback directly. Through these channels MPSC Staff, 5 Lakes Energy / Doug Jester, Attorney General's Staff, the NRDC, ABATE, Michigan EIBC / Advanced Energy Economy (AEE), and Soulardarity all provided input on the Draft plan.

Overall, the feedback was positive, with some common themes emerging which can be incorporated into future distribution planning efforts. A high level summary of common feedback is listed below.

General Plan Feedback and Observations:

- Common concern of many stakeholders remains reliability and resiliency improvements, reduction of storm related outages
- Several stakeholders express concerns about the impact of increased investment on affordability
- Scenario based planning was useful, though there is still some clarification needed between scenario based planning and detailed forecasting
- The plan included a concrete suite of NWAs to pilot technologies over the next few years
- The stakeholder engagement process from November through the draft plan filing in August was appreciated

Areas of future interest:

- Energy and environmental justice, including involving stakeholders in the further evolution of the plan
- Community resiliency, including how to structure programs to identify and strengthen key facilities – an issue which extends beyond the electric utilities
- Resiliency and interdependency on other infrastructure systems such as telecommunications
- Next steps on benefit cost analysis and future changes to DTEE's Global Prioritization Model

- Interest in mechanisms to share more data, particularly around outages and load forecasts.

2.2 Energy and environmental justice

DTEE's parent company, DTE Energy, is coordinating a corporate-wide, comprehensive Energy and Environmental Justice plan in conjunction with its broader Environmental, Social and Governance (ESG) initiatives. DTE has established a cross-organization Energy and Environmental Justice Committee to explore ways the company may be able to better serve customers living in highly impacted communities as defined by the Michigan Environmental Justice Screen (MIEJScreen) tool (see methodology below), across a variety of company initiatives. This Committee will also establish processes for external stakeholders to provide feedback on DTE's approach to Energy and Environmental Justice and programming. Additionally, DTE has taken an active role on the Michigan Advisory Council on Environmental Justice

One of DTEE's goals is to incorporate more equity considerations in our grid modernization and clean energy efforts. This aspiration aligns with our objectives of providing all customers and communities we serve with energy that is safe, reliable and resilient, affordable, clean, and community focused and accessible.

For the purposes of the Distribution Grid Plan, we will focus on energy justice as it relates to the long-term planning of the grid to meet the evolving needs of all our customers equitably.

2.2.1 Methodology

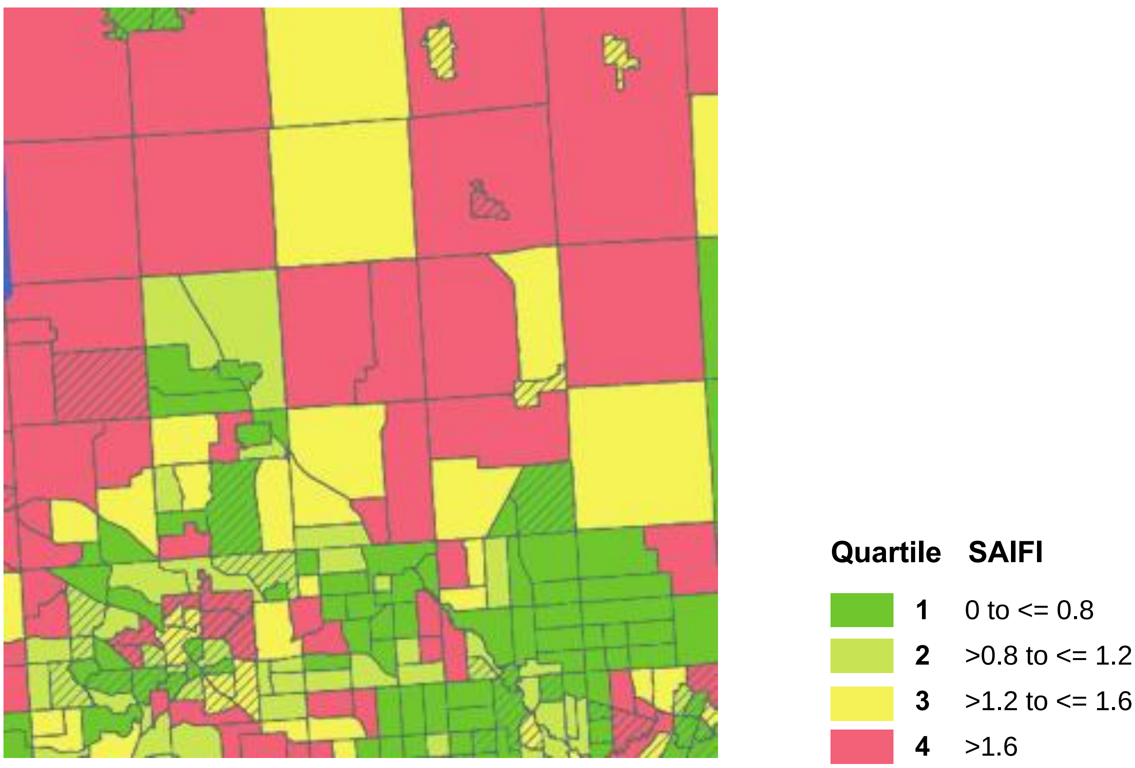
To assess our current state, DTEE intends to use the forthcoming MIEJScreen, which will provide a consistent data set and approach across the state for defining highly impacted communities within our service territory. The screening tool will generate a scale for rating each census-tract level community based on a comprehensive list of indicators that include environmental exposures and effects, sensitive populations, and socioeconomic factors.

DTEE plans to overlay electric reliability data with the MIEJScreen data to identify areas which are considered highly impacted communities and have experienced poor reliability relative to other customers. Customer-focused reliability data will include the three-year average for both number of outages (System Average Interruption Frequency Index – SAIFI) and the duration of the interruptions (System Average Interruption Duration Index – SAIDI) at the census-tract level.

To quantify the current state, the metrics will be categorized into different ranges based on DTEE's average system performance.

The data in Exhibit 2.2.1.1 shows what a hypothetical example of SAIFI by census-tract with highly impacted communities overlaid on a map might look like. This data is illustrative and will be updated with actual data once the MIEJScreen is available. Each census tract is color coded by SAIFI quartile within DTEE's service territory, and the impacted communities are identified with cross-hatching.

Exhibit 2.2.1.1 – Illustrative SAIFI by census tract with highly impacted communities identified



A system-wide analysis and map will be completed in Fall 2021, or when the final tool is released to the public, which will ensure that DTE is using a data set and methodology consistent across the state for any EJ screening initiatives. Once we have identified the overlap of impacted communities with poor reliability, we will review planned investments in those communicates, and make adjustments in the investments, individual programs, or timing to support improved reliability and resiliency more quickly.

2.2.2 Actions

DTEE will be completing this analysis to identify gaps and drive action. The results of the analysis will support the development of an action plan to review our investment programs and processes including investment prioritization, with a focus on reducing the burden of outages on highly impacted communities. Currently there are several initiatives being developed to support this action plan:

• Address areas of poor service in highly impacted communities, as indicated by red or potentially yellow areas with hash marks as illustrated in the image above. We will do this by:

- o Understanding which circuits are in the highly impacted communities with poor service
- o Understanding the reasons for outages on those circuits
- o Scheduling the corresponding work via the hardening, tree trim, pole top maintenance and modernization, or other reliability and resiliency programs, as needed
- o Understanding if larger strategic projects are needed and incorporating them into the capital plan
- o Monitoring these areas closely for improvement and follow up

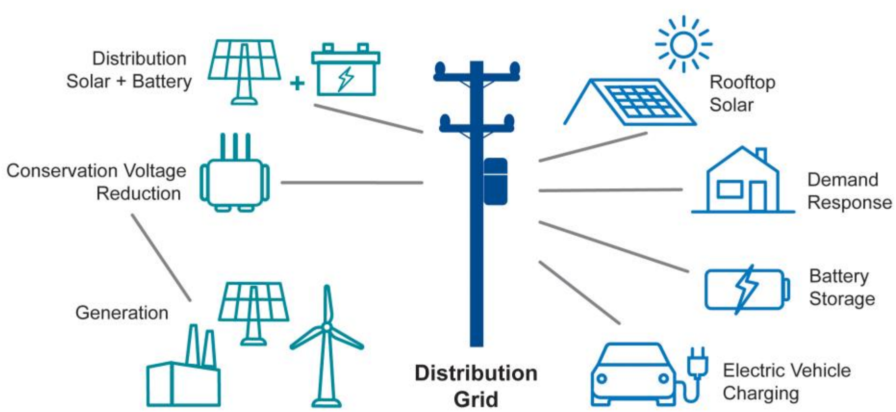
• Assess our global prioritization model and determine how to adapt it to better support highly impacted communities as we invest going forward

• Ensure our trouble and storm restoration strategies are optimized to prioritize highly impacted communities due to the impacts of a longer sustained outage could have on these communities.

The advancement and emphasis on DTE's Energy and Environmental Justice plan will ensure that the investments in grid modernization support the needs of all of our customers. The goal is to work across the organization to drive greater focus on equity and to build the framework to deliver outcomes that will provide benefits, or reduce burdens, on highly impacted communities. DTEE will be proactive by analyzing and addressing potential opportunities to alleviate the burden on highly impacted communities with the utilization of the MIEJScreen. DTEE's organizational approach to Energy and Environmental Justice is evolving, but efforts will focus on planning through an equity lens to deploy projects that are reflective of the communities we serve and create desirable outcomes for the future.

3 Grid modernization process

Customer demands and requirements are anticipated to rapidly evolve over the next 15 years as the electric industry undergoes a fundamental shift in the current grid landscape. This change stems from a complex multitude of factors including the growth of DERs within the distribution system, the effects of climate change, and the increasing decarbonization movement away from fossil fuels toward electrification including EVs. While these coming grid impacts 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. Through the grid modernization process, DTEE will work to create a more interconnected grid that is safe, reliable and resilient, clean, accessible and affordable for our customers.



DTEE understands that the future will fundamentally change the nature of the electric grid, to one that is different than the historic paradigm where power is centrally generated, transported via high voltage transmission lines, then sent through the distribution system to be utilized by the customer. These changes will move the grid toward a more distributed model where power flows both ways through the distribution system. This will require DTEE to address new and complex issues such as two-way power flow, intermittent generation, and DER aggregation and integration. In order to manage these new grid characteristics, greater visibility and data on demand will be needed by both customers and grid operators.

The grid modernization process is designed to facilitate DTEE's transition from the current paradigm to a more interconnected grid. The process calls for a robust, multiphase near-term and long-term investment strategy. Over the next five years, the Company's investments will target safety and reliability improvements along with those investments that are critical to support the longer-term customer desires and resulting grid needs that were identified through this process.

3.1 Methodology

The DTEE grid modernization process was developed using the DOE's DSPx grid modernization framework.[4] The Company began using the DSPx framework when developing the future investment plan in 2019. Since then, the framework's methodology has helped guide DTEE by providing tools and resources for the planning process. In preparation for the 2021 DGP efforts, the Company used the DSPx framework to help assess current and near-term planned activities and develop a set of recommended strategic investments. The approach that DTEE used in 2020-21 for the development of the Company's current grid modernization strategic process is shown in Exhibit 3.1.1:

Exhibit 3.1.1 Five Step Approach to DTEE's Grid Modernization Planning Process

1. **Define DTEE objectives –** The team solidified internal distribution grid and integrated resource planning objectives and aligned with MPSC planning objectives.

[4] *Modern Distribution Grid (DSPx)*. (2019 November) Pacific Northwest National Lab. [Modern-Distribution-Grid_Volume_I_v2_0.pdf (pnnl.gov)]

2. **Develop plausible scenarios for the future through 2035 –** DTEE worked with an external consultant to develop three plausible long-term scenarios that lay out potential grid changes over the next 15 years, as well as an analysis of each scenario's grid impacts.
3. **Assess current system capabilities –** The team worked with the consultant to assess the current state of the distribution system. Both the current and near-term strategic distribution system investment plans were also reviewed.
4. **Determine grid needs based on scenarios and current state –** The team analyzed the gaps between the grid needs and the current grid capabilities, and from this developed a list of potential "no-regrets"[5] investments that have positive payoffs irrespective of how the scenarios continue to develop in the future.
5. **Develop near-term plans and long-term vision –** DTEE enhanced its existing five-year distribution investment plan, as well as the longer-term 2026-2035 vision and plan for the grid.

Each of these steps will be discussed further in the subsequent sections.

3.2 Define DTEE objectives

As the first step in the grid modernization process, DTEE created unified planning objectives across both the distribution planning process and the integrated resource planning process. In August 2020, MPSC issued an order in Case No. U-20147 that reinforced what distribution planning objectives are foundational to successfully meeting the needs of our customers and communities. Exhibit 3.2.1 below shows an abbreviated overview of the MPSC's distribution planning objectives:

[5] As described in section 3.4.1 Scenario Impact Analysis, "no-regrets investments" are those investments determined to 1) mitigate the grid impacts of one or more scenarios; and 2) meet core safety and reliability requirements

Exhibit 3.2.1 MPSC Distribution Planning Objectives

U-20146 - Distribution Investment and Maintenance Plans		
Distribution Planning Objectives		
Customer Needs	Safety	Reduce risks due to equipment failures or outdated practices, third parties damage or inclement weather. Safety is the Commission's top priority.
	Reliability / Resilience	The ability to withstand and respond to major weather events and other disruptions and reduce how often and how long customers experience outages. Cybersecurity and physical security also play a key role in ensuring reliability and resiliency.
	Cost-effectiveness /Affordability	Data-driven, value-based approaches to determine when to repair versus replace aging equipment, integrate new technologies in an optimal manner, and provide planning tools and information to encourage efficient siting and operations of customer resources. Ensure long-term affordability for customers through reasonable and prudent investment strategies, considering alternatives and longer-term operational savings.
	Accessibility	Accommodate service to new or expanding customers without causing major network upgrades due to an underlying infrastructure challenge. Planning to assess system conditions under different scenarios to guide siting new projects or accommodating changing load patterns due to customer resources.

MPSC order no. U-20147 confirmed and defined the distribution planning objectives for customer needs under four categories: safety, reliability and resilience, cost-effectiveness/affordability, and accessibility. DTEE reviewed the MPSC objectives, as well as the planning principles that were used for generation planning in the Company's 2019-2020 Integrated Resource Plan (IRP). From this the IRP and distribution planning teams have developed the following DTEE planning objectives:

- Safe
- Reliable and resilient
- Affordable
- Customer accessibility and community focus
- Clean

Exhibit 3.2.2 DTEE 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

The team ensured the Company's objectives aligned with the MPSC's planning objectives to provide a solid basis for evaluating grid needs in both the five-year plan and longer-term vision. Both DTEE and the MPSC hold customer needs as the fundamental objective for distribution planning. DTEE recognizes that customer needs will be evolving in the coming years to support decarbonization efforts and the integration of DER into the distribution system. In turn, DTEE will look to adapt to these evolving needs by modernizing how the grid is planned and operated.

3.3 Scenario planning

Scenario-based planning is an established methodology for making informed decisions when the future is highly uncertain. To better understand the uncertainties surrounding the fundamental changes to the grid, three future scenarios were developed to assess the potential changes that could impact the electric grid as well as their implications over the next 15 years. This process enables a closer examination of both the engineering considerations and the identification of overlapping grid needs (i.e. technologies that will be beneficial across multiple scenarios).

The purpose of scenario-based planning is twofold: 1) Assess the robustness of current plans, assuring that current investments are appropriate to serve current needs even as the strategy shifts to incorporate emerging, future needs; and 2) Guide future investment strategies, including identifying areas for further engineering analysis to determine specific actions that may be required.

Grid modernization "plausible" scenario planning is quite different in intent and outputs from probabilistic scenario planning. In this context, plausible indicates that the scenario is directionally correct and seemingly possible; however, the exact forecast is not intended to be precise. The grid modernization scenarios were not input into a model to predict the probability of one or multiple scenarios, rather a plausible future state is developed to understand how the grid is impacted as that scenario progresses along the forecast. Similarly, in the analysis step of a plausible scenario, the grid impacts are determined as a model output, as opposed to a statistical "least-cost solution" output. The team defined the three plausible scenarios to identify the impacts to the grid, and in turn determine the functionalities and technologies that address or mitigate the grid impacts, which is described in detail in Section 3.4.1 Scenario impact analysis. As described in that section, there are technologies that support the grid impacts across multiple scenarios. This overlap helped the team identify no-regrets investments that will be effective no matter how the various scenarios continue to develop in the future. In addition, scenarios may also have offsetting grid impacts. For example, large scale adoption of PV with storage can potentially offset increased substation loading resulting from increased EV charging. Determining the appropriate technology solution to mitigate these impacts is difficult to ascertain given the nature of uncertainty regarding time, scope and magnitude of customer adoption and usage patterns. DTEE recognizes the need to address these and other gaps in future iterations of the grid modernization process. Specifically, as the team monitors the specific signposts over time, DTEE will alter its planning activities to better accommodate the more definitive trajectory.

Furthermore, this process did not intend to determine a definitive 15-year investment plan based on probability or stochastic analysis. Given the uncertainties with customer decision making regarding EV and distributed generation/distributed storage (DG/DS) adoption, as well as an everchanging and uncertain national regulatory environment, DTEE will develop and continue to refine the long-term investments as we monitor and analyze for the appearance of signposts associated with the scenarios.

Under each scenario DTEE has identified directionally plausible forecasts specific to each scenario (e.g. increased load from electrification), key uncertainties, signposts, and the associated grid impacts that may result. Plausible forecasts represent a possible outlook on the specific drivers for a scenario. The purposes of the plausible forecasts outlined below is not to predict with specificity the numerical value of that scenario; rather, as the directionally plausible forecast plays out, the teams can identify stresses that are seen on the system. Key uncertainties highlight unknowns that affect the scenario's course, such as technology, price or regulatory changes. Signposts are actions that confirm the trajectory of a scenario toward a more certain future. The grid impacts explain how a scenario may impact grid infrastructure given current conditions.

Consistent with DTEE objectives, the scenarios that were chosen are shown below:

Exhibit 3.3.1 DTEE 2035 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)

3.3.1 Electrification scenario

The electrification scenario focuses on transitioning vehicles, buildings and industrial processes away from fossil fuels via electrification. Under the electrification scenario, the increased movement toward decarbonization prompts residential and corporate customers to adopt EVs and major cities partially transform their public bus fleet.

Directionally plausible forecast[6]

DTEE's internal forecast from July 2020 includes up to 30% light duty EV growth annually from 2021-2035, reaching 17% market penetration by 2035. A summary of electrification load forecasts for each type of EV chargers is shown below in Exhibit 3.3.1.1:

Exhibit 3.3.1.1 Electrification Scenario Forecasts (2025-2035)

Key Drivers	2025	2030	2035
EV AC L1/L2	383 MW (3.8% peak)	1,425 MW (14.3% peak)	5,286 MW (53.7% peak)
EV DC L1	7.1 MW (0.1% peak)	12 MW (0.1% peak)	19 MW (0.2% peak)
EV DC L2	10 MW (0.1% peak)	50 MW (0.5% peak)	100 MW (1% peak)

Key uncertainties

Key uncertainties under the electrification scenario include EV ownership costs, charging flexibility/availability, community decarbonization initiatives and government regulated targets, including the restriction of fossil fuel use.

Signposts

Signposts for the electrification scenario include EV growth of more than 30%, EV fleets beginning development, public policy extending tax credits and public transportation electrification.

Grid impacts

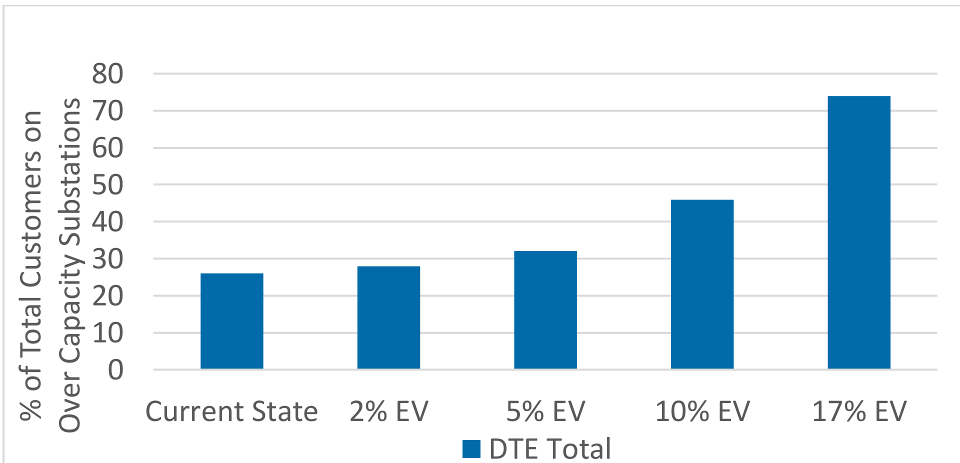
The forecasted electrification will significantly impact the distribution system, as it is expected to add additional load to circuits both on- and off-peak. This will pose additional challenges to the distribution grid which has limited existing capacity[7] in areas to accommodate the load growth.

[6] The Directionally Plausible Forecast is not intended to predict the specific impact on peak load, but rather to understand how the increased load stresses the system as it moves along the trajectory of this forecast.

[7] Capacity refers to distribution assets' ability to deliver electrical power, not the ability to generate the power. It is a measure of how much load DTEE's distribution system can accommodate without negatively impacting operational parameters (e.g. thermal limits). For more information see Section 11 - Infrastructure Redesign and Hardening

Exhibit 3.3.1.2 below shows the percent of total customers on substations that are over their nominal design capacity at varying levels of EV adoption, without increased investment to support the additional load. Substations that are over capacity for extended periods of time pose risks of accelerated equipment aging and failures. Additionally, substations that operate over capacity restrict the flexibility and resiliency of the grid, as load cannot be transferred between locations for planned or unplanned work.

Exhibit 3.3.1.2 Substation Loading[8]



3.3.2 Increasing catastrophic-level storms scenario

The increasing catastrophic (CAT) level storms scenario attempts to capture the risk to DTEE's infrastructure stemming from the increasing intensity and frequency of severe weather. The Company differentiates CAT level storms into two categories: CAT-1 level storms, which affect 5% of the customer base, and CAT-2 level storms, which affect 10% of the customer base.

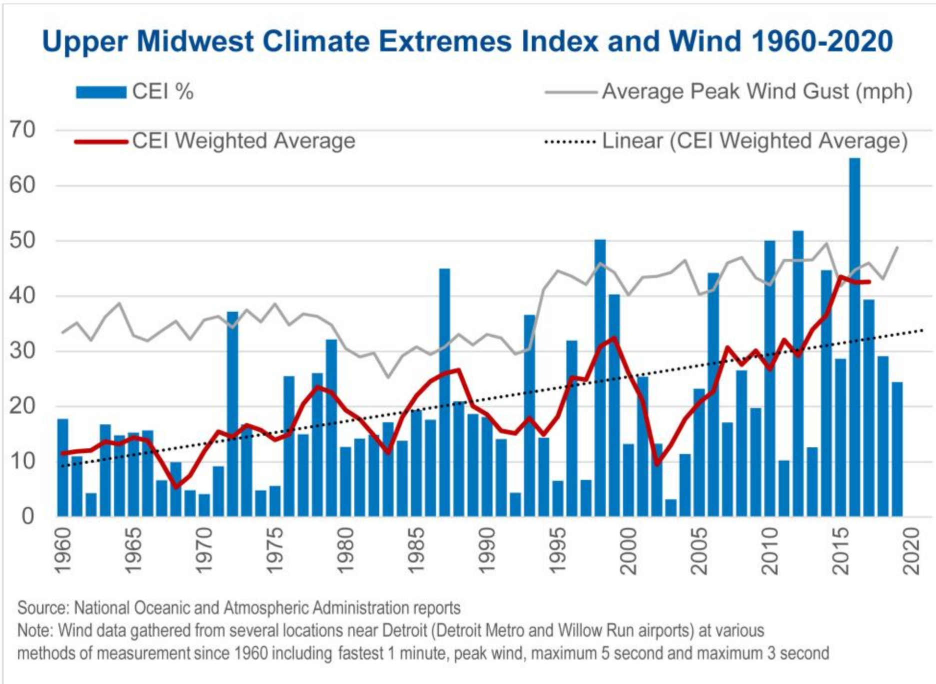
Directionally plausible forecast[9]

Since 2009, DTEE has experienced 35 CAT-1 level storms (average duration of 4.19 days), as well as 10 CAT-2 level storms (average duration of 5.95 days). One impact of climate change is

[8] Assuming 12 kW L2 Chargers. Charging set to occur 70% at midnight, 10% at peak, and 20% throughout the rest of the day.
[9] The Directionally Plausible Forecast is not intended to predict the specific quantity or intensity of future CAT storms, but rather to understand how the increase in CAT storms stresses the system as it moves along the trajectory of this forecast.

the potential for these CAT storm events to occur more frequently and with greater intensity. This is clearly indicated by the MPSC statewide energy assessment, which is included Exhibit 3.3.2.1 below:

Exhibit 3.3.2.1 Upper Midwest Extreme Weather is Increasing in Frequency and Intensity



Specific to Michigan, the National Weather Service has found that severe winds occur more frequently in the southern half of the lower peninsula than anywhere else in the state. In addition, 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 severe wind events across Michigan with an upward risk trend. In addition, extreme high temperatures and flooding negatively impact electrical equipment (e.g. cables, breakers and transformer failures), which can compound the effects of summer storms. DTEE is vulnerable to the increasing intensity and frequency of severe weather events due to aging infrastructure, system configuration and high operational utilization of the existing system.

Key uncertainties

Key uncertainties that affect the increasing CAT storm scenario involve future weather patterns, the ability of the grid to sustain weather events, and communities establishing resiliency targets and projects.

Signposts

Signposts that DTEE will look for to confirm the trajectory of the scenario include increasing storm severity and frequency, communities implementing resiliency initiatives and projects, and legislative approval of a bill(s) to support infrastructure projects.

Grid Impacts

The increased likelihood of catastrophic storms will threaten the Company's physical grid infrastructure. In addition to widespread outages that can disrupt service to customers for extended periods of time, storms can damage equipment, resulting in costly emergent work. This will increase the need for certain structural and operational changes (e.g. redundancy, automation) to enhance system reliability and resiliency.

3.3.3 Distributed generation/distributed storage growth scenario

Lastly, the Distributed Generation/Distributed Storage (DG/DS) scenario focuses on adoption of distributed generation and storage technologies that can reduce customer electricity demand and/or export power back to the grid. Both DG and DS are classified as subsets of DER technologies in MPSC Case U-20147, which defines DERs as:

> *"A source of electric power 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, solar PV is typical. Under the DG/DS scenario, residential customers and commercial and industrial (C&I) customers rapidly adopt DG/DS. The scenario also assumes some C&I adoption of Combined Heat and Power (CHP).

Directionally plausible forecast[10]

In this scenario, driven by government subsidies in the form of tax credits and decreased cost, distributed customer-sited solar PV could potentially grow an average of 23% annually from 2020-2030 and 15% from 2030-2035. Additionally, in the future battery storage is expected to be paired with approximately 60% of new solar PV systems, resulting in potentially 395 MW of added capacity by 2035. In this scenario, DER will be able to participate in wholesale markets (directly or through aggregations via Federal Energy Regulatory Commission (FERC) order 2222). Plausible forecasts are summarized in Exhibit 3.3.3.1 below:

Exhibit 3.3.3.1 DG/DS Scenario Forecast (2025-2035)

Key Drivers	2025	2030	2035
Solar PV – Residential	66 MW (0.6% peak)	210 MW (2.1% peak)	422 MW (4.3% peak)
Solar PV – C&I	52 MW (0.5% peak)	151 MW (1.5% peak)	304 MW (3.1% peak)
Storage – Residential	15 MW (0.1% peak)	94 MW (0.9% peak)	254 MW (2.6% peak)
Storage – C&I	10 MW (0.1% peak)	50 MW (0.5% peak)	141 MW (1.4% peak)
CHP	33 MW (0.3% peak)	53 MW (0.5% peak)	76 MW (0.8% peak)

Key uncertainties

The key uncertainties in the DG/DS scenario are customer adoption rates, federal and state policies (tax credits, MW targets, DG/DS carveouts) and MISO's implementation of FERC Order No. 2222[11].

[10] The Directionally Plausible Forecast is not intended to predict the specific impact on peak load, but rather to understand how this load stresses the system as it moves along the trajectory of this forecast.

[11] Through FERC Order 2222/2222A, Distributed Energy Resources (DERs) that were previously only able to participate in retail programs are now able to participate in the wholesale market via aggregations

ignposts

The signposts the Company will look for include MISO developing operational coordination with DTEE to implement FERC Order No. 2222, growth of solar + storage installations in the Company's service territory and Michigan increasing the solar PV cap and adopting storage targets within the next 15 years.

Grid impacts

Moderate to high levels of DG/DS on one or more circuits on a substation can cause several issues, including potentially problematic reverse power flow, mainline and lateral voltage and thermal issues, as well as protection malfunctions. At very high adoption rates, customer DG/DS can create issues with power back feeding into the subtransmission system, as other utilities have experienced. As a result, the Company will have to develop grid controls to ensure stability, that may include a need to curtail generation at those sites or invest in imperative system upgrades. Customer DG/DS adoption will also impact loading on secondary systems including service transformers, creating voltage and thermal issues. These system issues arising under different levels of DG/DS are expected to be widespread given the age, design, and condition of the DTEE distribution system. As a result, the ability for customers to interconnect even modest amounts of new distributed generation may be limited in many parts of the DTEE system absent system upgrades and/or significant efforts to optimize charging, as well as DG and storage utilization to relieve grid constraints. See Section 12.8 for further discussion on DER Control.

3.4 Current state assessment and grid needs analysis

DTEE worked with the consultant to conduct a deep dive of the current state and near-term investment plan. This included third-party interviews with several Company SMEs, a review of the 2018 grid plan as well as the initial plans for this filing and a detailed review of the Company's informational technology and operational technology (IT/OT) strategy roadmap. The team then applied the DOE DSPx investment prioritization to DTEE's current state and existing strategic investment plan. This step includes understanding asset health, risks and replacement cycles as described in detail in Section 8 Asset health assessment. This more clearly illustrates the near-term needs under DTEE's four strategic investment pillars, which formed the basis of the current state assessment.

3.4.1 Scenario impact analysis

Each scenario presents technical and operational challenges that are either unique to that scenario or common across scenarios. Results from the analysis of the grid impacts, discussed above, helped to identify grid needs by evaluating these impacts against a comprehensive catalog of planning and operational functionalities adapted from the DSPx framework. This tool consists of approximately 30 unique grid functionalities and dozens more corresponding technologies associated with a modernized electric grid[12]. In the scope of DTEE's grid modernization effort, grid functionalities are both the 1) physical grid infrastructure and 2) engineering and operational capabilities needed to mitigate impacts identified from each of the three scenarios. To enable a grid functionality, DTEE has a suite of technologies at its disposal, including hardware and software, planning tools, infrastructure upgrades, etc.

For instance, "Physical Grid" represents a foundational functionality under the DTEE adapted DSPx framework. A durable, modernized physical grid is crucial to withstand the grid impacts of increasing severe weather, as well as to expand system capacity to better enable electrification and DER growth. For "Physical Grid" the enabling technologies include voltage conversion, conductor/equipment capacity increases, and hardening. Another example, the functionality "Reliability Management", involves a number of processes and systems that enable distribution operators to discover, locate, and resolve power outages in an informed and efficient manner. Technologies that enable "Reliability management" include the Outage Management System (OMS) and Fault Location, Isolation and Restoration (FLISR).

Ultimately, no-regrets investments are the output of the scenario impact analysis. However, it is critical to note that not all technologies identified in the framework were categorized as "no regrets" investments. Specific to this analysis, and as defined in Section 3.1, no regrets investments were determined to be those functionalities and technologies from the adapted DSPx framework that met the following requirements: 1) effectively addressed grid impacts in one or more scenarios and 2) met core safety and reliability requirements. To date, DTEE's investment plans have largely been centered around the second requirement, such as investments in infrastructure resilience, hardening and redesign.

[12] Modern-Distribution-Grid_Volume_II_v2_0.pdf (pnnl.gov)

In addition to recommending investments corresponding to existing projects and programs, the Company also identified investments that expand on existing efforts, such as a prioritized and accelerated voltage conversion plan, as well as new grid needs, including DER control and monitoring and load forecasting. The Company's planning approach ensures that its chosen investments are sound irrespective of how the future scenarios develop.

3.4.2 Key categories of investment

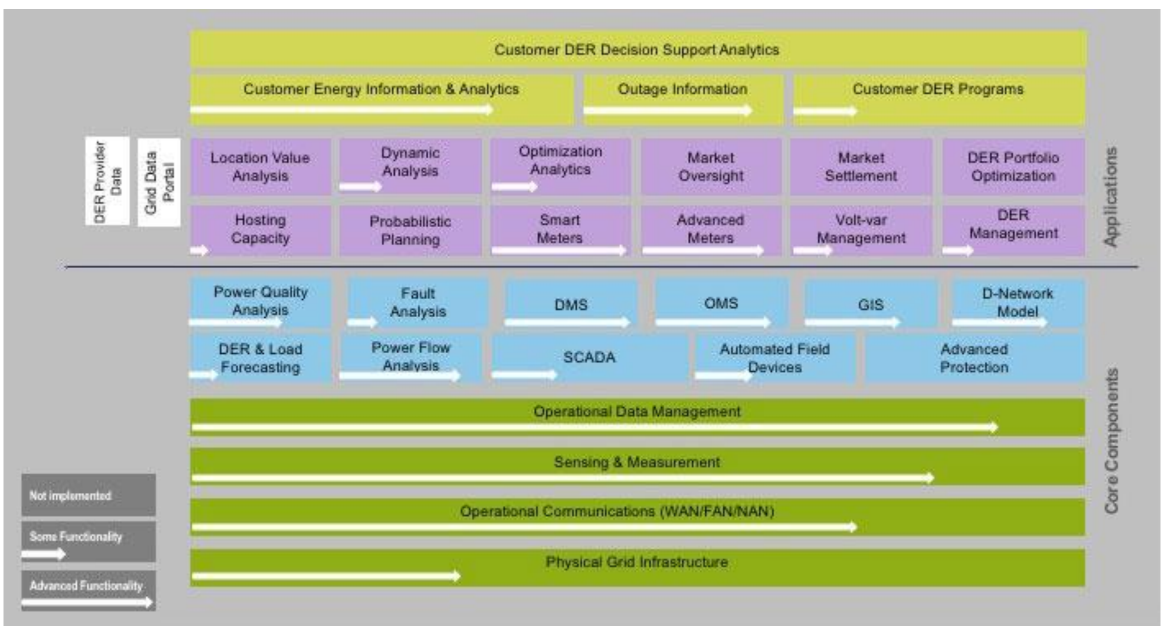
As further described in Section 3.5, DTEE organized more than a dozen cross-functional workgroups to develop no-regrets investment opportunities based on the three scenarios and core grid safety and reliability needs. The no-regrets investment opportunities have been consolidated across five key categories. For each category, a description of the current state and steps needed to progress toward the desired future state are discussed, with recommendations guided by the scenarios. Each section is representative of the largest initiatives taking place and is not meant to comprehensively cover all the no-regrets investment opportunities that were identified, or all the active grid modernization efforts underway at DTEE. A more comprehensive look at the Company's no regrets investments can be found in the sections corresponding to the four pillars of DTEE's strategic investment framework, as further described in section 6 – DGP investment summary. The investment categories are listed below:

- Physical grid infrastructure
- Observability
- Analytics & computing platforms
- Controls
- Communications

As part of grid modernization, DTEE plans to implement each of the no-regrets investments, however, the exact timing and sequence of these investment decisions beyond the next five years is uncertain and will be evaluated against enumerated signposts and changing scenario-driven grid impacts. DTEE's near term five-year plan positions DTEE for the future by supporting the Company's ongoing safety and reliability investments in its underlying infrastructure and addressing known scenario impacts.

The current state of the DTEE grid modernization effort, including the grid improvement projects that are currently in progress, is represented conceptually below in Exhibit 3.4.2.1. This figure is adapted from Volume 3 of the DSPx framework and has been included only to conceptually show the status of DTEE's core grid modernization platform and application layers. The graphic organizes grid modernization investments into two main categories: core components and applications. Per the DSPx framework, the core components shown comprise the essential technologies, as discussed in the scenario impact analysis, that provide a foundation for a modern distribution system[13]. The applications represent the various additional technologies that can layer on top of the foundation and add additional functionality as determined to be necessary by DTEE. The length of the arrow in the box represents the relative status of the Company's efforts in that category now or as projected considering the near term planned investments. For example, "smart meters" has a longer arrow due to DTEE's AMI network being well established.

Exhibit 3.4.2.1 DTEE Grid Modernization Near-Term Status



13 *Modern Distribution Grid Decision Guide Volume III*. (2017 June) Pacific Northwest National Lab. Modern-Distribution-Grid-Volume-III.pdf (pnnl.gov)

Physical grid infrastructure

DTEE has identified the need to invest in physical infrastructure (e.g. substations, poles and wires) upgrades as the foundation to meeting all future grid needs. The oldest DTEE distribution infrastructure, the legacy 4.8 kV system, has a design basis that is incompatible with a modern distribution grid platform. The system has its strengths in resiliency, however, due to its ungrounded design, fault locating can be challenging and may complicate restoration efforts. The lower distribution voltage inherent in the 4.8kV system is also becoming increasingly capacity constrained for meeting current electric load demands. As discussed in Section 11.3.2 – Conversion Prioritization, approximately 20% of 4.8 kV substations are currently over their firm rating. However, capacity constraints are not limited to the 4.8kV system. Currently, approximately 20% of 13.2kV substations are also operating above rated capacity. Firm rating of a substation is defined as the limit to carry load that a substation can have during a failure or outage of a single component (N-1). Loading beyond the firm rating does not overload equipment in normal conditions but introduces the risk of loss of power for customers in case of equipment failure for the duration of time when loads are beyond the firm rating. Options and risks are assessed against affordability to manage risk while the substation operates beyond the firm rating. In some cases, the limited increased risk will be managed for some amount of time to maintain affordability for the customers. As noted in the Electrification Scenario above, these constraints negatively affect the operational flexibility of the distribution system due to limited capacity available to support contingency operations and will only be exacerbated by even moderate levels of EV adoption.

An additional driver of the reliability and operational challenges is the age of many of DTEE's grid assets. On average, the Company's 4.8kV and 13.2kV substations are 68- and 43-years old, respectively. While not the only factor, aging equipment can increase the probability and severity of failure, resulting in service interruptions and the need for emergency replacements and repair. The cycle of emergent work — breaking and fixing — can undermine longer-term strategic investment plans, many of which are necessary for further grid modernization. This is because emergent work is typically more costly than the equivalent planned equipment repair or replacement. Further detail on the age and health of our assets can be found in Section 8 – Asset Health Assessment.

Simply put, in addition to impacting reliability today, an aging and constrained grid platform will be unable to reliably accommodate electrification growth and our customers' needs. In order to continue to support these customer needs, DTEE plans to significantly expand system capacity as discussed in Section 11 - Infrastructure Redesign and Modernization. DTEE's existing 4.8kV conversion program serves as the foundation of the Company's system capacity expansion efforts. However, the pace and magnitude of anticipated load growth are driving the need for the Company to accelerate this conversion work, beginning with substations facing the greatest capacity constraints and highest safety and reliability impacts.

The Company has initiated a study examining the feasibility of introducing a higher distribution voltage (25 kV+) onto the DTEE grid as discussed in Section 17 – Next Steps. In addition to already high system loading on the 4.8kV and 13.2kV systems, the EV adoption discussed in Section 3.3.1 Electrification scenario will translate to a significant increase in the number of substations over their firm ratings. Moving to a higher voltage class could provide DTEE with significantly more power delivered per line mile, lower cost per kW of capacity, improved voltage control, fewer substations and circuits, and an overall more capable system that can better accommodate DER growth and electrification.

Observability

In addition to physical infrastructure upgrades, a modern distribution grid needs operational visibility into physical variables and events for all grid conditions that may need to be addressed. Building out a robust situational awareness platform is essential to reliably plan and operate the grid. Sensing capability enhancement forms one of the core components of DTEE's grid modernization strategy. Over the last decade, DTEE has made significant strides in boosting its sensing coverage throughout the distribution system. The Company's investments in substation monitoring (DSCADA), line sensing and advanced metering infrastructure (AMI) and the new ESOC are proving to be indispensable assets as they are used to support a range of DTEE's internal functions, including grid visibility, forecasting, customer metering and billing, and supporting distribution planning and operations. Further details on the DTEE sensing capabilities can be found in Section 12.4 – Sensing.

Despite the addition of sensing assets in recent years, work remains to both enhance the Company's observational capabilities and translate those observations into situational awareness and actionable intelligence that help customers. The increase of DERs on the Company's system will create a need for enhanced, granular monitoring and sensing capabilities because DERs interact with the grid in fundamentally different ways than conventional technologies. Consequently, DERs will need to be managed carefully. Everyday grid operations such as power quality management will become more dynamic as customers adopt DG and transportation is electrified, resulting in a wider range of less predictable loading conditions.

As part of longer-term grid planning, DTEE is planning investments to improve observability on the distribution system. Observability is needed to monitor system attributes such as voltage, current and harmonics as well as increase awareness of real-time system conditions, including locating faults. Currently, DTEE has installed several thousand line sensors on the distribution system; however, these older vintage sensors have limited functionality as technology has evolved since installation. While these installed sensors can detect faults and read current, they are incapable of measuring voltage and harmonic data. Next generation line sensors are capable of measuring voltage, current and harmonics and will target monitoring locations with high penetration of DER or where voltage measurements are critical. Once installed, these sensors can also be reconfigured to a higher voltage class to maintain the system through planned conversion work. Ultimately, the exact technology solution and deployment strategy will include considerations for other grid needs, including system protection, and the capabilities of existing and planned sensing technologies.

Analytics & computing platforms

DTEE has made significant investments in its analytics and computing platforms, including mining data quality from AMI meter data, constructing a modernized ESOC and the ongoing implementation of its ADMS platforms. These investments substantially improve the Company's ability to efficiently monitor and operate the grid, respond to emergency conditions and outages and facilitate the integration of DER's into the distribution system. In addition, the Company is making the necessary investments to improve data quality and integrity through monitoring, validation and automated corrections tools. These data quality enhancements will enable the Company to fully realize the capabilities of its investments in the ADMS platform and better leverage AMI data through robust data analytics projects. These investments provide DTEE with the data and analysis for remote and autonomous operations on the system, which improves reliability.

While DTEE has made significant progress in improving its analytics and computing platforms in recent years, the Company recognizes that more work will be required to keep pace with the increasing volumes of data and associated analytics requirements driven by DER growth. As DER growth continues, grid impacts such as voltage regulation issues, reverse power flow and overloads will become more area and time specific. Accurate distribution system models and loading data will become increasingly important as planners work to forecast areas of DER adoption and identify distribution abnormalities well in advance of when they occur. In tandem, uncertainties surrounding consumer EV charging and consumption patterns can further complicate these planning and forecasting efforts. The coming expansion of DER technologies and their associated grid impacts will require expanded data collection and an advanced analytics platform to assist the Company with complex decisions relating to planning and operating the grid.

The Company has identified key investments to meet this challenge, as discussed further in Section 12.9 – Technology Roadmap. This includes tools and support for a more accurate mapping of the distribution system, forecasting, the interconnection process and hosting capacity. Technology investments in the Company's digital mapping and network model will increase alignment of this digital representation of the grid to physical field conditions. This will be crucial as increasing volumes of data driven from the growth of DER become integrated into the Company's computing platforms.

In addition to the above improvements, forecasting tools will need to integrate and leverage more granular data sources to support planners with identifying potentially constrained areas well in advance of potential problems. As described in Section 4.2 Forecasting, distribution-level forecasts have historically been developed spatially at the substation and circuit level, and for single annual peak demand. While this approach has historically performed well in predicting past load growth in DTEE's service territory, DER technologies such as EV and PV have complex load profiles that vary by the hour, day, month and year. As such, the Company is currently planning to develop robust "8760" forecasts to have accurate load forecasting for its circuits and substations all 8,760 hours of the year. These forecasts will able to modularly account for newer technologies such as EVs, PVs, and storage, as well as enable DTEE to adequately identify when and where distribution improvements will be needed. DTEE plans to develop these tools through an integrated forecasting process that will account for both system-wide resource and distribution planning. With distributed generation and storage growth also comes an increase in interconnection requests and studies. To adapt to the increased volume of interconnection requests, the Company will look to acquire tools to automate portions of the existing process and analysis. For more information please see sections 4.4 Interconnection process and 4.5 Hosting capacity analysis.

Controls

With significantly higher penetration of customer assets on the grid, DTEE will need increased coordination between utility and customer assets to operate a distribution grid of the future. Accommodating growing customer desires to adopt technologies such as renewable generation, storage and electric vehicles will require significant improvements in grid controls. This includes controlling switching devices to rapidly reconfigure the grid during outages, as well as coordinating certain DER assets (e.g. DER aggregations, energy storage, utility owned solar facilities) to maintain system integrity and reliability. Integrating technologies for our customers, such as electric vehicles, distributed generation and storage will require active management and control of these assets to maintain reliable grid operations. To this end, the Company has invested in remotely controlled devices on the existing subtransmission and 13.2kV systems, including automatic and nonautomatic pole top switches, line breakers and reclosers. These controlled devices help further enable distribution automation on the 13.2 kV and subtransmission systems. SCADA technology currently enables remote control of about 32% of distribution substations. At a circuit level, “loop schemes” work to facilitate automation by automatically transferring power into adjacent sections of the circuits when an outage is detected and are installed on about 5% of distribution circuits. These loop schemes are a standard for all new or converted circuits. Efforts are also underway to automate specific aspects of the 4.8 kV system where possible. More information on these automation efforts can be found in Section 12.5- Distribution Automation. As a separate but related measure, the Company is also piloting conservation voltage reduction (CVR) / Volt Var Optimization (VVO) to help reduce peak demand and energy consumption. While currently in its early stages, DTEE is expecting its CVR/VVO scheme to allow the SOC to remotely balance line voltage and system reactive power to reduce line losses and to improve system efficiency.

Increased coordination and control of DTEE’s physical grid assets and various interconnected resources will be crucial in a future where electrification, severe weather and DG/DS growth pose heightened risks to the systems reliability and resiliency. As discussed in Section 12.8 - DER Control Strategy, the increased interconnection of distributed generation introduces voltage variability that can adversely impact power quality on circuits with high DER penetration. In tandem, increasing storms will further threaten grid reliability and increase outages 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 supports DTEE's safety and reliability priorities and will assist the Company in integrating more DERs into its distribution system.

To properly enable a future where DTEE can adapt to DER grid impacts and mitigate the threats to reliability posed by severe storms the Company has been undertaking certain investments to improve its control capabilities. First, remote and automatic circuit reconfiguration will allow the new ESOC to remotely sectionalize the grid and transfer load onto adjacent circuits when the need arises (e.g. outages). This need will be addressed as part of DTEE's automation strategy in Section 12.5.1, which further outlines DTEE's goal to extend circuit automation to the entire overhead distribution system. Next, the Company recognizes that distributed resource management is needed to monitor and control DERs to ensure thermal and power quality standards are met. To address this, DTEE has developed a DER control strategy centered around managing reliability concerns originating from the increasing number of DERs in the distribution system.

Communications

DTEE has made investments in telecommunications technologies that enable field device observability and control. While much has been done to improve the grid telecommunications, the current architecture must be enhanced to meet the throughput, latency and reliability standards that a modern grid requires.

DTEE has built an existing communication architecture from the subtransmission system down to individual meters. The Company has been implementing a tiered design to serve communication needs now and in the future in a highly resilient manner to provide a high quality of service:

- Tier 1 consists of microwave and fiber backbones for the Tier 1 and Tier 2 systems that traverse between critical facilities such as data centers, power plants, service centers and subtransmission stations.
- Tier 2 consists of wireless point-to-point and point-to-multi-point systems that allow data collection from the Tier 3 system, distribution substations and pole top devices.
- Tier 3 consists of wireless mesh networks that support end point SCADA and AMI meter Communications.

In addition, DTEE has built a new Network Operations Center (NOC) co-located with the ESOC that will monitor all communications required for the Company's operational systems.

As DER growth continues, so too does the number of connected devices and associated volumes of data that must be sent securely and in near real time. While the Company has made headway with its three-tiered implementation, many of the older assets within the current telecommunications architecture are incompatible with modern systems and incapable of fielding the data requirements necessary to support DER growth. The radio-based communications system 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 well as the planned 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 resilience that a utility would. This has resulted in the strategic shift to build DTEE privately owned and maintained networks to securely control and operate assets requiring reliable telecommunication systems.

DTEE is expanding upon the privately owned tiered telecommunications system design to ensure that appropriate bandwidth and latency are available for the support of DER growth, grid distribution automation, and evolving customer needs. A large part of this strategy involves 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 supplement telecommunications needs to intelligent edge devices. The tiered telecommunications system design places emphasis on system redundancy and resiliency, better allowing the Company to operate during outages. For more information on DTEE's telecommunications strategy see Section 12.3 – Grid Telecommunications.

3.5 Short-term investment plan and long-term vision

This grid modernization process was the foundation of DTEE's five-year distribution investment plan, as well as a longer-term 2026-2035 vision and plan for the grid. Grid modernization is an organization-wide process, with all relevant business units within the Company actively contributing to develop DTEE's grid modernization process. More than a dozen workgroups of subject matter experts from various business units within the Company identified gaps between the current and future state for specific functional areas of the grid. The grid modernization scenario work informed the workgroups of additional no-regrets investment opportunities that should be considered in the five-year investment plan for that functional area. Each workgroup created the corresponding five-year investment plans to integrate the necessary no-regrets investment recommendations, along with the longer-term 2026-2035 vision. This five-year plan contains the expected system impacts from their investment plan, as well as details on strategic projects and programs. The process by which all the investments from the various workgroups were prioritized is described in Section 5.1 Benefit Cost Analysis Approach.

Exhibit 3.5.1 below contains a selection of the grid needs from the various categories discussed in Section 3.4.2 – Key categories of investment.

Each grid need is covered within a section of the report, and the table below serves as an index to where it can be found, as well as whether DTEE will be addressing it in the five-year plan, the longer-term 2026-2035 vision or both. This table is representative and is not intended to comprehensively cover all the no-regrets investment opportunities that were identified, or all the active grid modernization efforts underway at DTEE. Rather, this table is simply meant to highlight the largest initiatives taking place. Due to evolving customer needs and the uncertainty surrounding how the scenarios will develop, DTEE will continue to evaluate the signposts to assess the integration of the recommended no-regrets investment opportunities into the Company's longer-term vision and plan for the grid. Grid modernization is a continually evolving effort, and as signposts point to a more certain future, DTEE will take the necessary steps to modify the distribution system into a more reliable and resilient grid that better serves the evolving needs of our customers.

Exhibit 3.5.1 Mapping of Grid Needs to DGP Sections

Timeframe Grid Need	Bucket	Section of DGP Report	2021-2025	2026-2035
Acceleration of the asset upgrade/conversion strategy	Infrastructure	Section 11.3 - Conversion Plan	X	X
Evaluation of a higher voltage class	Infrastructure	Section 17 – Next Steps	X	X
4.8 kV Fault Detection	Observability	Section 9.5 - 4.8 kV Relay Improvements Section 12.5 - Distribution Automation	X	X
Boosting overall coverage of distribution system	Observability	Section 12.4 – Distribution Sensing and Monitoring	X	X
More accurate grid mapping	Analytics & Computing Platforms	Section 12.9 – Technology Strategy Roadmap	X	X
Load and DER forecasting solution	Analytics & Computing Platforms	Section 4.2 Forecasting	X	
Interconnection process tools	Analytics & Computing Platforms	Section 4.4 – Interconnection process	X	
Hosting capacity analysis	Analytics & Computing Platforms	Section 4.5 - Hosting Capacity Analysis	X	

Remote and automatic circuit reconfiguration	Controls	Section 12.5 - Distribution Automation	X	X
Distributed resource management	Controls	Section 12.8 - DER control	X	
Telecommunications strategy	Communications	Section 12.3 - Grid telecommunications	X	X

4 Distribution planning processes and tools

4.1 Introduction

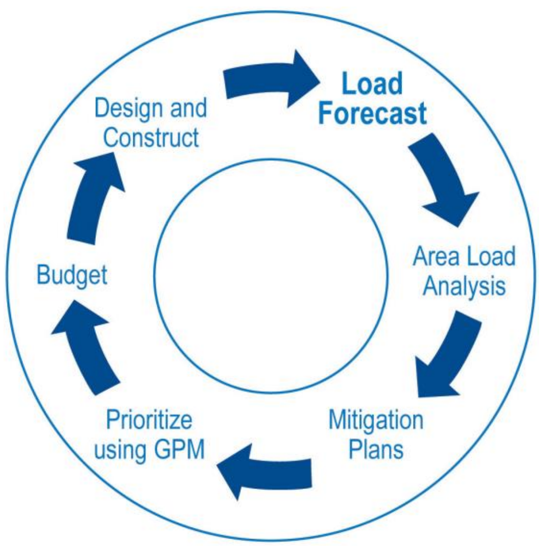
For many years, traditional distribution planning processes have supported utilities in meeting their core objectives to provide safe, reliable, and affordable delivery of electricity. As has been noted in prior sections of the DGP, DTEE is looking at the evolving landscape and preparing for a transformation of the grid. This grid modernization is primarily being driven by changing customer needs, advancements in technology, impacts of severe weather, and electrification led by decarbonization efforts. The confluence of these factors has prompted the Company to examine current planning processes, tools, and practices as we prepare investment plans and the grid moves to a more complex configuration. As described in Section 3.3, Scenario planning, DTEE has started using scenario planning to understand the potential impacts from evolving needs to support our long-term vision and plan. The Company is also focusing on six key distribution planning processes. This section of the report focuses on five of those processes, predominantly through a distribution lens: 1) forecasting, 2) non-wire alternatives (NWA), 3) interconnections, 4) hosting capacity analysis (HCA) and 5) integrated resource planning (IRP) and distribution planning (DP) alignment. The sixth process is stakeholder engagement, which was discussed in Section 2. As noted in Section 3 - Grid modernization process, many of the distribution planning processes are worked collaboratively across different groups within DTEE. In addition, these processes are at varying stages of maturity and will require continued investment in analytic tools as well as process changes to achieve the desired goals and objectives.

4.2 Forecasting

This section of the report describes the process to achieve aligned generation system level and distribution level load forecasts. Currently, the distribution load forecast within DTEE is developed using data, assumptions, and methodologies created within Distribution Operations, with advisory input from other departments in the Company. Distribution level forecasts are typically based on the previous year's actuals, adjusted for projected load growth.

As shown on the diagram below, the distribution level load forecast is an input into the distribution planning cycle and is used to identify grid impacts. If an issue is identified, mitigation plans are then developed and prioritized using the Global Prioritization Model (GPM) as detailed in section 5.

Exhibit 4.2.1 Current State of Annual Distribution Planning Cycle



The distribution level load forecasting process starts with gathering circuit and substation SCADA data. From this point, the forecasting process uses annual single historic peak demand (typically summer demand) from committed loads and applies a growth factor based on demographic and other economic data. While the distribution-level single historic peak demand load forecast approach has been sufficient in identifying and addressing grid impacts in the past, the potential for increased adoption of distributed energy resources (DERs) and electric vehicles (EVs) will require a change in forecasting approach to account for demand and load shifting. To date, the incorporation of the impacts of DERs and EVs to the load forecasts has occurred only at a generation system-level, not at a circuit/substation-level. Furthermore, all interconnection (section 4.4), energy waste reduction (EWR), or demand response (DR) requests at the distribution level are typically evaluated for grid impacts on a case-by-case and manual basis.

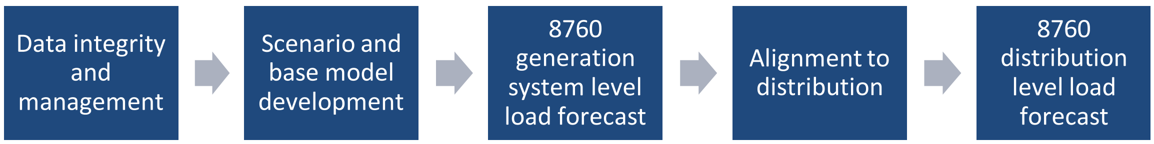
DTEE recognizes that load forecasting at the distribution level will need to advance and become more robust. The Distribution Operations (DO) team is working with the Corporate Energy Forecasting (CEF) team to develop a forecasting solution that accounts for the impact of DERs and EVs into the distribution load forecast. DTEE is working toward a transition to an integrated distribution and generation load forecast and will adopt a more integrated and progressively granular approach to load forecasting. The forecasting process will inform long-term planning at both the generation system and distribution levels. This approach is consistent with the commission's May 27, 2021 Order in Case No. U-20633, Integration of Resource, Distribution, and Transmission Planning, to align planning processes, data, assumptions, and methodologies for a more consistent, integrated and scenario-based approach.

Distribution load forecasts in the past have always been developed spatially at the substation/circuit level, and at a single annual peak demand. The distribution-level load forecast in the near term (five years) will change over time due to the dynamic characteristics of DER and EV load profiles. A load profile is a variation of electrical load versus time typically driven by customer type, temperature, and seasonality. Due to more complex load profiles for EVs and DERs (e.g. EVs typically charging at night and solar photovoltaics (PVs) intermittency due to cloud cover), load shifting will likely become more prevalent as adoption increases. DTEE is therefore pursuing the capability to conduct 8760 hourly load forecasting to help analyze and address any grid impacts from these evolving technologies. A project has been deployed to support integrated resource planning which will utilize hourly load shapes. In the next few years, the distribution planning group will coordinate and leverage the work done in integrated resource planning to adapt those hourly shapes for generation/sales to provide meaningful demand load profiles at the substation/circuit level. There will be further analysis into creating and refining hourly profiles for PVs, EVs, storage and other new or emerging technologies. This new aligned process will be called integrated forecasting solution (IFS).

4.2.1 Integrated forecasting solution

The development of IFS can be described in five broad process steps.

Exhibit 4.2.1.1 Integrated Forecasting Solution (IFS) Steps



To enable and support 8760 load forecasting at the substation/circuit level that incorporates EVs and DERs, DTEE has near term plans to invest in some of these steps.

With the incorporation of the identified investments and the move to a more integrated planning process over the next few years, DTEE plans to phase out the “Alignment to Distribution” process as it currently exists as an iterative corrective process. As we address the identified gaps that need to be bridged, DTEE expects that the distribution level load forecasts will transition to 8760 hourly load forecasting at the substation/circuit level in alignment with the 8760 system-level forecast using consistent data sets, assumptions, and methodologies. Investing in a more aligned load forecasting model will help avoid the risk of an under- or over-investment in capital assets for the future and ensure alignment between the generation and distribution load forecasts.

4.2.2 Data integrity and management

An accurate load forecast is essential to various types of planning activities; therefore, it is paramount to take steps to ensure data sources are current and consistent. The maturation of DTEE’s automated metering infrastructure (AMI) data has enabled the Corporate Energy Forecasting team to advance their modeling capabilities and has resulted in more granular forecasts with steady improvements in accuracy. These modeling approaches, along with the further refinements in accessing and expanding the use of SCADA data at the circuit/substation level, will ensure alignment and consistency across data platforms.

Although each area of planning may require unique forecast outputs, the goal of an integrated forecasting solution is to utilize the same inputs improving the alignment of load forecasts across business unit planning. There is a coordinated effort across the Company to ensure all data and data requirements are organized and standardized so that each process that makes use of data does so consistently, accurately and in a timely manner.

4.2.3 Scenario and base model development

The expected proliferation of new or emerging technologies has added complexity to the forecasting and utility planning processes. In addition to these technologies, the COVID-19 pandemic has altered the consumption patterns of many customers over the past year, and it is unknown at this time whether these load patterns will continue in the future. Having access to more granular interval data will increase the understanding of customer behavior driven by new trends or emerging technology adoption and provide useful insights to the business.

As adoption of these technologies expands, it will be important to understand where the expected load growth and resource needs will occur geographically within DTEE's service territory. Propensity studies are expected to deliver insights at the substation and circuit level so distribution planners can appropriately target cost-effective investments as well as potentially mitigate or defer grid impacts through innovative demand-side programs or rate structures. DTEE envisions the IFS model to be modular in order to be able to develop assumptions and potential impacts between forecast iterations for the following components of change:

- Weather
- EVs
- EWR
- PVs
- Storage
- CVR/VVO
- Other, as appropriate

These components are forecasted independently, thereby allowing DTEE to layer and aggregate the assumptions into a load forecast at a circuit/substation level. This allows both a clearer understanding of the individual impact from each forecast component on the overall forecast at an hourly level and provides the flexibility to adjust individual components, as needed, in various scenarios and sensitivities for further analysis.

4.2.4 8760 generation system-level forecasts

Prior to the recent ability to access and process customer AMI data, modeling an hourly system forecast relied on complex estimation processes. With the increased availability and accessibility of AMI data, model estimation processes can be eliminated in favor of direct calculations using metered data. The metered data is used to generate a bottom-up hourly system load forecast. Although many areas of forecasting have been improved with AMI data resulting in better planning, the opportunity to align the generation system forecasts with the aggregation of distribution level forecast will be the focus of our work in the near future as described in the next section.

4.2.5 8760 distribution-level forecasts

Leveraging AMI data in distribution level analysis has largely been underutilized, presenting a future opportunity to expand the use of this data through new tools and models. In order to forecast at the substation and circuit-level, DTEE plans to employ the same methodology used to produce the bottom-up hourly generation system load forecast to the distribution load forecast. The load forecasts will use the same set of assumptions including weather data, load shapes by customer class (i.e., residential, commercial and industrial) and end-use (i.e., EVs and PVs) to accurately calibrate unique substation and circuit load characteristics to the variables that impact changes in their load, thus providing linkage to the system-level 8760 forecast developed for Integrated Resource Planning.

DTEE will leverage the existing suite of software packages utilized for generation load planning and introduce a more scalable and sophisticated package. In the next few years, MetrixIDR, Itron's automated hourly load forecasting software program, will be implemented. This program has the capability to reconcile distribution-level with system-level forecasts using a multitude of analytical methods and model templates to generate hourly load shape forecasts across an entire system. Additionally, as noted above, incremental component loads can be layered to adjust the base hourly forecast for each of the Company's substations and circuits.

A summary of some of the process improvements DTEE plans to address in the near-term to enable 8760 forecasting at a substation/circuit level include:

- Load allocation methodology will be technical instead of billing-centric
- Aggregation of net power delivered and received with behind the meter DER will be modeled at the meter level
- Reconciliation of AMI data with applicable SCADA data will improve overall accuracy of the modeling
- Advanced hourly modeling techniques will be implemented to estimate values where SCADA data does not exist
- Acquisition or development of automation and validation tools for new load and load types will be employed
- Acquisition or development of propensity modeling to predict adoption levels of DER and EVs will be developed

The steps or processes that need to be accomplished in the next several years will be foundational to improve our overall forecasting framework and planning processes. As this effort progresses and more possible gaps emerge, DTEE will refine this framework. Using AMI data, along with the iterative refinement of the models with new or updated information established through new sources of data, is expected to improve the accuracy and timeliness of the distribution forecast. As DTEE dives further into these various investments, other issues and challenges will likely surface. DTEE expects to have aligned load forecasts at the distribution and generation system levels in the next five years and will provide an update in the next DGP. The timing of the IFS process improvements and investments is outlined in Section 12 – Technology & automation of the DGP.

4.3 Non-wire alternatives

A non-wire alternative (NWA) is defined in MPSC Case U-20147 as:

> *An electricity grid investment or project that uses distribution solutions such as distributed energy resources (DER), energy waste reduction (EWR), demand response (DR), and grid software and controls, to defer or replace the need for distribution system upgrades.*

As will be described in Section 12.7 – NWA Pilots, DTEE is pursuing a suite of NWA projects over the next five years. These projects have been developed through an initial NWA development process or through external partnerships and grants and have been evaluated by distribution engineers and partners across the organization. Many of the process and tools used to identify these projects are still being enhanced and refined. In order to more fully integrate NWAs into the distribution planning process, DTEE will incorporate learnings from the pilots to advance capabilities in the following areas: technology, processes, and people.

When approaching NWAs, DTEE considered the following framing questions posed by Mr. DeMartini through the MI Power Grid stakeholder process as instructed by the MPSC. High-level responses to these questions are provided below with additional information for each individual pilot presented in Section 12.7.

- **Why are non-wires alternatives being pursued? What are the pressing issues?**
  DTEE is developing processes and identifying opportunities for which non-wire alternatives can provide more value to customers than conventional solutions. Through internal evaluation, examination of trends related to NWA, and by recommendation of the August 20, 2020 Order in Case U-20147, DTEE primarily focuses on NWA projects to address situations in which circuits or substation equipment is or may become overloaded to help delay or offset planned traditional upgrades.

- **What are the desired outcomes?**
  The goal of the NWAs is to optimize utility distribution expenditures in addressing distribution capacity constraints. Specific system issues to address through the NWA pilots are outlined in Section 12.7. DTEE also seeks to learn about new technologies, process, and people implications through the application of these pilots as outlined further below.

- **What are the range of potential solutions?**
  As discussed in the technology section below, DTEE is focusing on demand-side solutions, but is also integrating energy storage and distributed generation controls into the suite of NWA pilots.

In several instances, EWR and DR can solve the distribution system capacity constraints without additional investment in more expensive technologies such as energy storage. However, as the electric generation and distribution industry continues to evolve, costs of technologies such as energy storage may continue to decline and become economic alternatives to traditional solutions. At the same time, the potential scenarios described in Section 3, such as increased DG/DS or electrification, could provide resources on the grid that could potentially be controlled to provide additional grid benefits.

- **Pricing, programs and procurements (3Ps)? What is the role of customers, DER developers, utilities, aggregators and others?**
  Customers are a central part of the NWAs, as are DTEE's programs and partners to deliver EWR, DR, and storage solutions as discussed further in the "people" section below. Pricing, programs, and procurement are discussed further for the individual NWA pilots.

- **Are the benefits and costs of NWAs accruing to all customers on an equitable basis?**
  DTEE conducted cost-effectiveness screening for the NWA pilots to ensure that the NWA would be less costly than traditional grid solutions, such as a substation upgrade. While individual participating customers benefit from investment in targeted NWA solutions, such as lower energy bills due to EWR, customers overall benefit from the deferred or displaced investment in costly infrastructure. Additional evaluation will further assess cost, benefit, and equity considerations. DTEE will also continue to refine its NWA selection criteria and process to ensure communities identified through the EJ screening tool have adequate opportunities to be included in NWAs.

Technology

Learning about new technologies, including understanding realized costs and benefits once implemented, is a primary goal of a new pilot. Once a technology has been vetted and evaluated, it can be added to the set of tools available for an engineer in the distribution planning process.

In developing NWA pilot projects, the Company has focused its efforts on evaluating technologies with the potential for benefits to customers and current technical viability. The technologies currently being evaluated are the following:

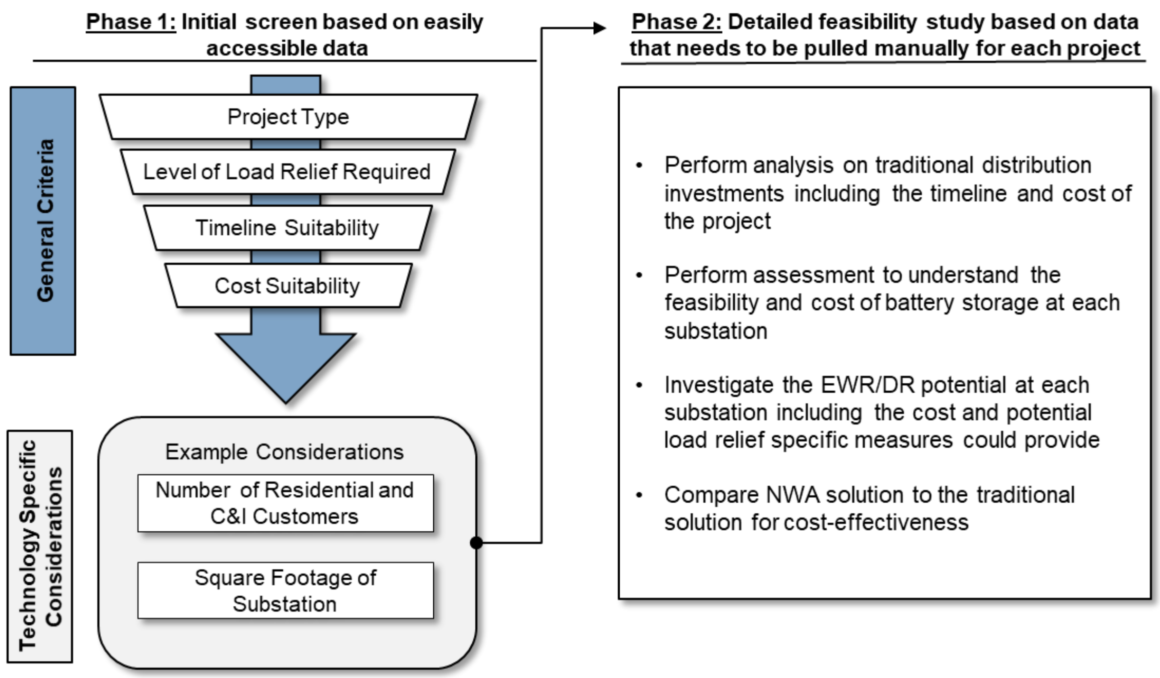
- **Energy waste reduction (EWR) –** geo-targeting of both Residential and Commercial & Industrial customers using the existing portfolio of EWR programs
- **Demand response (DR) –** geo-targeting of residential customers with Interruptible Air Conditioning (IAC) and Smart Thermostat programs
- **Energy storage –** utility-scale or distributed storage to manage peak, including testing of operational procedures and cybersecurity protocols
- **Solar photovoltaics** (PV) **–** utility-scale and rooftop
- **Electric vehicle (EV) charging –** testing grid impact of fast charging, as well as charge management and cybersecurity
- **Microgrid controls –** create microgrids using planned DERs, DR and grid controls, and implement and test cybersecurity protocols

In addition to learnings from these pilots, DTEE will supplement primary technical knowledge with learnings gained through benchmarking, workgroups and research initiatives.

Process

DTEE has developed a two-phased screening process for selecting potential projects that may be suitable for NWA as shown in Exhibit 4.3.1

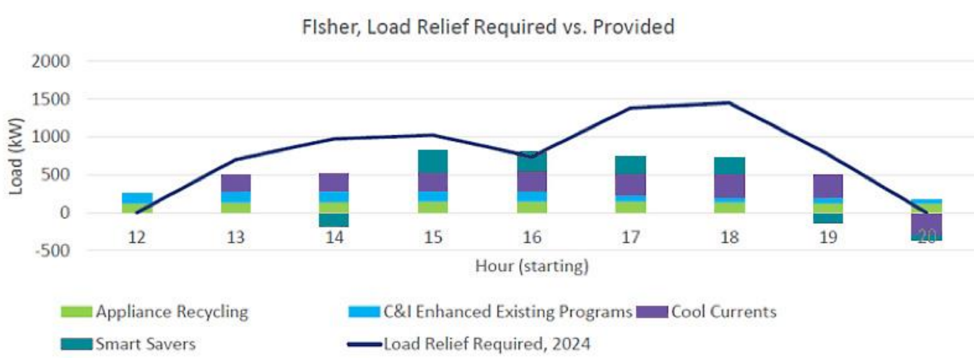
Exhibit 4.3.1 NWA Screening Process



The first phase was developed and has been integrated into the distribution planning process. This ensures that distribution engineers consider NWA options when developing any substation or circuit projects developed for load relief, as described in Section 11.1 – Distribution Load Relief Projects. The screen involves reviewing a general set of criteria as well as technology-specific considerations. For example, as NWAs are currently focused on addressing load relief issues, traditional projects that also address safety, outage event volume, and asset health concerns are not considered good candidates for NWA projects as the technologies in the NWA portfolio do not provide those grid benefits. Other criteria in the first phase screening involves magnitude, duration, and frequency of overload. These screens will be improved in the future based on EPRI's December 2020 report "Screening of Non-Wires Alternatives in Distribution Planning," the Company's pilot experience, and other factors.

The second phase, which is a detailed feasibility study, is much more resource-intensive than the first phase. Detailed load profiles at the circuit and substation are collected for potential projects that pass through the phase one screening. DTEE then uses the DER Estimator Tool to assess the potential for NWA programs to address the overload. This tool considers the load profile, the count of residential and commercial customers on the circuit as well as the types of C&I customers. Currently, portfolios of EWR and DR programs can be tested against the load profile and the expected participation rates based on historical data and customer demographics to determine the likely outcome for a portfolio of programs. A sample output of the tool is shown in Exhibit 4.3.2. This tool currently only evaluates EWR/DR options for NWA as it was developed as part of pilot projects to evaluate the effectiveness of focusing the EWR/DR programs, which had been applied system-wide, to geo-targeted areas. The tool is being enhanced to incorporate additional technologies, such as energy storage, into the optimization process. Even without these enhancements in place, DTEE was able to leverage partnership opportunities to integrate energy storage and distributed generation as part of this initial round of NWAs.

Exhibit 4.3.2 – Example DER Estimator Tool Output



In the chart above, the "Load Relief Required" line shows the magnitude and duration of the overload. In this case the overload reaches 1.5MW at 6pm (18:00 hours). The portfolio tested in this approach uses geo-targeted Residential EWR (appliance recycling), Commercial & Industrial EWR, Interruptible Air Conditioning (Cool Currents), and Smart Thermostats (Smart Savers) as the portfolio of technologies. In this example, the EWR/DR programs can address about half of the overload.

If the DER Estimating tool develops a feasible portfolio of NWA programs to address the overloading need, the NWA solution is compared to the traditional solution and considered for implementation if it provides customer benefit and defers the traditional investment.

The screening and evaluation process for NWAs will continue to evolve over time as tools are developed and other processes detailed in this section are matured. For example, development of a full 8760 forecast by circuit and substation will provide a readily available starting point for evaluation of magnitude and duration of potential overloads, and further refine the suitability, size, and duration of one or more NWA solutions to resolve the constraint. In addition, DTEE continues to develop internal tools to aid in the visualization of areas of the system that may allow for NWA opportunities, including those with current or planned deployments of DERs or penetration of EVs.

The solutions identified in this round of NWAs will rely on existing programs and vendor arrangements to deliver the NWA solutions, or will leverage existing partnerships. Programming will be adapted to allow for geo-targeting to reach the targeted customers. Going forward, procurement processes for new NWA solutions will be developed to ensure all solutions to the specific grid issues are tested in the marketplace. This could be conducted through use of RFIs and RFPs depending on the level of project development and available information. As cost and capabilities may rapidly evolve, this will also ensure up-to-date market information is included in the screening and evaluation process for NWAs.

People

While developing new technologies and incorporating them in the new planning process is important, change efforts can fail if the impact of these new technologies and processes on people is not considered. There are at least three groups of people impacted by the evolving effort to incorporate NWAs into the distribution planning process:

- **Employees involved in traditional distribution investments –** The team of engineers, designers, project managers and front-line employees will need to adopt new tools, processes and technologies to implement an NWA solution. For example, a project manager that typically executes a traditional construction project may also be deploying EWR or DR to complete a solution. Front-line employees will need new or additional training to understand new equipment on the grid and how to safely operate and maintain it
- **Internal partnerships –** The current suite of pilots involve collaboration across DTEE organizations including the EWR/DR team and the Renewables team. Solutions will be increasingly reliant on the Integrated Forecasting Solution to leverage the 8760 forecasts by circuit and substation

- **External stakeholders and project partners –** Leveraging technologies such as targeted EWR/DR or distributed solar and storage require outreach to communities, local organizations, energy technology and service providers, and other stakeholders in order to successfully implement programs

The prospect of incorporating new technologies into the suite of tools at the disposal of the distribution planning process is an exciting change. The possibility of meeting grid needs with these new strategies, at lower cost to our customers, is aligned with DTEE's planning objectives of creating a reliable and affordable grid. As new technologies evolve and become more cost effective to meet grid needs, DTEE will continue to evaluate, incorporate, and determine how best to manage the change involved in the design, implementation, and acceptance of these technologies. As part of developing this plan, a suite of NWA projects has been developed using the process and tools described above. More details can be found in Section 12.7 – NWA projects and other technology pilots.

4.4 Interconnection process

As described in Section 3 – Grid modernization process, DERs are expected to be an increasingly common technology deployed on the electric grid. In particular, the DG/DS scenario described in Section 3.1.2 considers directionally plausible forecasts where customer-owned generation, predominantly expected to be rooftop solar PVs and storage in the form of batteries, is expected to increase in adoption throughout DTEE's service territory. The first step for a customer who wants to own and connect those resources to the grid is to file an application for interconnection. Data from interconnection requests provides critical information to DTEE. As the number of applications for DER increases, a critical component in providing accessibility to the grid will be to ensure that the process to connect to the distribution grid is streamlined and efficient. Enhancements to the interconnection process to effectively capture and utilize information like the location, size and type of DER will help distribution planning efforts.

This section of the DGP describes the processes to improve the customer experience with interconnecting to the Company's electrical system. This includes the activities around compliance with new state and federal rules, as well as, the interconnection portal and study processes.

The distribution interconnection process covers a wide array of distributed generation and energy storage projects such as rooftop solar, combined heat and power applications, renewable landfill gas, and specialized applications like regenerative dynamometers. Any project that produces power while connected to the electrical grid needs to be carefully studied to ensure the operability, safety, and reliability of the electrical grid including the safety of the crews and operators that work on the grid. The interconnection process is designed to ensure that the interconnecting technology preserves the safety and reliability of the distribution grid, and consists of major activities like application review, engineering studies, and finally, testing and commissioning after the project is constructed.

The application review ensures that information provided is consistent across all documentation and that all necessary technical information is available for an engineering study. The engineering study reviews the impacts to the electric system of the proposed project and identifies any facility changes that would be needed to safely interconnect the project. The final testing and commissioning phase ensures that necessary operating controls and protections, such as anti-islanding protection, are in place, working as designed, and that the site can meet the requirements of the parallel operating agreement. Not all projects continue through all these phases to completion, and some projects and customers experience challenges navigating the existing process.

Over the past three years, solar installers have assisted approximately 5,000 DTEE customers in installing rooftop solar projects at their homes. DTEE has improved its processes and DER connection knowledge as the volume of applications continue to increase each year. DTEE hosts yearly webinars with developers to share knowledge and answer questions regarding requirements to interconnect to the DTEE grid. Suggestions received from the participants have been implemented. A dedicated interconnection hotline was established to help answer customers' questions. Along with emails being sent regarding approvals and/or corrections that need to be made, DTEE has also been making proactive calls to customers whose projects need revision to move forward through the process. Enhancements to the DTE webpages (Interconnection Process | DTE Energy & Rooftop Solar and Private Generation | DTE Energy) as well as the web-based interconnection application tool (PowerClerk) have been enhanced so the customer can see the status of their project throughout the process. In another example of streamlining the processes, DTEE changed its process to require customers sign the Parallel

Operating Agreement (POA) before the anti-island test and the meter re-programming to help ensure the project can be completed timely with all required documentation.

In the next five years, efforts will be undertaken to further improve the integration of interconnection processes with existing new customer service processes. DTEE uses Clean Power Research's PowerClerk software for new customer interconnection applications and to track the process through study and interconnection. A number of investments will be made to further improve the timeliness and accuracy of each customer interaction. Currently, application fees and study fees are collected through a paper check process. This introduces significant time delays in the application process while checks are sent through the mail and manually recorded. An electronic payment processing option will be added to the processes to minimize or eliminate the need for paper checks and mail deliveries, reducing the time needed to validate payment.

To implement this, multiple PowerClerk enhancements will take place with regards to automating updates, upgrading forms to accommodate new processes, and developing more user-focused application forms and processes, to provide additional transparency for customers. Additionally, the existing system has a separate customer logon that is not integrated into the Company's customer portal logon system. An interface will be developed to allow the customer to use one logon for interconnections as well as other Company services. Contractors and developers that install DER projects will be allowed to see all their projects regardless if they are load additions or interconnections. Furthermore, this will perform data validation of key application items such as customer address and account to minimize any potential conflicts of rates, status of account, or service installations.

Internally, process integrations to automatically create, update, and status workorders for payment processing and internal work tracking will be created within the work management system, Maximo, to minimize process delays and manual efforts. Data integration to the larger DTEE's data repository will allow for more comprehensive analytics and analysis of interconnection status and trends as well as the ability to link interconnection activities to other work and projects to identify project management and design synergies.

Finally, the interconnection portal will be further integrated with distribution planning tools to automatically perform some screens and data checks to validate if projects need specific upgrades that are common, or if known constraints are violated by projects prior to the screening processes. These anomalies can then be flagged for additional analysis. Once implemented, these improvements will lead to a more cohesive interconnection process that will closely align with the new business and new service processes, thereby, allowing for greater synergies to be leveraged, reducing interconnection processing times, cost and level of effort and, subsequently, improving customer satisfaction.

Along with these improvements, there are a number of investments that will be undertaken in the short term, to align with changes in the statewide interconnection process as well as alignment to changes at FERC and MISO relating to orders such as FERC 841, FERC 842, FERC 845, and FERC 2222.

Initially, all work will be focused to streamline the process and meet the new or proposed interconnection rules requirements. The new interconnection rules require that all qualifying projects go through a series of screenings for various grid impacts. A number of these screens can be readily implemented into the existing systems but are currently highly manual tasks. Other screens will require integration such as those with the planning tool to perform initial evaluations of grid constraints. Specifically, automating screens around loading, transformer size compatibility, and voltage constraints will require the planning tool integration. Other screens, such as the validation of a site being inside the service territory, will need to leverage geospatial service provided by the mapping systems.

The new interconnection rules define a batch study process for larger projects. These studies combine multiple DER applications into one larger study and will require planning and interconnection tools to be modified to identify the interrelated impacts of the projects and separate out the drivers and upgrades required. As part of near-term investments, this requires study preparation tools and databases that collect the interconnection information and models and validates that the appropriate information is available for the study to be completed on time and without rework. This includes system information such as the interconnecting DER models, site plans, equipment specifications as well as the system models for study, the scenarios for different loading conditions, the system operating constraints, and device settings for existing and planned DER configurations that will be impacting the study scope. These tools will also provide the scenario archives for the studies and help produce the report outputs that are sent to customers and developers. The investment levels and timeline for the next five years for these initiatives which enable the Interconnection process are outlined in Section 12 – Technology & automation.

4.5 Hosting capacity analysis

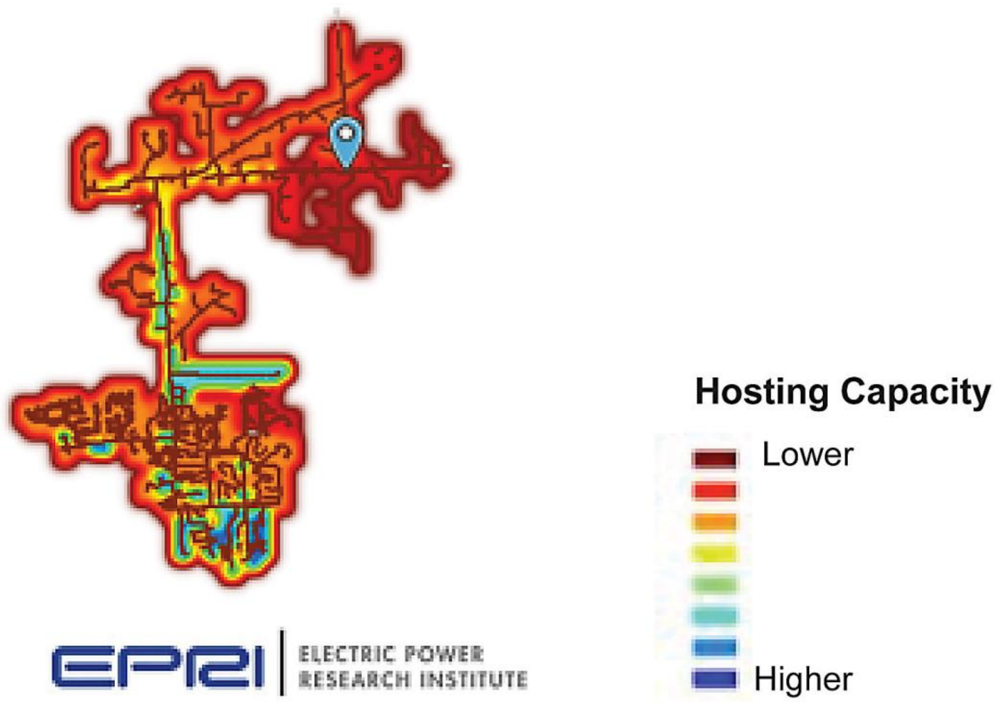
According to the definition in Case No. U-20147, hosting capacity analysis (HCA) is the amount of DER that can be accommodated without adversely impacting operational criteria such as power quality, reliability, and safety under existing grid control and operations without requiring infrastructure upgrades. In addition, in Case No. U-20147, the MPSC has requested that DTEE adopt a phased implementation approach for HCA pilots.

Like the interconnections process, HCA is linked to the DG/DS Scenario described in Section 3.1.2 and would also be impacted by increased electrification as outlined in the Electrification scenario. As the adoption rate of DERs on the system increases, HCA will be a critical tool for distribution planning to identify initial grid constraints. Furthermore, a hosting capacity map can give DER developers the ability to better select sites and possibly reduce interconnection applications for non-viable areas with grid constraints. However, as DTEE has noted in prior discussions and filings, HCA is not a substitute for the developer submitting an application to study interconnecting to the grid. An application to interconnect is still necessary to identify impacts caused by the interconnect and propose solutions to mitigate those impacts.

The approach to hosting capacity at DTEE will be implemented in several phases. The first phase, which is expected to be completed by the end of 2021, will be a high level, go/no-go map of the Company's electrical system. This go/no-go map will indicate the regions of the system where interconnection of DER on the distribution system will be likely to have few if any upgrades to the electrical infrastructure beyond what is necessary to interconnect the DER. Investments in this initial phase will include the development of a tool to maintain and update the hosting capacity and to display this information to customers and developers on the dteenergy.com website.

Further enhancements in this near-term period, which is likely to be in completed in 2022 and 2023, will include the integration of more advanced and detailed hosting capacity tools into the processes. This will be initially rolled out to areas of high DER penetration or those areas where known constraints require a more detailed analysis to properly inform prospective applicants of the limitations in these areas. These more advanced methods include tools such as EPRI DRIVE and CYME integration capacity analysis. Eventually this will link into the investments in the application and screening processes to allow the hosting capacity to visualize the areas where qualifying and standard projects are likely to pass the interconnection screens. This will also include updates to the hosting capacity that are determined from forecasting scenarios, other planning or interconnection studies and will increase the resolution of the hosting capacity and the frequency of which it is updated.

Exhibit 4.5.1 Illustrative Image of Hosting Capacity on a Distribution Circuit in the Second Phase



Initial investments that will be needed in order to support the implementation of FERC 841, FERC 842 and FERC 2222 compliance are still being evaluated. These orders could have an impact on the implementation of the interconnection process and HCA. The following gives a summary of these orders:

- Order 841 under the Federal Power Act (FPA) directs regional grid operators (i.e. Regional Transmission Organizations (RTO)/Independent System Operators (ISO)) to remove barriers for participation of energy storage resources in wholesale markets and allows participation of distribution connected storage resources > 100KW
- Order 842 states newly interconnecting large and small generating facilities, both synchronous and non-synchronous, to install, maintain, and operate equipment capable of providing primary frequency response and voltage ride through as a condition of interconnection
- Order 2222 requires regional grid operations (RTO/ISO) to allow both heterogenous and homogenous DER aggregations (>= 100kW) including demand response and energy efficiency resources, to participate in wholesale power market including energy, capacity, and auxiliary services

These orders combined place requirements on local distribution facilities, such as DTEE, to require frequency response from new interconnection agreements and facilitate distribution facility connected energy storage and other DER's participation in the wholesale markets. While investments needed to support the implementation of these orders are dependent on RTO/ISO compliance plans, it is currently known that there will be process and tool impacts in operational and planning areas. This includes aggregation review and approval processes related to record keeping, operational coordination requirements for distribution market participants, as well as investments in validation and reconciliation of wholesale market resources that are on the distribution systems. These upgrades will also allow for more comprehensive reporting and tracking of the new timelines and process steps that are included in the new interconnection rules and FERC/MISO processes.

To date, DTEE has commissioned two small studies of hosting capacity analysis to determine feasibility and limitations of providing hosting capacity analysis, along with options for displaying information in ways that are accurate and useful for customers and the DER development community. By the end of 2021, DTEE anticipates making a high level go/no-go map available for public use. Some of the remaining key activities in this area include ensuring that data used to generate a map is accurate, current, and can be updated on a regular basis, along with selecting a customer-friendly presentation method for publishing on DTE Energy's website. Investments in refining the map are expected in 2022 while integration links to the interconnection and screening process to be established in future rule sets are expected to be in 2023 and beyond. The investment levels and timeline for these initiatives are described in Section 12 – Technology & automation.

4.6 Integrated generation (resource) planning and distribution planning alignment

DTEE recognizes the benefits of increase alignment and coordination across the distribution, generation, and transmission planning processes. Increased alignment and collaboration across the planning processes benefits customers, as well as the Company. This alignment is an evolving process that will continue to develop and mature over time.

This section of the Distribution Grid Plan describes the progress achieved in aligning the Integrated Resource Planning (IRP) and Distribution Operations (DO) planning processes within DTEE, as well as the engagement with our transmission partner, International Transmission Company (ITC). The section also lays out the ongoing collaboration and coordination efforts between the IRP, DO, and DTEE Transmission teams, ITC and others.

4.6.1 Areas of past successful collaborations

DTEE identified enhanced alignment between generation planning and distribution planning as an opportunity, and throughout 2020 and 2021, the IRP and DO planning teams have been focusing on putting processes in place to do so. The combined teams collaboratively developed common planning objectives, building on the planning principles that were developed for the 2017 Certificate of Necessity and 2019 IRP. The outcome of this effort resulted in the identification of planning objectives that are meaningful to our customers and stakeholders. These planning objectives are 1) safe, 2) reliable and resilient, 3) affordable, 4) customer accessibility and community focus, and 5) clean. Common planning objectives provide an overall foundational approach to guide and align the planning processes.

Another successful example of collaboration between the IRP and DO teams was the work involved in determining the efficacy of Conservation Voltage Reduction / Volt Var Optimization (CVR/VVO) as a resource in the Company's 2019 IRP. As detailed in the CVR/VVO section (Section 12.6 – CVR/VVO), to support CVR/VVO in the IRP as a generation resource alternative, a pilot was commissioned to study and understand the viability and value of using CVR/VVO. DTEE is working to verify the early results of the first phase of this pilot and plans to further test more advanced CVR/VVO functionality when the Volt/Var Control (VVC) module of the ADMS is implemented in 2022. In addition, for the 2019 IRP, the IRP team worked with the DO team to identify a system-wide avoided transmission and distribution capacity value that one kW of peak load reduction in any location of the DTEE electric system would provide by deferring or eliminating upgrades to the transmission and distribution system.

Michigan is faced with a unique situation where significant elements of the electric grid are operated and controlled by separate entities that have specific obligations to their respective customers, employees and shareholders. To bridge the processes across the two companies, DTEE is in regular communication with ITC regarding how transmission can support future distribution system needs including customer connections, capacity planning and DERs impacts on transmission systems, and also how DTEE can support ITC transmission planning. Additionally, the two companies met as part of our distribution grid planning process to share our work and observations.

Several recent examples of ongoing collaboration include the transmission projects at MISO relating to the City of Detroit Cable project (MTEP #15981), the Nitro project (MTEP #12443), the Stone Pool – Temple project (MTEP #17998), and the Cato-Corktown project (MTEP #20167). The first two projects in this list are examples of transmission investments providing both transmission and distribution system benefits. The City of Detroit project, specifically, involved DTEE accelerating plans for the Islandview and Promenade conversion projects (Section 11.3 – 4.8kV Conversion). The last two projects are driven almost entirely by distribution system reliability enhancement needs. These projects resulted from significant planning and coordination between DTEE and ITC on how the transmission system can support the distribution grid. This planning took place within the regular planning cadence between the two companies and was reviewed within the MISO MTEP stakeholder process. The MISO stakeholder process provided the framework for stakeholders to publicly ask questions about these investments and propose alternatives.

4.6.2 Areas of continuing collaboration

Distribution Operations has been working on several fronts with different teams within DTEE to address the current challenges it is facing with the transformation of the grid. Some of these initiatives include:

4.6.2.1 Peak load reduction with CVR/VVO

Based on the CVR/VVO collaboration in the 2019 IRP, DTEE continues to evaluate the CVR/VVO pilot to reduce peak demand or energy consumption as well as any additional potential benefits to the distribution grid. These benefits include improving grid efficiency as well as providing sufficient capacity for demand. More about this initiative can be found in Section 12.6 - CVR/VVO of the Distribution Grid Plan.

4.6.2.2 DER load forecasting

As mentioned in Section 4.2, the Corporate Energy Forecasting and DO teams are developing methodologies to enhance modeling capabilities that will improve load forecast granularity, allow for the integration of new and emerging technologies in the forecast, and produce 8760 hourly load forecasts at the generation system and substation/circuit levels. Both generation and distribution planning teams will be able to use the same forecasting data sets and have consistent assumptions. The incorporation of DER and EV adoption into the forecasts through propensity and Time of Use (TOU) studies is one example that will help improve the robustness and consistency of both forecasts thereby increasing alignment between the planning processes.

4.6.2.3 Energy waste reduction and demand response

There are ongoing collaborations between the EWR, DR and DO teams to understand the grid opportunities of NWAs. Processes are being developed and refined across teams to identify, design and deploy potential pilots that will use EWR/DR resources. The successful completion of the Hancock pilot and subsequent rollout of the Fisher and other pilots are crucial for DTEE to understand the efficacy of NWAs as scalable resources to defer or replace traditional grid investments, as appropriate. Those learnings are being incorporated by the teams to develop the selection criteria and suitability of the technologies to address peak reduction. Furthermore, in the future, as results of the learnings from the Hancock and Fisher pilots emerge, evaluating the use of EWR and DR and other resources to defer or replace a distribution traditional investment will be incorporated into Distribution Operations planning processes. A further elaboration of these processes and pilots are detailed in two separate sections of this plan; Section 4.3 - Non-wire alternatives and Section 12.7 - NWA pilots.

4.6.2.4 FERC 841 and 2222

Orders 841 and 2222 are designed to create new opportunities in the coming years for DERs and DER aggregations by providing these resources a path to participation in the wholesale markets. Compliance with Order 2222 in particular will be a complex undertaking, and the framework for MISO's compliance with the order is currently under development. As a result, DTEE is still early in understanding how to incorporate these changes into our grid and planning processes, and the resulting impacts will need to be incorporated over time as the participation models and the level of interest by potential market participants become clearer.

While there is still uncertainty around the specific impacts arising from these orders, what is clear is that each of the planning processes will need to closely align to effectively manage the grid for DTEE's customers and other stakeholders. The impacts and expected growth of DER will likely require tools, systems and processes to automate aspects of the interconnection and planning processes as DER seek to interact with the grid in new ways and in larger numbers. As discussed in the Grid Modernization Section 3 – Grid Modernization Process, high penetration of DERs and DER aggregations, enabled by FERC orders, will also reinforce the need to better align integrated resource, transmission and distribution planning.

4.6.2.5 ITC and MISO coordination

DTEE will continue to work collaboratively with ITC to ensure regular communication via already well-established protocols. DTEE recognizes that transmission owners and distribution owners must coordinate and plan for system needs on a regular basis. With many anticipated generation retirements, rapid integration of new renewable resources and continued distribution grid modernization efforts, DTEE recognizes there is a need for continued close collaboration with ITC and MISO to ensure optimized deployment of transmission solutions. In addition, the MISO process allows for a broad group of stakeholders to provide inputs and feedback on transmission, and generation investments in a transparent format to facilitate regional and sub-regional transmission expansion planning. Meetings are held on a regular cadence with these entities so that any system change that could impact the grid and affect these organizations are addressed in a timely manner.

Coordinated planning begins with having common electric system engineering models and integrated planning assumptions between companies. DTEE has aligned its annual distribution system reliability assessment model development process to the MISO Transmission Expansion Plan (MTEP). Annually, the MISO MTEP model development process solicits feedback from stakeholders on changes to the transmission system and distribution system through common models. This includes new generation additions, grid topology changes, load forecast changes, and new interconnections. DTEE both provides and receives information through this process working collaboratively with ITC and MISO to develop two-, five- and ten-year system models. Through this process ITC communicates their planned and approved system upgrades. ITC also presents their future system plans that are represented in the planning models. DTEE shares load forecast information and communicates current and anticipated future distribution system requirements within the MISO process and within regular DTEE and ITC planning meetings. The transmission and distribution reliability planning processes work in parallel to evaluate system needs. As new distribution system needs are confirmed, DTEE works collaboratively with ITC to evaluate if those system needs are best served by the transmission or distribution system. MISO utilizes these inputs to facilitate the annual transmission system expansion planning process where stakeholders participate in an open and transparent forum to arrive at the most efficient solution for customers considering all alternatives.

There are also opportunities to collaborate with ITC on both a technical and policy level on emerging issues such as refinement of ITC's proposed EV fleet proposal, implementation of Order 2222, coordination of T&D infrastructure and associated jurisdiction classifications to meet specific customer requests, and alternative analyses and transmission system impacts in DTEE's next IRP.

Examples of more routine on-going collaborations between ITC and DTEE include mitigating equipment clearance issues, resolving easement relocation requests, decommissioning and coordinating shutdowns on equipment. Coordination meetings are conducted on a regular cadence and established protocols are updated judiciously when necessary between companies to ensure that the grid is planned and operated in a safe, reliable and accessible manner.

4.6.2.6 Stakeholder input

DTEE increased stakeholder engagement throughout the 2019 IRP process, and that approach, along with the learnings and best practices, has been integrated into the current distribution plan. The stakeholder engagement process and interactions will be iterative, and learnings from the DGP will then be incorporated into the next IRP process. The outreach events were designed to increase transparency, educate the participants, and provide an opportunity for questions and feedback. DTEE appreciates the engagement of and feedback obtained from stakeholders in this process. As was mentioned in Section 2- Stakeholder Engagement, at the heart of the grid analysis and planning is the customer.

DTEE recognizes and acknowledges that the planning processes are iterative and will continue to explore opportunities where generation, distribution, and transmission planning processes may be able to support each other and benefit customers. The implementation and improvement of processes, technology, and tools will significantly evolve over time. Utilities, regulators, and stakeholders should allow an appropriate lead time to invest in and implement the necessary tools, staff training and grid capabilities to enable more integrated planning. The planning teams frequently share information cross-functionally, collaborate on projects and initiatives, and work effectively together. The distribution and generation planning teams will continue to build on this foundation to strengthen communication, collaboration, and alignment around forecasts and scenarios, as well as common planning objectives.

5 Benefit cost analysis (BCA)

A robust BCA framework is a key component of the DSPx platform and is integral to the evaluation and prioritization of projects and programs. Just as the first and most important step in the DSPx process is defining objectives, a BCA framework should provide a link between investments and how they are expected to achieve desired objectives. A key challenge of BCA when applied to grid modernization is that investments can support multiple objectives, and the benefits can be difficult to disaggregate and quantify, also known as joint and interdependent benefits. For example, investments to replace aging infrastructure and increase system capacity, such as voltage conversions, not only improve reliability but also provide flexibility to enable greater customer adoption of EVs and DERs.

DTEE has developed the Global Prioritization Model (GPM) as a comprehensive method for evaluating strategic investments. The GPM aligns with the DSPx's "best-fit, most reasonable-cost" evaluation method, which is most relevant for core grid investments that have joint and interdependent benefits or are driven by standards and policy mandates. The GPM has been used to prioritize DTEE's strategic investments in rate cases and internal annual planning processes since 2018. The GPM has been shared with the MPSC and stakeholders during its development and ongoing use. While aspects of the GPM may need to be modified over time, it currently provides a rigorous and accepted methodology for evaluating investments to meet the grid needs identified in our grid modernization process.

5.1 Benefit cost analysis approach

As mentioned above, a BCA framework should be aligned with the overall objectives for distribution planning. The GPM was developed and aligned to the original key objectives of reducing risks, improving reliability, and managing costs. As discussed in Section 3 – Grid Modernization Process, current and expected changes in customer needs and the needs of the grid resulted in a reevaluation of the original objectives. DTEE's current Planning Objectives are shown below in Exhibit 5.1.1. The five current objectives of Safe, Reliable and Resilient, Affordable, Customer Accessibility and Community Focus, and Clean are an evolution of the original three objectives, and align with the Commission's overarching objectives for the electric distribution system of Safety, Reliability and Resilience, Cost Effectiveness and Affordability, and Accessibility.

Exhibit 5.1.1 DTEE 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

One layer deeper than the Planning Objectives, the seven impact dimensions are used to specifically evaluate and rank strategic investment projects and programs in a quantitative manner. The seven impact dimensions and their alignment to DTEE's objectives is shown in Exhibit 5.1.2. Currently, none of the seven impact dimensions align to the two planning objectives of 'clean' and 'customer accessibility and community focus'. Future steps to develop additional dimensions or enhance the current GPM methodology to better align with these objectives are discussed in section 5.2. Two near-term activities that will help provide data and insights that can be leveraged have already been discussed in the DGP. The enhancements to forecasting, described in Section 4.2 will help provide a future forecast for DER adoption at the distribution level and will help identify areas that could need investment. This may become increasingly important if our Grid modernization scenarios of increased electrification and increased DG/DS materialize. The other activities that will align with the 'customer accessibility and community focus' objective is the development of an Energy and environmental justice screening methodology, which was discussed in Section 2.2. Exhibit 5.1.3 shows a mapping of key programs to the current impact dimensions. As shown in the table, all programs will deliver benefits across multiple objectives.

Exhibit 5.1.2 Program Impact Dimensions

	Impact Dimension	Major Drivers
Safe	Safety	• Reduction in wire down events • Reduction in secondary network cable manhole events • Reduction in major substation events
	Load Relief	• System capability to meet area load growth and system operability needs • Elimination of system overload or over firm
	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 • 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
Reliable & Resilient	Reliability	• Reduction in number of outage events experienced by customers • Reduction in restoration duration for outage events
Affordable	O&M Cost Avoidance	• Trouble event reduction and truck roll reduction • Preventive maintenance spend reduction
	Reactive Capital Avoidance	• Trouble event reduction and truck roll reduction • Reduction in capital replacement during equipment failures

Exhibit 5.1.3 Selected Programs Project and Alignment to Objectives[14]

Planning Objective	Safe				Reliable and Resilient		Affordable
Program	Safety	Load Relief	Regulatory Compliance	Major Event Risk	Reliability	O&M Cost	Reactive Capital
Tree Trimming to the Enhanced Specification	X		X		X	X	X
4.8/8.3 kV Conversion	X	X		X	X	X	X
Substation Risk	X	X		X	X		X
System Loading		X		X			
System Cable Replacement	X			X	X		X
Breaker Replacement	X			X	X	X	X
Line Sensors					X	X	
ADMS	X	X		X	X	X	X
Automation	X			X	X	X	X
Subtransmission Redesign	X	X		X	X	X	X
4.8 kV System Hardening	X				X	X	X
Frequent Outage (CEMI) Program	X		X		X	X	X
URD Cable Replacement					X	X	X
Pole/Pole Top Hardware	X		X		X	X	X
Station Upgrade				X	X	X	X

A limited number of strategic investments are excluded from the prioritization model due to their unique benefits and specific situations addressed. Upgrades to our facilities, such as the

[14] Further enhancements to GPM to measure alignment to the objectives of Clean and Customer Accessibility and Community Focus are discussed in Section 5.2

construction of ESOC and ASOC, are necessary to fully realize the benefits of the ADMS platform and to provide full redundancy in the case of an emergency, but they do not directly provide quantifiable benefits in the dimensions measured by GPM. Other examples include programs to replace disconnect switches (Section 9.1.3 – Subtransmission Disconnect Switch) and the Pontiac vault projects (Section 11.5 – 8.3 kV System Conversion and Consolidation), which are necessary to meet operational safety needs. Over 88% of strategic capital is prioritized using the GPM method. A list of the projects and programs excluded from the model are included in Appendix II. In addition, projects that are excluded from the Global Prioritization Model are subject to close examination of their criticality before being deemed as “must fund” in the capital plan.

The process to prioritize strategic projects and programs in the GPM starts with detailed analyses based on historical data, engineering assessments and field feedback, which are performed annually to quantify how a project or program will deliver benefits within each impact dimension. The quantified benefits are then compared to the programs’ costs to derive their benefit-cost ratios.

Unit measurements used for benefit-cost analysis are different for each impact dimension. Reliability benefits are captured in customer minutes of interruption reduction. O&M and reactive capital benefits are captured in avoided costs. Safety, load relief, regulatory compliance and major event risk benefits are rated in indexed scores.

To determine a program’s overall benefit-cost score, the benefit-cost ratio in each dimension is indexed to a score of 0-100. The overall benefit-cost score is calculated as the summation of the indexed score in each dimension, multiplied by the dimension weight. Exhibit 5.1.4 lists the different weights given to the impact dimensions on a scale of 1 to 10. The weightings are anchored on safety, prioritizing the safety of our employees, customers, and community. The other dimensions have weightings set relative to dimension of safety.

Exhibit 5.1.4 Impact Dimension Weights

Impact Dimension	Safety	Load Relief	Regulatory Compliance	Major Event Risk	Reliability	O&M Cost	Reactive Capital
Weight	10	4	4	4	3	3	3

The benefit-cost scores for strategic capital programs, ranked from highest to lowest, are illustrated in Exhibits 5.1.5 and 5.1.6. Tree trimming to the enhanced specification under the surge program, excluded from the exhibits as non-capital program, continues to provide the highest customer benefits of any program in the five-year investment portfolio.

Exhibit 5.1.5 Overall Benefit-Cost Scores for Strategic Capital Programs and Projects

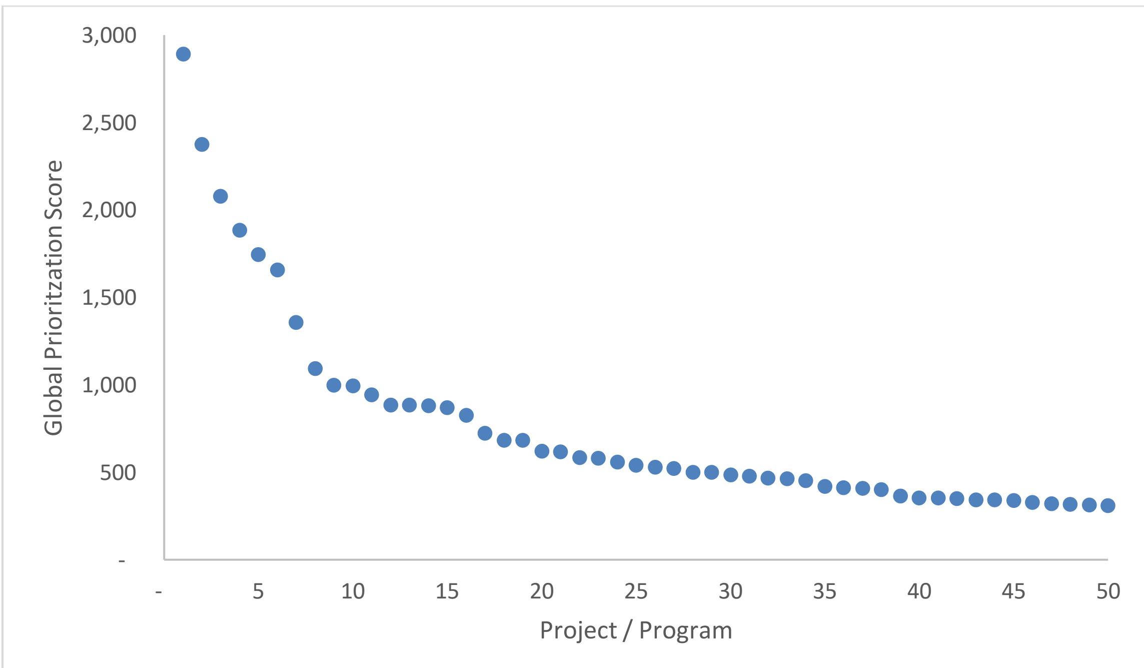


Exhibit 5.1.6 Top 50 Strategic Capital Programs and Projects Based on Benefit-Cost Prioritization Ranking

Rank	Capital Program/ Project	Rank	Capital Program / Project
1	ADMS	**26**	System Loading: Marlette/Tacoma/Brown City/Shaw
2	CODI: Charlotte Network Conversion	**27**	Line Sensors
3	Substation Risk: Port Huron	**28**	APTS
4	System Loading: Mandy 307 Load Transfer	**29**	4.8 kV CC: I-94 (Promenade)
5	4.8kV CC: ISO KERN	**30**	4.8kV CC: ISO WATFD
6	4.8 kV Hardening	**31**	URD Replacement
7	4.8kV CC: ISO CAMDN	**32**	PQ Meter Fault Locating
8	Poles / PTM	**33**	4.8 kV CC: Belle Isle (Island View)
9	Substation Risk: Novi Decommission	**34**	4.8 kV Conv/Cons - Birmingham
10	CODI: Garfield Upgrade	**35**	Relay Replacement: Northeast
11	4.8kV CC: ISO GLBRT	**36**	Subtransmission Redesign & Rebuild: Trunk 7106
12	4.8kV CC: ISO BRAZL	**37**	Subtransmission Redesign & Rebuild: Trunk 7333
13	Subtransmission Redesign & Rebuild: Trunk 4217	**38**	Subtransmission Redesign & Rebuild: TRK 3508
14	4.8kV CC: ISO VENOY	**39**	Breaker Replacement
15	4.8kV CC: ISO BIDLE	**40**	Subtransmission Redesign & Rebuild: Trunk 2255
16	Automation	**41**	4.8 kV Conversion: Belleville Circuit Conversion
17	4.8 kV Conversion: Hawthorne Conversion	**42**	System Loading: Cody Circuits
18	CODI: Amsterdam Upgrade	**43**	Relay Replacement: Navarre
19	Customer Excellence/ CEMI	**44**	System Loading: OTSGO/CAPAC/SHAW
20	8.3 kV CC: Pontiac Projects	**45**	Subtransmission Redesign & Rebuild: Boyne Station
21	CODI: Howard Conversion	**46**	Subtransmission Redesign & Rebuild: Tie 3416 (OH PIGON)
22	Subtransmission Redesign & Rebuild: Trunk 4266	**47**	Subtransmission Redesign & Rebuild: Thumb Electric Fault Isolation
23	Cable Replacement	**48**	System Loading: Macomb/Golf
24	Substation Risk: Apache	**49**	Subtransmission Redesign & Rebuild: Trunk 3509
25	Subtransmission Redesign & Rebuild: Tie 3416 (Badax Breaker & OH Reconductoring)	**50**	System Loading: Richmond/Armada

[1] CODI: City of Detroit (Downtown) Infrastructure

5.2 GPM next steps and other considerations

The benefit-cost scores of programs and projects and their prioritization ranking align DTEE's Planning Objectives of Safe, Reliable and Resilient, and Affordable and provide a solid foundation for DTEE's strategic investment decisions. As DTEE's Planning Objectives have recently evolved, GPM may evolve over time to ensure that both are completely aligned. The process of updating the GPM with additional objectives would involve a robust set of discussions and inputs from stakeholders, however, some initial direction has been considered.

Customer Accessibility and Community Focus

As discussed in Section 2.2 – Energy and Environmental Justice, DTEE is coordinating a comprehensive approach to Energy and Environmental Justice as it relates to the reliability and resiliency of the grid. As a first step, DTEE will overlay recent reliability performance on the grid with the MIEJScreen when it is released in the fall. Adding an additional dimension to GPM to enhance the priority of investments that address reliability in communities identified by the MIEJScreen tool would help align the investment strategy with the Energy and Environmental justice approach.

Clean

Grid investments that enable the transition to a decarbonized economy could be given enhanced prioritization in the GPM. Increased penetration of EVs and DER may require additional capacity, increased sensing and monitoring, reactive power management, and control capabilities. As mentioned above, however, core grid investments such as conversion to a higher voltage, already bring with them the benefits of the ability to integrate more DERs. Many projects in DTEE's plan through 2025 will enable a higher adoption of DERs (such as ADMS, conversions, load relief projects, automation, CVR/VVO, sensing, and many investments in the technology strategy), based on the grid benefits they deliver in the current framework. DTEE will continue to monitor the signposts under our scenarios for EV and DG/DS adoption and consider other dimensions to include in the GPM to meet the objective of Clean.

Additionally, there are other key considerations that impact capital funding decisions:

- Capital spend profiles for new projects are subject to key development milestones, especially in the conceptual and early development stage, including land availability and property purchases, municipal approvals and construction permits, right-of-way and easements and major equipment long-lead items from manufacturing companies. Additionally, while communities in Michigan are developing plans to improve infrastructure, DTEE will work with them to coordinate projects, look for construction efficiencies between DTEE and municipal projects, while minimizing road and other community impacts. While DTEE takes proactive measures, such as advanced planning and project monitoring, to mitigate some of these execution risks, some of these early stage milestones are out of the Company's control and can introduce schedule delays or cost increases. Therefore, DTEE's plan is designed to be flexible to accommodate these unpredictable variations in timing and cost.
- Funding decisions for programs and projects need to consider the implication on resources and workforce planning. Resources required from engineering, design, project management, scheduling and construction need to be evaluated not only by project type (substation, overhead or underground) but also by region and service center. Resource gaps need to be understood and addressed before funding decisions are made. Funding decisions on programs and projects also need to consider the Company's capability to effectively manage the work, as DTEE partners with industry vendors in project execution. DTEE bears the responsibility to oversee the project scope, schedule and cost, and to ensure adherence to DTEE standards.
- As DTEE continues to make investments in distribution infrastructure, the effectiveness of the capital spend is examined frequently. The benefit-cost scores of the programs and projects may change over time as new performance data and field experience become available. The prioritization ranking of the programs and projects may change accordingly.
- Some capital replacement programs are funded annually, despite having lower benefit-cost scores. This is done to avoid an acceleration of asset failures and a large number of assets reaching end-of-life concurrently, thus exceeding available resources to replace them.

- Last but not least, some programs and projects may not receive near-term funding due to their lower benefit-cost scores. This does not mean these programs or projects are not important. Rather, all the programs and projects identified in this report provide system improvements and are good candidates for funding over the next five years. While the strategic capital investment is primarily driven by the Global Prioritization Model, DTEE may adjust the annual plans based on changing circumstances. For example, system limitations including the availability of shutdowns (de-energizing parts of the system to execute work), may be limited in specific geographic areas. Project timing may need to be spread out in order to be able to execute the work.

5.3 Investment impact on reliability and avoided costs

The investments detailed in this Distribution Grid Plan will provide significant customer benefits including improved safety, operability of the distribution system, and reliability and resiliency. The investments will also reduce long-term emergent capital and O&M costs and enhance the distribution system's ability to support increased electrification and adoption of DERs.

Based on the capital investments and investments in tree trimming described in Section 6, DTEE projects reliability improvements will reach second quartile in All Weather SAIDI and first quartile All Weather SAIFI by 2025. Additionally, these investments will prevent further deterioration of reliability that would occur if strategic investments were not made. Exhibit 5.3.1 and Exhibit 5.3.2 illustrate the All-Weather reliability improvements resulting from the investments proposed in this DGP (the Five-Year Investment scenario) and the potential degradation if strategic investments are not made (the Constrained scenario). The Constrained Investment scenario illustrates the reduced reliability improvement if no strategic investments were made on distribution infrastructure beyond the "base capital" program set forth in Section 13.2 – Base Capital. The SAIDI and SAIFI baselines shown in the Exhibits are the three-year average values between 2018 and 2020. DTEE believes that the projections for Constrained Investment scenario could even prove to be optimistic, as some assets are approaching a condition in which there are accelerations in the current rate of equipment failures (e.g. system cable, URD).

Exhibit 5.3.1 System All Weather SAIDI

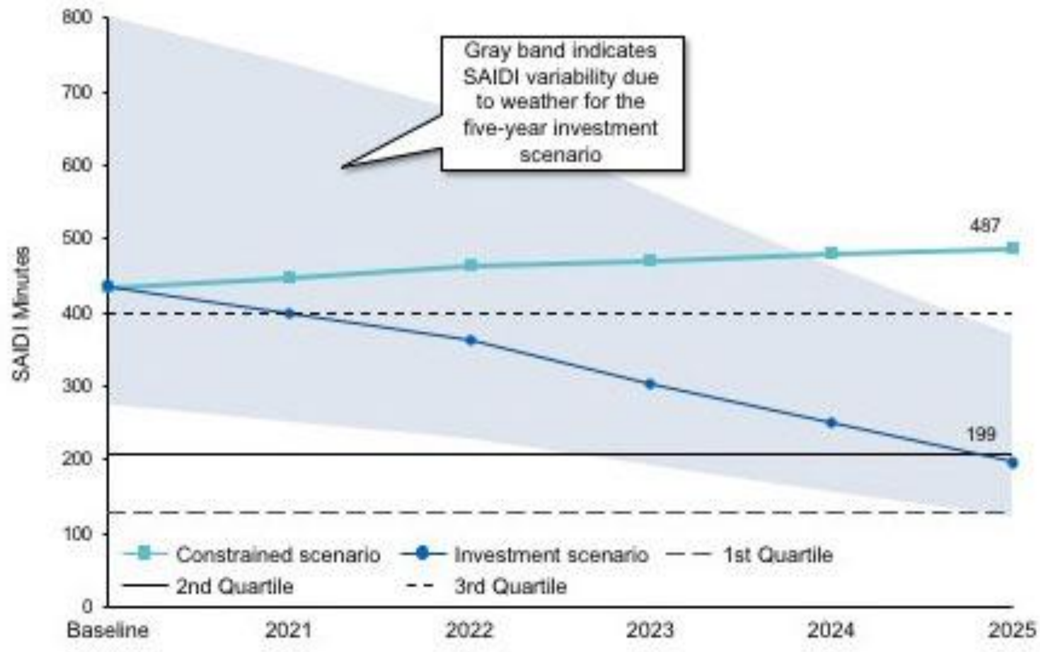
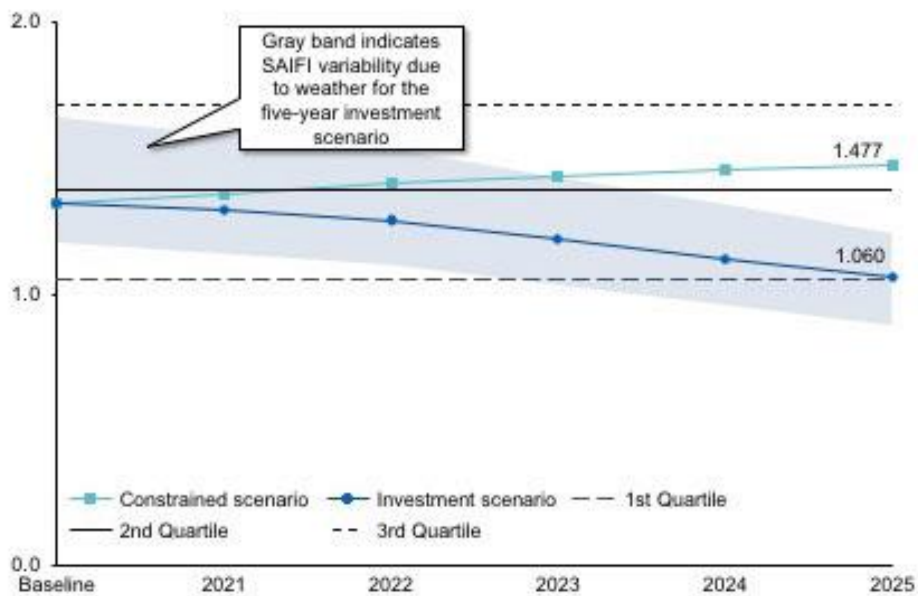


Exhibit 5.3.2 All Weather SAIFI



In addition to the improvements to all weather reliability, DTEE expects to see improvements in reliability excluding major event days (ex-MEDs). A major event day (MED) is a day in which SAIDI exceeds a threshold value based on the calculations set forth by the Institute of Electrical and Electronics Engineers, Inc. (IEEE). Removing MEDs from the reliability calculations better represents the day to day operation of the system and the associated reliability. DTEE expects to reach second quartile SAIDI ex-MEDs by 2025 and first quartile SAIFI ex-MEDs by 2025. Exhibits 5.3.3 and 5.3.4 illustrate the ex-MED reliability improvements.

Exhibit 5.3.3 SAIDI Excluding Major Event Days (ex-MEDs)

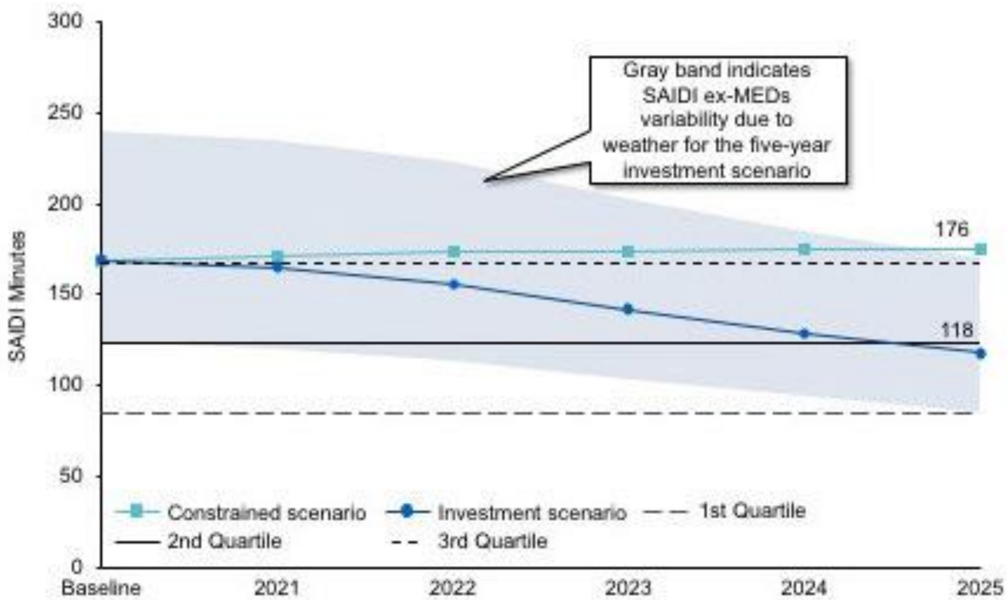
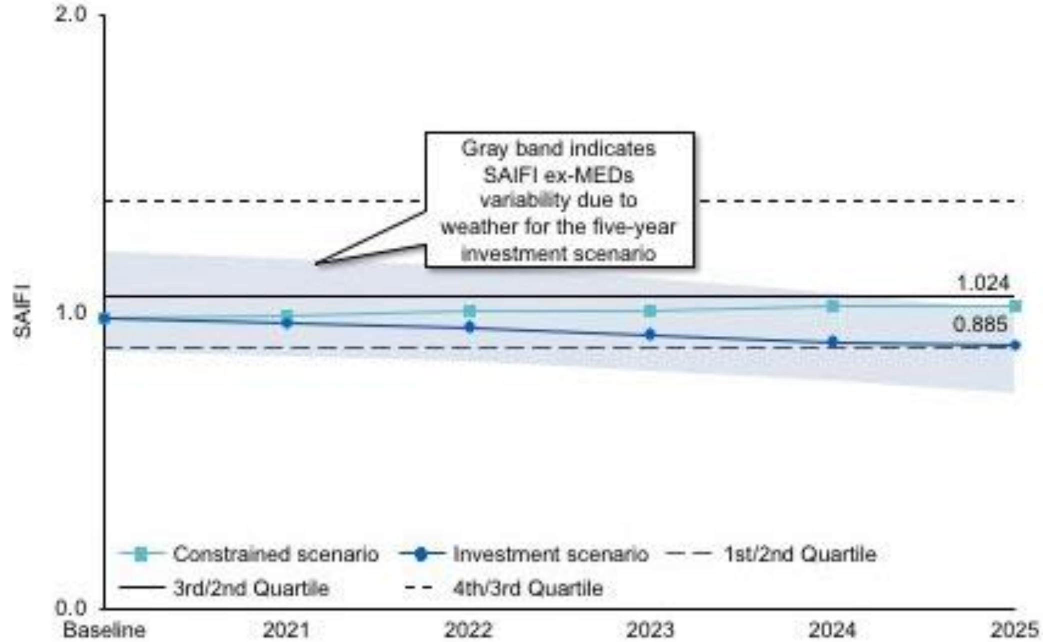
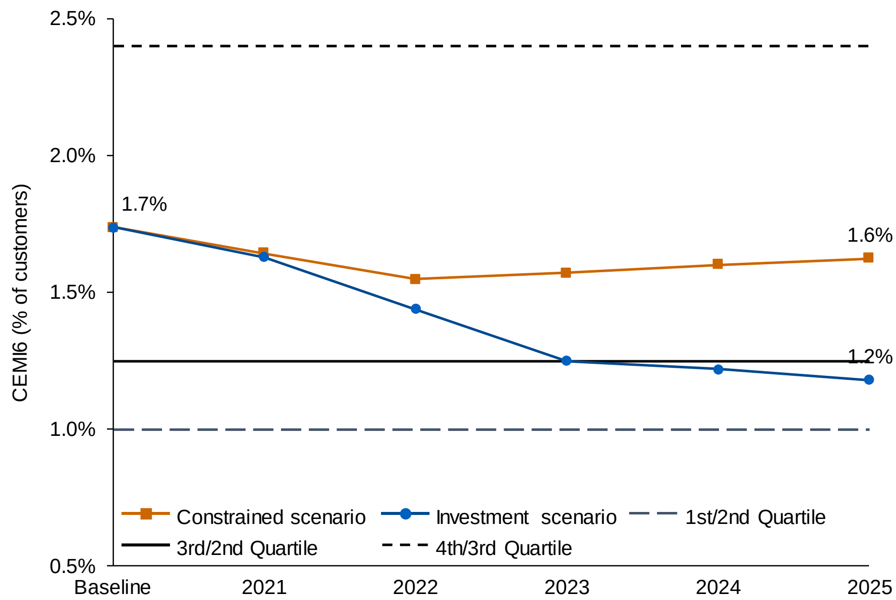


Exhibit 5.3.4 SAIFI Excluding Major Event Days (ex-MEDs)



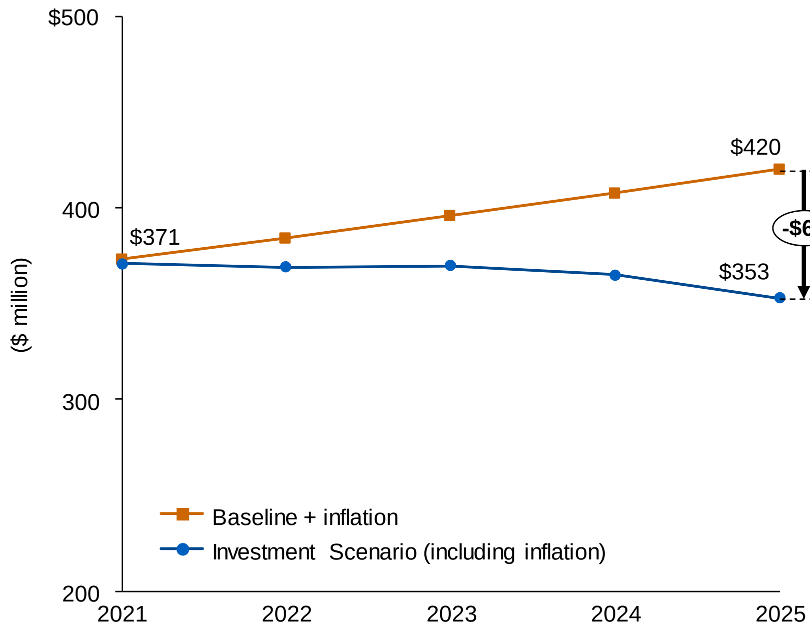
The reliability improvements discussed previously in this section are system level improvements. Additional metrics that help demonstrate the impact of our investments on our customers are CEMI4 and CEMI6, which measure the percentage of customers who have experienced at least four or six outages in a calendar year, respectively. Customers in this category experience some of the worst reliability on the system. It is important that the investments in the DGP not only avoid large outages that can drive SAIDI and SAIFI, but also target the long tail of outages to ensure that all customers experience reliability improvements. The overall portfolio of investment in DTEE's DGP ensures that the percentage of our customers experiencing frequent outages declines over the next five years as well. DTEE expects the percentage of customers experiencing six or more outages (CEMI6+) to be 32% lower in 2025 versus the baseline performance, which will also bring system performance into second quartile (based on 2017 benchmarking data from the Edison Electric Institute). The trajectory of expected CEMI performance is shown in Exhibit 5.3.5 below.

Exhibit 5.3.5 CEMI6



Reliability improvements detailed above are due to a reduction in the number of outages and duration of outages customers will experience. The reduction of outage events, and non-outage events, due to the investments detailed in this DGP will also lead to a direct reduction in the need for emergent expenditures. The reduction in emergent capital spend over the next five-years is expected to not only off-set the cost of inflation, but also reduce the need for emergent capital on an absolute basis. Exhibit 5.3.6 shows our baseline assumption, which is the previous 3-year average plus inflation, and the emergent capital projection based on the savings from investments in this DGP versus our baseline assumption.

Exhibit 5.3.6 Emergent Capital Spend Projection



5.4 Customer benefits

The Investments detailed in the DGP have a direct impact on the electric system in terms of reliability, operability, and avoided costs as shown in the preceding sections. More importantly, the system improvements driven by DTEE's DGP will directly benefit our customers. Determining the value of improved reliability from a customer perspective is an inexact science. Different customers experiencing the same outage may incur disparate hardships due to socioeconomic or other personal circumstances. The variability of the impact of outages on our customers may be wide, nevertheless, there are some methods that are used across the industry to attempt to quantify the benefits of reliability improvements.

One concept used in reliability planning to compare the costs and benefits of system upgrades is "customer interruption costs" (CIC), which is the economic cost a customer occurs when they experience an interruption in electricity service. DTEE uses the Interruption Cost Estimation (ICE) Calculator developed by Nexant and Lawrence Berkeley National Lab, which is the most well-established tool in the industry, to estimate improvements in CIC. Over the next five years, the expected benefits the investments will deliver are calculated to be between $9.8 billion and $13.2 billion.

While the ICE calculator is useful to estimate of the benefits of improved reliability, it has some known limitations. For example, 1) much of the survey data collected to form the basis of the calculations is dated, 2) areas of the country, particularly those which experience extreme cold, are not well represented in the data, 3) the calculator has a bias toward undercounting residential customer costs, and 4) the impact of long duration (>24 hours) is not accounted for. In addition, it does not account for the disparate impact of long outages on our highly impacted communities, as discussed in Section 2.2 – Energy and environmental justice. DTEE will continue to evolve how it evaluates reliability impact to provide the most benefit to our customers. As discussed in Section 5.2 – GPM next steps, one initiative will be to incorporate energy and environmental justice into the GPM model, which enhance weight of reliability benefits to residential and highly impacted communities when prioritizing grid investments.

6 DGP investment summary

The grid modernization process discussed in Section 3 outlined both the curent state of the grid and potential additional grid needs related to the three scenarios of increased electrification, increasing CAT storms, or higher customer adoption of DG/DS. The investment portfolio summarized in this section, which was developed and prioritized using the GPM model discussed in Section 5, is a no-regrets set of investments. In other words, the investments over the next five years not only address core reliability and safety needs of the current grid, they also will support the evolving customer needs if and when the various scenarios come to fruition.

Addressing aging assets is a key need of the grid in order to improve reliability and reduce reactive costs. Details of the age distributions and risk factors of our assets can be found in Section 8 – Asset Health Assesssments, though in general, many of the assets are already near or past end of life and replacement programs are being accelerated to prevent further deterioration. For example, 43% of system cable and 41% of URD are candidates for replacement based on age and other factors specific to known failure mechanimsms. Nearly 44% of poles are older than 50 years, which is considered the life expectancy of a wood pole.

Programs targeted at addressing the aging infrastructure, such as the 4.8kV Hardening program and Pole Top Maintenance and Modernization, drive significant reliability benefits that will enable DTEE to achieve second quartile SAIDI results in the near term and will help manage reactive costs. These programs also rebuild the overhead infrastructure to the latest standards, which will make them more resilient if the frequency or intensity of storms increases (e.g. the use of steel poles as a new standard for subtransmission).

Capacity constraints and overloading are another limitation of the current electrical system. Approximately 35% of substations have some loading limitation, either at the substation, equipment or circuit level. In addition, one-third of the subtransmission system has loading constraints. The lack of capacity decreases the resilience of the system by limiting flexbility (i.e., contingencies and redundancies) in the event of equipment failures. It is also a barrier to connecting new loads, whether through economic development, electrification, or other increasing demands on the system.

Sections 3.4.2 and 11.3.2 discuss the need to convert the 4.8kV system to a higher voltage, to add capacity and enable grid modernization. Investments to convert the 4.8kV system or upgrade the subtransmission system are targeted for areas that currently have loading constraints. However, these investments will also provide additional flexibility to expand if there is significant load growth due to electrification. For example, substations are often built with two transformers to support current load, but can be expanded to add a third transformer if additional load materializes in the area.

Overall, DTEE will invest $7 billion of capital, approximately $834 million in tree trimming, and $50 million in preventative maintenance on the electric grid over the next five years. Of this spend, approximately $3.8 billion is dedicated to strategic capital, which will deliver the benefits of improved reliability, reduced reactive cost, increased capacity to serve current and future load, and reduced system risk.

DTEE's strategic investments are categorized into four pillars: Infrastructure Resilience and Hardening, Tree Trimming, Infrastructure Redesign and Modernization, and Technology and Automation. Each pillar is described briefly below, and has a section of the DGP that will go into depth on the detail of each of the projects and programs, scope, investment levels and timing. Before the four pillars are discussed, a detailed assessment of the health of our assets is described in Section 8, including age distributions and risk factors. The asset health assessments are a key input to other investment programs, most specifically the capital replacement programs detailed in Section 9.1

The four pillars by which DTEE categorizes strategic investments are:

- **Infrastructure Resilience & Hardening (Section 9) –** These projects and programs are focused on replacing aging infrastructure, hardening the system, and addressing areas of the system with known poor reliability.

- **Tree Trimming (Section 10) –** 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 by the end of 2025. The program brings significant reliability benefits, resilience to storms and and ongoing reduction in reactive costs.

- **Infrastructure Redesign & Modernization (Section 11) –** These projects and programs make more fundamental changes to the electrical system, such as conversion of the 4.8kV and upgrades of the Subtransmission system that will increase system capacity. Overall redesign and modernization of the system also brings reliability and resilience improvements through the replacement of aging infrastructure.

- **Technology & Automation (Section 12) –** These programs are tightly linked to the grid needs identified as part of the grid modernization process, including investments to complete the ESOC and ADMS, expand the telecommunications infrastructure, increase the sensing and control on the system, and develop more advanced analytics capabilities. 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.

The overall investment levels are shown in Exhibit 6.1, with more detail by pillar and program shown in Exhibit 6.2 These investments represent all of capital investments, and the two key maintenance programs (tree trimming and preventative maintenance).

Exhibit 6.1 Projected DTEE Five-Year Distribution Grid Plan Investments (Excluding PLD)

		$ Millions					
Category		2021	2022	2023	2024	2025	5-Year Total
Capital Investments ($ Millions)							
Base Capital	Emergent Replacements (Reactive Trouble and Storm Capital)	$488	$372	$372	$366	$354	$1,952
Base Capital	Customer Connections, Relocations and Others	$272	$252	$256	$263	$270	$1,313
Strategic Capital Programs (details in Exhibit 6.2)		$381	$656	$816	$893	$1,007	$3,752
Total Capital Investments		**$1,141**	**$1,280**	**$1,443**	**$1,522**	**$1,631**	**$7,017**
Maintenance Programs ($ Millions)							
Tree Trimming[1]		$191	$195	$188	$152	$109	$834
Preventive Maintenance		$10	$10	$10	$10	$10	$50
1. Tree trim spend profile subject to complete surge by 2024, subject to further refinement							

Exhibit 6.2 Projected Five-Year DTEE Distribution Grid Plan Investments (Sorted by Reference Section Number)

Programs	$ Millions						Reference Section #
	2021	2022	2023	2024	2025	5-Year Total	
Infrastructure Resilience & Hardening							
Pole and Pole Top Maintenance and Modernization	$35	$61	$88	$121	$125	$430	Section 9.1.1
4.8 kV Automatic Pole Top Switch (APTS)	$2	$5	$6	$6	$6	$26	Section 9.1.2
Subtransmission Disconnect Switches	$2	$3	$3	$3	$3	$12	Section 9.1.3
Circuit Switchers	$1	$1	$1	$1	$1	$5	Section 9.1.4
Circuit Breakers	$11	$15	$18	$20	$20	$84	Section 9.1.5
System Cable Replacement	$13	$35	$55	$65	$75	$243	Section 9.1.6
Underground Residential Distribution (URD) Cable	$4	$6	$10	$15	$25	$60	Section 9.1.7
SCADA Pole Top Device	$1	$1	$2	$2	$3	$9	Section 9.1.8
Substation Regulators	-	$0	$0	$0	$0	$2	Section 9.1.9
Substation Outage Risk	$6	$11	$12	$11	$12	$52	Section 9.2.3
Station Upgrades	$3	$7	$6	$10	$4	$30	Section 9.2.3
4.8 kV Hardening	$69	$120	$116	$116	$116	$537	Section 9.3

Programs	$ Millions						Reference Section #
	2021	2022	2023	2024	2025	5-Year Total	
Frequent Outage (CEMI) including Circuit Renewal	$33	$45	$22	$22	$28	$150	Section 9.4
4.8 kV Relay Improvement	$2	$3	$3	$3	$3	$15	Section 9.5
Mobile Fleet	$5	$3	$3	$3	$1	$14	Section 9.6
Pontiac Vaults	$4	-	-	-	-	$4	Section 11.5
Infrastructure Redesign							
System Loading	$6	$11	$20	$50	$53	$140	Section 11.1
Subtransmission Redesign & Rebuild	$42	$82	$93	$101	$112	$429	Section 11.2
4.8 kV Conversion and Consolidation	$23	$61	$56	$50	$66	$256	Section 11.3
City of Detroit Infrastructure (CODI)	$44	$54	$95	$104	$107	$404	Section 11.4
8.3 kV Conversion and Consolidation	$1	$4	$12	$34	$38	$90	Section 11.5
Strategic Undergrounding	$2	$11	$30	$60	$100	$203	Section 11.6
Technology & automation							
Advanced Distribution Management System (ADMS)[15]	$30	$10	-	-	-	$40	Section 12.1

[15] In addition, the ADMS project requires $17.1 million of regulatory asset spend from 2019 to 2023

Programs	$ Millions						Reference Section #
	2021	2022	2023	2024	2025	5-Year Total	
System Operations Center (SOC) Modernization	$18	$34	$55	-	-	$107	Section 12.2
Grid Automation Telecommunications	$5	$15	$19	$17	$15	$71	Section 12.3
Distribution Sensing and Monitoring	$2	$6	$12	$13	$16	$49	Section 12.4
Substation Automation	<$1	$2	$3	$10	$12	$27	Section 12.5
Circuit Automation	-	$2	$5	$10	$12	$30	Section 12.5
CVR / VVO	$6	$7	$17	$18	$20	$69	Section 12.6
NWA Pilots	$7	$10	$15	$3	$1	$35	Section 12.7
DER Control	-	$3	$3	$3	$3	$11	Section 12.8
Mobile Technology	-	$0	$5	$1	$8	$13	Section 12.9.1
Work Management and Integrated Scheduling	$0	$3	$12	$3	$3	$21	Section 12.9.2
Asset Management	-	$1	$2	$2	$1	$6	Section 12.9.3
Distribution Planning Process Enablement	$3	$10	$10	$11	$9	$43	Section 12.9.4
Modernize Grid Management	$3	$11	$6	$6	$9	$35	Section 12.9.5
Substation Cybersecurity	-	$2	-	-	-	$2	Section 16.3

7 Distribution system overview

7.1 System overview

DTEE owns and operates approximately 31,000 miles of overhead distribution lines and 16,600 miles of underground distribution lines. Our service territory encompasses 7,600 square miles and includes approximately 2.2 million residential, commercial, and industrial customers. DTEE's distribution system consists of six voltage levels: 120kV, 40kV, 24kV, 13.2kV, 8.3kV and 4.8kV with the key statistics listed in Exhibits 7.1.1-7.1.6.

