Consumers Energy
Count on Us

September 27, 2023

Ms. Lisa Felice
Executive Secretary
Michigan Public Service Commission
7109 West Saginaw Highway
Post Office Box 30221
Lansing, MI 48909

Re: MPSC Case No. U-20147 – 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.

Dear Ms. Felice:

Enclosed for electronic filing in the above-captioned proceeding, please find **Consumers Energy Company's Electric Distribution Infrastructure Investment Plan ("EDIIP") 2024-2028**.

This is a paperless filing and is therefore being filed only in PDF. Also included is a Proof of Service showing electronic service upon the parties.

Sincerely,

Michael C. Rampe
Digitally signed by Michael C. Rampe
Date: 2023.09.27 16:44:48 -04'00'

Michael C. Rampe
Phone: 517-788-2194
Email: michael.rampe@cmsenergy.com

cc: Parties per Attachment 1 to Proof of Service

Electric Distribution Infrastructure Investment Plan (2024-2028)

September 27, 2023

Executive Summary

Consumers Energy Company ("Consumers Energy" or the "Company") is driven by its purpose to achieve world-class performance delivering hometown service, measured by a triple bottom line—people, the planet, and Michigan's prosperity. The triple bottom line balances the interests of customers with other stakeholders and captures the broader societal impacts of the Company's activities.

People – The Company's purpose and passion is to make life better for the people of Michigan. Consumers Energy is committed to providing safe, reliable, and affordable electric service to its customers, and dedicated to providing a great customer experience—what Company employees refer to as providing 'hometown service.'

Planet – Consumers Energy's ambitious *Clean Energy Plan* will lead to achieving net zero carbon emissions by 2040 by eliminating the use of coal, bringing additional renewable energy resources on to the system, and working with customers to use energy more efficiently. Consumers Energy is proud to be a leader in the clean energy transformation here in Michigan and across the country, as we forge a path toward a more sustainable energy future.

Michigan's Prosperity – Consumers Energy is committed to helping Michigan and its communities grow and thrive. A prosperous Michigan cannot exist without financially healthy utilities that provide safe, reliable, affordable, and increasingly cleaner energy. The significant funding the Company receives each year from investors and lenders makes possible the electric system infrastructure replacements and enhancements that benefit customers and the state of Michigan. Ensuring Michigan's prosperity also includes investing in local communities and supporting local nonprofits in addition to helping Michigan businesses grow and create jobs.

The Company has proudly served Michigan families and businesses since 1886, with more than 1.9 million electric customers across the state today. Consumers is committed to providing an electric distribution system that delivers safe, reliable, clean, and affordable electricity to customers today and in the future. To do that, the Company must address infrastructure risk in the near-term while adapting to meet evolving customer expectations and technology advancements.

The Company's commitment requires a distribution strategy based on four customer-focused outcomes, as follows:

- **Safe** – The Company will continue to design and maintain its distribution system to ensure the safety and security of customers and employees is maintained and ultimately enhanced.
- **Reliable and Resilient** –To ensure system *reliability* during predictable weather variations under normal operating conditions, the Company will improve its capabilities and visibility to proactively operate the system and better manage power quality to provide customers with a grid that remains stable and available. To ensure system *resiliency* and performance, the Company will harden the system where necessary to withstand abnormal conditions driven by increasingly severe and unpredictable weather and climate events.
- **Clean and Equitable** – The Company is building a system that will be modernized, smart, and capable of accommodating changing customer technology adoption patterns (such as electric vehicles and distributed energy resources) for all communities served, ensuring members of disadvantaged communities have equitable opportunities to participate. The Company will deliver reliability and resiliency equitably across all communities.

- **Competitive** – Provide affordable rates that will create value for customers by attracting and retaining businesses that provide jobs and economic opportunities, while ensuring every community—especially our most vulnerable—sees maximum energy investment according to its needs with minimal impact and energy burden.

The Michigan Public Service Commission ("MPSC" or the "Commission") first directed the Company to submit a five-year electric distribution investment plan in Case No. U-17990 in 2017.

On March 1, 2018, the Company delivered its first *Electric Distribution Infrastructure Investment Plan* ("EDIIP"), meeting the MPSC's directive. The Company filed a second EDIIP on June 30, 2021. On September 8, 2022, in Case No. U-20147, the Commission directed Consumers Energy to file an updated EDIIP by September 29, 2023, and provided updated guidance on new and revised content for inclusion in the plan.

Since the previous EDIIP was filed, the Company has received feedback from stakeholders, customers, and the MPSC on what would make future distribution plans more useful and engaging. In this EDIIP, the Company has completely revised the document to be more concise and to focus on the future state of the electric grid.

This Plan shows how the Company is anticipating the future needs of customers and developing an enhanced distribution strategy, informed by industry best practices from around the nation, that will deliver cost-effective reliability and resilience benefits.

Highlights of the 2023 EDIIP

- **An Overview of Emerging Scenarios and How They Impact Planning**: In the coming years, the electric distribution system faces two substantial, externally driven changes: **increasingly severe weather tied to climate change**, and **technological advances that affect how customers manage their electricity usage**. To prepare for this future, the Company modeled three different risk scenarios and impacts to the grid from electric vehicles and heat pump adoption, as well as weather impacts from extreme heat, wind, and thunderstorms driven by climate change. Through this detailed modeling and analysis, the Company presents the future all Michiganders must prepare for, and the Company's plan to deliver a reliable and resilient energy grid that addresses these threats.
- **An Overview of the Company's Capital Project Planning Process**: The Company's multi-faceted planning **process prioritizes and sequences investments to meet system needs and deliver safe, reliable electric service to all customers and communities in its service territory.** This Plan details how the process maximizes customer benefits and ensures those benefits are equitable throughout Michigan. This process will be used to provide reliable and resilient power based on the future climate and technology adoption scenarios.
- **Asset Management Approaches for Distribution Assets**: In this new edition of the EDIIP, the Company provides a **detailed overview of its distribution assets, including the system health of each asset group, the risks each group faces, and the proactive steps** the Company is taking to ensure they perform as intended. Asset subclasses are grouped based on whether they primarily ensure the reliability of the grid, resiliency of the grid, or the safety of the public and Company employees. The five-year investment plans for each asset, based on the need to address identified risks and deliver improved performance, are outlined in this report.

- **Additional Topics**: This section of the Plan particularly outlines technological and analytical innovations related to the distribution system, resource needs attached to the Plan, and distribution-related economic development proposals to help Michigan compete for prospective new large industrial customer facilities.

Throughout this EDIIP, the Company presents its vision for the electric distribution system, analyzed through the lens of the system's current state, and outlines an investment plan to bridge from the current state to the desired future state.

The Company fundamentally believes that the $7 Billion of annual investments outlined in this plan will deliver the safety, reliability, and resiliency benefits that customers expect. The Company plans to seek recovery for these investments.

Timely recovery of the costs of the investments described in this plan is essential to delivering the desired improvements in performance. Projects will not be executed in a timely manner if cost recovery lags or is denied. This trimming of capital would result in lower customer benefits and a lower performing system whereby the Company continues to delivery its customers 3rd to 4th quartile reliability.

The Company looks forward to working with the MPSC, Staff, and the broader set of stakeholders as this plan is executed and further improved over time. The Company plans to file updates to this plan, adding future years of investment and accounting for additional years of actual spending, with each subsequent rate case filing as an exhibit supporting test year investments.

A Note on Reliability Metrics

One of the most important ways the Company measures how reliable we are delivering energy to our customers is to use the **System Average Interruption Duration Index ("SAIDI")**. The Federal Energy Regulatory Commission ("FERC") uses this reliability measure as do utilities to drive improvements in services. Originally developed by the Institute of Electrical and Electronics Engineers ("IEEE"), these metrics are significant and useful when evaluating and improving the quality of services delivered to customers.

The SAIDI Index has two components for measuring and reporting reliability:

1. The **System Average Interruption Frequency Index ("SAIFI")** tells us how frequently outages occur due to system condition, configuration, and related external conditions (*e.g.*, weather patterns, forecasts, etc.). This measure is calculated by dividing the total number of customers interrupted by an outage by the total number of customers in the system.
    - Essentially, the SAIFI reveals *how often* the average customer has an interruption of power.
2. The **Customer Average Interruption Duration Index ("CAIDI")** tells us *how long* the interruptions last due to system conditions, resources available, number of interruptions, and storm restoration activities.
    - This measure is calculated by the total number of minutes customer energy is interrupted divided by the total number of customers whose service is interrupted.
    - CAIDI score reflects just the customers who were interrupted and measures the average time to restore services to those customers.

SAIDI results are calculated by multiplying **SAIFI** x **CAIDI**.

SAIDI is typically calculated excluding Major Event Days ("MEDs") to normalize performance data for unusually severe weather. The methodology for determining the level of storm activity to exclude in developing this chart is based on the *IEEE Guide for Electric Power Distribution Reliability Indices*[1].

- The Company's SAIDI performance was 182 in the year 2022, which means that the average amount of time a customer was without power that year was 182 minutes.

Understanding SAIDI is key to interpreting this Plan, which will quantify reliability in terms of SAIDI savings or outage minutes avoided because of specific investments.

As shown below in Figure 1, Low Voltage Distribution ("**LVD") Lines account for most of the Company's SAIDI minutes** due to the vast number of miles and territory served, exacerbated by its deterioration and exposure to trees and weather events. The Company's LVD system has 10 times more miles than its High Voltage Distribution ("HVD") system.

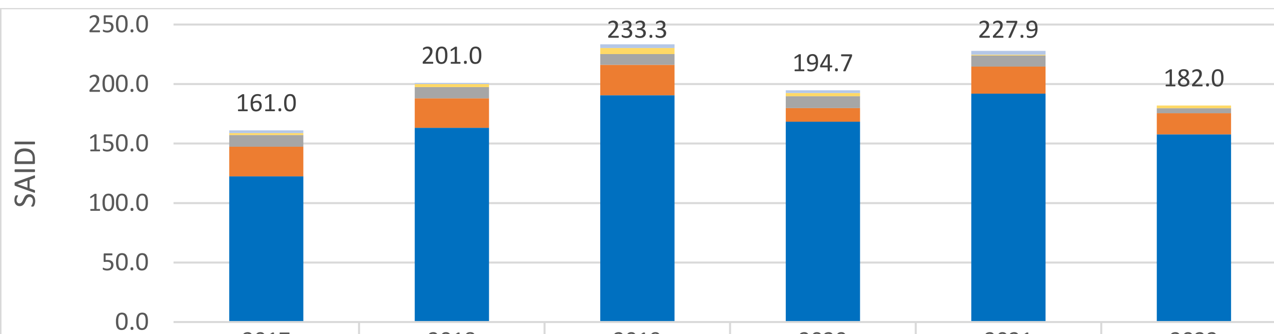
HVD Lines account for a smaller contribution to SAIDI—this is because SAIDI on HVD lines fell from 35.4 minutes in 2011 to just 17.8 minutes in 2022. This is attributable to increased investment in HVD assets over the last decade, in addition to the Company's aggressive and consistent *Forestry Line Clearing* program for HVD lines.

LVD and HVD substations account for a marginal amount of SAIDI minutes due to the redundancy built into the system, and maintenance and design choices that limit the probability of an outage. When substation failures do occur, the impacts could affect tens of thousands of customers.

SAIDI minutes attributed to Michigan Electric Transmission Company ("METC"), the transmission provider (sometimes referred to by the name of METC's parent company **ITC**), also represent a minor amount of the overall SAIDI.

Figure 1

SAIDI MINUTES BY ASSET TYPE



	2017	2018	2019	2020	2021	2022
Total SAIDI	161.0	201.0	233.3	194.7	227.9	182.0
ITC	2.3	1.0	3.1	2.3	3.2	0.0
HVD Subs	1.6	2.5	5.1	2.6	0.7	2.4
LVD Subs	9.8	9.5	9.0	10.0	9.3	4.1
HVD Lines	24.9	24.8	25.6	11.4	22.8	17.8
LVD Lines	122.5	163.2	190.6	168.4	191.9	157.7

[1] IEEE Standard 1366-2012 defines the methodology for calculating a MED. It is based on a statistical analysis of five sequential years of daily SAIDI values. In 2021, Consumers Energy adopted a refined methodology that transitions from a calendar day evaluation period to a rolling 24-hour evaluation period. This methodology better captures MEDs that straddle consecutive calendar days.

While this Plan accounts for growth in distributed energy resource penetration and explores early-stage means of enabling microgrids on its system (see the *Other Options for Defining and Considering Environmental Justice* section of this Plan), the threats of extreme weather and existing system deterioration are too great to address through developing technologies.

Simply put, our customers and business need safe, affordable, and proven distribution assets to deliver the reliability we all deserve.

While distributed energy resources have an important role in the state's energy future, they are not the answer to achieving desired improvements in reliability and resiliency. To achieve the desired improvements in reliability and resiliency, the **Company must focus on hardening and improving the performance of its distribution system** through improving poles and wires.

Effective increased investment in the LVD system is the key element needed to mitigate the worst effects of extreme weather and to begin to enable proactive planning for an increasingly electrified future.

Enhancing the HVD system is also needed to maintain recent progress through proactively inspecting all assets repairing components on the HVD system to keep them within their useful lifecycle.

Vision for Our Grid

The Company is modernizing its electric distribution system to safely deliver clean, affordable, reliable power to customers throughout Michigan. **The goal is simple: fewer and shorter power outages for customers.** The vision for the grid is a blueprint for serving Michigan today and innovating to meet the challenges of the coming decades.

Customers depend on electricity to meet their everyday needs. They expect electricity to be delivered reliably on normal days with blue skies days under normal operating conditions, and the grid to be resilient in the face of increasingly extreme and unpredictable weather events.

Whether customers are using electricity to charge their electric vehicles, run their electric appliances, or are sending their onsite generation back to the grid, the Company must deliver reliable and resilient energy, and it is building the grid of the future to meet these customer needs.

Historic, once-in-a-lifetime storms are now the norm, resulting in more damaging storms that occur more frequently. The Company's analysis of weather patterns in recent years shows that **the last four years have recorded the highest wind gusts in the past 10 years,** as shown in Figures 7 and 8. While the Company is making an important transition in electric generation to address climate change and its impact on the weather, the same transformation is needed with the distribution system.

These risks will require a significant shift in our investment levels and strategy to mitigate the risks from extreme weather and improve the reliability of electric power.

In the face of these challenges, the Company has developed the *Resilient Grid Plan* to respond to the immediate threats through proactive investments in automation, grid hardening and aggressive maintenance, and inspection of its system. This plan is the first step in developing the grid we expect and lays out the scale of the challenges we face as a State.

The *Resilient Grid Plan*, provided investment levels are fully approved, will serve as a bridge from our current grid to a grid that will be capable of achieving the following objectives:

1. **Delivering reliability performance into the 2nd quartile of nationwide utilities[2].**
2. **Delivering a grid where no single outage event will affect more than 100,000 customers.**
3. **Delivering a grid where no customer will be without power for more than 24 hours following an outage event.**

The *Resilient Grid Plan* will significantly improve the Company's SAIDI performance over the next decade when compared to what would be provided by recent electric rate case-approved levels of investment, providing a nearly 100-minute improvement in performance over the Company's recent performance[3].

In the near term, the Company must address the timeworn infrastructure already on the system and proactively plan for increasingly severe weather.

- The Company is preparing to meet these challenges through increased inspections, preventative maintenance, and aggressive investment in hardening the grid through programs like strategic undergrounding and use of automated tools, such as automatic transfer recloser ("ATR") loops, to shorten the duration of outages.
- When storms do strike, the Company works to keep the public safe and uses all available tools to restore power as quickly as possible.

In the longer term, the grid will need capacity to meet customers' growing energy needs from electrification of transit and other consumer products.

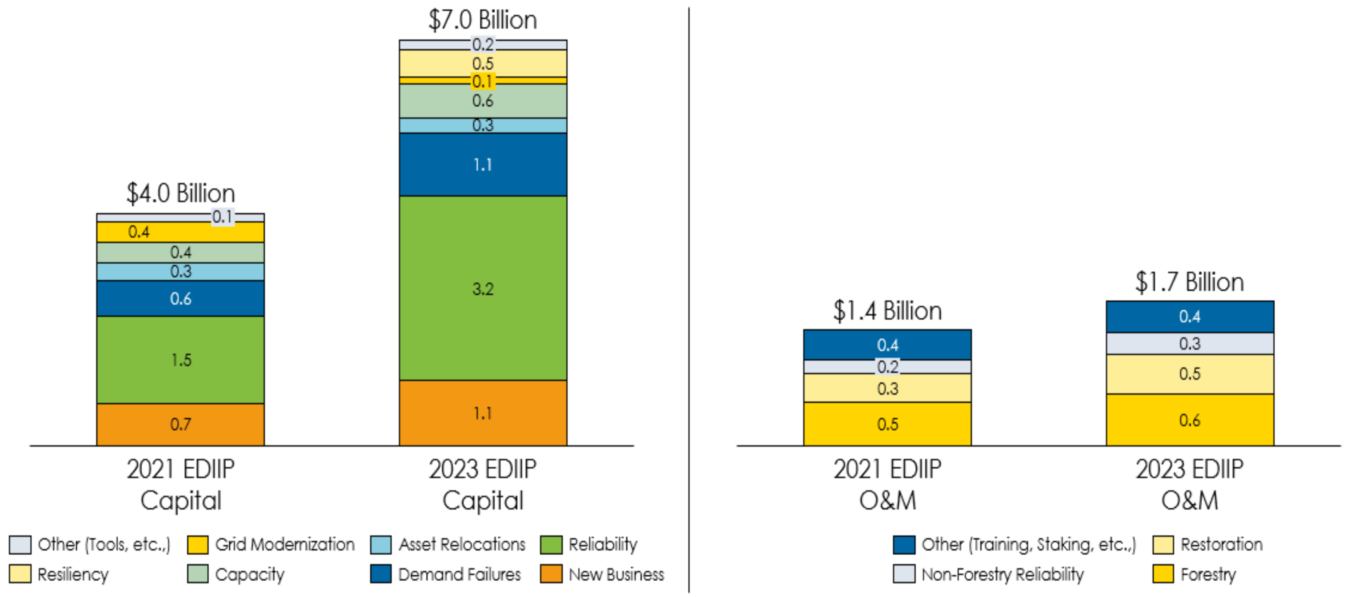
The deep electrification of the future will require investments to maintain reliable service and ensure every customer can power their homes, business, and vehicles.

Investments in the next five years will total $7.0 Billion—an increase of $3.0 Billion over what the Company outlined in its 2021 EDIIP. Operating and Maintenance ("O&M") increases to $1.7 Billion—an increase of $300 million.

This investment is driven primarily by increased investments in Reliability, and to a smaller extent, by the Company's increased frequency of system inspections as well as the expectation that New Business, especially that tied to Economic Development, will continue to require investment in the system.

[2] 134 minutes for IEEE Benchmark Year 2023 Results for 2022 Data
[3] 2018-2022 SAIDI excluding MED performance averaged 208 minutes

FIGURE 2
INVESTMENT FINANCIAL PLANS (2024-2028)[4]



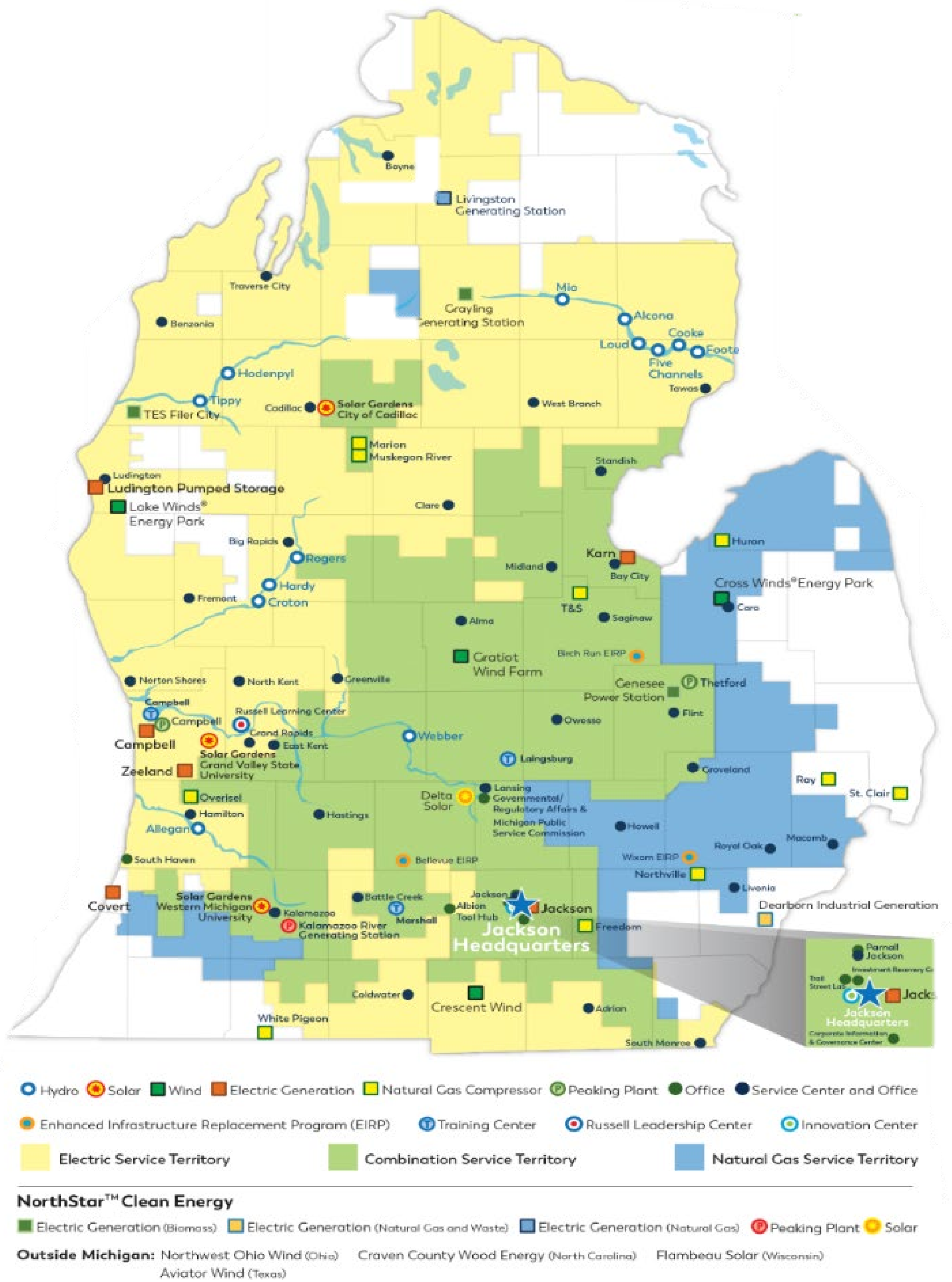
Distribution System Overview

Overview of Service Territory and System Components

The Company's electric distribution system is an essential part of Michigan's infrastructure, serving 1.9 million customers across more than 98,600 miles of distribution lines and 1,100 substations in the north, central, and western portions of Michigan from Monroe County to Mackinaw City, as shown in Figure 3.

[4] The 2023 EDIIP does not include investment in Grid Storage that was included in the 2021 version at $46 million.

FIGURE 3
CONSUMERS ENERGY SERVICE TERRITORY



The distribution system is functionally separated by operating voltage into HVD and LVD.

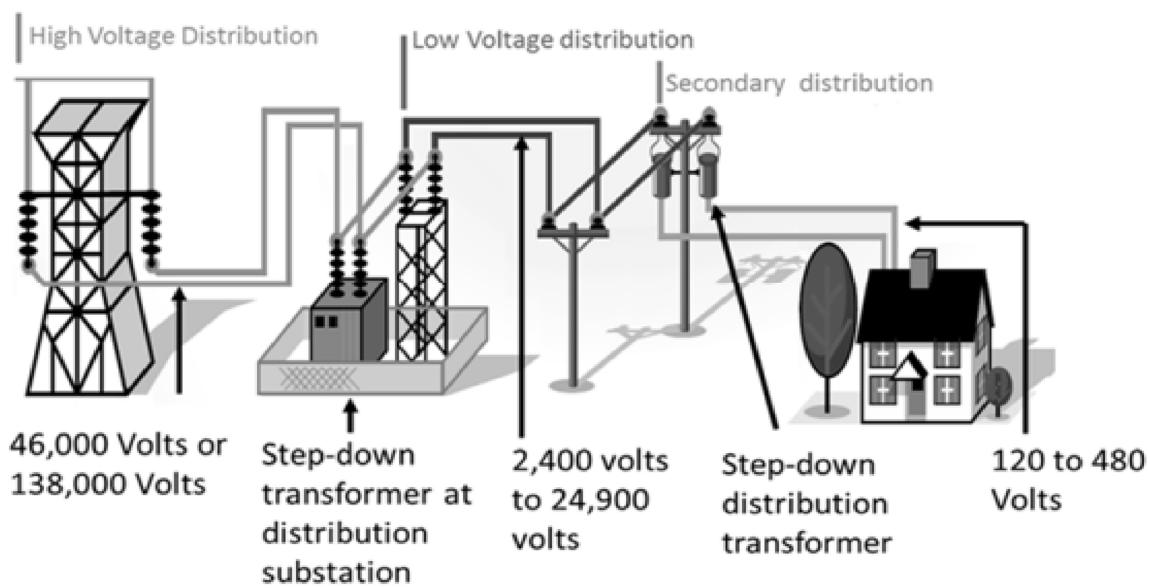
- **HVD operates at the highest voltages,** taking electricity from regional transmission companies, and transporting it across miles of lines, where it connects into the LVD system at 830 substations throughout the Company's service territory.
- **At LVD substations, high voltage is stepped down**, or reduced to lower voltages, onto the LVD system. LVD voltage is then further stepped down at secondary distribution transformers to secondary voltages (240 Volts), serving businesses and residences.

A *circuit* is a combination of electrical devices and hardware that are connected to and emanate from an LVD substation to deliver electricity to customers.

The Company's system has more than 2,000 LVD circuits.

- The primary distribution system begins at the distribution substation and ends at the distribution transformer.
- The secondary distribution system begins at the distribution transformer and ends at the customer, as shown below.

FIGURE 4
DISTRIBUTION SYSTEM COMPONENTS



LVD and Metro System

The LVD system is comprised of more than 94,000 total miles of lines, made up of approximately 61,000 miles of primary overhead and underground (carries electricity from substations to transformers), and 33,000 miles of secondary (carries electricity from distribution transformers to customers).

The LVD system consists of 13 different voltages. More detail on these assets and the Company's strategy for ensuring these assets operate as intended is described in more detail in the LVD Lines under the Asset Management Approaches section.

The LVD system also includes a distinct component called **the *Metropolitan Underground system (Metro)*, which provides underground distribution service** in the downtown areas of six cities in the Company's service territory: Battle Creek, Flint, Grand Rapids, Jackson, Kalamazoo, and Saginaw.

- The Metro distribution infrastructure is installed underground to promote public safety by keeping energized infrastructure away from densely populated areas and protecting the aesthetics of downtown areas.
- The Company's Metro planning group focuses solely on these key downtown areas, reflecting the Company's commitment to investment in Michigan by dedicating specific attention to these areas.

More detail on the Metro assets and the Company's strategy for ensuring these assets operate as intended is described in more detail in the Metro chapter under the Asset Management Approaches section.

HVD System and Substations

The HVD system comprises all assets from the point of interconnection with the transmission provider through the point at which LVD lines exit LVD substations. It is composed of and represented by three distinct networks:

1. HVD substations
2. HVD lines
3. LVD substations, which are included as part of the HVD system to leverage substation planning, engineering expertise, and large equipment resourcing in a consistent and efficient manner.

The Company's substation network consists of 1,144 substations.

The HVD substation network consists of 145 HVD substations and 164 dedicated customer substations in addition to the LVD and general distribution substations mentioned earlier.

In addition to the HVD and LVD substations, there are 35 customer-owned dedicated substations, 5 Company-owned substations providing wholesale distribution services to rural co-op and municipal systems, and 30 customer-owned substations providing wholesale distribution services to rural co-op and municipal systems.

More detail on these assets and the Company's strategy for ensuring they operate as intended is described in more detail in the HVD Lines and Substations chapters under the Asset Management Approaches section.

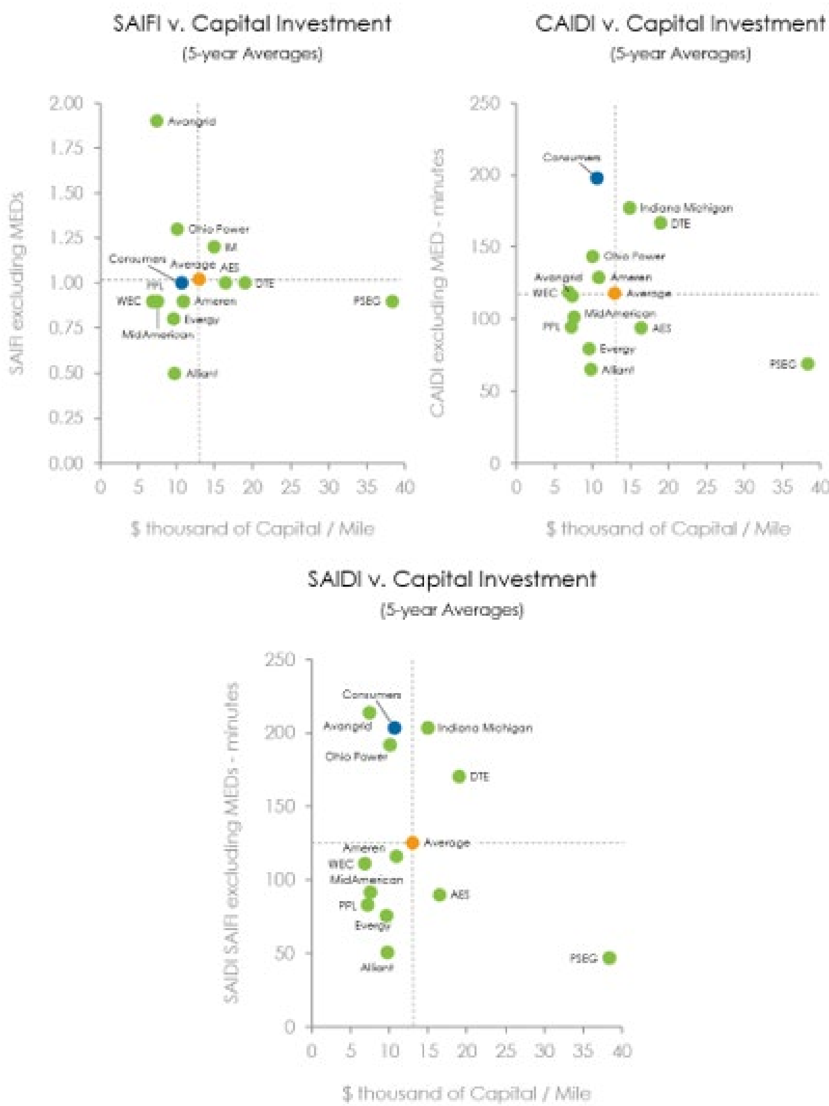
The HVD system is comprised of approximately 4,600 total miles, with approximately 4,400 of those miles being 46 kV and 69 kV overhead lines, and 19 miles being 46 kV underground lines, and approximately 200 miles being 138 kV overhead lines, and 4 miles being 138 kV underground lines.

System Condition

In accordance with the Commission's September 2022 Order in Case No. U-20147, the Company has benchmarked its reliability performance against peer utilities, and the results of this are shown in Figure 5 below.

FIGURE 5

RELIABILITY BENCHMARKING AGAINST PEER UTILITIES



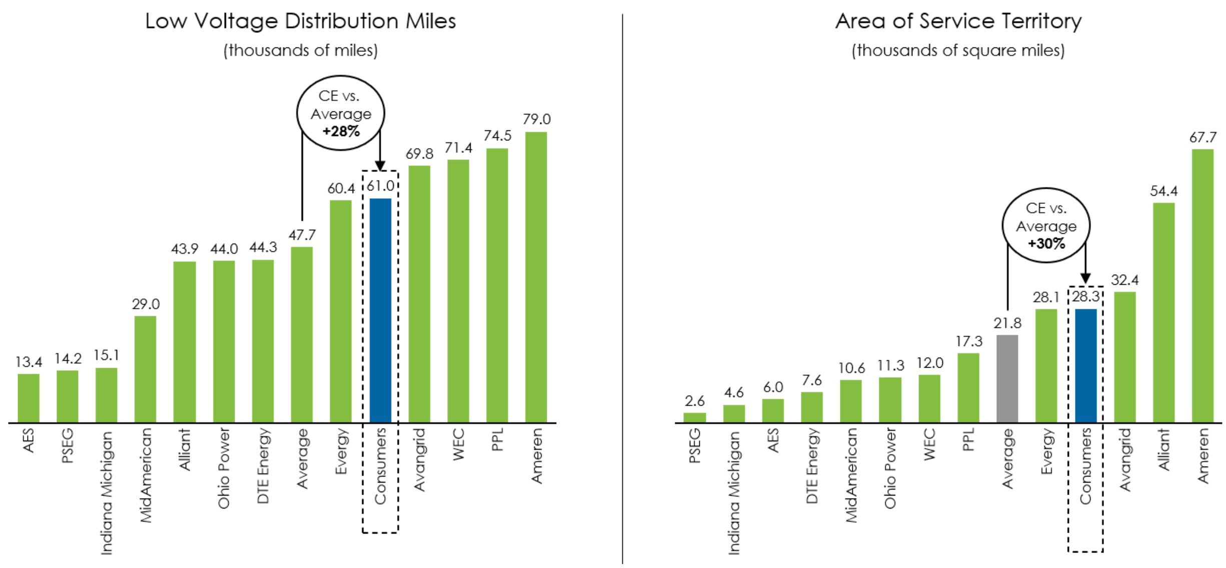
This benchmarking shows that, when normalized for capital investment per line mile, the Company provides slightly better than average reliability, but outages tend to last longer than those of peers.

This long duration can, in part, be contributed to the size of the Company's service territory and the large number of overhead line miles used to serve its 1.9 million customers.

On average, the Company's employees maintain a system that is approximately 30% larger than its peers on both a line mile and square mileage basis as depicted in Figure 6 below.

FIGURE 6

COMPARISON OF SERVICE TERRITORIES



The Company's service area has expanded to serve many new communities and businesses in Michigan throughout more than a century of distributing electricity. Much of this infrastructure—lines, poles, pole top equipment, and substations, among other assets—now needs replacement or upgrades to improve efficiency and reliability of the grid.

It is important to emphasize that age is *not* the only indicator of system health, nor is it the only driver of when an asset must be replaced—the pole shown below in Figure 7 is 86 years old and shows fewer reliability issues than some younger poles in the Company's service territory.

The Company thinks holistically about how to best serve customers reliably, and this means assets are replaced based on overall deterioration.

That said, age and deterioration are generally correlated, and the advanced age of many assets provides some indication of the general systemwide need for asset replacement.

FIGURE 7
1936 VINTAGE 35-FOOT LVD POLE

The deterioration and health of assets vary based on field conditions (e.g., soil, weather, slope, wind patterns, etc.), location, and materials used by the manufacturer (e.g., wood type, porcelain, polymer, interrupting media, etc.). For example, poles deteriorate at a faster rate in wet soil conditions than in dry non-acidic soil conditions, and porcelain is more susceptible to freeze or thaw conditions than polymer.

The Company proactively replaces, rebuilds, or rehabilitates assets before failure, when inspections or performance data indicate the asset is in a state of deterioration. Occasionally, the Company replaces assets that fail in the field causing an unscheduled and undesired customer outage.

Ultimately, the assets replaced, rebuilt or rehabilitated are done so to the specifications needed to meet future reliability and capacity needs of the grid.

The Company is enhancing its distribution asset management capabilities, as discussed in the Asset Management Approaches section, to address this issue.

Even as the Company's distribution asset management capabilities remain under development, the Company has developed new analytical approaches to assess system deterioration, particularly by using system performance data during adverse weather conditions, as discussed in the Operations and Maintenance section of this plan.

Scenario and Investment Planning

Drivers of Change

Increasingly Severe Weather

The Great Lakes region is not immune to climate change; the Company has been monitoring the impacts of the changing climate and weather on its operations for years and has been crafting an approach to remain resilient as new climate patterns emerge.

In 2022, the Company published its Climate Risk, Vulnerability and Resiliency report that identifies its susceptibility to the potential adverse effects of climate change, and discusses the Company's governance structures and proactive efforts to remain resilient to the potential impacts of climate change on its infrastructure.

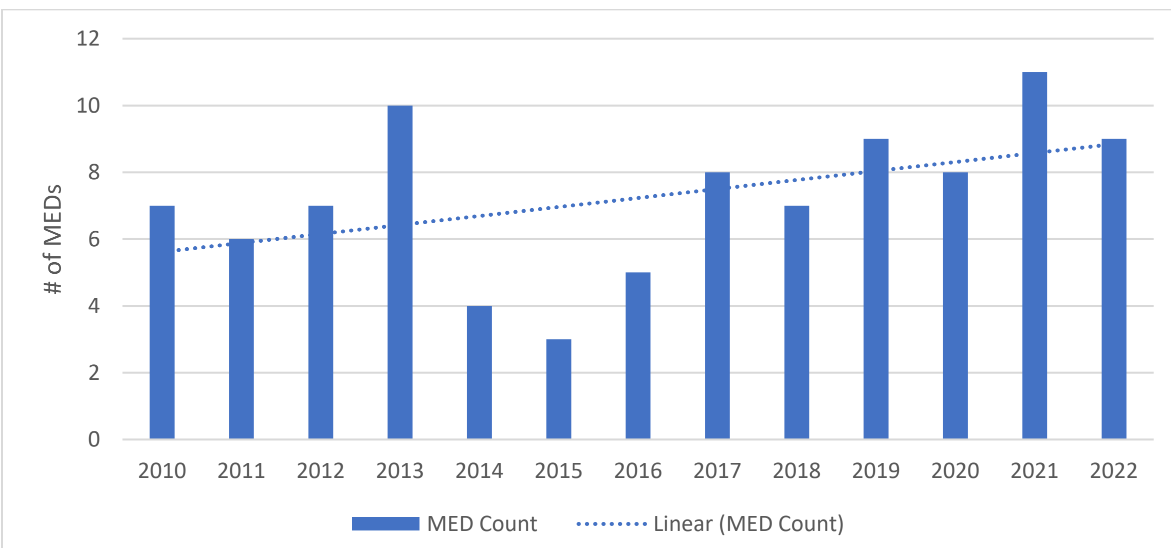
The analysis completed through the development of this plan examines similar risks, including wind gusts, extreme heat, wildfires, and severe storms.

For much of history, the climate has gone through small changes, but the climate and associated weather patterns are now changing at an accelerated rate.

In recent years, the Company has experienced repeated instances of strong winds causing large-scale outages; since 2010, the Company has seen a general increase in the number of MEDs per year, as shown in Figure 8 below.

FIGURE 8

MAJOR EVENT DAYS BY YEAR



In general, the Company's service territory has experienced increased high and sustained wind speeds as well as wind gusts.

The Company monitors wind speed data from many National Weather Service stations throughout its service territory. Figures 9 and 10 below illustrate the hours each year of sustained high wind speeds and of high wind gusts.

FIGURE 9

STATION HOURS EXCEEDING HIGH WIND SPEED THRESHOLDS

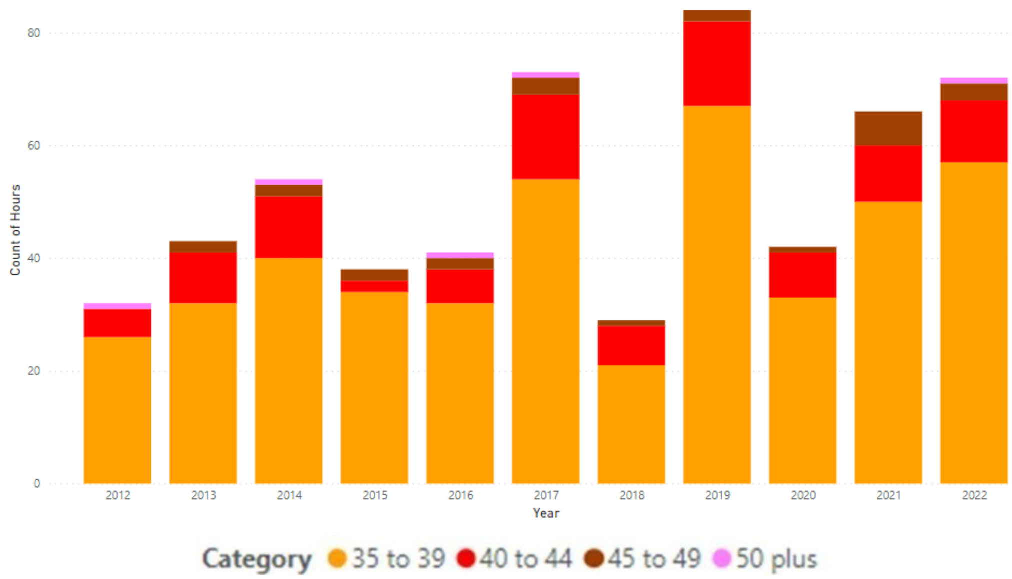
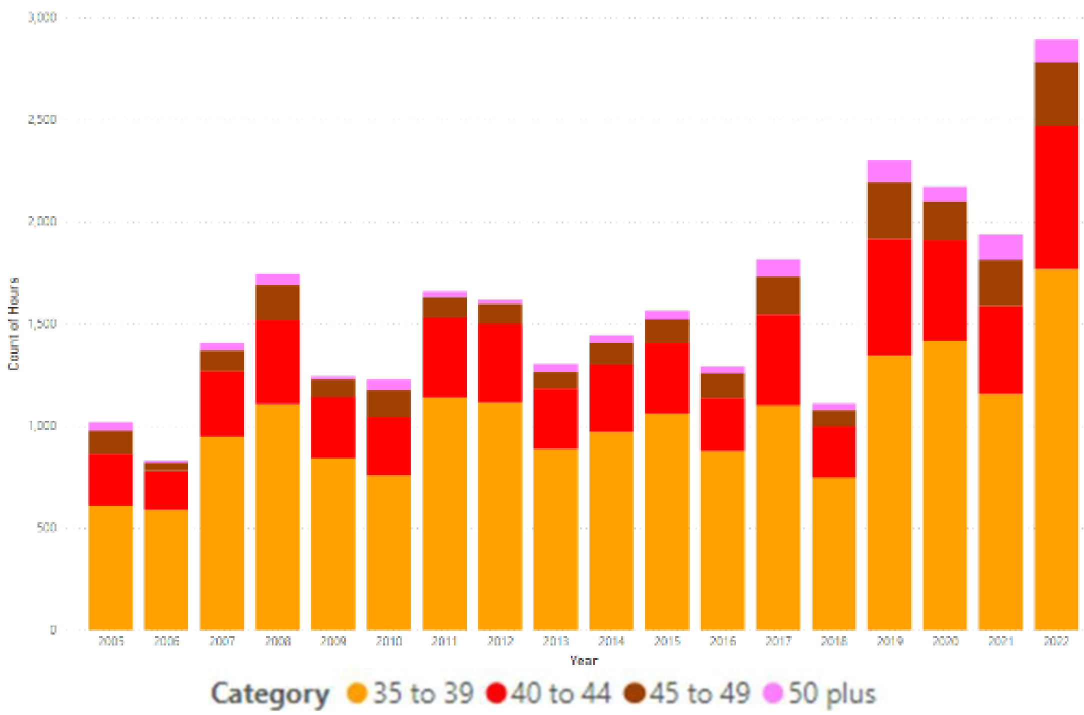


FIGURE 10

STATION HOURS EXCEEDING HIGH GUST THRESHOLDS



The number of wind-driven large-scale outages, while increasing, is still consistent with normal weather variability. However, those strong wind events are likely to become more frequent as climate change increases the frequency of storms that cause high winds.

Climate change will also increase the frequency of extreme heat conditions, which tend to increase loading on the grid as customers use more air conditioning.

In assessing its investment plans, the Company is considering the likely resiliency risks from more frequent severe weather conditions and what investments are needed to harden against those risks. The Company is also considering how to best plan for increased load on circuits as rising temperatures result in more cooling degree days.

Technological Innovation

In the future, climate policies and targets related to decarbonization will likely lead to increased adoption of technologies that *will* require more electricity, although to date these new technologies have not experienced widespread penetration in the Company's electric service territory:

- Solar distributed generation ("DG") has an installed capacity of 85MW[5].
- Electric Vehicles ("EVs") currently represent less than 1% of total vehicles.
- Electric heat pumps have been adopted by 2% of total households.

Going forward, the Company expects increased adoption of these technologies, driving load growth that will have wide-ranging impacts for the distribution system.

In assessing its investment plans, the Company is considering whether individual circuits can accommodate rising peak demands and whether they can accommodate increasing amounts of solar DG. This will inform the need for standard capacity improvements on the system but may also point to increased use of non-wire solutions to shave peak load or Distributed Energy Resource ("DER") management to interface with solar DG.

Overview of Scenario Analysis

As outlined in the previous section, the Company has identified severe weather and technological adoptions as the primary drivers of change on the distribution system, representing the most pressing challenges to the future grid.

To further refine this broad assessment of threats to grid reliability, the Company pursued a detailed analysis to predict the circuit-level impacts from severe weather and customer technology adoption.

Beginning in 2022, the Company developed a strategy to develop a resilient and reliability grid. This included creating a comprehensive vision of the future of the grid and ensuring near-term investments meet the needs and mitigate the risks anticipated in the future. This process sought to answer two key questions:

- What is the holistic set of challenges that the future grid must address?
- What are the most impactful potential grid impacts?

[5] See the Company's March 31, 2023 Report in Case No. U-15787

Key Impacts Modeled

The impact of the two key drivers (climate risks and customer technology adoption) were modeled on the distribution grid.

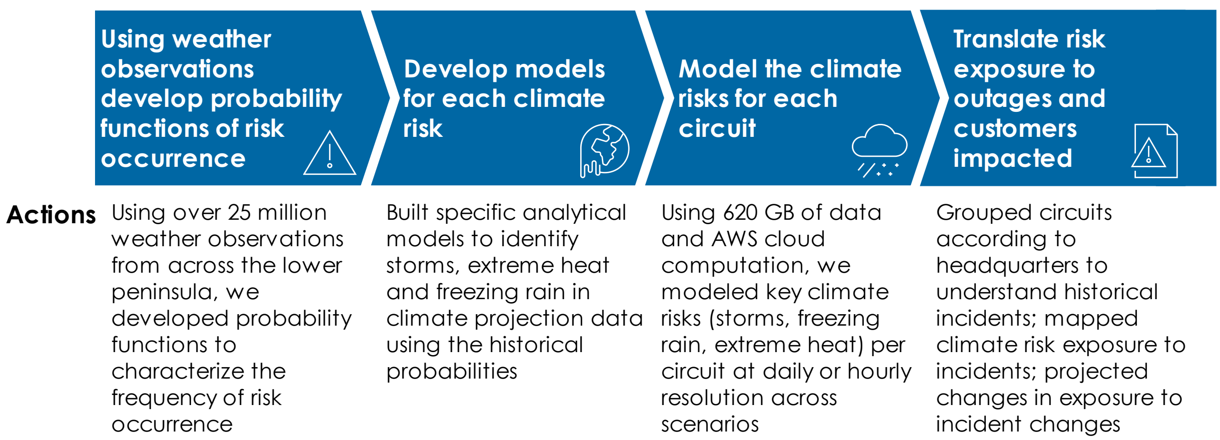
- **Climate risks** included the highest-impact hazards for the Company's service territory: storm conditions, ice conditions, and extreme heat.
- **Customer technology adoption** included the impacts to the grid from projected solar distributed generation, heat pumps, and electric vehicles as well as organic load growth driven by population changes.

A climate model was used to identify climate risks specific to the Company's service territory and translates exposure to outages as detailed in Figure 11 below.

This model used more than 25 million weather observations from across the lower peninsula of Michigan to develop probabilities of the frequency of risk occurrence. These models predict the specific climate risks to individual circuits and translate the impact of these risks in terms of outages and customers impacted.

FIGURE 11

CLIMATE MODEL METHODOLOGY[6]



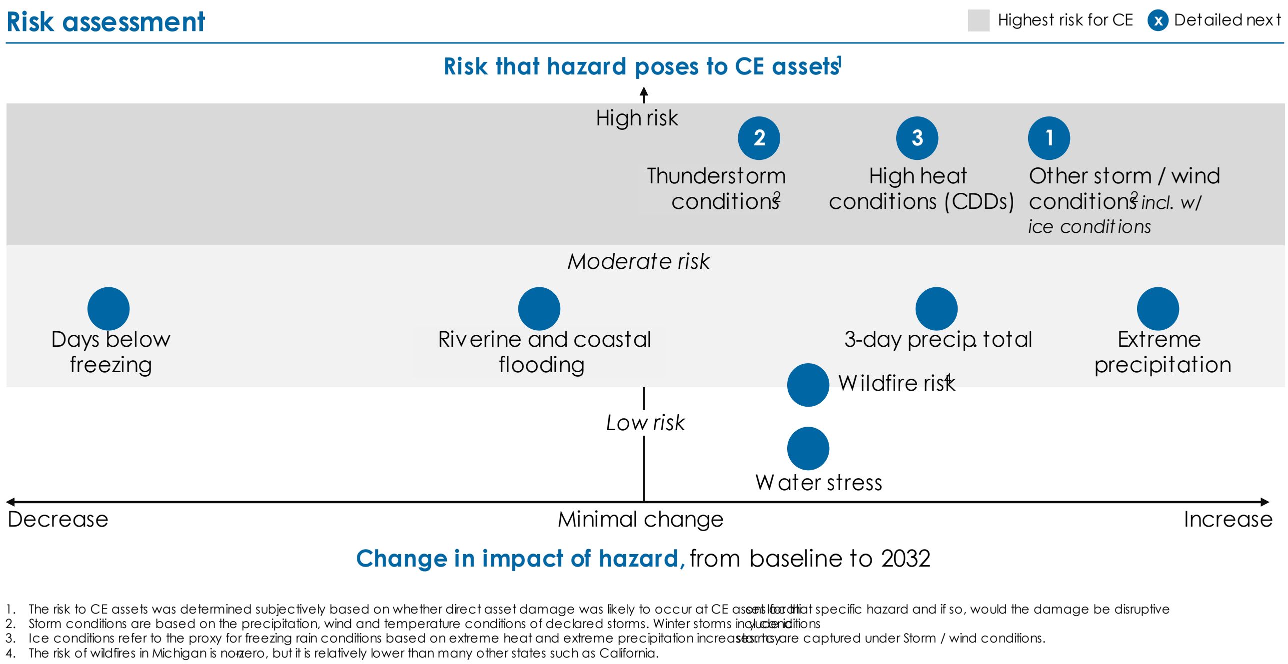
After evaluating numerous weather-related hazards shown in Figure 12 below, the modeling focused on the highest-impact hazards to Company assets and grid integrity including:

- **Thunderstorm conditions**, featuring extreme wind and precipitation, can impact tree and pole stability and often lead to outages. These storms are fueled by warm air and are thus most frequently observed in summer months.
- **Other storm conditions**, featuring extreme wind and precipitation, including in some cases the potential for damaging icing and freezing rain. Like thunderstorms, these storms can impact tree and pole stability, leading to outages but are observed year-round.
- **High heat conditions** defined as days above 86 degrees Fahrenheit, which may simultaneously increase customer demand and reduce the efficiency of the distribution grid (e.g., line losses).