Exhibit 7.1.1 DTEE Substations

Substation Type	Total Number of Substations	Number of Substations by Low Side kV							
		4.8	8.3	13.2	4.8 13.2	24	40	24 40	Other
General Purpose	543	245	4	241	32	4	13	3	1
Single Customer	145	49	0	86	1	0	0	0	9
Customer Owned	96	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Total	**784**	**294**	**4**	**327**	**33**	**4**	**13**	**3**	**10**

N/A: Not Applicable

Exhibit 7.1.2 DTEE Transformers

Voltage Level	Number of Transformers	kVA Capacity
Substation - Subtransmission	176	12,870,000
Substation – Distribution	1,468	24,480,561
Distribution - Overhead and Padmount	445,848	32,438,078
Total	447,492	69,788,639

Exhibit 7.1.3 DTEE Subtransmission Circuits

Voltage	Number of Circuits	Overhead Miles	Underground Miles	Total Miles
120 kV	67	61	8	69
40 kV	320	2,302	382	2684
24 kV	246	181	682	863
Total	**633**	**2,544**	**1,072**	**3,616**

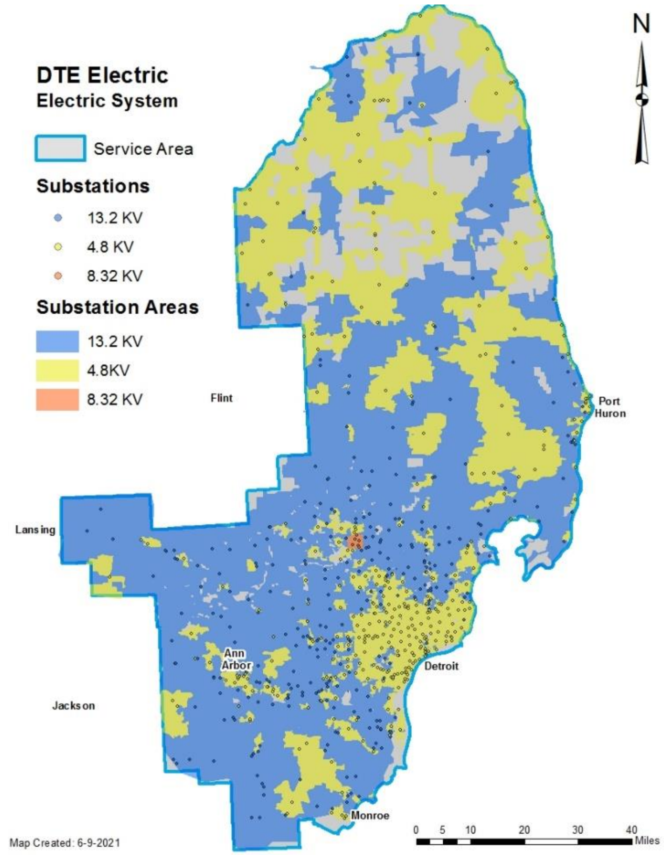
Exhibit 7.1.4 DTEE Distribution Circuits – Line Miles by Substation Bus Voltage

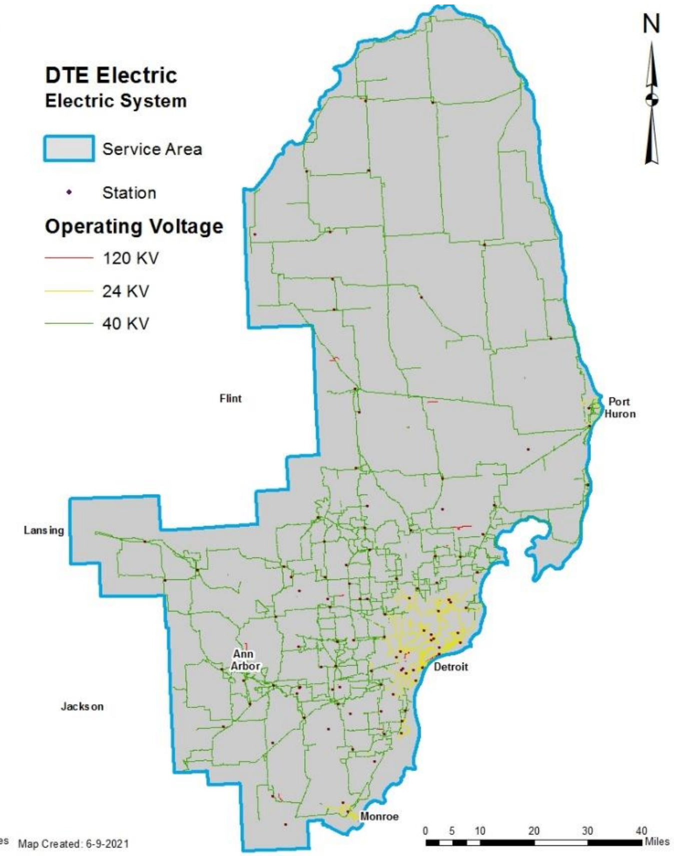
Voltage	Number of Circuits	Overhead Miles	Underground Miles	Total Miles
13.2 kV	1,244	17,320	13,001	30,321
8.3 kV	13	52	17	69
4.8 kV	1,982	11,176	2,522	13,698
Total	**3,239**	**28,548**	**15,540**	**44,088**

Exhibit 7.1.5 DTEE Distribution Circuits – Line Miles by Line Voltage

Bus Voltage	Number of Circuits	Overhead Miles			Underground			Total Miles
		13.2 kV	8.3 kV	4.8 kV	13.2 kV	8.3 kV	4.8 kV	
13.2 kV	1,244	11,742	19	5,559	12,602	1	398	30,321
8.3 kV	13	0	52	0	0	17	0	69
4.8 kV	1,982	32	0	11,144	269	0	2,253	13,698
Total	**3,239**	**11,774**	**71**	**16,703**	**12,871**	**18**	**2,651**	**44,088**

Exhibit 7.1.6 DTEE Distribution System





7.2 Reliability

7.2.1 Background

DTEE customers expect and deserve reliable service. In order to better serve the needs of customers, DTEE has made reliability one of the core planning objectives and recognizes that due to the aging infrastructure and capacity constraints in our current system, significant investments must be made to improve system reliability. Nearly all investments across DTEE's four strategic pillars that are part of the five-year DGP investment strategy will improve reliability. Measuring reliability performance helps drive operational performance improvement, prioritize strategic investments, and validate that those investments are delivering the desired benefits.

As illustrated in Section 5.3, DTEE has projected the impact on reliability from the Company's investment plan. The remainder of this section describes how DTEE measures its reliability performance and provides DTEE's historical reliability performance using the following industry standard measurements:

- SAIFI, SAIDI, and CAIDI – Sustained (greater than 5 minutes) outage frequency and duration-based metrics
- Causes of interruptions – Understanding what causes outages on DTEE's system
- MAIFI – Momentary (less than 5 minutes) interruption metrics
- $CEMI_n$ and $CELID_t$ – Customers experience multiple interruptions or long interruptions

While DTEE has long tracked outage data and the resulting reliability performance, wide deployment of AMI and the use of data analytics have enhanced its ability to measure customer reliability. For years 2017 and prior, the source for outage data was DTEE's outage management system. Beginning in 2018, AMI meter data became the source of the outage data. While the outage management system remains necessary to dispatch field personnel and track the restoration process, nearly full AMI saturation allows DTEE to more accurately know each individual customer's reliability experience without relying on customer or personnel input, or on a manual review of reliability data. However, it is impossible to know the cause of an interruption from AMI meter data alone (e.g., trees, equipment failure, public interference, etc.), as this can only be obtained by linking back to the outage management system and/or through further investigation. Currently, not all AMI outages can be linked with the outage management system; DTEE continues to investigate and resolve inconsistencies, which are attributable to several factors:

- One leg interruptions – one leg interruptions are when one of the two 120-volt service conductors is de-energized. AMI meter data may not indicate all instances of these interruptions due to the way in which the meter power supply is wired to the service conductors.
- Different interruption timestamps – for a given event, each meter may have a slightly different interruption time stamp, none of which may agree with the interruption time stamp in the outage management system (typically all are within seconds or minutes of each other). This may be a problem if there are multiple events occurring simultaneously.
- Outage management system interruption inaccuracies – even with manual reviews, the outage management data is not as accurate as data directly from the meters.
- Interruptions not captured by the outage management system – data from the AMI meters may indicate short duration, sustained interruptions (5 minutes or more in duration), while data from the outage management system may classify them as momentary interruptions (less than 5 minutes in duration) or low voltage events. This could be caused by lack of interruption verification by a customer from the outage management system (customer may be unaware of the interruption in real-time) or the failure of AMI meter real-time power outage notifications.

Data are obtained nightly from the AMI meter registry and are the most complete and accurate customer reliability data available. The use of AMI data for reliability statistics has resulted in higher SAIFI, SAIDI, CAIDI, CEMI and CELID values than the outage management system data used pre-2018. Prior to AMI, MAIFI was not able to be measured.

7.2.2 SAIFI, SAIDI and CAIDI

DTEE measures overall system reliability using the indices SAIFI, SAIDI, and CAIDI. These indices are defined in IEEE Standard 1366 and summarized in Exhibit 7.2.2.1 below.

Exhibit 7.2.2.1 Reliability Indices Definitions

Index	Full Name	Calculation
SAIFI	**S**ystem **A**verage **I**nterruption **F**requency **I**ndex	Total number of customer interruptions divided by the number of customers served
SAIDI	**S**ystem **A**verage **I**nterruption **D**uration **I**ndex	Total minutes of interruption divided by the number of customers served
CAIDI	**C**ustomer **A**verage **I**nterruption **D**uration **I**ndex	Total minutes of interruption divided by the total number of customer interruptions

SAIFI, SAIDI, and CAIDI are reliability performance indices defined in IEEE Standard 1366. In addition to all weather conditions, these indices are also calculated excluding Major Event Days (MEDs), which is any 24-hour period in which there is a significant statistical difference in daily SAIDI; the details of the calculation are in IEEE Standard 1366. Excluding Major Event Days leads to a clearer picture of day-to-day system performance and the customers' experience absent significant weather events.

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. Analysis using these stratifications allows better insight into reliability performance and root causes of customer outages, and therefore the remediations that are needed to improve performance under different conditions.

Catastrophic storms

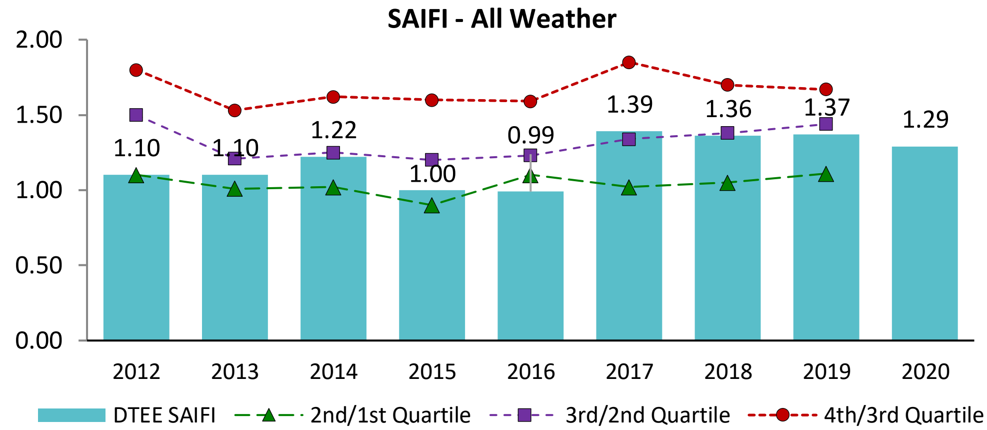
In MPSC case U-12270, catastrophic conditions are defined as "severe weather conditions that result in service interruptions to 10% or more of a utility's customers." DTEE, however, has an internal catastrophic storm threshold of approximately 5% of its customers interrupted. That is the level at which all internal resources, contract crews, local foreign crews, and mutual assistance from other utilities will be engaged, depending on the scale of the storm, to restore customers in a timely fashion. Typically, all restoration crews work 16-hour shifts per day with around-the-clock coverage until the restoration is complete.

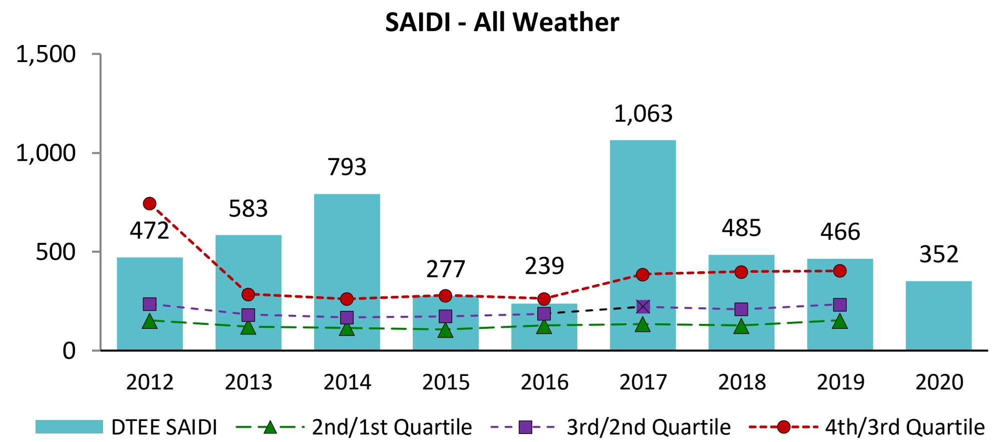
Non-catastrophic storms

DTEE is in non-catastrophic storm mode whenever a catastrophic-level has not been reached as defined above, but weather conditions result in customer outage cases that cannot be restored in a timely manner by the on-shift crews. For non-catastrophic storms, in addition to the DTEE restoration personnel, contract crews and local foreign crews may also be mobilized. Typically, the restoration crews work 16-hour shifts until the restoration is complete.

Exhibits 7.2.2.2 – 7.2.2.6 show historical SAIFI, SAIDI, and CAIDI values for various conditions. Included in the system reliability charts are benchmarked quartiles from IEEE. Benchmark data is not published until the fall of the following year and thus 2020 benchmark data is currently unavailable. All the indices are also reported by service center in Appendix IV.

Exhibit 7.2.2.2 Reliability Statistics - All Weather





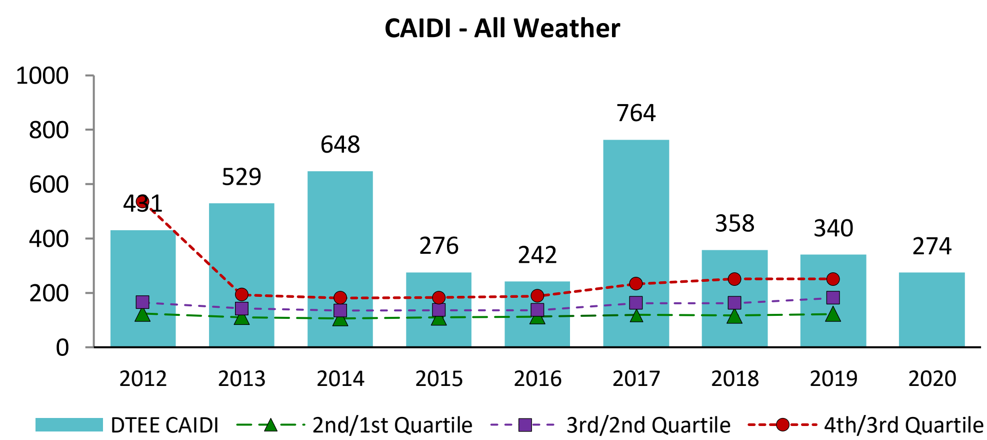
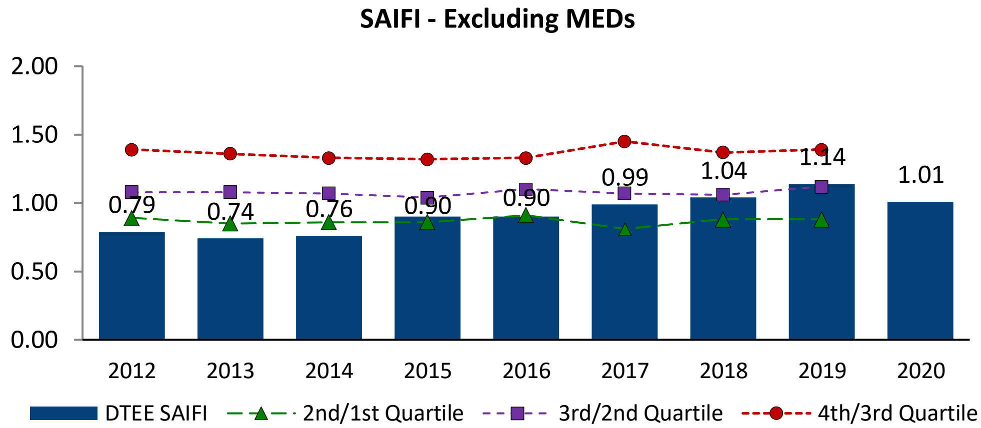
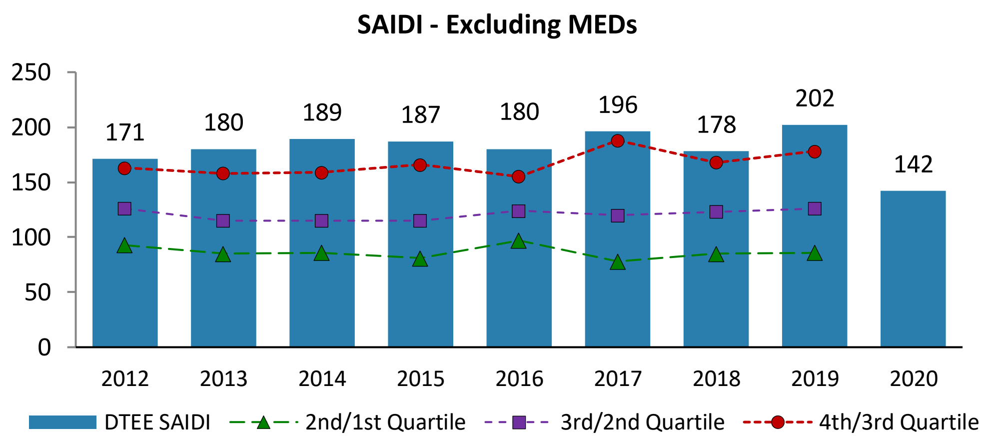


Exhibit 7.2.2.3 Reliability Statistics - Excluding MEDs





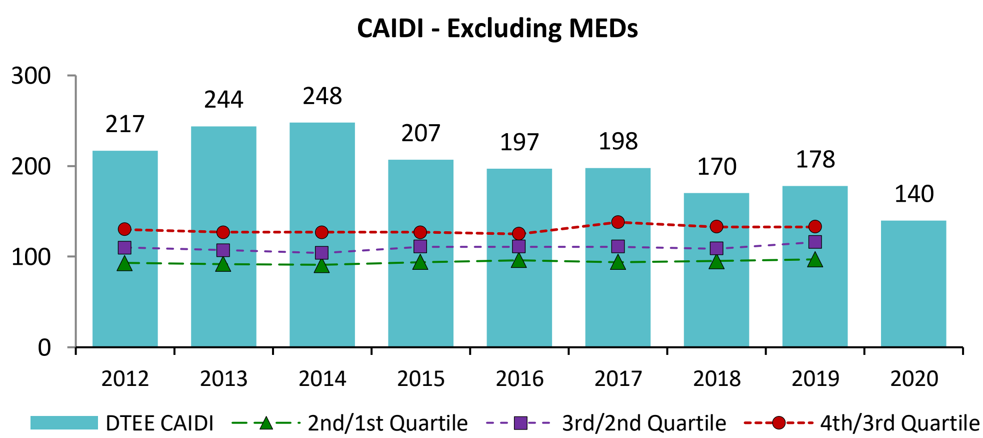


Exhibit 7.2.2.4 Reliability Statistics - Catastrophic Storms (DTEE Definition)

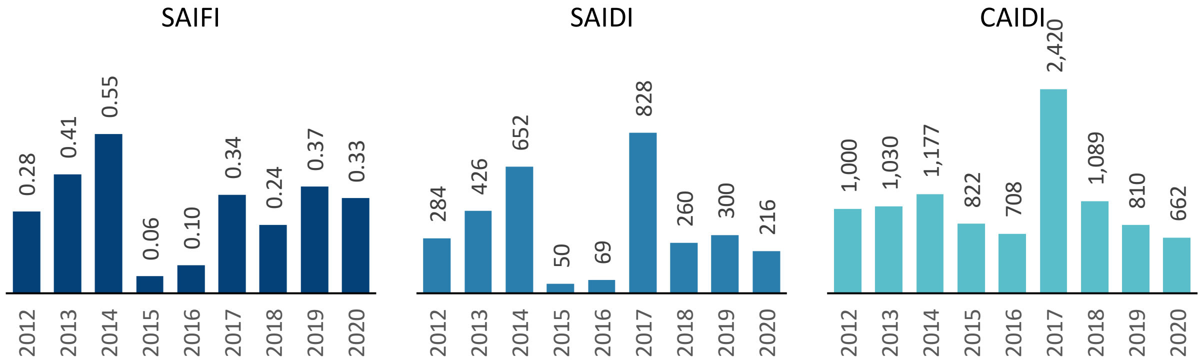


Exhibit 7.2.2.5 Reliability Statistics – Non-catastrophic Storms (DTEE Definition)

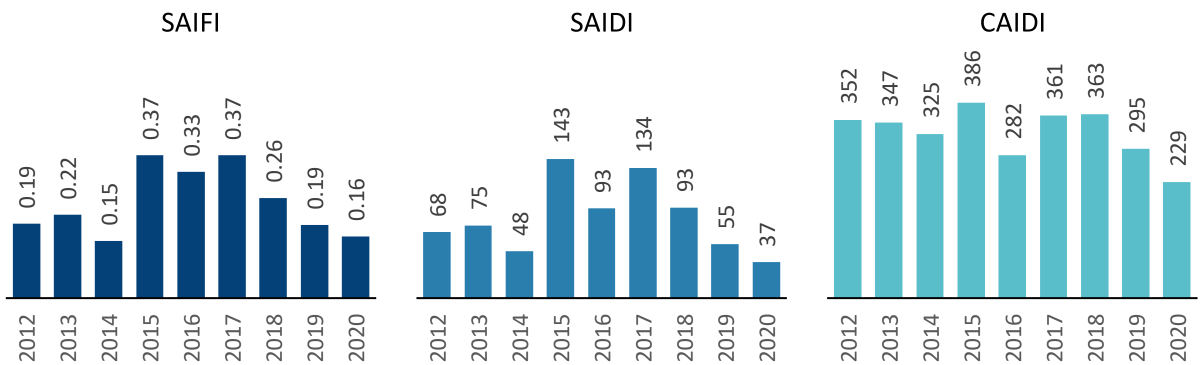
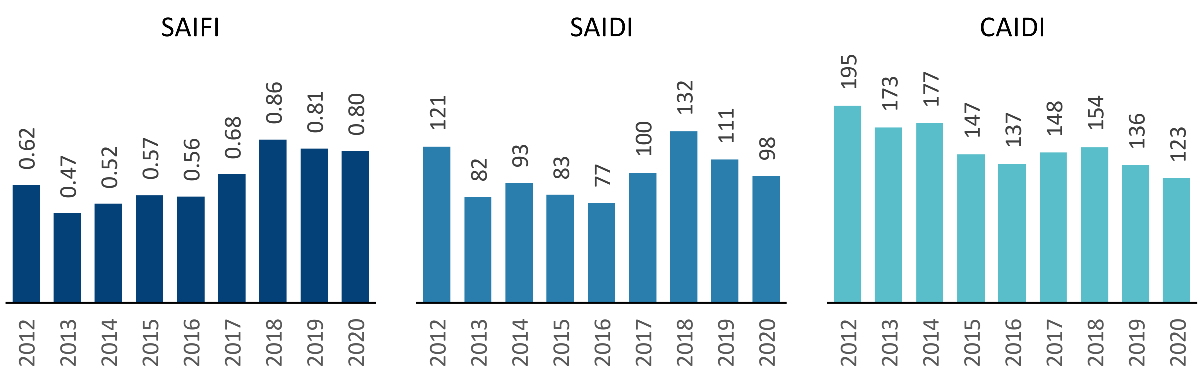


Exhibit 7.2.2.6 Reliability Statistics - Excluding All Storms



7.2.3 Causes of interruptions

Exhibits 7.2.3.1-7.2.3.3 illustrate the percent 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 customer interruptions (SAIFI) as well as overall number of outage events (within DTEE's Outage Management System) on the DTEE system. Therefore, a robust tree trimming program is critical to addressing system reliability including customer minutes of interruption and customer interruptions. Equipment failures are the second leading cause of the SAIDI, SAIFI, and outage events on the DTEE system. In order to improve customer reliability and reduce outage events and durations, DTEE is planning to increase the investment in capital replacement programs for key equipment.

Exhibit 7.2.3.1 5-Year Average Customer Minutes of Interruption by Cause (SAIDI)

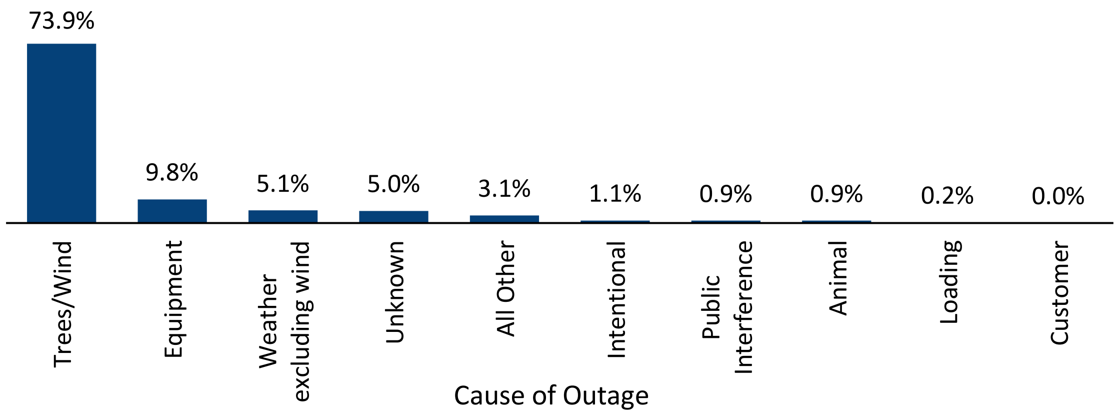


Exhibit 7.2.3.2 5-Year Average Customer Interruptions by Cause (SAIFI)

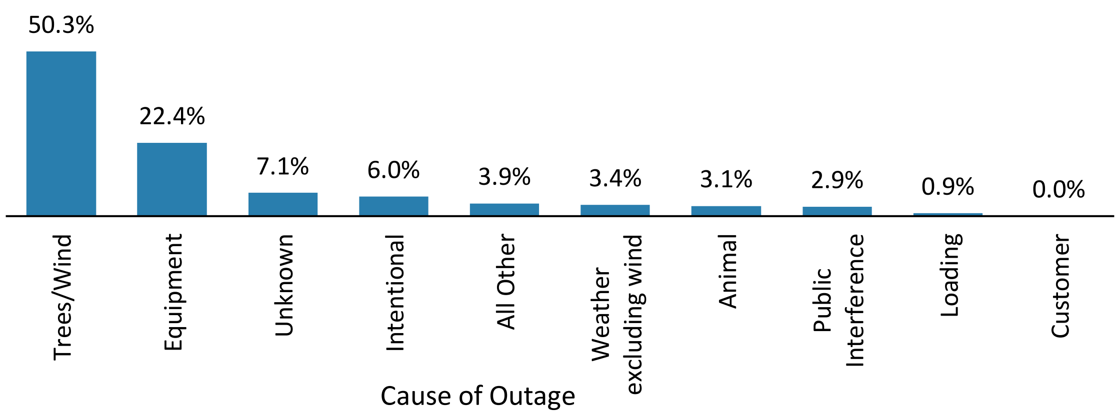
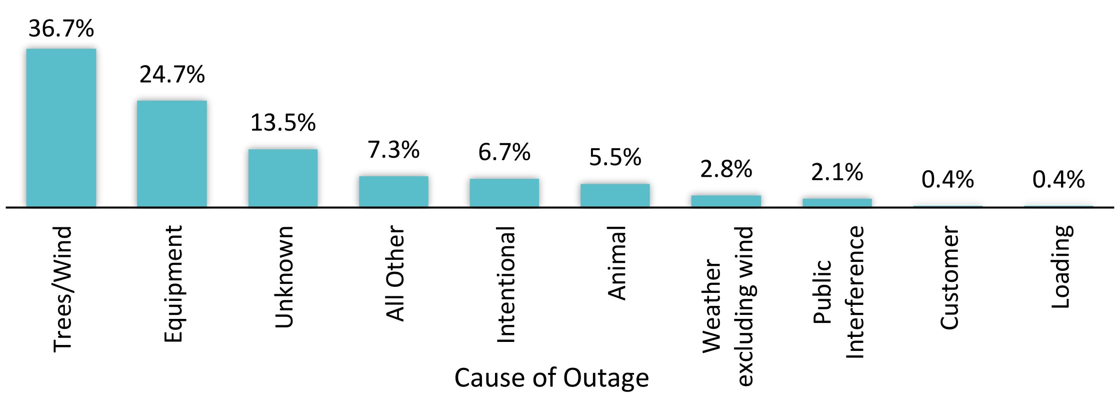


Exhibit 7.2.3.3 5-Year Average Outage Events by Cause



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

7.2.4 MAIFI

Sustained interruptions are not the only type of outage that impacts customers. Momentary interruptions, while brief in nature, are still a cause for concern and are tracked by DTEE. Customers need reliable power for the use of increasingly sensitive electronic devices that do not tolerate momentary interruptions. With the increase in remote work and schooling activities, customers are increasingly affected by momentary interruptions which often cause their internet connections to reboot.

IEEE Standard 1366 defines momentary interruptions and momentary interruption events.

Momentary interruption: The brief loss of power delivery to one or more customers caused by the opening and closing operation of an interrupting device**.**

> NOTE—Two circuit breaker or recloser operations (each operation being an open followed by a close) that briefly interrupt service to one or more customers are defined as two momentary interruptions**."**

Momentary interruption event: An interruption of duration limited to the period required to restore service by an interrupting device.

> NOTE 1— Such switching operations must be completed within a specified time of 5 minutes or less. This definition includes all reclosing operations that occur within 5 minutes of the first interruption.
>
> NOTE 2— If a recloser or circuit breaker operates two, three, or four times and then holds (within 5 minutes of the first operation), those momentary interruptions shall be considered one momentary interruption event.
>
> The Momentary Average Interruption Event Frequency Index ($MAIFI_E$) indicates the average frequency of momentary interruption events. This index does not include the events immediately preceding a sustained interruption."

The calculations of MAIFI and $MAIFI_E$ are shown in Exhibit 7.2.4.1 below. DTEE's MAIFI calculation is for all weather conditions.

Exhibit 7.2.4.1 MAIFI Indices Calculations

Index	Full Name	Calculation
MAIFI	**M**omentary **A**verage **I**nterruption **F**requency **I**ndex	Total number of customer momentary interruptions divided by the number of customers served
$MAIFI_E$	**M**omentary **A**verage **I**nterruption **E**vent **F**requency **I**ndex	Total number of customer momentary interruption events divided by the number of customers served; excluding events immediately preceding a sustained interruption

When DTEE fully implemented AMI meters in 2018, that technology enabled the ability to calculate MAIFI and $MAIFI_E$, however, due to data limitations currently DTEE only tracks MAIFI. While IEEE reporting is industry-accepted benchmarking for other reliability indices, MAIFI benchmarking is not yet included, and other widespread benchmark data regarding momentary outages are currently not published. DTEE's MAIFI for 2018 to 2020 is shown in Exhibit 7.2.4.2. As mentioned earlier in this section, MAIFI counts all momentary outages separately, which means an increased number of switching operations (which can occur in preventing sustained outages) will lead to an increase in MAIFI.

Exhibit 7.2.4.2 MAIFI by Year

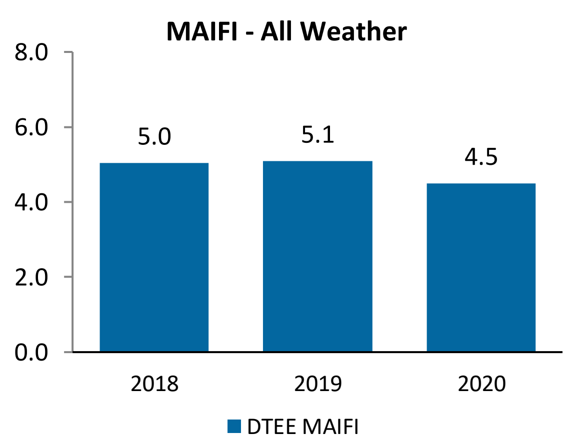


Exhibit 7.2.4.3 below contains MAIFI values by Service Center and for the System.

Exhibit 7.2.4.3 MAIFI by Year

(Average Number of Momentary Interruptions per Customer by Year)

Service Center	2018	2019	2020
Ann Arbor (ANN)	5.8	5.7	4.3
Caniff (CAN)	5.0	4.5	3.8
Howell (HWL)	4.7	6.9	6.2
Lapeer (LAP)	4.3	5.6	4.5
Marysville (MAR)	3.4	4.1	4.5
Mount Clemens (MTC)	4.2	4.5	3.6
North Area Energy Center (NAE)	7.4	6.6	5.3
Newport (NPT)	4.4	5.1	2.9
Pontiac (PON)	7.4	8.0	5.9
Redford (RFD)	5.5	4.6	4.4
Shelby (SBY)	4.1	4.1	4.4
Western Wayne (WWS)	4.3	4.4	4.7
System	5.0	5.1	4.5

7.2.5 CEMIn and CELIDt

CEMIn and CELIDt are measures that reflect customers' reliability experience with respect to multiple interruptions and long duration interruptions. These indices are defined in IEEE Standard 1366 and summarized in Exhibit 7.2.5.1 below. DTEE's CEMIn is based on all weather conditions; CELIDt is calculated for three conditions: all weather, normal, and catastrophic.

Exhibit 7.2.5.1 CEMIn and CELIDt Definitions

Index	Full Name	Calculation
CEMIn	**C**ustomers **E**xperiencing **M**ultiple **I**nterruptions of **n** or More	Count of the number of Customers with n or more interruptions
CELIDt	**C**ustomers **E**xperiencing **L**ong **I**nterruption **D**uration of **t** or More Hours	Count of the number of Customers with interruptions lasting t or more hours

The historical CEMIn and CELIDt values are listed in Exhibits 7.2.5.2 and 7.2.5.3, respectively.

Exhibit 7.2.5.2 CEMIn by Year
(Number of Customers Having "n" or More Outages by Year)

CEMIn	2012	2013	2014	2015	2016	2017	2017 ex Mar Storm	2018	2019	2020
CEMI1	1,482,953	1,443,749	1,421,322	1,273,402	1,245,866	1,528,465	1,302,141	1,399,468	1,415,643	1,377,066
CEMI2	788,531	786,657	779,176	622,180	596,814	859,466	648,574	765,711	779,763	719,205
CEMI3	380,037	399,349	388,076	282,709	270,676	423,990	297,999	413,715	399,023	353,989
CEMI4	175,709	192,366	178,812	125,496	121,110	193,470	129,299	208,042	201,835	181,175

CEMI5	79,285	97,726	76,180	58,121	51,279	86,695	54,959	99,455	105,862	90,837
CEMI6	32,892	44,130	30,307	25,957	24,692	37,508	24,485	45,757	54,591	47,317
CEMI7	13,662	18,916	11,152	11,485	12,334	16,524	10,613	19,844	28,106	26,685
CEMI8	5,420	7,092	5,143	5,432	4,634	7,711	4,958	9,647	15,235	15,710
CEMI9	2,371	2,741	1,943	3,236	1,712	2,813	2,228	4,867	8,021	9,251
CEMI10	1,562	1,395	1,204	2,737	605	1,483	1,134	2,623	4,814	4,798

Exhibit 7.2.5.3 CELIDt by Year

(Percent of Customers Experiencing t or More Hours of Interruption by Year)

Metric	2015	2016	2017	2017 Exclude March Storm	2018	2019	2020
CELID 8 Normal Conditions < = 10% Customers Interrupted	1%	0%	11%	2%	3%	4%	13%
CELID 36 All Conditions	14%	12%	10%	10%	9%	9%	2%
CELID 60 MPSC Catastrophic Conditions > 10% Customers Interrupted	N/A	N/A	23%	10%	2%	9%	N/A

7.3 Resiliency

Resiliency is a key concern for DTEE as well as the MPSC and other stakeholders. Emphasis was placed on this topic in the Commission's previous order in the U-20147 docket. Additionally, as described in Section 3.3.2 Increasing Catastrophic-Level Storms Scenario, there is evidence that DTEE is vulnerable to the increasing intensity and frequency of severe weather events. A strong focus on resiliency is necessary to ensure that impacts of severe weather events on DTEE's system are minimized and that systems are in place to address events when they do occur.

Resiliency for the electric grid is generally defined as the ability to withstand and recover quickly from an event that significantly impacts the grid. Typically, DTEE defines resilience as recovery from a weather-related event that causes power interruptions to at least 5% of customers. DTEE considers reliability metrics related to catastrophic storm, such as SAIFI, SAIDI and CAIDI, as the most relevant metrics to understand resiliency. These metrics are reported in Exhibit 7.2.2.4 and demonstrate that CAIDI during catastrophic storms, which measures the overall time for restoration, has improved by 40% from 2018 through 2020. The Company also considers the ability to respond to other more localize, high-impact outages, such as major equipment failures, as an important component of resiliency.

Most of the strategic investments in the DGP contribute to both reliability and resiliency. Efforts described in both Section 9 – Infrastructure resilience and hardening, such as 4.8kV Hardening, Pole Top Maintenance and Modernization (PTMM), as well as the Tree Trimming program (Section 10), provide significant benefit to withstand the impact of severe weather and catastrophic storms by strengthening the system and avoiding potential outages. The mobile fleet investments (Section 9.6) are key tools in responding to localized, high-impact outages such as major equipment failures, and aid in the restoration process. The investments in the Infrastructure redesign and modernization pillar both build the system to the latest standards, capable of withstanding severe weather, and provide additional capacity and flexibility to transfer load in the case of an equipment failure. In addition, the Strategic undergrounding initiative described in Section 11.6 will identify areas where access limitations such as rear-lot construction can be mitigated. Finally, many of the investments in Section 12 – Technology & automation, such as the Substation and Distribution Automation programs will help locate and isolate faults, speeding up restoration and minimizing the impact of outage events. These advanced technologies are enabled by the investments already made in ADMS and the Electric System Operations Center (ESOC).

In addition to specific investments, process improvements have improved DTEE's response to severe weather events and major equipment failures. Details of these process improvements are discussed in the next three sections (7.3.1 – 7.3.3.) and describe the prioritization process for restoration, which includes identifying and escalating the restoration of customer sites that impact public health, safety, and security.

7.3.1 Incident command system

One aspect of resiliency is having the ability to respond to outages and system events in a structured and efficient manner. While DTEE has always had a robust storm response structure in place, the Company has put in place the Incident Command System (ICS) in order to further improve storm and event response.

ICS is a best-practice method for responding to and managing emergencies that has been used by the US military, and more recently the private sector, for over 30 years. ICS is well suited for the utility sector due to its scalability, flexibility, and ability to manage a large influx of resources. ICS involves a response structure emphasizing chain of command and pushing decision-making down to the point of activity via a series of reporting sections.

DTEE has utilized an ICS structure since 2017 for significant events such as major equipment failures and implemented ICS for storm response in 2020. The ICS process has matured greatly over the course of 2020 and been documented into storm playbooks in early 2021. These playbooks ensure that best practices are used in every storm response regardless of the ICS leader, and the structure allows for improvements to be incorporated over time.

DTEE has seen significant improvement in storm response and storm metrics since implementing ICS and developing a best practices playbook. Specifically:

- Wire down response time during storm has improved by 58%, from 416 minutes in 2018 to 173 minutes in 2020
- Storm CAIDI has improved by 39% for CAT Storms and 37% for non-CAT storms between 2018 and 2020
- During the four CAT storms experienced in 2020, the accuracy of restoration estimates given to customers increased from 60% to 87% as process improvements were implemented. In 2021, estimate accuracy during the severe summer weather

was 72%. Gaps in processes and information systems were uncovered during the challenges of the largest CAT storm in August, and technology projects are being implemented to better align data and ensure that customers get accurate, error-free data during the restoration process.

7.3.2 Storm response

DTEE understands that losing power due to weather conditions is difficult for customers, particularly as outages during a storm tend to have longer restoration times than average. In order to provide an efficient response to potential weather events, DTEE has a multi-level classification of weather severity and initiates a response to a weather threat accordingly. Exhibit 7.3.2.1 shows DTEE's five levels of severity related to potential weather, ranging from normal "Blue Sky" conditions to Level 5 – Crisis.

Exhibit 7.3.2.1 Weather Severity Levels

Level	Mode	Customer Interruptions	Impacts
5. Catastrophic	Crisis	> 420K	• An event that is extremely disruptive to a wide range of operational and business processes both within DTEE and the communities it serves • Available resources are insufficient to adequately address the response
4. Severe	Catastrophic Storm	110K – 420K	• A confirmed, active event resulting in significant damage to- or loss of company infrastructure or ability to perform vital business processes • Highly probable that additional internal and external resources are required
3. Serious	Serious Storm	25K – 110K	• The event can impact multiple business operations or processes

			• Resources may need to move across regions or departments • Normal processes may not be able to address the response
2. Alert	High Impact Day	15K – 25K	• An event potentially limiting the ability to restore power using on-shift crews • Response strategies addressed with normally available local resources
1. Blue Sky	Routine	< 15K	• Common, day-to-day issues typically addressed through normal operating processes • Short in duration and result in little to no expectation of escalation

Storm response is managed through five phases: weather forecasting, ICS activation, ramp up, restoration, and ramp down.

1. Weather forecast

DTEE meteorologists prepare a two-day and five-day forecast by 8:00 am and 10:00 am each day, respectively. A potential weather threat noted in the five-day forecast that might lead to either a High-Impact Day or a Storm is escalated within the DO Emergency Preparedness and Response team (EP&R) to continue tracking it as it approaches. For threats with sufficient warning before impact, the forecast is refined each day leading into the two-day forecast as the Storm checkpoints and meetings begin.

The weather forecast is the first step in ensuring the organization is aware and ready for adverse conditions. The weather forecast is complemented by a customer outage prediction modeling tool.

- DTEE partnered with the University of Michigan-Dearborn graduate business analytics students to develop predictive outage models.
- Weather and outage data from the past 10 years for each service center was compiled and analyzed to identify impactful weather parameters. The result was the creation of a predictive model for each service center area.

- The output from the model shows how many weather-related jobs a service center can expect in a 24-hour period based on forecasted weather conditions. This is shared with DTEE Central Dispatch and Distribution Operations Leadership.

The number of predicted outage events initiates different readiness plans. One outage event could represent a single customer out of power or an entire circuit that is locked out, impacting thousands of customers. Each outage event in the Outage Management System (OMS) requires action by company personnel to resolve. This includes such tasks as dispatching of crews, updating crew status, adding notes to events, combining duplicate events in the system, adjusting event sizes based on information from the field, and creating associated events for other field resources such as tree trim or damage assessment. Thus, a higher number of events leads to a higher number of resources required to resolve the volume.

Predicted 0 – 150 outage events:

- Blue Sky day or normal operation day
- No internal escalations, each service center is self-sufficient in responding to trouble calls

Predicted 150 – 340 outage events:

- Gray Sky day, some level of escalation and central coordination exist
- Conference calls are initiated to ensure service centers are ready for higher trouble volume

Predicted 340 or more outage events:

- ICS activated in preparation for storm
- Emergency Headquarters is opened, and the formal storm processes and functions are initiated

2. ICS activation

If the weather forecast and modeling indicate that there is a potential for a storm, the on-call Incident Commander formally assumes command of the Storm event and officially activates all necessary Command and General Staff roles. Leading up to the Weather Update & Resource Ramp Up meeting, the activated Section Chiefs notify and/or activate necessary Functional Leads within their sections.

As previously mentioned, DTEE has documented its storm process and developed a series of playbooks for each of the Functional Leads to guide the storm restoration process. The Playbooks outline the flow of an event from the initial weather and outage forecasts, through the weather briefing and storm leads ramp up, resource notification and activation, initial response and assessment, storm management, demobilization of all response resources, and the development of an After-Action Report.

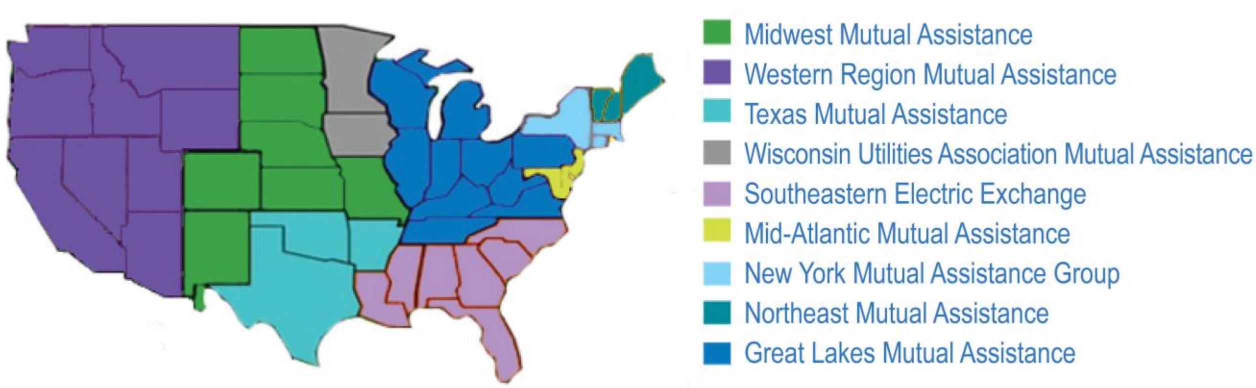
3. Ramp up

During the ramp up phase, the number of potential resources needed to address damage caused by the weather event and the strategy to secure those resources is determined. The Mutual Assistance (MA) Manager coordinates with the Operations Chief to gather initial reports from the field about the extent of damage to feed into the development of the Planning Scenario and Mutual Assistance Resource Plan. The Operations Chief, Logistics Chief, and MA Manager use this information to make a recommendation to the Incident Commander detailing the number and type of mutual assistance crews that should be requested through Regional Mutual Assistance Groups (RMAGs).

Depending on the severity and scope of the weather event, the MA Manager, Incident Commander, and Leadership may consider seeking resources from additional RMAGs if the initial request cannot be met through Great Lakes Mutual Assistance (GLMA).

DTEE participates in the GLMA group with neighboring utilities to assist with restoration after major events. A map of mutual assistance groups within the United States is shown in Exhibit 7.3.2.2

Exhibit 7.3.2.2 Mutual Assistance Groups within the United States

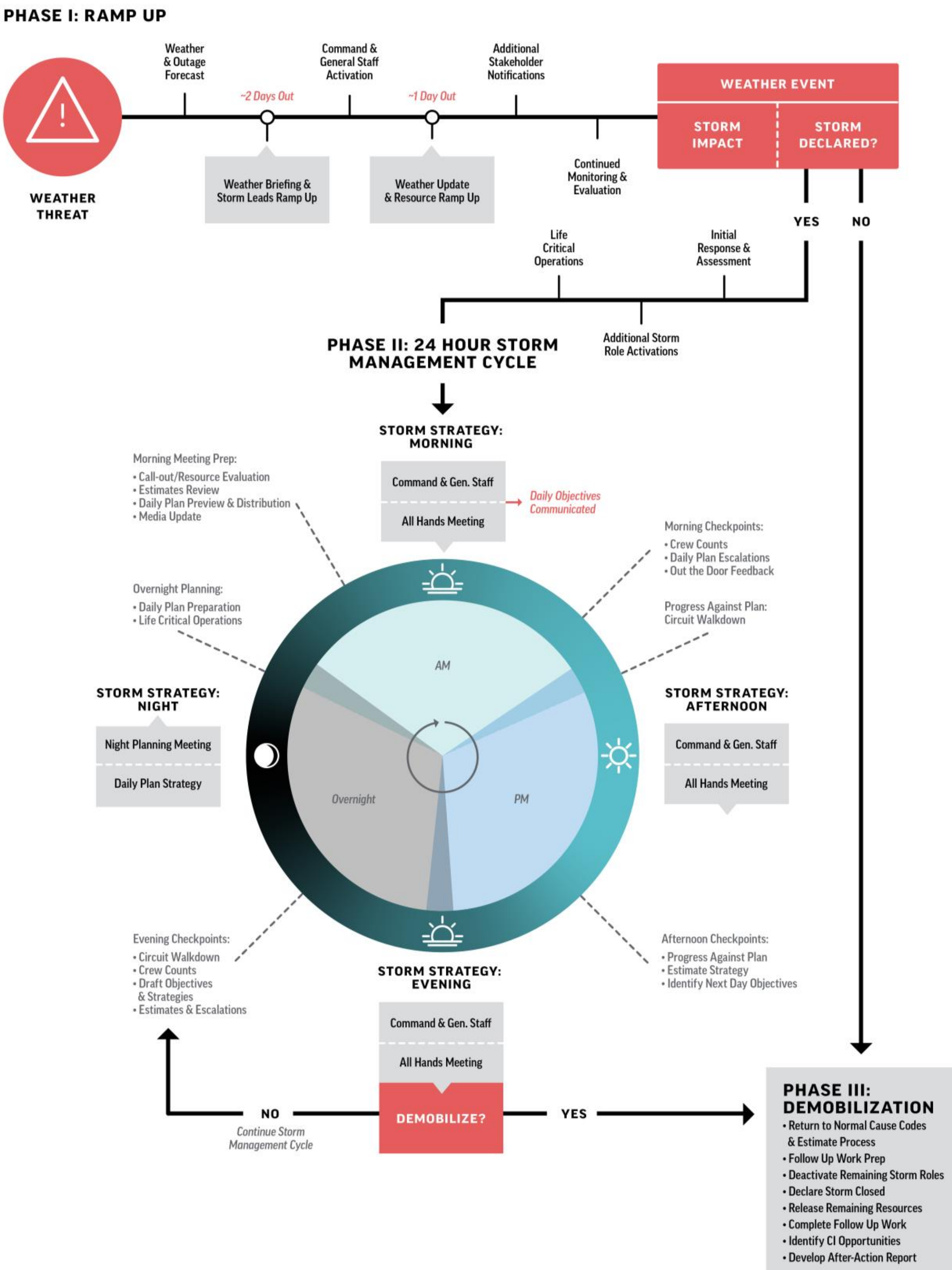


Map showing the seven mutual assistance group regions in the system of sharing resources to restore power in the U.S. Michigan is in the Great Lakes region.
Edison Energy Institute

4. Restoration

The restoration phase follows a structured 24-hour storm management cycle. This structured cycle allows the resources to be allocated to the restoration priorities in a methodical and predetermined manner. Exhibit 7.3.2.3 illustrates the 24-hour storm management cycle.

Exhibit 7.3.2.3 24-hour Storm Management Cycle



Based on the forecast and outage prediction models, DTEE follows a pre-specified storm plan. Before the incoming weather hits the DTEE service area:

- The Systems Operations Center (SOC) and Central Dispatch work to complete critical open maintenance jobs on the electrical system
- Central Dispatch, SOC, Regional Customer Operations, and other key stakeholders organize and conduct several strategy planning sessions for the expected outages in order to coordinate and arrange resources as necessary
- Additional resources (overhead line contractors – including mutual assistance, tree trim crews, etc.) can be secured as needed depending on the expected size of the storm. Additional pull-out yards (areas that house non-DTEE overhead linemen trucks and supplies near the point of expected activity) may also be secured
- Public Protection crews are alerted, as addressing downed wires in the field is the number one priority to ensure the safety of the public and our employees

DTEE follows clear prioritization criteria in addressing potential hazards and restoring customers regardless of the severity of the event. Exhibit 7.3.2.4 illustrates DTEE's restoration plan.

Priority 1: Safety Events

- Public contact / public trapped
- Police and Fire events
- Pole to pole wire downs
- Other hazards and ground alarms

Priority 2: Critical Customers

- Hospitals, pumping stations, police and fire departments
- Depending on time of the year: schools, polling stations, etc.
- Any other critical infrastructure

Priority 3: Large Outages

- Substation level outages, including ties and trunks
- Multiple customer outages resulting from failed overhead or underground circuits
- Other large outages (fuse and recloser level)

Priority 4: All Other Outage and Trouble Events

- Transformer and single customer outages

- Non-outage events (low voltage, flickering lights, etc.)
- Others

Exhibit 7.3.2.4 DTEE's Restoration Plan

Mobile command center

DTEE's Mobile Command Center serves as an extension of the Emergency Headquarters in responding to complex forced outage events and severe storms. It provides for onsite oversight at localized events. It has the same tools and technology as the Emergency Headquarters.

Exhibit 7.3.2.5 DTEE's Mobile Command Center

Customer communication and education

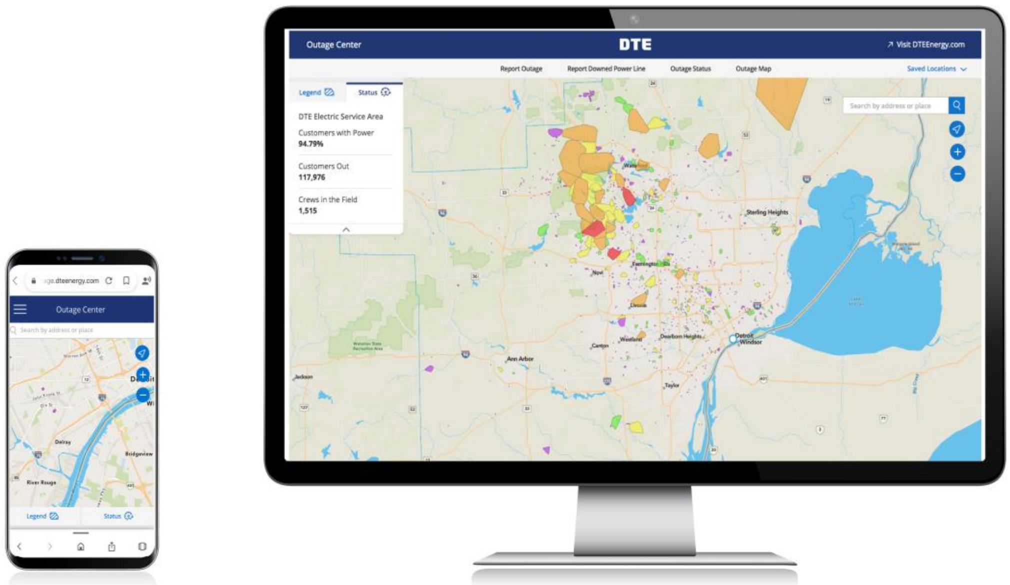
Losing power as a result of a weather event is a distressing situation for many customers. In addition to safety messages, knowledge about the cause and status of their outage as well as when to expect power to be restored is some of the information that DTEE communicates to customers during the storm. In addition, DTEE deploys resources such as our Community Vans and the Mobile Command center to provide relief in the form of water, blankets, and charging stations whenever possible.

Communication and education

To partner with and prepare communities for potential storm related outages, the emergency Managers in the 13 counties served by DTEE receive proactive communication whenever inclement weather is anticipated. Monthly problem-solving sessions are held with local firefighters and the Michigan State Fire Marshal to drive process improvements and improve communication of response times.

Customers are kept up to date about their outage through DTE's mobile app and website, as well as through notifications such as text messages and emails.

Exhibit 7.3.2.6 Outage Map on DTE's Mobile App and Website



Information available to customers includes:

- Estimated Restoration Time (ERT)
- Outage size and area affected
- Outage updates (on demand)
  - Crew en-route
  - Crew arrived
  - Cause of outage
  - Outage restored

DTE has partnered with National Energy Foundation (NEF) to create in-school educational program for K–5 students about energy safety, including important information such as staying away from downed power lines. To supplement verbal and written material, NEF also utilizes Hazard Hamlet simulator boards which simulate common hazards created by an energized down wire.

Exhibit 7.3.2.7 Hazard Hamlet Simulator

Community vans

DTEE maintains a fleet of Community Vans designed to offer support to customers in geographic areas impacted by planned and forced outage events, severe storms, customer excellence and community outreach events. The vans distribute outage kits to affected customers. The kits include helpful items such as: water, flashlights, battery chargers, blankets and literature[16] like a brochure that explains DTEE's storm response procedures and safety information. The vans also provide a point of contact for customers to ask questions about their outage event.

[16] "Guiding you through the storm" 23_Storm_Info_media_brochure.pdf (empoweringmichigan.com)

Exhibit 7.3.2.8 Community Van

7.3.3 Response to major (non-storm) events

The second type of event on the electrical system from which DTEE is prepared to recover quickly is a major event, such as a key equipment failure in a substation.

The first step to enhancing resiliency is proactively identifying vulnerabilities of the distribution system and preparing contingency plans. Asset health assessments, capital replacements, and preventative maintenance plans processes are some of the ways in which DTEE prevents equipment failures. These processes are described in Sections 8, 9.1, and 14 respectively. In addition, annual pre-peak assessments are performed to identify loading or voltage issues, and measures are taken to address them ahead of summer peak.

- Engineers identify voltage or overload violations through the Annual Area Load Analysis (ALA) process

- Relief plans are developed, and critical work is completed before the predicted summer peak period begins
- System Operations Center (SOC) and Engineers identify next contingency concerns and determine appropriate course of actions

A daily review of trouble work, such as temporary load transfers due to previous outages or equipment being offline, is performed to ensure the system is robust enough for the next contingency (system abnormality). This allows for awareness of equipment that is out of service, and for engineers to run N-1 contingency analysis daily to ensure system security. If issues are identified, corrective measures are developed to mitigate the next contingency with options including:

- Restrict timing for planned shutdowns
- Create must-do jobs for the day
- Use of throw-over circuits to transfer load
- Dispatch of mobile Distributed Generation (DG) units
- Dispatch of portable substations
- Dispatch of ISO-trailer (i.e., transformer trailer that connects systems with different voltages)
- Dispatch of mobile cable trailer
- Dispatch of mobile switchgear trailer
- Utilize manual and/or automatic under-frequency load shedding schemes for the subtransmission system
- Utilize local load shedding for issues on the distribution system

Despite the preparation and planning done to ensure resiliency in the system, equipment failures do occur that either create a large outage or put the system at risk of experiencing a large outage, were an additional equipment failure to occur. In this situation, the ICS process is implemented to manage the event. In addition, DTEE has a large mobile fleet of specific equipment that in many instances can provide back-up power to customers and support system needs during both trouble and planned work. Exhibit 7.3.3.1 provides a list of DTEE's mobile fleet of equipment while Exhibits 7.3.3.2 – 7.3.3.3 display two such pieces of equipment.

Exhibit 7.3.3.1 DTEE's Fleet of Mobile Restoration Equipment

Equipment	Units	MVA/MW
Mobile Generators	10	19.5
Portable Substations (+2 in 2020)	10	59.0
ISO-Trailers	9	35.0
Cable Trailer	1	N/A
Mobile Switchgear	1	N/A

Exhibit 7.3.3.2 Mobile Generator

Exhibit 7.3.3.3 Portable Substation

7.3.4 Low probability, high impact (LPHI) events

DTEE has robust planning, contingency procedures and protocols for LPHI events. As part of DTE's corporate emergency preparedness program, Distribution Operations completed simulation exercises on five LPHI events. Acting upon the lessons learned from these exercises and in conjunction with DTEE's standardized restoration process positions DTEE can efficiently address these situations in the unlikely event that they ever materialize.

Exhibit 7.3.4.1 Low Probably, High Impact Events

Event Exercised	Description	Lessons Learned
Electric Outage	420,000+ customer catastrophic storm	• Increase foreign crew visibility for safety • Maintain list of critical locations (hospitals and other critical infrastructure) per county • Design Storm Playbook including strategies around Operations, Planning, and Logistics
Mass Black Out	Loss of major portion of ITC transmission and DTEE systems caused by loss of generation capacity, transmission network, voltage collapse, or transmission system outside of territory	• Stand up satellite phone program in the event normal communication channels are lost • Improve integration of DTEE/ITC/State/County public information officers ensuring consistent dissemination of information during an incident
Geomagnetic Disturbance (GMD, EMP E3)	A geomagnetic disturbance (GMD), also known as a geomagnetic storm, is a major event in Earth's magnetosphere. It's caused by a very efficient transfer of energy from solar wind into the space environment surrounding Earth. Solar wind shockwaves result from a solar flare that is followed by	• MISO performs studies on the impacts of GMDs on Bulk Electric System transformers and DTEE supplies transformer data to them when requested, usually annually. • If the study indicates that a transformer may experience geomagnetically induced current (GIC) that exceeds NERC Standard TPL-007 criteria levels, then DTEE is required to perform a thermal impact assessment on that

	coronal mass ejections (CMEs) of charged and magnetized particles into space. GMDs are of particular concern to the reliability of the nation's power grid because they can cause geomagnetically induced currents (GICs)	transformer and determine appropriate mitigation. So far, none of DTEE's transformers have been identified from the MISO studies to date. • Recently, NERC has initiated a process where they will make an annual request for GIC data from transformer monitors. Data will be requested only for strong GMD events (Kp=7 and greater).
Physical Attack	Attack on DTEE stations/substations or other operations facilities	• Increase seating and technological capacity for Central Dispatch and System Operations Center at back-up location in the event the primary location is lost to a short-term disruption caused by a physical or cyber attack
Cyber Attack	Attack on critical computer systems	

7.3.5 Flood protection program

The typical storm impacts on the grid include the wind and tree damage to poles and wires. An additional weather impact, although rare, is significant rainfall that results in flooding events that can damage equipment and property. A recent example of this occurred due to a severe thunderstorm impacting DTEE's service territory with a total rainfall of over two inches on June 20, 2021 and then additional rainfall on June 25, 2021 that produced another six to eight inches of rain in a 24-hour period. Over ten inches of rain in less than a week caused flooding in some areas including the area near the intersection of I-94 and Wyoming Ave. This area includes McGraw and Scotten substations and resulted in the substations flooding, significant equipment damage and outages for customers. To prevent another occurrence of flooding resulting in equipment damage and customer outages at McGraw, Scotten or any other substation, the Company is initiating a Flood Protection Program. This work will progress over three phases.

In the first phase of this work, an assessment of the recent flooding events at McGraw and Scotten substations will be completed to fully understand the root causes and confirm that the countermeasures that the Company is planning will prevent a reoccurrence. With a complete understanding of the root causes of what occurred at McGraw and Scotten, a substation flood risk assessment will be completed for all the Company's substations and stations. The flood risk assessment will identify the susceptibility and mechanism of potential substation flooding based upon regional United States Geological Survey (USGS) topographical data to determine storm runoff patterns. Federal Emergency Management Agency (FEMA) maps will be reviewed for each location to determine what properties have active floodplains. Substation layout and the surrounding substation area topography will also be considered during this study. With the risk of flooding well understood, the concerning cases will be prioritized based on the potential consequences of a flood event. Some of the factors that will be used in this prioritization are substation class, customers served, critical customers served, potential for stranded load, environmental concerns, and equipment impacted by flooding, among others. In parallel with the risk and impact assessment, benchmarking work will be completed with peer utilities to identify those that have taken on similar efforts, and the most effective countermeasures for addressing the concerning cases.

In the second phase, short- and long-term countermeasures will be developed for each substation with field visits to confirm executability and confirmation of assumptions. Some of the mitigations needed might include reconfiguration of the substation, storm water management systems, elevating equipment, additional flood barriers, and possible relocation/replacement of substations. Schedules and cost estimates will be developed considering the priorities developed in the first phase.

The execution phase will quickly follow phase two and will include designing and constructing the required capital projects.

7.4 Power quality

While reliability and the related metrics were discussed in Section 8.2 on reliability, power quality encompasses an additional set of disturbances or irregularities a customer may experience with their electrical service. Customer needs have shifted recently, including a potential permanent shift to working from home, schooling from home, and a reliance on a stable internet connection for many aspects of life, making power quality even more important to customers. A momentary interruption that resets an internet connection and disrupts a business meeting is much less acceptable to customers than needing to reset a blinking digital clock.

7.4.1 Defining power quality and power quality events

According to IEEE Standard 1159, power quality refers to "a wide variety of electromagnetic phenomena that characterize the voltage and current at a given time and at a given location on the power system." IEEE breakdowns the phenomena into the following categories: Transients, Short-duration root-mean-square (rms) variations, Long duration rms variations, Imbalance, Waveform distortion, Voltage fluctuations, and Power frequency variations. DTEE has adapted these categories to assess power quality in terms of these characteristics of electric power:

1. **Interruptions – momentary and sustained**

   Electric power interruptions may be sustained (lasting longer than 5 minutes) or momentary (lasting 5 minutes or less). While momentary interruptions can be bothersome to customers, in most instances the source of momentary interruptions is a purposeful equipment operation that actually is preventing a sustained interruption. Devices on the system (breakers, reclosers, and fuses) are designed to open when an electrical fault occurs to isolate and de-energize the faulted part of the system. Breakers and reclosers, however, are programmed and coordinated to open/close several times at defined intervals. If the fault is temporary (e.g. tree branch falls, then clears the wires) the device will ultimately close restoring power. However, the customer experiences these distinct open/close attempts as momentary outages.

2. **Voltage – over/under, short and long duration**

   ANSI C84.1 defines voltage tolerance standards Range A and Range B for electrical systems with voltages of 600 or less. Acceptable sustained service voltage for Range A is between +5% to -5% and for Range B is between +6% to -8%. For nominal voltage of 120V these ranges are 114V to 126V for Range A and 110V to 127V for Range B. Although DTEE's distribution system is designed to provide voltages within Range A, various conditions can cause the system to operate within Range B. Customer equipment should be designed to operate at voltages within either range. Under-voltage events occur when the voltage is below the acceptable range; if the duration is less than two minutes it is a voltage sag event. Over-voltage events occur when the voltage is above the acceptable range; if the duration is less than two minutes it is a voltage swell event.

3. **Flicker – small and repetitive voltage fluctuations**

Flicker is generally observed in changes in lighting intensity due to voltage variations within the acceptable range. The voltage variations are generally below 7 % of nominal voltage with frequencies of less than 25 Hz. Causes of flicker include but are not limited to arc furnaces, rolling mills, large motors, welders, capacitor switching, transformer load tap changers, and loose electrical connections.

4. **Transients and Noise – large but very short duration voltage spikes**
   Transients or surges are events with significant changes in magnitudes of voltage, current, or both. These events may have durations of nanoseconds to milliseconds. Noise is a rapid series of transients, typically of less significant magnitude variation than an isolated event. Causes of transients and noise include but are not limited to lightning strikes, switching on the electrical system, recloser operations, transformer load tap changing, and loose electrical connections.
5. **Harmonics and Distortion – non-smooth sinusoidal waveforms**
   Harmonics are sinusoidal voltages or currents having frequencies that are integer multiples of 60 Hz. The harmonics combine with the 60 Hz voltage or current and result in a distorted sinusoidal wave form. Total harmonic distortion levels are characterized by the complete spectrum of the individual harmonic components. Harmonics are mostly caused by non-linear loads and devices connected to the electrical grid. These non-linear loads include but are not limited to arc furnaces, welders, rectifiers, adjustable speed drives, switched mode power supplies, high efficiency lighting, and data processing equipment.
6. **Frequency**
   The frequency of the interconnected electrical grid is usually very stable, and deviations are extremely rare – hence frequency is not an aspect of power quality that concerns customers on distribution systems.

Based on data collected from the Company's Customer Service organization, the majority of residential customers' power quality concerns in DTEE are related to the number and duration of power interruptions (approximately 87% of complaints), over/under voltages (approximately 13% of complaints), and to a lesser extent, flicker and transients. In addition to these concerns, commercial and industrial customers also have concerns related to distortion and harmonics. Transients and Noise, Harmonics and Distortion, and Frequency are critical issues relative to transmission and subtransmission planning and the overall electrical grid more so than the distribution system.

Power quality events or issues may originate from any part of DTEE's distribution system, the transmission system, or from the customers' equipment or operations. These events or issues may be isolated to a single customer or groups of customers in electrical proximity. Commercial and industrial customers may be more susceptible to power quality issues if their processes involve sophisticated machine controls.

7.4.2 Addressing distribution system power quality events

Distribution planning focuses on the two categories of power quality events that are both the most frequent and have the greatest customer impact: interruptions and high/low voltage.

Interruptions

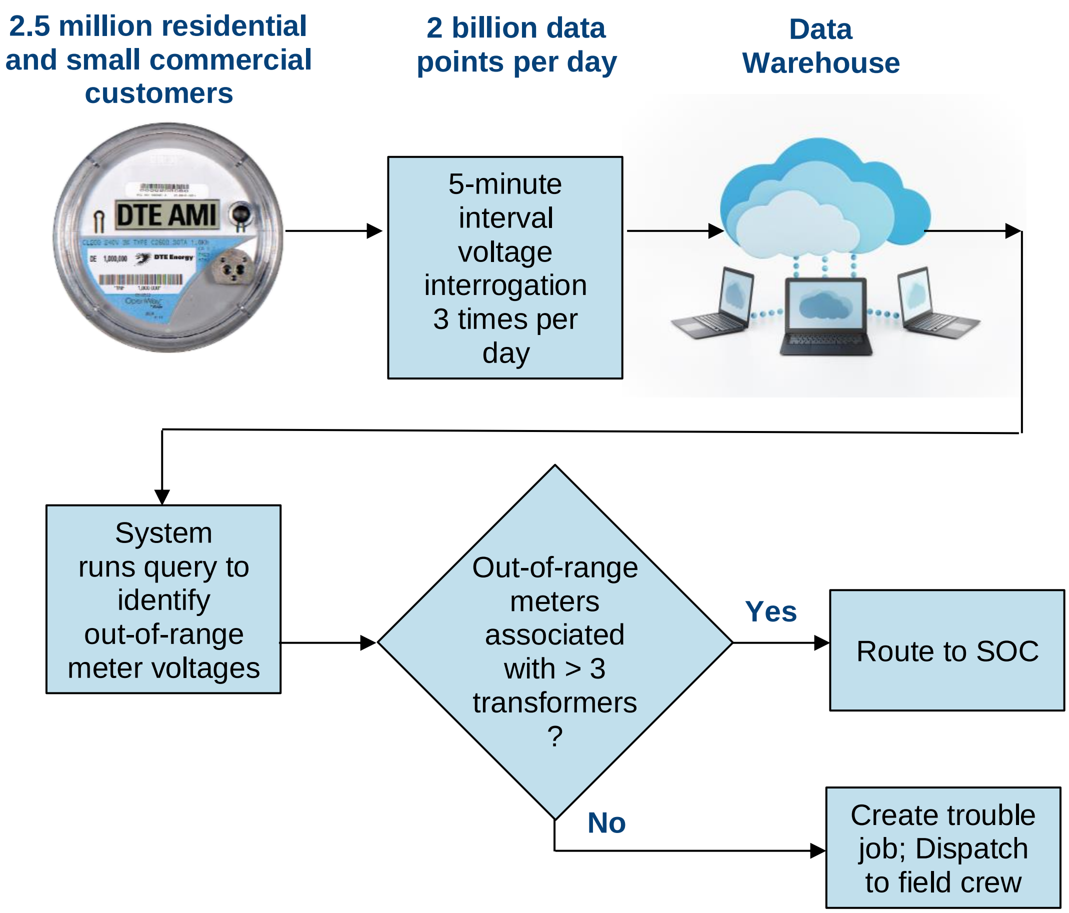
Minimizing the number and duration of customer power interruptions is one of the highest priorities of DTEE. As discussed throughout this grid plan, DTEE has programs, processes, and plans for today and the future to improve reliability and resiliency and thereby minimize power interruptions to customers. The key programs that aim to reduce interruptions are Tree Trimming, Automation, 4.8 kV System Hardening, URD Cable Replacement, and the Pole/Pole Top Hardware program. Additionally, DTEE has established a Customer Excellence program described in Section 9.4 – Frequent Outage Program. This program identifies customers with excessive recent sustained and momentary outages and expedites a remediation plan to improve their reliability. The remediation plan typically includes repairs to overhead infrastructure and equipment and spot tree trim where necessary and is implemented on average within 60 days of the identification of the power quality issue.

Voltage

DTEE has several initiatives to address voltage-related power quality issues. Historically, DTEE became aware of voltage issues when notified by the affected customer(s). Today, with AMI infrastructure and Power Quality meters, DTEE can pro-actively identify voltage events – even some that have not manifested to a level noticeable by customers.

AMI meters record 5-minute interval voltage. The AMI meters are interrogated three times per day. The data are then queried to identify meters with voltages outside the acceptable ANSI range. If the meters with abnormal voltages are associated with several distribution transformers, it may indicate a circuit problem; if only a few transformers are involved, it is likely a localized problem and a trouble job is proactively created in InService, DTEE's Outage Management System. Problems affecting larger circuit areas are sent to the System Operations Center. In either case, an investigation is launched to identify the root cause and remediate the problem. Prior to the current process it would take several days to over a week to address high voltage cases through the planned work process; now the issues are typically identified and addressed within three days. Exhibit 7.4.2.1 illustrates the process.

Exhibit 7.4.2.1 Identifying Abnormal Voltage Conditions



Investigations have shown that high voltage cases are frequently the result of damaged windings inside distribution transformers, usually caused by lightning strikes. Investigations have shown that after two 100kA surges, lightning arrestors attached to the transformers disconnect and subsequent lightning strikes can affect the actual transformer, leading to the damage that causes high voltage. Replacement of these transformers corrects the issue and are an example of work completed in the Emergent Capital category (Section 13 – Base Capital).

A case of high voltage due to ferroresonance, an electrical phenomenon caused by a non-linear interaction between capacitive and inductive elements on the circuit, was first raised in the Ann Arbor area by customer complaints and the cause was not immediately obvious when troubleshooting. This led to additional investigative methods being utilized, such as analyzing AMI data to detect patterns and affected areas including the creation of the process in Exhibit 8.5.1. Further study showed that AMI data of high voltage cases resulted in differing patterns for different causes; for example, the AMI data for the ferroresonance case did not follow the same patterns as in cases caused by damaged transformers. After extensive research the Engineering team suspected ferroresonance as all the conditions supported this conclusion. The team then sought support from industry experts to help confirm that this was the case.

In total, 94 circuits were identified as having potential ferroresonance issues utilizing the lessons learned from the original. A capacitor placement and control program has been developed to prevent any high voltage events on these circuits as a result of ferroresonance. Additional details and the investment profile can be found in Section 12.6 – CVR/VVO.

When the process to use AMI meters to seek out abnormal voltages was initiated in early 2020, nearly 3,000 customers meters were reporting a voltage over 106%. After investigating the initial cases and implementing an ongoing monitoring process, the number of customers meters reporting a high voltage is typically less than 10. During the same timeframe there were initially about 300 customer meters that were reporting a voltage over 110% and all cases have been addressed. DTEE now monitors and addresses cases on a regular basis.

Due to the success of the high voltage detection process, DTEE is in the process of developing a similar approach to handling Low Voltage and Momentary Interruption situations, utilizing AMI data to identify circuits or circuit sections that are experiencing low voltages or high numbers of momentary interruptions occurring above those expected due to circuit switching operations.

7.4.3 Addressing subtransmission system power quality events

In addition to the voltage analysis process described above, DTEE has an effective process in place that enables its large industrial and commercial customers typically served from the subtransmission or transmission system to report and resolve power quality issues. DTEE has various channels available to assist all Commercial and Industrial (C&I) customers which include account managers and a separate 24/7 customer support system. Account managers are assigned to industrial customers based on DTEE's Major Account Services six customer segments, which are defined using the industry standards, Standard Industrial Classification (SIC) / North American Industry Classification System (NAICS) codes. Each of the six customer segments are categorized from simple to complex and each customer is matched with an account manager depending on the complexity of service requirements, rates, business operations and electrical loads. Smaller sized C&I customers are eligible for an account manager when they meet two criteria: annual $300,000 revenue and 5 million KWh threshold. C&I customers without an account manager have a dedicated team within the call center to handle only their calls. Using a special coding system for C&I customers allows for their calls to be held in a separate queue outside of residential customer calls. This ensures that all C&I customers' calls are processed in the timely manner. Community, municipal, or government channels are also available for C&I customers to submit requests and comments to DTEE. Often, C&I customers have established relationships with these agencies and are able to work through regional managers or account managers.

Although many power quality events warrant an investigation, it is not feasible to provide a root cause analysis for all reliability or power quality issues experienced by C&I customers. Many events clear themselves after a one-time occurrence, such as animals or temporary tree interferences because DTEE's subtransmission system is constructed with redundancies to protect against such instances. As such, an isolated event experienced by C&I customers may not necessarily trigger an investigation or patrol on a section of the electrical system. Instead, an investigation and patrol are typically conducted when multiple reliability or power quality events are experienced by a C&I customer over a short time period. Multiple events are a better indicator that a more persistent issue exists, for example a piece of failing equipment.

During a power quality or reliability investigation, replacements of cracked insulators or spot tree trimming are typically performed as potential solutions. However, it is not always clear if these solutions resolve the root causes of the outage events. This is because DTEE's experience suggests that a customers' internal system is sometimes the root cause of the power quality and reliability problems and identifying and attributing any specific issue as the root cause of an interruption or voltage sag is occasionally challenging and uncertain.

To better identify and locate existing and potential power quality issues on the subtransmission system, it is necessary to have proper power quality (PQ) metering in place at critical substation and customer locations. Exhibit 7.4.3.1 shows the investment in PQ metering for 2021-2025.

Exhibit 7.4.3.1 Subtransmission Power Quality Meter Investments

	$ Millions					
Category	2021	2022	2023	2024	2025	2021-2025 Total
PQ Metering	$ <1	$<1	$ 2	$ 2	$ 3	$ 7

In addition to the investigations and troubleshooting in response to customer inquiries, DTEE conducts subtransmission modeling to identify power quality issues. Based on subtransmission modeling, there are 115 subtransmission circuits (18% of total) with potential thermal and/or voltage violations under certain loading and contingency conditions. A thermal overload indicates that equipment on the circuit or station exceeds its rating, and a voltage violation indicates that the voltage on at least part of the circuit is no longer within an acceptable range. This could lead to power interruptions or power quality issues for industrial, commercial, and/or residential customers. The investment that is planned to resolve these existing subtransmission planning criteria violations is discussed in more detail in Section 11.2 - Subtransmission Redesign and Rebuild Program.

7.4.4 Other power quality issues

Transients

Transients may result from lightning strikes or switching operations. Lightning arresters on the conductors are designed to shunt the lightning strike to ground eliminating the surge to customers. In some locations, sections of distribution circuits are attached on poles with subtransmission overbuilt which shield the distribution wire from a direct lightning strike. And, subtransmission lines typically have an overhead shield wire to protect them from direct lightning strikes.

During pole top maintenance patrols, failed lightning arresters and missing sections of shield wire are identified for replacement.

Harmonics

Harmonics are rarely a problem with residential and most commercial customers. Commercial and industrial harmonic problems typically originate from customers' equipment or processes and may impact customers in electrical proximity. Harmonic problems are addressed by a power quality technician and/or engineer on a case by case basis once DTEE is aware of the problem.

8 Asset health assessment

The purpose of the asset health assessments is to gather information related to our assets and proactively address any identified equipment issues. In this section, we discuss the 20 assets that have the greatest potential impact on customer reliability. The assets described here represent approximately 80% of the distribution plant asset base.

The average age, range of ages and life expectancy for the 20 asset classes are summarized in Exhibit 8.1. The life expectancy is based on a combination of 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 own experience. Age can become a significant factor when replacement parts become unavailable or in the specific cases where asset health deteriorates sharply with age, however DTEE is also using health-based assessments to evaluate its assets. The remainder of this section provides a detailed description of individual asset health assessments.

In addition to the asset health assessment process, DTEE ensures reliable performance of individual asset classes through the combined measures of preventive maintenance and proactive replacements programs where justified. These measures are summarized in Exhibit 8.2 and detailed in individual asset subsections. Equipment that is a candidate for replacement is identified through the asset health assessments. The scope of work and capital funding for these replacements over the next five years are detailed in Section 9.1 – Capital Replacement Programs.

Exhibit 8.1 Asset Age Summary

Section	Asset	DTE Electric Average Age (Years)	DTE Electric Age Range (Years)	Life Expectancy (Years)
8.1	Substation Power Transformers	43	0 – 96	40 – 45
8.2	Network Banks	64 (structures) 46 (transformers)	0 – 85+	20 - 30 (transformers)
8.3	Circuit Breakers	42	0 – 85	30 – 40
8.4	Subtransmission Disconnect Switches	Not Available	0 - 85	Not available
8.5	Circuit Switchers	18	0 – 35	Not available
8.6	Relays	32	0 – 60+	15 – 50
8.7	Switchgear	37	0 – 67	40
8.8	Poles and Pole Top Hardware	46	0 – 90+	40 – 50
8.9	Small Wire (i.e., #4, #6, and #8)	70+	Not Available	Varies based on field conditions
8.10	Fuse Cutouts	19	0 – 50+	40
8.11	Three-phase Reclosers	9	0 – 31	20
8.12	SCADA (Supervisory Control and Data Acquisition) Pole Top Switches	14	0 – 38	20
8.13	40 kV Automatic Pole Top Switches	36	0 – 50+	40
8.14	Overhead Capacitors	Not Available	Oldest: 25+	20
8.15	Overhead Regulators	Not Available	Oldest: 25+	20
8.16	System Cable	45	0 – 100+	20 – 40
8.17	Underground Residential Distribution (URD) Cable	25	0 – 60+	40
8.18	Manholes	78	0 – 100+	Varies based on construction and field conditions
8.19	Vaults	Not Available	Not Available	Varies based on construction and field conditions
8.20	Advanced Metering Infrastructure (AMI meters)	6.5	0 – 10	20

Exhibit 8.2 Asset Program Summary

Section	Asset	Preventative Maintenance Programs (Yes/No)	----- Proactive Replacement Program ------		
			Yes/No	2021-2025 Investment ($M)	2021-2025 Number of Units
8.1	Substation Power Transformers	Yes	No	Not Applicable	
8.2	Network Banks	Yes	Yes	Included in Downtown City of Detroit (CODI) Project	
8.3	Circuit Breakers	Yes	Yes	$84 M	267 units
8.4	Subtransmission Disconnect Switches	Yes	Yes	$12 M	194 units
8.5	Circuit Switchers	Yes	Yes	$5 M	30 units
8.6	Relays	Yes	Yes	Not Applicable	
8.7	Switchgear	Yes	Yes	Included in Substation Risk Reduction Program	
8.8	Poles and Pole Top Hardware	Yes	Yes	$430 M	Varies
8.9	Small Wire (i.e., #4, #6, and #8)	No	No	Not Applicable	
8.10	Fuse Cutouts	No	Yes	Included as part of Pole Top Hardware	
8.11	Three-phase Reclosers	Yes	Yes	$9 M	95 units
8.12	SCADA Pole Top Switches	Yes	Yes	Combined with 8.11 in SCADA Pole Top Device Program	
8.13	40kV Automatic Pole Top Switches	Yes	Yes	$26 M	70 units
8.14	Overhead Capacitors	Yes	No	Not Applicable	
8.15	Overhead Regulators	Yes	No	Not Applicable	
8.16	System Cable	No	Yes	$243 M	98 miles
8.17	Underground Residential Distribution (URD) Cable	No	Yes	$60 M	270 miles
8.18	Manholes	Yes	No	Not Applicable	
8.19	Vaults	Yes	Yes	$4 M	2

Section	Asset	Preventative Maintenance Programs (Yes/No)	----- Proactive Replacement Program ------		
			Yes/No	2021-2025 Investment ($M)	2021-2025 Number of Units
8.20	Advanced Metering Infrastructure	Yes	Yes	$1 M	4,928

8.1 Substation power transformers

DTEE has approximately 1,600 substation power transformers, which connect the transmission system (120kV) to the subtransmission system (40kV and 24kV) and to the distribution system (4.8kV, 8.3kV, and 13.2kV) and also connect the subtransmission system (40kV and 24kV) to the distribution system (4.8kV, 8.3kV, and 13.2kV). Approximately 31% of the transformers have a high side voltage of 120kV. Exhibit 8.1.1 shows a substation power transformer. Exhibit 8.1.2 shows the age distribution of substation power transformers connected to the DTEE system. The average age of substation power transformers is approximately 42.5 years. Exhibit 8.1.3 shows the historical substation power transformer failures.

Exhibit 8.1.1 Typical Substation Power Transformer

Exhibit 8.1.2 Substation Power Transformer Age Distribution

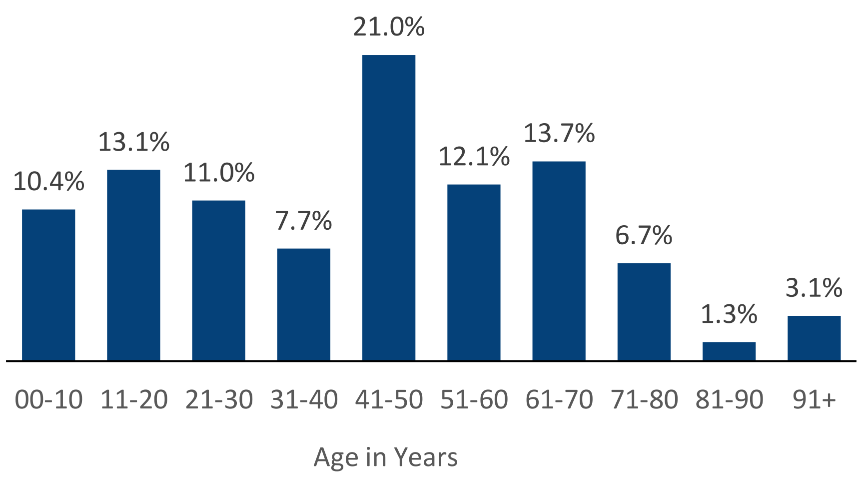
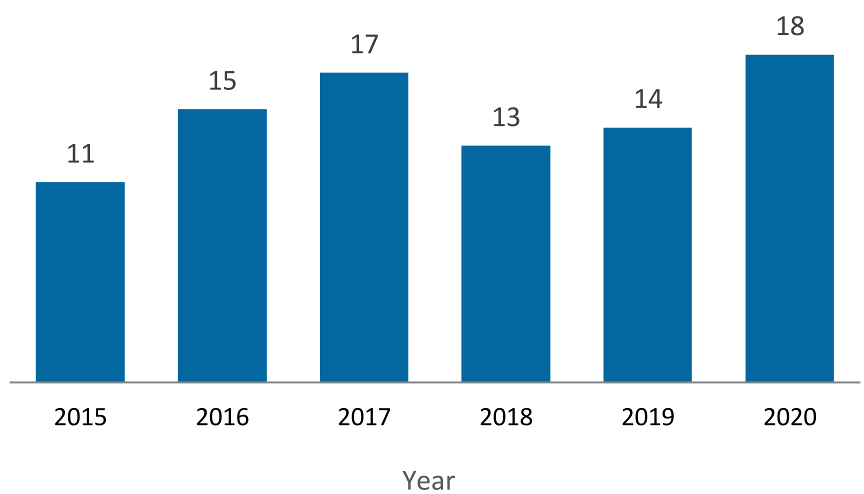


Exhibit 8.1.3 Substation Power Transformer Failures



The average number of substation power transformer failures over the past five years is over 15 per year – this includes units that were identified and proactively replaced prior to actual failure based on dissolved gas analysis (DGA) results. Bushings, load tap changers, and winding insulation breakdown account for approximately 65% of the failures. The transformer average age at time of failure is around 48 years.

Failures of substation power transformers can cause outages on multiple circuits simultaneously and can reduce system redundancy, effectively increasing outage risk to customers for extended periods of time, sometimes impacting thousands of customers. Based on the factors shown in Exhibit 8.1.4, approximately 15% of the substation power transformers are currently classified as candidates for replacement. These transformers are typically over 70 years old, have abnormal DGA ratios, and are water cooled with a potential active water leak into the unit.

Exhibit 8.1.4 Substation Power Transformers Replacement Factors

Factors	Impact
DGA results indicating gassing in the main tank	• Indication of early stages of failure
Water cooled transformers	• High costs to maintain water cooling

	• Greater chance of failures due to water leaking into the unit
High number of through faults	• High mechanical and electrical stress on the transformer core and winding insulation
70+ years old	• Deterioration of winding insulation • Uneconomical to repair
Chronic leaking of oil	• Environmental concern

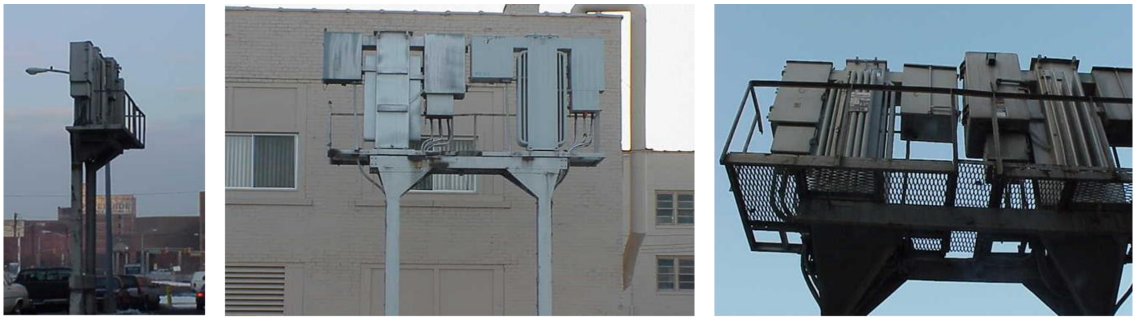
DTEE conducts regular inspections and DGA testing as part of our preventative maintenance (PM) plan on all substation power transformers once per year. DGA testing is an industry-proven Substation Predictive Maintenance Inspection (SPdM) methodology to identify internal transformer degradation and to predict incipient transformer failures. Based on results from routine inspection and DGA testing, DTEE determines when to either proactively replace or repair substation power transformers that do not pass inspection. Substation power transformers are sometimes also replaced reactively when they fail during service and are deemed uneconomical to repair. Preventative maintenance on ancillary components of power transformers such as load tap changers or bushings also takes place.

8.2 Network banks (Netbanks)

Netbanks are used to describe an installation consisting of specialized transformers, network protectors, and primary disconnect switches. A netbank system is recognized as the industry standard for the highest degree of continuity of service in heavy load-density city areas.

DTEE has netbank systems in the core downtown areas of Detroit and Ann Arbor as well as Mount Clemens and Port Huron. There is a total of 473 netbank transformers operating on the distribution system - the majority (90%) are located in Detroit. Netbank transformers are typically mounted on steel skids, steel columns, or wood poles, with a few located in underground vaults. The netbank wood pole supporting structures have an average age of 64 years, while the average age of steel supporting structures is 82 years. The netbank transformers have an average age of 46 years.

Exhibit 8.2.1 Netbank System Mounted on Steel Columns



DTEE conducts Electrical Integrity Inspections (EII) on a five-year cycle on netbank systems as part of the preventive maintenance program. It includes inspection of the primary disconnect and protector, visual (inside / outside) inspection of transformer tanks for corrosion, signs of water and oil sludge, PCB (Poly Chlorinated Biphenyl) and DGA oil analysis, and high voltage testing on the primary and secondary windings of the transformer.

The structural inspection of steel columns that support the netbanks is conducted to determine the replacement and repair needs based on the steel condition. In 2015 and 2016, a total of 115 structures were inspected. Of those, eight required replacements and 25 required repairs. Based on these results, DTEE expanded inspection efforts and completed inspections of the remaining 337 structures in 2017-2019, from which four required replacements and five required repairs. Netbanks found to require repair or replacement from 2015-2018, have been completed. Those found in 2019, will be completed by end of 2021.

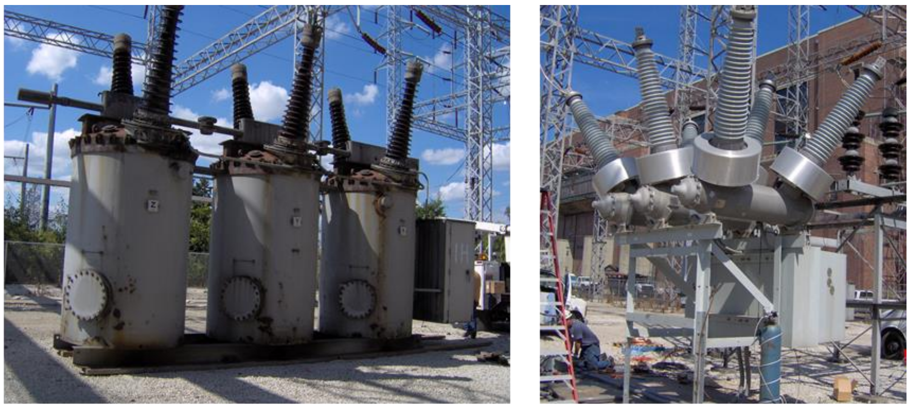
As mentioned above, some netbanks are mounted on wood poles. Inspection of these poles is conducted as part of the pole inspection and replacement program, as discussed in Section 9.1.1 – Pole and Pole Top Maintenance and Modernization.

Ultimately, the entire netbank system will be replaced as part of the 4.8kV conversion and consolidation program with a 13.2kV netbank system, as discussed in Section 11.4 – CODI Program.

8.3 Circuit 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. Exhibit 8.3.1 illustrates an oil breaker installed in the 1940s versus a recently installed vacuum breaker.

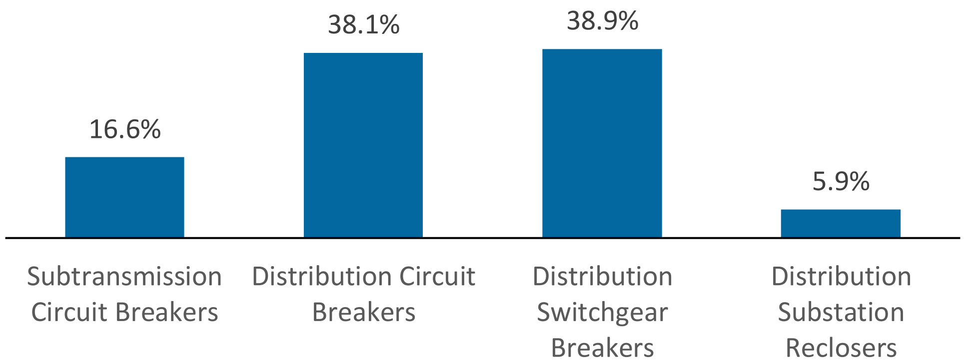
Exhibit 8.3.1 Circuit Breakers



Traditional 120 kV Oil Breakers   Modern 120 kV Gas Breakers

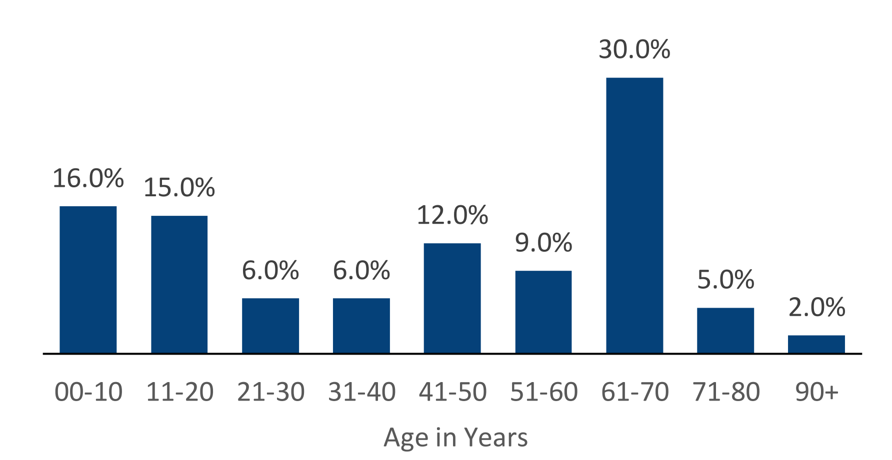
DTEE has approximately 6,000 circuit breakers on its system, which include subtransmission circuit breakers, distribution circuit breakers, distribution switchgear breakers, and distribution substation reclosers (Exhibit 8.3.2).

Exhibit 8.3.2 Circuit Breakers by Application



The life expectancy of a circuit breaker is approximately 40 years for early to middle 20th century equipment, while modern equipment has a life expectancy of 30 years and is designed for ease of maintenance and replacement. Exhibit 8.3.3 shows that approximately 60% of DTEE's circuit breakers are beyond their life expectancy.

Exhibit 8.3.3 Circuit Breaker Age Distribution



Of the approximately 6,000 circuit breakers, approximately 58% are candidates for replacement based on the latest assessment shown in Exhibit 8.3.4. All oil filled breakers are considered for replacement due to a combination of multiple risk factors associated with that equipment.

Exhibit 8.3.4 Circuit Breaker Replacement Factors

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

Circuit breakers that are candidates for replacement could degrade the reliability and operability of the subtransmission and distribution systems. 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. Exhibit 8.3.5 shows failures in the last five years, as categorized by failure to operate, in-service failure, and failure during preventative maintenance activity. Based on the type of failure, repairs may be possible instead of replacement, but this could lead to customer outages with long outage durations. When replacement is required or there is a major in-service failure, there could be extended outages that would require the system to operate in an abnormal condition for an extended period.

Exhibit 8.3.5 Breaker Failures by Year

Failure Type	2016	2017	2018	2019	2020
Failures to Operate – Trip (repair)	6	17	16	18	11
Failures to Operate – Close (repair)	36	44	65	83	63
Other Failures in Service (repair)	22	12	29	36	25
PM Failures (replace)	30	19	20	7	8
Other Failures in Service (replace)	12	8	24	17	6
Total # of Failures	106	100	154	161	113

DTEE performs regular periodic inspections of circuit breakers based either on a time interval or the number of breaker fault operations. Circuit breakers that do not pass inspection are either repaired (if economical to do so) or replaced. Over the last three years, an average of approximately 19 breakers fail inspection annually.

As stated above, there is a large population (approximately 60%) of breakers beyond their life expectancy. Failures of these breakers not only increase reactive costs but pose system risks. DTEE has a proactive capital replacement program to replace breakers that is further discussed in Section 9.1.5 - Breakers.

8.4 Subtransmission disconnect switches

Subtransmission disconnect switches are used to manually sectionalize and provide isolation points on the electrical system for operational reasons or for service / maintenance. DTEE has approximately 3,600 disconnect switches that operate at 24kV, 40kV, and 120kV.

Failures of disconnect switches during service are infrequent and do not usually lead to customer outages. However, failures of disconnect switches during operation, when operators attempt to open or close a disconnect manually, can lead to safety hazards, reduce system operability, and force additional equipment to be taken out of service to allow critical work to continue. Approximately 132 Cap & Pin style (Exhibit 8.4.1), 58 PM-40 model (Exhibit 8.4.2) and 22 Westinghouse Type R (Exhibit 8.4.3) disconnect switches are candidates for replacement, with replacement factors detailed in Exhibit 8.4.4.

Exhibit 8.4.1 Cap & Pin Disconnect Switch

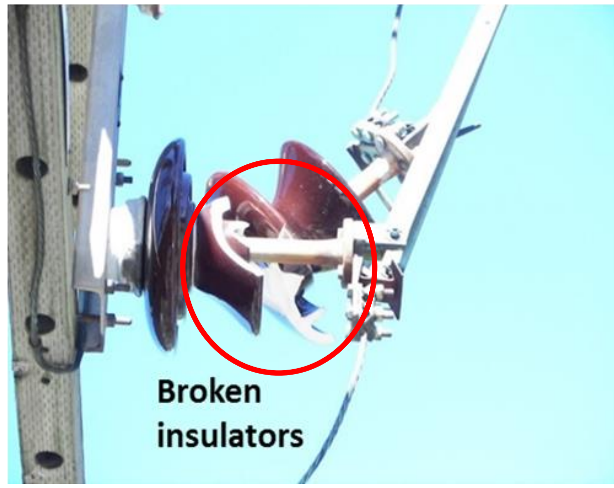


Exhibit 8.4.2 PM-40 Disconnect Switch

Exhibit 8.4.3 Westinghouse Type R Disconnect Switch

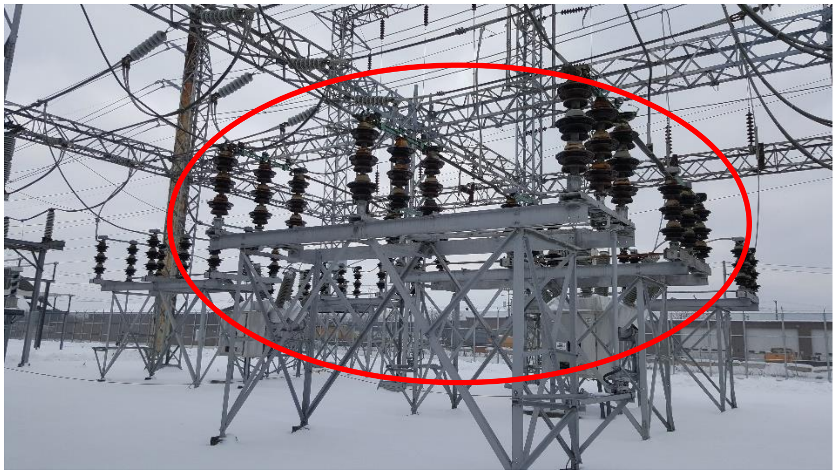


Exhibit 8.4.4 Subtransmission Disconnect Switch Replacement Factors

Factors	Impact
Cap & Pin Disconnects	• Insulators are problematic and could fail during operation • Employee safety concern upon failure during manual operation
Known Manufacturer Issues on PM-40 (120kV)	• Equipment could fail during operation due to bearing problems • Employee safety hazard
Westinghouse Type R	• PM inspections are revealing failed insulators, which could flash over during a fault condition. • Employee safety hazard • Disconnects are obsolete, up to 65 years old and in poor operating condition.

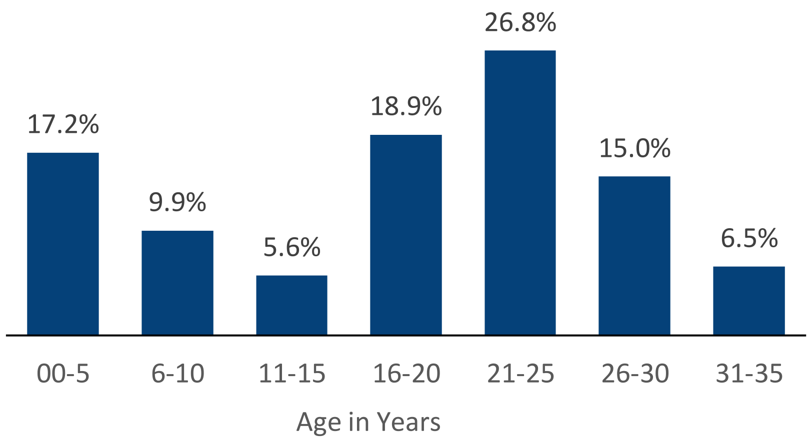
DTEE has a preventive maintenance program for subtransmission disconnect switches. In addition, DTEE has a proactive capital replacement program to replace the Cap & Pin, PM-40 and Westinghouse Type R disconnects that will be further discussed in Section 9.1.3 – Subtransmission Disconnect Switch.

8.5 Circuit switchers

DTEE has approximately 354 circuit switchers, which 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 used as a smaller and less expensive alternative to a circuit breaker when possible. The interrupting capability of a circuit switcher is not as high as a circuit breaker, so it cannot be used in all instances. Exhibit 8.5.1 shows two examples of circuit switchers. Exhibit 8.5.2 shows the age distribution of circuit switchers with the average age being 18 years old.

Exhibit 8.5.1 Circuit Switchers

Exhibit 8.5.2 Circuit Switcher Age Distribution



Based on the factors shown in Exhibit 8.5.3, approximately 22% of circuit switchers are classified as candidates for replacement. Failures of circuit switchers to trip when necessary can lead to system outages and damage to other critical equipment such as transformers. These circuit switchers will either undergo full replacement, component replacement, or inspection for further analysis.

Exhibit 8.5.3 Circuit Switcher Replacement Factors

Factors	Impact
Known failure modes	Insulating support columns manufactured prior to 1999 have a gasket that can fail, leading the columns to leak. This has the potential to cause the operating rods to seize resulting in failure to trip. All leaking units manufactured prior to 1999 will be replaced.
Potentially faulty components	The manufacturer has identified several components that may be faulty, based on manufactured year. Faulty parts could lead to failure to trip. Components will be tested and/or replaced as applicable.
Undersized units	These units do not have the interrupting capability to operate as designed. Delayed tripping is implemented until the proper rated switcher is installed.

Circuit switchers undergo periodic inspections after five automatic operations or when infrared survey programs produce unfavorable results. In addition, DTEE has a proactive capital replacement program to replace identified circuit switchers that is further discussed in Section 9.1.4 – Circuit Switcher.

8.6 Relays

The function of relays is to monitor system current and voltage, detect abnormal conditions (primarily fault current) and initiate breaker operations to isolate abnormalities.

DTEE relays operate on the transmission, subtransmission and distribution systems. There are three types of relays: electro-mechanical, solid state, and micro-processor. The majority (79%) of the approximately 27,000 relays are electro-mechanical relays as shown in Exhibit 8.6.1 and described in Exhibit 8.6.2.

Exhibit 8.6.1 Relays Design Types

www.naswgr-store.com

Electro Mechanical

Solid State

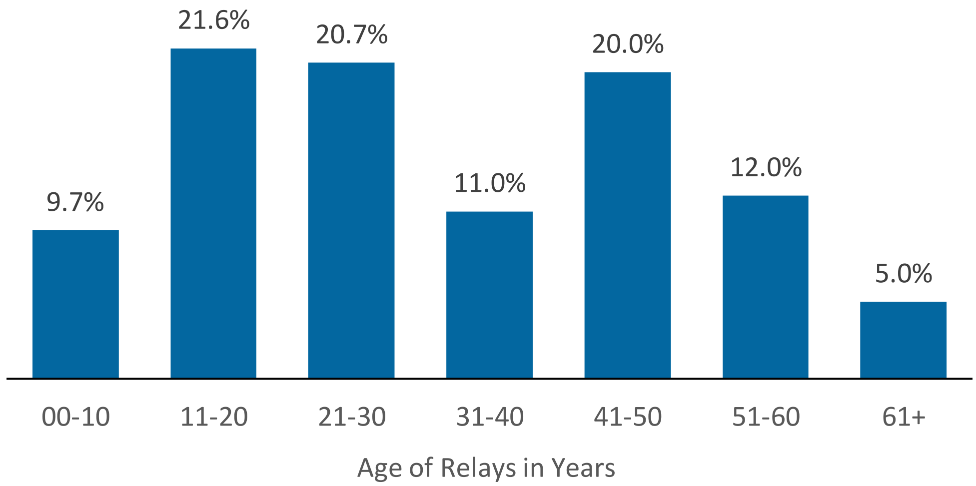
Micro-processor

Exhibit 8.6.2 Relay Design Type Benefits and Drawbacks

Relay Type	Life span	Benefits	Drawback
Electro-mechanical (79% of Total)	50 years	• Contain no electronics • Long life span • Low maintenance • Settings can be easily adjusted	• No SCADA or communication • No fault location detection • No metering or power flow monitoring • Unavailable parts
Solid state (2% of Total)	40 years	• Settings can be easily adjusted • No moving parts – mechanism does not wear out	• Obsolete technology • No SCADA or communication • No fault detection • No metering or power flow monitoring • Unavailable parts
Micro-processor (19% of Total)	15 – 20 years	• Provide SCADA, fault detection and metering functions • Replace 5+ electro-mechanical relay functions • Require limited preventive maintenance due to self-checking capability • Provide condition-based information for breakers and transformers • Relay settings can be applied remotely	• Relatively short life span • Early models have power supply issues and have limited capabilities as compared to newer models

The average age of DTEE relays is 33 years, with the age distribution illustrated in Exhibit 8.6.3. A relay failure can lead to loss of ability to return equipment to service. It may also result in a larger outage (e.g., a substation bus gets de-energized due to a distribution circuit relay failing to operate) or possibly result in damage to other control or power equipment.

Exhibit 8.6.3 Relay Age Distribution



Approximately 34% of the relays are classified as candidates for replacement based on factors listed in Exhibit 8.6.4.

Exhibit 8.6.4 Relay Replacement Factors

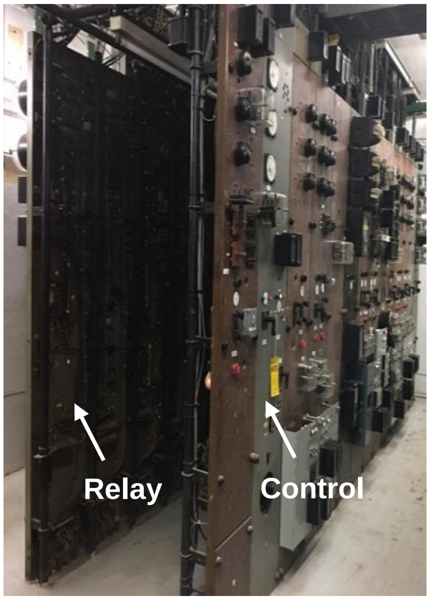
Factors	Impact
Known high impact failure modes	Poor operational performance that has led to customer outages Significant amount of time erroneously troubleshooting power equipment to find cause of fault indicated by the relay
Known high failure rate reclosing relays	Unnecessary sustained customer interruptions due to the inability of breakers to close automatically
Microprocessor relay 15+ Years (Distribution) and 20+ Years (Subtransmission)	Modern relays have a shorter life span and start failing after 15 years
Solid State 40+ Years	Solid state electronic components begin to fail with age Repetitive DC surges cause failures over time
Electromechanical Relays 50+ Years	Mechanical stress wears relay triggers (springs) out over time Electrolytic capacitors internal to relay dry out over time – causing non-correctable calibration issues Unavailable or expensive replacement parts

DTEE has a preventive maintenance program for relays. Relays found non-operational during maintenance or in service are replaced or repaired. Relay replacements are generally coordinated and included as part of the breaker or transformer replacements. In addition, DTEE plans to replace end-of-the-life marble relay panels (as shown in Exhibit 8.6.6). These marble panels exists at four stations and do not allow for replacing a single relay panel with a single breaker replacement in their current physical configuration. The schedule for these replacements is shown in Exhibit 8.6.5, and further details are included in Section 9.2.3. Additionally, as a part of the Substation Automation Program, electromechanical relays will be replaced with microprocessor relays. Today, roughly 32% of general-purpose substations in DTEE's territory have SCADA monitoring and control. Not all substations are good candidates for substation automation upgrades, but those that can support it will receive the upgrades which will include relay replacements. More details regarding how substations are prioritized for automation upgrades can be found in Section 12.5 – Distribution Automation.

Exhibit 8.6.5 Relay Panel Replacements as part of Station Upgrade Projects

Station	Years
Warren	Completion 2021
Northeast	2021-2023
Navarre	2023-2025
Lincoln	2022-2024

Exhibit 8.6.6 Relay Panels



Old Marble Relay Panel (Separate panels for relay and control functions)

Modern Relay Panel (Single panel for relay and control functions)

8.7 Switchgear

Switchgear is used at substations to house and protect from weather a combination of many equipment types including circuit breakers, power bus, relays, metering, SCADA control and communication support. The components within in a switchgear are housed in metal clad compartments / positions. Switchgear is used to de-energize equipment to allow work to be done and to isolate faults. Exhibits 8.7.1 and 8.7.2 provide exterior and interior views of switchgear.

Exhibit 8.7.1 Switchgear Design Types

Outdoor Single Row

Across-the-Aisle

Two-Tier Switchgear

For some switchgear models, a failure in a single switchgear position can cause damage to multiple adjacent switchgear positions This type of failure has the potential to result in the loss of power for an entire bus or substation, and under some circumstances may affect thousands of customers. This could also result in the system being in an abnormal state for an extended period of time until all the positions are repaired or replaced. Abnormal states can introduce risk to a circuit.

Exhibit 8.7.2 Switchgear Interior View

DTEE has 261 sets of switchgear on its distribution system. As illustrated in Exhibit 8.7.3, the majority (76%) of the switchgear are operating at 13.2kV. Due to their smaller configuration, many 4.8kV substations do not require the use of metalclad switchgear. As illustrated in Exhibit 8.7.4, the average age of switchgear in DTEE's system is approximately 37 years old, with more than 55% of the switchgear more than 40 years old.

Exhibit 8.7.3 Switchgear by Voltage

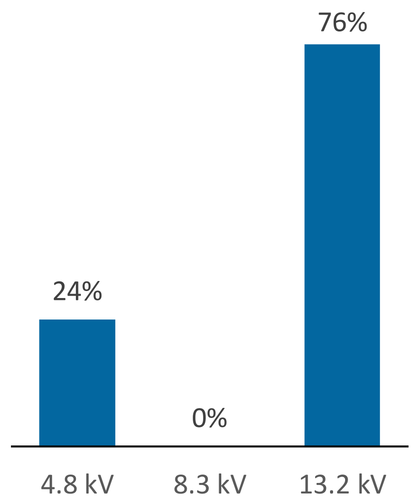
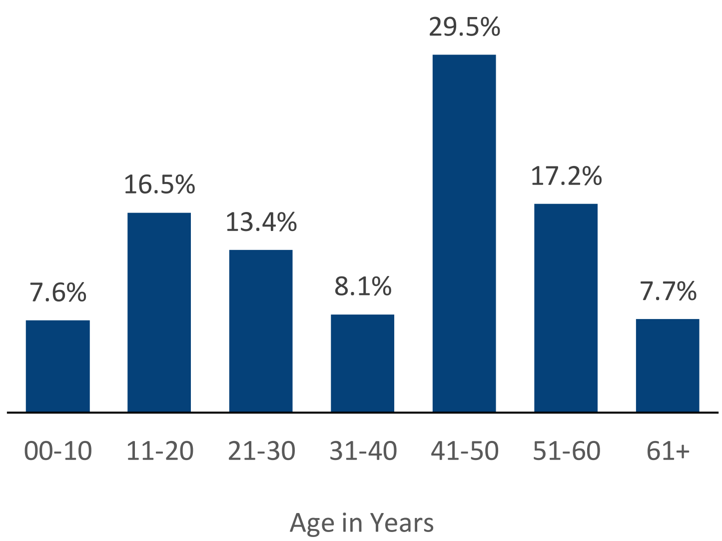


Exhibit 8.7.4 Switchgear Age Distribution



Based on the latest health assessment, approximately 27% of the switchgear sets are candidates for replacement. As shown in Exhibit 8.7.5, several risk factors are considered.

Exhibit 8.7.5 Switchgear Replacement Factors

Factors	Impact
Age	Bus insulation begins to degrade, which requires replacement to prevent bus failures. Replacing old insulation is a very expensive task and requires a lengthy shutdown of associated equipment
Calvert bus	Prone to failure due to exposure to the elements – see Exhibit 8.7.6
Design type	Some switchgear designs (outdoor single row, indoor across-the-aisle) are more likely to fail than others (two-tiered switchgear) – see Exhibit 8.7.1
Racking type	Some switchgear utilizes open door breaker racking which potentially increases arc flash hazards
Spare parts	Vendors/manufacturers no longer supply parts for some older vintage switchgear
Asbestos control wiring	Some control wiring inside the switchgear contain asbestos which is a health risk
Operating issues	Odd or unique situations like one-of-a-kind breakers or certain cell configurations
Spare land	If a major failure occurs on the site, no adjacent spare land is available to install mobile fleets and help restore customers
Previous failure	If the switchgear has experienced a major failure in its past, the likelihood of another major failure increases
Number of positions	The more positions connected in a single line-up without additional throw over capabilities, the larger the impact of the failure

Exhibit 8.7.6 Calvert Bus

DTEE does not have a stand-alone preventive maintenance program for switchgear; however, the different equipment types within the switchgear such as circuit breakers, power bus, or relays have their own preventive maintenance programs.

Replacing switchgear involves an extensive substation re-build. It includes pouring new concrete pads and executing a significant amount of underground work to install cable from the transformers, capacitors and circuit exits. Equipment control wiring and testing can take several weeks to complete. While the work is in progress, a significant amount of load must be transferred to adjacent substations or circuits, and/or fed by portable substations or distributed generation. The additional loading on adjacent circuits creates operational constraints on the system. Due to the complexity and cost requirements, switchgear replacement is typically executed as part of the broader Substation Risk Reduction Program discussed in Section 9.2 – Substation Risk Program.

8.8 Poles and pole top hardware

DTEE owns more than 1 million distribution and subtransmission poles and attaches to nearly 200,000 poles owned by other utilities (e.g., AT&T). The average pole age in the DTEE system is approximately 46 years. The age distribution for DTEE owned poles is illustrated in Exhibit 8.8.1, and the distribution of non-DTEE owned poles to which we attached equipment is shown in Exhibit

8.8.2. The life expectancy of a pole is 40 years for wood pine poles and 50 years for wood cedar poles, though the actual useful life expectancy can vary based on field conditions.

Exhibit 8.8.1 DTEE Owned Wood Pole Age Distribution

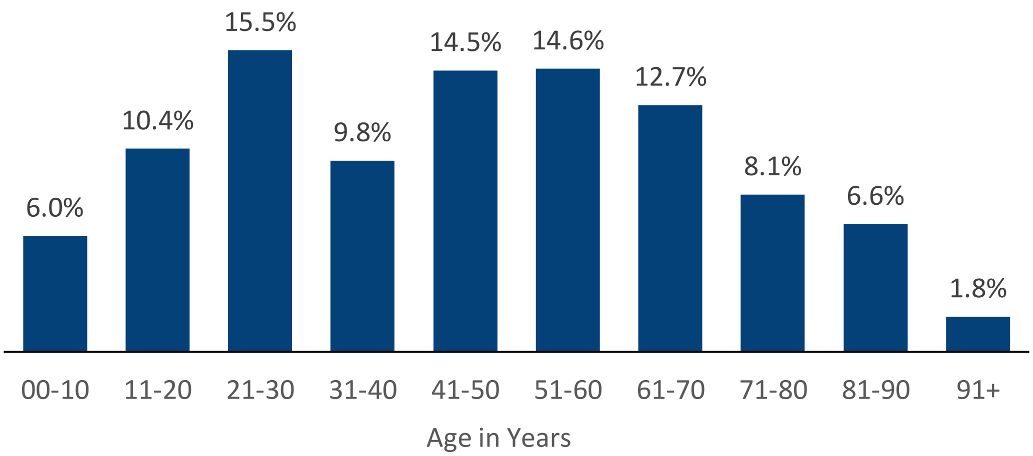


Exhibit 8.8.2 Non-DTEE Owned Wood Pole Age Distribution

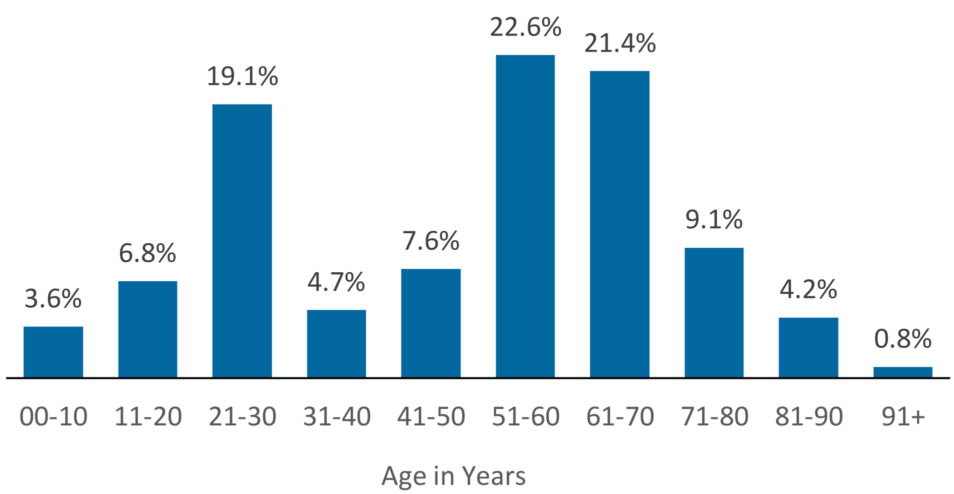
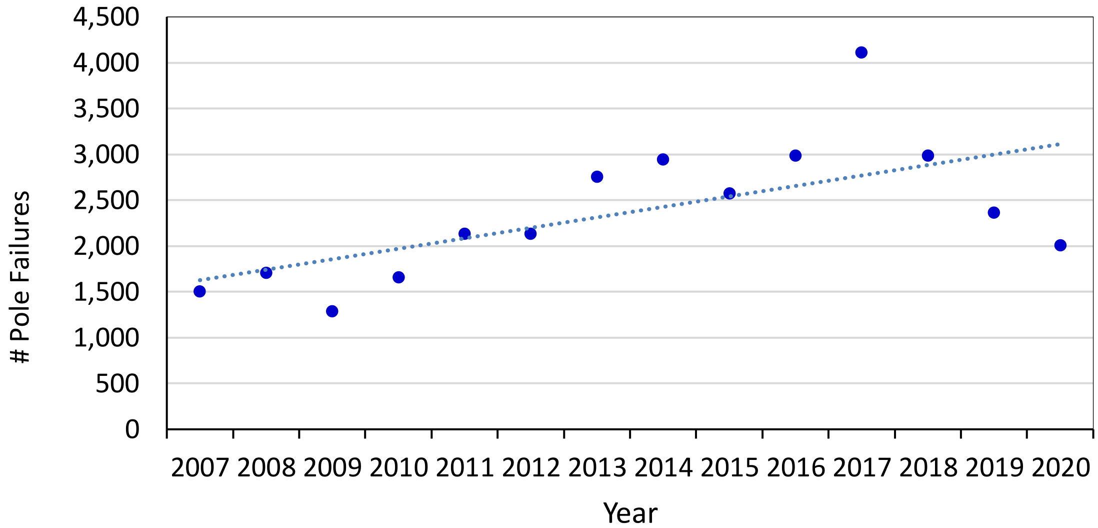


Exhibit 8.8.3 shows the increasing trend of broken poles. A broken pole does not always result in customer outages, in some cases the pole may be fractured or damaged, but the integrity of the conductors is maintained.

Exhibit 8.8.3 Annual Broken Pole Events (Failures during service)



Not all broken poles are the result of aging. A portion of them are due to vehicle strikes, trees, icing or wind loads above the design standard, etc. However, to identify and replace or remediate poles with deteriorating strength, DTEE conducts pole testing as part of the Pole and Pole Top Maintenance and Modernization Program (PTMM), as discussed in detail in Section 9.1.1. Non-DTEE owned poles that have DTEE assets attached are also visually inspected as part of the PTMM program.

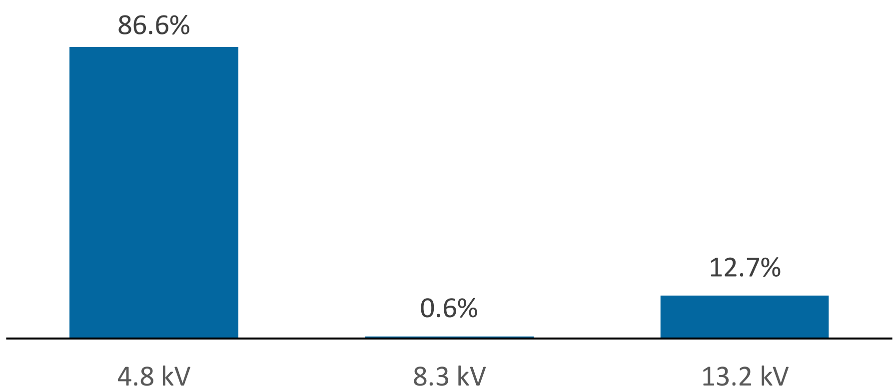
Pole top hardware is also inspected as part of the PTMM program. That hardware includes the following: cutouts, slack span sleeves, blackburn hot taps, ground wires, arresters, cross-arm parts, transformer parts, insulators, primary line sag, guy wire components, spacer blocks, neutrals on secondary taps and secondary equipment.

DTEE is increasing investment in PTMM for multiple reasons. As shown earlier in this section, the average age of poles on the system is at or approaching life expectance. Pole failures, as well as pole top equipment failures, lead to costly reactive work. The PTMM program, which is based on measurement of pole strength or observation of pole top equipment that is at risk for failure, allows for a much more efficient, planned replacement of assets that will be prone to failure in the near future. DTEE is also increasing investments in PTMM based on benchmarking and learnings from other key programs. The investments in this program will improve customer reliability and help manage emergent costs.

8.9 Small wire

Small wire is identified by the wire gauge, in this case #8, #6, and #4. The overhead distribution primary system has approximately 3,600 miles of small wire, representing 17% of the total overhead primary wire miles. Exhibit 8.9.1 shows the distribution of wire between the three operating voltages.

Exhibit 8.9.1 Small Wire by Voltage

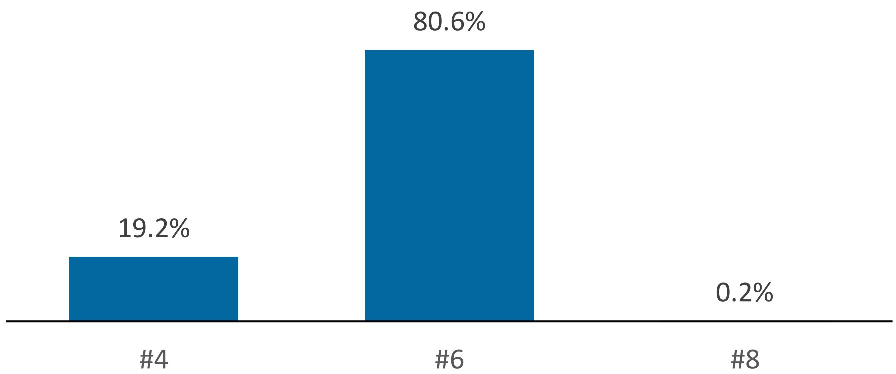


These wire sizes are no longer used for new installations, except some like-to-like replacements during emergent conditions (e.g., trouble or storm). Small wire is of concern because of its weaker mechanical strength.

To improve reliability, DTEE has upgraded standard sizes of conductors that are installed on all planned work. The new wire specifications provide strengths that are two to three times stronger than small wire sizes.

There is no stand-alone proactive replacement program for small wire currently. However, small wire replacement is performed during other capital work to support load growth, conversion and consolidation, or reliability improvements.

Exhibit 8.9.2 Small Wire by Size



Note: Small wire presents 17% of DTEE wire miles

8.10 Fuse cutouts

A fuse cutout is a combination of a fuse and a fuse carrier. This equipment provides overcurrent protection for the primary distribution system. The fuse opens (blows) when excessive current is produced by abnormal conditions such as line faults caused by trees, overloads, or equipment failures.

DTEE has approximately 668,000 fuse cutouts on its system. The fuse cutout replacement criteria are shown in Exhibit 8.10.1. Exhibit 8.10.2 illustrates the S&C R10/R11 Porcelain Cutouts. Over the past several years, DTEE has also made significant progress in replacing S&C Porcelain Cutouts. The population of this fuse cutout has reduced from 59,000 in 2018 to 11,000 as of today.

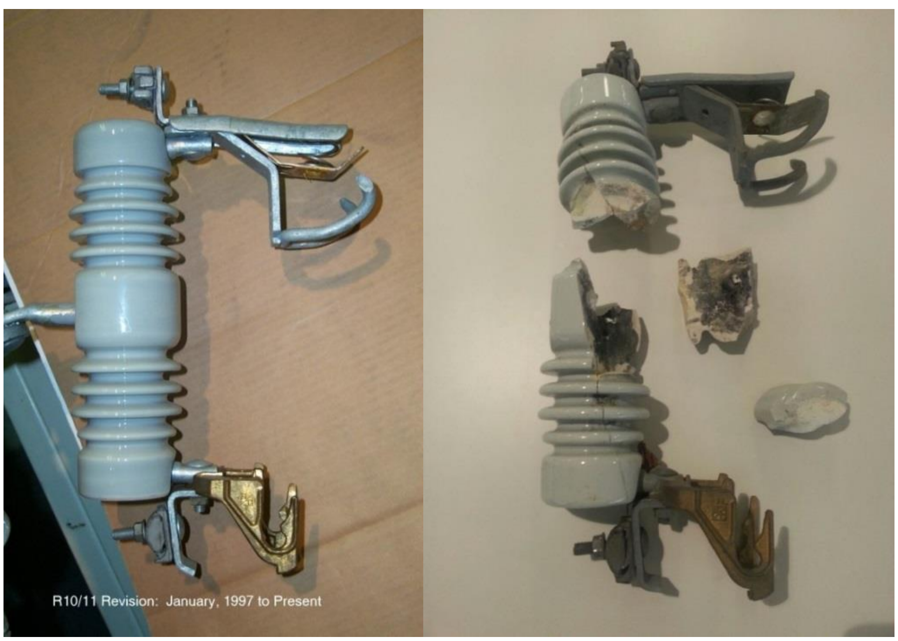
Other defective cutouts include certain vintages of AB Chance Porcelain and Durabute Polymer. Past programs replaced most of these devices.

The remaining defective cutouts will be identified and addressed through the Pole Top Maintenance and Modernization program as discussed in Section 9.1.1 – Pole and Pole Top Maintenance and Modernization.

Exhibit 8.10.1 Fuse Cutout Replacement Criteria

Type	Approximate population	Reason for replacement
S&C Porcelain R10/R11 (2005 – 2007 Vintage)	11,213	Premature failure due to latent defect
AB Chance Porcelain	21,000	Premature failure due to latent defect
Durabute Polymer	1,200	Improper operation
Total Defective Cutouts	33,413	

Exhibit 8.10.2 S&C R10/R11 Porcelain Cutout



8.11 Three-phase reclosers

An overhead three-phase recloser is a sectionalizing device that is located at key points on overhead circuits. It acts like a circuit breaker by opening under detection of high current 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 in order 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 restores power to customers with only a momentary interruption. In the case of a sustained fault, the recloser will eventually remain open and isolate the fault from the rest of the circuit.

Reclosers with SCADA control capability can be used for automatic restoration in distribution system loop schemes. A typical loop scheme involves at least two separate but adjacent circuits: each of the circuits has a normally closed recloser installed near the midpoint; a normally open recloser is installed at the tie point of the two circuits (as shown in Exhibit 8.11.1). The scheme automatically operates to isolate a fault that occurs between a circuit breaker and the midpoint recloser. After the breaker locks open, the midpoint recloser opens and the tie recloser closes between the two circuits. This automatically restores half of the circuit by transferring it to the adjacent circuit, reducing the number of customers experiencing an extended outage.

Exhibit 8.11.1 Typical Loop Scheme Diagram

DTEE operates approximately 1,173 overhead three-phase reclosers on its distribution system. Of the total, 93.1% are installed on the 13.2kV system and 6.9% on the 4.8kV system. Approximately 87% of the three-phase reclosers have SCADA monitoring and control capability.

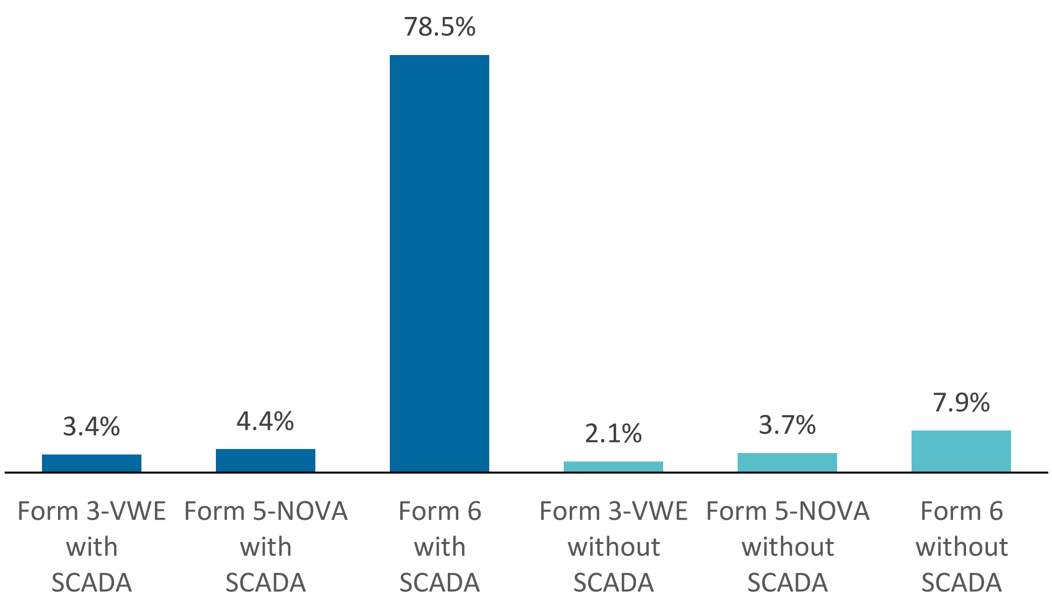
Exhibit 8.11.2 Three-phase Recloser Design Types

VWE Recloser

NOVA Recloser

Triple Single Recloser & Form 6 Control

Exhibit 8.11.3 Three-phase Recloser Type Distribution

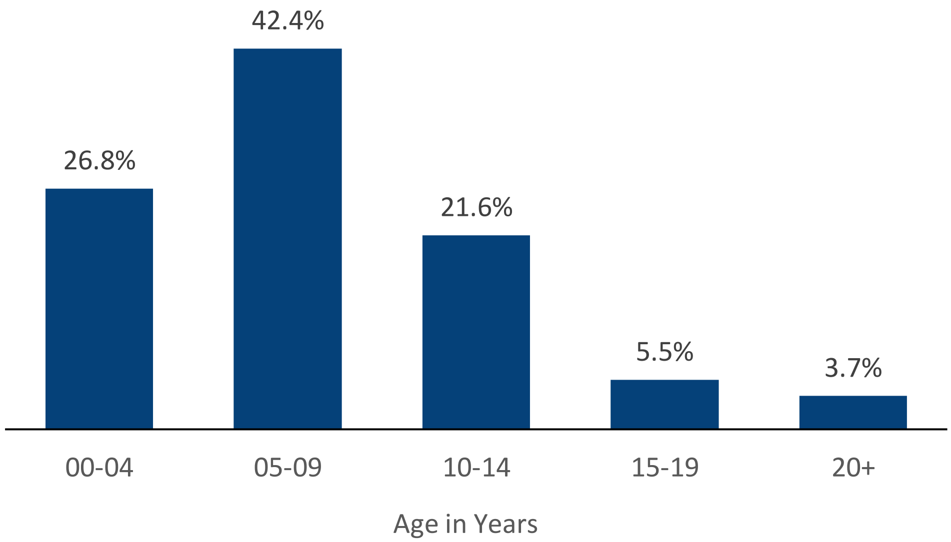


DTEE currently has Form 3-VWE, Form 5-Nova and Form 6-Triple Single reclosers on our system. The Form 3 and Form 5 reclosers operate all three phases simultaneously. DTEE now only installs Eaton Cooper Form 6 Triple Single reclosers for all new locations and all replacements. The Form

6 (Triple Single) reclosers can operate in single-phase mode as well as three-phase mode. The ability to operate single phase reduces the number of customers interrupted during an outage event. However, the single-phase mode is not used in areas that serve predominantly three-phase customers.