[6] Climate and Technical Adoption modeling was performed by an independent third-party consultant.

FIGURE 12

CLIMATE RISKS EVALUATED



While other risks (e.g., riverine flooding) are present, their more limited spatial footprint makes them less likely to drive frequent widespread outages.

Emergent risks, such as wildfires, and extreme precipitation were analyzed in this modeling and deemed less of an immediate risk to Company assets compared to the three modeled risks. Recent events, such the June 2023 fire in Northern Michigan, and the August 2023 wildfire in Maui, Hawaii, reinforce the Company's plan to continue evaluating for new and additional risks in the coming years. **As a result, the Company plans to put forth a wildfire mitigation plan in 2024.**

In addition to climate modeling, the modeling also analyzed **the impact of new technology** adoption such as solar DG, EVs, and heat pumps, and how they will impact electric demand and corresponding grid capacity needs.

- The modeling forecasted the uptake of these new technologies to develop a discrete choice model based on customer demographics to **determine customer likelihood of acquiring these technologies** on each circuit and their usage profiles as detailed in Figure 13 below.
- With these two factors developed, the modeling calculated total load increase on the grid for each driver to determine which hours, months, and seasons have the highest load increases and how the increases evolve over time.

FIGURE 13

TECHNOLOGY ADOPTION MODEL METHODOLOGY

	Driver adoption scenarios	Circuit-level acquisition	Customer's load growth	Total load increase
Actions	Forecasted service - territory-wide uptake utilizing adoption models, taking into account economic and non-economic adoption	Developed a discrete choice model that uses customer demographics to determine the likelihood of a customer acquiring each driver	Applied annual usage profiles to each driver to see the hourly impacts each driver has on the circuits load, as well as their cumulative impact	Looked at the cumulative impact to load from each driver to determine which hours, months, seasons have the highest load increases as well as tracking those increases over time

Identified Scenarios

The Company identified three scenarios governing the future through 2050. Each scenario assumes a given set of external trends encompassing both the rate of climate change and the rate of customer adoption of solar DG, electric heat pumps, and EVs.

The three scenarios are referred to as *Decelerated Transition* ("DT"), *Continued Momentum* ("CM"), and *Accelerated Transition* ("AT").

Federal policy, particularly as defined in the *Inflation Reduction Act of 2022* ("IRA"), makes a clear connection between the deployment and uptake of low-carbon technologies and achieving certain climate change targets. Correspondingly, these scenarios assume that uptake of low-carbon technologies will have a direct correlation with climate change outcomes.

In general, climate change will result in more severe weather and extreme heat, which creates increased reliability and resiliency challenges for the distribution system. Increased adoption of low-carbon technologies can also increase demand on the grid, at least in certain locations, which can also impact what investments are needed.

Decelerated Transition Scenario

The DT scenario assumes existing government climate policies, and other climate-related targets, are not fully implemented, and public action to mitigate climate risks slows down from current levels or even begins to reverse.

- In this scenario, uptake of low-carbon technologies is significantly delayed, with penetration levels remaining low overall. This scenario results in a temperature increase of ~2.5°C by 2050 compared to pre-industrial levels, with attendant increases in severe weather.

The Company's analysis generally assumes the DT scenario is the least likely, given the direction of climate policy and climate-related targets, although the Company has considered the impacts of this scenario to establish a worst-case baseline and conducted little analysis on it due to its improbability.

Continued Momentum Scenario

The CM scenario assumes climate policies already existing in law are fully executed, but that no new policies are implemented.

- In this scenario, public adoption of solar DG, heat pumps, and EVs broadly continue in their current post-IRA trends. This scenario results in a temperature increase of ~2.0°C by 2050 compared to pre-industrial levels; such a temperature increase still results in increased severe weather and increased resiliency risks to the grid, albeit not as large as under the DT scenario.
- The CM scenario makes further assumptions about electrification and decarbonization nationwide or worldwide. In particular, the CM scenario assumes the U.S. power grid becomes 80%-90% decarbonized by the late 2030s; that at least some heavy industry is deeply decarbonized in developed countries; that carbon capture and sequestration remains marginal; and that the U.S. and other developed economies transition to EV-majority vehicle sales during the period from 2030 to 2040.

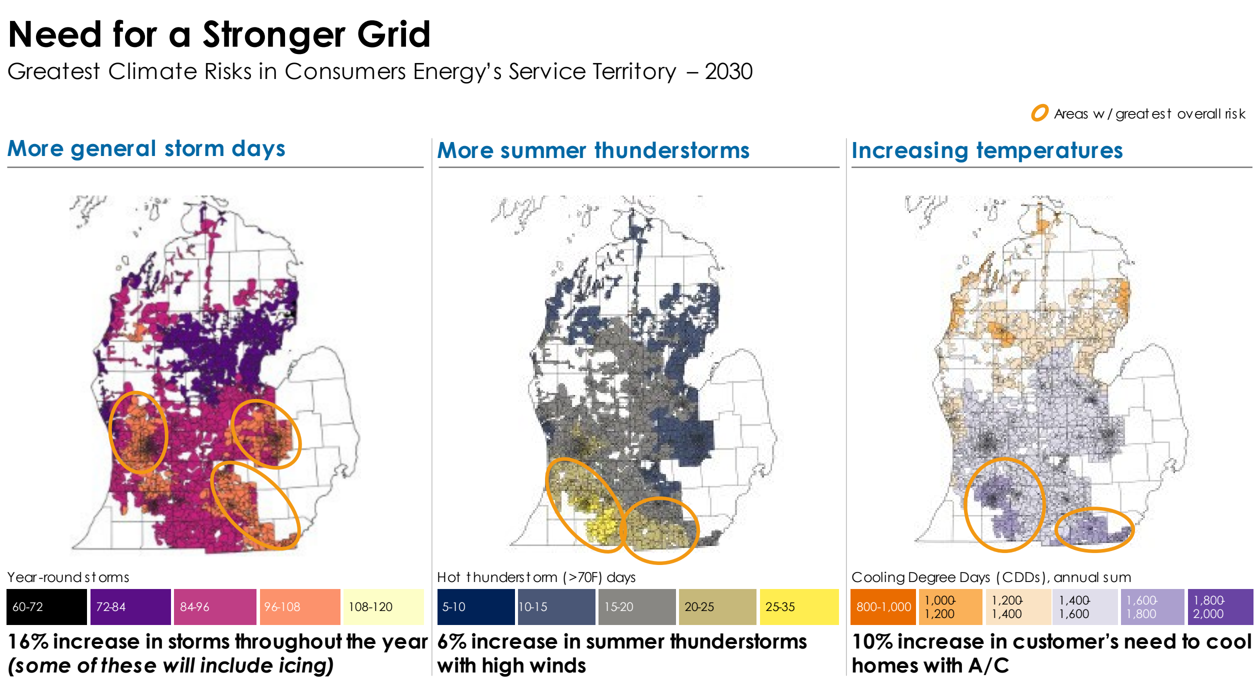
Without mitigation, the CM scenario projects that the Company’s system would experience a 12% increase in the number of MED outages by 2030, and a 24% increase by 2050, due to increasingly severe weather.

Further, while the CM scenario only projects that 2% of the Company’s circuits would be at risk of exceeding load constraints by 2030, this increases to 32% of circuits by 2050 as low-carbon technological penetration increases.

These increasing risks under the CM scenario are illustrated by the following maps that represent the projected situation in 2030, including where each risk is most acute.

FIGURE 14

CLIMATE RISK IN CONSUMERS ENERGY SERVICE TERRITORY



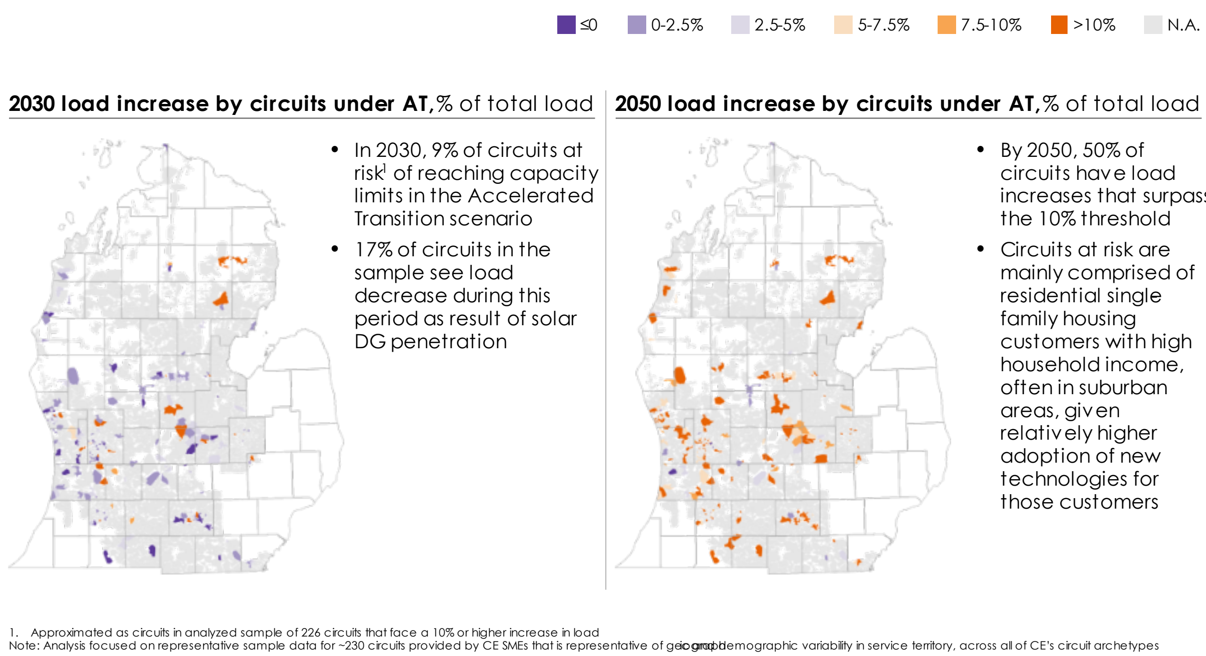
Accelerated Transition Scenario

The AT scenario assumes that, due to faster cost declines and increased financial incentives, solar DG and EVs are adopted even faster than on current trends, although heat pump adoption will remain stable as natural gas remains inexpensive in Michigan.

- In this scenario, temperatures increase by ~1.5°C by 2050 compared to pre-industrial levels, in line with targets set in the 2015 Paris Agreement and compatible with achieving global net-zero carbon dioxide emissions by 2050. This scenario minimizes the increased resiliency risk to the grid due to increasing severe weather, although there will still be increased resiliency risk compared to today.
- Like the CM scenario, the AT scenario makes several further assumptions about electrification and decarbonization nationwide and worldwide. The AT scenario assumes the U.S. power grid is fully decarbonized by 2035, and the global power system by 2040. It also assumes 90% of heavy industry is low emissions by 2050; that carbon capture and sequestration becomes widespread; and that no internal combustion cars are sold anywhere in the world after 2035.
- The AT scenario includes the greatest increase in risk of circuit overloads due to adoption of low-carbon technology. Under this scenario, by 2030 9% of circuits will face this risk based on a representative sample of over 10% of the Company's circuits. This risk only compounds after 2030, and by 2050 would apply to 50% of the Company's circuits.

FIGURE 15

ACCELERATED TRANSITION LOAD INCREASES



Of these scenarios, the Company chose CM and AT scenarios for further analysis given their closer alignment to likely post-IRA pathways. As a significant fall below CM, DT was viewed as an unlikely worst-case scenario for heightened climate risk. For prioritized scenarios, load impacts of solar DG, heat pumps, and EVs were considered alongside organic load growth.

Impacts of Scenarios on the Distribution System

The modeled evolution of climate risks and customer technology adoption, and their impacts at an individual distribution circuit level, present the following types of grid challenges to the Company's distribution system:

1. **While there is long-term uncertainty around the pace of emissions and climate change, there is more near-term certainty around increases in warming and weather hazards.** In short, **climate change represents the most urgent threat** to the reliability of the Company's distribution system and must be addressed immediately.
2. **Without shifts in the Company's current investment strategy, outages from severe weather are likely to increase 10-15% relative to 2020 levels by the early 2030s regardless of climate policy actions**. In assessing its investment plans, the Company is considering the likely resiliency risks from more frequent strong wind and storms, and what investments are needed to harden against those risks.
3. **The largest relative increase in other storm (non-thunderstorm) days is likely to be in the winter** when outages are typically most difficult to restore.
4. **Depending on the trajectory of EV, heat pump, and solar DG adoption, the Company could see up to 1-10% of circuits reach at risk load levels by 2030[7].** By 2050, as many as 40% of circuits could see load more than 10% higher than current peaks.
5. **The long-term future of Michigan's energy system is a more electrified and distributed one.** There is uncertainty, however, over the pace at which this will occur, and therefore when challenges associated with peak loads and DER adoption will materialize. Understanding the pace of customer technology adoption will be critical for pre-empting peak demand challenges.
6. **With heightened heat pump adoption, there's the potential for Consumers Energy to shift from a summer to a winter peaking system.** The expected increase in winter load has implications for broader network design and planning (e.g., generation, equipment standards, etc.)

Challenges from Climate Risks

The magnitude of climate risk impacts likely to be seen in the Company's service territory represents a significant step-up from current levels as detailed in Figure 16 below.

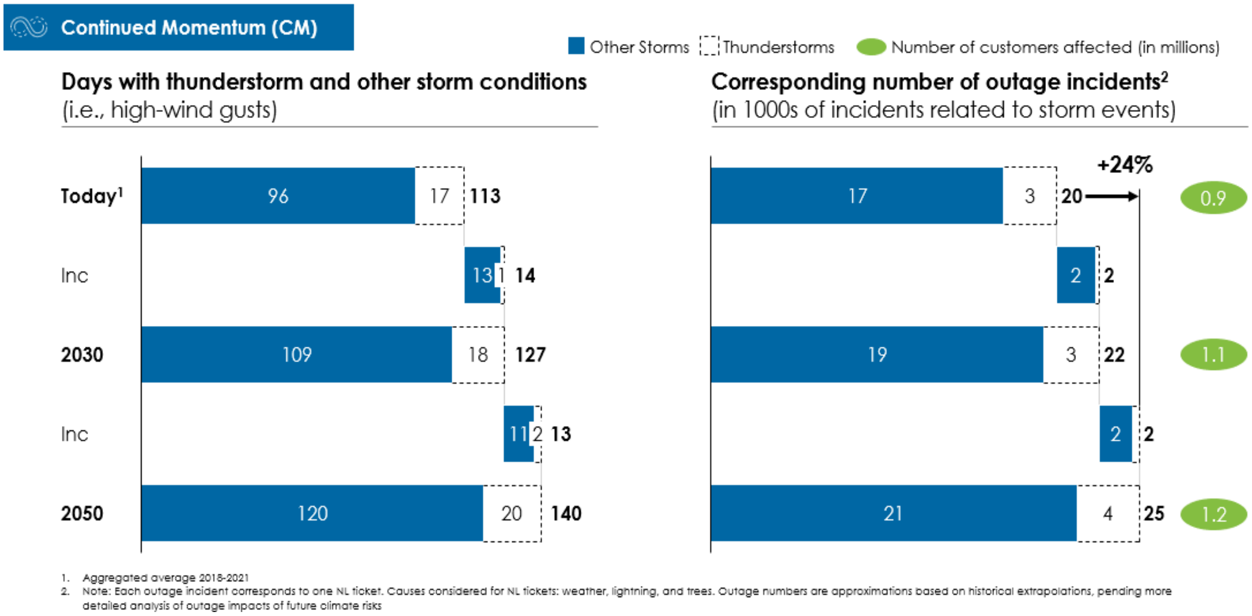
Key climate risks—storms with extreme wind, as well as high heat conditions—are projected to increase in the Company's service territory by up to 25% (20 storm days by 2030), and up to 45% (30 days by 2050).

These changes in climate conditions will compound with weather effects the Company has already seen over the last 15 years, such as a 9% or 7-day increase in storms and could lead to a 12% increase in the number of MED outages by 2030, absent countermeasures.

[7] Defined as increases more than 10% higher than current peak load, a typical threshold evaluated by CE.

Figure 16

PROJECTED DAYS WITH THUNDERSTORMS AND NUMBER OF OUTAGE INCIDENTS UNDER CONTINUED MOMENTUM

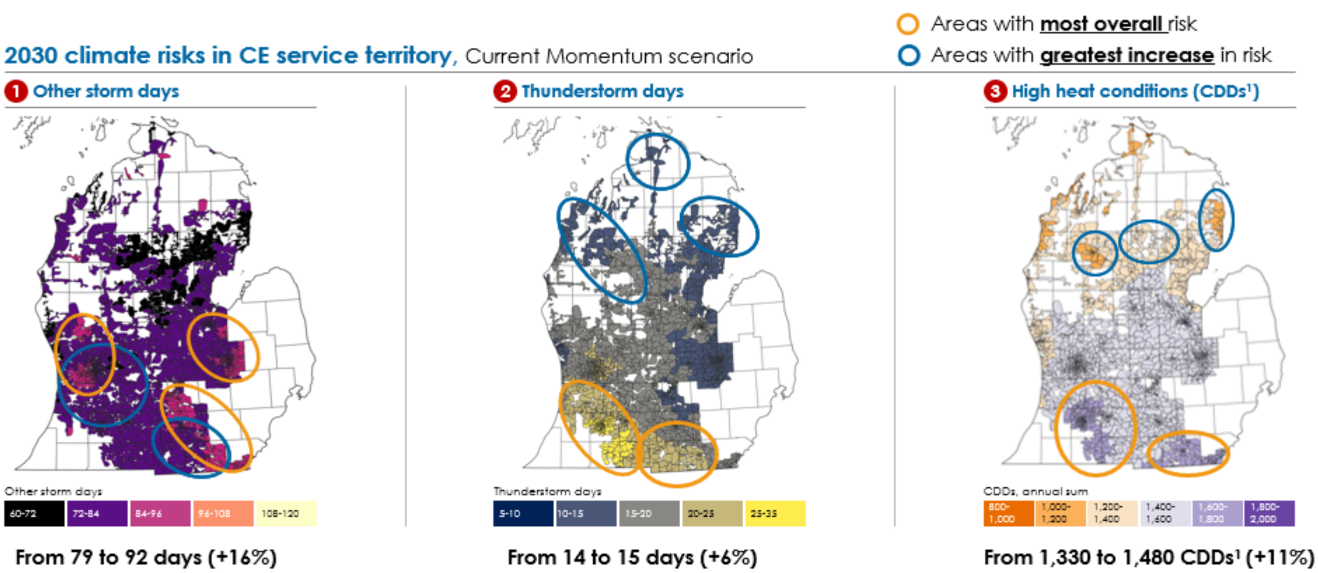


Risks are forecasted to materialize predominantly in northwestern and southern parts of the Company's service territory—by 2030, these areas see strong increases in thunderstorms (+30% / 3 days), other storms (+25% / 20 days) and high-heat conditions (+30% / 300 CDDs).

Climate risks and load impacts will significantly shape the grid environment—several areas in the Company's service territory will see their largest relative increase in climate risk as soon as in the next 7 years (e.g., 50% of increase / 20 days in storm days in Kalamazoo area may materialize by 2030), with another 50% increase realized by 2050.

Figure 17

2030 CLIMATE RISKS IN CONSUMER ENERGY SERVICE TERRITORY



Key changes, on average (maximum changes are greater) include:

Climate event	Today	Increase by 2030	Increase by 2050
Thunderstorms	17 days	~1 day (+4%)	~3 days (+17%)
Other storms	79 days	~13 days (+17%)	~21 days (+27%)
Cooling Degree Days	~1,330 CDDs	~147 CDDs (+11%)	~368 CDDs (+28%)
Days above 86°F	38 days	~12 days (+31%)	~26 days (+70%)

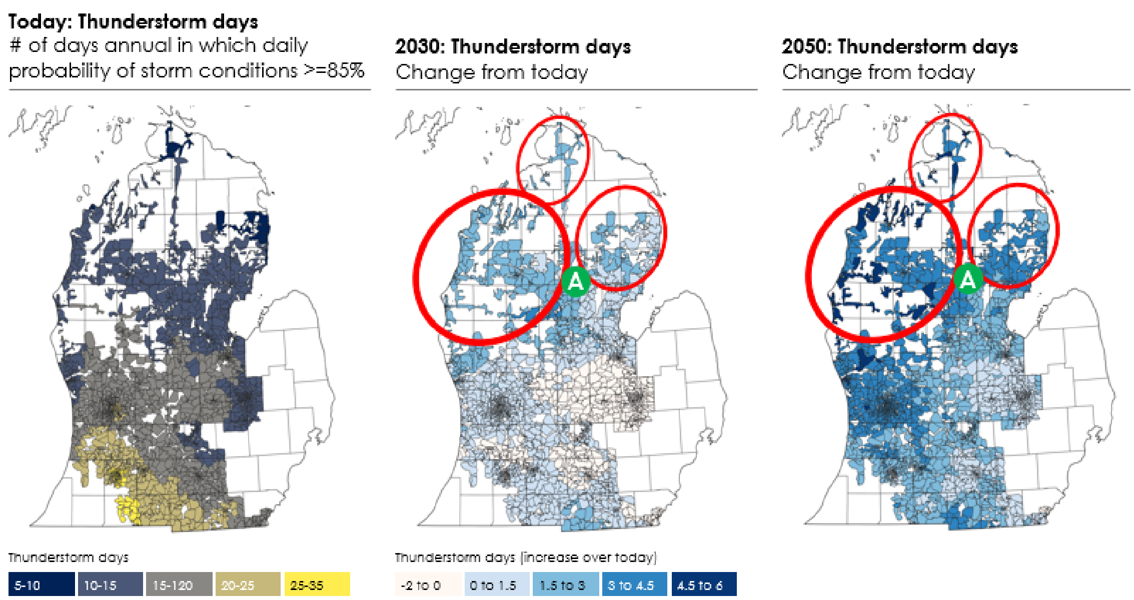
Figure 18 below depicts shifts in thunderstorm risk and the evolution from today's annual number of days with a daily probability of storm conditions greater than 85%.

Thunderstorms, defined as *events with maximum wind speeds greater than 30 mph and temperatures greater than 70°F,* are more prevalent today in southern and lower central Michigan. These thunderstorms are most associated with the high wind speeds that can disrupt the grid.

Central, northern, and eastern Michigan may experience a 30-60% increase in thunderstorm risk by 2050 (indicated by the letter A in the chart below). By 2050, 660 circuits may see a >20% increase in likely thunderstorm days.

Figure 18

2030 AND 2050 THUNDERSTORMS INCREASE IN CONSUMERS ENERGY SERVICE TERRITORY



Other storm annual frequency has been studied using the number of days annually, in which daily probability of storm conditions are greater than 50%. Storms and connected occurrence of wind, have some of the highest damage potential for the Company's grid.

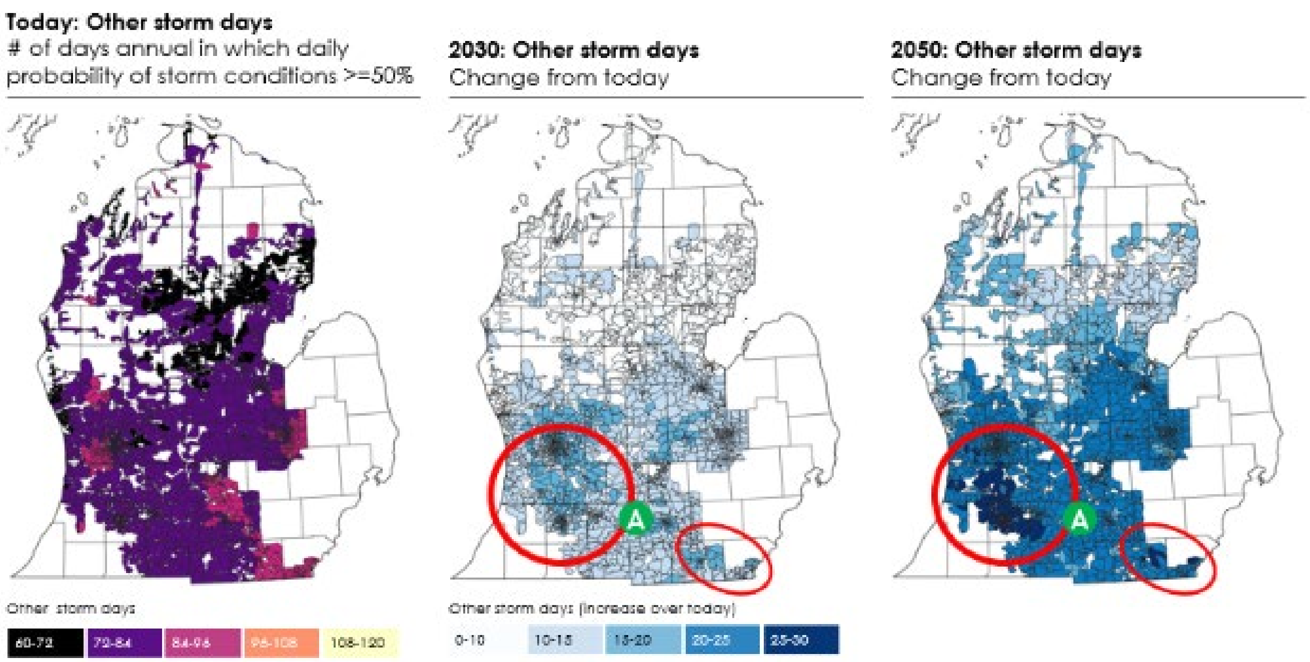
Almost all circuits (97%) are likely to experience at least a 20% increase in storm days by 2050 under a CM scenario, and nearly 20% of circuits are likely to see a 30% increase in storm days.

- As highlighted in red circles with a green letter A in Figure 19 below, **the Grand Rapids and Kalamazoo regions may see particularly large increases** with 25-30 additional potential storm days throughout the year by 2050.

As warming continues, these storms are increasingly likely to be accompanied by damaging freezing rain conditions like the catastrophic storm that swept through Michigan in February 2023, knocking out power to over 700,000 homes and businesses.

Figure 19

2030 AND 2050 STORM INCREASE IN CONSUMERS ENERGY SERVICE TERRITORY



Multiple measures of high heat conditions indicate a likely increase.

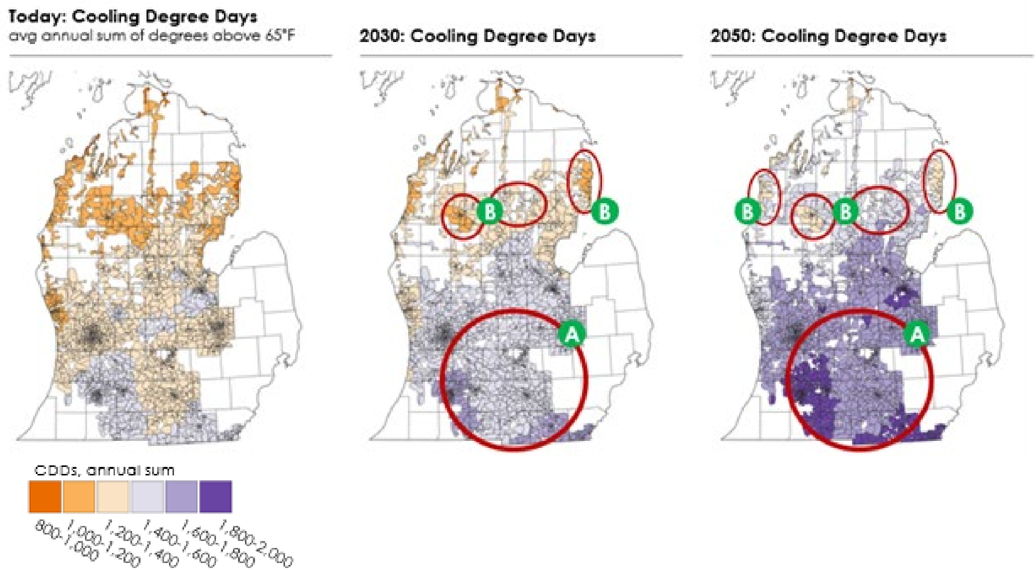
Increases in high heat conditions can result in lower line efficiency and higher customer loads, potentially bringing circuits closer to their rated capacity limits.

The largest absolute increases in cooling degree days, a benchmark used to measure broader heating, are in the southern Michigan circuits, which could see as much as 1,900 annual CDDs by 2050 (denoted by A in the Figure 17 below), an increase of 25% above today's conditions.

North central Michigan (denoted by B in the Figure 20 below) may see an even larger relative increase of as much as 33% in annual CDDs, up to 1,400 CDDs.

Figure 20

2030 AND 2050 COOLING DEGREE DAY INCREASE IN CONSUMERS ENERGY SERVICE TERRITORY



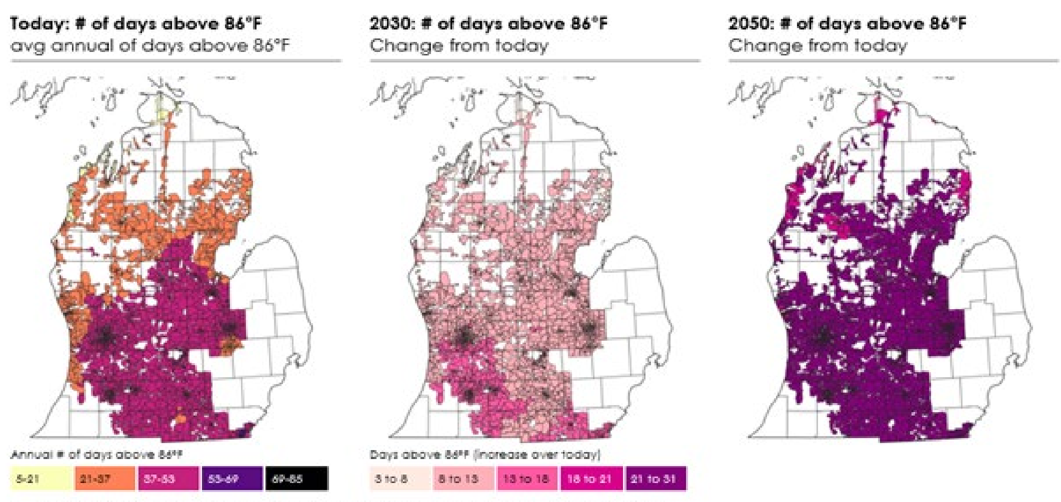
Days above 86°F, another measure of high heat conditions, can lead to reduced line efficiency of 7% and higher customer loads due to increased air conditioning usage, potentially bringing circuits closer to their rated capacity limits.

By 2050, almost all of Michigan is likely to experience more than 20 days of additional high heat. With some regions already experiencing ~50 days of high-likely air conditioning usage and line loss, this is a 40% increase from current levels.

The graph below in Figure 21 examines the average annual number of days with temperatures above 86°F in Consumers Energy's service territory.

Figure 21

2030 AND 2050 DAYS ABOVE 86 DEGREES INCREASE IN CONSUMERS ENERGY SERVICE TERRITORY



Taken together, these insights can help focus grid-hardening investments today to reduce the risk of future outages.

Challenges from Customer Technology Adoption

The magnitude of modeled customer technology adoption represents a significant step-up from levels seen today.

Even by 2030, and under a CM scenario, load-impacting technology adoption could greatly exceed current levels with statewide rooftop solar projected to increase to 1.3 GW, EVs projected to increase to 15% of vehicles, and heat pumps projected to increase to 15% of total households.

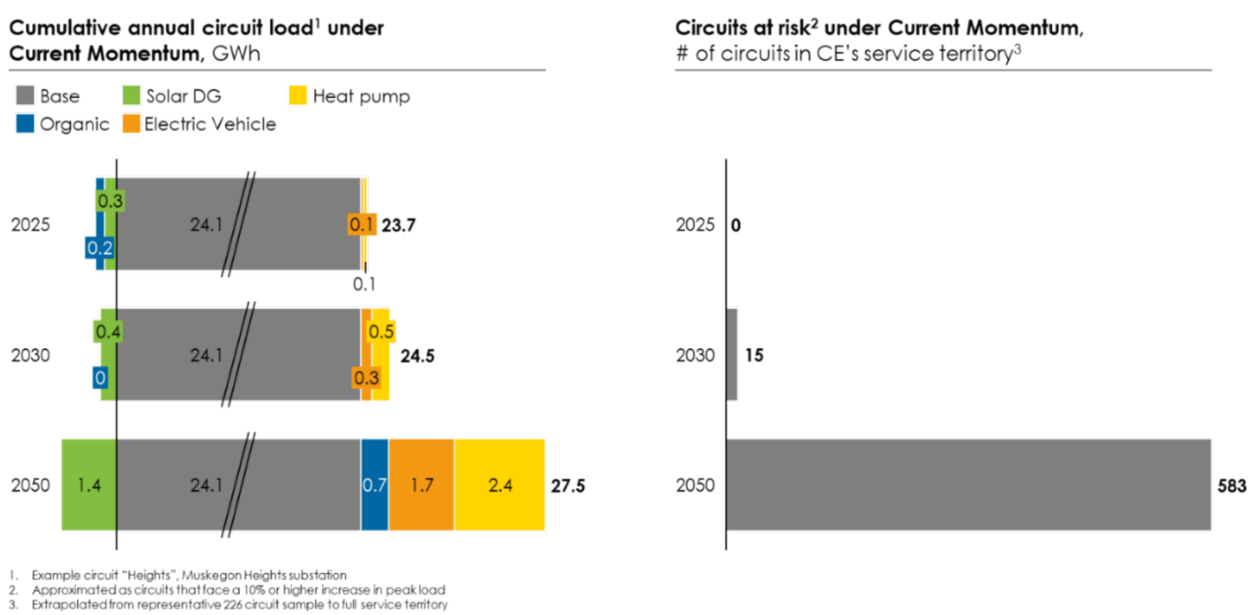
Load in the Company's service territory has been largely flat across the years due in part to the relatively limited adoption of electricity intensive heating and mobility technologies, coupled with the success of the Company's Energy Waste Reduction, Demand Response Programs, and summer time-of-use rates.

- Currently, EV adoption in Michigan is 1% of total vehicles and heat pump adoption is 2% of total households while solar DG encompasses 0.4 GW of installed capacity.

Customer adoption of electrification is projected to lead to ~1-10% of circuits expected to see peak demand increase to at-risk levels by 2030 as shown in Figure 22 below.

This reinforces the Company's plan to first address the reliability impact from climate change, while continuing to develop the capacity of the grid to accommodate future low-carbon technologies.

FIGURE 22
CIRCUITS AT RISK UNDER CONTINUED MOMENTUM

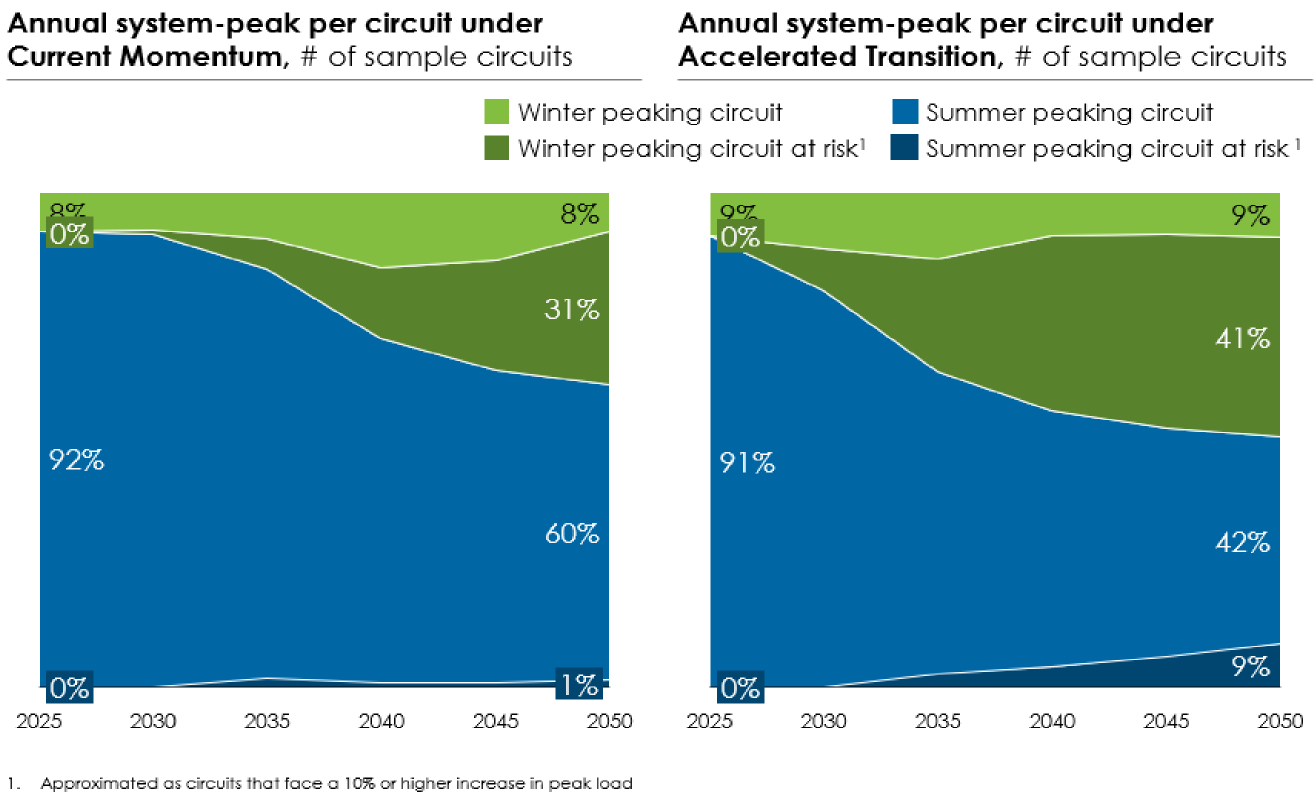


By 2050, peak load is projected to increase to at-risk levels, or greater than 10% increase in peak load, on ~25% of circuits in the CM scenario, driven by customer adoption of EVs and heat pumps.

Depending on the rate of heat pump adoption and the type of heat pumps adopted, hybrid versus fully electric, there is a potential shift from a summer-peaking system to winter peaking system with a ~50/50 summer/winter split by 2050 in the Accelerated Transition scenario as shown below in Figure 23.

FIGURE 23

ANNUAL SYSTEM-PEAK PER CIRCUIT UNDER CONTINUED MOMENTUM



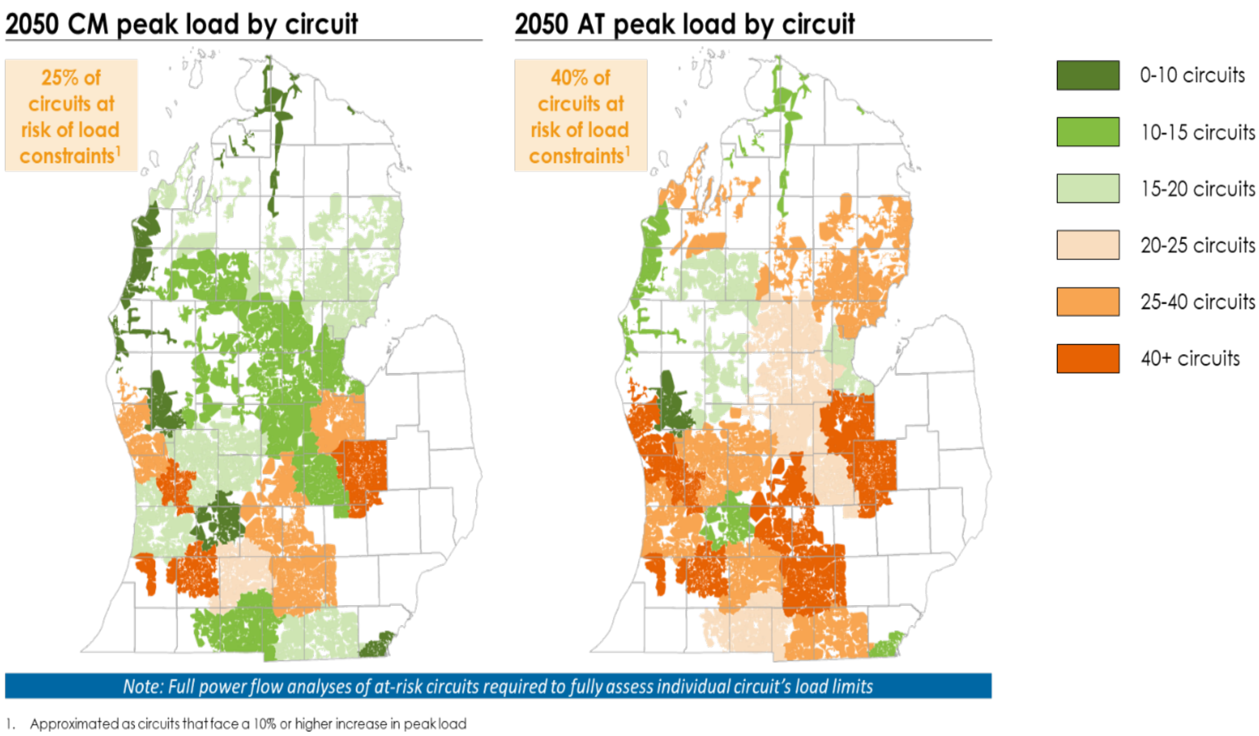
The highest levels of customer technology adoption are likely to materialize in specific circuits. Those at greatest risk of reaching load capacity limits are largely comprised of residential single-family housing customers with high household income, often in suburban areas, given a relatively higher propensity to adopt.

Circuits start reaching at-risk load threshold in 2030, and by 2050 there are 583 circuits out of 2,352 that see >10% peak load increase in a CM scenario.

In an AT scenario, 181 circuits are at-risk in 2030, with up to 40% of examined circuits at risk by 2050 (923 circuits) as shown in Figure 24 below.

FIGURE 24

PEAK LOAD BY CIRCUIT UNDER CONTINUED MOMENTUM AND ACCELERATED TRANSITION

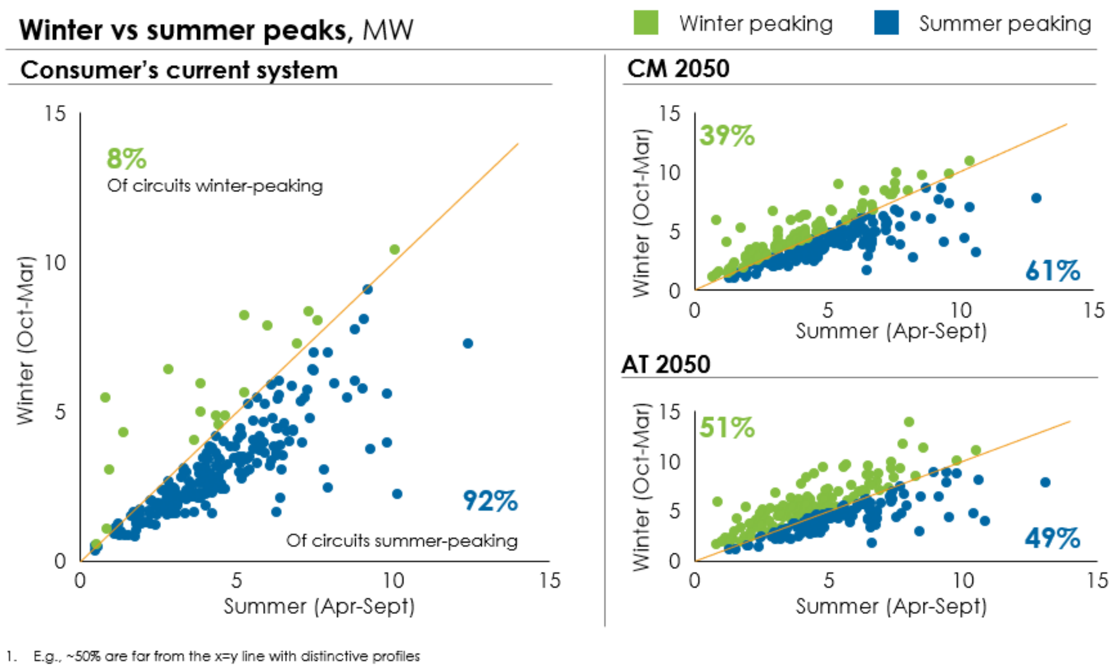


Regarding peak seasonality, summer peak increases remain relatively small—with solar DG offsetting EV load and no heat pump driven load increases.

For now, the Company primarily manages a summer-peaking system. However, the modeling for this scenario suggests this would shift in the future to winter peaking.

As Figure 25 below indicates, summer peaking could shift to winter peaking for 51% of circuits by 2050 in the AT scenario, and for 39% by 2050 in the CM scenario.

FIGURE 25
CIRCUIT PEAK LOADS BY 2050



This shift, driven by projected adoption of heat pumps and their wintertime use, results in a growing number of new winter-peaking circuits, with a substantial fraction reaching the at-risk threshold.

As adoption of electrification technologies continues, the expected circuit-level risk will be heavily impacted by both the timing and character of adoption.

Assumptions around the scale of penetration and time of use for when EVs and heat pumps use the grid have a significant effect on the volume and timeline of forecasted load constraints.

Non-Load Challenges from Customer Technology Adoption

Besides the direct load impacts of customer technology adoption of EVs, solar distributed generation and heat pumps, there is indirect impact on the Company's grid that stems from second-order effects of the uptake of these technologies. They include:

- Bi-directional power flows, especially in circuits that show a propensity to higher-than average adoption of solar DG.
- Power quality issues, stemming from increased decentralized load and generation, which could unbalance power factors and degrade voltage quality.
- Interconnections with third parties to facilitate control of distributed customer technology, and to influence load and consumption profiles for the benefit of the grid.

As part of the work going forward, CE must consider such indirect challenges and plan to take action to mitigate them, while simultaneously allowing and supporting the uptake of new load technologies in the service territory.

Such action can often be taken in tandem with actions that help increase resiliency to climate risks or to load increases (e.g., encouraging uptake storage on the LVD system can help mitigate peak load concerns, while at the same time reducing the occurrence of bidirectional power flows).
A centralized DER Management System ("DERMS") will be critical to supporting system-wide optimization of DER.

The Company defines DERMS as *an enterprise scale software platform that is located at the utility's operational center*.

- A DERMS monitors, controls, and optimizes DER in a manner that maintains or improves the reliability, efficiency, and overall performance of the electric distribution system.
- This structure allows DER performance to be optimized for reliability and efficiency while simultaneously accounting for local, regional, and system-wide constraints and requirements.

Optimization at a system-wide level will be driven by bulk power constraints and requirements (e.g., frequency, capacity requirements, SAIDI, etc.).

A DERMS provides the functionality required to manage these wide-ranging factors to realize system-wide optimization. This includes coordination with other enterprise systems such as an Advanced Distribution Management System ("ADMS") detailed later in this report, and the Demand Response Management System ("DRMS").

FIGURE 26

NON-LOAD CHALLENGES FROM CUSTOMER TECHNOLOGY ADOPTION

The Resilient Grid Plan

In the face of the challenges outlined above, the Company has developed the *Resilient Grid Plan* to ramp up its investment to develop a modern grid capable of mitigating the immediate threats from extreme weather.

- The *Resilient Grid Plan* represents an increase in the scale of established investments in infrastructure and spending on Forestry Line Clearing and increased inspections, while adding additional resiliency investment, such as Overhead to Underground Conversions.

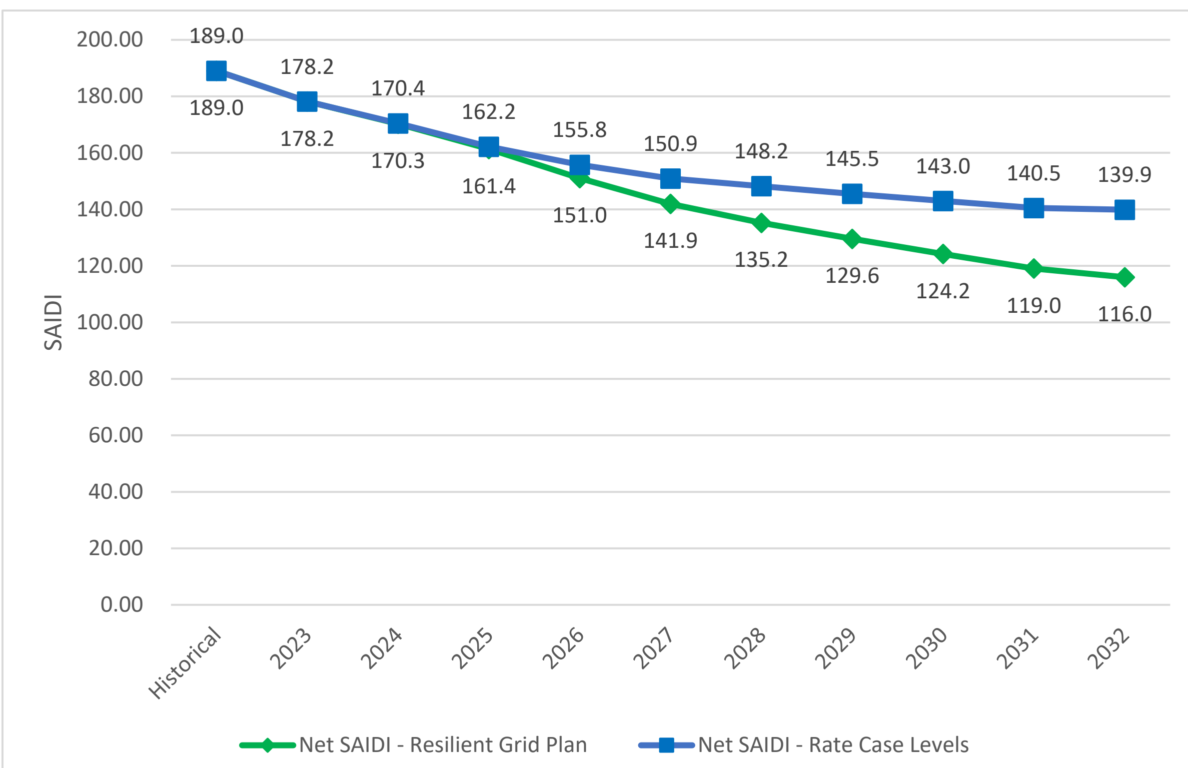
Investment at this scale will also set the Company on a path to build a grid that will deliver on the following three objectives mentioned earlier in the EDIIP:

1. **Delivering reliability performance into the 2nd quartile of nationwide utilities.**
2. **Delivering a grid where no single outage event will affect more than 100,000 customers.**
3. **Delivering a grid where no customer will be without power for more than 24 hours following an outage event.**

Additionally, investment at the scale outlined in the *Resilient Grid Plan* will deliver significantly improved SAIDI performance over the next decade when compared to the trend being set by recent electric rate case-approved levels of investment, as shown in Figure 27 below, if the improved spending levels are approved by the Commission. These investments will yield a glidepath that provides a nearly 100-minute improvement over the Company's average 2018 to 2022 performance of 208 minutes.

FIGURE 27

SAIDI PROJECTIONS – RESILIENT GRID PLAN VS. EXISTING APPROVED LEVELS



The *Resilient Grid Plan* has evolved from the 2021 EDIIP, which was developed prior to the Company's advanced climate and technology adoption modeling explained earlier in the Scenario and Investment Planning section of this report.

Additionally, The Company anticipates the pace of reliability investment level will level off after investments made to address rapidly changing climate and customer technology adoptions have been implemented.

Looking beyond 2030, the mix of investments will likely shift to ensure the system has capacity to service load from increased extreme heat days, and electrification of transit and home appliances.

The Company's SAIDI goal is achieved through numerous investments that all contribute to the overall reliability goal. These approaches can be grouped together into four categories: *Forestry Line Clearing*, *Hardening*, *Inspections*, and *Digital Automation*.

System Deterioration discussed under *System Condition* in the Distribution System Overview section, represents a threat to electric reliability as shown in Figure 26 above.

Assets that show deterioration from age or environmental factors are at a higher risk for failure either from malfunction or extreme weather and require investment to simply maintain current reliability performance.

The **Forestry Line Clearing category** includes the work responsible for maintaining clearance between vegetation and energized Company equipment, and to eliminate the vegetation hindering accessibility to the Company's electric lines.

- This vital work is the most impactful towards improving system reliability and encompasses both HVD and LVD specific programs as shown below in Figure 28.
- Further detail on the Company's approach to Forestry Line Clearing including the 5-year investment plan, best practices, and risks it responds to are included in the *Asset Management* sections of this plan under LVD Lines and HVD Lines.

The Hardening category includes capital investments to repair and replace HVD and LVD assets such as lines and substations.

- These investments address infrastructure on the system at risk from severe weather and allows for proactive resiliency plans, such as undergrounding or fractionalization.
- Further detail on the investment categories including the 5-year investment plan and approaches to reliable operations are included in the Asset Management Approaches section of this report under LVD Lines, HVD Lines, and Substations.

The Inspections Category includes ground and aerial inspections from helicopters on both the LVD and HVD systems as well as investments related to addressing failures.

- Company inspections of distribution lines and substations are used to locate and repair failed equipment, to identify specific areas to target investments based on probability of future issues, and to prioritize projects that will deliver the greatest reliability improvements for customers.
- Further detail on the investment categories including the 5-year investment plan and Company inspection cadence is included in the Asset Management Approaches section of this report under *LVD Lines*, *HVD Lines*, and *Substations*.

The Digital Automation category includes technological driven solutions to increase efficiency of the Company's distribution planning work, service restoration, and line clearing operations.

- An example of this work is the Company's use of drones and Imagery Analytics to re-imagine the Company's inspection processes by providing a 360-degree view of its distribution assets in the field. This application shows **the potential to enhance employee and customer safety, reduce the cost of work, and to improve reliability and resiliency** through more targeted work.
- These investments are a key component of the Company's glidepath to achieving breakthrough SAIDI and reliability performance.
- Further detail on the Company's digital and automation can be found in the *Asset Management Approaches* section of this plan under LVD Lines.

FIGURE 28

IMAGERY FROM DRONE INSPECTION COMPARED TO VISUAL GROUND INSPECTION

Planning Process

Annual Planning

The EDIIP flows from an iterative process in which planning engineers and operators identify projects and maintenance work needed to address system performance issues and meet the Company's strategic goals and objectives for the electric distribution grid.

All work is planned in consideration of expected customer demand and emergent replacements, planned maintenance, and improvements to the grid.

As engineers and operators identify work, this informs planned infrastructure investments, inspections and maintenance of existing assets, projected customer-requested and emergent work, and supporting staff.

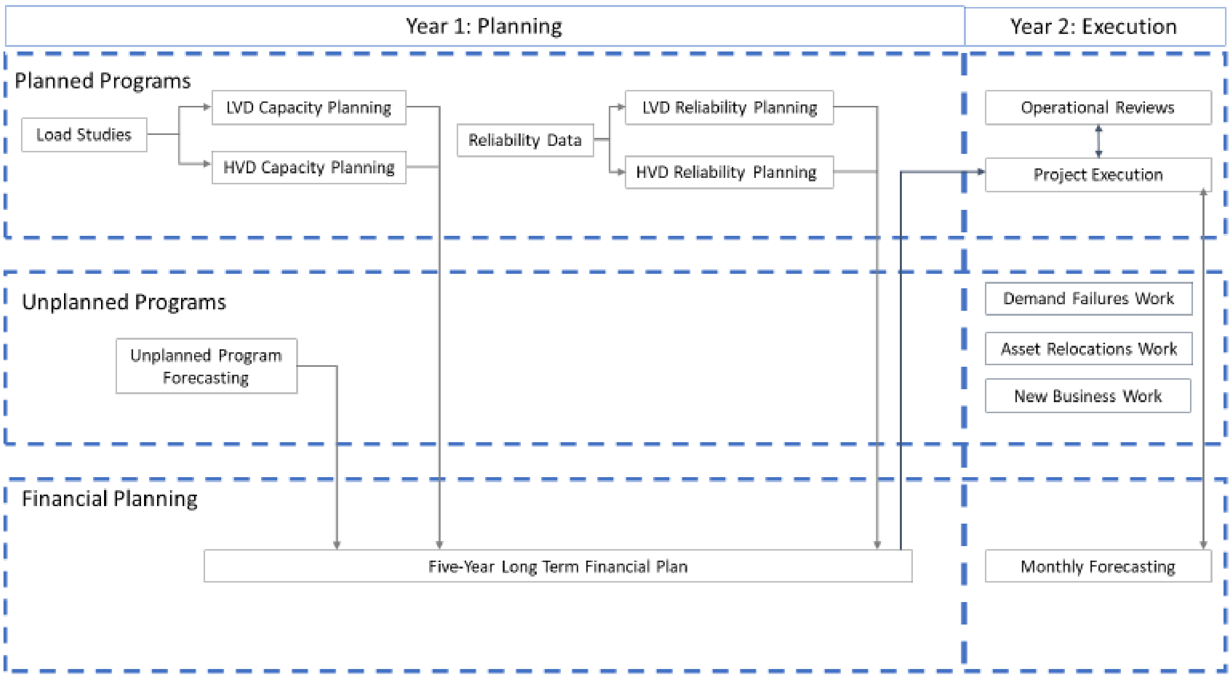
Repeating this process every year results in a rolling 5-year planning process in which one incremental year is added every cycle.

Depending on the nature of a given program, these identified investment needs are based on a combination of pre-planned or known projects, and anticipated volumes of emergent work, generally based on historical volumes of work accounting for observed trends.

Figure 29 shows how these planning activities connect with each other.

FIGURE 29

ELECTRIC DISTRIBUTION FINANCIAL AND ENGINEERING PLANNING PROCESS



To align with industry best practices, the Company has consulted the Electric Power Research Institute's ("EPRI") *Distribution Grid Resiliency: Prioritization of Options* report (EPRI, Palo Alto, CA: 2015. 3002006668) published in 2015 and made publicly available at the EPRI website.

EPRI published this report on the prioritization of options for grid resiliency incorporating research that EPRI conducted on overhead structures, vegetation management, undergrounding, grid technology, and storm response practices.

The report provides a benchmarking analysis of the costs and benefits of various options for improving reliability and resiliency, such as Undergrounding and Fractionalization, that the Company will apply to its distribution planning, as well as discussion on how to rank the reliability of circuits so that projects can be prioritized.

Engineering Planning Process

The Company's electric distribution engineering planning process runs throughout the year. The Company conducts engineering work in all programs to address specific objectives and issues on the distribution system, depending on the type of work, the affected customer profile, and the attributes of the assets in question (e.g., HVD, LVD, substations).

The Company makes capital investments under two broad classifications, known as *unplanned* and *planned*.

***Unplanned* capital investments** correspond to customer requests or emergent system needs, such as for new business connections, restoration of service after storms, or requests for asset relocations.

These investments are not strictly 'unplanned' as the Company does anticipate having to make these investments but is usually unable to plan specific projects until an interruption or defect occurs, the Company receives a request from a customer or another project-triggering event occurs, such as a broken crossarm.

The defects identified from inspection and maintenance programs, described further in the Asset Management Approaches section, are unknown prior to identification but are prioritized for mitigation based on safety and reliability risk.

Instead, using a variety of external economic and industry indicators the Company can (to some extent) forecast related volumes of work, funding required, and detailed analyses of the state of the system in advance. For example, the Company uses data from the *Home Builders Association of Michigan* to estimate new housing starts to help forecast future spending on new service connections.

***Planned* capital investments** proactively improve reliability, address capacity constraints, and invest in new tools and technology.

For these investments, the Company prioritizes investments to maximize customer benefit in the most cost-effective manner. Specific investment prioritization varies based on the type of asset, but broadly speaking the Company uses several critical inputs and analyses to aggregate multiple data sources to best target and prioritize customer reliability, identifying specific investments based on the probability of future issues.

Different components of distribution planning—for example, planning for LVD lines or HVD substations—are overseen by respective program managers, who are responsible for developing plans in those areas.

Under these program managers, engineering planning leads and individual engineering planners have responsibilities for developing specific projects. Investment planning for the *planned* investments broadly follows three stages:

1. **Reviewing system needs** – Engineering planners review system needs to identify critical target areas at an LVD circuit, LVD zone, LVD or HVD substation or HVD line level, using a variety of asset-specific technical inputs and analytical tools, including real-time data and inspection results.
2. **Determining required actions and developing projects** – Once a customer or system need is identified, engineering planners determine required actions and develop concepts that compare alternatives and identify a recommended project based on the most economical and effective solution, such as to repair the damaged asset or replace it.
3. **Prioritizing and sequencing work** – Program managers and engineering planners prioritize, and sequence projects based on project timelines, customer benefits, system-wide workload balancing, and customer base balancing.

In certain investment areas, particularly for the LVD system, the Company uses an additional initial step in its process for identifying and prioritizing projects, known as *Grid Archetypes*. Individual projects are evaluated using a *Concept Approval* process. Both are discussed below.

Concept Approval Process

To ensure its electric distribution investments are reasonable and prudent, the Company considers many of its planned electric distribution investments against alternatives and develops concept approval documentation to demonstrate why the selected project is the optimal investment to make.

Through this internal concept approval process, the Company ensures the problem is clearly defined, alternatives are evaluated based on cost and solution to the problem, and there is a strong business case for the recommended project.

The general structure of a concept approval includes the following:

- Background and identification of problem
- Evaluation of alternatives
- Determination of costs and benefits of alternatives
- Selection of best alternative
- Approvals and revisions, where necessary

Based on the Company's identified goals, program managers provide direction to the Company's engineering planners regarding the types of work to be targeted.

Engineering planners gather data and perform problem solving to identify alternatives and eventual selection of a project. Once the engineering planners have identified alternatives, selected a project, and drafted a concept approval, they are reviewed by successively higher levels of management based on the projected cost for the selected project.

For small projects with costs below $250,000, no approval may be needed beyond that of the engineering planning director. In most cases, projects approved by the engineering planning lead go on to the program manager for review and approval, and may go higher for further review, depending on the projected cost of the project.

At each level of review, the reviewing party may request further revisions.

Once a concept has received all necessary approvals, it is considered an approved part of the Company's investment plan. It is released to the Company's electric design engineers for detailed design work, which consists of the following:

- During the design phase, costs may vary slightly from the original concept approval cost projections.
- If costs vary significantly (i.e., greater than 20%) based on design work, the variance may be reviewed by the program manager and engineering planner and, if necessary, resubmitted for approval with revised costs.
- If there are no significant financial variances between concept approval and the finished design, then the project proceeds to construction.

At this point, the Company's Planning and Scheduling group identifies and assigns either Company or contractor workforce resources to the project (depending on project specifics) and the project is scheduled for execution.

During construction, the program manager regularly reviews actual costs incurred against the budget. Unexpected cost variances during construction are managed through the Company's ongoing monthly budgeting process, with adjustments to the overall workplan made as necessary to manage to budget.

Grid Archetypes

Since 2018, the Company has developed and used an approach referred to as *Grid Archetypes* to consider additional LVD circuit characteristics beyond traditional reliability metrics of SAIDI, SAIFI, and CAIDI, and to ensure investments are optimally made across the Company's distribution system and across different capital spending programs.

This approach is also meant to ensure that no section of the grid is inadvertently left behind—that **both rural and urban customers, and residential, commercial, and industrial customers all benefit equitably** from the Company's investments. While this type of equity has always been a goal of Grid Archetypes, in 2023 the Company added additional environmental justice ("EJ") considerations to its modeling, as discussed in more detail in the next section of this report.

To establish the Archetypes approach, the Company first groups each of its LVD circuits into one of seven archetype categories based on various circuit characteristics.

Circuit characteristics include geographic characteristics (i.e., circuit line-miles, distance to Company service centers), customer mix, circuit load and voltages, and reliability metrics. Full details on all circuit characteristics and their use can be found in Appendix A.

Figure 30 below defines each Archetype and illustrates where each of the Archetypes are located throughout the Lower Peninsula.

FIGURE 30

GRID ARCHETYPES

Once the LVD circuits are grouped, the Archetypes approach consists of four steps to develop an investment plan:

1. **Strategic Direction:** Company leadership establishes multi-year goals and broad budget guidance.
2. **Prioritization:** Electric Planning identifies circuits for investment in the following two years.
3. **Solution Options:** Electric Planning assesses a range of solutions to address circuit issues.
4. **Investment Plan:** An integrated investment plan is produced.

The *Strategic Direction* step is intended to provide multi-year guidance on guardrails for how much investment should be allocated to each archetype.

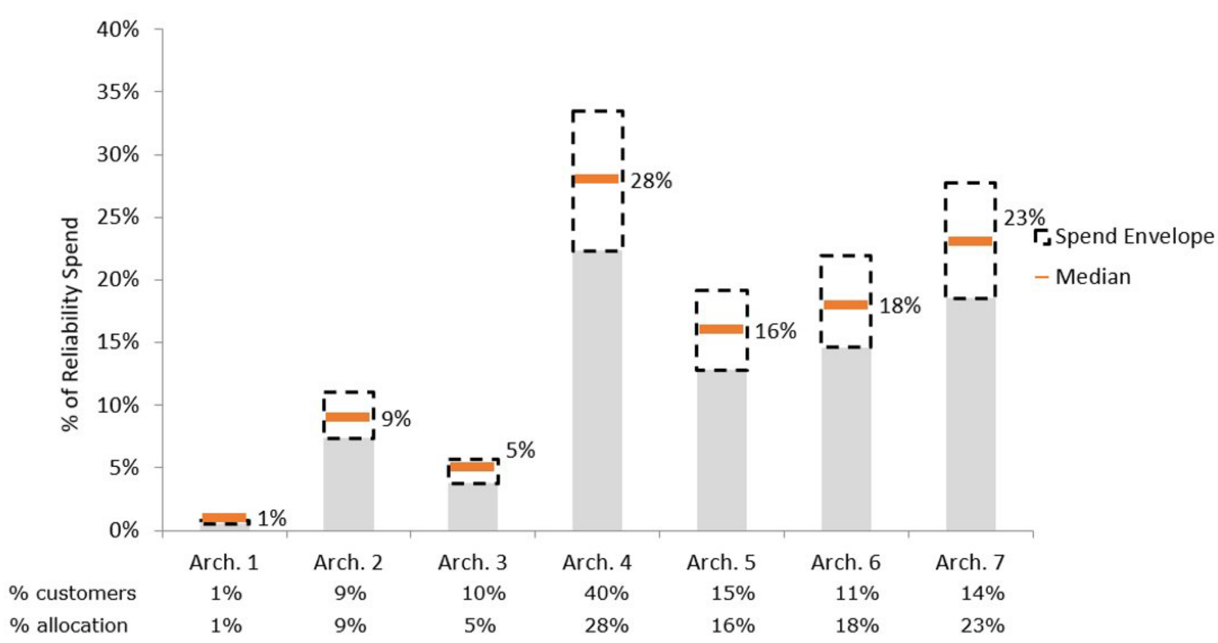
During this step, the Company takes its planned, system wide LVD capital spending for a given year and allocates the spending to each archetype based on different archetype characteristics or archetype performance measures.

The Company then takes the median allocation of all allocations and calculates spending guardrails for each archetype based on a certain amount of allowable variance. An illustrative example of these calculations is shown in Appendix A.

The result of this process is an illustration of targeted spending ranges for each archetype, as shown in Figure 31 below.

FIGURE 31

ARCHETYPE TARGETED SPENDING RANGES – ILLUSTRATIVE EXAMPLE



If the Company's planned spending in each archetype falls outside the "spend envelope" guardrails, then spending can either be reallocated to better ensure optimal prioritization of investment across the LVD system or the Company can develop a justification for why spending outside of the guardrails is necessary.

In the *Prioritization* step, the Company evaluates each LVD circuit, and flags them based on their characteristics or performance against each of the Company's distribution objectives (Safe, Reliable and Resilient, Clean, Equitable, and Competitive). Full details on the monitored characteristics and performance measures are provided in Appendix A, which shows the thresholds at which a circuit is flagged.

Once the flagging is complete, the Company prioritizes each circuit as follows:

- Circuits flagged for two or more objectives are considered 'priority' circuits.
- Circuits *not* flagged for any objectives are not considered 'priority' circuits.
- Circuits flagged for one objective may or may not be 'priority' depending on the specific flags identified.
- Circuits flagged for safety are prioritized.
- Circuits flagged for one reliability indicator are only prioritized if there is overloaded equipment or a zonal health score greater or equal to 15 (see later section on LVD Asset Health); otherwise two reliability indicators must be flagged.
- Circuits *only* flagged for "clean" and "competitive" indicators are not prioritized.

In 2023, the Company updated this flagging process to capture the environmental justice characteristics of a circuit, as discussed in detail later in this report.

Furthermore, the Company plans to update this decision tree in 2024 to capture risks driven by climate change as outlined in the earlier section of this report on Scenario and Investment Planning. Climate change updates are expected to drive resiliency investments into circuits located in the Southern and Northwestern area of the Company's service territory, where higher wind speeds, thunderstorms or extreme heat days are most likely to become more prevalent, as shown in Figure 16.

Once *Prioritization* is complete, the Company identifies the 'priority' circuits broken down by archetype, and by type and number of flags.

Based on this analysis, the Company can develop a pipeline of projects to address issues on the 'priority' circuits. These projects are then fed into the LVD component of the Company's annual planning cadence described above.

In the *Solution Options* step, the Company reviews the reason each 'priority' circuit was flagged and identifies solutions to impact the relevant circuit performance measure.

Finally, **in the *Investment Plan* step,** the Company creates specific projects with associated costs to implement chosen solutions on given circuits.

Once projects are planned, approved, and designed, the Company adds them to its sequence of work.

In general, the Company prioritizes projects in the sequence based on the number and type of objective flags identified in the *Prioritization* step.

For further information on the creation of specific projects with costs, see the discussion regarding concept approvals above.

Equity and Environmental Justice in the Planning Process

Since the Company filed its previous five-year EDIIP in June 2021, the MPSC and other parties have indicated increasing levels of interest in EJ, energy equity, and other similar topics.

For purposes of distribution planning, these issues primarily concern how different communities experience reliability and resiliency, as well as future implications for grid access when it comes to customer adoption of EVs and other electric technologies and customer adoption of distributed energy resources.

Reliability and resiliency concerns are pronounced because people living in disadvantaged communities may have more difficultly replacing spoiled food and medicine following power interruptions and may have fewer resources to secure back-up power or find alternative accommodations during extended power outages.

In its September 8, 2022, Order in Case No. U-20147 ("September 8 Order"), the Commission provided expectations around EJ and energy equity data to be shared in this EDIIP, directing utilities to provide information on the distribution system, particularly maps providing system information overlaid with socioeconomic context.

Additionally, in the settlement agreement for the Company's Electric Rate Case, approved by the Commission in Case No. U-21224 ("Settlement Agreement"), the Company agreed to further provisions around data that would be shared, as well as ways the Company would work to incorporate EJ considerations into distribution planning, as follows:

> "In its next Electric Distribution Infrastructure Investment Plan ("EDIIP"), the Company will provide circuit level reliability statistics, for those circuits with circuit spans within Environmental Justice communities and will provide a map of Company circuits overlaid on Environmental Justice communities. The Company will also provide (i) a map at the same scale as the overlay map visually displaying circuit voltage; (ii) zoomed-in maps visually displaying circuit voltage for each of Grand Rapids, Lansing, Flint, and Kalamazoo; (iii) a map at the same scale as the overlay map visually displaying circuit-level all-weather System Average Interruption Duration Index ("SAIDI"); and (iv) zoomed-in circuit-level all-weather SAIDI maps visually displaying each of Grand Rapids, Lansing, Flint, and Kalamazoo. Upon request of a party to this settlement agreement, the Company will provide the underlying data by zip code in Microsoft Excel. For this purpose, Environmental Justice communities are census tracts that are above the 80th percentile on the MiEJScreen Overall Score."

This section of this EDIIP addresses all these considerations, and defines EJ as specified in the September 8 Order, and in the Settlement Agreement (although an alternate approach defined by the federal government in the *Infrastructure Investment and Jobs Act* of 2021 ("IIJA") is discussed in a subsequent section).

The Company has made the following key observations about EJ performance, which will be discussed in further detail:

- While considering EJ in distribution investments is new, Grid Archetypes have led the Company to invest in EJ communities already.
- Recent reliability capital investment and vegetation management spending in EJ communities have been equitable when considering the size of EJ circuits relative to the Company's entire system.
- EJ communities experience better reliability and resiliency than the rest of the system, on average.

- The Company is still implementing ways to ensure that EJ communities receive needed, targeted resiliency investment.

The Company has 249 total circuits overlapping in whole or in part with EJ census tracts, as defined in the Settlement Agreement; of these, 24 are customer-owned or single-customer-dedicated circuits, leaving 225 general distribution circuits serving EJ customers according to this definition.

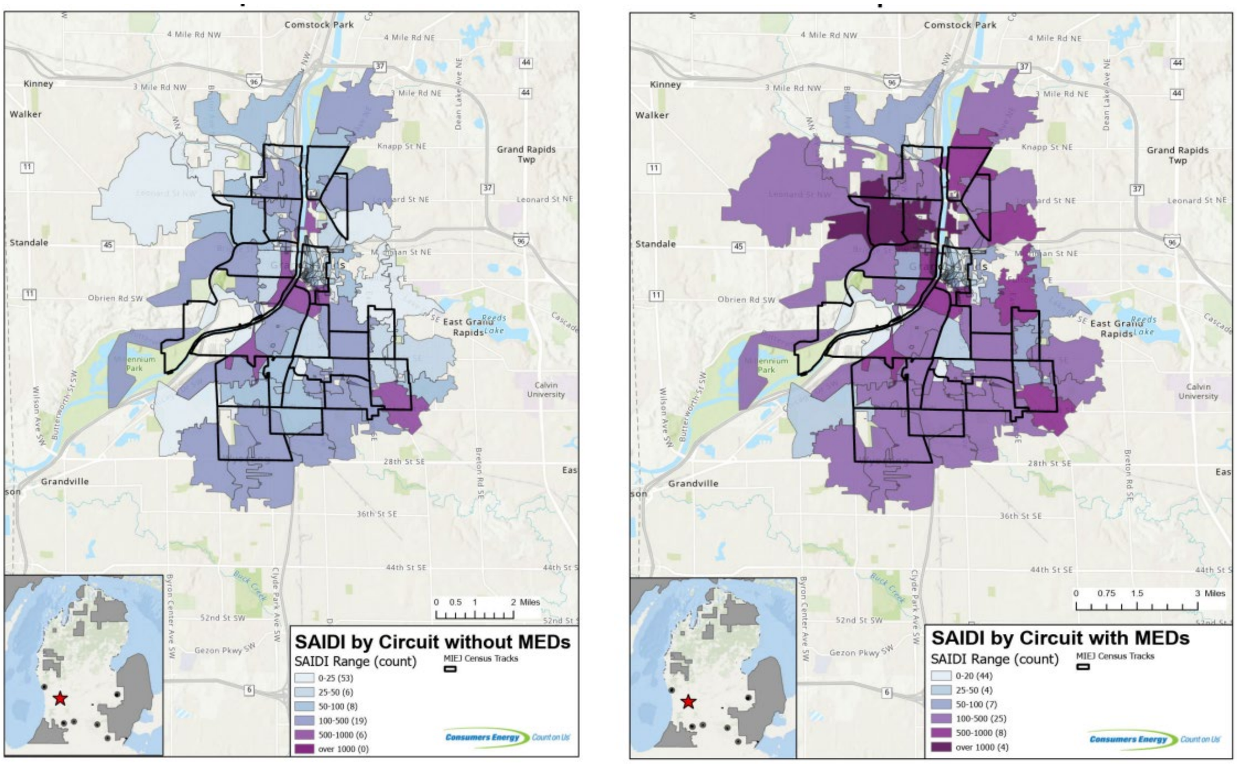
Reliability data for EJ circuits and a detailed series of maps, both addressing the Company's commitment in the Settlement Agreement, is provided in Appendix B of this EDIIP.

Each map indicates the location of census tracts that are above the 80th percentile on the MiEJScreen and shows key data about each circuit located in part or in whole within one or more of those census tracts.

To illustrate, maps showing 2022 reliability in Grand Rapids are provided in Figure 32.

FIGURE 32

RELIABILITY MAPPING GRAND RAPIDS METRO AREA



Impacts of Grid Archetypes for EJ Communities

The Company's Grid Archetypes approach to circuit planning creates groups of circuits based on a wide variety of characteristics, as previously discussed.

- Of note here, Archetype 4 consists of urban customers with long circuits and high customer density who are more susceptible to outages.
- Archetype 7 consists of rural customers with long circuits and poor reliability.

The Grid Archetypes approach has directed more reliability investment towards those two groups; Archetype 4 has considerable overlap with EJ communities in the Company's service territory.

Recent Distribution Spending in EJ Communities

From 2018 through June 2023, the Company invested approximately $20.1 million in reliability projects on circuits serving EJ census tracts. This represents 3.1% of all reliability investments in the Company's LVD lines system.

For comparison, circuits serving EJ census tracts comprise approximately 1,500 line miles, which represents 2.5% of the line miles on the primary LVD system. On a line-mile basis, then, the Company has been investing more than would be expected in EJ circuits if investment were perfectly proportional.

Additionally, while environmental justice has not been an explicit consideration in Line Clearing prioritization, the Company has started including disadvantaged community status in its Forestry model to ensure visibility.

This visibility allows the Company to make the comparison that, on a systemwide basis, the Company currently has approximately 55% of overhead circuits on its targeted 7-year clearing cycle, and (the Company is in the middle of a process to bring all circuits on cycle, as presented in recent Electric Rate Cases).

Conversely, 81% of EJ circuits are on-cycle. In other words, a much higher percentage of relevant EJ circuits are within the line clearing cycle than the general population of overhead circuits.

In the past few years, the Company has directed increased line clearing resources towards Flint and Grand Rapids which include significant EJ communities.

Since 2021, the Company has increased Forestry crewing in those cities by 300%. In 2023, 16% of the Company's LVD line clearing work is taking place on EJ circuits.

Recent Circuit Performance for EJ Communities

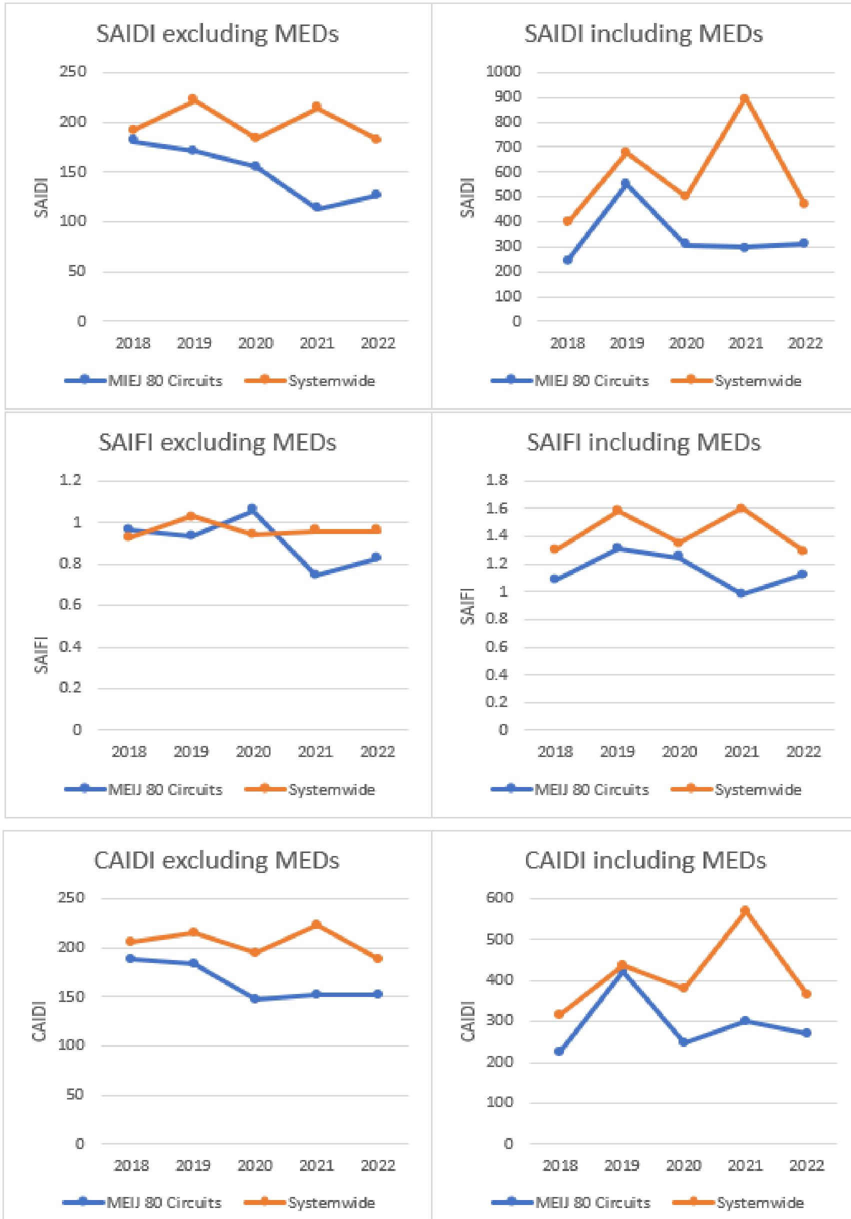
The Company's maps suggest that blue-sky reliability is better in EJ communities than in surrounding areas, and that circuits in EJ communities experience a wide range of reliability outcomes.

The maps also suggest that SAIDI, including MEDs, may be worse in a few key EJ areas than in the respective surrounding regions, and those EJ areas therefore have less resiliency.

However, the underlying data shown in Figure 33 below indicates that, while *individual* circuits in EJ communities may have poor resiliency in a given year, it is not a systemwide issue, and this holds true whether considering SAIDI, SAIFI, or CAIDI.

NOTE: This data only includes circuits with 15 or more customers.

Figure 33

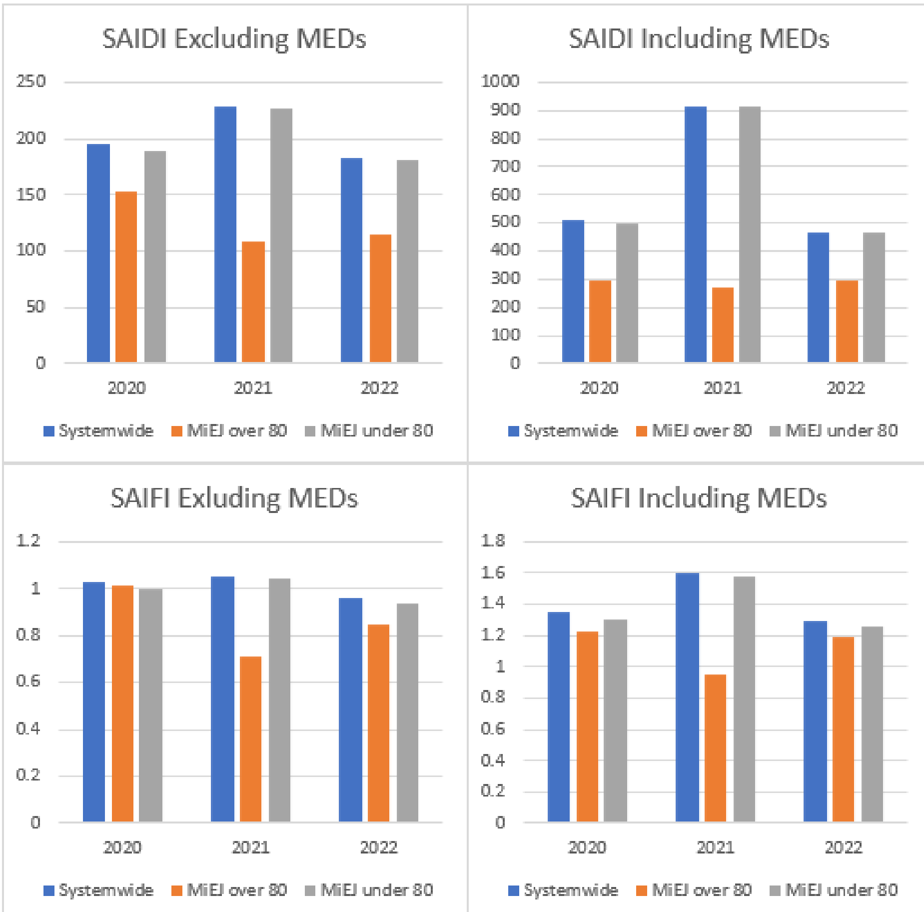


In addition to analyzing the reliability and resiliency of *circuits* in EJ communities, the Company has also analyzed the reliability and resiliency experienced by *customers in EJ census tracts*.

These results, for 2020 through 2022, are shown below in Figure 34.

FIGURE 34

RELIABILITY AND RESILIENCY IN EJ CENSUS TRACTS



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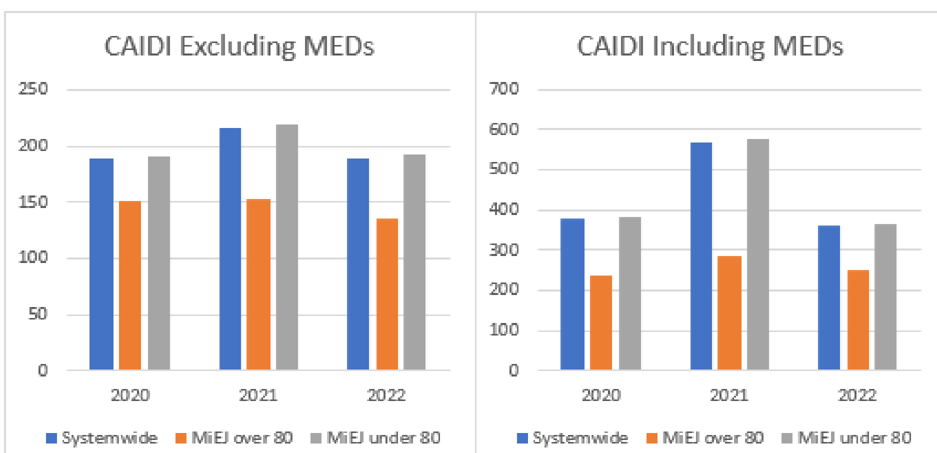

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As this data shows, customers in EJ census tracts ("MIEJ over 80") consistently experience better reliability and resiliency than the system, and better than customers outside of EJ census tracts.

While EJ communities do not have systematically worse reliability than other communities, and may even have better reliability, the Company recognizes that long duration outages following catastrophic storms hit these communities particularly hard when they do occur.

- An EJ community circuit might have good blue-sky reliability and therefore not be targeted for reliability investment, but if that circuit is prone to catastrophic outages, then the Company will consider resiliency investments to reduce the burden on those customers.
- Indeed, in its most recent electric rate case (Case No. U-21389), the Company is seeking an Investment Recovery Mechanism related to improving resiliency; if approved, this would help the Company increase resiliency investments in EJ communities.

Overall, having more visibility into which individual EJ circuits face poor resiliency will help the Company ensure that investments are appropriately targeted to those communities.

Incorporating EJ and Equity into Distribution Planning

In the Settlement Agreement as part of Case No. U-21224, the Company committed that "no later than the Company's next EDIIP, the Company will propose a plan to incorporate environmental justice and equity into the Grid…Archetypes analysis which the Company uses to prioritize its distribution investments in rate cases."

Consistent with this commitment, during the summer of 2023, the Company updated its Grid Archetype planning methodology. As part of this update, the Company integrated EJ considerations into the methodology.

As described in the prior section of this report on Grid Archetypes, the process involves prioritizing a circuit based on whether it triggers certain "flags."

In the summer of 2023, the Company added a new reliability flag to the process; this new flag indicates whether a circuit intersects with an EJ census tract. If it does, then that counts as one reliability flag that has been triggered.

Intersecting with an EJ census tract is not, by itself, enough to prioritize a circuit. However, as discussed in the Grid Archetypes section, if a circuit triggers two or more reliability flags, then it is prioritized. By adding EJ status to the list of reliability flags, an EJ circuit that previously only triggered one reliability flag (and therefore was not prioritized) will now be prioritized.

In addition to using Grid Archetypes to systematically consider EJ circuits in planning, the Company is also proposing targeted replacement of open-wire secondary, which heavily impacts EJ communities in the Company's service territory. Furthermore, the Company is proposing to convert non-standard voltages to standard voltages.

These conversions of non-standard voltages will:

a. Eliminate ungrounded conductors, which can pose safety hazards.

b. More easily facilitate load transfers to reduce outage times.

c. Improve the capacity of the circuit to accommodate increased load in some cases.

The Company's plans for open-wire secondary and non-standard voltages are discussed in more detail later in the LVD Public and Employee Safety Programs section of this report.

Finally, while environmental justice has not been an explicit consideration in Forestry prioritization, and while the Forestry backlog is smaller in EJ communities than statewide, the Company will begin using EJ status as a tiebreaker when comparing two circuits that are otherwise equal in Forestry prioritization terms when comparing traditional reliability performance.

As the Company executes on these plans for EJ communities, it recognizes the need to hear direct input from representatives of impacted customers in those communities, and the Company will explore avenues to get that input through appropriate channels.

- The Company has been an active collaborator in the MPSC Staff's Energy Affordability and Accessibility Collaborative; this ongoing workgroup provides a cross-functional way for utilities and other organizations to discuss challenges in energy equity, and the MPSC's process includes representation for low-income customers and other opportunities for those customers to be heard.
- The Company's Community Affairs team regularly reaches out through a variety of communication channels to local governments, community organizations, and individual customers regarding plans for major projects, including those designed to improve reliability in an area.
- The Company is willing to explore an annual meeting during which affected customers and their representatives can get information and provide input on the Company's efforts in EJ communities.

Other Options for Defining and Considering EJ

The American Rescue Plan of 2021, the *Inflation Reduction Act of 2022*, and the *Investment and Jobs Act of 2021* all allocate considerable federal funding for energy infrastructure, including focuses on environmental justice.

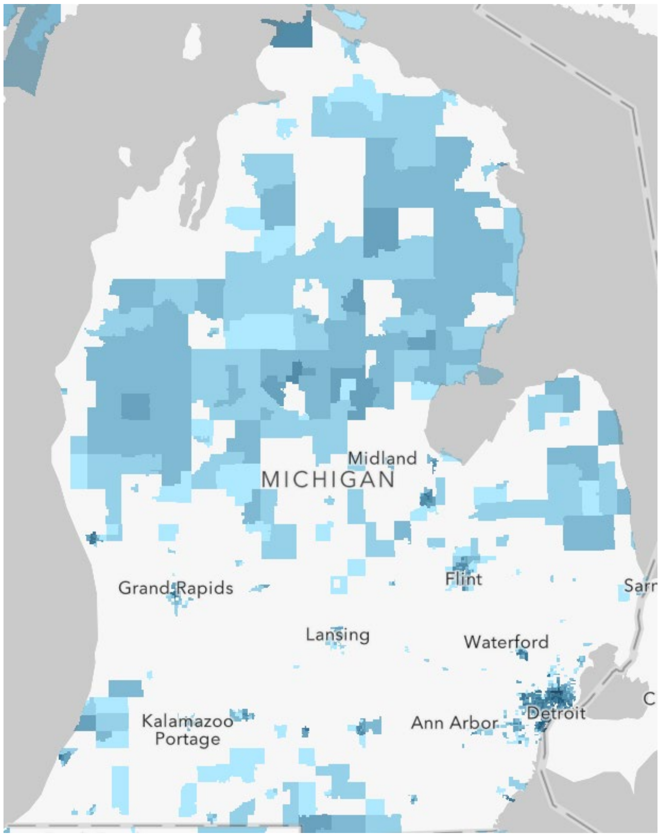
To support these programs, the federal government has developed its *Justice40 Initiative*, which creates a goal for 40% of the overall benefits of the relevant federal investments to flow to disadvantaged communities that are marginalized, underserved, and overburdened by population.

- As part of the *Justice40 Initiative*, the federal government has developed its own Justice40 screening tool (see www.Screeningtool.geoplatform.gov) to map out the locations of Federally defined disadvantaged communities ("EJ40 communities").
- The Justice40 screening tool produces a list of Michigan communities that overlaps in part with the communities defined in the September 8 Order and the Settlement Agreement, but also differs in part. Figure 35 below shows Michigan's lower peninsula with federal Justice40 data overlaid on top with the most disadvantaged areas shaded the darkest.

Of note, the EJ40 communities include multiple locations across northern Michigan, many of which align with Archetype 7.

FIGURE 35

EJ40 COMMUNITIES IN THE LOWER PENINSULA



While the Company has changed its Grid Archetypes process to address EJ communities, the Company is also pursuing federal grants through the *Infrastructure Investment and Jobs Act* ("IIJA") that will improve reliability and resiliency in EJ40 communities including:

- Proposed grid resilience and innovation projects in Flint, Saginaw, Muskegon, and Lansing to construct 3-phase ties between circuits that serve EJ40 communities and neighboring circuits to have the ability to install automation devices which will improve customers' reliability and resiliency.
- Proposed community driven clean energy project to develop a microgrid meant to service an individual governmental customer in Battle Creek, Michigan, and a battery energy storage system ("BESS") installation at the Company's Quincy substation. This project will allow the Company to conduct the studies and simulations necessary to develop a system protection scheme for microgrid applications as well as the know-how required to operate and maintain a microgrid on the Company's distribution system.

These projects will serve as a template, enabling the Company to replicate similar solutions in communities with long laterals exposed to many trees to limit outage frequency and duration.

Hosting Capacity in EJ Communities

The Settlement Agreement also included a commitment by the Company to include maps and data on hosting capacity in EJ communities in future electric rate cases. To date, the Company's hosting capacity analysis has largely been limited to an initial "go/no-go" analysis that was discussed in the 2021 EDIIP, and published in detail on the Company's website in the fall of 2021. Information based on that analysis was already provided in the Company's 2023 electric rate case in Case No. U-21389.

The Company acknowledges that continued work is needed to make hosting capacity analyses more detailed. Further guidance from the Commission would be useful regarding what more detailed analyses might look like before the Company commits more time and resources to it. The Commission's recently concluded Distribution System Data Access workgroup provided some intermediate guidance on how further information, including maps, could be provided, but no further action has been taken on it to date.

The Company is also awaiting further refinement of an EPRI software tool to be able to perform detailed hosting capacity analyses more easily.

The Company plans to continue discussions with key stakeholders on how to develop more detailed hosting capacity analysis methodology that could provide more granular data for EJ communities to use. The Company expects that the product of these efforts can be provided in future electric rate cases.

Asset Management Approaches

The *Resilient Grid Plan* reflects the Company's strategy to meet the safety, equity, reliability, and resiliency needs of the grid both now and into the future. This plan focuses on assets to modernize the Company's electric distribution system to safely provide power with fewer, shorter, and less frequent power outages for customers.

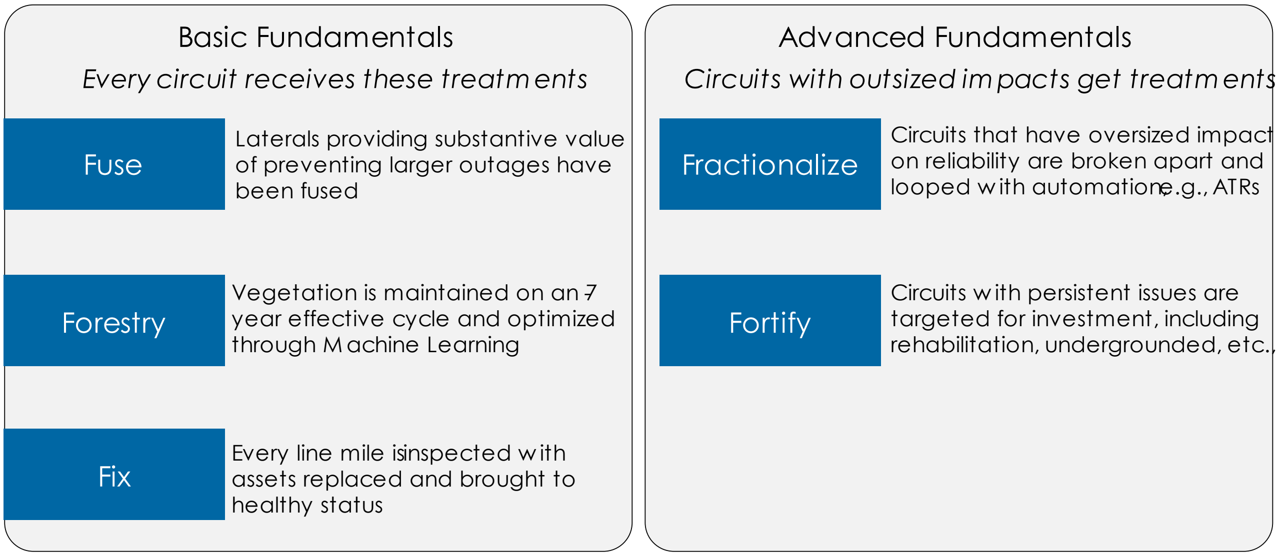
The Company's distribution system consists of several classes of assets. LVD lines, HVD lines, the Metro System, and substations were introduced earlier in the Distribution System Overview section of this report. In addition to these major classes, the distribution system also includes the protective system; distribution meters; distribution transformers; and streetlights.

The Company developed a strategic approach for each asset class to identify risks that affect reliability performance; developed countermeasures to mitigate those risks; created a workplan that implements those countermeasures in a prioritized manner; and defined an investment plan needed to support that work.

Each investment plan includes the planned Capital expenses to construct the distribution assets, and the Operations and Maintenance ("O&M") expenses for assets' annual inspections and upkeep, where applicable.

Each workplan is characterized by the Five Fundamentals Approach (Five Fs) shown in Figure 36 below, which succinctly covers the various approaches the Company will use to ensure reliable operations:

FIGURE 36
FIVE FUNDAMENTALS APPROACH



The Company's investments through the Five Fs are aimed to improve the expected performance of the system while ensuring circuits perform as expected.

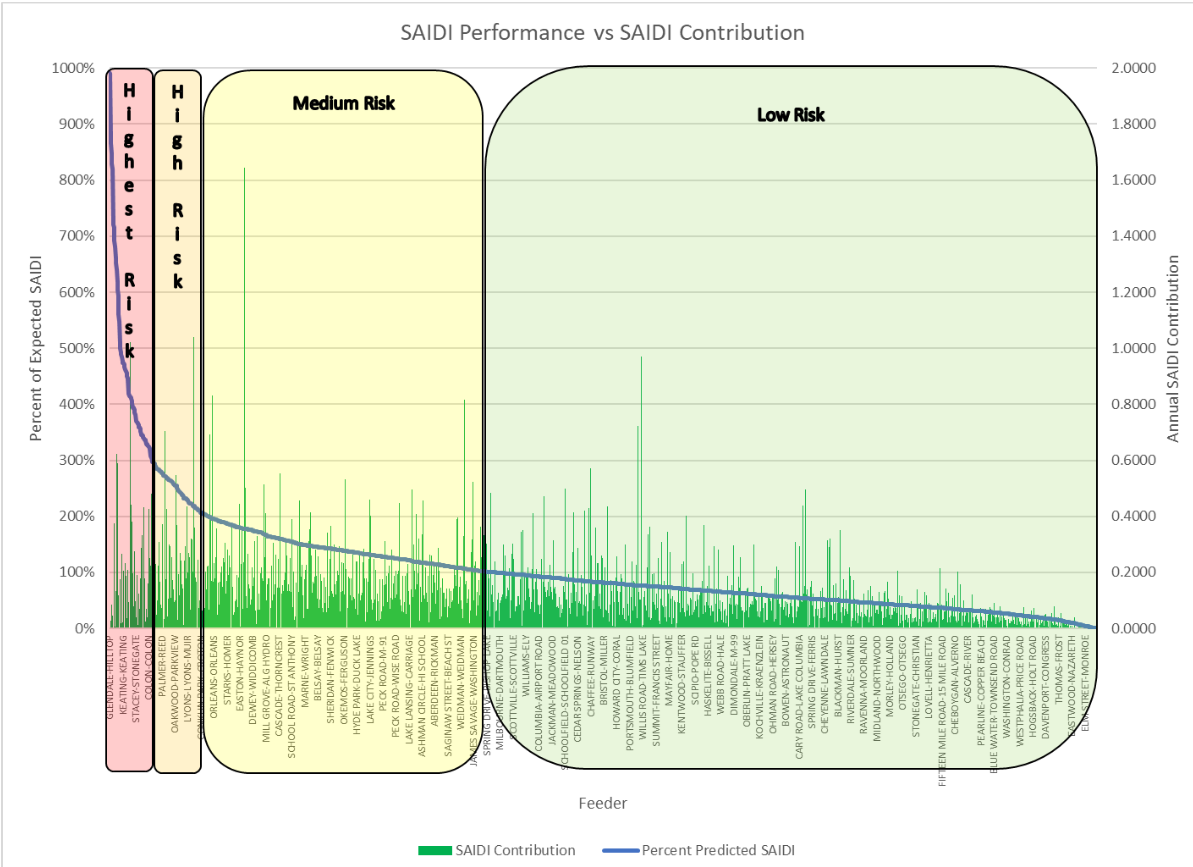
- The chart below in Figure 37 shows all LVD circuits within the Company's service territory on the horizontal axis with two measures of reliability performance on the vertical axis (the right side of the vertical axis shows actual SAIDI contribution, while the left side shows the percentage of expected SAIDI).
- The **100%** line on the vertical axis represents a circuit performing as it is engineered, while any green lines extending above this line represent circuits performing worse than expected.