The average age of the three phase reclosers is approximately nine years. Exhibit 8.11.4 shows the age distribution.

Exhibit 8.11.4 Three-phase Recloser Age Distribution



Form 3-VWE and Form 5-NOVA reclosers (13.6% of the total population) are candidates for replacement, based on the factors shown in Exhibit 8.11.5. Depending on the failure mode (failed to close or open), the number of customers impacted can range between 300 and 1,500.

Exhibit 8.11.5 Three-phase Recloser Replacement Factors

Factors	Impacts
Unavailable parts	Many replacement parts for Form 3-VWE and Form 5-NOVA are unavailable; others are becoming increasingly unavailable
Known high failure rate	Form 3-VWE reclosers have seen high failures of batteries, controls and mechanical parts Form 5-NOVA reclosers have seen high failures of mechanical parts
Environmental issues	Form 3-VWE reclosers contain oil and can leak during service
SCADA capability	Form 3-VWE does not have diagnostic capability. It is expensive to retrofit SCADA on Form 3 controls

DTEE has a preventive maintenance (PM) program for overhead three-phase reclosers. Reclosers not passing PM inspection or failing in service are replaced or repaired.

8.12 4.8 kV & 13.2 kV SCADA distribution pole top switches

A complete SCADA pole top switch (PTS) includes a switch and a SCADA control box that provides an interface between the switch and the Energy Management System (EMS) master-station computer.

A distribution SCADA PTS allows the System Operations Center (SOC) to quickly isolate faults and restore customers remotely. Additional switches permit the circuit to be divided remotely, so load can be transferred to other circuits in the event of an outage.

DTEE operates 289 SCADA PTS's. There are two types of SCADA PTS's: S&C SCADA Mate switches and Bridges Auto Topper switches (Exhibit 8.12.1).

Exhibit 8.12.1 SCADA Pole Top Switch Types

S&C SCADA Mate switches

Bridges Auto Topper switches

Exhibit 8.12.2 SCADA Pole Top Switch Type Distribution

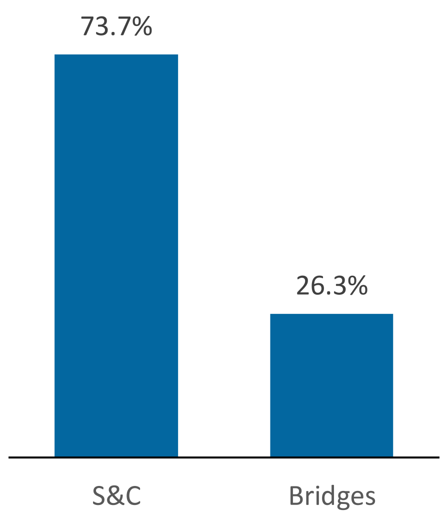
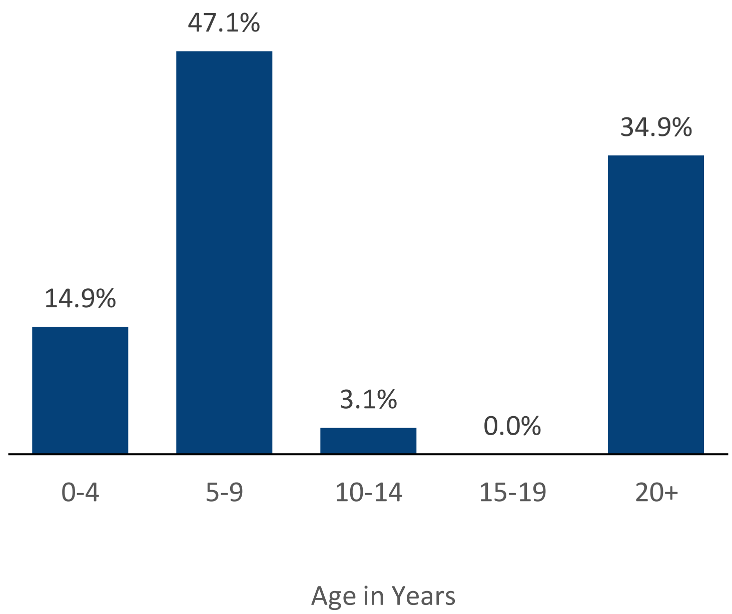


Exhibit 8.12.3 SCADA Pole Top Switch Age Distribution



The average age of all SCADA pole top switches is approximately 13 years. The Bridges switches average age is more than 25 years. Historically, Bridges switches have had a significantly higher failure rate. From 2017 – 2019, Bridges switches failed 21.9% of Preventative Maintenance inspections versus S&C failing 9% of inspections. Because of the factors in Exhibit 8.12.4, all Bridges SCADA PTS's (263% of the SCADA PTS population) are candidates for potential replacement.

Exhibit 8.12.4 SCADA Pole Top Switches Replacement Factors

Factors	Impacts
Switch design	Bridges switches have an open-air switch design vulnerable to adverse weather conditions, motor–timer failures, control board failures and Lindsey sensor failures
RTU control box design	Bridges switches have RTU control boxes with carbon steel cabinets, which are prone to rusting

When SCADA pole top switches fail to open or fail to close, remote restoration is unavailable and the switch must be opened manually by field personnel, resulting in longer restoration times. DTEE has a preventive maintenance program on SCADA pole top devices (Section 9.1.8). S&C SCADA units that do not pass preventive maintenance inspections or fail in service are either repaired or replaced, while failed Bridges SCADA units are generally replaced.

8.13 40kV automatic pole top switches (40kV APTS)

DTEE has approximately 146 automatic pole top switches (APTS) with control boxes on the 40kV subtransmission system. Similar to the Pole Top Switches (PTS) described above in section 8.12 – 4.8kV & 13.2kV SCADA Distribution Pole Top Switches, the function of the APTS is to sectionalize, isolate, or connect portions of the system.

The failure rate of these switches is approximately 15% over a year. A failure of one of these switches has the potential to interrupt thousands of customers or result in significant operational constraints. The entire 40kV APTS population is considered for replacement as part of the APTS capital replacement program (Section 9.1.2) to address high failure rates and unavailable spare parts for early vintages.

The exact age of each 40kV APTS is difficult to determine as parts and controls have been replaced throughout their lives; however, Exhibit 8.13.1 shows a few of the APTS on our system and Exhibit 8.13.2 shows percentage of switches on the system by vintage.

Our current standard SEECO switch is manufactured as a single integrated component by only one provider which has resulted in a reliable cost-effective component with a shorter lead time.

40kV APTS recent failure modes are shown in Exhibit 8.13.3.

DTEE is also conducting a pilot study for the SEECO switch with updated technology. The current SEECO switch can only sense voltage on one side. A pilot study is being conducted with a switch with upgraded capabilities, namely the ability to sense voltage on both sides of the switch. This will allow for automatic fault isolation and prevent a larger outage from occurring if the fault were to cause the breaker to open, resulting in fewer customers losing power. Once this modification to the SEECO switch proves compatible with the subtransmission system and the SEECO switch, it will be installed on all future locations.

DTEE has a 40kV APTS preventive maintenance program which includes both verification of the mechanical operation of the device and testing of the relay and control settings.

In addition, DTEE has a proactive capital replacement program to replace APTS's which is further discussed in Section 9.1.2 – Automatic Pole Top Switch.

Exhibit 8.13.1 40kV Automatic Pole Top Switches

S&C R9

S&C R10

SEECO

S&C Horizontal

Exhibit 8.13.2 40kV Automatic Pole Top Switches by Vintage

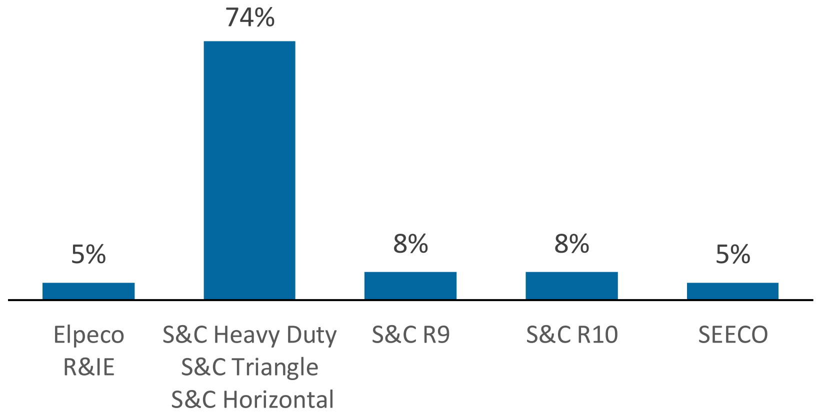
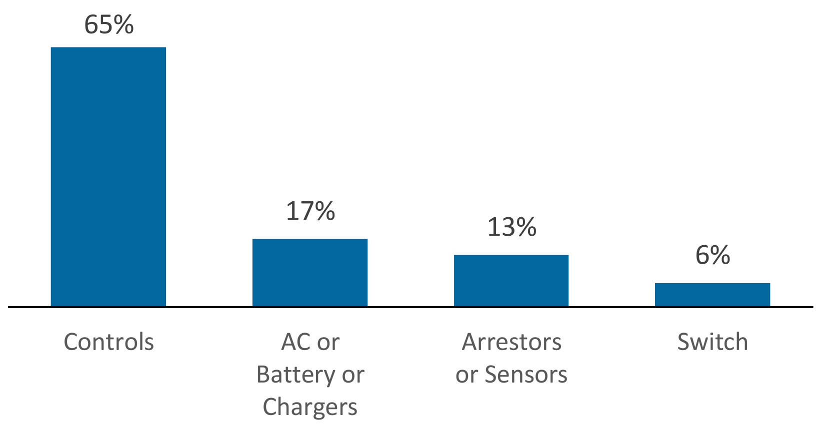


Exhibit 8.13.3 40kV Automatic Pole Top Switch Failure Modes



8.14 Overhead capacitors

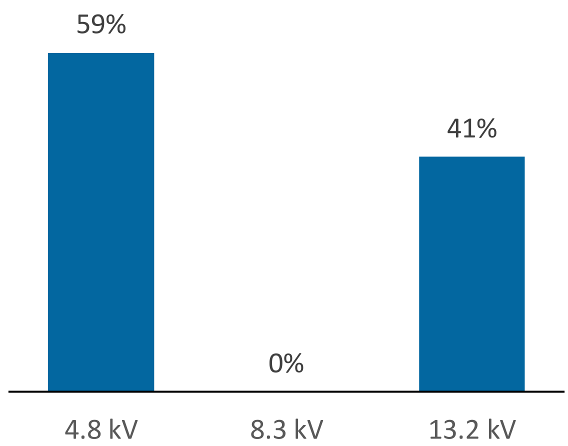
Overhead capacitors are passive electronic components that provide a static source of reactive power to the distribution system. They are used to manage the reactive power and consequently voltage and losses on a distribution circuit.

DTEE has approximately 3,160 overhead capacitor banks installed on 1,753 overhead circuits. They provide approximately 2,100 MVAR of reactive power. Not all circuits have or need capacitors. Engineering analyses are done to determine which circuits would benefit from the addition of capacitors and where those capacitors should be located on the circuit. Most capacitors were installed in the early 1990s.

Exhibit 8.14.1 Overhead Capacitor Bank

DTEE's System Operations Center (SOC) has control over capacitors through 11 different radio transmitters. These radio transmitters allow SOC to operate areas rather than individual units, however, this technology is becoming obsolete and is a candidate for replacement with updated technology. Smart capacitor control boxes, which function through the SCADA network, are in the pilot phase to take place of the radio transmitters. This would allow the SOC to control each capacitor individually. The capacitor banks will not be replaced but will be retrofitted with the new control box and sensors. There are currently 16 pilot control boxes on the system, we expect to install up to 300 per year for the next 10 years, primarily as part of the CVR/VVO program.

Exhibit 8.14.2 Overhead Capacitor Bank Voltage Distribution



Overhead capacitor failures typically impact localized power quality and line losses. If power quality is negatively affected, manual intervention may be taken in some circumstances to interrupt customers until the issues can be corrected.

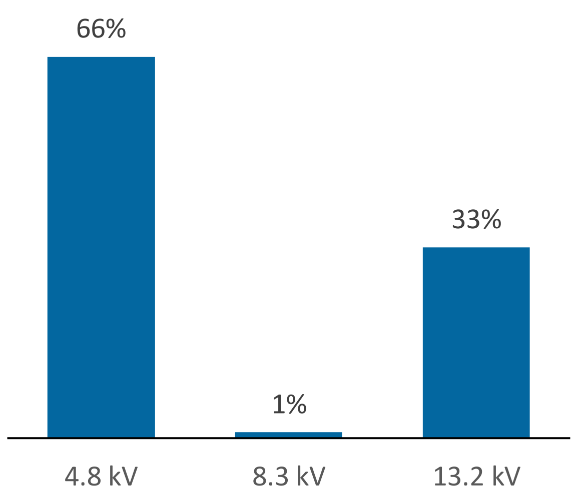
DTEE has a preventive maintenance program (PM) for overhead capacitors. Reactive replacements are made for those units that fail inspection and for those that have failed in-service. The updated standard configuration using remote monitoring and control capability is used with any new installations of the capacitor banks installed due to failure, obsolescence, or capital programs such as Conservative Voltage Reduction / Volt Var Optimization (CVR/VVO). Details regarding the CVR/VVO program can be found in Section 12.6 – CVR/VVO.

8.15 Overhead regulators

Overhead regulators are used to maintain circuit voltage, particularly in situations where the load is distant from the substation. DTEE regulators adjust automatically based on the changing load to maintain circuit voltage level. Not all circuits have or need regulators. Engineering analyses are done to determine which circuits would benefit from the addition of regulators and where those regulators should be located on the circuit. DTEE has approximately 2,400 regulators on its overhead circuits.

Exhibit 8.15.1 Overhead Regulator

Exhibit 8.15.2 Overhead Regulator Voltage Distribution



Overhead voltage regulator failures typically do not lead to customer interruptions but may result in low voltage situations.

DTEE has a preventive maintenance program for overhead voltage regulators. Reactive replacements are made for units that do not pass PM inspection or fail in service. In addition to the PM program, remote monitoring, control, and condition-based monitoring for overhead regulators will be tested in late 2021 as part of the CVR/VVO pilot program. If the pilot results demonstrate the efficacy of the remote monitoring capabilities, new devices and devices replaced due to failure will be installed with these new control capabilities as standard. Details regarding the CVR/VVO program can be found in Section 12.6 – CVR/VVO.

8.16 System cable

DTEE's distribution and subtransmission system has over 3,200 miles of underground system cable. System cable 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 are much greater. System cable is especially useful to route multiple circuits through a small congested area (e.g., entrances and exits of a substation).

Exhibit 8.16.1 Underground System Cable Types

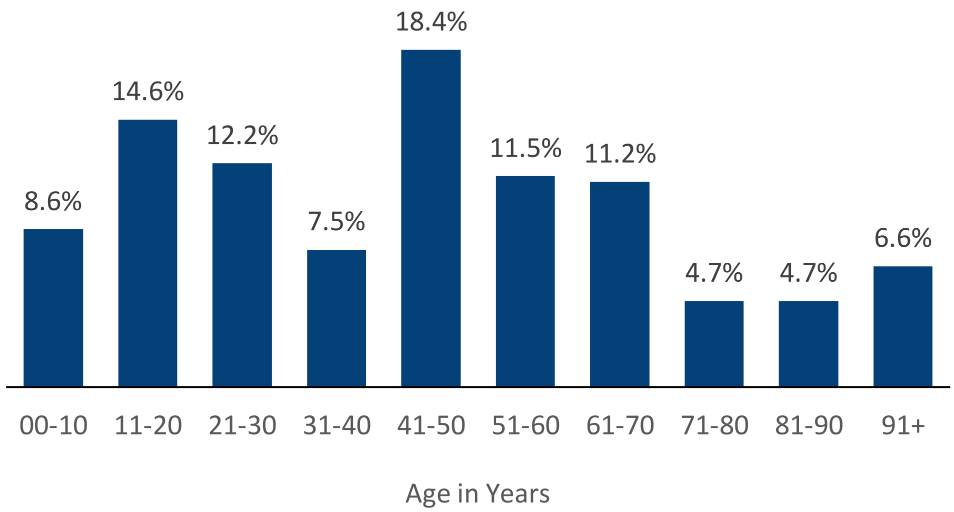
Exhibit 8.16.1 illustrates five of the six major types of underground system cable (BUYTL not pictured) installed in DTEE's distribution system. Exhibit 8.16.2 shows the types, quantities, average age, and life expectancy of system cable in the DTEE system. The average life expectancy of system cables is 40 years or less, although actual useful life varies depending on cable type and field conditions.

Exhibit 8.16.2 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	2,365	570	125	55	35	69	35
% of Total population	72.7%	17.5%	3.8%	1.7%	1.1%	2.1%	1.1%
Average age	50	16	59	54	20	36	52
Life Expectancy	40	35	40	40	40	25	20

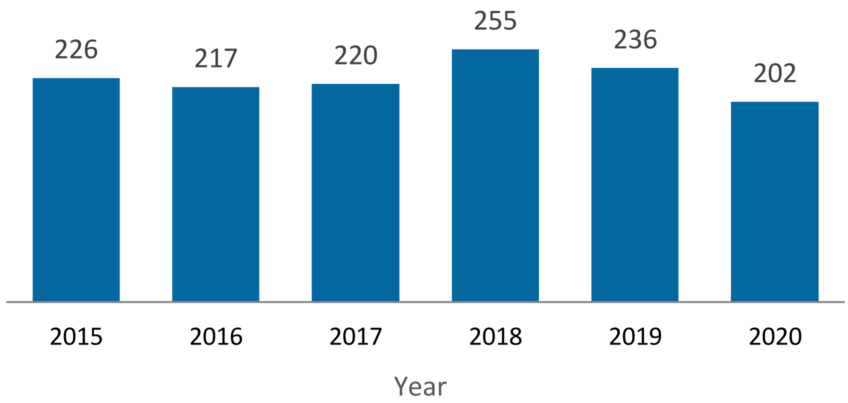
As shown in Exhibit 8.16.3, more than 57% of DTEE system cable is beyond its typical life expectancy.

Exhibit 8.16.3 Underground System Cable Age Distribution



System cable is a critical component for both the subtransmission and distribution systems. A cable failure reduces system redundancy and resiliency and can interrupt a large number of customers for an extended period of time. System cable failures over the past five years are shown in Exhibit 8.16.4.

Exhibit 8.16.4 System Cable Failures by Year



Based on the latest asset health assessment, 43% of system cable is a candidate for replacement. Replacement factors for system cable are detailed in Exhibit 8.16.5.

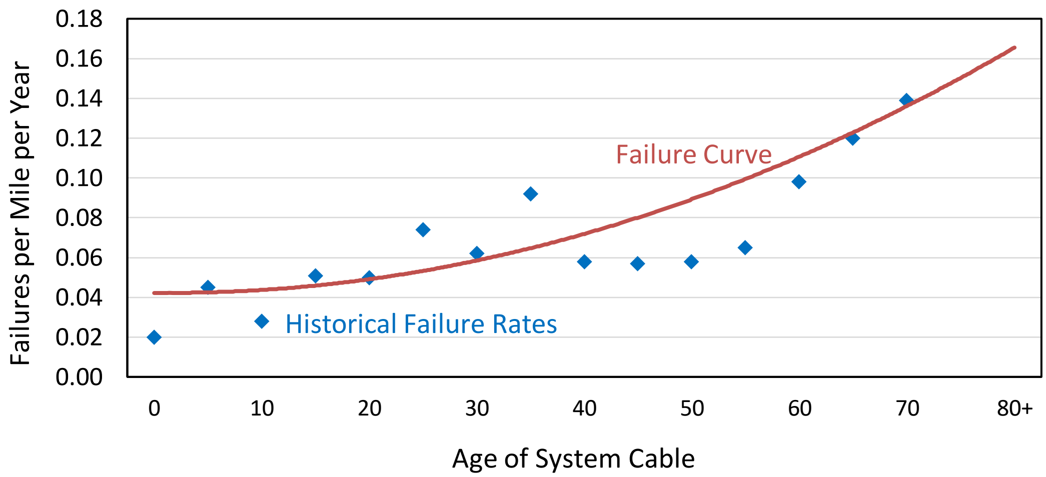
Exhibit 8.16.5 System Cable Replacement Factors

Factors	Impact
Insulation type	• Specific cable types have known issues that lead to failure: • XLPE (cross-linked polyethylene) cable manufactured before 1990 has a design defect that leads to premature insulation breakdown and dielectric failures (also called "Treeing"). The XLPE cable failure rate is approximately 0.06 failures per mile per year. • Gas (gas filled paper lead) cable has cavities within the insulating layer that are filled with gas (usually nitrogen gas) under pressure. This type of cable is prone to mechanical damage that leads to gas leaks and dielectric failures. Re-gassing this type of cable is very expensive. The Nitrogen Gas cable failure rate is approximately 0.15 failures per mile per year. • BUTYL (polyisobutylene) cable can be found mostly in the secondary networks. Under high temperatures, the cable releases gases which can cause arcing. • VCL (varnished cambric lead) cable is prone to failure under heavy loading and high temperature environment. The heavy loading or high temperature causes the insulation to degrade and lose its dielectric integrity. The VCL cable failure rate is approximately 0.08 failures per mile per year.

	• PILC > 60 years old is prone to failure due to age. As age increases, failure rates increase, as shown in Exhibit 8.16.6.
Cable loading	• Cables that are overloaded are prone to failure
Past failures	• Cables that have experienced failures in the past are prone to another failure

Exhibit 8.16.6 shows the system cable failure rates based on age.

Exhibit 8.16.6 System Cable Failure Rates



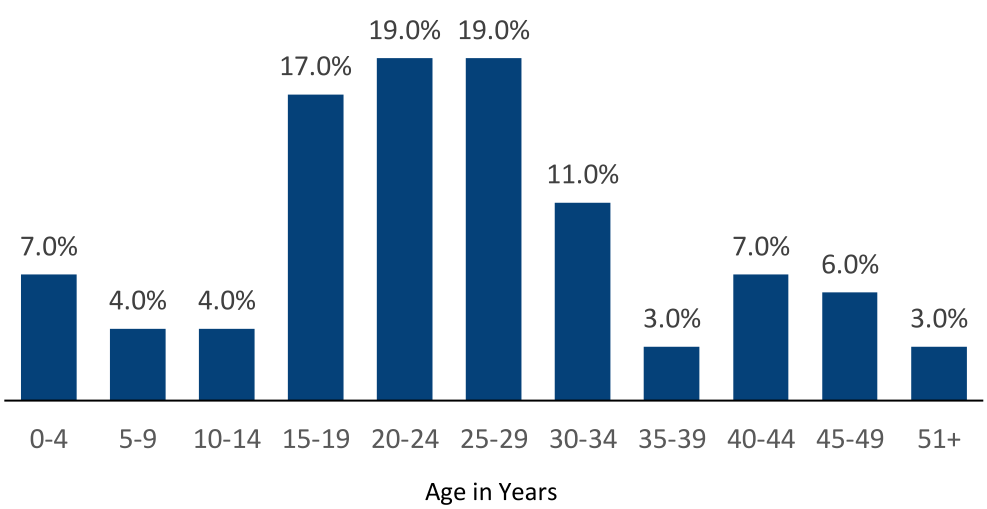
Partial discharge testing of system cable can find defects in the cable before they result in failure and allow for proactive replacement. Partial discharges are small electrical sparks in the air-filled voids or cavities in the cable insulation. Defects in the system cable grow during over voltage conditions until it bridges the entire insulation. Partial discharge testing will catch these defects before it becomes an issue. Starting in 2021, this testing will be done on all newly installed EPR system cables to find any workmanship or cable defects before they result in premature failure. Testing will also be done on all system cable or network circuits consisting mostly of EPR or XLPE that has failed to better understand the cause of failure. Partial discharge testing does not give as accurate of results on gas, VCL, BUYTL, or PILC.

As described in this section, much of the system cable on the DTEE system has exceeded its life expectancy (approximately 57%). In additions to age, specific types of cables have known issues that lead to failure. DTEE is increasing investments in cable replacement for two main reasons. First, replacing cable failures is more costly than doing planned cable replacements. To limit system risk during a cable failure, particularly a failure during the summer, additional measured must be taken to support loading, such as transferring load or deploying mobile generators. Many of these types of costs can be avoided if replacements are planned during non-peak times. Second, cables failures can interrupt a large number of customers for a lengthy period of time as well as reduce the level of redundancy on the system itself. In some cases, cable failures can damage adjacent equipment and lead to a larger outage, more costly repair, and additional system risk. More details about the proactive system cable program will be discussed in Section 9.1.6 – System Cable.

8.17 Underground residential distribution (URD) cable

DTEE has approximately 11,000 miles of underground residential distribution (URD) cable, with 89 % of the URD cable on the 13.2kV system. All subdivisions built since the early 1970s are served with URD cable. Buried underground, URD is not exposed to tree-related or other overhead related outages, however, it is more expensive to install and repair compared to overhead lines. Underground cable failures are less frequent but take a long time to repair or replace. DTEE is currently evaluating options to underground parts of circuits in order to improve the reliability for customers. More details on these projects can be found in Section 11.6 – Strategic Undergrounding. The average age of DTEE URD cable is 25 years. The age distribution is provided in Exhibit 8.17.1.

Exhibit 8.17.1 URD Cable Age Distribution



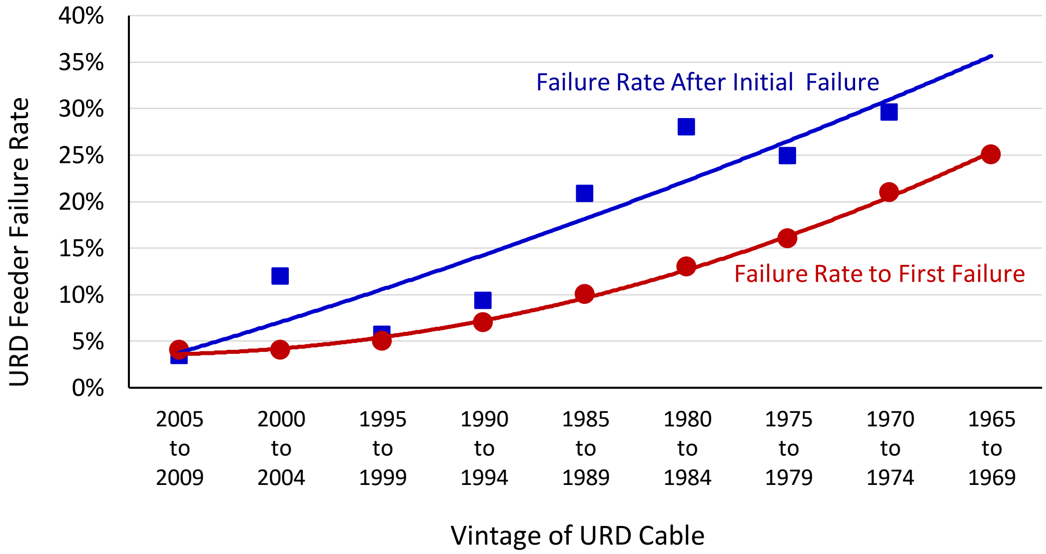
Based on the latest health assessment, 41% of URD is a candidate for replacement due to factors outlined in Exhibit 8.17.2.

Exhibit 8.17.2 URD Replacement Factors

Factors	Impact
Manufacturing year	Pre-1985, the insulation is XLPE (non-tree retardant) Post-1985, the insulation is TR-XLPE (tree retardant)
Number of outages	The rate of URD cable failures increases with the age of the cable; the rate further increases once a cable experiences its first failure as shown in Exhibit 8.17.3.

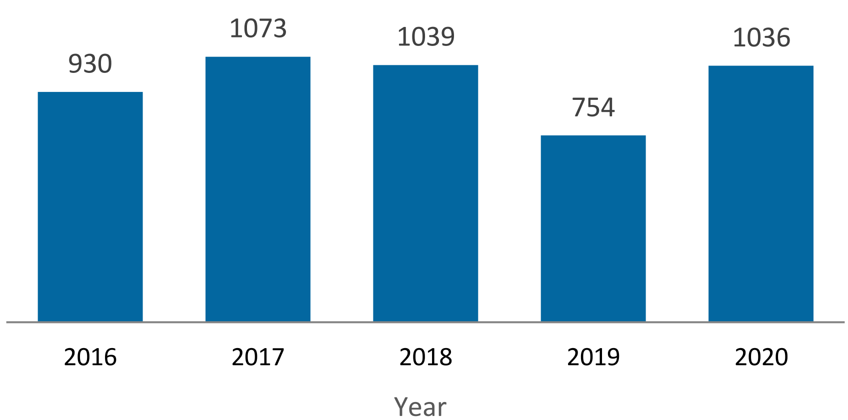
Year 1985 is a demarcation point in the manufacturing of URD cable. Pre-1985, the insulation is XLPE (non-tree retardant) and post-1985, the insulation is TR-XLPE (tree-retardant). In cable insulation, treeing refers to the tree-like pattern of insulation breakdown. The breakdown typically originates at an impurity or defect in the solid insulation and grows gradually over time to resemble the branches of a tree, ultimately leading to a cable failure.

Exhibit 8.17.3 URD Feeder Failure Rate (per mile)



As shown in Exhibit 8.17.4, for the five-year period from 2016 through 2019, there were on average nearly 1,000 URD feeder cable failures per year.

Exhibit 8.17.4 URD Cable Failures by Year



Not all URD failures lead to sustained outages; when a failure occurs on a URD in a looped configuration customers can still be fed by isolating the fault. Looped URD configurations with one failure are called open loops. When the failure is repaired the loop is returned to a normal operating configuration. Should a second failure occur prior to the open loop being repaired; customers will experience outages and lengthy restoration times due to the nature of the underground loop. As URDs continue to fail, DTEE has seen a build-up of open loops on the system, increasing the risk of sustained customer interruptions due to a second failure. As shown in Exhibit 8.17.3, URD cables that have experienced a failure in the past are observed to have accelerated failure rates in the future.

Based on the asset health analysis described in this section, DTEE is increasing investment in proactively replacing URD to manage reactive costs and to improve reliability for customers. As shown earlier in this section, approximately 41% of cable is a candidate for replacement due to cable age or previous failures. URD failures require a lot of front-line resources to restore customers. Proactively replacing URD will help make the replacement process more efficient and cost effective. For example, a crew may be able to replace an entire loop of URD on a planned project, whereas following a failure, the crew may only replace the section that failed. A more comprehensive URD replacement program will reduce annual failures and additionally prevent a build-up of open loops on the system, which will reduce costly reactive work and reduce the risk of a lengthy outage for customers. This proactive URD cable replacement program is discussed more in Section 9.1.7 – Underground Residential Distribution (URD) Cable.

8.18 Manholes

Underground system cables are pulled and spliced inside manholes. The cables are mounted on support arms on the manhole walls to maintain separation and allow safe entry into the manholes for work, as illustrated in Exhibit 8.18.1. Failures of any part of the manhole infrastructure have the potential to impact a large number of customers because multiple cables typically run through the same manhole, and a fault on one cable can damage adjacent cables. DTEE has approximately 18,000 manholes. Their age distribution is shown in Exhibit 8.18.2.

Exhibit 8.18.1 Manhole and Cables

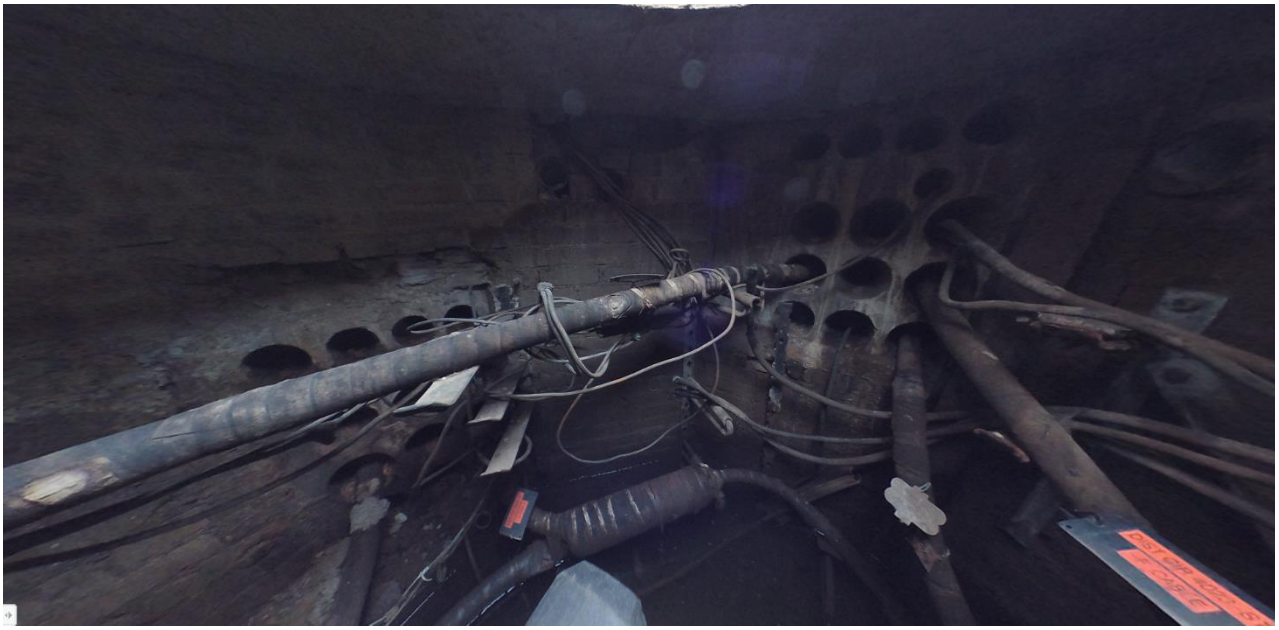
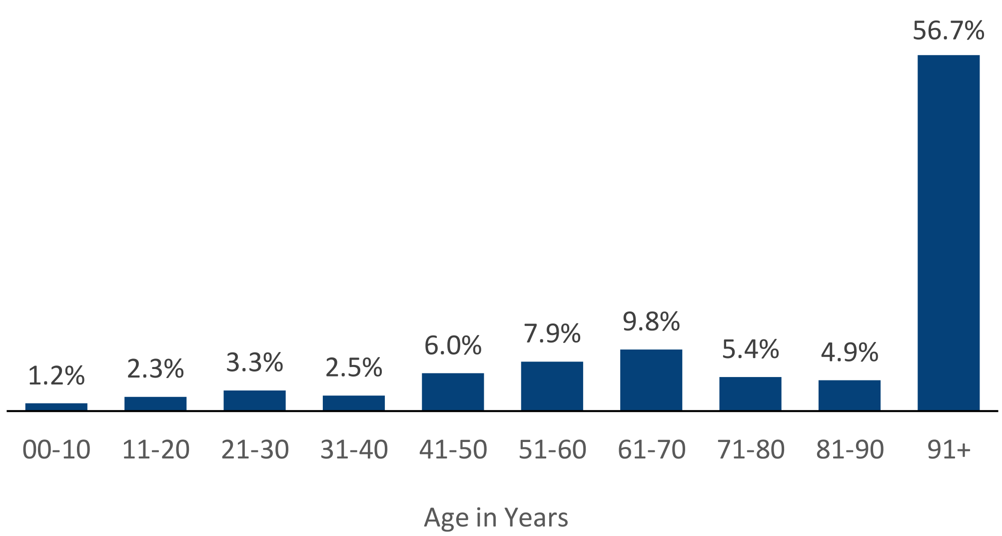


Exhibit 8.18.2 Manhole Age Distribution



Whenever a manhole is entered to perform cable work, it is inspected, and repairs are made as needed. In 2016, DTEE estimated that approximately 8,500 manholes have not been entered in over 20 years. As a preventative measure, DTEE started a manhole inspection program in 2016 for these 8,500 manholes. At the beginning of 2021, nearly 60% of the 8,500 have been inspected, with 3,605 remaining. DTEE plans to inspect the remaining manholes by 2026. Issues identified during manhole inspections include degradation of structural strength due to surface vibration, presence of ground water, etc. Any identified issues will be addressed either as part of the capital work or repair work.

8.19 Pontiac 8.3kV system vaults

DTEE has 33 vaults as part of the 8.3kV system in the city of Pontiac. DTEE acquired the Pontiac 8.3kV system from CMS Energy in the late 1980's. Theses vaults are typically located beneath city sidewalks with an overhead grating. Overhead style equipment (8.3kV) is used in the vaults. Much of the equipment used in the vaults is obsolete and spare parts are no longer available. Due to the confined space in the vaults, there is also a shock hazard to personnel entering the vaults. The minimum arc flash distance may not exist, making it difficult or impossible to operate within the vaults without causing customer interruptions during maintenance activities. This can add considerable restoration time to an outage event. Exhibit 8.19.1 provides an interior view of an underground vault.

Exhibit 8.19.1 Underground Vault and Equipment

To address the safety hazards and operating limitations associated with the vaults, DTEE has decommissioned nine vaults and replaced them as services directly to the customer between 2012 and 2020. Twelve switching vaults have also been replaced between 2019 and 2020, as shown in Exhibit 8.19.2 and 8.19.3. Switching vaults allow for isolation and replacement of cable or other failed equipment. In addition, 12 service vaults will be replaced with dual voltage (8.3kV and 13.2kV) submersible equipment over the next five years. The submersible equipment utilizes the latest technology. This not only provides safe, reliable operation of the equipment in the vaults, but also standardizes the vault equipment to reduce the cost of future repairs. The current live front equipment will be replaced with new dead front equipment reducing the risk of an arc flash. The operating and switching of this equipment can be done outside of the vault reducing the arc flash exposure to DTEE personnel. The dual voltage feature of the equipment will allow continued utilization of the equipment as the aging and islanded 8.3kV system is converted to 13.2kV. Additional details can be found in Section 11.5 – System Conversion and Consolidation.

Exhibit 8.19.2 Before Pictures of a Service Vault

Exhibit 8.19.3 After Picture of a Service Vault

8.20 Advanced metering infrastructure

DTEE replaced nearly all its electric meters with AMI (Advanced Metering Infrastructure) technology, also known as smart meters in 2010 – 2018. Based on set configurations, these meters are capable of measuring, recording, and uploading various parameters, as well as predefined events and event exceptions (i.e. alarms) that are transmitted upon occurrence. Ninety-nine percent of DTEE meters are solid-state meters with AMI capabilities and the remaining are either digital meters with no radios (0.3%) or digital AMR 2-way communication meters (0.2 %).

AMR 2-way communication meters require advanced registers for industrial customers and have their billing data collected wirelessly daily by a service provider.

To obtain data for digital meters with no radio, meter readers must walk up to the meter to record energy usage once per month. Disconnecting or connecting of a service must be done at the meter location. These types of meters serve customers using the DTEE Opt Out program.

AMI is considered fully deployed as of January 2018.

Exhibit 8.20.1 Electric Meter Types

Mechanical meter

AMI meter

The average age of the AMI meters is 6.5 years and expected life of the AMI meters is 20 years; however, meters may need to be replaced or upgraded earlier due to failures.

In order to ensure the health of our fleet of AMI meters, DTEE conducts a preventive maintenance program for meters includes meter testing as part of the MPSC mandated Sample Test Program, on-going meter replacement based on meter event conditions and refurbishment of equipment returned from field deployment. Routine review of meter conditions are also proactively administered and resultant actions taken (i.e. low battery, retired configurations). Meter communication functions are also independently reviewed and analyzed independent to ensure consistent operation. Similar to mechanical meters previously used, AMI meters are replaced if malfunctioning or failing during service.

The proactive programs mentioned above to maintain our AMI infrastructure is key to both current operations and future capabilities identified as part of the grid modernization process. AMI technology provides a number of current benefits to DTEE customers, such as:

1. Meter reading

AMI technology provides accurate daily and on-demand meter reads without the need for field visits or access to meters installed inside buildings. DTEE has seen a 90 % decrease in month-over-month estimated bills:

2018 per month average: 16,678

2019 per month average: 4,037

2020 per month average: 1,877

AMI provides customers with actual and accurate consumption data every month. Customers with multiple homes and or buildings can have all their sites combined in one bill with the readings on the same day. Starting and stopping billing services can also be done remotely with accurate meter reads.

2. Billing accuracy

AMI technology eliminates human errors in reading the meter and manual entry of the data. Customers also benefit in the elimination of estimated bills. Customers are billed on their actual usage, eliminating the need for estimated bills and related adjustments.

3. Outage restoration efficiency

a. Detection – Early outage notifications aid in damage assessment and initiation of service restoration operations.

b. Restoration efficiency – Timely initiation of restoration efforts coupled with an amplified ability to detect and assess nested trouble after restoration jobs are completed greatly reduces customer interruption durations. It also enables DTEE to assess the quality of restored electrical services to assure customers may return to their normal operations.

c. Daily storm and non-storm outage statistics – AMI data is currently used to create all daily outage statistics such as CAIDI, SAIFI, and SAIDI. This improves the accuracy of the outage data based on the outage experience at the customer site. The quantity and quality of the AMI data improves the overall storm modeling and restoration process.

- d. Enhanced automated storm job closures – AMI is used to automate single customer outages that are auto closed as electrical power is restored in an area. The auto close algorithms are currently implemented for daily and storm day outages and are preventing numerous “ok on arrival” truck rolls. This feature also shortens the follow-up visits required after an outage and allows the crews to have a higher percentage work time on confirmed outages.

4. **Power quality**

a. DTEE has started developing analytics that leverage the minimum, maximum, and average voltage monitoring data from AMI meters. Currently, this data has been used to drive distribution transformer replacements. Although DTEE has begun to leverage this data, there remain additional uses that are in development. In process is a more comprehensive approach to proactively perform more robust analysis and respond to customer voltage inquiries and complaints.

b. Hazard detection – The Company is continuing to build on results from pilot studies modeling AMI alarms and voltage data along with phase connectivity, circuit design and protective device status to indicate possible human hazard cases from potentially broken conductors.

5. **Safety risk reduction**

The remote meter read capability eliminates the potential risk of injury to meter readers due to slips, trips, falls, vehicle accidents, and dog bites. Remote technologies also greatly assisted DTEE in maintaining physical distancing during the COVID-19 pandemic response.

6. **Customer energy usage**

Customers who use the free DTE Insight app with their AMI meters can see exactly how much energy they are using, which can help them find ways to be more energy efficient.

7. **Turn on/turn off/restore**
8. Remote capability to connect or disconnect electrical service enables more responsiveness to customer requests for Account Services as well as eliminating costs arising from the field visits. Theft and Tampering Notification

The technology continuously monitors for meter tampering. DTEE elected to further expand theft detection in conjunction with AMI data and launched a project in Spring 2020. The

Company is refreshing its theft analytics to also include usage patterns in addition to AMI tamper alarms which we anticipate will enable AMI data to better inform us when theft is occurring.

9. **Meter testing**

Annual meter testing takes place per MPSC Technical Standards rule 613 under DTEE's Sample Test program. Routine meter functional testing is also conducted as part of our Meter Refurbishment program. Per MPSC requirements, AMI meters must have an accuracy of 1 %.

Grid Security and Reliability Standards Workgroup – Technical Standards for Electric Service Rules U-20630 metering subgroup proposes two major changes that will impact DTEE. The first one is changing the meter accuracy requirement from 1 % to 0.8 % and the second one is a three-tier sample test plan, which based on current high accuracy meters would reduce the yearly volume of tested meters in half. A SAP IS-U enhancement is required to implement the new Sample Test program, along with new BOR reports.

Telecommunication providers (Verizon and AT&T) will retire 3G technology in the beginning of 2022. DTEE will replace approximately 6,000 large commercial and industrial customer 3G meters and 3,600 cellular 3G Cell Relays, serving 2.6 million commercial and residential customer meters. The Cell Relays serve as a communication "aggregator" or "gateway" for AMI meters. The Cell Relays communicate with DTEE data centers via either cellular telecommunications or Ethernet. Without the replacements, the meters serving 6,000 large commercial and industrial customers and 2.6 million commercial and residential customers would no longer be remotely accessible for billing, outage detection, voltage data or remote connect / disconnect capabilities, severely impacting customer service. This meter replacement project is summarized in Exhibit 8.20.2 with costs detailed in Exhibit 8.20.3. DTEE will also continue to expand capabilities to use data from AMI meters to enhance forecasting and provide additional information about grid operations. Investments in data analytics using AMI data are discussed in more depth in Section 12.9 – Technology Roadmap.

Exhibit 8.20.2 AMI Upgrade Projects Summary

Project	Scope of Work	Drivers
AMI 3G Cellular cell relay upgrade	Replace 3,600 3G Cell Relays with 4G devices due to obsolescence of 3G telecommunication	Telecommunication providers plan to phase out 3G in Michigan in 2022
AMI 3G Cellular large commercial and industrial meters upgrade	Replace 6,000 3G cellular meters serving large commercial and industrial customers with 4G devices Among the 6,000 sites, approximately 1,000 of the 6,000 will be replaced with advanced power quality meters	Telecommunication providers plan to phase out 3G in Michigan in 2022 SCADA and more advanced power quality data needed at selected sites, given the size of their load or the percentage of load of circuits they are on

Exhibit 8.20.3 Projected Costs and Timeline for AMI Upgrade Projects

Project	2021	2022	2023	2024	2025	2021-2025 Total
AMI 3G to 4G Upgrade	$1.3 M					$1.3M

9 Infrastructure resilience and hardening

As described in Section 6 – DGP Investment Summary, Infrastructure Resilience and Hardening is one of the four pillars in DTEE's strategic investment framework. One of the fundamental grid needs identified through the grid modernization process discussed in Section 3 is addressing the aging physical infrastructure of DTEE's system, which will be required to maintain reliable and affordable electric service. Investments in this pillar not only meet the current grid needs, they will also address the CAT storm scenario that projects a higher frequency and intensity of severe weather.

In working through the grid impacts of the three scenarios, DTEE identified that the existing grid infrastructure will need foundational investment in the near-term to support safety and reliability, even as some parts of the grid will start to see the enhancements including substation and circuit conversions and advanced sensing and control technologies that are needed to account for projected electrification and distributed resource adoption by customers over the coming decades. In the next phases of distribution planning, the near-term resilience and hardening strategy programs will be optimized along with the longer-term programs that support the 10-15 year grid vision. The no regrets investments that harden the grid and support the oldest infrastructure replacements will support reliability and resiliency until future investments are implemented that will allow for longer term capacity and other advanced grid needs. These investments also result in a reduction in emergent costs.

The 4.8kV Hardening and Pole Top Maintenance and Modernization (PTMM) programs replace current overhead equipment with equipment designed to our latest standard, which provides additional strength and resistance to failures. In addition, our Automatic Pole Top Switch and SCADA Pole Top Device programs (Sections 9.1.2 and 9.1.8) will help ensure we maintain the capability to isolate faults and minimize customer interruptions.

Projects and programs in this pillar include replacement of aging infrastructure, primarily due to asset health assessments or inspections, and upgrades to circuits in areas of poor reliability. The investments in this pillar will provide a reduction in reactive costs, as the 4.8kV Hardening and PTMM programs are two of the three highest ranked programs for emergent cost reduction (Tree Trimming, as described in Section 10, is also among the top programs for reducing emergent costs). The projects and programs are targeted specifically at equipment with known issues or in areas with known poor reliability and will help drive performance to second quartile within the next five years. Compared to the projects described in Infrastructure Redesign and Modernization, Infrastructure Resilience and Hardening programs can reach more customers in a shorter amount of time. For example, DTEE's goal for PTMM is to address pole top equipment on a five-year cycle, whereas rebuilding the 4.8kV system will likely take 15 years or longer. In addition, the Capital Replacement programs described in Section 9.1 will make the system more resilient and reduce the amount of risk by reducing the volume of failures of System Cable, URD, and breakers experienced by the system currently.

9.1 Capital replacement programs

Capital replacement programs for eight asset classes are summarized in Exhibit 9.1.1. The Pole and Pole Top Equipment program addresses equipment that is found defective as part of an inspection process. The remaining replacement programs were developed as a result of the Asset Health Assessments described in Section 8 – Asset Health Assessment.

Exhibit 9.1.1 Capital Replacement Program Summary

Section	Asset	2021-2025 investment ($M)	2021-2025 number of units
9.1.1	Pole and Pole Top Equipment	$430 M	Varies
9.1.2	Automatic Pole Top Switch	$26 M	70 units
9.1.3	Subtransmission Disconnect Switch	$12 M	194 units
9.1.4	Circuit Switcher	$5 M	30 units
9.1.5	Breaker	$84 M	267 units
9.1.6	System Cable	$243 M	98 miles
9.1.7	URD (Underground Residential Distribution) Cable	$60 M	270 miles
9.1.8	SCADA Pole Top Devices	$9 M	95 Units
9.1.9	Substation Regulators	$2 M	20 units

9.1.1 Pole and pole top maintenance and modernization

Poles and pole top hardware are one of the fundamental, most visible parts of the distribution system. Poles and their associated equipment are exposed to harsh conditions (e.g., ice, heat, sunlight and wind), causing them to degrade and weaken over time.

Long and costly customer outages result when this equipment fails unexpectedly. This program proactively identifies and replaces damaged or defective equipment before unexpected failures occur. The PTMM (Pole and Pole Top Maintenance and Modernization) program is designed to catch these issues prior to failures. This program was called the Pole Top Maintenance (PTM) program in the past, but with an enhanced specification that replaces old and outdated components with components of an enhanced specification, the term “Modernization” was added to the title. The enhanced specifications include higher grades of materials and updated more reliable design for individual components.

Annually, patrols are performed on a portion of the system to test and inspect poles and pole top hardware. DTEE strives to inspect poles on a 10- to 12-year cycle, as specified by the MPSC; however, in 2020 the 10- to 12-year cycle was not met. In 2020, DTEE’s planned onboarding of an additional contractor to perform inspections was delayed due to COVID and contract negotiations. This contributed to the low number of poles inspected through the pole top maintenance program. DTEE is prioritizing this work and expects to get back on cycle in 2021. Results from these patrols have typically shown that approximately 8% of the total poles inspected have reduced strength and need to be remediated. These poles are either replaced or reinforced based on the remaining strength of the pole and shell thickness. During the patrols, pole top hardware is also inspected, and those that are broken or have failed are also addressed. Examples of replaced hardware include: cracked or broken insulators which can lead to pole fires, broken guy wires which can lead to excessive leaning and potentially to broken poles, and obsolete equipment that is prone to failures, such as cutouts and arrestors with known defects. The full list of hardware that is inspected for potential defects is detailed in Section 8.8 – Poles and Pole Top Hardware.

When DTEE replaces these items, it uses equipment that complies with its latest upgraded standards. For example, the minimum pole class for distribution poles with primary voltage wire (4.8kV and 13.2kV) is higher than previous standards (meaning that the pole strength is increased). Also, DTEE is now replacing wood crossarms with stronger fiberglass crossarms, porcelain cutouts with more resilient polymer cutouts, and porcelain insulators with more resilient polymer clamp-top insulators. Fiberglass crossarms have five times the mechanical strength of their wood counterparts, and polymer equipment has six times the mechanical strength of its porcelain counterparts.

DTEE has reviewed and enhanced its pole inspection specification and plans to increase its investments in the pole and pole top hardware program as a key lever to address overhead system related emergent failures. In addition to reliability and resiliency, there are two other main drivers for the increased investment plans in this area: benchmarking and the learnings from other key programs.

DTEE has benchmarked pole and pole top inspection practices with two utilities in the Midwest and two utilities in the Northeast. All four utilities inspected pole top equipment on a five or four-year cycle. Two utilities inspected poles on a 10-year cycle while the other two inspected poles on a five-year cycle. DTEE meets its 10- to 12-year pole inspection standards based on a mix of a dedicated PTMM program, the 4.8kV hardening program, and pole inspections that occur as a part of other processes.

Only the dedicated PTMM inspections and hardening program also address pole top equipment, so while the pole inspection is following a 10- to 12-year cycle, pole tops are currently inspected less frequently than the five-year cycle that is industry best practice. DTEE is reviewing the PTMM program and cycle times; and by 2025 investments will achieve a 10-year cycle on poles and PTMM. The ultimate vision for the PTMM program is to achieve a five-year cycle to be in line with industry best practices.

One of the improved specifications is for the pole itself in the inspection process, which is a part of the dedicated PTMM program. The age threshold for pole testing, as opposed to visual inspection alone, was modified from greater than 40 years old to 20 years and older, ensuring that the first signs of pole decay in older poles are identified and addressed. Also, the enhanced specification requires visible decay to be removed and the pole treated to prevent the spread of the decay on poles that are reinforceable. The enhanced specification allows for pole reinforcements in lieu of pole replacements whenever feasible, as pole reinforcement is widely adopted by the utility industry as a cost-effective measure to lengthen pole life. The enhanced pole inspection specification and process are aligned with industry best practices and expected to reduce the risk of pole failures, improve customer reliability and reduce reactive costs during trouble and storm events.

A second driver for an increased investment is the learnings from programs including the Customer Excellence (CE) and 4.8kV Hardening programs. As described in Section 9.4 – Frequent Outage below, the CE program has been successful in quickly addressing issues for customers experiencing poor reliability.

However, the issues that are commonly found during the evaluation process in CE would also commonly be remediated through a pole top maintenance program, if the program was on a shorter cycle. Common issues found through the CE program are broken cross arms, cracked insulators and other visibly defective pole top equipment. While the 4.8kV Hardening program has broader scope than PTMM (including arc wire removal and the removal of infrastructure associated with abandoned properties), much of the other scope around pole and pole top hardware is similar.

As a result of the planned improvements to the PTMM program, DTEE expects to see a significant reliability improvement. As proven in an examination of the reliability data and cause codes described in Section 7.2.3 – Causes of Interruptions, equipment-related issues are the second leading cause for SAIDI, SAIFI, and outage events, trailing only tree-related outages. In fact, equipment related outages account for almost 25% of all events.

As shown in Exhibit 9.1.1.1 below, DTEE plans to invest $430 million over the next five years in the Pole and Pole Top Maintenance and Modernization Program. The PTMM program ramp up will begin by increasing the volume of patrols in 2021. These patrols identify the specific pole top equipment and pole remediations needed and help gather information to plan and schedule the execution of the work in the field. In 2021, the increased volume and budget towards patrolling will support ramped up field construction in 2022. As the patrol cost per mile is less than the cost of construction, 2021 has a significantly lower cost per mile than future years. Due to aging infrastructure and the need to provide annual maintenance, this program will continue beyond five years.

Exhibit 9.1.1.1 Pole and Pole Top Program Future investment

	2021	2022	2023	2024	2025	2021-2025 Total
Investment Projection	$35 M	$61 M	$88 M	$121 M	$125 M	$430 M
Miles Inspected on PTMM	1,089	1326	1940	2,739	2,739	9,876
Miles Inspected on 4.8kV Hardening	195	375	340	352	334	1,596
Inspection Cycle	24	18	14	10	10	

9.1.2 Automatic pole top switch

As discussed in Section 8.13 – 40kV Automatic Pole Top Switches (40kV APTS), the entire 40kV APTS population, except for the SEECO switches, are considered for replacement to address high failure rates and unavailable spare parts for the early vintages based on the findings from the asset health assessment. There are 135 APTSs that remain to be replaced. The entire at-risk APTS population will be replaced by end of year 2029.

Replacing an APTS requires shutting down 40kV subtransmission and these shutdowns can typically only be performed from January through May or October through December to avoid peak loading of the system. And, depending on system constraints for a specific subtransmission line, such as weather or adjacent work at substations fed by the subtransmission line needing the shutdown, the shutdown may require extensive work and planning to complete.

In addition to the APTS replacements, shutdowns are also needed to perform routine maintenance and inspections. This can often require the need to deploy portable substations or generators to serve load during the shutdowns, which can limit the window for taking a shutdown, increase O&M costs, or delay maintenance. To avoid this, it is practical in some locations to build an overhead line extension to serve as a bypass for when maintenance or inspection work is done, or to perform repairs or replace equipment. The bypass eliminates the need to de-energize the entire line, so portable substation or generator deployments are not needed to continue serving the load. This results in lower O&M costs, scheduling flexibility, and efficiently performing replacements, maintenance, and inspections as required.

As shown in Exhibit 9.1.2.1, DTEE plans to invest $21.2 million over the next five years in replacing automatic pole top switches and $5 million to construct overhead bypasses.

Exhibit 9.1.2.1 APTS Replacement Investment

	2021	2022	2023	2024	2025	2021-2025
Investment projection – APTS replacement	$2 M	$4.8 M	$4.8 M	$4.8 M	$4.8M	$21.2
Quantity (units)	6	16	16	16	16	70
Investment projection - APTS overhead bypass	-	$0.5 M	$1.5 M	$1.5 M	$1.5 M	$5 M

9.1.3 Subtransmission disconnect switch

As discussed in Section 8.4 – Subtransmission Disconnect Switches, 216 subtransmission disconnect switches remain to be replaced, as shown in the asset health assessment. Total cap & pin style subtransmission disconnects on the system totaled 424 in 2011 and there are 132 remaining. There are also 58 PM-40 and 22 Westinghouse Type R disconnects still left on the system to be replaced.

Replacing disconnect switches requires shutdowns the same as with the APTS. The shutdown allows crews to safely replace the disconnect switches. These shutdowns typically occur during specific months of the year and are limited by specific system constraints on the subtransmission line, weather and adjacent work at substations.

As shown in Exhibit 9.1.3.1, DTEE plans to invest $12 million over the next five years to replace subtransmission disconnect switches. The program will continue past 2025 as additional issues with switches are identified during the annual health assessments.

Exhibit 9.1.3.1 Subtransmission Disconnect Switch Replacement Program Investment

	2021	2022	2023	2024	2025	Total iInvestment 2021-2025
Investment Projection ($ millions)	$2.0	$2.5	$2.5	$2.5	$2.5	$12
Quantity (units)	35	42	40	39	38	194

9.1.4 Circuit switcher

As discussed in Section 8.5 – Circuit switchers, 80 circuit switchers remain to be replaced as shown in the asset health assessment. The equipment identified for replacement is prioritized based on risk of failure and inadequate equipment sizing.

As shown in Exhibit 9.1.4.1, DTEE plans to invest $5 million over the next five years to replace circuit switchers. This program will continue beyond 2025 to complete the replacement of the switchers identified through the asset health assessments.

Exhibit 9.1.4.1 Switcher Replacement Program Investment

	2021	2022	2023	2024	2025	Total investment 2021-2025
Investment projection ($ millions)	$1.0	$1.0	$1.0	$1.0	$1.0	$5
Quantity (units)	6	6	6	6	6	30

9.1.5 Breakers

As discussed in Section 8.3 – Circuit breakers, 58% of breakers are candidates for replacement based on the findings in the asset health assessment. Due to the large at-risk breaker population and because these assets will continue to age, the replacement program will be continuous.

Exhibit 9.1.5.1 lists the types and quantities of the breaker replacements planned for the next five years. Subtransmission H breakers, subtransmission outdoor breakers and substation PR reclosers are prioritized for near-term replacements as allowed by field execution.

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.

Exhibit 9.1.5.1 Breaker Replacements by Type 5-year Plan

Breaker type	Target quantity
Subtransmission H breaker	30
Subtransmission outdoor breakers	97
Substation recloser	24
Distribution breaker (oil and $1^{st}/2^{nd}$ generation air magnetic)	116
Total number of breakers	267

As shown in Exhibit 9.1.5.2 below, DTEE plans to invest $84 million over the next five years on the Breaker Replacement program. Due to the number of breakers considered candidates for replacement, the program will continue beyond 2025.

Exhibit 9.1.5.2 Breaker Replacement Program Investment

	2021	2022	2023	2024	2025	Total investment 2021-2025
Investment projection ($ millions)	$11	$15	$18	$20	$20	$84
Quantity (units)	54	55	54	53	51	267

9.1.6 System cable

As discussed in Section 8.16 – System cable, 43% of system cable, or approximately 1,300 miles, is a candidate for replacement based on the findings in the asset health assessment. Due to the large at-risk system cable population, and because these assets will continue to age, the replacement program will be continuous.

System cable is a critical component of the subtransmission and distribution systems. While underground cable provides a higher resiliency to storms than overhead lines, a failure can interrupt a large number of customers for an extended period of time. In-service failures are also more difficult to locate and repair than on overhead circuits.

Overall, the cost and time to install, replace and repair system cable issues are much greater. Cable failures can also cause failures in adjacent cables or other equipment, such as switchgear, which can then impact an even larger number of customers for a longer period of time. XLPE (cross-linked polyethylene) cable manufactured before 1990 has a design defect that leads to premature insulation breakdown and dielectric failures (also called “treeing”) and has contributed to switchgear failures. Gas cable (cable that has cavities within the insulating layer that are filled with nitrogen gas under pressure) is an obsolete design that is prone to mechanical damage that leads to leaks and dielectric failures and costly repairs.

DTEE is increasingly concerned about the level of failure risk posed by the age and condition of system cable. This concern is further escalated by the impact a system cable failure has on the overall system, because when a cable fails, it reduces the level of redundancy in the system itself. An acceleration in cable failures with simultaneous failures of multiple cables across the system could lead to very lengthy outages. In addition, planned replacements, compared to unplanned replacements, are more cost effective and reduce system risk.

In response to the need to increase investment in system cable replacements, DTEE created a dedicated team focused on underground work. This group has been building execution capacity and updating work processes to prepare for the needed levels of cable replacement. DTEE has developed partnerships with engineering, design, project management, and construction firms that have successfully helped other utilities build their cable replacement programs to significant levels.

DTEE has also conducted benchmarking with other utilities that have been involved in significant cable replacement efforts to learn best practices. An electric utility that is similar to DTEE averaged over 130 miles of system cable replacement per year between 2013 and 2017 and peaked at nearly 190 miles in a single year, demonstrating it is feasible to ramp up an efficient cable replacement program to address the risk on the system in an efficient manner.

As shown in Exhibit 9.1.6.1, DTEE plans to ramp up and invest $243 million over the next five years in the Cable Replacement Program. While this represents a significant increase in cable replacement, it still does not fully address all at-risk cable on the system. Therefore, DTEE expects this program to continue to grow beyond 2025 to reduce the likelihood that customers experience lengthy outages, improve reliability, protect substation equipment from damage and reduce reactive costs.

Exhibit 9.1.6.1 System Cable Replacement Program Investment

	2021	2022	2023	2024	2025	Total Investment 2021-2025
Investment Projection ($ millions)	$13	$35	$55	$65	$75	$243 M
Quantity (miles)	7	13	21	27	31	98

9.1.7 Underground residential distribution (URD) cable

Although underground cables are not subject to the storm impacts of trees and wind, they do have identified expected life and failure modes. As discussed in Section 8.17 – Underground residential distribution (URD) cable, 41% of URD cables (about 4,500 miles) are candidates for replacement based on findings in the asset health assessment. Currently, the system averages over 1,000 URD failures per year, which can create a build-up of open loops, and create the potential for extended outages if a concurrent failure were to occur. As planned replacements are more cost effective than unplanned replacements, and to help manage the build-up of open loops, DTEE is ramping up efforts to replace at risk URD cable. Even at the planned investment level by 2025, it still does not address all of the cable that is considered a candidate for replacement. Due to the large at-risk URD cable population and because these assets will continue to age, DTEE intends to continue to expand investment in the program.

As shown in Exhibit 9.1.7.1, DTEE plans to invest $60 million over the next five years in the URD Cable Replacement Program.

Exhibit 9.1.7.1 URD Cable Replacement Investment

	2021	2022	2023	2024	2025	Total investment 2021-2025
Investment projection ($ millions)	$4	$6	$10	$15	$25	$60
Quantity (miles)	24	28	45	66	107	270

9.1.8 SCADA pole top devices

The SCADA Pole Top Device Replacement program addresses the equipment that was discussed in Sections 8.11 - Three-phase reclosers and 8.12 – 4.8kV & 13.2kV SCADA Distribution pole top switches. This program targets two of the types of equipment that have experienced high rates of failure – the Form three reclosers and the Bridges pole top switches. There are 140 of these units on the system, and the program targets replacing 90 of these devices in the next five years.

In addition, the Circuit Automation program described in Section 12.5 – Distribution automation, will replace or upgrade reclosers as part of deploying increased sectionalize and control on the distribution system, a key component of grid modernization.

As shown in Exhibit 9.1.8.1, DTEE plans to invest $9.4 million over the next five years in the SCADA Pole Top Device Replacement program.

Exhibit 9.1.8.1 SCADA Pole Top Device Replacement Investment

	2021	2022	2023	2024	2025	Total investment 2021-2025
Investment projection ($ millions)	$0.9	$1.4	$1.9	$2.4	$2.8	$9.4
Quantity (units)	5	15	20	25	30	95

9.1.9 Substation regulators

DTEE uses substation regulators to regulate voltage at substations where the transformers are non-LTC (load tap changing).

The Substation Regulator Replacement program targets proactive replacement of regulator styles identified as being obsolete and technology that is no longer manufactured or supported. This includes induction, tri-delta, and tri-wye type regulators.

An increasing number of issues are occurring with these types of units with repair time continuing to increase due to a need to dry out the insulation in the units and repair or replace voltage controls.

DTEE plans to systematically replace obsolete units with modern step voltage regulators. This replacement will allow for proper voltage regulation at those substations and avoid out of range voltage damaging customer equipment or causing reliability problems.

As shown in Exhibit 9.1.9.1, DTEE plans to invest $1.7 million over the next 5 years in the Substation Regulator Replacement program.

Exhibit 9.1.9.1 Substation Regulator Replacement Investment

	2021	2022	2023	2024	2025	Total investment 2021-2025
Investment projection ($ millions)	-	$0.4	$0.4	$0.4	$0.4	$1.7
Quantity (units)	-	5	5	5	5	20

9.2 Substation risk

The concept of substation risk is tied closely to resiliency, which was defined in Section 7.3 as the ability to withstand and recover quickly from an event that significantly impacts the grid. DTEE's framework on substation risk considers the likelihood and impact of the complete loss of a substation, which is an event that can impact a significant number of customers (thousands) for an extended duration (a couple of days). A resilient system would have the flexibility to recover quickly from any type of failure or event that could potentially lead to a full substation outage.

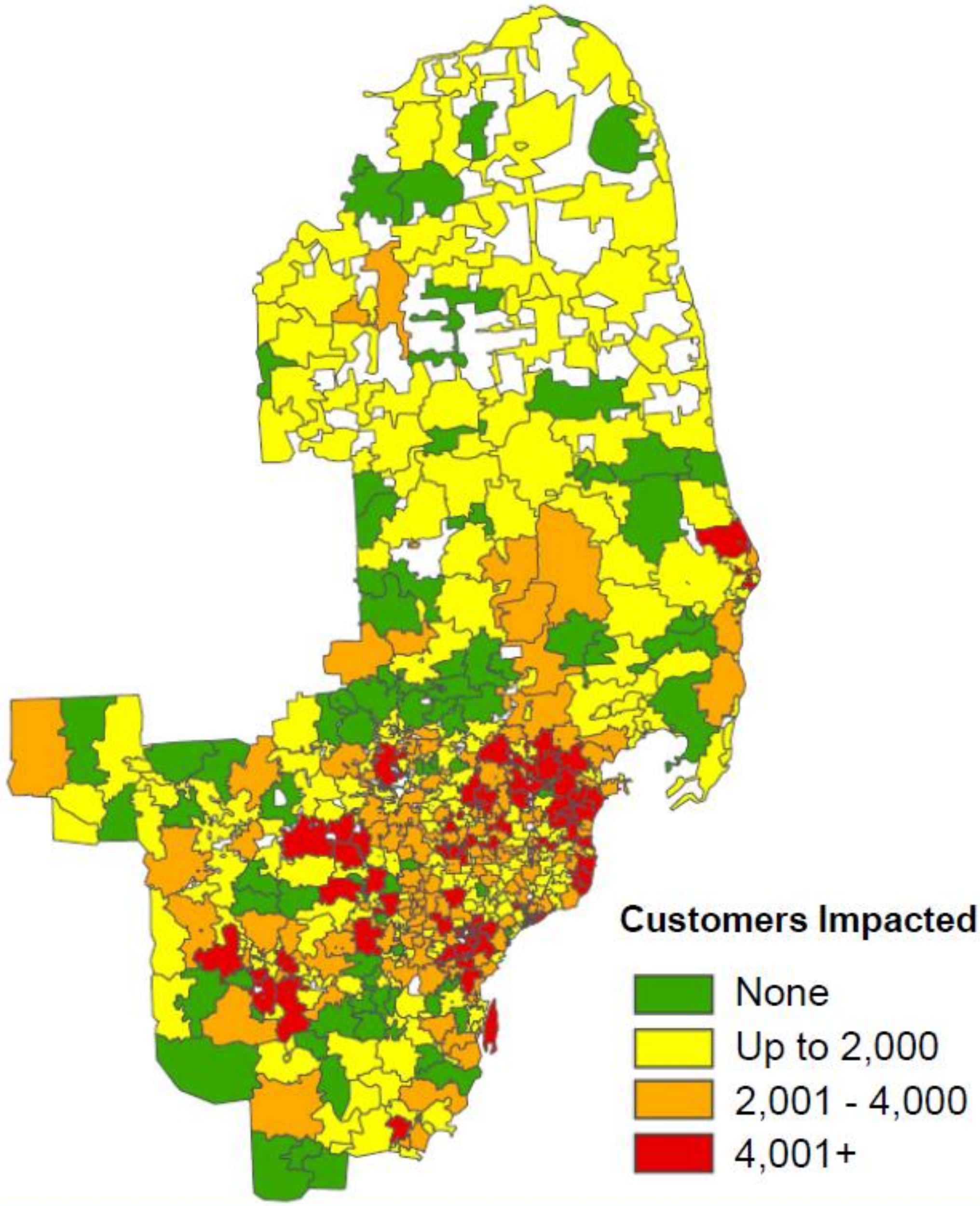
This section describes the overall substation risk framework and components, potential impact of future scenarios on substation risk, and the investments DTEE will make to manage risk and ensure the system can recover quickly from major events.

9.2.1 Substation outage risk model

To help DTEE identify and mitigate the risk of additional substation events, a substation outage risk model was developed. The model quantifies the relative substation outage risk scores and is used to help prioritize the capital investment to reduce this risk. Reduction in substation risk is one of the seven components quantified in the GPM methodology described in Section 5. The model calculates an outage risk score for each substation based on two factors: 1) impact, as measured by the stranded load at peak, and 2) risk, as measured by the asset conditions.

1) Substation stranded load at peak is the amount of load that cannot be restored by transferring load to adjacent circuits in the event of a substation outage during peak hours. There are multiple reasons why in a particular situation load cannot be transferred to adjacent circuits. First, in some cases the adjacent circuits operate at a different voltage, and therefore cannot be directly connected, which is called jumpering. While equipment in our portable fleet can allow for connections between different voltages, it adds complexity to the process. Second, the adjacent circuits and substations may not have capacity to take on additional load. As will be discussed more thoroughly in Section 11 – Infrastructure redesign and modernization, many of our substations and our subtransmission lines are over capacity now and would not be able to accept a load transfer if an adjacent substation had an outage. Exhibit 9.2.2.1 shows a stranded load map with red indicating substations that could result in 4,000 or more customers without power for more than eight hours (i.e., minimum time required to install mobile fleet to restore power) in a substation outage event during summer peak.

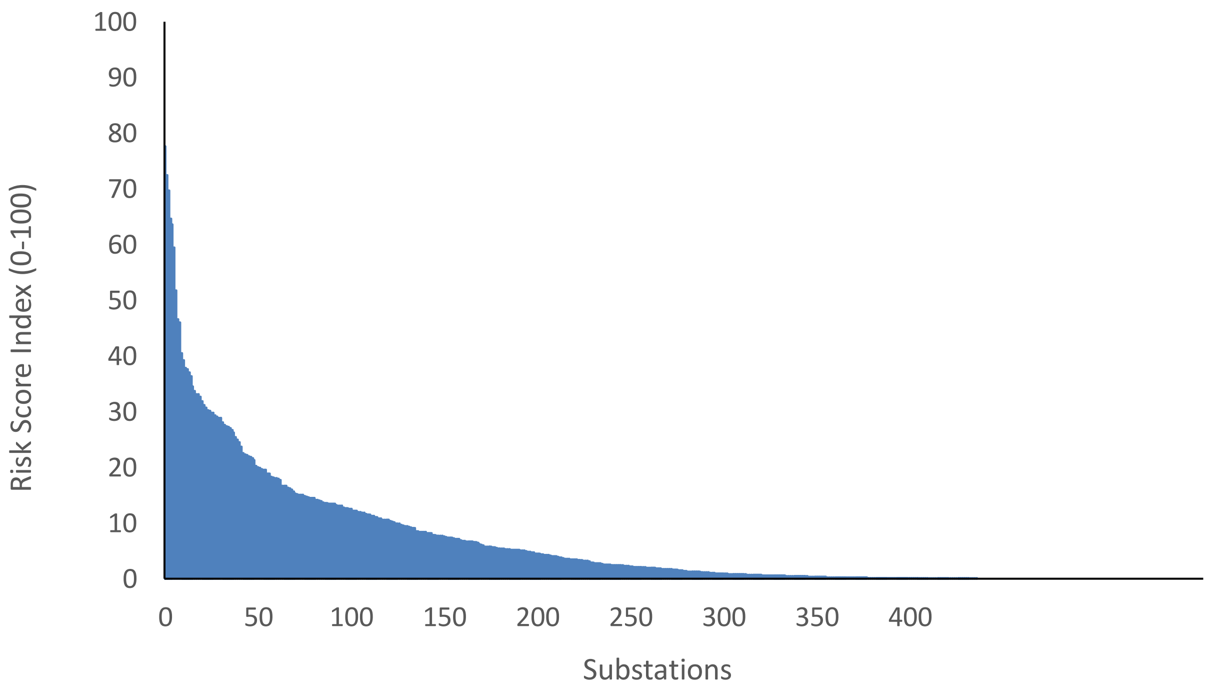
Exhibit 9.2.1.1 Potential Stranded Load Map During Complete Loss of a Substation



2) Substation asset condition risk represents the combined risk of four critical asset classes: system cable, transformers, breakers and switchgear. The condition of assets that feed substations, specifically subtransmission cable and subtransmission breakers, are also included when in the risk score. The basis for determining asset condition risk are the asset condition assessments (see Section 8 – Asset Health Assessments) with system considerations such as load impacted by the asset and the number of contingencies before the entire substation loses power also incorporated into the overall score.

Combining stranded load impact risk and asset condition risk, the risk profile of distribution substations is generated, as shown in Exhibit 9.2.2.2. Substation outage risk scores are indexed between 0 and 100, with 100 representing the score that Malta substation received when the model was first developed in 2018. The risk at Malta has been reduced through a switchgear replacement project, which was completed in 2019. The highest risk substation is currently Garfield with a score of 78. Load transfers at Garfield are currently taking place as part of the CODI project, which will improve Garfield's risk profile by reducing stranded load.

Exhibit 9.2.1.2 Substation Risk Score Distribution



The top five substations, listed in descending order by risk ranking, are shown in Exhibit 9.2.1.3 below, along with the project or program in the plan to address risk.

Exhibit 9.2.1.3 Top 5 Substations by Risk Ranking

Substation	Investment to address
Garfield	Garfield, Amsterdam and Madison are located within the city of Detroit (CODI) footprint, and will be addressed as part of the long-term CODI plan discussed in Section 11.4
Amsterdam	
Madison	
Chestnut	Chestnut switchgear replacement (Section 9.2.3)
Warren	Warren Station upgrade (Section 9.2.3)

9.2.2 Recent examples of substation events and future risks

Complete loss of a substation is a relatively rare event. While DTEE experienced approximately three major events per year from 2014-2018, there have been fewer events since then. Generally, due to the redundancy built into the system, multiple failures would be needed to cause the complete loss of a substation.

Despite the reduced frequency of total substation outages in recent years, the substation risk framework is still a useful tool to highlight examples of risk on the system and the programs and projects needed to reduce the risk of extended outages for our customers. Two examples of major events that occurred in the months before the filing of the DGP highlight the ongoing risk and costs of operating aging assets on a system with limited capacity.

Erin-Savoy-Baker

Savoy and Baker are two substations in St. Clair Shores. Both are fed via two subtransmission lines from Erin, which is a 120kV to 40kV subtransmission station. Combined, Savoy and Baker substations serve approximately 10,000 customers. In early June 2021 during very hot weather, a cable failure on one of the subtransmission lines left both Savoy and Baker substations with a single contingency. A concurrent failure on a second cable before the first cable was replaced (a process that can take a couple of days) would have led to a full substation outage at both Baker and Savoy. In addition, the cable that fed Baker and Savoy after the first failure was showing signs of failure as it supported an increased load. Due to system limitations and capacity constraints in the area, Baker and Savoy had a combined 32 MVA of stranded load, indicating that jumpering load to adjacent substations based on the current configuration of the circuits was not a viable option. To mitigate the risk and potential of a substation outage, mobile generators were deployed to the site, and multiple jumpering points were built to allow for the load to be transferred in case of a second cable failure. While the second cable did not fail and therefore no customers experienced an outage, the overall cost of the contingency plans developed to avoid this outage was approximately $800,000.

McGraw and Scotten flooding

A recent risk highlighted for DTEE's grid is flooding. Aligned with the scenario of increased catastrophic storms laid out in Section 3, climate change may drive increased precipitation and risk of flooding as a result of more frequent and intense storms. On June 26, 2021, the Detroit/Dearborn area near the I-94 corridor experienced a significant storm with rainfall in some areas in excess of 5 inches in a single day and 8 inches over two days. Two DTEE substations in Detroit, McGraw and Scotten, flooded as a result of this storm. The damage that resulted from multiple electrical faults caused by the flood left much of the equipment, including breakers, and buses unrepairable at McGraw. The damage at Scotten was not as extensive and the majority of the equipment was salvaged. McGraw and Scotten have a combined stranded load of 35 MVA, indicating there were limited options to transfer load to neighboring substations to quickly restore power. Instead, the restoration effort deployed mobile generators and portable substations and built temporary structures to enable customer restoration. In total, approximately 3,600 customers were without power for an average of 30 hours, with a cost of restoration for this event of approximately $600k. As a result of the flooding, DTEE is conducting an assessment to evaluate flood risk for the key infrastructure at all substations and determine recommendations to mitigate risks that are found. A preliminary view of the system shows that other substations with below grade equipment are already planned for replacement as part of the CODI project.

Future risk and grid modernization scenarios

The substation risk model will be informed by our scenarios described in Section 3 in at least two key ways. First, the potential for increased CAT Storms can directly impact the likelihood of failure events that could lead a substation outage. In addition to increased intensity of wind, extreme heat will further strain the aging equipment, and flooding risk creates additional complications. The other scenario that will impact the risk model is increased electrification. The loading that will come with higher adoption of EVs can further increase loading at substations. This will further increase the stranded load as both jumpering options will become more limited and the amount of load that needs to get transferred will increase. To continue to manage the risk of the system, asset replacements, hardening and capacity increases will be needed to avoid more frequent substation events, and avoid the costly contingency plans now associated with equipment failures.

9.2.3 Programs to address substation risk

The Substation Outage Risk Model provides a framework for DTEE to measure risk reduction as a result of investments. There are multiple needs identified by the model and recent examples: the need to replace assets identified by asset health assessments, the need for increased capacity, and the need for solutions to mitigate risk in the daily system operations. The following programs specifically help address substation risk:

- **Capital Replacement Programs (Section 9.1**) – Replacement of at-risk cable and breakers, at both substations and subtransmission system, will directly provide a risk reduction by reducing the probability of failure of key substation equipment.
- **Infrastructure Redesign and Modernization** – Increasing capacity of the system is a primary driver of the projects in the major categories of our Redesign and Modernization pillar. Subtransmission projects, conversion projects, and system loading projects all address the system's over-capacity areas and include load relief as one of the primary prioritization factors. Increasing system capacity will increase options to transfer load from substation to substation, thus reduce stranded load and improve the overall substation risk profile. In addition, the eventual conversion of the 4.8kV system (and 8.3kV) system, will eliminate one contributing factor to stranded load, which is having substations with different voltages adjacent to each other.
- **The Mobile Fleet program –** This program is expanding mobile generation, portable substations, and mobile switchgear in order to have more tools to decrease restoration time for stranded substation load or to support substations on a single contingency to avoid outages. The mobile fleet provides relatively quick restoration of customers and the ability to facilitate the repairs of the failed equipment inside the substation. Though expanding the mobile fleet capacity is relatively low cost, it does not reduce the substation outage risk, it does allow DTEE additional flexibility to restore customers. Moreover, the application of the

mobile fleet during restoration may be limited due to the feasibility of connecting it at substation sites and considerations on space, traffic, environmental and community impacts. Exhibit 9.2.3.1 shows a portable substation and mobile generator that are part of the fleet.

Exhibit 9.2.3.1 Mobile Fleet

Mobile generator Portable substation

- **The Substation Risk Reduction program –** This program involves replacing aging, at-risk equipment (mostly switchgear) to reduce the probability of a failure. This approach reduces substation outage risk; however, it can be costly and difficult to execute due to site-related construction constraints and the need to continue serving customers during the process. As such, the plan is to limit initial implementation to substations where deployment of mobile fleet assets is limited and cannot restore the entire substation load; in other words, load will be stranded for more than 24 hours.

  Exhibit 9.2.3.2 shows the projected costs and timelines for the identified substation outage risk reduction projects. The timeline considers multiple factors including relative substation outage risk, resource availability, specific site conditions and other execution constraints. The cost and timeline estimates for the projects are based on the best knowledge and information known today by DTEE. Actual project costs and timeline could deviate from the projection due to various unforeseen factors or new information/learnings.

Exhibit 9.2.3.2 Projected Investments and Timeline for Substation Risk Reduction Projects

Project	2021	2022	2023	2024	2025	2021-2025 Total ($ million)
Savage						$0.4
Drexel						$2
Belleville						$2
Port Huron						$2
Apache						$19
Chestnut						$14
Savage Switchgear						$12
Total	$6	$11	$12	$11	$12	$52

- **The Station Upgrade program –** This program is an evolution of the former Relay program, which originally focused on end-of-life relaying. The first project executed as part of this program intended to only replace relays at Warren Station. As the project progressed, the scope was reviewed and expanded to replace at-risk breakers within the substation as well. This helps reduce the long-term costs of having to revisit these substations later to replace equipment in need of replacement. With this expanded scope, the Station Upgrade program helps reduce substation risk on the system.

Exhibit 9.2.3.3 shows the projected investment and timelines for the identified Station Upgrade projects. The timeline considers multiple factors including relative substation risk, resource availability, specific site conditions and other execution constraints. The investment and timeline estimates for the projects are based on the best knowledge and information known today by DTEE. Actual project costs and timeline could deviate from the projection due to various unforeseen factors or new information/learnings.

Exhibit 9.2.3.3 Projected Investment and Timeline for Station Upgrade Projects

Project	2021	2022	2023	2024	2025	2021-2025 Cost Estimate ($ million)
Warren						$1
Northeast						$9
Lincoln						$10
Navarre						$10

9.3 4.8kV Hardening program

9.3.1 Introduction to the 4.8kV Hardening program

The 4.8kV system in Detroit and its surrounding communities was the first part of DTEE's distribution network built. Due to its age, it has the highest volume of trouble events in our service territory. Those problems are exacerbated by the abandoned and overgrown alleys in the city of Detroit.

DTEE continues to work to maintain the electric grid across the entire service territory in a cost-effective manner. However, in many areas, general maintenance practices are simply no longer sufficient and DTEE has begun investing more aggressively to harden and upgrade the infrastructure.

DTEE reviewed and evaluated four alternatives for improving the safety and reliability of the 4.8kV system (full conversion, Pre-conversion of overhead only, secondary program, and 4.8kV Hardening), as discussed in detail in MPSC Case No. U-20162. Because the full conversion of the 4.8kV system in the city of Detroit is estimated to cost over $4 billion and take more than a decade to complete, DTEE has selected the 4.8kV Hardening program as this program provides improvements in safety and reliability at a much faster pace and more affordable cost.

Although the current scope of the 4.8kV Hardening program is focused on Detroit and its surrounding communities, DTEE will continue to evaluate the application of the program to other parts of the 4.8kV system in its service territory, as compared to the 4.8kV Conversion and Consolidation program. Such comparison and considerations are addressed in detail in Section 11.3 4.8kV Conversion.

The scope of work for the 4.8kV Hardening program includes:

- Testing all utility poles that have DTEE equipment attached and replace or reinforce those poles as needed
- Replace wooden crossarms with fiberglass crossarms
- Remove Detroit Public Lighting Department (Detroit PLD) arc wire from DTEE-owned equipment and ensure the remaining DTEE wires are left in a safe configuration
- Remove Detroit PLD distribution wire from DTEE-owned equipment when it can be confirmed that the wire is not serving customers
- Remove service lines to abandoned properties
- Trim trees as required to support construction activities
- Perform any additional necessary work as dictated by field conditions
- Conduct pilot projects to explore and assess alternatives to existing rear lot overhead configurations. The pilots include converting rear lot overhead construction to underground residential distribution construction, removing primary overhead construction, and adding secondary overhead construction to serve sparsely populated areas. The pilots aim at improving reliability and reducing trouble events in some areas of Detroit where inaccessible overhead construction in rear lots is encroached by fence lines and overgrown trees.

9.3.2 4.8kV Hardening program prioritization

DTEE prioritizes 4.8kV system hardening on four factors:

- Recorded wire downs per overhead line mile
- Estimated foot traffic within the substation service area
- Total substation SAIDI
- Total outage and non-outage events requiring the dispatch of a line crew

Data is collected and reviewed at the substation level as it is more efficient to plan and perform work for circuits fed by the same substation at the same time.

Ranking the substations follows DTEE's overall goal of reducing safety risk, improving reliability, and managing costs. Recorded wire downs and estimated foot traffic are measures of risk reduction metrics.

DTEE takes a three-year historic average of wire downs per overhead line mile multiplied by the estimated foot traffic for each substation. Foot traffic is estimated based on the number of each type of customers on a substation (residential, commercial, industrial) as well as schools, hospitals, and the occupancy rate for each type of customer, determined by census and other related business data. Substation SAIDI indicates the total minutes of interruptions experienced by customers served by a substation and represents a reliability metric. A three-year average of substation SAIDI is used for substation prioritization. Total outage and non-outage events requiring the dispatch of a line crew represents the cost management metric. The three-year historic average of the number of events per overhead line mile is used as a proxy for costs. The scores are normalized and then combined to provide an aggregate score, with greater weight given to safety risk reduction. The weighting is 45% for risk reduction and 27.5% each for reliability improvement and cost management.

The prioritized list of substations for the 4.8kV Hardening program is cross referenced with the schedule for planned 4.8kV Conversion and Consolidation program to eliminate overlap, as substations that are part of the conversion and consolidation in the next 5-10 years should not be considered for the 4.8kV System Hardening to achieve the maximum cost efficacy. It is important to note that prioritization factors and weightings may be adjusted over time based on the ongoing assessment of program effectiveness and customer needs.

9.3.3 4.8kV Hardening program progress and effectiveness

DTEE has aggressively ramped up the program since its beginning in 2018, as can be seen in Exhibit 9.3.3.1. In 2018, the first year of the program, DTEE hardened 105 miles. In 2021, DTEE will almost double that total, and will continue to ramp the program to achieve over 300 miles a year by 2022.

Results on three key metrics show that the 4.8kV Hardening program has been very effective thus far: (1) All-Weather SAIFI; (2) SAIDI excluding major event days (SAIDI ex-MEDs); and (3) unaudited wire down events.

All-weather SAIFI reflects the frequency of the outage events experienced by customers on the circuits regardless of weather conditions.

SAIDI ex-MEDs is an indicator of the amount of time customers are without power, excluding the most significant weather events, such as very large storms. SAIDI ex-MEDs contains multiple storm and weather impacts, with only the most extreme weather events removed.

The number of wire downs is a measure of the effectiveness of safety improvements for the circuits that were hardened. Circuits hardened in 2018 and 2019 show improvement over those not hardened during that time. (The control group consists of circuits in the city of Detroit not worked on in 2017 or 2020.)

Exhibit 9.3.3.1 shows the All-weather SAIFI improvement of hardened circuits vs. the control group, Exhibit 9.3.3.2 shows the SAIDI ex-MEDs improvement of hardened circuits vs. the control group, and Exhibit 9.3.3.3 shows the wire down event improvement of hardened circuits vs. the control group.

In addition to the circuit improvements, the 4.8kV Hardening program has successfully removed over 200 miles of arc wire from the system.

Exhibit 9.3.3.1 All Weather SAIFI Before and After Hardening

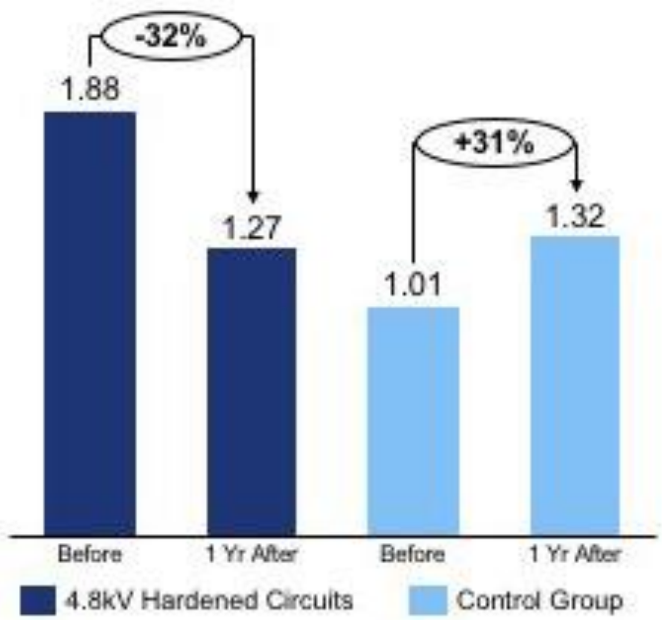


Exhibit 9.3.3.2 SAIDI ex-MEDs Before and After Hardening

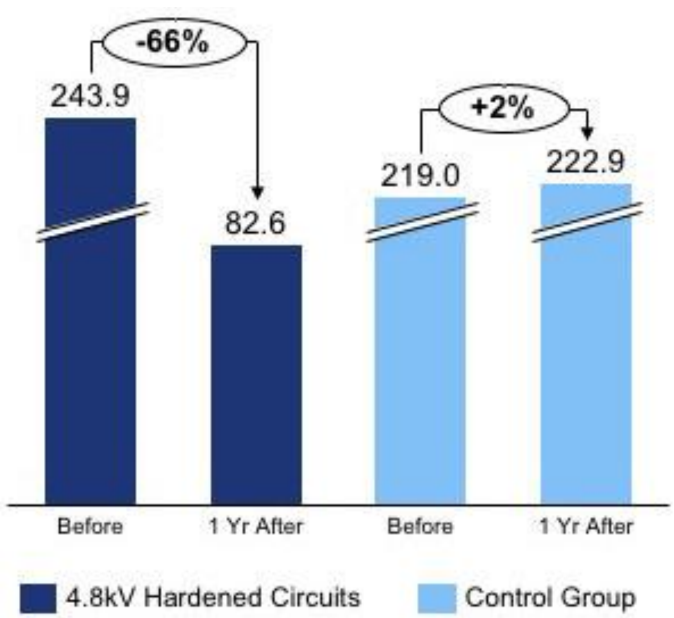
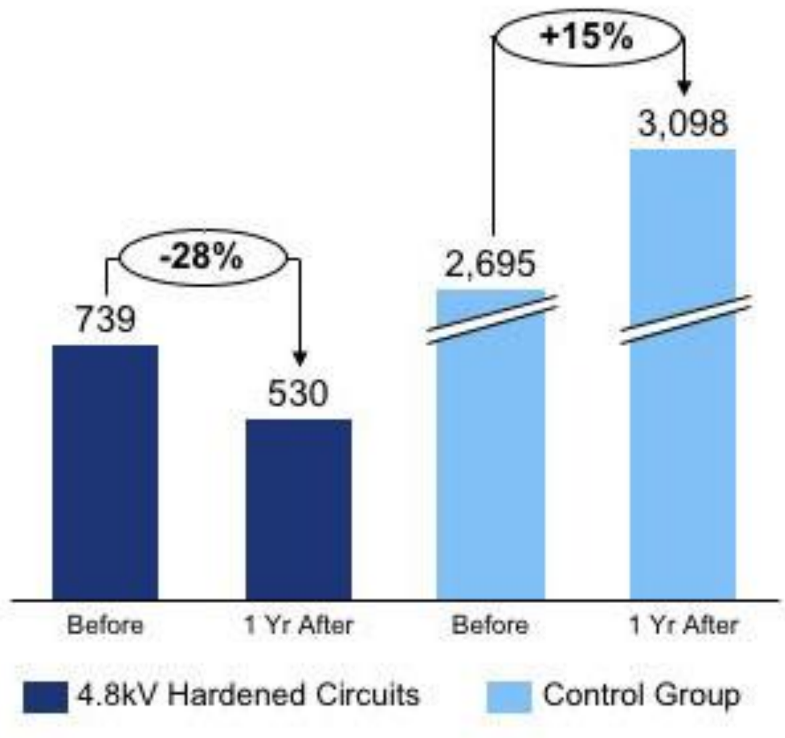


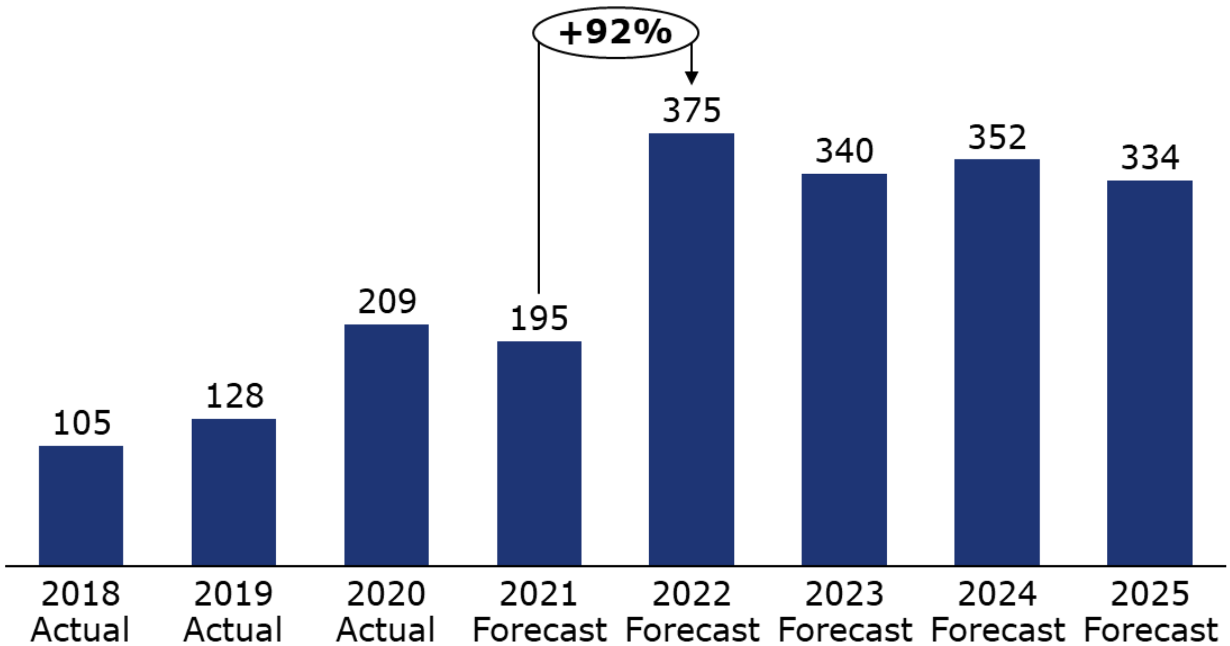
Exhibit 9.3.3.3 Wire Downs Before and After Hardening



9.3.4 4.8kV Hardening program plan and timeline

DTEE is expected to increase the number of miles completed annually through 2023 and is expected to complete over 2,000 miles by 2025.

Exhibit 9.3.4.1 4.8kV Miles Hardened



DTEE plans on continuing the 4.8kV Hardening program through 2029. DTEE expects to harden four to six substations and 200 to 300 overhead line miles per year. By the end of the program, DTEE will have hardened over 45 substations and over 2,220 overhead lines miles and removed 1,300 miles of arc wire within the city of Detroit and immediately adjacent suburbs.

Exhibit 9.3.4.2 4.8kV Hardening Program Investment

	2021	2022	2023	2024	2025	Total investment 2021-2025
Investment projection ($ millions)	$69	$120	$116	$116	$116	$537

9.3.5 Alternatives methods to improve to 4.8kV reliability

The Company has considered five options to improve the reliability of 4.8kV circuits that were built with rear-lot overhead construction. These five options are shown below in Exhibit 9.3.5.1. Two of the pilots which are in progress evaluate the costs of converting rear-lot overhead to rear-lot underground and front-lot underground. These pilots are discussed in more detail in Section 11.6 – Strategic Undergrounding. The third option being evaluated is selective deconductoring in sparsely populated areas (Option 5 in the table below).

Exhibit 9.3.5.1 Comparison of Rear-Lot OH Construction Alternatives

Rebuild Method	Description	Key Benefits	Key Considerations
1. Overhead Rear Lot	Install poles, overhead wires, and equipment in alleys, vacated alleys or rear lots	• Easy connection to existing meter boxes • Away from foot traffic	• Not truck accessible – climb required for tree trim, maintenance, and restorations • Maintenance tree trim required • Pole and Pole Top Maintenance (PTM) required
2. Underground Rear Lot	Install underground padmount transformers, pedestals, cable and conduit etc. in alleys, vacated alleys or rear lots	• No exposure to downed wires • Easy connection to existing meter boxes • No need for maintenance tree trim • No need for Pole and Pole Top Maintenance (PTM) • No need for 4.8 kV Hardening	• Encroached fence lines and obstacles in alleys make underground construction difficult • Difficulty in obtaining permits & customer approvals • Damage to landscape • Installation cost is significantly higher than overhead installation
3. Underground Front Lot	Install underground padmount transformers, pedestals, cable and conduit etc. in front lots adjacent to the road and reroute service wire to meter box in rear lot	• No exposure to downed wires • No need for maintenance tree trim • No need for Pole and PTM • No need for 4.8 kV Hardening	• Damage to customer property (driveways, landscape, etc.) • Interference with existing utilities (sewer, gas, water, etc.) • Difficulty in obtaining easements, permits and community approvals • Difficulty in connecting to existing meter boxes • Installation cost is significantly higher than overhead installation
4. Overhead Front Lot	Install poles, overhead wires, and equipment in front lots adjacent to the road and reroute service wire to meter box in rear lot	• Improved truck access • Reduced tree interference (typically front lots have less tree density) • Reduced cost in maintenance tree trim • Reduced cost in Pole and PTM • Reduced cost in 4.8kV Hardening	• Aesthetically not appealing • Damage to customer landscape • Interference with existing utilities (sewer, gas, water, etc.) • Difficulty in obtaining easements, permits and community approvals • Difficulty in connecting to existing meter boxes • Maintenance tree trim required • Higher foot traffic in vicinity of overhead wires

5. Primary De-conductoring	Remove primary wires in sparsely populated areas and reconductor secondary wires where necessary	• Reduced exposure to downed primary wires • Improved truck access • Reduced cost in maintenance tree trim • Reduced cost in Pole and PTM • Reduced cost in 4.8 kV Hardening • Radial secondary results in easier to locate and isolate trouble	• Potential low voltage issues for end customers • Rebuild required if the area repopulates

Primary Deconductoring Pilot

DTEE is working on a pilot to deconductor specific circuits in areas that have seen significant population decline. For instance, the infrastructure in the city of Detroit was established to serve the peak population of approximately 1.8 million in the 1950s. With the population now at approximately 670,000, there are many unoccupied properties and underutilized and aging assets. The goal of this pilot is to remove underutilized infrastructure that is no longer needed. The primary wires, distribution transformers and other equipment only increase maintenance costs and the exposure for outages and other events for customers in these areas. When an area is redeveloped, the infrastructure can be rebuilt with newer standards that are consistent with new construction.

Exhibit 9.3.5.2 Unoccupied Areas in DTEE's Caniff Service Center Area

(East side of the Detroit metropolitan area)
Unoccupied properties represented by dots

In these sparsely populated areas, primary deconductoring may be an option to improve reliability and reduce risk. Primary deconductoring involves the removal of small-sized primary wire, arc circuit wire, overhead transformers and pole tops. Reconductoring secondary wires is also completed where necessary. The amount of infrastructure removal is dependent upon the sparsity and location of customers in the neighborhood. Maintaining adequate voltage on the secondary (in absence of the primary) and jumpering points for contingencies is the key engineering consideration. Two circuits were selected for the pilot: Wayburn DC 2136 and Grant DC 1598. Combined, the two circuits serve 1,300 customers and have 19 miles of overhead primary, or 68 customers per overhead mile of primary – sparse for an urban neighborhood.

One of the two deconductoring projects has been completed: Wayburn DC 1236. This circuit was completed ahead of schedule for several reasons, including the population density was such that there were limited issues. Grant DC 1598 is still under construction and has seen some additional challenges. The population density is higher on Grant, which caused some voltage issues when deconductoring that were addressed by adding back some the removed infrastructure. Through these two projects, DTEE has learned several keys lessons, most importantly that removing some sections of primary has caused voltage issues on the circuits. As such, some primary has been left in place to maintain proper voltage. DTEE also learned that the less dense the population is in an area, the quicker that installation will proceed and the more effective the deconductoring project can be.

9.4 Frequent Outage program

DTEE has two programs specifically targeted toward a rapid solution for customers who are experiencing a high frequency of reliability issues. These reliability programs continually evolve to address emerging problems using the best available equipment and techniques. The main recurring reliability programs are listed in Exhibit 9.4.1.

Exhibit 9.4.1 Reliability Programs Summary

Program	Scope of work	Target areas
Customer Excellence	• Perform tree trim • Reconductoring • Replacement of broken pole top equipment • Pole replacement	• Circuit pockets with high SAIFI and/or MAIFI
Frequent Outage (CEMI)	• Perform tree trim • Underground portion of the circuits • Rebuild/reconductor/relocate overhead lines • Add or strengthen circuit ties • Provide circuit load relief • Install sectionalizing and switching devices, etc.	• Remediate small pockets of customers or single customers experiencing frequent outage events by focusing on removing root causes of reliability and power quality events • Address circuits with chronically poor reliability performance by focusing on removing root causes of reliability and power quality events

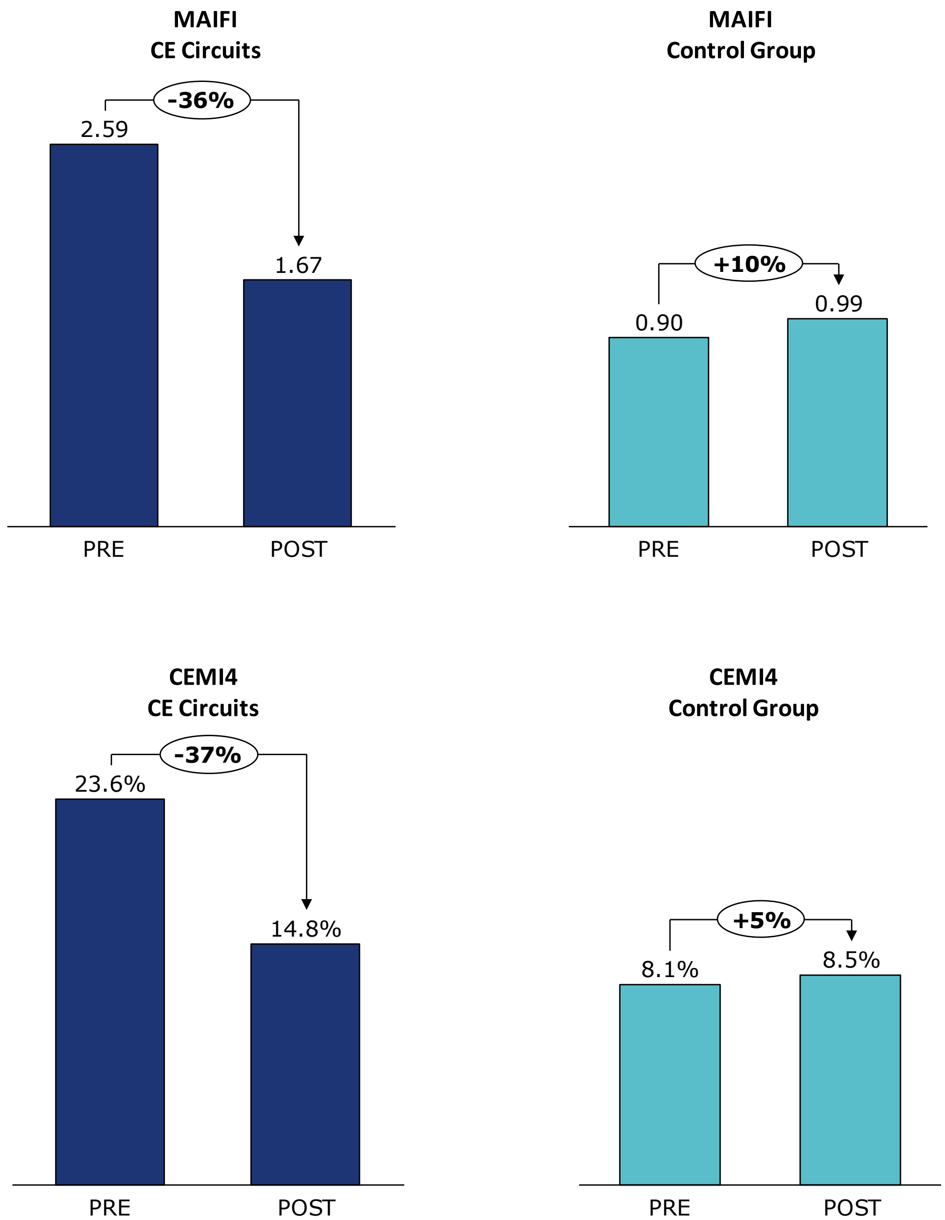
In 2019, the Customer Excellence (CE) program was established to provide rapid solutions to small pockets of customers experiencing poor reliability. These customers are identified as experiencing four sustained outages (SAIFI > 4.0) or nine momentary outages (MAIFI > 9.0).

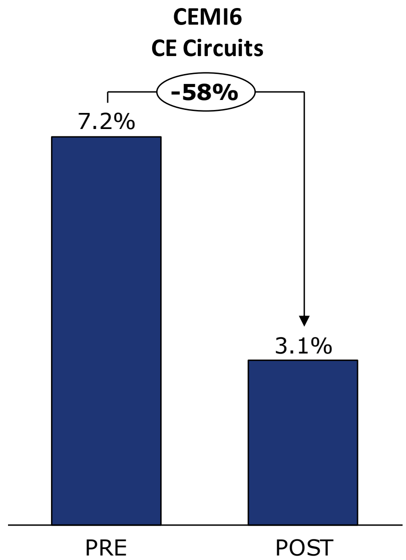
The prioritization method for the Customer Excellence program relies on AMI data to identify these customers on a rolling 12-month basis to address issues more rapidly than other programs that rely annual analysis of reliability events. In addition to reliability event data, the prioritization also includes time since last tree trim, any other planned work on the circuits, and customer complaints.

Upon identification of a circuit that meets the CE prioritization criteria, DTEE conducts a field patrol to understand both equipment and tree conditions. After patrol, the scope of work is developed for both tree-related and equipment-related problems identified. In addition to the tree trimming and defective equipment replacements, 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. On average, the solutions cost $60,000 to $80,000 per circuit to implement.

The cycle time from circuit selection to field completion averages less than 55 days, allowing for quick resolution of identified reliability problems. Throughout the CE process, customers on the selected circuits receive communication, starting with an initiating email. The CE team coordinates with the Corporate Communication team to collect photos of work being conducted in the field and utilizes social media to update the progress of the improvements. Once work is completed, customers receive a close-out email outlining the completed work. The CE program has had a positive impact on the customer experience and provided improvements in both CEMI and MAIFI, as shown in Exhibit 9.4.2 below. Examples of equipment issues found during patrols are shown in Exhibit 9.4.3.

Exhibit 9.4.2 Customer Excellence Reliability Impact




CEMI6
CE Circuits
-58%
7.2%
3.1%
PRE
POST

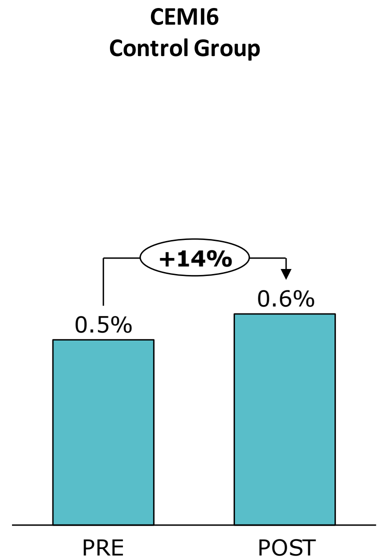

CEMI6
Control Group
+14%
0.5%
0.6%
PRE
POST

Exhibit 9.4.3 Example of Scope of Work for Customer Excellence Circuits

(Loose fuse cutout (left), broken cross arm (top right), broken fuse cutout (bottom right))

The other program that addresses customers who experience frequent reliability problems is the Frequent Outage program, also known as the CEMI (Customers Experiencing Multiple Interruptions) program. This program includes improvements to either circuit sections (customer pockets) or entire circuits. The primary distinctions between the Customer Excellence and the CEMI programs are that circuits are 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 $300,000 and $250,000.

Exhibit 9.4.4 shows the projected annual capital investment for these reliability programs.

Exhibit 9.4.4 Projected Reliability Programs Capital Investment

	2021	2022	2023	2024	2025	Total investment 2021-2025
Frequent Outage (CEMI) including Customer Excellence ($ millions)	$33	$45	$22	$22	$28	$150

9.5 4.8kV relay improvements

The Ground Detection program (4.8kV Relay Improvement program) allows the System Operations Center (SOC) to receive alarms for 4.8kV wire down events so actions can be taken quickly to remediate and make repairs.

The first step of the Ground Detection program is to install or upgrade telecommunications at 4.8kV substations, as most 4.8kV substations are of a vintage that precedes SCADA (a similar telecommunications program exists for 13.2kV substations, see Section 12.3). The second step is to upgrade to modern ground detection relaying utilizing microprocessor relaying. Ground detection relaying will identify real-time wire down events seen at the substation bus. Knowing that a ground wire exists in real-time allows for immediate crew dispatch to locate and repair the downed wire, reducing the amount of time needed for repair.

Exhibit 9.5.1 Projected 4.8kV Relay Improvements Capital Investment

4.8kV Ground Detection	2021	2022	2023	2024	2025	2021-2025
Investment ($ millions)	$2	$3	$3	$3	$3	$15
Units	11	17	17	17	17	79
Remaining units	252	235	218	201	184	-

9.6 Mobile fleet

DTEE's mobile fleet program allows for system shutdowns to complete preventive maintenance at single transformer substations and safely executing planned strategic capital projects, while minimizing customer impacts. As referenced in Section 9.2.3 – Programs to address high risk substations, the program also provides options for restoring customers while making repairs of failed equipment at substations.

DTEE's current mobile fleet includes 11 portable substations, 10 portable distributed generation (DG) units, six manual portable ISO transformers, three portable ISO transformers including switchgear and pole, and two portable load banks.

DTEE plans to purchase five new portable substations between 2021 and 2024 to allow for the proper execution of preventive maintenance programs, including addressing the backlog of preventive maintenance for single tap substations.

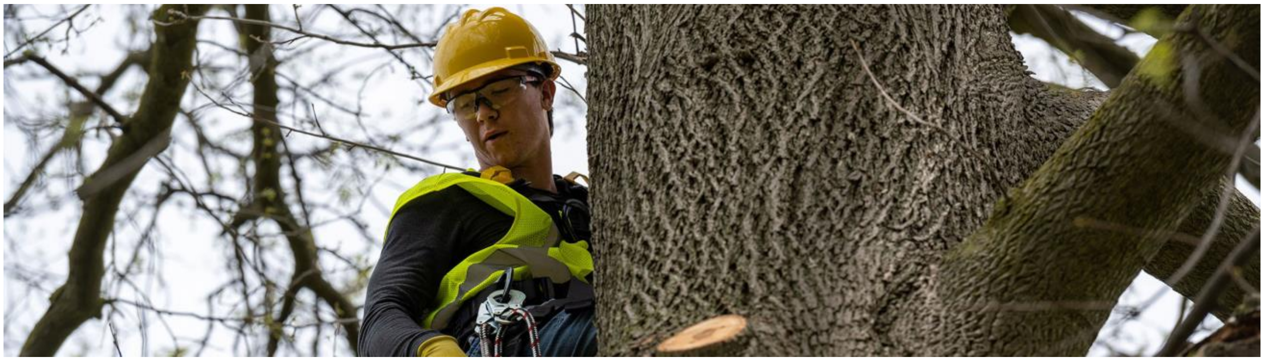
In addition, DTEE will purchase a portable switchgear cable trailer and complete ongoing work to upgrade and integrate controls, support equipment purchases and refurbish and repackage DG units based on ongoing condition assessment. All of this work will support the ability to deploy distributed generation on the system when needed.

Exhibit 9.6.1 shows the projected annual capital investment for the mobile fleet program that enhances system reliability and resilience.

Exhibit 9.6.1 Projected Mobile Fleet Capital Investment

	2021	2022	2023	2024	2025	Total investment 2021-2025
Mobile fleet capital investment ($ millions)	$5	$3	$3	$3	$1	$14

10 Tree Trimming program



10.1 Introduction

DTEE's Tree Trimming program addresses interference between vegetation and electric distribution facilities. The objectives of the program are to increase system reliability by reducing tree-related safety hazards and the volume of tree-related trouble cases. This program is particularly important to the grid modernization scenario envisioning "increasing CAT storms." If the volume and/or intensity of weather events increases, maintaining sufficient tree clearance from DTEE's electrical equipment and lines becomes even more critical to ensuring the safety and reliability of our customers. The Tree Trimming program addresses current system needs and is key to improving the overall resiliency of the DTEE grid.

Since 2016, DTEE has made two significant improvements to the Tree Trimming program. The first was moving to an enhanced trimming specification, based on industry best practices and the Company's experience, known as the Enhanced Tree Trimming program (ETTP). The ETTP was described in detail in testimony in the Company's last four rate cases: Case Nos. U-18014, U-18255, U-20162 and U-20561.

The second improvement was an increase in annual funding to help the Company achieve a five-year trimming cycle. In Case U-20162, DTEE proposed a "surge" in funding for 2019-2025 to reclaim areas that have yet to be trimmed under the ETTP, while maintaining the investment already made in the ETTP. The Commission was supportive of the surge, noting:

... the Commission agrees that falling behind in this area will cost more in the future and perpetuate reliability challenges. The record also shows direct, quantifiable benefits in terms of reliability improvements resulting from the ETTP program. 3 Tr 200-206.
[MPSC Case No. U-20162, May 2, 2019 Order, p 79.]

The ETTP has provided significant benefits to customers in improved reliability and safety. As outlined in DTEE's Annual Tree Trimming Report, customers that live on circuits that have been trimmed as part of this program experience significantly fewer outages, shorter outage durations when an outage does occur and significantly fewer wire downs. A circuit that has been trimmed as part of the ETTP experiences 62.9% fewer customer interruptions and 57.3% fewer customer-outage minutes than circuits that have not been trimmed in the ETTP within the first year of trimming. More of these results are discussed in detail later in this section.

In light of the severe storms DTEE's customers experienced during the summer of 2021, the Company has committed to accelerating the "surge" outlined in U-20162. An additional $70 million of funding for the program will allow for an increased number of miles to be trimmed in 2021 and future years. The result of the additional funding is the completion of the surge program by the end of 2024, a year earlier than previously proposed. DTEE is not seeking cost recovery for this additional funding, providing an affordability benefit to our customers. The acceleration of the tree trim program will improve the safety, reliability and affordability of our electric system for our customers and make the system more resilient to severe weather sooner than previously planned.

10.2 The need for tree trimming

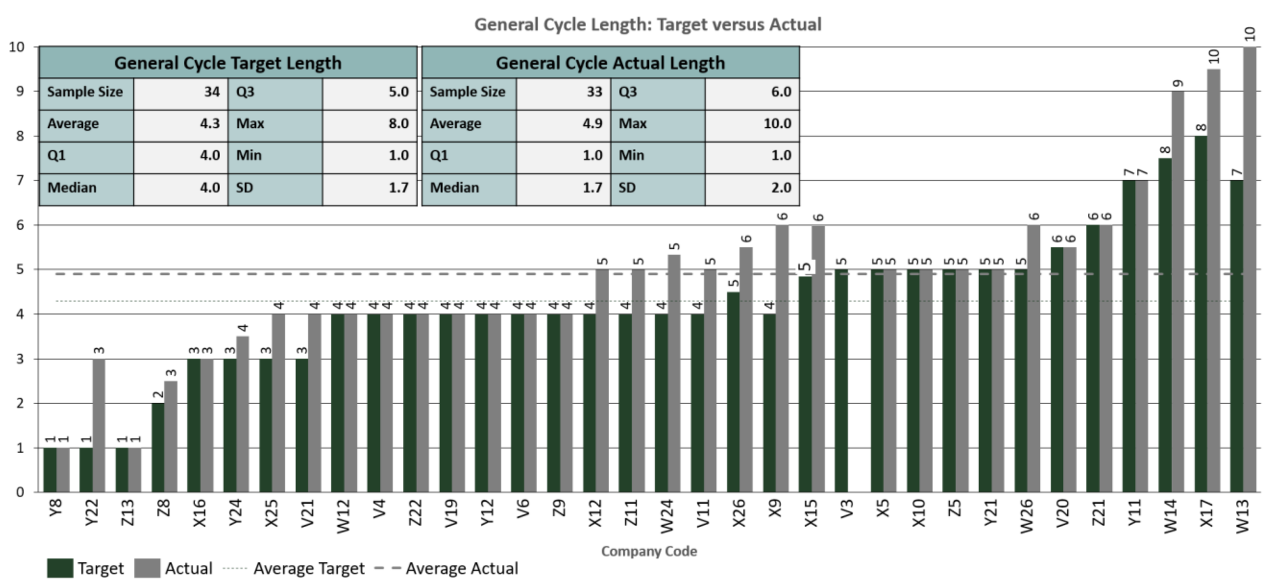
Tree interference is the leading cause of customer outages. Tree-caused outages account for two-thirds of the time that customers spend without power. A robust tree trimming program is needed to maintain and improve system reliability and resilience. It significantly reduces outage events, customer interruptions, customer minutes of interruption, wire downs and other non-outage trouble events. The goal is to achieve and maintain a five-year cycle for distribution circuits and a three-year cycle for subtransmission circuits. Tree trimming is one of the highest priority investments for Distribution Operations. No other program or project has a greater immediate impact on mitigating risks, improving system and customer reliability, and managing the electric distribution system operating costs.

The ETTP clears trees and branches to a distance of 15 feet on either side of the distribution pole centerline, or approximately 10 feet from the conductors (the actual clearance is species-specific). Because trees in our service area grow an average of 10 feet in five years, the five-year cycle provides a reasonable and acceptable level of tree-to-conductor contact comparable to the industry standard of 10%-15%. (Tree-to-conductor contact represents the likelihood of any portion of the tree touching the conductor. A tree-to-conductor contact level of 10%-15% denotes the estimated average percentage of trees in contact with the overhead electrical facilities across the entire distribution system when the recommended cycle length and clearance standards are reached.)

For subtransmission, a 3-year cycle is used because of the high customer impact associated with subtransmission line failures. An outage on a subtransmission line can potentially cause an entire substation to lose power, which would affect, on average, over 3,600 customers. By comparison, an outage on a distribution circuit would affect, on average, approximately 700 customers. The three-year cycle further reduces the likelihood of trees contacting overhead conductors.

The targeted goal of a five-year cycle on distribution circuits is comparable to the actual industry average of 4.9 years, per a report published by CN Utility Consulting, Inc. (CNUC), “Distribution Utility Vegetation Management Benchmark Survey Results 2016.” All but six of the participating companies target a cycle of five years or less.

Exhibit 10.2.1 CNUC Benchmark Study (34 Respondents)



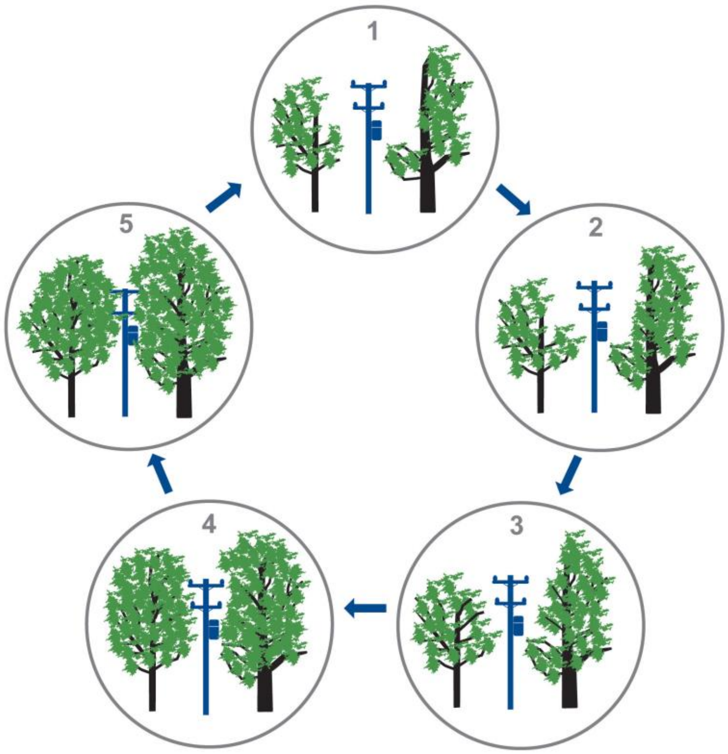
Target & actual cycle length (Years)

Deferring tree trimming maintenance beyond the five-year cycle results in cost escalation as described in a May 1997 study funded by International Society of Arboriculture (ISA) and conducted by consulting firm ECI, LLC, “The Economic Impacts of Deferring Electric Utility Tree Maintenance.” The table below shows the relative cost, excluding inflation, of deferring tree trim maintenance beyond the optimum time – five years since last trim. As the time since last trim gets longer, the work becomes more complex as trees begin to interfere with the conductors.

Exhibit 10.2.2 Cost of Deferred Tree Trim

Timing of trimming	Year since last trim	Relative cost
Optimum	5	$ 1.00
1 year past optimum	6	$ 1.16 to $ 1.23
2 years past optimum	7	$ 1.30 to $ 1.43
3 years past optimum	8	$ 1.40 to $ 1.59
4 years past optimum	9	$ 1.47 to $ 1.69

Exhibit 10.2.3 Illustration of Tree Growth Impact on Complexity Based on Years Since Last Tree Trim



The table below shows the number of miles per year necessary to be on-cycle. These numbers are averages and actual miles per year may vary based on density and complexity as discussed later in this document.

Exhibit 10.2.4 Tree-trimming Cycles

Circuit type	Overhead miles	Cycle length (years)	Trim miles per year
Distribution	28,459	5	5,692
Subtransmission	2,539	3	846
Total	30,998	4.75	6,538

10.3 Tree Trim Surge program

At year-end 2020, the Company had an average distribution cycle time of six years, with 16,152 circuit miles considered on-cycle. Our average subtransmission cycle time was three years, with all 2,539 circuit miles considered on-cycle. On-cycle means the circuit miles have been trimmed within the last three or five years (for subtransmission and distribution respectively) to either the ETTP specification or the Company's previous trim specification. The ETTP specification is the current and preferred specification. Circuit miles not yet trimmed to the ETTP specification are referred to as the "backlog." To expedite reaching the targeted goal of a five-year cycle, the Tree Trim Surge program was put in place. The Surge program is designed to ensure all miles are on-cycle and eliminate the backlog by the end of 2024.

Reducing the tree-trimming cycle length to three or five years respectively will provide several benefits and savings:

- Fewer wire-down events, resulting in improved safety.
- Fewer outage and non-outage events, leading to improved reliability and a positive impact on reactive O&M and capital costs. This will also allow reallocation of resources to other necessary work across the Company's distribution system.
- Lower future trimming costs as the number of trees growing within the right-of-way are trimmed or removed more frequently, resulting in less wood near the lines. In 2018, the Company commissioned ECI to perform a detailed study of the cost improvements during the second cycle of tree trimming. According to ECI the cost per line mile is expected to decrease by an average of 40% compared to the initial trimming conducted as part of the ETTP.
- Lower customer costs as tree-related outages are reduced. The improved reliability will reduce downtime for customers' manufacturing processes, allow commercial businesses to remain open and reduce inconveniences residential customers experience.

At the completion of the Surge program, tree-related O&M and capital costs for reactive maintenance and storm will be lower. With fewer tree-related events, the need for tree crews and overhead crews will be reduced. There will be less of a need to repair and replace assets on the system that have failed because of tree interference. The table below shows current O&M and capital costs compared to the projected costs upon completion of the Surge program, excluding inflation.

Exhibit 10.3.1 O&M and Capital Cost Comparisons

Estimated tree-related cost savings, excluding inflation					
Cost categories		Current cost	Post surge (2026)	Reduction
Tree-related O&M	Tree trim reactive	$ 12.9 M	$ 8.8 M	$ 4.1 M
	Tree trim storm	$ 11.5 M	$ 7.9 M	$ 3.6 M
	Storm Service operations storm and trouble	$ 12.2 M	$ 8.4 M	$ 3.8 M
Tree-related capital	Tree trim reactive	$ 4.5 M	$ 3.1 M	$ 1.4 M
	Tree trim storm	$ 21.4 M	$ 14.7 M	$ 6.7 M
	Service operations storm and trouble	$ 36.6 M	$ 25.4 M	$ 11.2 M

Exhibit 10.3.2 Average Annual Outage and Non-outage Events

	Pre-surge 2014-2018 average	Post surge 2026	Percent reduction
Tree-related outage and non-outage events	44,700	25,378	43%

In addition to a decrease in reactive trimming costs, at the completion of the Surge program the annual O&M for the Tree Trimming program is expected to be about $100 million, not adjusted for inflation. This reduction will be realized because the entire system will be a on five-year cycle, and future trim cycles will require less wood removal (as discussed previously in this section). In 2025 and subsequent years, the Company expects to trim an average of 6,538 miles annually.

DTEE is committed to completing the Surge program by 2024. The program has had a very strong start and we are on track to meet this committed completion date.

10.4 Miles completed and spend

The charts below show ETTP miles completed in recent years.

Exhibit 10.4.1 Annual ETTP Miles Completed by System

Circuit Type	2015	2016	2017	2018	2019	2020	Total	% System
Distribution	257	2,270	2,733	3,128	3,181	4,583	16,152	56%
Subtransmission [1]	188	1,030	868	540	1,006	1,006	4,638	100%
Total	445	3,300	3,601	3,668	4,187	5,589	20,790	60%[2]
% System	1%	12%	24%	35%	46%	60%	60%	

(1) 1,093 of these miles are subtransmission that are on their second cycle and show up in the numbers twice. Only unique miles are included in percent complete calculation.

(2) Numerator only includes unique miles – it does not double count subtransmission on second cycle.

The chart below shows the annual O&M spend on tree trimming.

Exhibit 10.4.2 Annual O&M Tree Trim Spend (millions)[17]

O&M spend	2016	2017	2018	2019	2020
Line clearance maintenance	$59.2	$69.3	$71.8	$116.7	$151.0
Trouble	$10.7	$11.4	$13.0	$16.6	$12.2
Tree Trim program and other	$2.8	$1.8	$2.5	$10.2	$8.2
Program administration	$1.5	$1.7	$1.9	$2.7	$3.7
Total	**$74.2**	**$84.6**	**$89.1**	**$146.2**	**$175.2**

[17] Table does not include all spot trimming expenses from other programs.

10.5 ETTP reliability results

The ETTP has provided significant benefits to customers in improved reliability and safety. Circuits that have been trimmed in the ETTP have fewer outage events, fewer customers interrupted, shorter outage duration and fewer wire downs compared to circuits that have not been trimmed in the ETTP.

The tables below compare the performance of ETTP circuits versus a control group (non-ETTP circuits) for four metrics: outage events, customers interrupted, customer-minutes interrupted and wire down events. Performance is measured as the percent difference between years one, two, three and four years after trimming compared to the average over the three-year period prior to trimming. Exhibits 10.5.1, 10.5.2, 10.5.3 and 10.5.4 illustrate the reduction/increase in performance for the ETTP and non-ETTP circuits compared to prior performance. Additionally, Exhibits 10.5.1, 10.5.2 and 10.5.3 state the difference between the ETTP and non-ETTP circuits compared to what was expected from the Surge Model. Comparison to a control group is done to account for natural weather variations or general deterioration/improvements to the system year-to-year. The ETTP circuits and the control group experience the same conditions each year, hence a comparison between the two negates the effect weather or system variations introduce into performance.

Exhibit 10.5.1 Outage Event Performance

		Percent change in outage events			
Years after last trim	Number of distribution circuits with ETTP	ETTP circuits	Non-ETTP circuits	Difference ETTP vs. non-ETTP	Surge model reduction
1	1651	-34.6%	38.7%	-73.3%	-57.0%
2	1108	-9.1%	62.1%	-71.2%	-57.0%
3	532	-11.2%	71.2%	-82.4%	-50.0%
4	180	16.6%	88.3%	-71.7%	-37.0%

Exhibit 10.5.2 Customer Interruption Performance

		Percent change in customers interrupted			
Years after last trim	Number of distribution circuits with ETTP	ETTP circuits	Non-ETTP circuits	Difference ETTP vs. non-ETTP	Surge model reduction
1	1651	-43.8%	29.3%	-73.1%	-57.0%
2	1108	-22.2%	45.8%	-68.0%	-57.0%
3	532	-40.1%	42.0%	-82.1%	-50.0%
4	180	-12.2%	45.0%	-57.2%	-37.0%

Exhibit 10.5.3 Customer-minute Interruption Performance

		Percent change in minutes of customer interruption			
Years after last trim	Number of distribution circuits with ETTP	ETTP circuits	Non-ETTP circuits	Difference ETTP vs. non-ETTP	Surge model reduction
1	1651	-53.8%	12.5%	-66.3%	-57.0%
2	1108	-19.3%	36.8%	-56.1%	-57.0%
3	532	-56.9%	-7.6%	-49.3%	-50.0%
4	180	-44.4%	-1.7%	-42.7%	-37.0%

Exhibit 10.5.4 Wire Down Event Performance

		Percent change in actual wire down events		
Years after last trim	Number of distribution circuits with ETTP	ETTP circuits	Non-ETTP circuits	Difference ETTP vs. non-ETTP
1	1651	-25.6%	9.6%	-35.2%
2	1108	-15.4%	21.7%	-37.1%
3	532	-13.0%	13.9%	-26.9%
4	180	-7.8%	4.9%	-12.7%

10.6 Program Improvements

DTEE has made several significant improvements since the beginning of the ETTP:

- The Company has dedicated a team to improve and advance tree trimming scheduling. Tree trimming supports several workstreams (e.g. maintenance trimming, trouble trimming, capital trimming). Effectively prioritizing and scheduling these workstreams has been disaggregated in years past, often done at the service center level. The scheduling team is working to develop an integrated scheduling tool that monitors all these workstreams in a centralized format. This will allow the Company to more efficiently schedule tree trimming required for customers and construction projects, while staying on-schedule for the annual maintenance trimming. The scheduling team has also developed dashboards to track maintenance miles trimmed on a weekly basis, and the dashboards are available to other DTEE stakeholders, such as our customer support teams, who use them to understand when tree trimming is taking place in different communities.

- In late 2018, the Company expanded the use of EPA-regulated herbicides to replace mechanical removal of vegetation from the right-of-way with a chemical treatment, which only controls tree species with the potential to grow into electrical wires. The Herbicide program uses industry best practices that were collected and developed through benchmarking and by working with an outside consultant, ECI. The Company has expanded its use of herbicides by implementing foliar herbicide treatment, basal herbicide treatment, and dormant stem treatment.

    - The herbicide treatment will reduce the cost of maintenance trimming in the right-of-way by reducing tree density. There are other advantages besides realizing cost savings. As tree density and brush height decreases, the electrical system becomes more reliable and the right-of-way becomes more accessible for overhead crews to repair a downed wire or broken equipment. Also, because grasses and shrubs are not affected by the herbicide treatment, the area will become a habitat for pollinators, birds and small mammals. The treatment will also target invasive plant species, limiting their spread.

- The Company is partnering with its tree-trim contractors on new ways to improve production using innovative tree-trim equipment.
    - An alley mowing pilot program in the city of Detroit has proven successful and has been expanded. Many Detroit alleys have become overgrown and impassable. Using mechanical mowers, our contractors have been able to clear brush and small trees allowing access for bucket equipment, which makes removals less expensive and easier. As part of this pilot, our contractors have obtained blanket permits with the city to remove alley trees. (Before and after pictured below.)
    - A pilot using a new insulated boom-mounted saw (one of two of its kind in the world) allows for the use of the saw within the “energized zone” near the wires. These saws can quickly and safely 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. (Example pictured below)

- The Company is also exploring other ways to utilize specialty equipment in back-yard areas where climbing crews are normally required. These include increased use of backyard buckets, backyard chippers, mowers and backyard Jarraffs.

Exhibit 10.6.1 Innovative Tree Trimming Equipment

Mowing Alleys

Before

After

Removing Unstable Trees

Removing a dead tree which has grown into the wires. Dead trees cannot be climbed, therefore specialty equipment is required

10.7 Resources

An average of approximately 1,200 tree trimmers are needed to execute the annual scope through the end of the Surge program, assuming average annual storm volume. Today, the Company primarily uses five tree-trimming contract companies.

Because there are not enough local tree trimmers to complete Surge program goals, DTEE must hire qualified tree-trimming crews from outside of our service territory to supplement the contract workforce. The long-term plan is to achieve an adequate level of qualified local workers to displace the non-local workers. A local trimmer lives within reasonable driving distance of the DTEE service territory and makes union wages. Non-local trimmers normally work in other parts of the country but have come to work for DTEE contractors on a temporary basis. A non-local trimmer makes union wages but also requires a daily per diem rate to cover room and board. These requirements make non-local trimmers more expensive than local trimmers.

DTEE faces several risks that could erode its current non-local trimmer population:

- Due to the Company's location in a colder climate, many non-local trimmers do not want to work in the area during the winter months. To make up for the potential manpower shortfall in the winter months, a higher volume of workers is necessary during the warmer months.
- The market for non-local trimmers is tight and these workers are in high demand due to the utility industry's collective renewed focus on tree trimming. If DTEE does not stay on pace with market rates, non-local trimmers will leave for other utilities.
- DTEE requires specialized climbing tree-trim workers due to its high percentage of backlot construction. Safe and experienced climbing crews are difficult to acquire, and it could be difficult to grow the work force to the levels needed.
- Large weather events, such as hurricanes, often draw traveling non-local trimmers from across the country for the overtime hours and generous per diem rates. Not only could this delay implementation of our Surge program due to a temporary loss of workforce, but trimmers could choose not to return after the storm if other opportunities prove more attractive.

The Company has several initiatives underway to increase the local tree trimmer workforce and reduce dependency on non-local trimmers.

- The Company has partnered with the City of Detroit, IBEW Local 17 and its tree-trimming contractors to develop and implement a pre-woodsman training pilot program to satisfy the demand for qualified tree trimmers. The pilot tree trimming academy is located within the City of Detroit with the goal of preparing local resident candidates to work as woodsmen. Graduates of the six-week academy enter the nine-day boot camp that was designed in partnership with IBEW Local 17 and the Company's tree-trimming contractors. The boot camp gives participants intensive training and hands-on work experience on subjects such as safety, climbing systems, climbing techniques, arborist equipment, arborist tools, commercial vehicle operation, tree species identification, communication with line crews, customer relations, and aerial rescue techniques. Boot camp graduates enter the Line Clearance Tree Trimming Apprentice Program. The 5,000-hour apprenticeship program, which includes 160 hours of classroom training, is recognized by the Department of Labor as an approved apprenticeship program and, as one of two programs in the United States, is benchmarked throughout the industry.

- The Company has implemented a pilot tree-trimming training program into the Vocational Village at Parnall Correctional Facility in Jackson. The training program was developed to allow returning citizens to directly enter the apprenticeship program upon leaving the correctional facility. In selecting applicants, the Vocational Village administration heavily weighs the applicant's county of residence to decrease the distance they would have to commute to work once they are released. Graduates are paired with jobs upon graduation.
- The Company is encouraging our local contractors to hire additional new trimmers through their normal processes, which in the past was used primarily to replace attrition.
- The Company is partnering with Local 17 and its contractors to reach out to local high schools, career fairs, and local nonprofit organizations to introduce the tree-trimming trade to interested candidates.

10.8 Conclusion

The tree-trimming program is one of the most impactful and important programs in the Company's commitment to reliability and safety. The program has shown that it significantly decreases system risk (specifically reduced wire downs), increases reliability (fewer and shorter outages), and decreases reactive trouble costs. Continuing to bring the system on-cycle and completing the Surge program will address the grid's current needs, while supporting the Company's long-term goals of resiliency and affordability.

11 Infrastructure Redesign and Modernization

Infrastructure Redesign and Modernization is one of the four pillars in DTEE's Distribution Grid Plan framework. It includes 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 more standard 13.2 kV system. The ultimate goal of these projects and investments is to enhance safety, reliability, and grid resilience for our customers.

As identified in the Grid Modernization section, the lack of capacity on significant portions of DTEE's distribution and subtransmission systems is a grid need that must be addressed to accommodate our customers' increased adoption of DERs and EVs. This section provides a detailed description for each of the infrastructure redesign projects identified for the next five years, based on current loading constraints. This area of redesign and modernization will likely grow in importance as DTEE continues to focus on the grid of the future and the role of increased electrification and DG/DS develop.

11.1 Distribution load relief projects

It is necessary to assess the load on the system and its impact on individual pieces of equipment in order to ensure that distribution system capacity exists to serve demand. Throughout this section, capacity refers to distribution assets' ability to deliver electrical power, not the ability to generate the power. There are areas within the system where the peak load is expected to increase. These increases may be the result of new load, or of customers relocating geographically from one area of the system to another. It is critical to identify expected capacity needs well in advance of the expected load increase in order to complete planning, siting, permitting, and construction of necessary infrastructure and to provide the expected service and reliability to customers.