Circuits on the left side of this figure, which present the highest risk to system performance if there is an outage, will need to be **Fortified** and in some cases **Fractionalized** to harden circuits against future risks and reduced in circuit line miles to minimize the impact of outages, respectively.

These approaches are detailed further in the Resiliency Investments section of this plan.

Circuits in the middle and right side of this figure that do not have an outsized impact when there is an outage may also be Fractionalized, but will primarily be addressed through **Fusing**, **Forestry**, and **Fixing** to improve the expected performance of most circuits, and are detailed further in the LVD Lines Reliability and Forestry Line Clearing sections of this plan.

FIGURE 37
LVD CIRCUIT SAIDI



The LVD System section of this plan below focuses specifically on the LVD Lines, which consist of several sub-classes of assets each with a specialized asset management approach.

Asset subclasses are grouped based on whether they primarily ensure the reliability of the grid, resiliency of the grid, or the safety of the public and Company employees.

This plan will outline the risks each subclass faces, a workplan tailored to address the most urgent risks, and the 5-year investment needs to execute this plan.

LVD System

LVD lines carry electricity from substations to customers' homes. Please see the Distribution System Overview section for more details.

The entire distribution system contains approximately 94,000 miles of LVD lines, including 61,000 of Primary and 33,000 miles of Secondary as shown below in Figure 38.

FIGURE 38

LVD PRIMARY LINES MILES BY TYPE

	Overhead	Underground	Total
LVD Primary Line Miles	51,500	9,500	61,000
LVD Secondary Line Miles	30,000	3,000	33,000
Total	81,500	12,500	94,000

In 2022, the LVD system comprised approximately 2,400 circuits, although some of these circuits are dedicated to a single customer or are part of the Metro system, which is discussed in more detail in the Metro System section of *Asset Management Approaches*.

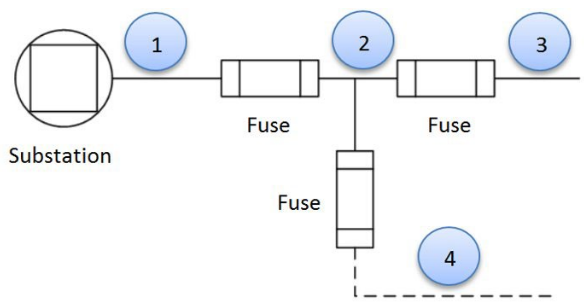
LVD circuits are subdivided into protective zones, as shown in Figure 39 below. As of this filing, the LVD system was apportioned into approximately 137,000 protective zones, with the number continuing to grow as the Company makes investments into the system to increase sectionalization and decrease the size of outages impacting its customers.

- Beginning in 2022, the Company set out to fuse overhead laterals to mitigate the size of outages by reducing the average number of customers out for an outage incident or event, lessening the impact of a fault to a smaller number.
- By the time this program is complete in 2025, the Company will have added approximately 23,000 fuses, reducing 41,000 customer outages annually and saving an estimated 9 minutes of SAIDI.

Upon its completion, the Company will re-evaluate the grid to determine if additional fusing opportunities will yield reliability gains for the customers.

FIGURE 39

ILLUSTRATION OF CIRCUIT SUBDIVIDED INTO ZONES



Additionally, the LVD system includes approximately 1.5 million poles—1.1 million on the primary system, and 400,000 on the secondary system.

Based on the Company's historical data, the overall average lifecycle of an LVD primary circuit is expected to be 57 years. The average age of an LVD pole is 65 years.

Asset Health, Risks, and Workplan

The **largest reliability risks to the LVD lines system are those that lead to outages and interruptions to customers.** The two largest contributors to frequency of outages (measured by SAIFI) on the overhead LVD system are **trees and asset failures**.

Besides frequency of outages, **duration of outages (measured by CAIDI) contributes to LVD lines risk**. Much of this outage duration risk is addressed through the Company's Service Restoration efforts, but there are also outage duration implications of system configuration.

LVD Public and Employee Safety Programs

The **greatest public safety risk from the LVD system comes from downed wires**, usually following weather events. Energized downed wires are dangerous and, if contacted, cause injury or fatality.

To mitigate this risk, the Company works to repair downed wires as soon as possible, and has procedures to guard downed wires until they can be fixed (emergency responders will also do this, and the MPSC rules provide that the Company must relieve emergency responders in a timely manner).

The investments planned as part of the following LVD asset subclasses reduce this risk by preventing outages, downed wires, and other contact with energized equipment:

- Standardizing the Company's system voltages **through Voltage Conversions** to mitigate the safety risk from ungrounded wires and allow for quicker recoveries from outages.
- Removing **Subsurface transformers** to improve employee safety, avoid potential public contact and environmental contamination.
- Modernizing legacy **secondary distribution assets**, to provide a safer and more resilient final service to many customers after the final transformer.

Legacy open wire secondary presents a particular safety issue in the event of a downed wire because they are not well-insulated, are not always easily accessible to crews, and usually located in higher population areas.

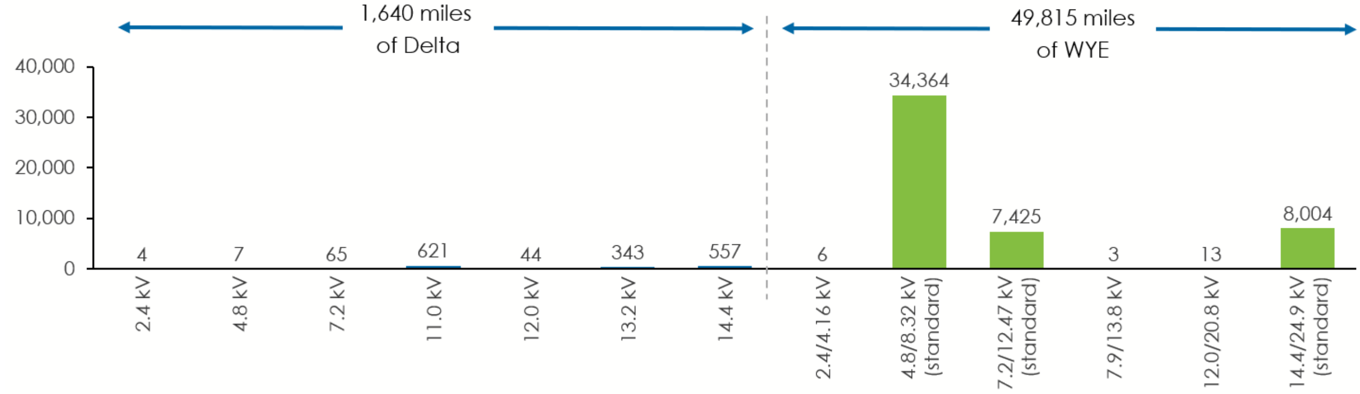
Voltage Conversions

The Company's LVD system consists of 13 different voltages, a holdover from when the Company acquired smaller systems throughout its history. Non-standard voltages restrict the Company's ability to install transfers between circuits and modernize the grid in a streamlined fashion because circuits of different voltages cannot be connected.

Figure 40 below, shows the Company's three standard voltages, which are 4.8/8.32 kV, 7.2/12.47 kV, and 14.4/24.9 kV, along with the 10 remaining non-standard voltages and associated overhead line miles.

Figure 40

OVERHEAD PRIMARY LINE MILES BY VOLTAGE AND CONFIGURATION



With only a fraction of the overall system, the 1,640 miles of Delta are less safe to operate compared to a grounded wye system.

- Delta systems require two phase ground faults to be present before the phase protective device trips, which means a downed Delta wire will not trip a primary protective device until a second phase fault develops.

By converting non-standard components to one of the three standard voltages, **the Company will mitigate the safety risk from ungrounded wires and increase operational flexibility** by expanding the ability to transfer loads to reduce outage times.

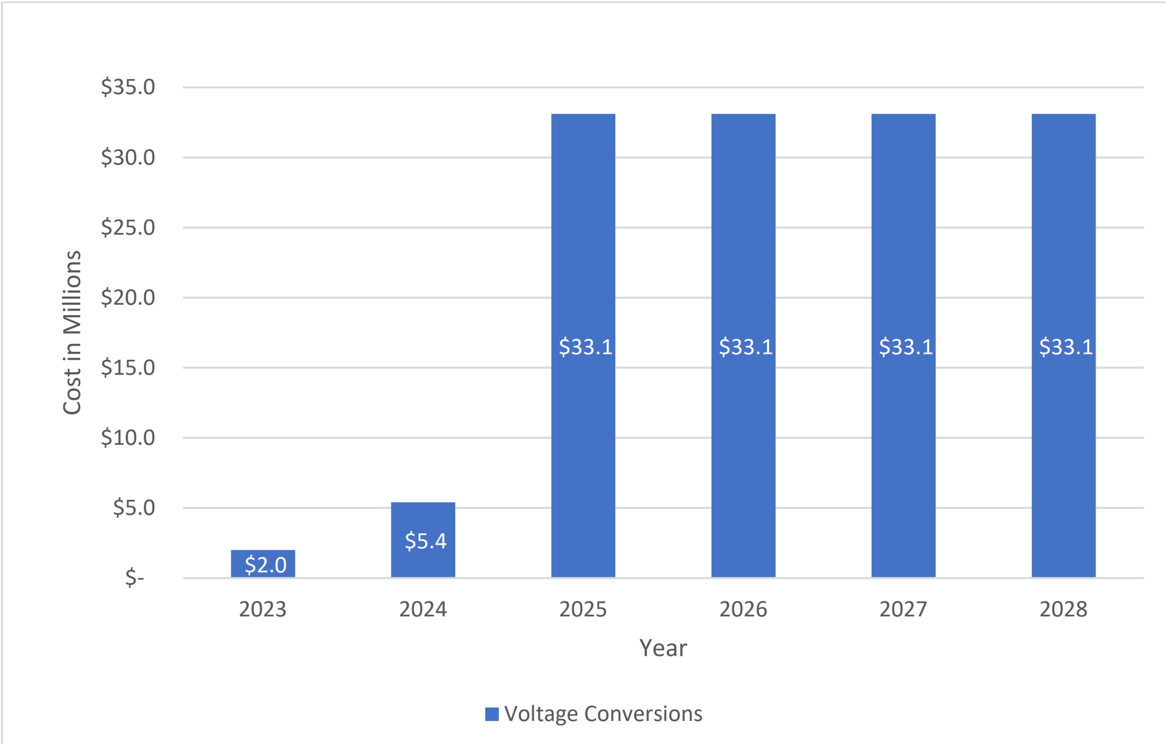
Additionally, voltage conversion will increase efficiency and reduce the operating costs through requiring lower levels of inventory to serve the variety of voltages.

The Company plans to invest $33 million per year over the next 10 years to convert 165 miles per year of non-standard voltage overhead lines, with an end goal of converting all non-standard voltages.

The first 5 years of spending for this plan is detailed in Figure 41 below.

Figure 41

VOLTAGE CONVERSIONS 5-YEAR INVESTMENT PLAN



Year	Miles of Nonstandard Voltage Converted
2023	8
2024	47
2025	165
2026	165
2027	165
2028	165

Subsurface Transformers

Figure 42

FIELD VIEW OF SUBSURFACE TRANSFORMER

The underground system still has 159 of its original subsurface transformers, representing 0.15% of the transformers serving the underground system.

While few in number and while not having a major impact on reliability, **subsurface transformers present a safety risk for Company employees, the public, the local environment, and grid reliability**.

- Since these assets are located underground, Company employees have difficulty accessing and repairing them when they fail, leading to an outage lasting roughly four times longer compared to padmount transformers.
- The location makes it difficult for the public to recognize these transformers in the field, making it easier for them to come into contact with these transformers.
- Lastly, these transformers are more difficult to inspect when they do fail, making a subterrain oil leak more likely, contaminating nearby land and ecosystems.

Subsurface Transformers Investment Plan

The Company will begin proactively replacing all 159 subsurface transformers with padmount transformers, which are easier to inspect and repair.

This plan will cost $3 million starting in 2025, and be completed in 2027 by replacing 53 subsurface transformers each year. The 5-year investment plan is shown below.

Figure 43

SUBSURFACE TRANSFORMERS 5-YEAR INVESTMENT PLAN

Year	Subsurface Transformers Replaced
2023	15
2024	15
2025	53
2026	53
2027	23
2028	0

Secondary Circuit Assets

Secondary circuit assets are located between the distribution transformer and customer meter.

Repairs are more challenging than primary repairs for crews for various reasons.

- In urban areas—in many cases in EJ communities—the secondary is typically located behind homes in backyards instead of roadside. When secondary is behind the home instead of roadside, it is more difficult to access with a bucket truck (e.g., along property lines with fences without an ally way) and may require Forestry assistance to access.
- Of the 30,000 miles of secondary on the Company's system, 26,000 miles are multiplex, and 4,000 miles are open wire. Examples of multiplex and open wire secondary are shown below in Figure 44.

Open wire secondary is more challenging to repair than multiplex secondary because breaks often occur mid-span, and if bucket truck access is not possible, repairs require splicing on the ground and then routing the conductor through trees.

- Much of the open wire secondary is nearing or at the end of its life, which causes the conductor to be brittle and not easily repaired.
- Open wire secondary is also more vulnerable to tree damage than multiplex. In general, the solution to issues with open wire secondary is to convert it to multiplex.

FIGURE 44
MULTIPLEX VS. OPEN WIRE SECONDARY

The factors that make secondary repairs more challenging contribute to higher average outage durations with an average duration of more than 10 hours.

Secondary outages occur at an average of 10 outages per day across the state and affect, on average, 3 customers per outage.

These long duration, high frequency outages cause the Company's line crews to spend more time, at a higher cost, to address emergent outages at the expense of planned work to proactively improve system reliability.

Outages overnight cause crews to have delayed start times, which further reduces the amount of planned work the Company can complete. They also drive costs higher as the repair work is done on overtime. Approximately 13% of secondary repairs are made during overnight hours.

The reliability and safety risks associated with secondary are particularly important for EJ communities.

- Approximately 18% of the Company's secondary in EJ communities is open wire. The long duration nature of secondary outages has a heightened impact on EJ communities, where customers are less likely to have back-up power generation, and experience financial and health impacts from long outages more acutely.
- Secondary in EJ communities tends to be in high population areas. This increases the risks associated with downed wires.

A key benefit to secondary replacement is that it includes installing larger secondary conductors with more capacity, in anticipation of future electric vehicle loads and rooftop solar installations. Please see Challenges From Customer Technology Adoption.

Another benefit of having larger secondary conductors installed is that this will reduce the number of future upgrades required for our customers when they adopt new technologies.

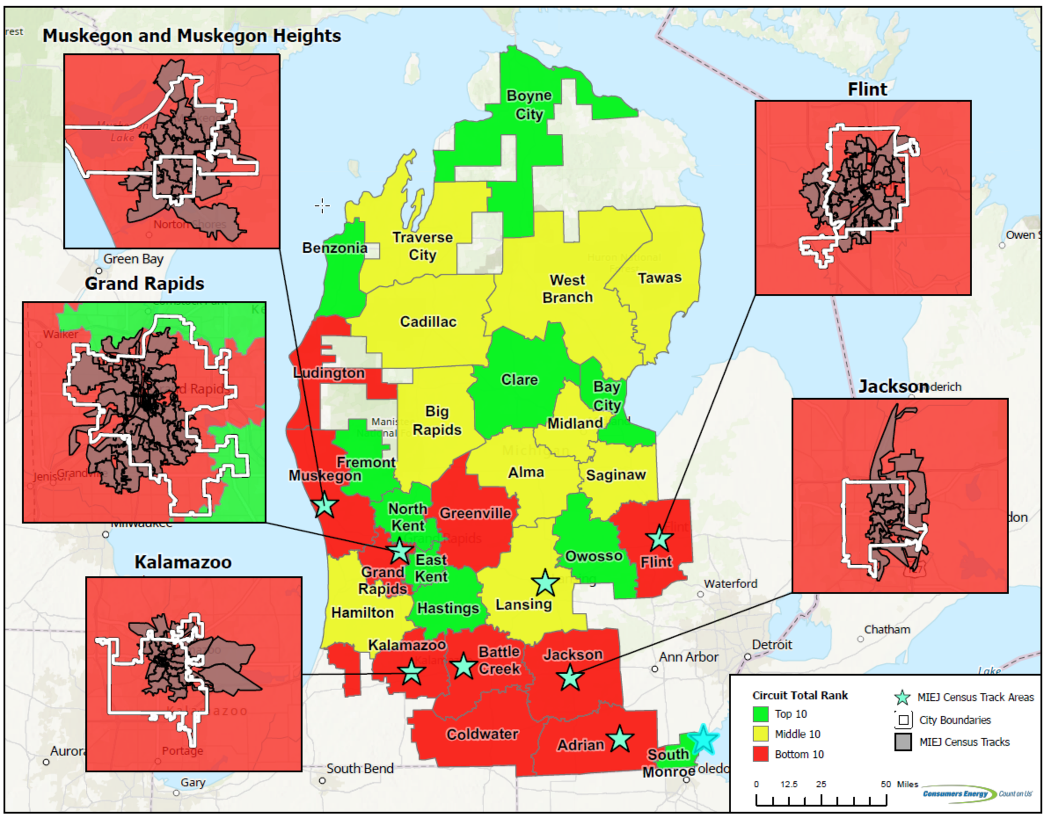
The Company measures secondary asset health through a combination of impacts to customers and number of interruptions.

In Figure 45 below, the Service Center regions with the worst performing secondary across the Company's service territory are highlighted.

Many of these service areas contain high concentrations of urban areas and EJ communities. Focusing our investments in these areas will result in the greatest cost benefit for improving reliability while investing in EJ communities.

Figure 45

WORK HEADQUARTERS WITH MIEJ CENSUS TRACK



When open wire secondary is replaced with multiplex secondary, reliability increases.

- The Company has observed that SAIDI performance resulting from secondary outages is worse in Headquarters that have higher percentages of open wire secondary in the Headquarters.
- To scale the impact of open wire secondary replacement, the Company proposes to accelerate replacement of open wire secondary with a program of targeted replacements for the worst-performing circuits.

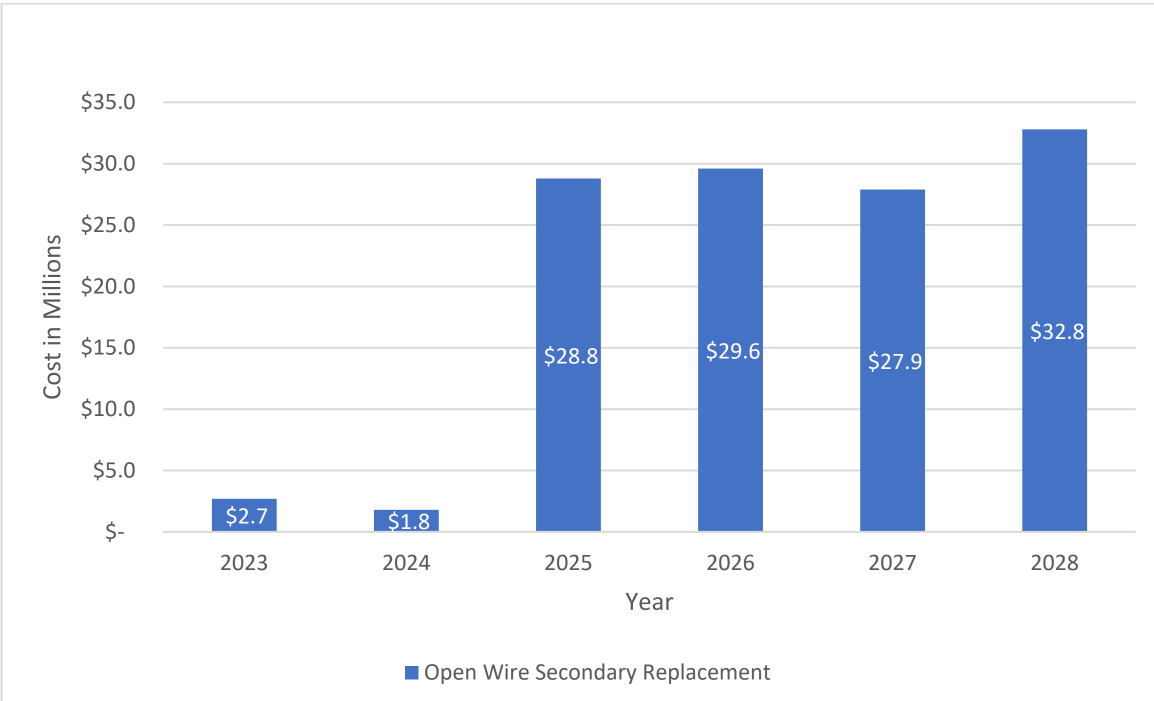
The Company plans to invest $30 million per year over the next 10 years to replace 917 miles of open wire secondary on the worst circuits in its territory.

The first 5 years of spending for the plan is detailed in Figure 46 below.

Once the secondary replacement program is fully scaled to $30 million a year, it is expected to reduce SAIDI by 0.5 minutes per year.

Figure 46

OPEN WIRE SECONDARY REPLACEMENT 5-YEAR INVESTMENT PLAN



Year	Miles of Open Wire Secondary Replacement
2023	7.4
2024	6.2
2025	100
2026	104
2027	98
2028	115

LVD Lines Reliability

The investments planned as part of the following LVD asset subclasses improve the reliability of the electric distribution system through the reduction of outage risks by:

- Identifying and mitigating problems with primary conductor, poles, and other supporting components through **Targeted Circuit Health Improvements** and addressing the worst-performing areas of the system.
- Replacing and upgrading deteriorated **LVD poles that** perform better in under extreme weather.
- Upgrading **overloaded components** to prevent overload-caused outages.
- Rejuvenating and replacing deteriorated **LVD Vintage underground cable**.
- Promoting safety, efficient operations, and aesthetics in the downtown areas of Battle Creek, Flint, Grand Rapids, Jackson, Kalamazoo, and Saginaw through the **Metro system.**
- Performing the Company's **Forestry Line Clearing Program** is designed to mitigate tree-related outages which are the biggest external risk factor for LVD Lines. The Line Clearing Program is also discussed as part of LVD Lines asset management, although the program also functions to mitigate risk on HVD Lines.

Inspection and System Maintenance

The Company is reducing reliability and safety risks through inspection and maintenance programs recommended by the *IEEE*.

The Company is proposing the following schedule, shown below in Figure 47, based on good engineering practice to help identify and correct problems before they result in outages.

FIGURE 47

LVD INSPECTION CADENCE

Inspection Task	Cadence	Components Checklist	Annual Cost
LVD Line Inspections	2 Years	• Visual Inspection of pole and pole top components. • If a pole is suspected of failure perform test for strength.	$34.3M
Padmount Inspections	Significant Sample Annually	• Visual external safety inspection to identify if secure, holes or leaking.	$709K
Electronic Circuit Recloser	Remote Monitoring	• Monitor for any abnormality in performance and investigate for correction.	$118K
	6 Years	• Inspect reclosers without modems for any abnormality in performance and correct as abnormalities are identified.	$250K
	4 years	• Replace battery	$91K
Switched Capacitor Bank	Remote Monitoring	• Monitor for any abnormality in performance and investigate for correction.	$190K
Unswitched Capacitor Bank	Annual	• Visually inspect for any abnormality and correct as abnormalities are identified.	$73K
Gang Operated Switches	3 Years	• Inspect and cycle the switch to ensure proper performance and correct as abnormalities are identified.	$600K
Disconnect Switches	3 Years	• Inspect, cycle and clean contacts to ensure proper performance and correct as abnormalities are identified.	$6.2M
Total			**$42.5M**

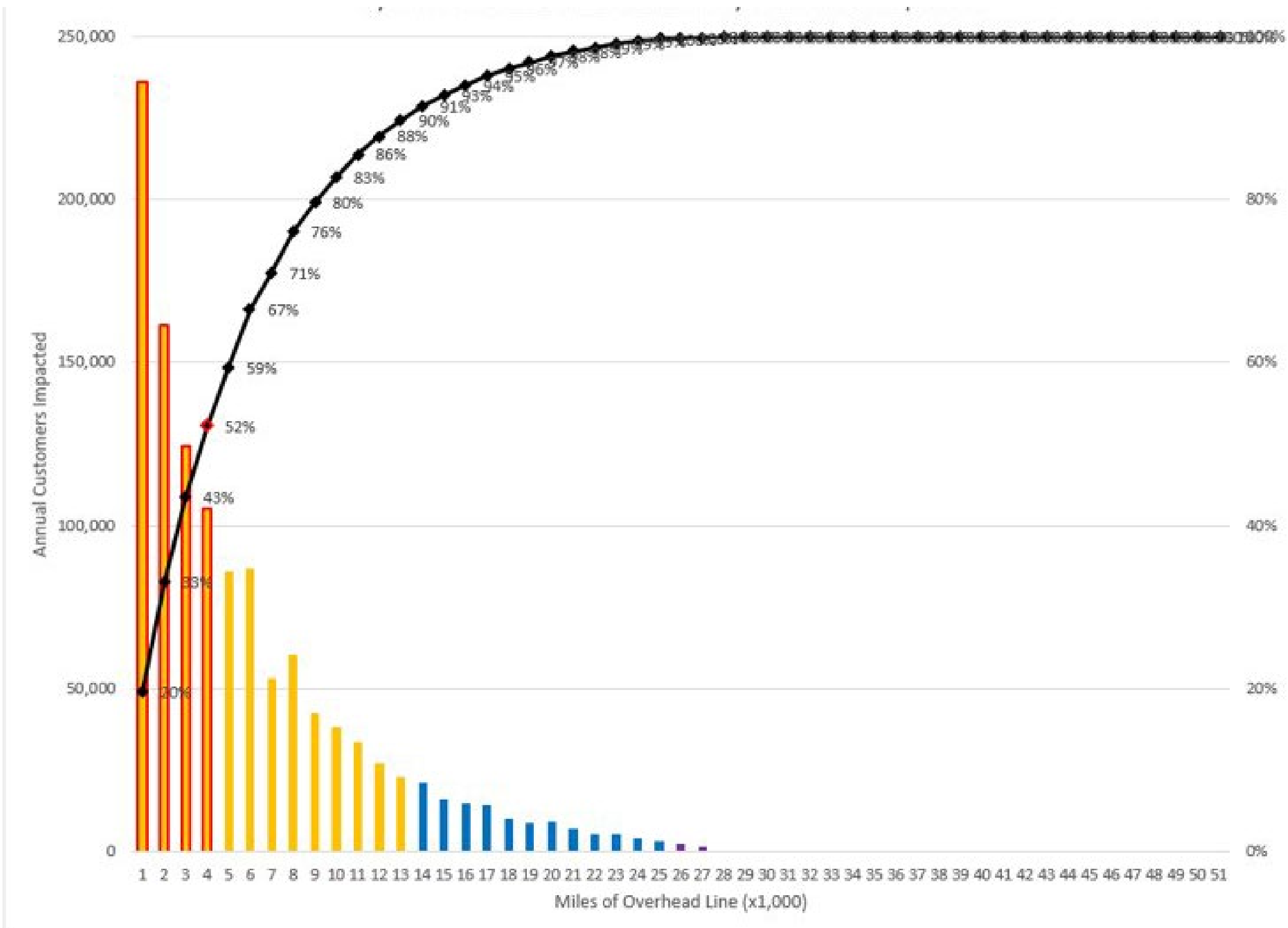
Low Voltage Circuit Health

In assessing LVD lines asset health, the Company has found that 91% of customer interruptions happen on just 25% of system miles, as shown in Figure 48.

Because of this, **the Company focuses on protective zones when assessing asset health and mitigating risk,** rather than on whole circuits. This enables the Company to focus on those parts of the system causing the most interruptions.

Furthermore, by focusing on the zones with the worst health, the Company can improve the reliability of customers downstream from the zone, not just the customers directly in the zone.

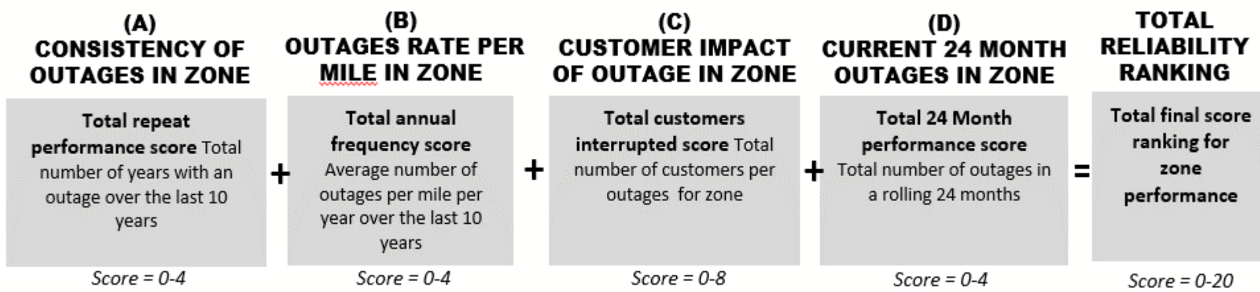
FIGURE 48
SYSTEM OVERHEAD MILES RANKED BY CUSTOMERS IMPACTED
(2012-2021)



When the Company assesses zonal health, it uses a 20-point scale based on inputs from the Reliability Analytics Engine, with four data points driving the score. These are shown in Figure 49 below.

FIGURE 49

ZONAL HEALTH ASSESSMENT SCORING RUBRIC



- Of the Company's approximately 137,000 total zones, approximately 25,000 of those zones currently have a score; the remainder do not have a score, which means they have had no outage activity at all for at least two years.
- In other words, more than four-fifths of zones on the system are working as intended and do not need to be prioritized for any investment at all at this time.
- The Company has found that customer interruptions in a zone begin to increase exponentially once the total zonal health score exceeds 10 and gets particularly severe once it exceeds 15.

Preventing large outages is imperative in delivering the Resilient Grid. Of the approximately 25,000 zones that currently have a zonal health score, just over 6,000 of them have a score of 10 or higher, representing approximately 4.5% of the Company's total LVD system.

When the Company identifies poor-performing zones on LVD circuits, it designs "targeted circuit improvement" project to address one or more zones to resolve the problem.

- Targeted circuit improvements can include replacing equipment at end of life, hardening existing assets, installing new system protection devices like fuses and reclosers, and improving the capability to isolate and transfer load. Taken together, all these actions reduce the probability of an outage.
- Targeted circuit improvements have consistently delivered reliability benefits for the LVD system because these under-performing zones have been strategically selected for rehabilitation.

As shown in Figure 50 below, SAIDI improves substantially following the completion of targeted circuit improvement projects.

FIGURE 50

SAIDI IMPROVEMENT FOLLOWING TARGETED CIRCUIT IMPROVEMENTS

Project Year	Zones Targeted	% Improvement Prior 3 years Post improvement
2017	147	51%
2018	138	57%
2019	151	66%
2020	146	71%
2021	249	62%
Weighted Average Improvement		**64%**

In addition to targeted circuit improvements, the Company also installs ATR loops on the LVD system to automatically restore power to customers when an outage occurs. This is described later in this report in the section on Resiliency Investments.

LVD Zonal Health Investment Plan

The Company plans to address all zones with scores of 10 or greater, since interruptions to customers begin increasing exponentially once the zonal health assessment score exceeds 10 out of 20. This will require targeted zonal improvement projects for each of these zones, and the Company estimates it will cost $2.3 billion over 20 years.

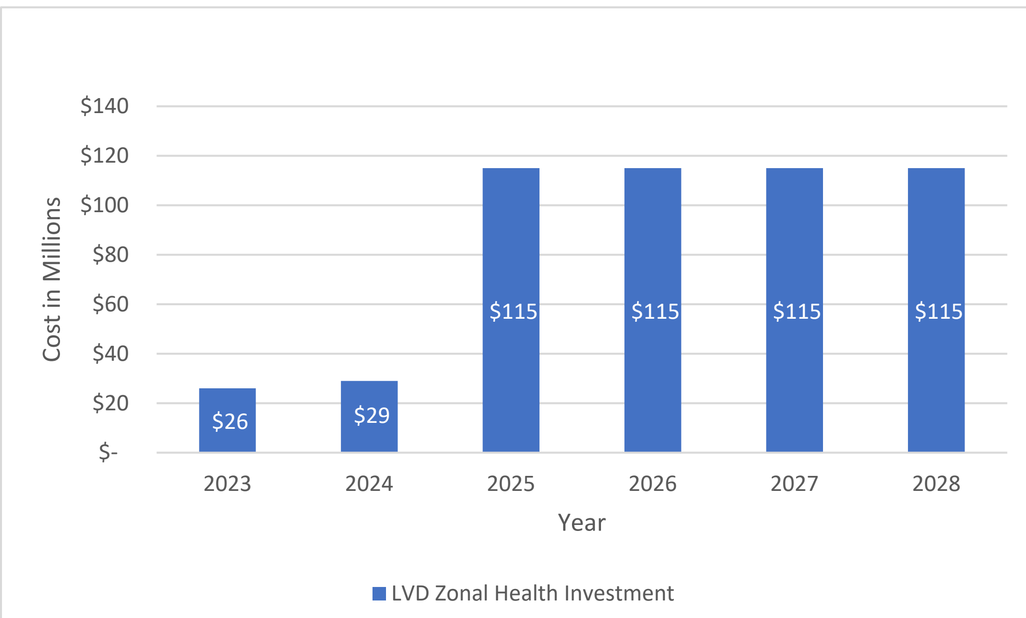
At this investment rate, the Company will be able to resolve approximately 280 zones per year, with the exact number of zones varying based on the complexity of the work for a given year.

The Company will rank zones from worst to best by zonal score and address zones in that order, periodically reprioritizing to ensure that the Company's workplan is continually targeting the worst-performing zones.

The 5-year investment plan for LVD zones is shown below in Figure 51.

Figure 51

LVD Zonal Health 5-Year Investment Plan



Year	LVD Zones Addressed	Fusing Projects	SAIDI Benefit
2023	24	901	0.6
2024	95	1,004	1.3
2025	280	44	7.1
2026	280	0	4.7
2027	280	0	3.4
2028	280	0	4.5

SAIDI benefits from targeted zonal improvements will be the highest in the initial years of the ramp-up in spending beginning in 2025, as the worst zones are addressed first, although projections of SAIDI benefits in future years may be adjusted as zones are reprioritized, as noted above.

LVD Poles

As noted earlier, the average age of an LVD pole is 65 years. Pole failures take roughly twice as long to replace compared to replacing damaged pole top equipment, such as pins or wood crossarms.

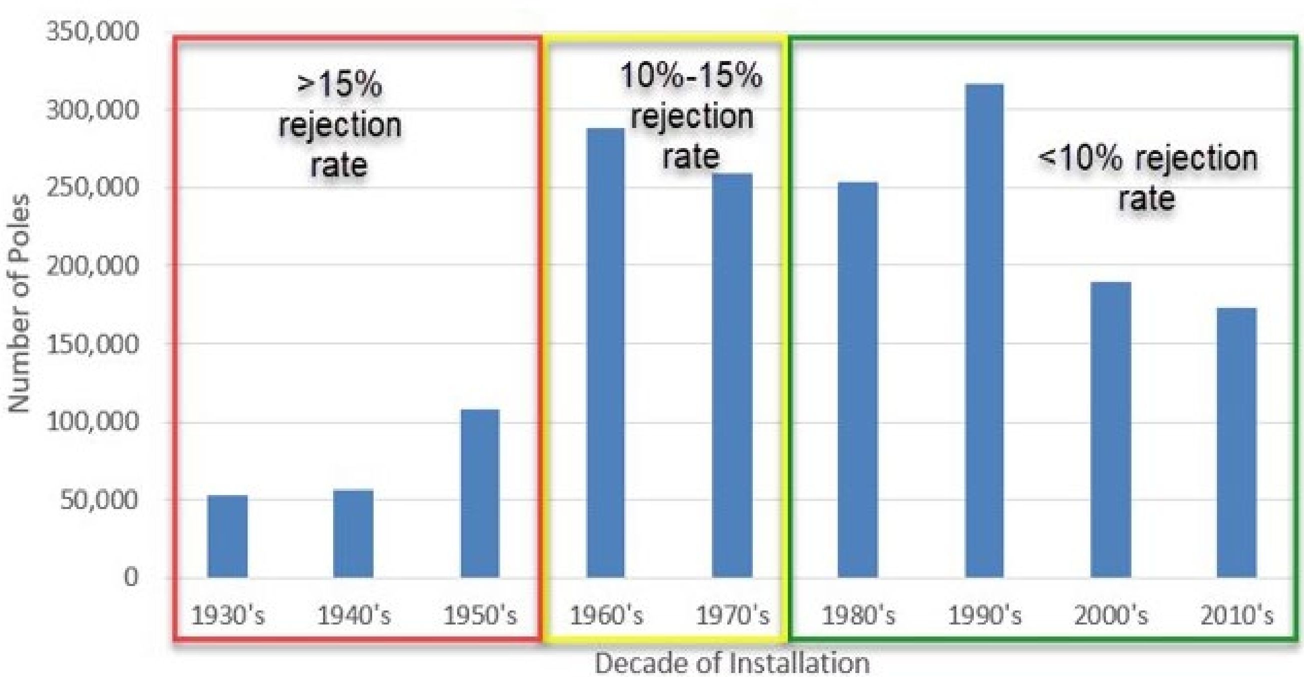
Additionally, underground facilities need to be located by an outside agency prior to digging for safety reasons. These locate requests can take up to three hours in an emergency.

According to *National Electric Safety Code* ("NESC") standards, if a pole deteriorates to below two-thirds of its original install state, it is classified as "rejected" meaning the pole is more vulnerable to failure in car-pole accidents or by high winds, ice, trees, or other external factors.

Figure 52 below shows the number of poles on the LVD system by the decade in which they were installed, with the corresponding rejection rates for each vintage.

Based on this information, the Company estimates that 10% of the system, or approximately 150,000 poles, would be classified as rejected.

FIGURE 52
NUMBER OF LVD POLES BY VINTAGE



The Company is working to reduce risk from poles by performing visual security inspections and replacing the most urgent poles identified from the pole inspection program.

To build a more resilient system while aligning with industry standards, the Company has changed the minimum standard pole classes to provide greater capacity for LVD overhead lines and a more reliable outcome for the future.

- The Company went from Class 6 to a Class 3 for our primary applications from 2010 to 2021, which will increase capacity by nearly 200% as shown in the Figure 53 below.

Figure 53

NESC GRADE C CONSTRUCTION - LVD POLES[8]

No Significant Pole Deterioration as Noted in NESC Table 261-1		
NESC Grade C Construction-LVD		
Pole Size Minimum	No ICE, Wind speed at failure (MPH 3 sec gust)	½ inch ICE, wind speed at failure (MPH 3 sec gust)
Class 5	110 mph	60 mph
Class 4	120 mph	70 mph
Class 3	140 mph	80 mph
Class 2	150 mph	90 mph

The largest impact of this change is when the Company replaces existing poles in the field that failed during storm restoration and were originally sized using smaller pole class minimums, or for new overhead line construction.

Based on the larger number of LVD distribution lines, it is estimated that 2-3% of our overhead LVD distribution system is replaced or newly installed with this new standard each year.

Additionally, poles are regularly replaced as a component of targeted zone improvement projects, plus other programs like Asset Relocations and New Business.

LVD Poles Investment Plan

The Company will identify and replace all rejected poles on a 12-year pole inspection cycle and inspect 125,000 primary and secondary poles each year.

- Using the historical 10% rejection rate, the Company expects approximately 12,500 poles will need replacement each year. The inspections program will cost $10 million annually in maintenance spending.
- Additionally, on a regular 2-year circuit inspection cycle, the Company will identify and replace all poles more than 45 years old to reduce the average pole age, and to align with EPRI standards for average pole age.

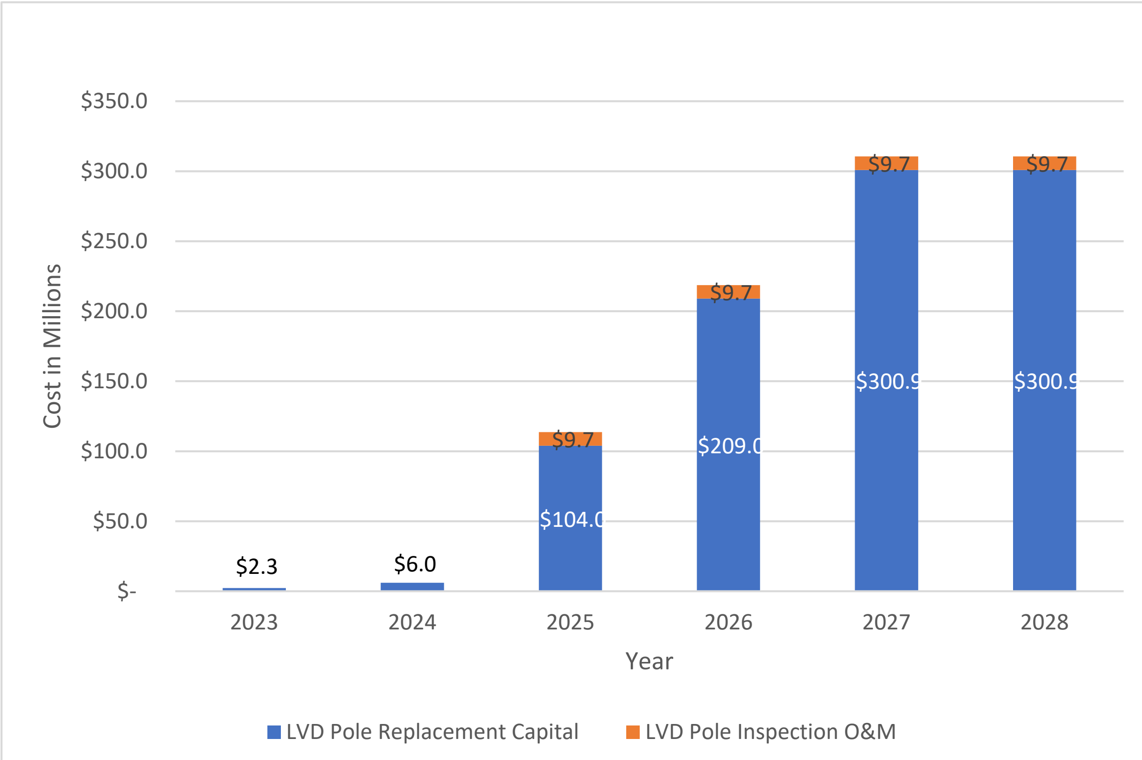
Altogether, this replacement plan will identify and replace approximately 20,000 aged poles annually and will cost approximately $300 million in capital spending per year.

The investment plan for LVD poles is shown below in Figure 54.

[8] Assumptions: 1. Linear analysis (no secondary moments, p-delta). 2. ANSI O5.1 per current NESC edition. 3. NESC Grade C Construction. 4. 1/0 ACSR 3 phase conductor with #4 ACSR Neutral. 5. 350' spans (ahead and back). 6. 45' length poles.

Figure 54

LVD POLES INVESTMENT PLAN



Year	LVD Poles Replaced	SAIDI Benefit
2023	207	--
2024	563	--
2025	7,000	0.15
2026	14,000	0.31
2027	20,000	0.49
2028	20,000	0.49

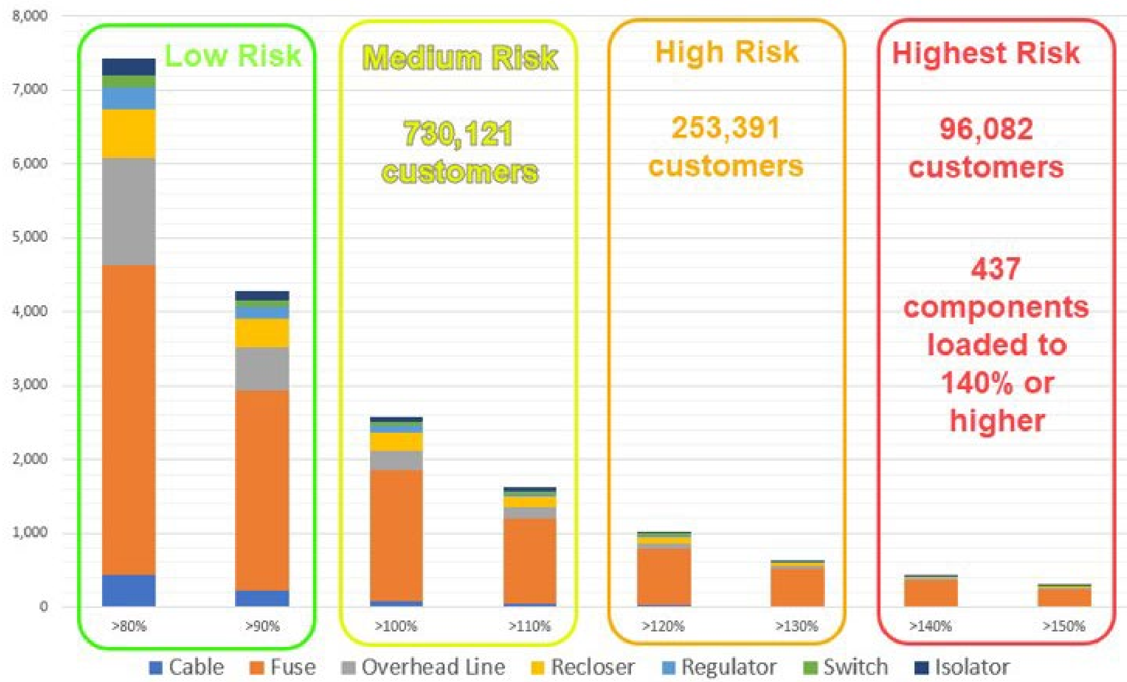
LVD Overload Risk Reduction

The LVD system also faces risks related to components overloading driven by local load growth.

When a component fails due to being overloaded, it results in an unplanned outage. These unplanned outages generally take longer to restore than planned outages, increasing SAIDI. The risks to customers due to component overloads are shown in Figure 55 below.

FIGURE 55

QUANTITY OF COMPONENTS LOADED TO SPECIFIC PERCENTAGES, SUMMER 2022



In general, individual components can withstand loading to greater than 100% of their rating for relatively short periods, such as a few hours on a hot summer day, but if overloaded too long or too frequently, they begin to deteriorate.

Any component has a loading at which it will absolutely fail; these vary by component type, but the Company classifies components at the highest risk if they are projected to exceed 140% loading.

Components in the medium and high-risk categories may be able to continue operating normally for the foreseeable future as long as they are not regularly loaded past the 100%-130% range, as the components are designed to operate with that loading for short periods. However, those components still face risk because a modest increase in load, such as from an increase in EV penetration nearby, could quickly load those assets to 140%.

Of the overload-related risks on the LVD system, **isolators present the highest risk** because they are complex to replace, stock is limited, and outages tend to be for extended durations.

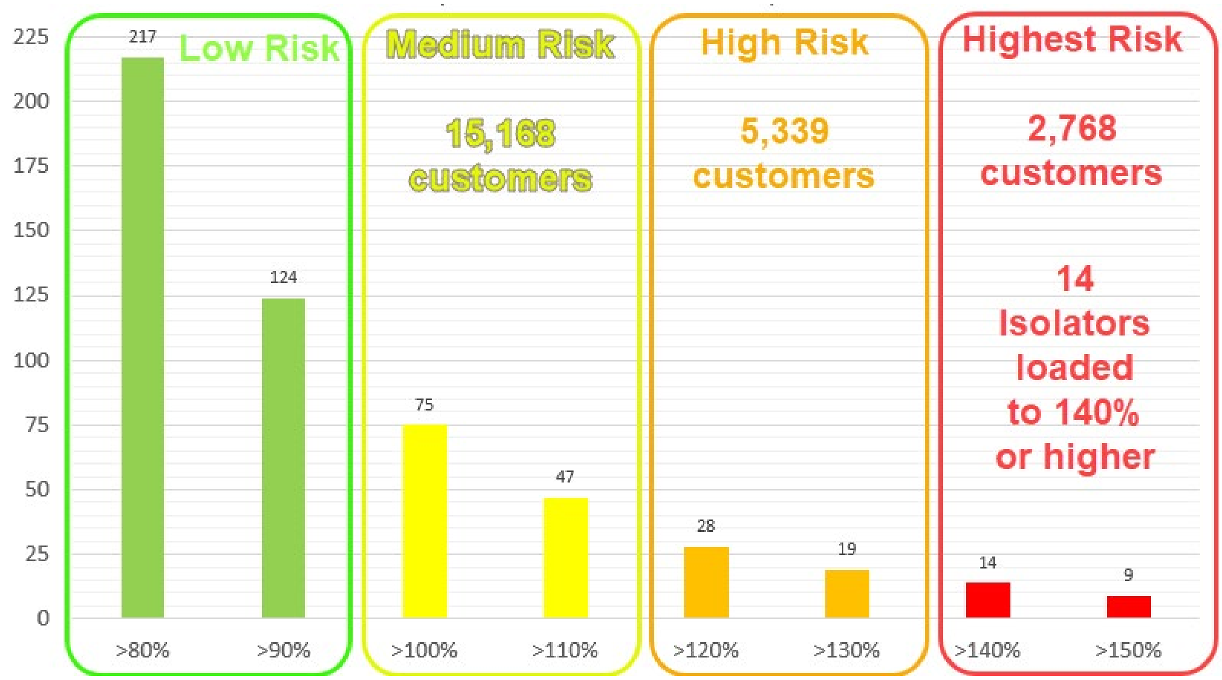
- Isolators are a specific type of transformer used to convert one primary voltage to another primary voltage.
- If an isolator fails due to an overload, it can create an extended duration outage.
- For comparison, a failed fuse can be replaced very quickly by crews throughout the state, which all maintain a sufficient inventory of fuses.

The number of isolators at risk is shown in Figure 56 below.

The Company intends to address overloaded isolators on the grid over the next 10 years to mitigate this risk to customers.

FIGURE 56

QUANTITY OF ISOLATORS LOADED TO SPECIFIC PERCENTAGES, SUMMER 2022



In addition to replacing overloaded isolators, the Company is replacing other overloaded components through its *LVD Lines Capacity Investment* subprogram, prioritizing projects based on the projected overload for the specific component and on a dollar-per-customer impacted basis.

The Company develops project proposals once components get loaded above the levels identified in Figure 57 below.

FIGURE 57

LOADING CRITERIA FOR OVERLOAD RISK REDUCTION

Device	Loading Criteria
Conductor	115%
Fuse	140%
Hydraulic Recloser	140%
Electronic Recloser	150%
Regulator/Booster	140%
Isolator	100%

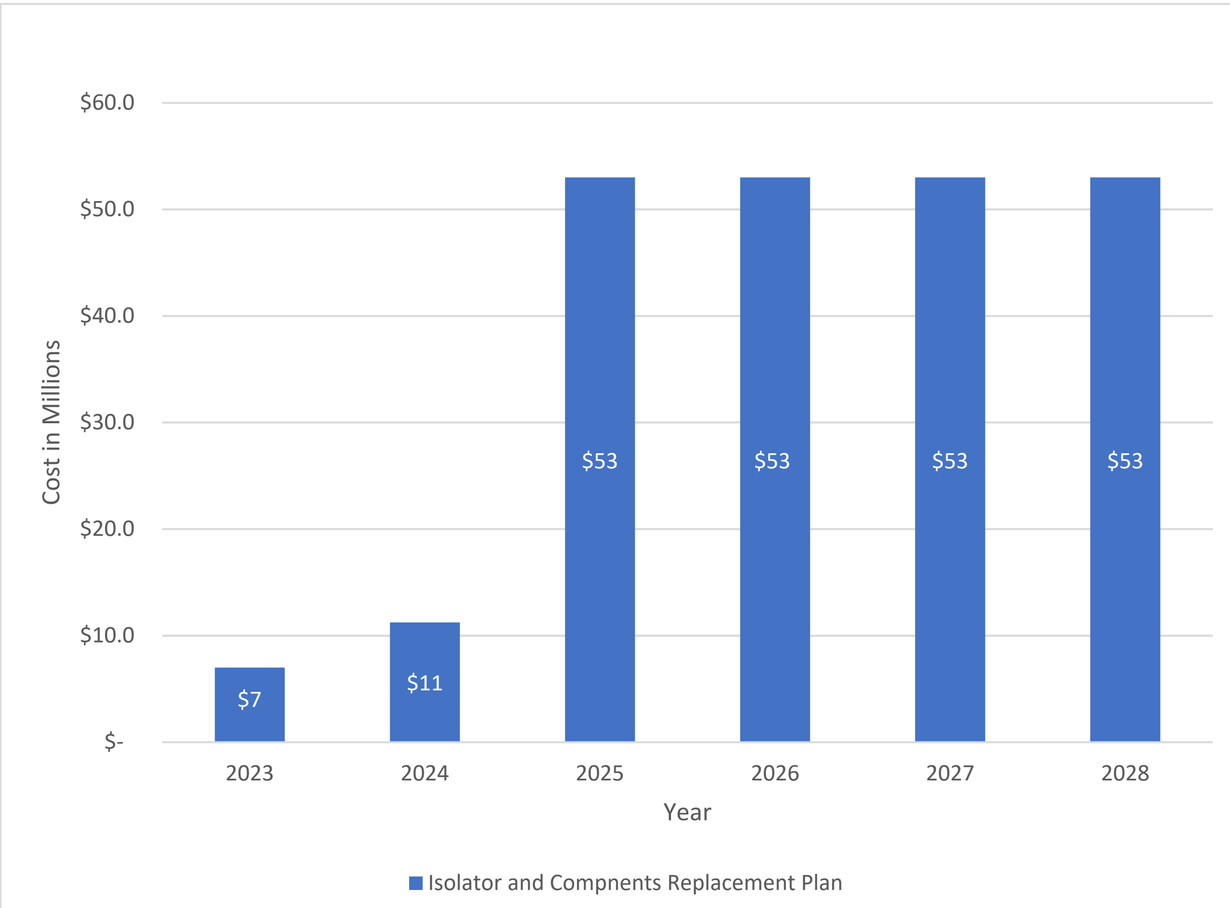
LVD Overload Risk Reduction Investment Plan

The Company will address all the isolators and other components currently loaded at or above the component-specific planning criteria.

This replacement plan will cost $450 million over 10 years. The 5-year investment plan for LVD Overload Risk Reduction is in Figure 58 below.

FIGURE 58

LVD OVERLOAD RISK REDUCTION INVESTMENT PLAN



Year	Isolators Replaced	Components Replaced	SAIDI Benefit
2023	6	25	0.5
2024	8	157	3.8
2025	12	69	2.0
2026	11	68	1.8
2027	10	67	1.6
2028	9	66	1.4

As discussed in the Challenges from Customer Technology Adoption section, load-impacting technology adoption could greatly exceed present levels, depending on consumer behavior, leading the Company to anticipate where customer adoption is most likely.

Specific to EVs, the Company has completed studies to determine where residential EV charging is likely to occur by examining the likelihood of a customer having an EV based on several factors including income level, and customer proximity to another EV. Based on this user profile, the Company predicts the circuits with the highest density of EV adoption over the next 4 years and will continue to re-evaluate further in the coming years.

While historically EV adoption has been in higher income areas, the Company expects to see increasing adoption across all segments, given developments such as the used EV tax credit, the increasing range of EVs and low battery degradation over time, and more EV models coming to market in general.

LVD Vintage Underground Cable

There are unique risks applicable to the underground primary system. While underground cable has historically lasted beyond its expected lifespan, vintage underground cable does present a heightened risk of failure.

- Out of a total of approximately 9,500 miles of underground primary cable, the Company has an estimated 2,500 miles of 15 kV underground cable dating to before the 1980s.
- As this underground cable ages, the insulating material begins to degrade, reducing the remaining service life of the cable. This at-risk cable is also unjacketed, leaving the neutral conductors exposed to accelerated deterioration from direct exposure to external elements, such as soil and moisture.

The Company has recently begun using cable injection to rejuvenate cable, initially rolling this approach out in the Grand Rapids and Flint communities.

Cable Rejuvenation is *the process of taking a cable out of service, performing neutral and air flow testing, injecting a fluid like insulation that solidifies over time, and then putting the cable back into service,* all **at a lower cost than replacing the cable with new**.

- Any cable that fails the testing portion of the process gets replaced with new, jacketed cable.
- Approximately 2,300 miles of the 2,500 miles is smaller cable serving residential subdivisions and small commercial businesses and is eligible for cable rejuvenation.

A third-party contractor performs cable rejuvenation work, and it is most cost-effective to have this contractor complete all work in one area before moving on to other parts of the system. Therefore the Company has targeted the work in only two communities at this point.

The Company plans to continue targeted 15 kV underground cable rejuvenation; prioritization is based on which underground zones have the worst zonal health scores as explained earlier in the LVD Zonal Health Investment Plan section. Additionally, project selection considers feedback from the Company's electric crews who provide insight into repetitive repairs or field conditions.

Cable that is not eligible for cable rejuvenation, whether because of size or insulation properties, requires additional funding for replacement as it also begins to approach end-of-life expectancy. Thus, as insulation properties of underground cables have improved due to advances in technology and manufacturing capabilities, the ineligible cable must be replaced instead of rejuvenated.

In addition to vintage underground cable rejuvenation, **the Company is planning an aggressive program to convert overhead lines to underground** to mitigate the risks from severe weather, and dramatically improve the resiliency of its electric grid. This program and its associated costs and benefits are detailed in the *Resiliency Investments* section of this report.

LVD Vintage Underground Primary Investment Plan

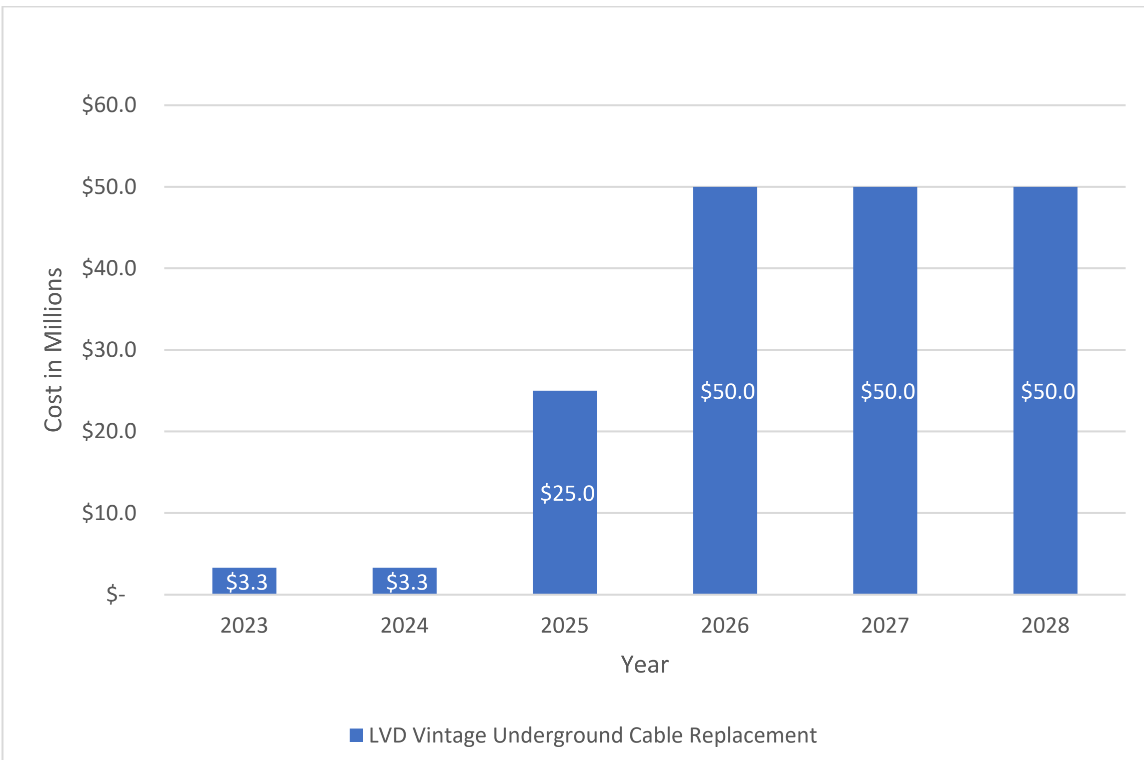
The Company will address all the 15 kV cable installed between the 1960s and 1980s, at a cost of $700 million over 15 years, beginning in 2025.

Once the rejuvenation program is fully scaled to $50 million a year, it is expected to reduce SAIDI by two minutes per year.

The 5-year investment plan for LVD Vintage Underground Primary is shown below in Figure 59.

Figure 59

LVD VINTAGE UNDERGROUND PRIMARY 5-YEAR INVESTMENT PLAN



Year	Miles of Vintage Underground Cable Rejuvenated or Replaced
2023	9
2024	10
2025	83
2026	160
2027	160
2028	160

Resiliency Investments

The increasing frequency of major and extreme interruption events due to severe weather has increased the Company's focus on ways to mitigate major weather events through resiliency investment.

Resiliency is defined as the *ability of the system to withstand a major event—particularly, a large or extreme storm—and the ability of the system to recover from a major event where damage occurs, minimizing the needed restoration and repair time.*

Reliability is defined as the *ability of the system to withstand normal variation and continue serving customers predictably*.

Resiliency and reliability are related.

- While *reliability* focuses on the typical days of the year, when conditions are normal, *resiliency* actions are focused on the much less frequent large or extreme storms. A resilient electric system yields reliable customer service by withstanding these extreme storms.

The following investment categories represent the Company's forward-looking investment in the grid to enable it to better withstand these extreme events, and to facilitate improved restoration times after these types of events occur.

LVD Undergrounding

The radial configuration of the LVD system and the proximity of large parts of the system to trees and other weather impacts necessitates additional investments to harden the LVD system to improve resiliency.

For one component of this, the Company will expand its underground system, strategically converting parts of existing overhead circuits to underground.

- Research conducted by peer utilities, most notably WEC Energy Group, has found that **undergrounding improves circuit performance by 90% or more,** as lines are no longer exposed to trees and other weather impacts.
- The Company estimates that **the cost to customers of undergrounding is comparable** to other means of hardening against trees and other weather impacts, such as by installing aerial spacer cable or tree wire.

To begin, the Company is proposing to convert 10.3 miles of overhead lines to underground in 2024, as detailed in its Electric Rate Case filed in Case No. U-21389.

The Company's rate case proposal includes an option to convert an additional 11 miles in 2024 if approved by the Commission.

- This initial limited amount will provide the Company with valuable information on reliability benefits and costs, while using a limited scope to minimize electric rate impacts for customers.

The selected portions of the LVD system for 2024 meet a specific criterion the Company has set for the Pilot, namely circuits which meet all the following:

- Are single-phase sections of the system
- Have at least one outage in the last 24 months
- Serve between 10 and 100 customers

- Are operated at one of the three standard voltages
- Do not have other project work planned to enhance reliability
- Have a history of long duration outages; are exposed to dense tree cover
- Would have capacity available to account for future load growth

Single-phase sections will have a lower conversion cost. Lines with at least one outage in the last 24 months were selected to provide more immediate benefit.

Limiting the customers served by the zone to between 10 and 100 ensures the project provides benefits to more than a few customers, while limiting the impact of any future outage on the underground facilities.

Underground conversion of only the three standard voltages ensures that additional costs are neither initially incurred on the additional equipment to accommodate delta configurations nor the conversion cost to a standard voltage later.

Similarly, selecting zones that are not considered for another reliability project avoids duplication of efforts. Underground conversion is considered an alternative when reliability projects are developed for targeted circuit improvement work.

Lines with historically high restoration times were selected to improve customer experience. Underground conversions in areas with dense trees provides the maximum benefit of the undergrounding and will minimize future forestry clearing costs.

Actual costs and lessons learned from undergrounding efforts in 2024 will be used to inform undergrounding projects and determine scalability.

- Assuming this undergrounding is scalable, the Company will ramp up to undergrounding work significantly to 400 miles of line, annually.
- Roughly 3,200 miles of the LVD system is a candidate for strategic, targeted undergrounding based on the criteria above, which demonstrates a significant opportunity to invest in the resiliency of the Company's distribution network.
- In identifying circuits for undergrounding both in 2024 and in future years, the Company is considering whether circuits serve EJ communities, given that these communities are more vulnerable in the event they experience a long outage following a catastrophic storm.

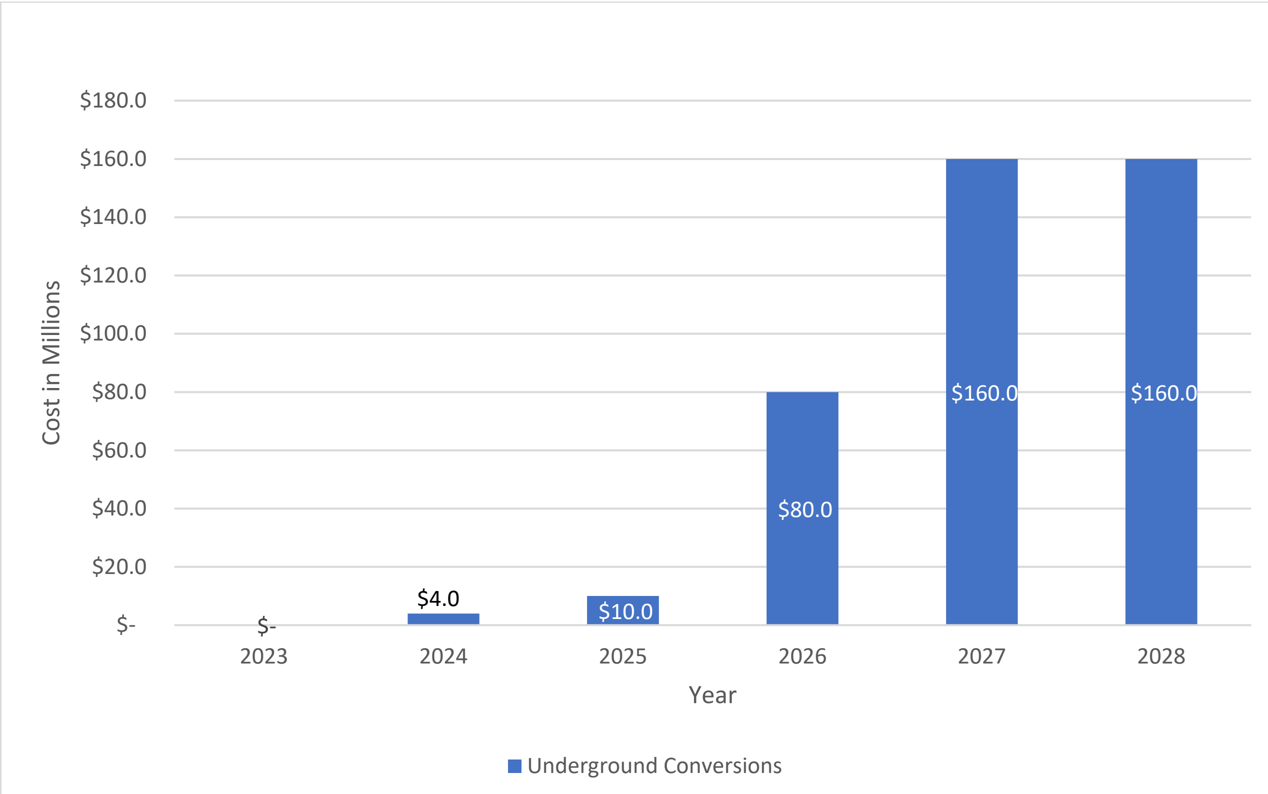
The Company will continue to seek out laterals on circuits serving census tracts with MiEJScreen scores over 80, as well as circuits serving federally defined EJ40 communities.

The projected cost for this work is identified below in Figure 60, with the ramp up beginning in 2024, and full annual capacity of the undergrounding work beginning in 2027. With only 12% of lines currently undergrounded, the Company has a much larger exposure to the elements than its regional and Michigan peers, who average 25% of their systems undergrounded.

Expanded, strategic underground conversion of more of the Company's system is imperative to bring the Company's system in line with its peers and thereby improve reliability and resiliency for customers.

Figure 60

UNDERGROUND CONVERSIONS 5-YEAR INVESTMENT PLAN



Year	Underground Conversion Miles
2023	0
2024	10
2025	25
2026	200
2027	400
2028	400

Fractionalization

On average the Company's LVD circuits are 30 miles with an average of 1,045 customers. Circuits with mileage exceeding the average exposes our customers to a much higher risk of weather-related outages.

Fractionalization, described earlier in the Five Fundamentals Approach, is another approach used by the Company to improve resiliency on the LVD system and involves **segmenting existing LVD circuits into smaller sections with fewer customers.**

- At present, this work takes place in substations, adding new transformer banks and circuit exits so that more circuits with fewer customers can be served from that substation. **This reduces the number of customers affected when there is an outage on a given circuit.**
- Fractionalization also provides more opportunities for load switching if an outage occurs, allowing for improved fault isolation and faster restoration of customers.

- Additionally, fractionalization results in fewer line miles for line workers to patrol and repair, further reducing outage times.

Projects proposed for 2024 are projected to save 0.3 SAIDI minutes.

In the near term, the Company is focusing fractionalization on circuits in the top 3% of customer count, and overhead line exposure; circuits in this top 3% serve more than 2,400 customers or have more than 90 miles of overhead lines as shown below in Figure 61, with the 5-year investment plans shown in Figure 62.

Figure 61

CIRCUITS RANKED BY CUSTOMER COUNT

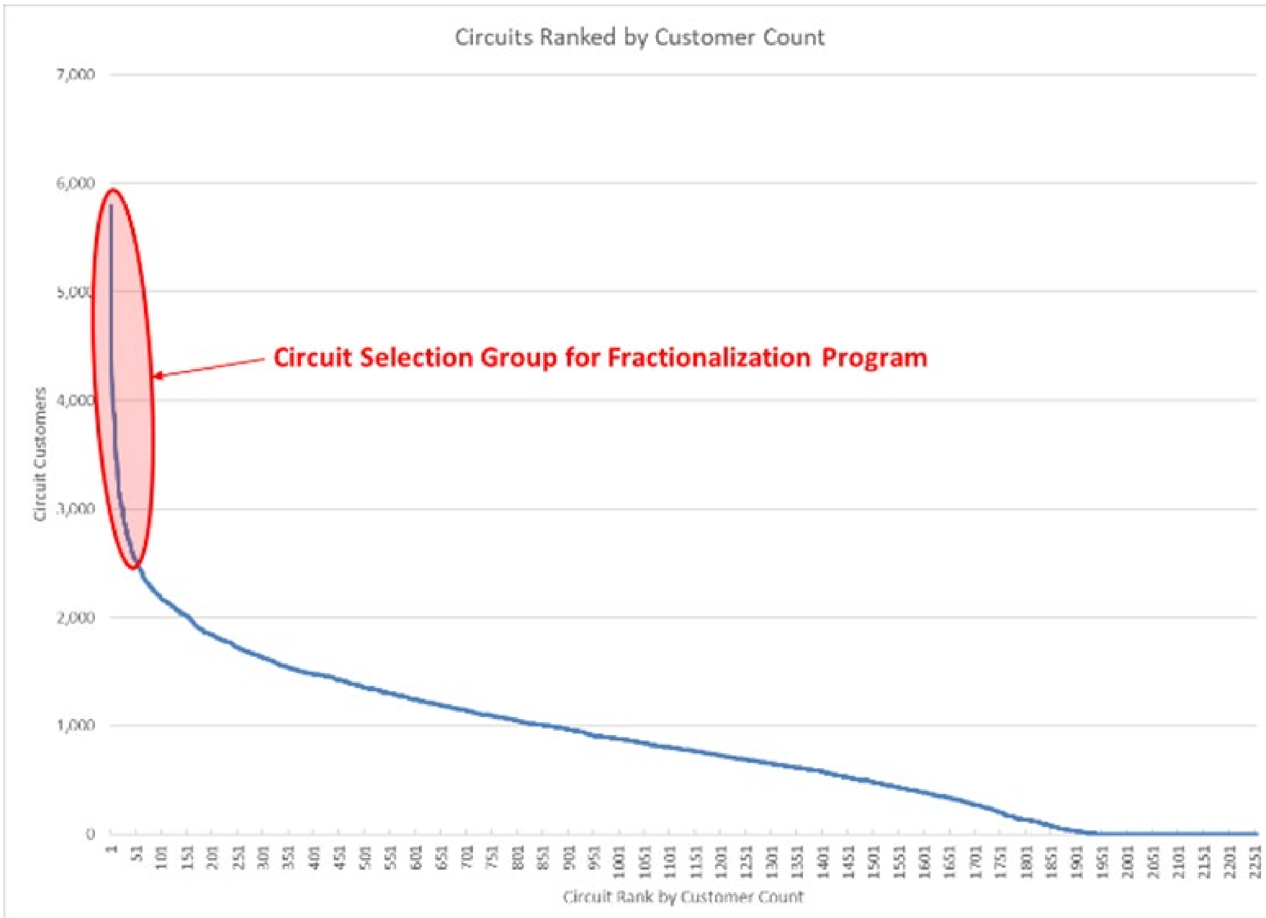
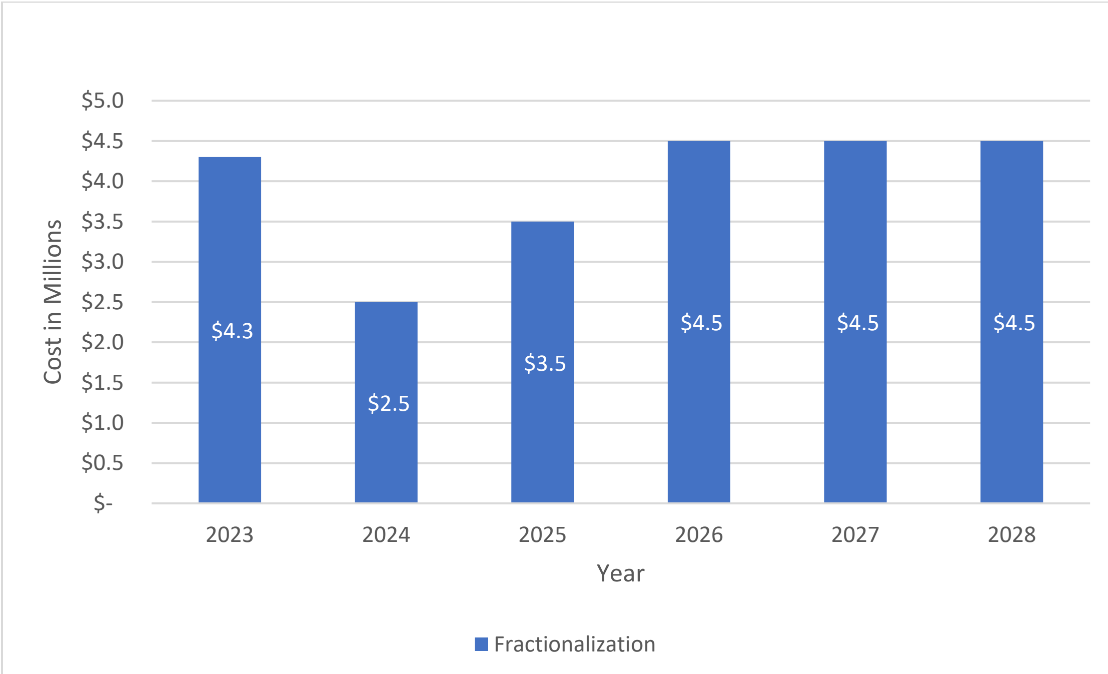


Figure 62

FRACTIONALIZATION 5-YEAR INVESTMENT PLAN



Year	Circuits Fractionalized
2023	2
2024	5
2025	7
2026	10
2027	10
2028	9

Automatic Transfer Recloser (ATR) Loops

ATR loops have been an integral part of the Company's resiliency plan over the last decade.

Deploying ATR devices on adjacent LVD circuits enables **automatic transfer of customers if an outage occurs. This reduces customer outages and improves system reliability** by isolating a faulted section of a circuit.

- As of August 2023, there are 147 loops in service throughout the state.
- In 2022 alone, there were 97 instances in which an ATR loop operated, avoiding 18.2 million customer outage minutes, and preventing over 63,000 customers from experiencing an outage.
- Over the next five years, the Company plans to deploy between 25-35 additional loops annually to enhance automation on the grid and increase reliability savings.

As the ATR loop deployment matures, the Company is employing new, complex planning techniques to maximize benefits.

Currently, the Company is using "load limited" and "mutually exclusive" loops to enable ATRs, and to get the most out of the distribution system's capacity to avoid costly equipment upgrades, while still achieving significant automation benefit.

Previously, the Company may have ruled out an ATR solution for circuits where peak load conditions would exceed the equipment's thermal or loading ratings.

- Using ADMS, the Company can create real-time alerts that inform system operators when a circuit is approaching its peak load. Loops on these types of circuits are called "load limited."

Similarly, the Company has expanded the ATR loop selection criteria to include circuits fed from the same substation as an existing loop.

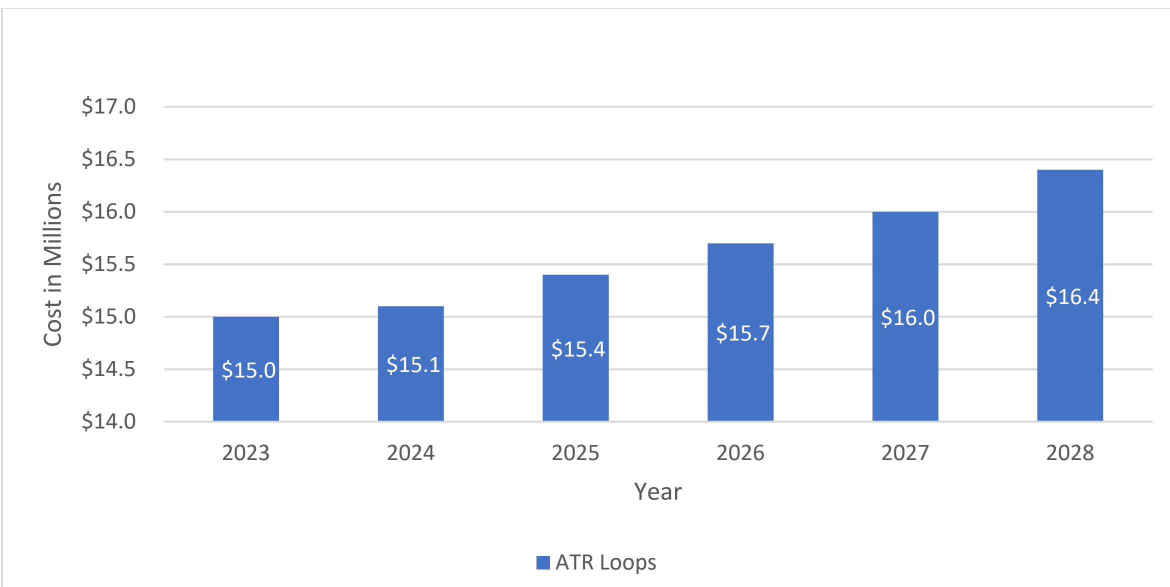
- To avoid overloading a substation transformer, alerts have been set up to notify operators when one of these mutual-substation loops has operated. These alerts trigger a newly established process for the operator to remotely disable loop scheme capability. Loops on these circuits are called "mutually exclusive."

These "load limited" and "mutually exclusive" loops allow for more circuits to be considered in the selection process, and as a result the Company can increase the achievable benefits from this investment category.

The ATR loops 5-year investment plan is shown below in Figure 63.

Figure 63

ATR LOOPS 5-YEAR INVESTMENT PLAN



Year	ATR Loops Installed Plan
2023	30
2024	30
2025	30
2026	30
2027	30
2028	30

Forestry Line Clearing Program

Trees are one of the greatest causes of interruptions to electric service to customers on the LVD system, contributing 44% of all-weather outages and 38% of all non-MED outages.

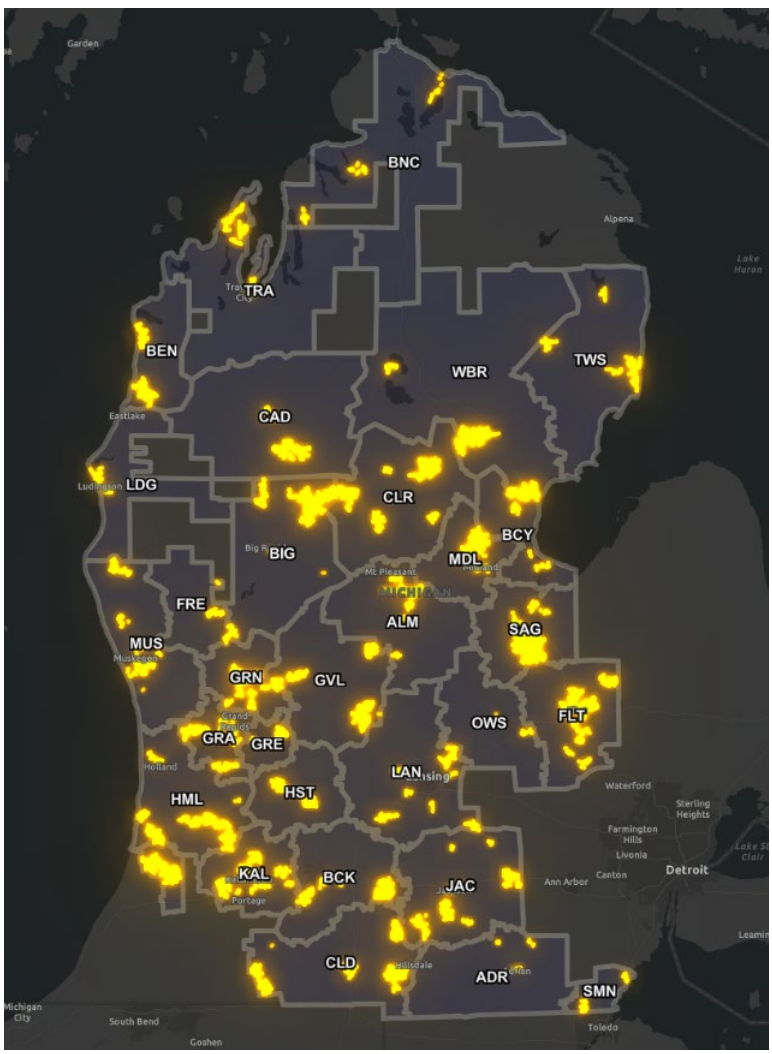
The Forestry *Line Clearing Program* manages vegetation (trees, bushes, vines, etc.) along its primary voltage systems and its secondary voltage systems, including service conductors.

The Company clears vegetation within a 30-foot-wide right-of-way (“ROW”) for primary voltages to attain a minimum of 10 feet of separation between conductors and vegetation at the time of clearing. This is to maintain accessibility along the ROW for maintenance and repair of the line.

- The largest subprogram within the *Line Clearing Program* targets **full circuit clearing,** where advanced analytics identify work locations throughout the service territory on a full-circuit level.
- This portion of work, encompassing several thousand miles of LVD primary wires, is shown in the 2023 workplan snapshot in Figure 64 below, in which the geographic locations of circuits to be cleared are highlighted in yellow.

Figure 64

2023 LVD FULL CIRCUIT CLEARING WORKPLAN



The Company's *Line Clearing Program* also provides benefits not easily quantified, such as **improved habitat for many plants and animals (including threatened and endangered species) and decreased risk of wildfires from tree contacts with conductors.**

Enhancing the Company's Line Clearing Program will result in less aesthetic impacts to customer properties and will improve public safety.

Reliability Benefits of the Forestry Line Clearing Program

Line clearing reduces the occurrence of tree-conductor interference, which can cause customer outages. The prevention of outage incidents results in a better customer experience through reduced tree caused SAIDI and SAIFI.

A full understanding of projected reliability impact of line clearing on each individual circuit paired with a cost estimation to perform that work results in the ability to maximize the overall return on investment of the Forestry Line Clearing spend.

Following completion of line clearing, the average LVD circuit reliability improves by:

- Approximately 300 fewer customers experiencing more than 3 outages in the year after tree clearing.
- Approximately 125 fewer customers experiencing outages lasting longer than 24 hours in the year after tree clearing.
- Approximately 225 fewer customer outages during catastrophic storm events within the year after tree clearing.

Forestry Workplan Intelligence & Strategy Engine ("WISE")

The Company is expanding its use of data-driven strategies to modernize its existing linear regression Forestry model to influence and guide its LVD full circuit clearing.

- This model is built into a web-based tool, called Forestry WISE, to allow for a consistent, stable, and sustainable methodology to optimize the yearly LVD full circuit clearing workplan, and to capture the most reliability and safety benefit for annual spend.
- Among the most impactful advancements in model maturity are integrating new data such as historical weather data, detailed circuit attributes, tree canopy cover data derived from *National Agriculture Imagery Program* ("NAIP") satellite imagery, and pole attributes.

These, coupled with increased analytic capabilities, **provide a more robust predictive outage model to inform the annual LVD full circuit clearing workplan,** thus allowing the Company to target its line clearing work where it will be the most impactful.

Figure 65 illustrates the improvement in tree-related incidents prediction that resulted from the development of a new *Forestry Line Clearing* model.

- Each graph shows the comparison of actual tree incidents on the X-axis to predicted tree incidents on the Y-axis, with the solid diagonal line representing a perfectly predicted future.
- Each dot represents a LVD circuit. The improved prediction model has an accuracy that is more than 2.5x that of its predecessor.
- The more accurately the future can be predicted, the better the Company can plan and mitigate risks before they lead to an outage for customers.

Figure 65

FORESTRY LINE CLEARING MODEL IMPROVEMENT IN CIRCUIT PREDICTIONS

After careful consideration, the Company decided on an internal approach to technology-based enhancement of the work selection process through the development of the Forestry WISE tool.

An internal build of a digital product helps to ensure the tool is flexible in the event of change; for example, the tool currently analyzes and chooses work on a circuit-level, but the Company is pursuing additional opportunities to gain a higher level of granularity through a proposed "Phase 2" of Forestry WISE.

This opportunity to take a more surgical approach to line clearing is especially impactful in areas of poorly performing circuit segments within an otherwise well-performing circuit. Not only does tool this **aid in selecting locations for line clearing,** but also provides higher-level data granularity, reliability prediction, and analytic tool integration fuels intra-circuit strategy.

- For example, it can take several months for line clearing crews to clear a long circuit of trees, and it is in the best interest of both customers and the Company to first position crews at the worst performing sections of that circuit and prioritize those areas accordingly over the next several months of clearing.
- This strategy prevents more outages within the timeframe of clearing than otherwise clearing the circuit from one end to the other.

Another **core component of Forestry WISE is analysis of historical reliability data** to understand the individuality of each circuit and its previous and current reaction to line clearing from a reliability perspective.

In general, the Company assumes an improvement in reliability when a circuit is fully cleared.

- The Company has developed a prescriptive line clearing impact analysis, with a focus on reliability metrics of SAIDI, SAIFI, and tree-caused incidents to analyze each circuit's individual reliability history. This helps to provide an estimation of how line clearing affects circuit reliability performance.
- This analysis also leverages machine learning techniques to transform data into meaningful insights that are then directly fed into the Forestry WISE tool and line clearing strategy.

It is important to have these insights into circuit uniqueness because differences in environment, construction, voltage, and other characteristics can determine the return on investment of line clearing for each circuit.

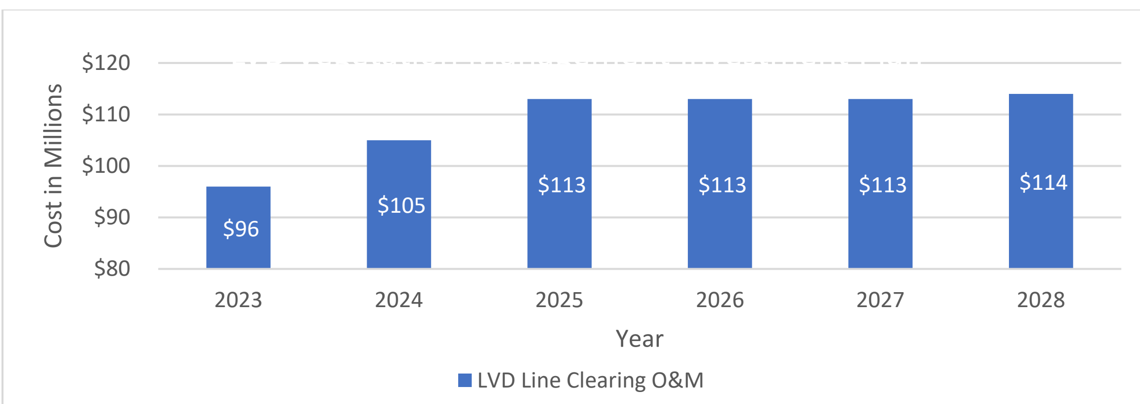
The Company continues to perform an in-house review of the line clearing process with the Company's Operations Performance group and Transformation departments to determine if any additional changes are needed to improve data analytics and performance.

As the Company has been defining in its electric rate cases since 2020, and in the 2021 EDIIP, the Company is continuing to scale up O&M spending to achieve and maintain a 7-year effective clearing cycle for its LVD system, with year-over-year funding increases through 2025. Once the necessary level of investment is achieved, the Company expects to maintain that level of funding.

In 2022, the Company conducted a pilot to remove canopy more aggressively over 42 miles of 3-phase LVD, beyond the current clearing specifications. Experimental circuits and control circuits that experience the same weather patterns were selected for comparative analysis. The Company will continue to evaluate outage performance on these line segments to better inform the next maturation of its line clearing program once the program is on cycle.

Figure 66

LVD LINE CLEARING PLAN



Year	LVD Line Miles Cleared
2023	5,875
2024	6,760
2025	7,232
2026	7,449
2027	7,672
2028	7,932

Service Restoration

The Company's Service Restoration program prepares for and executes work related to public emergencies and restoration activities for all outage categories, including MEDs[9] and Catastrophic Events[10].

This work includes addressing hazards such as broken poles, wire downs, and emergency orders. In addition to the workplan projections, this program includes the non-capital portion of standby costs and on-call costs for resources, such as travel, lodging, and food costs for storm responders.

Current Service Restoration Capabilities

In normal operations, the Company makes available approximately 140 crews and 60 electric service workers ("ESWs"), which can vary based on vacations, sick leave, and training. This enables the Company to respond effectively to approximately 420 incidents or 20,000 customer outages in a 24-hour period before additional resources are required.

When severe weather or a storm creates incidents beyond the Company's standard capabilities, the Company may need additional crewing and will reach out to off-system crews to supplement the Company's resources.

- Off-system crews are primarily obtained as necessary from other utilities, municipalities, and contractors, and are deployed when all Company resources are engaged.

The Company uses an Incident Command System ("ICS") to address emergency situations, and storm response is always addressed through an ICS.

Within the Company's ICS, crew-to-dispatcher ratio is maintained at no greater than 15 to 20 points of contact with field personnel. To control the number of points of contact, field leaders obtain work from dispatchers and issue work assignments to five to seven crews, allowing for a greater span of control and efficiency with field personnel.

The Company uses an outage prediction model to analyze current weather patterns, past outage history, and machine learning to determine the approximate number of customers and geographic locations that may be potentially impacted. In some cases, the Company may pre-stage resources in locations where severe storm impacts are expected, meaning those resources can be ready to respond as soon as possible after outages occur.

The Company currently operates four separate control centers, located in three separate facilities in Jackson and Grand Rapids as shown below in Figure 67.

These centers operate 24 hours a day, 7 days a week, with the following general areas of responsibility:

- **The System Control Center**, in Jackson, controls HVD lines and HVD substations.
- **The Distribution Control Center**, in Grand Rapids, controls LVD substations.

[9] IEEE Standard 1366-2012 defines the methodology for calculating a MED. It is based on a statistical analysis of five sequential years of daily SAIDI values. In 2021, Consumers Energy adopted a refined methodology that transitions from a calendar day evaluation period to a rolling 24-hour evaluation period. This methodology better captures MEDs that straddle consecutive calendar days.

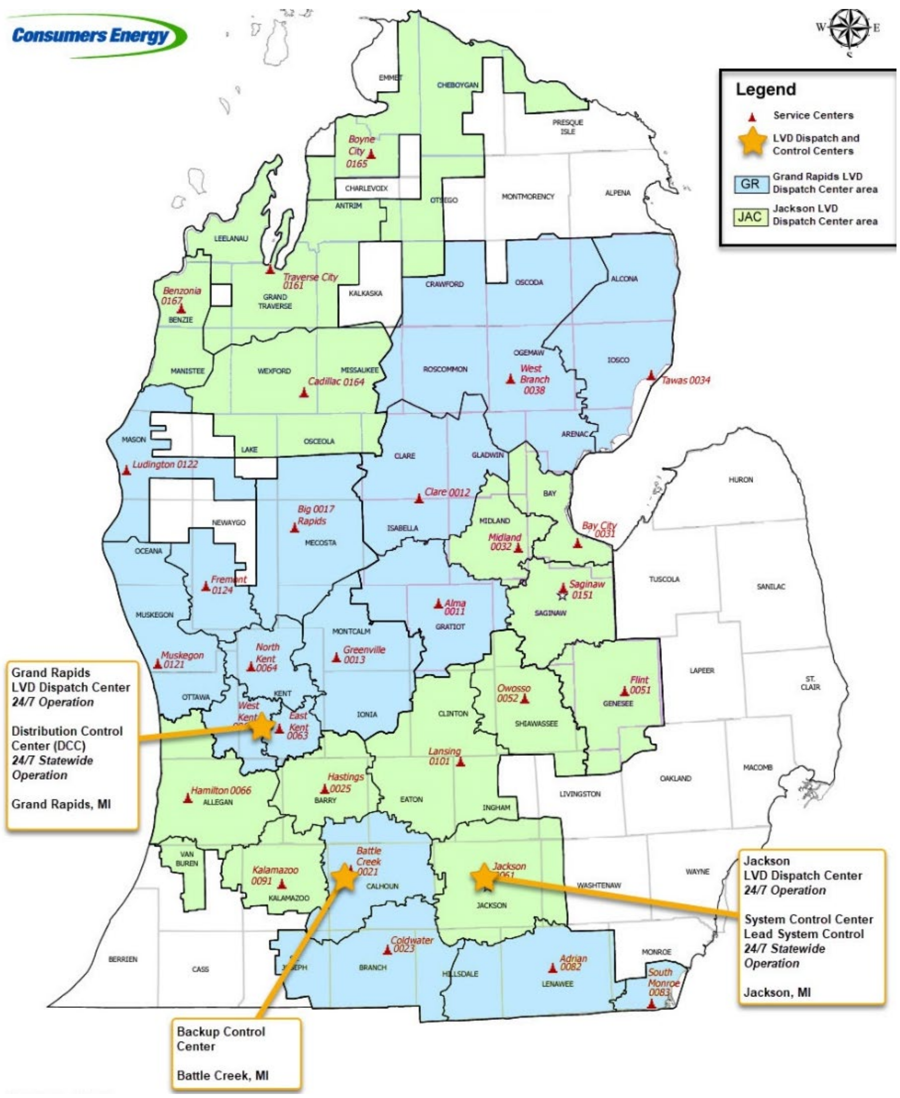
[10] Catastrophic Events is defined in the Public Service Commission *Service Quality and Reliability Standards for Electric Distribution Systems* R 460.702(c).

- Two **LVD Dispatch Centers**, one each in Jackson and Grand Rapids, controls LVD overhead and underground lines.

Staffing in these control centers is increased as required during storm restoration. Storm support is operated from all four centers, depending on the severity and impact to the system, with statewide ICS operations managed from the Emergency Operations Center, also in Jackson.

Figure 67

SYSTEM CONTROL, DISTRIBUTION CONTROL AND LOW VOLTAGE DISTRIBUTION DISPATCH CENTERS



Gray Sky and Catastrophic Service Restoration

High impact Gray Sky days, (conditions that result in sustained interruptions between 1% and 10% of a utility's customers) and catastrophic restoration events (conditions that affect more than 10% of the customer base) provide the greatest challenge and opportunity for the Company to improve Service Restoration performance.

The investments outlined in this plan will result in fewer outage events; the Company will realize savings from having to restore fewer outages, but those savings will be more than offset by the cost to add incremental Service Restoration resources to meet the improved restoration times required in the *Service Quality and Reliability Standards for Electric Distribution Systems* that were published in March of this year.

To illustrate this point, in August 2023, the Company acquired a record level of Electric Line Crews to restore customers following a catastrophic storm.

- The peak line crew staffing reached a total of more than 660 crews, counting both Company crews and contractors.
- Even with this high level of crewing, the Company did not reach 90% of impacted customers restored until 87 hours had elapsed, short of the MPSC Performance Standard to restore 90% of customers within 48 hours.

The Company's service restoration planning begins several days prior to an actual event. Our team of meteorologists develop forecasts that are incorporated into an outage prediction model.

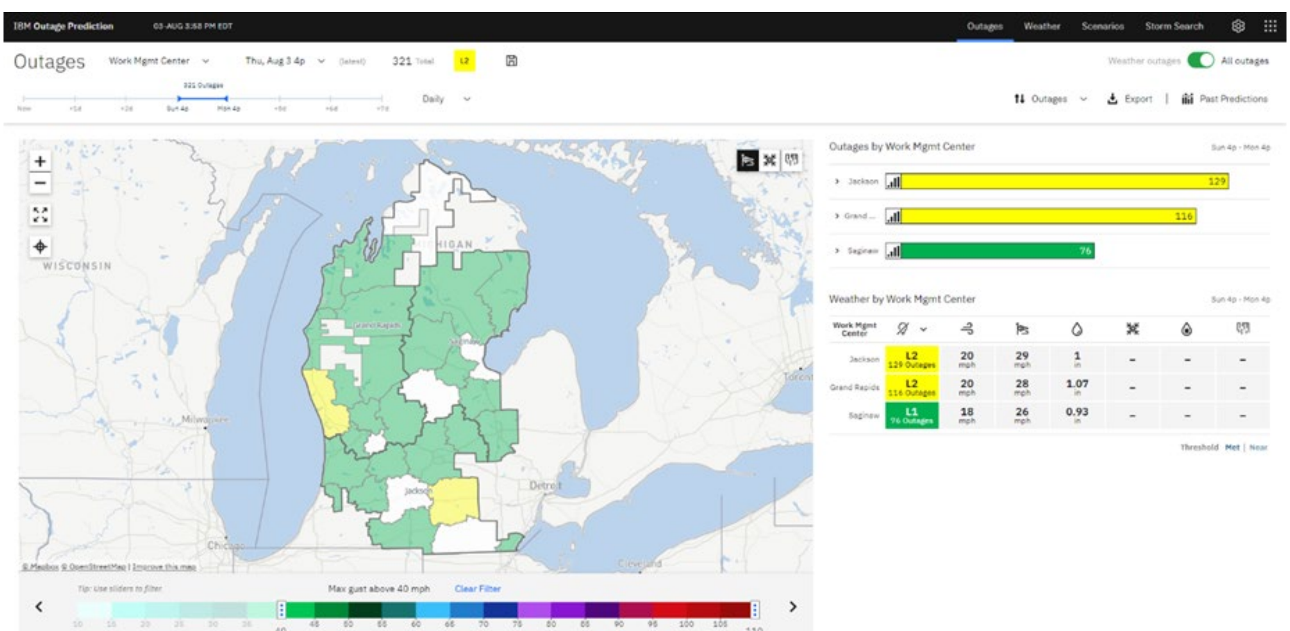
Figure 68 is a snapshot of our prediction model. The boundaries of our service centers are outlined within the State. The model is run every hour each day. Service areas with elevated outage forecasts are visibly displayed.

In the example below, our Restoration Management team used the model to ensure sufficient resource availability to respond to elevated outages in our Grand Rapids and Jackson Work Management Centers.

Written weather forecasts are received every 12 hours; 365 days a year to inform our prediction model. This ongoing planning cycle ensures we have restoration plans in place to meet or exceed acceptable levels of restoration performance.

Figure 68

OUTAGE PREDICTION MODEL



Workplan

In addition to meeting performance levels for customers set by the Commission[11], **the end goal for Service Restoration is a minimum frequency and quantity of outages,** as well as reduced response time for resources, optimal operational efficiencies between control centers, and maximum on-the-job time for field resources.

As described earlier in *Non-Load Challenges* from the Challenges from Customer Technology Adoption section, the electric grid is expected to become much more complicated with DERs coming online at the distribution level of the grid.

This increase in DERs will aid with the transition to a two-way power flow with more renewable generation; however, managing this shift in grid operations requires optimized communication with those employees who operate the electric grid.

To achieve both internal and MPSC defined goals, the Company will consolidate the Distribution Control, LVD Dispatch, and System Control centers into a single operating center called the Unified Control Center ("UCC").

This consolidation is key for implementing grid operation improvements under all conditions including:

- Improving communications with the co-location of Grid Operators.
- Adopting an optimized demarcation of responsibilities among the groups managing the grid.
- Increasing the authority of field resources to manage outage incidents.