Capacity needs are considered for two conditions: normal state and contingency states. The normal state exists when all equipment and components are in service and operating as designed. The contingency states exist when there is either 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, cable or breaker). Under contingency conditions, equipment in the rest of the system may see an increase in loading to compensate for the out-of-service equipment, therefore requiring additional capacity above normal state.

To meet the two capacity requirements, most components and equipment have two ratings: day-to-day and emergency. These ratings are calculated to maintain the viability of an asset throughout its expected useful life. Operating equipment above its designated ratings can cause immediate failure or accelerate end-of-life.

- The **day-to-day** rating (for normal state conditions) is the load level that the equipment can be operated at for its expected life span.

- The **emergency** rating (for contingency state conditions) is typically higher than the day-to-day rating and indicates the load level that the equipment can operate for short periods of time only. Operating at the emergency rating adds stress to the equipment and shortens its lifespan. If a piece of equipment exceeds its emergency rating, DTEE's System Operations Center takes immediate steps to transfer load or shed load if necessary.

- Substations also have a firm rating, which is the maximum load the substation can carry under a single contingency condition and is based on the lowest emergency rating of all the substation equipment that is required to serve the load.

To ensure that expected load growth can be served within the equipment ratings, DTEE planning engineers conduct annual Area Load Analyses (ALA). These analyses include verification of equipment ratings and substation firm ratings, past loading data, system conditions and configurations, known new loads, and input from large customers and municipal officials about potential development. Based on DTEE's 2020 ALA study, approximately 35% of distribution substations have loading constraints, including substations operating over its firm ratings, substation equipment working near or over its day-to-day rating during peak hours, or circuit equipment operating over its day-to-day rating during peak hours. Since the study is conducted for peak load conditions, the over firm or overload assessments are usually of concern for just a small percent of hours annually, depending on loading characteristics of individual substations or subtransmission lines. As such, additional substation capacity is needed in certain areas to prevent customer interruptions during a single contingency event and to help maintain the useful life of the existing equipment.

For areas and cities that have experienced steady and/or strong load growth, capital investment is required to add or upgrade overhead or underground lines (subtransmission and/or distribution) and/or to expand or build new substation capacity.

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 general purpose substation, may have the added benefits of mitigating substation risk at neighboring substations and improving overall reliability for the area.

11.1.1 Load relief prioritization

As mentioned above, approximately 35% of DTEE's distribution substations have loading constraints based on DTEE's 2020 ALA study. It is not feasible, nor cost effective, to address all the loading constraints at once due to other higher priority investments, as explained in DTEE's Global Prioritization Model (GPM) in Section 5. Therefore, DTEE has developed a prioritization methodology to assess substation loading constraints based on criticality. Results of the load relief prioritization are fed into DTEE's Global Prioritization Model to ultimately drive future capital planning.

This load relief prioritization methodology has evolved over time and is now based on four variables:

- **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, 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 with and without load transfer (or load jumpering). Under contingency conditions, any MVA load over substation firm rating represents customers that cannot be served by the substation itself. Some of this load can be subsequently transferred to adjacent substations for the duration of the contingency. This creates a difference in values and scoring in MVA over firm before load transfer, and MVA over firm after load transfer.
- **Circuit equipment overload** (peak load exceeding circuit equipment day-to-day ratings or exceeding circuit equipment emergency ratings – While the original load relief prioritization centered on substation equipment, the latest iteration has been expanded to include circuit equipment overloads, and thus provides visibility around the overall loading constraints of the distribution system. 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 conductor. 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. 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 in the area. Being able to create a project that not only serves the new customers but also resolves the substation overload or over firm situation is preferred from the economic perspective.

The final priority ranking of distribution load relief is a combination of the above four variables. Exhibit 11.1.1.1 lists the top 25 substations based on this methodology with applicable variables.

Exhibit 11.1.1.1 Top 25 Load Relief Substations Overview

Index	Substation	Voltage (kV)	Region	Community	Substation Equipment Overload	Substation Over Firm	Circuit Equipment Overload	Strong Load Growth Prospect
1	Alfred	13.2	SE	Detroit			✓	✓
2	Hawthorne	4.8	SE	Dearborn Heights	✓	✓	✓	
3	St. Antoine	13.2	SE	Detroit			✓	✓
4	Madison	4.8	SE	Detroit			✓	✓
5	Cato	13.2	SE	Detroit			✓	✓
6	Garfield	4.8	SE	Detroit			✓	✓
7	Temple	13.2	SE	Detroit			✓	✓
8	Walker	4.8	SE	Detroit			✓	✓
9	Cody	13.2	NW	South Lyon		✓	✓	✓
10	Prospect	4.8	SW	Ann Arbor	✓	✓	✓	
11	White Lake	4.8	NW	White Lake	✓	✓	✓	
12	Howard	4.8	SE	Detroit			✓	✓
13	Cato	4.8	SE	Detroit			✓	✓
14	Snover	4.8	NE	Snover	✓	✓	✓	
15	Shaw	4.8	NE	Imlay City	✓	✓	✓	
16	Roseville	4.8	NE	Roseville	✓		✓	
17	Golf	13.2	NE	Macomb			✓	

Index	Substation	Voltage (kV)	Region	Community	Substation Equipment Overload	Substation Over Firm	Circuit Equipment Overload	Strong Load Growth Prospect
18	Daly	4.8	SE	Dearborn Heights	✓	✓	✓	
19	Marlette	13.2	NE	Marlette	✓		✓	
20	North Branch	13.2	NE	North Branch	✓	✓	✓	
21	Brown City	4.8	NE	Brown City	✓	✓	✓	
22	Mayville	4.8	NE	Mayville	✓	✓	✓	
23	Carleton	4.8	SW	Carleton	✓	✓	✓	
24	Wolverine	13.2	SW	Ann Arbor	✓	✓	✓	
25	Goodison	13.2	NW	Oakland	✓		✓	✓

11.1.2 Consideration of non-wire alternatives

DTEE continues to investigate Non-wire alternatives (NWAs) to provide targeted load relief to the electrical system. If a substation or distribution circuit is identified as a potential candidate for NWA through the screening process, planning engineers would work with technology and EWR/DR experts to evaluate detailed designs. The process by which NWAs are evaluated by planning engineers as a potential load relief solution is discussed in detail in Section 4.3. Pilot projects as NWA solutions are discussed in Section 12.7.

DTEE will leverage learnings from in-house pilots and other utilities to refine its criteria, develop new tools and advance the overall process for pursuing NWAs as part of the distribution project review process.

11.1.3 Projects to address distribution loading

Exhibit 11.1.3.1 lists the scope of work planned to address the load relief for the top ranked substations. There are also other projects planned which address load relief along with additional project drivers. These projects are shown in Exhibit 11.1.3.2 including the additional drivers.

Exhibit 11.1.3.1 Top 25 Load Relief Substation - Project Summary

Index	Substation	Region	Community	Project and Scope of Work
1	Alfred	SE	Detroit	CODI – Alfred Expansion: Expand 13.2 kV Alfred substation by installing 3rd transformer and a 12-position switchgear
2	Hawthorne	SE	Dearborn Heights	4.8 kV Conversion: Hawthorne Relief and Circuit Conversion: • 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
3	St. Antoine	SE	Detroit	Load relief will be provided by the CODI – Alfred Expansion project, see index #1, and CODI – New Corktown Substation: • Construct new 13.2 kV Corktown substation which will support load relief of surrounding substations including St. Antoine
4	Madison	SE	Detroit	CODI - Madison Conversion: • Rebuild 31 miles of network feeder cable • Rebuild 30 miles of system cable

				• Replace or remove 92 netbank transformers • Convert 24 primary customers • Convert three miles of overhead • Convert and consolidate the circuits to 13.2 kV fed by Temple substation • Decommission Madison substation
5	Cato (13.2)	SE	Detroit	CODI – Cato Substation Expansion: Expand 13.2 kV Cato substation by installing 3rd transformer and a 12-position switchgear
6	Garfield	SE	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
7	Temple	SE	Detroit	CODI – Midtown Expansion: Expand 13.2 kV Midtown substation by installing 3rd transformer and a 12-position switchgear
8	Walker	SE	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 (built in 1923) substation

				• Decommission aging 24kV cables and infrastructure
9	Cody	NW	South Lyon	System Loading: Cody: • Reconfigure circuits by performing phase balancing and load transfers • Rebuilding of circuit backbones to meet current standards • Establish new circuit backbones and build to current standards • Install sectionalizing and voltage correction equipment • Convert section of 4.8 kV to 13.2 kV
10	Prospect	SW	Ann Arbor	System Loading: Prospect: Replace existing transformer
11	White Lake	NW	White Lake	4.8 kV Conversion: White Lake Decommissioning and Circuit Conversion: • Build a new 40 kV to 13.2 kV substation • Convert distribution circuit 307 White Lake to a 13.2 kV circuit • Establish four load carrying circuits supporting White Lake Substation load and a portion of Clyde Substation • Establish new jumpering points and loop schemes between the new substation and Clyde, Wardlow, Teggerdine, Placid, and Osprey substations • Decommission White Lake substation
12	Howard	SE	Detroit	CODI – Howard Conversion: • Rebuild 6 miles of network feeder cable • Rebuild 12 miles of system cable

				• Replace or remove 89 netbank transformers • Convert 26 primary customers • Convert 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
13	Cato (4.8)	SE	Detroit	CODI – Cato/Orchard Conversion (Cato portion): • Rebuild 17 miles of system cable • Convert 15 primary customers • Convert and consolidate the circuits to 13.2 kV fed by Temple substation • Decommission Cato 4.8 kV substation
14	Snover	NE	Snover	4.8 kV Conversion: Snover Decommissioning and Circuit Conversion: • Build a new 13.2 kV Class T substation • Reconductor approximately 13 miles on Snover circuits • Convert and transfer load from the Snover distribution circuits to the new substation • Decommission Snover Substation
15	Shaw	NE	Imlay City	Load relief will be provided by the System Loading: Brown City project, see index #21, and System Loading: Otsego/Capac/Shaw: • Install a new 13.2 kV skidmount substation

				• Convert and transfer about 10 miles of Otsego, Capac, and Shaw circuits to the new skidmount substation
16	Roseville	NE	Roseville	A detailed area plan study will be performed for Roseville and the surrounding substations to determine a holistic solution that will address load relief for Roseville and is beneficial to the overall area
17	Golf	NE	Macomb	System Loading: Macomb/Golf: • Expand Macomb substation by adding a 3rd transformer and two 12-position switchgears • Install about 3 miles of underground conduit and 5 miles of underground cable for new distribution circuits • Reconductor about 5 miles of overhead line • Transfer load from Golf and Burbank substation areas to new Macomb distribution circuits
18	Daly	SE	Dearborn Heights	Load relief will be provided by the 4.8 kV Conversion: Hawthorne Relief and Circuit Conversion project, see Index #2
19	Marlette	NE	Marlette	Load relief will be provided by the System Loading: Brown City project, see Index #21
20	North Branch	NE	North Branch	No additional load growth projected – will be re-evaluated during Fall 2021 Area Load Analysis
21	Brown City	NE	Brown City	System Loading: Brown City: • Build a new 13.2 kV Class T substation at Bennett station • Reconductor approximately 3.5 miles on Tacoma circuits • Reconductor approximately 4.5 miles on Marlette DC 8281

				• Rebuild and convert approximately 8 miles of Brown City distribution circuits from 4.8 kV to 13.2 kV • Transfer load from Brown City, Shaw, Tacoma, and Marlette substation areas to the new substation • Decommission Brown City Substation
22	Mayville	NE	Mayville	System Loading: Mayville: • Construct a new 13.2 kV Skidmount STDF and transfer 1200 kVA from Mayville and 1500 kVA from Clifford to new STDF • Reconductor 7 miles of overhead distribution • Install 5 miles of neutral • Convert about 12 miles of overhead distribution from 4.8 kV to 13.2 kV
23	Carleton	SW	Carleton	System Loading: Carleton: • Reroute 4.8kV and 40kV overhead on the substation property • Expand substation fence on the north side • Install new control center • Replace both transformers at Carleton and upgrade associated equipment • Re-establish jumpering point between the two circuits
24	Wolverine	SW	Ann Arbor	System Loading: Grenada: • Install new 13.2 kV Class A substation with two transformers and 12-position switchgear • Install one mile of underground conduit and 2 miles of underground cable

				• Rebuild two miles of overhead backbone • Convert iso-pockets on DC 9813 Grenada by replacing 10 miles of overhead conductors • Rebuild and convert 20 miles of overhead line from the Prospect substation area • Establish new distribution circuits to relieve load from Grenada, Wolverine, Prospect, and Price substations
25	Goodison	NW	Oakland	System Loading: Goodison: • Construct a 13.2 kV skidmount substation • Establish two new distribution circuits to relieve load from Goodison • Install underground conduit and cable to connect to existing circuits • Extend one primary main and create two new primary mains • Reconductor 1.3 miles of overhead line

Exhibit 11.1.3.2 Load Relief Projects with Additional Drivers

Substation(s) / Location	Region	Community	Drivers	Project and Scope of Work
Mack	SE	Detroit	• Inoperable tap changers on adjacent transformers • Long shutdowns causing increased risk of stranded load if energized transformer lost	System Loading: Mack Transformer 102: Install new 120 kV to 24 kV Transformer 102 at Mack to allow for repair of tap changers and future shutdowns
Mandalay	SE	Birmingham, Beverly Hills, Clawson	• Circuit overload • Poor reliability performance	System Loading: Mandy 307 Load Transfer: Convert 7,600' of 4.8kV distribution circuit 307 Mandalay and transfer to distribution circuit 9893 Ariel and install sectionalizing
Richmond / Armada	NE	Richmond, Armada	• Antiquated 4.8 kV switchgear at Richmond • Richmond and Armada 4.8 kV substations over firm • Circuit overload on DC 302 Armada • Expected load growth with lack of capacity • Limited jumpering	System Loading: Richmond/Armada: • Upgrade Richmond substation to a Class A substation, installing a new transformer, replacing the existing transformer, and installing new switchgear • Install 1,000 feet of underground conduit • Install 2,000 feet of underground cable • Decommission the existing Richmond 4.8kV substation and switchgear • Reconductor and convert 15 miles of overhead distribution line • Decommission Armada 4.8kV Substation

Port Sanilac	NE	Port Sanilac	• Port Sanilac and Foster substations over firm • Day-to-day circuit overload on DC 302 Port Sanilac and DC 301 Foster just under day-to-day with minimal differences between day-to-day and emergency ratings for both circuits • Limited jumpering and capacity	System Loading: Port Sanilac: • Install new Skidmount STDF between Foster & Port Sanilac • Establish new 13.2 kV distribution circuits • Rebuild and convert 3 miles of DC301 Foster • Rebuild and convert 3 miles of DC302 Port Sanilac • Decommission Foster substation
Jewell	NW	Washington	• Jewell substation just under firm, but has two circuits over day-to-day rating and three just under day-to-day rating • Load center doesn't allow for transferring load without causing issues on adjacent circuits • Expected load growth with lack of capacity • Closest adjacent substation is 4.8 kV Washington	System Loading: Jewell: • Build a new 13.2 kV substation with two transformers and 12-position switchgear • 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
Wixom	NW	Wixom	• Wixom substation over firm • Circuit overload on DC 8239 with 4 other circuits	System Loading: Wixom: • Add a third transformer at Wixom substation • Replace existing switchgear with two 12-position switchgear

			approaching day to day rating • Expected load growth with lack of capacity • Existing switchgear nearing end of life	• Build multiple miles of underground cable (22), conduit (5) and overhead lines (4)
New Baltimore / Chesterfield	NE	New Baltimore, Chesterfield	• New Baltimore and Chesterfield substations over firm with New Baltimore limited by subtransmission feed • Three circuits exceeding day-to-day rating with another at 99% • High load growth in Chesterfield substation area	System Loading: New Baltimore/Chesterfield: • Build a new 13.2 kV substation • Install 4,000 feet of underground conduit and 8,000 feet of underground cable • Reconductor 12 miles of overhead line • Establish 5 new distribution circuits
Diamond	SW	Dexter	• Diamond substation significantly over firm • Expected load growth with lack of capacity	System Loading: Diamond: • Upgrade one substation transformer with a larger unit • Rebuild primary and secondary tower to meet current standards • Install circuit switcher, transformer control panel in a new control center, and upgrade relays

Exhibit 11.1.3.3 lists the projected costs and timeline for load relief projects. This exhibit excludes the CODI and 4.8 kV conversion projects providing load relief as the projected investment for those projects is listed in Section 11.3 and Section 11.4 respectively. It is important to note that DTEE has based the cost and timeline estimates for the identified projects on the best knowledge and information known today. Actual project cost and timeline could deviate from the projection due to various unforeseen factors or new information/learnings.

Exhibit 11.1.3.3 Projected Costs and Timeline for Load Relief Projects

Project	2021	2022	2023	2024	2025	2021-2025 Cost Estimate ($ million)	2026 to 2029 Cost Estimate ($ million)
System Loading: Mack Transformer 102						$0.2	$-
System Loading: Carleton						$2	$-
System Loading: Mandy 307 Load Transfer						$1	$-
System Loading: Brown City						$30	$-
System Loading: Richmond/Armada						$23	$3
System Loading: Grenada						$18	$19
System Loading: Port Sanilac						$18	$-
System Loading: Prospect						$1	$-
System Loading: Cody						$3	$-
System Loading: Otsego/Capac/Shaw						$12	$2

Project	2021	2022	2023	2024	2025	2021-2025 Cost Estimate ($ million)	2026 to 2029 Cost Estimate ($ million)
System Loading: Macomb/Golf						$19	$21
System Loading: Jewell						$5	$51
System Loading: Mayville						$3	$28
System Loading: Goodison						$1	$13
System Loading: Wixom						$1	$83
System Loading: New Baltimore/Chesterfield						$1	$32
System Loading: Diamond						$1	$4

It should be noted that the load relief projects previously listed are proposed based on DTEE's assessments of area load growth and system loading conditions as of today and are subject to change in the future. 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. In addition, as mentioned in Section 4.2, DTEE expects to enhance and refine substation and circuit level forecasting in the next three years. The loading information used in the current ALA process primarily relies on past years' peak load and known new load, based on customer or input from municipal officials. Planned future enhancements include developing forecasts at a more granular/hourly level and incorporating impacts of adoption of new technologies. Regardless of forecasting methodology, uncertainty remains in the nature of predicting future load growth, so the projects proposed to address loading concerns may change from year-to-year. Based on project proposals known today, DTEE estimates the annual capital investment on load relief projects as shown in Exhibit 11.1.3.4.

Exhibit 11.1.3.4 Projected Load Relief Capital Investment

	2021	2022	2023	2024	2025	Total Investment 2021-2025
Load Relief Capital Investment ($ million)	$6	$11	$20	$50	$53	$140

11.2 Subtransmission Redesign and Rebuild Program

DTEE's subtransmission system is operated at a voltage of either 24kV, 4kV, or 120kV and is used to step down transmission voltage to serve distribution and industrial substations. The design of the system is intended to introduce redundancy to the feed points of the distribution and industrial substations, resulting in continued service to customers during a single contingency situation. DTEE's subtransmission system differs from that of most other utilities because it includes both radial and network designs. The radial configuration, called a trunk line, has one source station and can feed one or multiple substations. The network configuration, called a tie line, has multiple source stations and feeds multiple substations. DTEE utilizes a coordinated system of automatic pole top switches (APTS) as discussed in Section 8.13, and line section breakers on the networked tie lines to isolate faults and maintain service to customers in single contingency failure situations.

The subtransmission redesign and rebuild program is focused on installing station equipment, as well as rebuilding both the overhead and underground portions of the subtransmission system. The station work involves the installation of large transformers, capacitor banks and associated equipment. The overhead work includes the replacement of old wooden poles with new steel poles, porcelain insulators with polymer clamp top insulators, and small aging conductors – which are often damaged by multiple lighting strikes – with larger, stronger conductors. The underground work consists of replacing at-risk or overloaded cable with new sections and rebuilding cable poles to new specifications.

The need for a subtransmission redesign and rebuild program has become increasingly apparent during the attempted normal operations of the electric system, through the evaluation of new customer load requests, and during review of the increasing number of outages on DTEE's subtransmission system. The subtransmission system has seen increasing limitations to serve DTEE's customers during a single contingency situation.

Though the system was originally designed to efficiently serve customers with the necessary redundancy and in most cases to maintain service under a single contingency, system loading and the impact of outages on customer operations have increased over time. The increase in system loading has resulted in increasing limitations of the subtransmission system to serve customers during a single contingency situation. This condition has led to an increased number of outages and extended the length of time to restore large outages affecting one or multiple substations. Additionally, these system limitations, coupled with increasing customer sensitivity to outages, has led to the costly deployment of mobile generation or portable substations for normal planned work.

In addition, like the distribution system, the subtransmission system is aging, leading to an increased number of failures on both the overhead and underground system. These failures can result in either a large sustained outage or the loss of redundancy, depending on the system configuration and any existing violations of the planning criteria. Some areas of the overhead system are in deep-wooded areas and along railroads, increasing the difficulty for restoring service or maintaining equipment. The underground cables can be difficult to replace and restore within the conduit system, increasing the length of time that these lines are not available for use to multiple days.

Subtransmission Planning Engineers analyze the condition of the system on a yearly basis to determine existing and projected limitations to serving customers in a single contingency situation. This analysis is conducted by utilizing industry-standard modeling software (PSSE & TARA) with individual substation loads submitted by the Distribution Planning & Industrial Power Engineers and the models used by the Midwest Independent System Operator (MISO). The models provided by MISO include multiple electric system scenarios, including current and future peak loading conditions. Using these models, a study is run on each individual subtransmission line with all possible contingency situations assessed to identify all violations of subtransmission planning criteria. The planning criteria focuses on both thermal overloads and voltage violations under normal system conditions and during a single contingency configuration.

A thermal overload indicates that equipment on the circuit or station exceeds its rating, and a voltage violation indicates that the voltage on at least part of the circuit is no longer within an acceptable range. The presence of planning criteria violations on a subtransmission circuits has two main implications. First, it means the system has additional operational risk, particularly during days with high load. Ideally, the subtransmission system would be able to serve all load at any time under a single contingency. If an equipment failure creates a thermal overload or voltage violation, load will be shed to protect equipment and maintain system integrity, leading to an outage. Second, the planning criteria violation means that the circuit has no capacity for additional load, either from a new large customer connection or general area load growth.

The results of the analysis on the subtransmission system determined that approximately one-third of the circuits on the subtransmission system violate a planning criteria under either normal or single contingency. A high-level estimate is that it would cost $2 billion to address all of these violations. To begin addressing the constraints on the subtransmission system, the planning criteria violations have been ranked based on severity, and projects have been developed to address the limiting elements on the system, which will be discussed in the next two sub-sections.

The Subtransmission Planning Engineering group also closely monitors the reliability of the system, identifies circuits with multiple reliability issues, and works with communities that express reliability concerns to develop plans to address customer concerns. In developing a project plan, the Planning Engineers consider existing routes of the lines as well as sections where wire down events have occurred. Based on the analysis, the Planning Engineers identify which sections to focus on for redesign and rebuild. The project scope can include rebuilding the lines to the current more resilient construction standards and relocating the lines to road accessibility wherever possible.

In addition, DTEE performed an in-depth study of the subtransmission system in the Thumb area in 2019 by closely analyzing the current condition and performance of the system, and evaluating what long-term options would best serve the needs of its customers with respect to upgrades to the subtransmission system in the area.

Through this in-depth 2019 study and close monitoring of reliability performance, DTEE has concluded that the condition of the subtransmission system has degraded to a point where a much more urgent and large-scale investment plan is required. A robust subtransmission system is required to serve large amount of dense load and provide the necessary reliability through well-designed redundant systems, where both large and small customers will benefit.

To achieve these improvements on the system, DTEE must rebuild the lines with larger conductors, and redesign the configuration of circuits to meet the load profiles of current customers, all while providing capacity for future expansion. The additional capacity provided by the subtransmission system redesign and rebuild would support the community by allowing for new business expansion and electrification integration in the area with reduced construction time and cost to connect or interconnect new customers.

The subtransmission system analysis has also shown the importance of taking a holistic view of an area when addressing loading issues on a line. This is especially evident when redesigning the networked tie system in rural areas. Improving capacity on a single circuit often requires work on multiple adjacent circuits, and the addition of transformers and capacitor banks at source stations due to the required redundancy of the system.

When designing system upgrades and executing rebuilds, DTEE will keep the future in mind by using strengthened standards (steel poles, larger conductors) and build in the appropriate system redundancy. For station upgrades, designs will ensure additional space, ground mats, oil containment, and the necessary below-grade infrastructure to allow for future expansion.

11.2.1 Subtransmission prioritization

DTEE considers multiple criteria when evaluating priority of the subtransmission redesign and rebuild projects. Consistent with the rest of the strategic investment portfolio, the load relief prioritization scores for subtransmission feed into the GPM model to help formulate the future capital plan. The Load Relief model was updated to capture considerations on established planning criteria for subtransmission redesign & rebuild projects. Subtransmission load relief prioritization scores are assessed based on load loss for single contingency, load over allowable emergency rating for single contingency, load over day to day ratings, strong load growth prospect, and whether there is a voltage violation. Exhibit 11.2.2.1 below shows the details of the criteria. Exhibit 11.2.2.2 lists the top 25 subtransmission load relief projects based on this methodology with applicable dimensions.

Exhibit 11.2.2.1 Subtransmission Load Priority Criteria

Subtransmission Dimensions	Definition
Load Loss for Single Contingency	Total load that will be shed when a subtransmission line can longer support the substation and does not have a back-up or the back-up cannot support the load
Load over allowable Emergency Rating for Single Contingency	Total load when a subtransmission line exceeds its emergency rating of its alternative route during an event (i.e., outage)
Load over Day to Day Rating, Normal Conditions	Total load that exceeds the rating of a subtransmission line during normal conditions
Strong Load Growth Prospect	Consideration given to subtransmission lines that are predicted to experience load growth
Voltage Violation	Consideration given to subtransmission lines that experience low voltage conditions when they are not in their normal configuration (i.e., due to an outage)

Exhibit 11.2.1.2 Top 25 Subtransmission Load Relief Project Dimensions Overview

Index	Project	Region	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 - Bad Axe	NE	Bad Axe	✓	✓	✓	✓	✓
2	Trunk 7333	NW	Madison Heights	✓	✓	✓		
3	Trunk 7106	SE	Southfield	✓	✓	✓	✓	
4	Trunk 4217	SE	Grosse Pointe, Harper Woods, Detroit	✓	✓	✓		
5	Boyne	NE	Macomb	✓	✓		✓	
6	Bad Axe - Transformer 102 Addition	NE	Bad Axe	✓	✓		✓	✓
7	Trunk 4266	SE	Eastpointe	✓	✓	✓		
8	Tie6907	NW	Rochester Hills	✓	✓		✓	✓
9	Tie 3416 - Pigeon	NE	Elkton, Pigeon	✓			✓	✓
10	Trunk 4911 Voltage	NE	Lenox, Chesterfield, New Baltimore, Ira	✓			✓	✓

11	Trunk 2255	SE	Detroit	✓	✓	✓		
12	Trunk 2237	SE	Redford	✓	✓	✓		
13	Tie 7504	NE	Novesta	✓			✓	✓
14	Derby	NE	Vassar				✓	✓
15	Sandusky Transformer 101 Breaker	NE	Sandusky			✓		
16	Sandusky - Transformer 102 addition	NE	Sandusky	✓	✓			✓
17	Pigeon Area	NE	Multiple	✓	✓			✓
18	Trunk 3509	NW	Royal Oak		✓	✓		
19	Trunk 3508	NW	Troy	✓	✓			
20	Tie 6602	SW	Lima Twp	✓	✓			
21	Trinity	SW	Monroe	✓				✓
22	Bernard	NE	Wales Twp	✓				✓
23	Trunk 4911 Load	NE	Lenox, Chesterfield, New Baltimore, Ira	✓	✓			
24	Tie 1568	SW	Ypsilanti	✓	✓			
25	Trunk 328	SE	Detroit	✓	✓			

11.2.2 Subtransmission projects and programs

As DTEE continues to increase investment to improve the subtransmission system, the portfolio of over 50 projects listed below includes the projects previously mentioned in Exhibit 11.2.1.2, additional subtransmission load relief projects, and projects developed to improve the reliability of the system and address planning criteria violations. Exhibit 11.2.2.1 lists the community and scope of work for the identified subtransmission redesign and rebuild projects. Exhibit 11.2.2.2 lists the projected costs and timeline for the projects. It is important to note that the cost and timeline estimates for the identified projects are based on the best knowledge and information known today by DTEE. Actual project cost and timeline could deviate from the projection due to various unforeseen factors or new information/learnings. The planned investments in the subtransmission system from 2021-2025 mark a significant increase from previous years. However, as shown in Exhibit 11.2.2.2, the total for the program over the next five years is less than $500M. This means that it would require approximately two decades of spending at the existing spend rate to address current planning criteria violations.

DTEE intends to continue to grow the investment in the subtransmission system in future years, with the pace of that growth depending on 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.

Exhibit 11.2.2.1 Subtransmission Projects Summary

Tie or Trunk	Community	Scope
Subtransmission Redesign & Rebuild: Maxwell Amherst	Detroit	• Decommission and remove Amherst Transformer 2 and associated station equipment and cable • Install new Transformer 2 and associated station equipment and cable
Ann Arbor System Improvements	Ann Arbor	Construct two new substations and five miles of 120 kV lines, and reconfigure subtransmission tie lines and trunk lines
Transformer High Side Protection Program	Various	• Install high side switching devices on 19 subtransmission and distribution transformers located at 15 different stations within DTEE territory • 8 of these transformers will also require relocation and/or replacement due to space constraints at their current sites
Station Upgrade: Cortland Station Expansion	Highland Park	Purchase property adjacent to Cortland station and install two new transformers, 104 and 105 to replace existing transformers 101 and 102 to resolve physical replacement restrictions at existing Cortland site
40kV Capacitor Banks at Armada and Adair	Armada, Columbus	Install one 40 kV 9.6 MVAR capacitor at Armada substation and one 40 kV 9.6 MVAR capacitor at Adair substation
Subtransmission Breaker Short Circuit Violations	Multiple	Install reactors or replace breakers at multiple stations
Subtransmission Redesign and Rebuild: Trunk 7106	Southfield	Reconfigure Trunk 7106 into two trunk lines – Trunk 7106 and Trunk 7187

		Install 2.3 miles of underground cable for new Trunk 7187
Subtransmission Redesign and Rebuild: Trunk 7333	Madison Heights	• Reconfigure Trunk 7333T into two trunk lines - Trunk 7333 and Trunk 7370 • Install 3 miles of underground cable for new Trunk 7370 • Install a 40 kV breaker and two 40 kV disconnects (2000 Amp) at position SB Chestnut
Subtransmission Redesign and Rebuild: Trunk 2255	Detroit	Install 1.3 miles of new cable to split load of Trunk 2255 while removing old cable
Subtransmission Redesign and Rebuild: Boyne	Macomb	• Install new 120-40 kV transformer 102, 40 kV section breaker, and bus 2 at Boyne • Install one 40 kV line breaker, disconnect on the low side of transformer 102, install circuit switcher on the high side of transformer 102 • Install disconnects and breaker for the new position (new trunk) on Bus 2 and install relay panels • Install 1.5 miles of new conduit and 40 kV cable • Install 2.5 miles of new overhead 40 kV • Replace 2.1 miles of overhead conductor on Trunk 7909 • Replace 0.3 miles of overhead conductor and 0.4 miles of underground cable on Trunk 6759
Subtransmission Redesign and Rebuild: Badax Transformer 102 Addition	Bad Axe	• Expand Badax 40 kV Bus 2 and add two 40 kV positions • Install one 120-40 kV 45/60/75 MVA Transformer 102 from ITC's Bus 102 to new 40 kV position on Badax Bus two

		• Install one 120 kV S&C 2020 circuit switcher • Install one 40 kV 2000A breaker • Install two 40 kV 1200A disconnects
Subtransmission Redesign and Rebuild: Tie 4105	Lexington, Croswell	• Reconductor 35 miles of 40 kV overhead line • Rebuild 18.6 miles of distribution underbuild
Subtransmission Redesign and Rebuild: Trunk 2237-ST	Redford	Install 0.8 miles of underground cable to parallel overloaded Trunk 2237-ST cable
Subtransmission Redesign and Rebuild: Sandusky Transformer 101 Breaker	Sandusky	Replace existing Transformer 101 secondary disconnect switch, 40 kV breaker and associated control cables and current transformers

Subtransmission Redesign and Rebuild: Tie 810	Lenox	• Build a new station (Gramer Station)
		• Reconfigure Tie 810 into Tie 9505, Tie 9514, and Trunk 4938
		• Complete the following work for Tie 9505, Tie 9514 and Trunk 4938:
		  ○ Install 11 miles of overhead conductor
		  ○ Reconductor 13 miles of overhead conductor
		  ○ Decommission five miles of overhead conductor

Subtransmission Redesign & Rebuild: Slocum	Trenton	Remove onsite subtransmission lines and equipment and make modifications at Slocum station due to Trenton Channel Power Plant decommission
Subtransmission Redesign and Rebuild: Trunk 4217	Grosse Pointe, Harper Woods, and Detroit	Replace 2.1 miles of underground cable and associated station work

Subtransmission Redesign and Rebuild: Trunk 4266	Eastpointe	Replace 2.5 miles of underground cable
PQ Fault Meter Locating	Various	Install a total of 177 PQ meters throughout the system including 82 station transformer positions and 95 24 kV/ 40 kV tie lines
Subtransmission Redesign and Rebuild: Trunk 3509	Royal Oak	Install new Trunk 3562 by installing about one mile of new underground cable to relieve Trunk 3509 overloads and repurpose Trunk 3509 cable to improve reliability at Mandalay substation
Subtransmission Redesign and Rebuild: Tie 6602	Dexter	Rebuild 3.5 miles of overhead 40 kV line and replace all distribution underbuild conductor
Subtransmission Redesign and Rebuild: Tie 1568	Ypsilanti	Replace 1066' of underground cable
Subtransmission Redesign & Rebuild: Pigeon Area Improvement	Unionville, Sebewaing, Kilmanagh, Pigeon, Bayport, Caseville, Kinde, Port Austin	• Extend 120 kV line from Cosmo to Pigeon • Install 120 kV breaker at Bad Axe • Install 120 kV one way switch to new tap at Pigeon • Install new 120 kV to 40 kV transformer at Pigeon with associated station equipment
Subtransmission Redesign and Rebuild: Tie 7504	Novesta	• Tap 120 kV ITC line and extend the 120 kV line 12 miles to Wilmot • Expand Wilmot station by installing a 120-40 kV transformer, circuit switcher, and two 40 KV breakers, upgrading relays, • and reconfiguring busses • Reconductor 16 miles of Tie 7504

Subtransmission Redesign and Rebuild: Tie 6907	Rochester Hills	• Reconfigure Tie 6907 and Trunk 6941 Spokane ends to eliminate overload on Tie 6907 and abandon cable & conduit of Bridge Main 005 & Bridge Main 014 • Install 1,700' of overhead conductor • Replace existing breaker at SPKNE with 2000A gas breaker
Subtransmission Redesign & Rebuild: Trunk 4911 Voltage Correction	Lenox, Chesterfield, New Baltimore, Ira	• Install new 40 kV position on Bus 2 at Victor Station • Install 9 miles of overhead 40 kV line and upgrade the underbuild overhead distribution • Install 0.6 miles of underground conduit • Install 0.6 miles of underground cable
Subtransmission Redesign and Rebuild: Sandusky Transformer 102 Addition	Sandusky	• Install one 120-40kV 45/60/75 MVA Transformer 102 from a new 120kV source to a new 40kV position on Sandusky 40kV bus 2 • Install one 120kV S&C 2020 circuit switcher, one 40kV 2000A breaker, and two 40kV 1200A disconnects • Move Sandusky Trf 101 from bus 3 to bus 4 • Install 40kV section breaker between bus 2 and bus 4
Subtransmission Redesign & Rebuild: Trunk 2443	Southfield	Replace 0.9 miles of underground cable
Subtransmission Redesign and Rebuild: Trunk 4911 Load	Lenox	Replace about 0.1 miles of underground cable and 6.7 miles of overhead conductor

Subtransmission Redesign and Rebuild: Trunk 4245	Eastpointe	• Install 1,000' of new conduit under I-94 • Install 1,800' of new underground cable • Remove 1,700' of old underground cable
Subtransmission Redesign & Rebuild: Trunk 5838	Howell	Reconductor 2 miles of overhead 40 kV line
Subtransmission Redesign and Rebuild: Trunk 2308	Macomb	Rebuild 2.9 miles of overhead 40 kV line along with 2.4 miles of distribution underbuild
Subtransmission Redesign and Rebuild: Tie 4104 North	Sherman and Sand Beach	• Reconductor 7.3 miles of overhead 40kV line • Reconductor 5.1 miles of distribution underbuild • Install 13 miles of overhead 40 kV line • Decommission 17.8 miles of overhead 40 kV line • Decommission 5.5 miles of distribution underbuild
Subtransmission Redesign and Rebuild: Custer Republic	Monroe	• Decommission Republic transformer 3 • Reconfigure TRK1456 and TRK1470 to feed Republic transformer 1 • Decommission Custer positions RS and SN • Decommission TRK1459 • Replace relay panels at Custer position RM
Subtransmission Redesign & Rebuild: Trunk 2419	Detroit	Replace 0.3 miles of underground cable

Subtransmission Redesign & Rebuild: Tie 3416 – Bad Axe	Bad Axe	Replace breakers, trainers, disconnects, and relay panel for position RH at Bad Axe Reconductor 1.6 miles of overhead 40 kV line
Subtransmission Redesign & Rebuild: Trunk 3508	Troy	Replace 2.8 miles of underground cable
Subtransmission Redesign & Rebuild: Tie 3416 - Pigeon	Elkton, Pigeon	• Replace trainers at substation • Reconductor 6.3 miles of overhead 40 kV line
Subtransmission Redesign & Rebuild: Thumb Electric Fault Isolation	Kinde Watertown, Ubly, Owendale, Millington	Replace five 40 kV pole top switches with automatic pole top switches with 40 kV bypass to support shutdowns and future maintenance
Subtransmission Redesign & Rebuild: Trunk 362	Detroit	Replace 3.3 miles of underground cable
Subtransmission Redesign & Rebuild: Trunk 2659	Waterford	Reconductor 0.7 miles of overhead 40 kV line
Subtransmission Redesign and Rebuild: Derby	Vassar	• Install Transformers 101 and 102, 60/80/100 MVA 138x120-40 kV series multiple switch transformers • Install two 120 kV S&C circuit switchers • Install two 40 kV 2000 A gas breakers • Install two 40 kV 1200 A disconnect switches
Subtransmission Redesign & Rebuild: Trunk 328	Detroit	Replace 3.4 miles of underground cable

Subtransmission Redesign & Rebuild: Trunk 3546	Troy, Birmingham, Royal Oak	• Install 0.9 miles of conduit • Replace 2.9 miles of underground cable
Subtransmission Redesign & Rebuild: Trunk 1444	Monroe	Install one 6.6 MVAR capacitor at Trinity Station
Subtransmission Redesign & Rebuild: Tie 3205	Pigeon, Caseville, Oak Beach, Port Austin	Reconductor 26 miles of overhead 40 kV line
Subtransmission Redesign & Rebuild: Mohican	Marysville	Complete decommission and equipment removal at Mohican Substation
Sutransmission Redesign & Rebuild: Bernard	Wales Twp	Install one 6.6 MVAR capacitor on Bus 2 at Bernard Station
Subtransmission Redesign & Rebuild: STPS6	Snover	Removed unused overhead subtransmission line feed and associated equipment from former STPS6 site
Subtransmission Redesign and Rebuild: Trunk 2455	Detroit	• Install 1,400 ft of 15-5" conduit • Install seven 2-way manholes • Install 1,860 ft 40 kV underground cable • Install 1,860 ft 15 kV underground cable • Remove 1.9 miles of underground cable
Subtransmission Redesign & Rebuild: Kennett	Pontiac	Complete decommission and equipment removal at Kennett Substation
Subtransmission Redesign & Rebuild - Small Projects	Various	Complete necessary work to address small overload issues

Exhibit 11.2.2.2 Projected Investment and Timeline for Subtransmission Projects

	$ Millions					
Project	**2021**	**2022**	**2023**	**2024**	**2025**	**Total Investment 2021-2025**
Subtransmission Redesign & Rebuild: Maxwell Amherst						$0
Ann Arbor System Improvements						$35
Transformer High Side Protection Program						$15
Cortland Station Expansion						$9
40kV Capacitor Banks at Armada and Adair						$3
Subtransmission Breaker Short Circuit Violations						$9
Subtransmission Redesign & Rebuild: Trunk 7106						$3
Subtransmission Redesign & Rebuild: Trunk 7333						$2
Subtransmission Redesign & Rebuild: Trunk 2255						$4
Subtransmission Redesign & Rebuild: Boyne						$26
Subtransmission Redesign & Rebuild: Badax Transformer 102 Addition						$4
Subtransmission Redesign & Rebuild: Tie 4105						$43
Subtransmission Redesign & Rebuild: Trunk 2237-ST						$2
Subtransmission Redesign & Rebuild: Sandusky Transformer 101 Breaker						$2
Subtransmission Redesign & Rebuild: Tie 810						$40
Subtransmission Redesign & Rebuild: Slocum						$2

Project	$ Millions					
	2021	2022	2023	2024	2025	Total Investment 2021-2025
Subtransmission Redesign & Rebuild: Trunk 4217						$5
Subtransmission Redesign & Rebuild: Trunk 4266						$4
PQ Meter Fault Locating						$7
Subtransmission Redesign & Rebuild: Trunk 3509						$2
Subtransmission Redesign & Rebuild: Tie 6602						$4
Subtransmission Redesign & Rebuild: Tie 1568						$1
Subtransmission Redesign & Rebuild: Pigeon Area Improvement						$14
Subtransmission Redesign & Rebuild: Tie 7504						$34
Subtransmission Redesign & Rebuild: Tie 6907						$2
Subtransmission Redesign & Rebuild: Trunk 4911 Voltage Correction						$15
Subtransmission Redesign & Rebuild: Sandusky Transformer 102 Addition						$3
Subtransmission Redesign & Rebuild: Trunk 2443						$2
Subtransmission Redesign & Rebuild: Trunk 4911						$8
Subtransmission Redesign & Rebuild: Trunk 4245						$5
Subtransmission Redesign & Rebuild: Trunk 5838						$2
Subtransmission Redesign & Rebuild: Trunk 2308						$10

	$ Millions					
Project	2021	2022	2023	2024	2025	Total Investment 2021-2025
Subtransmission Redesign & Rebuild: Tie 4104 North						$27
Subtransmission Redesign & Rebuild: Custer Republic						$3
Subtransmission Redesign & Rebuild: Trunk 2419						$1
Subtransmission Redesign & Rebuild: Tie 3416 Breaker Replacement and Reconductoring						$2
Subtransmission Redesign & Rebuild: Trunk 3508						$5
Subtransmission Redesign & Rebuild: Tie 3416 Reconductoring - Pigeon						$7
Subtransmission Redesign & Rebuild: Thumb Electric Fault Isolation						$1
Subtransmission Redesign & Rebuild: Trunk 362						$5
Subtransmission Redesign & Rebuild: Trunk 2659						$1
Subtranmission Redesign & Rebuild: Derby						$5
Subtransmission Redesign & Rebuild: Trunk 328						$5
Subtransmission Redesign & Rebuild: Trunk 3546						$6
Subtransmission Redesign & Rebuild: Trunk 1444						$1
Subtransmission Redesign & Rebuild: Tie 3205						$21
Subtransmission Redesign & Rebuild: Mohican						$1
Sutransmission Redesign & Rebuild: Bernard						$1

	$ Millions					
Project	**2021**	**2022**	**2023**	**2024**	**2025**	**Total Investment 2021-2025**
Subtransmission Redesign & Rebuild: STPS6						$1
Subtransmission Redesign & Rebuild: Trunk 2455						$5
Subtransmission Redesign & Rebuild: Kennett						$1
Subtransmission Redesign & Rebuild - Small Projects						$12
Total Investments	$42	$82	$93	$101	$112	$429

11.3 4.8kV Conversion

11.3.1 Introduction to the 4.8kV Conversion program

DTEE's original distribution system voltage was 4.8kV. The system was designed to an ungrounded delta configuration and banked secondary standard, which has both benefits and risks. Delta configuration is a design from the early 1900s, which provided very low occurrence of outage events for our customers. In most neighborhoods, the 4.8kV system was constructed as overhead rear-lot poles and wires, which is aesthetically preferable to front-lot construction. Initially, right-of-way truck access was readily available through municipally maintained alleys in many areas, including much of Detroit. Starting in the mid-1900s, many municipalities began to abandon alleys and allowed property owners to extend their fence lines, preventing DTEE trucks access to the poles and wires. Consequently, the limited access resulted in a significant increase in the time to locate and repair trouble on the 4.8kV system, as well as increases in time to perform tree trimming and maintenance work. The average restoration time for an outage on the 4.8kV system is 70% longer than on the 13.2kV system, which was typically constructed to provide better access to locate and repair trouble. In addition, other key issues impacting the reliability and operability of DTEE's 4.8kV system are summarized below:

- The 4.8kV system has most of the #6 and #4 conductor (the wires), which is weaker in strength compared to current higher standard wires.
- Inherent in the design, the 4.8kV substations and circuits have lower capacity than the 13.2kV system
- The 4.8kV system can experience more significant voltage drops than the 13.2kV system
- The 4.8kV system is an ungrounded delta configuration, making detection, location, and protection of single-phase downed wires challenging.
- Ringed circuit and banked secondary designs make maintenance, fault identification, troubleshooting, and restoration more difficult and longer in duration. Opening the rings on 4.8kV circuits may result in low voltage and/or more outage events for customers.
- The 4.8kV system has a limited amount of remote monitoring and control capability. Due to equipment age, the retrofits on 4.8kV substations and circuits to enhance

remote monitoring and control capability are challenging. The original 4.8kV substation design included individual relays for individual functions, usually on a 3-foot-by-7-foot panel. When a new breaker is installed, the entire relay panel and all the wiring must be replaced to accommodate the new technology.

In addition to the 4.8kV system limitations on reliability and operability in its current state, the constraints on the 4.8kV system make it incompatible with some of the requirements of grid modernization. As mentioned above, the 4.8kV system has less capacity to serve load, due to both the smaller conductor and the inherent limitations from the lower voltage. Increased loads at the grid edge, such as adoption of EVs and the likelihood of a significant portion of charging at home, can both thermally overload these conductors and create significant voltage drops. In addition, the challenges of enabling remote monitoring and control will present an even bigger challenge than it does today when more dynamic and unpredictable loading patterns from DERs become increasingly concentrated on a circuit. Overall, the constraints of the 4.8kV design negatively affect the operational flexibility of the system due to limited capacity needed to support contingency operations, which will only be exacerbated by moderate levels of EV and DER adoption. In addition, the system's uniqueness and complex design limit distribution automation opportunities. For further detail on 4.8kV conversion related to grid modernization, see Section 3.

The voltage map for DTEE's distribution system is shown in Exhibit 11.3.1.1. Comparisons among the three distribution system voltages are shown in the Exhibits 11.3.1.2-11.3.1.4.

Exhibit 11.3.1.1 DTEE Distribution System Voltage Map

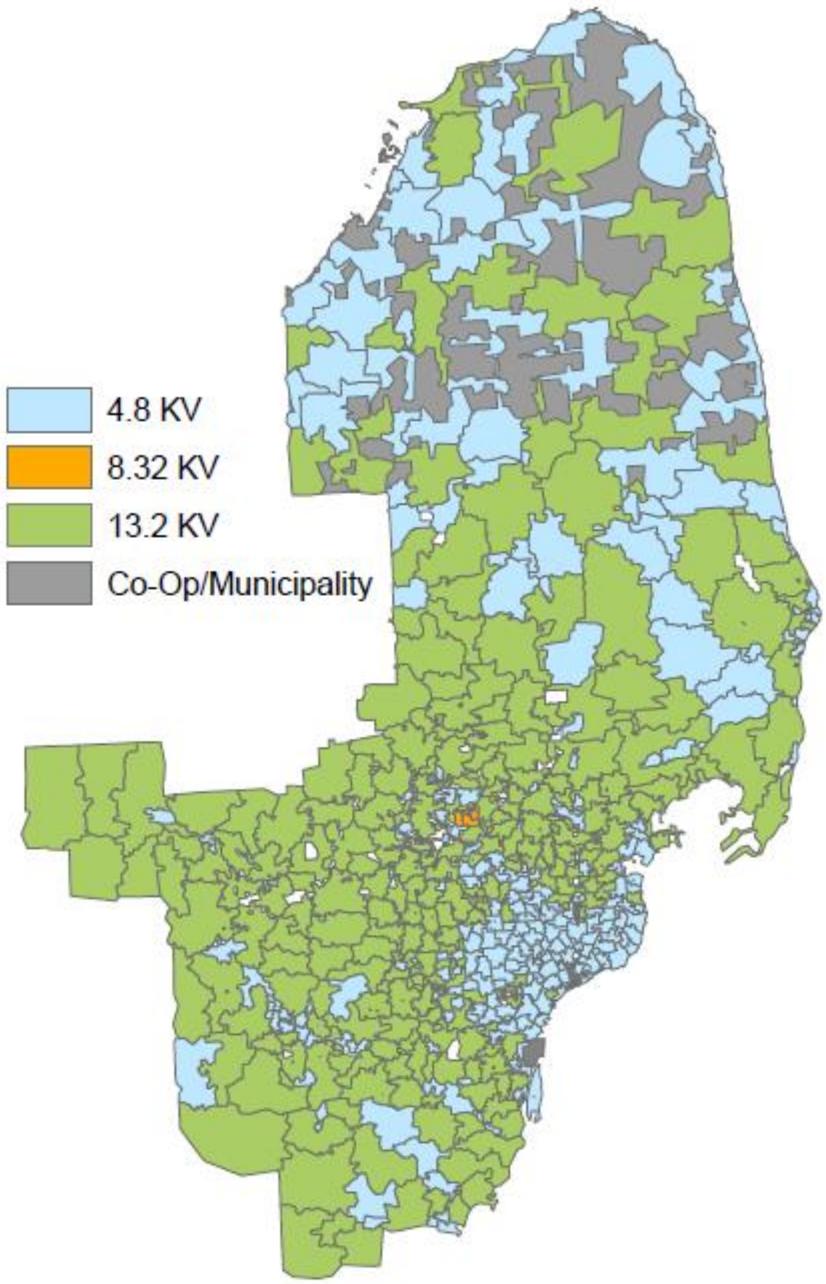
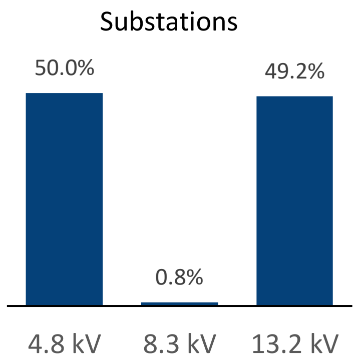
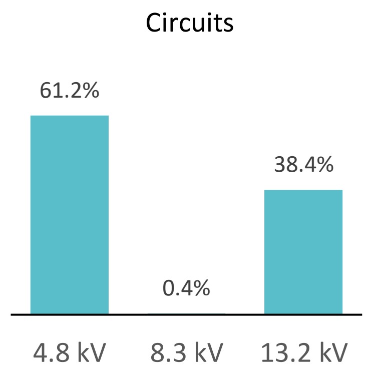


Exhibit 11.3.1.2 Percentage of Substations, Circuits, and Circuit Miles by Distribution Voltage





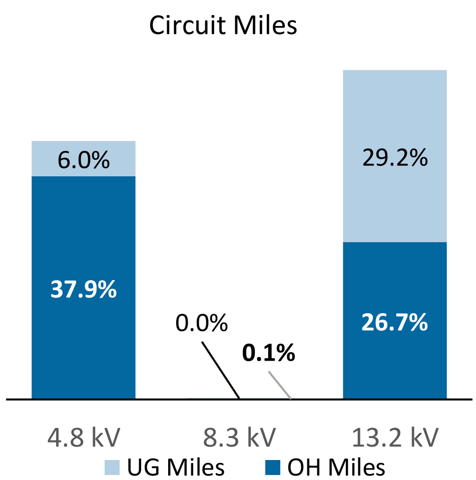
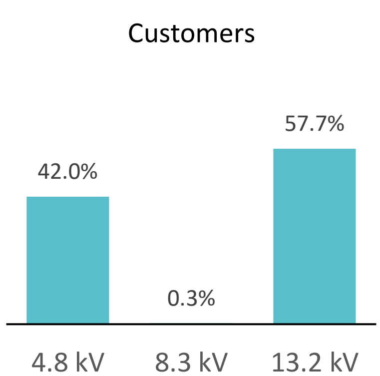


Exhibit 11.3.1.3 Percentage of Customers and Average Annual Trouble Events by Distribution Voltage



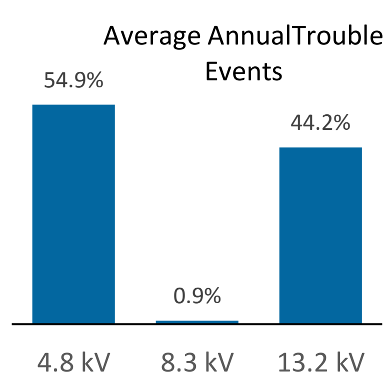
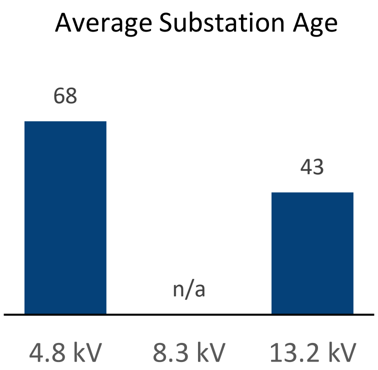
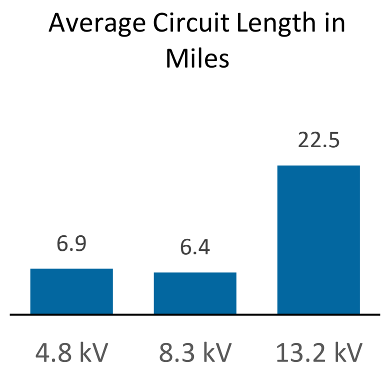
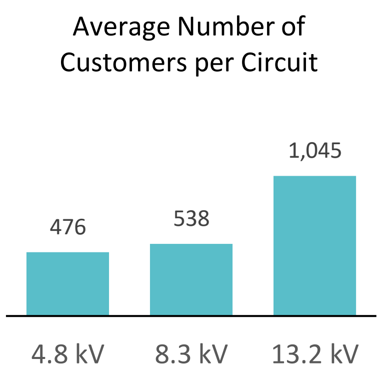


Exhibit 11.3.1.4 Substation Average Age, Average Circuit Length in Miles, and Average Number of Customers per Circuit by Distribution Voltage







11.3.2 4.8kV Conversion prioritization

While DTEE addresses immediate challenges associated with the 4.8kV system through the hardening program discussed in Section 9.3, strategically phasing out the 4.8kV system has been an integral part of DTEE's long term strategy. Higher voltage systems are more efficient and allow for multiple 4.8kV substations to be taken out of service at the completion of a conversion project. In the previous section, the loading and operability limitations of the 4.8kV system were mentioned, including lower capacity for load and challenges in integrating remote monitoring control into the legacy equipment. The overall grid modernization assessment in Section 3 concluded that as customers adopt newer technology such as EVs, rooftop solar, and storage, a capacity constrained system will struggle to keep pace with customer needs.

As mentioned in Section 11.1, approximately 35% of our system has some form of loading constraint on substations, circuits, or equipment. On the 4.8kV system, approximately 25%of the substations are over the firm rating. Similar to some of the constraints seen on the subtransmission system, there are two major impacts of operating substations over their firm rating. The first is that during high loading periods, normally the summer season, an equipment failure in a substation that is over firm will likely lead to a customer outage until either the equipment is repaired, load is jumpered to a neighboring substation, or another mitigation plan is enacted such as deploying a mobile generator. In a system with limited capacity, the option of transferring load to an adjacent substation may also 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 likely to get more severe over time.

It is through the primary lens of capacity that DTEE prioritizes the conversion of the 4.8kV system. In the current prioritization methodology, the following factors are considered when proposing a conversion project:

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

While these criteria initially prioritize substations for conversion, many additional criteria are considered when developing and proposing a project. For example, adjacent substations are also evaluated for inclusion in the conversion, the feed for a new substation must be considered (either subtransmission or transmission), and property for expanding a current substation or building a new substation must be available and acquired.

Other considerations include avoiding projects that would create an island of 13.2kV substations surrounded by 4.8kV substations, which would add operational complexity and may be de-prioritized against a project that was already adjacent to a 13.2kV substation. In addition, constructing multiple projects in close proximity may not be feasible due to system shutdowns required to execute the work.

The conversion projects in the near-term consist of the completion of on-going projects that were driven by system capacity needs, and newer projects which meet the criteria listed above.

Prioritization and sequencing of a long-term conversion plan will be an iterative process. All of the near term (five-year) projects reflect no-regrets investments that address current loading constraints on the system. A summary of these projects and details can be found in sections 11.3.3 and 11.3.4, and in the discussion on the CODI project in Section 11.4. In the longer term, DTEE plans to convert the entire 4.8kV system to a higher voltage. While this may take decades, DTEE's aspiration is to convert it in the next 15 years, particularly as the grid needs from the electrification and increased DG/DS adoption scenarios materialize. Looking beyond the no-regrets investments of the next five years, DTEE will create longer term plans through the use of more advanced tools and analytics discussed in the DGP, such as the Integrated Forecasting Solution described in Section 4.2. These tools will enhance planning capabilities and incorporate additional data, such as propensity studies and hourly load shapes, into the current substation loading profiles, which typically only consider peak load during planning. In addition, the pace at which the electrification scenario develops, and the signposts of that scenario materialize, will impact prioritization results.

11.3.3 4.8kV Conversion plan and timeline

The conversion and consolidation projects are expected to bring multi-faceted benefits of safety improvements, load relief, risk reduction, reliability improvements, technology modernization and cost reduction.

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

- Building new 13.2kV substations or upgrading existing 13.2kV substations.
- Installing controls and automation in the substations and circuits to our latest design standards
- 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 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 of the 4.8kV substations to the 13.2kV substations.
- Decommissioning of aging 4.8kV substations and associated subtransmission infrastructure

Due to the extensive scope of work involved in a conversion, converting the entirety of the 4.8kV system is estimated to cost in excess of $30 billion, and may span multiple decades. DTEE evaluates conversion and consolidation projects on a substation-by-substation basis, using the prioritization criteria described in Section 11.3.2 – 4.8kV Conversion Prioritization. In the next five years, several conversion and consolidation projects are identified as listed in Exhibits 11.3.4.1 and 11.3.4.2. While the scope of work in Exhibit 11.3.4.1 refers to the entire project, which can extend beyond the next five years, the cost estimate in Exhibit 11.3.4.2 captures the projected investment in the next five years. Since many of these projects will extend beyond the next five years due to their size and complexity, the remaining cost to complete these projects beyond 2025 is also provided in Exhibit 11.3.4.2. As noted earlier, the cost estimates and timeline for these projects are based on the best knowledge and information known today by DTEE. Actual project costs and timeline could deviate from the projections due to various unforeseen factors or new information/learnings.

11.3.4 Large current and near-term conversion projects

Exhibit 11.3.4.1 4.8 kV Conversion Projects

Project	Community	Drivers	Scope of Work
Hilton Substation and Circuit Conversion Phase One	Ferndale Hazel Park	• Provide load relief to Ferndale area • Replace aging infrastructure • Reduce trouble events and O&M expenses • Improve reliability in the Ferndale and Hazel Park areas	• Started in 2013, the project constructed a new 13.2kV Hilton substation and is in the final stage of converting 10 existing 4.8kV circuits from Ferndale and Hazel Park to four new 13.2kV circuits
Ariel Substation and Circuit Conversion	Birmingham	• Provide load relief and capacity needs for downtown Birmingham • Improve reliability in the area	• Started in 2014 • Construct a new 13.2kV substation • Convert seven existing 4.8kV circuits from Dudley, Birmingham and Quarton Road substations to three new 13.2kV circuits at Ariel substation
Zenon Substation and Circuit Conversion	Detroit	• Provide load relief and capacity needs for the City of Detroit, west of downtown. • Improve reliability in the area	• Started in 2012 • Construct a new 13.2kV substation • Convert or transfer circuits from aging McKinstry, West End and Artillery substations to Zenon

Cortland / Oakman / Linwood Consolidation	Detroit	• Reduce trouble events and O&M expenses by decommissioning two aging, underutilized 4.8kV substations	• Started in 2016, this project consolidated 4.8kV Oakman and Linwood into 4.8kV Cortland substation to decommission aging substation equipment and system cable
Calla Circuit Conversion	Dexter	• Improve reliability in the area • Improve power quality	• Construct a new 13.2kV substation • Install underground cable and conduit for new circuits • Reconductor and transfer load from Lima substation to Calla
McKinstry Substation Decommission	Detroit	Decommission substation as all load has been transferred to Zenon or West End substations due to the Gordie Howe International Bridge project	McKinstry substation will be decommissioned and all equipment removed.
Quincy Conversion	Yale	Aging wood foundation supporting transformer at Quincy substation	• Construct new padmount substation • Convert 3 miles of overhead and install ISO-down transformers • Transfer load from Quincy to new padmount • Decommission Quincy substation
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

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 and Lambert • Decommission Lynch and Lambert substations
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, converting them to 13.2kV
Lapeer-Elba Expansion and Circuit Conversion (Apollo)	Lapeer / Elba Twp	• Provide load relief (Lapeer 13.2kV is 107% of firm rating and Elba is 103% of firm rating) • Replace aging infrastructure • Increase jumpering capability • Eliminate 40kV tap that has a history of poor reliability performance	• 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
Almont Relief and Circuit Conversion (Midas)	Almont Twp	• Provide load relief (Almont is 160% of firm rating) • Replace aging infrastructure • Increase jumpering capability • Improve circuit voltage	• Build a new 120-13.2kV Midas substation • Transfer Almont load to new substation, converting it to 13.2kV • Reconductor 3 miles of overhead backbone • Establish new jumpering points
Novi Decommissioning and Circuit Conversion	Novi	• Address aging 4.8kV infrastructure • Islanded 4.8kV area with lack of jumpering options	• Convert and transfer Novi load to adjacent 13.2kV circuits • Decommission Novi substation
Hawthorne Relief and Circuit Conversion	Dearborn Heights	• Provide load relief (Hawthorne substation is 133% of firm rating and	• Extend overhead from Mallard distribution circuits and convert 4.8

		Daly substation is 115% of firm rating) • Address aging infrastructure • Provides capacity for new growth	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
Birmingham Decommissioning and Circuit Conversion	Birmingham / Bloomfield Hills	• Substation outage risk for Birmingham • Provide capacity for new growth • Address aging infrastructure at Birmingham and Quarton Road substations	• Construct new 13.2kV substation in Birmingham area • Convert and transfer load from Birmingham and Quarton Road substations to new 13.2kV substation • Decommission Birmingham and Quarton Road substations
Belleville Substation and Circuit Conversion	Belleville	• Addresses aging infrastructure • Provides jumpering capability with surrounding 13.2kV substations • Provides capacity for new growth	• Install new 13.2kV transformer and replace transformer 3 with 13.2kV transformer • Rebuild and convert over 10 miles of overhead to 13.2kV • Create new jumpering points with adjacent substations
White Lake Decommission and Circuit Conversion	White Lake	• Provide load relief (White Lake 13.2kV substation is 108% of firm rating and White Lake 4.8kV substation is 110% of firm rating)	• Build a new 40kV to 13.2kV substation with four load carrying circuits • Convert distribution circuit 307 White Lake to a 13.2kV circuit

		• Replace aging infrastructure • Allows for jumpering (existing 4.8kV is islanded – surrounded by 13.2kV)	• Establish four load carrying circuits supporting White Lake Substation load and a portion of Clyde Substation • Establish new jumpering points and loop schemes between the new substation and Clyde, Wardlow, Teggerdine, Placid, and Osprey substations • Decommission White Lake substation
Calla Circuit Conversion Phase 2	Dexter	• Provide load relief and capacity needs for Dexter (Diamond substation is 144% of firm rating) • Improving reliability • Increase jumpering capability	Rebuild approximately 2 miles of 4.8kV Diamond circuits to 13.2kV and transfer this portion to Calla substation
Unionville Decommissioning and Circuit Conversion	Unionville	• Provide load relief (Unionville substation is 111% of firm rating and Fairgrove substation is 113% of firm rating • Provide capacity for connecting new customers and accommodating load growth	• 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
Snover Decommissioning and Circuit Conversion	Snover / Sandusky / Marlette	• Provide load relief (Snover substation is 127% of firm rating and one Snover circuit and one Marlette circuit are over their ratings) • Lack of jumpering capability	• Construct a new 13.2kV substation • Reconductor over 12 miles of overhead line • Convert and transfer load from Snover to the new 13.2kV substation

			• Create new jumpering points with Marlette and Opal substations • Decommission Snover substation
Monroe Substation and Circuit Conversion	Monroe	• Address aging infrastructure • Provide load relief (Roosevelt substation is 107% of firm rating) • 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 substation
Rochester Decommissioning and Tienken Relief	Rochester Hills	• Address aging infrastructure • Provide load relief (Tienken substation is 107% of firm rating)	• Construct a new 13.2kV substation • Convert and transfer load from Rochester and Tienken substations to the new 13.2kV substation • Decommission Rochester 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

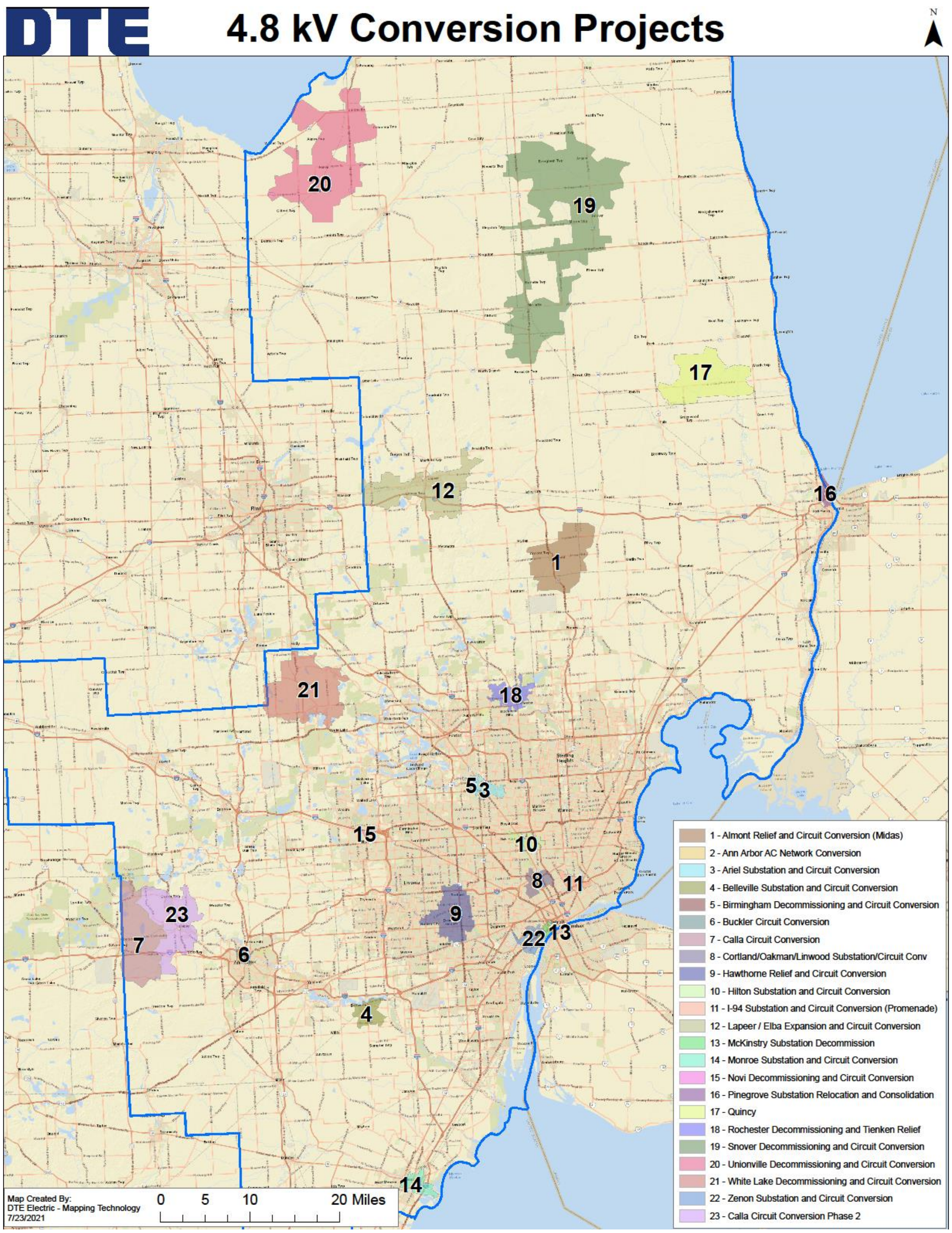
Exhibit 11.3.4.2 Projected Costs and Timeline for 4.8 kV Conversion Projects

Project	$ Millions						
	2021	2022	2023	2024	2025	Total Investment 2021-2025	2026 to 2030 Cost Estimate ($ million)
4.8 kV CC: Hilton Substation and Circuit Conversion						$0	$-
4.8 kV CC: Ariel Substation and Circuit Conversion						$3	$-
4.8 kV CC: Zenon Substation and Circuit Conversion						$0	$-
4.8 kV CC: Cortland / Oakman / Linwood Consolidation: Linwood						$4	$-
4.8 kV CC: Calla Circuit Conversion						$0	$-
4.8 kV CC: McKinstry Sub Decommission						$4	$-
4.8 kV CC: Quincy Conversion						$4	$-
4.8 kV CC: Pine Grove Substation Relocation and Conversion						$22	$-
4.8 kV CC: I-94 Substation and Circuit Conversion (Promenade)						$54	$72
4.8 kV CC: Buckler Circuit Conversion						$18	$-
4.8 kV CC: Lapeer - Elba Expansion and Circuit Conversion (Apollo)						$36	$-
4.8 kV CC: Almont Relief and Circuit Conversion (Midas Sub)						$23	$-

Project	$ Millions						2026 to 2030 Cost Estimate ($ million)
	2021	2022	2023	2024	2025	Total Investment 2021-2025	
4.8 kV CC: Novi Decommissioning and Circuit Conversion						$5	$-
4.8 kV CC: Hawthorne Relief and Circuit Conversion						$37	$85
4.8 kV CC: Birmingham Decommissioning and Circuit Conversion						$18	$35
4.8 kV CC: Belleville Substation and Circuit Conversion						$1	$12
4.8 kV CC: White Lake Decommissioning and Circuit Conversion						$3	$48
4.8 kV CC: Calla Circuit Conversion Phase 2						$1	$-
4.8 kV CC: Unionville Decommissioning and Circuit Conversion						$3	$15
4.8 kV CC: Snover Decommissioning and Circuit Conversion						$2	$15
4.8 kV CC: Monroe Substation and Circuit Conversion						$2	$34
4.8kV CC: Rochester Decommissioning and Tienken Relief						$2	$40
Ann Arbor AC Network Conversion						$3	$45
Total Investments	**$23**	**$61**	**$55**	**$48**	**$60**	**$247**	**$402**

Exhibit 11.3.4.4 provides a map to illustrate the locations of the 4.8 kV Conversion and Consolidation projects.

Exhibit 11.3.4.4 4.8kV Conversion Map



11.3.5 4.8kV isolation down areas (ISO down) conversion

In some instance there is a need to address immediate overloading on a circuit or circuits fed from a substation at which other circuits are not overloaded. This issue can be addressed economically by building a higher voltage substation, typically 13.2kV, and converting only the overloaded circuits, or portions of the circuit, to the higher voltage and operating the remain circuits at the current voltage, typically 4.8kV. All the circuits on the new 13.2kV substation are fed at 13.2kV and circuits that were previously overloaded will be operated at 13.2kV relieving the overload; and circuits that were not overloaded will have the voltage dropped to 4.8kV by a transformer and will operate unconverted as 4.8kV circuits, thus isolating them from the 13.2kV circuits. This practice is known as "iso-downs." There are iso-downs on over 400 circuits, Exhibit 11.3.5.1 provides the number of circuits with iso-downs and miles of 4.8kV overhead and underground lines.

Exhibit 11.3.5.1 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	433	143,504	5,559	398

Circuits fed by a 13.2kV substation that have been iso-downed, operate at 4.8kV, have not been upgraded or modernized like the circuits that operate 13.2kV fed from the same 13.2kV substation. The 4.8kV circuits have the same characteristics of 4.8kV circuits fed from a 4.8kV substation, they have the same reliability issues, safety concerns, and operational concerns, and will face the same challenges to incorporate increasing EVs and DERs. As part of DTEE's long term vision to convert the 4.8kV system, upgrading the ISO down areas to a higher voltage will also be required.

11.3.6 4.8kV ISO down conversion prioritization

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 need to consider substation factors, safety (wire down reduction), reliability (customer minute interruptions), and costs (avoided O&M and capital) become the driving factors for prioritization of 4.8kV ISO down circuits. These factors feed directly in to the GPM model and allow for the ranking of proposed 4.8kV ISO down conversion with other investments in the DGP.

11.3.7 4.8kV ISO down conversion plan and timeline

The 4.8kV ISO down conversion projects are expected to bring multi-faceted benefits of safety improvements, reliability improvements, technology modernization and cost reduction.

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

- Installing controls and automation on the circuits to our latest design standards
- 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.
- Reconfiguring circuits and establishing new jumpering points.
- Removing ISO down transformers.

Due to the extensive scope of work involved in converting a 4.8kV ISO down circuit, converting the entire population of the 4.8kV ISO downs on the system is estimated to cost in excess of $2 billion and may span multiple decades. DTEE evaluates conversion and consolidation projects on a substation-by-substation basis, using the prioritization criteria described in Section 11.3.3 – 4.8kV ISO Down Conversion Prioritization. In the next five years, several conversion and consolidation projects are identified as listed in Exhibits 11.3.7.1. While the scope of work for these projects is still being identified (projects start with engineering and design as early as 2023), the cost estimate in Exhibit 11.3.7.1 captures the projected investment in the next five years. Since many of these projects will extend beyond the next five years due to their size and complexity, the total cost to complete the project is also provided in Exhibit 11.3.7.1. The cost and timeline estimate for these projects is based on the best knowledge and information known today by DTEE. Actual project costs and timeline could deviate from the projections due to various unforeseen factors or new information/learnings.

Prioritization and sequencing of a long-term ISO down conversion plan will be an iterative process. All of the near term (five-year) projects reflect no-regrets investments that address current safety, reliability and emergent cost issues.

Exhibit 11.3.7.1 Projected Costs and Timeline of 4.8kV ISO Down Conversion Projects ($ Millions)

Project	2021	2022	2023	2024	2025	Total Investment 2021-2025
Camden	$-	$-	$0.5	$0.6	$0.6	$1.6 (total cost $3.7)
Gilbert	$-	$-	$0.5	$1.3	$1.3	$3.1 (total cost $7.2)
Kern	$-	$-	$-	$0.5	$0.9	$1.4 (total cost $4.9)
Biddle	$-	$-	$-	$0.5	$2.2	$2.7 (total cost $11.4)
Brazil	$-	$-	$-	$-	$0.5	$0.5 (total cost $10.1)
Total Investment	**$-**	**$-**	**$1.0**	**$2.9**	**$5.4**	**$9.3 (total cost $36.9)**

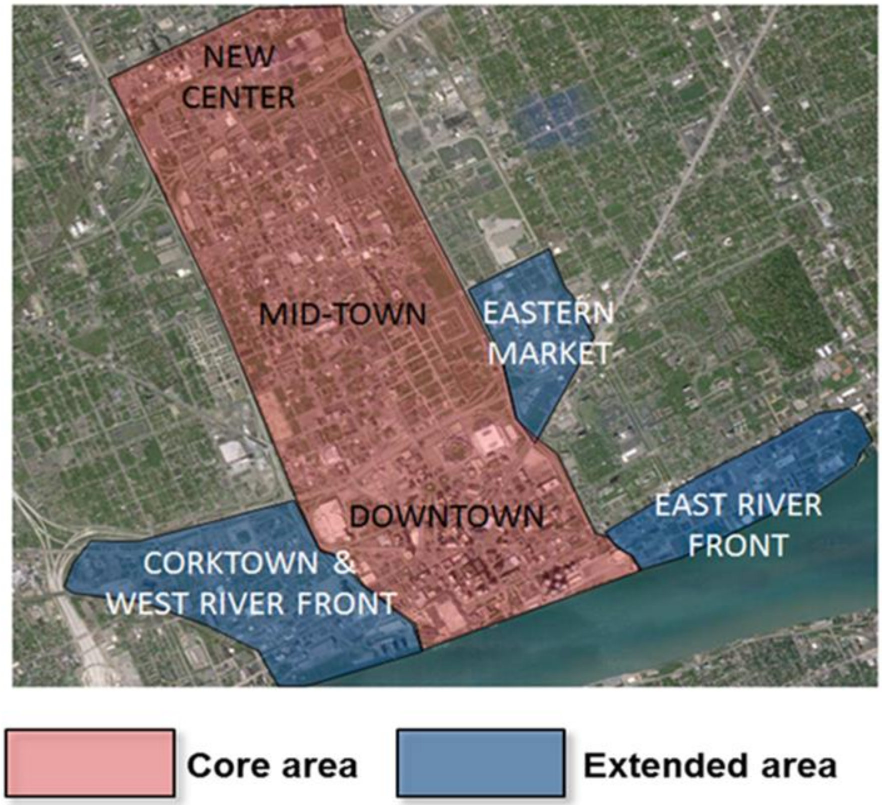
11.4 CODI Program

The City of Detroit Infrastructure (CODI) program 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 to the early 20th century. A significant portion of the infrastructure is at end-of-life. The resurgence of development in the greater downtown Detroit area in recent years has resulted in increased loading on the end-of-life assets. The downtown Detroit Infrastructure (CODI) area has been experiencing load growth since 2012, with potential for up to 20% of additional load growth by 2023. Due to significant cable network configuration in the CODI area, substation and circuit upgrades must be sequenced and conducted in a robust, multi-year program as opposed to individual episodic projects to address the interdependency of the system. DTEE has developed the CODI program for that purpose. It is important to note that even without further load growth beyond what has already been added over the last 8 years, the substations, underground cables and manholes, and other assets which have served the area well over many decades, are experiencing higher failure rates, increasing the risk of long-duration outages that can lead to high reactive maintenance costs.

The downtown CODI program is also different from other conversion and consolidation projects due to presence of large amounts of system cable and secondary network cable, which add to the complexity of operating, maintaining, and upgrading this part of the system.

Exhibit 11.4.1 shows the areas of Detroit that will be addressed by the CODI program which includes a core area from Downtown to the Midtown and New Center areas and an extended area including Eastern Market, Corktown, and the West and East River Fronts. There are 31,800 customers served in this area including 27,486 residential, 4,299 commercial, and 15 industrial customers. The Detroit area upgrades identified in Exhibit 11.3.4.1 for 4.8 kV Conversion Projects, are separate from the CODI scope of work outlined in this section.

Exhibit 11.4.1 Downtown City of Detroit Infrastructure (CODI) Scope Area



The Downtown CODI program consists of 13 projects including the targeted network secondary cable replacement program. The high-level scope of work and estimated timeline is listed in Exhibit 11.4.2 with Exhibit 11.4.3 illustrating the substation areas for the CODI program. The yearly project estimates for the next five years are shown in Exhibit 11.4.4. The CODI program is expected to be complete by the end of 2035.

Exhibit 11.4.2 Downtown City of Detroit Infrastructure Modernization (Downtown CODI)

Project	Key Scope of Work	Estimated Timeline
CODI – Midtown Substation Expansion	Expand 13.2 kV Midtown substation by installing 3rd transformer and a 12-position switchgear	2019-2021
CODI – Targeted Secondary Network Cable Replacement	Replace targeted sections of the secondary network cable system that have a higher probability of failure	2019-2025
CODI – New Corktown Substation	Build a new general purpose substation named Corktown	2019-2022
CODI – Alfred Substation Expansion	Expand 13.2 kV Alfred substation by installing 3rd transformer and a 12-position switchgear	2021-2023
CODI – CATO Substation Expansion	Expand 13.2 kV Cato substation by installing 3rd transformer and a 12-position switchgear	2022-2024
CODI – Charlotte Network Conversion	• Rebuild 30 miles of network feeder cable • Rebuild 7 miles of system cable • Replace or remove 83 netbank transformers • Convert 8 primary customers • Convert the circuits to 13.2 kV fed by Temple substation • Decommission Charlotte substation	2017-2024
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	2020-2030

CODI – New Islandview Substation and Walker Conversion	• Construct a new 13.2 kV Islandview substation • Convert 32 existing 4.8 kV circuits from Walker and Pulford • Decommission Walker (built in 1923) substation • Decommission aging 24kV cables and infrastructure	2020-2027
CODI – Kent/Gibson Conversion	<u>Kent Substation</u> • Rebuild six miles of system cable • Convert one primary customer • Convert seven miles of overhead • Convert and consolidate the circuits to 13.2 kV fed by Corktown substation • Decommission and remove 2 miles of 4.8 kV cable • Remove 24 kV cable and equipment • Remove 6 breakers and decommission Kent substation <u>Gibson Substation</u> • Rebuild 10 miles of system cable • Convert 22 miles of overhead • Convert and consolidate the circuits to 13.2 kV fed by Corktown substation • Decommission and remove 4 miles of 4.8 kV cable • Remove 24 kV cable and equipment • Remove 8 breakers and decommission Gibson substation	2021-2028
CODI – Howard Conversion	• Rebuild 6 miles of network feeder cable • Rebuild 12 miles of system cable • Replace or remove 89 netbank transformers • Convert 26 primary customers • Convert 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	2023-2030

CODI – Amsterdam Conversion	• Rebuild 22 miles of network feeder cable • Rebuild 50 miles of system cable • Replace or remove 60 netbank transformers • Convert 28 primary customers • Convert seven miles of overhead • Convert and consolidate the circuits to 13.2 kV fed by Stone Pool substation • Decommission Amsterdam substation	2025-2034
CODI – Madison Conversion	• Rebuild 31 miles of network feeder cable • Rebuild 30 miles of system cable • Replace or remove 92 netbank transformers • Convert 24 primary customers • Convert three miles of overhead • Convert and consolidate the circuits to 13.2 kV fed by Temple substation • Decommission Madison substation	2028-2033
CODI – CATO/Orchard Conversion	Cato 4.8 kV Substation • Rebuild 17 miles of system cable • Convert 15 primary customers • Convert and consolidate the circuits to 13.2 kV fed by Temple substation • Decommission CATO 4.8 kV substation Orchard Substation • Rebuild 12 miles of network feeder cable • Rebuild 13 miles of system cable • Replace or remove 80 netbank transformers • Convert 12 primary customers • Convert and consolidate the circuits to 13.2 kV fed by Temple substation • Decommission Orchard substation	2029-2034

Exhibit 11.4.3 CODI Program Substation Areas

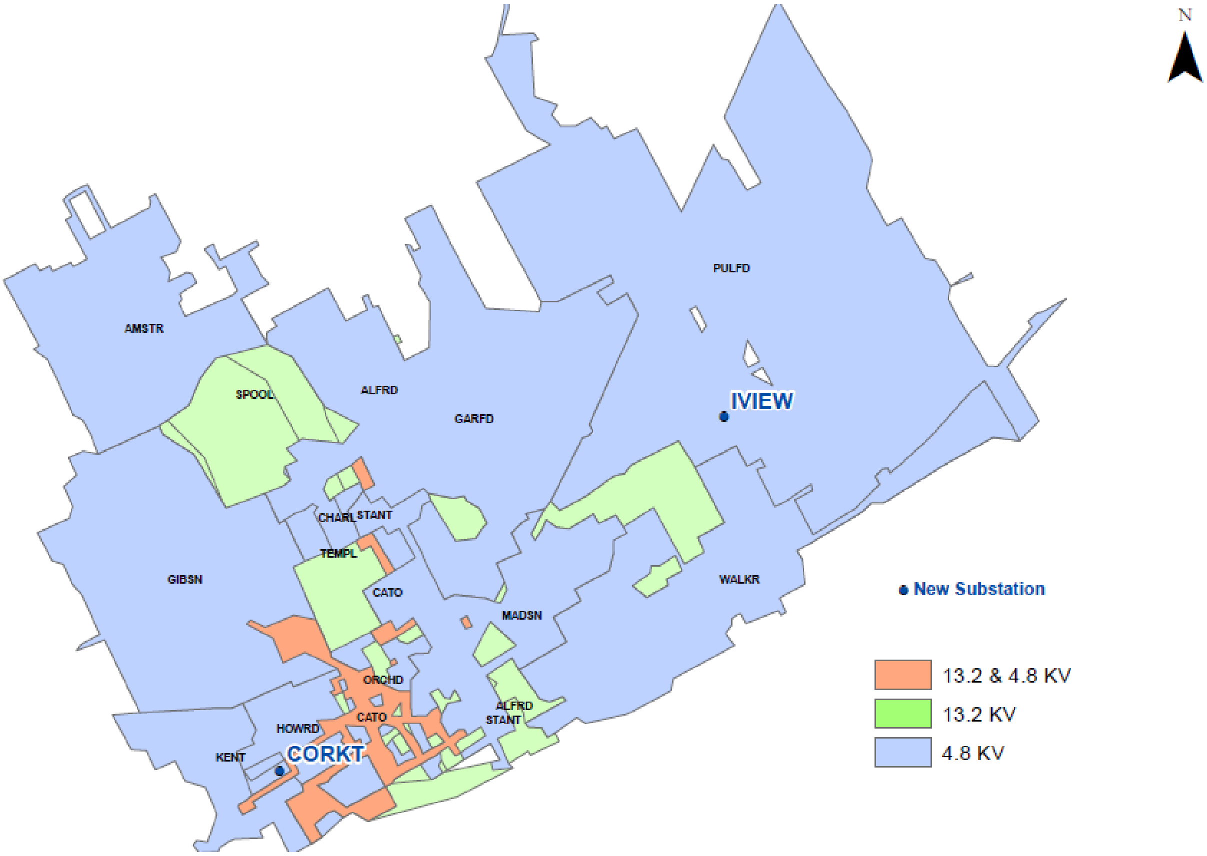


Exhibit 11.4.4 Projected Costs and Timeline for CODI Projects

Project	2021	2022	2023	2024	2025	2021-2025 Cost Estimate ($ million)	2026 and Beyond Cost Estimate ($ million)
CODI – Midtown Substation Expansion						$7 (Total Cost[18]: $11)	
CODI – Targeted Secondary Network Cable Replacement						$15	
CODI – New Corktown Substation						$16 (Total Cost: $18)	
CODI – Alfred Substation Expansion						$10	
CODI – Cato Substation Expansion						$20	
CODI – Charlotte Network Conversion						$49 (Total Cost: $78)	
CODI – Garfield Network Conversion						$108	$120

[18] Total cost represents the anticipated spend through 2025 including prior to 2021

Project	2021	2022	2023	2024	2025	2021-2025 Cost Estimate ($ million)	2026 and Beyond Cost Estimate ($ million)
CODI – New Islandview Substation and Walker Conversion						$98	$90
CODI – Kent/Gibson Network Conversion						$44	$51
CODI – Howard Conversion						$36	$108
CODI – Amsterdam Conversion						$2	$201
CODI – Madison Conversion							$165
CODI – CATO/Orchard Conversion							$122
Total Investments	$44	$54	$95	$104	$107	$404	$858

11.5 8.3kV system conversion and consolidation

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 4.8kV and 13.2kV systems, 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 5 years including seven new large service requests received in 2019 and 2020 from prospective new customers.

The plan to address the 8.3kV system has been developed, starting with the upgrading of the system vaults. As discussed in Section 8.19 – Pontiac 8.3kV System Vaults, the original underground vaults were a safety hazard, with live front equipment and often insufficient arc flash distances. Of the 15 vaults, three were eliminated and 10 were upgraded in 2020. The remaining two will be completed in 2021. To date, a small portion of the circuit conversion has been executed. In 2020, about 12.5 miles of overhead was converted and transferred from Stockwell and Paddock circuits to a newly extended distribution circuit out of the Catalina substation. The next phase will involve the extension of another Catalina distribution circuit with another 13.4 miles of overhead being converted and transferred from Stockwell, Paddock, and Bartlett substations. In addition, there will be a partial conversion and transfer of two underground Stockwell circuits.

Three main options were evaluated for building a new substation to complete the conversion of the 8.3kV system. These options included building a new 40kV fed 13.2kV substation in the Pontiac area at DTEE's Ninja property, building a new 120kV fed 13.2kV substation at the Ninja property, or upgrading the existing 13.2kV Wheeler substation. The Wheeler substation upgrade was determined to be the most cost-effective solution at this time, as it will utilize existing 120kV feeds while providing the capacity needed in the area and highest number of potential new circuits. The Ninja property will be available for future use as demand requires. All remaining overhead and underground infrastructure from Bartlett, Paddock, Rapid Street and Stockwell substations will be converted and transferred to the upgraded Wheeler substation. In order 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 2028. In addition, the Wheeler substation upgrade will enable load to be transferred off Bloomfield Substation. This will allow for Bloomfield Substation to be decommissioned, thus taking its at-risk switchgear out of service. Exhibit 11.5.1 illustrates the geographic locations of the substations under discussion. Exhibit 11.5.2 provides a summary of the project capital investment for the next 5 years with another $67 million to be spent after 2025.

Exhibit 11.5.1 Pontiac Area Substations

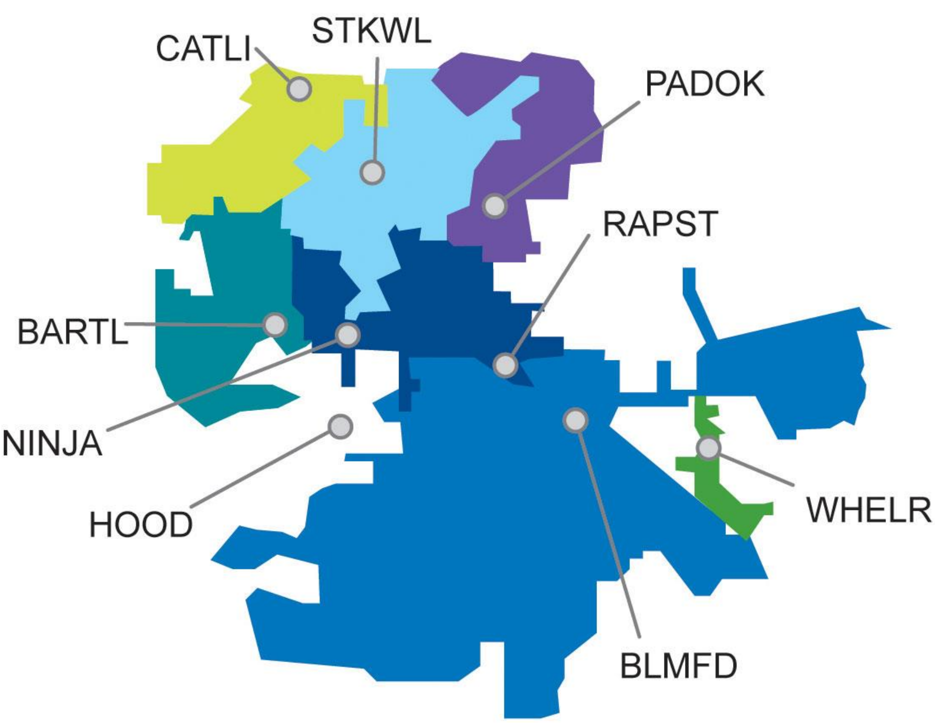


Exhibit 11.5.2 Pontiac 8.3 kV Overhead Conversion Capital Investment

	2021	2022	2023	2024	2025	5 Year Total	2026 and Beyond
Pontiac 8.3 kV Conversion Capital Investment ($ millions)	$1	$4	$12	$34	$38	$90	$67
Pontiac System Vaults	$4	-	-	-	-	$4	-
Total	$5	$4	$12	$34	$38	$93	$67

11.6 Strategic undergrounding

Customers have been impacted by an unusually high number of severe weather events during the summer of 2021, as described in Section 1.2. To reduce the risk of future weather events impacting the Company's customers as significantly as they did in 2021; DTEE is planning for a future that could include an increased number of weather-related storm events and for those events to have a higher level of severity, as discussed in Section 3 - Grid Modernization.

The weather impacts in the form of outages from the summer of 2021 have led many customers and other stakeholders to ask why DTEE does not bury the lines. The Company has received questions on this topic from a number of stakeholders, including direct meetings with state and local leaders, direct questions from customers in town hall meetings and comments left on social media channels. The answer is we do bury lines –well over 30% of the DTEE system is currently underground. Since the 1970s, underground lines have been installed during the construction phase of all new subdivisions and other construction projects where possible. What our customers and other stakeholders really want to understand is "why don't you bury existing overhead lines." DTEE employs a robust program to build resiliency on our system including tree trimming, infrastructure hardening, pole top maintenance and customer excellence. As we look to develop additional solutions to build resilience, Strategic Undergrounding is a program we are analyzing as an option. In addition to an undergrounding pilot that is underway, the Company is developing plans to partner with communities to convert overhead lines to underground lines where it makes sense by implementing Strategic Undergrounding pilots. As part of program development, DTEE will undertake a study to look at the overall life cycle costs of underground construction.

Strategic Undergrounding is the practice of replacing overhead infrastructure with underground infrastructure. It must be implemented strategically to balance the reliability and other benefits of underground infrastructure to the higher installation cost when compared to overhead infrastructure. A pilot is currently underway, and additional pilots are being planned to study best practices that reduce costs and evaluate the overall total cost of ownership for underground infrastructure compared to overhead infrastructure. Depending on the results of the pilots, Strategic Undergrounding as an established program in the future might be applied to areas based on several factors including recent reliability and history of downed wires, storm resilience program status and effectiveness in a specific area, as well as coordination with city, DTE Gas and other infrastructure projects and community support.

Appoline Pilot

DTEE began an undergrounding pilot in 2018 on the Appoline DC 1346 circuit. The scope of this pilot is to move rear-lot overhead infrastructure to rear-lot Underground Residential Distribution (URD). This pilot was described by Company Witness Bruzzano in MPSC Case No. U-20561, and the goals of the pilot are to determine actual installation costs, understand customer acceptance, and determine opportunities to improve cost and construction efficiency in subsequent pilots. The Appoline DC 1346 Strategic Undergrounding pilot, which started in late 2018, includes approximately 60 residential customers on two city blocks in Detroit as shown in Exhibit 11.6.1. The scope of the pilot project includes the installation of a looped URD system with approximately 1,300 feet of primary, six transformers, and underground services to residences. When the underground equipment is completed and functional, the overhead infrastructure will be removed.

Exhibit 11.6.1 - Appoline 1346 Pilot:

Two City Blocks for Rear-Lot Overhead to Rear-Lot URD Conversion

Yellow Lines – Primary Conductors / Red Lines – Secondary Conductors / Green Lines – Edge of Right-of-Way

To install the pad mounted transformers and prepare the site for the installation of the URD loop, the area first needed to be cleared of debris. During this process DTEE had to address a higher level of tree and brush removal than expected, several fences and a few garages in the previous alley right of way, and significant garbage removal. These cost and project schedule impacts would have to be remediated or considered in any future rear-lot undergrounding projects. Another significant challenge impacting the schedule of this pilot was difficulty in contacting the customers to obtain approvals for modified attachments to their homes. After limited success using several mailings and door hangers, the Company is currently using door-to-door customer outreach, which has improved results, but reaching all property owners remains a challenge that will need to be addressed in this pilot and future work.

Customer Engagement in Detroit

As we mitigate the challenges identified in the Appoline pilot, Detroit continues to be a favorable location for Strategic Undergrounding deployments, as it meets many aspects of our current pilot criteria (wire downs, areas with little improvement after tree trim, community interest and others). DTEE has engaged the Mayor's office on possible resilience projects, with favorable feedback on undergrounding existing overhead infrastructure. The City supports additional pilots to develop this program. For future pilots, the Company will work with existing city stakeholders including neighborhood leaders and customers.

Lessons Learned from Benchmarking

When developing and enhancing programs, the Company frequently engages in benchmarking efforts to identify best practices. Benchmarking has been done on Strategic Undergrounding among other infrastructure considerations with a dozen or so peer utilities. This work was 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 approaches to underground construction. Front-lot URD provides the best customer experience for both reliability and aesthetics.

Key lessons learned from benchmarking efforts on how too improve efficiency of execution include the importance of streamlined contracting for design, customer outreach, and construction, and utilizing public right-of-way. The greatest challenge identified by other utilities for other configuration options was community acceptance.

Circuit Construction Factors

The benchmarking results led DTEE to re-evaluate existing circuit construction as factors in a successful underground program. There are three main factors to evaluate when considering the construction of a circuit:

- Location: Rear-Lot versus Front-Lot
- Configuration: Overhead versus Underground
- Scope: Optimum Circuit Segments Convert

<u>Location: Rear-Lot versus Front-Lot</u>

Much of the Company's oldest infrastructure includes rear-lot overhead circuits, which have the poles and conductor located at the back of customer lots. This is compared to front-lot construction, where the electrical infrastructure is near the road. Poor accessibility of rear-lot circuit equipment in both alley and non-alley neighborhoods has resulted in challenges to crews who are performing both planned and storm/emergent work. The Company's discussions with communities and benchmarking with other utilities have shown that customer acceptance is low for converting rear-lot overhead infrastructure to front-lot overhead infrastructure.

Configuration: Overhead versus Underground

As shown in Exhibit 11.6.2, overhead construction is typically completed at a lower cost when compared with underground construction. Overhead assets in the rear-lot offer challenges to locating trouble and maintaining the assets, especially in alleys that are not maintained, and front-lot overhead construction is often opposed by municipalities and customers. While overhead construction has initial lower cost of construction, the full longer-term life cycle cost of overhead circuits compared to underground circuits is something that will be further analyzed as part of developing an undergrounding program. As part of our Strategic Undergrounding pilots, DTEE electric will conduct studies of the costs as well as reliability and maintainability over the lifetime of the distribution assets.

Exhibit 11.6.2: Cost of Rebuilding Overhead Rear-Lot Overhead Assets

Rebuild Method	Cost per Mile ($M)
Overhead Rear-Lot	1.1
Underground Rear-Lot	3.3*
Underground Front-Lot	TBD
Overhead Front-Lot	N/A**

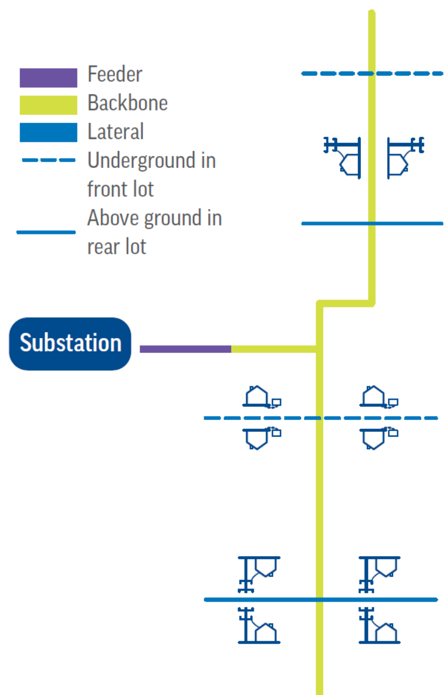
**Based on limited data from a single DTEE pilot project. As the Company enhances through benchmarking, cost efficiencies, and as the work grows using economies of scale, we can expect the cost to reduce between 20% to 30%*

***Discussions with community leadership and benchmarking results have shown that conversion to front-lot overhead will not be accepted by customers and will not provide the needed reliability benefits.*

Scope: Optimum Circuit Segments Convert

Circuits have different segments that need to be considered separately when considering construction. Circuit configuration is typically comprised of feeder, backbone and lateral segments as shown in Exhibit 11.6.3.

Exhibit 11.6.3 –Distribution Circuit Illustration



The backbone and feeder portions of circuits are most typically constructed as front-lot overhead, where they are accessible but are still vulnerable to storm and other impacts. The backbone and feeder portions of a circuit are the costliest to convert to underground because the construction requires trenching in active streets to place concrete incased conduit at approximately three or more times the cost of similar work on laterals. The standard since 1969 has been to provide service to all new subdivisions through URD construction, which would be on the lateral portion of the circuit.

<u>Services</u>

Services, sometimes called service drops, are the secondary voltage (typically 120V/240V) conductors connected to each customer's home. In areas with overhead laterals, the service wires run above ground from an overhead asset to customers' homes, and for URD areas, the service conductors run from equipment at ground level to customers' homes. As described by Witness Pogats in MPSC Case No. 17767, overhead residential services are approximately 16 times more likely to fail during storms than underground residential services. Witness Pogats also described how the Company prioritizes the largest outage cases, which leaves the restoration of single customer service outages to near the end of the storm restoration work. This led the Company to require any new, relocated or upgraded service to be placed underground. Given customer interest in underground electrical infrastructure, the Company is exploring extending this concept to proactively undergrounding existing service drops under some circumstances.

<u>Circuit Construction Factors Conclusion</u>

The Company has listened to feedback from its customers, analyzed the lessons learned from a current pilot and benchmarking efforts, and looked at the data on cost and reliability impacts to determine next steps with pilots in developing a Strategic Undergrounding program. In addition to other resilience programs, Strategic Undergrounding options will be explored and developed. Where it makes sense to address areas based on reliability, down wires, community interest and other factors, front-lot URD is the best construction alternative to replace overhead rear-lot construction on laterals. While a challenge is the significantly higher cost than overhead construction and the benefits and total cost of ownership must be further studied through the deployment of pilots, front-lot URD offers an opportunity to enhance resilience and reliability on those circuits that are difficult to maintain through traditional overhead circuit design. The construction would also be built to the higher 13.2 kV standards and with dual voltage transformers, which will allow for easier and less costly future conversion of the circuits to higher grid voltages. Pilots will also be explored for proactively undergrounding services in situations where it may make sense.

DTEE will continue benchmarking work with other utilities that have been successful with Strategic Undergrounding efforts. The purpose of these benchmarking discussions is to identify best practices that will reduce costs and better engage customers.

Ramp Up

For the next phase of Strategic Undergrounding pilots, DTEE is planning a project on Fairmount DC 1593. The circuit currently serves a well populated neighborhood with overhead rear-lot laterals. The customers on this circuit have experienced a higher than average number of down wires per mile, even after tree trim has been completed, so an additional solution is needed. The scope of the project will be to convert the current rear-lot overhead laterals to front-lot URD using the lessons learned from Appolline and benchmarking. For the portion of the circuit that has Strategic Undergrounding scope completed, we expect to achieve reduced emergent capital and O&M, improved reliability, and the elimination of wires down. This project will be used to gain a better understanding of the full life cycle cost of underground infrastructure compared to overhead, customer acceptance, cost effective methods and improved processes in order to develop a future effective, cost-efficient Strategic Undergrounding program.

Based on what is learned from the Fairmount project to improve processes and quantify the benefits expected for our customers, the Company will develop a program to implement Strategic Undergrounding where it makes sense, as one of our programs to improve reliability and resiliency. The Company plans to allocate the funding included in Exhibit 11.6.4 for moving rear-lot overhead assets to front-lot URD. The aspirational cost per mile view in Exhibit 11.6.4 is based on customer acceptance with easements, community engagement, and minimal unforeseen construction concerns. We will continue working to identify areas of cost reductions through benchmarking, continuous improvement, and realization of economies of scale. As the cost per mile improves, DTEE expects to achieve even more miles than are reflected in Exhibit 11.6.4.

Exhibit 11.6.4: Strategic Undergrounding Program Investment

Strategic Undergrounding	2021	2022	2023	2024	2025	2021-2025 Total
Cost	$0.5 M	$10 M	$30 M	$60 M	$100 M	$200.5 M
Miles	0	3	10	24	40	77

In addition to rear-lot overhead to front-lot undergrounding, the Company is investigating areas with a high number of service failures and is developing an additional pilot to underground the services in one of these areas. The pilot will have the goals of determining the costs, the reliability and storm impact, customer interest, and the overall process for this work. Based on the results of the pilot the Company will consider future program development.

11.7 Impact of generation on the distribution system

As one part of the overall grid, the electrical distribution system is dependent on a robust transmission system and generation fleet to ensure consistent reliable power is available to all customers. The generation fleet as it exists today was strategically designed and located to provide the necessary capacity and redundancy to support the transmission and distribution system with power delivery to the customers.

Historically, when locating generation facilities, the goal was to balance locating the power plants near both load centers, and areas that improved the efficiency of production, such as cooling water sources and locations with ease of access to fuel delivery. Redundancy and consistency were other critical goals of the generation fleet design. It was deemed important to have multiple layers of redundancy both at a specific plant level and over the entire grid to prevent or minimize the impact to service to customers during one or multiple system failures that might take place concurrently.

Additionally, the overall system was designed to allow for shutdowns of certain equipment to perform regular maintenance and replacements while still being able to handle other equipment failures that may take place at the same time. A consistent power flow into the system supporting DTEE's customers has been achieved historically with traditional synchronous generators that helped maintain system strength due to their high inertia and ability to be dispatched to meet forecasted load demand. These characteristics, which today are often called ancillary services, are valuable and necessary for grid stability, and to ensure that the available short circuit level during disturbances is high enough for protective devices to operate and remove these disturbances from the system safely.

Another important task or ancillary service of the current generation fleet is to provide reactive power support to the system, which helps improve low voltages due to high demand or large industrial loads. The design of a robust generation fleet, coupled with a well-planned transmission system, has ensured that, during both normal operations and multiple equipment outages, the distribution system has been able to provide service within expected voltage levels, system frequency, and without overloading any equipment.

11.7.1 Generation benefits for the distribution system

Generation resources have multiple benefits to the distribution system beyond simply supplying energy and powerflow to meet customer demands at any given time. The generation fleet plays a key role in multiple areas that have a direct impact on the reliability of the distribution system and the service provided to our customers.

Thermal overloads and low voltage

System overloads and low voltages can occur when power flows through certain parts of the system that are limited by the equipment's ability to carry the demanded powerflows. The dynamic nature of the location and magnitude of both the customers' load and power generation provided, along with the system impedance, will determine the direction of the power flow on the distribution system and loading of any specific piece of equipment. These changing paths and magnitude of the powerflow can have an adverse effect on the system resulting in overloads or low voltages, especially when powerflows have fewer available paths due to planned or unplanned system outages. The changing directions and large swings in magnitude of powerflows are mostly observed on the subtransmission tie lines when considering the distribution system. Additional generation sources and new lines or other equipment can be added to increase the number of powerflow paths and system upgrades to the limiting equipment can help strengthen the ability of existing paths.

Flicker

Some customers with large loads that require a significant amount of current inrush for their processes can cause a short-term voltage sag on the system resulting in a perceived flicker to their service and other customers served from the same line. The magnitude, duration and frequency of the voltage sag is determined by the customer's operation/current inrush needs and the robustness of the system in the area serving that customer. Distribution and transmission system strength, as well as proximity to generation sources, can help minimize the impact of flicker on the system. System upgrades may be required to provide the same level of voltage/flicker support as the generation portfolio shifts.

Stability

In addition to providing power during normal system conditions, the generation fleet is also responsible for ensuring that the grid remains stable during disturbances to the electrical system. This includes providing stable voltage and frequency support for many different types of issues, including equipment failures and malfunctions. Though this stability can be impacted locally by one or two local generators, it is the generation fleet at large that provides for the widespread stability of the electrical system.

In the past, the retirement or suspension of isolated generators did not typically have a large impact on system stability. However, with today's increasing pace of retiring older rotating generators, system stability has become more important than ever. Though current rotating generators provide voltage and frequency stability primarily through the inertia of their large rotating masses, newer technologies have sophisticated control systems, governed by IEEE 1547, that provide grid stability by constantly monitoring and adjusting their inputs to the grid. The electrical industry is still studying and improving the ability of newer generation technologies to effectively support the stability of the electrical system.

Short circuit

Traditional synchronous generators are critical for the reliability and safe operation of the power systems because they are sources of short circuit needed for protective relaying systems. Protective relaying systems are dependent on short circuit detection to clear disturbances safely from the system. Synchronous generators are excellent sources of short circuit due to their high inertia. A challenge faced by DTEE, other utilities, transmission companies, and ISO's in planning for a modernized grid is that with fewer of these resources and the addition of newer generation technologies that do not supply the equivalent short circuit, grid planning will need to adapt and evolve in order to continue to operate safely and reliably. These planning processes are described in section 11.7.2.

Reactive power

Though electrical loads always require a supply of "real" and much smaller amounts of "reactive" power, many large industrial loads that incorporate sizeable inductive machinery, such as motors and pumps, require large amounts of reactive or VAR support as well. Without this support, voltages can be impacted and begin violating local or NERC planning criteria. Additionally, large transmission lines require reactive power support to overcome their often high amounts of capacitive line charging. The generation fleet typically provides this by adjusting their reactive power controls to vary reactive input into the system. These reactive controls can both produce and absorb reactive power based on system needs, and the amount of reactive support is governed by the generator capability curves of individual generating units. Though large generation units can provide considerable amounts of reactive support, it is typically far less than the "real" output of these units. This is another area where the sophisticated control systems of newer generator technologies can prove beneficial to the system. Depending on the type of controls and power supplies installed, some newer generation sources can provide nearly their entire power output as reactive power. Depending upon system conditions, this support could prove crucial to avoid low voltage conditions or other potential power issues.

Peaker units and black start

In addition to supporting generation system load, the Peaking generator fleet serves many functions in support of the larger and local distribution electrical grid. Though the "base load" generation described above is typically dispatched in order to meet the expected load as forecasted in the MISO day ahead market, sometimes this generation is not enough to meet unexpected real-time increases in local load demand. In these situations, the local balancing authority dispatches these peaking generator units to help meet this unexpected demand growth. Additionally, these local peaking generators can be dispatched to provide some amount of reactive support if local loads are experiencing lower than normal voltages. Typically, peaking generators run for much shorter time periods than base load coal or nuclear generation, and use different fuel sources, often natural gas turbines or diesel in some cases.

In addition to the above load balancing function, often peaking generation can be used to support local operational concerns such as unplanned outages of local transmission or sub-transmission equipment. For unplanned outages, to avoid temporary load shed on the next contingency loss, area peakers can be operated prior to losing another piece of equipment to help reduce the loading on specific lines / transformers. This helps avoid potential cascading outages and further equipment damages due to next contingency losses.

DTEE has developed and maintained several System Operating Practices (SOP) which documents the system load levels that would trigger the use of localized peaking generators. During additional system emergencies, DTEE uses Real-Time Contingency Analysis results displayed in the Energy Management System (EMS) software to further assist System Operations Center (SOC, and, in the near future, ESOC), and may deploy additional generation to alleviate the system concerns. DTEE is currently exploring the possibility of using alternative dispatchable sources, such as storage, to replace smaller and less efficient diesel generators that could provide all of the benefits outlined above. A peaker analysis that incorporates generation and distribution needs will be included in the next IRP.

Finally, local peaking generation is often used as a “black start” resource. A black start is the process of restoring an electric power station or a part of an electric grid to operation without relying on the external electric power transmission network to recover from a total or partial shutdown. This will occur during those periods when the grid has experienced a large-scale disturbance and large parts of it have gone offline. During these periods, large base load generators cannot start themselves due to the lack of local grid support to run pumps, conveyors, and other necessary equipment.

In these very rare circumstances , such as occurred with the August 2003 blackout in the Midwest and Northeast regions of the US, smaller peaking generators can often be started independently of the offline grid to provide the necessary power required by larger generation units. Typically, a special “cranking path” will be established between a peaking and base load generator pair that will be used to supply energy to start the larger unit, with voltages and frequency closely monitored by local operators.

Once the large base load unit comes online, it can be used to support other base load generator’s start up routines and the electrical grid, at large, can finally be reestablished. It should be noted that a robust and geographically diverse peaking generation fleet, with varying fuel sources, is critical to the safe and efficient operation of the electrical grid.

To summarize, there is an emerging challenge faced by DTEE, other utilities, transmission companies, and ISO’s in planning for a modernized grid, that bridges across all of the entities responsible for generating, delivering, and managing the flow of power to customers. As baseload units retire and newer generation technologies with different grid support capabilities are added, grid planning will need to adapt and evolve in order to continue to operate safely and reliably.

11.7.2 Evaluating the impacts of generation retirement on the grid

As described in the Executive Summary, DTE and DTEE are on a path to cleaner energy. Consistent with announced decarbonization goals, DTEE developed and filed an integrated resource plan (IRP) in 2019 that included the retirement of several base-loaded coal plants. Periodic updates to the IRP plan will be filed in future years.

To identify potential impacts that retiring centralized generating units could have on the system and develop the necessary mitigations, multiple studies are required. This level of grid planning also requires close collaboration with MISO and the transmission provider in the DTEE service territory, ITC. When DTEE determines that it plans to retire a generation unit, the next step is for DTEE to initiate with MISO an Attachment-Y filing (notification of generator change of status, including notification of rescission). As part of the Attachment-Y process, MISO conducts studies to evaluate the potential reliability impact due to generator suspension. Sensitivities to generation and loading assumptions are evaluated through each individual study process. Multiple stakeholders are involved in the MISO study process to provide inputs and develop potential mitigations to the reliability issues identified in the study process. These studies can be complex, requiring a significant amount of time, especially when future operation of generating facilities is unclear and multiple scenarios of both continued and suspended generation need to be analyzed.

DTEE recognizes the importance of a collaborative approach to generation, transmission and distribution system planning and works proactively with MISO, ITC, and other stakeholders on generation retirement planning through multiple venues, for example:

- Individual generating unit Attachment-Y studies
- Annual MISO Transmission Expansion Plan (MTEP) reliability planning
- Integrated resource planning filings
- Long range transmission planning
- Within the established planning committee meetings cadence between the respective entities

Below are some examples of successful collaborations with both MISO and ITC to achieve the best project solutions for the area:

- DTEE initiated the Attachment-Y process at MISO several years before the intended retirement date for Trenton, St. Clair and River Rouge power plants. This allowed MISO and stakeholders to go through multiple studies, and more importantly provided sufficient time for robust mitigation development to resolve identified issues.
- Definitive resolution of the Trenton 9 System Support Resource. DTEE, in collaboration with ITC and MISO, developed a cost-effective, non-transmission solution that resolved the potential voltage concerns in the area of the Fermi nuclear plant. This solution entailed replacing two distribution transformers with LTC equipped transformers in the nuclear plant and allows for the safe retirement of Trenton 9 generation.
- Addressed grid issues associated with line ratings reductions, the concurrent retirement of multiple generating units (St. Clair, River Rouge, and Trenton), and the addition of the Blue Water Energy Center (BWEC).
- The BWEC reinforcement project to ensure system reliability when the plant becomes commercially available.
- City of Detroit Load interconnections and transmission overload mitigations.

Process for formally introducing a generation retirement and evaluating the impacts

The study process begins at the transmission level and then iteratively includes the distribution system. Issues on the higher voltage transmission system flow down to the lower voltage distribution system. As a starting point, a secure transmission system is needed before fully assessing distribution system concerns. If system issues are identified, then transmission projects can be proposed through the MISO MTEP planning process to address these issues.

After considering the impacts that the transmission projects will have on the system, a study on the distribution system is needed to identify any further impacts and mitigation projects. The type of projects that can be proposed range from reconductoring and adding new lines to adding new equipment like transformers, capacitors, reactors, or other voltage compensating devices.

The assessment of transmission system impacts begins with an Attachment-Y analysis. Attachment-Y studies are a specific study specified by MISO which seeks to identify serious grid issues that could cause cascading outages or wide-scale voltage collapse. The results of these studies indicate if a generating unit is able to retire without system mitigations. Some of the Attachment-Y study limitations are that the studies are typically only steady-state and do not require system dynamics studies by default, they allow for load shed to mitigate system issues, and do not quantify the impact or cost of addressing all system issues to facilitate the generating unit retirement – only the most serious ones.

Additional studies required to identify system impacts

To properly identify all system impacts to the change in generation, additional studies that go beyond the typical planning review and scenarios must be completed. These additional studies are highlighted in the table below.

Exhibit 11.7.2.1 Types of Studies Performed to Assess Change in Generation

Studies	Reason
Transient stability analysis	Assess the stability of nearby generators and their ability to "ride through" various fault conditions
Voltage stability analysis	Ensure that system voltages can recover and remain stable after a wide range of system disturbances
Short circuit studies	Evaluate the grid to determine if there are locations that have low short circuit capacity. This low short circuit capacity can lead to relay mis-operation and flicker
Customer specific analysis (motor start/flicker)	Ensure end use large industrial customers are able to maintain operations after changes to the generation fleet
Transfer studies	Confirm no adverse impact on import / export limits. These types of studies will be increasingly important as more generation is retired
Black start studies	Performed if the retiring generation resource is currently included in the system restoration plan

11.7.3 Future of distribution grid with flexible generation resources

The electrical grid is going through a period of rapid transformation including large scale changes to the generation fleet, at DTEE, in Michigan, and across the US. new and different types of distributed generation resources, including solar, wind, and storage, are expected to interconnect to the electrical system, and, in many cases, replace the conventional rotating generators currently in-use. These sources support the goal of cleaner generation, but bring challenges because of their intermittent nature, which will require novel solutions for electric utilities that need to balance safety and reliability goals with green energy targets.

It is expected that adding storage to the generation fleet will be an important tool that will help to manage the variability inherently associated with the nature of some of the renewable resources. DTEE is already using storage in its generation portfolio through the Ludington Pumped Storage Plant, an 1100 MW hydroelectric facility. Other forms of storage are also showing promise and will be reviewed for applicability in future years. Additionally, locating these DER resources in geographically diverse areas will help to mitigate their intermittent nature and take advantage of the existing transmission infrastructure.

Though the changing nature of the generation fleet will undoubtedly require new technologies and new ways of supporting the electrical grid, these same technologies may offer new tools that can be used to ensure that DTEE continues to meet the energy needs of our customers in a way that is safe, clean, reliable and affordable.

12 Technology & automation

Technology and Automation is one of the four pillars in DTEE's Distribution Grid Plan framework. This pillar is tightly linked to the grid modernization process and includes investments that develop capabilities in observability, analytics and computing, controls, and communications. DTEE's Technology and Automation projects and programs over the next five years meet current grid needs and provide immediate benefits to our customers. For example, increased automation of our substations and circuits will reduce outage frequency and duration, and improve reliability, particularly when linked with the capabilities of the new ADMS. At the same time, these investments lay the foundation to support increased adoption of DERs and EVs that may materialize as part of planning scenarios. Increased sensing, monitoring and control of distributed assets is a necessary capability to manage the voltage and power quality across the system. In addition, many of the capabilities discussed in Section 4 – Distribution Planning Processes and Tools, such as improved forecasting and more streamlined interconnections, will be enabled by investments in this pillar.

DTEE is implementing multiple programs to enhance and modernize electric grid technology and in support of the DTEE's overall grid modernization strategy. Exhibit 12.1 provides the projected costs and timeline for the identified technology and automation programs.

Exhibit 12.1 Projected Investments and Timeline for Grid Technology Modernization Programs

Project	Section	2021	2022	2023	2024	2025	2021-2025 Cost Estimate ($ million)
ADMS[19]	12.1						$40
SOC Modernization	12.2						$107
Grid Automation Telecommunications	12.3						$71
Distribution Sensing and Monitoring	12.4						$49
Substation Automation	12.5						$27
Circuit Automation	12.5						$29
CVR / VVO	12.6						$69
NWA Pilots	12.7						$35
DER Control	12.8						$11
Mobile Technology	12.9.1						$13
Work Management and Integrated Scheduling	12.9.2						$21
Asset Management	12.9.3						$6
Distribution Planning Process Enablement	12.9.4						$43

[19] In addition, the ADMS project requires $17.1 million of regulatory asset investment from 2019 to 2023

Project	Section	2021	2022	2023	2024	2025	2021-2025 Cost Estimate ($ million)
Modernize Grid Management	12.9.5						$35

12.1 ADMS

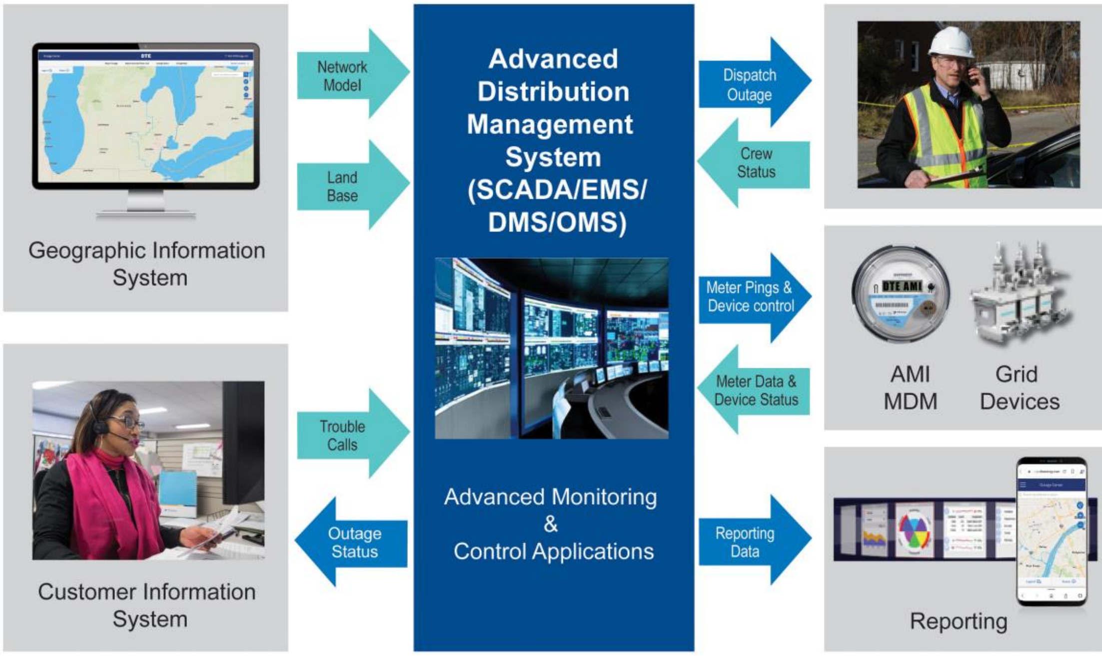
The Advanced Distribution Management System (ADMS) is an advanced operating technology platform that is essential to DTEE's grid modernization efforts to improve system reliability and operational efficiency.

The ADMS leverages the enhanced technology deployed on the distribution system (such as line sensors, SCADA, etc.) and provides all users the same "as-operated" view of electrical system status and its performance. The ADMS will provide the foundation for integrating and managing distributed energy resources (DERs) in the future. The ADMS will also allow DTEE to fully integrate the Outage Management System (OMS), Distribution Management System (DMS), Energy Management System (EMS) and Supervisory Control and Data Acquisition System (SCADA) and provide seamless interface with the Geographical Information System (GIS), the Customer Relationship Manager (CRM), and AMI.

Exhibit 12.1.1, below, illustrates the ADMS as an integrated technology platform that will allow DTEE to perform advanced engineering and analytics and provide our system operators with industry-leading functionality to monitor and control the electric grid to meet customers' needs.

DTEE began the ADMS implementation in 2018 and is expected to complete an EMS upgrade, OMS launch, and DMS application launches in 2022.

Exhibit 12.1.1 ADMS - An Integrated Technology Platform



The ADMS is comprised of the following functional components:

- **Energy Management System (EMS)** – Allows DTEE to manage the subtransmission system and the connections to the transmission system, provides the tools to perform state estimation and contingency analysis on the balanced electrical network, and allows DTEE to operate devices on the subtransmission system.
- **Outage Management System (OMS)** – Performs outage analysis based on the as-operated state of the electrical system, inputs from the AMI infrastructure, and customer channels. Outage and non-outage jobs are aggregated to ensure field crews are dispatched appropriately by the dispatchers and system supervisors working together to return the equipment back to normal operating state.

- **Distribution Management System (DMS)** – Starts with the as-operated Network Model (eMap) that serves as a building block for the use of advanced DMS applications such as Fault Locating, Switching Analysis, and Volt/Var Control functions that will provide for the safe, reliable and efficient management of the planned and unplanned events on the electrical system.
- **Network Management System (NMS)** – Allows DTEE to maintain high quality and accurate distribution and subtransmission locational and operational system data essential to the safe and effective monitoring and operations of the grid. See Section 12.9.4.3 – Network Model, for more information on the Network Model.

During the planning phase of this project, DTEE benchmarked multiple utilities that have implemented, or are in the process of implementing, an ADMS. These utilities shared the same goal of improving reliability by setting a foundation for technology deployed in the field and providing real-time views of the “as-operated” system.

The implementation of ADMS varied among the utilities, depending upon the components or modules needed or systems requiring replacement. One key “lesson learned” that was common among utilities is that data quality is crucial and requires process improvements to ensure sustainability once ADMS is fully functional.

Since successful ADMS implementation is dependent upon the accuracy of the data entered and stored in the systems, DTEE conducted a data gap analysis in 2017 to provide a clear understanding of potential issues in our current systems. The results, shown in Exhibit 12.1.2 below, indicate that DTEE’s data quality at the time was below the recommended level to achieve full benefits from an ADMS.

Exhibit 12.1.2 DTEE 2017 Data Quality Gap Analysis Results

Data Quality	DTEE Data Gaps	Third Party Assessment
Spatial integrity accuracy	Displacement up to 200 feet with further misalignment	Below Industry Standard
Single operating model	Many models. Including AC, PQ View, GIS	Below Industry Standard
Controlled operational data	Device and asset data lack location and system control	Below Industry Standard

Data Quality	DTEE Data Gaps	Third Party Assessment
SCADA integration	Data lacks operationally consistent nomenclature; lack of incremental registration	Below Industry Standard
AMI data in operations	Load, voltage and connectivity not in use for operations	On Par with Industry Standard
Power flow models	Lack of power flow model integration to GIS	Below Industry Standard
Underground network, cable and duct bank	AC networks are not modeled	Below Industry Standard
Visibility to quality	Lack of correlative validation and visualization	Below Industry Standard
GIS network connectivity	GIS distribution connectivity with transformer to meter connectivity supplying OMS	On Par with Industry Standard
Secondary system	18,000 miles of secondary is not connected in the system	Below Industry Standard

Based on this analysis, DTEE created a Network Management System for the as-built GIS Network Model to ensure all electrical network assets and their respective locations are accurately represented in one source. This project focused on creation of a network model, along with initial data cleansing and migration, hardware, and software upgrades to better track and maintain data going forward. DTEE has made significant strides in addressing spatial integrity accuracy, moving toward a single operating model, use of AMI data in operations, modeling of underground network cable and duct bank, visibility to quality, and connecting of the secondary system. The Network Model program is geared toward continuing to enhance the single operating model, expanding the use of work management and GIS integration for better asset data management, and visibility to quality by implementing solutions to enhance sustainability of data maintenance. See Section 12.9.4.3 – Network Model, for more information on the sustainability and continuous improvement of the Network Model.

The ADMS connects and aggregates several operational functions to provide real-time situational awareness and a controllable distribution grid. Implementation of the ADMS is expected to bring many benefits, including:

- **Enhanced visibility and operational safety** – The ADMS provides a tool for system supervisors to run "what-if" scenarios, perform pre-operation analysis checks for potential issues before issuing operating orders and validate switching orders in "study mode" prior to execution.
- **Improved system performance** – The ADMS supports Volt/VAR optimization and can automatically balance line voltage and system reactive power to reduce power line losses, reduce peak demand and improve the efficiency of the distribution grid.
- **Improved system reliability** – The ADMS reduces customer outage duration (SAIDI) by providing the following: automated outage verification; automated crew assignment optimization; automated power flow analysis and fault location; switching studies to isolate faults and restore the maximum number of customers; and eventually remote switching and automatic isolation and restoration operations.
- **Advanced data analytics** – The ADMS provides a platform to analyze significant volumes of data from various portals and provides system supervisors the information in one place.
- **Improved integration of distributed energy resources** – The ADMS increases grid visibility, allows flexible, real-time operation and provides appropriate balancing and control of power flow to lay the foundation for accommodating increased distributed energy resource penetration in the future.

The implementation of ADMS has been phased in over recent years. DTEE successfully launched the Generation Management System (GMS) in December 2018 and the EMS in May 2019. An EMS system upgrade is on track for completion in Q4 2022 to allow for decoupling of the EMS from the GMS.

Deployment of the new GMS and EMS systems has allowed DTEE to modernize IT infrastructure with virtualization technology and to increase cyber security design with physical and virtual networking, in addition to these other improvements:

- Data tables are stored in a consistent fashion, improving the user's ability to search, find and correct entries when necessary.
- Application modules have improved visual and functional setting parameters.

- The display and database maintenance process has been improved, with new capabilities of the system to lock, edit and track data changes. Display archiving and database rollback options bring an additional level of security in case the data gets corrupted and needs to be re-populated from a backup repository.
- Hardware has been upgraded to a virtual environment (virtual servers) and is fully redundant from the data center perspective. The hardware has the latest processors, memory and graphics cards, greatly improving the user's experience when navigating the application on the client machines.
- Tools have additional features that help the users build situational awareness displays and dashboards.
- The system has a fully operational Operator Training Simulator domain that is ready to be used as a simulation tool for training and developing new system operators and engineers.
- The EpilogPro application module, planned to be implemented in 2021, will allow electronic logging, which is needed for electronic switching and tagging, and will also benefit compliance with improved record retention and archive searching capabilities.
- The system will be on the same platform as the Outage Management System (OMS) and Distribution Management System (DMS) once implemented, allowing transparency of the system to all appropriate personnel.
- The new system will allow for more straightforward system upgrades in the future, as it was configured with standard vendor-offered functionality and not custom built for DTEE.

The Outage Management System (OMS) and Compass Mobile field extension tool will be launched in Q4 2022. The new OMS will allow for improved outage identification time and visibility, which will enable DTEE to more safely and quickly work to restore power to customers. The Compass Mobile tool will be used to manage work and view the as-operated DMS Network Model and improvements planned for the future such as the Damage Assessment, Fault Location and Switch Order Management modules.

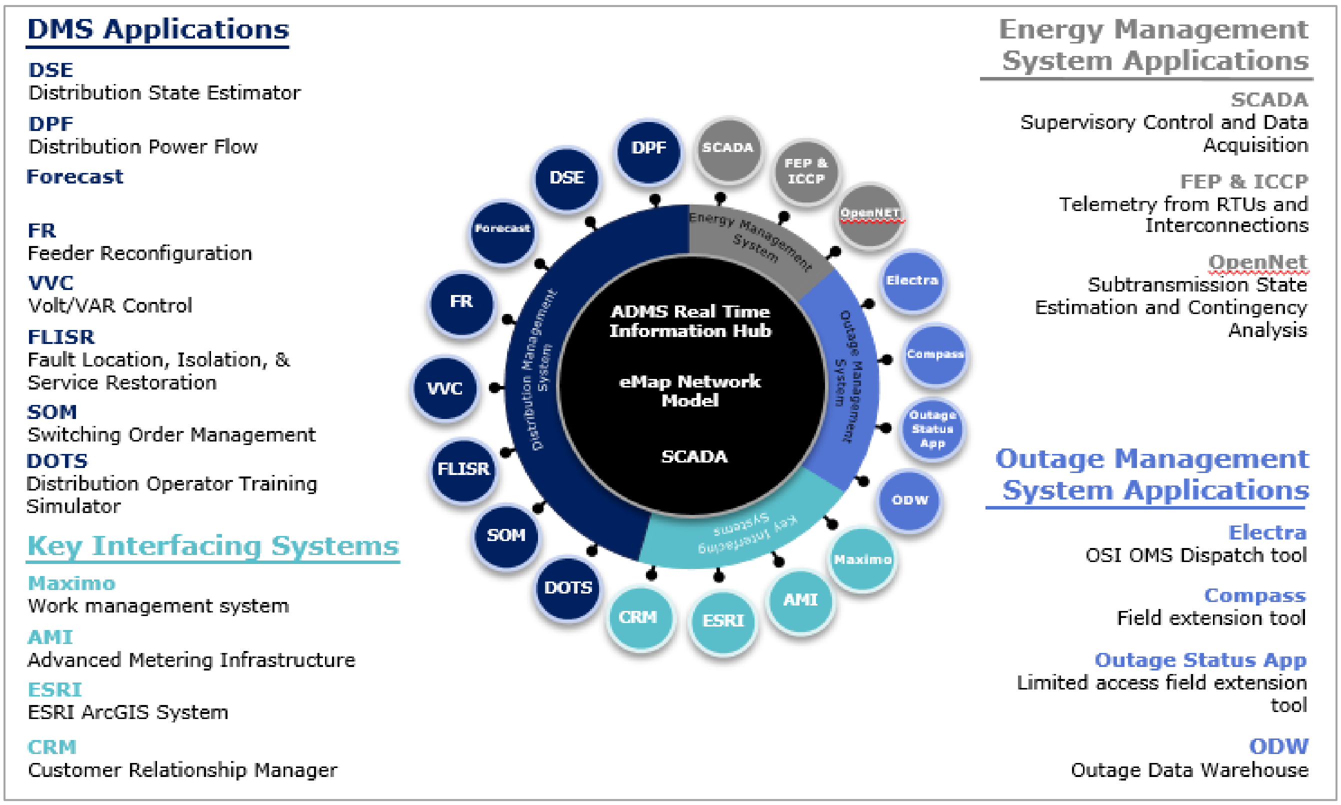
A key component of the Distribution Management System (DMS), eMap, will be launched in Q4 2022 and will provide a schematic of the as-operated network model representing the overall DTEE system.

Between Q3 and Q4 of 2022, DTEE has plans to roll out the remaining DMS applications listed in Exhibit 12.1.3, below. Exhibit 12.1.4 shows all the applications associated with the EMS, OMS, and DMS as part of the ADMS platform and the key interfacing systems.

Exhibit 12.1.3 Distribution Management System (DMS) Applications

Application	Description of Application Use
Distribution State Estimator (DSE)	Used to determine 3-phase voltage and load values on the system to feed into other advanced applications
Distribution Power Flow (DPF)	Used to determine 3-phase voltage and load values on the system and to run studies to analyze future conditions of the system
Forecast	Uses historical load and weather data to forecast electrical load for periods of one hour to 35 days to be used by System Operations and as inputs to other applications
Feeder Recognition (FR)	Used for response to system events to develop switching procedures to resolve overload and low voltage conditions, improve load balance, and improve system performance as it relates to losses and voltage profiles
Volt/Var Control (VVC)	Used to manage voltage and reactive supply levels and reduce system load to prevent load shedding
Fault Location, Isolation, & Service Restoration (FLISR)	Used to detect a fault or loss of voltage condition and recommend switching actions to isolate the fault and restore service
Switching Order Management (SOM)	Allows for quickly determining switching solutions for restore-before-repair
Distribution Operator Training Simulator (DOTS)	Used for scenario-based training on the Distribution Management System

Exhibit 12.1.4 ADMS Applications and Key Interfaces



As part of the implementation strategy, a focused change management approach is being deployed. A change management team was formed early in the project due to the significant changes in how work would be done with the implementation of the ADMS. The team identified the key internal stakeholders, has provided consistent messaging throughout the project, and has developed training plans for the affected roles.

The total capital investment for the ADMS project is $72 million, including investments in 2021 and 2022 (shown in Exhibit 12.1.5), and investments made prior to 2021.

Exhibit 12.1.5 ADMS Capital Investment

	2021	2022	2023	2024	2025	Total Investment 2021-2025
ADMS ($ millions)	$30	$10	-	-	-	$40

12.2 SOC modernization

Another technology improvement that is essential to grid modernization is the System Operations Center (SOC) Modernization project. While the ADMS addresses the operating technology platform, the SOC Modernization project addresses the physical infrastructure and technology constraints within the current SOC. This project is aimed at replacing the outdated primary SOC and the smaller, outdated backup SOC by constructing two facilities designed using current industry security, resiliency and operability standards. The current SOC was built in the early 1980s and poses significant limitations including:

- **Outdated facility** – The facility lacks the redundancy in mechanical and electrical systems necessary to ensure continued operations in the event of a significant system event.
- **Outdated technology –** The current SOC, which is in service until the changeover later in 2021, uses a magnetic tile representation of the electric network, as opposed to an electronic display board of the transmission, subtransmission and distribution network, which is now very common in the industry. This severely limits situational awareness, which is always critical, but particularly during periods of significant system events, such as large storms. In addition to being outdated technology, the tile map board is running out of space to accommodate growth in the distribution system. The lack of modern technology also limits training opportunities.
- **Space limitations –** The SOC and dispatch personnel are physically separated, and their primary method of interaction is through repeated phone calls to share information and collaborate on dispatching field resources. The current SOC does not have sufficient space to collocate these resources that manage the system and dispatch field personnel to resolve operational issues. Colocation of SOC and dispatch personnel is a well-established industry best practice, as it provides significant customer benefits in terms of the speed at which issues can be addressed and electric service restored.

- **Limited visibility of telecommunication infrastructure performance –** The reliability of telecommunication paths from field devices to the SOC is critical for the effective monitoring of the grid and for remote operations. Developing the ability to separately monitor the condition of the telecommunication network through the construction of a Network Operations Center (NOC) is part of the SOC Modernization project.

Construction began on the new primary Electric SOC (ESOC) in June 2019 at DTEE's downtown Detroit headquarters complex. Building construction has been completed, the equipment and remaining infrastructure are being installed, and DTEE will begin using the ESOC in Q4 2021.

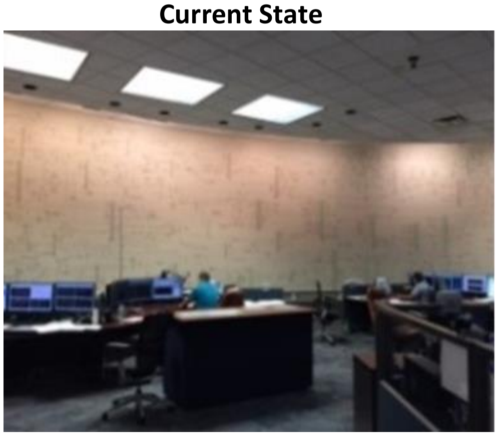
The ESOC facility will allow for co-location of dispatchers and operators and improve DTEE's ability to manage significant operational disruptions, thus improving the resiliency of the system.

The new Network Operations Center (NOC) built within the ESOC will improve visibility of the status and availability of field telecommunications, increasing DTEE's ability to respond to issues quickly. The facility includes electronic displays and improved console designs to meet dispatcher and operator needs, as illustrated in Exhibit 12.2.1. This improves situational awareness and improves safety and reliability.

The Alternate SOC (ASOC) is required to allow DTEE to move ESOC operations nearly seamlessly to a fully functional alternate site in the event the primary ESOC is unavailable. The design of both the ESOC and ASOC is based on extensive benchmarking discussions with many top utilities and industry experts. The ASOC is being designed in 2021 with plans to construct in 2022 and 2023 within DTEE's new Waterford Service Center.

Exhibit 12.2.1 Current and Future State Example of SOC Facility

Current State



Future State

The total investment for the ESOC is $97 million with the new facility including:

- Tier III building standards providing redundant mechanical and electrical systems as well as being hardened to withstand 250 mph winds – EF5 category tornados
- 66,000 square feet on three floors and a 10,000 square-foot mechanical and electrical equipment yard
- Energy Management System, Data Center, mechanical room, UPS, switchgear rooms, and equipment yard on one floor
- ESOC Control Arena, with a state-of-art technology video wall, Dispatch Operations, Smart Grid Operations, Generation Control, and Outage Coordination on one floor
- Storm Command Center, media/overview room, open offices and mechanical room on one floor
- NERC CIP requirements at selected work areas on day one with ability to comply with NERC CIP requirements throughout the entire facility, if required
- Redundant electrical feeds, UPS, chillers and generators for uninterrupted operation
- Automobile crash guard planters, new site security fence and entrance gates and building security cameras

The remaining ESOC investment (included in the $97 M total) in 2021 is shown in Exhibit 12.2.2 in addition to the investment for the ASOC and Waterford Service Center.

Exhibit 12.2.2 SOC Modernization Capital Investment

	2021	2022	2023	2024	2025	Total Investment 2021-2025
Primary Electric System Operations Center (ESOC) ($ millions)	$15	-	-	-	-	$15
Alternate Electric System Operations Center (ASOC) and Waterford Service Center ($ millions)	$3	$34	$55	-	-	$92[1]
Total SOC Modernization Investment ($ millions)	$18	$34	$55	-	-	$107

1. ASOC/Waterford facility is still under review and design, and may undergo significant changes before being finalized

12.3 Grid telecommunications

Grid modernization has increasing reliance on communication technology, making telecommunication foundational to a modern grid and a requirement for many of the advanced programs and features of the distribution system, especially automation. As an example, telecommunications enable the use of key functions of the ADMS, such as monitoring and device control. Such automation requires a resilient, secure, high-speed telecommunications network using interoperable protocols that provides very high-quality service.

To ensure a successful program, operability, security and resiliency must be built into the program from the start. This will allow future use cases and technologies beyond current grid technologies, such as DERs and coordination and control of customer and devices owned by third parties. To increase efficiency with other elements in DTEE's grid modernization efforts, the telecommunications plan is being coordinated with other related projects.

According to the Department of Energy's DSPx Grid Modernization Framework:

> The operational communication network that enables the transformation of grid modernization efforts is an important aspect that cuts across the entire industry and is a key component in any modern grid. As such, there should be a consideration of the various components of operational networks based on needed capabilities and functions.

The DOE's DSPx Grid Modernization framework was discussed in the Section 3 – Grid Modernization Process and, as shown in Exhibit 3.4.2.1, Operational Communications is a Core Component that is foundational to all other aspects of grid modernization.

Starting in 2015, DTEE assessed the industry for best practices around telecommunications and developed Distribution Design Orders around network installations and grid equipment. For example:

- DDO 100-001: Requires remote Power quality metering at substations and industrial sites.
- DDO 100-003: Requires all new and retrofitted breakers and reclosers to be SCADA equipped.
- DDO 100-004: States all SCADA sites shall implement private and secure IP communications with fiber as the preferred medium to stations and substations and radio mesh for pole-top devices.

- DDO 100-005: States all interconnected generators must follow IEEE 1547-2018 and SunSpec communications standards.
- DDO 100-007: States all SCADA substations shall meet cyber security rules.

DTEE's Network Engineering has been implementing a tiered design to serve communication needs now and in the future in a highly resilient manner to provide a high quality of service:

- Tier 1 consists of microwave and fiber backbones for the Tier 1 and Tier 2 systems that traverse between critical facilities such as data centers, power plants, service centers and subtransmission stations.
- Tier 2 consists of wireless point-to-point and point-to-multi-point systems that allow data collection from the Tier 3 system, distribution substations and pole top devices.
- Tier 3 consists of wireless mesh networks that support end point SCADA and AMI meter Communications.

Many modern electrical components require communications that will be coordinated by the ADMS. Some of the ADMS functions requiring communications are:

- Remote operation/SCADA
- Electronic switching and tagging
- FLISR (fault location, isolation and service restoration)
- Volt/Var & CVR
- Distribution State Estimation
- Dynamic protection
- DER integration
- Field mobile and redlining

Among the thousands of existing device types that ADMS will connect over the network are:

- Inside the substation
  - Relays, meters, breaker controls, capacitor controls, transformer controls systems
  - RTUs (microprocessor-based devices that monitor and control field devices that then connects to plant control or SCADA systems) and communication processors
  - Alarms and Human-Machine Interfaces (HMI)
  - Asset health sensors such as voltage monitors

- Security Cameras and Access Control systems
- Outside the substation
  - Reclosers
  - Pole top switches
  - Capacitors
  - Regulators
  - Line sensors
  - Power quality meters
  - AMI meters

Telecommunications systems will be installed in accordance with the Distribution Design Orders to enable communications with devices being installed as part of the automation plan (see Section 12.5 – Distribution Automation) and other projects. All these devices require a secure, high speed data network to communicate with the ADMS and with each other.

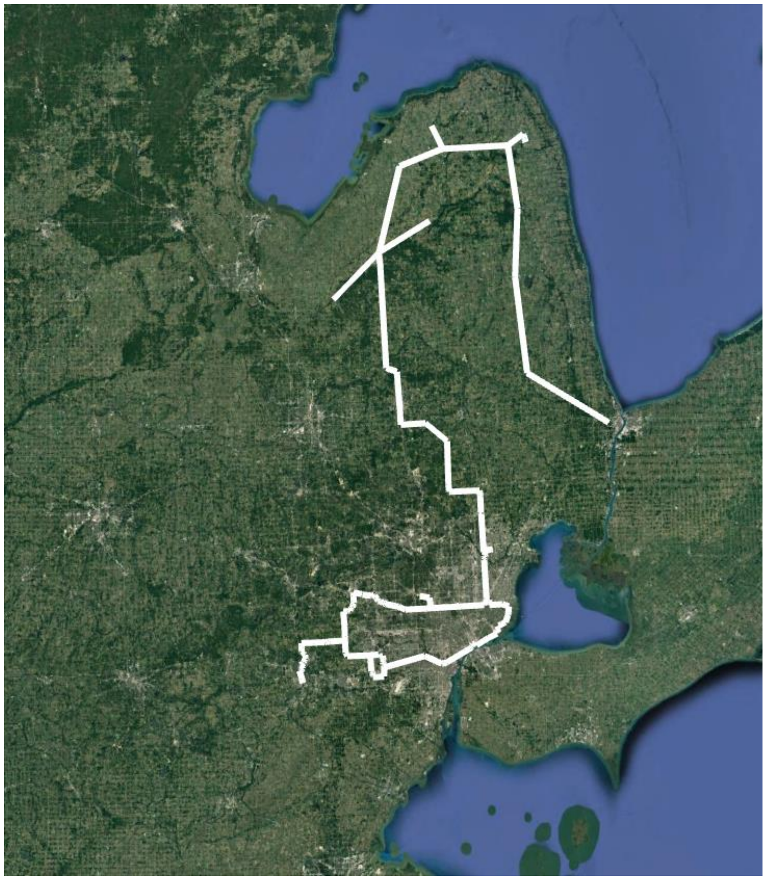
In addition to remote device management, configuration and operation, additional assets and functions that benefit from the telecommunications network are:

- Integration of DER control schemes and distributed generation (smart inverters)
- Future asset health monitoring devices such as voltage monitors and line sensors
- Collection of data from the AMI mesh of over two million AMI meters
- Future enhancements for field mobile for crews and planners
- High resolution security cameras and access control systems for infrastructure security at critical facilities

The first tier of DTEE's field network is made up of private fiber, leased fiber and point-to-point microwave systems, shown in Exhibit 12.3.1. This network was designed to interconnect data centers, power plants and critical distribution and generation systems across the service territory.

DTEE-owned fiber forms a loop around the center of the metro-Detroit area with taps to include the Ann Arbor and Lapeer Service Centers. The leased fiber is used to support the critical Thumb area substations and wind parks, the North Area Energy Center and the Lapeer Service Center. Microwave links extend the Tier 1 backbone to other service centers, power plants and critical subtransmission stations, however it is scheduled to be replaced in sections through 2025.

Exhibit 12.3.1 Map of existing Fiber systems – private and leased



DTEE's existing field communications network (FCN) does not currently have adequate capacity and does not have coverage over the entire service territory. In order to support the automation plan, it will be necessary to deploy fiber optic backbone and wireless systems to support the demand.

The majority of DTEE's service territory is without high bandwidth communications. Many of the outdated systems are radio-based systems utilizing serial protocols. This type of communication method is incompatible with modern systems, thereby limiting the system's usefulness when deploying new technologies.

Additionally, much of the equipment utilizing the radio-based systems are beyond end-of-life. Spare parts cannot be purchased or maintained. When the initial radio-based system was designed, it was not intended for transmitting large volumes of data from the distribution system, and especially not the volume of data associated with modern network communications.

In addition to the stated gaps that will be filled with the telecommunications plan investment, there are also many associated potential O&M savings:

- For locations with cellular backhaul communications, the private network can be expanded there, saving between $20-$50 per month per cellular unit installed. Currently over 3,300 cellular units are supporting the existing field communications network.
- Leased lines can be eliminated, with costs ranging from hundreds to thousands of dollars a month. This includes phone lines for nearly 500 circuits, each costing between $75 and $200 a month, with specific data lines costing up to $5,000 per month, plus 20-30% year over year increases due to tariff rates.
- Decreased latency and higher bandwidth will enable other uses in the substation, including high resolution security cameras and distributed energy management systems that can reduce local data storage and maintenance costs.
- Increased bandwidth availability in the mesh network may reduce cellular bills for mobile workers and line crews and will enable future applications, such as better mobile connections for new technology, including future cloud services, augmented reality and real-time system maps from the ADMS.

Projects to support new natural gas power plants and renewable energy generation sites will supplement a small portion of the fiber backbone system, however the DTEE telecommunications investment is essential in order to close the infrastructure gaps.

In evaluating alternatives for expansion, cellular technology was considered, however it has many limitations that make it unsuited for grid use:

- Due to the proximity between DTEE's service territory and Canada, cellular equipment attempts to connect to the wireless service available, sometimes between countries, degrading reliability.
- Coverage in rural areas is poor.
- Cellular network technology changes often, leading to frequent hardware replacements – for example the upcoming retirement of 3G.

- Cellular providers do not provide maintenance or unplanned outages or reliability statistics despite many requests. Tests of cellular services reliability over time have proved to be unacceptable use cases for critical control functions.
- Cellular Service Providers package utility data communications, which are ultimately sent over the public internet, leading to cyber security concerns.

Although fiber technology has many benefits, it is not practical to install fiber at every location, leading to the usage of other communication mediums to supplement connectivity. DTEE's Tier 2 telecommunication systems include wireless point-to-point and point-to-multi-point networks. To ensure these supplemental wireless systems can provide the necessary network connectivity, a fiber backbone system is needed to backhaul their communications. These fiber backbones, or trunks, are estimated to be needed within five miles of Tier 2 systems in urban areas and within 12 miles in rural areas.

To further develop the optimal solution, installation locations were weighed against the resiliency of the solution. For instance, underground fiber installations come at a very high cost unless there is existing conduit with space for additional cabling. Underground lines are still subject to dig-ins and animal interference in manholes. Optical Ground Wire (OPGW) is a specialized metal jacketed fiber that is embedded in the shield wire above the energized conductors at the top of the pole. This solution is most common for transmission system communications. However, it has limited bandwidth due to size constraints and failures typically require shutdowns and specialized equipment to fix. Modifications or new equipment installations in the transmission system space must be installed around energized conductors, leading to a much more hazardous working environment.

Locating the fiber in the internet services joint use space on the utility poles proves to be the more cost-effective area to install, as it is easy to repair and modify without shutdowns or specialized equipment, provides the easiest access to pole top equipment, and follows existing paths between circuits. Limitations include increased exposure to weather impacts, falling trees, animal interference and public interference. It also must follow existing pole leads and clearances may need to be adjusted to find room on crowded poles.

To facilitate connectivity between the overhead fiber network and substations, fiber is installed outside of the substation. Tier 2 and Tier 3 wireless systems are then used to provide last mile communications to the equipment within the substation property. This is the most cost-effective means of data acquisition. In addition, it also has the added benefit of strengthening the Tier 3 network responsible for pole-top SCADA and AMI meter data acquisition. For many 4.8kV substations along fiber paths, this method allows those substations to get network connections for very low cost when compared to underground trenching and conduit and would not lead to stranded infrastructure should the substations be decommissioned. Substations with existing underground network communications entrances will utilize the existing access points.

Additionally, placing routers at junctions in the fiber at critical points will create independent rings in the network, reducing impacts of outages or damage and allowing communications to reroute along a different available path automatically. Newer routers have fault location technology embedded so that damage can be accurately located and addressed. An additional benefit to this is that it can supplement the electrical fault locating accuracy if damage brings down a pole or a major section of overhead wire.

Prioritization criteria for choice of new installations within grid telecommunication consider the following:

- Criticality of sites (peakers, service centers)
- RTU on SOC critical and cranking path (Cranking path is the portion of the electric system that can be isolated and then energized to deliver electric power from a generation source to enable the startup of one or more other generating units.)
- Number of devices at each location that have communications capabilities
- Number of customers served by the location
- Existing network infrastructure (towers, backhaul points)
- Planned upgrades or decommissioning at the location
- Number of pole top devices in the area
- Number of leased lines, Radio Communication Systems (DTEE's existing infrastructure and radio devices used for remote communications) radios, or sites with bandwidth issues
- Proximity to existing backbone
- Overlap with existing programs such as delta ground protection and substation physical security

DTEE has achieved cost savings by utilizing contractors already knowledgeable in the telecommunications industry. For example, there are many contractors who already install communications equipment for joint users such as cable and telephone providers and are familiar with DTEE's specifications and requirements. In developing DTEE's standards, DTEE engaged fiber installers who provided specifications for telecom companies including Verizon and Comcast. Leveraging experienced installers alone has provided a 50% cost savings over other contractors.

Additionally, DTEE is planning for further cost reduction with additional improvements to standards and creating compatible units. Exhibit 12.3.2 shows the investment summary for Grid Telecommunications. The build out of telecommunications infrastructure will also continue beyond 2025.

Exhibit 12.3.2 Grid Telecommunications Investment Summary

	2021	2022	2023	2024	2025	2021-2025 Total
Investment Projection ($ millions)	$5	$15	$19	$17	$15	$71

12.4 Distribution sensing and monitoring

DTEE's Distribution sensing and monitoring strategy has been developed as part of the Grid Needs Analysis (see Section 3.4) under the premise that increased grid visibility will improve the operation of the electrical grid and allow DTEE to maintain best-in-class safety and reliability given all the new technologies that are transforming the way the grid functions as well as customer expectations.

As discussed in Section 3 – Grid Modernization Process, grid changes, including the expected increase in the penetration of distributed energy resources (DERs), aggregations made possible under FERC Order 2222, and DTEE's pursuit of non-wire alternatives (NWAs) will present challenges to operation of the grid. Tools such as ADMS and its suite of advanced applications, as well as future Distributed Energy Resource Management Systems (DERMS), will be key to DTEE's ability to adapt. Real-time data from the distribution system will be vital to fully leverage the functionality and potential of these operational technologies and provide the necessary information to make decisions impacting safety, reliability and customer satisfaction every day.

Additional operational benefits will be achieved with enhanced sensing and monitoring data, such as ensuring more timely and accurate information regarding power quality is being delivered to customers, more granular data from an increasing number of monitoring points on the distribution system utilized to support a DERMS application, and the ability to manage distribution connected DERs as they participate in the energy markets and co-exist with traditional customer loads.

In addition to the operational benefits, there are other functions within DTEE that will benefit from robust sensing and monitoring capabilities. For example, the Distribution System Planning and Interconnections groups, as well as Corporate Energy Forecasting, will use more granular data for capacity planning (increased electric vehicle adoption, new DER loads) and impact studies, and Equipment Engineering can develop a more accurate assessment of asset health through enhanced monitoring of potentially harmful harmonics generated by DER devices on the system, which could lead to distortion in system voltage and currents.

The Sensing and Monitoring team has broken down DTEE's strategy into the following categories:

- Smart Fault Indicators/Line Sensors
- Low-cost Substation Monitoring
- SCADA and AMI Enhancement

Within these categories are the following key plans:

- Complete line sensor coverage of entire grid and pursue next generation sensor technologies
- Upgrade existing low-cost substation monitoring to provide SCADA-grade capabilities
- Enable SCADA on all overhead and substation voltage regulating equipment
- Enable SCADA on all sectionalizing equipment on distribution and sub-transmission grids
- Enable near-real-time load and power quality data from AMI meters

Overall, the investment in sensing and monitoring from 2021-2025 is $53 million. Many of these efforts will likely extend through 2035 to provide comprehensive sensing coverage on the system. Several of these efforts will require specialized and skilled resources, which will be incorporated into the future workforce planning efforts.

To mitigate this, the work will steadily ramp up over the next five to 10 years to allow for necessary hiring and training of the resources required to support the installation and maintenance of new sensors, communication assets and smart grid devices. Exhibit 12.4.1 shows the projected investment summary for Sensing and Monitoring strategy. Sections 12.4.1-12.4.3 discuss the specific sensing technology that will be deployed in more detail.

Exhibit 12.4.1 Sensing and Monitoring Investment Summary

	2021	2022	2023	2024	2025	2021-2025 Total
Investment Projection ($ millions)	$2	$6	$12	$13	$16	$49
Smart Fault Indicators/Line Sensors ($ millions)	$2	$4	$8.5	$8.5	$8.5	$31.5
Low-cost Substation Monitoring ($ millions)		$1	$2	$3	$3	$8
ION Meter Data Integration ($ millions)		$1	$1.5	$2	$5	$9

12.4.1 Smart fault indicators/line sensors

Line sensors provide a low-cost and easily deployed means for DTEE to monitor the distribution system as well as provide valuable data such as periodic current readings, fault status and magnitude, and in some cases voltage and harmonic information. Line sensors can be installed at the head of circuits with no SCADA to provide near-real time load data to DTEE's Electric System Operations Center, as well as historical load-profile data that can be used by Planning and Engineering groups during their annual load analysis efforts. These sensors can also be deployed across overhead circuits for the purposes of fault locating. The real-time outage and fault data these line sensors provide has become an integral part of DTEE's outage restoration procedures, and allows operations teams to more quickly and accurately pinpoint the location of faults on the overhead system, thus reducing circuit patrol times and allowing for more timely isolation and repair.

In the future, the ADMS will rely heavily on smart fault indicator data to enable fault locating functionality such as that provided by the FLISR advanced application. To fully leverage those capabilities, DTEE will need to increase its penetration of overhead line sensors, begin to deploy more enhanced devices with voltage sensing and power quality data, and pursue an underground smart fault indicator solution.

12.4.1.1 Overhead line sensors/SFIs (current sensing)

Since 2013, DTEE has deployed over 11,000 current-sensing smart fault indicators on the distribution system, and the plan over the next five years includes completion of that deployment, as well as a transition to routine replacement, upgrades and repairs. The five-year Sensing and Monitoring plan calls for installing or replacing approximately 3,600 units per year between 2021-2025 to provide the highest level of device availability and geographical coverage of fault data for use by the ADMS fault locating functionality. Specific focus will be paid to circuits where fault status and magnitude data are not currently available and near key sectionalizing points such as A/B points.

12.4.1.2 New underground line sensor technology

DTEE has been actively pursuing an underground line sensor solution for fault locating and load monitoring on its underground distribution circuits. DTEE also plans to upgrade and expand upon the existing underground line sensor deployment on its A/C Network netbanks in downtown Detroit, an area where historically DTEE has not had any remote visibility. The benefits of this type of data are numerous, including understanding when netbanks have gone offline due to blown fuses or equipment issues. Because of the redundant build of the system, it has been difficult to understand loading on the various netbanks and allow for Planning and Engineering to accurately model the system.

Overall, DTEE expects to equip approximately 500 distribution circuits with underground smart fault indicators (line sensors) and another 500 A/C Network netbank transformers for a total of approximately 3,000 devices (three per location) over the next five years. Beyond that timeframe, around $100,000 a year will be needed to cover device failure replacements and upgrades.

12.4.1.3 Voltage-sensing smart fault indicator technology

As part of grid modernization, there is a need for voltage data on the circuits and near the substations, in parts of the grid where there currently are no smart relays, SCADA-enabled overhead equipment or other means to collect that data and bring it back to EMS, ADMS and PI, the data archive. There are several line sensor products that have come to market in recent years that can provide this data at a relatively low cost for equipment and installation.

As part of the five-year and 10–15-year Sensing and Monitoring strategy, DTEE plans to deploy voltage-sensing line sensors at key locations on the overhead system to collect real-time current, voltage and harmonic data in of support programs including CVR/VVO (See Section 12.6 - CVR/VVO), DER monitoring/DERMS (See Section 12.8 – DER Control) and asset health.

For asset health, many of these voltage-sensing devices also provide harmonic data, which can be used to observe whether harmful harmonics are being introduced as result of DER devices or other causes on the distribution.

DTEE plans to deploy voltage-sensing devices out on the distribution system at approximately 500 locations over the next five years to provide ADMS and DERMS the necessary voltage information to make operational decisions to preserve the reliability of the grid. DTEE will also install voltage-sensing SFIs at another 150 locations to support CVR/VVO over the next five years, and then another 500 locations in the next 10-15 years.

12.4.2 Low-cost substation monitoring

Low-cost Substation Monitoring (LCM) has been a program run by the DR-SOC (Distributed Resources System Operations Center) with the goal of providing distribution substation data availability where there has traditionally been no SCADA telemetry, such as with many of the older 4.8kV substations. Instead of SCADA, DTEE will install low-cost meters that retrofit onto substation control circuitry to provide near real-time load and breaker status information at each feeder position, and voltage and current readings at each distribution transformer position. The data is transmitted over cellular back to the SOC at 5-minute intervals, as opposed to 2-4 second intervals with traditional SCADA data. Over 25% of all distribution feeders are now monitored using Low Cost Metering (LCM) technology.

The Sensing and Monitoring strategy calls for some necessary upgrades to the existing LCM substations as well as an expansion of the LCM deployment in order to provide more reliable substation-level situational awareness for operational tools like ADMS as well as engineering resources like PI, which can make the data available for capacity planning and analysis.

12.4.2.1 Low-cost monitoring technology upgrades

In order to increase reliability of the monitoring platform and the rate at which data is transmitted back to ADMS via the DR-SOC, the LCM data loggers will be upgraded to SCADA grade Remote Terminal Units (RTUs) with improved telecom backhauls such as TropOS, Digi modems (another communications technology provider) or fiber. The metering and communicating wiring beyond the RTU will remain the same, however. The expectation is that with these upgrades, data from all LCM-equipped substations will be transmitted every 2-4 seconds, instead of every five minutes, resulting in much more real-time visibility into the state of the feeders and transformers at those substations. The cost to perform these upgrades includes a Real Time Automation Controller (RTAC) RTU, network switch and engineering and field labor to install and test. There are approximately 200 LCM substations that will be upgraded as part of the five-year plan.

12.4.2.2 Complete low-cost monitoring deployment

Low-cost Substation monitoring is a technology option that will defer or avoid SCADA retrofitting at older substations, but still provide SOC and Engineering with the real-time telemetry needed to operate and maintain the distribution grid until these substation breakers or substations themselves are replaced and fitted with traditional SCADA.

There are approximately 40 4.8kV substations and 75 13.2kV substations that do not have SCADA at which DTEE will explore deploying LCM technology. Many of those substations currently use line sensors at the head of circuits to provide the real-time load data to SOC but lack the breaker status and transformer data that is provided by LCM. Furthermore, line sensor data is transmitted every 5 minutes whereas LCM after the upgrades implemented in the Sensing and Monitoring plan will provide more data at the higher rate of every 2-4 seconds.

12.4.3 ION meter data integration

The DR-SOC has been deploying Schneider's ION meters at substation transformer positions as part of the low-cost monitoring installations to provide real-time current and voltage data to the SOC. There is potential for these meters to provide even more valuable data to DTEE, including more detailed power quality data, as well as fault information at the transformer/bus level. DTEE plans to integrate these LCM substation transformer ION meters into ADMS as well as into the PQView power quality software system to collect data in the same way as Commercial & Industrial (C&I) and subtransmission ION meters collect data. There are also additional capabilities using Schneider's PME2020 software to achieve even further integration with DTEE's operational technology systems.

There are approximately 250 ION meter installations as part of the LCM program, but that number will likely double over time. Any new installations will be set up with the necessary integration steps during construction of the job.

12.4.3.1 SCADA and AMI enhancements

DTEE's deployment of an Advanced Distribution Management System (ADMS), along with an anticipated Distributed Energy Resource Management System (DERMS), will have a profound impact on the operation of the grid to provide safer, more reliable power to its customers. The suite of advanced applications these tools provide require timely, accurate and available data sources in order to inform correct operating decisions.

Two of the most vital sources of system data are SCADA and AMI. In addition to the remote-control capabilities SCADA provides, the variety of available data and alarms from all remote SCADA-enabled field devices provides crucial situational awareness and feedback to System Operations. AMI provides key data directly from the customer, but the current system is not real-time, other than power-off and power-restoration notification, limiting its use in operations.

The following sections describe some of the key enhancements to SCADA and AMI that are being targeted with Sensing and Monitoring strategy.

12.4.3.2 SCADA on all 3-phase operating devices

A key aspect of distribution sensing and monitoring includes providing 2-4 second interval SCADA updates from all distribution and subtransmission 3-phase operating devices including per phase voltage, current and power quantities (bidirectional and on both sides of the disconnect), as well as fault magnitude and waveform data.

On the distribution system, all older vintage Form 3 and Form 5 reclosers, which only provide basic information, need to be upgraded to a more modern device, such as Form 6 or Viper recloser, which includes the larger set of data required for ADMS and other application.

Additionally, some Form 6 controls will also need to be updated in order to be able to retrieve fault data. Additionally, installing automated, SCADA-capable devices at two jumpering points per circuit (approximately 6,000 total) is preferred.

It should be noted that the distribution overhead work is already included as part of the Distribution Automation program (Section 12.5 – Distribution Automation), therefore costs for this work are not captured as part of the Sensing and Monitoring strategy. However, enabling SCADA on all subtransmission 3-phase operating devices, such as pole top switches, is not included in the Distribution Automation program, so the costs to implement SCADA monitoring on the approximately 3,000 devices across 550 subtransmission lines are included in this program.

12.4.3.3 Substation transformer data enhancements

DTEE plans to equip all substation and station transformers with breaker duty monitoring for asset health, and sequence of events recording, which monitors collected data and records the time and sequences of changes, as well as power quality meters with harmonic monitoring to the 50th harmonic, including asset health monitoring. This will enable better situational awareness and predictive maintenance capabilities as well as understand the impact of increased DER penetration on these critical assets.

It should be noted that the 13.2kV substation work is already included in the Substation Automation program scope, therefore costs for this work are not captured as part of the Sensing and Monitoring strategy. However, enabling SCADA on other voltage class substation transformers is not included in the Distribution Automation program. This program will implement SCADA monitoring on the estimated 1,000 devices not covered by Substation Automation.

12.4.3.4 SCADA on all voltage regulating equipment

Having voltage data as well as state and condition data of voltage regulating equipment on DTEE's system is necessary to support programs like CVR/VVO, and to handle the increasing penetration of DERs on the distribution system. Tools like ADMS and DERMS will require accurate voltage data in order to facilitate critical decisions involving power quality and compliance with voltage standards.

Voltage regulating equipment, such as regulators and capacitors, can be found both in the substations and on the overhead circuits. As part of the Sensing and Monitoring strategy, DTEE expects to outfit all equipment with 2-4 second interval SCADA data. The cost of the devices themselves will be covered under other programs, but the cost of SCADA integration is expected to cost approximately $10,000/device on the overhead. The Distribution Automation program will include equipment and SCADA integration for all capacitors and regulators within the substations, so that cost is not included here. That said, the combination of substation and overhead voltage regulating equipment data is necessary to leverage the full capabilities of the ADMS and DERMS.

12.4.3.5 C&I and large customer meter data enhancement

The goal with this aspect of the Sensing and Monitoring strategy is to gain real-time power quality and load data from most of DTEE's largest customers. These customers are 500kW and above in size, but not large enough to have industrial substations. This data will allow DTEE to make better operating decisions as well as to develop more accurate models of the commercial and industrial loads throughout the system for operating studies and capacity planning.

The five-year plan will be to retrieve five-minute data from all C&I AMI meters, using an updated Meter Data Management system (currently funded IT project) and an appropriate data retrieval tool based on meter type. There are two AMI vendors for C&I sites: Schneider and Honeywell. For the approximately 1,000 Schneider ION meters, DTEE will utilize the PME2020 software to access the required data. For the remaining Honeywell meters, a third-party system like Itron will be needed to access the same data.

Beyond 2025, DTEE will pursue two- to four-second interval data updates from the large customer meters which is more in line with SCADA-enabled metering. This will involve IT and potentially some meter upgrades.

12.4.3.6 Push Notifications for AMI near DER or CVR/VVO

The AMI enhancements DTEE is seeking to implement over the next 15 years will enable full situational awareness of customer load, power quality and outage status data in real-time, straight from the customer's meter.

The five-year plan calls for implementation of "push notification" functionality which is currently planned and under development. It enables near real-time updates of AMI data to a collection engine where it can be routed to downstream systems like ADMS, PI, or a cloud-based data lake. The AMI group within DTEE has determined that, due to significant data and network requirements, this feature will be limited to approximately 10% of the meter population or around 260,000 AMI meters, so the limited subset will be prioritized for customers with bidirectional DER meters (DG/DER tariffs) and key customer locations on feeders that are part of the CVR/VVO program.

The operational benefits to ADMS are numerous, but specifically with DER customers, the data will allow DTEE to perform analysis of individual customer loads in near real-time. As DTEE develops plans to maintain grid stability under high DER penetration, it may be necessary to develop strategies that will permit/deny individual DER participation in market activities at a given time, such as those enabled by FERC Orders 841 and 2222 during abnormal system conditions or during circuit maintenance.

12.5 Distribution automation

As part of DTEE's grid modernization effort described in Section 3 – Grid Modernization Process, a large investment is required to upgrade the distribution system so that it enables automation capabilities. As explained in the DOE report, "Distribution Automation: Results from the Smart Grid Investment Grant Program[20]," published in September 2016, "Distribution automation (DA) uses digital sensors and switches with advanced control and communication technologies to automate feeder switching, voltage and equipment health monitoring; and outage, voltage and reactive power management. Automation can improve the speed, cost, accuracy of these key distribution functions to deliver reliability improvements and cost savings to customers."

DTEE has identified five areas where automation can provide a significant positive impact to the grid:

- **Safety –** Increasing the amount of equipment that can be operated remotely to deenergize sections of lines that have potential hazards will ensure safety to employees and the public, including wire down detection and isolation on the 4.8kV system.
- **Reliability –** Remote identification and isolation of faults will be possible, reducing crew patrol time and enabling faster restoration for sections of circuits unaffected by the fault.

[20] "Distribution Automation: Results from the Smart Grid Investment Grant Program" (Sep 2016) Distribution Automation: Results from the Smart Grid Investment Grant Program (energy.gov)

- **Operability –** Realize reconfigurations of the substations and circuits from the Electric System Operations Center to support daily operational needs, eliminating travel time to operating points and minimizing handoffs among trades.
- **Asset Health –** The health of advanced devices will be more visible, improving the availability and reliability of automatic restoration and switching.
- **Cost –** The benefits to reliability, operability, and asset health ultimately lead to cost saving opportunities for DTEE customers.

The Smart Grid Investment Grant Program as discussed by the DOE, demonstrated how distribution automation technologies can achieve substantial beneficial grid impacts, including improved Fault Location, Isolation and Service Restoration (FLISR) capabilities, improved distribution system resilience to extreme weather, more effective equipment monitoring and preventative maintenance, more efficient use of repair crews, reduced repair times and improved grid integration of DER.

As detailed in the DOE report on Distribution Automation, five utilities reported a 50-55% reduction in the number of customer interruptions and customer minutes of interruptions per outage events during FLISR operations and three utilities reported SAIFI improvements of 17-58% from pre-deployment baselines, thanks to the ability to more quickly identify the location of a fault and perform switching activities that allow the fault to be isolated so that fewer customers are impacted during the repair activities.

For DTEE, Distribution Automation is planned for substation automation and circuit automation, while Conservation Voltage Reduction / Volt-Var Optimization (CVR/VVO) has automation as part of the project but is identified as a separate program (Section 12.6 – CVR/VVO).

Substation automation involves control panel replacements with modern, standardized relays, installation of Remote Terminal Units (RTU), incorporation of the RTUs and automation controls in the same substation network and breaker replacements as needed.

Circuit automation involves installation of remotely controllable/automatic reclosers and sensing devices, replacements of end-of-life automation devices that cannot be retrofitted, and reconductoring as needed to enable circuit load transfer during outage conditions.

The automation technologies installed on substations and circuits will also be linked to the ADMS for enhanced applications. These include, but are not limited to, the FLISR application, which combines fault location information with the circuit loading to optimize restoration and automatically restore service, and the Optimal Feeder Reconfiguration application, which analyzes load transfer options that can be executed across multiple substations to manage system loading conditions and improve system performance. While distribution automation applies to both circuits and substations, each area has specific requirements, functionalities and prioritization methods.

12.5.1 Circuit automation

DTEE's long-term goal for its Circuit Automation program is automating the entire overhead distribution. Because DTEE's distribution system has 4.8kV, 8.3kV, and 13.2kV infrastructure, which have vastly different configurations, short-term and long-term plans for each voltage type vary.

For the 13.2kV system, circuit automation involves installing SCADA reclosers and pole top switches, replacing outdated SCADA devices (such as Form 3 and Form 5 Reclosers), upgrading controls and protocols, or adding SCADA controllable devices to existing circuits.

All new circuits constructed today follow a standardized distribution design order and are installed with SCADA controllable reclosers and switches for every 4 MVA of load or circuit section containing 500 or more customers with a tie recloser between adjacent circuits. Any circuit improvement projects may also include SCADA reclosers, switches, regulators, and capacitors as part of the toolbox to improve circuit reliability. These devices will be used to isolate faults and provide service restoration automatically or under the direction of the ADMS and Electric System Operations Center. According to the DOE report referenced previously, other electric utilities have had significant reliability improvements after implementing circuit automation technology.

As discussed in Section 11.5 - 8.3kV Conversion and Consolidation, the 8.3kV system will be converted to 13.2kV by 2028, at which time automation will be added, as it is part of the distribution design orders.

Because of the complexity and uniqueness of the 4.8kV system, DTEE has done several equipment studies to determine how to address automation for this portion of the distribution system. For example, DTEE is currently testing a new recloser installed on the start of a 4.8kV circuit to be utilized to detect and isolate grounds on the circuit. As 4.8kV circuits are converted to 13.2kV, automation will be added as well (see Section 11.3 - 4.8kV Conversion).

Today, about 25% of the distribution circuits in DTEE's territory have SCADA monitoring and control. Approximately 5% of the distribution circuits in DTEE's territory have automatic loop schemes, which can automatically transfer sections of the circuits to adjacent circuits when an outage is detected. In order to achieve automation of the entire distribution system there will be a significant engineering effort to analyze and design the circuit equipment as well as Power Equipment and Relay Testing (PERT) SCADA resources for deployment of SCADA distribution devices.

Additionally, this program will require significant coordination with the long-term circuit planning process as the schemes increase operational flexibility but limit planning options to reconfigure circuits and increase distribution costs to adjust for new customers and changing loads. Significant portions of the system also require capacity upgrades to fully utilize automation once installed.

Exhibit 12.5.1.1 shows the anticipated investment and work to be done over the next five years.

Exhibit 12.5.1.1 Distribution Automation Circuit Investment Plan

	2021	2022	2023	2024	2025	2021-2025 Total
Circuit Automation ($ millions)	-	$2	$5	$10	$12	$29
Units (Circuit)		6	14	28	33	81
Units Remaining	2057	2051	2037	2009	1976	1976

Key considerations for prioritizing circuits for remote monitoring and control capabilities include historical circuit reliability performance, existing infrastructure considerations such as wire sizes, as well as the number of options for transferring load to adjacent circuits. For example, a circuit that has sufficiently large wire is more ready to automate than a circuit with smaller wire (see Section 8.9 – Small Wire). Establishing an objective prioritization method ensures that the program is implemented the most efficiently to ensure maximum benefits are achieved for DTEE's customers and the distribution system. While circuit automation will be executed strategically to maximize customer benefits, not all circuits are good candidates because of their circuit configuration and cost effectiveness. For example, if a 4.8kV circuit is part of the 13.2kV conversion program in the short term, then it will be excluded from the automation program because automation will be included in the conversion. Additionally, circuits that are mainly underground, have low load, or small customer counts may not benefit from circuit automation upgrades.

12.5.2 Substation automation program

The Substation Automation program involves installing SCADA control at all DTEE substations to allow for full remote monitoring and control. The program is designed to retrofit existing substations with advanced monitoring and control technology. Over the past year, DTEE has worked on developing a standardized panel design for substation automation that involves replacing electromechanical relays with microprocessor relays, as well as upgrades to the SCADA and telecommunications infrastructure within the substation. This allows monitoring, control, and automation of each circuit position within the substation. Roughly 32% of general-purpose substations in DTEE's territory have SCADA monitoring and control.

This program is part of DTEE's long-term strategy to modernize the electric grid and will greatly improve operational efficiency during substation planned work and improve restoration efficiency during trouble and storm events. When advanced remote monitoring equipment is installed at substations, there is a potential to use breaker operation data to assess breaker and relay functions. If the equipment is assessed to be performing as designed, it may be possible to defer equipment maintenance activities.

Due to today's limited remote monitoring capability at substations, DTEE has not yet been able to widely apply this methodology to defer breaker or relay inspections. DTEE's telecommunications, breaker replacement and substation automation programs, despite targeting different areas of the substation assets, will need to be coordinated to increase the penetration of such advanced remote monitoring technology and enable the application of condition-based maintenance on breakers and relays. These programs are also highly coupled with the ADMS.

As with the Circuit Automation program, 13.2kV substations are better candidates for the Substation program as their configurations better facilitate the technology upgrades needed for automation. Additionally, the primary goal of 4.8kV automation is the detection and response to ground alarms; therefore, the installation of reclosers as previously described also serves in part as the Substation automation for these substations.

Key considerations for prioritizing substations for remote monitoring and control capabilities primarily include historical substation reliability performance, gauged by number of circuit level lockouts, as well as the current level of automation at each substation. For example, if a substation already has some automation capabilities, then completing the automation for that substation may take precedence over a substation with no automation. However, reliability must also be taken into consideration when prioritizing which substations to automate; a substation with poor reliability may be chosen to be automated ahead of another substation with existing automation capabilities if the former's reliability performance could be improved with automation. As with Circuit Automation, establishing an objective prioritization method ensures that the program is implemented the most efficiently to ensure maximum benefits are achieved for DTEE's customers and the distribution system. While substation automation will be executed strategically to maximize customer benefits, not all substations are good candidates for automation given physical constraints or cost effectiveness. For instance, some 4.8kV substations do not have the physical infrastructure (breakers, relays, etc.) to support distribution automation. It will become possible to deploy automation to those sites as they are converted to 13.2kV. Additionally, coordination with other projects is an important consideration, such as conversion and consolidation and 4.8kV breaker replacements.

DTEE is currently upgrading its Jefferson substation in Trenton as part of the automation program. There have been many lessons learned along the way that will shape how DTEE executes the program, including development of standards for replacing existing relay panels, as well as working through resource constraints in design, panel fabrication and the field resources that complete the work in the substations.

There are 3,254 active distribution positions on DTEE's electrical system, with 1,050 already having SCADA control and monitoring (an additional 1,280 have monitoring without control). This leaves 352 13.2kV positions and 1901 4.8kV positions that require upgrades for this project.

Exhibit 12.5.2.1 shows the anticipated investment and work to be done over the next five years.

Exhibit 12.5.2.1 Distribution Automation Substation Investment Plan

	2021	2022	2023	2024	2025	2021-2025 Total
Substation Automation ($millions)	<$1 M	$2	$3	$10	$12	$27
Units (13.2kV substation positions)	1	9	14	45	54	123
13.2kV positions remaining	351	342	328	283	229	229

12.6 CVR/VVO

To further upgrade DTEE's distribution system as part of its grid modernization efforts, DTEE has been evaluating Conservation Voltage Reduction/Volt-Var Optimization (CVR/VVO) as an option to reduce peak demand and energy consumption. The initial pilots were developed as part of DTEE's Integrated Resource Planning (IRP) filing in Case U-20471. DTEE is continuing to evaluate CVR/VVO through pilots both as an offset to peak generation and because of the potential benefits to the distribution grid. These benefits include improving grid efficiency as well as having sufficient capacity for demand.

Volt-Var Optimization (VVO) manages system-wide voltage levels and reactive power flow to achieve one or more specific operating objectives. The objectives can include reducing losses, managing voltage volatility due to intermittent renewable generation, optimizing operating parameters and/or optimizing power factors. Conservation Voltage Reduction (CVR), as one of the Volt-Var Control (VVO) options, is designed to maintain customer voltage levels in the lower portion of the allowable voltage ranges, thus reducing system losses, peak demand, or energy consumption.

CVR is achieved by utilizing equipment such as transformer load tap changers (LTC), overhead line regulators and capacitor banks. In addition, SCADA monitoring devices and line sensors are used to help manage voltage levels and advanced telecommunication and optimization tools can be used to achieve optimal demand and energy savings in the system.

DTEE has engaged industry experts (Burns & McDonnell and Dynamic Energy Group) and peer utilities (AEP, CMS, First Energy, and OG&E) that have implemented CVR/VVO methods to achieve energy and demand savings for customers. DTEE is in the process of implementing two pilot studies across four substations to validate benefits realization for DTEE's system ahead of full-scale implementation.

12.6.1 First CVR/VVO pilot

The initial pilot began in 2020 as part of DTEE's IRP filing, at Beck (Roseville) and Medina (Clinton Township) substations, and follows a more static approach to CVR, as initially it will not be utilizing an advanced computer system, such as Advanced Distribution Management System (ADMS), for automatic device controls; however, construction will facilitate smooth transition to future ADMS control. These substations were chosen because they have a diverse base of residential, commercial and industrial customers, substation conditions (SCADA presence), voltage (mixed 4.8kV and 13.2kV) and minimal Distributed Generation.

The original scope for the project called for manually setting the substation transformer voltage, installing SCADA controlled capacitors with time-based settings, and then measuring customer voltage impacts through AMI on secondary lines and voltage sensors on primary lines. However, as the project went through its design phase, it was found that it was necessary to install SCADA controls at the substation transformers, allowing Engineering or the System Operations Center (SOC) to program and modify, if needed, the voltage schedule to better manage voltage conditions for the customers.

Additionally, using automatic voltage settings instead of time-based settings on the capacitors will lead to better risk mitigation with the CVR scheme if real-time conditions, such as low-voltage conditions, warrant a change in operations. Additionally, using smart capacitor controls may eliminate the need for annual capacitor inspections, increase capacitor availability and ultimately help improve power quality.

As additional substations are investigated during design phase of CVR, more improvements may be discovered as well. For example, there is investigation underway of potential benefits of adding additional capacitors at certain substations ahead of full CVR implementation that could lead to immediate system peak and loss reduction and prepare those substations for advanced CVR/VVO when in place.

As reported in DTEE's U-20471 Integrated Resource Plan Annual Report[21], DTEE's CVR/VVO pilot is designed to use various technologies to balance line voltage and system reactive power to reduce system line losses, reduce peak demand and improve the efficiency of the distribution grid. This is accomplished by reducing the voltage on the distribution system and utilizing monitoring devices and line sensors to ensure the voltage remains within the allowable voltage range.

As part of this pilot, DTEE successfully enabled CVR/VVO technology on six pilot circuits on the distribution system in December 2020. The CVR/VVO pilot's scope was to choose up to 20 circuits for study and implementation, ultimately 6 circuits were chosen for the implementation phase. The identification criteria for these pilot circuits was based on a conceptual engineering study which identified that complete 13.2kV circuits (those without 4.8kV areas) in mixed urban/suburban areas were the most suitable candidates for CVR/VVO. Circuits with these types of characteristics are the least likely to require expensive circuit upgrades that were required to avoid experiencing voltages below the lower bounds.

CVR/VVO can achieve demand reduction and energy savings by lowering the voltage on all circuits fed by that transformer. This is achieved by changing the load tap setting at the substation transformer. To determine the magnitude of voltage reduction possible, detailed engineering studies and modeling must be performed to ensure that while the circuit voltage is lowered, no customers on the circuit experience voltage below the acceptable lower bounds.

In 2019 and early 2020, DTEE conducted field verification and performed detailed engineering studies on 18 circuits fed from six transformers. Field verification is an important step to achieve a high degree of circuit model accuracy and to ensure that low voltage conditions are avoided across the entire circuit. After the circuit models were updated, detailed engineering studies were performed to determine the voltage reductions possible at substation transformers and LTCs while at the same time avoiding any low voltage conditions for customers, particularly at peak load. The detailed screening analysis performed showed that out of the 18 circuits and six transformers studied, two substations, Beck in Roseville and Medina in Clinton Township, and six associated circuits were suitable for CVR.

[21] See Exhibit in filing, "IRP REPORT OF DTE ELECTRIC COMPANY," 068t000000MNdSmAAL (force.com)

After the screening analysis was completed, field implementation began for the six circuits. Deploying CVR in 2020 was subject to challenges which delayed implementation until December 1, 2020. The major causes of delays were equipment procurement and the additional time to complete engineering and field work. Both delays were due to COVID-19 related issues, which impacted the availability of the equipment and the ability to do field work as planned.

DTEE began the initial measurement and verification process in December 2020 after implementation on the six circuits was completed. DTEE will continue this process throughout 2021 to measure demand reduction and energy conservation for the full year and to determine the overall effectiveness of the CVR pilot.

Each of the four seasons has different customer load characteristics, which can cause markedly different CVR results. Analyzing results from spring, summer, fall and winter is needed to obtain a valid estimate of the pilot results. Demand reduction and energy conservation due to CVR are expected to be highest during the peak summer season.

DTEE plans to continue the investments on CVR/VVO beyond the pilots to cover additional circuits and substations with the goal of maximizing energy and demand savings for customers. The pilot application of CVR/VVO uses a static approach where the voltages are reduced permanently. Phase 2 of the CVR/VVO program will use a more advanced approach, which will be enabled by the VVC module of the ADMS to realize real-time dynamic control of the equipment involved. It is expected to produce higher demand and energy savings than the static approach and will also provide flexibility of adjusting voltages to better accommodate distributed energy resources.

12.6.2 Second CVR/VVO pilot

The second pilot, or advanced CVR/VVO, will use the new ADMS' built-in CVR/VVO modules to setup, monitor and control the CVR implementation dynamically, based on real-time conditions to achieve the maximum potential peak and energy savings at two substations. These substations, Augusta (Macomb) and Jefferson (Trenton), were chosen based on potential CVR savings and because additional grid modernization work is being done at Jefferson. Engineering activities were done in 2020 with the actual CVR implementation expected to occur in 2022 once the ADMS module is operational.

The ADMS is crucial to achieving full potential of CVR across any large-scale portion of the distribution system. There is close coordination ongoing with the ADMS technical and management teams on go-live timelines. Additionally, the SOC is actively engaged in identifying required procedures and documentation for the control room. Lastly, requirements for ADMS control of devices is being designed into all field devices that will be installed ahead of go-live. That way the hardware can be installed and brought online for seamless integration once ADMS is in operation. An example of such hardware would be capacitor controllers, which historically have been set to turn on/off on a schedule rather than on real-time data. Using sophisticated capacitor controllers in conjunction with ADMS will allow real-time system conditions to determine when to turn capacitors on/off rather than set times of day.

Highlighting the differences between the two pilots, with the first pilot approach of CVR/VVO, if a voltage reduction on substation transformer leads to low voltage conditions during any time period, the substation transformer would not be selected for CVR/VVO implementation, thus limiting its applicability. In contrast, the substation transformer could still be selected for the advanced approach of CVR/VVO because the substation transformer voltages would be adjusted up and down to maximize voltage reduction and still avoid low voltage conditions during certain time periods. The advanced approach can lead to energy consumption and peak demand savings ranging from 1.5-3.5 % based on industry benchmarks, depending upon the substation conditions. DTEE has hired an experienced third-party vendor (DEG) for the Evaluation, Measurement and Verification (EM&V) of the pilots.

It is important to note that it is neither feasible nor cost-effective to implement CVR/VVO across the entire system of DTEE. Based on recommendations from industry experts, due to low energy reduction potential, circuits on the 4.8kV system are not suitable for CVR projects. Additionally, some substations on the 13.2kV system would not yield a sufficient yearly energy reduction to justify the cost of CVR at those substations.

Based on DTEE's initial analysis, substations that feed less than 35 gigawatt-hours per year are not ideal candidates to be cost effective for an advanced CVR/VVO program; this results in approximately 740 circuits across approximately 140 substations as potentially viable candidates for the advanced CVR/VVO program.

Further prioritization and selection criteria for these circuits and substations include four steps:

- First, all the substations are analyzed and prioritized based on largest potential CVR savings.
- Second, a more in-depth feasibility and constructability assessment of the substation equipment at each substation would be completed to determine if the estimated savings matched modeling results.
- Third, an assessment of the respective circuits' AMI, SCADA and circuit models would be studied for customer voltage risks.
- Fourth, a preflight would occur to verify the study assumptions. As stated in the Power Quality section of this report (7.4 – Power Quality) additional attention regarding placement and operation of the capacitors needs to be taken into consideration to avoid potential ferroresonance on the electrical system.

Between 2021 and 2025, a total of $69 million capital investment is projected, which would cover 100 substations, 590 circuits, and yield a max potential savings of between 200 and 270 GWh of energy savings and between 70 and 140 MW of peak demand reduction. Exhibit 12.6.1 shows the investment summary for CVR.

Exhibit 12.6.1 CVR Investment Summary

	2021	2022	2023	2024	2025	2021-2025 Total
Investment Projection	$6 M	$7 M	$17 M	$18 M	$20 M	$69 M

12.7 NWA pilots and other technology pilots

As discussed in Section 4.3 – Non-Wire Alternatives, a non-wires alternative (NWA) project is an investment or project that uses DER, energy waste reduction (EWR) or demand response (DR) to defer or offset the need for a traditional investment. The focus of DTEE's current suite of projects is to address a capacity need. There is currently a suite of six NWA projects planned in the near-term five-year plan which address the current grid needs. There are also two additional Technology Pilots (Small Solar and Storage Testing Facility and Electric Vehicle Extreme Fast

Charging and charge management) that will help DTEE understand the grid impacts of DERs and EVs and may help facilitate the development of future NWAs.

A table at the end of each pilot summarizes the key information on each project, including:

- Cost of traditional solution compared to the cost of the NWA solution
- Loading patterns with and without the NWA
- Implementation Timing
- Assumptions used in the analysis.

These pilots being pursued should be viewed as building blocks which will form a foundation for how to include NWAs into the overall distribution planning process. As the capabilities of the NWA technologies are confirmed, multiple NWAs can be combined together to further advance the Company's utilization of NWAs. This will depend to a large extent on the results of the different pilots and on the experience of other utilities that are pursuing similar pilots. Once the understanding of NWA applicability and economics has matured, the planning process will allow engineers to identify projects where NWAs could be effective options when compared to traditional wire solutions. If a project is identified as a potential candidate, planning engineers would work with storage and EWR/DR experts to evaluate detailed designs. As more is learned from the Company's pilots and other utilities, and as technology advances, the Company will refine its criteria, develop new tools, and advance the overall process for pursuing NWAs as part of the distribution project review process.

In addition, the design of these pilots will follow the guidelines developed as part of the MI Power Grid collaboration on pilots under docket U-20645, including providing details on the six key areas of 1) Need and goals, 2) Design and evaluation plan, 3) project costs, 4) timeline, 5) stakeholder engagement, and 6) public interest. Many of these pilots are currently under development and are expected to evolve and be refined as they are proposed for regulatory approval. Details on how the NWA pilots are being designed to follow the guidelines can be found in Appendix V.

Exhibit 12.7.1 summarizes the expected spend on these projects. Exhibit 12.7.2 summarizes the technologies included as part of the suite of NWA projects, as well as the high-level objective.

Exhibit 12.7.1 NWA Projects and Other Technology Pilots Investment Summary

Project	2021	2022	2023	2024	2025	2021-2025
NWA Pilot Projects						
Fisher	$0.04 M	$0.8 M	$3.4 M	-	-	$4.2 M
Port Austin	-	$2.0 M	$2.5 M	-	-	$4.5 M
Omega	$3.4 M	$3.5 M	-	-	-	$6.9 M
Veridian	-	$1.8 M	$5.6 M	$0.3 M	$0.3 M	$8.1 M
O'Shea	$1.3 M	-	-	-	-	$1.3 M
Other Technology Pilots						
Mobile Energy Storage	$1.5 M	$0.5 M	$1.5 M	$1.5 M	-	$5.0 M
Small Solar and Storage Test Bed	$0.4 M	$0.4 M	$0.3 M	$0.3 M	$0.3 M	$1.6 M
EV Fast Charging and Charge Management	$0.7 M	$0.8 M	$1.3 M	$0.4 M	$0.4 M	$3.6 M

Exhibit 12.7.2 Technology Projects Use Cases, Technologies and Objectives

Use Case	Project	Technology							Objective
		EWR	DR	Storage	Solar	BTM DER	EV Charging	Micro- grid	
Substation Loading	1. Hancock (Completed)	✓							• Initial pilot to test geo-targeted EWR and develop DER Estimating tool
	2. Fisher	✓	✓						• Test geo-targeted EWR/DR costs • Measure implementation timing
	3. Port Austin			✓	✓			✓	• Test solar and storage to address substation capacity • Test redeployment of stationary battery from Omega
Subtransmission Loading	4. Omega			✓					• Deploy storage to address subtransmission loading • Install battery that can be re-located
Customer Load and DER Control	5. Veridian		✓	✓	✓	✓	✓	✓	• Develop secure and effective methods to interface and control behind the meter (BTM) DER in conjunction with utility scale DER
Voltage Mitigation	6. O'Shea			✓					• Test effectiveness of storage to address voltage instability due to intermittent solar
Portable Battery	7. Battery Trailer			✓					• Test use of energy storage in place of traditional portable generators

12.7.1 Hancock substation NWA pilot

DTEE began its first NWA pilot at Hancock substation in 2018 as a collaborative team that consisted of DTEE and four external entities: ICF, Guidehouse, Energy Sciences, and the Natural Resources Defense Council (NRDC). The pilot had three main goals:

- To field test the effectiveness of energy efficiency (EWR) programs to address substation loading
- To understand the costs of deploying targeted energy efficiency
- To begin developing evaluation tools for future NWA projects

The design and implementation of the pilot ran approximately 18 months – from May 2018 to December 2019 – with field implementation (i.e., roll-out of EWR programs to the geo-targeted region) occurring during the last eight months of that period. Analysis of the program impact occurred in 2020. Initially, the Hancock substation was selected to address an overload of approximately 0.6 MVA. Over the course of pilot design, development in the area increased the overload projection to be 12 MVA by 2021. Due to this change, a traditional solution, including upgrading substation transformers and creating a new circuit to relieve load, was implemented.

The team selected a portfolio of EWR programs for residential, and commercial and industrial (C&I) customers. These programs included HVAC upgrades, appliance recycling and home energy survey programs for residential customers and lighting and HVAC upgrades for C&I customers.

Overall, the program set a target of 40kW of peak load reduction based on the limited implementation duration of the pilot (about eight months). An NWA project that targets achieving load reduction over a multiyear period should be able to achieve a proportionally higher reduction. After verification of peak savings, the pilot achieved 57kW of peak reduction, or approximately 141% of the goal.

There were multiple lessons learned from the pilot and processes developed that will be applied to future projects. The first is the development of the DER estimator tool, which allows for various technologies to be evaluated as a means to reduce peak demand. Secondly, the pilot allowed for some initial benefit-cost analysis that indicated that the C&I programs show more potential than residential programs. The takeaway is that having a representation of C&I customers on future

NWA circuits would be key to achieving peak reductions. Finally, there were multiple learnings from an implementation standpoint, such as the incentives necessary to drive the adoption of programs, the seasonality of customer interest in HVAC upgrades, and the type of marketing materials and approaches that were most successful.

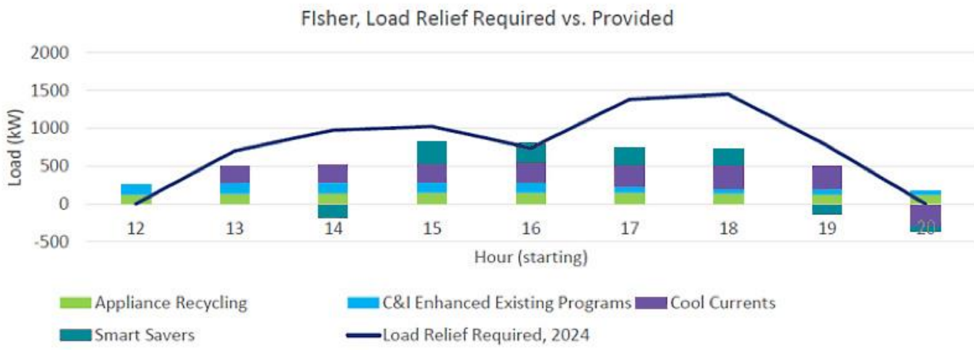
12.7.2 Fisher substation NWA pilot

Fisher substation is a 13.2kV substation that serves approximately 4,400 residential customers and 400 C&I customers in the Brownstown, Rockwood, Flat Rock and Gibraltar communities. This Fisher pilot is a direct follow-up to the Hancock substation pilot and will leverage several key learnings from Hancock, including the need to select an area with a representation of C&I customers to provide EWR benefit, and leveraging the DER Estimator tool and methodology. The portfolio of EWR and DR programs targeted for Fisher were developed and optimized using this DER Estimator tool.

Fisher substation is over its firm rating by approximately 2.5MVA. In addition, two circuits served by Fisher are over or expected to be over the 8MVA design standard for 13.2kV circuits. The traditional investment planned for Fisher is to expand the substation and do some reconfiguration at an estimated cost of $8 million.

The Fisher project expands upon the scope of the Hancock project by incorporating geo-targeted demand response (DR) into the portfolio of programs. The two DR programs included are Cool Currents (or interruptible air conditioning) and Smart Savers (bring your own smart thermostats). The portfolio of geo-targeted EWR and DR programs is expected to provide approximately 56% of the load relief, as shown in Exhibit 12.7.2.1 below. The process for developing and optimizing the portfolio of programs was previously described in Section 4.3 – Non-Wire Alternatives.

Exhibit 12.7.2.1 – Fisher Overload and Load Relief Portfolio



This load relief portfolio assumes a participation rate in the EWR programs of 15% of residential customers and 18% of commercial and industrial customers. The demand response programs target residential customers at a rate of 5% for Smart Savers and 7% for Cool Currents.

The NWA work at Fisher will provide a portion of the load relief needed and allows for a lower cost traditional solution to provide the remaining needed load relief. A Subtransmission Distribution Facility (STDF), which is a facility that consists of a set of equipment which creates a single circuit from a substransmission connection, will be installed to relieve load on one of the overall circuits.

In addition to the $4.2 million capital cost of this project, an additional $1.2 million of O&M related to the EWR/DR portfolio will be needed. This is less than the traditional substation expansion, which was estimated at $8 million.

Overall, this pilot is expected to provide significant information on the effectiveness of geo-targeted EWR programs, including:

- Verifying the load relief achieved from demand response
- Determining if the targeted participation rates can be achieved
- Understanding the time to deployment and the level of incentives needed to achieve the desired participation rates
- Understanding customer acceptance of more frequent demand response interruptions
- Verifying deployment costs and progress toward optimizing targeted marketing and administrative costs

Exhibit 12.7.2.2 – Fisher NWA Pilot Summary

Fisher NWA Pilot information	

Cost and Scope of traditional solution	• Traditional Solution Scope
	  ○ Upgrade Fisher Substation from a Class "F" to a Class "A"
	  ○ Replace existing transformers with 15/20/25MVA transformers and install a 9 position PDC
	  ○ Construct and commission two new circuits, split the load and throw-over circuit
	• Traditional Solution Cost
	  ○ $8M – 2022 to 2024

Cost and Scope of proposed NWA solution	• DR Scope and Cost
	  ○ Program implementation for (IAC & BYOD), technology platform (Energy Hub) and IAC equipment upgrades
	• EWR Scope and Cost
	  ○ Residential Implementation, Incentives and installation labor
	  ○ C&I Implementation and Incentives
	• STDF Scope and Cost
	  ○ Establish STDF (Sub-transmission Distribution Facility) along same sub-transmission line that feeds Fisher Substation
	  ○ Split FISHR DC 8188 with STDF circuit
	  ○ Install new conduit and cable
	• The EWR and DR solution combined with traditional equipment solution defer the original traditional solution investment by four to eight years
	Total cost = $4.2M in capital

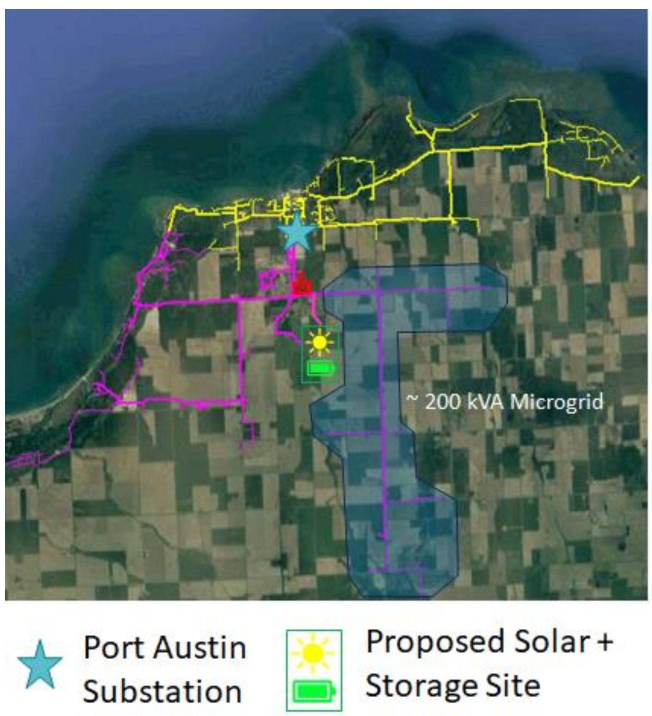
Consumption / Loading patterns with and without NWA	Fisher substation overload, and EWR/DR contribution to address loading is shown in Exhibit 12.7.2.1
Implementation Timing	• STDF to be commissioned in 2022 • EWR/DR programs to run 2021 through 2024
Assumptions in analysis	Participation Rates: • EWR Residential (15% participation) • EWR Commercial (18% participation) • DR Cool currents (7% participation)

	• DR Smart savers (5% participation) Participation rates and demand impact based on models of customer demographic and loading data.

12.7.3 Port Austin substation NWA pilot

Port Austin substation serves approximately 2,000 customers in Port Austin in the Thumb region. The substation is at 120% of its firm rating. One circuit is at 108% of its day-to-day rating, indicating that during peak load some of the equipment is overloaded. A map of the general area and project is shown in Exhibit 12.7.3.1.

Exhibit 12.7.3.1 Port Austin Area Map



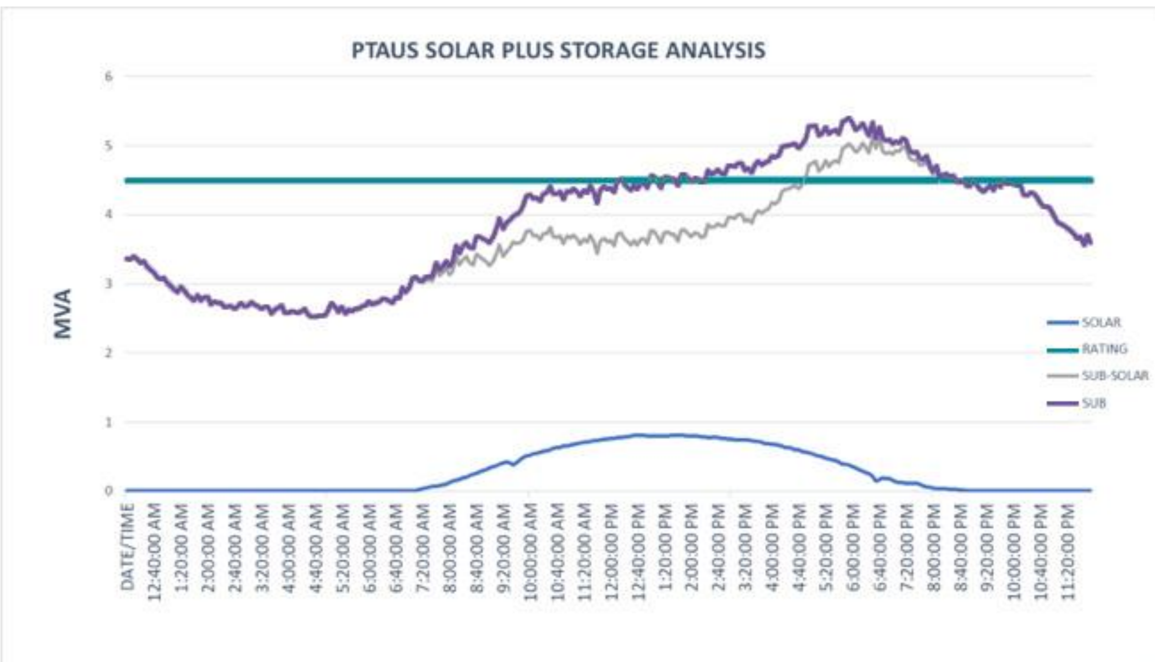
The traditional investment to alleviate load in this area would be to upgrade the substation and some of the circuits to 13.2kV, with an expected cost of approximately $15 million.

The scope of the NWA pilot is to:

- Install a 500kW solar site
- Relocate a 1MW x 4MWh battery from Omega
- Explore feasibility of microgrid equipment and controls that could serve about 200kVA

Circuit modeling of the substation, as seen in Exhibit 12.7.3.2, shows the hourly load curve of the overloaded substation in yellow. A conceptual generation curve is shown in blue has been constructed using data from nearby arrays. The net load at the substation is shown in gray. Overall, the initial analysis indicates the solar could reduce the peak overload from 900kW to 600kW, and the total energy needed above the rating is reduced from 2.8MWh to 1.2MWh. Though more thorough study is needed, the analysis indicates that the 1MW x 4MWh battery could alleviate the remainder of the overload after accounting for operating margins of the battery.

Exhibit 12.7.3.2 Port Austin Loading with and without Solar



As described above, the overall goals for this pilot are to:

- Successfully re-deploy a battery from another site (Omega)
- Demonstrate the effectiveness of solar plus storage for addressing a loading concern
- Refine tools for evaluating solar and storage

Exhibit 12.7.3.3 – Port Austin NWA Pilot Summary

Port Austin NWA Pilot information	
Cost and Scope of traditional solution	Upgrade Port Austin substation to 13.2kV Cost is approximately $14M to $16M
Cost and Scope of proposed NWA solution	• Solar + Storage ○ Install approximately 500 kW solar site ○ Use one existing 1MW x 4MWh battery from OMEGA ○ Cost is approximately $4.5M • Microgrid ○ Could be expanded for approximately 200 kVA Microgrid ○ Install Triple Single Recloser with SCADA ○ Total cost is forecast to be $300k-$400k
Consumption / Loading patterns with and without NWA	Overall Port Austin substation loading pattern is shown in Exhibit 12.7.3.2. The estimated generation from the solar array reduces peak overload from 0.9 MVA to 0.6 MVA, and the total energy needed from 2.8 MWh to 1.2 MWh. The remaining overload would be served by the installed battery.
Implementation Timing	2022-2024
Assumptions in analysis	The analysis is based on substation loading data, and the generation profiles of solar arrays in the same area

12.7.4 Omega substation NWA pilot

Omega substation serves approximately 4,000 customers in Harrison Township in Mount Clemens. This part of DTEE's service territory has experienced load growth due to indoor agriculture developments. Omega is served by two subtransmission lines which are currently overloaded, preventing the connection of new load.

A traditional distribution investment is in progress to address the loading in the area, as described in the Boyne project in Section 11.2.3 – Subtransmission Projects and Programs. However, the timing of these projects will not relieve load until after the 2022 peak.

The goal of this NWA project is to:

- Deploy batteries at Omega substation before 2022 peak to provide load relief and reduce risk of stranded load
- Test effectiveness of storage at reducing peak load, including developing and implementing operational procedures for load relief
- Install equipment that can be relocated and re-used in an efficient manner (equipment will be re-used at Port Austin or other sites)

Exhibit 12.7.4.1 – Omega NWA Pilot Summary

Omega NWA Pilot information	
Cost and Scope of traditional solution	There are multiple traditional solutions for the area, however the NWA solution will provide load relief before the traditional solutions (load transfer, subtransmission circuit rebuilt, and subtransmission station upgrades) can be completed
Cost and Scope of proposed NWA solution	Storage Purchase 2 mobile batteries for Omega (will be used for other projects) Install mobile batteries at Omega substation before 2022 peak Total cost of the batteries and installation is estimated at $7M
Consumption / Loading patterns with and without NWA	Mobile batteries to provide temporary relief Provides about 1 MVA of load relief at peak times Reduces blocking hours and the risk of stranded load
Implementation Timing	2021/2022 Battery procurement 2022 Battery installation
Assumptions in analysis	The analysis is based on substation loading data

12.7.5 Veridian

Veridian is a planned development in Ann Arbor with net-zero community goals. A high penetration of solar, storage and EV charging is expected as part of this development. The area is served by Regent substation, which is a 4.8kV substation at 81% of firm rating. While substation loading is not the primary concern, the overall load of the development is expected to approach 1.5MVA, and none of the existing circuits would have capacity to accommodate the full requested load. Traditional infrastructure upgrades to support the needs of the development could have included significant 4.8kV to 13.2kV conversion and construction of new distribution substation capacity.

Instead, by leveraging the onsite solar and storage capabilities as offsets to peak load, the proposed scope to support the load at Veridian is to reconductor existing circuit backbones and continue service from Regent substation.

The NWA portion of the project will involve the use of microgrid controls, which will manage the overall loading of the site through control of the solar, customer-owned storage, and potentially EV charging management.

The overall goals of the pilot are to understand:

- Effectiveness of solar and storage at reducing load
- Consumer behavior with microgrid and customer owned DER
- Control, protection and security requirements for storage
- Deployment costs, time and challenges
- Operating processes, procedures and staffing

Funding for the project will come from a mix of DTEE, developer and DOE grants. A final decision on DOE funding is expected in late 2021. If DOE funding is not approved, the timing, scope and cost of the project may undergo significant revision.

Exhibit 12.7.5.1 – Veridian NWA Pilot Summary

Veridian NWA Pilot information	
Cost and Scope of traditional solution	Short-Term: Upgrade circuit backbones to support load, back feed and voltage Perform load transfers to provide additional capacity Long-Term: Convert the entire substation area to 13.2kV for approximately $50M+
Cost and Scope of proposed NWA solution	Create community microgrid utilizing demand response and grid controls Deploy additional large-scale generation and storage Total cost: $8.3M (DTEE + Developer + DOE Grant) plus additional private and public funding
Consumption / Loading patterns with and without NWA	Loading patterns are still to be determined. Pilot will collect data from DG and DS, and test analytics and other technology for customer demand side management. Microgrid controller will also be implemented
Implementation Timing	Implementation is expected to take place from 2022 to 2026, and will be dependent on the progress of the development
Assumptions in analysis	In progress – details of the development and loading are still in early phases

12.7.6 O'Shea solar and storage

O'Shea Park in Detroit is the site of a 2MW solar array connected to the Chicago substation, which serves approximately 11,500 customers. The solar generation frequently exceeds circuit load, causing power to flow back through the substation. During periods where solar generation is intermittent or changing rapidly, voltage data as reported by AMI meters indicates there is some potential for small over-voltages or flicker.

The project will install a 1MW x 1MWh battery co-located with the solar array. There are multiple goals of this pilot, including:

- Improving power quality in the area
- Creating standardized designs, safety policies, and operating procedures for integrating storage
- Testing communication and control protocols
- Testing wholesale market participation for FERC Order 841 by responding to pricing signals and coordinating the priorities of multiple reliability use cases. Also developing the DTEE processes and framework for other energy storage resources to participate in FERC841
- Engaging communities on the permitting and approval process for siting batteries
- Receiving fire protection and UL certifications, including NFPA 855 compliance

The O'Shea battery project is expected to be complete by early 2022.

12.7.7 Other technology pilots

Mobile battery trailer

DTEE expects to receive and complete assembly of a portable 1MW x 4MWh hour battery trailer in 2021. Once the equipment is received, DTEE will test the unit and develop documentation and required operating procedures to deploy the mobile battery in the field. Once the new equipment has been fully vetted, it can be used for various use cases, including siting in place of traditional portable generators, supporting system needs during shutdowns or maintenance, or siting at substations or on circuits to reduce peak load as part of a broader NWA project. The Company plans to purchase four additional mobile trailers by 2025, pending results from the initial evaluation of the equipment.

Small solar and storage testing facility

Up to 60% of new projects for rooftop solar at residential and small commercial customer sites are proposed with some amount of battery storage. The MPSC has requested that DTEE provide a solution to properly meter and integrate these storage solutions into the grid while still maintaining compliance with distributed generation, net metering and other tariffs. Additionally, FERC and MISO are expected to require ride-through protection for primary frequency response as part of the FERC 841 order.

This requires that all inverters have a verified setting for specific protection parameters to support the bulk electric system stability. Smart inverters are also capable of providing voltage and reactive support in either a passive or actively controlled mode. As the testing standards in IEEE 1547.1-2020 on smart inverters are finalized and interoperability standards such as IEEE2030.5 evolve and reach the market. DTEE must develop the capability to validate the settings and communicate with the DERs to ensure any new installations with smart inverters follow the standards to prevent any potential power quality, voltage and safety issues in the electric system and to determine the best method to utilize these new capabilities.

This project is to install solar arrays, commonly used inverters, storage units, switching and metering systems, and utility gateway communication systems at a DTEE site. The project will allow validation of behavior, interaction and compliance of the new features for smart inverters and act as a location to test new features and capabilities while also serving as a training platform for DTEE engineers, technicians and field employees. Standards can be developed around these technologies to ensure safety and reliable operation.

The testing facility costs $2.1 million and most of the infrastructure work is scheduled to be completed in 2022, however incremental improvements will continue to support new projects and technology integration efforts. The use of this facility will assist customers seeking to integrate solar with battery storage into DTEE's distribution system by providing clear standards and thereby streamlining the interconnection process for this type of technology application.

The lab facility will support several evaluations and will be continually updated to demonstrate technology interoperability and the processes and technologies to integrate customer resources into the grid. These evaluations will have project specific targets and be measured on the ability of the products and solutions to meet DTEE operational requirements, work practices and industry standards and interoperability.

EV Extreme fast charging demonstration at the American Center for Mobility (ACM)

The ACM is a unique, purpose-built facility focused on testing, validation and self-certification of connected and automated vehicles and other mobility technologies at the 500-plus-acre historic Willow Run site in Ypsilanti Township in Southeast Michigan. DTEE will leverage this charging network to get a better understanding of the capabilities to control charging and predict the need for charging from autonomous vehicles. DTEE is supporting the implementation of the Delta

Power Electronics DC Xtreme 400KW fast charger when it becomes available in 2021 as part of a DOE project. This DOE pilot program, EVS-at-RISC, will help DTEE develop cyber secure monitoring and control capabilities with smart charge controls and inductive road charging to ensure reliable and secure interfaces and will further enhance knowledge of the grid impact of these new technologies. This pilot project is expected to:

- Install a utility gateway and communications portal to enable charge management
- Develop control algorithm and conduct testing on a Delta Extreme fast charger and its interfaces
- Develop cyber security interfaces and control, install additional sensing capabilities, and monitor performance on charging network
- Develop monitoring and control algorithm for in-road inductive charging at the ACM site

The initial Delta fast charger will be available by the end of 2021 with an anticipated second phase to be awarded in late 2021 with implementation in 2023 of a commercially available charger. Smart charge management will be implementing in three phases through 2024 and will be available during the later phases of the project for wider testing.

These projects are predominately research and development to establish the capabilities of utilizing charge management on charge control in extreme fast charging environments and the scope of evaluation with the Department of Energy is to demonstrate technical feasibility and meet demonstration milestones.

12.8 DER control

As discussed in Section 3.3.3 – Distributed generation/distributed storage growth scenario, there is a likelihood that many more distributed energy resources (DERs) will be introduced to the grid. Furthermore, with the implementation of FERC Order 2222/2222A, DERs that were previously only able to participate in retail programs are now able to participate in the wholesale market via aggregations. DTEE's DER Control strategy has been developed to help manage the grid stability reliability concerns that stem from the interconnection of large numbers of these DERs across its grid.

As noted in Section 12.4 – Distribution Sensing and Monitoring, proper operation of any distribution grid starts with the timely monitoring of distribution network assets. As more energy sources are connected to the grid, voltage variability is introduced that, if unmanaged, affects the quality of power being delivered to loads connected to the affected circuits.

The DER Control workgroup has identified several areas of focus that will yield the visibility and control required to ensure that DTEE is delivering safe, reliable, and affordable electric service to all its customers.

The projected cost of implementation is $44.1 million through 2036, of which $12 million will fall in the 2021-2025 timeframe. The resources required to support the proposed changes span an array of disciplines from SCADA, (Network Data & Application Support (NDAS), Power Equipment & Relay Test (PERT), Engineering), IT (SCADA Realtime Support (SRS)) and Regional Planning. Exhibit 12.8.1 shows the investment summary for DER Control.

Exhibit 12.8.1 DER Control Investment Summary

	2021	2022	2023	2024	2025	2021-2025 Total
Investment Projection ($ millions)	-	$3	$3	$3	$3	$12

12.8.1 Large and medium-sized DER monitoring & control

Interconnection Control System Enclosure Integration

The telecommunications and SCADA package developed by DTEE's Interconnections team is intended to be a drop-in solution for monitoring larger DER installations. This package contains all the equipment required for SCADA and performs the following functions:

- Metering using ION power quality meters
- Communications (network switches)
- Automation (Schweitzer Engineering Labs (SEL) RTAC Remote Terminal Unit (RTU))
- Security (firewalls)

DTEE expects to equip key DER installations on its distribution system with this package. These sites include Demille Solar Park (Lapeer), Turrill Solar Park (Lapeer), and IKEA (Canton). The intent is to demonstrate that DTEE utilizes the same package for its sites as it is requiring its larger customers to use.

12.8.2 Upgrade of DR-SOC monitored solar sites to RTAC RTU

DTEE-owned solar sites installed as part of the SolarCurrents program were outfitted with DR-SOC low-cost monitoring (LCM) very similar to the low-cost substation monitoring outlined in Section 12.4 – Distribution Sensing and Monitoring. LCM has provided data at 5-minute intervals since its inception, but as the needs of the System Operations Center (SOC) and Merchant Operations Center (MOC) have evolved over the years, the systems put in place have not yielded the 2-4 second interval data that is typically available in SCADA installations.

Under this initiative, the data logger installed at 31 Renewable Energy solar sites would be replaced with an SEL RTAC RTU capable of yielding the required scan rates, thus increasing visibility into the operations and impact these systems have on their hosting circuits.

12.8.3 Viper recloser sensing/data

The ability of larger DERs to affect their hosting circuit continues to be a source of concern for the SOC and Regional Planning. Having a SCADA-operable device such as a Viper recloser available for the SOC's use at these larger sites provides a necessary isolation capability if the DER is adversely impacting the reliable operation of the circuit to which it is connected or if the circuit is in an abnormal condition, such as during outage repairs or maintenance.

Additional benefits include SCADA telemetry from the device monitoring the recloser. This data represents the interconnection point on the system and would be very useful for use with the ADMS state estimator, power flow and contingency analysis algorithms.

It is expected that the installation costs of such operable devices be borne by the customers meeting Engineering's size criteria, with a small trailing O&M component required for the telecommunications and maintenance of the equipment.

12.8.4 Small DER monitoring

While current MPSC rules primarily focus on metering, they do not offer clear guidelines for when telemetry is required. DTEE's Interconnection Standards need to clearly delineate what assets have a mandate to provide telemetry. The SOC requires EMS/ADMS to have accurate power injections for all DERs systems connected to the Distribution Network to properly model power flow, as well as keep its State Estimator (SE) and Contingency Analysis (CA) systems converged.

This translates into a need for near-real time visibility into DER units as small as 100kW and SCADA for individual DER units 500kW or larger in size.

Aggregations made possible by FERC Order 2222 will pose a whole new set of challenges and opportunities for DTEE's Distribution System. With DER Aggregations (DERAs) being dispatched on a purely economic basis, on-peak charging of energy storage resources (ESRs) with the resultant higher peak demand is theoretically made unattractive via unfavorably high locational marginal prices (LMPs). This does not, however, guarantee that on-peak charging will not happen, and this is an area of concern which requires careful consideration and planning for future circuit loads based on forecasted per-circuit DER penetration levels.

12.8.5 DERA monitoring integration

Proper integration of DER Aggregations includes per-circuit sums of kW and kvar for each aggregator. Data points provided by an aggregator via Inter-Control Center Protocol (ICCP) should be formatted as follows for each circuit on which they are participating:

- <*DERA Name*>_<*Substation*>_<*Circuit*>_KW (eg. DERA1_LINCN_2800_KW)
- <*DERA Name*>_<*Substation*>_<*Circuit*>_KVAR (eg. DERA1_LINCN_2800_KVAR)

The costs associated with this implementation are primarily in the NDAS area and cover the creation and maintenance of points and their mappings via ICCP.

12.8.6 ICCP connectivity – DERs in a DERA

Though it may seem appropriate to simplify integration by solely summarizing data from DER aggregators at the electric pricing node, doing so comes with a significant challenge for the grid operator of reduced visibility, and is therefore not advisable. Accounting for all DER injections/withdrawals on the system is key to ensuring that state estimator and contingency analysis run properly. An example of how this could be achieved would be via ICCP exchange with DER aggregators for each of their connected DER units:

- <*DERA Name*>_DER<*DER Number*>_KW (eg. DERA1_DER127_KW)
- <*DERA Name*>_DER<*DER Number*>_KVAR (eg. DERA1_DER127_KVAR)
- <*DERA Name*>_DER<*DER Number*>_VOLT (eg. DERA1_DER127_VOLT)

As with the previous area of focus, NDAS resources constitute the bulk of the expenditure for this endeavor.

12.8.7 ICCP connectivity – load shed in a DERA

In the event of a load shed situation, the MOC and SOC control rooms both have a need for a tally of traditional Demand-Response Resources (DRR) being dispatched. The MOC's need centers on NSO load reconciliation, while the SOC needs to know how much load may appear on a per-circuit basis once a load shedding event is complete. Mapping this data via ICCP could be achieved as follows:

- *<DERA Name>*_*<Substation>*_*<Circuit>*_DRR_COUNT (eg. DERA1_LINCN_2800_DRR_COUNT)
- *<DERA Name>*_*<Substation>*_*<Circuit>*_DRR_KW (eg. DERA1_LINCN_2800_DRR_KW)

12.8.8 AMI and de-aggregated load data

For proper and required differentiation of retail vs. wholesale market transactions, submetering of generation assets considered Behind The Meter (BTM) is necessary. De-aggregating this data also permits SOC's Operations Engineering to better identify overload conditions on circuits with high DER penetration and an anticipated large drop in generation (such as inclement weather setting in on circuits with high solar penetration).

12.8.9 DERMS module

While in some circumstances it may be possible to operate without a DERMS system, as outlined in the ICF "DTEE Grid Modernization" report, there is a need for DTEE to acquire DERMS functionality to assist in the management of DERs in the long run. Distribution Operations (DO) is working with Corporate IT and Generation Optimizations to identify a suitable DERMS for implementation.

The primary drivers for this need are:

- DTEE currently has 5,000 DERs on its distribution system, and this number has been growing at an increasing rate as measured by the interconnection volume. DO expects 2,000 additional DERs to seek interconnection this year.
- Extrapolating the numbers from the Interconnections Group, the DERMS will need to support at minimum of 25,000 DERs to cover the 10-year horizon using the most conservative estimates.

The possibility of developing tools in-house has been evaluated, but the concerns raised about the scalability of a home-grown solution remain an unknown. This risk was deemed unacceptable and DTEE approached multiple vendors regarding their offerings.

DTEE will be working to determine the specific needs for a DERMS platform and plans to develop a project within the next year. Essential investment areas to enable this capability include software licensing, compute capacity planning, engineering and implementation services.

12.8.10 DERMS module modelling

One of the key areas of focus for the DER Control strategy involves the accurate modeling of DERs on the distribution system. This cross-functional effort will utilize resources from NDAS, Electrical Engineering's Interconnections Group, Mapping and Regional Planning to ensure that units are placed properly on the network model for ADMS and DERMS' use. As this work depends in part on the operational status of the DERMS detailed in Section 12.8.9, it is anticipated that work performed under this effort will begin Q1 2023.

12.8.11 OSI enterprise customer agreement

The current EMS licensing makes a fixed number of analog and digital points available for SOC's use. Though neither of these limits have been hit to date, the limits could easily be reached in the future if there are a large number of DER installations that require aggregation under FERC Order 2222. As outlined in the ICCP Connectivity - DERs in a DERA Section (12.8.6), DTEE will require a minimum of three data points per DER for such participation. It is unlikely that the licensed limits will be hit before 2024 based on present projects, however, these limits will need to be reviewed yearly.

12.9 Technology Strategy Roadmap

Strategic Goals

DTEE operates across a large service territory, serving over 2.2 million customers with more than 600 substations and thousands of miles of distribution lines managed from a central System Operations Center (SOC). DTEE, with the help of supporting software, must continue to integrate new streams of data and information in near real-time to better respond to customer requests for information about their energy usage and to leverage that same data to increase reliability and manage distribution operations.

As detailed in Grid Modernization, Section 3 – Grid Modernization Process, DTEE's long-term planning efforts include integrating new technologies including EVs, DERs and storage.

Meanwhile, planning engineers leverage all available information to identify grid needs, develop forecasts, analyze trends, inform investment strategies and ensure that the grid and its operators are prepared to meet evolving customer needs and expectations.

Finally, field crews can currently leverage mobile technology to more efficiently interface with grid operators and distribution engineers to assess situations and determine the best path forward as field crews are more likely to use this information to interface with others. Mobile technology improves operational efficiencies and keeps customers and employees safe. To ensure the technology approach remains aligned with business objectives, the technology roadmap for Electric Distribution focuses on the key business objectives:

- **Operate the grid safely** – Ensure employees consistently display the proper behaviors to safely operate and maintain the grid and minimize operational risks and challenges, with a target of top-decile industry performance
- **Support customers** – Build a culture of customer service using the communication, collaboration, leadership and recognition enablers to ensure all internal and external transactions deliver on DTE's Service Keys – Safe, Caring, Dependable and Efficient
- **Work management** – Create and implement a well-defined process for all strategic and emergent work among all asset families to ensure the safe and efficient work execution
- **Distribution system reliability** – Achieve the Company's "Best-Operated" and aspirational reliability targets (SAIDI ex MED, CEMI6)
- **Capital efficiency and work productivity** – Continue to focus on capital cost efficiency for both planned and reactive work
- **Grid of the future and new technology** – Develop a flexible grid to serve the ever-evolving needs of customers, through upgrades, system monitoring and automation

To deliver these business objectives, the technology investments for Electric Distribution focus on five goals, described below:

1. **Improve productivity of employees through mobile technology**
    - The first goal is to provide seamless transitions between online and offline operations using mobile applications and devices and to provide integrated workflows between the control room, back office, field leaders and field crews.
2. **Deliver best-in-class work management and scheduling**
    - The second goal is to achieve best-in-class work management in the "Initiate, Plan, Schedule, Execute, Close" (IPSEC) model of workflow, ensuring the highest level of safe, efficient and reliable grid management and operations.
3. **Drive top-quartile DO asset management**
    - The third goal is to enable rapid decision making and improve service delivery with an improved understanding of asset performance by aggregating and analyzing current and historical operational and geospatial data to assess and visualize asset health.
4. **Transform capabilities for distribution planning processes**
    - The fourth goal is to safely and efficiently interconnect DERs, while incorporating scenario analysis and performing planning to achieve network and economic optimization across the grid, improve grid reliability, ensure power quality and enable ancillary services.
5. **Modernize grid management**
    - The fifth goal is for operators, dispatchers, planning engineers and supervisors to act in a coordinated manner, accessing real-time, as-built and as-operated representation of network information that underpins sensing and control for efficient, safe and reliable management of grid operations. ADMS is a key component of this goal.

12.9.1 Goal 1: Improve employee productivity through mobile technology

Mobile technology allows collecting and distributing data at the point of activity through mobile devices, across all personas and use cases. 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.

To benefit from the opportunities and business value that mobility will offer DTEE, it is important to understand the current state of those assets and to clearly highlight the future investments in this area in a planful way. Today, the mobile technology deployed for DTEE is sufficient to handle the needs of the Company's existing corporate systems and pre-Covid working model.

DTEE is actively investing to improve and upgrade the level of mobile technology available to the field force as new systems come online and in coordination with the Company's ADMS roll out and its associated capabilities.

Additionally, with the onset of the Covid-19 pandemic, Distribution Operations has accelerated plans to deploy more capable technology into the field with an emphasis on system offerings that provide the frontline workers and leaders the flexibility of remaining in the field for extended periods without having system constraints that require them to return to the service centers or to congregate as frequently as was needed in the past. Even after the pandemic, these new skills and processes will continue to drive efficiency.

- The implementation and upgrades to DTEE's grid operating systems, such as ADMS, ESRI Mapping and AMI investments, all demand expanded device capabilities as the new investments take the Company beyond the capabilities of the currently deployed technologies. While the existing mobility computing fleet has served the enterprise well up until now, it is no longer sufficient, without additional investment, to meet the future needs of the Company's workforce.
- Mobility is ultimately most useful when it is used to maximize the amount of time that workers can remain mobile and more often be on site where the actual work is to occur. This means that deploying technology securely and effectively to allow increased time onsite as a key priority in this area. Deployment of up-to-date systems and equipment improves the efficiency and value of the Company's service delivery. To realize this value, DTEE will need ongoing investments to operate and replace field equipment as new capabilities are delivered by system and hardware partners.

- As DTEE deploys more system tools into the hands of the field force and remote digital workers, the Company remains responsible for all the regulations and compliance mandates that govern the Company's usage of both operating data and customer data, which is held in trust. These include payment card industry, grid operating information and any interconnection with NERC or SOX systems. When developing the Company's mobile enterprise strategy, all compliance requirements must be evaluated and considered as the Company moves toward a more off-site employee presence.
- The move to more mobility-based systems presents an ever-changing threat landscape often requiring additional security measures. This move also needs to account for a wider variety of device types and requires more use cases than ever before. Concurrently, mobility exposes the Company's systems to different forms of possible exploitation even while it offers better ways of serving customers. As a result, heightened security vigilance is a part of our mobility expansion.
- DTEE will ensure that mobility enhances daily work by providing timely and accurate information, as well as allowing quick and easy capture of critical data in the field, including photos, markups and videos for planned work, outages and equipment failures.
- DTEE plans to deploy optimized task-based mobile-first applications and general-purpose apps, and mobile access to all enterprise systems and documents.
- DTEE will better track the time that field workers spend completing work orders and other manhours tracking scenarios.
- In 2023, DTEE will select and implement a new and improved vegetation management platform that will provide a more reliable and scalable mobile end-to-end tree trimming operations solution to support initiation, planning, execution and audit close-out. This solution will include computer hardware, licensing, configuration and integrations to work management systems.
- In 2025, DTEE will implement an interface between the AMI system and the mobile dispatch and work management solution for the Electric Field Operations organization to perform meter reads and other operations remotely, allowing for safer operations and the ability to verify work completed while in the field.

Exhibit 12.9.1 Mobility Capital Investment

Mobility ($ millions)	2021	2022	2023	2024	2025	2021-2025 Total
Vegetation Management Platform	-	-	$4.3	-	-	$4.3
AMI Integration with Mobile	-	-	-	-	$4.7	$4.7
Other Mobility	-	$0.5	$0.3	$0.7	$2.8	$4.7
Total	**-**	**$0.5**	**$4.6**	**$0.7**	**$7.5**	**$13.3**

12.9.2 Goal 2: Deliver best-in-class work management and integrated scheduling

Work management includes scheduled and unscheduled work, work order creation, resource scheduling, and work execution for employees, vendors and third-party crews. This includes job planning, labor, material, tools and services for both large and complex work efforts and smaller, short-term jobs. Upon completion, work must be audited and verified to reconcile time capture and payment.

An effort is underway in DTEE to improve work management and scheduling processes to ensure field resources have the processes and tools to support the right jobs, with the right people, at the right time. This includes ensuring unscheduled work is reflected in the work management system, Maximo, and field resources can receive and status jobs in real-time to create a feedback loop on asset condition and performance in alignment with the asset management capabilities. Process improvements, reduction of jobs held due to resource constraints, higher schedule compliance rate, and CWIP backlog reduction have resulted in savings.

Very similar to the Company's enterprise mobility systems, DTEE employs a platform of tools and systems centered around Maximo to enable effective work management. The core Maximo system is out of date and requires an upgrade to the current version before vendor support of the existing system is discontinued in late 2021. The upgrade is required before portions of the platform can be moved to the cloud, a more efficient means of storing information in the longer term. Investments are already underway to return Maximo to health, improve stability and prepare it for modernization over the next three years, including working to provide each major business area that uses the platform its own asset. This will decrease operational complexity and align each asset more directly with the business outcomes of that area.

- The Company's currently deployed enterprise system is several version upgrades behind the industry standard and will go out of support in October 2021. This will result in increased operational fragility until upgraded.
- A project is active to return this to a supported, on-premise version, by the Q4 2021.
- The current system version limits the ability to utilize the mobile aspects, making it more difficult to take advantage of operational efficiencies in the field.
- The existing production system implementation has all business units across the Company enterprise using a single system, which imposes operating requirements on all business units when only one unit has that requirement. For example, a decision in Generation impacts Distribution and vice versa. As the system moves to the cloud platform, each business unit will have its own implementation and will only be affected by its specific operational needs, functions, security requirements and schedules, which will improve efficiency and the ability to incorporate change.
- To facilitate a future move to a cloud version of the product, the current version must first be updated.
- Future enhanced functionality will include better internal resource planning and AIassisted automatic work scheduling.

Exhibit 12.9.2 Work Management and Integrated Scheduling Capital Investment

Work Management and Integrated Scheduling ($ millions)	2021	2022	2023	2024	2025	5 Year Total
Stabilize Distribution Operations' Maximo Instance	-	-	$5.2	-	-	$5.2
Other Work Management and Integrated Scheduling	$0.1	$2.9	$6.8	$3.0	$3.2	$16.1
Total	**$0.1**	**$2.9**	**$12.0**	**$3.0**	**$3.2**	**$21.3**

12.9.3 Goal 3: Drive top-quartile DO asset management

The overall goal of effectively managing assets is to minimize the total cost of ownership and operations while delivering the 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.

Asset management includes managing the full lifecycle of an asset, engineering and financial management, as well as linking spatial information in the ESRI Mapping system to an asset.

Managing the electric grid is an asset-intensive operation, and as such, relies heavily on the capabilities of its Asset Management systems. Several of these systems are common to both Work Management and Asset Management with Maximo and ESRI Mapping systems sitting at the core of this capability. Critical issues include:

- Both currently deployed systems are several version upgrades behind the industry standard and will no longer be supported by the vendor after October 2021. This will result in increased operational fragility until upgraded.
- Projects are active to return them to a supported on-premise version by Q4 2021.
- Once the ESRI Mapping system is upgraded to a vendor supported version in 2021, additional investment will be made to in the ESRI platform to improve digital asset management processes. This includes investment in ESRI-based design tools that provide a streamlined asset management process from design to field completion through integration with existing mobile mapping technology, ArcFM Mobile.
- Investment in DTEE's centralized asset data repository is required to obtain the value of a 360-degree view of assets including master, transactional and performance data. This would include the capability to fully link and deliver supporting documents such as asset manuals and engineering drawings to off-site field workers digitally.
- The current system has differing levels of capability to manage asset processes online, offline and via mobile activities. This requires investment to digitally deliver the highest service levels to the mobile workforce.
- Investment is required to improve the timeliness of asset updates from the field and support for map-centric asset management.

- Investment is needed to improve the system's ability to track labor, materials, and tool charges by all asset types and linear measures in a fully automated fashion that reduces/eliminates manual errors and delays.

As part of DTEE's ongoing technology plan, the Maximo and ESRI Mapping systems are in the process of being upgraded to both return them to health and to expand their capability in conjunction with the ADMS investment.

With the implementation of ADMS, the Maximo version upgrade, and the ESRI Mapping upgrade over the next three years, systems will be both up-to-date and able to support the anticipated business outcomes.

Exhibit 12.9.3 Asset Management Capital Investment

Asset Management ($ millions)	2021	2022	2023	2024	2025	5 Year Total
ESRI System Upgrades	-	$0.8	$1.1	-	-	$1.8
Other Asset Management	-	$0.5	$1.0	$1.5	$0.8	$3.8
Total	-	$1.3	$2.1	$1.5	$0.8	$5.6

12.9.4 Goal 4: Transform capabilities for distribution planning processes

As discussed in Section 4 – Distribution Planning Processes and Tools, one of the critical aspects for a smart and integrated grid is the capability to connect customer equipment, run alternative scenario analysis at scale, and provide situational awareness for targeted system upgrades. These capabilities rely on systems to continuously manage and process large volumes of data from many sources as both the grid and customers connect devices and sensors.

An emerging issue for most utilities, including DTEE, is that the planning tools that are currently being used to analyze the loading data are not sufficient to meet this quickly growing challenge.

To enable the maturing distribution planning business processes discussed in detail in Section 4 – Distribution Planning Processes and Tools, the existing technology platforms supporting DER interconnection analysis and distribution planning will need to be upgraded and new analytical tools, models and platforms will need to be implemented in five key areas:

- **Interconnection process enablement** – This investment includes upgrading the new interconnection application software to provide seamless customer logon, payment and transparent application experience. Additional investment includes tools and integrations supporting the application review process. The Interconnection process is discussed in further detail in Section 4.4 of the DGP.
- **Hosting capacity enablement** – This requires deploying tools to support stakeholder hosting capacity visualization and enhanced analysis tools, and integration with existing planning tools. More on the Hosting Capacity Analysis (HCA) process is discussed in detail in Section 4.5 of the DGP.
- **Network model** – The foundation for the evolving Distribution Planning processes is a high-quality network model including grid topology and electrical characteristics. Network model investments include technology to better align field conditions and maps to the digital representation of the grid, integrations between asset systems, new data models to support planning and operations topology and characteristics, and advanced analytics to leverage sensor data to continuously improve the network model.
- **Distribution load forecasting** – Investment is required to develop DER and load forecasting capability at a granular level to support studies and scenario planning that enables DTEE circuit design to be responsive to meet ever-changing customer needs. For further details on the Forecasting process, see Section 4.2 of the DGP.
- **Situational awareness analytics** – Key investments are planned for analytics platforms to provide situational awareness and proactive recommendations of grid upgrades to improve customer reliability, power quality and DER connectivity.

12.9.4.1 Interconnection process enablement

Technology investment is needed to achieve the maturing processes discussed in Section 4.4 – Interconnection Process. The interconnection application software, Power Clerk, currently requires customers to maintain separate login information and provide payments via check. Investment is required to upgrade the portal to provide a seamless customer logon, electronic payment and a transparent application experience. Funding will include investments to upgrade the Power Clerk software to accommodate new processes and updated forms. This also includes investments to implement single sign-on and customer information system integrations, as well as integration with Maximo to help streamline the work management process of interconnection applications.

As DTEE sees increasing volumes of interconnection applications, investment must support internal processes for interconnection application review by integrating the application system with the planning study tool, CYME planning tool, as well as the Company enterprise data lake for circuit analysis, application trending reporting, and project optimization.

Investments are also required to support the interconnection process in the screening steps for qualifying projects. This includes specific integrations to the CYME planning tool to support automating screens for loading, transformer size compatibility, and voltage constraints, as well as to DTEE's spatial solution, ESRI Mapping, to support screening within the service territory.

The Interconnection Process Enablement program also includes technology enhancements that will be needed to ensure DTEE is equipped to meet emergent regulatory requirements including FERC orders 841 and 2222. Study tools will need to be enhanced to support the integration of aggregated resource across locations on the grid, while evaluating interrelated impacts. DTEE will also integrate the planning tools with scenario-based forecasts to determine opportunity and assessment.

Exhibit 12.9.4.1.1 Interconnection Process Enablement Capital Investment

Interconnection Process ($ millions)	2021	2022	2023	2024	2025	5 Year Total
New Interconnection Application	-	$1.1	$0.5	$0.6	$1.1	$3.4
Internal Process Integrations	-	$1.8	$1.4	$1.3	$1.9	$6.3
Other Tools and Integrations	-	$0.9	$1.7	$3.5	$1.5	$7.6
Total	**-**	**$3.8**	**$3.6**	**$5.5**	**$4.5**	**$17.4**

12.9.4.2 Hosting capacity enablement

Technology investment is needed to achieve the maturing processes discussed in Section 4.5 – Hosting Capacity Analysis. To improve the speed in which customers can evaluate the ability to interconnect DERs with the grid, investment is required in both customer-facing and internal evaluation tools. The technology investment will include a system to store information on likelihood of system upgrades needed to support DER interconnection, as well as a visual interface that is externally facing for customers and developers to access.

To support DTEE's processes to evaluate hosting capacity at a granular level, investments in tools and integrations are needed. This will begin with tools such as EPRI DRIVE and CYME integration capacity analysis to evaluate areas with high penetration of DER. Further years will see investments to link the hosting capacity into the interconnection application portal.

Exhibit 12.9.4.2.1 Hosting Capacity Enablement Capital Spend

Hosting Capacity ($ millions)	2021	2022	2023	2024	2025	5 Year Total
Total	-	$0.25	$0.25	$0.15	$0.15	$0.8

12.9.4.3 Network model

The network model is a series of IT and data architecture that will provide DTEE with the foundation needed to deploy advanced grid simulations and analytics called for by the evolving distribution network. The Electric Power Research Institute (EPRI), which refers to this as "Grid Model Data Management (GMDM)," has provided a reference framework for utilities and vendors to leverage in addressing the network model challenges.

As discussed in Section 3 – Grid Modernization Process, grid modernization has brought significantly higher requirements for the tools and analytics used to plan, operate and manage the electric grid. Due to the increases in volume, velocity and the granularity of data needed to support the planning tools, ADMS, and distribution system real-time controls, DTEE needs to continuously improve the network model systems to enhance detailed modeling and better support data flows for systems of records to provide historical, as-built, and future scenario-based network models. In addition to the tools, models and interfaces required to meet network models needs for operations and planning, advanced analytics will also be leveraged to ensure data integrity.

Although the grid model data management relies heavily on ESRI Mapping functionality, this program does not include basic ESRI Mapping software upgrades, which is supported by the corporate IT investment portfolio. This program also excludes work specifically needed to migrate data to the ESRI Mapping utility network.

Common platform operating maps

Currently, most operating diagrams are maintained in computer-aided design (CAD) software in addition to ESRI Mapping, DTEE's Geographic Information System (GIS). This can cause discrepancies between sources, which leads to extra field verification or rework during the planning, construction and operation of the electrical system. There are over 14,000 map documents for the subtransmission, Underground Residential Distribution (URD), AC Network, and cable conduit systems that reside and are maintained in both CAD files and the ESRI Mapping network model.

To ensure data consistency, all the data or information related to subtransmission, URD, AC Network and cable conduit need to be transferred, reconciled and validated within the ESRI Mapping platform. This program track will create a unified network model with ESRI Mapping becoming the single source of data for the DTEE as-built network model and operational maps.

Asset data integrations

The data lifecycle of an asset is the digital representation of an electrical asset from installation through decommissioning. The current process to update asset and network model information includes many manual and duplicated steps between systems, such as creation of the digital representation in Maximo and ESRI. To support the increasing velocity of network model updates for real-time grid operations and planning, DTEE plans to expand integrations among its enterprise asset management systems (Maximo, ESRI, SAP). These integrations help efficiently manage asset data lifecycles for asset management and grid model requirements.

These integrations will focus initially on data flows needed for current planning and operations functionality, such as power flow and area load analysis (CYME, ADMS, PSSE), with focus shifting to advanced integrations with detailed control settings for equipment (Relay and device settings) to support bidirectional power flow, dynamic protection, and even advanced Distributed Energy Management System (DERMS) in the future as ADMS and Distribution Automation functionality mature.

Network model enhancements

With the switch to electronic operational orders and advanced functionality of ADMS required to manage bidirectional power flow, current network model granularity will not suffice. Additional details needed range from schematics to support switching and tagging in the short term, to engineering and control setting information to support advanced functionality, such as smart inverters functionality in ADMS in the long term.

This program track will enhance the data model in the ESRI Mapping system to meet the needs of planning and operations functions in DTEE's Grid modernization plan. DTEE will also perform first-time data capture and consolidation for digital representations that do not currently exist.

Grid model analytics

With the increasing volume of data needed to support grid models for planning and operations, there will be a need for increased staffing in order to maintain high quality data. For example, the impedance per mile of conductor and the substation transformer phase shift information is needed to support real-time load flow in ADMS; millions of these data points will need to be provided with sufficient quality in near-real time. To increase efficiency and accuracy of maintaining the grid models for planning and operations, DTEE will need technology solutions to continuously improve data integrity.

DTEE will leverage the big data cloud computing infrastructure to explore and develop machine learning algorithms to address data quality gaps based on existing and derived information. Once the algorithms are tested and proven, DTEE will integrate the machine learning workflow with source systems to raise overall data effectiveness.

Network model orchestrator

In order to study the impacts of proposed system upgrade projects, there is a significant amount of manual work required in the current distribution planning processes and tools to create historical analysis and network models for studies performed on an individual basis. Although there is no commercialized industry product to manage historical, current and future network models, including planning scenario analysis, DTEE sees this functionality will be necessary in the five-to-fifteen-year outlook. The technology architecture recommended by EPRI, which includes management and orchestration services for various planning and operational scenarios, will enable stage two and stage three planning tools, such as time-series power flow, scenario-based project evaluation, and asset replacement optimization.

The Network Model program will deliver both the grid network model and model management technologies needed as a foundation for many functionalities of integrated distribution planning and a modern grid.

Exhibit 12.9.4.3.1 Network Model Capital Investment

Network Model ($ millions)	2021	2022	2023	2024	2025	5 Year Total
Common Platform	$0.4	$0.8	$1.2	$1.3	$1.3	$5.1
Asset Data Integrations	$0.7	$0.8	$0.6	$0.6	$0.4	$3.2
Network Model Enhancements	$0.3	$0.4	$0.3	$0.2	$0.2	$1.5
Grid Model Analytics	$0.6	$0.8	$0.8	$0.8	$0.8	$3.9
Total	**$2.0**	**$2.8**	**$2.9**	**$2.9**	**$2.7**	**$13.3**

12.9.4.4 Distribution load forecasting

As discussed in Section 4.2 – Forecasting, new developments in distributed generation resources, electric vehicle adoption, and energy waste reduction/demand response are requiring a change in process for distribution load and generation forecasting. The process, and thus data infrastructure, need to evolve into a more integrated and granular approach to distribution load and generation forecasting.

To address the needs to forecast changing customer-side equipment adoption, such as DER, energy waste reduction, and microgrids, which will inform the scenario-based distribution planning, DTEE will need to collect data on customer adoption and propensity of future adoption for various customer-side equipment.

DTEE will need to implement machine learning models to forecast and verify expected system impacts, including customer energy usage and system efficiency. Additional models will need to be developed to provide decision support to system planners by optimizing system upgrade options based on known and forecasted scenarios. These models must support the ability to optimize multiple likely scenarios to efficiently plan for changing customer needs within DTEE's Distribution Planning processes.

To enable these loading and forecasting functionalities, DTEE will implement big data tools in the Azure and Databricks data platform in conjunction with the PowerRunner Energy Platform to continuously validate, process and prepare the loading and voltage data for automatic analysis and system modeling, forecast DER adoption, and provide decision support for system planning. Features of the big data forecasting solution include:

- **Load curve generation –** Functionality to prepare representative disaggregated usage curves for loads and generation at customer levels at hourly values for an entire year is necessary to ensure that forecasting system and customer conditions are accurately incorporating the separate impacts of DER on the grid, such as with solar panels varying output based on the amount of light. Once load curves are generated at individual customer level, the toolset will aggregate to various levels of system equipment, such as service transformer and fuses.
- **Development of DER and EV propensity forecasting tools –** Creation of machine learning models will incorporate external factors and demographics to predict customer adoption of DER, such as energy efficiency equipment, electric vehicles, solar inverters, and micro-grids.
- **Verification of expected impacts and benefits –** Analysis tools will allow system planners to validate the impacts of DER on energy usage, system efficiency and reliability. These verification tools and models are needed as DER becomes more widespread, making current methods difficult to disaggregate from aggregated loads across time.
- **System planning decision support**: Optimization analytics will be developed to consume the forecasted scenarios and run numerous plausible scenarios for customer adoption across the system to determine system investments that will result in a reliable grid for all connected customers while also considering costs and project timing. These decision support models based on load forecasting scenarios will interface with the

situational awareness analytics tools (see Section 12.9.4.5 – Situational Awareness Analytics, below) for detailed planning at the individual component level.

Exhibit 12.9.4.4.1 Distribution Load Forecasting Capital Investment

Distribution Load Forecasting ($ millions)	2021	2022	2023	2024	2025	5 Year Total
Total	$0.5	$2.2	$1.6	$1.8	$1.5	$7.5

12.9.4.5 Situational awareness analytics

Advanced situational awareness analytics are needed for planning system upgrade decision support. This investment will build on the existing Company enterprise data lake to develop a data analytics architecture based on use case capability, while integrating systems to bring additional power quality data and other sensor information into the data architecture in the data lake. Feature engineering will be performed to summarize data aligned with integrated Distribution Planning use cases. Investments in this space include developing artificial intelligence and machine learning technologies that describe, predict and prescribe suggested actions to take during the integrated distribution planning process. This will improve reliability, power quality and customer flexibility. Anticipated scope and timing of investments is as follows:

- 2022: Investments include development and deployment of data engineering pipelines and visualization applications to create toolsets for integrated grid power flow modeling with load projections, constraints based on aging infrastructure, and planning for multiyear projects, as well as spatial and time-based contextualization of grid overloads, capacity, planned work and asset conditions to aggregate and visualize data to support distribution investment prioritization.
- 2023: Investments include development and deployment of data engineering pipelines to integrate detailed financial data, electric vehicle grid services and charging data, as well as commercial and industrial power quality data into the enterprise data lake to support analysis of reliability and power quality performance. Investments also include licenses and configurations of advanced artificial and machine learning capabilities in the enterprise data platform to support future investments in predictive and prescriptive

analytics, such as evaluation of system upgrades in Section 12.9.4.1 - Interconnection Process Enablement and in Section 12.9.4.4 - Distribution Load Forecasting .

- 2024: Investments include licenses, configuration and development of analytics to process meter and edge monitoring devices within context of the connected grid to trigger action for targeted system upgrades.
- 2025: Investment includes development and deployment of analytic tools that will process power quality information such as flicker, harmonics and advanced fault waveforms to integrate analysis of the impacts of modern grid devices into the integrated distribution planning analysis process.

Exhibit 12.9.4.5.1 Situational Awareness Analytics Capital Investment

Situational Awareness Analytics ($ millions)	2021	2022	2023	2024	2025	5 Year Total
Total	-	$0.9	$1.5	$0.8	$0.4	$3.6

12.9.5 Goal 5: Modernize grid management

Grid management includes the full suite of distribution management applications, including advanced metering infrastructure, distribution automation, outage response, and advanced control toolsets. Mature grid management enables distribution operators to model and manage the distribution network, monitor the power system, manage planned and unplanned outages, and analyze and optimize the quality and reliability of the network.

In this area, DTEE also relies upon an existing platform of systems to deliver superior operating results and contribute to the Company's commitments surrounding power quality, reliability and safety. These systems require the following investment:

- The existing communications infrastructure that DTEE relies upon to monitor and manage the grid in real time will require additional investment as new or expanded use cases and data requirements are identified which surpass the systems' current implementation.

- The Advanced Metering System and its associated infrastructure are operationally stable, however with new use cases, they are being relied upon to provide operational data beyond their original design specifications. Initially deployed as a daily usage collection system and given its success, AMI is now relied upon provide additional information at a much higher intra-day frequency. DTEE is investing in this system to bring this deployment to a more real-time data network to meet both current and future demands. This will be a significant long-term effort.
- As the first meters installed during DTEE's Advanced Metering Infrastructure deployment approach end of life, DTEE will evaluate the next generation of meter and meter communication technology that will meet the needs for advanced planning and operations functionality. In 2025, DTEE will invest in meters to deploy limited scale tests of viable next generation mesh meters to evaluate functionality and performance.
- The microwave network is used as a primary and secondary WAN communications for corporate and SCADA networks. The modernization of telecom microwave tower equipment will optimize performance and align DTEE's frequency usage with the FCC. Due to the FCC deregulation of privately owned frequencies, a number of DTEE's microwave systems must be replaced to maintain a reliable network and avoid collisions with other entities using the same frequency. DTEE will design and implement new microwave backhaul communications, install modern dishes for tower weight reduction, install hardware for network redundancy and resiliency, and replace end-of-life hardware.
- Investment is needed to support operational use of sensor technology on the grid, including devices being deployed at the grid edge to provide information to both DTEE and its customers about their real-time and historical energy information for the submetering customer programs.
- Utilizing sensor information for operational analytics will require investment in real-time streaming and analytics in DTEE's data platform to proactively respond to customer outage and power quality issues.
- Investment is needed to implement an industry standard configuration and test records platform to manage the increasing amount of grid control device configurations. This investment will include procuring an industry standard database

tool with integration into Maximo for work and asset management functionalities, as well as purchasing advanced test sets to be used by field technicians to automate relay testing and recording of test records to the database.

Exhibit 12.9.5.1 Modernize Grid Management Capital Investment

Modernize Grid Management ($ millions)	2021	2022	2023	2024	2025	5 Year Total
Configuration and Test Records Platform	$0.3	$2.3	$1.7	$0.7	-	$5.0
Grid Edge Insights	-	$0.8	$0.9	$0.9	$0.6	$3.1
AMI Mesh Network Enhancements	-	$0.5	$0.5	$0.5	$0.5	$2.0
Microwave End of Life	-	$0.5	$0.5	$0.5	$0.5	$2.0
Evaluate Next Generation Metering and Communication Network	-	-	-	-	$4.8	$4.8
Other Modernize Grid Management	$2.8	$7.3	$2.9	$3.4	$2.2	$18.6
Total	**$3.1**	**$11.3**	**$6.5**	**$5.9**	**$8.5**	**$35.3**

12.9.6 Technology strategy roadmap capital investment summary

Exhibit 12.9.6.1 Technology Strategy Roadmap Investments ($ millions)

Program Track	2021	2022	2023	2024	2025	2021-2025 Total
Mobility	$-	< $1	$5	$1	$8	$13
Work Management and Integrated Scheduling	<$1	$3	$12	$3	$3	$21

Asset Management	$-	$1	$2	$2	$1	$6
Distribution Planning Processes Enablement	$2	$10	$10	$11	$9	$43
Modernize Grid Management	$3	$11	$6	$6	$9	$35
Total	$6	$26	$35	$22	$29	$118

13 Base capital

Base capital refers to work activities that DTEE performs as part of the normal business of serving our customers. Activities include, but are not limited to, restoration of customers after a storm or equipment failure, connection of new customers, and relocation of existing assets.

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

13.1 Emergent replacement

Emergent replacements are expenditures that are used to address immediate customer needs (outages, broken equipment, etc.) or immediate system needs (loss of a contingency, unsafe operating conditions, etc.). Exhibit 13.1.1 provides the forecasted emergent spend for 2021-2025.

If the Distribution Grid Plan investments, summarized in Section 6, are implemented as described through the DGP, then DTEE forecasts that capital required for emergent replacements will be reduced compared to what it otherwise would have been, which includes offsetting inflation; and is projected to be lower than current emergent spend. The savings were calculated during the development of the DGP by modeling the reduction in emergent events due to strategic capital investments and a base level of tree trimming and other maintenance. These savings were then applied to the forecasted emergent capital spend projected. As was shown in Section 5.3, the projected emergent costs are $67 million lower per year than the baseline scenario, which projected $420 million in emergent costs by 2025.

Emergent replacements fall into three categories of work: storm, non-Storm, and substation reactive. Each category is described in detail in the following sections.

Exhibit 13.1.1 Emergent Replacement Expenditures ($ millions)

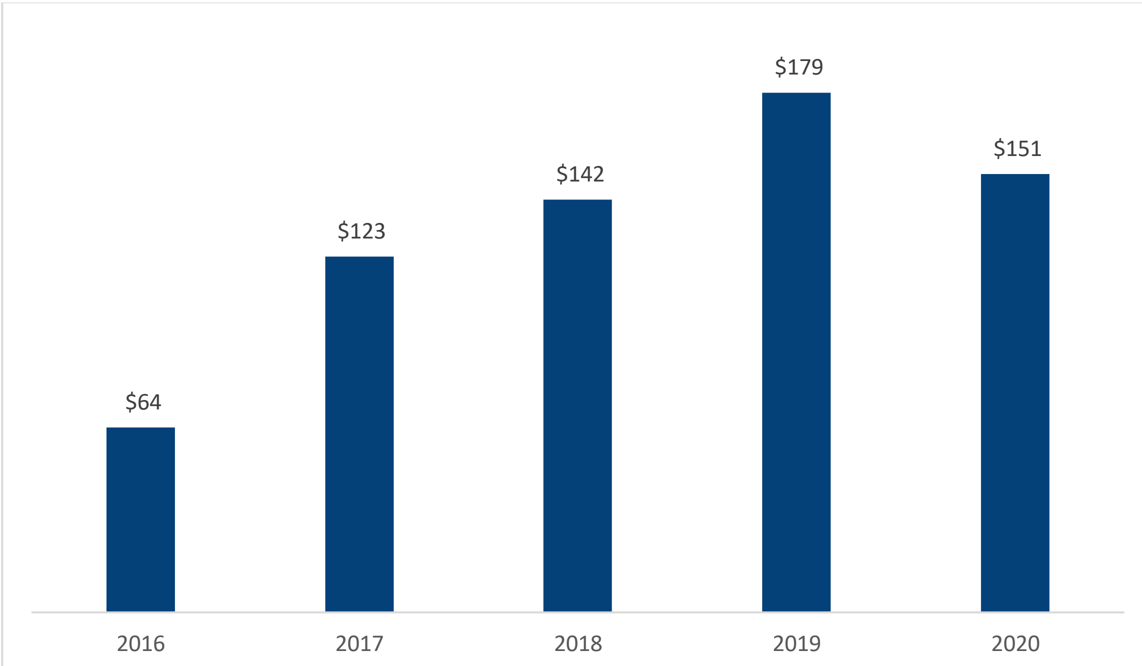
Category	2021	2022	2023	2024	2025	5-Year Total
Emergent Replacements	$488	$372	$372	$366	$354	$1,952

13.1.1 Emergent replacement during storm conditions

This category includes expenditures required to replace damaged assets on DTEE's overhead and underground distribution and subtransmission systems during storm conditions, which is defined as having more than 340 outage events impacting at least 125 circuits across the entire system. This threshold is typically equivalent to 25,000 customers affected over a 24-hour window. Several events can cause storm conditions distribution failures, such as wind causing trees or tree branches to come in contact with poles and power lines causing outages. It should be noted that not all weather related incidents create storm conditions.

Capital investments in emergent replacements during storm conditions has been increasing over the past five years. Exhibit 13.1.1.1 shows the amount invested from 2016 through 2020.

Exhibit 13.1.1.1 Capital Spend on Emergent Replacement during Storm Conditions ($ millions)



The primary driver of the increased investment is the increasing number of catastrophic (CAT) storms DTEE has experienced over the last five years.

There are two CAT storm classifications: a CAT-1 storm is defined as more than approximately 5% of DTEE customers without power and a CAT-2 storm is defined as more than approximately 10% of DTEE customers without power.

Exhibit 13.1.1.2 shows the number of CAT storms DTEE has experienced since 2015 and Exhibit 13.1.1.3 shows the number of customers impacted by the CAT storms.

Exhibit 13.1.1.2 Number of CAT Storms 2016 – 2020

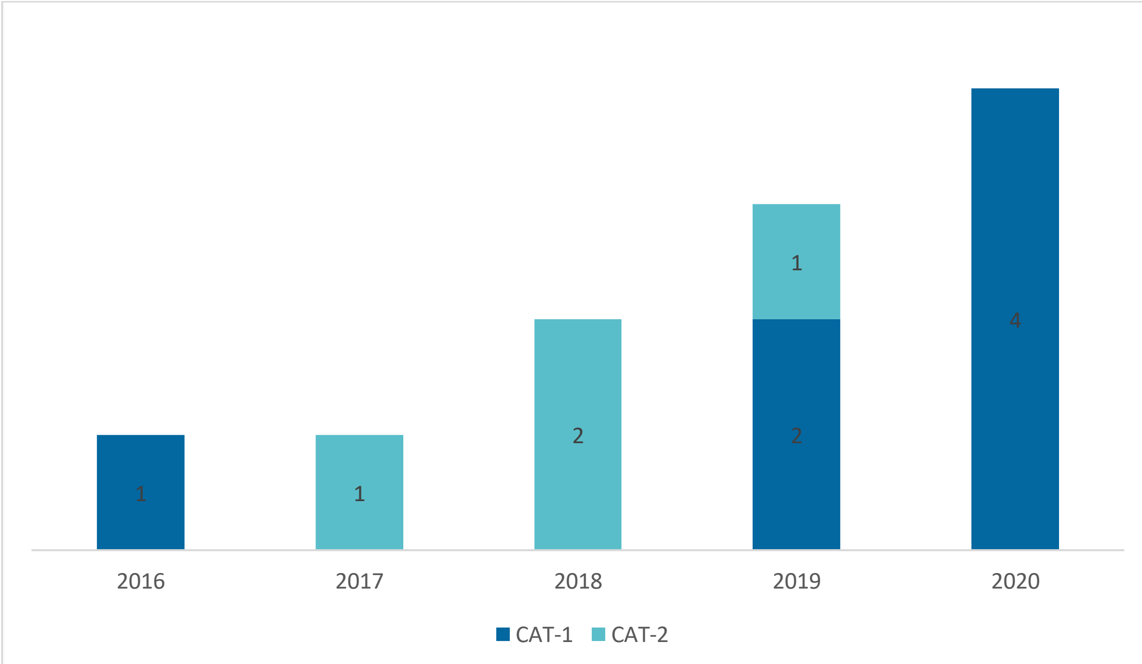
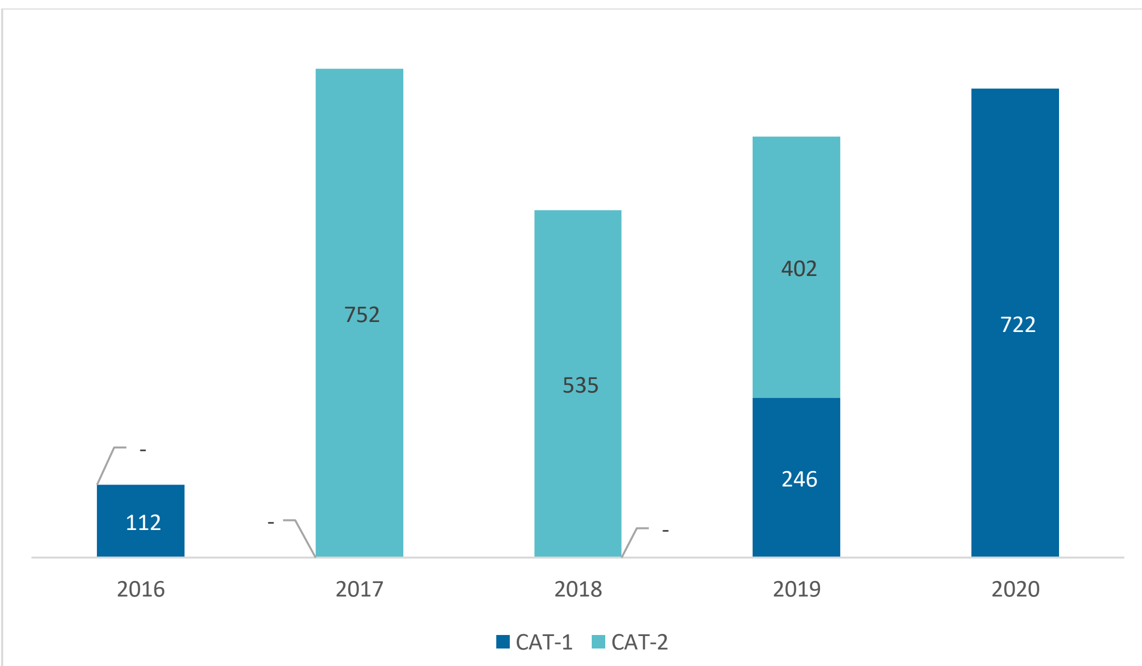


Exhibit 13.1.1.3 Number of Customers Impacted 2015 – 2019 (thousands)



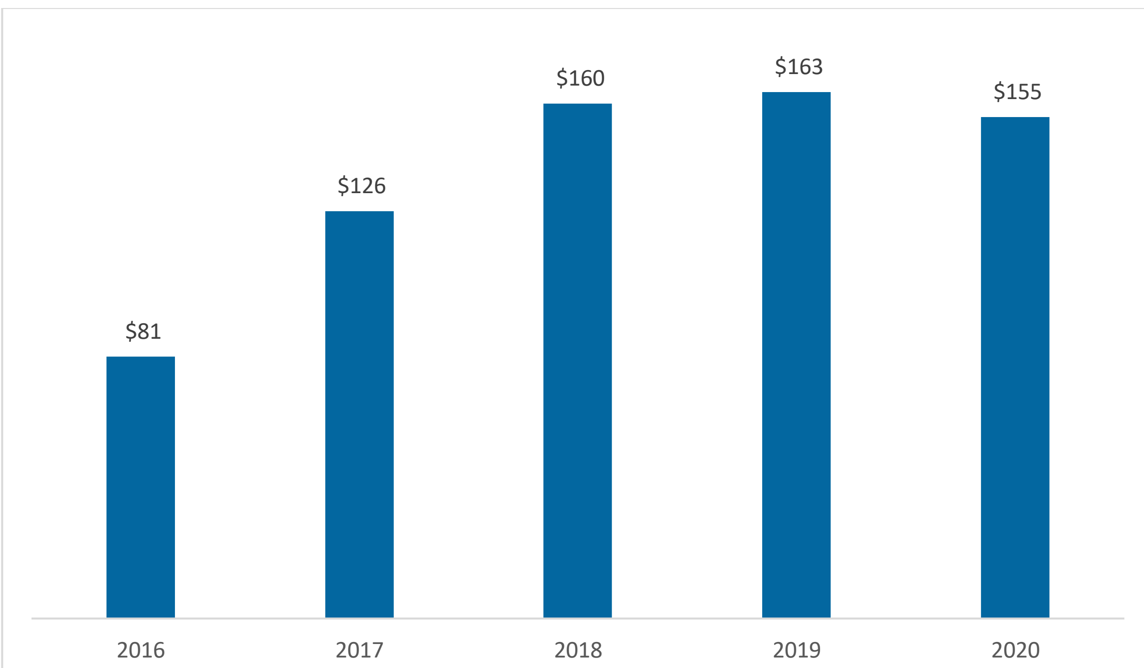
13.1.2 Emergent replacement during non-storm conditions

This category includes expenditures required to replace damaged assets on DTEE's overhead and underground distribution and subtransmission systems during non-storm conditions, defined as less than 340 outage events (approximately 20,000 customers) for the entire system.

The "non-storm" description does not imply that these events are not caused by thunderstorms and high winds. It simply means that there were not enough system-wide outages to be considered a declared storm for the system; yet localized thunderstorms and weather events could occur. Assets can also fail due to age, overloading, other electrical or mechanical issues, vehicles striking poles, or animal interference.

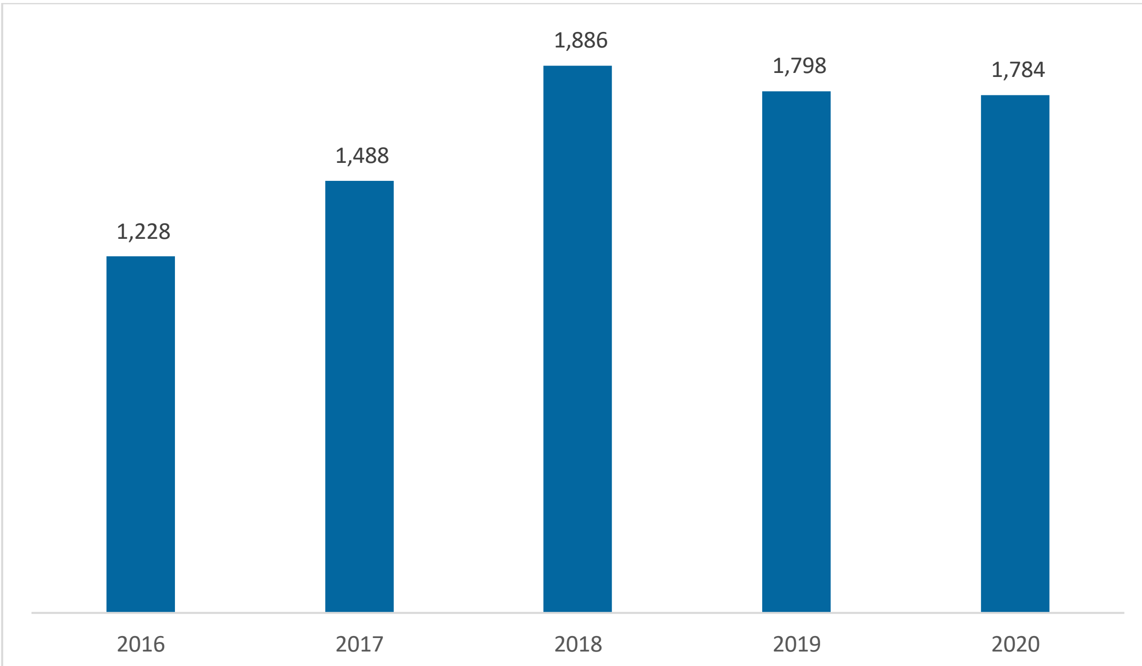
Capital spend on emergent replacements during non-storm conditions has been increasing over the past five years. Exhibit 13.1.2.1 shows the spend from 2016 through 2020.

Exhibit 13.1.2.1 Capital Spend on Emergent Replacement during Non-storm Conditions ($ millions)



There are several factors driving the increase in non-storm capital spend. A key contributing factor has been the increase in the number of customers experiencing interruptions in non-storm conditions. This increase has been caused by aging infrastructure as well as an increase in weather events that do not rise to the level of a storm threshold as defined in Section 13.1.1. As shown in Exhibit 13.1.2.2, there has been over a 40 % increase in the number of customers that lost power during non-storm conditions since 2016.

Exhibit 13.1.2.2 Number of Customer Interruptions during Non-storm Conditions (thousands)



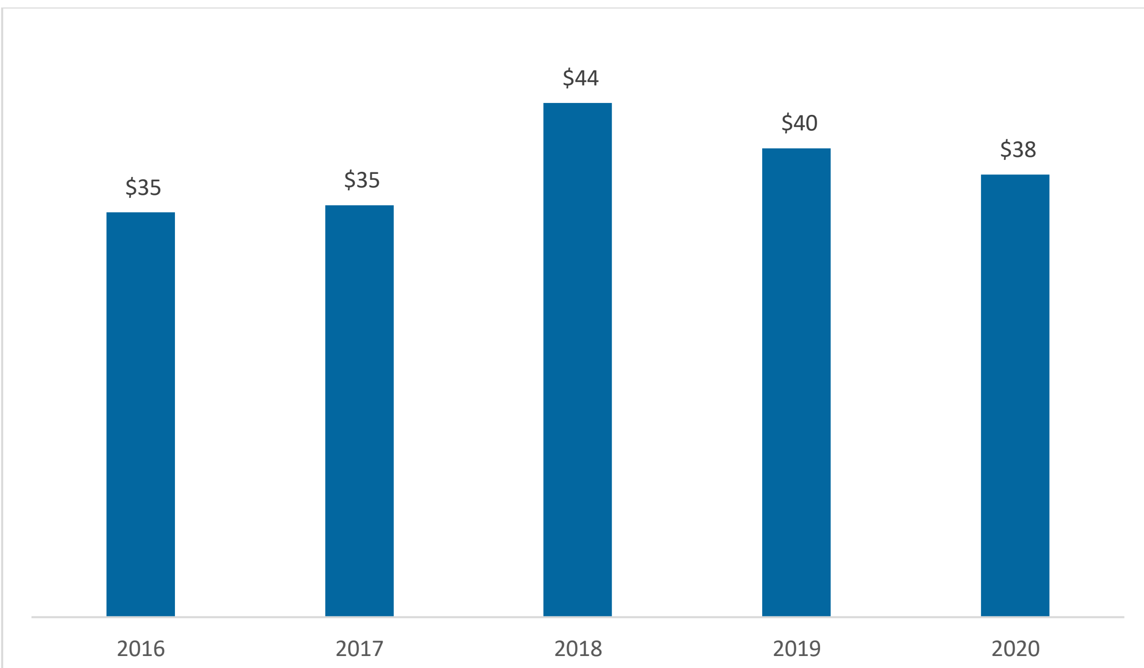
Another driver for increased emergent capital spend has been the increase in asset failures and replacements due to system aging, deterioration, and other factors like tree damage. As the system ages and damage accumulates, there is a need to replace equipment instead of repairing. For example, a span of wire that has experienced repeated failures and repaired with multiple sleeves should be replaced; as opposed to adding an additional sleeve and increasing the probability of future failure. At-risk underground residential distribution (URD) cable should be replaced upon failure to avoid increased probability of experiencing another failure and the extensive restoration time needed to repair. And a service line that is past its useful life or not up to current standard should be replaced once it has failed in order to avoid additional failures that are driven by that same service line.

Using materials designed to higher engineering standards to improve system reliability and resiliency has also contributed to increased emergent capital spend. Examples include the use of fiberglass crossarms, which cost more than wood crossarms, but provide much greater longevity and resistance to damage; higher wood pole class and armless construction, which increases the strength of poles by a factor of more than 2; and use of the more rugged K-line clamp-top polymer insulators, which have six times the mechanical strength of the older design F-neck porcelain insulator and can better secure the wires to mitigate downed wire risk.

13.1.3 Emergent replacement for substation reactive

This category includes expenditures required to replace damaged assets or assets failed during inspections in stations and substations. These expenditures were made to replace broken assets that either led to customer outages, elevated the risk of wide-spread outage events or impacted the redundancy or operability of the electric system. Substation reactive expenditures have increased slightly over the last five years as shown in Exhibit 13.1.3.1.

Exhibit 13.1.3.1 Capital Spend on Emergent Replacements for Substation Reactive ($ millions)



Factors that have contributed to the increased substation reactive capital include:

- Inspections and consequent replacements of defective netbank structures and associated system cable since 2016
- A more integrated approach to replace failed substation assets as well as adjacent at-risk assets to achieve higher cost efficiency since 2016
- Major substation failures and reactive replacement work, such as Plymouth substation event in 2018, Gay substation event in 2019, and Stephens substation event in 2020
- Increasing utilization of mobile fleets in support of restoration work, to preserve grid reliability and resiliency when a substation is in an abnormal condition due to equipment failures; for example should a substation experience a switchgear failure, portable switchgear can be mobilized to the site and connected to the circuits, restoring power to the customer and providing time for DTEE to replace or repair the failed switchgear

13.1.4 Measures to reduce emergent capital spend

As described in Section 5 – Benefit Cost Analysis; DTEE investments are prioritized based on their ability to meet the planning objectives of Safety, Reliability and Resiliency and Affordability. Affordability includes the impact investments have on avoided emergent capital costs. The investments detailed in this DGP are expected is expected to reduce emergent capital spend by $67 million in 2025.

Among the entire investment portfolio, tree trimming, 4.8kV hardening, 4.8kV conversion and consolidation, and pole and pole top hardware are among the top contributors to improve storm resiliency, reduce day-to-day trouble and event volumes, and ultimately reduce emergent capital spend. A robust pole top maintenance and modernization program, discussed in Section 9.1.1 - Pole and Pole Top Maintenance and Modernization, is critical to maintain the health of the overhead system and keep the emergent spend under control on a long-term basis.