The cost savings will be attained by:

- Balancing storm and non-storm resources and workload to be able to run 70% of storms without activating ICS.
- Improving processing efficiencies of outage incidents by using automation, and leveraging data provided by Line Sensors, ADMS, and other Supervisory Control and Data Acquisition ("SCADA") devices.
- Reduction of overtime for field and office resources

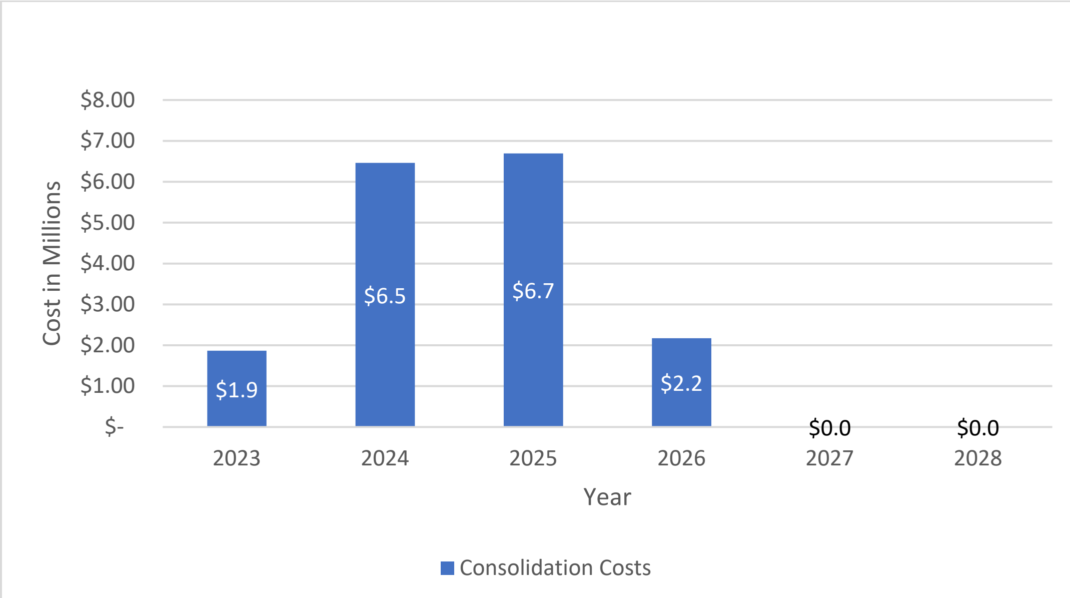
The Company's consolidation of the Distribution Control, LVD Dispatch, and System Control centers into the UCC will cost $17.2 million over four years.

Total savings are projected to be $8.6 million annually resulting in a two-year payback with net positive cost savings in 2027. The total UCC investment plan is below.

[11] Unacceptable levels of performance are defined in the Public Service Commission *Service Quality and Reliability Standards for Electric Distribution Systems* PART 2.

Figure 69

UNIFIED CONTROL CENTER INVESTMENT PLAN



In concert with UCC, investments in technology, analytics, and grid modernization are key enablers for our Restoration Management team to meet service restoration expectations.

The Company has **recently launched a Wire Down App that aims to improve data collection and Wire Guard effectiveness**. Improvements in the Wire Down program were put in place in 2023, allowing a greater response to downed wires. These enablers will drive efficiencies in our restoration process and allow our team to restore customers faster with less external support.

LVD Transformers

What Transformers Do

Distribution transformers convert voltage levels to enable customers to use standard equipment in their household or business.

- *Isolators*, a specific type of transformer used to convert one primary voltage to another primary voltage.
- *Regulators* are a special transformer that help ensure the primary voltage remains in a desired range to ensure reliable end of line voltage for customers.

In all, distribution transformers provide safe and reliable service to new and existing customers at an acceptable, reliable voltage. **The correct transformer, sized to meet the customer's usage, is key to providing a reliable service experience.**

Number of Transformers in Service Territory

There are roughly 600,000 padmount and pole mount transformers units active.

Lifecycle Analysis

The overall average lifespan of a distribution transformer as quoted by transformer manufacturers is approximately 25 years.

However, a typical transformer can exceed the manufacturer's lifespan, depending on different factors. The load and environment have the largest contribution on the health of a transformer and it's common to see transformers exceed 30 or 40 years of life.

The average transformer in the Company's service territory is 47 years old.

Transformer Asset Health and Risks

Monitor for High Load

Transformers are Company assets that will be directly impacted by increased electrification of consumer appliances and transit.

The Company is anticipating the need to upgrade transformers more frequently due to the increasing loads with EV chargers, heat pumps, and other home electrification efforts.

In short, as customers begin using more electricity, the Company will have to replace more transformers more frequently to provide service for the new customer load.

Supply Chain Risk

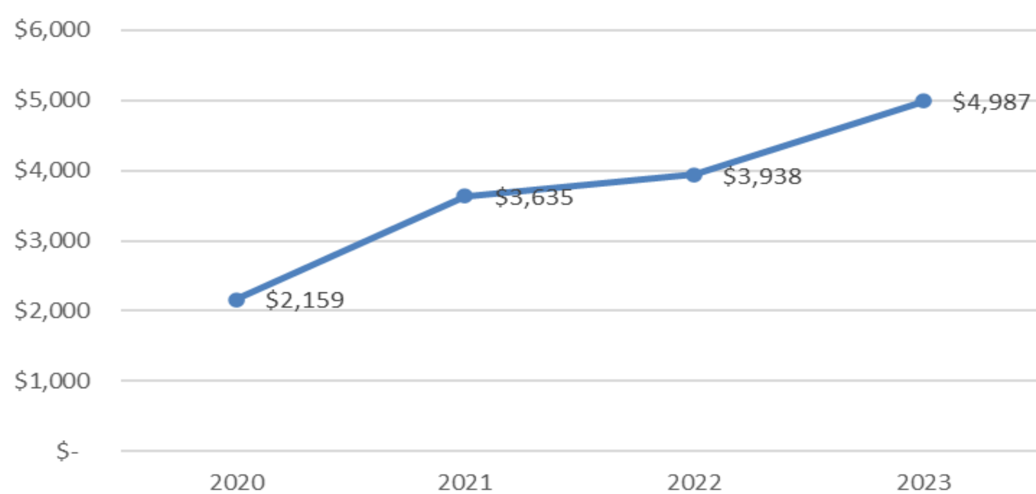
The current risk to the Company and all utilities is transformer availability and unit cost.

The strain on raw materials, which began in 2020 because of the COVID pandemic, has put a major constraint on transformer production in the United States.

This resource scarcity has driven up the price of transformers, as shown in Figure 70 below, and has limited the supply across the industry.

Figure 70

LOADED AVERAGE TRANSFORMER UNIT COSTS



Load Growth

Another challenge for transformers is the drastic increase in load without notification to the Company by customers.

Residential transformers are sized to meet traditional residential demand load. However, when customers add load after a transformer is installed without notifying the Company, this can put a major strain on the transformer and other customers whom that transformer serves.

Added activities like indoor growing operations installed in a residential home are creating voltage problems for customers as well as overloads on transformers, which can lead to an earlier than expected end of life for the transformer up to and including failure.

The Company is working to diversify its supply chain and enhanced the standards of new transformers to meet the increased customer load of the future. This will help ensure we have enough transformers on hand to support our existing customers as well as meeting any new requests for electric service.

- In addition to exploring new contracts with foreign suppliers, shown in Figure 71 below, to gain additional capacity, the Company is also reviewing different styles of transformers that are compatible with its grid, such as *amorphous core* style units and dry type transformers.

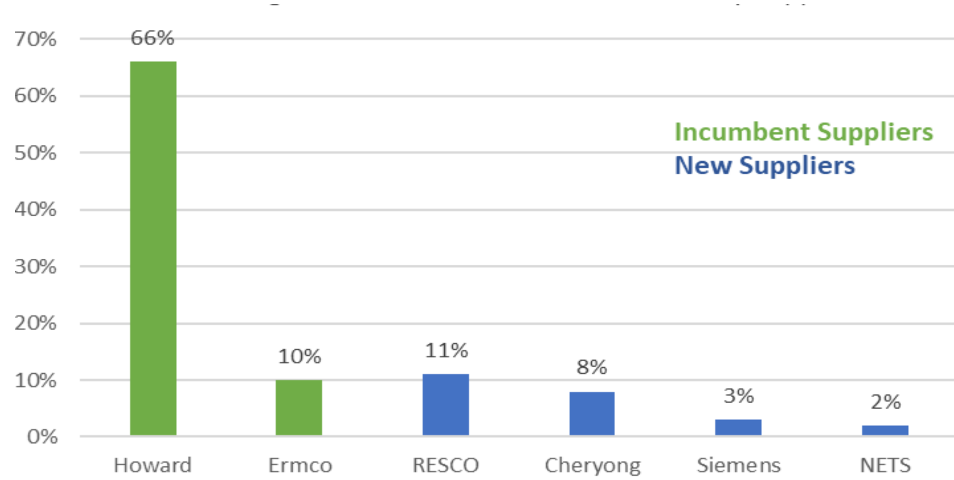
  NOTE: Amorphous core transformers differ from traditional silicon steel transformer cores in that amorphous cores are made up of ribbons of metal that are *not* grain-oriented versus a rolled sheet of grain-oriented steel that is used in a traditional silicon steel core. **The different way of making an amorphous core compared to the traditional silicon steel core results in lower voltage losses in the voltage transformation process.**

- The amorphous style units are especially important as the current proposal by the United States Department of Energy to increase transformer efficiency will increase demand for amorphous core transformers due to their low no-load loss properties. Should this proposal pass, the Company will be ready to meet the new energy efficiency standards.

The Company is also updating its standards to account for the anticipated addition of EV chargers on new builds and remodels. Taken together, these strategies will ensure the Company is able to prepare for the future while continuing to provide reliable service.

Figure 71

PERCENTAGE OF TRANSFORMERS ORDERED IN 2023 BY SUPPLIER



The Company will procure enough transformers to serve new load requests and restore power in the event of unplanned outages on the system.

These estimates account for the drastic increase in transformer costs we have realized in 2023 as well as additional need for transformers to be available for EV adoption over the next 5 years.

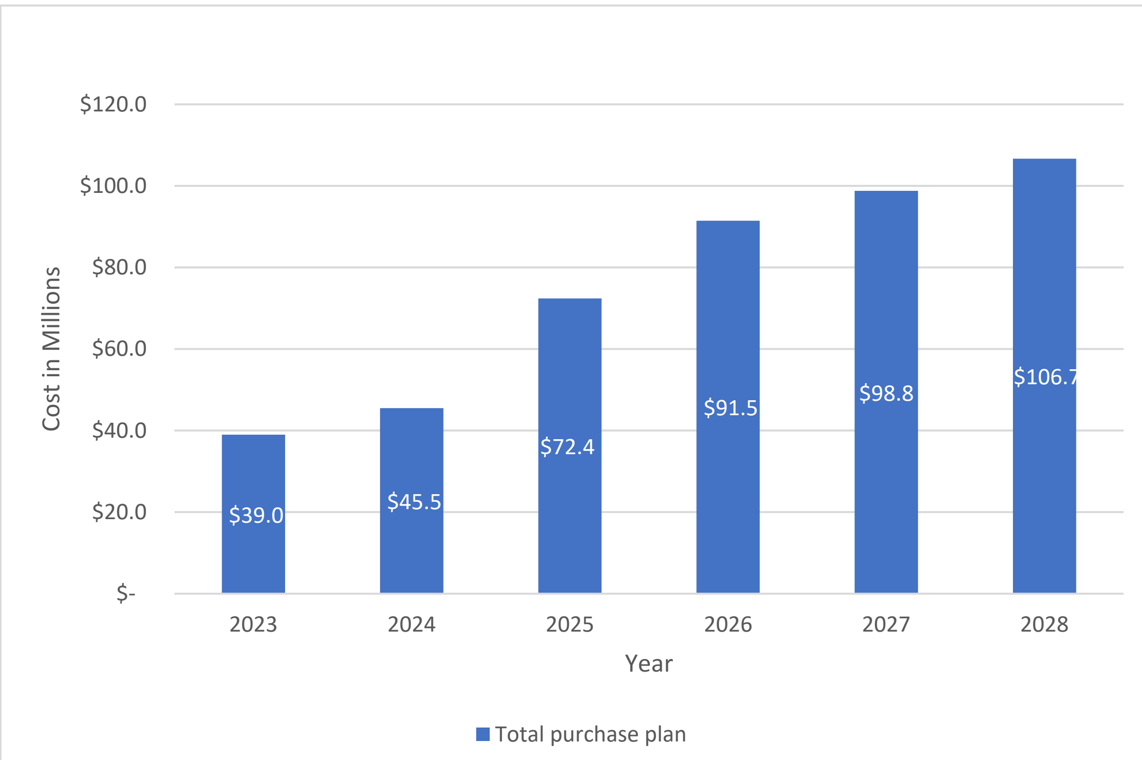
The 5-year Investment Plan for LVD Transformers

As a result of delays stemming from the COVID-19 pandemic, we are expecting additional deliveries of transformers in 2023 and 2024 as the industry plays catch-up.

In 2025, we expect purchase volumes to return to pre-pandemic levels with some additional demand factored in. From then on, we expect the need for transformers will increase as customers adopt electric vehicles. This is reflected in the 5-year investment plan and unit forecast in Figure 72 below.

Figure 72

PLANNED TRANSFORMERS TO BE PURCHASED



Year	Number of Planned Transformers to be Purchased
2023	15,322
2024	20,000
2025	14,000
2026	15,120
2027	16,330
2028	17,363

Meters

What Meters Do

Electric meters, meter sockets, and metering transformers are needed to **provide safe and reliable measurement of electricity usage** for customers.

The LVD Metering subprograms are part of the Company's obligation to serve and provide the means to measure customer electricity usage, provide the data required to generate customer bills, and provide usage data to customers safely and accurately.

Further, smart meters installed as part of this subprogram support the objective to provide customers with data to enable them to take greater control of their energy consumption.

Metering is an essential part of the Company's broader requirement to connect new customers through its overall New Business Program, as well as replacing failed equipment. Additionally, *advanced metering* is an essential component in many of the Company's current and future demand response and renewable programs.

- *Advanced Metering* is defined as *an integrated system of smart meters, data management systems, and communication networks that enable two-way communication between the utilities and the customers.*

Number of Meters in Service Territory

There are roughly 1.87 million electric meters currently installed, of which 1.85 million are smart meters, with the remainder being a combination of legacy (non-communicating), and commercial or industrial metering.

Lifecycle Analysis

The overall average lifespan of an electric meter is 20 years. However, with the deployment of cellular smart meters, meter lifespan can be affected by the availability of the communications network, as meters contain communications modules that are network-specific, such as 3G LTE, 4G LTE and 4G CATM1.

3G Meters

From 2021-2022 the Company worked to exchange and upgrade 620,000 3G meters to 4G CatM1 technology, which is 5G forward compatible.

The goal of this project was to have all 3G meters off the system when Verizon retired its 3G LTE network. Beginning in 2023, Verizon retired the 3G LTE network making the remaining 188,000 3G meters obsolete. The Company has since completed the remaining exchanges that are accessible. As of September 19, 2023, there are 782 3G meters remaining installed that are in the Company's letter process to secure access and get the meters exchanged.

4G LTE Meters

As of June 2023, there are 1.18 million 4G LTE meters installed on the Company system.

Without a formal notice regarding the retirement of the 4G LTE communications network from Verizon, the Company is preparing for the retirement of the network at the end of 2032 and will address the 4G LTE meters by that time.

The current plan is to replace these 4G LTE meters with 4G CatM1 or 5G meters prior to the sunset date on the communications network, to ensure continuity of accurate bills based on actual usage data.

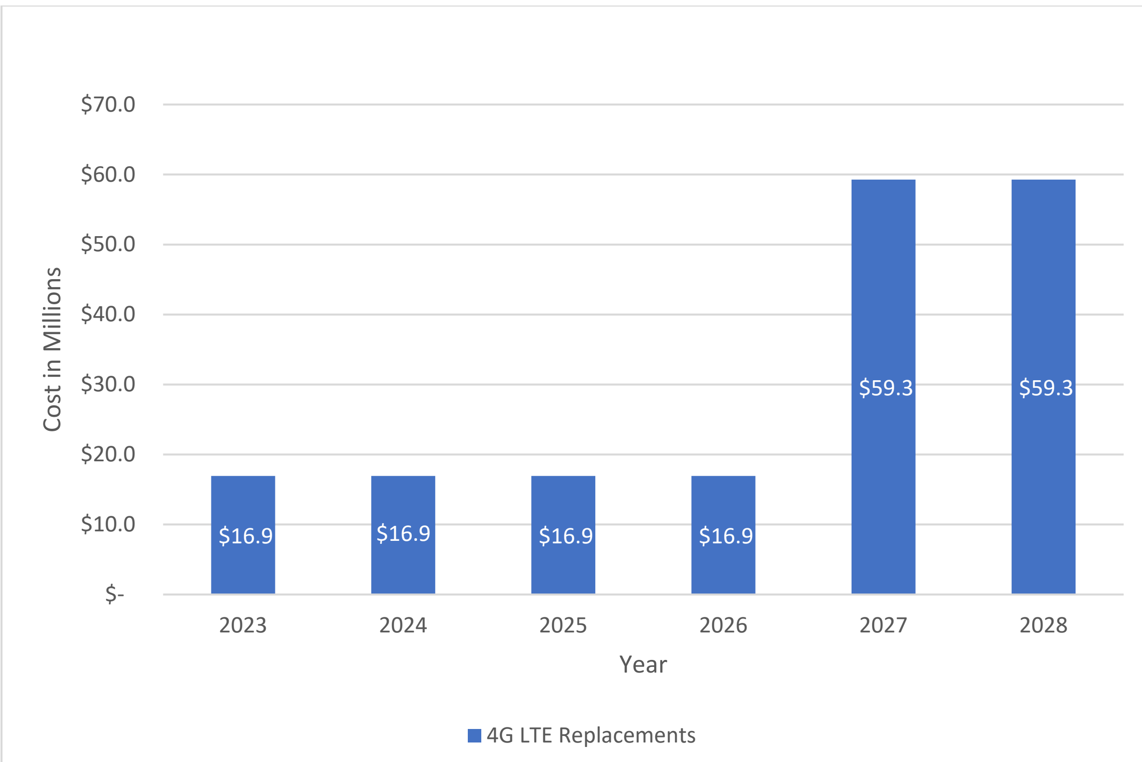
The Company will proactively replace over 1 million 4G meters with 5G compatible meters by 2032.

Starting in 2024, the Company will be purchasing 50,000 meters per year to begin the process of upgrading the remaining 4G LTE meters before ramping up to 175,000 meters per year from 2027 through 2032.

This purchase plan will cost $406.4 million over nine years. The 5-year investment plan for LVD Meters is shown below in Figure 73.

Figure 73

5-YEAR INVESTMENT PLAN FOR LVD METERS



Year	4G LTE Meters Replaced
2023	50,000
2024	50,000
2025	50,000
2026	50,000
2027	175,000
2028	175,000

Metro System

What the Metro System Does

The Company's Metro system provides underground electric distribution service in the downtown areas of Battle Creek, Flint, Grand Rapids, Jackson, Kalamazoo, and Saginaw.

Metro distribution assets consist of conductors contained in duct banks encased in concrete, with transformers and switching points placed below ground in larger working spaces called vaults and smaller working spaces called manholes.

Some of the cable is made of oil-and-paper-insulated, lead-sheathed conductor that is no longer manufactured.

The Metro system also includes padmounted switchgear, which consists of above ground switches and fuses in steel enclosures.

The Metro system promotes safety by ensuring the public does not encounter energized equipment. It also promotes aesthetics, and ensures it is less disruptive to the community and businesses to conduct repairs.

Number of Assets in Service Territory

Metro infrastructure includes 162 total vaults and 1,423 total manholes. Vaults and manholes are connected to each other through duct banks.

Lifecycle Analysis

The expected lifecycle of Metro assets is between 45 and 62 years.

Much of the Company's Metro infrastructure was first installed from 1910 through the 1950s and is still in service today.

The average lifecycles for Metro assets along with the average ages of these assets that were retired between 2017 and 2021, are shown in Figure 74 below.

Note that many assets are beyond their expected useful life, with some assets functioning for more than double the expected life.

FIGURE 74

METRO LIFECYCLE DATA

Device	Metro Conduit/Civil Infrastructure	Metro Conductor and Electrical Assets	Metro Transformers	Metro Services
Expected lifecycle	60 years	62 years	47 years	45 years
Average retirement age, 2017-2021	88 years	61 years	N/A	46 years
Maximum retirement age, 2017-2021	121 years	101 years	N/A	69 years

Public and Employee Safety Risks

Vaults and Metro system represent a minor public safety risk due to assets being located underground in public rights of way (typically under the sidewalk), making accidental public contact exceedingly rare.

Metro System Asset Health and Risks

The Metro system consists of two primary components:

- Civil infrastructure consisting of vaults, manholes, and duct banks.
- Electrical infrastructure consisting of conductor, transformers, and controlling devices.

Each infrastructure type has unique risks detailed below.

Civil Infrastructure Risks: The biggest risk to civil infrastructure is the age and physical size of vaults, manholes, and duct banks. Today's modern electrical cables, controlling devices and transformers require more physical space to safely maintain and operate this electrical equipment.

Electrical Infrastructure Risks: The biggest risk to the electrical infrastructure in the Metro system is driven by the live primary exposed parts in vaults and padmount switchgear, which presents a safety risk to the Company's workforce. Due to the enclosed space of the vaults, employees must take precautions to maintain working space clearances when working around these live metal parts.

Lead Risk: Another risk to the electrical infrastructure in the Metro system is driven using Paper Insulated, Lead Covered ("PILC") and Varnished Cambric, Lead Covered ("VCLC") primary cables. As noted above, this type of cable is obsolete and no longer manufactured; the existing lead conductor in the Metro system is more than 50 years old. Because of this obsolescence, if lead cable fails it cannot be replaced, and instead must be spliced back together, which is a laborious process. The Company has more than 240,000 feet, approximately 11% of the overall Metro system, of primary lead-covered cables of various sizes in service interconnecting the vault system to the metro substations.

Modeling & Prioritizing Risk

Metro planning and design engineers use a model to assess multiple components of each vault which produce a vault health score ranging from 0 to 180.

These components are assessed first to determine whether the risk is present, then given a multiplier based on the severity of the risk.

- Vaults with some risks present will receive a weighted score with the highest weighting given to wall, roof, and entrance condition as well as electrical connections.
- Based on the severity, a vault will be labeled as Yellow or Red, which will then multiply the score by 1 or 2, respectively.
- Vaults with no risk for a certain component are assessed as Green with a multiplier of 0.

Figure 75 below shows how the evaluation criteria is applied to a hypothetical vault.

FIGURE 75

METRO RISK ASSESSMENT MODEL

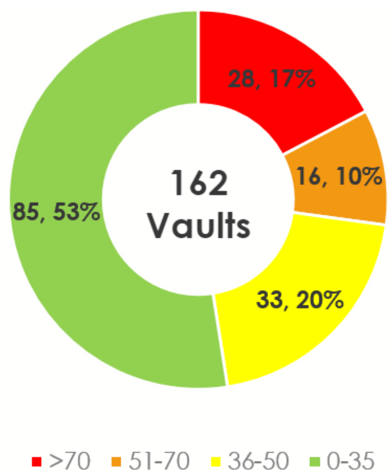
		Weighting:	10	10	10	2	4	3	1	10	7	2	5	5	4	3	4	3	3	2	2	180
			Civil							Electrical												
Asset Name	Reviewer	Review Date	Roof condition	Wall condition	Entrance condition	Entrance Location	Ventilation	Cable Rack Condition	Depth of water, as found	Electrical Connections live/dead	Working space	Switch type	Switch Condition	Transformer condition	Equipment sized for Fault Current	Grounding/Bonding Conditions	Lead cable	Splice Condition	Fireproofing/Arc Tape	Primary configuration (delta or grounded)	Alternate primary feed	Total Score
Sample Vault			R	R	R	G	G	Y	G	R	Y	Y	Y	Y	Y	Y	Y	G	R	G	G	119

Based on an assessment of these characteristics, a vault with a score above 70 qualifies for a red rating, which indicates major deterioration. A score between 51 and 70 is given an orange rating, showing moderate deterioration.

The most recent Company assessment of Civil Infrastructure vault health in Figure 76 below shows that 27% of the vaults inspected show major or moderate deterioration, which the Company will prioritize.

FIGURE 76

SUMMARY OF METRO HEALTH VAULT ASSESSMENT RESULTS



Workplan

The Company's ideal end state would be to rehabilitate and deadfront all the vaults with moderate or major deterioration.

The Company's strategy for civil infrastructure is to rehabilitate or rebuild at-risk vaults, manholes, and duct banks in a way that aligns with projects undertaken by municipal governments, commonly referred to as 'One Dig' or 'coordination of utilities' projects.

Coordinating with local authorities means that the Company cannot unilaterally decide to rehabilitate all 'red' or 'orange' vaults over a defined near-term period.

To ensure optimal performance and operation of the Metro system, the Company carries out the following actions to properly protect and maintain its assets:

Deadfronting and Vault Rehabilitation

The Company performs Metro vault rehabilitations and reliability deadfront projects to remediate risks to identified vaults.

The *Deadfronting* process is used to reduce employee exposure to live equipment and *involves replacing exposed primary termination points and bushings with covered or insulated components to reduce the risk of workers contacting energized components*.

Rehabilitation projects will typically replace the vault structure and its electrical components in its entirety.

The pictures in Figure 77 and Figure 78 illustrate vaults before and after rehabilitation and reliability projects take place.

- The pictures in Figure 77 show the difference between exposed and deadfronted components on rehabilitation project, with a new vault installed to replace the existing structure.

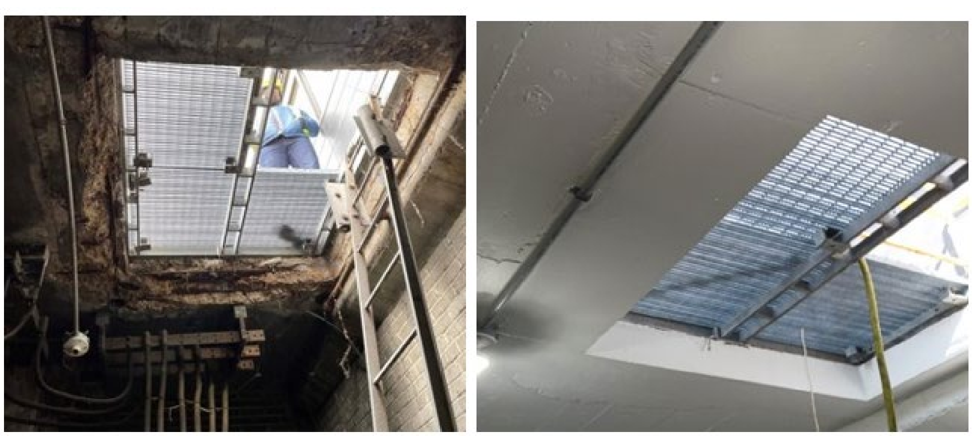
FIGURE 77

VAULT BEFORE AND AFTER REHABILITATION PROJECT

- The pictures in Figure 78 show a vault reliability project that rebuilt the electrical infrastructure and performed minor concrete repairs.

FIGURE 78

VAULT BEFORE AND AFTER RELIABILITY PROJECT



Replace Obsolete Electrical Assets

To remediate risks posed by obsolete lead cable, the Company has an initiative to modernize primary cables, allowing them to be more modular so additional cable can be added later if needed.

- Modernizing primary cable also improves capacity and resiliency and creates more capability to accommodate grid modernization components.
- Replacing PILC cable reduces environmental impacts during operations such as dewatering manholes or vaults and reduces occupational hazards when working on lead cable joints and splices.
- PILC cables are no longer manufactured, with replacement cable, joints and splice materials becoming scarcer.

Metro Inspection and System Maintenance

The Company is reducing reliability and safety risks through its metro inspection and maintenance programs recommended by the *IEEE*.

The Company is proposing the following schedule, shown below in Figure 79, based on good engineering practice to help identify and correct problems before they result in outages.

FIGURE 79
METRO INSPECTION AND MAINTENANCE SCHEDULE

Inspection Task	Cadence	Components Checklist	Annual Cost
Vault Inspections	4 Years	Visual Inspection of vault structure, transformers, switches, cables and other components	$ 400k
Manhole Inspections	4 Years	Visual Inspection of manhole structure, cables, splices, and other components	$ 850k
'Hi Rise' Vault Inspections	Annually	Visual Inspection of the room/structure, transformers, switches, cables, and other components	$ 125k
Infrared Thermography Inspections	As Needed	Inspection of electrical components. Can be performed with visual inspections	$ 125k
Total			**$ 1,500k**

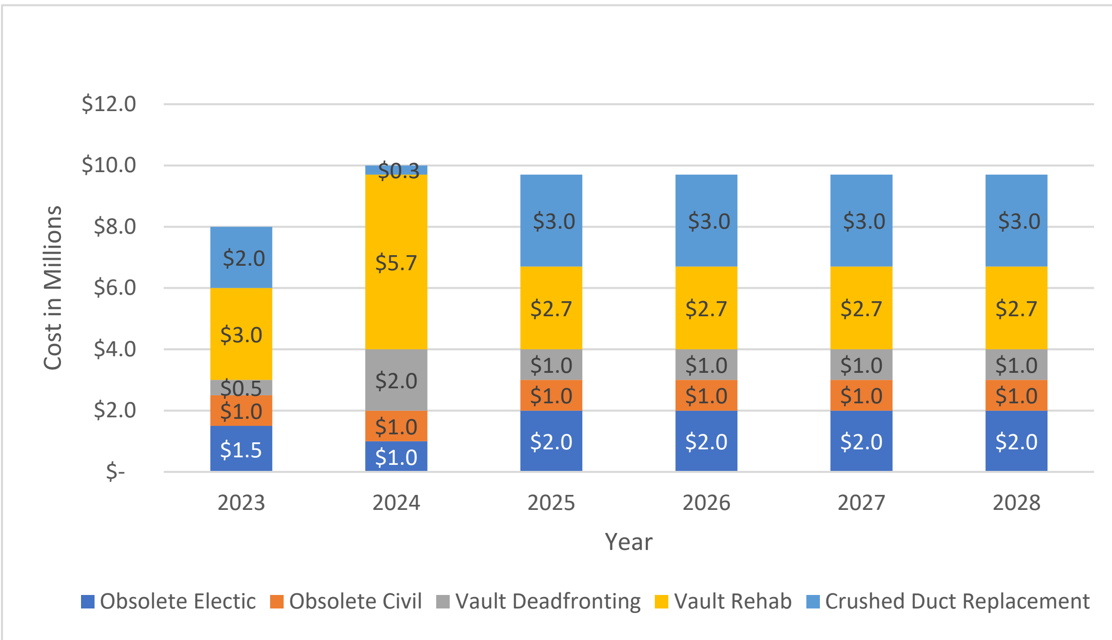
5-Year Capital Investment Plan

The Company will invest in its vaults and primary cable replacement in coordination with local governments to limit interruption of business and commerce in the municipality.

- This plan will enable the Company to complete approximately four vault rehabs, deadfront two vaults, and replace obsolete electric and civils assets on 4 or more vaults per year.
- The 5-year investment plan for the Metro system (shown below) will address workforce safety, reliability, and operational constraints.

Figure 80

METRO RELIABILITY CAPITAL INVESTMENT PLAN



Year	Electric Projects	Civil Projects	Vault Deadfronting	Vault Rehabilitation	Crushed Duct Replacement
2023	5	2	2	5	3
2024	3	1	3	4	1
2025	4	2	2	4	1
2026	3	1	2	4	1
2027	4	2	2	4	1
2028	3	1	2	4	1

HVD System

The HVD system comprises all assets from the point of interconnection with the transmission provider through the point at which LVD lines exit LVD substations.

Where the LVD Lines system evaluated each investment category individually, this section will focus on each HVD asset in detail, with a comprehensive overview of major risks, and the workplan to mitigate risks and five-year investment category for each asset class including:

- Mitigating the risks from obsolete pole tops and deteriorated pole through **HVD Lines**
- Mitigating the risks from deterioration through securing, inspecting, and upgrading **HVD and LVD Substations**
- Enhancing and modernizing the protective system with **System Protection Relays**
- Ensuring the HVD System can serve electric peak demand, new interconnections and support economic development through **HVD Load Growth & Interconnections**

Trees are a significant external risk factor for HVD Lines, and the Company's *Forestry Line Clearing Program* is designed to mitigate this risk. Therefore, the line clearing program is also discussed as part of HVD Lines asset management.

Like the LVD section detailed above, each investment plan includes the planned Capital expenses to construct the distribution assets, and the O&M expenses for preventative work, compliance requirements and emergent repairs.

Adequate funding for Capital as well as O&M is vital to ensuring both the reliability and cost efficiency of the distribution system through taking proactive measures to address problems before they occur. Continued funding of O&M and adherence to O&M standards provides:

- Increased reliability and resiliency by avoiding outages due to equipment failure or mis-operation.
- Decreased costs by avoiding emergency repairs, allowing for more predictability in the workplan.
- Extension of asset life, avoiding emergent capital replacements and allowing for more predictable future capital investments.

HVD Lines

Figure 81

EXAMPLES OF HVD LINES

What HVD Lines Do

HVD Lines carry electric power at high voltage from a source substation to several substations.

HVD Poles are comprised of a pole top, which includes cross-arms, conductors, and switches that sit atop a wooden or steel pole.

Line miles in Service Territory

The HVD system is comprised of around 4,600 total miles, with approximately 4,400 of those miles being 46 kV and 69 kV overhead lines, and 19 miles being 46 kV underground lines. Approximately 200 miles are 138 kV overhead lines, and 4 miles being 138 kV underground lines.

Lifecycle Analysis

The overall average lifecycle of an HVD line is 60 - 70 years for the physical HVD poles. The life expectancy for pole top hardware, such as cross-arms, insulators, and cross-arm braces, is 30 - 35 years or roughly half the life of poles.

Safety Risks to the Public

HVD Lines represent a minor public safety risk since the height from the ground makes public contact exceedingly rare, however, the deterioration of the Company's HVD poles shows that poles that fail can reach ground level either from deterioration, storms, or vehicle accident.

HVD Line Asset Management Health and Risks

Conductors

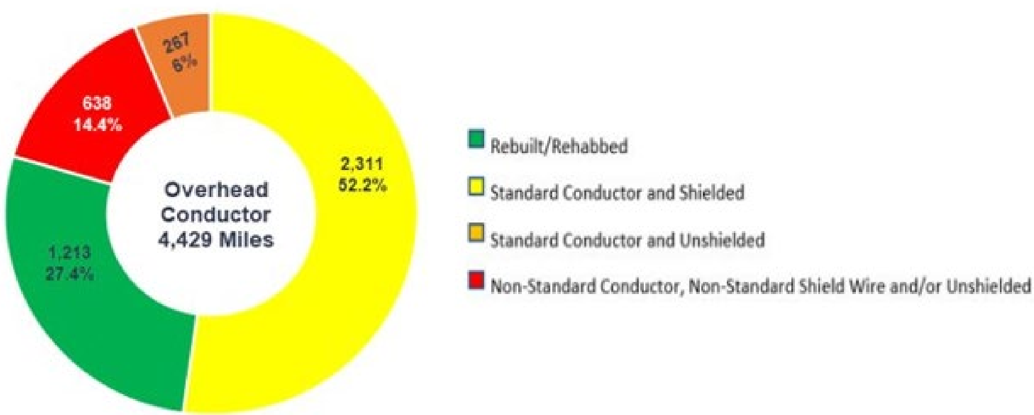
'Non-standard conductors' made from copper or small single layer aluminum conductors with a steel core wire do not meet the Company's present design standards. This is due to the increased probability of an outage from icing conditions, weather events or tree incidents compared to multi-layer aluminum conductors.

- Copper conductors previously installed have become obsolete across the industry, therefore maintenance and replacement parts procurement have become difficult.
- Outages that occur on non-standard lines constructed with these styles of copper conductors regularly are of a longer duration and more costly.

The most recent Company assessment of HVD conductor health shows nearly 14.4% of HVD conductors are a high priority for repair and replacement based on being non-standard conductor and/or unshielded. Another 6% are in the moderate concern category, based on being unshielded, as shown in Figure 82 below.

FIGURE 82

HVD LINES CONDUCTOR HEALTH



Insulators

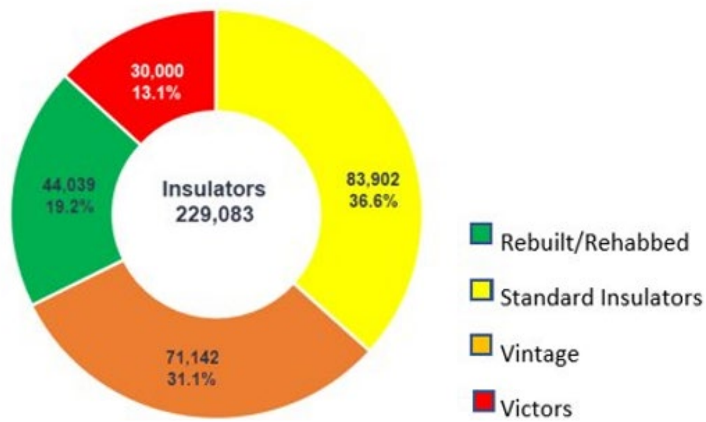
Vintage insulators, specifically victor type insulators, are the biggest driver of outages on the HVD system.

- The Company has approximately 30,000 victor type insulators that were installed between 1969 and 1994 and their replacement is prioritized in this plan.

The Company has begun using artificial intelligence software and machine learning to automate the video review from annual helicopter inspections which will help to identify specific locations of victor type insulators. This will be detailed further in the Technology, Analytics and Grid Modernization section of this plan.

The most recent Company assessment of HVD insulator health shows 13.1% of HVD insulators are victor type insulators and are a high priority for repair and replacement, and another 31% are in the moderate concern category as vintage insulators.

FIGURE 83
HVD LINES INSULATOR HEALTH

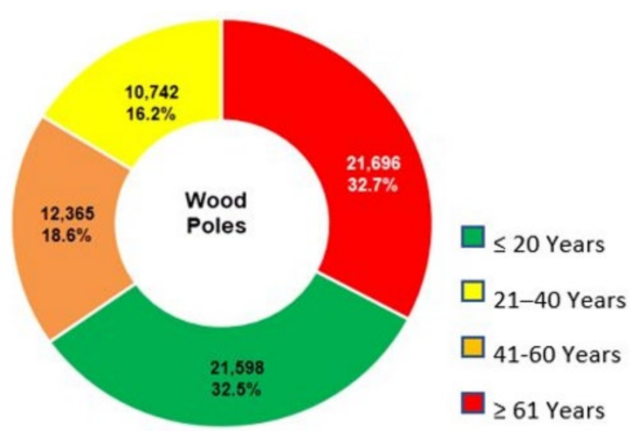


Poles

The Company currently maintains a 12-year cycle for HVD pole inspections. The most recent Company assessment of HVD pole health shows one-third are over 60 years old, with nearly 19% being between 40 and 60 years old, as shown in Figure 84 below, making them a priority for replacement based on pole inspection results.

Historical data shows that 11-15% of HVD poles inspected each year will fail inspection and be identified for replacement. The Company incorporates this data into the overall system condition and defines a plan to replace the poles. This pole inspection is in addition to annual helicopter and ground patrol inspections of all HVD lines that is described in more detail later in this section.

FIGURE 84
HVD POLE HEALTH



Trees

Trees present a potential risk of outage or interruption of electric service on the HVD system. The Company's *Forestry Line Clearing Program* is designed to minimize the risk of these occurrences, improve reliable service to its customers, and decrease reactive maintenance and capital expense associated with interruptions during weather events.

The Company clears vegetation within an 80- to 120-foot-wide ROW for these voltages to attain a minimum of 15 feet of separation for 46 kV lines, and 20 feet of separation for 138 kV lines between conductors and vegetation at the time of clearing. This wider clearing standard ensures better reliability and fewer tree hazards on the HVD system.

The Company also manages vegetation within the ROW to maintain accessibility along the ROW for maintenance and repair of the line. The HVD Line Clearing Program is currently on a 4-year clearing cycle.

Workplan

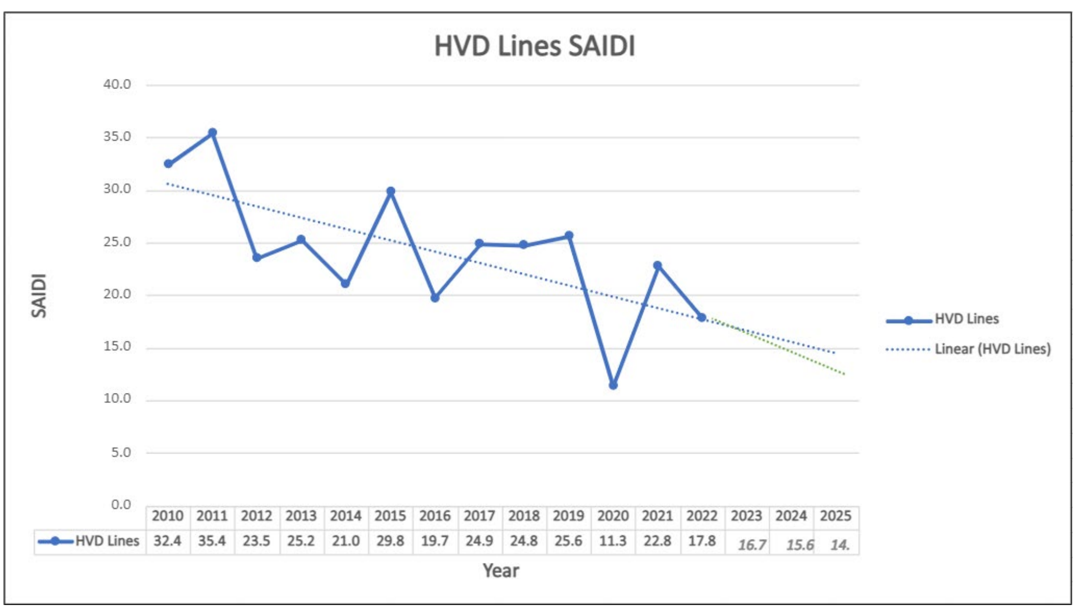
The desired outcome for all HVD lines is to eliminate poles, pole tops, conductors, and switches that have exceeded their life expectancy through fixing and fortifying assets.

The Company focuses on lines with consistently poor reliability performance and looks for the best remediation strategy to prevent future outages in the most effective and economical way.

The **primary driver for investment decisions is line performance**—lines with the highest average of incident rates and customer outage minute totals in a rolling three-year period are given higher priority for remediation.

As Figure 85 below shows, the reliability performance of the HVD system has steadily improved due to the Company's aggressive investment in HVD lines.

FIGURE 85
HVD LINES SAIDI PERFORMANCE



The top priorities for HVD Lines are improving reliability by addressing the system health risks of victor or vintage type insulators, non-standard conductors, and aging or deteriorated poles.

Based on regular inspection results and annual planning the Company will use the following approaches to improve performance and longevity of all HVD lines:

Repair and Replace Aging Assets

The Company prioritizes HVD line segments based on actual outage history, conductor type, shielding, and the potential customer impact if the line segment were to fail. This provides a first cut for Company engineers regarding where preventative outage work would be most beneficial.

The Company also performs an annual reliability planning review of its HVD line sections, considering both line performance and line condition, to determine which lines and line components need to be addressed in the next year or years, as some projects may be large enough to span multiple years.

The Company addresses the system health risks of insulators, conductors, and poles using a combination of line rebuilds, pole top rehabilitation, and pole replacements to reduce the population of these risks and improve reliability performance.

- With few exceptions, lines that use non-standard and obsolete construction or equipment are rebuilt to the modern standard with a new insulator, conductor, cross-arms, structure replacements, tree clearing, and ROW procurement as needed.
- Lines that use standard construction and conductor, have adequate pole health, but have deteriorated pole top equipment and/or, vintage insulators are rehabilitated via pole top rehabilitation instead of a complete rebuild.
- The Company's plan to rebuild or rehabilitate lines and replace poles to address the long-term asset health of the HVD Lines systems includes replacing 1,600 victor type insulators, an additional 11,000 vintage insulators and 77 miles of non-standard / unshielded conductors per year.

This plan will ultimately replace all non-standard conductors by 2032 and all victor type insulators by 2042. The Company's plans also include replacing approximately 1,500 poles per year via pole replacement and line rebuilds, to mitigate the risk from poles beyond lifecycle in the next 20 years.

HVD Annual Line Inspections

The Company inspects HVD lines annually, and addresses the anomalies found and fixes defects before they cause a customer interruption.

- The primary HVD line inspection is performed by a helicopter that uses visual observation along with infrared and ultraviolet cameras.
- For safety reasons, helicopters do not fly approximately 400 miles of the HVD system. This is because it is difficult to land quickly and safely in the event of an emergency. Most of these "no-fly lines" are in densely populated urban areas. To inspect these lines, the Company completes biannual ground patrols that may include infrared and/or corona inspection using handheld cameras.

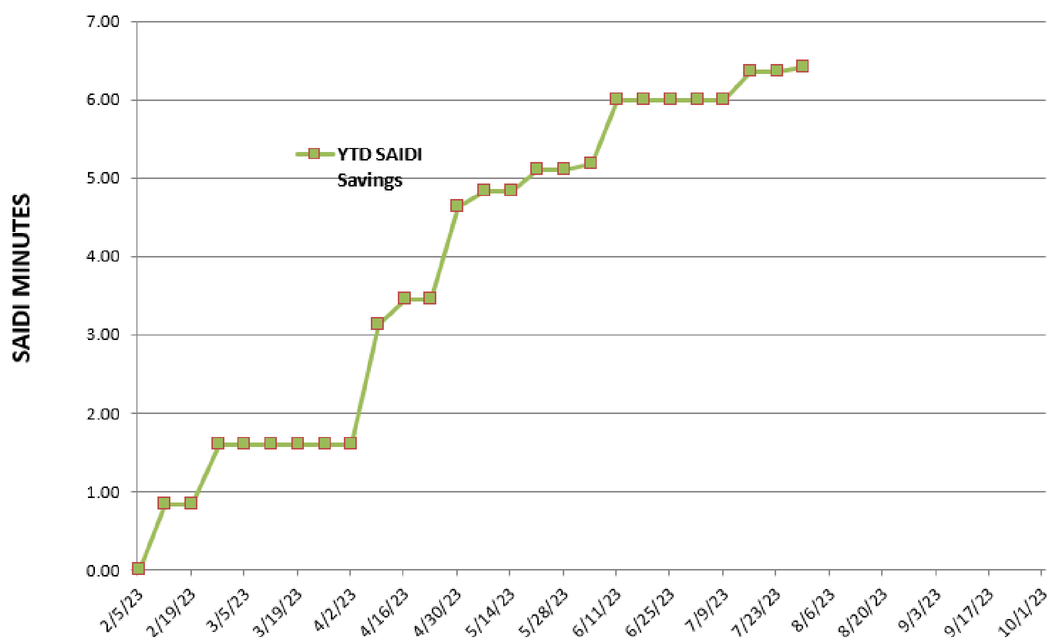
As shown in Figure 86 below, the Company has seen significant SAIDI benefits by completing both helicopter and ground patrols, and projects to save 10 minutes of SAIDI.

To date in 2023, there have been 36 anomalies found and repaired consisting mainly of floating conductor, cracked insulators, hot connections, and broken cross arms.

These repairs resulting from our inspection process have saved approximately 6.5 SAIDI minutes.

FIGURE 86

2023 YEAR TO DATE SAIDI IMPACT FROM INSPECTIONS



Operations and Maintenance (O&M)

As described earlier, the Company uses aerial, ground, and pole inspections to assess the condition of the HVD Lines system. Funding of the operations and maintenance program for these inspections provides increased reliability by identifying equipment nearing failure and making repairs before an outage can occur.

The Company has seen a continued reduction in HVD Lines SAIDI minutes because of an increased investment in HVD Lines asset health, a focus on line and equipment inspections, and preventative maintenance.

Even with a downward trend in SAIDI, the *Resilient Grid Plan* will require additional O&M funding to sustain this momentum. The increased O&M funding would be used to increase helicopter inspections, expand switch and pole inspections, and to repair all anomalies identified during the inspections.

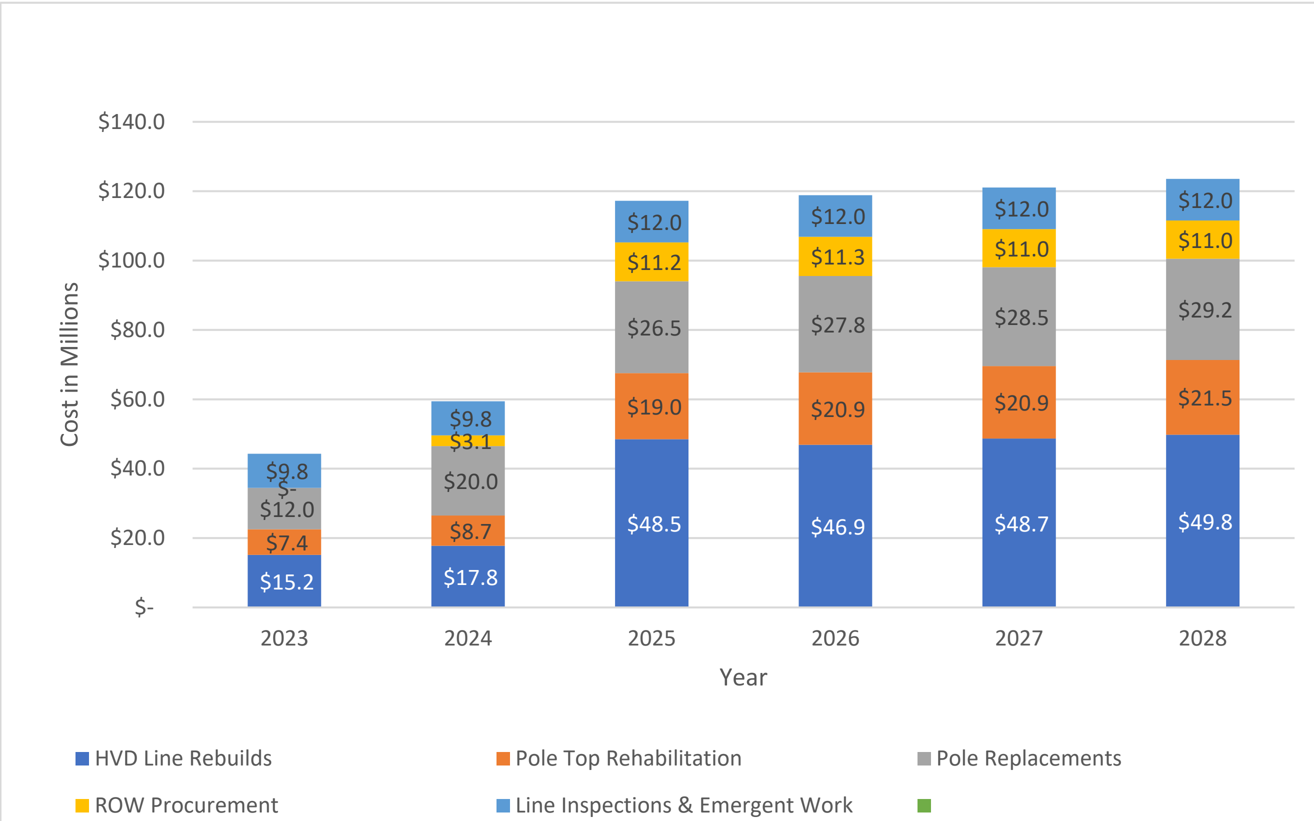
5-Year Investment Plan

The Company will rebuild or rehabilitate an average of 175 HVD line miles per year and replace approximately 1,200 poles per year as part of this plan to support the company's reliability goal.