Technology programs can also have a positive impact on avoided costs, improved reliability, and improved operational efficiency by incorporating enhanced sensing, communication and control of the electric grid that will allow for faster identification of faults and outages, quicker customer restorations, reduced patrol times, and increased remote operation of the gird. These technologies include: Grid technology such as Advanced Distribution Management System

(ADMS) discussed in Section 12.1, Telecommunications in Section 12.3, and Distribution Automation in Section 12.5.

13.1.5 Emergent spend forecast

DTEE uses a historic average spend for emergent capital forecast to normalize for weather and other factors that change year to year. In MPSC cases U-20162 and U-20561, DTEE forecasted emergent capital spend by calculating a historic average in each category, adding inflation through the "test year," and subtracting a calculated avoided cost based on the level of proposed strategic capital spend.

Based on the recent historic trends, such as increase in catastrophic storms, number of customers out during non-storm conditions, etc., as noted in the proceeding subsections; DTEE has decided to use a three-year historic average for emergent capital spend as opposed to the previous method of using a five-year average. A three-year historic average better represents the current conditions of the system and weather-related patterns that DTEE has experienced and allows for more accurate projections of future emergent expenditures.

13.2 Connections, relocations and other

The connections, relocations and other investment category is 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. These sub-categories are discussed in more detail below. Exhibit 13.2.1 provides the connections, relocations and other spend for 2021-2025. Except for the specific projects described in Section 13.2.6, the forecast in Exhibit 13.2.1 for 2022-2025 is based on the last full year of spend (2020) plus inflation. The 2021 budget is based on known projects and requests.

Exhibit 13.2.1 Connections, Relocations and Other Spend ($ Millions)

Category	2021	2022	2023	2024	2025	5-Year Total
Connections, Relocations and Other	$272	$252	$256	$263	$270	$1,313

13.2.1 Connections and new load

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

Small Load Growth & Customer Connections projects are projects that typically cost less than $500,000 to complete and are developed and executed by distribution regional service centers. These 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. Activities to support these customer needs may include reconductoring lines, expanding a substation, or transferring load to provide load relief. DTEE could also install 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 load requested and service requirements.

New Business investment projects are larger customer-driven projects, in excess of $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, just on a larger scale. Activities to support the customer new business needs often include installing additional overhead and underground lines, 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 carry a CIAC cost wherein the customer may be responsible for an allocated cost of system upgrades, depending on the existing system conditions, the load requested 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 improve customer satisfaction.

13.2.2 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 padmount transformers, or possibly substations and system cable. With expected federal investment in 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 can carry a CIAC cost wherein the requester pays for part of the costs of relocating DTEE assets.

13.2.3 Electric System equipment

DTEE maintains an inventory of critical spare equipment in order to both support 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.

13.2.4 NRUC and improvement blankets

Normal Retirement Unit Change-out (NRUC) consists of projects to perform scheduled work for replacement of assets determined to be end-of-life. Improvement Blankets include several types of small projects aimed at addressing improvements to the electrical system, software applications for field use, and animal mitigation.

The scope of work for this sub-category includes small improvements to address localized reliability issues, projects to perform scheduled work for change out of items on the subtransmission and distribution systems (e.g. replacement of reclosers and switches) determined to be at end-of-life, batteries and charger replacements at substations that are at end-of-life, development of software applications for field use, and animal mitigation (e.g. installing squirrel guards on bus insulators). Capital replacement programs detailed in Section 9.1 are designed to handle larger replacement projects, in addition multiple strategic projects that fall under Infrastructure Redesign and Modernization (Section 11) include replacements of larger assets such as substation breakers, etc.

These projects are focused on improving operating conditions to reduce the frequency and duration of outage events. Example of projects performed including installing/upgrading fusing on a circuit and installing fault indicators.

13.2.5 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 for engineers. In addition, this sub-category includes substation physical security.

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.

13.2.6 Other known major projects

DTEE supports some grid work that is outside of the more typical categories already described in this plan. The Gordie Howe bridge project is a large relocation project example. The United States, Canada, and the State of Michigan agreed upon a new U.S. customs plaza and international bridge, now known as the Gordie Howie International Bridge (GHIB), linking Detroit, Michigan and Windsor, Ontario.

In order to build the GHIB and U.S. customs plaza, the Windsor Detroit Bridge Authority (WDBA) and Michigan Department of Transportation (MDOT) requested that DTEE relocate all its facilities outside the plaza footprint. DTEE agreed to a joint venture with MDOT wherein MDOT would pay half the cost to relocate DTEE facilities. The project is expected to be completed by the end of 2021.

Another example of a major one-time project in the New Business project is Warren Service Center (WSC) Transformer Yard Reorganization. The transformer yard located at WSC has reached capacity and needs to be upgraded to provide better handling and storage of these assets (transformers and regulators). In order to support more efficient transformer replacements in the future, the WSC transformer yard will be reorganized and upgraded to accommodate a total of 193 transformers/regulators and will include an assembly area.

Stone will be added as a base to aide in stabilization of the stored transformers and electric power will added so that the transformer control panel will be continually operational, and the equipment health information can be monitored.

14 Preventative maintenance

Preventive maintenance (PM) is performed to achieve three primary objectives:

1) Control or reduce unplanned equipment-related outages.
2) Maximize the total life expectancy of the equipment at minimum lifecycle cost while maintaining an expected level of reliability and safety.
3) Acquire timely asset performance and condition data to support trend data analysis and identify potential issues.

An effective PM program is critical in managing asset conditions and capital and O&M costs. Risks of not performing preventive maintenance include compromised equipment performance during service and/or increased trouble costs due to equipment failing prematurely.

The PM program was developed by DTEE Engineering based on DTEE's maintenance policies which set the inspection scope and intervals based on:

- Manufacturer's recommendations
- Industry standards and best practices
- Historical inspection results and equipment condition data
- Engineering studies
- Benchmarking with utility peers

DTEE continues to refine its maintenance policies in order to find efficiencies and reduce failures. Some examples of the continuous improvement integrated into the PM program are:

- Changing inspection intervals based on engineering analyses of inspection results and equipment failures (condition-based maintenance).

- Using substation predictive maintenance (SPdM) data to drive inspection timelines instead of time-based inspections, to be aligned with condition-based maintenance principles and to achieve cost efficiency.
- Reducing maintenance activities by using new technologies (e.g., smart relays).
- Coordinating inspection intervals on different equipment to reduce the need for multiple shutdowns.

Furthermore, DTEE has developed condition-based maintenance and substation predictive maintenance (SPdM) plans to maximize maintenance efficiency. By evaluating certain monitored data available on some assets, engineers can prioritize equipment on the maintenance schedule and where appropriate, may defer some equipment to the next inspection cycle. One successful example is the prioritization of substation power transformer maintenance using dissolved gas analyses, which takes a sample of the oil in the transformer or regulator and looks for gases that are early indicators of insulation failure. Predictive maintenance includes taking pictures of substation equipment taken with infrared cameras to detect thermal hot spots, operational checks such as stepping through a regulator's settings, verifying oil circulation, and ensuring operational counters are functional. Information collected from these types of activities help drive the priority of maintenance activities on substation equipment.

The previous activities require personnel to interact with the equipment. Alternatively, when advanced remote monitoring equipment is installed at substations, breaker operation data can be used to assess breaker and relay functions. If the equipment is assessed to be performing as designed, it may be possible to defer equipment maintenance activities. Currently, remote monitoring capability at substations is limited, and DTEE has not yet been able to widely apply this methodology to defer breaker or relay inspections. However, DTEE's investments in telecommunications, breaker replacement, and substation automation programs described throughout Section 12 will increase the penetration of such advanced remote monitoring technology and will enable the application of condition-based maintenance on breakers and relays.

DTEE's preventive maintenance programs are categorized in three groups, substations, overhead, and underground, as shown in Exhibits 14.2.1– 14.2.3. The projected O&M spend associated with each preventive maintenance Exhibit 14.2.4.

Exhibit 14.2.1 Preventative Maintenance Activities - Substations

#	Asset	Population (approx)	General inspection cycle (years)
1	120kV disconnects	352	10
2	120kV breakers	32	10/12
3	24/40kV breakers	1,021	3/10/12
4	Distribution breakers	5,334	3/10/12
5	Buses	250	10
6	Regulators	269	10
7	Portable substations	10	1
8	Single tap substations	118	10
9	13.2kV capacitor banks	224	1
10	AC netbank transformers	505	5
11	AC netbank structures	384	10
12	DC systems	589	1
13	Dissolved gas analysis (DGA)	3,323	1
14	Substation predictive maintenance (SPdM)	1,640	3
15	Voltage Control periodics	1,435	1
16	Relay periodics	9,703	5/7/10
	Total	**25,198**	

Exhibit 14.2.2 Preventative Maintenance Activities - Overhead

#	Asset	Population (approx)	General inspection cycle (years)
1	40kV pole top switches	862	8
2	Distribution remote devices	1,455	4/8
3	OH capacitor & regulator controls	4,505	1
4	OH distribution device battery replacements	1,455	4
5	Towers	332	10
6	DTEE equipment in high rise structures	45	20
	Total	**8,654**	

Exhibit 14.2.3 Preventative Maintenance Activities - Underground

#	Asset	Population (approx)	General inspection cycle (years)
1	Primary switch cabinets	1,731	5/10/15
2	Manholes	19,356	10
3	Vaults	30	5
	Total	**21,087**	

Exhibit 14.2.4 Preventative Maintenance O&M Spend Projections

	2021	2022	2023	2024	2025	Total
Preventative maintenance O&M spend	$10M	$10M	$10M	$10M	$10M	$50M

15 Performance-based rate making

Performance-based rate-making (PBR) refers to regulatory frameworks that aim to create a stronger connection between a utility's achieved returns and its performance. This section will describe the recent history of PBR in Michigan, the Commission's Order in Case No. U-20561, and DTEE's approach to benchmarking, developing and proposing a holistic PBR plan for the Commission's consideration. The section is organized into three primary areas and reflects the direction set forth in Case Nos. U-20561 and U-20147:

- **Background and context** – The Michigan context and discussion has shaped DTEE's proposal, reflecting perspectives articulated by the Commission, Commission Staff, other stakeholders, and DTEE over the last several years.
- **Benchmarking** – DTEE undertook an extensive benchmarking effort following the Commission's Order in Case No. U-20561 with the goal of understanding how jurisdictions around the country have approached PBR both from a process perspective and a substantive perspective.
- **DTEE's proposed PBR plan –** The proposed plan focuses on additional transparency of key reliability metrics and offers a flexible pathway to manage continued reliability and grid accessibility investments.

15.1 Background and context

In 2018, the Commission completed a "Report on the Study of Performance-Based Regulation." The report discussed several pertinent topics related to PBR, with particular focus on performance incentive metrics and their associated goals, multiyear rate plans (MRP) and examples of broad-based PBR in the United Kingdom and New York state. Michigan utilities and Commission staff supported the creation of this report through additional survey reporting of PBR around the country and the key considerations identified. One of the key recommendations from the report was, “The Commission’s review of PBR mechanisms indicates that they can be used to augment the existing cost-of-service approach provided that they are tailored to the specific requirements associated with utility regulation in Michigan,” and further observed that, “[a] variety of approaches are available.”

The Commission’s Order in Case No. U-20561 said “...the Company should consider the following:

1. The utility’s financial PBR system should include both incentives and disincentives based on performance; incentive structures should be holistically considered in terms of impacts on potential earnings;
2. The utility should consider the pros and cons of a comprehensive PBR system, which would avoid concurrent regular annual rate cases and separate PBR reconciliations;
3. Performance metrics should include outcome measures (e.g., customer average interruption duration index (CAIDI)) and not be limited to output metrics such as number of poles replaced;
4. Performance metrics should be linked to regional, national, and/or peer utility benchmarks, where possible;
5. Data and calculation methodologies should be well defined, transparent, and open for auditing/verification purposes;
6. Targets should be utility specific; and
7. Potential areas of performance focus are safety, customer service (end-use customers, builders, interconnecting generators, etc.), timeliness and quality, reliability and resiliency, long-term costs, and innovation.”

The proposal contained in this section addresses considerations specified by the Commission.

As the Commission observed in the 2018 report, “PBR is complex and has both advantages and disadvantages.” DTEE agrees with this perspective and, as described in more detail below, is supportive of a deliberate approach to PBR that allows for a thoughtful and measured implementation as a first step. Benchmarking indicates that measured deployment over time can create broad stakeholder buy-in on the elements, while ensuring that each is well understood and the sum of the parts can be reasonably estimated. Over time, PBR is something that may grow toward an expanded implementation in future years as DTEE learns and adopts best practices. As such, and with the venue for the initial PBR plan in the Distribution Grid Plan, the focus on distribution reliability and customer outcomes and engagement reflects what DTEE believes is the appropriate entry point for PBR.

DTEE views the included proposal as foundational groundwork for future PBR and an opportunity to explore and apply many of the PBR concepts discussed in the Commission's report and e observed elsewhere. Continued stakeholder engagement as the Company learns more about the applied impacts and effects of the proposal will serve to enhance the plan going forward. This may be informal engagement or under the purview of the Commission.

15.2 Benchmarking

Benchmarking is a key input to the development of new approaches to problem solving and growth. A robust understanding of how different states and regulatory environments have considered PBR supports a proposal that leverages those insights while simultaneously reflecting the Michigan-specific context of the concepts. Beginning in mid-2020, DTEE undertook an extensive benchmarking effort to understand the diverse applications of PBR around the country, focusing on 1) the process of how states engaged the conversation and 2) the substance generated by those processes. The goal of these inquiries was two-fold. The first was to baseline how the various states thought about and approached process and substance, and what the key considerations were. The second was to highlight the learnings generated from those states as a means to leverage best practices as a starting point for our own work here in Michigan, without starting from scratch.

The benchmarking included two key modes of understanding:

- **Research –** In conjunction with stakeholders, DTEE synthesized existing dockets, publications and other available materials from numerous states. The initial list of states to review was generated through internal research and input from local and national stakeholders. This step was critical in narrowing down the focus to those states which provided useful comparability to Michigan and also represented diverse approaches, goals and objectives for PBR.

- **Engagement** – Primary perspectives on PBR from involved parties provide context and insight that is not necessarily available in published documents. DTEE coordinated live discussions with organizations in multiple states to better understand both how they viewed the role of PBR, but also to learn about their experiences and advice. This live engagement included regulators, utilities, the financial community and non-governmental organizations representing customer and other stakeholder perspectives.

Key state focus

- **Minnesota –** Minnesota's PBR journey has unfolded over a decade of focused collaboration between the utilities, regulators, stakeholders and facilitators. Minnesota is an important benchmarking focus for three reasons: 1) the long record of development offers many insights into successes and pitfalls, 2) the state's process provides a strong example of broad stakeholder engagement, and 3) Minnesota's approach to performance incentive mechanism (PIM) development and the iterative perspective on PIMs provides an instructive framework.
- **Colorado –** Colorado has had elements of performance regulation for more than a decade, including for demand side management, revenue decoupling, earnings sharing, and quality of service plans (QSPs). The recent move to a more structured and comprehensive investigation of performance regulation was spurred by state legislation in 2019, which directed the Colorado Commission to investigate financial performance incentive mechanisms and metrics and return a report to the state senate. The legislation specified the forum for gathering information and certain specific pieces of content, including existing and potential metrics, future test years and new performance incentives.
- **Illinois –** Illinois is an instructive state for benchmarking, with a highly prescribed approach to PBR. Legislation in Illinois was first enacted in 2011 with the Energy Infrastructure Modernization Act ("EIMA") and expanded on in 2016 with the Future Energy Jobs Act ("FEJA"). Illinois utilizes formula ratemaking and has multiyear performance incentives, each which alter allowed ROE. There are no defined dollar penalties in the Illinois PBR approach.
- **Massachusetts –** Massachusetts has legislatively enabled performance-based regulation premised on several pieces of legislation. Its inclusion in recent Eversource and National Grid rate cases is closely tied with Massachusetts' grid modernization docket opened in late 2013. In 2015, the large utilities filed company specific plans to address the requirements, which

included individual and statewide performance metrics related to grid modernization. The combined 2018 order in the grid modernization docket directed the inclusion of additional PBR elements in future rate cases, requiring utilities to include "performance metrics that measure progress toward the objectives of grid modernization."

- **Pennsylvania –** Pennsylvania's PBR process is legislative enabled and non-prescriptive. The utilities have the discretion to introduce PBR, which method(s) to request, and deployment approaches. The Pennsylvania Public Utility Commission (PPUC) efforts, which began in 2016, have since developed into guidelines on how PBR will be considered by the Commission. Separately but in parallel action, PBR legislation was adopted and the PPUC approved a Final Implementation Order of Act 58 in April 2019. Act 58 gives the PPUC authority to approve PBR plans and while it does outline specific PBR methodologies, it does not limit the Commission's authority to approve any other methodologies proposed.

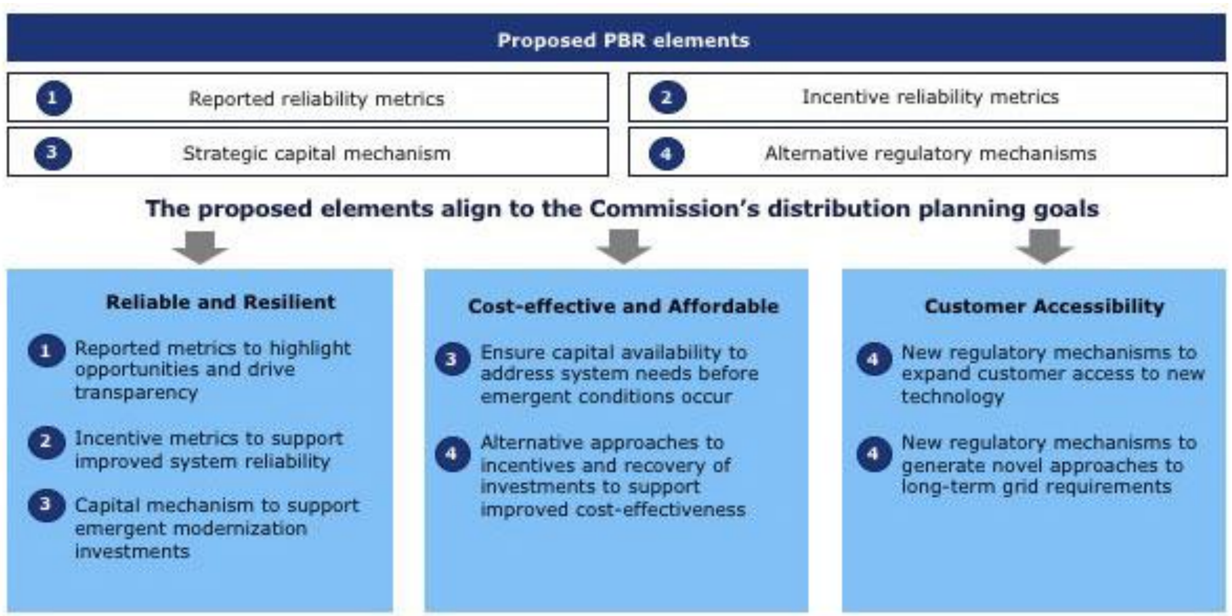
Key findings

- An impactful but measured pace serves all stakeholders and drives win-win outcomes for customers, utilities, regulators and other stakeholders. Minnesota did not move toward a "comprehensive" PBR plan at the outset but stress-tested and evaluated each step before evolving to the next iteration, for example. Other states each had a form of iteration or reflection between the initial requirement or proposal and the formal implementation of a PBR element in their ratemaking process. This is instructive for a Michigan approach and is consistent with how DTEE has considered this proposal, as a focused and initial step into what may evolve into a broader PBR framework.
- The processes undertaken by each state are unique and reflect their past engagement with performance ratemaking, stakeholder perspectives and the intended outcomes of the efforts. This diversity is evident in the types of PBR under discussion (multiyear rates vs. performance metrics vs. other), the financial mechanisms (dollar basis vs. allowed ROE), and in who has been the leading facilitator and enabler of these efforts. The Michigan background is punctuated by certain PBR elements, such as a future test year, certain shared savings mechanisms, and penalties associated with certain reliability performance. Each of these, in addition to the many discussions, workgroups and past explorations provides the foundation for the present effort.

15.3 DTEE's proposed PBR plan

DTEE's proposed PBR plan provides a balanced and forward-looking pathway to expanded linkages between utility performance and returns, as well as increased transparency of reporting and communication of performance. The proposal is designed to align with the overarching goals of DTEE's Distribution Grid Plan as well as the Commission's distribution planning goals as outlined in Case No. U-20147. These key goals are achieved through two primary and two support elements within the PBR plan, as shown below. The Plan will further highlight the cross-cutting themes of customer experience and equity throughout the four elements.

Exhibit 15.3.1 DTEE PBR Goals and Plan[22]



- **Reported reliability metrics** – Submit a new, standalone annual report that will include new metrics and expanded context and discussion of metric performance. The result of increased transparency and learnings will support more effective metrics and a better understanding of how the Company can continue to improve the impact of investments. Implementation of reporting would commence in the year following an Order in this docket.
- **Incentive reliability metrics** — Associating incentives with key metrics continue to drive alignment of operational performance and financial performance for the Company while providing additional consideration to customers if performance is significantly below target.

[22] Safety is a key DTEE Planning Objective as shown in Exhibit 4.2.2, and should remain outside of this PBR framework

Implementation of reliability metrics with financial incentives would follow an Order in a contested case subsequent to this case.

- **Strategic capital mechanism** – A capital tracking mechanism is one approach to investment flexibility in response to quickly evolving grid usage. DTEE is not proposing the near-term implementation of a mechanism, but the Company does highlight the role it could have going forward in a comprehensive PBR framework.
- **Alternative regulatory mechanism –** Alternative regulatory mechanisms are a key component of a broad-based and holistic approach to performance regulation. Beyond traditional COSR and a reliability focused PBR plan are alternative regulatory mechanisms which, in tandem with COSR and other metrics, can drive additional focus on 1) policy goals, 2) customer engagement and accessibility and 3) cost management.

Reported reliability metrics

Performance metrics may be published for additional transparency and communication, or they may be tied to incentives; DTEE's PBR Plan includes both. The reporting metrics in DTEE's PBR Plan have been structured to support two goals:

- **Learning –** Reporting metrics before incentivizing them encourages forward thinking approaches to measure and reflect performance before attaching the risk of financial incentives. This approach creates learning periods as specific metrics are defined and the supporting methodologies are refined. This allows the Company to better consider metrics to accurately reflect system performance and customer experience, and also to understand the conditions that drive those metrics. A period of learning will also allow the Company to calibrate forecasted improvement with actual improvements over the same historical period, which, over time, will support improved understanding of how specific investments impact reliability.
- **Transparency and communication –** Reported metrics support enhanced transparency of the Company's performance on a range of key reliability indicators. Many of the metrics proposed for annual reporting are currently included in compliance filings made by the Company each year. The filings are highly technical documents and were a step forward in communicating system performance; the additional reporting will provide further opportunity for context and understanding of system reliability metrics. As discussed below, an enhanced approach to reliability reporting will provide an opportunity to better communicate with customers and share how the Company is addressing reliability considerations on a more regular cadence.

Existing metrics

DTEE proposes the following, currently reported metrics and information for inclusion in a new PBR Report:

- System Average Interruption Duration Index (SAIDI)
- System Average Interruption Frequency Index (SAIFI)
- Customers Experiencing More than Six Interruptions (CEMI-6)
- Customers Experiencing Long Duration Interruptions (CELID)
- Worst Performing Circuits (SAIDI and SAIFI)

New metrics

DTEE additionally proposes to include metrics that are not reflected in existing reporting. Legacy electric reliability metrics are often focused on system considerations, which is an important indicator for overall performance. The Company is also focused on the customer experience, and leveraging available technology allows reporting to achieve a better focus on that experience. These new metrics each serve to further highlight the customer reliability experience as a critical element of service excellence:

- **Momentary Average Interruption Frequency Index (MAIFI) –** Traditional reliability indicators, such as SAIFI, include only those outages above 5 minutes and do not account for very short duration, or momentary, outages. However, customers experience brief service interruptions during momentary outages and those may have noticeable impact. Thus, this proposal includes MAIFI as one opportunity to further highlight the customer reliability experience.
- **Enhanced granularity of SAIDI and SAIFI reporting –** DTEE's broad service territory is subject to diverse weather impacts, system conditions, voltages and other characteristics. While system-level reliability metrics remain a critical indicator for the Company, it is not always intuitive for customers to connect those figures to their own experience. SAIDI and SAIFI reported at the zip code level begins to facilitate those connections, while also ensuring that the Company continues its equity focus in maintaining and improving the reliability of the system for all customers. This approach is consistent with the principles outlined in Section 2.2 – Energy and Environmental Justice, which in part describes the

Michigan Environmental Justice Screen and Company's efforts to expand the availability and framing of reliability data.

Further defined in Section 7 – Distribution System Overview, of the Distribution Grid Plan, DTEE calculates the metrics as follows:

SAIDI	(∑ Customer interruption durations) / Total number of customers served
SAIFI	Total number of customer interruptions / Total number of customers served
CEMI - "n"	(∑ Customer experiencing "n" or more interruptions) / Total number of customers served
CELID - "x"	(∑ Customer experiencing interruptions longer than "x" hours) / Total number of customers served
MAIFI	Total number of momentary outages / Total number of customers served

Annual reporting will include the intent and methodology for each of the included metrics, and forecasted and actual performance of the metrics, and discussion of what is driving the performance outcomes of the metrics. It may additionally highlight investment themes that could address some portion of the reported output metrics DTEE intends to provide in the report to Commission staff and share it on the DTEE website to make it accessible. The metrics within the report will be refreshed concurrent with subsequent Distribution planning cycles – while targets and forecasts for performance may update annually, the metrics themselves will not.

Incentive reliability metrics

Incentivized reliability metrics are often the first thing included in a discussion of PBR. In other contexts, they may be referred to as performance incentive metrics (PIMs) or targeted performance incentives (TPIs). The purpose of these mechanisms is to create a direct linkage between a Company's performance on a given metric and a corresponding financial reward or penalty. The underlying theory asserts that by associating financial impacts with performance, as opposed to the non-financial impacts of reduced customer satisfaction, utilities will be more proactive in reducing incidents of underperformance. Based on this definition, the Company is currently subject to incentive metrics through the outage credits provided to customers for long duration outages.

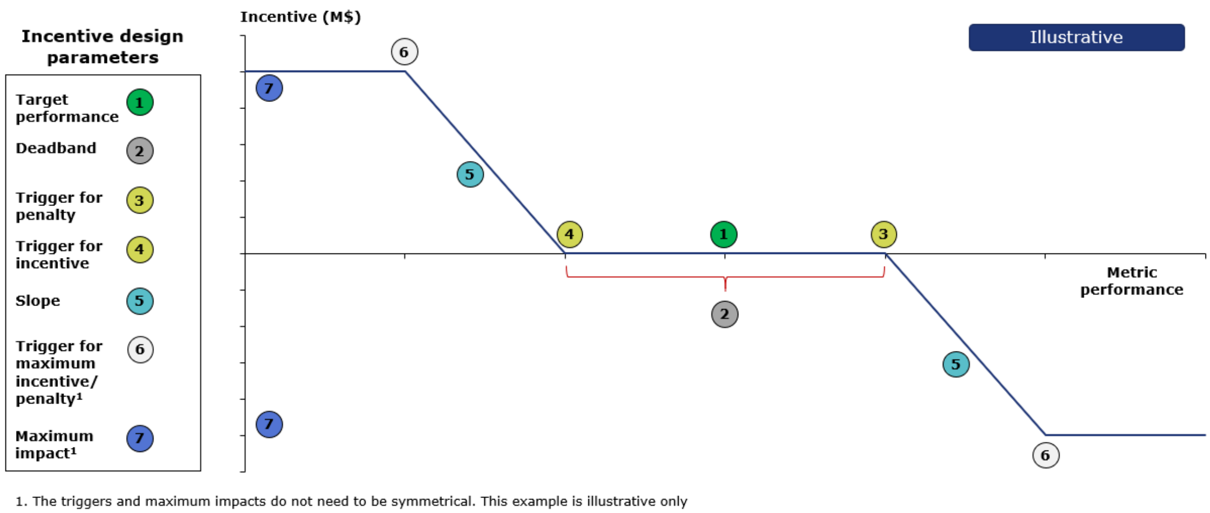
DTEE proposes to design new incentive structures for two reliability metrics: SAIDI excluding major event days (MEDs), and CEMI6.

- **SAIDI excluding MEDs –** SAIDI is representative of overall system performance and is a clear entry point for new reliability incentive metrics. There are two primary versions of SAIDI – all weather and excluding MEDs. While investments in distribution infrastructure should, over time, improve the performance of both, DTEE has significantly less control over all weather metrics on a year-to-year basis. The unpredictability of weather, and the associated volatility of all-weather SAIDI, suggests that removing the most severe weather impacts on the metric is prudent and focusing on SAIDI excluding MEDs. This construct best aligns the incentives with performance that is most directly under the Company's control. Major event days are defined in Section 7 – Distribution System Overview.
- **CEMI-6 –** CEMI is complimentary to SAIDI and takes a customer-focused view of reliability. The proposal reflects a focus on CEMI-6 because of both the importance of enhancing reliability for those customers and because six outages is a threshold that can be reasonably addressed and managed by the Company. Over time, as the Company is able to reduce the tail of CEMI customers (i.e., the proportion of customers experiencing repetitive outages), it may make sense to tension either the performance of CEMI-6 or the observed metric (e.g., an evolution to CEMI-5).

Incentive design

The design of the incentive structure should accomplish two objectives. First, it should appropriately account for volatility in the metric, understanding that the Company does not have full control over metric outcomes in a given year. And second, both the target and the point at which a penalty is applied should reflect enough tension to drive improved performance while still being achievable. The key elements of the incentive design are described in Exhibit 15.3.2 below, which represents an example of symmetric design. However, as discussed in the descriptions of specific incentive design elements below, the incentive need not be symmetrical. Depending on the specific metric, existing incentive structures, or other factors, the incentive may be designed in an asymmetric fashion. Incentive design proposals specific to CEMI-6 will be designed in conjunction with a resolution to the Commission's ongoing discussions of outage credit valuation and methodology.

Exhibit 15.3.2 Illustrative Incentive Design



- **Target performance –** This is the intended outcome in a given year for a given metric. The targets for the proposed incentive metrics are defined by the projected system improvements as shown in Section 6.3.

- **Deadband –** Deadbands are used in incentive design as an acknowledgement that neither forecasts nor Company control of metric outcomes are perfect. The deadband allows for performance within a pre-defined range above or below the target and which generates neither a penalty nor a reward. Given their role managing volatility, DTEE proposes that the deadband for SAIDI excluding MED be based on one standard deviation of historical performance, as represented in minutes. This band is initially set at +/- 21 minutes. The historical information used to determine the deadband can be found in Section 7 – Distribution System Overview.

- **Trigger for penalty or incentive –** These are the points at which penalties or incentives begin to accrue, and which are defined by the edges of the deadband. Thus, the trigger for a penalty or incentive to begin accruing is +/- 21 minutes of target performance.

- **Slope –** The slope describes the rate at which a penalty or incentive accrue, up to the maximum impact. DTEE proposes a linear slope, beginning at one standard deviation and concluding at two standard deviations. With this slope, penalties or incentives would accrue between one standard deviation and two standard deviations at a constant rate. Reflected in minutes, the slope is linear between 21 minutes and 42 minutes.
- **Maximum incentive –** This is the total dollars available for an incentive for a given metric.
- **Maximum penalty –** This is the total dollars at risk for a given metric.

Over time, as incentive metrics such as these become more familiar and understood, tension can be added either through changes to the targets, reducing the deadbands or modifying the slopes to achieve the desired structure. The proposed deadbands and maximums are intended to remain in place through the next Distribution Grid Plan, therefore the +/- 21-minute deadband will not be recalculated annually and will be updated in the next Plan filing.

Incentive timing and accounting

The metrics proposed for incentives would be measured on a calendar year basis. It is a defined, well understood boundary for measuring performance, however, it may be misaligned with general rate case timing. Therefore, DTEE proposes to describe any incentives or penalties applied from the year prior in its annual PBR report and reflect them as regulatory assets (for incentives) or regulatory liabilities (for penalties) as of March 1, and carry them until the next opportunity to reflect the impacts in rates. 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 maximum amounts, as well as the accounting treatment, would be addressed through a specific proposal by DTEE in a contested case prior to implementation.

Capital tracking mechanism

Performance-based regulation, as noted in the introduction, is intended to more closely link operational performance with financial performance. There are diverse drivers of operational performance discussed in the preceding sections of the distribution grid plan. The investments reflected in this plan support continued achievement of reliability targets and system improvements. However, it also reflects a point-in-time view of system conditions, load growth and locational impacts that might be forecasted over the planning period.

In the coming years, the ability for DTEE to deploy capital quickly and flexibly may become necessary as the adoption of distributed energy resources (DERs), such as electric vehicles and rooftop solar, become more widespread. The potentially substantial changes in how and when customers use energy could drive large changes in usage patterns and peak demands. This may require flexible and responsive investments in locations with high activity. For example, if electric vehicle uptake occurs more quickly than expected and is not uniformly distributed, it could create circuit-level load in excess of equipment capacities. The available interventions would be to improve the infrastructure to support and promote customer accessibility or manage load and potentially risk curtailing customer activity.

A capital tracking mechanism is one option for investment flexibility to be responsive to quickly evolving grid usage. DTEE is not proposing the near-term implementation of this mechanism, but the Company does highlight the role it could have going forward in a comprehensive PBR framework. A tracker would provide specific benefits to customers:

- Improved reliability and grid performance through targeted investments on circuits
- Ensure no reduction in overall grid performance while supporting customer access to new technologies
- Support investments that can be measured and reporting in a systematic and transparent way

A future capital tracking mechanism could be designed as a two-way tracker with an upper limit of spend. It would have a target spending level for urgent and targeted circuit improvements, a reconciliation for underspend (a refund to customers) or incremental spend (additional recovery) and a limit on allowable incremental spend. There would be no minimum spending requirement. DTEE may propose a similar mechanism to the one described here at such time it becomes prudent for the operational integrity of the distribution system and the ability to seamlessly integrate customer adoption of DERs.

Alternative regulatory mechanisms

Beyond traditional COSR and a reliability focused PBR plan are alternative regulatory mechanisms which, in tandem with COSR and other metrics, can drive additional focus on: 1) policy goals, 2) customer engagement and accessibility, 3) cost management or other yet to be defined goals. They reflect a key component of a broad-based and holistic approach to performance regulation. The term "alternative regulatory mechanism" does not refer to a single tool, but a broad range of options available to achieve preferred outcomes. This section highlights three such mechanisms that could be utilized to generate specific outcomes in specific contexts, but highlights that the list here is not exhaustive. DTEE is not proposing a specific mechanism or approach in this document and is including the overview here to generate discussion and engagement with the many stakeholders in Michigan.

Exhibit 15.3.3 Alternative Regulatory Mechanisms

Mechanism	Description
Incentives for exceeding policy driven targets	Policy-related incentives provide additional earnings opportunities for achieving or exceeding specific adoption targets, thresholds, or other measures of performance. These incentives are structured as "one-way," without penalty risk
Rate-basing of assets or payments to customer	Provides an opportunity to capitalize contracts with customers for certain grid services and which may cost effectively displace capital investment
Earnings mechanism for targeted O&M spend	Provides an opportunity to earn on O&M spend that may displace capital investments. Any resulting cost savings could reduce upward rate pressure

Future areas of opportunity

This proposal is oriented toward reliability metrics and the distribution system based on the venue of the filing and the robust discussions in Michigan around reliability and distribution. Improvements in the electric distribution system are also essential to supporting a more dynamic, and clean electric system with increased customer engagement. Going forward, there may be additional areas that support an exploration of PBR structures and opportunities. These could include customer engagement, long-term planning, environmental considerations, or expanded areas of distribution reliability. The Company looks forward to these discussions at the appropriate time and in the appropriate venue.

16 Enablers

16.1 Distribution design standards

DTEE develops and maintains a comprehensive set of distribution design standards (DDS) that promote uniform construction practices and provide the foundation to design, build and maintain a safe, resilient electric infrastructure. These standards comply with National Electric Safety Code (NESC) and have evolved to incorporate industry best practices gained from DTEE's involvement in the Edison Electric Institute (EEI), Electric Power Research Institute (EPRI), Institute of Electrical and Electronics Engineers (IEEE), National Electric Energy Testing, Research & Applications Center (NEETRAC) and benchmarking with peer utilities.

DDS is the "single source of knowledge," that consist of detailed specifications which contribute to the resiliency of the electric infrastructure.

Additionally, the DDS consist of specific distribution design orders (DDOs), which contain detail design orders to guide DTEE engineers when planning and designing the electric system. These orders allow for maintaining system design consistency throughout DTEE's service territory. Furthermore, the DDOs specify the equipment to be used and contain methods and procedures which determine how the distribution system is designed and modified. There are also Job Aids to supplement the DDOs. The job aids contain step-by-step instructions and any additional information useful for the planners or engineers.

At times, the planning engineer may encounter extenuating circumstances where implementation of the DDS or DDOs may be impossible, impractical or result in excessive cost. In these cases, the planning engineer may develop an alternate approach. This exception to the DDS or DDOs must be presented to a technical peer group for discussion and review. The peer group then makes the decision to accept or deny the exception prior implementation. Exceptions are tracked as a basis for potential future modifications to the DDS and DDOs.

To ensures DDS and DDOs are compliant and up to date with code requirements, DTEE established the Five-year Cycle Review process in 2018. The Five-year Cycle Review process calls for the DDS and DDOs to be reviewed and updated every five years as NESC (National Electric Safety Code) requirements are updated. Additionally, DDS and DDOs are updated based on new equipment or technologies, as dictated by developments in the industry, or based on asset and system performance/field experience. Updating DDS and DDOs is a cross-functional effort and collaboration with Engineering and other DO groups is essential in the development and successful implementation of these standards. Over the years, the Company has enhanced the minimum standards for construction to further harden the system and better sustain impacts from inclement weather and tree interference. These improved design standards, grade B construction, are based on NESC (National Electric Safety Code) factors and industry best practices.

The structural upgrades include using armless construction or fiberglass crossarms, larger conductors, polymer insulators that are four times stronger than pin insulators, and standard poles that are one and a half times stronger, as illustrated in Exhibit 16.1.1. These structural upgrades are intended to standardize overhead construction materials and specifications to significantly streamline the design and construction of overhead facilities, and to increase the structural strength to improve system reliability and storm resiliency.

In addition to hardening, DTEE continues to develop standards that will support our vision of grid modernization. DTEE is developing 69kV standards for the subtransmission system in replacement of 40kV standards. Although the system will remain energized at 40kV in the near term, 69kV standards development allows for the rebuilding of the existing 40kV system to 69kV standards. This new standard construction will enable the grid to have the capability to be energized at 69kV, if that level of capacity is needed to accommodate growth in the future.

The implementation of wood pole alternatives is another example of DTEEs effort to further harden the electric infrastructure and commit to system resiliency. Wood pole alternatives are a good option when evaluating ways to strengthen parts of the distribution and subtransmission system and make it more tolerant to catastrophic events. Wood poles can lose strength overtime due to deterioration of organic material. Wood pole alternatives, such as steel, concrete and composite poles, are engineered to retain their strength overtime if installed and manufactured properly. DTEE continues to evaluate these poles and evaluate their use case where it makes sense. As one example, steel poles have been standardized for all truck accessible locations for substransmission rebuilds.

Furthermore, updated circuit designs improve circuit configuration and allow crews to more quickly restore customers during outage events. Examples of updated design standards include ensuring valid jumpering points on circuits with properly sized operating equipment, installing fault indicators to reduce outage patrol time and installing loop schemes for automatic restoration of sections of circuits during an outage, as illustrated in Exhibit 16.1.2.

The topics covered by the DDS and DDO are summarized in Appendix VI.

Exhibit 16.1.1 DDO Structural Upgrades to Distribution Circuits

(stronger poles, stronger conductors, and polymer insulators)

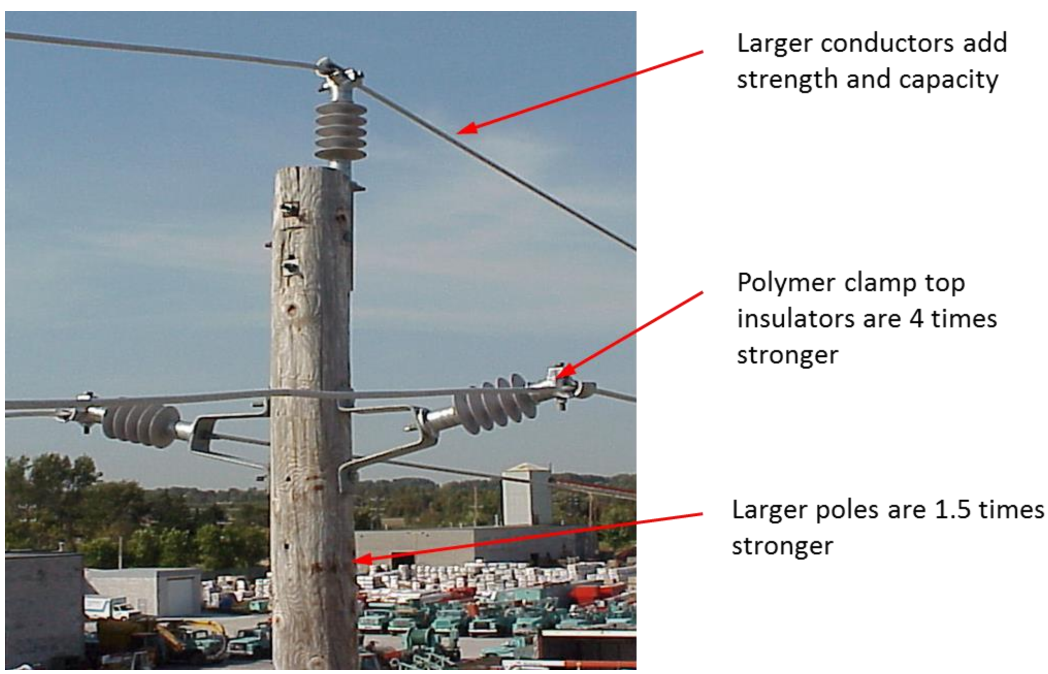
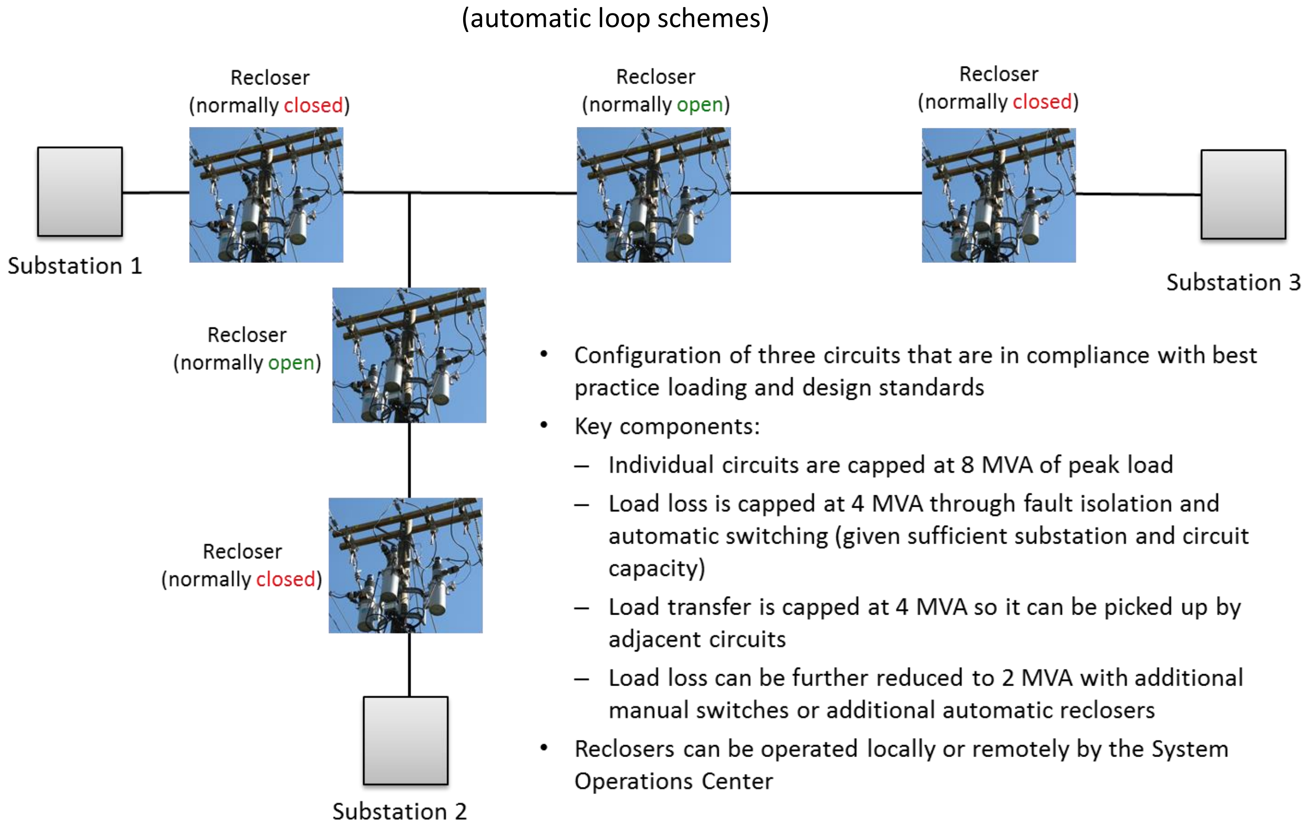


Exhibit 16.1.2 13.2 kV DDO Restore-before-repair Design



The use of the DDS/DDO framework is vital to ensuring that as work is designed and complete in the field it is consistent with the long-term plans for the distribution system. Examples of this include the use of standard conductor sizes for primary and secondary conductors, circuit load limits, and automation standards to new investments are consistent with grid moderation efforts to allow for increasing electrification, adoption of DERs, automatic restoration, and better system visibility. Standards enforcing the use of 15kV equipment and grade B construction standards also support long term effort to reduce the cost of future conversion from 4.8kV to 15kV and other traditional infrastructure improvements. The DDS/DDO framework is useful in both helping to understand how to integrate future technologies such as distributed resource interconnection, electrification, and automation within the existing system as well being able to understand what standards changes might help better facilitate future developments.

16.2 Workforce and resource planning

Workforce and resource planning is a key factor for the successful implementation of the investment plan and grid modernization strategy outlined in this filing.

Workforce planning process

As DTEE is planning for the increase in investment that will rebuild and modernize the distribution grid, an essential element of success will be to plan for the workforce of the future. The Company is at the beginning of a process to determine the needed workforce, the specific skill sets, and the timing for successful implementation of the five-year investment plan as well as the long-term vision.

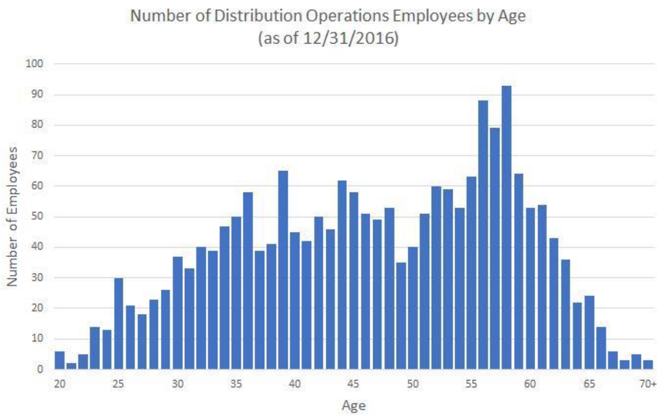
The overall objective for DTEE is to build a detailed workforce model that will support operational decisions to successfully identify workforce needs based on planned work, criticality of role, and skillset needed to effectively execute the plan. The workforce needed for planned work must be coordinated with expected emergent work that results for storm restoration, day-to-day outage and non-outage events, customer requests for connections, relocation requests and others. Exhibit 16.2.1 illustrates the Company's overall workforce planning process, which was also described in the Distribution Operations Five-year (2018 to 2022) Investment and Maintenance Plan Final Report.

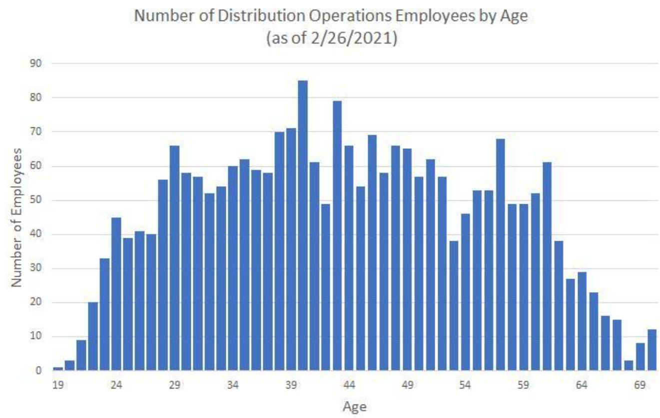
Exhibit 16.2.1: Workforce Planning Process

Realized improvements

The Company has leveraged this process over the last few years to address several workforce related risks to the execution of its plans. One of the most concerning aspects in 2018 was expected retirements. Exhibit 16.2.2 shows that the established workforce process has reduced this risk by shifting the workforce makeup to be less skewed toward near-term retirements.

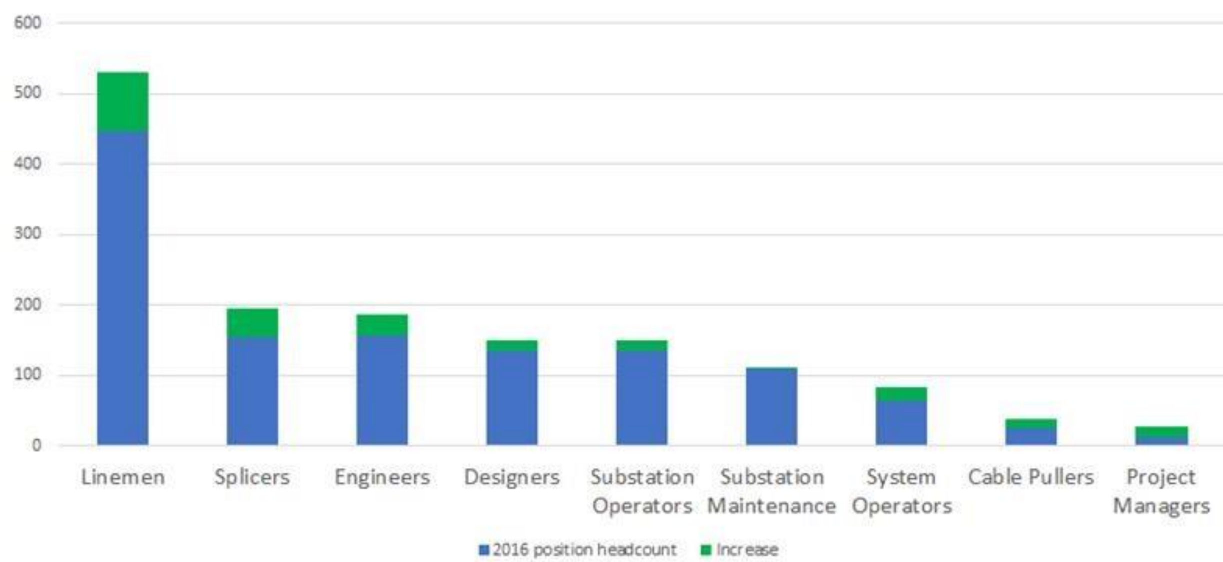
Exhibit 16.2.2: Reduced Retirement Risk





Another area of improvement has been adding workforce to key job classifications that are critical to execute the plans described. Exhibit 16.2.3 shows the increases to key positions.

Exhibit 16.2.3: Additions to Key Positions to Implement the DGP



Planned improvement

Building upon these improvements, the Company is continuing to enhance its processes and tools for workforce planning. Further integration of processes that consider different positions is one aspect of continuous improvement. Since the plan involves several different work groups, there will be benefits from a more defined, coordinated process and model. DTEE is leveraging benchmarking data and best practices to develop a capital organization structure that will integrate with DTEE's internal systems to provide full costs, labor and unit information inputs to advance financial modeling capabilities. The results of the integrated planning workstreams will increase collaboration within the decision-making process to recommend the best approach for meeting resource needs. Another component of workforce planning will include strategies to retire our power plants with pride, which provides opportunities for employees to transition to other roles at the Company. A transition team has conducted initial focus groups to report findings and recommendations to identify needs to support our future workforce. DTEE will focus on providing tools, communication and aligning skillset with career or training opportunities to plan for this aspect of workforce transformation.

An additional aspect of workforce planning improvement is the development of a skilled resource pool. Section 10.7 describes what the Company has done to develop a local tree trimming workforce pool. In addition to that, the Company has increased the number of linemen apprentices and cable splicer apprentices. DTEE has developed relationship with local universities to expand the number of engineers and data scientists with an interest in power systems work. DTEE is also developing role-based training to provide engineers and data scientists with the skills necessary to be successful.

Increasing workforce demands

Despite the robust workforce process and the improvements it is bringing to the Company's personnel makeup, the level of work described in this document will present a challenge for the Company to address. Ramping up investments in overhead line work and system cable replacement, for example, will increase the demand for highly skilled positions. The training timeframe to develop these resources tests the ability to ramp-up quickly. DTEE maintains partnerships with the unions to develop this workforce, which can be seen by the increase in apprentices in these areas over the last few years (65% increase in linemen apprentices and 48% in splicer apprentices since 2016). Other areas, such as engineering, design, construction and project management, will also present a challenge for the Company, and the Company is increasing hiring in these areas as well.

In addition to the hiring and training of direct employees, the Company has developed partnerships with engineering, design, project management and construction firms that have successfully helped other utilities build their capacity. For example, the cable replacement programs described in this document will require significant increases available staff. The Company has conducted benchmarking with other utilities that have been involved in significant cable replacement efforts to learn best practices. An electric utility in a very large Midwest city averaged over 700,000 feet of system cable replacement per year between 2013 and 2017 and peaked at nearly 1,000,000 feet in a single year. DTEE is partnering with the same service providers that helped that utility build its capacity.

Material & equipment resource planning

The increased investment to rebuild and modernize the distribution grid will drive the need to consider and plan procurement of additional levels of materials and equipment and understand and mitigate associated risks.

Procurement processes

DTEE Supply Chain proactively anticipates and mitigates both cost and material availability issues through the following processes:

- Forecasting material and equipment demand and securing supply or shop time early;
- Holding weekly meetings with our top suppliers (including material integrators) to stay ahead of any market fluctuations;
- Monitoring the market and increasing stock inventories when market tightening is observed;
- Building long-term relationships with our key suppliers to get preferred customer status;
- Putting our eyes and ears on key suppliers and sub-suppliers via site visits to validate availability of critical materials; and
- Evaluating current contract structures to quantify market inflation.

DTEE Supply Chain monitors material requirements for critical inventory continuously and adjusts for changes in market conditions.

Procurement risks

DTEE Supply Chain works with its integrator to continuously monitor and minimize risk of both key materials as well as long lead equipment. Our close collaboration with our integrator helps us minimize our risk for key materials. We monitor risk throughout the supply chain including raw materials, manufacturer capacity, and distribution supplies. Mitigation strategies can include some of the following examples:

- Buying additional inventory where possible
- Sourcing additional capacity at current/alternative suppliers
- Securing production space in advance
- Securing contracts on future raw material commitments

DTEE Supply Chain also works with our integrator to survey the industry and identify trends in pricing and lead times for key items such as transformers, switchgear, poles, underground cable and meters. We leverage our supplier relationships to mitigate price and lead time uncertainty. Below is an example of some of the risk exposure and mitigation plans put in place.

Workforce & resource planning conclusion

With the capital investments outlined in this distribution grid plan, the workforce and resource planning processes will optimize constrained resources to successfully execute the plan. The process that the Company has established is already showing a positive impact on the workforce and the Company is continuing to improve its workforce plans. DTEE is confident that the process can provide the needed workforce to implement that plan, and the Company is already reviewing current headcount, determining resource gaps, assessing the criticality of positions and preparing estimates of future resource needs for the plan described in this document. DTEE Supply Chain has developed processes to forecast and monitor the increased material and equipment inventory. The Company is already working with integrators and key suppliers to identify risks of inflation and lead times and develop risk mitigation plans where necessary to ensure availability.

16.3 Cybersecurity

The importance of maintaining cybersecurity in electric utilities has long been recognized as reflected in the industry's NERC-CIP (National Electric Reliability Corporation – Critical Infrastructure Protection) standards. The increasing intelligence and interconnected nature of the electric distribution system will continue to add to the importance of cybersecurity. Cyber-attacks targeting the electric grid are becoming more numerous and aggressive. The increasing threat, paired with the increasing deployment of interconnected intelligent devices, is leading to an increased focus on securing distribution assets. At DTEE, the focus of the next five years will be to ensure that as distribution assets increasing become cyber assets the necessary policies, standards, and protections are in place to ensure the safe, reliable operation of the electrical distribution grid.

Securing the distribution system from cyber-attacks requires a defense in depth approach to protect against internal and external and as well as amateur and sophisticated attackers. This requires enhancing the cyber security and physical security capabilities. Adding these defenses requires updating existing design standards to ensure that newly constructed sites have adequate protection as well as identifying and addressing latent vulnerabilities in the existing system. This defense will continue to evolve as the threats change and the industry progresses and learns from new events.

Increasing physical defense of cyber assets includes improving fencing, layered protection of network connected devices with multiple locked barriers, and increased access restrictions on exposed devices. Limiting electronic access includes allowing only the necessary network traffic, limiting group or individual access through password protection on intelligent devices, restricting electronic and physical access from unapproved computing devices (such as laptops) and portable media, standardized device hardening processes to ensure consistent protection across the system increasing the ability to detect and respond to cyber-attacks, performing anti-virus scanning, sound patching and firmware management procedures, scanning of network connected devices for vulnerabilities and detecting unauthorized accesses or changes to configuration and settings files. The steps are being included in the updates of engineering and design standards, and will be piloted in 2021 and 2022 to facilitate potential future retrofitting options for 2023 and beyond. The initial focus will be on developing the process and infrastructure to support these programs in the future and the preliminary estimate will require $1-2M to initiate the program and will expand based on pilot results.

The initial efforts will focus on securing sites that DTEE considers high impact beyond those that meet the more restrictive NERC high impact definitions. These will include sub transmission stations and other high capacity, or critical load facilities. In addition, priority will be given to distribution substations that have significant connectivity and intelligent electronic devices already deployed. Future efforts will expand to distribution system devices including overhead and underground components with SCADA access.

Additional concerns will be reviewed and assessed over the next five years to address the growing importance of distributed energy resources and methods will be developed to ensure the cyber protection between new devices, the electric grid and other necessary parties.

16.4 Physical security

The DTEE Distribution Site Security program is a multi-year effort designed to reduce the risk associated with intentional and unintentional security events that could affect DTEE Distribution infrastructure, affecting the Company's ability to distribute energy to its customers. Substations have been targeted internationally and within the US, requiring improved security measures. The Site Security program has two components that are tightly integrated 1) Implementation of baseline security and 2) Security Risk Assessment (SRA) process which focuses on site specific vulnerabilities and threats.

Baseline security standards

An enterprise-wide Security Assessment model is used to prioritize sites. It uses multiple attributes to rank distribution sites as either high, moderate or low criticality to our operations. The assessment also determines the application of baseline security standards (Standards) commensurate with the ranking.

DTE security teams and distribution personnel conducted initial site walk-downs in 2018/19 to identify security gaps. Security measures are currently being implemented to address the gaps identified and to bring the security levels at each site in line with the standards. Additionally, a sustainability program is being developed to maintain these security measures.

SRA

Critical/high risk facilities are further assessed for site-specific risk through the SRA process which involves an in-depth analysis of specific attack paths, likely targets, potential threat actors (design basis threats), and impacts of successful attacks. Security countermeasures are recommended to reduce the likelihood of a successful attack taking place and implementation is prioritized by risk. SRAs will be conducted on a periodic basis, not to exceed five years, within 12 months after completion of a significant enhancement or modification to the facility, within 12 months of a newly identified critical facility, or newly constructed facility identified as critical.

Scope:

The scope of security work that is in progress includes: installation of new fence, upgrade of existing fences, automation and/or other upgrades of main gates, brushing/removal of trees along fence lines, lighting upgrades, installation of cameras for intrusion detection and alarming, critical area access control through badging system installation and new doors with automatic locking systems. Additional target hardening measures are applied that are site specific as identified during the SRA. DTE has also begun assessing cyber security gaps at these sites and the measures required to address these gaps. This can be reviewed in Section 16.3 – Cybersecurity, of the Distribution Grid Plan.

Future state solutions under consideration include the implementation of a preventative maintenance program for security equipment to ensure longevity and reliability, and the application of controls as needed to further protect distribution infrastructure in accordance with the Company's Insider Risk program. The Insider Risk program is designed with the intent of deterring employees from becoming insider threats, detecting those who pose a risk, and mitigating the risks through response protocols.

17 Key next steps

Throughout this Distribution Grid Plan, DTEE has outlined a comprehensive five-year plan and 15-year vision which: 1) assesses the current state of the electric system, 2) defines the desired future state of the electric system, and 3) describes key initiatives to move from the current to future state. Executed successfully, this strategy will deliver on key objectives of a safe, reliable, resilient, affordable, accessible, and clean power system for the customers and communities that DTEE serves. Listed below are some initiatives and steps that we will take in the next couple of years to continue to prepare for the grid of the future:

Forecasting

DTEE's integrated forecasting solution is a project made up of experts from Corporate Forecasting and Distribution Operations, Corporate Strategy and other support teams from across the organization. As a first step, the project team produced an integrated forecast modeling framework that can be leveraged for both generation resource and distribution planning.

This forecast development process has three distinct elements, with the first step being completed in Q2 2021. The initial project step involved finalizing the organization-wide baseline forecast. While many of the data inputs are the same, modeling outputs for distribution planning requires more granularized forecasts relative to generation resource planning. For instance, when considering Electric Vehicles (EVs) in the respective planning processes, resource planners can make effective use of a model detailing the total number of EVs and corresponding load on the system. However, for distribution planners it is crucial to also estimate the charging patterns and location of EVs on substations and circuits across the system.

Next, the team is currently focused on developing the work process for creating substation and circuit-level 8760 forecasts. Modeling of the substation and circuits will require the use of AMI data, modeling weather response functions at the circuit and substation level and incorporating changes due to the adoption of new technologies (EV, PV, Battery, EWR, etc.) A key element of this work will involve creating forecasted adoption rates by technology at the zip code/circuit level and defining a formal process for the development and prioritization of sensitivity analysis. This work is currently ongoing with a distribution forecast Proof of Concept model for Walnut and Sunset substations to be completed by Q4 2021.

In the final phase of the project, the Proof-of-Concept work will inform next steps in which the output of the circuit-level forecasts will be reconciled to the overall system-level forecast. DTEE expects to refine the modeling output over multiple iterations before publishing the forecasts. One of the primary reasons for this is the availability of AMI/SCADA data across all circuits and substations. While modeling is an effective tool in estimation, validation with actual data will take some time.

Upon completion of the model validation work, the project will integrate 8760 hours per year modeling into distribution planning processes. Currently, the distribution planning process is largely based on peak load planning. The availability of 8760 forecast will allow DTEE to plan the distribution system by optimizing the distributed generation, storage and loads. Moving to hourly forecast instead of annual peak will be a fundamental shift in distribution planning and will require changes to most of the planning criteria and processes.

Develop accelerated conversion plan

The scenarios developed through the grid modernization process, specifically the electrification and distributed generation scenarios, identified the potential need to convert the 4.8kV system to a higher voltage at an accelerated pace. One of the next steps is to develop the tools and processes necessary to create and execute a plan for conversion beyond the projects identified in the DGP. The development of these tools and processes began in Q2 2021 and is expected to be fully integrated into distribution planning by Q4 2023. The project will be completed in two phases: the first phase will be complete by the end of 2021 and will define the parameters for developing a long-term conversion plan. During this phase, the project team will design and run several cross-functional workshops with key internal subject matter experts to outline key design elements that will impact the total cost of the conversions, including assumptions on customers per transformer, sectionalizing, looping circuits and voltages. Additionally, this first phase will include the development of the conversion tool. The tool is expected to outline the total estimated cost, resources and timeline of undertaking a conversion (circuit and substation) of the entire 4.8kV system.

The second phase of the project is still being refined in terms of key activities and timing. However, it is expected that this phase will result in the prioritization of circuits/substations for conversion in the five- to 15-year timeframe, more detailed estimates of costs for the specific projects that will be pursued, and benchmarking peer utilities' most recent conversion efforts. It should also be noted that developing a full conversion plan for the 4.8kV system will be an iterative process that will need to be updated periodically, especially as the signposts identified during the scenario planning processes materialize. For example, as the pace and locational impacts of the adoption of electrification and distributed generation resources become more certain, the areas of the grid where the 4.8kV system can no longer meet customer needs may become more apparent and will need to be prioritized accordingly.

Higher distribution voltage

In the near future, the Company will continue to evaluate the introduction of a higher distribution voltage onto its system. Internal discussions have begun on the potential to develop a new 34.5kV voltage class along with continued research and benchmarking. By Q2 2022, an implementation plan will be created by a cross functional team of stakeholders within the Company. Next, through data analysis and stakeholder input an ideal candidate profile for a pilot will be defined. Pilot candidates will be narrowed down by Q4 2022 through internal stakeholder interactions and by cross-referencing investment plan to maintain capital efficiency. With a pilot candidate identified, engineering will begin for all components required for implementation. Engineering will include but is not limited to geographic location selection and site due diligence, operating procedures, circuit layouts, construction standard development, protection scheme development, and equipment selection and testing. This engineering phase of the project will last until Q1 2025. After the engineering phase completes, design and construction will begin sometime in 2025.

Secondary Loading and Electric Vehicle Monitoring

While electric vehicles will increase loading on all levels of the system, the effects of their adoption will first materialize on DTEE's customer facing assets such as URD (Underground Residential Distribution) loops and service transformers. To confidently integrate the grid impacts of EV (Electric Vehicles) growth, DTEE will require advanced analytics tools to increase its situational awareness of customer facing, “grid edge” distribution assets. To help achieve this DTEE is currently in the beginning phases of developing an AMI (Advanced Metering Infrastructure) based tool to assess loading on its service transformers. By the end of 2021, DTEE plans to have refined the project plan, scope, data needed, and business unit collaboration required for developing the AMI tool. From the beginning of 2022 until the end of Q1 2023, DTEE will develop the planning tool and ensure that it can determine the magnitude and location of existing transformer overloads and current EV locations. In the beginning of 2023, DTEE will verify that the tool works as intended and integrate the tool within the Distribution Operations (DO) organization. While this process is wrapping up in Q3 2023, the Company will also begin expanding the tool to assess the impacts of EV loading on more grid edge assets such as secondary and URD loops, as well as future overloads from increasing EV adoption.

In tandem with development of the secondary loading tool, the Company also plans to thoroughly assess what standards changes are required to accommodate the increasing penetration of electric vehicles within DTEE’s service territory. From the beginning of Q3 2022 until the end of Q3 2023, DTEE will determine current and probable DDO (Distribution Design Orders)/standards violations resulting from EV growth, and in turn develop and distribute the upgraded and new standards within the DO organization.

Additional efforts

In addition to developing new planning tools and long-term investment plans, DTEE will expand the current investment prioritization framework (GPM), to ensure that all planning objectives and customer needs are included in the evaluation and prioritization of investments. As discussed in Section 5 on benefit cost analysis, two of DTEE’s planning objectives, Clean and Customer Accessibility and Community Focus, do not have specific dimensions aligned to them in the current Global Prioritization Model. By the end of 2022, DTEE anticipates updating GPM to fully align with the five planning objectives. Part of this expansion of GPM dimensions will also incorporate a focus on equity and improving reliability for all customers. Changes to the GPM will include robust stakeholder discussion, starting with the planned MPSC workgroups on BCA in Q4 2021, to ensure transparency in how these additional factors are incorporated into the prioritization of the investment portfolio.

Advanced analytic capabilities derived from grid modernization efforts will support the Company’s PBR plan and goals which are aligned with the Distribution Grid Plan and the Commission’s

Distribution planning goals. DTEE will continue to work with stakeholders and the Commission to further enhance the PBR plan through formal and informal engagement. The Company will continue to enhance transparency by reporting and communicating performance annually through a new PBR report. DTEE's first PBR report will be filed by July 1, 2022 and will include the intent and methodology for each identified metric including the drivers behind the performance outcome. DTEE's proposed report will expand available reliability information and ensure that the Company continues its equity focus in maintaining and improving the reliability of the system for all customers. DTEE will continue to explore the role of capital mechanisms and alternative regulatory approaches to drive policy outcomes, cost-beneficial grid solutions, and expanded customer engagement and accessibility.

Successful development and execution of the grid modernization roadmap is reliant upon continued efforts around staffing of current and future positions within DTEE. While much progress has been made in this space, enhanced modeling of workforce needs will assist in identifying resource gaps to allow DTEE to proactively attract and retain a diverse and highly skilled workforce.

In summary

With changes in climate, customer needs and emerging technology, the electric grid of the future is a constantly evolving target. While this presents challenges, the strategies outlined in the DGP are designed to navigate the uncertainty with a combination of flexible and no-regrets investments in modernizing the electric grid. Just as prior efforts and current initiatives have laid the groundwork to redesign DTEE's electric system, the Company is confident that the grid modernization roadmap will establish the path to deliver an efficient electrical system to serve the evolving needs of customers well into the future.

18 Conclusion

DTE Electric is committed to providing the Michigan families and businesses we serve with energy that is safe, reliable, clean, affordable and accessible. This report has outlined the process we used to plan for grid modernization, the investments our Company will make over the next five years to improve and modernize our electric system to ensure we deliver the service and value they expect and deserve, as well as our vision for the future of the grid.

We would like to thank the Michigan Public Service commissioners and staff for their leadership and guidance in this effort. We also would like to thank the residential and business customers who participated in the focus groups that were an important part of our planning process (Section 2 – Stakeholder Engagement and input), our technical stakeholders who joined us in webinars and individual discussions, and our state, local and community partners who shared feedback through one-on-one conversations. Their input helped shape this plan, as well as our vision for the future, which is referenced throughout this document.

The electric industry is in the midst of fundamental change – in the way we generate and deliver energy, and the way our 2.2 million customers use that energy. Our customers are more dependent than ever on our service, not just to keep the lights on, but also to power an ever-growing array of technologies and services that are now essential to their lives and businesses. Demand for our services will continue to grow, driven by emerging innovations like electric vehicles, and customer interest in advances like private generation, storage and residential electrification.

This, and other factors are driving the need for continued, significant investment in DTEE's electric system. While demands for the electricity we provide are surging, portions of our grid – some more than 90 years old – are beyond life expectancy and are in dire need of replacement. Climate change and increasingly severe weather are presenting serious challenges to grid reliability, and the summer storms of 2021 are a good example of that. In addition, state of Michigan sustainability goals, DTEE's own sustainability goals and commitment to net-zero carbon emissions by 2050, and customer demand for cleaner energy have led our Company to increase investments in renewable energy and energy efficiency.

These are challenges – and opportunities. And in response, DTEE has accelerated investment in grid hardening and system upgrades. Since submitting our Distribution Operations Five-Year

Investment and Maintenance Plan to the MPSC in 2018, we've invested nearly $1 billion per year to upgrade aging infrastructure, enhance our tree-trimming program, and install leading-edge equipment to improve safety, and better detect, prevent and manage outages. We've built new substations and updated others to expand capacity and improve power quality and reliability. We also broke ground on a new state-of-the-art Electric System Operations Center that will significantly improve our ability to manage system disruptions and response time.

We know these improvements are working. In areas where our grid hardening work has been completed, reliability has improved by 50-70%. Projects that have made our infrastructure more resilient have reduced time and money spent on outages caused by equipment failure and storms. With continued investment and infrastructure upgrades, we'll be able to improve reliability for our customers by 60%, helping to bring DTEE's electric reliability to best-in-class standards.

While we're proud of the progress we have made, we know there is more we can and must do. We want all of our customers to have this level of service, and we believe our new Distribution Grid Plan will bring us closer to that goal.

Guided by the MPSC's goals and our own planning objectives, DTEE's plan calls for increasing spending on grid improvements from $1 billion to $1.5 billion a year by 2025, focused on four key areas: infrastructure resilience and hardening, infrastructure redesign, technology and automation, and tree trimming. The new plan builds on the strength of our 2018 strategy, but also takes into account plausible, future scenarios that DTEE developed with an outside consultant.

Clearly, there are challenges we have to overcome, but continued investment will help us meet our goals while meeting the demands of our customers. It has to be done thoughtfully, efficiently and over time to keep the energy we deliver affordable for our customers, communities, and especially those who are most vulnerable. It needs to address environmental concerns and climate change in a meaningful way. And, we agree with our customers who told us our investments must ensure fairness for all customers.

There's a great deal of work ahead, but we believe that offers us a tremendous opportunity to rebuild and modernize our distribution system to provide safe, reliable, clean energy that is affordable and accessible to all our customers.

Appendix I Distribution Plan Requirements

Category	Distribution Plan Requirement (MPSC Order text)	Order /Date Page	Incorporation into the DGP
General Requirements	The Commission reiterates its support for the four objectives (safety, reliability/resiliency, cost-effectiveness/affordability, and accessibility) outlined above to guide this next iteration of distribution planning. Although some stakeholders suggested replacing these objectives with the MI Power Grid focus on customer engagement, integrating emerging technologies, and optimizing grid performance and investment, the Commission finds that this is unnecessary and prefers to retain the existing distribution planning objectives.	U-20147 2020-08-20 (p38)	DTEE's planning objectives, described in the Executive Summary and Section 3 - Grid Modernization, are well aligned with the Commissions' objectives
	Commission agrees with the Staff and stakeholders that it is important to articulate the Commission's vision for the future of the grid, and specifically adopts Mr. De Martini's concept that the elements of distribution planning should all relate to a core objective of "customer needs" that binds everything together.	U-20147 2020-08-20 (p39)	DTEE's four planning objectives are well aligned with customer needs
	Staff's final report, p. 34. In its executive summary, the Staff also recommends that utilities include measurable goals and objectives as part of their long-term strategic vision and plan. Id., Executive Summary, p. vii.	U-20147 2020-08-20 (p22-23)	Measurable goals and system performance projections for SAIFI, SAIDI, and emergent cost reductions are including in Section 5
	Therefore, the Commission directs DTE Electric, Consumers, and I&M to continue to develop detailed distribution plans over a five-year period, but also include in the plan their vision and high-level investment strategies 10 and 15 years out. This approach is consistent with the planning horizons used in IRPs.	U-20147 2019-09-11 (p4)	The scenario-based planning approach looked at grid impacts with a 15-year planning horizon, as well as a summary of grid needs in the next 5 and 5-15 year timeframe.

	The Commission concurs with the ALJ that Soulardarity's concerns were substantially addressed in Case No. U-20162. However, the Commission also agrees with the ALJ that, in its next general rate case, DTE Electric shall provide a more detailed explanation of the factors and scoring process the company uses to prioritize the circuits to be hardened. In addition, DTE Page 111 U-20561 Electric shall provide a plan and timeline for system hardening and conversion in its next distribution investment and maintenance plan to be filed by June 30, 2021.	U-20561 2020-05-08 (p110)	Prioritization criteria and plans for Hardening and Conversion are discussed in detail in Sections 9.3 and 11.3-5 respectively
Dynamic System Load Forecasting	The Commission seeks to avoid prescribing specific methods or approaches in the next round of distribution plans but acknowledges that the Staff's recommended dynamic approach to load forecasting with scenario analysis could help better understand and accommodate uncertainty associated with DERs, PEV charging, and other factors. The Commission encourages continued discussion of forecasting methods to inform the next iteration of distribution plans	U-20147 2018-11-21 (p32)	Scenario analysis, including forecasts for DER and EV adoption, was fundamental to the Grid Modernization Process (Section 3)
	The Commission agrees with the Staff's recommendation for the utilities to consider EWR in their upcoming distribution plans due next year. The Commission finds it important to run sensitivities in load forecasts for distribution planning and to start modeling locational impacts from customer behavior (whether through plug-in electric vehicles, EWR, storage, solar DG, DR, etc.). The Commission recognizes that the purpose of distribution planning is not to design EWR programs or to conduct localized EWR/DR potential studies, but finds that a stronger linkage between EWR and DR efforts and distribution planning would facilitate the identification of potentially cost-effective NWAs that could defer to displace an expensive distribution upgrade. Indeed, in the 2019 SEA, Recommendation E-5 states that a framework should be developed "to evaluate non-wires alternatives such as targeted energy waste reduction and demand response in IRPs and distribution plans." 2019 SEA, p. 196. As such, the	U-20147 2020-08-20 (p49-50)	Section 4.2 provides a clear explanation of the updates to forecasting methodologies that will take place in the near term, and coordinate with other resource planning efforts, including EWR and DR

	Commission is already on record recommending exactly the type of targeted demand-side programs supported by the joint commenters, ACEEE, and the Staff. Moreover, the Commission agrees with joint commenters, ACEEE, and the Staff that geotargeting demand-side programs to impact distribution-level system needs is consistent with the statutory framework for delivering EWR and DR. The system-wide EWR requirements contained in statute, as well as the EWR and DR commitments approved as part of utility IRPs, represent a baseline for demand-side resources. However, as the joint commenters and ACEEE point out, demand-side investments may provide additional and situation-specific cost savings and other benefits for customers in specific distribution system contexts. While these situation specific applications can certainly be included as part of utility compliance strategies with statutory mandates and IRP commitments, the fulfillment of those other obligations does not relieve utilities from considering–and ultimately implementing–demand-side options where doing so results in cost savings or other quantifiable benefits.		
	The Commission should require a dynamic approach to load forecasting for the purpose of distribution planning which considers multiple scenarios and probabilistic planning to properly accommodate uncertainty around distributed energy resource penetrations.; The Commission emphasizes the importance of accurate forecasting in planning and investment decisions and the need to ensure best practices in forecasting methods as technologies and customer behavior evolve with the adoption of DERs and PEV charging, which may include scenario-based forecasting to account for uncertainties and identify least regret solutions. Whether it is at the bulk transmission system or the individual distribution circuit level, the Commission believes prudent planning and investments will require more sophisticated forecasting approaches to develop best practices and mitigate risks. The Commission seeks to	U-20147 2018-11-21 (p4,32)	

	avoid prescribing specific methods or approaches in the next round of distribution plans but acknowledges that the Staff's recommended dynamic approach to load forecasting with scenario analysis could help better understand and accommodate uncertainty associated with DERs, PEV charging, and other factors. The Commission encourages continued discussion of forecasting methods to inform the next iteration of distribution plans		
Hosting Capacity Analysis	The Staff specifically recommends the following be adopted by utilities for HCA pilots under this framework: Adopt streamlined interconnection of DER and improved utility distribution mapping capabilities as the use-case for HCA	U-20147 2020-08-20 (p15)	Section 4.5 provides a status update on the Hosting Capacity analysis, including both the zonal go/no-go analysis and more specific analysis. Noting that the HCA pilots have not yet been completed. Section 4.4 covers the interconnection process, with additional capabilities to streamline interconnection of DER provided in Section 12.9
	Adopt a phased implementation approach for HCA pilots to allow utilities to focus on providing cost-effectively obtained, basic system-level information and at the same time highlighting areas of their system that cannot safely accommodate an increase in DER penetration by doing the following: - Perform base-level approach with a zonal go/no-go map. - Conduct specific, detailed analyses on areas of the distribution system with high DER penetration and incorporate this information into a more detailed map with feeder voltage level information as DER penetration continues to increase - Examine HCA best practices and methods for cost reduction, as demonstrated by other jurisdictions nationally. - Benchmark projected and actual HCA pilot costs against HCA costs nationally - HCA information should be publicly available with a downloadable map and spreadsheet.	U-20147 2020-08-20 (p15)	
	The Staff specifically recommends the following be adopted by utilities for HCA pilots under this framework. The recommended HCA activities should be accomplished within the next two years, while resulting information is made available publicly throughout the two year period. A detailed	U-20147 2020-08-20 (p14-15, 41)	

	status update should be provided in the electric distribution plans filed in 2021		
Non wires alternatives	The Commission agrees with the Staff that recommendations stemming from the MI Power Grid Energy Programs and Technology Pilots workgroup should inform the pilots proposed in the utility distribution plans. The Commission further notes that the Staff's draft report on Energy Programs and Technology Pilots was circulated to stakeholders on July 31, 2020, and the final report is scheduled to be filed on September 30, 2020. The Commission will provide additional guidance on structuring of pilots included in utility distribution plans following the filing of the Staff's final report on this issue, and encourages utilities to begin considering how to apply the recommendations from that stakeholder process as they begin to develop and refine the pilots to be included in their distribution plans next year	U-20147 2020-08-20 (p48)	The NWA pilots developed in Section 12.7 are being designed with the MI Power Grid pilots requirements in mind. Initial responses to the questions are found in Appendix V, with further refinement needed as the projects are developed
	Indeed, in the 2019 SEA, Recommendation E-5 states that a framework should be developed "to evaluate non-wires alternatives such as targeted energy waste reduction and demand response in IRPs and distribution plans." 2019 SEA, p. 196. As such, the Commission is already on record recommending exactly the type of targeted demand-side programs supported by the joint commenters, ACEEE, and the Staff.	U-20147 2020-08-20 (p49-50)	The NWA screening process is discussed in Section 4.3, including development of an analytical tool to evaluate the ability of targeted EWR and DR to solve distribution needs
	In the distribution plans to be filed in 2021, the Commission expects further progress on articulation of decision criteria used by utilities to screen projects for NWA analysis, as well as additional pilots that could be considered.	U-20147 2020-08-20 (p42)	
	Regarding the distribution plans to be filed in 2021, the Commission agrees that, in the short-term, NWA projects should focus on capacity and substation projects. As the Staff and interested parties work to integrate NWAs into the utility planning process, limiting the number of capacity and	U-20147 2020-08-20 (p42-43)	A suite a pilots is included in Section 12.7 that incorporate a wide range of technologies beyond EWR/DR

	substation projects considered for NWAs, as well as the scope of the eventual NWA pilots, in the next round of distribution plans is prudent. With this in mind, as noted in the May 8 order, p. 112, the Commission expects to be presented with “a robust suite of NWAs that may be evaluated for prudency as possible programs.” Longer term, the Commission looks forward to continuing to refine the criteria under which NWAs would be considered, drawing on the experience of other jurisdictions from around the country, and directs the Staff to continue to work with utilities and other stakeholders in developing this criteria.		
	• As a threshold matter, the Commission notes the Staff’s endorsement of a series of questions that should be addressed by utilities “prior to refining and implementing additional NWA pilots.” Staff’s final report, p. 28 (footnote omitted). These questions, taken from Mr. De Martini’s recommendations as well as the Staff’s addition, focus on a “customer-centric approach to NWA” and include the following: • Why are non-wires alternatives being pursued? o What are the pressing issues? • What are the desired outcomes? o Optimize utility distribution expenditures? o Enable greater value for customer/developer DER investments? o Enable greater adoption of DER to meet renewable/customer choice goals? • What are the range of potential solutions? o Pricing, programs and procurements (3P’s)? • What is the role of customers, DER developers, utilities, aggregators[,] and others? • Are the benefits and costs of NWAs accruing to all customers on an equitable basis?	U-20147 2020-08-20 (p44)	Staff and Mr. De Martini's questions are addressed in Section 4.3
	The Commission specifically directs the utilities mentioned above to include in their draft plan responses to the questions	U-20147	

	posed by Mr. De Martini and the Staff, and invites comment from the Staff and stakeholders on these issues as well. While the Commission will not be approving the distribution plans, it continues to emphasize the role a robust consideration of alternatives will play in the consideration of alternatives–including NWAs–in specific proposed investments included in future rate cases.	2020-08-20 (p45)	
	Further, as part of the NWA analysis, the Commission would like greater transparency into the need for, costs, and timing of traditional solutions. For proposed NWAs, the Commission expects information regarding costs and savings, impact of the NWA in offsetting the need for traditional investment, customer consumption patterns with and without the NWA, implementation timing, and assumptions used in the analysis, including minimum customer participation levels. The Commission expects this to be an iterative process, with additional guidance on specifics relating to the affected project areas, substation characteristics, and details on both proposed wired and NWAs on a going-forward basis.	U-20147 2020-08-20 (p44)	The information requested here is listed in table form at the end of each NWA pilot detailed in Section 12.7
Integration of IRPs and distribution plans	The Commission sees value in aligning distribution plans and IRP filings and is interested in such an alignment to the best extent possible. The Commission, however, recognizes that a perfect line up between the two may not be achievable given the statutory framework of MCL 460.6t and the utility-specific nature of each IRP case. See, e.g., Case Nos. U-20165 and U-20471. Moreover, given the pressing need to respond to the coronavirus pandemic during 2020 and the timing of this order, the Commission finds additional time is warranted to prepare the distribution plans and extends the previous deadline of June 30, 2021 to September 30, 2021.	U-20147 2020-08-20 (p51)	Collaboration between the IRP and Distribution planning processes are described in Section 4.6. The impact of generation planning on distribution planning is also discussed in Section 11.7
	The Commission expects it will take several iterations of plans to more fully align integrated resource planning and distribution planning and is not envisioning such alignment to	U-20147 2019-09-11	

	be completed with this next round of distribution plans. It is nonetheless important to raise this longer-term objective as utilities, the Staff, and stakeholders are working on both IRPs and distribution plans. These ongoing planning activities may shed light on opportunities and barriers that affect alignment, particularly as it relates to forecasting, modeling tools, and analysis of alternatives. This, in turn, could help inform updates to the Michigan Integrated Resource Planning Parameters for the next round of IRPs pursuant to 2016 PA 341. To be clear, however, the Commission is not initiating a process to update the IRP parameters in this docket as such updates would be handled in a separate proceeding at a later time.	(p3)	
Alternative Regulatory Approaches	Directed DTE Electric to include in its next distribution plan "proposed PBR [performance-based regulation] elements with reasonable metrics tied to utility financial performance, improvement targets, and timelines for achievement," and specified the following elements for consideration: - The utility should consider the pros and cons of a comprehensive PBR system, which would avoid concurrent regular annual rate cases and separate PBR reconciliations; - The utility's financial PBR system should include both incentives and disincentives based on performance; incentive structures should be holistically considered in terms of impacts on potential earnings - Performance metrics should include outcome measures (e.g., customer average interruption duration index (CAIDI)) and not be limited to output metrics such as number of poles replaced; - Performance metrics should be linked to regional, national, and/or peer utility benchmarks, where possible; - Data and calculation methodologies should be well defined, transparent, and open for auditing/verification purposes; - Targets should be utility specific; and - Potential areas of performance focus are safety, customer service (end use customers, builders, interconnecting	U-20147 2020-08-20 (p47)	Section 15 discusses DTEE's PBR plan in detail

	generators, etc.), timeliness and quality, reliability and resiliency, long-term costs, and innovation.		
Cost/Benefit Analysis	While the Commission finds this an important topic to tackle in the near term, this is not a topic that can be resolved before the next round of distribution plans are due next year. The Commission appreciates the Staff's recommendation to convene stakeholders on the BCA framework after the plans are filed next year, but the Commission refrains from making this commitment so that it can evaluate priorities in 2021 in light of other MI Power Grid activities; the Commission directs the Staff to continue to work with utilities and other stakeholders in continuing to explore the appropriate framework for evaluating BCA, including consideration of experiences from other jurisdictions and recommendations related to the issues highlighted in the Staff's final report. The Commission expects these additional details to inform and be integrated into future utility distribution plans.	U-20147 2020-08-20 (p45)	Current cost benefit approach (GPM) as well as proposed next steps involving stakeholder discussion included in Section 6
Resilience	The Commission agrees with DTE Electric on the description of resilience, in terms of the ability to restore power following a major catastrophic event. The Commission also thinks about this term more broadly such as planning to mitigate more localized, high-impact outages caused by equipment issues, access limitations, or system configurations that inhibit timely restoration or backup capabilities, e.g., specialized equipment necessary to replace substation failure cannot be replaced in timely manner and the area cannot receive backup power through an alternative means or obstructions limit access to distribution equipment (e.g., closed in alleyways in Detroit). Resilience in this context should also consider the vulnerability of loads that would affect public health, safety, or security under an extended outage, and related mitigation strategies to ensure continuity of service. With the potential for supply chain disruptions due the pandemic or other factors, as well as cyber or physical security threats, the Commission underscores the	U-20147 2020-08-20 (p48)	Resiliency is covered in many sections, including Section 7.3. High-impact outages can be mitigated through the use of the mobile fleet, or longer-term investments driven by the substation risk framework (9.2). The storm restoration process incorporates vulnerable loads in restoration priority (Section 7.3). Additionally, pilots and further efforts to underground or move circuits in areas with access issues is discussed in Section 11.6

	importance of robust, risk-based resilience evaluations and mitigation strategies as part of distribution planning efforts.		
Workforce adequacy plans	The Commission acknowledges that an adequate utility workforce is key to the distribution system. However, the Commission believes that a focus more on implementation considerations generally, with workforce being a component, would be sufficient for the next round of distribution plans. The Commission is also sensitive to publishing detailed workforce information that could affect bidding and contracting by utilities.	U-20147 2018-11-21 (p36-37)	DTEE's process and general approach to workforce and resource planning is discussed in Section 16.2

Appendix II Strategic Capital Programs excluded from Global Prioritization Model prioritization

Investment Name	DGP Section	2021-2025 Investment ($M)	Notes
Strategic Pillar: Infrastructure Hardening and Resilience			
Substation Risk: Drexel	**9.2**	$ 1.9	Completing construction on switchgear replacement which was damaged due to failure
Belleville Switchgear Decommissioning	**9.2**	$1.7	Switchgear is end of life with no replacement breakers available and safety concern with control wiring
Disconnect and Switcher: Disconnect	**9.1**	$12.0	Replacement of equipment that is obsolete or prone to failure during operation
Disconnect and Switcher: Switcher	**9.1**	$5.3	Replacement of equipment with known failure modes, potentially faulty components, or undersized for the need
Mobile Fleet Program: Portable Equip / DG	**9.6**	$7.0	Allows for timely restoration of customers during major events and improves system operability while providing for completion of planned work and preventive maintenance.
Mobile Fleet Program: Portable Substation	**9.6**	$7.4	Allows for timely restoration of customers during major events and improves system operability while providing for completion of planned work and preventive maintenance.
SCADA Pole Top Device Replacement	**9.1**	$9.4	Replacement of equipment with unavailable parts and known high failure rate
Substation Regulator Replacement	**9.1**	$1.7	Replacement of equipment that is obsolete and employs technology that is no longer manufactured or supported
Strategic Pillar: Infrastructure Redesign and Modernization			
Transformer High Side Protection Program	**11.2**	$15.0	Installation of high side protection as required by NERC standards
Station Upgrade: Cortland Station Expansion	**11.2**	$9.3	Existing transformers 101 and 102 cannot be replaced in existing location due to physical restrictions leaving high amount of load at risk in the event of a failure
40kV Capacitor Banks at Armada and Adair	**11.2**	$3.3	Work is necessary to maintain adequate voltage for multiple contingencies on Tie 810 and facilitate shutdowns for the Tie 810 (Gramer) project
Subtransmission Redesign & Rebuild: Slocum	**11.2**	$2.2	Needed due to decommissioning of Trenton Channel Power Plant
Subtransmission Redesign & Rebuild - Small Projects & Reserve	**11.2**	$11.5	Needed to implement small projects aimed at addressing overloads and voltage violations on the subtransmission system.
4.8 kV Conversion: Ariel Substation and Circuit Conversion	**11.3**	$2.8	Project is under construction

4.8 kV Conversion: Cortland / Oakman / Linwood Consolidation: Linwood	**11.3**	$4.3	Project is under construction
4.8 kV Conversion: Pinegrove Substation Relocation and Conversion	**11.3**	$22.4	Project is driven by MDOT work requiring relocation of Pinegrove substation
Ann Arbor AC Network Conversion	**11.3**	$3.1	Upgraded capacity of downtown Ann Arbor network to accommodate increased load
Pontiac Vaults	**11.5**	$3.5	Necessary to meet operational and safety needs
Strategic Pillar: Technology and Automation			
ESOC	**12.2**	$15.0	Upgrades of physical infrastructure and technology constraints in the current SOC needed to fully utilize the new ADMS platforms
ASOC	**12.2**	$92.6	Needed to provide for full redundancy with the new ESOC
CVR/VVO	**12.6**	$65.5	Currently a pilot program being evaluated as an offset to peak generation and for grid efficiency and having sufficient capacity for demand
DER Control	**12.8**	$11.3	Comply with upcoming regulatory requirements such as FERC2222
Mobile Technology	**12.9**	$13.3	Improve data availability to field resources to improve operational efficiency
Work Management & Scheduling	**12.9**	$21.3	Upgrade work management systems to streamline project execution
Asset Management	**12.9**	$5.6	Upgrade mapping system
Distribution Planning Process Capabilities	**12.9**	$42.6	Support processes such as Interconnections, HCA, load forecasting
Modernize Grid Management	**12.9**	$35.6	New technology to enable and support grid modernization efforts
2021-2025 Investment Total		**$425**	**11% of the $3.8B in Strategic capital is not prioritized by GPM**

Appendix III Historical Storm Events

Exhibit A-2 Storm Event and Restoration Duration History

Storm #	Conditions W – Wind L – Lightning R – Rain I – Ice S – Snow H – Heat C – Cold	Storm Start	Restoration Duration in Hours	Customers Affected	Cost $ million
2016001	W - - - S -	01/10/16 05:30	39.0	42,871	$ 5.746
2016002	W - - - - -	02/19/16 12:00	77.5	112,419	$ 10.416
2016003	W - R I S C	02/24/16 07:30	53.5	26,590	$ 4.509
2016004	W - R I S C	02/28/16 19:00	36.5	20,052	$ 2.058
2016005	- - R - - -	03/13/16 10:00	35.0	20,519	$ 1.757
2016006	W - R - - -	03/16/16 07:30	75.5	54,601	$ 10.970
2016007	W - R - - -	06/04/16 12:00	71.0	41,376	$ 6.288
2016008	W - - - - H	06/11/16 12:00	35.0	33,444	no w/o
2016009	W - - - - H	06/19/16 14:00	56.0	46,495	$ 6.477
2016010	W L R - - H	07/08/16 00:00	91.0	100,228	$ 11.194
2016011	W L R - - H	07/12/16 16:00	76.0	54,799	$ 7.357
2016012	W - - - - H	07/17/16 15:00	50.0	26,933	$ 7.363
2016013	W L R - - H	07/21/16 12:00	59.5	36,313	no w/o
2016014	W L R - - -	07/29/16 14:00	57.5	23,158	no w/o
2016015	- L R - - -	08/12/16 15:00	59.5	43,902	$ 4.725
2016016	W - R - - -	08/16/16 00:00	37.0	28,692	$ 5.330
2016017	W L R - - H	09/07/16 13:00	32.0	24,553	$ 4.613
2016018	W L R - - -	09/10/16 04:00	44.5	17,312	no w/o
2016019	W L R - - -	09/29/16 05:00	58.0	32,104	no w/o

Storm #	Conditions W – Wind L – Lightning R – Rain I – Ice S – Snow H – Heat C – Cold	Storm Start	Restoration Duration in Hours	Customers Affected	Cost $ million
2016020	W L R - - -	11/18/16 19:00	80.0	57,216	$ 6.682
2016021	W - - - - -	11/28/16 20:00	33.5	52,256	$ 4.339
2016022	W - - - - -	12/26/16 00:00	24.0	33,644	$ 1.758
2017001	W - - - - -	01/10/17 15:00	65.9	74,371	$ 8.337
2017002	- L R - S -	01/16/17 15:00	36.1	19,301	$ 0.870
2017003	W - R - s -	02/12/17 10:00	34.3	17,934	$ 1.180
2017004	- L R - S -	02/24/17 16:00	26.5	8,223	$ 0.896
2017005	W - - - - -	02/28/17 22:00	46.5	39,339	$ 3.831
2017006	W - - - - -	03/08/17 08:00	202.0	749,511	$ 91.426
2017007	W - - - s -	03/18/17 02:00	40.2	26,915	$ 6.373
2017008	W - R - s -	03/30/17 09:00	51.8	26,179	$ 0.732
2017009	W - - - - -	04/05/17 21:00	142.4	100,839	$ 10.732
2017010	W - - - - -	04/26/17 15:00	53.0	24,702	$ 1.900
2017011	W L R - - -	04/30/17 22:00	48.0	15,748	$ 0.801
2017012	W - - - - -	05/17/17 08:00	133.3	92,221	$ 11.422
2017013	W - - - - H	06/10/17 07:00	229.0	128,406	$ 11.939
2017014	W - R - - -	06/22/17 09:00	92.0	93,330	$ 8.419
2017015	- - R - - H	06/29/17 21:00	66.8	28,651	$ 3.647
2017016	W - R - - -	07/06/17 23:00	52.0	56,145	$ 4.887
2017017	W L R - - -	07/10/17 10:00	83.1	54,192	$ 7.017
2017018	- L R - - H	07/23/17 03:00	40.1	26,099	$ 0.921
2017019	W - - - - H	07/28/17 15:00	32.5	10,688	$ 0.678

Storm #	Conditions W – Wind L – Lightning R – Rain I – Ice S – Snow H – Heat C – Cold	Storm Start	Restoration Duration in Hours	Customers Affected	Cost $ million
2017020	W L R - - -	08/02/17 16:00	85.4	67,461	$ 9.310
2017021	W L R - - H	08/11/17 05:00	58.5	14,189	$ 1.051
2017022	W L R - - H	08/16/17 20:00	46.0	25,497	$ 1.600
2017023	- L R - - -	08/28/17 18:00	44.5	26,299	$ 1.526
2017024	W L R - - H	09/04/17 16:00	55.3	19,118	$ 2.228
2017025	W - R - - -	10/07/17 13:00	61.9	30,103	$ 4.904
2017026	W - R - - -	10/11/17 05:00	38.2	34,854	$ 4.252
2017027	W L R - - -	10/14/17 18:00	80.1	79,164	$ 7.237
2017028	W - R - - -	10/23/17 18:00	73.3	51,957	$ 9.955
2017029	W L R - - -	11/15/17 15:00	27.6	13,636	$ 1.890
2017030	W - - - - -	12/05/17 04:00	20.0	27,597	$ 2.165
2018001	W - R - S - -	03/01/18 13:00	79.5	87,922	$ 10.9
2018002	W - R - S - -	04/04/18 07:30	35.8	5,894	$ 3.2
2018003	W - R I S - -	04/15/18 05:30	126.2	284,535	$ 39.1
2018004	W - R - - - -	05/04/18 12:00	107.8	250,063	$ 35.7
2018005	W - R - - H -	05/30/18 17:00	55	53,095	$ 9.7
2018006	W - R - - H -	06/13/18 14:00	32	23,201	$ 4.6
2018007	- - R - - H -	06/18/18 9:00	51.3	47,425	$ 7.9
2018008	- L R - - H -	07/01/18 15:00	37	20,200	$ 7.5
2018009	W L R - - H -	07/16/18 09:00	38.3	29,667	$ 7.6
2018010	W L R - - H -	08/01/18 0:00	45	35,461	$ 5.3
2018011	W L R - - H -	08/06/18 13:00	80	54,956	$ 13.1

Storm #	**Conditions** W – Wind L – Lightning R – Rain I – Ice S – Snow H – Heat C – Cold	Storm Start	Restoration Duration in Hours	Customers Affected	Cost $ million
2018012	W L R - - H -	09/01/18 16:00	78	52,560	$ 6.8
2018013	W L R - - H -	09/05/18 20:00	27.5	21,984	$ 7.2
2018014	W - R - - - -	09/21/18 10:00	64.5	66,447	$ 16.7
2018015	W L R - - - -	10/20/18 13:00	58	69,431	$ 15.8
2019001	W - R - - - -	02/07/19 21:00	42.7	34,238	$ 5.8
2019002	W - R I - - -	02/12/19 8:00	36	43,075	$ 8.5
2019003	W - R - - - -	02/24/19 8:00	59.2	128,515	$ 21.6
2019004	W - R - - - -	05/23/19 6:00	39.5	50,070	$ 7.3
2019005	W - R - - - -	06/1/19 13:00	32	40,432	$ 8.9
2019006	W L R - - H -	07/02/19 9:00	139.2	117,854	$ 17.2
2019007	W L R - - H -	07/19/19 16:00	151.8	402,442	$ 51.8
2019008	W L R - - H -	07/28/19 15:00	71	97,173	$ 16.5
2019009	W L R - - H -	08/18/19 12:00	41.5	41,059	$ 8.5
2019010	W L R - - - -	08/26/19 18:30	42	40,847	$ 10.0
2019011	W L R - - - -	09/11/19 14:00	49.5	59,054	$ 7.5
2019012	W L R - - - -	09/13/19 15:31	48	28,877	$ 13.5
2019013	W - R - - - -	10/27/19 01:00	47.8	44,480	$ 10.3
2019014	W - R - - - -	11/27/19 10:00	64	74,376	$ 19.3
2019015	W - R - - - -	12/30/19 06:00	37.5	30,883	$ 12.7
2020001	W - - I - - -	01/11/20 05:00	56	35,717	$ 10.5
2020002	W L R - - - -	03/29/20 13:00	34	31,287	$ 7.6
2020003	W L R - - H -	06/03/20 03:00	32.6	30,384	$ 4.5

Storm #	Conditions W – Wind L – Lightning R – Rain I – Ice S – Snow H – Heat C – Cold	Storm Start	Restoration Duration in Hours	Customers Affected	Cost $ million
2020004	W L R - - H -	06/10/20 13:00	102.3	187,824	$ 31.1
2020005	W L R - - H -	06/23/20 08:00	37	34,978	$ 5.0
2020006	W L R - - H -	06/26/20 23:00	42	51,598	$ 8.1
2020007	W L R - - H -	07/07/20 19:00	131	143,875	$ 24.6
2020008	W L R - - H -	07/19/20 09:00	80	184,726	$ 29.7
2020009	W L R - - H -	08/02/20 5:30	39.8	41,510	$ 6.2
2020010	W L R - - - -	08/27/20 17:00	69.7	48,785	$ 16.2
2020011	W - R - - - -	10/23/20 17:30	48.3	38,762	$ 4.9
2020012	W - R - - - -	11/01/20 08:30	55	47,311	$ 8.0
2020013	W - R - - - -	11/15/20 02:30	112	203,919	$ 46.3

Appendix IV Reliability Indices for Service Centers

Exhibit A.3.1 SAIFI, SAIDI, CAIDI – All Weather, All Causes

SAIFI - All Weather, All Causes

SC	2015	2016	2017	2018	2019	2020
ANN	1.07	1.19	1.37	1.52	1.81	1.40
CAN	0.68	0.62	1.45	1.22	1.19	0.96
HWL	1.31	1.57	1.63	1.87	2.52	2.10
LAP	1.58	1.50	1.45	1.15	1.89	1.90
MAR	1.88	1.19	1.22	1.22	1.37	1.33
MTC	0.76	0.89	1.13	1.03	1.36	1.47
NAE	1.69	1.29	2.08	2.09	2.52	2.38
NPT	0.82	0.66	1.27	1.25	1.41	0.97
PON	1.00	0.98	1.55	1.68	1.82	1.60
RFD	1.13	0.90	1.46	1.34	0.97	0.90
SBY	0.72	1.17	1.19	1.06	1.00	1.10
WWS	0.84	0.95	1.46	1.33	1.29	1.28

SAIDI - All Weather, All Causes

SC	2015	2016	2017	2018	2019	2020
ANN	255	290	1,023	449	467	323
CAN	397	169	1,829	543	684	498
HWL	219	377	1,241	304	1,220	421
LAP	428	431	883	551	897	440
MAR	486	313	983	437	416	375
MTC	151	181	553	195	318	258
NAE	1,147	483	1,041	1,109	769	1,193
NPT	158	185	876	317	273	181
PON	248	209	983	366	484	334
RFD	322	190	1,586	788	473	288

SBY	100	177	496	238	192	203
WWS	228	304	914	466	403	422

CAIDI – All Weather, All Causes

SC	2015	2016	2017	2018	2019	2020
ANN	238	244	747	295	258	230
CAN	584	273	1,261	445	575	519
HWL	167	240	761	163	484	200
LAP	271	287	609	479	475	232
MAR	259	263	806	358	304	282
MTC	199	203	489	189	234	175
NAE	679	374	500	531	305	501
NPT	193	280	690	254	194	186
PON	248	213	634	218	266	209
RFD	285	211	1,086	588	488	319
SBY	139	151	417	225	192	185
WWS	271	320	626	350	312	329

Exhibit A.3.2 SAIFI, SAIDI, CAIDI – Excluding MEDs, All Causes

SAIFI - Excluding MEDs, All Causes

SC	2015	2016	2017	2018	2019	2020
ANN	1.01	1.15	1.03	1.17	1.49	1.07
CAN	0.53	0.59	0.90	0.84	0.91	0.67
HWL	1.23	1.42	1.19	1.62	1.90	1.67
LAP	1.45	1.35	1.03	0.82	1.43	1.38
MAR	1.72	1.06	0.76	0.89	1.09	1.00
MTC	0.69	0.81	0.87	0.84	1.19	1.30
NAE	1.32	1.25	1.53	1.54	2.09	1.61
NPT	0.74	0.60	0.92	0.97	1.33	0.88

PON	0.94	0.92	1.13	1.39	1.59	1.28
RFD	1.03	0.84	0.91	0.93	0.74	0.70
SBY	0.69	1.13	0.98	0.89	0.90	0.91
WWS	0.73	0.82	1.08	0.96	1.07	0.99

SAIDI – Excluding MEDs, All Causes

SC	2015	2016	2017	2018	2019	2020
ANN	215	255	175	192	220	129
CAN	195	147	323	231	199	140
HWL	160	284	196	204	393	216
LAP	359	319	172	140	266	210
MAR	381	270	126	103	187	122
MTC	103	115	155	114	190	144
NAE	453	441	392	351	426	380
NPT	125	142	115	159	226	104
PON	208	175	194	202	289	158
RFD	219	154	217	184	151	116
SBY	81	158	125	123	124	112
WWS	145	165	212	146	180	137

CAIDI – Excluding MEDs, All Causes

SC	2015	2016	2017	2018	2019	2020
ANN	213	222	170	164	148	120
CAN	368	249	359	275	219	209
HWL	130	200	165	126	207	130
LAP	248	236	167	171	186	152
MAR	222	255	166	116	172	122
MTC	149	142	178	136	160	111
NAE	343	353	256	228	204	237
NPT	169	237	125	164	170	119

PON	221	190	172	145	182	124
RFD	213	183	238	198	204	167
SBY	117	140	128	138	138	123
WWS	199	201	196	152	168	138

Exhibit A.3.3 SAIFI, SAIDI, CAIDI – Catastrophic Storms, All Causes

SAIFI – Catastrophic Storms, All Causes

SC	2015	2016	2017	2018	2019	2020
ANN	0.04	0.07	0.29	0.13	0.43	0.35
CAN	0.12	0.05	0.49	0.32	0.40	0.29
HWL	0.02	0.23	0.38	0.06	0.89	0.35
LAP	0.04	0.24	0.33	0.32	0.65	0.30
MAR	0.02	0.17	0.37	0.32	0.45	0.16
MTC	0.04	0.10	0.22	0.15	0.25	0.14
NAE	0.00	0.04	0.19	0.52	0.53	0.49
NPT	0.08	0.07	0.26	0.19	0.19	0.08
PON	0.06	0.07	0.34	0.11	0.48	0.27
RFD	0.07	0.07	0.50	0.36	0.36	0.18
SBY	0.02	0.03	0.19	0.11	0.20	0.15
WWS	0.09	0.16	0.33	0.27	0.32	0.30

SAIDI – Catastrophic Storms, All Causes

SC	2015	2016	2017	2018	2019	2020
ANN	26	41	837	81	269	160
CAN	152	36	1,457	268	525	309
HWL	3	111	1,021	14	938	105
LAP	23	140	644	407	692	83

MAR	18	54	742	330	264	54
MTC	29	72	373	63	137	66
NAE	1	43	311	711	384	410
NPT	37	47	719	121	64	24
PON	38	39	764	100	275	99
RFD	70	44	1,345	554	369	108
SBY	17	19	363	87	91	49
WWS	62	164	661	265	235	229

CAIDI – Catastrophic Storms, All Causes

SC		2015	2016	2017	2018	2019	2020
ANN	650	586	2,886	623	626	450	
CAN	1,267	720	2,973	838	1,313	1,079	
HWL	150	483	2,687	233	1,054	301	
LAP	575	583	1,952	1,272	1,065	272	
MAR	900	318	2,005	1,031	587	340	
MTC	725	720	1,695	420	548	462	
NAE	0	1,075	1,637	1,367	725	831	
NPT	463	671	2,765	637	337	291	
PON	633	557	2,247	909	573	365	
RFD	1,000	629	2,690	1,539	1,025	588	
SBY	850	633	1,911	791	455	330	
WWS	689	1,025	2,003	981	734	759	

Exhibit A.3.4 SAIFI, SAIDI, CAIDI – Non-Catastrophic Storms, All Causes

SAIFI – Non-Catastrophic Storms, All Causes

SC	2015	2016	2017	2018	2019	2020
ANN	0.38	0.45	0.40	0.33	0.21	0.24
CAN	0.26	0.24	0.44	0.30	0.19	0.21
HWL	0.60	0.54	0.43	0.51	0.43	0.49
LAP	0.65	0.55	0.29	0.11	0.27	0.47
MAR	0.70	0.35	0.26	0.17	0.19	0.47
MTC	0.27	0.21	0.30	0.18	0.22	0.19
NAE	1.03	0.67	0.79	0.23	0.36	0.74
NPT	0.22	0.21	0.37	0.28	0.32	0.15
PON	0.36	0.36	0.46	0.38	0.17	0.30
RFD	0.36	0.30	0.33	0.23	0.11	0.20
SBY	0.33	0.34	0.27	0.17	0.12	0.17
WWS	0.28	0.30	0.39	0.22	0.17	0.25

SAIDI – Non-Catastrophic Storms, All Causes

SC	2015	2016	2017	2018	2019	2020
ANN	127	135	93	131	71	79
CAN	185	75	259	162	54	113
HWL	147	190	113	144	127	165
LAP	256	199	129	40	52	203
MAR	300	145	167	30	72	224
MTC	66	37	111	46	56	67
NAE	1,054	326	515	56	96	589
NPT	63	83	89	72	87	82
PON	99	95	110	103	57	117
RFD	151	76	132	108	34	109

SBY	46	60	58	55	27	61
WWS	97	71	131	86	58	102

CAIDI – Non-Catastrophic Storms, All Causes

SC	2015	2016	2017	2018	2019	2020
ANN	334	300	233	397	338	332
CAN	712	313	589	540	284	541
HWL	245	352	263	282	295	340
LAP	394	362	445	364	193	433
MAR	429	414	642	176	379	479
MTC	244	176	370	256	255	357
NAE	1,023	487	652	243	267	801
NPT	286	395	241	257	272	555
PON	275	264	239	271	335	386
RFD	419	253	400	470	309	546
SBY	139	176	215	324	225	351
WWS	346	237	336	391	341	408

Exhibit A.3.5 SAIFI, SAIDI, CAIDI – Blue Sky, All Causes

SAIFI – Blue Sky, All Causes

SC	2015	2016	2017	2018	2019	2020
ANN	0.64	0.68	0.67	1.05	1.16	0.81
CAN	0.29	0.33	0.52	0.60	0.60	0.47
HWL	0.70	0.80	0.81	1.30	1.19	1.26
LAP	0.88	0.71	0.84	0.72	0.98	1.12
MAR	1.16	0.67	0.60	0.73	0.73	0.70
MTC	0.45	0.59	0.60	0.70	0.89	1.14
NAE	0.66	0.58	1.10	1.34	1.63	1.15
NPT	0.52	0.37	0.64	0.78	0.91	0.74
PON	0.57	0.55	0.75	1.19	1.17	1.02
RFD	0.70	0.53	0.64	0.75	0.49	0.52
SBY	0.37	0.80	0.73	0.78	0.68	0.77
WWS	0.47	0.49	0.74	0.84	0.80	0.73

SAIDI – Blue Sky, All Causes

SC	2015	2016	2017	2018	2019	2020
ANN	102	114	93	237	126	84
CAN	60	57	113	113	104	76
HWL	68	76	108	146	155	151
LAP	148	92	110	104	153	154
MAR	169	113	74	76	80	97
MTC	55	72	68	85	125	125
NAE	92	115	216	342	289	194
NPT	58	55	67	124	122	75

PON	112	74	108	164	153	118
RFD	101	70	110	126	69	70
SBY	37	97	75	96	73	93
WWS	69	69	121	116	110	91

CAIDI – Blue Sky, All Causes

SC	2015	2016	2017	2018	2019	2020
ANN	159	168	139	226	109	104
CAN	207	173	217	188	173	164
HWL	97	95	133	112	130	119
LAP	168	130	131	144	156	137
MAR	146	169	123	104	110	138
MTC	122	122	113	121	140	109
NAE	139	198	196	255	177	169
NPT	112	149	105	159	134	100
PON	196	135	144	138	131	115
RFD	144	132	172	168	141	136
SBY	100	121	103	123	107	120
WWS	147	141	164	138	138	124

Exhibit A.3.6 SAIFI, SAIDI, CAIDI – All Weather, Cause = Tree/Wind

SAIFI - All Weather, Cause = Tree/Wind

SC	2015	2016	2017	2018	2019	2020
ANN	0.43	0.65	0.78	0.70	0.83	0.68
CAN	0.42	0.27	0.98	0.58	0.63	0.50
HWL	0.62	0.71	0.98	0.81	1.38	0.93

LAP	0.64	0.76	0.83	0.44	0.92	1.16
MAR	0.62	0.50	0.73	0.48	0.60	0.59
MTC	0.25	0.32	0.53	0.49	0.59	0.47
NAE	0.81	0.71	1.31	1.02	1.06	1.34
NPT	0.35	0.27	0.66	0.62	0.57	0.47
PON	0.38	0.47	0.92	0.76	0.98	0.66
RFD	0.44	0.44	0.95	0.61	0.56	0.48
SBY	0.24	0.30	0.45	0.39	0.34	0.30
WWS	0.38	0.46	0.82	0.60	0.63	0.66

SAIDI - All Weather, Cause = Tree/Wind

SC	2015	2016	2017	2018	2019	2020
ANN	160	179	862	256	328	207
CAN	322	109	1,469	309	512	405
HWL	132	219	1,142	150	1,000	263
LAP	225	277	738	331	695	323
MAR	275	171	850	235	273	235
MTC	82	110	441	97	209	149
NAE	718	345	901	546	492	941
NPT	99	104	758	173	137	132
PON	123	128	812	204	356	195
RFD	198	124	1,276	454	392	212
SBY	49	60	394	113	103	99
WWS	152	226	766	259	299	298

CAIDI – All Weather, Cause = Tree/Wind

SC	2015	2016	2017	2018	2019	2020
ANN	372	275	1,105	366	395	304
CAN	767	404	1,499	533	813	810
HWL	213	308	1,165	185	725	283
LAP	352	364	889	752	755	279
MAR	444	342	1,164	490	455	396
MTC	328	344	832	198	354	320
NAE	886	486	688	535	464	704
NPT	283	385	1,148	279	240	280
PON	324	272	883	268	363	293
RFD	450	282	1,343	744	700	441
SBY	204	200	876	290	303	331
WWS	400	491	934	432	475	448

Exhibit A.3.7 SAIFI, SAIDI, CAIDI – Excluding MEDs, Cause = Tree/Wind

SAIFI - Excluding MEDs, Cause = Tree/Wind

SC	2015	2016	2017	2018	2019	2020
ANN	0.38	0.62	0.48	0.51	0.58	0.45
CAN	0.28	0.25	0.53	0.37	0.41	0.24
HWL	0.55	0.59	0.58	0.63	0.92	0.60
LAP	0.58	0.65	0.47	0.22	0.60	0.71
MAR	0.56	0.45	0.30	0.28	0.40	0.38
MTC	0.19	0.26	0.29	0.40	0.47	0.31
NAE	0.56	0.68	0.84	0.73	0.80	0.66
NPT	0.27	0.22	0.34	0.45	0.51	0.40
PON	0.33	0.42	0.55	0.58	0.79	0.44

RFD	0.35	0.40	0.51	0.36	0.39	0.31
SBY	0.21	0.28	0.27	0.28	0.26	0.17
WWS	0.30	0.34	0.47	0.41	0.45	0.45

SAIDI – Excluding MEDs, Cause = Tree/Wind

SC	2015	2016	2017	2018	2019	2020
ANN	125	147	97	101	111	73
CAN	123	89	234	131	99	72
HWL	86	131	129	89	258	93
LAP	180	199	89	45	142	114
MAR	201	152	76	41	81	53
MTC	41	54	81	64	102	39
NAE	280	306	294	216	266	184
NPT	67	61	62	72	105	62
PON	87	99	111	101	172	69
RFD	100	93	143	103	102	66
SBY	31	47	43	43	49	28
WWS	79	93	105	78	111	74

CAIDI – Excluding MEDs, Cause = Tree/Wind

SC	2015	2016	2017	2018	2019	2020
ANN	329	237	202	198	191	162
CAN	439	356	442	354	241	293
HWL	156	222	222	141	280	155
LAP	310	306	189	205	237	161
MAR	359	338	253	146	203	139

MTC	216	208	279	160	217	127
NAE	500	450	350	296	333	280
NPT	248	277	182	160	206	156
PON	264	236	202	174	218	157
RFD	286	233	280	286	262	210
SBY	148	168	159	154	188	165
WWS	263	274	223	190	247	162

Exhibit A.3.8 SAIFI, SAIDI, CAIDI – Catastrophic Storms, Cause = Tree/Wind

SAIFI – Catastrophic Storms, Cause = Tree/Wind

SC	2015	2016	2017	2018	2019	2020
ANN	0.04	0.05	0.27	0.04	0.31	0.23
CAN	0.12	0.04	0.40	0.17	0.29	0.23
HWL	0.01	0.13	0.37	0.04	0.67	0.19
LAP	0.04	0.18	0.31	0.22	0.42	0.25
MAR	0.02	0.06	0.34	0.20	0.28	0.09
MTC	0.04	0.06	0.18	0.05	0.15	0.10
NAE	0.00	0.03	0.17	0.22	0.30	0.40
NPT	0.08	0.06	0.24	0.12	0.08	0.06
PON	0.04	0.05	0.30	0.07	0.37	0.15
RFD	0.06	0.05	0.40	0.19	0.27	0.15
SBY	0.02	0.02	0.17	0.06	0.11	0.09
WWS	0.07	0.15	0.30	0.12	0.23	0.20

SAIDI – Catastrophic Storms, Cause = Tree/Wind

SC	2015	2016	2017	2018	2019	2020
ANN	23	37	753	35	235	103
CAN	147	34	1,193	149	441	288
HWL	1	93	992	9	833	82
LAP	22	101	597	285	588	66
MAR	18	22	666	192	206	39
MTC	25	60	335	17	115	59
NAE	0	40	292	281	253	377
NPT	36	45	669	80	42	21

PON	33	32	677	62	242	61
RFD	65	36	1,108	309	329	93
SBY	16	13	346	47	65	39
WWS	58	153	623	142	207	175

CAIDI – Catastrophic Storms, Cause = Tree/Wind

SC	2015	2016	2017	2018	2019	2020
ANN	575	740	2,789	875	758	452
CAN	1,225	850	2,983	876	1,521	1,238
HWL	100	715	2,681	225	1,243	439
LAP	550	561	1,926	1,295	1,400	271
MAR	900	367	1,959	960	736	419
MTC	625	1,000	1,861	340	767	592
NAE	0	1,333	1,718	1,277	843	945
NPT	450	750	2,788	667	525	356
PON	825	640	2,257	886	654	412
RFD	1,083	720	2,770	1,626	1,219	638
SBY	800	650	2,035	783	591	434
WWS	829	1,020	2,077	1,183	900	860

Exhibit A.3.9 SAIFI, SAIDI, CAIDI – Non-Catastrophic Storms, Cause = Tree/Wind

SAIFI – Non-Catastrophic Storms, Cause = Tree/Wind

SC	2015	2016	2017	2018	2019	2020
ANN	0.21	0.26	0.22	0.15	0.09	0.16
CAN	0.18	0.12	0.35	0.18	0.11	0.14

HWL	0.40	0.36	0.30	0.28	0.22	0.38
LAP	0.31	0.33	0.18	0.03	0.09	0.30
MAR	0.37	0.18	0.20	0.10	0.11	0.25
MTC	0.11	0.12	0.19	0.11	0.12	0.11
NAE	0.63	0.49	0.56	0.16	0.15	0.53
NPT	0.14	0.09	0.26	0.12	0.13	0.08
PON	0.19	0.20	0.29	0.23	0.09	0.20
RFD	0.18	0.16	0.22	0.14	0.08	0.16
SBY	0.14	0.15	0.10	0.11	0.07	0.07
WWS	0.17	0.15	0.22	0.13	0.10	0.16

SAIDI – Non-Catastrophic Storms, Cause = Tree/Wind

SC	2015	2016	2017	2018	2019	2020
ANN	90	79	67	66	40	61
CAN	150	51	219	105	33	92
HWL	109	94	92	86	82	134
LAP	135	142	90	7	32	169
MAR	213	90	150	17	33	154
MTC	43	26	82	31	29	60
NAE	686	261	463	39	53	460
NPT	43	34	64	37	40	71
PON	72	65	83	70	44	89
RFD	94	55	101	81	28	89
SBY	25	31	25	41	19	40
WWS	69	46	96	53	35	78

CAIDI – Non-Catastrophic Storms, Cause = Tree/Wind

SC	2015	2016	2017	2018	2019	2020
ANN	429	304	305	440	444	395
CAN	833	425	626	583	300	644
HWL	273	261	307	307	373	348
LAP	435	430	500	233	356	562
MAR	576	500	750	170	300	608
MTC	391	217	432	282	242	563
NAE	1,089	533	827	244	353	876
NPT	307	378	246	308	308	880
PON	379	325	286	304	489	457
RFD	522	344	459	579	350	565
SBY	179	207	250	373	271	606
WWS	406	307	436	408	350	487

Exhibit A.3.10 SAIFI, SAIDI, CAIDI – Blue Sky, Cause = Tree/Wind

SAIFI – Blue Sky, Cause = Tree/Wind

SC	2015	2016	2017	2018	2019	2020
ANN	0.19	0.34	0.30	0.50	0.43	0.30
CAN	0.13	0.12	0.23	0.22	0.23	0.12
HWL	0.20	0.22	0.31	0.48	0.49	0.36
LAP	0.29	0.24	0.35	0.19	0.41	0.61
MAR	0.24	0.26	0.19	0.19	0.21	0.25
MTC	0.10	0.14	0.15	0.33	0.32	0.26
NAE	0.17	0.19	0.58	0.65	0.61	0.41
NPT	0.13	0.12	0.15	0.38	0.35	0.33
PON	0.14	0.22	0.33	0.45	0.52	0.32

RFD	0.19	0.23	0.33	0.27	0.21	0.18
SBY	0.08	0.13	0.18	0.23	0.16	0.14
WWS	0.14	0.16	0.29	0.35	0.29	0.30

SAIDI – Blue Sky, Cause = Tree/Wind

SC	2015	2016	2017	2018	2019	2020
ANN	48	63	42	155	53	43
CAN	25	24	57	56	39	25
HWL	22	32	59	55	85	48
LAP	68	34	51	40	75	87
MAR	45	59	34	26	34	42
MTC	14	24	24	49	65	30
NAE	32	45	146	226	185	104
NPT	20	25	25	56	55	40
PON	19	31	52	73	70	45
RFD	38	33	66	65	36	30
SBY	8	15	23	25	19	20
WWS	24	28	47	63	57	44

CAIDI – Blue Sky, Cause = Tree/Wind

SC	2015	2016	2017	2018	2019	2020
ANN	253	185	140	310	123	143
CAN	192	200	248	255	170	200
HWL	110	145	190	115	173	133
LAP	234	142	146	211	183	143
MAR	188	227	179	137	162	171

MTC	140	171	160	148	203	115
NAE	188	237	252	348	303	252
NPT	154	208	167	147	157	121
PON	136	141	158	162	135	140
RFD	200	143	200	241	171	170
SBY	100	115	128	109	119	137
WWS	171	175	162	180	197	148

Exhibit A.3.11 SAIFI, SAIDI, CAIDI – All Weather, Cause = Equipment

SAIFI - All Weather, Cause = Equipment

SC	2015	2016	2017	2018	2019	2020
ANN	0.15	0.23	0.34	0.35	0.27	0.26
CAN	0.12	0.19	0.23	0.18	0.07	0.16
HWL	0.31	0.38	0.34	0.59	0.40	0.36
LAP	0.34	0.23	0.21	0.28	0.19	0.36
MAR	0.21	0.25	0.20	0.31	0.18	0.16
MTC	0.24	0.27	0.22	0.21	0.32	0.50
NAE	0.22	0.22	0.44	0.27	0.37	0.32
NPT	0.13	0.19	0.29	0.29	0.22	0.22
PON	0.25	0.26	0.34	0.37	0.34	0.42
RFD	0.22	0.30	0.31	0.26	0.10	0.19
SBY	0.21	0.40	0.46	0.30	0.34	0.33
WWS	0.18	0.25	0.39	0.26	0.23	0.28

SAIDI - All Weather, Cause = Equipment

SC	2015	2016	2017	2018	2019	2020

ANN	34	48	76	71	41	55
CAN	31	33	111	54	27	28
HWL	51	57	42	79	63	62
LAP	62	53	45	42	40	57
MAR	49	60	43	44	35	34
MTC	34	35	48	29	40	67
NAE	45	44	58	75	45	45
NPT	19	55	80	59	32	23
PON	60	46	78	67	50	68
RFD	53	46	103	54	14	28
SBY	28	62	68	49	40	34
WWS	37	44	89	41	37	53

CAIDI – All Weather, Cause = Equipment

SC	2015	2016	2017	2018	2019	2020
ANN	227	209	224	203	152	210
CAN	258	174	483	300	386	177
HWL	165	150	124	134	158	173
LAP	182	230	214	150	211	161
MAR	233	240	215	142	194	217
MTC	142	130	218	138	125	133
NAE	205	200	132	278	122	141
NPT	146	289	276	203	145	103
PON	240	177	229	181	147	161
RFD	241	153	332	208	140	151
SBY	133	155	148	163	118	103

WWS	206	176	228	158	161	192

Exhibit A.3.12 SAIFI, SAIDI, CAIDI – Excluding MEDs, Cause = Equipment

SAIFI - Excluding MEDs, Cause = Equipment

SC	2015	2016	2017	2018	2019	2020
ANN	0.15	0.23	0.33	0.33	0.27	0.22
CAN	0.11	0.19	0.21	0.17	0.07	0.16
HWL	0.29	0.36	0.31	0.58	0.32	0.35
LAP	0.31	0.22	0.20	0.26	0.18	0.32
MAR	0.21	0.25	0.20	0.30	0.15	0.14
MTC	0.24	0.27	0.21	0.20	0.31	0.50
NAE	0.21	0.22	0.42	0.26	0.35	0.30
NPT	0.13	0.19	0.26	0.25	0.22	0.22
PON	0.24	0.25	0.33	0.32	0.33	0.39
RFD	0.22	0.29	0.28	0.25	0.09	0.18
SBY	0.21	0.39	0.44	0.29	0.34	0.32
WWS	0.17	0.25	0.37	0.24	0.23	0.25

SAIDI – Excluding MEDs, Cause = Equipment

SC	2015	2016	2017	2018	2019	2020
ANN	32	48	54	50	35	26
CAN	28	33	64	44	17	26
HWL	40	55	35	74	45	47
LAP	52	50	34	32	36	50
MAR	47	59	22	36	30	16
MTC	30	34	32	26	37	65

NAE	39	41	46	61	43	37
NPT	19	55	30	47	30	20
PON	58	41	49	47	46	52
RFD	52	43	54	44	13	22
SBY	26	61	53	42	38	31
WWS	35	42	77	31	34	32

CAIDI – Excluding MEDs, Cause = Equipment

SC	2015	2016	2017	2018	2019	2020
ANN	213	209	164	152	130	116
CAN	255	174	305	259	243	165
HWL	138	153	113	128	141	138
LAP	168	227	170	123	200	159
MAR	224	236	110	120	200	114
MTC	125	126	152	130	119	131
NAE	186	186	110	235	123	125
NPT	146	289	115	188	136	92
PON	242	164	148	147	139	135
RFD	236	148	193	176	144	125
SBY	124	156	120	145	112	97
WWS	206	168	208	129	148	129

Exhibit A.3.13 SAIFI, SAIDI, CAIDI – Catastrophic Storms, Cause = Equipment

SAIFI – Catastrophic Storms, Cause = Equipment

SC	2015	2016	2017	2018	2019	2020
ANN	0.00	0.00	0.01	0.00	0.01	0.07

CAN	0.01	0.00	0.01	0.01	0.01	0.00
HWL	0.00	0.02	0.00	0.00	0.09	0.01
LAP	0.00	0.01	0.01	0.01	0.02	0.04
MAR	0.00	0.02	0.00	0.01	0.02	0.00
MTC	0.00	0.01	0.00	0.01	0.03	0.01
NAE	0.00	0.00	0.00	0.03	0.07	0.02
NPT	0.00	0.00	0.01	0.02	0.02	0.01
PON	0.01	0.01	0.01	0.01	0.04	0.04
RFD	0.00	0.01	0.02	0.01	0.01	0.01
SBY	0.00	0.00	0.01	0.01	0.05	0.03
WWS	0.01	0.01	0.01	0.02	0.01	0.03

SAIDI – Catastrophic Storms, Cause = Equipment

SC	2015	2016	2017	2018	2019	2020
ANN	2	1	22	3	6	29
CAN	3	1	41	6	13	1
HWL	1	9	4	1	24	3
LAP	1	7	10	10	8	12
MAR	0	6	14	7	6	2
MTC	4	2	15	2	7	2
NAE	0	3	9	17	11	8
NPT	1	1	38	9	5	1
PON	2	7	29	9	10	7
RFD	2	4	49	13	2	3
SBY	1	1	11	8	9	4
WWS	2	4	11	6	3	14

CAIDI – Catastrophic Storms, Cause = Equipment

SC	2015	2016	2017	2018	2019	2020
ANN	0	0	2,200	0	600	404
CAN	300	0	4,100	600	1,300	360
HWL	0	450	0	0	267	349
LAP	0	700	1,000	1,000	400	298
MAR	0	300	0	700	300	592
MTC	0	200	0	200	233	185
NAE	0	0	0	567	157	322
NPT	0	0	3,800	450	250	119
PON	200	700	2,900	900	250	188
RFD	0	400	2,450	1,300	200	509
SBY	0	0	1,100	800	180	136
WWS	200	400	1,100	300	300	563

Exhibit A.3.14 SAIFI, SAIDI, CAIDI – Non-Catastrophic Storms, Cause = Equipment

SAIFI – Non-Catastrophic Storms, Cause = Equipment

SC	2015	2016	2017	2018	2019	2020
ANN	0.07	0.08	0.12	0.07	0.04	0.01
CAN	0.04	0.09	0.05	0.03	0.01	0.04
HWL	0.09	0.10	0.09	0.12	0.04	0.02
LAP	0.11	0.06	0.05	0.01	0.02	0.06
MAR	0.07	0.08	0.03	0.03	0.02	0.04
MTC	0.07	0.05	0.06	0.03	0.02	0.01
NAE	0.10	0.05	0.11	0.03	0.03	0.03

NPT	0.02	0.08	0.07	0.05	0.04	0.02
PON	0.06	0.05	0.07	0.06	0.05	0.07
RFD	0.07	0.10	0.08	0.02	0.01	0.02
SBY	0.07	0.08	0.09	0.02	0.03	0.01
WWS	0.03	0.10	0.10	0.04	0.04	0.03

SAIDI – Non-Catastrophic Storms, Cause = Equipment

SC	2015	2016	2017	2018	2019	2020
ANN	13	23	17	16	10	5
CAN	13	18	30	21	4	7
HWL	25	26	12	22	7	15
LAP	24	24	14	4	6	12
MAR	19	27	11	8	15	18
MTC	8	6	14	7	4	1
NAE	32	12	12	9	2	5
NPT	5	40	16	11	5	7
PON	10	11	15	15	6	17
RFD	27	14	22	7	1	6
SBY	11	11	20	4	4	1
WWS	7	17	24	10	8	14

CAIDI – Non-Catastrophic Storms, Cause = Equipment

SC		2015	2016	2017	2018	2019	2020
ANN	186	288	142	229	250	414	
CAN	325	200	600	700	400	169	
HWL	278	260	133	183	175	778	

LAP	218	400	280	400	300	177
MAR	271	338	367	267	750	511
MTC	114	120	233	233	200	179
NAE	320	240	109	300	67	185
NPT	250	500	229	220	125	314
PON	167	220	214	250	120	255
RFD	386	140	275	350	100	381
SBY	157	138	222	200	133	243
WWS	233	170	240	250	200	415

Exhibit A.3.15 SAIFI, SAIDI, CAIDI – Blue Sky, Cause = Equipment

SAIFI – Blue Sky, Cause = Equipment

SC	2015	2016	2017	2018	2019	2020
ANN	0.08	0.14	0.22	0.28	0.22	0.17
CAN	0.07	0.10	0.17	0.15	0.06	0.11
HWL	0.22	0.25	0.25	0.46	0.27	0.33
LAP	0.23	0.16	0.15	0.26	0.14	0.25
MAR	0.14	0.15	0.18	0.27	0.14	0.12
MTC	0.17	0.22	0.15	0.18	0.27	0.49
NAE	0.12	0.17	0.33	0.21	0.27	0.27
NPT	0.11	0.11	0.21	0.22	0.16	0.19
PON	0.18	0.19	0.26	0.30	0.25	0.32
RFD	0.16	0.19	0.21	0.23	0.08	0.17
SBY	0.14	0.31	0.36	0.27	0.27	0.29
WWS	0.15	0.15	0.28	0.20	0.18	0.22

SAIDI – Blue Sky, Cause = Equipment

SC	2015	2016	2017	2018	2019	2020
ANN	19	25	37	52	25	20
CAN	14	14	40	26	10	20
HWL	25	23	26	56	32	43
LAP	37	22	21	29	26	34
MAR	30	27	18	29	13	14
MTC	22	27	18	20	29	64
NAE	13	29	37	50	32	32
NPT	13	15	26	39	22	15
PON	49	29	35	43	34	44
RFD	24	28	32	35	10	20
SBY	16	50	37	38	27	28
WWS	28	23	55	25	25	25

CAIDI – Blue Sky, Cause = Equipment

SC	2015	2016	2017	2018	2019	2020
ANN	238	179	168	186	114	113
CAN	200	140	235	173	167	174
HWL	114	92	104	122	119	132
LAP	161	138	140	112	186	134
MAR	214	180	100	107	93	118
MTC	129	123	120	111	107	131
NAE	108	171	112	238	119	120
NPT	118	136	124	177	138	78
PON	272	153	135	143	136	138

RFD	150	147	152	152	125	118
SBY	114	161	103	141	100	97
WWS	187	153	196	125	139	115

Appendix V Pilot guidelines and information

U-20645 Pilot Plan Criteria
1. Pilot need and goals detailed • a. Need for the pilot is expressed. Results of past similar pilots and findings are shared to justify the need for the proposed pilot. • b. Pilot goals and desired learnings detailed. • c. Reference any pending applicable regulatory dockets, legislation, or other consideration relevant to the pilot project.
2. Pilot design and evaluation plan designed and presented together • a. Pilot program design and evaluation plans are designed together so examined metrics and collected data support evaluation of the pilot in meeting goals and desired learnings • b. If applicable, define target customer population, selection rationale (including those for location-driven programs), recruitment plans, and evaluation plans for customer adoption and satisfaction. • c. If statistical analysis will be conducted on pilot results, a statistically significant sample size must be selected, supported, and detailed. If a statistically significant sample size is not selected, justification must be provided. • d. If statistical analysis will not be conducted, justification must be provided as well as an approach for evaluating pilot goals. • e. If changes are required during implementation, pilot design, and evaluation impacts are shared.
3. Pilot project costs detailed • a. Project costs are detailed by source and amount for applicable periods. • b. Availability of non-utility funding and whether any was pursued (such as state or federal funding opportunities) described. • c. Anticipated cost-effectiveness and net benefits when deployed at scale described.   ○ i. Quantification of expected benefits of the pilot and the evaluation criteria/methods used. • d. Proposed rate recovery approach detailed.
4. Pilot timeline detailed • a. Proposed timeline for the pilot project and any related reports or evaluations delineated
5. Stakeholder engagement plan detailed • a. Stakeholder engagement plan before, during, and after pilot takes place detailed. • b. Interim and final stakeholder reporting described. • c. Expected publicly available data from pilot shared under proper protections and privacy.
6. Public interest detailed

- a. Public interest justification, including supporting the transition to clean, distributed energy resources; enhancing reliability, safety, affordability, or equity; or other related goals, and the pilot's expected impacts described.
- b. Any added benefits to ratepayers or the energy delivery system, either due to proposed site selection or through other pilot variables, especially if any system weaknesses or forecasted needs are addressed, shared.
- c. Expected impacts of the piloted measure on reliability, resilience, safety, and ratepayer bills detailed.
    - i. Pilot reduction goals for metrics like customer bill, outage minutes/frequency, and OSHA reportable, as well as the translation to full deployment expectations.
- d. Expected local or Michigan-based employment and business opportunities created by pilot described.
- e. Any potential impacts or added benefits of the pilot on low-income customers, seniors or other vulnerable populations described.
- f. Any other public benefits detailed.

Fisher NWA Pilot Design	
1. Pilot need and goals detailed	• Fisher substation pilot project will leverage several learnings of acquired from the Phase I, Hancock substation cost benefit model. These learnings include leveraging a newly developed DER Estimator tool to plan and target high impact, cost-effective programs with tested geographically targeted marketing to maximize participation results and minimize administrative costs in driving and tracking toward a set of highly analyzed peak load goals. • Determine the effectiveness of EWR and DR at addressing a substation over firm rating. Combining NWA options with traditional solutions will also be tested. The lessons learned will help develop future pilots and lasting process changes that reduce costs and carbon emissions.

2. Pilot design and evaluation plan designed and presented together	• Measures will include the following:
	  • Demand impact to expectation
	  • Participation rate
	  • Deployment time and incentives relationship to participation rates
	  • Customer acceptance of more frequent demand response interruptions
	  • Deployment costs

3. Pilot project costs detailed	• DR Scope and Cost
	  • Marketing (IAC & BYOD)
	  • Platform (EnergyHub)
	  • IAC equipment upgrades
	  • $208K – 2021 to 2024
	
	• EWR Scope and Cost
	  • Residential Implementation, incentive, and labor
	  • C&I Implementation and Incentive
	  • $1.8M – 2021 to 2024
	
	• STDF Scope and Cost
	  • Establish STDF (Sub-transmission Distribution Facility) along same sub-transmission line that feeds Fisher Substation
	  • Split FISHR DC 8188 with STDF circuit
	  • Install new conduit and cable
	  • $4.1M – 2021 to 2022

4. Pilot timeline detailed	• STDF Schedule
	  • 2021 – Conceptual design
	  • 2022 – Detail design and begin construction
	  • 2023 – Complete construction and commission
	• EWR Programs Schedule
	  • 2021
	    o Residential programs, September launch
	    o C&I programs, September ramp up and launch
	  • 2022-2024
	    o EWR programs continue through September 2024
	
	• DR Schedule
	  • 2021
	    o Establish program baseline
	    o Marketing
	      ▪ Introduce programs
	      ▪ Equipment upgrades
	  • 2022 – 2023
	    o Marketing
	      ▪ New customer acquisition
	      ▪ Existing customer education
	    o Equipment upgrades and maintenance
	    o Energy hub portal and subscription
	  • 2024
	    o Marketing
	      ▪ Customer retention and attrition management
	    o Equipment upgrades and maintenance
	    o Energy hub portal and subscription

5. Stakeholder engagement plan detailed	• Partner with NRDC for pilot review • Partner with Staff for pilot review
6. Public interest detailed	• Corporate and Government Affairs team will work with local businesses and community organizations to discuss the scope of the pilot and benefits from participating

Port Austin NWA Pilot Design	
1. Pilot need and goals detailed	**Needs** • Port Austin substation is 120% of firm rating • Over firm for approximately 60 hours per year • One circuit is 108% of day-to-day **Goals** • Effectiveness of solar + storage at reducing blocking hours • Refine evaluation tool for storage • Control, protection and security requirements for storage • Deployment costs, time and challenges • Operating processes, procedures and staffing • Microgrid development, operations and benefits
2. Pilot design and evaluation plan designed and presented together	• Measures will include the following: • Demand impact compared to expectation • Deployment time • Deployment costs • Reliability impact compared to expectation
3. Pilot project costs detailed	• Solar plus storage Installation: $4.5M • Potential Microgrid addition $0.4M
4. Pilot timeline detailed	• 2021 – 2022 o Property search o Conceptual engineering • 2022 o Detail design o Purchase property o Site prep o Start construction • 2023 o Complete battery installation o Complete solar installation o Evaluation of solar/storage to relief loading conditions • 2024 o Microgrid implementation and testing
5. Stakeholder engagement plan detailed	• Partner with MPSC Staff for pilot review
6. Public interest detailed	• Corporate and Government Affairs team will engage with local community leaders and officials

Omega NWA Pilot Design	
1. Pilot need and goals detailed	**Needs** • Two subtransmission lines feeding Omega had more than 1000 blocking hours in 2020 • High load growth in the area due to indoor agriculture **Goals** • Effectiveness of storage at reducing blocking hours • Refine evaluation tool for storage • Control, protection and security requirements for storage • Deployment costs, time and challenges • Operating processes, procedures and staffing
2. Pilot design and evaluation plan designed and presented together	• Measures will include the following: • Demand impact compared to expectation • Deployment time • Deployment costs • Reliability impact compared to expectation
3. Pilot project costs detailed	• Batteries – 5.7M • Install Batteries – 1.0M • Engineering – 0.5M • Total – 7.2M
4. Pilot timeline detailed	• Install batteries – Summer 2022 • Operate batteries – Summer 2022 to December 2023
5. Stakeholder engagement plan detailed	• Partner with MPSC Staff for pilot review
6. Public interest detailed	• Corporate and Government Affairs team will engage with local community leaders and officials

Veridian NWA Pilot Design	
1. Pilot need and goals detailed	Pilot Need • Net-zero community with solar, storage and EV charging • Base load + EV load could approach 1.5MVA • Fed by two circuits from Regent substation at 4.8kV, 81% firm rating Pilot Goals • Effectiveness of solar and storage at reducing load • Consumer behavior with microgrid and customer owned DER • Control, protection and security requirements for storage • Deployment costs, time and challenges • Operating processes, procedures and staffing • Microgrid development, operations and benefits
2. Pilot design and evaluation plan designed and presented together	• To be developed following customer application for service
3. Pilot project costs detailed	• Estimated cost is approximately $8.3M (DTEE + Developer + DOE Grant) plus additional private and public funding • Estimate to be revised during design

4. Pilot timeline detailed	• 2021
	  • Customer to submit formal request (Q3)
	  • URD detail design (Q4)
	• 2022
	  • OH circuit upgrades
	  • URD construction
	  • Start of Microgrid implementation
	• 2022 -2026
	• Expand Microgrid as customer units are constructed

5. Stakeholder engagement plan detailed	• Refine scope and expectations from the developer • Partner with MPSC Staff for pilot review
6. Public interest detailed	• Partner with the Ann Arbor community for pilot engagement

Front Lot URD - FRMNT1593 Pilot Design	
1. Pilot need and goals detailed	Pilot Need • The weather impacts from the summer of 2021 have generated customers interest in undergrounding lines. The Company is developing plans to partner with communities to convert overhead lines to underground lines where it makes sense by implementing Strategic Undergrounding pilots • In order to improve customer reliability and resilience to severe weather, alternatives to rear lot overhead construction are being piloted to determine the overall cost and performance of modifying the current infrastructure • In this pilot, overhead lateral infrastructure from rear-lot alleys will be removed and replaced with a looped URD system in the front lot. • Primary, secondary and services will be undergrounded • Poles will be removed from rear lot alleyway Pilot Goals • Determine down wire improvements of the strategic undergrounding for the customers on the FRMNT circuit • Develop a customer engagement plan and determine best practices for customer engagement • Refine estimates for URD costs, project duration, and uncover unforeseen challenges before ramping the program • Document operating processes, procedures, and staffing • Develop turnkey contractor for program level strategic undergrounding • Evaluate the overall total cost of ownership for underground infrastructure compared to overhead infrastructure
2. Pilot design and evaluation plan designed and presented together	• Evaluation of the pilot will include comparing down wires, reliability and emergent costs on the circuit before and after construction is complete, as well as completing an overall assessment of the total lifecycle cost of an underground lateral against an overhead lateral
3. Pilot project costs detailed	• Estimated cost is approximately $30M (URD, services, restoration, tree trimming, customer engagement) • Estimate to be revised during design

4. Pilot timeline detailed	• 2021
	    ○ Complete Engineering (Q4)
	    ○ Onboard Turnkey Contractor (Q4)
	• 2022
	    ○ URD detail design (Q1)
	    ○ Start FRMNT construction (Q23)
	    ○ Deploy Customer Engagement (Q1- Q4)
	• 2023
	    ○ Continue Customer Engagement
	    ○ Complete FRMNT Construction

5. Stakeholder engagement plan detailed	• Develop Customer Engagement Plan • Partner with MPSC Staff for pilot review
6. Public interest detailed	• Partner with the City of Detroit and Community Organizations for pilot engagement

Appendix VI Distribution Design Standards and Distribution Design Orders

Exhibit A-5 Distribution Design Standards and Distribution Design Orders

DDS Section 10 DDO Number	General Information Topic
DDO-0010-001	General Information
DDO-0010-002	DDO Writer's Guide
DDO-0010-003	DDO Procedures and Attachments
DDO-0010-004	DDO Index

DDS Section 20 DDO Number	Overhead Topic
DDO-0020-001	OH Construction Standards
DDO-0020-002	Subtransmission Systems Construction Voltage
DDO-0020-003	Distribution System Construction Voltage
DDO-0020-004	Overhead Construction Type
DDO-0020-005	Distribution Circuit Construction Grade
DDO-0020-006	Circuit Accessibility Construction
DDO-0020-007	Distribution Construction Pole Size
DDO-0020-008	Subtransmission Circuit Standard Conductor Sizes
DDO-0020-009	Distribution Circuit Backbone Standard Conductor Sizes
DDO-0020-010	Distribution Circuit Lateral Standard Conductor Sizes
DDO-0020-011	Distribution Circuit Crossings Standard Conductor Sizes
DDO-0020-012	Distribution Circuit Tree Exposure Standard Conductor Sizes
DDO-0020-013	Distribution Circuit Lightning Protection
DDO-0020-014	Overhead Construction Shield Wire
DDO-0020-015	Overhead Circuit Sectionalizing- Reclosers
DDO-0020-016	Overhead Circuit Sectionalizing- Switches

DDS Section 20 DDO Number	Overhead Topic
DDO-0020-017	Overhead Loop Schemes
DDO-0020-018	Overhead Jumpering Points
DDO-0020-019	Overhead Circuit- DG Interconnection Point
DDO-0020-020	Sectionalizing and Jumpering Points Requirements
DDO-0020-021	Circuit Laterals Sectionalizing
DDO-0020-022	Overhead Fault Indicators
DDO-0020-023	Secondary Construction
DDO-0020-024	Secondary Standard Conductor Type
DDO-0020-025	Distribution Transformers
DDO-0020-026	Services
DDO-0020-027	Circuit Tree Trimming

DDS Section 30 DDO Number	Underground Topic
DDO-0030-001	Underground Construction Standards
DDO-0030-002	Underground Conduit Design
DDO-0030-003	Underground System Cable
DDO-0030-004	URD Front Lot Design
DDO-0030-005	Cable Size and Type for Three Phase URD Loops
DDO-0030-006	Cable Size and Type for Single Phase URD Loops
DDO-0030-007	Residential Padmount Transformer Size
DDO-0030-008	UG Fault Indicators

DDS Section 40 DDO Number	Substation Topic
DDO-0040-001	Substation Construction Standards

DDO-0040-002	Substation Property
DDO-0040-003	Substation Blocking
DDO-0040-004	Station Class Standard
DDO-0040-005	Substation Class Standard
DDO-0040-006	Industrial Substation Standard
DDO-0040-007	Class A and R Substation Transformer Size
DDO-0040-008	Class T Substation Transformer Size
DDO-0040-009	Portable Substation
DDO-0040-010	Subtransmission Distributed Resource

DDS Section 50 DDO Number	Circuit Protection Topic
DDO-0050-001	Substation Fault Current
DDO-0050-002	Minimum Fault Current
DDO-0050-003	Protection Device Coordination
DDO-0050-004	Fuses and Oil Reclosers Loading
DDO-0050-005	Fault Current Interrupting
DDO-0050-006	Minimum Fault Current
DDO-0050-007	Primary Fuse Saving
DDO-0050-008	Maximum Number of Devices

DDS Section 70 DDO Number	Voltage Topic
DDO-0070-001	Primary Voltage Limits
DDO-0070-002	Secondary Voltage Limits
DDO-0070-003	Voltage Unbalance
DDO-0070-004	Voltage Flicker
DDO-0070-005	Power Factor

DDS Section 70 DDO Number	Voltage Topic
DDO-0070-006	Harmonics
DDO-0070-007	Subtransmission Power Service

DDS Section 80 DDO Number	Project Benefit Evaluation Topic
DDO-0080-001	Project Benefit Evaluation

DDS Section 90 DDO Number	Loading Topic
DDO-0090-001	Maximum Outage Duration
DDO-0090-002	Peak Demand Load
DDO-0090-003	Substation Loading
DDO-0090-004	Load Imbalance
DDO-0090-005	13.2 kV Normal Circuit Loading
DDO-0090-006	13.2 kV Emergency Circuit Loading
DDO-0090-007	4.8 kV Normal Circuit Loading
DDO-0090-008	4.8 kV Emergency Circuit Loading
DDO-0090-009	13.2 kV Load Loss
DDO-0090-010	13.2 kV Single Phase URD Loading
DDO-0090-011	13.2 kV Three Phase URD Loading
DDO-0090-012	Redundancy

DDS Section 100 DDO Number	System Automation Topic
DDO-0100-001	Device Monitoring, Power Quality, AMI and Industrial Metering
DDO-0100-002	System Network Model and Asset Data Model

DDS Section 100 DDO Number	System Automation Topic
DDO-0100-003	System Automation
DDO-0100-004	Telecommunications
DDO-0100-005	Interconnection
DDO-0100-006	Technology Maturity

DDS Section 110 DDO Number	Urban Networks Topic
DDO-0110-001	Network Feeder Configuration
DDO-0110-002	Urban AC Network Substation Configuration
DDO-0110-003	Network Feeder Routing
DDO-0110-004	Contingency Design Criteria
DDO-0110-005	Feeder Group Configuration
DDO-0110-006	Feeder Cable Size
DDO-0110-007	Feeder Sectionalizing
DDO-0110-008	Network Platforms
DDO-0110-009	In-Building Installations
DDO-0110-010	Netbank Cable Size
DDO-0110-011	Netbank Voltage Configuration
DDO-0110-012	Netbank Size
DDO-0110-013	Netbank Protector SCADA
DDO-0110-014	Secondary Areas
DDO-0110-015	Secondary Main Size
DDO-0110-016	Secondary Main Protection
DDO-0110-017	Secondary Moles
DDO-0110-018	Secondary Services

The following appendices are attached separately to this document

Appendix VII Customer focus groups

Appendix VIII Community leader engagement

Appendix IX DTEE/ICF Grid Modernization Study 2021-2035

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
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 (SCADA) 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 daily 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 misoperation 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
SOC	System Operations Center
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

DTE

Distribution Grid Study

Appendix VII Customer Focus Groups

Final Report

May 20th, 2021

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Study Overview

Study Background and Research Objectives

- As DTE prepared to present its 5-year Electric Distribution Grid Plan to the Michigan Public Service Commission, it was cognizant of the need to incorporate input from a cross section of its customer base, both on the residential and commercial sides of its business.
- This input was intended to inform the plan as well as provide insights into emerging customer priorities when it comes to their own electricity usage as well as the best context in which to continue communicating to customers about changes to DTE's electric grid.
- In order to provide a forum where customer's natural priorities and language can "bubble up" and enter into DTE's grid plan, a qualitative, conversational approach was recommended rather than a quantitative research survey.
- This qualitative research explored five key areas:
    - Current perceptions of DTE's current grid reliability
    - Awareness of positive or negative trends to that reliability
    - Anticipated trends in terms of electricity usage at a household or business level over the next five years
    - Support for grid improvement (and willingness to fund actions that do more than maintain status quo)
    - Reactions to potential messaging/communications

Study Methodology

- This study consisted of 13 Zoom-based focus group discussions among both residential and commercial customers, among a total of 52 residential customers and 23 commercial customers.
- Participants were recruited from DTE-provided customer lists.
- Discussions were 75 minutes in length. Residential customers were incentivized with a $125 Amazon eGift Card and commercial customers were incentivized with a $150 Amazon e-Gift Card.
- The residential discussions were hosted on April 27th, 28th, and 29th, 2021. Commercial discussions were hosted on May 5th and 6th, 2021.

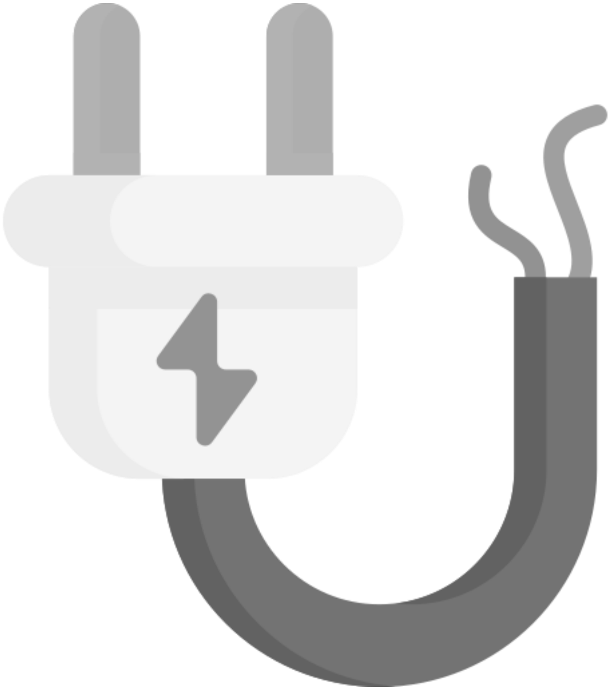
Study Methodology

- A total of 7 residential customer groups were completed:
  - Financially vulnerable households
  - Clean energy advocates in Washtenaw County
  - Rural electric customers in Thumb area
  - City of Detroit combo customers
  - Geographic mix of customers in high reliability/recently upgraded grid areas
  - Geographic mix of customers in average reliability grid areas
  - Geographic mix of customers in low reliability areas due for grid upgrades
- A total of 6 unassigned commercial customer groups were completed:
  - Geographic and industry/category diverse mix of owners with low/average electricity component of their cost of goods/services sold (COGS)—one group each of owners in low, average, and high reliability areas
  - Geographic and industry/category diverse mix of owners with high electricity component of their cost of goods/services sold (COGS) —one group each of owners in low, average, and high reliability areas

75-minute Discussion Flow

- Current experience (25 minutes)
  - Perceptions of DTE as a provider in terms of service, maintenance, innovation
  - Customer experiences relating to energy “cleanliness” and reliability
  - Current electric usage profile
  - Current environmental priorities/perceive connection to electric production/usage
- Anticipated trends (20 minutes)
  - Probable shifts in electricity usage
  - Concerns relating to cost, reliability, environmental impact of higher electric demand
- DTE distribution grid plan (30 minutes)
  - Short “education” deck to explain needed infrastructure improvements and associated costs
  - Initial reactions to distribution grid plan, including perceived benefits, concerns, areas of confusion, etc.
  - Willingness to accept/perceived appropriateness of rate increases relating to plan

Energy Usage



ENERGY USAGE

- Both residential and commercial customers felt their **energy usage has been fairly consistent for the past 5 years**. Lifestyle or domicile changes were noted as drivers of increased usage among residential customers.
- **Expectations for future usage varied** between residential and commercial customers:
  - Most residential customers anticipated their future energy usage will stay fairly consistent over the next 5 years – the remainder anticipated their usage would increase due to continued expanded use of personal electronics and potentially an electric vehicle.
  - Commercial customers that expected an increase in usage plan on expanding or requiring more electrical-intensive appliances. Businesses that expected their electrical usage to stay consistent over the next 5 years are often those that have recently taken action to become more energy efficient, with the intention of those savings will offset any potential rise in usage or rates.
- Regardless of their personal usage, both residential and commercial consumers consistently **expected regional electrical use to increase over the next 10 years**, driven by personal electronics and technology advancements – particularly electric vehicles.

"We're more electronically connected [than 5 years ago]. We have Alexa and Echo devices in all of our major rooms, and we have Ring outside." –Residential customer

"We will likely go up in our electric bill, but it will get truncated when we start using gas as our heating element [rather than electricity]. 5 years ago we were working out of my parent's garage, and we're moving into our second building, so we were using way less [electricity] than 5 years ago." –Commercial customer

"People are growing pot inside and mining cryptocurrency, that takes a lot of energy. Even with the more efficient [technology], it seems as civilization progresses, it demands more energy. Right now, the focus is on using electricity as a power sources and people are against fossil fuels." –Commercial customer

- **Electric vehicles are a technology that virtually no residential customers anticipated adopting** within 10 years, once again showing indications that the auto industry is moving to EV adoption at a much faster rate than consumer demand would suggest.
- Residential customers were also not aware of near-term shifts in the availability of electric vehicle models or the industry's ability to expand electric vehicle range to 300+ miles per charge (suggesting that **consumer attitudes toward electric vehicles may change dramatically in the next 5 years**).
- **Commercial customers were more likely to recognize the inevitability of electric vehicles** becoming the dominant type of vehicle.

"Just looking around my neighborhood, I'm the only one that has an EV. I know that definitely contributes to my energy consumption." –Residential customer

Does anyone else anticipate moving to an electric vehicle in the next 10 years?

"I hope not." –Residential customer

"I hear the cars are going electric. [I may] end up with an electric car, which I'm not planning on. I'm not convinced yet." -Residential customer

"Our cars are over 10 years old, but I think the way the world is going, we may not be able to buy a non-electric vehicle. An EV wouldn't be our first option, but it may be what we're left with." –Residential customer

"I think [the region] may increase in [electric] usage, and that's whether or not the electric vehicle takes off." –Commercial customer

"With everyone talking about going green, there's a tremendous push to get away from fossil fuels and to move to electricity. More and more I see Teslas running about. I have to think that our electric consumption is going to creep up as we get more electric trucks and cars on the road." –Commercial customer

Current Perceptions of DTE

CURRENT PERCEPTIONS OF DTE

- **Perceptions of DTE were fairly positive** in terms of reliability, innovation, and environmental stewardship, regardless of their reliability classification at a DTE circuit level.
- Nevertheless, **DTE affinity was driven almost exclusively by personal reliability experiences**.
- **Customers found it almost impossible to talk about DTE's performance on a regional or company-wide level** – they simply don't pay that much attention.
  - Residential customers' confidence in DTE's ability to meet future demand was highly correlated to the company's ability to provide that customer's household with reliable power right now.
  - Commercial customers tended to take a more regional view about reliability and were often more cognizant of problems in part of the gird that may not affect their account directly.

"We don't have brownouts here, or times where we are asked not to used electricity, and I've never been told not to use hot water heaters in the winter, so based on my personal experience I would think [DTE can handle future demand]. We seem to be doing alright." –Residential customer

"I'm very confident DTE is doing a good job. They're providing the best service to my business, as I can see." –Commercial customer

"I don't have any concerns. When we flip the switch, the lights go on, and it's always been like that. I think DTE is generally very responsive. I'm a satisfied customer." –Commercial customer

- **Both residential and commercial customers often cited the <u>lack of visible or specifically identifiable maintenance or upgrades to the electrical grid</u>** as evidence that DTE does not aggressively maintain or upgrade its distribution grid.
- In all honesty, customers don't know what they should be looking for other than the presence of DTE work trucks or crews in their area doing "something" – essentially, presence=maintenance.
- Recognizing that they may be missing DTE's actual performance when it comes to maintenance and infrastructure upgrades, residential customers often **suggested that DTE regularly <u>communicate to them infrastructure updates</u> that represent modernization in their immediate communities** so they better understand what is actually taking place even if they don't personally see the work getting done.

"We're in the dark, literally, about what [DTE is] doing to make improvements. They are, but it should be visible to the customer. We see the trucks and sometimes see the [tree] trimming, but there's no bigger picture for us.

It's the only way to build trust and confidence, is if there's a little bit of information. It doesn't have to be too much." –Residential customer

"As I drive around and I look, a lot of DTE's structures are in poor condition, arm braces are falling off. It's because DTE is not spending the money on maintenance." –Commercial customer

Reactions to Smart Grid Benefits

Before talking about specific changes to the distribution grid, residential respondents were given an "off the shelf" overview of what the electric industry anticipates over the next 10 years in the form of an Edison Electric Institute video (bottom left).

- Confusion and a lack of reaction were common.
  - Virtually no residential respondents were able to identify benefits of a modern distribution grid as presented in the Edison Institute video.
  - Once the moderator outlined the benefits more clearly, there was a recognition among residential customers that there might be concrete benefits to modernizing the grid, although serious doubts and significant confusion remained.

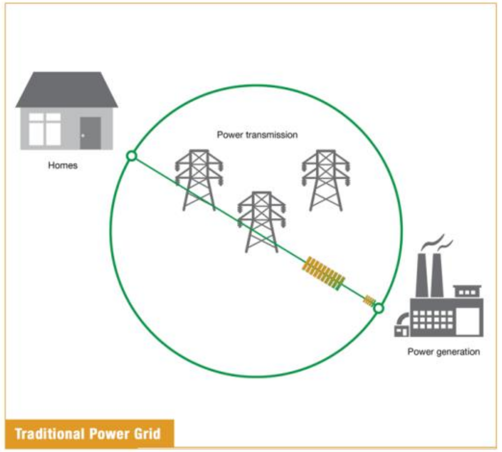
"It was a little too school-house rock. There wasn't enough detail. A little more detail would have helped me grab onto it better." –Residential customer

"It really didn't show me anything. It didn't really say that anything is going to change." –Residential customer

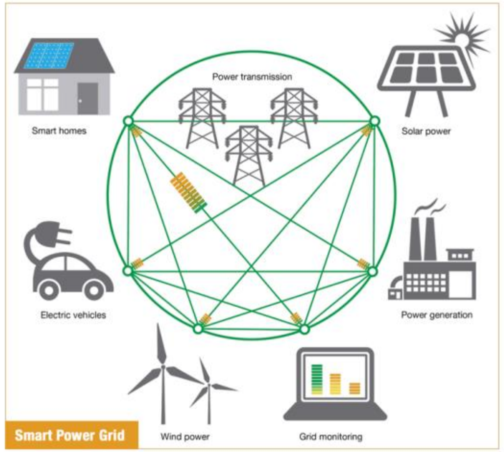
Because the Edison Institute Video was so confusing among residential respondents, commercial respondents were given a visual overview by the moderator of what the electric industry anticipates over the next 10 years (bottom).

The visual overview included two diagrams highlighting the differences between a traditional and advanced gird, as well as a bullet-point list of benefits to enhance clarity and further drive discussion.

Traditional Electric Grid



Advanced Electric Grid



Advanced Electric Grid Benefits

- Replaces technology that hasn't changed dramatically across the US in past 100 years (immediately improving reliability and durability in poor weather conditions)
- Ability to handle higher electricity loads (so reliability stays high as the number of electric vehicles and personal electronics increases)
- Ability to manage higher number of distributed power sources (for example, homes with roof solar panels) back into the grid
- Better remote visibility/monitoring/adjustment of the electrical system by utilities (leading to fewer outages, smaller outage areas, and faster power restoration)
- Increases customer choices in terms of rate plans and access to customized programming/products

- **Initial reactions to the smart grid varied by customer type.**
  - Residential customers were open to the need for maintenance and modernization of today's basic grid, but were less likely to be excited about the more "intelligent" elements of a smart grid – largely because the majority did not anticipate widescale adoption of electric vehicles in the next 10 years.
  - Not surprisingly, initial reactions from commercial customers suggest they were more open to the need for modernization but were more immediately concerned about the cost implications and potential bill increases.
- Across both types of customers – even among those who were enthusiastic about a grid overhaul – **it wasn't until they were made aware of the downside risk of NOT modernizing the grid that customers ultimately saw enough value in the modernization to pay more to get it**.

"Especially with the power outage situation, if [DTE] can get most of the houses back on [with electricity], that will help everyone out." –Residential customer

"The theory is great. From a business perspective, especially one with computer servers, reliability is absolutely essential." –Commercial customer

"I think you would do yourself a disservice if you didn't have holistic conversation about both the positives and the negatives [of improving the grid] and you need to find a path in the middle. Yes, you pay a little more, but you improve [the grid].

[Conversations with business customers] need to work with different organizations. What a new bakery post-pandemic is looking at versus a 100-year-old art organization are two different conversations." –Commercial customer

Equity

EQUITY

- **The <u>issue of equity</u> surfaced spontaneously in virtually every residential discussion group**, often at different times and focused on different aspects of the grid plan.
  - One equity concern was the **potential inability of lower income households to pay for the increase** in their electric costs.
  - A second equity concern was **whether industrial customers would be paying their fair share** of the modernization or whether they would benefit off the backs of residential customers.
  - A third equity concern was **making sure the new grid was built out in a way that did not benefit more affluent areas first**.
- Perhaps because of their focus on their own bottom line, **equity was rarely an issue raised in business groups**.

"It sounds lovely that [infrastructure updates] would happen all across the board, so the communal grid can happen,. But I worry about how that's dispersed."-Commercial customer

"Personally, I could absorb the cost I imagine DTE could charge [for upgrades], but if there weren't assistance programs available I could see [increased costs] being a real impact for people who are struggling to pay their electric bills." –Residential customer

"In my building I live with all seniors who are on a very fixed income. If you're going to buy groceries or pay for your medicine, you need to keep those [electric] costs down." -Residential customer

"Is this going to be a persistent goal to improve reliability in communities of color and communities of lower socioeconomic status?"
–Residential customer

"I could absorb the cost but I'd like to see [grid improvements] be balanced across all walks of life and make sure that everyone has equal access to power."
–Residential customer

Reactions to Potential Headlines

"DTE is listening to our customers and preparing the energy grid for the growth and demand for electric technologies like electric vehicles and private and universal solar."

- **Most preferred approach** to introduce dialogue about the grid.
- **Provides specific customer-side benefits** (increase demand for electric technologies like electric vehicles).
- Suggests that the decisions are being made **to address needs from DTE customers**.
- An issue that come up several times in the commercial groups was a question about the legitimacy of demand for electric vehicles and alternative energy sources and whether the utility was reacting to regulatory pressure instead of proceeding in a direction that most customers would actually want.

"It mentions two new technologies."
–Residential customer

"DTE directly said they're listening."
–Commercial customer

"People have painted a target on natural gas. That's what concerns me, when those influences cause the company to then put time and effort into things that they maybe shouldn't be at the time."
–Commercial customer

"'The concept that stands out is that 'we are making this better'. This is a better message than 'we are doing so much for [our customers]'. Nobody is going to believe that." –Commercial customer

"[I prefer this one because] I would rather DTE tell me how they're going to improve things and THEN they can tell me what it costs."
–Commercial customer

"DTE has been investing $1 billion per year on behalf of our customers to upgrade the grid to help improve safety and reliability, but we need to do more."

- Although some saw the $1 billion as evidence of commitment, the lack of reference or scale left some customers feeling lukewarm and **unsure of how significant the investment truly was**.
- The statement **provides no concrete, customer-side benefit** other than a generic safety and reliability promise.
- "We need to do more" does suggest a need for further attention from the reader and **acknowledgment from DTE that the current pace won't address the problem**.

"I like to know they are investing in our future." –Residential customer

"I like the last line. It makes me think that DTE is looking for my input." –Commercial customer

"They're stating what they're going to do and stating it in words that allow them to be held accountable." –Residential customers

"'On behalf of our customers'… that feels so fake." –Commercial customer

"Before asking us for more money, DTE is stating that they are giving $1 billion per year on behalf of their customers. It makes the best sense, to me. They're putting in, it's not just the customers." –Residential customer

"$1 billion seems very broad. That's a huge number; it's too abstract. I would love to see 'in your local community, this is how it impacts you'. If you show me on a granular level in [my area], that's a part of that billion dollars, it speaks in a different way. It's like a statement of proof; I made this claim, here's how you can see it in action." –Commercial customer

"DTE will Leverage the latest technology to increase safety and improve reliability into the future."

- **Least preferred approach** to introduce dialogue about the grid.
- **Lacked any reference to changes to the grid and provided no specific customer-side benefits** other than safety and reliability, which customers view as DTE's cost of doing business.
- The approach **lacked any sense of newness or shift in business strategy**. Essentially, this was viewed as something DTE has said for years.

"It's just blah and vague." –Residential customer

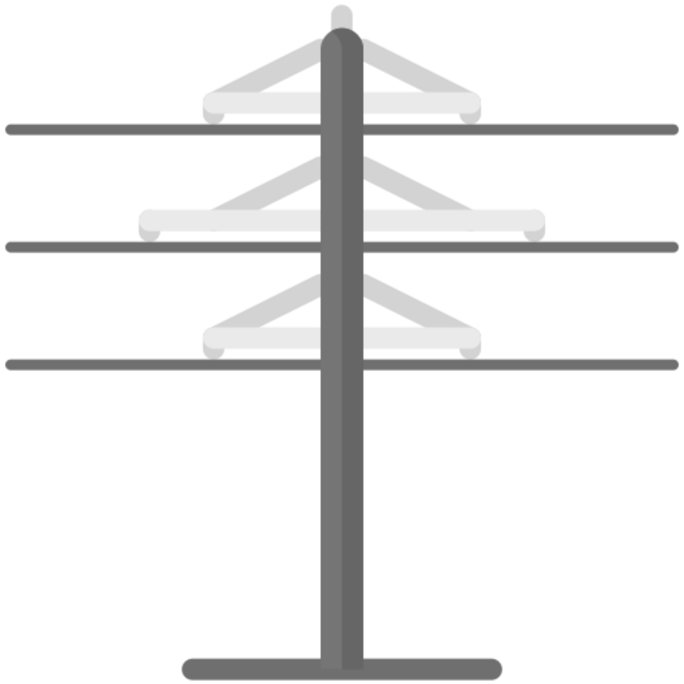
"That's jargon and vague. It's a random mission statement." –Commercial customer

"It feels generic and like I've already seen that one, so it doesn't feel like information. It just doesn't register anymore." –Commercial customer

"It sounds like a mission statement on the DTE website. It doesn't elicit any response, it's just a blanket statement." –Commercial customer

Special Issue: Rear Lot to Front Lot

Residential Groups Only



- A special topic presented only to residential participants, DTE was curious about residential customer reactions to the possibility of moving backyard power lines to the front yard with the intention of cutting down recovery time.
- Reactions were mixed to this idea with no clear majority point of view.
  - **Residential customers in favor of this switch** expected a faster recovery from outages, and those in more urban areas noted this switch would no longer need them to relocate vehicles parked in alleys.
  - **Customers against this switch** noted the negative aesthetic impacts. There were some concerns about increased car/pole collisions if poles were relocated to front boulevards.

"Where would it even go in the front yard? It just seems really awkward." –Residential customer

"I don't want to look at power lines in front of my building." –Residential customer

"Safety and reliability. There's too much traffic in the front , hence, you can have more accidents." –Residential customer

"That would be lovely!" –Residential customer

"[I would support moving the lines to the front yard] as long as it is safe." –Residential customer

"It wouldn't bother me, none." –Residential customer

Conclusions & Implications

As a region, both residential and commercial customers anticipate an increase in electric usage and electric vehicles.

- Thinking about energy usage outside their own residence was difficult for residential customers. Most lacked a desire to adopt EV technology, further driving their expectation of personal usage to maintain steady (as opposed to expected regional usage). In turn, infrastructure upgrades were not often viewed as necessary.
- On the other hand, commercial customers were more likely to expect largescale EV adoption, as well as usage increases within their own business. Even so, their positive experience with DTE tended to cloud their understanding of why grid modernization was needed; if I'm not having reliability issues, why invest money in an upgrade?
- **Infrastructure upgrades designed to ease the transition will need to be made before customers realize they need them.**

While perceptions of DTE were positive, customers felt DTE does not aggressively maintain or upgrade its distribution grid because of a lack of visible upgrades and maintenance.

- Maintenance and infrastructure upgrades were largely tied to seeing those changes first-hand. If customers aren’t seeing work done, they don’t believe it *is* being done.
- It was clear that customers don’t want to know “how the sausage is made”, but there was still interest in infrastructure updates and maintenance within their community. In the end, most customers only care about what changes will impact their household.
- **Including local modernization efforts on customer bills may alleviate perceptions of DTE not maintaining or upgrading the grid.**

Value and willingness to pay for modernizing the grid was not recognized solely on benefits of this plan. Customers being made aware of the negative implications of NOT making modernization efforts is what ultimately drove value in the plan, as well as willingness to pay.

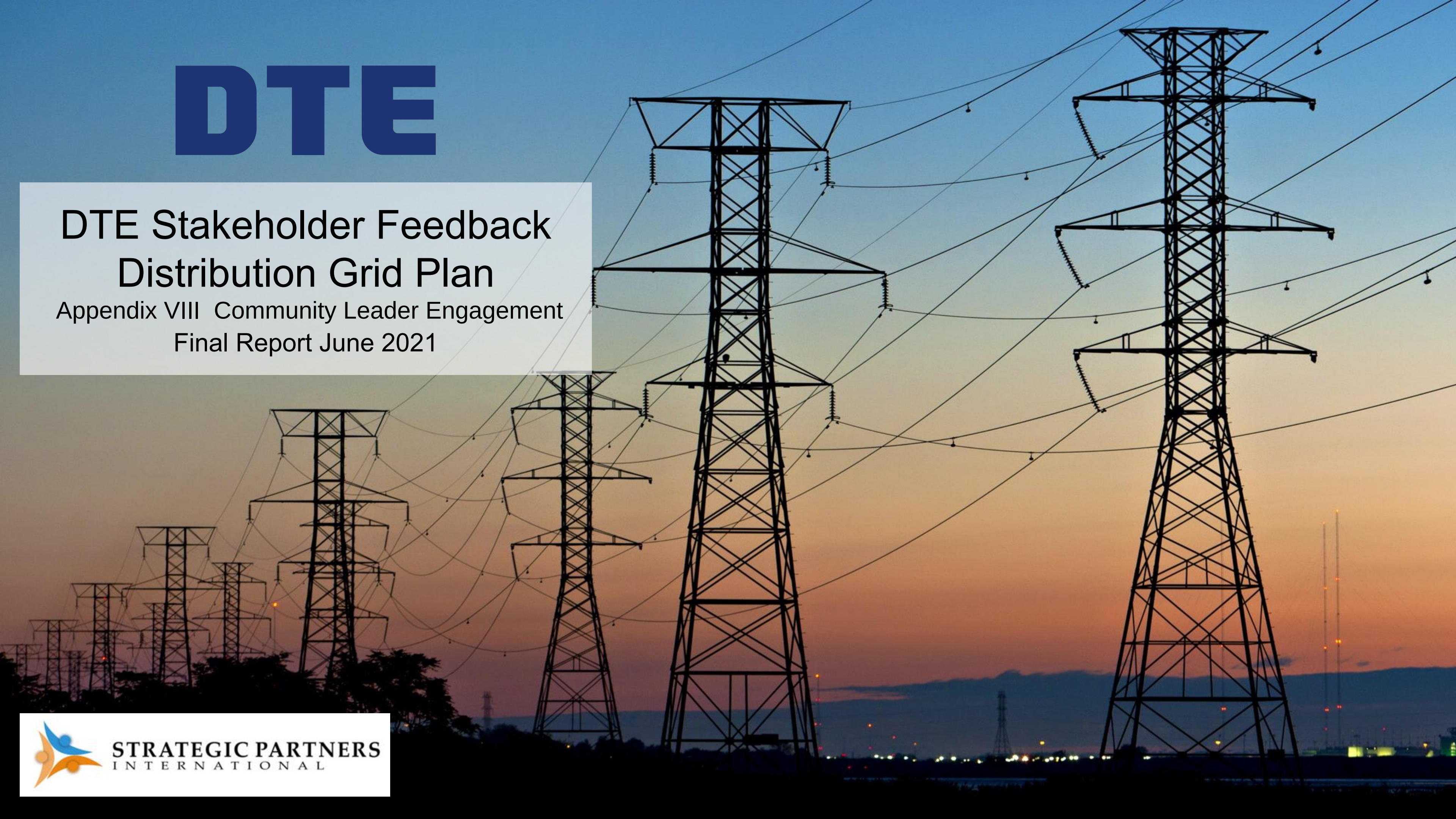
- Coupled with the negative implications of not taking action, the personal benefits customers can expect for their household further resulted in “buy in” of the grid modernization plan.
- When communicating this plant to both residential and business customers:
  - Provide specific customer-side benefits (“What do I get out of this?”)
  - Provide customer-side downfalls if action isn’t taken (“What if I say no?”)
  - Indicate customer needs are being addressed and the plan is reflective of what customers want (“DTE, is this plan for me or you?”)
- **Introducing the modernization effort must include benefits of action and risks of inaction to truly engage customers enough for them to accept the reality of higher cost.**

DTE

DTE Stakeholder Feedback Distribution Grid Plan

Appendix VIII Community Leader Engagement

Final Report June 2021



STRATEGIC PARTNERS INTERNATIONAL

OVERVIEW & APPROACH

Stakeholder Outreach Plan & Objectives

- Strategic Partners International interviewed influential community leaders to gather feedback on their constituent's energy usage and anticipated needs over the next five to fifteen years. These leaders were also asked their views on the role of DTE and the role of energy for their constituents.
- DTE wanted to understand this insight for incorporation into their Electric Distribution Grid Plan for the Michigan Public Service Commission. This plan will lay out DTE's vision for the electricity grid to meet the needs of Michigan communities.
- The interviews focused on 4 key areas:
  - Introduction & Purpose of Interview
  - Current Electric Usage Profile
  - Current Perceptions of DTE
  - Grid Plan Review

Stakeholder Types

Community Activists

Community Service
Organizations

Faith Based
Leaders

Public Sector Officials
(elected & non-elected)

Discussion Flow

- Introduction & Purpose of Interview (3 minutes)
  - Option for feedback to be anonymous, or provided to DTE for a follow-up discussion.
- Current Electricity Usage Profile (12 minutes)
  - How constituents energy usage compares to others in the community/region and what pulls the most electricity day to day.
  - Shifts in usage over the last 5-10 years (including impact of the pandemic) and anticipated shifts over the next 5-10 years
- Current Perceptions of DTE (20 minutes)
  - Perceptions of DTE in terms of reliability, innovation, environmental stewardship, and affordability.
  - What, if anything, DTE does really well and where future improvements should be focused.
  - Trends and societal shifts that may be a challenge for DTE over the next 10 years - and the ability of DTE to stay ahead of those trends.
- Grid Plan Review (15 minutes)
  - Educational slide to explain DTE’s current grid and how it needs to shift to meet future demands (screenshared).
  - Initial reactions to DTE’s plan, how it would benefit constituents, and the risks of the plan not coming into being.
  - The most persuasive arguments for making an investment to modernize the grid.
  - Any aspects of the plan that are relatively unimportant.
  - Willingness to bear additional costs to achieve a modern electric grid.

CURRENT ELECTRICITY USAGE

Perceptions of Constituents’ Current Usage

- Majority of stakeholders believe their constituent’s energy usage is ***average or above*** - almost none responded with below average.
  - Heating, insulation, efficiency are top of mind in Detroit.

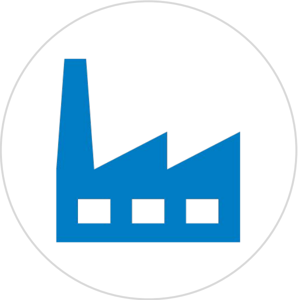
- The ***top contributing factors*** to this belief were:
  - Increased technology usage and dependence (despite more energy efficient devices).
  - Constituents, particularly seniors, living in older homes that are not weatherized and don’t have energy efficient appliances, or other energy saving technologies.
  - Manufacturing entities involved in processing, assembly, and injection.
  - Large families contributing to household use, including kids home over high school age.
  - Constituents working multiple jobs and shifts leading to energy usage around the clock.
  - Businesses and apartment buildings drawing a lot of energy.
  - New grow houses being developed in different communities.

COVID-19: Impact On Usage

- There were ***mixed responses*** on how energy usage has shifted the last year during the pandemic.
  - Residential usage is overwhelmingly believed to be up. Although less so in areas where the digital divide is still prevalent.
  - Usage among businesses, however, is believed to have decreased due to the shutdown. Same with manufacturing, with new limitations on how many operators can be online at once.
- The ***top contributing factors*** to believing usage increased were:
  - Students using technology to attend school from home - and adults online to work remotely.
  - More time spent in homes, overall.
- Alternatively, others believe the ***economic shutdown*** decreased energy consumption.
  - Lower income communities, particularly Southwest Detroit, did not use as much energy in part due to lack of technology and businesses permanently closing.
  - The chip shortage was also cited as a possible factor.
  - Some were more conscious of their energy usage in an effort to cut down on expenses.

Top Contributors to Electric Bills

- According to community leaders, ***household upkeep*** and ***everyday technology***, draw the most energy usage on a day-to-day basis.
  - Majority of usage comes from keeping the lights on, using appliances, and running air conditioning/heat.
  - Charging multiple phones, computers/laptops, and tablets draw electricity as well - and many families keep TVs/cable boxes on 24 hours/day.
- Stakeholders who represent commercial entities cited ***large industry*** and ***intensive manufacturing*** as the biggest energy draw (particularly for the top 10 tax-paying businesses in MI).



Looking Ahead: Increasing Energy Usage & Efficiency

- Contributors to the ***increase in demands for energy*** include:
  - Grow houses and the up-and-coming trend of indoor agriculture.
  - Increased work-from-home opportunities after the COVID-19 pandemic.
  - New business development and gentrification in Detroit.
  - Electric vehicles as they expand outside of higher-income communities.
  - Climate change and extreme temperatures increasing the need for heating and/or air conditioning.
  - New bridge to Canada and business subsidiaries.

- While demand for energy is increasing, stakeholders also voiced the counterbalance of potential decreases in usage thanks to ***energy efficient technologies***.
  - Energy efficiency improvements made possible by the 2009 American Recovery and Reinvestment Act, and hopefully future programs as well.
  - Participation with MI Green Power, Smart Savers (Ecobee3 Lite) and other DTE programs, although increased participation is needed.
  - Pushes for clean energy at the federal level, including electric vehicles, will alter energy mix
  - A growing awareness of the need for clean energy - due to environmental (more than financial) reasons.

Stakeholders Anticipate Greater Usage

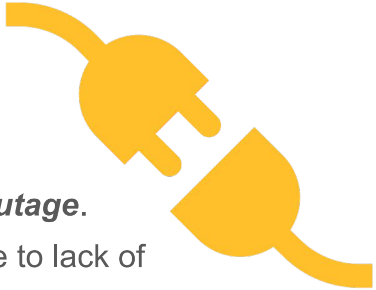
- Overall, there is consensus that there will be ***increased demand for energy*** in the next five to fifteen years as recent trends are expected to expand and solidify.

- The top ***contributing factors*** to increases in usage include:
  - Heavier reliance on technology, particularly as televisions continue to remain a significant source of home entertainment.
  - Economic growth in various neighborhoods, including increased housing stock, businesses, and energy drainers like indoor agriculture.

- In anticipation of greater usage, ***affordability and sustainability*** are top of mind.
  - There is significant concern around affordability given the current economic situation
    - "Are we risking leaving large swaths of population without access to energy?"
  - Solar is consistently cited as a very important aspect to the mix as there is a transition to clean energy.
  - The economy will play a huge factor as more jobs and better paying wages will allow more people to achieve energy efficiency through new appliances and weatherization.

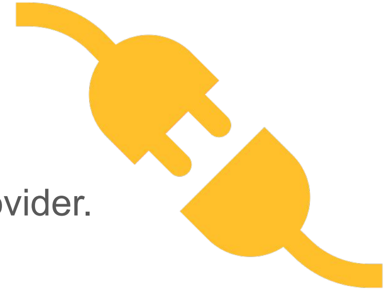
CURRENT PERCEPTIONS OF DTE

Summary of Stakeholder Feedback



- ➔ DTE is seen as a ***reliable service provider***. Reliability is usually ***only top of mind during an outage***.
- ➔ Overall, DTE is ***not seen as a leader in innovation or environmental stewardship,*** in part due to lack of awareness.
  - ◆ ***Solar*** was the most common form of renewable energy mentioned.
- ➔ Overall, ***DTE is seen as affordable*** among the general public, but there are large portions of communities that don't believe so.
  - ◆ Several community leaders mentioned the critical ***role of the federal government*** in supporting low-income individuals with affordability challenges.
  - ◆ There is a ***perception*** that DTE is placing the onus of increased costs on individual consumers rather than businesses.
- ➔ DTE's ***community engagement*** is seen as a strength.
- ➔ ***Social responsibility***, in part based on DTE's anti-racism statement last year, was mentioned as an expectation — especially as regards innovative solutions to advance affordability among low-income households.

Reliability of DTE



- DTE is seen as a ***reliable service provider***, and an increasingly more reliable provider.
  - Recent winters seem to be milder, so outages aren’t as top of mind.
  - New substations and tree-trimming are helping decrease outages, or at least the duration of outages.
  - Natural gas and nuclear power plants will help retain reliability as more coal plants are closed.
- Reliability is only ***top of mind during an outage***.
  - Outages are typically caused by storms and other factors outside of DTE’s control.
  - Certain neighborhoods continue to have reliability issues due to infrastructure, but many areas have been addressed.
    - There are a few special cases where reliability is frequently a problem year-round, including Detroit’s Scotten-Vernor area.

Innovation of DTE

- ➔ Overall, DTE is ***not seen as a leader in innovation,*** in part due to lack of awareness.
    - ◆ There was some recognition that work is <u>likely being done</u>, but most stakeholders could not speak to it personally - of if they could, their constituents could not.
    - ◆ Innovation in terms of movement away from coal to <u>clean energy and net zero</u> was mentioned generally by grasstops leaders with whom DTE communicates regularly.
- ➔ DTE can ***do more to communicate*** what it is doing relative to preparing for the future of energy.
- ➔ There is a great opportunity for DTE to ***innovate relative to affordability***.
    - ◆ Innovation isn't just technological advances to produce cleaner energy, but how can it be done in an <u>affordable and equitable</u> manner.
    - ◆ DTE can develop <u>innovative business models and policy solutions</u> and emerge as a leader among utilities nationwide.

Environmental Stewardship of DTE

- ➔ For majority of residents, environmental stewardship is ***not a top of mind*** issue.
  - ◆ Most consumers are largely unaware of DTE's green programs.
  - ◆ There is some level of awareness of DTE's efforts among grasstops leaders.

- ➔ DTE is ***not generally seen as an environmental leader***.
  - ◆ Some stakeholders feel DTE could be more proactive in this space, rather than taking action when pushed.
  - ◆ There is some desire for a faster timeline to achieving net zero, which specifically impacts perceptions of the company's overall environmental stewardship.

- ➔ ***Solar*** was the most common form of renewable energy mentioned.
  - ◆ There is a concern that DTE is not involving African American communities in solar efforts.
  - ◆ Stakeholders desire more pilots and education around solar.

Affordability of DTE

- ➔ Overall, ***DTE is seen as affordable*** among the general public but there are large portions of communities that don't believe so.
  - Among those who struggle to pay their utility bills, those who are <u>enrolled in DTE programs</u> are generally OK with cost.
  - Low-income customers who are <u>unaware</u> of available programs are very unhappy.
- ➔ Several community leaders mentioned the critical ***role of the federal government*** in supporting low-income individuals with affordability challenges.
  - Some states have a cap on the percentage of one's income that goes to utility bills, say 4%.
- ➔ There is a ***perception*** that DTE is placing the onus of increased costs on individual consumers rather than businesses.
  - Some consumers even take action to lower costs only to be <u>disappointed</u> by the lack of impact on their bill. For example, replacing all of the windows in their home.

DTE's Strengths

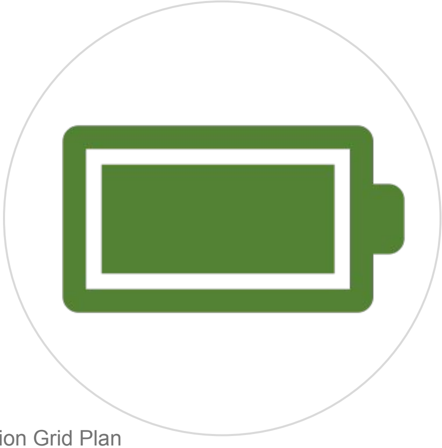
- Almost every stakeholder highlighted DTE's ***community engagement*** and ***involvement with community organizations*** as a great strength of the company.
  - Stakeholders feel DTE staff and leadership are <u>accessible and available</u> to them, especially around power outages and communicating upcoming projects.
  - Many shared stories of <u>partnering with DTE</u> - or opportunities to partner in the future.
  - Beacon Park and others <u>provided by DTE</u> were also cited as a positive.
- ***Reliability*** was another strength mentioned time-and-time-again by stakeholders.
- A number of stakeholders mentioned ***DTE's recent statements*** in response to issues like voter suppression and diversity, equity and inclusion.
  - Last year's announcement of reaching <u>net zero by 2050</u> was also highlighted as a step in the right direction to battle climate change.
  - There is an <u>increased expectation</u> among stakeholders that corporations speak out on important issues and ensure their actions are aligned with their statements.

DTE’s Future Improvements

- Stakeholders wish to see DTE focus future improvements on ***diversifying its portfolio*** and establishing itself as a ***leader in innovation*** and clean energy.
  - The growing demand for renewable energy, particularly <u>solar projects</u>. was mentioned in every interview. According to some, DTE is perceived as blocking small scale projects.
  - Awareness is growing around the <u>effects of climate change</u> - including the role energy providers play and the impact severe weather has on reliability.
  - DTE should begin <u>curating conversations and providing data</u> to educate communities, including students.
    - A “Climate Resiliency Center” could help small businesses and municipalities get to net zero.
- The grid infrastructure must be designed to ***accommodate the latest technologies***, including electric vehicles.
- DTE must ***put people over profit*** and ensure low-income customers aren’t left behind by finding creative ways to keep the lights on and lower costs for customers in poverty.
  - Expectations are now that corporations will be <u>socially responsible</u> and align their actions and values.
    - Community leaders would love to see greater Hispanic representation in DTE leadership.

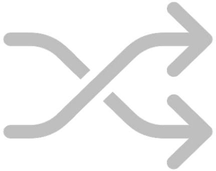
DTE’s Service Over Time

- → Majority of stakeholders believe DTE is ***getting better*** at delivering its core electric business.
- → The key driver of this opinion is that stakeholders believe ***reliability has improved***, so their constituents experience less frequent outages, or decreased restoration times if one occurs.
- → Specific mentions to ***DTE’s recent work*** around tree trimming and improvements to the grid were attributed to the improved service.



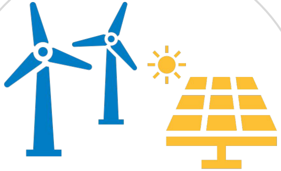
Challenges for DTE Identified by Stakeholders

Infrastructure for Electric Vehicles



Shifts in Population & Manufacturing

Technological Dependence



Growing Demand for Renewables

Increased Energy Demand

Confidence in DTE

- Overall, there is ***trust and confidence*** among stakeholders that DTE will meet demands despite evolving trends in energy.
  - A common response was that DTE is on the <u>right path</u>.
  - There is some <u>concern over the pace</u> at which DTE will tackle the upcoming challenges.
  - Stakeholders would like to see DTE be <u>proactive as possible</u>, rather than adapting when necessary.
- The ***clean energy goals*** DTE has set for itself are a big reason why stakeholders are hopeful for the future.
  - Michiganders are eagerly watching to see how DTE <u>actualizes their plan</u> and achieves these goals.
  - There is an <u>opportunity for DTE to lead</u> not only Michigan, but the entire country, into the next generation of energy.

GRID PLAN REVIEW

Reactions to DTE’s Plan

- While all stakeholders had a ***positive reaction*** to the grid plan as laid out on the summary slide, there was ***hesitation*** on taking a firm stance without additional information and hearing from top company leaders.
  - The key components of the plan, particularly, tree trimming were welcomed by stakeholders at-large.
  - Flagging the technical nature of the language used was common, as was the lack of specificity around why each action is necessary.
  - Areas of further inquiry included:
    - What exactly does the language really mean? What does this work look like?
    - How will DTE accomplish this plan? Why are these DTE’s areas of focus?
    - How much does this plan cost to execute? How will this impact affordability?
    - How does each component of the plan relate to the others? Big picture, what does it mean?
    - How will this plan allow DTE to achieve the clean energy goals it has set for itself? How will this plan allow other entities to achieve the clean energy goals they’ve set for themselves?

Anticipated Benefits to Constituents

- Tree trimming and ***preventative maintenance*** will make service more reliable.
    - These efforts are the most <u>outward facing</u> activities and typically how customers come in contact with DTE employees.
    - While needed to avoid downed wires, residents are often <u>unhappy with the result</u>, either due to the appearance of trees, or lack of shade on property.
        - Education on the necessity for this work would likely be beneficial.

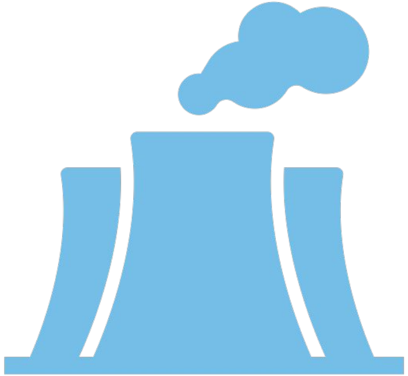
- ***Reduced restoration times*** is key for residents, so the negative impacts outages have on daily life can be minimized.
    - Losing all of the food in the fridge can be an <u>extreme burden</u> for families, especially those who can barely cover the cost of their bills.

- Updating the grid infrastructure will allow for the ***transition to more renewables*** and cleaner energy, while not sacrificing reliability.
    - <u>Keeping up with demand while going green</u> is a top priority for community leaders.

Downside Risk if Plan Does Not Happen

- Stakeholders identified ***two key concerns*** if DTE does not invest in the grid:
  - The inability to advance towards net zero and a cleaner energy future.
  - The inability to provide reliable service in the face of extreme weather, the popularization of electric vehicles, and growing demand for renewable energy sources.

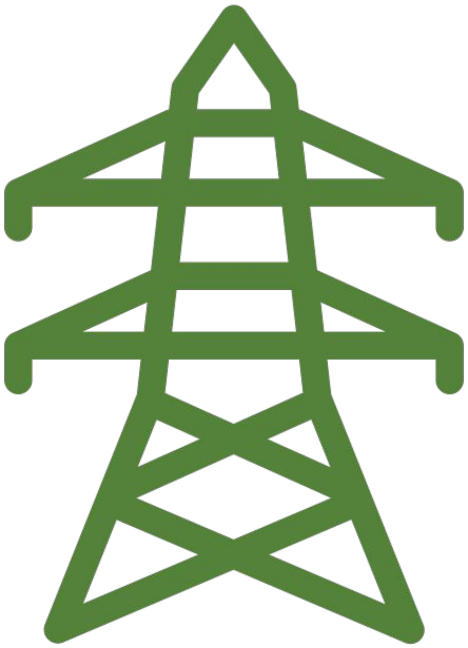
- Additionally, without a modern electric grid, Michigan is at risk of being ***passed over for investments*** and economic growth.
  - Many residents are unaware of the ripple effect an unreliable grid will cause, not only for them at home but for the entire region and state.
    - New businesses won’t relocate or expand in Michigan if they cannot count on reliable service.
    - Travelers or potential new residents may avoid Michigan if they have electric vehicles and the state lacks the infrastructure for charging stations.



Most Persuasive Arguments for Investing in the Grid

→ The ***negative risks of not investing*** in the electrical grid were time and time again highlighted as the most persuasive arguments.

- The threat of decreased reliability and decreased opportunity for renewable energy were top motivators for supporting investments.
- The added benefits of having a modern electric grid were persuasive as well, but not to the same extent as facing the reality of what will happen without an updated grid.



Costs to Achieve a Modern Electric Grid

- ➔ There is ***hesitation around increasing electric rates*** to compensate the costs of updating and modernizing the current electric grid.
  - ◆ While there is consensus that updates are needed, the <u>full burden</u> falling on residents is in question.
  - ◆ Several respondents indicated that there was <u>no argument</u> to convince community residents, particularly low-income families, that a rate increase was warranted.
- ➔ Particularly due to the current economic situation, stakeholders ***warned of the impacts*** rate increases have on vulnerable populations.
  - ◆ While some communities may be able to tolerate a 5-10% increase in their utility bill, there are others that would need to <u>fight to adjust</u> to an increase as small as 2%.
- ➔ In order to protect residents, there is a call for ***policy solutions*** to help DTE make investments in the grid in an ***equitable*** way.

KEY FINDINGS

Summary of Key Findings

- ***Affordability and Equity*** are top concerns for community leaders, particularly those serving constituents in the City of Detroit.
  - Families that fall <u>just above the poverty line</u> are hit hard because they often don't qualify for assistance programs, but still cannot afford their bills.
  - All communities should be <u>included in advancements</u> towards clean energy and achieving energy efficiency.

- Stakeholders wish to see bold ***policy solutions incorporated*** into the discussion.
  - What <u>structural changes to the business model</u> is DTE uniquely positioned to make?
  - Community leaders recognize there is a critical role for <u>state and federal government</u> in updating the country's infrastructure for the 21st century.

- Stakeholders and consumers are ***hungry for more information*** from DTE that is simple, focused on issues important to them. This information should be drafted through an ***educational lens***.
  - Energy is not top of mind for most individuals, but there is an opportunity to <u>engage with community members and share how DTE</u> positively impacts the region.

KEY FINDING: AFFORDABILITY & EQUITY

Affordability Must be Prioritized

- Despite understanding the need to update the electric grid, there is a common concern that residents ***won't be able to keep up with rising costs***.
  - Everyday necessities like heating/cooling homes, powering appliances, and keeping the lights on are the biggest energy draw for most consumers.
  - High energy users are often in older homes and these residents cannot afford energy efficient appliances, weatherization, and other upgrades to decrease usage.
  - Residents are unable to afford their bills - not just energy and gas, but water, too.

- While investments are needed to ensure reliability in the long-term, it is very ***hard for people to see past their current situation***.
  - Many are still unemployed and in a hard spot financially from the COVID -19 pandemic - and the lasting impacts are still unknown.

The Future of Energy Must be Equitable

- ***Equity*** is a top concern for majority of stakeholders, particularly when discussing higher rates to achieve a modern electric grid.
  - The divide between commercial and residential investments should be equal to their share of energy use.
  - Families that fall just above the poverty line are hit hard because they often don't qualify for assistance programs, but still cannot afford their bills.
- As a company that calls a city with a 35% poverty rate home, stakeholders challenge DTE to keep ***equitable solutions to affordability*** at the forefront.
  - All communities should be included in advancements towards clean energy and achieving energy efficiency.
  - Community energy solutions, such as community solar, may help in low income and/or low populated areas.

KEY FINDING: BOLD SOLUTIONS

Policy & Long-Term Solutions

- Stakeholders wish to see ***policy solutions incorporated*** into the discussion of upgrading the electric grid, so the burden of cost doesn't fall on consumers alone.
  - A <u>sliding scale</u> for rates, <u>base fee + usage costs</u>, or even a <u>cap on utility bills</u> based on income can prevent an overwhelming burden on customers.
  - <u>Older homes</u> in Detroit must be addressed to realize energy efficiencies.
- How is DTE ***uniquely positioned*** to make a difference?
  - Look at <u>policy and structural changes to the business model</u> that would help low-income customers afford their energy bills and avoid shutoffs.
- There is a role for ***federal and state government*** to play in the transition of infrastructure to meet the changing needs of our country, and the world.
  - There is a <u>leadership gap among local municipal governments</u> that DTE has an opportunity to fill in the journey to net zero.

KEY FINDING: DESIRE FOR INFORMATION

Stakeholders are Hungry for Information

- ➔ Interest in understanding DTE’s work around ***innovation and environmental stewardship*** was common among all stakeholders.
  - These are two <u>areas of interest</u> to many, but also where there is a lack of knowledge.
  - Stakeholders hope for more information on DTE’s progress ongoingly, as well as the <u>opportunity to partner</u> in each of these areas.
- ➔ Stakeholders are looking for ***easy to understand information*** for themselves and their constituents on topics like:
  - Programs available for low-income households.
  - How DTE will achieve its clean energy goals - and help others achieve theirs as well.
  - What investments in the grid mean in both the short and long term.
- ➔ ***Access to data*** is huge for stakeholders and there is an opportunity for DTE to be a leader in collecting and sharing data for climate resiliency.

Communicate More with Consumers

- → Everyday consumers are ***largely unaware*** of what DTE does.
  - ◆ Most residents <u>don't think about electricity</u> - unless there is an outage, or they are unable to pay their bill.
- → Consumers, not just stakeholders, should know what DTE does for the community - ***especially around the grid plan*** if it will increase rates.
- → Specific DTE efforts cited include:
  - ◆ Creating good paying jobs like tree trimming.
  - ◆ Supporting local economic development.
  - ◆ Workforce development projects.
  - ◆ COVID-19 relief efforts and PPE assistance.
  - ◆ Supporting Detroiters and closing the digital divide.
  - ◆ Dismantling the drivers responsibility fee.
  - ◆ Opposing voter suppression efforts.

Education and Engagement

- DTE does a fantastic job communicating with top-level community leaders, but future efforts should focus on ***community members*** as well.
  - Expand DTE's reach <u>deeper</u> into the community.
  - Municipalities and key organizations have <u>great relationships</u> with DTE.
- Residents are largely unaware of energy issues or policies, so communication should be viewed through an ***educational lens***.
  - Shutoffs are seen as a <u>threat</u> by constituents who don't know about DTE's payment programs. Those who are aware, however, are more likely to see DTE as affordable.
  - Education on <u>solar is critical</u>, including how to avoid companies that hide large upfront fees in long-term monthly payments and operations that don't support after they install.
- In addition to education, a greater emphasis can be placed on ***engagement***.

Reaching Residents

- Community leaders provided suggestions for how DTE can ***best reach and connect with*** residents, including:
  - Providing additional <u>information on energy usage</u>, similar to what appears on bills.
  - Utilizing <u>texting programs</u> as form of communication to reach target audiences.
  - Creating a bigger presence on <u>Spanish-speaking media</u>.
  - When sponsoring an event, be available to <u>answer questions and problem solve</u> on site with residents.

KEY FINDING: MAXIMIZING COMMUNICATION

Design Messaging that Resonates

- In communicating more with stakeholders and consumers, DTE must use ***simple language*** to educate and tie DTE's service to ***everyday experiences*** of consumers.
  - The educational slide shared with stakeholders used complex and technical language.
  - Many stakeholders didn't know what the plan laid out meant for them or their constituents other than assuming more reliable service.
- There is a ***disconnect*** in the language DTE uses to talk about energy vs. the language used by stakeholders, activists, and residents.
  - The result is a lack of understanding and awareness, which appears to be a key contributor in the gap between customer perceptions and reality.
  - It is harder for community members to feel like they are on the same page and working towards the same things as DTE when they are talking about different things.

Listen and Explore New Ideas

- A common request is for DTE to have ***more open discussions*** with community activists to encourage creative solutions.
    - The disconnect between DTE and the activist community is not unnoticed.
    - Stakeholders want to see DTE lean into the discomfort and unknown in order to identify the best path forward, period.
        - Is moving wires underground the best long term solution for reliability in anticipation of increased extreme weather events?
        - Is solar the answer to affordably deliver energy to areas with high vacancy rates, particularly in Detroit?
    - There may always be disagreement on what is "best" but everyone has the same end goal in mind - a stronger, cleaner future for Michigan.
- While a lot of work is done in Detroit, there is an ***opportunity for greater involvement*** in suburban communities.

CONCLUSIONS & IMPLICATIONS

Anticipation of Increased Usage

- There is consensus that Michiganders will ***consume more energy*** in the next ten years, in-large part due to new technologies, including electric vehicles.
- Stakeholders feel a ***tension*** between the anticipated increase in demand for energy and the concurrent increase in demand for renewable energy.
  - DTE will need new technologies to continue to meet demand while closing coal plants and switching to more environmentally friendly ways of producing energy.
- There is an awareness and concern around the impacts extreme weather will have on the electric grid and DTE's reliability unless ***major investments in infrastructure*** are made.
  - From storms to higher temperatures in the summer, the electric grid must adapt to handle the load.

Education Around DTE's Grid Plan is Essential

- It will be important to communicate with stakeholders and consumers alike how DTE's Distribution Grid Plan will ***benefit them***.
  - Discussions of <u>affordability</u> must be front and center.

- An emphasis is needed on how reliability, affordability, and clean are ***all connected***.
  - Residents may see tree trimming, but they don't see the <u>big picture plan</u>.
  - Much of DTE's work <u>isn't visible</u> to consumers, so it must be communicated clearly and effectively.

- Stakeholders believe residents will be more ***favorable towards DTE*** and understanding of price increases if they feel engaged and in the know with what is happening and why.
  - Even stakeholders themselves want to be <u>briefed in detail</u> on the grid plan by DTE before committing to an opinion.

Appendix IX DTE/ICF Grid Modernization Study 2021 - 2035

DTEE Grid Modernization Study 2021 – 2035

FINAL DRAFT

February 1, 2021

Submitted to:

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ICF and EnerNex

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Executive Summary

Grid modernization involves the deployment of technologies and processes that increase flexibility, accessibility, connectivity, and diversification of the electric distribution system to support evolving customer needs. It is necessarily a multi-phase undertaking, as customer demands and requirements of the grid are anticipated to rapidly change over the next 15 years. This Grid Modernization Study provides a strategic assessment of foundational grid infrastructure and advanced technology investments that support the identified grid needs, based on DTEE's vision, objectives, and plausible future scenarios to meet evolving customer needs.

ICF and EnerNex (ICF Team) with support from DTE, performed a Grid Modernization Study as the first phase of a strategic grid modernization planning process. Firstly, by assessing DTE Electric's (DTEE) existing and planned grid modernization investments and considering plausible future scenarios to perform a long-term grid needs assessment (2026 - 2035). This enabled the ICF Team to identify near-term recommendations for further analysis to complete a strategic and detailed long-term investment plan as a second phase within the next two years.

As part of this grid needs assessment, the ICF Team also developed a conceptual roadmap to provide a directional view of grid modernization investments that builds on DTEE's existing and ongoing 5-year plan, which will be described in the 2021 Distribution Grid Plan. The conceptual roadmap identifies technology categories that may be needed over the next 10 to 15 years.[1] These technologies will require further assessment as part of the strategic investment planning process.

This engagement did not include the development of detailed engineering or business plans and associated cost estimates for recommended technology and business and did not cover an assessment of traditional asset management and work management.

[1] The conceptual grid modernization roadmap is described in more detail in Section 4.7

Methodology

The ICF Team adapted the US Department of Energy's (DOE) Modern Distribution Grid (DSPx) framework to identify objectives and assess DTEE's current and near-term planned activities in light of the plausible 2035 scenarios.[2] The ICF Team's focus was on Step 2 of the three-step process illustrated in Figure 1 below, the Grid Needs Analysis, which identified required capabilities and functionalities for future grid needs, tying back to the scenarios and objectives. In Step 3, the Grid Needs Analysis is translated into a set of recommendations for directional strategic investments (Section 4) and near-term planning activities, including areas for additional analysis (Section 5).

Figure 1. Approach to Developing Grid Modernization Study

Step 2.A - 2035 Scenarios

To understand how potential changes may impact the electric distribution system, the ICF Team coordinated with DTEE to develop three high-level 2035 scenarios (Table A) representing plausible futures driven by electrification (i.e., electric vehicles (EVs) and heat pumps), extreme weather events (i.e., catastrophic storms), and customer-sited distributed energy resources (DER). The scenarios help identify potential gaps in current grid investment plans, and define future grid needs regarding infrastructure and functionalities to serve multiple objectives. The areas of overlapping grid needs and related investments enable the development of robust, least regrets investment strategies. Least regrets investments represent investments driven by core safety and reliability requirements and those that provide the flexibility to support one or more of the 2035 scenarios.

[2] U.S. Department of Energy (DOE), Modern Distribution Grid Project (DSPx). Available at: https://gridarchitecture.pnnl.gov/modern-grid-distribution-project.aspx

Table A. DTEE 2035 Grid Modernization Scenarios

Scenario	Description
Electrification	High electrification of transportation and buildings
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)

Step 2.B - Current System & Plan Assessment

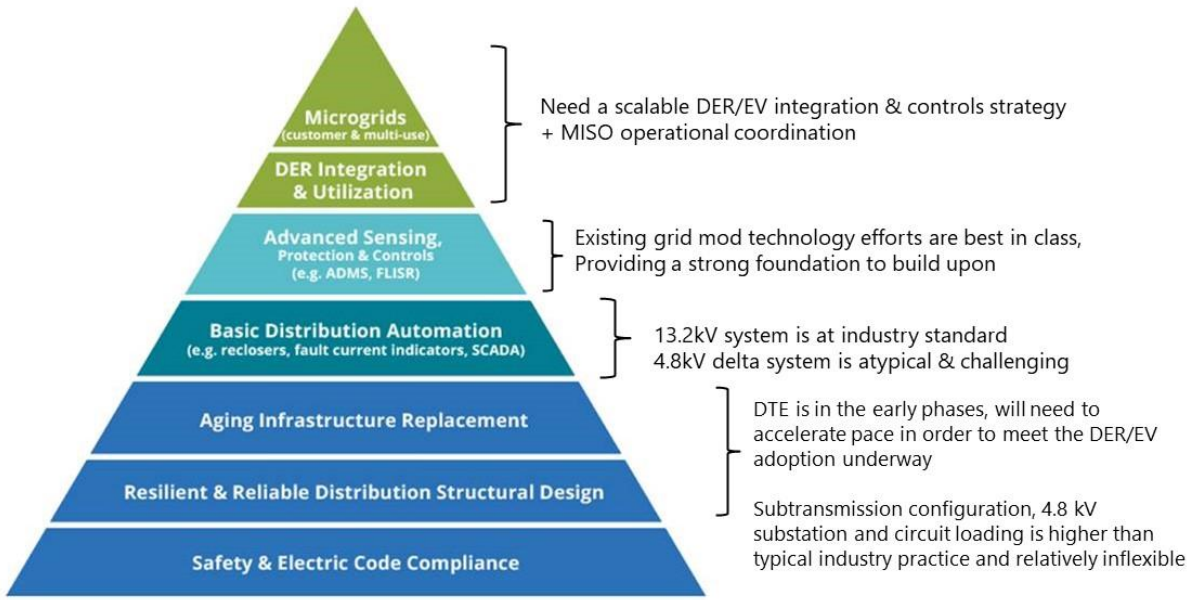
The ICF Team's assessment of DTEE's current system and planning efforts was informed through analysis of information and data provided by DTEE and interviews with DTEE personnel. Additionally, several investment plans were reviewed including the 2018 and draft 2021 distribution system five-year plans and the information and the operational technology (IT/OT) strategy roadmap. In summary, DTEE is at the forefront of the industry in several areas, such as:

- Advanced Metering Infrastructure, particularly the level of sophistication for outage management
- Advanced Distribution Management System (ADMS) for distribution monitoring, control, and automation.
- Data management systems and operational communications, including wide area network, TropOs and meter communication conversion to 4G

As DTEE continues to increase grid visibility, situational awareness, and the ability to respond to grid conditions in real time, the value of these investments will multiply.

A summary view of DTEE's existing strategic grid investments is provided in Figure 2 applying the DOE DSPx investment prioritization model. The ICF Team referenced this model in the Grid Needs Analysis in Section 4, which provides more details behind DTEE's current state and grid needs for infrastructure, observability, analytics, controls, and communications.

Figure 2. Grid Modernization Investment Pyramid



Step 2.C - Grid Needs Analysis

The Grid Needs Analysis employed the DSPx framework to identify specific grid needs (e.g., capabilities and functionalities) in relation to the scenarios. These needs were then translated into specific technology categories with further detail into specific technologies and applications (e.g., relay protection on 4.8kV).

A central investment focus for DTEE has been improving safety and reliability. This focus has been appropriate as much of the Company's electric infrastructure is either approaching or beyond its expected life expectancy. For example, DTEE's 4.8kV ungrounded delta system is unusual for electric utilities and heavily loaded in some areas, with many existing substations and related feeders operating above normal ratings that stress older cable and breakers. This results in increased risk of potential cable and equipment failures, a lack of capacity headroom, and limited operational flexibility that pose reliability challenges that are currently being addressed in the Company's asset initiatives. However, enhancements to the current asset strategy and acceleration of investment are needed to account for upcoming electrification and distributed resource adoption by customers projected over the next 15 years.

There are additional operational technologies and related information technologies needs that are likely over the next 15 years, particularly in the areas of expanding situational awareness and distributed controls capabilities with expectations of growing numbers of managed charging and distributed resources on DTEE's system. These are discussed in Section 4.

Step 3 - Near-Term Grid Modernization Recommendations

Given the scope of the project, the recommendations do not include elaborate specific technology deployment plans beyond the recommended long-term infrastructure and technology investment examples. In cases where information was unavailable, near-term next steps are recommended to support the development of more comprehensive strategic and data-driven investment plans.

In the near term, the ICF Team recommends development of the following strategic planning activities in order to better inform a detailed investment plan for 2026-2035:

1. **Long-term Distribution System Impact Study** – holistic assessment of EV and DER adoption under different sensitives to determine grid impacts at a granular level
2. **Asset Modernization Strategic Plan** – longer-term grid infrastructure modernization plan that more fully addresses electrification and DER in addition to safety and reliability
3. **Situational Awareness Strategic Plan –** greater numbers of variable loads and resources will require better visibility, planning tools and operational analytics
4. **Distributed Controls Strategic Plan** – new customer devices and expanded field automation will require a more complete control strategy that traditional approaches
5. **Global Prioritization Model (GPM) Enhancements –** opportunities to improve the clarity and transparency of GPM will support regulatory review along with the further alignment with MPSC planning objectives

These recommended near-term next steps will enable the development of a more definitive investment roadmap from 2026-2035 and associated cost estimates that will support internal management discussions and those with the MPSC and stakeholders. Each activity could require a year or more of effort, can be undertaken concurrently, and assumes that existing data and analysis will be leveraged to conduct a more complete analysis of the scenario impacts, particularly electrification of transportation on DTEE's distribution system over the coming decade. These activities also include internal review and refinements to develop a complete set of deliverables.

1 Introduction

1.1 Purpose

This report summarizes the ICF Team's assessment of DTEE's grid modernization investments and plans and the development of a longer-term organizing framework for future grid modernization efforts. As such, this report should be considered the first phase of the strategic grid modernization planning process.

The scope included a high-level assessment of DTEE's current grid modernization initiatives, which informed a summary of long-term needs through 2035. DTEE directed the ICF Team to place particular focus on longer-term investment needs in the 2026-2035 time period. Within scope were grid modernization operational technologies and selected information technology (IT), as well as modern physical grid architecture to enable greater accessibility, flexibility, and reliability. Excluded from the scope of this engagement were cost estimates for recommended technology investments and recommendations pertaining to traditional asset management and work management. The end result is an initial Grid Modernization Study consistent with the DOE DSPx framework[3] that provides a:

- Conceptual and directional view of the types of technologies to be considered over the 15-year period.
- Set of near-term recommendations to more fully develop a detailed long-term investment plan.

Key to the development of the Grid Modernization Study is a scenario-driven methodology that sets the context for potential demands placed on the distribution grid in the future, including customer needs, change drivers, and anticipated grid impacts. From these plausible scenarios, the Grid Needs Analysis identifies overarching objectives and the desired future state, as well as the capabilities, functionality, and system requirements that are needed to move from the current state to the future state. The Grid Modernization Recommendations section summarizes the Team's recommendations related to investment strategy, benefit-cost analysis, asset strategy, and planning and business processes. Near-term recommendations focus on what is needed to complete a strategic and detailed long-term investment plan.

1.2 Report Organization

The balance of the report is organized as follows:

- **Section 2 (Methodology)** presents the methodology used to assess DTEE's current and near-term planned activities and develop a set of recommended planning efforts and strategic investments. It also introduces the DSPx taxonomy that links the impact of future drivers and the implication on grid needs to strategic grid infrastructure and technology investments.

[3] US Department of Energy, Modern Distribution Grid Project, https://gridarchitecture.pnnl.gov/modern-grid-distribution-project.aspx

- **Section 3 (Scenario Based Grid Modernization Planning)** describes three plausible future scenarios with a focus on specific distribution system impacts when integrating electrification, DER, and greater weather hazards.
- **Section 4 (Grid Needs Analysis)** presents a grid needs analysis based on the scenarios and assessment of current and planned state, which determines the additional capabilities, functionalities, and technology investments needed over the next 15 years to meet the stated objectives. The current state discussion highlights past and ongoing efforts to add new capabilities and technologies to the grid, as well as current challenges at the subtransmission, substation, distribution technology investments to meet emerging and future customer needs. Also included are potential next steps to achieving the future state.
- **Section 5 (Near-Term Recommendations)** offers recommended next steps to enable the development of a more detailed investment plan and associated cost estimates that will support further decision-making. It includes a discussion of the benefit-cost analysis framework for assessing grid modernization solutions and adapting the DOE's DSPx cost-effectiveness framework to DTEE's GPM methodology.

2 Methodology

The ICF Team employed the DOE's DSPx grid modernization framework to assess DTEE's current and near-term planned activities and develop a set of recommended planning efforts and strategic investments. Specifically, the recommended three-step methodology for the development of a grid modernization strategic plan is consistent with the scope of this engagement.

This approach started with quickly identifying DTEE's vision and objectives related to grid modernization as well as those of the Michigan Public Service Commission (MPSC). The second step was the identification of future grid needs as recognized through plausible, discrete scenarios for 2035. These grid needs were assessed relative to the current state of DTEE's grid and current (including near-term) strategic investments underway. In the third step, this "Grid Needs Analysis," is translated into a set of recommended strategic investments and near-term planning activities. Also, in cases where insufficient information was available, specific near-term planning activities are recommended to support the development of strategic investment plans. The resulting set of recommendations form the long-term strategic roadmap.

Figure 3. Approach to Developing Grid Modernization Strategic Plan

The ICF Team's focus was on Step 2, identifying future grid needs (i.e., capabilities and functionality). While Step 3 includes a set of recommended technologies, it is not complete, as additional analysis is recommended to develop specific investment strategies in several key areas with significant cost considerations, such as accelerating distribution voltage conversions.

Step 1: DTEE Vision and Objectives

DTEE's strategic vision echoes the state's policy goals and commitment to customers, stating:

> *DTEE is a reliable partner for Michigan, local communities, and individual customers to achieve their carbon emission reduction goals by lowering our own emissions and offering unique customer solutions. In doing so, we will not only address climate change, but create growth opportunities for our businesses.*

The MPSC articulated their vision of the Michigan electric grid as follows:

> *The Commission envisions the distribution grid of the future facilitating the interconnection and optimized operation of a diverse set of resources, whether they are owned by the utility, third parties, or directly by customers…. the Commission envisions*

> *a distribution grid of the future with increased DERs and active utility monitoring and controls to manage bidirectional energy flows and to detect and respond to reliability disturbances. – August 20, 2020 MPSC Order* [4]

These vision statements articulate a future where customers and communities adopt decarbonization strategies and distributed technologies, changing the way the grid is planned and operated. In addition, the MPSC's August 2020 Order confirmed and defined the distribution planning objectives under the customer needs umbrella: safety, reliability and resilience, cost-effectiveness/ affordability, and accessibility. DTE Electric's planning objectives (safe, reliable and resilient, affordable, customer accessible and community focus, and clean)) are generally aligned with the MPSC's guidance.

For this Grid Modernization Study, the ICF Team used DTE's vision and objectives, which are aligned to the MPSC objectives, to guide the assessment and strategic outlook over the next 15 years. The definition of clear objectives facilitates mapping back the selected capabilities and investments, as applied in the DSPx framework.[5] Table B provides an overview of the MPSC's distribution planning objectives and includes abbreviated definitions.

Table B. MPSC Distribution Planning Objectives

U-20147 - Distribution Investment and Maintenance Plans		
Distribution Planning Objectives		
Customer Needs	Safety	Reduce risks due to equipment failures or outdated practices, third parties damage or inclement weather. Safety is the Commission's top priority.
Customer Needs	Reliability / Resilience	The ability to withstand and respond to major weather events and other disruptions and reduce how often and how long customers experience outages. Cybersecurity and physical security also play a key role in ensuring reliability and resiliency.
Customer Needs	Cost-effectiveness /Affordability	Data-driven, value-based approaches to determine when to repair versus replace aging equipment, integrate new technologies in an optimal manner, and provide planning tools and information to encourage efficient siting and operations of customer resources. Ensure long-term affordability for customers through reasonable and prudent investment strategies, considering alternatives and longer-term operational savings.
Customer Needs	Accessibility	Accommodate service to new or expanding customers without causing major network upgrades due to an underlying infrastructure challenge. Planning to assess system conditions under different scenarios to guide siting new projects or accommodating changing load patterns due to customer resources.

Step 2: Grid Capabilities & Functionalities

The Grid Capabilities and Functionalities are identified through three sub-steps; A) Development of Plausible Scenarios to 2035, B) Assessment of the Current System and Investment plans, and C) Grid Needs Analysis based on Scenarios. This approach provides a line of sight from vision and objectives in Step 1 through Step 2 analysis to the resulting infrastructure and technologies investment recommendations in Step 3. This approach, consistent with the DOE's DSPx framework, supports robust decision-making about the impact of future drivers and the

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[4] Case U-20147, *In the matter, on the Commission's own motion, to open a docket for certain regulated electric utilities to file their distribution investment and maintenance plans and for other related, uncontested matters.* Order (August 20, 2020), p. 38 and 40.

[5] U.S. DOE, Modern Distribution Grid Project, https://gridarchitecture.pnnl.gov/modern-grid-distribution-project.aspx

implication on grid needs and associated strategic grid infrastructure and technology investments.

Grid Capabilities can be thought of as broad buckets, containing several underlying business functions. These business functions involve business process techniques and operations that can be used to achieve enhanced grid functionalities or enable advanced grid processes. Functionalities often work together to enable a capability, as in the case of outage management involving monitoring, observability, coordination, and control. The analysis of capabilities and functionalities needed is shaped by the objectives defined in Step 1. This is augmented by the needs that were identified by developing three plausible 2035 scenarios in Step 2A (Figure 3) and is described in detail in Section 3. An assessment of DTEE's current grid and strategic investments provides the basis for current capabilities and functionalities as a baseline to describe future needs. This Current State Assessment is Step 2B, and is described in detail in Section 4. In Step 2C, potential future grid needs are identified based on the 2035 scenarios. These in turn, are considered in relation to the current system and planned investments to identify incremental enhancements to existing efforts, or in some cases new advanced functionality that may be needed. Additionally, based on the scenario analysis, grid functionality can be identified as "least regrets" if driven by core safety and reliability requirements, and one or more of the scenarios.

Grid functionality can be identified as "least regrets" if driven by core safety and reliability requirements, and one or more of the scenarios.

Step 3: Grid Modernization Strategies

In Step 3, the Grid Capabilities & Functionalities assessment is translated into a set of directional strategic investments and near-term planning activities. DTEE directed the ICF Team to place particular focus on longer-term functionality investment needs in the 2026-2035 time period. The resulting Study covers three 5-year investment periods through 2035: 2021-2025, 2026-2030, and 2031-2035.

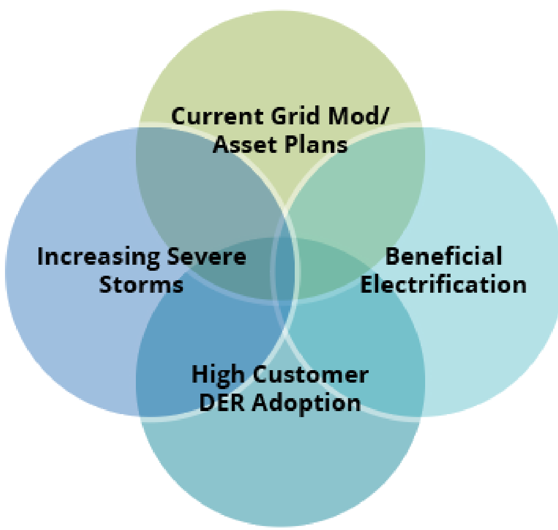
The near-term planning activities will need to be undertaken to prepare a more complete grid modernization and investment strategy in several key areas including distribution level forecasting of EV and DER, asset modernization, situational awareness, and controls. Also, there was limited information available on DTEE's subtransmission system, resulting in an incomplete assessment for this area. As such, the assessment described in this report should be considered the first of a two-part process to fully develop a long-term grid modernization strategy and investment roadmap.

While Step 3 includes a set of recommended technologies, it is not complete. Therefore, this report provides specific near-term planning activities to support the additional planning analysis and development of strategic investment plans. The near-term recommendations are focused on key areas with strategic significance such as accelerated distribution voltage conversions.

3 Scenario Based Grid Modernization Planning

Grid modernization scenarios are used to guide the identification of robust or least regrets grid investment strategies. That is, plausible future scenarios help to identify potential gaps in current grid infrastructure and operational capabilities. Scenarios that focus on a discrete set of drivers with common grid impact characteristics, such as distributed solar PV, enable a closer examination of the engineering considerations. In this way, a set of discrete scenarios allows for a better understanding of the resulting grid impacts, as well as the potential for overlapping impacts on needed capabilities and related investments. These drivers, combined with the current safety and reliability investments underway, create a Venn diagram of potential grid needs over the 15-year planning horizon (Figure 4).

Figure 4. Overlapping Grid Needs



The areas of overlapping needs and related investments enable the development of robust, least regrets investment strategies that perform well in two or more plausible futures. This type of scenario analysis does not attempt to determine an optimal, definitive 15-year investment plan, as there are too many uncertainties given the role of customers' decision-making regarding EV and solar PV adoption and associated location and use, for example.

Distribution planning, in contrast to resource planning, involves considerably more uncertainty at the level of specific assets when looking beyond a five-year horizon. As such, scenario planning in this context is used to: 1) assess the robustness of current plans, including potential stranded assets/investments, and 2) guide future investment strategies including identifying areas for further engineering analysis to determine specific actions that may be required.

The following principles guided the development of the potential future scenarios in the ICF Team's grid needs analysis:

1. Consider multiple plausible futures with a focus on possibility rather than probability.
2. Identify scenarios with unique potential grid capabilities and functionality and adequately stress test proposed strategies and investments.
3. Base scenarios on a small number of key assumptions related to material changes in grid requirements that differentiate alternative decision-relevant paths.
4. Employ adaptive strategies to incorporate flexibility to evolve over time in response to new information.

In collaboration with DTEE, three future scenarios were defined (Table C) to think about the feasible changes and potential implications over the next 15 years. The scenarios are focused on specific grid impacts to the electric distribution system driven by electrification, extreme weather events (e.g., catastrophic storms), and customer-sited DER. Each scenario includes directionally plausible forecasts, key uncertainties, and signposts that may result in significant changes over time. This scenario-based analysis is not attempting to assess impacts at a fine level of precision. As such, the focus is on the directional magnitude of these scenario forecasts to determine potential material impacts to DTEE's distribution system through 2035. Consistent with the principles above, three scenarios were selected: Electrification, Increasing catastrophic (CAT) Storms,[6] and Distributed Generation (DG) / Distributed Storage (DS).

Table C. DTEE 2035 Grid Modernization Scenarios

Scenario	Description
Electrification	High electrification of transportation and buildings
Increasing CAT Storm	Increased frequency and intensity of catastrophic (CAT) storms threat aging infrastructure
DG/DS	High adoption of distributed generation (DG) solar PV and distributed storage (DS) as batteries behind the meter (BTM)

The scenarios are articulated below with an introduction framing the scenario and providing context of how they may evolve over the next 15 years. These descriptions also include an overview of the following areas:

- *Key uncertainties*: outline unknowns that may affect the course of a scenario, such as advancements in technology operations, prices, or changes in policies.
- *Signposts*: outline possible actions that would confirm the path of a scenario.
- *Grid Impacts*: describe examples on how aspects of a driver may impact grid infrastructure given the existing conditions.

[6] Michigan Public Service Commission, Michigan Statewide Energy Assessment, Final Report, p. 15. (September 11, 2019).

3.1 Electrification Scenario

The electrification scenario focuses on electrification of on-road vehicles and residential heating to reduce fossil fuels in other economic sectors and deliver benefits to Michigan communities. Under the electrification scenario, residential and corporate customers adopt EVs and major cities partially transform their public bus fleet. There is also a substantial conversion of residential heating to heat pumps.

DTEE plans to achieve net zero carbon emissions by 2050 while also continuing to serve as a leader in helping to grow Michigan's clean energy economy and infrastructure. The increased adoption and utilization of EVs will play a crucial role in Michigan's clean energy progression. That is why DTEE has launched the Charging Forward program to increase EV awareness by offering residential charger rebates and infrastructure enablement incentives to help create a charging network across Michigan.

EV adoption grows significantly as:

- Policies (e.g., rebates and tax breaks) drive the price and total cost of ownership lower than traditional Internal Combustion Engine (ICE) vehicles or communities and companies set EV adoption goals;
- Technology maturity and scale expand and market players transition vehicle options[7]; and
- Customers charge their EVs at home with AC L1 and L2 stations, while DC fast charging (DCFC) stations are deployed in commercial and public spaces to support fleets, personal vehicles, and transit buses.

DCFC stations are deployed by the Michigan Department of Environment, Great Lakes, and Energy (EGLE); municipalities; third-party networks; and DTEE. Specifically, under this scenario, distributed light-duty EV will grow an average of 30% annually from 2021-2035, reaching 17% market penetration by 2035.[8] Combined with DC L2 charging station, this translates to 5,405 MW of additional capacity by 2035 (without managed charging strategies).

Cities, communities, and corporate customers announce carbon neutrality or decarbonization plans, thus driving higher adoption of EVs and heating electrification in buildings. This scenario is centered on the impacts of heating electrification in the residential sector, where DTEE expects a slow adoption of 1% annually, potentially reaching up to 15% adoption by 2035, which is equivalent to approximately 285,000 residential customers or 1,425 MW of added load.[9]

The cumulative outlook of drivers every five years is summarized in Table D.[10] While this scenario presents significant electric load demand increase for DTEE, the supply resources to serve the new load is not within the scope of this Grid Modernization Study and will be covered under the Company's Integrated Resource Plan (IRP). Detailed assumptions under each driver are included in Appendix A: Future Scenarios Assumption.

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[7] General Motors, for example, has pledged to stop making gasoline-powered passenger vehicles, cars, vans, and sport utility vehicles by 2035.

[8] These estimates are based on total vehicles in the road, not in new sales. DTEE's 2019 IRP forecast load assumed 24% of new vehicles sales to be electric by 2030, while corporate scenarios suggested 50% and 20% of new vehicles sales by 2035 under the policy scenario and the economic-driven scenario, respectively. For more details on the assumption, reference Appendix A.

[9] (internal document) DTE, Air Source Heat Pump Opportunities (January 2020)

[10] The system peak is based on DTEE's 2019 IRP "Bundled Non-coincident Peak Demand" forecast.

Table D. Electrification Scenario Load Forecast 2025 - 2035

Key Drivers	2025	2030	2035
EV AC L1/L2	383 MW (3.8 % peak)	1,425 MW (14.3 % peak)	5,286 MW (53.7 % peak)
EV DC L1	7.1 MW (0.1 % peak)	12 MW (0.1 % peak)	19 MW (0.2 % peak)
EV DC L2	10 MW (0.1 % peak)	50 MW (0.5 % peak)	100 MW (1 % peak)
Heat Pumps	475 MW (4.7 % peak)	950 MW (9.5 % peak)	1,425 MW (14.5 % peak)

3.1.1 Electrification Scenario: Key Uncertainties

The key uncertainties under the electrification scenario are those impacting EV ownership costs and charging flexibility, building codes, and community decarbonization initiatives, such as:

1. EV and charging station market availability.
2. EV state target, city public transit electrification, corporate/government fleet electrification.
3. Building code or regulation banning gas in new constructions and/or requiring EV infrastructure.
4. Uptake of community solar and storage projects (i.e., microgrids).
5. Michigan 100% carbon neutrality by 2050 pathway goals and requirements.

3.1.2 Electrification Scenario: Signposts

The signposts for the electrification scenario are centered around possible actions that will confirm the trajectory and uptake of EVs and heat pumps over the next 15 years, such as:

1. Realize EV uptake growth of 30% or more annually.
2. EV delivery fleet centers begin development.
3. Public transportation electrification (e.g., buses) begins.
4. Public policy extends vehicle sales tax credit and supports EV OEMs including Michigan-based businesses.
5. Communities with decarbonization goals will incentivize adoption of heat pumps.

3.1.3 Electrification Scenario: Grid Impacts

The expected electrification of transportation and heating will have a significant impact on the Company's 4.8 kV and 13.2 kV distribution systems, given the current high system loading levels. DTE does not have much existing capacity headroom to accommodate the anticipated size of the vehicle charging loads and the eventual residential heating conversions. DTEE is likely to see a growing number of Level 2 residential and DCFC installations in commercial locations. Also, there is an expectation of large delivery fleet charging systems and the potential for electrifying bus fleets by 2035.[11] The potential shift toward residential electric heat pumps would add to the loading impact and reliability challenges. As these developments play out over time, they will create the need to proactively address structural issues and capacity constraints in those locations.

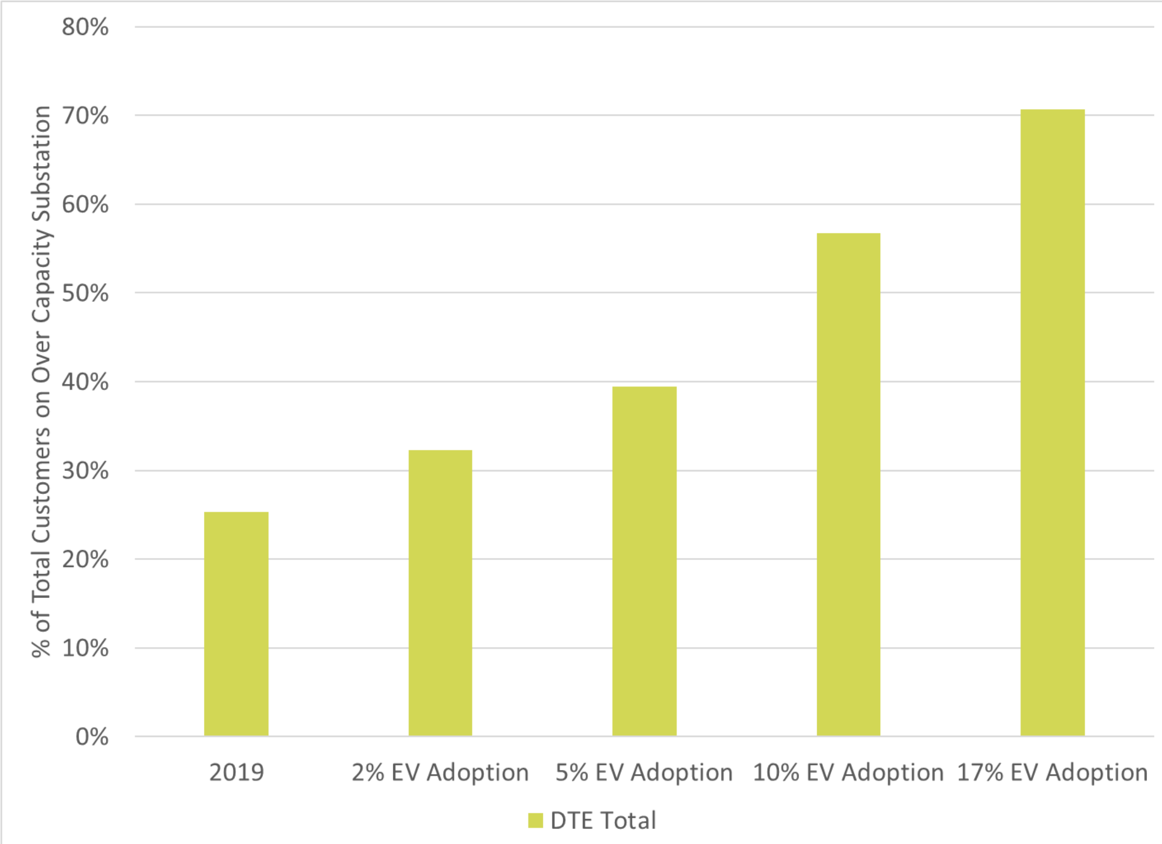
For example, using 2020 load data as a baseline and adding potential EV adoption scenarios provides insights into potential distribution impacts given the loading constraints of substations (Figure 5).

- Under current loading (<0.5% EV Adoption), 101 of the 563 DTE substations serving 25% of DTE customers are running over capacity.
- At 2% EV adoption, 112 of the 563 DTE substations serving 33% of DTE customers would be running over capacity.
- At 5% EV adoption, the number of overloaded substations climbs to 132 substations serving 40% of DTE customers.

The related distribution circuits also experience overloading and service quality issues that would need to be addressed. While this scenario does not consider the impacts of solar PV, storage, and increased storms, the challenges posed to the grid from those factors would be additive.

Figure 5. Percentage of Total DTE Customers Served by Substations Operating Above Their Firm Rating Under Various EV Adoption Scenarios (2019 Baseline Loading)

[11] Ann Arbor transit CEO talks future: electric buses, service expansion (February 14, 2020); GM, Our Path to an All-Electric Future (November 2020)



3.2 Increasing CAT Level Storms Scenario

The increased CAT level storms scenario attempts to capture the risk associated with the increasing intensity and frequency of severe winds and ice storms, resulting in resiliency challenges to DTEE's aging infrastructure and impacts to communities and customers.

DTEE defines CAT level storms under two categories:

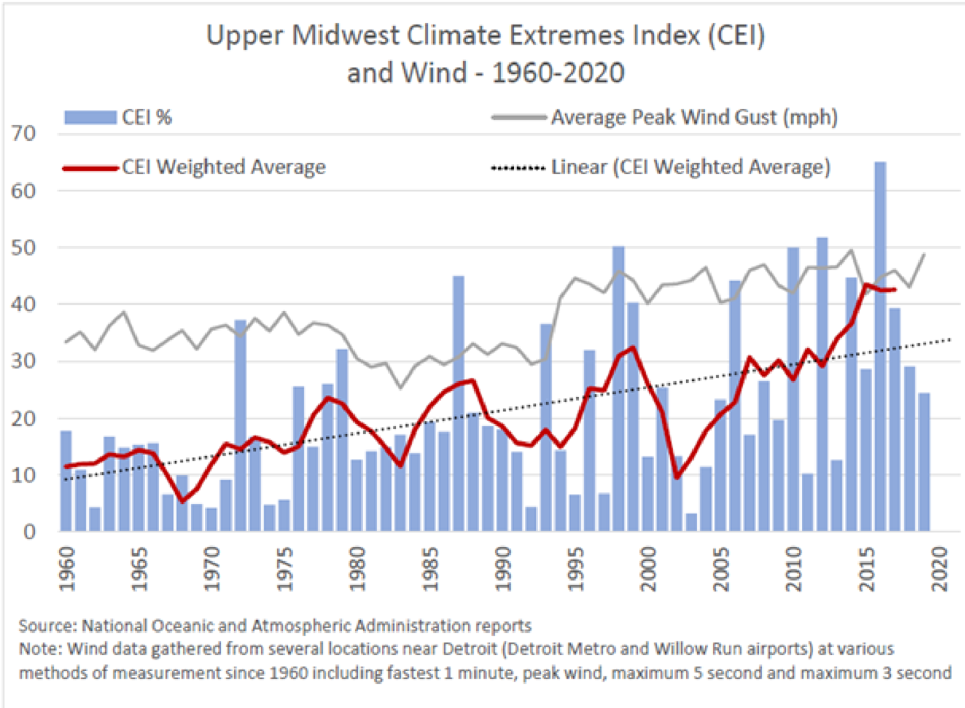
- CAT-1 level for storms affecting 5% of the customer base (approximately 110,000 customers).
- CAT-2 level for storms affecting 10% of the customer base (approximately 220,000 customers).[12]

Over the past decade, DTEE has experienced 21 CAT-1 level storms with an average duration of 3.7 days, and 8 CAT-2 level storms with an average duration of 5.2 days with up to 750,000 impacted customers in 2017. The MPSC Statewide Energy Assessment included Figure 6 below showing data of extreme weather and storm events occurring more frequently and with greater intensity over the past 60 years.[13]

[12] There are other storm classifications such as small, medium, and large, which affect up to 40,000, 75,000, and 110,000 customers, respectively.

[13] MPSC, Michigan Statewide Energy Assessment Final Report (September 11, 2019).

Figure 6. Michigan Relative Increase Weather Events 1960 – 2014



Moreover, the 2019 Michigan Hazard Mitigation Plan (MHMP) identified severe winds and ice storms as high frequency hazards for the Southern Lower Peninsula and Detroit Metro Area regions encompassing DTEE's service area.[15] The MHMP reported an average of 395 annual severe wind events across Michigan with an increasing risk trend. National Weather Service analysis indicates that severe winds occur more frequently in the southern half of the Lower Peninsula than any other area of the state. This includes derechos that can exceed 100 mph at times and often result in damage that is more widespread than most other storms and tornadoes in Michigan. On average, severe wind events can be expected 5-7 times per year in the Southern Lower Peninsula. Additionally, ice and sleet storms and tornados are also identified as increasing in risk as noted in the MHMP table excerpt below Table E.

[14] Based on data collected by the National Oceanic and Atmospheric Administration from the upper Midwest region of Minnesota, Wisconsin, and Michigan.

[15] Emergency Management and Homeland Security Division, Michigan Department of State Police, and The Michigan Citizen-Community Emergency Response Coordinating Council, Michigan Hazard Mitigation Plan, April 2019. Available at: https://www.michigan.gov/documents/msp/MHMP_480451_7.pdf

Table E. Michigan Hazards Analysis - Excerpt

	Avg. annual events	Avg. annual deaths	Avg. annual injuries	Avg. annual property and crop damage	Development trend effects	Risk rating: casualties	Risk rating: Property	Risk rating: economic cost	Risk rating: infrastructure effects	Risk rating: environment	Frequency as a top local hazard
Hail	191	0	0.2	$ 18.2 million	+	1	2	2	1	1	Some
Lightening	14	0.8	5.3	$ 0.2 million	=	1	1	2	2	2	Some
Ice and sleet storms	16	0.2	0.5	$ 11.4 million	+	1	2	3	3	1	Some
Snowstorms	360	0.1	0.1	$ 1.9 million	+	1	1	2	2	1	Many
Severe winds	395	12.6	12.6	$ 51.3 million	+	1	2	3	3	1	Many
Tornados	18	49.6	49.6	$ 17.2 million	+	2	2	3	3	2	Many

In the increased CAT level storm scenario, communities and customers increasingly take steps to address their respective reliability needs through back-up generation, storage, and microgrids by 2035. Community resilience initiatives such as Ann Arbor's climate resilience hub – a 24 kW solar + storage microgrid – may increasingly be pursued by other communities.[16] Customer adoption of back-up generation in the US is currently at about 5% of households and growing at approximately 6% CAGR. Leading genset manufacturers are adding battery storage to their offerings as the cost effectiveness of storage as a reliability option has improved (note: batteries are already cost competitive with stationary back-up gen for many homes, though their limited capacity makes them best suited for short duration outages).[17]

3.2.1 CAT Storm Scenario: Key Uncertainties

The key uncertainties under the increased CAT storm scenario are related to weather events and asset resilience, such as:

1. Future weather patterns regarding intensity, frequency, and scope of events.
2. The ability of grid assets to sustain weather events.
3. Communities establishing resilience targets and projects.

3.2.2 CAT Storm Scenario: Signposts

The signposts for the increased CAT storm scenario include:

[16] Ann Arbor unveils plan for city's first solar-powered, climate resilience hub (June 28, 2020). Available at: https://www.mlive.com/news/ann-arbor/2020/06/ann-arbor-unveils-plan-for-citys-first-solar-powered-climate-resilience-hub.html
[17] Generac, Investor Presentation, Nov. 2020, http://investors.generac.com/static-files/a99be79f-ab26-4695-9f5a-f0cbaee0ed0d

1. Increasing storm severity and frequency in DTEE's service area.
2. Communities implement resilience initiatives such as microgrids, storage, and other distributed back-up generation.
3. Congress approves a resilience bill to support infrastructure projects in ~2023.

3.2.3 CAT Storm Scenario: Grid Impacts

DTEE's system is vulnerable to increasing intensity and frequency of severe weather events due to the aging condition, design configuration, and operational utilization of the existing system. Extrapolating the recent experience since 2017 toward 2035 suggests an increasing threat risk that requires consideration of structural changes and physical grid contingency upgrades, in addition to existing hardening, to provide greater operational flexibility to address reliability and resilience needs.

3.3 DG / DS Scenario

The DG/DS scenario focuses on customer adoption of DER that reduce customer electricity demand and/or export power back to the grid.[18] Under the DG/DS scenario, residential and commercial and industrial (C&I) customers rapidly adopt DG and DS. There is also some C&I adoption of CHP. The outlook of drivers by 2035 is summarized in Table F below.

In support of carbon emission reductions, federal, state, and local governments offer rebates, tax breaks, and/or establish distributed solar and storage carve-outs. In addition, technological advances and efficiency gains reduce DG/DS costs and the payback period, driving more customer adoption. Eventually, DER can participate in wholesale markets (directly or through aggregations) when opportunities beyond offsetting consumption become available.

Specifically, in this scenario, distributed customer-sited solar PV will grow an average of 23% annually from 2020-2030 and 15% from 2030-2035. This translates to 680 MW of additional generation capacity by 2035, where 54% of the residential customers and 20% of C&I customers are expected to export back to the grid, which will represent ~2-3% of total energy generation.[19] These customer exports will have material effects on load forecasting and distribution grid operations, particularly during peak solar production hours.[20] Additionally, battery storage is expected to be paired with approximately 60% of new solar PV systems, resulting in 395 MW of added capacity by 2035. This scenario estimates that Michigan will adopt a battery storage target allocated across different configurations (utility-scale, front of the meter (FTM), or behind the meter (BTM)).

As DER adoption rate increases, the Company leverages customer devices to support demand-side response to manage system peak. It optimizes capital expenditures by smoothing load profiles and lowering peak load on specific infrastructure to facilitate the larger effort to address the fundamental infrastructure changes during this period. Additionally, MISO's compliance with

[18] DER includes Demand Response (DR)
[19] [internal document] ICF, Forecast Penetration of Residential and Commercial and Industrial (C&I) Customer Photovoltaic (PV) Systems for DTE (May 28, 2020)
[20] Under this scenario, DG/DG may provide grid services as defined by distributed or wholesale markets.

FERC Order 2222 will involve an operational coordination capability related to potential DG or storage participation in the wholesale market.

The cumulative outlook of drivers every five years is summarized Table F.[21] Detailed assumptions under each driver are included in Appendix A.

Table F. DG/DS Scenario Load Forecast 2025 - 2035

Key Drivers	2025	2030	2035
Solar PV – Residential	66 MW (0.6 % peak)	210 MW (2.1 % peak)	422 MW (4.3 % peak)
Solar PV – C&I	52 MW (0.5 % peak)	151 MW (1.5 % peak)	304 MW (3.1 % peak)
Storage-Residential	15 MW (0.1 % peak)	94 MW (0.9 % peak)	254 MW (2.6 % peak)
Storage – C&I	10 MW (0.1 % peak)	50 MW (0.5 % peak)	141 MW (1.4 % peak)
CHP	33 MW (0.3 % peak)	53 MW (0.5 % peak)	76 MW (0.8 % peak)

3.3.1 DG/DS Scenario: Key Uncertainties

The key uncertainties under the DG/DS scenario are those affecting customer adoption, incentives, and market participation.

1. Customer DG/DS adoption rates.
2. Federal and state policies (i.e., tax credits, DG/DS carve-outs, and MW targets).
3. MISO implementation of FERC Order 2222 for DER participation.

3.3.2 DG/DS Scenario: Signposts

The signposts for the DG/DS scenario are centered around possible actions that will confirm the trajectory of BTM DG/DS update over the next 15 years, such as:

1. MISO compliance with FERC Order 2222 to develop operational coordination capability with DTE.
2. Growth of customer solar PV + storage installs in DTEE service area.
3. Michigan increases solar PV cap and adopts a storage target in the next 15-20 years.

3.3.3 DG/DS Scenario: Grid Impacts

Over 60% of the 3,254 distribution circuits operate at 4.8 kV in an atypical delta configuration for the electric utility industry. This 4.8 kV system is also currently operated at 80-100% of firm capacity, which is higher than the typical 65% capacity loading for peer utilities and leaves little to no headroom for incremental DER integration. As has been recognized in various industry

[21] The system peak is based on DTEE's 2019 IRP "Bundled Non-coincident Peak Demand" forecast.

studies and Company analysis, the 4.8 kV system will be increasingly unable to integrate DER and/or electrification due to physical capacity constraints.

Customer DG/DS adoption will impact loading on secondary systems including service transformers, creating voltage and thermal issues. Moderate to high levels of DG/DS on one or more circuits on a substation can cause several additional issues, including reverse power flow through the substation transformer, mainline and lateral voltage and thermal issues, as well as protection malfunctions. At very high adoption rates, customer DG/DS can create issues back up into the subtransmission system, as has been experienced by other utilities. Renewable generation and storage connected to subtransmission systems can create voltage and instability issues if the system was not designed for such use.

3.4 Scenario Impact Analysis

As described earlier, these future scenarios create grid impacts both unique to that scenario and common to one or more other scenarios. These unique and overlapping grid needs have been identified through a detailed mapping of the scenario-specific functionalities and related technology categories leveraging the DSPx taxonomy. Table G and Table H below shows an adaptation of a DSPx matrix map of functionalities and detailed technology categories in relation to the three scenarios. This directional mapping identifies which scenarios impact which functionalities and related infrastructure and technology categories. Those functionalities and technologies needed to meet core reliability or safety requirements combined with those that are related to one or more scenarios suggest potential least regrets investment opportunities. These specific scenario-driven areas would need deeper analysis to fully determine the commonality of requirements. Ultimately, the appropriate investments may address the specific engineering/operational requirements and locational and timing needs driven by multiple scenarios.

Table G below identifies the DO grid infrastructure and operational technology areas that are impacted by each scenario. An "X" indicates that technology addresses or supports the mitigation of the impacts of the scenario.[22]

[22] The DOE DSPx Volume I v 2.0 (November 2019) includes definitions for the grid modernization functionalities. The DOE DSPx Volume II v 2.0 (November 2019) includes definitions for the grid modernization technologies. The four DOE DSPx Volumes are available at: https://gridarchitecture.pnnl.gov/modern-grid-distribution-project.aspx

Table G. Distribution Operations Functionality & Technology by Scenario

Distribution Operations		Electrification Scenario	CAT Storm Scenario	DG/DS Scenario
Functionality	**Technologies**			
Physical Grid	Hardening	X	X	X
	Conductor/Equipment Capacity Increases	X	X	X
	Voltage Conversion	X	X	X
Observability	Electrical Parameter/Event Sensors	X	X	X
	Grid Asset Monitoring	X	X	X
	Environmental Sensing		X	X
	Advanced Metering	X		X
Integrated Operational Engineering & System	Network Operational Scheduling Systems	X	X	X
Threat Assessment & Remediation	Contingency Analysis & Restoration Analysis (see Planning)	X	X	
Operational Information Management	Field Data Management	X	X	X
	Meter Data Management System (MDMS)	X	X	X
	Data Historian	X	X	X
	Data Warehouse/Data Lake	X	X	X
	Data & Analytics Platform	X	X	X
Distribution System Representation	Geographic Information System (GIS)	X	X	X
(Network & State Information)	Electric Network Connectivity Model	X	X	X
	State Estimator	X		X
Reliability Management	Outage Management System (OMS)		X	
	Fault Location, Isolation & Restoration (FLISR)		X	
Power Quality Management	Integrated Volt-var Control	X		X
	Power Electronics-Var Compensator	X		X
	Advanced Inverters	X		X
Distribution Grid Control	Distribution Supervisory Control & Data Acquisition (SCADA)	X	X	X
	Advanced Protection		X	X
	Advanced Switches, Circuit Switchers & Reclosers	X	X	X
	Grid Energy Storage	X	X	X
Grid Optimization	Distribution Management System	X	X	X
	Asset Management System	X	X	X
	Control Center Modernization	X	X	X
	Operational Analytics	X	X	X
Operational Telecommunications	Wide Area Network	X	X	X
	Field Area Network	X	X	X
	Neighborhood Area Network	X	X	X
	Communications Network Management System	X	X	X
DER Operational Control	Distributed Energy Resource Management Systems (DERMS)	X		X
	DER Portfolio Optimization	X		X
DER Services to Distribution and/or Wholesale Market	DER Management Platform	X		X
Distribution to Customer/Aggregator Coordination	EV Charging Enabling Grid Infrastructure	X		
MISO - Distribution Coordination	Operational Data Exchange			X
	Operator-to-Operator Communication Interface			X

Additionally, Table H below provides a multi-scenario assessment of distribution planning tools and methods adapted from the DSPx framework. Investments in planning tools may be driven by core reliability needs, or a single scenario's planning requirements. The adoption pace for tools and new methodologies will, however, be shaped by the timing and other considerations related to a scenario.

Table H. Multi-scenario Assessment of Distribution Planning Tools and Methods

Distribution Planning			DER Scenario	Electrification Scenario	CAT Storm Scenario
Functionality[1]	**Technologies[2]**				
Short and Long-term Demand & DER Forecasting	Customer DER Adoption Models		X		
	Customer-EV Adoption Models			X	
	Demand Forecast Models		X	X	
	Load Profile Models		X	X	
	Scenario Analysis Tools		X	X	X
Short-Term Distribution Planning	**Power Flow, Power Quality & Fault Analyses**	Peak Capacity Analysis	X	X	
		Voltage Drop Analysis	X	X	
		Ampacity Analysis	X	X	
		Contingency & Restoration Analysis	X	X	
		Balanced and Unbalanced Power Flow	X	X	
		Time Series Analysis	X	X	
		Load Profile Analysis	X	X	
Long-Term Distribution Planning		Volt-var Analysis	X	X	
		Voltage Sag/Swell Analysis	X	X	
Hosting Capacity		Harmonics Analysis	X	X	
		Fault Current Analysis	X	X	
		Arc Flash Hazard Analysis	X	X	
		Protection Coordination Analysis	X	X	
EV Readiness		Fault Probability Analysis	X	X	
Reliability & Resilience Planning	Resilience Study Models		X	X	X
	Resilience Benefit-Cost Models		X	X	X
	Reliability Study Tool		X	X	X
	Value of Lost Load (VoLL) Models		X	X	X
Planning Analytics	DER Impact Evaluation		X	X	X
	Stochastic Analysis Tools		X	X	
Interconnection Process	Process Management Software & Portals		X		
Locational Value Analysis	Cost Estimating Tools		X		
Integrated Resource, Transmission &	Planning Integration & Analysis Platform		X	X	
Planning Information Sharing	Web Portals		X	X	X
	Geospatial Maps		X	X	X

Notes: 1, 2 The DOE DSPx Volume I v 2.0 (November 2019) includes definitions for the grid modernization functionalities. The DOE DSPx Volume II v 2.0 (November 2019) includes definitions for the grid modernization technologies. Available at: https://gridarchitecture.pnnl.gov/modern-grid-distribution-project.aspx

4 Current State Assessment & Grid Needs Analysis

This section discusses the results of steps 2B, Current State Assessment and 2C, Grid Needs Analysis. To simplify the structure and discussion of grid needs in this report, the grid infrastructure and operational technologies in Table G and Table H above are consolidated into five categories, which each address subtransmission,[23] substation and distribution, and the grid edge:[24]

- Infrastructure (Section 4.2)
- Observability (Section 4.3)
- Analytics and computing platforms (Section 4.4)
- Controls (Section 4.5)
- Communications (Section 4.6)

For each category, we present a description of the current state and discuss steps needed to progress toward the desired future state, with recommendations guided by the scenarios. Reflected in this discussion are DTEE's ongoing and sometimes industry-leading modernization efforts to add new grid systems and technologies to address ongoing and emerging issues affecting safety, reliability, and resilience. This assessment also highlights challenges facing DTEE in further modernization, particularly limitations associated with aging infrastructure asset conditions and constraints arising from 4.8 kV legacy system design. The current state and challenges are contrasted with the desired future state to identify steps needed to develop the capabilities and functions characteristic of a modern grid.

This Grid Needs Analysis is supported by the expanded scenario-capability-technology matrix tables in Appendix B: Detailed Grid Needs Analysis Tables.

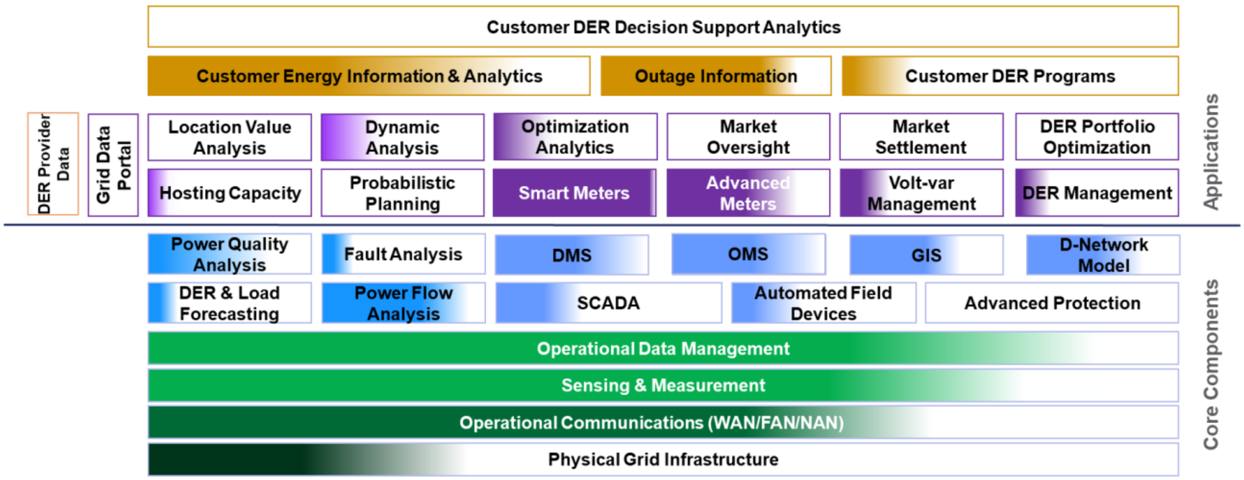
4.1 Overview of Current Grid Modernization Status

The ICF Team used the DOE DSPx platform framework to guide our observations and recommendations.[25] That framework distinguishes between core components and applications and illustrates how multiple distribution technologies fit together to achieve business objectives. Core components enable the application layer of grid modernization, which includes analytics, planning, and optimization. In some cases, enabling these applications is more of a business process and data integration project than additional technology investment.

DTEE's current state of grid modernization, including efforts underway, is represented conceptually in Figure 7 below utilizing the DSPx platform framework that provides a lower level of detail regarding technology and infrastructure investment categories summarized in the Grid Modernization Pyramid (Figure 2) discussed in the executive summary.

[23] The ICF engagement prioritized grid edge and substation and distribution in our analysis. The subtransmission details may be light throughout this section as a result. Prioritization was driven by the needs of the scenarios that guided our analysis (Section 3).
[24] We have used the term "grid edge" here to discuss the seam where the utility distribution system meets the customer premise. It is a broad term intended to capture the Company's most distributed assets and customer equipment. Smart-energy.com defines the grid edge as "The grid edge refers to technologies working near or at the end of electrical grids." https://www.smart-energy.com/industry-sectors/smart-grid/digital-transformation-at-the-grid-edge/
[25] DOE Next Generation Distribution System Platform (DSPx) http://doe-dspx.org/sample-page/dspx-volumes/

Figure 7. DTEE Grid Modernization Near-Term Status



The degree of shading for each box represents the relative status of grid modernization now or in the near future. For example, as shown above, DTEE has made investments in many of the core components of the DSPx modern grid framework and implementation continues. Additionally, shading of the Distribution Management System (DMS), Outage Management System (OMS), Geographic Information System (GIS), D-Network Model and Power Flow Analysis boxes reflect the completion of the next phase of ADMS implementation. DTEE continues to pursue efforts to advance its grid modernization in the core operational and planning technologies as discussed in this Study. However, Figure 7 also highlights the basic need to enhance the foundational core physical grid infrastructure. The items within this graphic are discussed throughout this chapter and definitions for each are contained in the Appendix C: Glossary of Terms.

4.2 Infrastructure

Physical grid infrastructure forms the foundation of DTEE's subtransmission and distribution systems. Making up this infrastructure are power transformers, wires, cables, switches, and poles, among other grid assets. Like other peer utilities, much of DTEE's grid infrastructure was installed decades ago and is approaching or exceeding expected lifespans. Equipment that is still in operation after its life expectancy can increase the probability and risk of failure, resulting in service interruptions and the need for emergency replacements and repair. The cycle of emergent work—breaking and fixing—can undermine longer-term strategic investment plans, many of which are necessary for further grid modernization. It can also present operational risks and make the system more vulnerable to cascading system problems, affecting reliability. Further, an aging system may not be able to withstand the demands placed on it, both in terms of increasingly variable electricity demand and customers' desire for behind-the-meter technologies including EVs and rooftop solar photovoltaic. Table I provides a summary of asset age by equipment type.[26]

[26] [Internal Doc] – DRAFT 2021 Distribution Grid Plan

Table I. DTEE Asset Age Summary

Asset	DTEE Average Age (Years)	DTEE Age Range (Years)	Industry Life Expectancy (Years)
Substation Power Transformers	43	0 – 96	40 – 45
Network Banks	64 (structures) 46 (transformers)	0 – 85+	40 – 45 (transformers)
Circuit Breakers	42	0 – 85	30 – 40
Relays	32	0 – 60+	15 – 50
Switchgear	37	0 – 67	35 – 45
Poles and Pole Top Hardware	46	0 – 90+	40 – 50
Small Wire (i.e., #6 Copper, #4 ACSR, and #4 Copper)	70+	NA	Varies based on field conditions
Fuse Cutouts	19	0 – 50+	40
Three-Phase Reclosers	9	0 – 31	20
SCADA (Supervisory Control and Data Acquisition) Pole Top Switches	14	0 – 38	20
40 kV Automatic Pole Top Switches (ATPS)	36	0 – 50+	40
Overhead Capacitors	NA	Oldest: 25+	20
Overhead Regulators	NA	Oldest: 25+	20
System Cable	45	0 – 100+	20-40
Underground Residential Distribution (URD) Cable	25	0 – 60+	40
Advanced Metering Infrastructure (AMI meters)	6.5	0 – 10	20

In addition, DTEE faces more capacity constraints when compared to peers due to high utilization of assets, leaving less capacity for new loads. For grid technology to affect advanced operating capabilities, it must be coupled with a sound foundation of infrastructure. DTEE has been working to address aging assets through system hardening and manage loading constraints through substation expansions, conversions, and consolidations.

This Grid Modernization Study is intended to provide insight on how current and future investments in systems and technology can help identify infrastructure with capacity, voltage, or other challenges, how technology can partially mitigate those infrastructure issues in the near term, and how the data gathered can be analyzed to drive decisions regarding infrastructure priorities and refining infrastructure specification and design. There is also an opportunity to include deployment of technologies for monitoring, control, and automation with an opportunistic approach. For example, if a field crew needs to perform infrastructure work (e.g., for a 4.8 kV hardening project) and it is convenient to install sensors and controls that interface with the ADMS, the work orders and design specifications should include these deployments.

4.2.1 Current State

4.2.1.1 Subtransmission

The subtransmission system is a combination of older 24 kV and newer 40 kV substations. Elements of the 24 kV subtransmission system are approaching or beyond the accepted industry life expectancy. For example, the average age of a subtransmission distribution switch is 51 years old, with some switches over 75 years old.

In 2019, the Company performed a study of the NE Region "Thumb" areas of the system, which determined the existing aging subtransmission system is not adequate to serve customers' long-term needs given its limited capacity and reliability performance. Within these Thumb areas, the Company identified approximately 26 trunk lines, 24 tie lines, and 13 subtransmission substations requiring upgrades. By analyzing limitations in serving customers in a single contingency situation, the Company identified necessary investments to add capacity and flexibility to improve reliability. Informed by this study, the Company initiated a subtransmission redesign and rebuild plan for the entire service territory to increase conductor sizes and reconfigure circuits to better serve customers' load and reliability needs.

This redesign and rebuild plan does not include expanding or adding new customers to the existing 24 kV subtransmission system. While some of the subtransmission system is now operating at 40 kV, there is no active program to convert 24 kV lines to a higher voltage class. Instead, conversion, consolidation, and decommissioning are considered on a case-by-case basis when specific subtransmission needs are identified and where multiple benefits would be achieved by the conversion.

4.2.1.2 Substation and Distribution

Complete loss of 13.2 kV or 4.8 kV substations is rare, but substation equipment failure events resulting in large amounts of dropped load have been increasing (0 events in 2011 to 3-5 events per year from 2017-2020).[27] While this trend of substation equipment failures may not continue, it is indicative of issues related to aging substation assets. For example, the average age of substation power transformers is 43 years compared to a life expectancy of 40-45 years. This means that substation transformers could reach end of life in coming years and require emergent or planned replacements. Further, the degree of overloading issues DTEE is experiencing and the associated reliability risk is high based on current loading as depicted in Figure 8 and Figure 9.

During times of potential contingency operations overload (e.g., failure of one out of two transformers at a given substation), which affected 40% of all substations (4.8 kV and 13.2 kV) in 2015, substation auto-transfer schemes are disabled.[28] While this mode of operation prevents potential overload damage to the remaining transformers, it nonetheless has the potential to

[27] [Internal doc] DTE Draft 2021 Distribution Plan;
[28] [Internal doc] DTE Investment Strategy, Load Planning and Circuit Modernization (does not include breakdown of 4.8 kV versus 13.2 kV)

delay restoration times as crews must manually respond to an event where many customers may be without power. Crew response may take a few hours for simpler issues and up to half a day for more serious issues that require temporarily installing portable generation or substation assets. The capacity limitations could affect the Company's ability to realize reliability improvements expected from grid modernization investments in systems like the ADMS and intelligent switches intended to reduce the number of customers affected by an outage.

4.2.1.2.1 The 4.8 kV system

Roughly half of the Company's substations operate at a 4.8 kV distribution voltage, a system design originating approximately 100 years ago, which poses reliability, operational, and capacity challenges today. Further, DTEE's 4.8 kV ungrounded delta system design is very uncommon for utilities in the US and is not compatible with modern grid design.[29] DTEE's legacy system design poses three significant challenges:

1. Detecting and isolating fault conditions
2. Serving needed capacity, and
3. Managing voltage

Detecting and isolating fault conditions on DTEE's 4.8 kV delta system poses operational concerns due to the challenge of selectively isolating a single-line-to-ground fault (e.g., single wire down) situation. Traditional distribution protection techniques, which rely on a high degree of fault current for single-line-to-ground faults, are not effective on this type of system. Wire down events can be extraordinarily challenging to detect.

The Company's 4.8 kV substations have an average age of 68 years. Further, based on 2019 load data, around 37% of 4.8 kV substations have firm overloaded (single contingency) and around 26% would have firm overloads when considering the jumpering[30] capabilities to pick up load on adjacent substations. These numbers are indicative of the number of substations that cause extended outages for customers for single contingency conditions (e.g., substation transformer failure). Further, a 4.8 kV system has lower capacity than higher voltage systems. As a result, as shown in Figure 8 below, areas of the 4.8 kV distribution system are already functioning above their capacity, which results in capacity and voltage management challenges.

It is difficult to regulate voltage on the 4.8 kV systems due to the relatively high impedance (i.e., resistance and reactance) of the circuits. Serving customers from a 4.8 kV system requires a higher amount of current for a given power draw and the system is constructed with small wires that increase the voltage drop effects and reduce efficiency through increased line losses. The voltage regulation challenge with 4.8 kV is magnified as customer adoption of DG and EV increases, resulting in a wider range of loading conditions.

Simply put, the Company cannot build a modern distribution platform on aging, constrained, non-standard legacy 4.8 kV system infrastructure. In the near term, as the Company works toward converting the 4.8 kV sections of its distribution grid, DTEE is working to mitigate the risks associated with the 4.8 kV system through targeted circuit hardening projects resulting in

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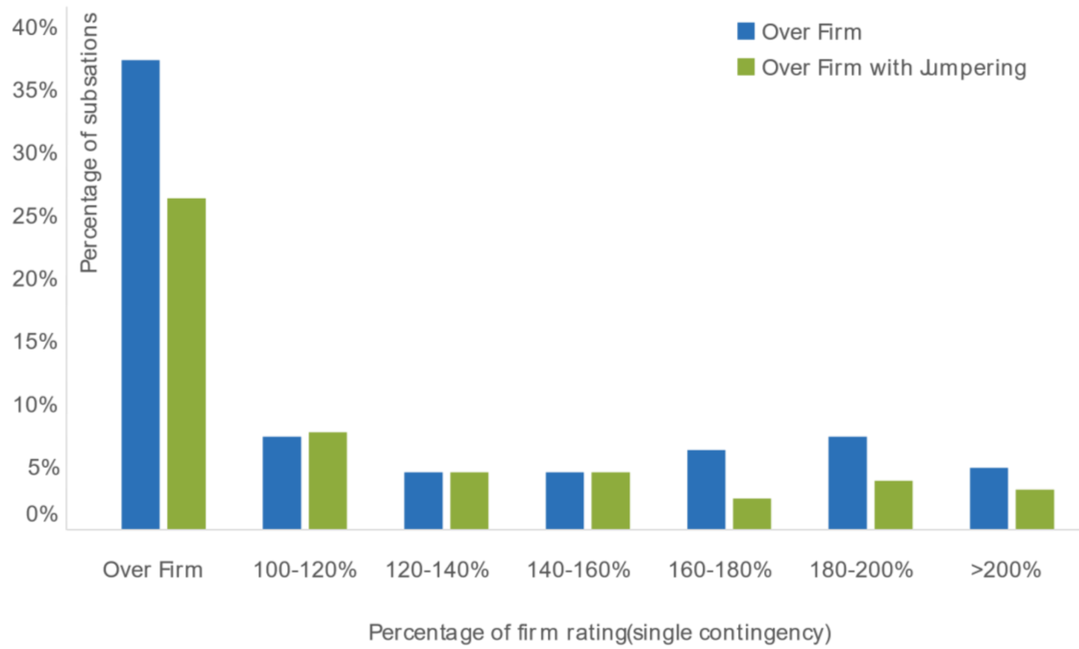
[29] Schweitzer Engineering Laboratories, Review of Ground Fault Protection Methods for Grounded, Ungrounded, and Compensated Distribution Systems, Table 1. Available online at: https://cms-cdn.selinc.com/assets/Literature/Publications/Technical%20Papers/6123.pdf?v=20151125-184914

[30] Jumpering is the act of transferring a portion of a distribution circuit onto and adjacent circuit to continue serving customers during outages or system maintenance affecting the normal circuit configuration.

improved reliability of those circuits after hardening. Because hardening is not a substitute for voltage conversion of 4.8 kV substations with capacity constraints, the Company has a plan to continue consolidating and converting the 4.8 kV system over a long planning horizon.

Figure 8. Percentage of 4.8 kV Substations Exceeding Firm Ratings[31]



4.2.1.2.2 The 13.2 kV System

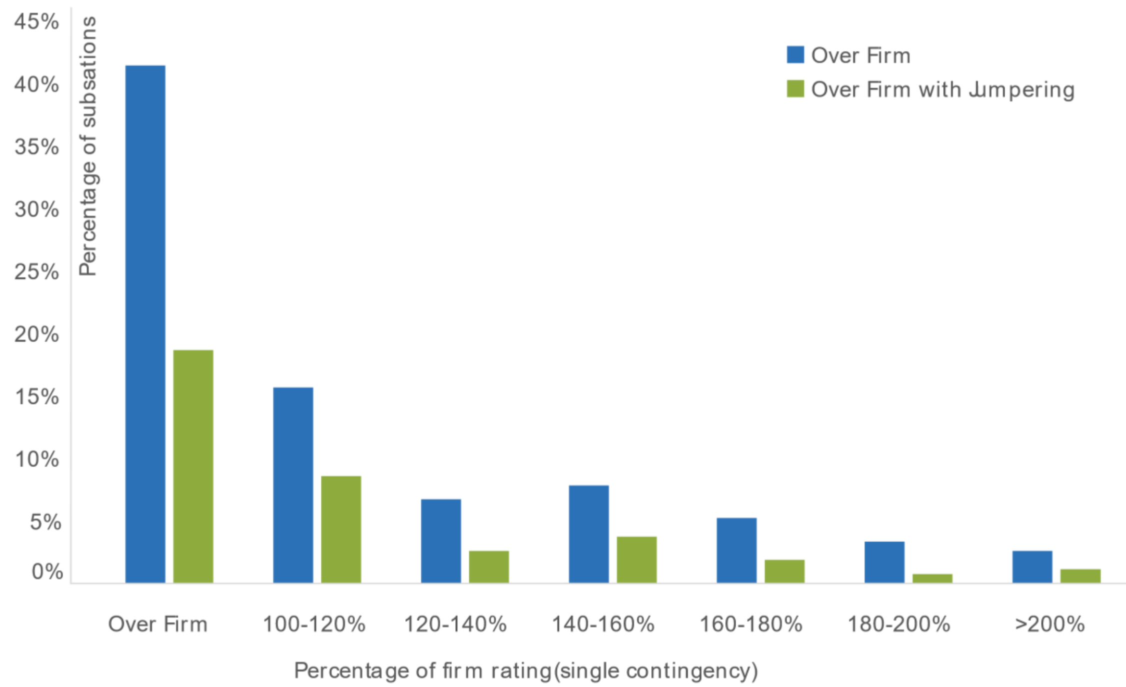
The same aging asset condition and capacity concerns that affect other areas of the distribution system are also present at the 13.2 kV circuit level, resulting in reliability risks and limited operational flexibility (see Figure 9). The 13.2 kV substation average age is 43 years, which is on average 25 years newer when compared to the 4.8 kV system described above. Individual circuit jumpering points have limited capacity. This is partially due to a mix of different conductor sizes and types making up the backbone, as well as the limited number of jumpering points and overall substation and circuit capacity loading constraints affecting contingency load-serving capabilities.

Of the Company's 13.2 kV substations, around 41% exceed firm ratings (single contingency) without jumpering and around 19% exceed substation firm ratings when considering load that can be served by jumpering. Typically, utilities limit the number of substations over firm (i.e., greater than 100% of firm rating) to a very small percentage of a utility's overall substations, and these often represent a handful of capacity expansion projects that came in just underneath risk model thresholds for initiating a project to increase substation capacity. To limit the number of firm rating violations, utilities often perform single-continency planning for distribution substations and mainline feeders, resulting in maximum normal loading around 70% and a

[31] Another 6% of substations are over 95% of firm rating without jumpering, indicating a population of additional substations nearing firm overload conditions.

maximum firm loading around 100%. The Company's over-firm situation is the result of legacy planning standards, as DTEE only recently started considering N-1 contingency situations in a similar manner as many peer utilities.