This plan will cost $495 million over five years and will result in a SAIDI savings of 4 minutes per year. The 5-year investment plan for HVD Lines is below.

Figure 87

HVD LINES 5-YEAR INVESTMENT PLAN



Year	HVD Line Rebuilds	Pole Top Rehabilitation	Pole Replacements
2023	10	16	543
2024	34	41	851
2025	91	95	1160
2026	85	95	1185
2027	85	90	1185
2028	84	95	1185

Substations

FIGURE 88
HVD SUBSTATION

FIGURE 89
LVD SUBSTATION

What Substations Do

Substations take electricity at a higher voltage and step it down so it can be distributed to households and businesses.

HVD substations receive power from the METC transmission system and reduce the voltage to feed the Company's 46 kV lines, which in turn feed the Company's Distribution substations.

There is a subset of substations dedicated to serving single industrial customers; these are classified as *Strategic Electric Customer* ("SEC") substations, like the one shown below in Figure 90.

FIGURE 90
SEC SUBSTATION

LVD substations, as shown above in Figure 90, **are the interface point between the HVD and LVD systems, where voltage levels are stepped down.** LVD lines emanate from LVD substations to deliver electricity to customers.

The Company maintains a mobile substation fleet to provide electric service to customers during planned and unplanned substation outages where redundancy is not present or load transfers to adjacent substations are not available.

- Mobile substations are vital to the Company's ability to maintain and operate substations because substation projects and repairs can take several days to several months to complete.

Mobile substations are also deployed to support HVD Line projects, to prevent outages for emergent concerns, and to restore electric service during unplanned outages. An example of a mobile substation is shown in Figure 91.

FIGURE 91

MOBILE SUBSTATION

Number of Substations in Service Territory

The total substation network currently consists of 1,144 substations.

- The HVD substation network consists of 145 HVD substations and 164 SEC substations.
- The LVD substation network consists of 830 general distribution substations.
- In addition to the HVD and LVD substations, there are 35 customer-owned dedicated substations, 5 Company-owned substations providing wholesale distribution services to rural co-op and municipal systems, and 30 customer-owned substations providing wholesale distribution services to rural co-op and municipal systems.
- The mobile substation fleet currently consists of 30 mobile units with varying electrical capacity, electrical configuration, and service function.

Lifecycle Analysis

Substations are a collection of several key components that determine the health and longevity of the Company's substations.

The overall average lifespan of key substation and mobile substation components average 50 years, including Power Transformers, Circuit Breakers, and Switches.

Safety Risks to the Public

Substations represent a minor public safety risk because of the barriers and fencing surrounding the assets, making accidental public contact exceedingly rare.

In the case of mobile substations, safety barriers can be erected inside of existing substations or outside with fencing.

Substation Asset Health and Risks

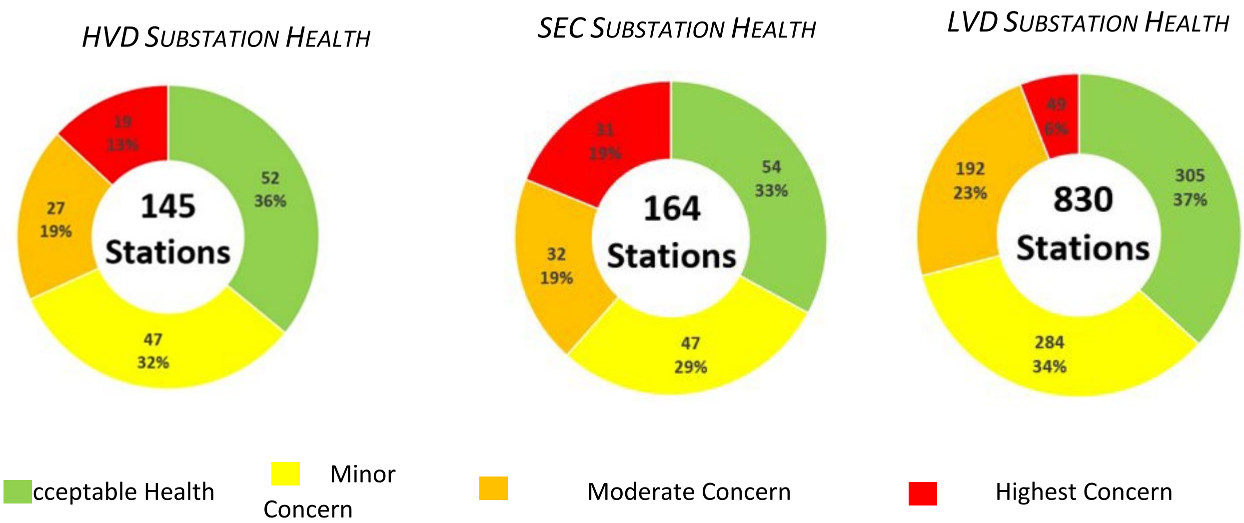
Substation health represents an overall assessment of equipment data and component evaluation for each substation.

Assessments include items such as equipment condition, equipment type, equipment age, visual inspection data, infrared inspection data, oil and gas test data, and electrical test data.

Four health categories have been created with action plans for each color rating as shown in Figure 92.

Figure 92

SUBSTATION HEALTH



HVD Substations

The most recent Company assessment of HVD substation health shows 13% are a high priority for repair and replacement, with another 19% in the moderate concern category.

Of the remaining HVD substations, 68% of substations are in acceptable health or only show minor concerns as shown in the Figure above.

Strategic Electric Customer (SEC) Substations

The most recent Company assessment of SEC substation health shows 19% are a high priority for repair and replacement, with another 19% in the moderate concern category.

Of the remaining SEC substations 62% of substations are in acceptable health or only show minor concerns as shown in the Figure above.

LVD Substations

The most recent Company assessment of LVD substation health shows 6% are a high priority for repair and replacement, with another 23% in the moderate concern category.

Of the remaining LVD substations, 71% of substations are in acceptable health or only show minor concerns as shown in the Figure above.

Key Risks Substations Must be Protected From

Major Equipment Failures

Some substations in the Company's service territory were built in the 1920s and are approaching 100 years in age, and still employ original equipment.

Old and obsolete equipment such as Power Transformers, Circuit Breakers, and Switches can cause large customer outages if they fail, often at a significant cost.

- Failures at HVD substations are less likely to cause customer outages due to the redundancy built into the station design, but when customers are interrupted it can be upwards of 10,000 customers affected.
- Failures at SEC substations will impact only the customer being served.
- Failures at LVD substations are more apt to cause customer interruptions due to less redundancy in the design, but such interruptions typically affect fewer customers ranging from several hundred to a few thousand.

Physical Security Gaps

Animal contacts from squirrels and raccoons are some of the most common customer interruptions at substations.

However rare, due to the critical importance of substations to the overall electric grid, the Company must also prepare for the case of intentional coordinated attack at these facilities.

- The customer impact of such an attack would be like that of a major equipment failure.
- Opportunities to mitigate this risk are continually being identified and implemented by engineering and operations teams with support from Corporate Security.
- Opportunities include upgrading substation surveillance systems and adding additional security to equipment to prevent inadvertent operation.

Extreme Weather

Extreme heat or cold will increase loadings on substation equipment and may shorten equipment lifespan, which could result in more frequent replacement.

- Extended periods of extreme cold can affect the operation of breakers, circuit switchers, and other electromechanical equipment.
- While substations typically hold up well to violent winds, debris blowing into a station and creating faults in exposed conductors or equipment poses a risk to substations.

Workplan

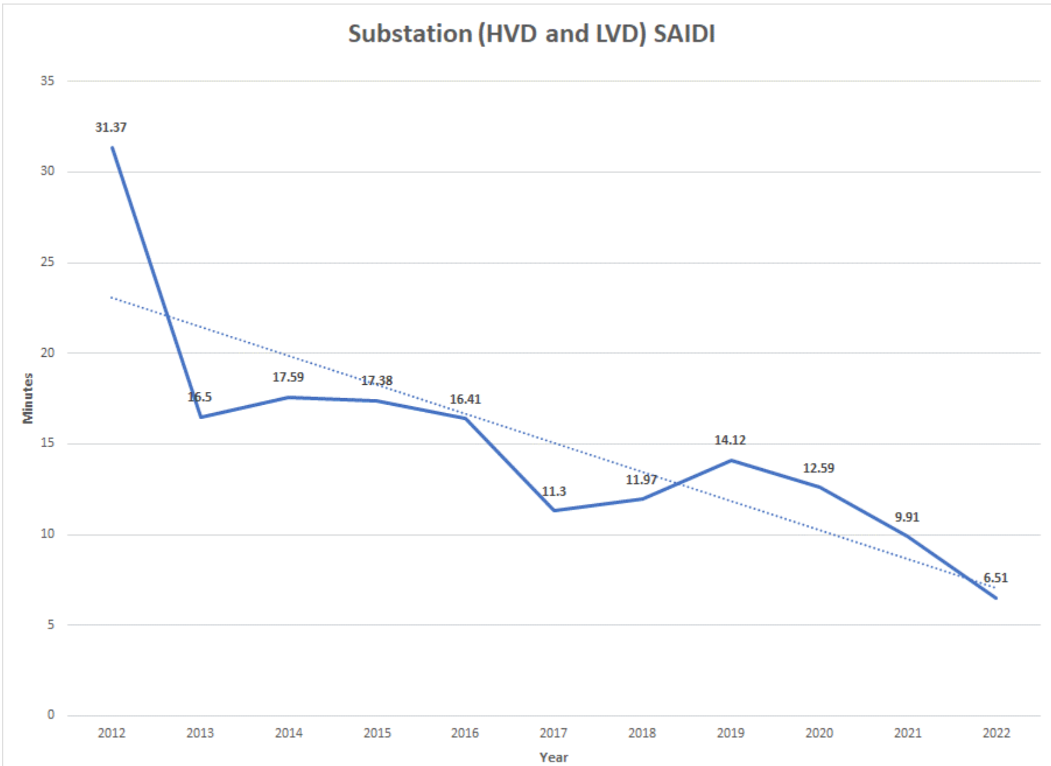
The desired outcome for all substations is to monitor electrical loading, and to provide adequate inspections, maintenance, and end-of-life asset replacement for all substations.

The top priority for substations is providing reliable electric capacity to all customers through timely resolution of equipment loading and substation health concerns, new electrical load connections, and substation reliability improvements.

Like HVD Lines, Figure 93 below shows the reliability performance of substations has steadily improved due to the Company's investment in equipment replacement and animal mitigation for both LVD and HVD lines substations.

FIGURE 93

SUBSTATION SAIDI PERFORMANCE



The Company has shown that substations, if properly maintained, can operate beyond their average lifespan. However, these assets must be monitored, inspected, and maintained regularly, and repaired in a timely manner if a failure does occur.

To ensure optimal performance and operation of substations, the Company carries out the following actions to properly protect and maintain substations:

Repair and Replace Aging Assets

The Company regularly reviews reliability data, inspection data, industry practices, and operation practices to identify end-of-life assets and modernization opportunities to improve overall customer service reliability, improve substation health, and mitigate customer outage risk.

Based on this data, the Company plans to rebuild substations that are at end-of-life or have working clearances that do not meet current standards and operating practices.

- The Company plans to rebuild 55 substations over the next 5 years.
- The Company will also purchase four new mobile substations to support planned and emergent projects that improve customer reliability and substation health, and to support outage prevention and outage restoration.

Where possible, the Company seeks to repair and replace degrading assets to prolong the substation lifespan and reduce cost to customers. The Company regularly reviews reliability, inspection, and operating data to identify where substation equipment is degrading, has reached end-of-life, or requires modernization.

Based on this data, the Company plans to replace equipment to mitigate customer outage risk and to resolve decreased service quality.

- The Company will replace degrading equipment such as transformers, breakers, regulators, switches, and reclosers as concerns are identified.
- The Company will replace all transformers and circuit breakers that are beyond end of life.
- This plan will replace 9 HVD transformers per year, 10 SEC transformers per year, 30 LVD transformers per year, and 40 circuit breakers per year to support the Company's Reliability goal.

Operations and Maintenance

The Company uses maintenance standards for both LVD and HVD substation equipment, referred to as the *Electric Substation Reliability Guidelines* or (ESR-1) that were developed based on vendor recommendations, industry best practices (including EPRI and IEEE) and collective experience by Company personnel. The recommended maintenance activities outlined in ERS-1 are shown in Figure 94 below.

FIGURE 94

ESR-1 RECOMMENDED SUBSTATION MAINTENANCE ACTIVITIES

Category	Activity
	NERC/HVD/strategic substation inspections (monthly)
	NERC/HVD equipment test operating & profiling (annual)
	Motor Operated Air Break (MOAB) switch test operating (annual) and battery exchanges (every 4 - 5 years)
	NERC/HVD/strategic substation infrared inspections (annual)
	NERC required testing and battery maintenance (annual)
	Strategic customer online insulator cleaning (annual, select customers)
NERC/HVD/Strategic Substations	HVD infrared inspections (annual)
	SF6 breaker gas quality testing
	HVD breaker inspections and maintenance
	Circuit switcher inspections and maintenance
	Spring operated ground switch inspections and maintenance
	Capacitor bank inspections and maintenance
	Transformer Load Tap Changer inspections and maintenance
	Station power transformer inspections and maintenance
Category	**Activity**
	LVD substation inspections (Increase from every other month to monthly)
LVD Substations	Single-phase regulator maintenance
	Single-phase regulator oil samples and dissolved gas analysis (5-year program)
	LVD substation inspections (every other month)
	LVD substation animal mitigation inspection (twice per year, Spring and Fall)
	LVD substation equipment test operating (annual)
	LVD infrared inspections (every other year)

Category	Activity
All Substations	Emergent and planned 'Broke-fix' work for NERC/HVD/Strategic/LVD substations and Metro
	Infrared repairs (Priority 1)
	Third-party switching and tagging support (strategic customers, ITC, third-party generation)
	Substation transformer oil sampling and analysis (annual), Total Combustible Gas testing (annual)
	Substation snow plowing (Every winter)
	Substation weed control (1 application per year)
	Substation mowing (typically twice per month per sub OR more frequent)
	Substation property clean-up and repairs (trash cleanup, homelessness encampment cleanup, control house repairs etc.)
	Misc. items such as: Substation eye wash station cartridge replacements (annual); switch stick, personal protective ground testing and fuse testing (annual)
	Misc costs (fleet loadings, access control/telecom costs, Doble Engineering membership etc.)
	Power transformer inspections and maintenance (limited by outage availability)
	Infrared repairs (Priority 2 and 3)
	Switch repairs
	Facilities O&M repairs

Funding for the O&M standards in ESR-1 provides increased reliability and resiliency by avoiding outages due to equipment failure or mis-operation at a reduced cost by avoiding emergency repairs, which can cost up to 70% more than proactive maintenance. Additionally, the Company's O&M plan **extends the life of assets by avoiding emergent capital replacements** and allowing for more predictable future capital investments.

The Company has seen continued reduction in SAIDI minutes because of an increased operational focus on preventative maintenance.

Despite the encouraging trend in SAIDI, the *Resilient Grid Plan* will require additional O&M funding to sustain this trend, execute required preventative activities, and continue to improve the internal processes to enhance asset management.

Physical Security Gaps and Animal Mitigation

All substations are enclosed within a fence or wall barrier to provide physical security and public safety, and additional measures are installed to mitigate animal intrusions that can result in substation outages.

The purpose of the Company's animal mitigation is to keep large and small animals out of the substation, and to insulate equipment to extend touch potential if an animal gets into a substation, with specific measures chosen based on substation characteristics.

The Company's current animal mitigation standards were developed based on research conducted at Michigan State University, experiments conducted at the Company's Marshall Training Center, utility industry reports and best practices (e.g., EPRI), and experience gained from previous animal mitigation projects.

The Company's animal mitigation measures include:

- 1-inch mesh fence (squirrels can squeeze through larger mesh)
- Concrete gate foundations (minimizes gaps and frost heave that create gaps over time)
- Polycarbonate panels (3-foot panels installed at the top of the fence to mitigate animals from climbing over the fence)
- Pole wraps and line discs (installed on poles and wires outside the substation to mitigate aerial access to the substation)
- Interior and exterior stone (eliminates gaps at the fence bottom to mitigate animals from crawling under the fence)
- Bushing guards on regulators and reclosers to extend touch potential to mitigate contact to energized components if an animal climbs on equipment.
- Vegetation management

Animal-caused outages are typically the highest contributor to substation SAIDI, leading the Company to aggressively update animal mitigation at the LVD substations.

Approximately 86.5% of the LVD Substations now have standard animal mitigation measures installed. The Company plans to have animal mitigation installed at 99% of the LVD Substations within the next 5 years.

Distribution Supervisory Control and Data Acquisition ("DSCADA")

DSCADA is **the key component of substation automation, allowing the Company to monitor and control substation devices remotely** without requiring the dispatch of a human operator.

When DSCADA is installed at a substation it includes a Remote Terminal Unit (RTU), a local device that facilitates communications with substation devices and remote software systems and captures over 300 data points.

- The enhanced visibility into substations and the remote-control capabilities allow the Company to address outages more quickly and effectively.
- The enhanced visibility also allows the Company's planning engineers to perform more accurate load flow studies because DSCADA provides access to real-time circuit data.

The remote-control aspects of DSCADA are crucial in enabling advanced automation such as the ATR loops described earlier in the Resiliency Investments section of this plan.

The Company plans to install DSCADA at 40 more substations over the next 5 years.

5-Year Investment Plan

For HVD Substations, the Company is beginning a comprehensive plan to replace all components that are beyond end-of-life and rebuild substations where needed.

The plan requires $69 million of capital spend per year until 2035, along with a ramp-up of two years until fully implemented.

Also included is an increase in O&M spending across all Substation Reliability and Demand Failures programs to adhere to the recommended maintenance intervals as defined in ESR-1, provide best practice maintenance of all major equipment, and eliminate the backlog of inspection and repair orders.

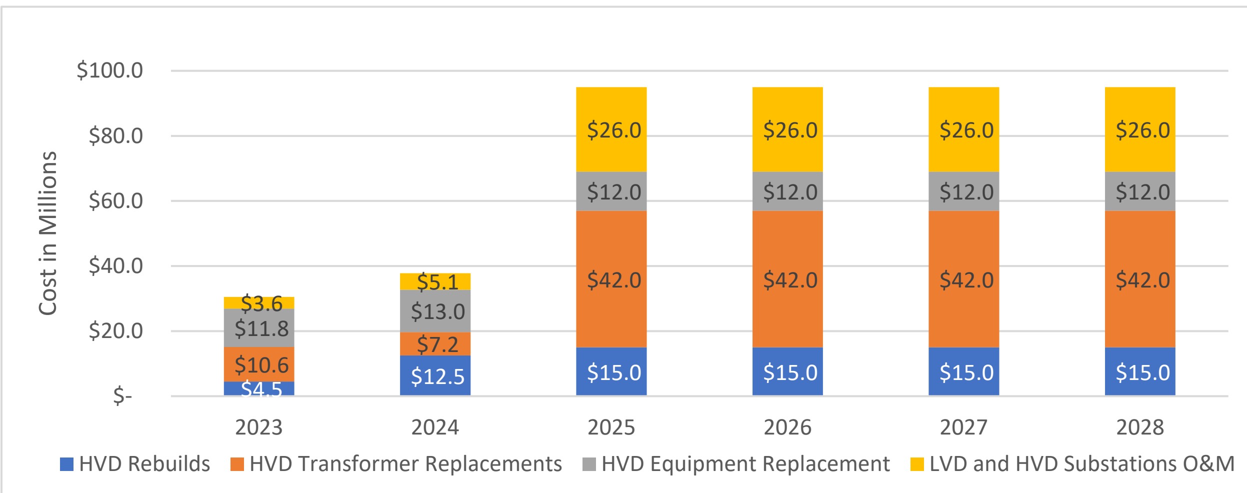
The O&M for both HVD and LVD substation are included in the HVD Substation investment plan below.

- This plan will cost $358 million over the next 5 years (see Figure 95 below) to rebuild 2 HVD substations per year, replace 9 HVD transformers per year, 10 Strategic Customer transformers per year, 40 circuit breakers per year, and other substation equipment replacement to support the Company's Reliability goal.

The reliability impact of this work is estimated to result in two less HVD or Strategic Customer Substation outages per year, reducing SAIDI by two minutes per year.

Figure 95

HVD SUBSTATION INVESTMENT PLAN



Year	Substation Rebuilds	Transformer Replacements	Equipment Replacements
2023	1	4	112
2024	2	5	65
2025	2	19	100
2026	2	19	100
2027	2	19	100
2028	2	19	100

For LVD Substations, the Company is beginning a comprehensive plan to replace all components that are beyond end-of-life, rebuild substations, and build new substations where needed.

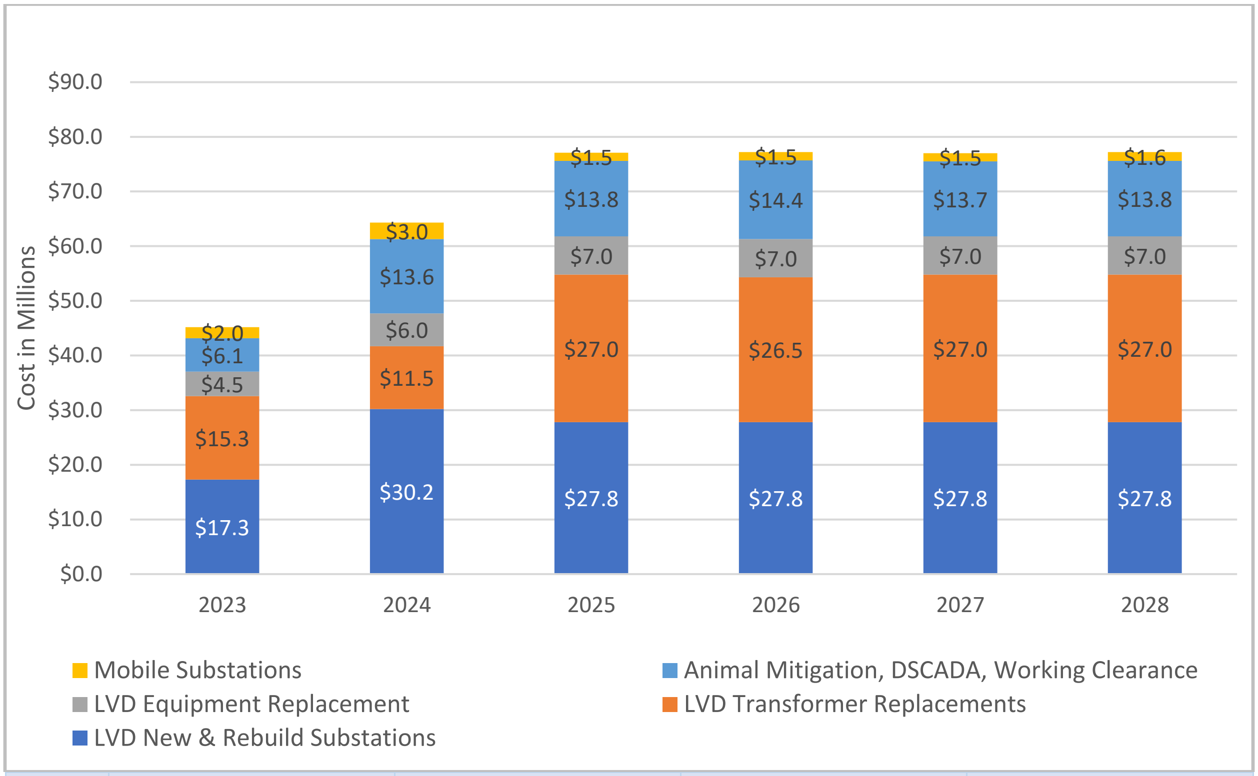
This plan will continue to maintain substations with industry best practice inspections and animal mitigation while installing DSCADA at substations for efficient control and monitoring.

- This plan will cost $373 million over the next 5 years (as shown below in Figure 96) and includes the building of 4-5 new substations per year, the rebuild of 13-14 substations per year, and the replacement of substation transformers and other equipment to support the Company's Reliability goal.

The reliability impact of this work is estimated to result in two fewer LVD Substation outages per year reducing SAIDI by two minutes per year.

Figure 96

LVD SUBSTATION INVESTMENT PLAN



Year	New & Rebuild Substations	Transformer Replacements	Equipment Replacements	Mobile Substations
2023	8	16	174	1
2024	18	13	224	1
2025	18	30	244	1
2026	18	30	244	1
2027	18	30	244	1
2028	18	30	244	1

System Protection Relays

What Protective Relays Do

The purpose of a protective system is to **de-energize as quickly as possible** the minimum amount of the electric network that has experienced an electrical fault, to **isolate the fault**, and **mitigate damage** to other equipment.

Protective systems within a substation consist of protective relays designed to trip a circuit breaker when a fault is detected.

Protection systems have two modes of failure.

- The first is **incorrect operation**—when a protective device operates when it should not. This failure mode can cause unnecessary customer outages, and in severe cases, can lead to cascading outages that result in widespread blackouts.
- The second failure mode is **when a protective system does not correctly de-energize an electrical fault**. The failure of a relay to trip properly under fault conditions can lead to severe system consequences, including an extended outage, more customers interrupted than are necessary, equipment damage as lines or transformers burn up, environmental hazards due to ruptured transformers, and public safety hazards due to fires, shrapnel from exploding equipment, and electric shocks due to uncleared electrical faults. Proactively identifying and replacing relays that are prone to failure greatly reduces the risk of these consequences.

Number of HVD Relays in Service Territory

There are 5,336 relays in the Company's service area. A relay unit is defined as a relay panel consisting of 5 electromechanical relays, 10 solid state relays or 2 digital relays.

Lifecycle Analysis

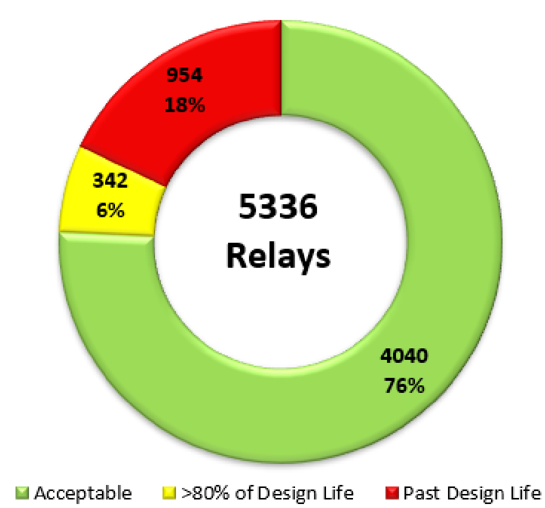
The Company has determined design life for protective relays based on vendor recommendations, industry best practices as documented by the IEEE Power System Relaying Committee, and Company experience with failure of specific relay types.

Protective Relay Asset Health and Risks

The most recent Company assessment of Relay health shows 82% of relays are in acceptable health or have not yet reached the end of their lifecycle, as shown in Figure 97 below. Of the remaining relays, approximately 18% of the protective relay population is older than the designated design life.

As relays age, they are more frequently out of settings tolerance, which can cause interrupting devices (like circuit breakers, circuit switchers, etc.) to open when they don't need to, leading to interruptions, or, not open when they should, leading to larger scale interruptions, equipment damage, and possible safety hazards. More frequent field testing and calibration is required to ensure proper performance.

FIGURE 97
RELAY HEALTH ASSESSMENT



Workplan

The Company's primary desired outcome for relay health and reliability is to keep all protective relays within design life.

Relay Replacement Plan

The relay replacement plan is a capital program to replace end of life relays with new modern relays. Multiple factors are considered to assign a risk score to each relay.

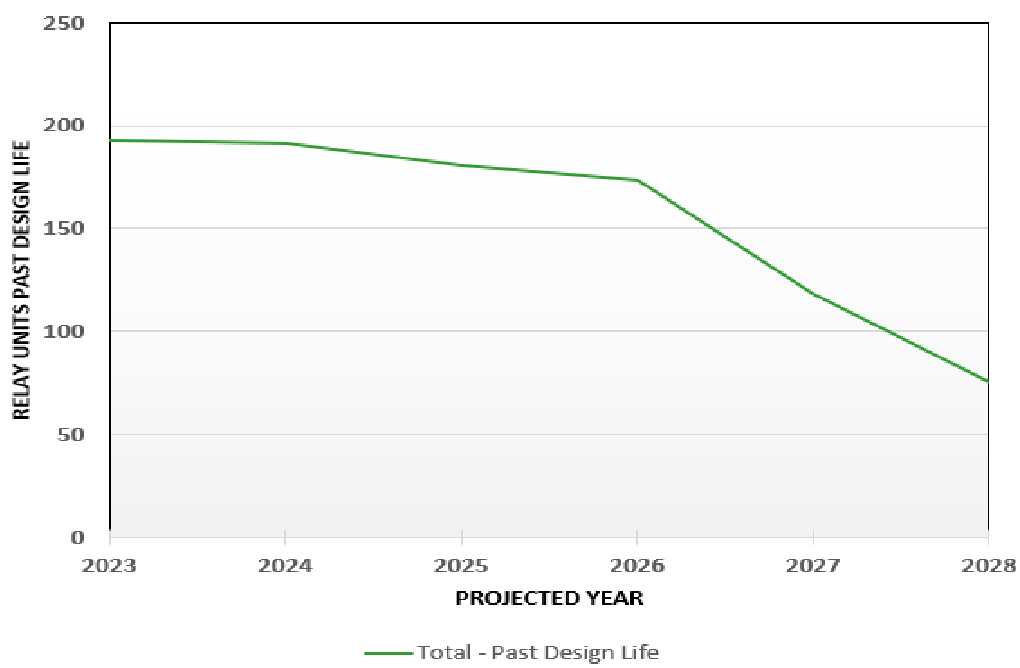
- The factors considered include relay age, relay types with a history of malfunctions, substations without digital oscillography, etc.
- The relays are then prioritized based on this risk ranking for capital replacement.

Figure 98 below shows the projected number of relay units that are past design life based on the proposed capital relay replacement plan.

The relay replacement plan will maintain all relays within lifecycle by 2031.

FIGURE 98

PROJECTED NUMBER OF RELAY UNITS PAST END OF DESIGN LIFE



Operations and Maintenance

All relays on Consumers Energy's HVD system are tested and maintained on periodic intervals, and all testing done on the relays is based on manufacturer recommendations.

The intervals are based on the type and function of relay, informed by best practices as defined by NERC Standard PRC-005, and trends observed from historical testing data.

Relays that test out of tolerance are recalibrated or replaced as necessary.

Event Analysis & Corrective Actions

The Company investigates every event on the HVD System to ensure correct operation of the protective systems.

- For all incorrect operations, the immediate cause is identified and resolved.
- For any systemic problems identified, long term corrective actions plans are developed.

System 5-Year Investment Plan

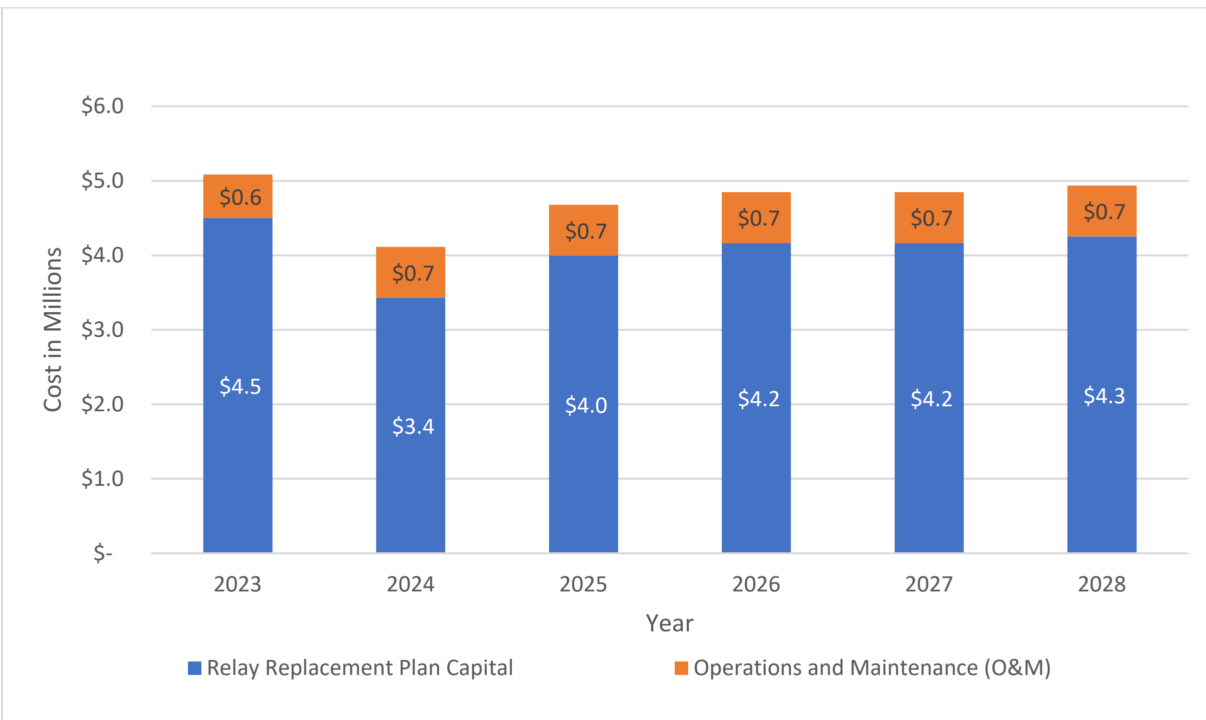
The Company will implement the relay replacements identified above, which requires $3.43 million in 2024, and $4 million in 2025, in capital spend.

Beyond 2025, the annual spend will increase with inflation as shown in Figure 99 below. This plan will replace approximately 56 relay units in 2023, 42 relay units in 2024, and 50 relay units per year starting in 2025.

The ongoing operational maintenance and corrective actions described above will require $600,000 in 2023, and $700,000 in 2024, and beyond.

FIGURE 99

SYSTEM PROTECTION INVESTMENT PLAN



Year	Relay Replacement Plan
2023	56
2024	42
2025	50
2026	50
2027	50
2028	50

HVD Load Growth and Interconnection

HVD Load Growth and Interconnection projects consists of the following:

- HVD enhancements to ensure the HVD system can serve electric peak demand in accordance with HVD planning criteria
- Work to accommodate new interconnections
- Work to improve functionality through standards
- Upgrades to protection
- Operability of the system
- Coordination with transmission infrastructure additions

HVD Load Growth and Interconnection also supports Real Estate and ROW acquisition supporting projects.

HVD Asset Health and Risk

Because the HVD system is the backbone infrastructure of the electric distribution network, projects in this sub-program must be completed on an as-needed basis to serve customers and maintain the safety and overall reliability of the grid.

Investments in this sub-program improve system reliability by preventing future overloads. These investments also help avoid dangerous wire downs and equipment failures due to overloads and exceedance of equipment interrupting capability, improving system safety.

Workplan

The Company's primary desired outcome for HVD Load Growth and Interconnection is to ensure the HVD system can serve electric peak demand in accordance with HVD planning criteria, accommodate interconnections to the HVD system, and ensure current standards to support improved functionality of the system.

Load Carrying Capabilities and Voltage Support

Load Carrying Capabilities and Voltage Support projects eliminate unacceptably low voltage, and loadings above line and equipment ratings.

The Company studies the HVD system using power flow analysis to calculate the base power flow and voltages, and changes in power flow and voltages resulting from single outages for present and future versions of the HVD system.

New Interconnections

The New Interconnection category encompasses **new interconnections to other utilities and to generation facilities** that must be completed as requested by the interconnecting party.

Costs to interconnect other utilities and generation facilities to the Company's HVD system are reimbursed by the other utilities or generators being interconnected.

Improved Functionality

The Improved Functionality category comprises **projects completed to meet changes in standards, and upgrades** to protective schemes on a planned basis over a period.

- An example of this is the Company alleviating substation NESC working space issues systematically over a 10-year period.
- These projects are often coordinated with other major projects when they occur at the same location.

Configuration changes to improve operability are made at the request of the Grid Management group or through coordination with other major projects when they occur at the same location.

Coordination with Transmission

The Coordination with Transmission projects, such as HVD relay upgrades associated with transmission upgrades, must be coordinated with those transmission upgrade projects that require the HVD upgrades to be completed.

These are completed as needed over time, in conjunction with the transmission owner.

Right of Way ("ROW") Procurement

ROW Procurement projects are necessary to **procure HVD line rights or substation sites**. These projects are critical to prepare for HVD construction and can require significant lead time.

Acquiring the necessary land or land rights is integral to advancing HVD lines and substation projects.

These projects must be prioritized to adequately support the project that is depending on the new rights (*e.g.*, new HVD line, HVD line relocation or rebuild off-center, new HVD or LVD substation, or improved easements where rights are determined to be inadequate).

Through the process of monitoring and studying load profiles, properties are sought and procured to build electric infrastructure at the right point in time needed to serve customers.

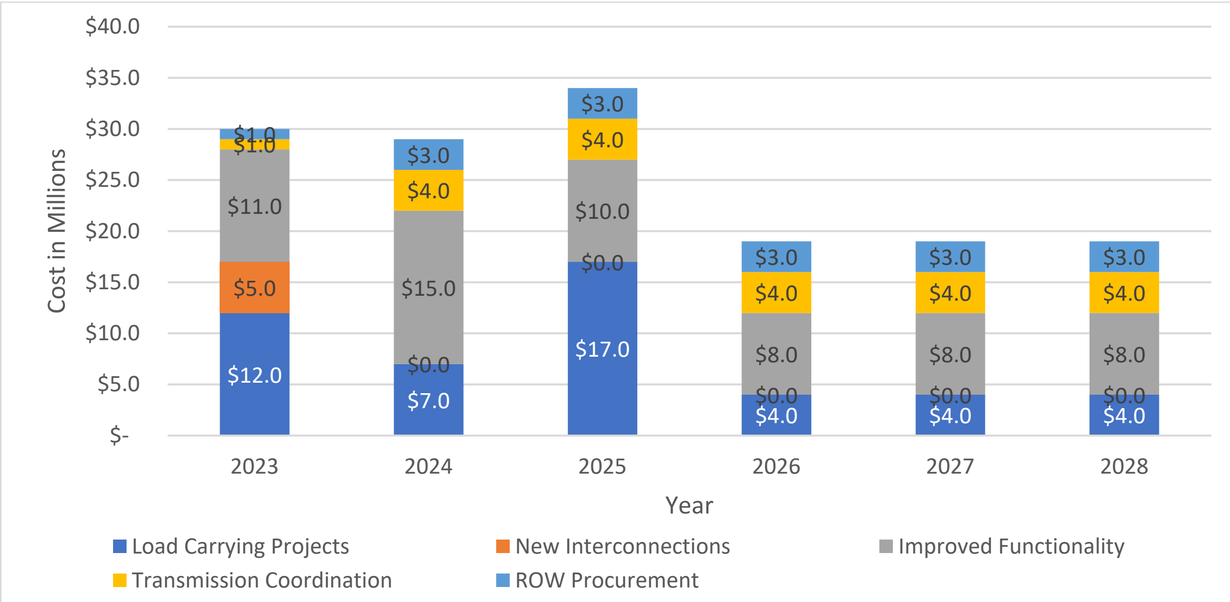
HVD 5-Year Investment Plan

The Company's investment plan is projected to cost $120 million over the next five years.

The 5-year investment plan (shown below in Figure 100) will ensure that the HVD system has the capacity to accommodate peak system load including potential changes to load profiles needed for new and changing technologies, maintain safety and reliability, and accommodate interconnection to the system.

Figure 100

HVD LOAD GROWTH AND INTERCONNECTION 5-YEAR INVESTMENT PLAN



Year	Load Carrying Projects	Improved Functionality Projects	Transmission Coordination Projects
2023	2	69	14
2024	2	91	10
2025	7	60	9
2026	7	60	9
2027	7	60	9
2028	7	60	9

Streetlighting

What Streetlights Do

Streetlights provide illumination to enhance safety and the aesthetics of roadways, residential areas, and cityscapes in various applications throughout the Company's service territory. The Company operates and maintains all Company-owned lighting.

Quantity and Technology of Streetlights in Service Territory

Consumers Energy owns and maintains approximately 173,000 streetlights. Most of these streetlights are cobrahead fixtures (see Figure 101 below).

The remainder of the fixtures are comprised of 11,000 center suspension streetlights shown and approximately 45,000 post-top fixtures (as shown below in Figure 102).

FIGURE 101

STREETLIGHT FIXTURE COUNT

Fixture Type	Count
Cobrahead	117,000
Center Suspension	11,000
Post-Top	45,000
TOTAL	**173,000**

Figure 102

EXAMPLES OF STREETLIGHTS

Cobrahead Streetlight Fixture

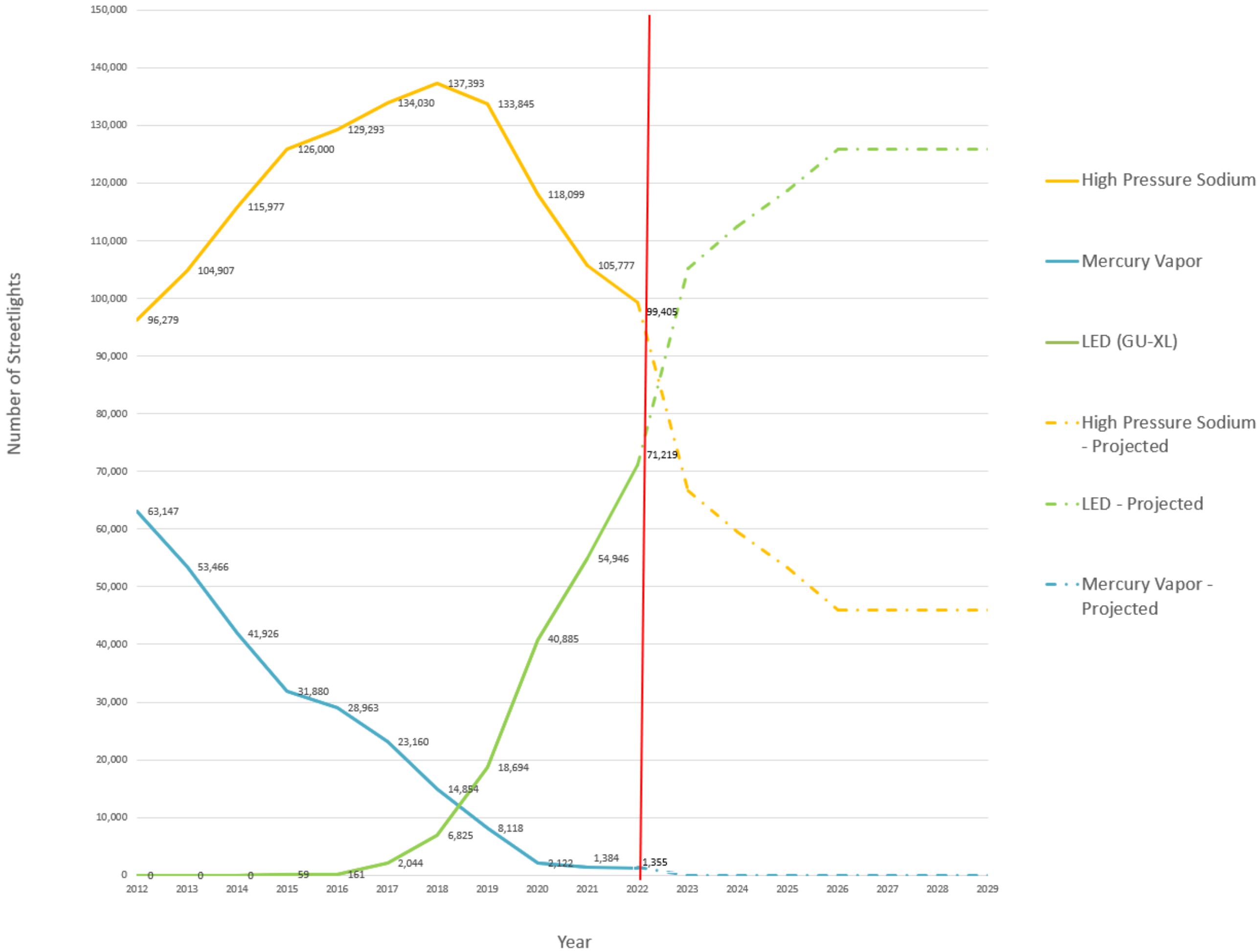
Center Suspension Fixture

Post-Top Fixture

The Company's streetlighting portfolio includes three types of fixtures: *High Pressure Sodium, Mercury Vapor,* and *Light Emitting Diode* technology.

Figure 103 below represents historical and projected technology trends. The trends reflect the Company's transition from *High Pressure Sodium* fixtures to *Light Emitting Diode* fixtures due to the increase in efficiency.

FIGURE 103
Streetlight Technology Trend



Lifecycle Analysis

The shortest lifecycle component of a streetlight is the *lamp*, which drives the useful life of a streetlight.

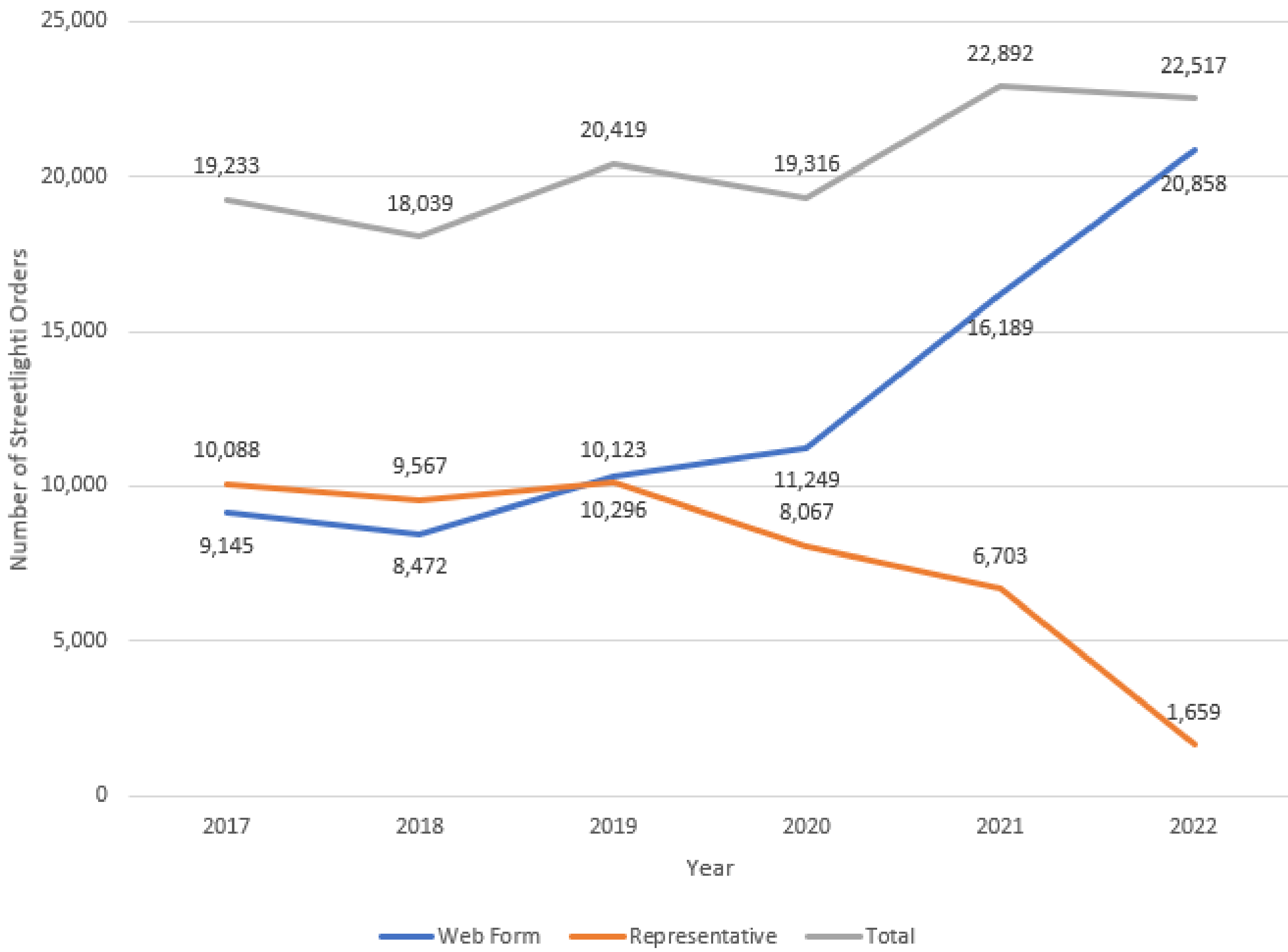
- Lamps on the high intensity discharge ("HID") fixtures are rated for 24,000 hours of service.
- With approximately 4,200 hours of lighting service annually, the average life of the lamps in HID fixtures is approximately six years.
- Newer lighting technology light emitting diode ("LED") fixtures are more efficient and are rated for 84,000 hours of service bringing the average life of a LED fixture to 20 years.

Streetlight Asset Health and Risks

As shown in Figure 104 below, approximately 20,000 streetlight outages and issues are reported each year.

- Non-third party related primary causes of streetlight outages are attributed to bulb failures.

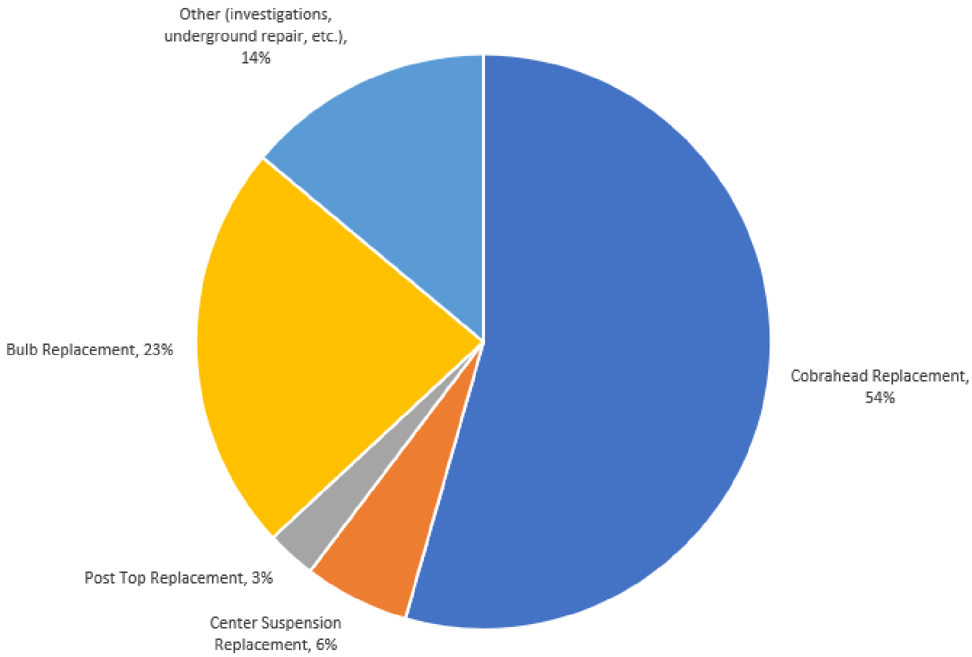
FIGURE 104
Streetlight Orders by Creation Type



A breakdown of *work type* is shown in Figure 105 below.