Figure 9. Percentage of 13.2 kV Substations Exceeding Firm Ratings[32]



Unrelated to system loading issues, the Company recently updated its 13.2 kV overhead design standards with hardened assets to withstand severe weather conditions, which when implemented, should improve reliability and resilience. For example, the Company is installing larger poles that are 2.5 times stronger and polymer clamp insulators that are six times stronger.

4.2.1.3 Grid Edge

Similar to other utilities, DTEE has installed distribution transformers over many decades to satisfy the electricity demand and forecasted grid needs at the time. These legacy assets are not sized to meet the emerging needs associated with DER integration and electrification, as revealed in the asset analysis. The Company is analyzing the changes to equipment standards (e.g., size of distribution transformers and secondary conductors) needed for the new types of load and resources expected to be adopted by customers over the coming years.

The Company's network banks, a specialized subset of distribution transformers that support the downtown area of the City of Detroit, are on average 46 years old, thus exceeding the expected lifespan of 40-45 years. The City of Detroit Initiative (CODI) program is underway and will address the asset condition for most network banks.

[32] Another 4% of substations are over 95% of firm rating without jumpering, indicating a population of additional substations nearing firm overload conditions.

4.2.2 Steps to the Future State

DTEE's current distribution investment strategy and engineering design standards will need to evolve and accelerate to meet the electrification growth and DER adoption likely to occur over the next 15 years. Considering that both the 4.8 kV and 13.2 kV systems have a significant amount of capacity constrained substations, incremental steps are recommended below to develop strategic engineering plans. Section 5 includes additional information regarding asset and infrastructure strategy.

- Prioritized voltage conversion of the 4.8 kV substations with the most capacity constraints and highest reliability impacts.
- Engineering analysis to determine whether expanding substation capacity and reconfiguring feeders can alleviate the 13.2 kV overcapacity conditions.
- Initiate an assessment to determine whether a higher voltage class (e.g., 25 kV, 34.5kV) is needed to support future grid needs. If so, 13.2 kV and the higher voltage class would gradually become the two standard voltages for the distribution system.
- Continue hardening efforts coupled with strategic technology deployments (e.g., sensing, automated switching) for the 4.8 kV and 13.2 kV substations and feeders that are not likely to be converted to a higher voltage class in the next decade.
- Increase deployment of automatic pole top switch replacements to address aging asset reliability impacts and to upgrade monitoring and control capabilities (2021-2035).
- Evaluate adding 40 kV reclosers to the DTEEs equipment standards, as equipment becomes commercially available, and deploy as needed to improve subtransmission reliability and operability (2025-2035).
- Analyze the capacity implications of DER and electrification forecasts to inform future line expansions or voltage conversions.
- Deploy sufficient sensing for situational awareness as DER of electrification changes load flow patterns.

4.3 Observability

To ensure that the grid is capable of meeting shifting customer expectations, DTEE operators and planners need to gather data on grid conditions across each level of the system. Observability broadly allows for observation of the distribution grid and DER, as well as environmental factors that influence grid operations and customer behavior. The electrical observations include monitoring of grid parameters such as three-phase voltage, current, phase angle, and power factor.

DTEE has made significant investment in sensing at each point in the distribution grid architecture, including advanced metering for customers and sensing at substations. Additionally, the Company is expanding distribution automation on the 13.2 kV system consistent with modern utility practice and automated switching devices on the 13.2 kV system are largely SCADA-enabled. As part of modernizing grid visibility capabilities, the Company's system operations center (SOC), currently under construction, will have a video wall to display the status and configuration of the Company's subtransmission system. This modern display will replace the current board that consists of a subtransmission system map with indicator lights.

Despite these advances, work remains to both enhance the observational capabilities and translate those observations into situational awareness and actionable intelligence. For example, complete coverage of substation and grid edge observability will alert system operators when power quality issues are occurring, identify areas where issues are likely to arise, and, through controls, will enable some mitigation of issues before they arise. Additionally, detecting the potential for failures before they occur and transmitting incipient fault data from the field to the SOC improves system reliability and the customer experience. Table J below summarizes the findings for observability.

Table J. Observability Summary

Observability		
Current State	**Gaps**	**Next Steps**
• Most substations monitored • Some primary sensing • Advanced meters capable • Monitoring capabilities worsen as voltage class decreases	• Need to monitor every circuit for situational awareness and planning • Deployed line sensing may miss some power problems (voltage)	• All substations and circuits get monitoring • Assess dedicated line sensor requirements given AMI capabilities • Long-term aim for accurate DSSE to confidently integrate DG and EV

4.3.1 Current State

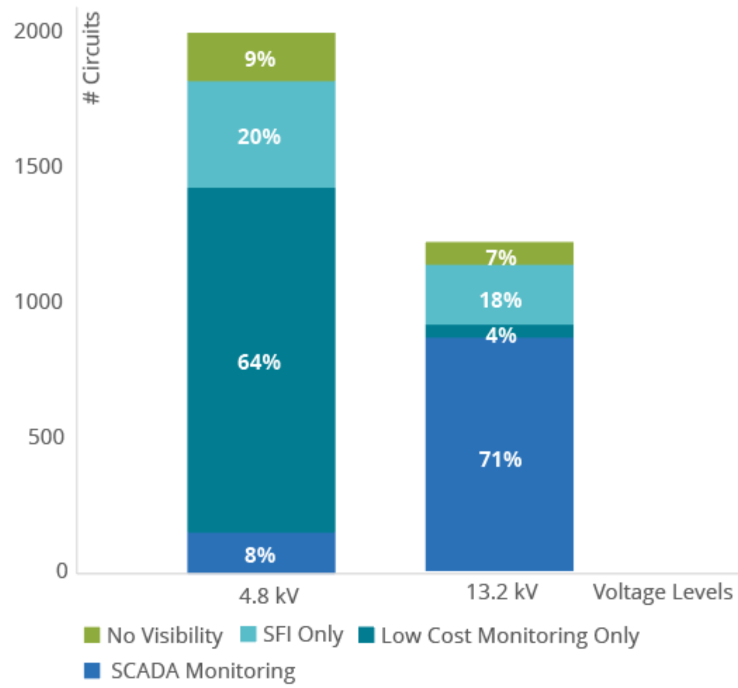
4.3.1.1 Subtransmission

DTEE will continue to transmit monitoring information to the energy management system (EMS) for display in the SOC. DTEE's EMS uses state estimation and contingency analysis software to monitor real-time conditions of the subtransmission system. To contribute to situational awareness capabilities associated with the Company's ongoing ADMS deployment and SOC construction, the subtransmission system will be modeled in its entirety by the end of 2021.

4.3.1.2 Substation and Distribution

Substation monitoring continues to progress as the Company has implemented a variety of solutions to effectively gain visibility into substation and circuit power characteristics. The Company generally separates substation monitoring into three categories: SCADA monitoring, low-cost monitoring, and smart fault indicators. As shown in Figure 10, these solutions are used across the 4.8 kV and 13.2 kV systems at various deployment levels depending on substation voltage class.

Figure 10. Current Status of Substation and Circuit Monitoring



SCADA enables two-way communication between the substation and system operations and supports data collection for analysis. Most of the 13.2 kV system (71%) has SCADA monitoring, whereas only a small portion of the older 4.8 kV system (8%) has this form of monitoring. The majority of SCADA on DTEE's system is not Internet Protocol (IP) based,[33] which is required for DER and more advanced controls. However, IP addressability has implications for NERC CIP that require designing and configuring the system to comply with the associated cyber security requirements.

Many of the systems with SCADA monitoring do not utilize the control aspect of SCADA for the substation equipment. This may be a result of either the substation equipment capabilities or a lack of appropriate communications. However, controllability, described in subsequent sections, is a key capability for improving operational flexibility when responding to outages or performing planned switching.

Low-Cost Monitoring provides an alternative to retrofitting older substation equipment with SCADA. DTEE has deployed a low-cost monitoring solution very near the substation equipment that informs system operations of electrical current and breaker status at each feeder and the power and voltage at each transformer. An example of low-cost monitoring technologies is a remote terminal unit capable of transmitting limited information from each feeder breaker. All substation data is captured and transmitted every five minutes, with occasional latencies up to 15 minutes depending on communication reliability.

Smart Fault Indicators (SFIs) use line sensors to detect and indicate fault conditions, allowing the Company to efficiently isolate faults and restore power to customers. The Company has

[33] Internet protocol is a common smart grid communication protocol standard which identifies the address of systems and devices.

attempted to optimize the deployment of these SFIs at the beginning of each circuit and at strategic points along the circuit, informing fault location analysis, while also providing load monitoring at each location. Load data is captured and transmitted by the line sensors in either 5-minute or 15-minute intervals, with the shorter intervals utilized near the head of circuits. Fault and outage event data is transmitted immediately.

The Company is expanding distribution automation on the 13.2 kV system consistent with modern utility practice, which includes installation of automated mid-line reclosers and automated reclosers at tie (jumpering) points for each section. Roughly 30-40% of the existing approximately 2,000 pole-top reclosers and switches provide monitoring of current, voltage, and status/alarms. Automated switching devices on the 13.2 kV system are largely SCADA-enabled (87%).

4.3.1.3 Grid Edge

The Company's system operations are also informed by AMI outage notifications and by customer calls. The Company's utilization of its AMI system to also address specific grid applications is an industry best practice. As an early adopter of AMI, DTEE replaced the Company's 2.6 million meters over a six-year span starting in 2009 to gain more insight to nearly all residential customers. The meters' average age is around 4.5 years with an industry life expectancy of around 15-20 years. The AMI system is utilized for both customer metering and billing functions as well as capable of supporting outage management.

AMI currently allows DTEE to identify outage locations by treating meter alarms similarly to customer calls in the OMS through an automated process. For example, meter "last gasp" outage notifications are transmitted to DTEE's backend system. The meters can also be interrogated to identify if customers' power has been restored. The meter information is used to confirm customer outage calls, indicating the problem is not on the customer side of the meter, and also records the time customer power is restored, simplifying, and increasing accuracy of the Company's outage records. Additionally, the Company's outage metrics (e.g., SAIDI, SAIFI, CAIDI) are calculated based on AMI information. Further, DTEE dispatchers and field crews can ping meters (send a message and verify a response is echoed back) to confirm power is restored without needing to send a field crew. The Company's ongoing ADMS OMS will build upon these capabilities.

The DTEE system is also capturing line-to-line voltage data (minimum, maximum, and average) on five-minute intervals, which is transmitted to the meter data management system three times a day (approximately every 8 hours). DTEE is currently implementing an AMI back-end system upgrade, planned to be in place early 2021, which will allow for broadcasting of voltage and power from meters at five-minute increments.

Finally, the Company has deployed high-resolution metering capable of power quality monitoring for most of the industrial customers and key locations on the subtransmission and distribution systems. These meters give the Company insight into voltage and power conditions at each site, which can feed data into ADMS applications and distribution planning, as well as assist with fault location for the subtransmission system.

The current AMI system is being utilized to the maximum of its original design. A design that was based on interval meter billing data collection through a periodic polling process to relay that information back to a central location for action or analysis. The existing AMI system, like others deployed in the industry, were not originally designed for real-time grid operations. As DTEE identifies additional use cases for sensing and measurement (e.g., harmonics related to DER and EV adoption) there may be further potential enhancements to the existing system. However, there comes a point of diminishing returns that may require a substantive restructure of the AMI mesh network to enable the more data and bandwidth.

Any expansion in the collection and analysis of data from edge devices, including meters or other devices, will require an evaluation of an enabling operational architecture. A recommendation in Section 5 is aimed at identifying operational architectures to ensure that each link in the system of systems is appropriately configured for the desired use case.

4.3.2 Steps to the Future State

- **Appropriate coverage of substation and grid edge observability**

Proliferation of DG/DS will provide acute grid challenges in areas with 4.8 kV, many of which are already nearing, at, or above rated capacity. Voltage regulation on 4.8 kV grids is more dynamic as customers adopt DG and transportation is electrified, resulting in a wider range of less predictable loading conditions. As a result, grid modernization investments to improve observability will alert system operators when power quality issues due to voltage violations, harmonics, reactive power flows are occurring, identify areas where issues are likely to arise, and, through controls, will enable some mitigation of issues before they arise.

Observability is needed on the 4.8 kV system to regulate voltage, monitor current, and have awareness of real-time system performance and device status to detect emerging issues. For example, system operators can use near real-time load information to support decisions on load transfers during contingency or maintenance operations. Additionally, planners can use historic sensing and monitoring data to identify and prioritize projects.

The exact technology solution and deployment strategy to address this challenge will include considerations for other grid needs, including system protection, and the capabilities of existing and planned sensing technologies, including advanced metering. The Company can focus on increasing sensing and measurement in 4.8 kV substation and circuits in tandem with ongoing hardening programs in the short term. Next generation line sensors, capable of measuring voltage and current, facilitate a cost-effective means of monitoring line conditions. The Company is currently working on incorporating sensors into its material standards, allowing for streamlined future deployments.

In addition to the 4.8 kV sensors, the 13.2 kV circuits should be outfitted with next generation line sensing capabilities. With several thousand previous generation line sensors (current measurements only) installed on the 13.2 kV system, next generation sensors will target areas where voltage measurements are crucial. Key monitoring locations could be those with high penetration of DG/EV or in locations that need to be monitored for potential voltage management improvements.

Line sensor deployments on both system voltages should begin in the 0-5-year timeframe, following a coordinated strategy effort, and could extend into later years, especially as replacements to the current generation of line sensors are warranted. Both the 13.2 kV and 4.8 kV line sensor deployments will require communications to achieve the desired results. It should be noted that line sensing capabilities are included with many of the other technologies (e.g., reclosers, smart fuses, and secondary Volt-Amps Reactive (VAR) controllers). Part of achieving accurate distribution system state estimation (DSSE) is to determine where sensors are needed. For example, in some instances installing a sectionalizing switch can provide both the needed sensing capabilities, as well as FLISR sectionalizing to reduce the number of customers affected by an outage.

DTEE should consider prioritizing the substations and circuits that currently do not have any primary monitoring, before shifting to updating previous generation sensors, which do not monitor voltage. That is, DTEE should consider addressing the “No Visibility” and “SFI Only” portions first, before transitioning to strategically placed voltage measurement devices. By prioritizing in this manner, the bellwether meter voltage measurements may evolve to meet similar business requirements as the functionality provided by new line sensor deployments.

- **Incipient fault detection**

Part of protecting system reliability is detecting the potential for failures before they occur, which also allows for replacement solutions that better align with the Company’s long-term asset strategy (as opposed to emergency replacements). Considering the average age of many types of assets on the Company’s system, the need to identify failing assets gains greater urgency.

Technology Investment

Highly granular and niche sensors aimed at identifying failing equipment before it causes a sustained outage.

Location: 4.8 kV and 13.2 kV systems

Timeframe: 3-7 years

Identifying failing assets requires pattern recognition analysis supported by sufficiently granular current and voltage arcing characteristic data and potentially electromagnetic frequency signature detection capabilities and harmonic analysis. Also required is the communications capabilities to transmit incipient fault data from the field to the SOC.

In the absence of highly granular sensing of this nature, being able to identify the cause of momentary faults and address them before they lead to sustained outages improves system reliability and the customer experience. For example, a failing pole top device may cause multiple momentary interruptions prior to causing a sustained outage and requiring replacement. Capabilities required include locating and mitigating intermittent issues.

4.4 Analytics and Computing Platforms

New grid capabilities are achieved when field investments are combined with analytics and computing platforms to provide grid operators and planners insights about the performance of the system. DTEE operates across a large service territory, serving over 2.6 million customers with over 600 substations and thousands of miles of distribution lines managed from a central SOC. Operators, with the help of supporting software, must continue to integrate new streams of data and information in near real-time to better serve customers and manage distribution operations. Meanwhile, planning engineers must leverage that same information to identify grid needs, develop forecasts, analyze trends, inform investment strategies, and ensure that the grid and its operators are prepared to meet evolving customer needs and expectations. Finally, field crews can leverage mobile technology to more efficiently interface with grid operators and distribution engineers to assess the situation and determine the best path forward.

Through DTEE's near-term IT/OT Roadmap and associated efforts, the Company is continuing to improve its ability to leverage increased volumes of system data to monitor and operate the grid, respond to emergency conditions and outages, and facilitate the integration of DER and leveraging of grid assets. Building a robust ADMS platform will unlock additional functionality in the DMS, OMS, and Power Flow Analysis, as well as support substation and distribution automation to speed outage restoration.

DTEE's progress in this area positions them well to proceed with advanced applications, but care should be given to the sustainability and desired future state of grid data utilization, including model management, load forecasts, data transportation, systems of record, and analytics tools. Table K below summarizes the findings for analytics and computing platforms.

Table K. Analytics and Computing Platforms Summary

Analytics and Computing Platforms		
Current State	Gaps	Next Steps
• Significant effort in underlying data in recent years • Cloud infrastructure established • ADMS and other planning tools still maturing	• Still work to do for data integrity for ADMS and planning accuracy • Granular DER and load forecasting to inform plans and strategies • Integrated data architecture supporting multiple business units	• Complete ADMS rollout • Develop multi-use data architecture • Pursue data-driven proactive asset replacement • Use data to inform future investments

4.4.1 Current State

The Company is modernizing its SOC by building a new facility with a digital video wall, which will visualize the distribution system and provide operators with a real-time view of system performance. In addition to allowing a utility to visualize and manage an increasingly complex distribution grid, modern control centers with advanced distribution management functionalities can leverage data from across the system, enhancing resiliency and storm response while also improving cyber and physical security.

Through a large internal initiative, DTEE has developed a near-term IT/OT Roadmap that organizes the main areas of investment around: Operating the Grid Safely, Grid of the Future, Service Excellence, Distribution System Reliability, Work Management, Capital Efficiency & Work Productivity, and Sustainment . The IT/OT Roadmap is being pursued in two phases for investments, with phase 1 addressing near-term needs and establishing the groundwork for achieving the phase 2 long-term business and technology objectives. The near-term phase 1 plan calls for the replacement of specific applications and has identified gaps in capabilities to support each of the seven IT/OT priorities.

Prior to the development of the IT/OT Roadmap, DTEE made investments in software tools to meet growing needs, including the utilization of vendor-provided and in-house tools. Depending on the use case, DTEE can develop in-house tools using modern programming languages. To bolster this capability, DTEE has also purchased Seeq, which helps to visualize data over time.

Like most utilities, DTEE is confronting the challenge of data integrity. Historical asset data record-keeping and system representation have been fairly manual processes, subject to human error. As a result, existing GIS data, for example, is still being checked for accuracy and completeness of each data record. Based on the data integrity analysis conducted in 2017, the Company has been cleaning up system data to support future ADMS capabilities, as well as a broad range of future grid needs. The Company's current data clean-up program uses automated analytical methods paired with field crew verification. Robust field data, resulting from the Company's ongoing efforts, will be crucial for the network model underlying ADMS, which is foundational to key applications such as power flow analysis, feeder reconfiguration, and FLISR.

4.4.1.1 ADMS

ADMS is key as DTEE moves to incorporate more data into their decisions at every level. The Company is implementing a three-phase plan to build an ADMS platform that can interface with other systems and field devices to support more dynamic grid operations. The ADMS is the system operator interface for substation monitoring, control, and automation. It is expected to substantially improve DTEE's ability to monitor and operate the grid and respond to emergency conditions and outages, along with facilitating the integration of DER and leveraging grid assets.

DTEE's ADMS implementation has emphasized data gathering and integrity as first steps, but the same data sources that underlie the ADMS can be utilized for a variety of other uses, including asset health analytics, more granular distribution planning leveraging advanced metering information, and detailed forecasts that help inform distribution equipment solutions, resource plans, and customer programs. The strategy for planning and analytics data generally follows a four-pronged approach:

1. Prioritizing data gathering/integrity
2. Automating information integration and validation
3. Transitioning to a proactive and prospective outlook
4. Using advanced analytics and algorithms to unlock more capabilities

DTEE's ADMS is being implemented in three phases. Phase 1 of the ADMS has already gone live and is based on a 2016 version of the OSI (Open Systems International) Monarch software platform. Phase 1 includes a generation management system (GMS) and EMS, as well as SCADA integration. Phase 2 is planned to be implemented in Q2 2021 and will include an upgrade to the 2019 version of OSI Monarch. Phase 3 is scheduled for late 2021 / 2022. It will include the transfer of EMS SCADA to the ADMS, as well as the integration of the DMS network model and ESRI GIS, and will include the systems integration to interface with AMI and the customer information system (CIS). It will also include three to four different rollouts that add new digital capabilities. For example, the ability to do distribution power flow, state estimation, fault location isolation and service restoration (FLISR), volt-VAR optimization (VVO), dynamic network visualization, and switch order management. These represent significant advancements over current processes, some of which are entirely manual today like switch order management.

4.4.1.2 Data Collection and Utilization

As mentioned in Section 4.3.1.3, the Company is also leveraging data collected through the AMI and sensor network. AMI data has recently been utilized for network management system

(NMS) and OMS data quality enhancements and for a meter-to-transformer mapping project in progress, which will unlock a variety of distribution planning use cases, including phase balancing and more transformer asset health analytics. The AMI data is being populated into an OSIoft PI data warehouse, but there is work to be done to utilize the distribution sensing data (e.g., substation and SFI data), which resides in a separate instance of OSIsoft PI in conjunction with the AMI data for analytics and distribution planning.

The data produced from substation monitoring devices (and strategically located SFIs) is populated to the OSIsoft PI data management warehouse as well as an Azure Data Lake cloud-based solution that leverages a Hadoop database for analytics on transformer and meter collation (mapping). These two different platforms are likely to provide different approaches to analytics and will take time to understand the capabilities and features of each. The OSIsoft PI data is analyzed using PowerBI and other data lake analytics tools. Additionally, distribution planning engineers can access the OSIsoft PI data for use in CYME modeling software for power engineering analytics. Underlying both the ADMS and CYME network models is the same GIS source data. This approach for data storage and analytics is relatively new and will mature over time.

Underlying these software tools are databases that provide structure and authorized access for analysis. DTEE currently supports multiple database platforms, each with their own set of tools that can be utilized by Company engineers to gain insights from data. For instance, the OSIsoft PI data warehouse for data collected from substation and distribution automation equipment can be queried for historical hourly loading conditions and voltage data on certain distribution equipment.

In other applications, the Company currently uses Power System Simulator for Engineering (PSSE) to identify subtransmission thermal loading and voltage constraints associated with tie lines. A project was recently implemented to model all trunk lines in PSSE to account for automatic pole top switches (APTS) operation and the resulting contingency loading. Further, DTEE’s ongoing EMS deployment will form the foundation for future potential advanced applications.

Additionally, DTEE is currently piloting and evaluating a DER forecasting tool in its Phase 2 Non-Wires Alternative (NWA) pilot. The tool projects customer-level achievable load reductions from DER based on meter and SCADA interval data, residential customer demographic data, C&I customer firmographic data, utility program participation, and building energy simulation data. The effort is focused on Energy Waste Reduction (EWR) in two DTE substations (Fisher and Malta), but the underlying tools and methods are adaptable to all customer resource types including demand response (DR) such as interruptible air conditioning (IAC), DG, and DS. Field results are expected in 2021-2022, which will be used to validate the forecasting methodology.

4.4.2 Steps to the Future State

- **Distribution system models with accurate connectivity, topology, and electrical characteristics**

To realize additional value from the ADMS's situational awareness capabilities, an accurate representation of field conditions will need to be modeled. This model management may include managing shifts from the as-built to the as-is model of the distribution system, which would incorporate system changes from emergent replacements during storm or other outage conditions.

Field crews often use the equipment they are carrying on their trucks to make emergent repairs or replacements and restore customers as quickly as possible. The Company is working to develop new business processes that maximize the capabilities of new enterprise systems (e.g., GIS and ADMS) to ensure that the digital twin network model of the distribution system is accurate. The Company may need a combination of trained field crews and technology such as drones to get the distribution system model efficiently to an appropriate level of accuracy for distribution state estimation.

To correctly associate customer load and customer DER on the network model as measured by AMI, an accurate customer-to-service transformer mapping will be required. It is typical for the customer location information to be within the CIS and the customer-to-service transformer mapping will be the mapping between GIS and CIS. This association also enables load analysis for a specific service transformer or to be aggregated up and combined with distribution and automation data analytics.

➢ Planning decision support for deploying technology associated with ADMS applications

When combined with modern field equipment, the Company's ongoing ADMS deployment will bring advanced capabilities for distribution automation and voltage controls. Placing field equipment to simultaneously optimize for reliability, situational awareness, and operational feasibility will require tools and processes that support new operating schemes aimed at unlocking ADMS benefits. For example, the capability to plan where to place distribution automation devices to support FLISR can maximize reliability benefits for a given level of automated recloser deployments and built-in power sensing of these pieces of equipment can inform state estimation. The planning decision support tools will require analytics capabilities to input historic reliability information and sync it with system topology and customer connectivity.

➢ Multi-purpose data historian architecture

To streamline data analysis, the ICF Team recommends exploring combining or interfacing the instances of the OSIsoft PI such that the AMI data and distribution data can both be accessed for analysis. Per DTEE's plans, AMI data will soon include five-minute interval voltage data provided by bellwether meters. This AMI voltage data should be combined with the distribution monitoring information to provide a more robust data set for analytics.

Technology Investment

Suite of software, hardware, and processes aimed at enabling data consistency across DTE.

Location: Enterprise Systems

Timeframe: 3-10 years

As part of that shift in data architecture, DTEE should consider additional (non-operational) use cases for the data collected from the field. As the Company transitions to more data-driven decision-making, ensuring that the data is available for use by different business groups will be important to support new, cross-functional business objectives.

Load and DER forecasting

Accurately forecasting load is essential to system planning. Currently, the forecasting approach accounts for systemwide EWR, DER such as customer-owned generation, and new technologies such as EV adoption and heating electrification. As the system becomes more distributed through adoption of the above-mentioned technologies and behavioral changes, load and DER forecasting become more complex.

To ensure DTEE can effectively plan for these changes, accurate forecasting tools will need to integrate and leverage more granular data sources to support planners with identifying potentially constrained areas well in advance of potential problems.

Forecasting with more granular data at the customer, circuit, or substation level will be needed as load growth re-emerges in some parts of the service territory from increased electrification and other factors. This may require significant work in data management to include granular consideration of customer-sited resources including EWR, DR, DG, and energy storage. Short-term 5-year and longer-term 10-year forecasts of load and DER could provide DTE distribution planners with a more accurate view of future system conditions. Customer load profiles can also be grouped into segments based on customer attributes including DR, DG, EV and other differentiators for more refined planning insights.

Technology Investment

Suite of software tools to more effectively model and forecast a shifting customer-side load profile.

Location: Enterprise Systems

Timeframe: 1-3 years

An initial step in DER forecasting capabilities would be to incorporate load reduction forecasts from business-as-usual EWR programs. While these programs target reductions in energy usage across the service territory, they also result in localized load reductions. Capturing the results of these programs, in terms of load reductions achieved at the distribution substation level, would provide distribution planners with a more complete view of future load. Other utilities have addressed this by implementing databases to gather customer program participation data and algorithms to project future load reductions based on expected order-of-magnitude funding levels.

As DR programs are assessed and potentially implemented for use at a local level, as is currently being evaluated for the Fisher and Malta substations, these resources can be incorporated into forecasts. Later steps could include incorporation of customer-sited DG, beginning with solar PV, and energy storage in forecasts. These could be disaggregations of system-level forecasts to circuit-levels, or bottom-up customer and circuit level forecasts, as is currently being piloted in the Phase 2 NWA project.

DER modeling capabilities

With the complexity introduced by DER, such as two-way load flow, localized load areas, and masked load, comes the need for more advanced modeling that accurately reflects the impact of DER on system operations and the distribution and subtransmission grid. To support engineering decisions for DER interconnections in planning and operations, DTEE would benefit from the following:

- Customer decision support tools to guide DER to system locations that can more easily absorb the energy produced/exported (e.g., hosting capacity analysis).
- Technical screening tools to process applications that require less than a full impact study. As interconnection request volume increases, DTEE may need to automate portions of technical screening.
- Power flow analysis tools capable of modeling advanced DER capabilities (e.g., volt-VAR, volt-watt, etc.) when full impact studies are required, to determine DER settings compatible with DTE equipment (e.g., voltage regulators) and constraints.
- ADMS capabilities that account for the monitored and estimated DER state for use in power flow, state estimation, VVO/ conservation voltage reduction (CVR), FLISR, and feeder reconfiguration functionalities.

The modeling capabilities and associated processes should be scalable and efficient to support a potential influx of DER applications. Other potential use cases for DER modeling tools include capacity planning, DER production and availability forecasting, and power flow modeling at the DER secondary equipment level. Advanced modeling tools can also integrate DR into load flow models and consider advanced inverter real and reactive power controls.

4.5 Controls

DTEE increasingly needs control of utility and customer assets to operate a more dynamic future grid. This includes controlling switching devices to rapidly reconfigure the grid during outages and voltage regulation equipment during normal operations. On the customer side, control of certain DER assets (load control, energy storage) is needed to balance bulk system load and generation and to help alleviate distribution capacity constraints.

DTEE currently has some control capabilities from subtransmission down to individual customer devices and can continue to build on this foundation. For example, the Company has incorporated automated devices, such as reclosers and pole-top switches, in new 13.2 kV substations and circuits. However, many of the installed control devices have limited capabilities or are facing end of life.

Increasing control capabilities, such as incorporating greater system protection and voltage regulation, supports DTEE’s safety and reliability priorities and assists DTEE in integrating higher levels of BTM assets, including DER and EVs. Table L below summarizes the findings for controls.

Table L. Controls Summary

Controls		
Current State	**Gaps**	**Next Steps**
• Some automated pole top switches on subtransmission and distribution • Most distribution reclosers have SCADA • Few capacitor banks are switchable with SCADA controllers • Interruptible air conditioners and controllable thermostats	• Advanced system protection for 4.8 kV system and future power flows • Field device management to maximize capabilities • Switching capability for system reconfiguration • Voltage regulation equipment with electronic controls and SCADA capabilities • DER management platform for more granular control	• Complete pilot and scale 4.8 kV protection solution • Expand automated switches for FLISR where operational flexibility exists • Evaluate field device management software • Investigate feasibility of standard high-voltage reclosers • Continue rollout of voltage regulation controls for VVO • Plan for longer-term DER management needs

4.5.1 Current State

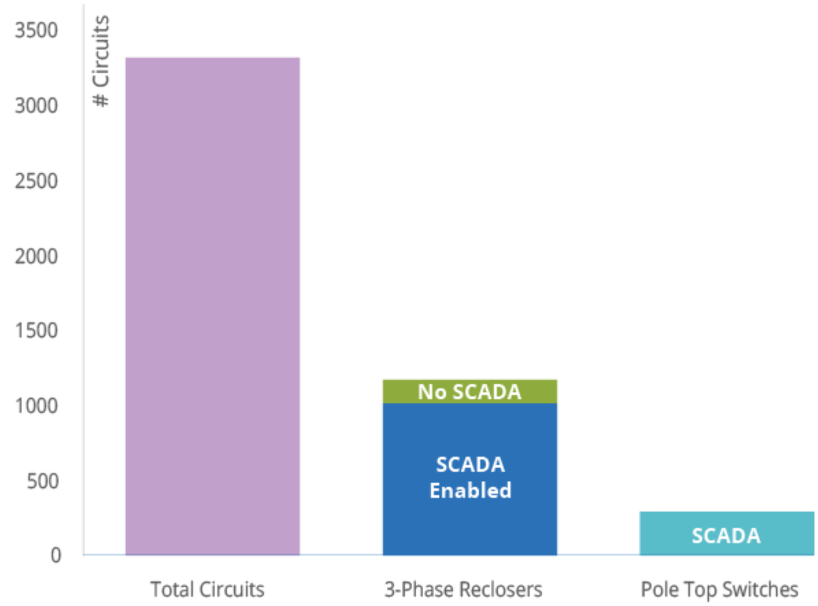
Subtransmission

The Company utilizes a coordinated system of subtransmission APTS and line section breakers on the networked tie lines to isolate faults and maintain service to customers in single contingency failure situations. As shown in Table I, the APTS are on average 32 years old with an expected lifespan of 30 years. This means that many APTS are at or could reach end-of-life in the coming years.

Substation and Distribution

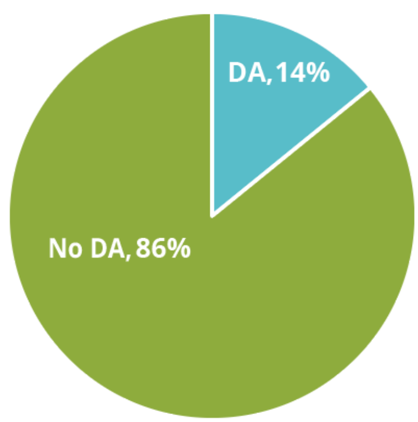
DTEE continues to implement and deploy technology and systems to support outage management, situational awareness, and automated controls for 13.2 kV substations and circuits. Over the last 10 years, the Company has incorporated automated devices, such as reclosers and pole-top switches, in new 13.2 kV substations and circuits consistent with engineering standards. Among DTEE's 13.2 kV substations, 68% currently have SCADA breaker control. In contrast, only 7% of the 4.8 kV substations have this control. The Company is also investing in remotely controlled devices on the existing system. Among the total 3,254 load carrying circuits, DTEE operates 1,169 overhead three-phase reclosers. Many of these have monitoring and control, but some also need to be replaced as they are approaching end of life and have high failure rates. DTEE has 290 pole top switches (S&C SCADA Mate) integrated with the SOC. These statistics are depicted in Figure 11 below.

Figure 11. Current Status of Remote Distribution Switching Capabilities



The Company is working to establish manual and automated jumpering capabilities to allow for power transfer between adjacent circuits when needed (e.g., outage restoration). However, the figure below shows that true distribution automation schemes capable of providing multiple routes for electric power flow—and minimizing customer outage duration—make up a small percentage of the 13.2 kV system. They are not present on the 4.8 kV system. This is partially because capacity constraints on many parts of the system cause the Company to have minimal ability to transfer load, especially during peak conditions. As a result, there are relatively low investments in back-tie capabilities to transfer load between circuits.

Figure 12. 13.2 kV Circuits with Distribution Automation



DA= Distribution Automation

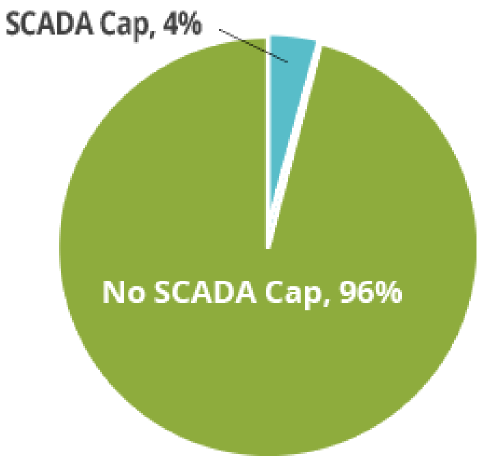
In addition to maintaining reliability through advanced switching schemes, the power grid must control dynamic grid edge voltage conditions to meet standard requirements.[34] The existing voltage management devices have limited capabilities. However, the Company's planned CVR/VVO deployment will greatly increase capabilities for dynamic and efficient voltage control and reactive power in a way that more precisely provides service within the required voltage range.

DTEE has made investments in voltage management to date with 3,160 overhead capacitor banks installed, which are largely fixed (i.e., not switchable) and without SCADA control. The Company's planned CVR/VVO application, which utilizes ADMS functionality, requires remote control and switching functionality for capacitors to manage voltage and reactive power flow, which means installing

[34] Standard ANSI C84.1 voltage ranges determine standard voltage requirements.

digital controls. There is a new retrofit program in the Company's most recent five-year plan to provide new capacitor controls and sensors for measurement and control, with a plan to install 3,000 over the next 10 years. In addition, the Company installs digital controls as capacitor banks need replacement and to mitigate high and low voltage. The current status of 13.2 kV SCADA-enabled distribution line capacitors is provided in the figure below. None of the 4.8 kV substations are outfitted with capacitor controls.

Figure 13. Current Status of 13.2 kV Distribution Line SCADA Cap Controls



There are approximately 2,400 voltage regulators on the overhead distribution circuits, which currently do not have remote monitoring or control capabilities. However, under the CVR/VVO program, remote monitoring, control, and condition-based monitoring for overhead regulators will be piloted in late 2021 on a small subset of circuits. Once the pilot is completed, the Company anticipates installing SCADA capabilities on existing overhead regulators through control replacement. Further, new devices and devices replaced due to failure will be installed with these new control capabilities as standard.

4.5.1.1 Grid Edge

DTEE has grid-edge control over two DR resources: IAC switches through the Cool Currents program and customer thermostats through the newer Smart Savers "Bring Your Own Device (BYOD)" program. To date, these resources have been used to help offset system peak demand. However, efforts are underway to evaluate their potential for meeting local needs in the Fisher and Malta substation areas.

4.5.2 Steps to the Future State

- **System protection**

Currently, the 4.8 kV three-phase, three-wire ungrounded distribution configuration creates challenges for detecting single-line-to-ground (SLG) faults. Typical distribution circuit overcurrent relaying schemes are not effective because the fault current is minimal and indistinguishable from load current. The 4.8 kV system needs ground fault protection technology, which could involve a combination of advanced relaying techniques often used on transmission or generation assets along with an innovative DTEE automation scheme (e.g., "ground-hunting") the Company is piloting. The advanced relaying approaches rely on calculated abstract values (sequence components) to detect system anomalies

<u>Technology Investment</u>

Single-line-to-ground fault detection to ensure "wire down" events are quickly and appropriately de-energized, keeping customers and crew safe, while maintaining service to unaffected customers.

Location: 4.8 kV systems

Timeframe: 0-5+ years

indicative of a ground fault.[35] Methods that use zero-sequence impedance[36] could be implemented through breakers or reclosers with electronic relays. Other methods, specifically those that employ negative-sequence components, would require field sensors along the circuit with sensors that are downstream of the fault conditions sensing the fault. Additionally, these sensors will need appropriate telecommunications and digital processing capabilities.

DTEE is currently piloting an innovative "ground-hunting" automation scheme. When a fault is detected at the substation transformer level, substation feeder breakers open one by one until the ground fault alarm clears. The feeder with the ground fault is left with an open breaker so that DTEE crews can locate and isolate the ground fault. While this method is likely to be effective at reliably isolating faults to a particular feeder, customers served from 4.8 kV substations with this scheme will start seeing more momentary outages.

The ground-hunting scheme will require electronic reclosers outside the substation for each feeder, which is equipment that would also provide the benefit of advanced relaying schemes discussed above. After the ground-hunting scheme is proven and scaled, DTEE should explore whether advanced relaying techniques could be layered in to reliably detect and isolate ground faults while minimizing momentary outage impacts to customers. Since the type of ungrounded distribution system DTEE operates is uncommon except for industrial applications in the US, these 4.8 kV techniques should be piloted through field demonstrations prior to scaling the technology deployments.

The technology is needed today to address existing protection issues. The 4.8 kV consolidation and conversion efforts discussed in the Asset Modernization section of this report are the ultimate solution to address existing 4.8 kV protection issues, but 4.8 kV conversion will take decades to complete. Any work to improve 4.8 kV protection (and hardening) at certain substations should be coordinated with the broader conversion and consolidation effort to ensure that large investments are not made just prior to a conversion.

Separate from the 4.8 kV ungrounded system protection issue, DTEE will be facing adaptive protection challenges common to the industry as a whole. Systematically managing and customizing protection settings for the specific need can support reliable service. For example, modifying protection settings, such as fuse-saving schemes on the 13.2 kV system, for many devices across a broad geographic area in advance of an approaching storm could reduce outages. However, absent storm conditions, this could cause excess momentary outages.

Additionally, protection settings may need to be modified for cold-load pick-up to allow for system restoration after a lengthy outage, where load diversity is lost upon restoration, in order to prevent protective devices from tripping and extending the outage. Finally, protection settings may need to be managed in the longer term to enable reverse power flow from one circuit to another or onto the transmission system. The ability to automatically manage settings would allow the Company to optimize protection for a given situation. Thus, having adaptive protection

[35] SEL, New Directional Ground-Fault Elements Improve Sensitivity in Ungrounded and Compensated Networks, 2001. Available at: https://cms-cdn.selinc.com/assets/Literature/Publications/Technical%20Papers/6124.pdf?v=20151125-191110
[36] See IEEE Xplore® Estimation of Line Zero Sequence Impedance using Real Field Fault Data for Fault Location Application https://ieeexplore.ieee.org/document/8759762

capabilities will allow the Company to manage settings based on real world conditions, including the impact of DER.

"Advanced protection" refers to digital and software-driven relays with standards-based communication interfaces. Over the longer term, DTEE will require a software application to manage operational protection settings profiles. This application may be an additional module within ADMS, but it is not known whether the ADMS solution has this functionality available at this time. Reclosers and breakers would require SCADA-enabled digital controls to take part in an adaptive protection scheme. Many of these controls are needed to enable FLISR deployments.

Technology Investment

Advanced Protection and field device management software to oversee settings under different system conditions, unlock FLISR potential, and manage firmware.

Location: Primarily 13.2 kV with applicability everywhere

Timeframe: 5-10+ years

Relatedly, as the number of intelligent field devices (e.g., cap bank controllers, voltage regulator controls, recloser controls, etc.) increase, a need arises to monitor, maintain, and modify device settings and firmware. This would allow the Company to verify that devices are programmed as intended and that inadvertent or malicious changes (e.g., cyber attacks) that could threaten system security or reliability can be quickly identified and addressed. Implementing these capabilities requires a centralized field device management solution, which may be a function of the ADMS or fit within a separate asset management application.

The software application(s) could be needed in the 5-10-year timeframe (or even sooner) and sequenced with when a substantial number of field devices are available to make use of the functionality. Determination of the timeframe and technology solution(s) should be addressed as part of the Controls Strategy, which is recommended in Section 5.

➢ Next generation subtransmission protection and switching

Driven by system reliability and operability needs, the Company requires a cost-effective sectionalizing and fault interrupting solution for 40 kV subtransmission. It would in part fulfill the Company's need for simpler switching station design. To do this, the solution needs to have fault interrupting capabilities to support system protection. Standardizing on high voltage reclosers will help to develop a simpler switching station design. Since 40 kV is a non-standard subtransmission voltage, DTEE has been working with equipment manufacturers to evaluate potential options.

Technology Investment

Standardized high-voltage reclosers that provide sectionalizing and fault interruption.

Location: Subtransmission

Timeframe: 5-10+ years

➢ Remote and automatic sectionalizing and jumpering

DTEE's ability to reconfigure the distribution system is limited in part by system loading challenges. Additionally, many of the locations that serve as potential locations of system flexibility are outfitted with conventional switches that require a crew be deployed to manually operate the switch and reconfigure the system.

Technology Investment

Remotely operated switches to unlock limited system flexibility and enhance reliability today and prepare for future needs.

Location: 4.8 kV and 13.2 kV systems

Timeframe: 0-10+ years

Advanced switches contain sensors, microprocessors, and communication interfaces, with the ability to remotely operate, thus enhancing flexibility and, therefore, reliability and DER integration. This is done through coordination of line measurements, fault identification, and circuit reconfiguration often through a centralized system such as an ADMS FLISR module. Measurements and event information and actions are transmitted in real-time to the operations control center.

Advanced switches can also be enabled to automatically and locally sectionalize, restore, and reconfigure circuits. Regardless of the centralized/decentralized architecture, these switches and the associated software aim to rapidly reconfigure the system configuration so that some or all customers can avoid experiencing sustained outages.

Because of the system loading challenges and asset strategy, the deployment of advanced switches will need to be phased in over time. Recommendations are to:

- Focus near-term equipment standards updates to incorporate intelligent devices/controls on assets with a high-age population and those that are consistently encountered in break-fix work.
- Develop standards for a cost-effective, very easy to install SCADA controlled and monitored three phase operating device that can close into faults for throw-over and jumpering switching points.
- Develop standards for 4.8KV system automation including ground hunting, sensors, and inexpensive protection.

➢ Remote and automatic voltage and reactive power control

Having better control of system voltage will be important as DER and beneficial electrification cause increased voltage variability and change the reactive power flow on DTEE's system. As a result, the Company will need more flexible distribution voltage regulation devices (e.g., switched versus fixed capacitors) and the ability to coordinate and manage these devices (e.g., ADMS VVO/CVR module). Over time, DTEE may need to include inverter reactive power control capabilities into ADMS VVO/CVR schemes to coordinate and optimize sometimes conflicting objectives. For example, DER volt-VAR control can increase reactive power flow to reduce voltage impacts while ADMS VVO could reduce overall reactive power flow to minimize losses.

Technology Investment

A combination of investments is required for voltage and reactive power control (VVO), including the ADMS, SCADA-enabled digital controls for capacitors, load tap changers, voltage regulators, and secondary var controllers.

Location: 4.8 and 13.2 systems

Timeframe: 0-10+ years

While DTEE's ADMS deployment is well underway and some field devices are being installed and planned for coming years (e.g., capacitor controls), additional SCADA-enabled digital controls for LTCs and regulators will be required as VVO rollouts expand to include more circuits. While a subset of DTEE's LTC's currently have some level of SCADA capabilities, the current functionality does not allow for the granular control needed for VVO. DTEE's ongoing AMI upgrade will provide bellwether meter capabilities, but the resulting measurements will need to be augmented with additional next generation line sensor technologies. The combination of the technologies needed to support VVO are expected to be scaled up over the next 10 years.

- **Distributed resource management**

Distributed resource management is the set of capabilities and technologies necessary to have visibility into and control over DR and DER integrated into the operation of the distribution system. As DER penetration increases across the distribution and subtransmission system, DTEE's needs in this area will similarly increase. As such, we have divided this section into considerations across each of the Study durations. As outlined in Section 5, the themes and considerations mentioned here should be further refined through a detailed Distributed Control Strategy.

Broadly speaking, the Company will need to invest in the appropriate controls for utility and third-party DER coordination, including potential MISO and ITC operational coordination systems. One opportunity to learn from past lessons is to establish a DER control and dispatch structure upfront before a patchwork system develops organically. As evidenced by DTEE's multi-faceted distribution automation approach, utility systems that take many years to deploy and mature can become difficult to manage. This is especially true for the complexities of multi-vendor and customer-sited equipment that constitute the DER control and dispatch domain. DTEE is currently piloting targeted DER dispatch mechanisms and should proactively define the DER data management and dispatch architecture.

1-5 years: Presently, DTEE has grid-edge control over two DR resources: IAC switches through the Cool Currents program and residential customer thermostats through the newer Smart Savers "BYOD" program. To date, these resources have been used to help offset overall system peak demand. However, efforts are underway to evaluate their potential for meeting targeted local circuit needs in the Fisher and Malta substation areas. If these pilots prove that local targeted DR programs are feasible, DTEE will look to use its existing DR-management software to pilot the use of DR resources in a substation area. This may be done in conjunction with the deployment and management of a distribution-system sited energy storage device, perhaps as part of a future pilot design. Additional opportunities to evaluate Distributed Resource Management pilots may be pursued and will inform future DERMS investment.

5-10 years: As more PV solar systems and energy storage are interconnected onto the system, the need to monitor and control power characteristics (active and reactive) to adhere to grid thermal and voltage constraints will grow. As these basic grid operating needs are met, DTEE may further need to reliably and accurately control a subset of DER to manage system peak loading or as part of distribution system deferrals (i.e., NWA).

DTEE recognizes that its existing DR management capabilities will become insufficient under higher penetrations of DER and that a DERMS will be needed. DERMS is a software solution that incorporates a range of operations to adjust the production and/or consumption levels of disparate DER directly or through an aggregator. The DERMS system may be a standalone software application or could be integrated within an ADMS as an additional application or module.

The visibility of a DERMS within the distribution grid is typically from the substation downward (or outward) to the low-voltage secondary transformer and includes different levels of aggregation, such as at the substation bank, individual feeders, segments comprising a feeder, and distribution transformers. A DERMS may individually address disparate DER at the edge of the distribution grid by communicating directly with smart inverters, DC converters, other equipment, or communicating with third-party providers who have aggregated DER in an operational area and are presenting the aggregated DER as a combined controllable resource.

Being able to control DER real and reactive power, including autonomous functions, and on/off status will help the Company best leverage DER as a system resource. This will require secure DER communications with adequate latency and bandwidth. Additionally, future solutions for distribution system needs may be comprised of more complex portfolios of resources including traditional upgrades, EWR, DR, energy storage, and others. Managing the operation of combinations and aggregations of resources will be important for addressing distribution needs.

Consideration for interconnection agreement specification of IEEE 1547-2018 configuration is another consideration.[37] The IEEE 1547 progression has evolved from the inverter not tripping when the inverter detected abnormal voltage outside of a specified range in 2003 to allowing inverter voltage regulation and abnormal voltage “ride through” in 2014 to mandating voltage ride through, requiring active voltage regulation and frequency response/support capabilities, and providing optional inertia support. Given the voltage management challenges on the 4.8 kV system, the inverter configuration for interconnection should be thoroughly tested as PV/DS proliferates.

Figure 14 shows the potential interactions a DERMS may have with DER, DER aggregators (e.g., Google Nest, Tesla solar and storage,[38] etc.), and other DERMS systems. Each of these interactions requires a communication device (and network) and DER or site controller. Some controllers are integrated directly within the DER (e.g., smart inverter), whereas others may require additional technology furnished by the Company or customer (e.g., microgrid controller). DTEE has developed a standard solution for communicating with larger DER systems that could require scaling at the pace that DER adoption dictates.

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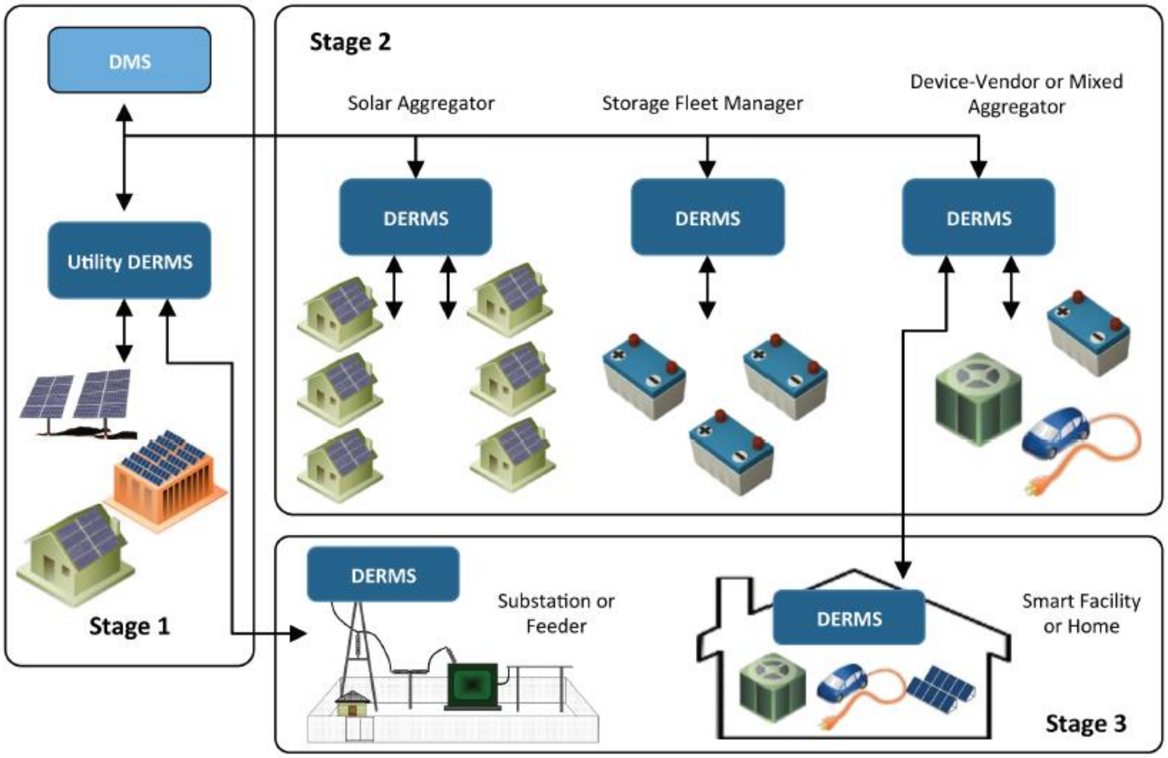
[37] See IEEE 1547-2018 - IEEE Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces https://standards.ieee.org/standard/1547-2018.html
[38] See https://electrek.co/2020/02/17/tesla-technology-revolutionize-electric-grid/

Figure 14. Utility DERMS Potential Functionalities[39]



Additionally, FERC Orders 2222[40] and 841[41] require ISOs/RTOs to develop DER aggregation and energy storage participation models, respectively. To the extent these participation models result in DER and distributed storage participating in the MISO market, the Company will need to facilitate operational coordination with the DER operator to ensure MISO dispatch instructions are compatible with distribution system safety and reliability. While these operational coordination processes can likely be handled with manual processes at low levels of DER participation, there will be a greater need for automated coordination as the number of DER participating directly in the wholesale market increases.

Developing a utility system/portal can support coordination and communication and enable market functions, such as registration, bidding into MISO, and settlement. For example, automated communications with DER aggregators/operators can inform them of distribution system conditions (planned and emerging) impacting ability to participate in the MISO wholesale market. Additionally, there is the potential for a utility system/portal to interface with other utility operational (e.g., ADMS, DERMS, OMS, metering/billing systems) and market (e.g., DRMS, settlement) systems, supporting integration.

Technology Investment

DER Market Integration software to facilitate DTE participation in MISO markets and co-dispatch for distribution and market functions.

Location: Enterprise Software

Timeframe: 5-10 years

[39] EPRI, Understanding DERMS, June 2018. Available at: https://www.epri.com/research/products/3002013049
[40] See https://www.ferc.gov/media/ferc-order-no-2222-fact-sheet
[41] See https://www.ferc.gov/media/order-no-841

4.6 Communications

Connecting field devices to the central office requires a reliable telecommunications pathway. DTEE has made investments in telecommunications technologies to enable field device connectivity. As the number of connected devices and the volume of associated data grows, the communications strategy must similarly be extendable to meet throughput, latency, and reliability requirements in support of the future state scenarios. DTEE's plans to extend approximately 500 miles of fiber to substations and other critical infrastructure is consistent with this aim.

To support that functionality, DTEE is building a new Network Operations Center (NOC) that will be co-located with the new SOC. The NOC will monitor all communications required for the Company's operational systems, which includes substation and field communications networks, connected devices (e.g., SCADA switches and reclosers), and the AMI network. A video wall dedicated to the NOC will support the Company's technical staff in monitoring and addressing communication and cybersecurity performance and any issues that arise. Table M below summarizes the findings for communications.

Table M. Telecommunications Summary

Telecommunications		
Current State	Gaps	Next Steps
• TropOS system established • AMI network capable • Expanding fiber to substation deployment	• WAN build-out still expanding to communicate with substations • Telecom requirements will grow with more deployed devices • DER control architecture undetermined	• Continue prioritized communications roll-out • Ensure today's solutions meet tomorrow's needs • Establish DER Control architecture

4.6.1 Current State

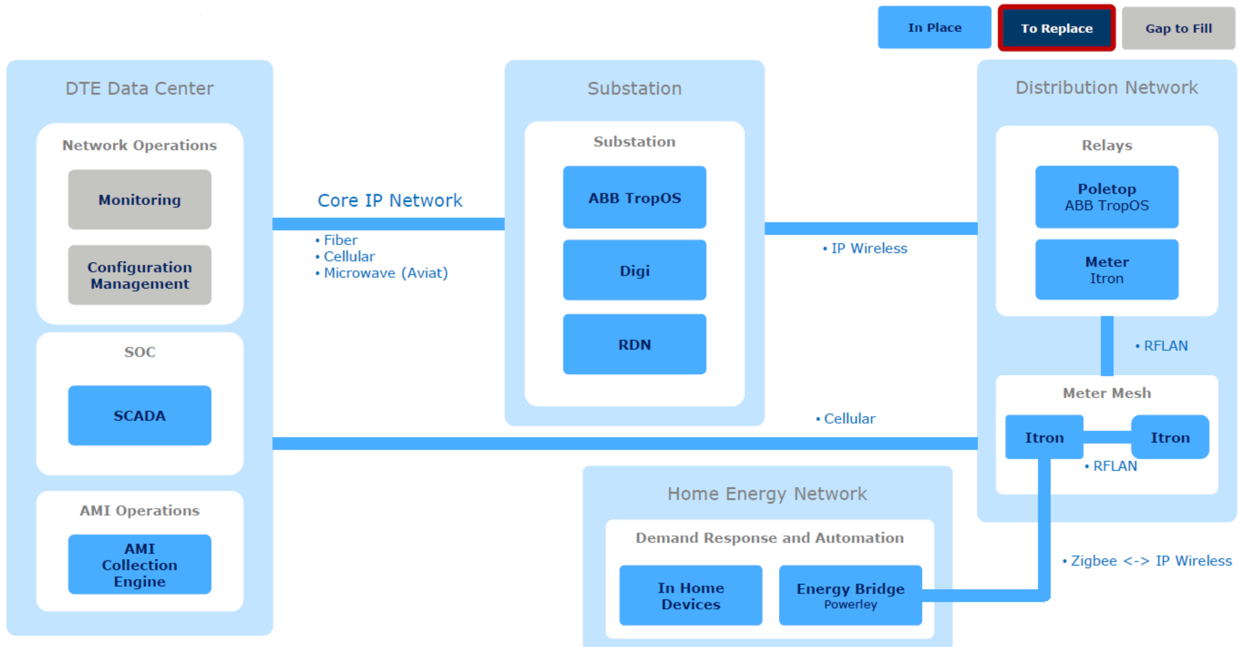
4.6.1.1 Subtransmission

The Company's TropOS network facilitates field communications with subtransmission SCADA-enabled devices. Similar to distribution substations, a combination of microwave radios, fiber optic cables, and leased lines form the Company's wide area network (WAN) communications. As mentioned above, the company has many SCADA monitored APTS that can use TropOS or Cellular networks, but older switches would either require a total replacement or upgrade to the local communication device while retaining the legacy RTU. Effectively the infrastructure is well-established, but certain end uses will need to be enhanced to phase out legacy point-to-point communications.

4.6.1.2 Substation and Distribution

The Company is in the process of creating a consistent telecommunications architecture that can be enhanced to meet the current and growing requirements of a modern electrical system and allow the deployment of the appropriate cybersecurity protocols. Part of the deployment plan includes extending the communications network, as depicted in Figure 15 by supplementing the existing TropOS mesh network, building fiber to existing substations sites, and establishing a telecommunications network inside existing substations to connect relays and metering.[42] Benefits include improved situational awareness with higher visibility and control.

Figure 15. DTEE Network Technology Landscape



Specifically, the Company plans to install approximately 500 miles of fiber and 30 routers for 230 substations and other critical locations in the next five years. Areas are being prioritized based on strategic value, including the number of customers served, automation and communication devices currently installed, and existing infrastructure availability and reliability. To scale and streamline this work, the Company established standards and refined the process, as well as developed standardized substations telecommunications and SCADA cabinets. As a result, in 2020, five substations were connected to a longer fiber run terminating at a service center tower. In 2021, approximately 27 substations will be connected through seven new routes and fiber will be run to two service center microwave towers. In 2022, approximately 200 miles of fiber connecting 100 substations and other locations are planned. Additionally, microwave tower transmitters and Worldwide Interoperability for Microwave Access (WiMAX) pole top transmitters will be replaced with transmitters operating on different frequencies in 2021 per Federal Communications Commission (FCC) guidance.

For distribution automation, the field area network (FAN) mesh network uses TropOS technology, which leverages the same radio spectrum as Wi-Fi, with thousands of nodes currently active. Just like many other utilities, DTEE also operates legacy distribution automation equipment that use serial protocol and utilize RTUs at the substation functioning as a data concentrator. It appears that these legacy serial-protocol-enabled devices will not be integrated in the new SOC. Legacy SCADA-monitored switches and reclosers may need to be replaced completely to migrate to the common TropOS or cellular technology.

[42] [internal doc] Distribution Operations Information Technology Strategy July 7, 2020

DTEE has standardized on new equipment communication protocols over the last 5 years. Distribution automation devices will continue to be on the TropOS system, and, where appropriate, the Company will also leverage cellular technology.

4.6.1.3 Grid Edge

The Company has made investments in grid edge communications, including through the AMI mesh network, which is continuing to be updated as aging assets are replaced at the end of their useful life. For example, to preserve the many benefits of AMI, the Company must transition from 3G cellular to 4G LTE communications, as cellular carriers phase out 3G in 2021. The phase-out of 3G cellular provides an opportunity to replace 6,000 meters, which have integrated cellular communications and serve large commercial and industrial (C&I) customers. These meters will be replaced with 4G (or 5G) devices, including upgrading 950 of the 6,000 meters to advanced power quality meters.[43]

The AMI mesh network is an Itron OpenWay system utilizing IEEE 802.15.4 mesh communications for the physical telecommunication and an Itron proprietary approach to the network and application/presentation aspects of telecommunication. The Company has taken a step to combine TropOS and AMI field area routers (i.e., access points or gateways) at common points with radios supporting both the OpenWay and TropOS telecommunication networks within a single asset (containing an OpenWay and a TropOS receiver). Each of these systems is common in the industry.

4.6.2 Next Steps to the Future State

- **Telecommunications strategy**

Telecommunications is at the foundation of a next generation electric grid. A new wave of telecommunication technology will soon unlock more bandwidth and lower latency potential than currently utilized. To be prepared, the Company needs to proactively define the telecommunications requirements of modern distribution equipment, including appropriate bandwidth and latency to support distribution automation.

The Company's current telecommunication initiative to utilize the TropOS FAN and a fiber WAN backbone to support distribution and substation automation is in line with current utility best practice. However, new technologies, including private LTE, can blur the lines between FAN and WAN functionalities, subverting what was a well-established communications network architecture. As technologies evolve, the functions will remain of a FAN to support field devices and a WAN system to ensure that data makes it back to a centralized repository.

A potential area for telecommunication convergence is the existing Itron OpenWay AMI telecommunication solution upgrading or transitioning to a secure and standards based routable Internet Protocol (IP) protocol like Wi-SUN.[44] Wi-SUN holds some promise for enabling a vendor independent interoperable network that can support products from different vendors. Testing and certification and the first lab tests are complete for the physical layer aspect of

[43] Beginning with 4G LTE, cellular devices are intended to remain compatible with future cellular generation technologies. Indeed, 4G technologies, including meters, utilize IP-based communications technologies, which have previously been compatible with future generations.

[44] Wi-SUN Alliance https://wi-sun.org/

interoperability but standardizing the networking portion to the telecommunications standard is a work in progress. However, migrating to an IP-based mesh network for AMI either via Wi-SUN or from a meter vendor like Itron, who purchased the Silver Spring AMI network solution, enables a more modern and standardized approach to AMI networking.

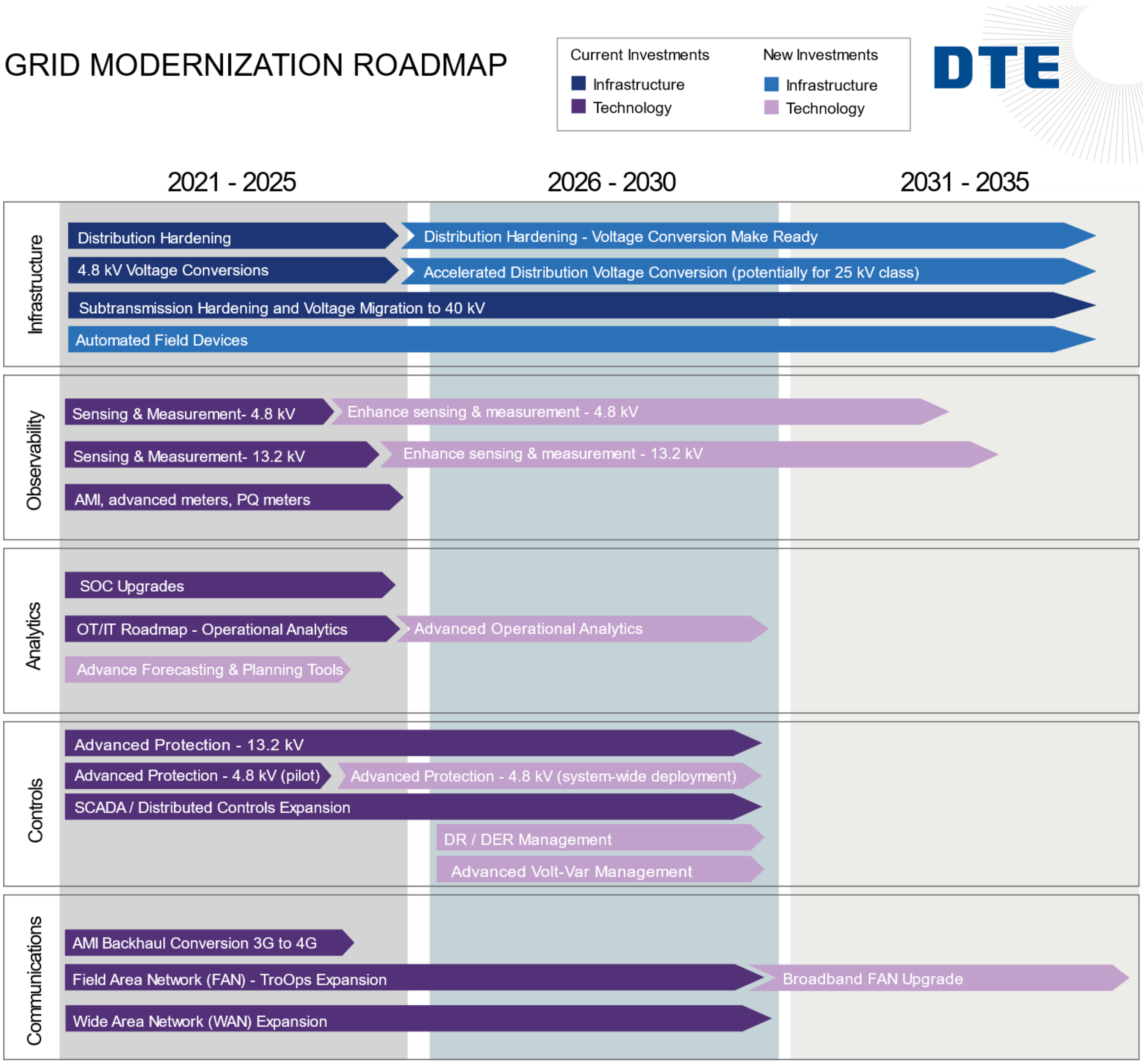
- **DER control strategy**

As mentioned in the Controls section, the dispatch of DER will require connectivity from the utility distribution management system to customer-sited DER. One link in that connectivity chain will be communications, whether via utility-owned infrastructure or otherwise. DTEE should establish that pathway early to ensure that different vendors and resource-types follow similar communications and dispatch architectures.

4.7 Conceptual Grid Modernization Investment Strategy

The preceding Grid Needs Analysis has identified a directional set of modernization technologies that should be further evaluated in order to more fully develop a strategic implementation plan as discussed below in Section 5. These technologies are summarized by technology categories (Infrastructure, Observability, Analytics, Controls and Communications) in Figure 16 below. The timing and sequence shown in this directional strategy are indicative requiring the recommended additional analysis to develop and more definitive longer-term investment plan and roadmap. Section 5 discusses recommendations for additional analysis.

Figure 16. Conceptual Grid Modernization Strategy



5 Near-term Recommendations

In addition to the preliminary identification of longer-term infrastructure and technology investment categories discussed in Section 4, the ICF Team recommends the following near-term steps to develop a strategic and detailed long-term investment plan:

1. Longer-term distribution-level forecasting incorporating granular electrification and distributed resource propensity.
2. Asset modernization strategy based on longer-term distribution forecast to determine capacity needs and voltage conversion strategy including consideration of a new voltage class (e.g., 25kV, 34.5kV).
3. Situational awareness strategic plan based on the longer-term forecast and asset modernization strategy to identify future OT/IT needs.
4. Distributed control strategic plan based on the longer-term forecast and asset strategy to identify future OT/IT needs.
5. GPM enhancements to more fully align strategic capital investment planning with the MPSC's distribution planning objectives.

These recommended next steps will enable the development of a more definitive investment roadmap and associated conceptual cost estimates that will support internal management discussions and those with the MPSC and stakeholders. Each activity could require a year or more of effort (though they may be undertaken concurrently), and assumes that existing data and analysis will be leveraged to conduct a more complete analysis of the scenario impacts, particularly electrification of transportation on DTEE's distribution system over the coming decade. These activities also include internal review and refinements to develop a complete set of deliverables. Each of the recommendations are discussed in greater detail in the following sections.

5.1 Longer-term Distribution Forecast & Impact Study

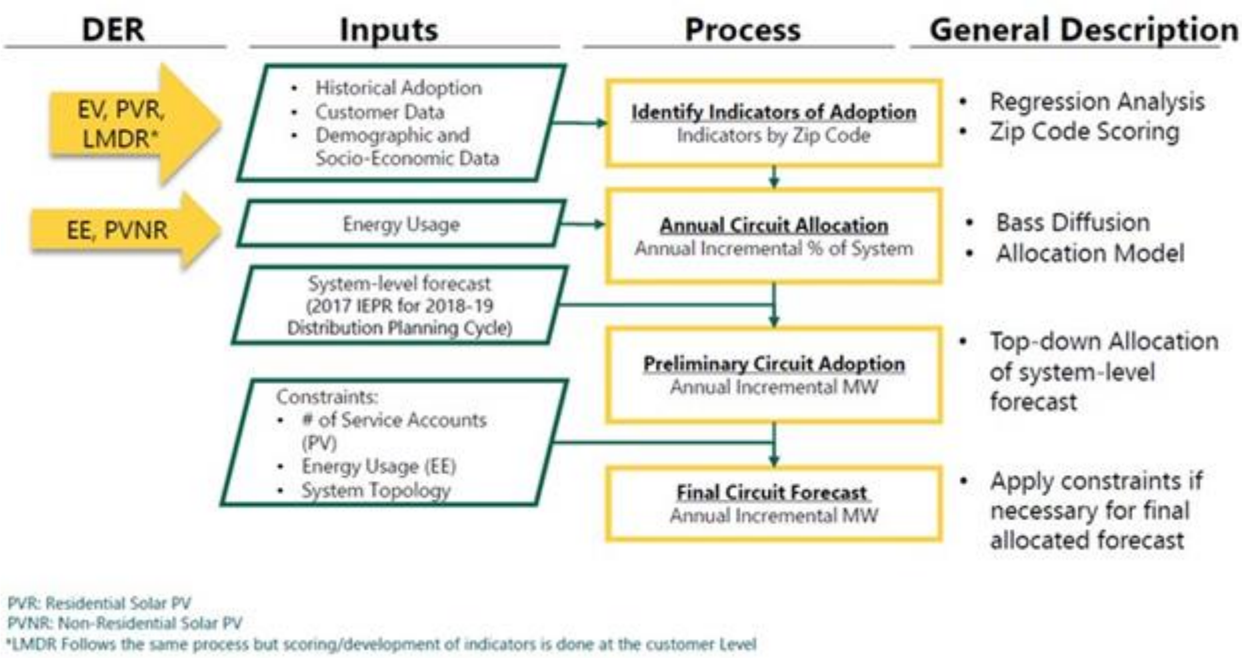
Distribution planning requires a closer examination of the potential changes to load and DER that would be experienced at a substation and at feeders, and, in some cases, sections of a feeder. This involves development of granular, locational forecasts, as well as more detailed temporal forecasts. These forecasts not only incorporate traditional information regarding residential and commercial developments but also electrification and DER propensity and use patterns, as well as other relevant information that will shape a multi-year, hourly forecast at a distribution substation level. This is now the industry best practice.

By comparison, system-level forecasts, used in integrated resource planning, include macroeconomic trends, policy changes, retail rates, technology advancements, and diffusion patterns. System load and resource forecasts, inclusive of electrification and DER, reflect broad changes across a jurisdictional area and are not detailed to a specific location at the distribution system. System forecasts combined with technical planning criteria (e.g., resilience, reliability, and operational standards) inform the development of more "bottom-up" granular locational forecasts that are applicable to the specific distribution planning areas under assessment. The aggregate results are typically compared with system-level projections. Ideally, the granular distribution forecasts in aggregate comport with the system level forecasts.

Additionally, distribution-level forecasts are inherently more uncertain than system-level forecasts given the significant uncertainty as the planning time horizon lengthens and the law of large numbers diminishes at a substation level.[45] This is particularly true for forecasts beyond five years. For example, policy changes, a single large DER interconnection, new residential or commercial development, EV fast-charging infrastructure, or a commercial business closing can quickly change a circuit's loading shape and magnitude substantially. Conversely, a system-level forecast inherently benefits from the law of large numbers, as well as resource and load diversity, which has a dampening effect on potential variability of projected aggregate loading and related bulk power system needs.

Figure 17 illustrates this type of granular distribution planning process as applied by Southern California Edison (SCE) and other utilities today.

Figure 17. SCE Distribution Planning Process



The starting point for developing a distribution locational forecast is assessing available data. For example, development of circuit-level load forecasts draws upon substation transformer (and circuit) loading data sourced from a SCADA system, historical circuit data (e.g., from load studies), and customer meter readings (i.e., AMI or other metering as available). The intent is to identify the temporal loading profile and related demand observed at the substation transformer and circuits that the grid must accommodate along with timing of the needs.

Given the relatively high operational loading of DTEE's distribution system there is very limited headroom to accommodate EV adoption expected this decade. This granular forecast is needed to better assess the need to accelerate voltage conversions, situational awareness, and controls strategies.

[45] The law of large numbers, in probability and statistics, states that as a sample size grows, its mean gets closer to the average of the whole population.

In the case of potential DER adoption, “loading” is increasingly bi-directional in nature with several utilities already experiencing the highest demand on some circuits driven by reverse power flow from DER. As such, in high DER environments, the daytime minimum load may be the period at which the risk of operation outside of thermal or service quality standards may be greatest. Higher fidelity temporal forecasts are dependent on the availability of data and models to prepare these forecasts.

Along with historical loading information and new service requests, other inputs that contribute to long-term distribution forecasts include: EVs, agricultural grow house development, and DER adoption forecasts, including operating profiles, at a local area (e.g., zip code) and substation/circuit level. These are needed to assess the net-load effects, as well as intended and unintended export energy quantity and timing. These granular locational forecasts in turn inform both near-term and longer-term distribution asset and modernization planning.

The ICF Team recommends that DTEE undertake a detailed 10-year electrification and DER forecast and impact study, including the following elements:

- Extend EV and DER adoption propensity forecasts (including sensitivities) to sufficient granularity (minimally to zip code level) to support distribution level asset impact analysis.
- Synthesize the various engineering impact studies for EV and DER into a guide for identifying high likelihood circuit/substation transformer overloads.
- Conduct forecasted circuit-level analysis to assess potential voltage, thermal, and protection issues based on DER and EV forecasts to produce a list of most vulnerable circuits/substations and related components.

5.2 Asset Modernization Strategy

The asset modernization strategy would cover planning years 2026 – 2035, beyond the current 2021 Distribution Investment and Maintenance Plan. DTEE’s electric grid is increasingly challenged by changing customer demands on the subtransmission and distribution systems over the next 15 years. This is largely due to the age of the system, very high asset utilization in relation to general industry practice, and operational inflexibility. In short, there is very little headroom to accommodate load growth from electrification and customer DER.

For example, Figures 9 and 10 illustrates the percentage of customers that are currently served by 13.2 kV and 4.8 kV substations with normal overloads[46] at some point throughout the year. Today, customers served by these heavily loaded substations are at increased risk of extended outages following equipment failure. The capacity constraint also impacts DTEE’s ability to reconfigure and reroute power across distribution lines served by nearby substations. This reliability situation will only get worse with increasing customer adoption of EVs. Additionally, these loading levels will limit the ability to respond to customer needs and choices to adopt EVs at the desired scale. These capacity limitations will also create interconnection issues for those customers seeking to adopt DG and battery storage.

[46] This is not inclusive of the single contingency emergency rating (N-1).

The lack of capacity headroom, limited operational flexibility, and aging assets pose reliability challenges that are currently being addressed in the Company's asset initiatives to: a) harden feeders, and b) convert and consolidate selected feeders to 13.2 kV. This strategy has been effective at addressing safety and reliability issues, but in the long term is insufficient for the anticipated load growth from electrification and customer adoption of DER.

The potential for significant overloads across a large portion of the system is apparent with moderate EV adoption, as illustrated in the electrification scenario sensitivities. This is due in large part to DTEE's 4.8 kV system design that is very uncommon for utilities. It is a design consisting of an ungrounded delta system – a configuration for industrial applications that is not compatible with modern utility grid design. This requires a long-term asset modernization strategy extending beyond the current reliability-centric efforts to achieve Michigan's decarbonization goals and enable customers to correspondingly benefit.

The ICF Team recommends the development of a strategic plan that incorporates the following elements informed by the results of the recommended longer-term distribution impact study in Section 5.1:

- Conduct an industry benchmarking study regarding best practices for:
  - Distribution system loading planning criteria
  - Voltage conversion planning criteria
  - Voltage class/es for conversions
- Reassess existing engineering design standards for potential capacity increases, and voltage and protection mitigation to address forecast EV and DER impacts.
- Identify candidate circuits/substations for accelerated voltage conversions.
  - Determine whether a new distribution voltage class (e.g., 25kV, 34.5kV) is needed.
  - Re-assess existing voltage conversion plans to determine if specific circuits/substations should be converted to a higher voltage (if a new voltage is pursued)
- Identify adjustments for the current distribution hardening plans as needed.
- Develop a long-term detailed asset modernization investment roadmap from these analyses including conceptual cost estimates.

This long-term asset modernization strategy would address the following cases:

- *Safety & Reliability Hardening*: No to low customer EV/DER adoption, no material overloading issues, but with aging infrastructure issues that could turn into safety or reliability issues. Can use opportunistic approach for sensing and component upgrades (e.g., service transformers)
- *Current Conversion Plan*: Low to moderate EV/DER adoption along with safety and reliability issues result in identified need for conversion within the current timing and prioritization parameters.
- *Observability & Component Upgrades*: Low to moderate EV/DER adoption requires secondary voltage measurement and service transformer loading measurement to

determine whether voltage correction is needed and/or whether any lateral or secondary component overloading is occurring, and component upgrades are needed.

- *Accelerated Conversion*: Near-term forecast EV adoption exceeding the design capacity of the feeder and/or substation necessitating voltage conversion and consolidation.

DTEE faces a large scale, costly 4.8 kV conversion and consolidation effort that will continue into the next decade. This asset modernization strategy will enable DTE to better understand the coming changes to the use of the electric grid and respond proportionally in a cost-effective manner.

5.3 Situational Awareness Strategic Recommendations

To unlock the envisioned capabilities of a modern grid, the people and processes supporting a modern grid must be aligned with the vision. As DTEE's system becomes more distributed, the business processes that supported the utility under the old paradigm will need to be modified to reflect growing interdependence and coordination of utility functions and objectives. For example, system planning should account for DER (e.g., DG, DS, and DR), including how they can be leveraged to meet system needs using grid modernization technologies like the ADMS.

DTEE is beginning to contemplate touchpoints between the IRP and DGP, with an eye toward greater alignment. The grid will need to support the optimized generation mix identified in the resource planning process. As discussed earlier, the existing challenges may be exacerbated by shifting characteristics of the resource portfolio, which will need to be reflected in transmission and distribution capital plans. For example, decommissioning peaker generation stations while interconnecting wind generation at the subtransmission level may necessitate new sources of VAR support. Replacements will be needed to replace the peaker fleet's support of contingency scenarios. Identifying viable alternatives will be a cross-functional activity as the feasibility and economics of NWA mature and shift.

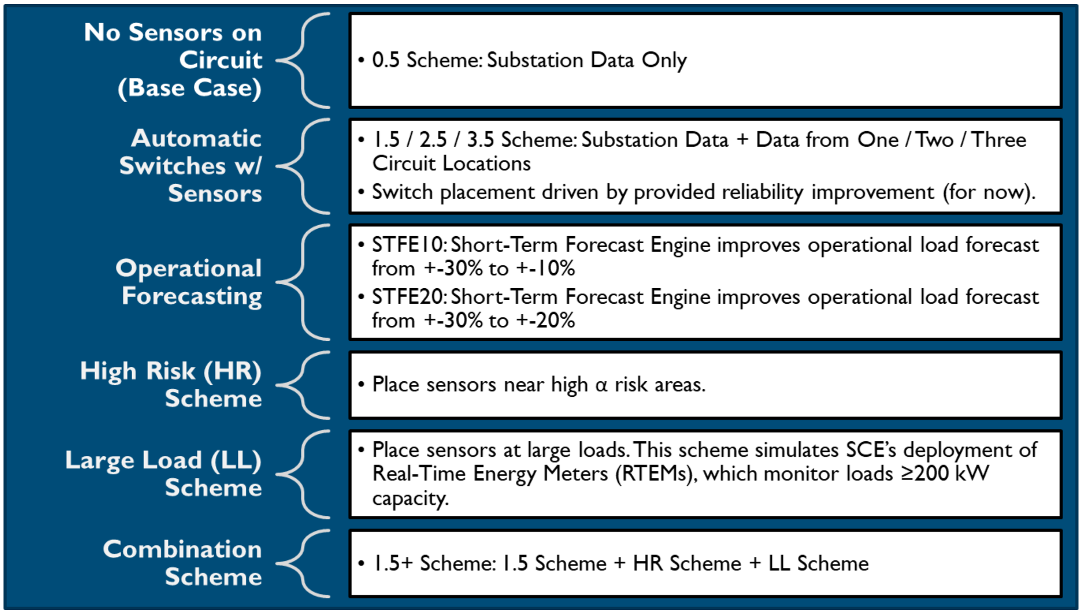
These shifts in priorities can create new engineering challenges, which DTEE will need to manage. Rather than create additional problems stemming from inconsistency, DTEE will need to leverage common data sets and models as tools to inform decision-making throughout the organization.

5.3.1 Prioritized and Coordinated Observability Strategy

As DTEE contemplates placement of additional sensing devices, the placement of those devices will need to be oriented around operational requirements. Given the variety of potential sensor placement locations, sensor types, and use cases utilizing the data, the placement criteria and optimization algorithm for sensor placement and prioritization can quickly get complicated. DTEE should also consider the benefit of multiple sensors relative to insights possible from advanced metering. In Section 4, observability investments prioritized informing operational flexibility in the near term followed by a more granular state estimation in the longer term. While those contexts are priorities for DTEE, others may arise as more granular, intermediate steps.

Strategies for sensor deployment criteria are outlined in Figure below, which has been adapted from work by EnerNex employees.[47]

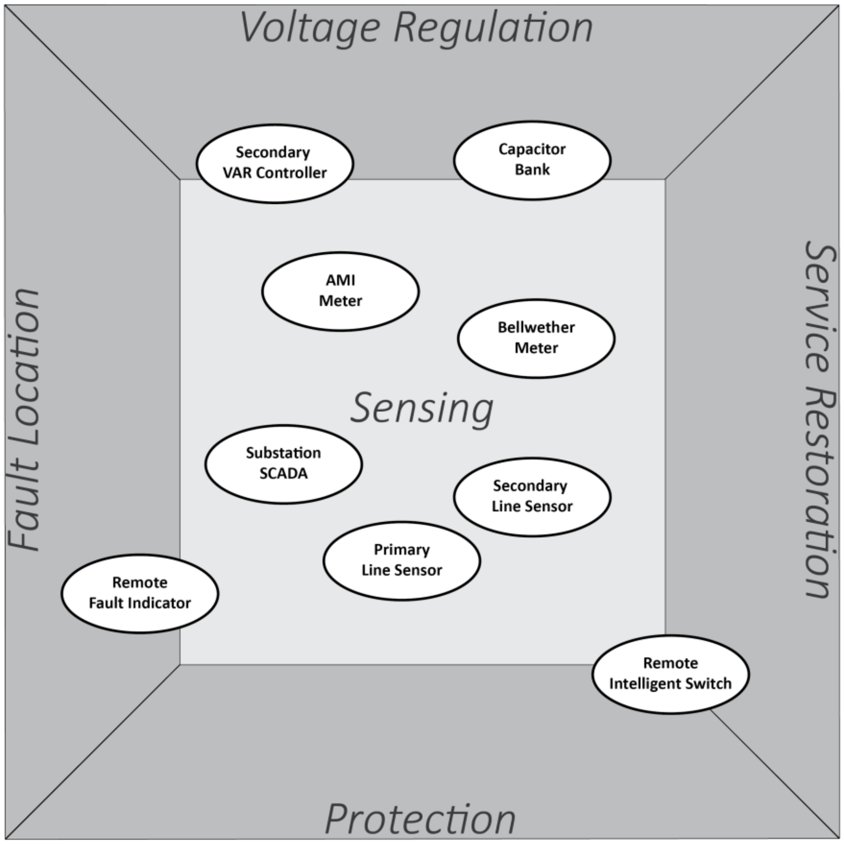
Figure 19. Potential Sensor Deployment Schemes[48]



With respect to the placement of sensors, these are not single-use devices, but rather they can support a variety of use cases. Just as with other components of grid modernization, the placement of sensors should not be driven by a single priority (e.g., situational awareness). Instead, decisions on sensor placement should be guided to enable greater benefit later. The figure below outlines how different technologies may be aligned to not only provide sensing capabilities (center square in the figure) but also voltage regulation, fault location, system protection, and/or service restoration.

[47] J. Schoene et al., "Quantifying Performance of Distribution System State Estimators in Supporting Advanced Applications," in IEEE Open Access Journal of Power and Energy, vol. 7, pp. 151-162, 2020. Available at: https://ieeexplore.ieee.org/document/9076073
[48] Figure adapted from EnerNex work on distribution system state estimation with Southern California Edison. See https://ieeexplore.ieee.org/document/9076073 for more information.

Figure 20. Competing Sensor Placement Criteria Example[49]



Generally, DTEE should consider these complex themes and future needs in coordinating, justifying, and prioritizing their sensor deployment strategy. Placing sensors everywhere will be helpful, but budgetary constraints require prioritization of a logical and sequential deployment plan.

5.3.2 Multi-Use Enterprise Data Architecture

Ensuring that the data from every potentially informative device is available to the people who operate and plan the grid will be more important as future insights and analytics can take advantage of those data points. Beyond making that data available, DTEE should ensure that systems of record, historians, service buses, and extract, transform, and load (ETL) processes maintain data integrity while supporting independent work from common data sets with validated distribution data.

Insights gained from AMI can be paired with substation-level observations to paint a complete picture of the state of the distribution system. DTEE should consider how to pair this data in a structured, sustainable manner to provide insights for future use cases, whether in granular load

49 Image adapted from EnerNex work with multiple other utilities in development of their line sensing and field device strategies.

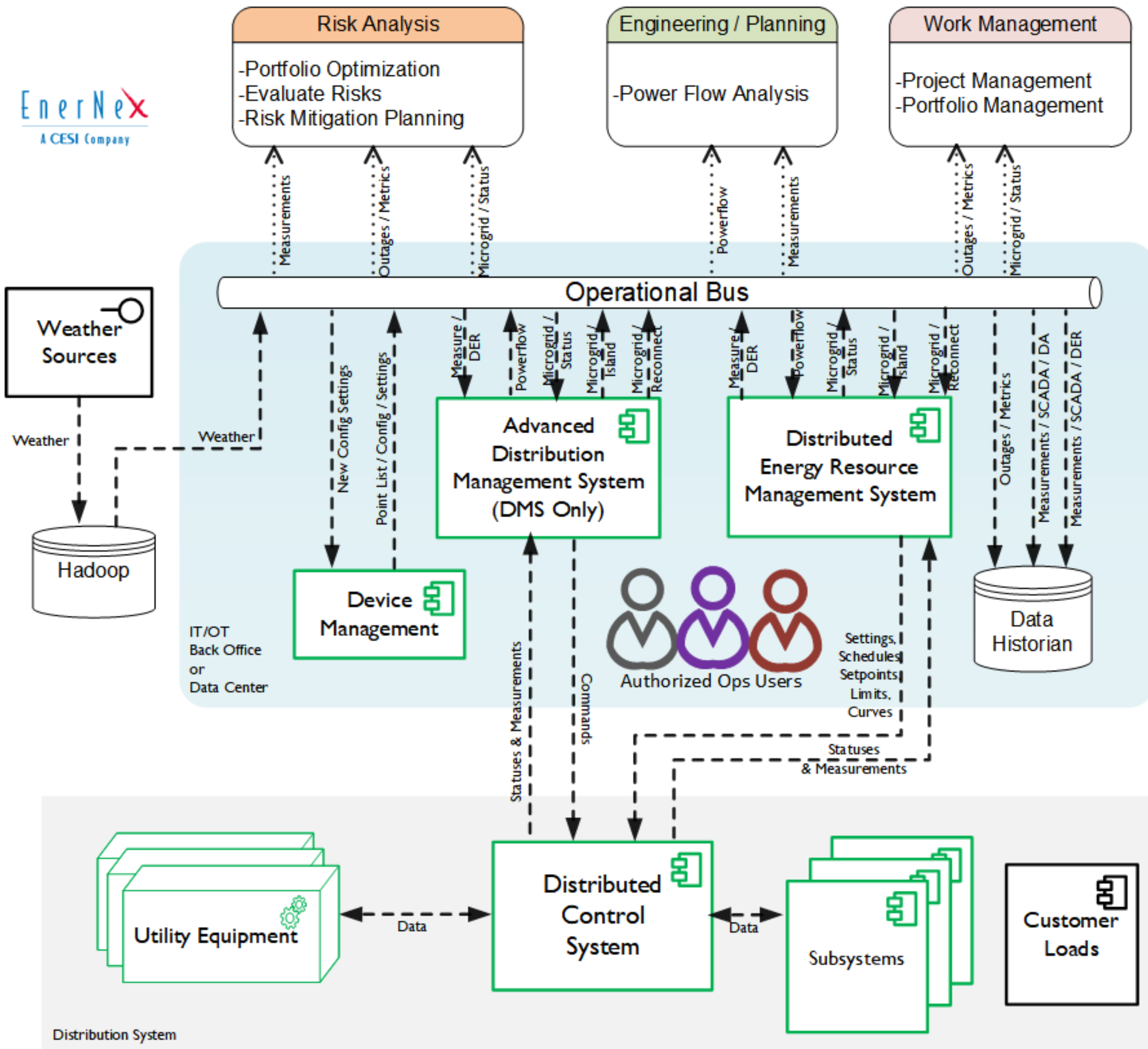
forecasting in support of resource planning or providing insights into the effect of system adjustments on customers.

DTEE has put significant work into identifying the analytic tools that will be used in the future, and in mapping/prioritizing future grid use cases.[50] DTEE should formalize this effort in a deliberate way. A robust analytics strategy will build on observability capabilities and existing analytic capabilities to identify the incremental capabilities needed given system changes from increased electrification and renewable distributed resources and other aspects, such as potential community microgrids. The recommended next step is to identify the desired functionalities, data sources, transfer mechanisms, analytic tools, and business users who will unlock insights through data-driven decision-making.

The investment in this data architecture and supporting infrastructure to enable various business units will maximize the benefits of the observational investments. Not only will real-time observations be available to operators, some measurements and alerts will be appropriately synthesized and archived for use in retrospective analysis and planning. There are several industry reference models for systems architecture that support smart grid and modern grid integrations.[51] An example of a potential reference model showing how the same data can support multiple business units internal to a utility is shown in the figure below. The business units of risk analysis, engineering/planning, and work management perform their own analysis from common data sets.

[50] See DTE Internal File: "Grid Modernization Use Cases Mapping - 11-5-2020"
[51] See National Institute of Standards and Technology (NIST) Smart Grid Framework v4.0 updated July 2020 (https://www.nist.gov/el/smart-grid/smart-grid-framework) and Pacific Northwest National Laboratory (PNNL) Tutorials and Advanced Concepts for Architecture of Electric Power Grids (https://gridarchitecture.pnnl.gov/)

Figure 21. Multi-Use Data Architecture Example[52]



5.4 Distributed Control Recommendations

Over the next 15 years, DTEE plans to deploy a range of intelligent field devices to further advance grid safety, reliability, and power quality. While these assets will provide DTE with the necessary control capabilities, such as managed EV charging, they will also pose coordination challenges among the different devices and systems. Several fundamental decisions on control strategies and architectures should be addressed prior to widespread deployment of these new controls. DTEE's ADMS capabilities offer a key starting point for defining a subset of control options – namely around FLISR and VVO – while other aspects of a full control strategy are currently undefined (e.g., EVs, DER).

As customers increasingly adopt DER, DTEE will need to integrate DG, DS, and controllable loads (e.g., DR and EV chargers) in a way that supports grid planning and operating objectives.

[52] Adapted from work by EnerNex in support of other utilities. The EnerNex resource who developed this graphic is also supporting this effort with DTE.

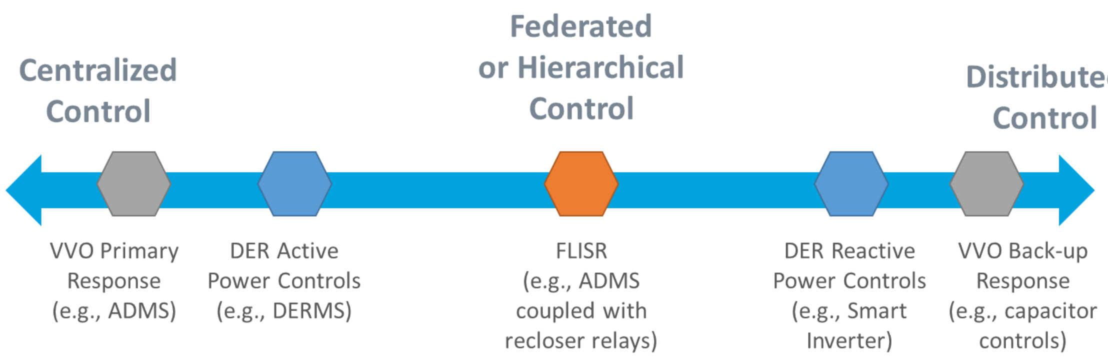
On the planning side, DER utilized to help meet grid capacity objectives will need to couple with effective DER controls to ensure the DER is producing as expected, scheduled, or dispatched. For system operations, DER controls are needed to manage controllable DER based on grid conditions such as temporary reconfigurations used during maintenance or outage restoration. The emerging DER needs are indicative of a broader distributed controls strategy that DTEE should develop.

5.4.1 Develop a Distributed Controls Strategic Investment Plan

DTEE should develop a controls strategy for the myriad controls used to maintain reliability, manage voltage, and provide operational flexibility. The strategy should draw on industry best practice and be informed by the EV and DER impact study recommended in Section 5.2. It should identify hierarchical control strategies for DTE assets, customer resources, independent resource developers, microgrids, and others under various use cases. The strategy should include consideration of centralized (direct) control, federated control, and distributed autonomous control. It may include an expansion of ADMS and SCADA capabilities to meet the emerging control needs and could incorporate the deployment of new systems such as DERMS. As part of the plan, DTEE should develop a control system architecture to translate the strategy's capabilities into designs that support development of a 10-year strategic investment plan.

Controllability of DER and other grid assets can use a combination of centralized and distributed controls. Centralized controls include systems such as ADMS or DERMS to coordinate and control many devices, often in support of an objective on a part of the system distant from the controllable devices (e.g., minimizing reactive power at the substation by using field devices). These same devices, however, typically have a degree of distributed or local control capabilities. Distributed controls include smart inverter volt-VAR operation or switched capacitor controls, both of which sense the voltage conditions at the asset location and automatically adjust operation accordingly based on their configuration. The distributed and centralized control options form a spectrum with hierarchical or federated control[53] in the middle (e.g., FLISR that relies both on distributed protective relays and centralized ADMS control), as shown in Figure .

Figure 22. Spectrum of Distributed and Centralized Controls for a Sample of Distribution Applications



[53] Federated controls work in a coordinated fashion while retaining a significant degree of internal autonomy.

Distributed controls work well when devices do not need to be directly coordinated with each other, as is often the case for smart inverters at low DER penetration levels. Distributed controls minimize single points of failure (e.g., back-end system, communications). Centralized controls, on the other hand, are well suited for uses where geographically disparate information is required for control decisions. For instance, VVO schemes need to input sensing data from many sensors and meters to control voltage regulation devices. Centralized schemes are also well suited for applications where the grid configuration (i.e., topology) needs to be known. Federated control, sitting between distributed and centralized control on the spectrum, allow for local autonomy while still coordinating responses.

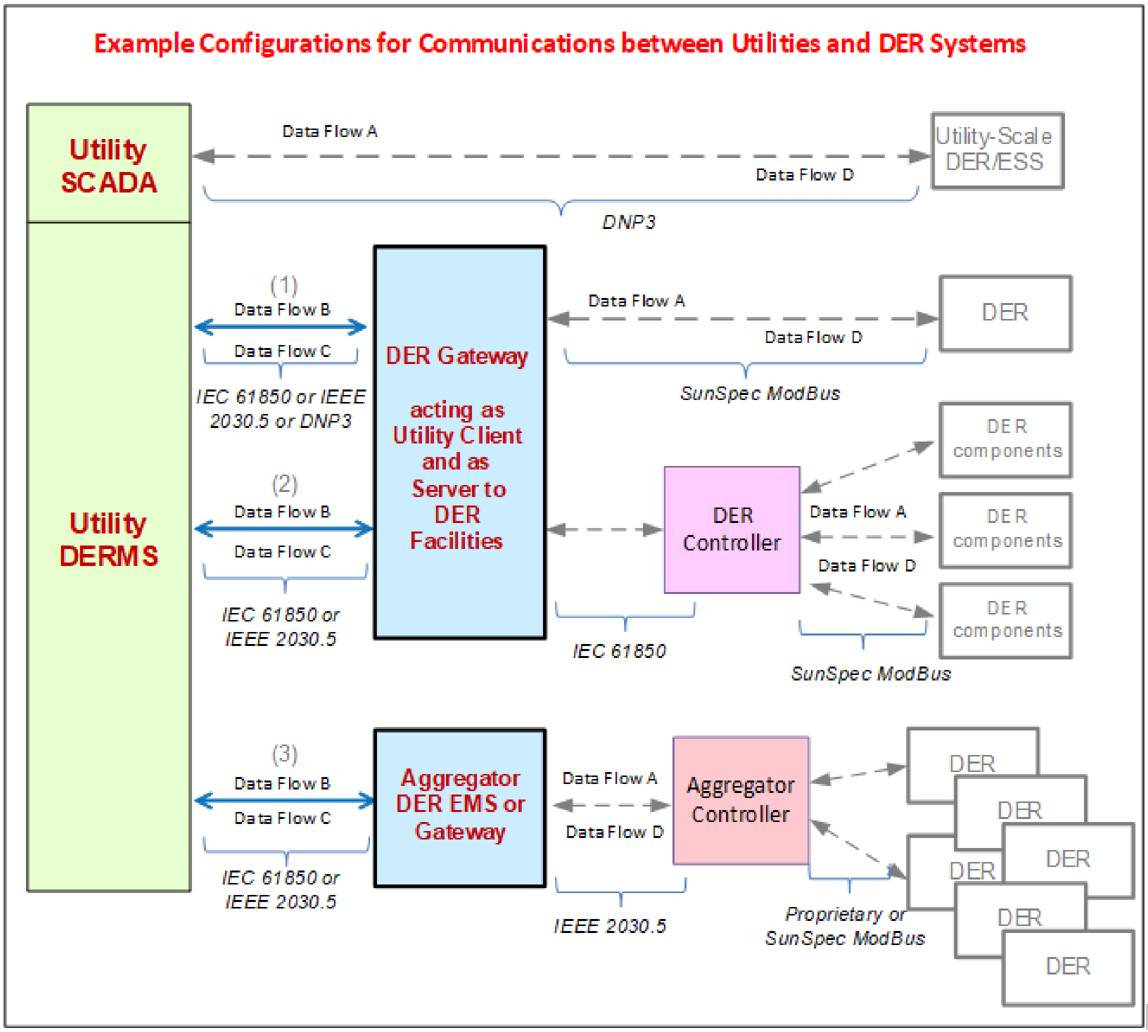
5.4.2 Develop a DER Control Strategy

Smart inverters, certified to the IEEE 1547-2018 standard, offer distributed controls and an interoperability interface that enable autonomous decentralized actions as well as communications and centralized control from an ADMS or DERMS. There are immediate benefits to specifying IEEE 1547-2018 (and the supporting UL 1741 inverter certification) as a condition of interconnection to enable smart inverter functions that support bulk system reliability and distribution system voltage management. These functions, such as voltage ride-through or volt-VAR operation, can be used without the need for communications and are likely able to meet DTEE operating needs while DERMS systems are still maturing. DTE should evaluate DER controllability use cases and develop a DER control strategy using a combination of centralized and distributed controls.

5.4.3 Plan for a DERMS Investment

While DERMS have matured in recent years, they are still in the early stage of commercialization. DTEE evaluated a DERMS product from their ADMS vendor and concluded that the technology needs to be further developed. Adopting a DERMS too early in the technology maturity cycle could lead to higher costs and more time intensive implementation. On the other hand, waiting too long could result in DER control challenges that affect system operations. While DERMS may not yet be ready for adoption at DTEE, the Company should start evaluating system architectures to facilitate information exchange with DER (e.g., discovery, monitoring, control) when DERMS deployment timing is appropriate. An initial implementation of this architecture could include deploying DER communications or gateway devices capable of remote monitoring in the short term through ADMS and full controllability using a DERMS in the future. To address longer term needs, DTEE should start planning for a DERMS deployment in 3-5 years.

Figure 23. DERMS and DER Communications Architectures[54]



5.4.4 Plan for a DER Market Participation Platform

Additional longer-term DER control and coordination needs will result from the evolving electric markets, as is the case with MISO's ongoing implementation of energy storage participation through FERC Order 841 and DER aggregation through FERC Order 2222. There will be a greater need for automated coordination as the number of DER participating directly in the wholesale market increases. DTEE will eventually need a software platform to enable market functions, such as registration, bidding into MISO, and settlement. For example, automated communications with DER aggregators/operators can inform them of distribution system conditions (planned and emerging) impacting ability to participate in the MISO wholesale market. Additionally, there is the potential for a utility system/portal to interface with other utility operational (e.g., ADMS, DERMS, OMS, metering/billing systems) and market (e.g., DRMS, settlement) systems, supporting integration.

[54] Image used with permission from Frances Cleveland at Xanthus Consulting International. Please do not reproduce without subsequent permission.

5.5 Benefit-Cost Analysis (BCA) Recommendations

5.5.1 DSPx BCA Methodology

The DSPx BCA framework is based on clearly identified grid modernization objectives as the cornerstone for economic evaluation. As noted in the DSPx Guidebook, "Objectives provide the link between investments and their expected benefits and can help regulators and utilities prioritize investments."[55]

The DSPx framework helps to unpack the myriad BCA-related issues with grid modernization investments. One of the key challenges of traditional BCA when applied to grid modernization is that many of the investments support more than one objective and may have multiple benefits that are difficult to disaggregate and quantify. An example of this is the core investments identified by DSPx, such as the communications network, which when deployed without field sensing and measurement devices and back-end analytic and data management systems may not itself create as many benefits. Also, grid infrastructure investments to replace aging infrastructure that involve increasing system capacity, such as voltage conversions, not only improve operational reliability but also increase the capacity and flexibility to enable greater customer adoption of EVs and distributed resources. Core investments may also require multiple years to deploy and more than one application to yield desired benefits. These issues were recognized by the California Public Utilities Commission:

> *"There are challenges to establishing a method to evaluate the cost effectiveness of grid modernization requests related to DER integration. Grid modernization investments can span a portfolio of interrelated distribution expenditures that simultaneously support DER integration and ensure safety and reliability."*[56]

Grid modernization benefit-cost evaluation methods are specific to investment drivers, or the rationale for making investments. As DSPx highlights, grid modernization investments have four main drivers (Figure):

1) *Joint and interdependent benefits*: Core platform investments that are needed to enable new capabilities and functions in the distribution grid.

2) *Standards compliance and policy mandates*: Utility investments that are needed to comply with safety and reliability standards or to meet policy mandates for proactive investments to integrate DER.

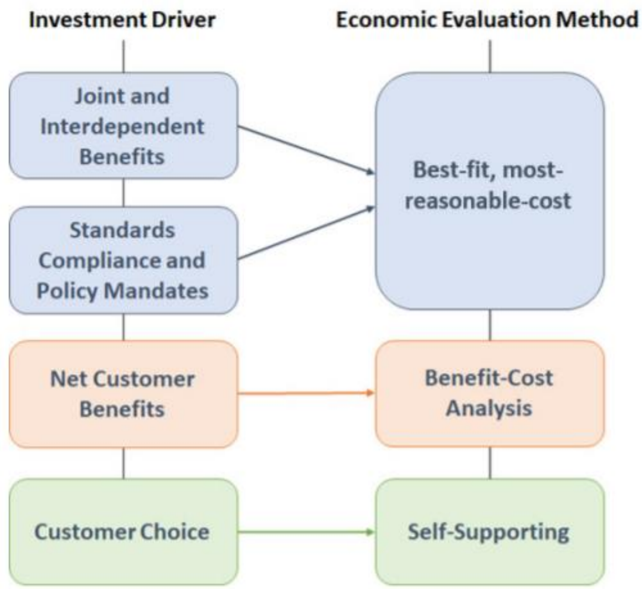
3) *Net customer benefits*: Utility investments from which some or all customers receive net benefits in the form of bill savings.

4) *Customer Choice*: Utility expenditures triggered by customer interconnection and customer-driven service improvements paid for by individual customers under interconnection agreements and special facilities agreements, for example.

[55] Note 2, *supra*.

[56] *Id*.

Figure 24. Economic Evaluation Methods by Investment Driver



5.5.2 DTE BCA Approach is Consistent with DSPx Framework

DTEE's benefit-cost assessment methods are consistent with the DSPx benefit-cost framework. Specifically, this includes DTEE's:

- Global Prioritization Model (GPM)[57] used for evaluating investments with joint and interdependent benefits and those investments involving standards compliance and policy mandates.
- Use of customer-oriented BCA for demand side management programs, for example.
- Approach to incremental cost allocation based on causation where one customer benefits, as in the case of interconnection costs, for example.

This report is primarily focused on grid modernization investments and the application of DTEE's proprietary GPM. GPM aligns with the DSPx BCA framework for assessing proposed grid modernization investments as it maps desired objectives with value creation mechanisms. The investment drivers are explicitly linked to DTEE's objectives through the DSPx taxonomy to individual investments as discussed in Section 2. Aligning objectives, required capabilities, and investments is how DTEE evaluates investments based on objective-specific performance metrics and longer-term strategies. The investments identified in the 2035 Study described in Chapter 4 all fall within the joint and interdependent benefits and compliance and policy-driven objectives.

GPM prioritizes strategic grid investments for funding driven by aligning objectives to specific projects that meet the highest customer needs, standards compliance, and policy objectives.

[57] Case No. U-20561, *In the matter of the Application of DTEE COMPANY for authority to increase its rates, amend its rate schedules and rules governing the distribution and supply of electric energy, and for miscellaneous accounting authority*.

The GPM also enables the assessment of joint and interdependent benefits. The GPM is based on seven objective-driven impact dimensions: Safety, Load Relief, Regulatory Compliance, Major Event Risk, Reliability, O&M Avoidance, and Reactive Capital Avoidance. The impact dimensions are defined below in Table M.

Table M. GPM Impact Dimensions

	Impact Dimension	Major Drivers
Risk Reduction	**Safety**	• Reduction in wire down events • Reduction in secondary network cable manhole events • Reduction in major substation events
Risk Reduction	**Load Relief**	• System capability to meet area load growth and system operability needs • Elimination of system overload or over firm
Risk Reduction	**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 hrs. • Docket U-12270 – Service restoration under catastrophic conditions within 60 hours • Docket U-12270 – Service restoration under all conditions within 36 hrs. • Docket U-12270 – Same circuit repetitive interruption of less than 5 within a 12-month period
Risk Reduction	**Major Event Risk**	• Reduction in extensive substation outage events that lead to a large amount of stranded load for more than 24 hours
Reliability Improvement	**Reliability**	• Reduction in number of outage events experienced by customers • Reduction in restoration duration for outage events
Cost Management	**O&M Cost Avoidance**	• Trouble event reduction and truck roll reduction • Preventive maintenance spend reduction
Cost Management	**Reactive Capital Avoidance**	• Trouble event reduction and truck roll reduction • Reduction in capital replacement during equipment failures

Unit measurements used for BCA are different for each impact dimension. For example, reliability benefits are captured in customer minutes of interruption reduction. O&M and reactive capital benefits are captured in dollar savings. Safety, load relief, regulatory compliance and major substation outage benefits are rated in indexed scores.

The GPM is used to quantify a strategic program's benefits within each impact dimension, based on detailed analysis supported by historical data, engineering assessments, and field feedback. The quantified benefits are then compared to the program's costs to derive the benefit-cost ratios.

To aggregate a program's benefit-cost ratios across all the impact dimensions, DTEE assigns different weights to each impact dimension to reflect customer priorities, with safety being the highest. Thus, a program's overall benefit-cost score is the weighted summation of the program's benefit-cost scores across all the impact dimensions.

As such, GPM enables the assessment of joint and interdependent benefits, as well as investments that are needed to address safety and reliability and support customer interest in DER integration and electrification. The GPM methodology as proposed is consistent with the DSPx best fit, lowest reasonable cost method as described above and will be applied to the proposed Grid Modernization Study.

5.5.3 GPM Enhancements

The ICF Team proposes enhancements to the GPM to incorporate more fully the four MPSC objectives. Specifically, GPM should add "Accessibility" related to "accommodating changing load patterns due to customer resources and consumption patterns" due to electrification, for example. Accessibility also is intended to encourage "optimization the integration of customer and utility resources" to minimize grid impacts.[58]

Figure 25. Enhance GPM Objectives

	MPSC Distribution Planning Objectives			
GPM Objectives	Safety	Reliability / Resilience	Cost-effectiveness	Accessibility
Risk Reduction	●			
Reliability Improvement		●		
Cost Management			●	
Accessibility				●

Additionally, the GPM weighting may be improved by developing a more structured weighting system that is more explicit regarding the scale used and allocation of the specific weights to each objective criterion. Unlike other utilities, the weighting system does not appear to be on a structured 1-10 scale with clearly identified meaning applied to each increment in the scale. Also, safety is weighted at 10 and all others at 3 or 4. While this certainly prioritizes safety-related projects, it is not clear that the weighting method effectively differentiates among the other criteria, as there is effectively no weighting difference. The application of GPM in practice also incorporates some judgment regarding the sub-factors that enables the system to achieve effective results. However, this would be better documented with clearer weighting system and factors that are applied.

GPM today is also implicitly premised on an assumption that all capital grid investments will increase rates given that DTEE has not had load growth for many years. Therefore, GPM provides an effective spend-efficiency from a customer bill impact perspective. However, as the expected electrification of transportation grows, certain enabling infrastructure investments, such as voltage conversions, may need to be assessed somewhat differently than the current approach to GPM. That is because growing load spreads the cost against larger overall

58 Case U-20147, MPSC Order (August 20, 2020)

consumption, resulting in a lower $/kWh rate impact. Rate impact analysis is a complex calculation to undertake for each project, but it is possible to develop a simpler approach (e.g., a heuristic) to incorporate into the GPM spend efficiency prioritization for projects related to increasing capacity for electrification.

Appendix A: Future Scenarios Assumption

A.1. Electrification Scenario Assumptions

Electric Vehicles – AC L2

- This scenario assumes that single light duty EV, at 0.3% today, will grow 30% annually from 2021-2035, reaching a total market share of 17% by 2035, or 700,000 EVs, assumed to charge in AC L2 of 7.5 kW, resulting in added 5,300 MW of load by 2035.[59]
- Today, there are over 4 million vehicles in DTEE's service territory, with many households having between two and four vehicles. DTEE is projecting that EVs will be 3%-4% of vehicles on the road and 8%-9% of new purchases in Michigan by 2030. That adoption curve would increase EVs in Michigan from ~20,000 on the road today to ~300,000 in 2030. As of February 2020, Michigan has ~19,500 EVs in the state, with ~13,600 (70%) of them in DTE territory.[60]
- DTEE's 2019 IRP assumed 24% of new vehicles will be PEV by 2030.[61]
- The 2017 MJ Bradley MI study uses MISO's (McKinsey) and Bloomberg's PEV forecast, which extrapolating 2030 and 2040 % EV penetration results in 9% and 26% PEV by 2035, respectively and ~$426 on annual savings for PEV owners.
- B&M EV impact study of 12 circuits includes a high case scenario of 30% penetration, where EV charging levels include: AC L2 = 7.5 kW, DC L1 = 50 kW, DC L2 = 500 kW.[62]
- DTE grid mod scenarios estimated 50% EV sales market share by 2035 under the policy-driven scenario and 20% for the economic-driven scenario.[63]

Electric Vehicles – DC L1

- EGLE Charge Up Michigan Program EV Charger Placement project Phase I estimated 67 DC fast charging stations (296 charging outlets under the mix-tech scenario, with a 150 kW charging station power and 70 kWh battery by 2030 in the state). We assume 60%m or 40 DCFC (DC fast charging) will be in DTEE's territory.[64]
- DTEE's Charging Forward estimates 65 DC L2 of 50 kW by 2021. The scenario adds 5 units annually until 2030.
- From 2030-2025 the cumulative sum of DTEE's and EGLE DCFC is estimated the grow 10% annually, reaching 248 DCFC by 2035.
- Corporate fleets moving towards EV, such as Amazon's 100,000 by 2035 goal.[65]
- All auto manufacturers pivot to focusing mostly on EV production as part of their drive to reducing carbon emissions in the transportation sector.[66]

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[59] [Internal doc] ICF assumptions based on a review of additional DTE and public documents.
[60] DTE, Electric Vehicle-Grid Impact Study Summary Report (May 2020)
[61] DTE, 2019 Integrated Resource Plan. Available at: IRP_Summary.pdf (empoweringmichigan.com)
[62] [Internal doc] Burns & McDonnell (B&M), Vehicle Electrification Penetration Impact Study (June 6, 2020)
[63] [Internal doc] DTE, Grid Modernization Scenarios (October 2020)
[64] EGLE, Office of Climate and Energy, Charge Up Michigan Program, EV Charge Sites (April 2019)
[65] Amazon, Announcement to order 100,000 electric delivery vans from Rivian (October 2020)
[66] GM, Our Path to an All-Electric Future (November 2020). Available at: GM's Path to an All-Electric Future | General Motors

Electric Vehicles – DC L2

- Detroit Department of Transportation (DDOT) operates ~300 buses in Detroit. For this scenario assume by 2035, 25% or 75 buses will be electric charging in a DC L2 station at 500 kW.

- Ann Arbor's Area Transportation Authority (AAATA) might see the full deployment of electric buses in the mid-2030s or 2040. There are currently 150 buses in Ann Arbor between AATTA and the University of Michigan, which could reach 200 if the desired increased frequency of service is reached. For this scenario assume by 2035, 50% or 100 buses will be electric charging in a DC L2 station at 500 kW.[67]

Heat Pumps

- Based on 1.9 million residential customers and 15% market penetration by 2035 growing incrementally ~1% annually. Assumes 5 kW added winter load per heat pump.
- DTE grid mod scenarios estimated 15% residential heat pump adoption by 2035 under the policy-driven scenario and 5% under the economic-driven scenario.[68]
- By 2030, switching reduces emissions by ~30-35% on a percent basis; after the retirement of Monroe in 2039, emissions from space heating are reduced by 70-75% compared to using natural gas[69]
- Data provided by a manufacturer indicates that ~60% of the units sold provide supplemental heat; it also shows that a significant portion of sales occurs in rural areas where access to natural gas may be limited.
- Adoption at these levels would have material impacts on DTEE's system. Total load served by DTEE could increase by up to 35% through 2040 (or ~17,000GWhs), much of which will occur during the winter months. Annual system peak would start shifting towards winter month at adoption levels of ~25 -30%; at 100% adoption the projected system peak would grow from ~9.5GW to 17.7GW-19.7GW [70]
- Nearly 60% of the units sold in 2018 and 2019 were sized to provide supplemental heating rather than covering a whole home.
- 40-50% of Mitsubishi's total sales in the state, only one of the many manufacturers. Total sales over the last 12 months were ~2,700 units[71]
- Low adoption levels (e.g., <10%) may be relatively manageable, but validating this requires further analyses. At higher adoption levels, the system would have to be upgraded substantially to accommodate a substantial increase in load during the winter months[72]

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[67] Ann Arbor transit CEO talks future: electric buses, service expansion (February 14, 2020).
[68] [Internal doc] DTE, Grid Modernization Scenarios (October 2020)
[69] [Internal doc] DTE, Air Source Heat Pump Opportunities (January 2020)
[70] [Internal doc] DTE, Air Source Heat Pump Opportunities (January 2020)
[71] [Internal doc] DTE, Air Source Heat Pump Opportunities (January 2020)
[72] [Internal doc] DTE, Air Source Heat Pump Opportunities (January 2020)

A.2. DG/DS Scenario Assumptions

Solar PV (residential and C&I)

- The capacity factor for both systems is ~15% and the average system sizes are 7 kW_{DC} for residential and 48kW_{DC} for C&I.[73]
- Based on ICF's 2021-2030 solar PV forecast aggressive case scenario for residential and C&I customers, and assumed a 15% annual growth 2030-2035
- PV deployment growth will rise especially rapidly by 2029-2030 as the compounding positive effects of declining system capital costs, improving system performance, and increasing retail electricity prices push IRRs up to 10%-12% in the base case (BC) scenario and 20% in the aggressive case (AC) scenario.
- ICF forecasts that total (residential + C&I) cumulative customer PV penetration will reach about 210 MW in the BC and 360 MW in the AC scenario by 2030, representing 2% - 3% penetration of customer PV as a portion of DTEE's current total generating capacity, which would have material effects on load forecasting, especially in peak solar hours.
- Residential PV systems sized to produce 90% of annual electricity leads to 54% of PV power being exported to the utility at outflow credits, while C&I customers exports are assumed to be 20% [74]
- Federal Tax Credit available 22% 2021-2023; 10% 2023-2035 (C&I only)
- EGLE Community Energy Management Incentive Program offers up to $15,000 rebate award between November 1, 2020, and July 31, 2021, for energy programs ($100k budget)

Distributed Storage (residential)

- Storage included in 40% of new solar installations[75] from 2021-2025, in 55% from 2025-2030 and 75% from 2030-2035.
- Average system size 7 kW, equivalent to one Tesla Powerwall.
- TOU options and third-party developers offering zero upfront capital cost include battery storage with solar PV systems
- DTE estimates ~60% of new rooftop solar PV in residential and small commercial customers will include battery storage

Distributed Storage (C&I)

- Storage included in 30% of new solar installations from 2021-2025, in 40% from 2025-2030 and 60% from 2030-2035.
- Assumes Michigan establishes a state energy storage target in 2022
- The starting point in 2020 includes the EV fast-charging plus storage 120 kW / 150 kWh battery.[76]
- Average system size 50 kW, equivalent to one Tesla Powerpack.

[73] DTE, 2019 Integrated Resource Plan. Accessed via: IRP_Summary.pdf (empoweringmichigan.com)
[74] DTE, 2019 Integrated Resource Plan. Accessed via: IRP_Summary.pdf (empoweringmichigan.com)
[75] DTE, 2018 Distribution Investment and Maintenance Plan (January 2018)
[76] [Internal doc] DTE, Monthly Energy Storage Check-in (October 2020)

- DTE estimates ~60% of new rooftop solar PV in residential and small commercial customers will include battery storage.
- The ICF Demand Response Roadmap estimated 101 MW of added DR from C&I battery storage capacity from 2019-2028 with a progressive 0-10% participation and 25% DR impacts.
- The 2017 State of Michigan DR Potential Study identified 806 MW of technical DR energy storage potential by 2037 across all customer segments in the state (~484 MW for DTE, considering ~60% load share in the state).[77]
- ICF solar study noted economic viability highly dependent on the exact peak demand and consumption patterns of the customer vis-a-vis its rates. C&I customers can also benefit from using batteries to increase the portion of PV output used on-site.

CHP

- 2021-2030 forecasted 6.4 MW of adoptions across 23 sites by 2030 for systems under 1 MW and an economical potential of 33 MW in 25 sites by 2030 for systems 1-2 MW. [78]
- There is currently an estimated 9 MW of CHP installed in all of Michigan from systems under 1 MW in size.[79]

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[77] Applied Energy Group (AEG), State Of Michigan Demand Response Potential Study, Technical Assessment (September 29, 2017). Accessed via: State of Michigan Demand Response Potential Study

[78] EGLE, Community Energy Management Incentive Program (November 2020). Accessed via: Climate and Energy - Community Energy Management Incentive Program (michigan.gov)

[79] EGLE, Community Energy Management Incentive Program (November 2020). Accessed via: Climate and Energy - Community Energy Management Incentive Program (michigan.gov)

Appendix B: Detailed Grid Needs Analysis Tables

The tables below are based on the DOE DSPx taxonomy. They show the linkage between each scenario and specific functionality required along with related technology categories. They also indicate whether DTE currently has this functionality and technology investments, or near-term plans to address. The “recommend” column reflects ICF’s suggestion for further examination given potential grid needs identified by the scenario analysis. The matrices identify the section/s where the functionality and/or technology are discussed in Sections 3 and 4 of this study.

Note that the scope of this study did not include a complete assessment of all the functions and technology categories identified by DOE in these tables. ICF Team used its judgement for those categories not explicitly discussed in this study regarding DTE’s current state based on inferences drawn from discussions with DTE personnel and review of documents. For these elements, an X is used to denote applicability.

Distribution Planning			DER Scenario	Electrification Scenario	CAT Storm Scenario	Current	Planned	Proposed
Functionality[1]	Technologies[2]							
Short and Long-term Demand & DER Forecasting		Customer DER Adoption Models	X			4.4.1		4.4.2
		Customer-EV Adoption Models		X		4.4.1		
		Demand Forecast Models	X	X		X		
		Load Profile Models	X	X				4.4.2
		Scenario Analysis Tools	X	X	X			X
Short-Term Distribution Planning	Power Flow, Power Quality & Fault Analyses	Peak Capacity Analysis	X	X		X		
		Voltage Drop Analysis	X	X		X		
		Ampacity Analysis	X	X		X		
		Contingency & Restoration Analysis	X	X		X		
		Balanced and Unbalanced Power Flow	X	X		X		
		Time Series Analysis	X	X		X		
		Load Profile Analysis	X	X		X		
Long-Term Distribution Planning		Volt-var Analysis	X	X		X		
		Voltage Sag/Swell Analysis	X	X		X		
Hosting Capacity		Harmonics Analysis	X	X		X		
		Fault Current Analysis	X	X		X		
		Arc Flash Hazard Analysis	X	X		X		
		Protection Coordination Analysis	X	X		X		
EV Readiness		Fault Probability Analysis	X	X		X		
Reliability & Resilience Planning		Resilience Study Models	X	X	X		X	
		Resilience Benefit-Cost Models	X	X	X			X
		Reliability Study Tool	X	X	X	X		
		Value of Lost Load (VoLL) Models	X	X	X		X	
Planning Analytics		DER Impact Evaluation	X	X	X			5.1
		Stochastic Analysis Tools	X	X				X
Interconnection Process		Process Management Software & Portals	X			X		
Locational Value Analysis		Cost Estimating Tools	X					X
Integrated Resource, Transmission &		Planning Integration & Analysis Platform	X	X				X
Planning Information Sharing		Web Portals	X	X	X	X		
		Geospatial Maps	X	X	X			X

Notes 1 & 2: The DOE DSPx Volume I v 2.0 (November 2019) includes definitions for the grid modernization functionalities. The DOE DSPx Volume II v 2.0 (November 2019) includes definitions for the grid modernization technologies. The four DOE DSPx Volumes are available at: https://gridarchitecture.pnnl.gov/modern-grid-distribution-project.aspx

Distribution Operations		DER Scenario	Electrification Scenario	CAT Storm Scenario	Subtransmission			Substation & Distribution			Grid Edge		
Functionality	Technologies				Current	Planned	Rcmd.	Current	Planned	Rcmd.	Current	Planned	Rcmd.
Physical Grid	Hardening	X	X	X	4.2.1			4.2.1			4.2.1		
	Conductor/Equipment Capacity Increases	X	X	X	4.2.1			4.2.1				4.2.1	
	Voltage Conversion	X	X	X	4.2.1	4.2.1		4.2.1	4.2.1	4.2.2	4.2.1		4.2.2
Observability	Electrical Parameter/Event Sensors	X	X	X	4.3.1					4.3.2			4.3.2
	Grid Asset Monitoring	X	X	X	4.3.1			4.3.1		4.3.2			
	Environmental Sensing	X		X						X			
	Advanced Metering	X	X									4.3.1	
	DER Production Metering	X											X
	LIDAR Sensor			X	X			X					
	Satellite/Arial Imaging & Sensing	X		X	X					X			X
Operational Forecasting	*See Planning*												
Integrated Operational Engineering & System Operations	Network Operational Scheduling Systems	X	X	X		X			X				
Threat Assessment & Remediation	Contingency Analysis & Restoration Analysis (see Planning)		X	X									
Operational Information Management	Field Data Management	X	X	X	4.4.1			4.4.1					
	Meter Data Management System (MDMS)	X	X	X							4.3.1		
	Data Historian	X	X	X	4.4.1			4.4.1					
	Data Warehouse/Data Lake	X	X	X	4.4.1			4.4.1			4.4.1		
	Data & Analytics Platform	X	X	X	4.4.1			4.4.1					
	Operational Service Bus	X	X	X	X			X		5.3.2	X		
Distribution System (Network & State Information)	Geographic Information System (GIS)	X	X	X				4.4.1					
	Electric Network Connectivity Model	X	X	X	4.4.1			4.4.1					
	State Estimator	X	X							5.3.1			
Reliability Management	Outage Management System (OMS)			X	4.4.1			4.4.1					
	Fault Location, Isolation & Restoration			X						4.4.2			
Power Quality Management	Integrated Volt-var Control	X	X						4.5.1	4.5.2			
	Power Electronics-Var Compensator	X								X			
	Advanced Inverters	X								4.5.2			
Distribution Grid Control	Distribution Supervisory Control & Data	X	X	X	4.5.1			4.5.1		4.5.2			
	Advanced Protection	X							4.5.2	4.5.2			
	Advanced Switches, Circuit Switchers &	X	X	X				4.5.1		4.5.2			
	Grid Energy Storage	X	X			X				X			X
	Power Flow Controllers	X								X			
Grid Optimization	Distribution Management System	X	X	X				4.4.1					
	Asset Management System	X	X	X	4.4.1			4.4.1					
	Control Center Modernization	X	X	X	4.3			4.3					
	Operational Analytics	X	X	X	4.4.1		X	4.4.1		4.4.2			
Operational Telecommunications	Wide Area Network	X	X	X	4.6.1			4.6.1					
	Field Area Network	X	X	X				4.6.1					
	Neighborhood Area Network	X	X	X							4.6.1		
	Communications Network Management	X	X	X	4.6.1			4.6.1					
DER Operational Control	Distributed Energy Resource	X	X							4.5.2			
	DER Portfolio Optimization	X	X							4.5.2			
DER Services to Distribution and/or	DER Management Platform	X	X								4.5.1		
Distribution to Customer/Aggregator	EV Charging Enabling Grid Infrastructure		X						X				
Microgrid Management	Microgrid Interface (PCC & Controllers)	X		X						4.5.2			
MISO - Distribution Coordination	Operational Data Exchange	X				X	4.5.2		X	4.5.2			
	Operator-to-Operator Communication	X				X	4.5.2		X	4.5.2			

Appendix C: Glossary of Terms[80]

- **ADMS - Advanced Distribution Management Systems -** Software platforms that integrate numerous operational systems, provide automated outage restoration, and optimize distribution grid performance. ADMS components and functions can include distribution management system (DMS); distributed energy resource management system (DERMS) for DR and DER management; automated fault location, isolation, and service restoration (FLISR); conservation voltage reduction (CVR); and Volt-VAR optimization (VVO).
- **AMI - Advanced Metering Infrastructure -** Typically refers to the full measurement and collection system that includes meters at the customer site, communication networks between the customer and a service provider, such as an electric, gas, or water utility, and data reception and management systems that make the information available to the service provider and the customer.
- **APTS - Automatic Pole Top Switch** - Switching device used at medium and high voltage systems to enable system flexibility and protection.
- **BCA - Benefit-cost Analysis -** Method that determines the economic benefits of a project and compares those benefits to its costs.
- **BYOD – Bring Your Own Device –** A terms used in demand response programs that allows customers to bring their own device to participate in load management programs.
- **CAIDI - Customer Average Interruption Duration Index** - Reliability index commonly used by electric power utilities to determine average length of time customers were out of power during a year (in hours).
- **CAT Storm -** Catastrophic storm that cause more than 110,000 customers to be without power during a single storm event.
- **CIS - Customer Information System –** A repository of customer data required for billing and collection purposes. CIS is used to produce bills from rate or pricing information and usage determinants from meter data collection systems and/or manual processes.
- **CVR - Conservation Voltage Reduction -** Operating strategy of the equipment and control system used for VVO that reduces energy and peak demand by managing voltage at the lower part of the required range.
- **DCFC - DC Fast Charging** - High power (50KW - 350KW), fast charging method used to resupply an EV battery using direct current electricity, typically 208/480V 3 phase.
- **DER** - **Distributed Energy Resources –** Include distributed generation resources, distributed energy storage, demand response, energy efficiency, and electric vehicles that are connected to the electric distribution power grid.

[80] Unless noted, definitions are sourced from the U.S. Department of Energy, Modern Distribution Grid Project. Available at: https://gridarchitecture.pnnl.gov/modern-grid-distribution-project.aspx

- **DERMS - Distributed Energy Resource Management System -** Software-based solution that increases an operator's real-time visibility into the status of distributed energy resources and allows distribution utilities to have the heightened level of control and flexibility necessary to more effectively manage the technical challenges posed by an increasingly distributed grid.
- **DG - Distributed Generation -** generation interconnected on the medium voltage electric system, including behind their meter or in front of the meter configurations.
- **DMS – Distribution Management System -** Software used to manage the medium voltage distribution system. Makes up one part of the ADMS.
- **DR - Demand Response** - Can be interpreted broadly as any modification of end-use electricity load operation for the purpose of providing grid services.
- **DRMS – Demand Response Management System** - Software solution used to administer and operationalize DR aggregations and programs.
- **DS - Distribution System -** The portion of the electric system that is composed of medium voltage (e.g., 69 kV to 4 kV) sub-transmission lines, substations, feeders, and related equipment that transport the electricity commodity to and from customer homes and businesses and that link customers to the high voltage transmission system. The distribution system includes all the components of the cyber-physical distribution grid as represented by the information, telecommunication and operational technologies needed to support reliable operation (collectively the "cyber" component) integrated with the physical infrastructure comprised of transformers, wires, switches, and other apparatuses (the "physical" component).
- **DSSE - Distribution system state estimation -** The process of inferring the values of system's state variables using a limited number of measured data at certain locations in the system.
- **EGLE - Michigan Department of Environment, Great Lakes, and Energy**
- **EMS - Energy Management System -** System to monitor, control, and optimize the performance of the transmission system and in some cases primary distribution substations.
- **ETL - Extract, Transform, and Load -** The general procedure of copying data from one or more sources into a destination system which represents the data differently from the source or in a different context than the source.[81]
- **EV - Electric Vehicles –** Vehicles that obtain all or part of their power from electricity. They include all-electric vehicles (AEVs) and plug-in hybrid electric vehicles (PHEVs). Also known as plug-in electric vehicles (PEV).
- **EWR - Energy Waste Reduction** - DTEE''s energy efficiency and demand response programs.

[81] https://en.wikipedia.org/wiki/Extract,_transform,_load

- **FAN - Field Area Network** - Private, multiple purpose network capable of providing last-mile connectivity with low latency and high availability.
- **FCC - Federal Communications Commission -** Independent US government agency regulating interstate and international communication by means of radio, television, satellite, and cable.
- **FLISR - Fault Location, Isolation, and Service Restoration** - Automatic sectionalizing, restoration, and reconfiguration of circuits. These applications accomplish distribution automation operations by coordinating operation of field devices, software, and dedicated communications networks to automatically determine the location of a fault, and rapidly reconfigure the flow of electricity so that some or all customers can avoid experiencing outages.
- **GIS - Geographic Information System** - Software system that maintains a database of grid assets, including transmission and distribution equipment, and their geographic locations to enable presentation of the electric power system or portions of it on a map GIS may also serve as the system of record for electrical connectivity of the assets.
- **GMS - Generation Management System –** Software used to manage schedule and dispatch of bulk-scale generation.
- **GPM - Global Prioritization Model –** DTEE's proprietary model to effectively prioritize strategic capital investments and maximize customer benefits. It leverages historical reliability and system data, incorporates up to date assessments of the asset and system conditions, assigns values and a weighting system to analyze both monetized and nonmonetized benefits and prioritizes projects and programs among the investment portfolios.
- **Grid Edge** - comprises technologies, solutions and business models advancing the transition toward a decentralized, distributed and transactive electric grid.[82]
- **IAC – Interruptible Air Conditioning –** A DTEE EWR program available to residential or commercial customers that separately meter their central A/C or heat pump usage and install a remote-control device. Enrolled customers receive a discount on their space-conditioning equipment usage through tariff D1.1, in exchange of allowing DTE to remotely switch their A/C load on and off in 15-minute increments. The cycles do not exceed 30 minutes in any one hour, or eight hours total in any one day. DTE may issue a control signal for capacity, as directed by MISO during emergency events or for economic or system integrity reasons.
- **ICE - Internal Combustion Engine** - Engine in which the reactants of combustion (oxidizer and fuel) and the products of combustion serve as the working fluids of the engine.
- **IRP - Integrated Resource Plan –** An energy capacity roadmap to meet forecasted utility demand needs using both supply and demand side resources while considering the

[82] https://www.greentechmedia.com/articles/read/what-is-the-grid-edge

associated risks and benefits to customers, particularly cost-effectiveness and environmental impacts. [83]

- **LTC – Load Tap Changer** – Mechanical device similar to a circuit breaker - it makes, and breaks load current while operating at high voltage and carries the current that is being supplied by the transformer to the load. While most circuit breakers may perform a few hundred opening and closing operations in 20 years, an LTC may be required to operate (change taps) a few hundred times per week.[84]
- **LTE - Long-Term Evolution-** Standard for wireless broadband communication for mobile devices and data terminals, based on the GSM/EDGE and UMTS/HSPA technologies. It increases the capacity and speed using a different radio interface together with core network improvements.
- **MISO - Midcontinent Independent System Operator** – Regional Transmission Operator (RTO) that provides open-access transmission service and monitors the high-voltage transmission system in the Midwest United States and Manitoba, Canada, and a Southern US region.
- **NMS – Network Management System –** is a software system used to administer telecommunications networks and interfaces with connected devices, including the ability to configure networks, monitor performance, and manage network behavior.
- **NWA - Non-Wires Alternatives** - Non-traditional electrical grid investment intended to defer or eliminate the need to construct or upgrade components of a distribution and/or transmission system, or "wires investment".
- **OMS - Outage Management Systems** - is a computer-aided system used to better manage the response to power outages or other planned or unplanned power quality events. It can serve as the system of record for the as-operated distribution connectivity model, as can the DMS.
- **OSI - Open Systems International -** Open automation solutions for real-time management and optimization of complex production, transport, and delivery networks for utilities.
- **PSSE - Power System Simulator for Engineering** – A software tool used by power system engineers to simulate electrical power transmission networks in steady-state conditions as well as over timescales of a few seconds to tens of seconds.
- **SAIDI - System Average Interruption Duration Index** - Total duration of interruptions for the average customer during a given time period. SAIDI is normally calculated on either a monthly or yearly basis; however, it can also be calculated daily, or for any other time period.
- **SAIFI - System Average Interruption Frequency Index**- Average number of outages a customer experienced during a year.

[83] https://blog.aee.net/understanding-irps-how-utilities-plan-for-the-future
[84] https://www.doble.com/understanding-load-tap-changers/

- **SCADA - Supervisory Control and Data Acquisition** - Systems operate with coded signals over communications channels to provide control of remote equipment of assets.
- **SFIs - Smart Fault Indicators** - Use line sensors to detect and indicate fault conditions, allowing the Company to efficiently isolate faults and restore power to customers.
- **SLG - Single Line to Ground** - Fault on a transmission line occurs when one conductor drops to the ground or comes in contact with the neutral conductor.
- **SOC - System Operations Center (SOC)** - Utility control center to remotely monitor and control the electric power system.
- **TropOS -** ABB IP broadband technologies for mission-critical communications.[85]
- **VAR - Volt-Amps Reactive** - Standard abbreviation for volt-ampere-reactive, written "var," which results when electric power is delivered to an inductive load such as a motor.
- **VVO - Volt/VAR Optimization -** Optimally manages system-wide voltage levels and reactive power flow to achieve efficient distribution grid operation.
- **WAN - Wide Area Network** - Telecommunications network that extends over a large geographic area for the primary purpose of computer networking.
- **WiMAX - Worldwide Interoperability for Microwave Access** - Telecommunications protocol describing fixed and fully mobile Internet access services. The protocol conforms to certain parts of the IEEE 802.16 Standard.

[85] https://global.abb/group/en/about/history/heritage-brands/tropos

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter, on the Commission's own motion, to open a docket for certain regulated electric utilities to file their five-year distribution investment and maintenance plans and for other related, uncontested matters. ____	))))))	Case No. U-20147

PROOF OF SERVICE

ESTELLA R. BRANSON states that on September 30, 2021, she served a copy of the executed DTE Electric Company's 2021 Distribution Grid Plan Final Report in the above caption matter, via electronic mail upon the persons listed on the attached service list.

Estella R. Branson Digitally signed by Estella R. Branson
Date: 2021.09.30 16:05:52 -04'00'

ESTELLA R. BRANSON

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