FIGURE 105

WORK TYPE BREAKDOWN OF 2022 STREETLIGHT ORDERS



Workplan

The ideal state for the Company's Streetlighting program is to repair or replace streetlights only at the end of the component lifecycle, rather than having to replace components that fail early. Extending the lifecycle of the luminaire reduces repair expenses across the Company's streetlight portfolio.

LED Conversion of HID lamps across all applications reduces the frequency of bulb-related outages.

To facilitate this, Cobrahead and center suspension HID installations will be converted to LED technology upon failure, and post-top streetlights will be converted to LED upon failure.

In addition, vicinity conversion tactics will be used for Cobrahead and Post-Top installations. Vicinity conversions upgrade in-service HID lighting in the vicinity of a failed luminaire, and this reduces costs per conversion by reducing frequency of repair worker mobilization to the same area.

Streetlight 5-Year Investment Plan

The Company will commence one vicinity upgrade for each Cobrahead failure starting in 2025 through 2026, at an estimated rate of 11,100 Cobrahead vicinity conversions per year.

- The Company estimates all Cobrahead fixtures will be converted to LED technology near the middle of 2026. This plan will cost $11.5 million over three years.

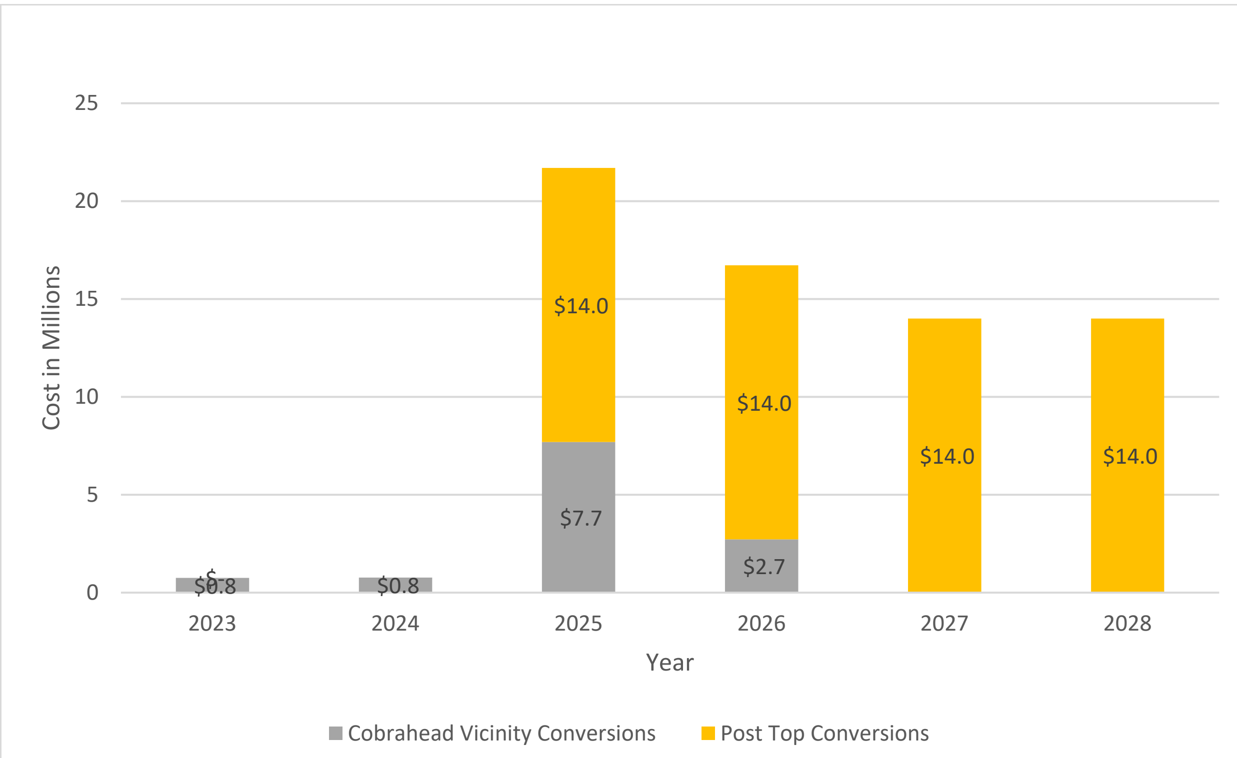
The Company will also begin converting failed HID Post-Top lights to LED technology and implement a vicinity conversion upgrade of in-service HID Post-Top fixtures starting in 2025.

- This effort is expected to convert approximately 7,850 HID Post-Top lights to LED technology per year.
- The Company estimates all Post-Top fixtures will be converted to LED technology by mid-2030. This plan will cost $84 million over approximately six years.

Failure costs of streetlight assets are expected to be reduced following the completion of LED conversions. The 5-year investment plan for streetlighting is shown below in Figure 106.

Figure 106

STREETLIGHTING INVESTMENT PLAN



Year	Cobrahead Vicinity Conversions	Post Top Conversions
2023	1,600	0
2024	1,600	0
2025	11,100	7,850
2026	6,400	7,850
2027	0	7,850
2028	0	7,850

Additional Topics

Technology, Analytics, and Grid Modernization

Grid Modernization refers to the planned process of **investing in grid infrastructure improvements** (poles, wires, transformers, etc.), **incorporating new technologies and applications into the electric system to increase reliability**, **optimizing energy delivery**, and facilitating the **optimal utilization of DERs**.

While many utilities share common themes for defining Grid Modernization, every utility has a unique approach for implementing and enabling Grid Modernization capabilities due to their unique customer, geographical, operational, regulatory, and business needs.

- Grid Modernization plans include **standardization and deployment of new technology** in substations and on electric lines.
- Also included are **development of new tools and systems** to improve the way the Company monitors, controls, and optimizes assets.

The Company continues to invest in new technologies and digital tools to build for the future through research, testing, and development of modern grid technologies that support key Company objectives of safety, reliability, and efficiency.

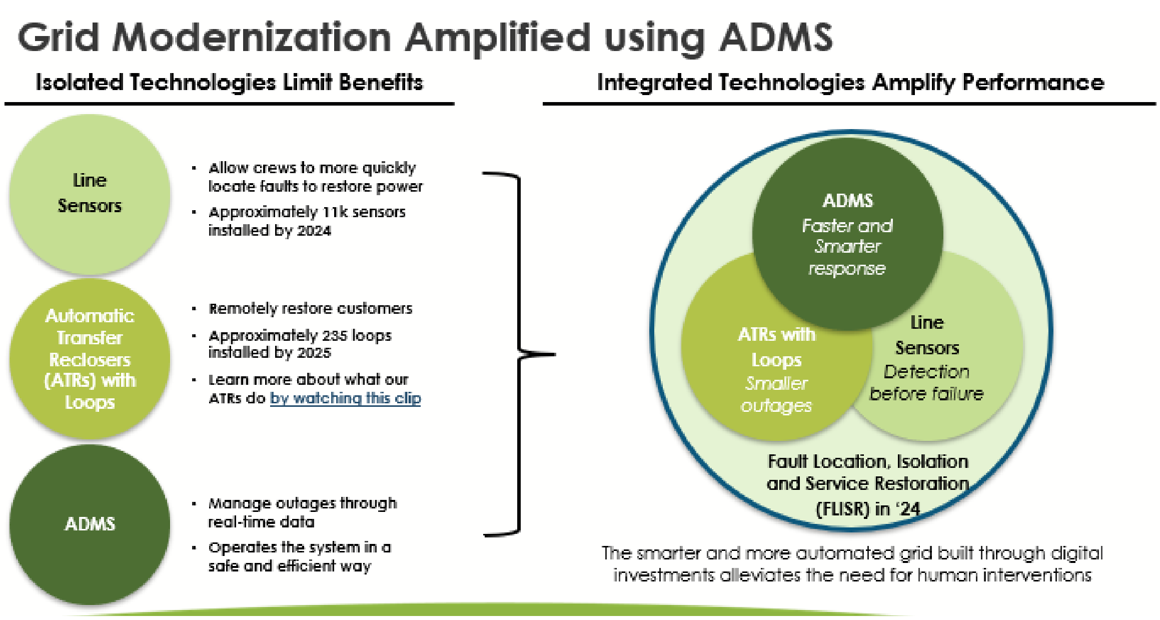
Advanced Distribution Management System (ADMS)

ADMS is the **software platform that supports the full suite of distribution management and outage management** systems.

This platform brings together the Company's Distribution Management System ("DMS"); its Field Mapping Applications; and its Electra Outage Management System ("OMS"), which includes additional outage applications (tools that integrate with ADMS and aggregate outage-related information).

Figure 107

GRID MODERNIZATION INTEGRATION WITH ADMS



ADMS is dependent on the following:

- Supervisory Control and Data Acquisition or SCADA, as described in the Substations section.
- Geographic Information System ("GIS")
- Advanced Metering Infrastructure or "AMI"—a two-way communication system that collects detailed metering information throughout the Company's service territory.

ADMS real-time functionality drives improved decisions to make the electric distribution grid more efficient, enabling the Company to get customers' lights on faster.

There are two main enhancements to the ADMS platform planned, along with continued integration improvements with additional outage applications, including:

1. Implementation of the Field Mapping Application
2. Completion of the DMS platform to include:
    a. Fault Location Isolation & Service Restoration ("FLISR")
    b. Switching Order Management ("SOM")

The ***Field Mapping Application*** will extend the use of ADMS core functionality to the Company's field workforce.

This Application **will improve workforce efficiency by providing field employee precise real-time circuit maps and damage assessment information**.

Real-time damage assessment—when combined with 2024 implementation of Live Wire Down—will **improve customer experience** through the Company's current online outage map while also improving public safety through reduced restoration times.

Completing the *DMS* portion of ADMS will add enhancements focused on implementing all FLISR and SOM software modules.

- **FLISR** is an ADMS application that **uses electronic reclosers and line sensors to automatically identify where faults are on the system**; FLISR then automatically reroutes power to the affected areas. A subsequent benefit is that it decreases public safety risk of encountering energized downed wires.
- **SOM** is an ADMS **application that generates switching orders for field workers**, which will send automatic control signals via SCADA to perform and verify automatic switching operations. Using 'point-and-click' interaction with graphical applications, a switch order is established and validated against real-time operating conditions via network interface (allowing pre-verification of the order before it is dispatched, saving time in outage response).

In addition to the two primary enhancements, the Company expects to **improve system Reliability and Resiliency through use of automation and digital tools to support ADMS.** Better integration of outage applications not currently incorporated into the Electra OMS or DMS will better integrate real-time data for restoration.

Aside from Reliability benefits, the Company will be less at-risk from catastrophic system failure.

The Capital investments for 2024 and 2025 forecasted to cost approximately $4 million in total and deliver 15 minutes of SAIDI savings by 2025 as shown in Figure 108 below.

FIGURE 108

ADMS COST and SAIDI

ADMS Enhancement	2023 Capital	2024 Capital	2025 Capital	SAIDI Savings (excluding MEDs)
OMS Electra incl Live Wire Down	$800k	$900k	$0	5 minutes
Field Mapping Application	$0	$1,600k	$0	4 minutes
DMS complete FLISR and SOM				
Outage Applications Integration	$250k	$250k	$0	4 minutes
AMI Automation Use Case	$150k	$0	$0	2 minutes
Total	**$1,200k**	**$2,750k**	**$0**	**15 minutes**

Line Sensors

Line sensors are **devices that attach to primary lines to monitor current and faults as shown in Figure 109.** They detect faults and determine a probable location of an event, making them critical in enabling FLISR.

Line sensors also provide information such as loading, phase balance, momentary outages, line disturbances, and other alarms.

- Line sensors can be used to improve the LVD planning process by providing more accurate load flow modeling. This more precise and real-time load information can be used to improve the load transfer process both for planned and unscheduled outages.
- This tool reduces the duration of the manual load transfer writing process and improve the accuracy of the modeled transfers.

Today, the Company has installed more than 8,000 sensors on the LVD system and more than 500 on the HVD system.

Over the next 5 years, the Company plans to have more than 12,000 sensors installed on the LVD system that it anticipates will provide optimal coverage of the grid to support the FLISR program.

FIGURE 109

3-PHASE LINE SENSOR INSTALLATION

Distribution Circuit and Substation Modernization

In addition to the technologies listed above, the Company continues to participate in utility research projects and innovation forums.

As new LVD technologies are shown to provide utility value they are considered for inclusion within the strategic **Distribution Circuit Modernization ("DCM") roadmap** that provides a long-term plan to enable new technologies that build on the learnings and capabilities of others in the roadmap.

New technologies are run through a robust *Technology Enablement Process* ("TEP") (see Figure 110 below) to ensure all facets of the technology solution are ready for use by Company stakeholders.

FIGURE 110

HIGH-LEVEL TECHNOLOGY ENABLEMENT PROCESS

- The DCM roadmap is a living document that will iterate based on learnings and success from newly established technological integrations on the grid, as well as align with utility industry best practices and research.

Similarly, the **Substation Modernization** program maintains a strategic substation technology roadmap with a vision to advance substation infrastructure to the next generation and includes IP-enabled networking capabilities.

- Substation Modernization initiatives will also follow the *Technology Enablement Process* and build out progressively beneficial and interdependent substation systems and devices.

Distributed Energy Resources ("DER") Optimization

The Company has launched an initiative to standardize and prepare the grid for the anticipated growth of DER, as discussed earlier in the Non-Load Challenges from Customer Technology Adoption section.

The DER Optimization initiative consists of a variety of hardware and software deployment projects to develop, evaluate, and standardize DER management capabilities across the spectrum of DER types.

- Projects will be sequenced so that initial deployments focus on grid-edge capabilities that include DER gateways.
- DER gateways optimize controllable resources based on local conditions, as well as provide communications and translation services to a diverse set of DER.
- DER gateway projects on the grid-edge include solar arrays, batteries, EV chargers, and circuit-level deployments.
- As DER penetration increases, the Company plans to deploy a centralized DER management system (DERMS) that will provide system-level grid benefits such as peak shaving and market participation.
- A centralized DERMS is critical in managing bi-directional power flows, power quality concerns, and interconnections with third party DER.
- High levels of DER penetration may negatively impact reliability, efficiency, and overall grid performance if not properly monitored and managed.

The DER optimization will not only mitigate these threats but will lead to reliability and efficiency improvements. **DER benefits can only be fully realized when they are comprehensively integrated into grid operations.** Therefore, DER must be visible to and controllable by the Company's grid operators to ensure reliable, affordable, and safe electric service.

Distribution Asset Management ("DistAM")

DistAM is the application of **asset management principles and processes to electric distribution assets to maximize the usefulness and realization of value over their lifecycle.**

Previous sections covering LVD and HVD assets described current state asset health and management practices. However, the Company has identified the need to develop a centralized and standardized asset management strategy that encompasses all electric assets in a unified approach.

Our DistAM program will enhance existing lifecycle management capabilities by **collecting key asset data (*e.g.*, age, nameplate data, location) to drive a risk-informed, value-based decision-making methodology** to manage and optimize asset investments. This work is aligned with industry best practices defined in ISO 55001, as well as from the *Michigan Infrastructure Council Asset Management Program*.

Asset Management will standardize the Company's asset life-cycle processes, data, and technology, allowing for improved capture, analysis, and visualization of asset health, which will lead to more optimized investment planning scenarios.

The primary benefits of DistAM include:

- Reduced capital and maintenance costs.
- Reduced customer outages and restoration costs.
- Reduced power quality issues and system losses.
- Increased asset availability and deferred capital depreciation.
- Reduced asset degradation risk.
- Improved resilience of the electric distribution system.

The DistAM strategy identifies three key components that will deliver a robust asset management system. These components are *Asset Repository*, *Asset Performance Management* ("APM"), and *Asset Investment Planning* ("AIP").

These components will leverage collected distribution asset data into a single centralized database, which provides enhanced integration into asset health performance analysis and investment strategy platforms.

- In 2023 the Company plans to initiate development of the Asset Repository.
- The frameworks for AIP and APM are expected to follow, however, development and growth of these will continue over the following years as more assets are rolled in through an agile methodology.

Data and analytics are becoming increasingly critical to inform daily business tasks, long-term investment decisions, and to drive continuous improvement of grid operation.

DistAM is an essential part of the Company's broader initiative to maximize reliability and resiliency by optimizing how the electric distribution system is proactively maintained and managed.

Realizing the benefits of these assets requires effective management of the electric distribution system which is the foundation that DistAM provides.

Grid Modernization 5-Year Investment Plan

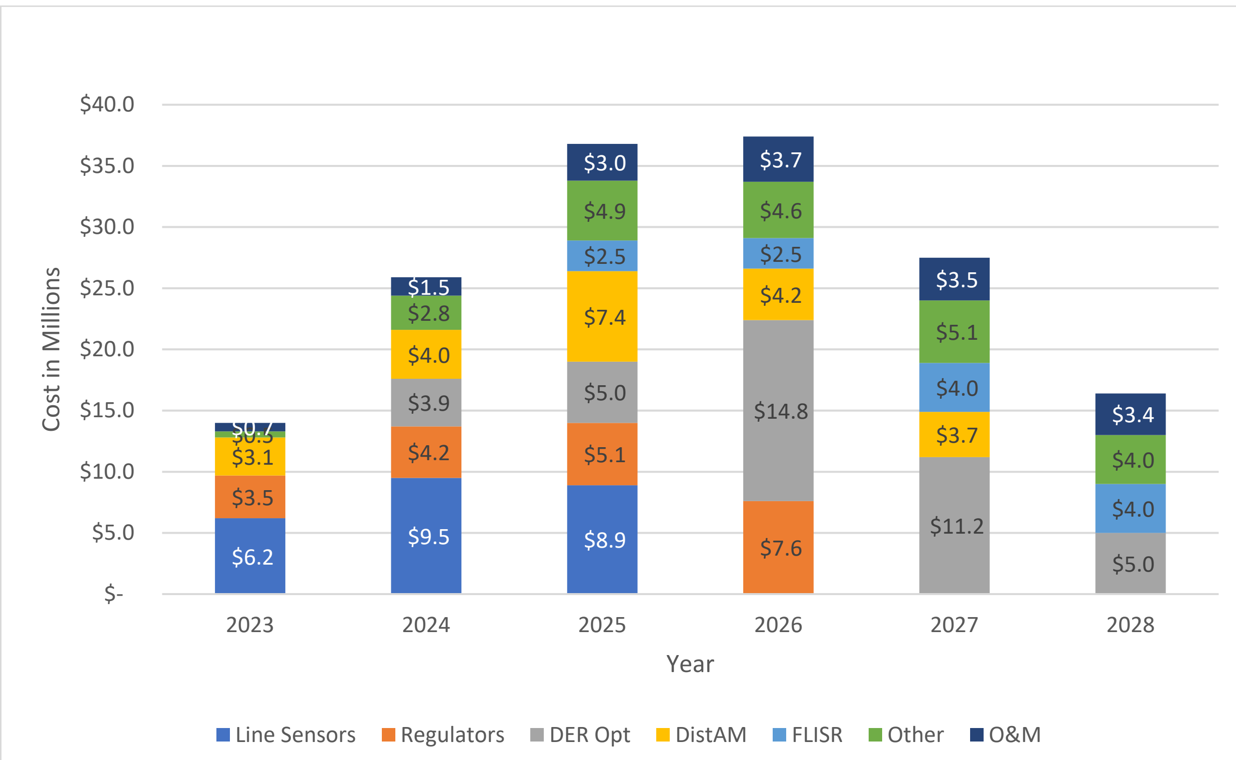
The Company will invest in the modernization of the electric grid through various hardware and foundational software deployments.

This includes deployments of remote-communicating grid equipment such as Line Sensors and Voltage Regulators. It also includes foundational software deployments such as DistAM, DER Optimization, and FLISR that prepare the grid for the future.

This plan will cost more than $130 million over the next 5 years and is detailed below.

Figure 111

GRID MODERNIZATION 5-YEAR INVESTMENT PLAN



Year	Line Sensors	Regulators
2023	2,370	160
2024	2,860	201
2025	1,000	170
2026	0	254
2027	0	0
2028	0	0

Next Digital Investments

Integrating emerging technologies, data, and analytics for Consumers Energy is instrumental in achieving our Company goals with great precision and foresight.

Our Next Digital Investment strategies provide valuable insights enabling **data-driven decision-making leading to enhanced efficiency, improvement to risk management, and cost reductions**—all to ensure our business remains resilient and reliable in a rapidly evolving digital landscape.

Additionally, using emerging technologies helps provide actional insights to tailor our tools and services to meet customer demands effectively.

By leveraging the next digital investments such as artificial intelligence, machine learning, and automation, we can **optimize processes, identify trends, and improve customer experiences**.

Transformer Analytics

Transformer Analytics will allow the Company to **identify and understand the imminent failure of a transformer before it occurs**. Such knowledge will **enable crews to replace the transformer proactively at a lower cost to rate payers, instead of replacing it emergently** after the transformer has failed.

- This will be accomplished by leveraging numerous data sources to determine if the characteristics of a transformer are displaying signs that will result in near-term failure.

The Company is pursuing an internally developed machine learning model that can provide an on-going list of identified transformers close to failure. The list will then be integrated into our work management systems, signaling an order must be created and work must be scheduled for the transformers to be proactively replaced.

- The first iteration of this model will be implemented in January 2024.
- Information Technology will start work in the second quarter 2024 to begin integrating model output, and this is planned to be completed early in the fourth quarter 2024.

This project is expected to save one minute of SAIDI in 2025.

Restoration Wait Time Tracker

The Restoration Wait Time Tracker will **provide the ability for storm response teams to understand in real-time what is happening in the field** during restoration activities.

Visibility into work orders, crews, hazards, and outages all in one place is critical in identifying where we have waste within our processes. Our storm response teams can then see in real-time when and where delays are occurring and take action to resolve barriers. This will lead to faster storm restoration.

- The Tracker will be an internally developed tool designed to leverage real-time access to a multitude of data sources so that it can display outage response performance in a single location.
- Real-time data will be available in second quarter 2024, and development of the product is planned to be completed in first quarter 2025.

This project is expected to result in 0.5 minutes of SAIDI savings.

Catastrophic Crewing Replacement

Catastrophic Crewing (“CatCrew”) is the Company’s 15-year-old home-grown resource management software tool used during storm restoration.

- This tool captures information about who is engaged in storm restoration, the Headquarters they are working from, and their work and rest time periods.
- CatCrew also captures lodging and food requirements needed for resources engaged in storm response.

This tool **enables the Company to have a clear and up-to-date picture of resource capacity and engagement**, ultimately leading to a more efficient and faster restoration.

After restoration work is complete, we use the data captured within CatCrew to perform advanced analytics and identify improvement opportunities.

We are pursuing a vendor-provided software product to replace CatCrew due to our current software becoming outdated and difficult to maintain. The procurement of internal and external resources during storm restoration can be a prolonged process and **replacing the current software with a more responsive system will allow us to realize efficiencies** in procuring needed resources.

- Vendor-provided products exist with the functionality we need, including integration with hotels and food providers.
- The Company is in the beginning stages of the Request for Proposal (“RFP”) process and estimates this will run through 2023, with selection occurring in first quarter 2024.
- The Company plans to have a new software solution implemented in 2025.

We expect this project to result in one minute of SAIDI savings.

Anomaly Detection Analytics

Anomaly Detection Analytics **leverage sensor data across our LVD and HVD systems to understand whether we are experiencing conditions** (asset deterioration, tree branch interference, etc.) **on our lines that are likely to cause an outage.**

These analytics will allow crews to complete work to mitigate these conditions proactively at a lower cost to rate payers as opposed to addressing these in an emergent condition after the outage has occurred.

In 2023 we have partnered with a third party to work on initial analytics as a pilot.

- In 2024 we will make the determination on whether to continue to use a third party solution or move to developing an in-house model.
- Scaling and operationalizing these models will occur in 2025.

This project is expected to result in 1 minute of SAIDI savings.

Forestry Workplan Intelligence & Strategy Engine ("WISE") Phase 2

As discussed in the *Forestry Line Clearing Program* section, the Company is working to enhance its use of advanced technology in this space.

One opportunity is in **field work management and the automation of data collection** processes to a more granular level for Line Clearing planning and execution.

- The decision to build or purchase a solution is being evaluated through the RFP process.

If built internally, this project is estimated to result in 1.5 minutes of SAIDI savings in 2025.

Imagery Analytics

The Company will re-imagine the inspection process across the various energies, **using drones in a much more intentional manner, while investing in automation and machine learning** to increase the efficiency with which defects are identified.

- Currently, the Company performs cycle-based inspections on its Electric System through manual processes that require employees to physically walk or drive the system to perform a visual inspection, take photos, and manually document, and classify their findings.
- Through investments in automation and machine learning, the Company can achieve Full System Inspection, including 360-degree views of assets created through automated image collection by various methods (drone, helicopter, robotics, etc.) and trained machine learning models that identify and analyze assets to target reliability improvements.
- For example, as mentioned above in the HVD Lines section, the Company is using artificial intelligence software and machine learning to automate the review of video from the annual helicopter inspection to identify specific locations of victor-type insulators, which are the biggest driver of outages on the HVD system.

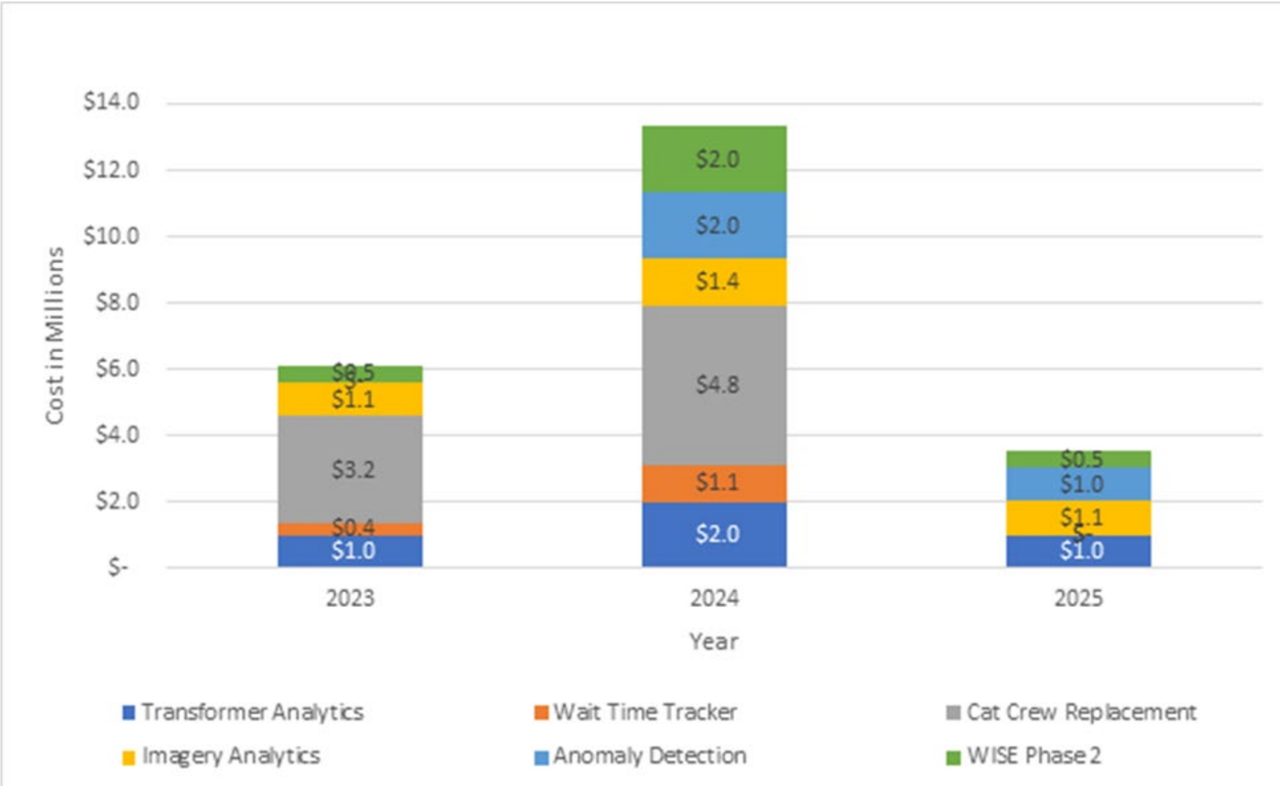
This project is expected to result in 2 minutes of SAIDI savings by 2025.

Technology and Analytics Investment Plan

The plan for Next Digital Investments will cost $20 million over the next three years and result in seven total minutes of SAIDI savings.

See Figure 112 below for the Next Digital Investments plan.

Figure 112
NEXT DIGITAL 3-YEAR INVESTMENT PLAN



Resources

Overview

Field resources are an essential component for the successful continued investment into the electric distribution system. Resources both internal to the Company and externally contracted are staffed to match the work demand.

- The Company uses a **long-range resource planning process** to build workforce plans through a cross-functional planning methodology and deliver an optimally sized workforce that meets the Company's long-term strategy needs.
- **This process reviews and aligns with a one-to-five-year resource plan**, factoring in demand, resource requirements, and resource availability to bring visibility to gaps and develop actions and scenarios to close them.
- The team leading the process **engages with Executive Leadership monthly** to adjust resource plans and ensure resource adequacy.

This collaborative resource planning process works across the Electric Distribution organization to make informed decisions about the Company's electric field resources. The multi-year view ensures resource decisions are made with sufficient lead time to recruit, hire, and prepare Company field resources and external workforces for the work required.

The Company's field resource growth over the last five years has been deliberate to match the forecasted work demand and resource requirements for future years identified through the resource planning process.

This growth was due primarily to acquiring LVD field resources through apprenticeship hiring. This headcount has been complimented during peak work demand months with a contractor workforce and has successfully met the work demand within each year.

Historic headcount levels for Company field resources over the last 5 years are shown below:

Figure 113

ELECTRIC DISTRIBUTION OPERATIONS: HISTORIC FIELD RESOURCE HEADCOUNT LEVELS

	2018	2019	2020	2021	2022
Year End Headcount	942	1,019	1,034	1,164	1,235

Ensuring Resource Adequacy

Using the resource planning process in collaboration with Electric Operations leadership, the upcoming multi-year resource forecast is available for field resources.

Figure 114 indicates the year end headcount required to meet our ambitious electric distribution investment strategy for 2023 through 2027.

Figure 114

ELECTRIC DISTRIBUTION OPERATIONS: FORECASTED FIELD RESOURCE HEADCOUNT REQUIREMENTS

	2023	2024	2025	2026	2027	2028
Starting Headcount (2023 = Current HC)	1,284	1,326	1,494	1,650	1,876	2,032
LVD Apprentices (typical plan)	30	72	48	24	24	24
LVD Overhead (Resilient Grid Plan)	0	0	66	160	96	0
Underground	22	60	60	60	54	0
HVD (including HVD Lines)	0	66	12	12	12	12
Attrition	-10	-30	-30	-30	-30	-30
Year End Headcount Plan	1,326	1,494	1,650	1,876	2,032	2,038
Growth Percentage		**12.7%**	**10.4%**	**13.7%**	**8.3%**	**-0.3%**

The previous 5 years and years 2023-2024 incorporated resource growth with the Company's LVD workforce to meet identified work demand; however, implementing the *Resilient Grid Plan* will require that workforce growth accelerates more rapidly to meet the immediate resiliency investment needs of the grid.

The Company supports its widespread LVD overhead system with a small workforce for its extensive mileage and coverage across the state of Michigan. This is executed with an efficient workforce and operations.

Even with this demonstrated efficiency, the scale of work outlined in this plan requires an even more aggressive growth rate to adequately support the planned investments.

Projected headcount growth is driven by three main factors:

1. **LVD overhead field resource growth** of apprentices or qualified line workers to support the necessary system investment, which will be balanced with external contractors across peak time periods.
2. **Underground workforce growth** to match the proposed conversion work of 400 miles per year beginning in 2027.
3. **HVD workforce** to support committed overhead line programs.

Maintaining a consistent workforce size or planning for growth—both require a reliable pipeline of talent to balance or exceed forecasted attrition. Therefore, to ensure a talent pipeline for a long-term sustainable workforce, the Company initiated partnerships with strategic community colleges starting in 2008 to host line worker pre-apprenticeship programs.

These programs embody the triple bottom line by providing skilled trade training opportunities to local communities and future employees, investing in communities and their prosperity, and bringing diverse talent to the forefront of leading the clean energy transition.

- The *School to Work* program is one partnership that is currently investing in communities such as Flint, Muskegon, Alpena, Lansing, Grand Rapids, and Jackson, where career opportunities are immensely impactful, and continues to reinvest in the state of Michigan.
- This purposeful effort has yielded great success, as 74% of the Company's apprentice line worker hires have come through its *School to Work* programs since 2014.

Figure 115 and Figure 116 showcase some of these students and their training experiences.

Figure 115

SCHOOL TO WORK STUDENTS: MOTT COMMUNITY COLLEGE (FLINT, MI) & ALPENA COMMUNITY COLLEGE (ALPENA, MI)

Figure 116

Line Worker Pre-Apprenticeship Training: Alpena Community College (Alpena, MI)

The growth requirements of the underground workforce will be met as the Company will promote opportunities to other field resource roles in the Company who would be well-suited for this growing workforce.

The external programs that recruit these entry level roles confirm prerequisite skills for successful energy careers and have an extensive nation-wide pipeline.

To meet the investment into the electric grid that customers need and require, the Company's workforce plans also integrate the following methods to adequately staff for the future work demand, which will balance staffing growth:

- Drive towards increased efficiency in work or optimized scheduling, such as packaging similar work on a common circuit or within a single outage.
- Build work plans with agility to use the right workforce at the right time for the right response, allowing work to be levelized across months or peaks to be supported by contractor workforces.
- Manage workforce plans to inform talent pipeline programs with adequate lead time for apprenticeship training and hiring.

Using these methods will ensure work demand and field resource needs are identified for a minimum of a 5-year forecast. The Company's past successful hiring practices instill confidence that all forecasted headcount requirements will be met and will deliver a diverse and hometown-focused workforce.

Economic Development and "Mega-sites"

EPRI recently published a prospectus (*The Impact of Industrial Onshoring on Electric Sector Demand Growth*) assessing the impacts of industrial onshoring that represents a unique opportunity for the Company and Michigan to partner together to win major industrial projects and boost the state's economy.

Following the Russian invasion of Ukraine and the COVID-19 pandemic, business sectors and individual organizations are factoring supply chain risks into strategic positioning and operational decision-making.

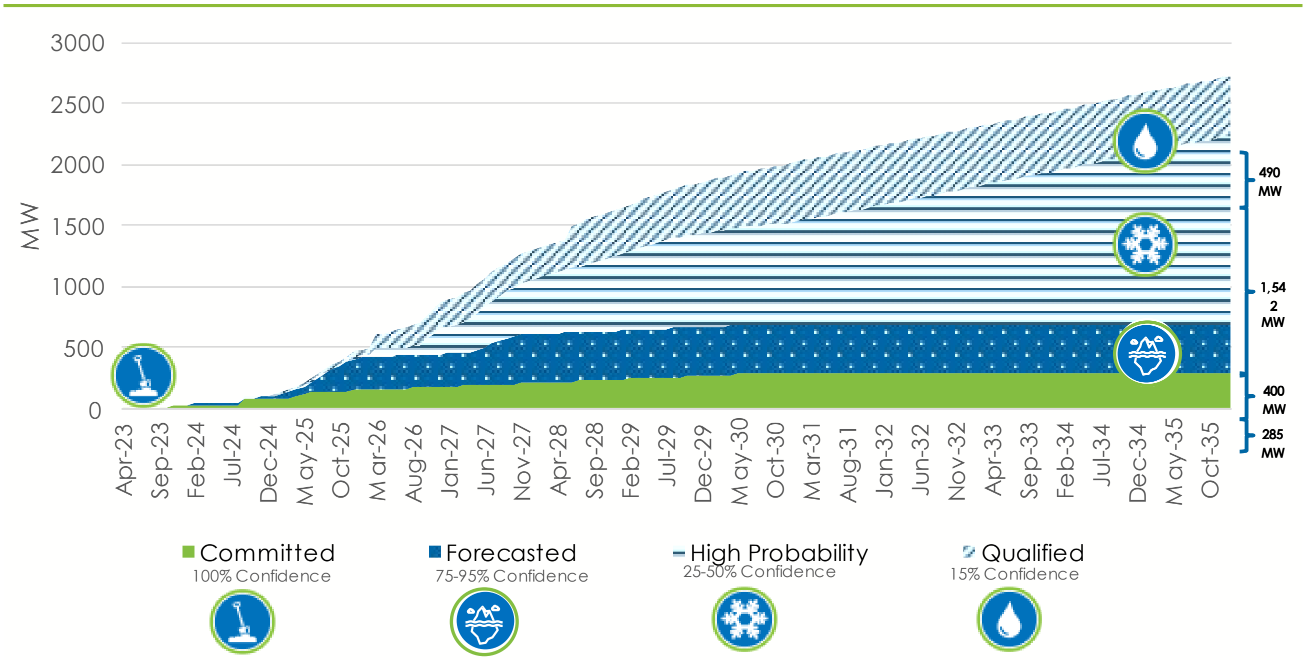
Similarly, US policymakers are investing unprecedented sums in domestic manufacturing, infrastructure, and decarbonization to improve national security and create jobs.

These events have created new conditions and opportunities for states to coordinate with the utilities to address the complex needs associated with securing these projects.

New manufacturing plants can generate significant local impact by adding large blocks of load. Serving new demand creates the need for new approaches to load as well as coordinated planning and development of grid infrastructure. This is because the demand growth created by industrial onshoring can have disruptive impact at local levels. Figure 117 below shows the load projected to be added to the system as part of large projects greater than 35 megawatts ("MW").

Figure 117

ECONOMIC DEVELOPMENT LARGE PROJECT MW PROJECTIONS



Industrial reshoring is already creating demand growth in the Company's service territory, which is poised to play an outsized role in the EV battery industry, due to its auto manufacturing proximity to existing manufacturing plants for American automakers.

- To win these major projects, **increased coordination among the Company as well as manufacturers, system operators, development agencies, regulators, and other stakeholders is essential** to ensuring significant new demand can be met efficiently and in a timely fashion.

Workplan

The Company regularly works with the *Michigan Economic Development Corporation* ("MEDC") and other local economic development groups competing for prospective new large industrial customer facilities that are considering establishing a site in Michigan.

- We provide competitive electric service proposals as part of a broader Michigan response to RFPs.
- Many of these RFPs are very competitive in nature, and consider sites across North America, including considering if a site is ready and able to meet customer project timelines.

These RFP response efforts benefit the broader economy of the state of Michigan when a Michigan site is selected as the final location.

Large new customer connections and load additions provide the benefits of job creation, plus other state and local government revenue streams associated with business expansion.

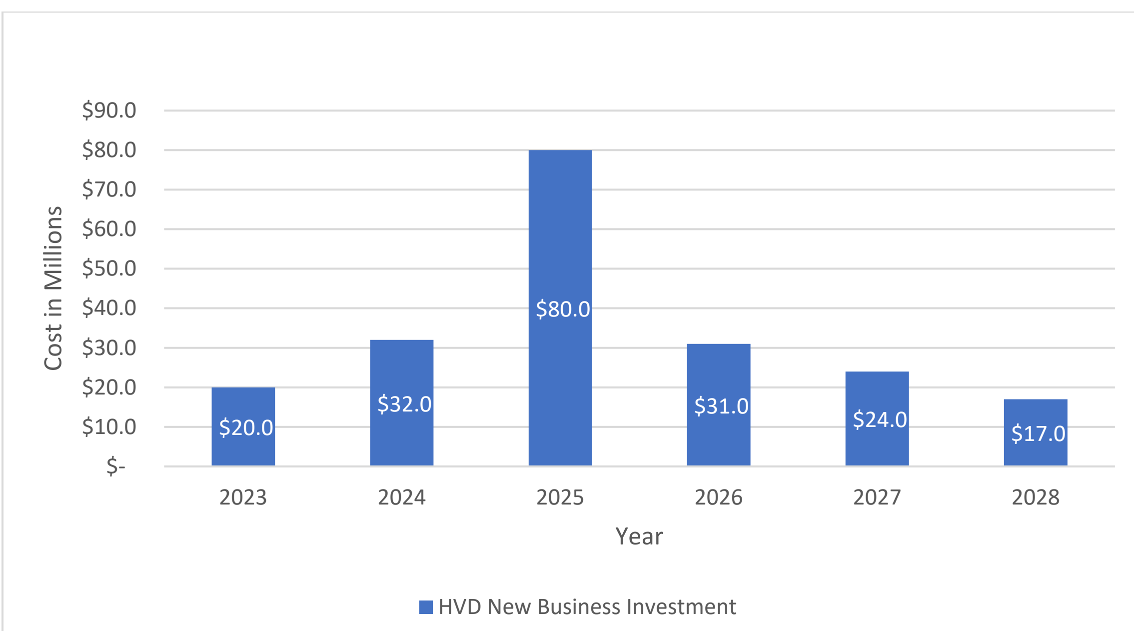
However, the Company has learned that the lead time to install a large, new dedicated customer substation and the associated lines are often prohibitive for potential customers, who are looking for "shovel-ready" sites where they can start production as soon as possible.

- As first detailed in Case No. U-21389, the Company is proposing that it prepare for such a situation in advance by designing, purchasing long lead-time equipment, and acquiring ROW easements for a new dedicated substation in advance of a customer commitment.
- This will reduce the time it takes to be able to provide the electric solution needed by these potential customers, and create an advantageous position to attract large, transformational, and new business opportunities to the state of Michigan.

Figure 118 below represents the planned investment needed to support known and planned projects and potential projects that are known but not yet committed.

Figure 118

NEW BUSINESS PLANNED INVESTMENT



Conclusion and Financial Summary

The Company is modernizing its electric distribution system to safely deliver clean, affordable, reliable power to customers throughout Michigan. **The goal is simple: fewer and shorter power outages for customers. T**he vision for the grid is a blueprint for serving Michigan today and innovating to meet the challenges of the coming decades.

The *Resilient Grid Plan*, laying out the investment levels summarized in the chart below, charts a new course for the Company in terms of reliability, resiliency, and investment.

The Company has identified **severe weather and technological adoption as the most pressing challenges** to the future grid and modeled the circuit level impacts from these risks through 2050.

This plan will underpin the Company's strategy for distribution investment planning to mitigate the current risk of severe weather and storms, and will serve as a bridge from our current grid to a grid capable of achieving the following reliability objectives:

1. **Delivering reliability performance into the 2nd quartile of nationwide utilities.**
2. **Delivering a grid where no single outage event will affect more than 100,000 customers.**
3. **Delivering a grid where no customer will be without power for more than 24 hours following an outage event.**

The *Resilient Grid Plan* will also **significantly improve the Company's SAIFI performance** over the next decade when compared to what would be provided by recent electric rate case-approved levels of investment.

Increased risks from weather and technological adoption will require a significant shift in investment levels and strategy to mitigate the risks from extreme weather and improve the reliability of electric power.

The *Resilient Grid Plan* features a unique approach for each voltage system and detailed work plan for each asset type.

- The plan for the LVD system will mitigate the worst effects of extreme weather and begin proactive planning for an increasingly electrified future, while the plan for the HVD system will focus on maintaining recent progress through proactively inspecting all assets repairing components on the HVD system to keep them within their useful lifecycle.
- This plan will focus on assets to modernize and harden the Company's electric distribution system to safely provide power with fewer, shorter, and less frequent power outages for customers through the Five Fundamentals Framework: **Fix, Fuse, Fractionalize, Fortify** and **Forestry**.

To execute on this vision, the plan proposes to invest approximately $7 billion over the next 5 years and to spend $1.7 billion in O&M in the following areas:

FIGURE 119

INVESTMENT PLAN (2024[12]-2028)

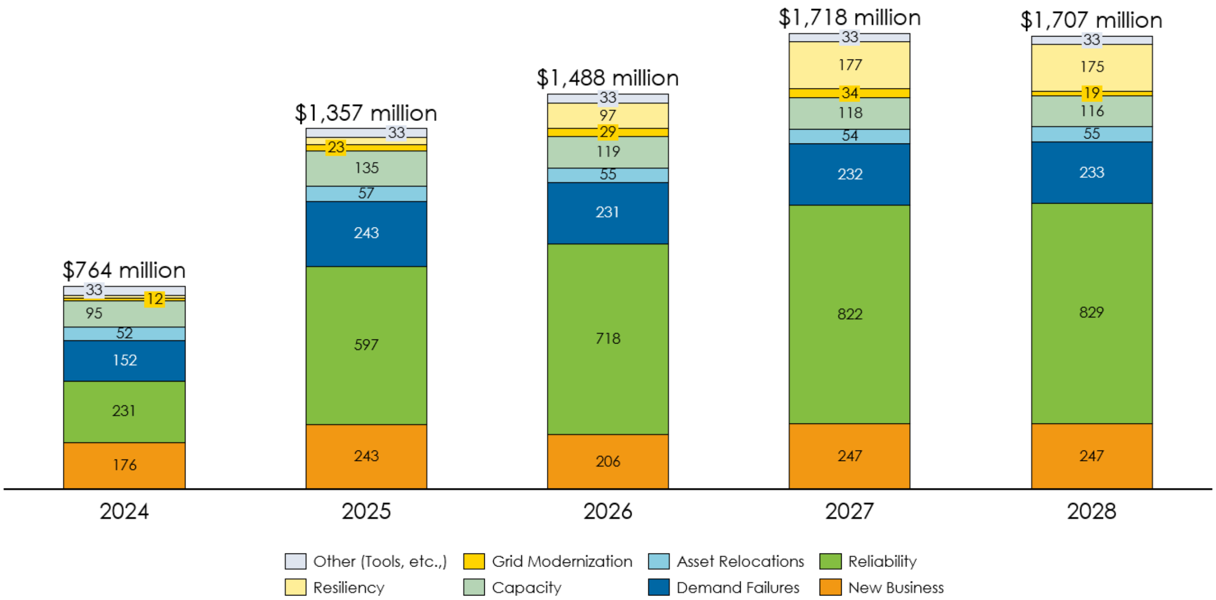
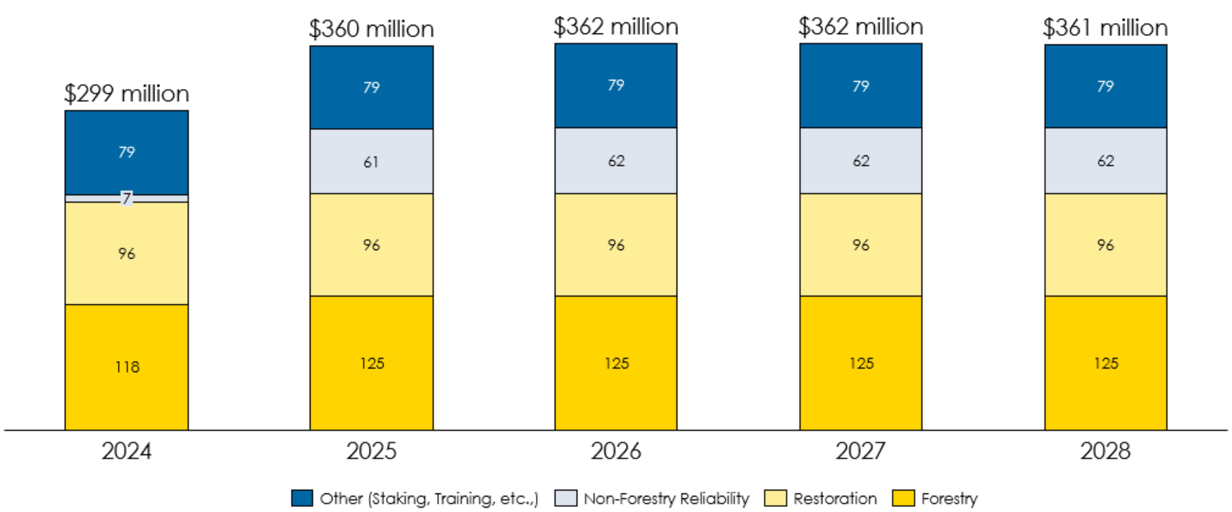


FIGURE 120

O&M PLAN (2024[13]-2028)



This plan also reflects the Company's revised planning process, which incorporates Environmental Justice into its planning for capital projects and maintenance to ensure disadvantaged communities receive reliable power.

[12] 2024 conveys the currently proposed spend in test year in current Electric Rate Case No. U-20389, less Grid Storage and including Streetlighting

[13] 2024 conveys the currently proposed spend in test year in current Electric Rate Case No. U-20389

The Forestry Line Clearing work included in this plan is essential to **addressing the largest single risk to reliability on LVD system** and the Company has developed a prescriptive line clearing impact analysis, with a focus on reliability metrics and tree-caused incidents to inform this work.

The Company is **expanding its use of data-driven strategies** to modernize its existing linear regression Forestry model to influence and guide its LVD full circuit clearing and will continue ramping up to an effective 7-year clearing cycle for all distribution lines.

Technology, Analytics, and Grid Modernization will complement the asset investments through developing **new tools and systems to improve the way the Company monitors, controls, and optimizes assets.** Digital will serve as the accelerant to achieve our reliability aspirations by leveraging artificial intelligence, machine learning, and automation to optimize processes, identify trends, and improve customer experiences.

The work described in this Plan relies on adequate field resources, both internal to the Company and externally contracted, to match the work demand.

Our unionized workforce is an essential component for the successful continued investment into the electric distribution system. The Company has seen continued field resource growth over the last 5 years and has been deliberate in matching the forecasted work demand. This plan will accelerate this growth into the future with a combination of new resiliency investment and increased maintenance of our system.

As described earlier in the Highlights of the 2023 EDIIP section, the Company fundamentally believes that the **investments outlined in this plan will deliver the safety, reliability, and resiliency benefits** that customers expect. The Company plans to seek recovery for these investments. Timely recovery of the costs of the investments described in this plan is essential to delivering the desired improvements in performance.

The Company looks forward to working with the MPSC, Staff, and the broader set of stakeholders as this plan is executed and further improved over time.

The Company plans to file updates to this plan, adding future years of investment and accounting for additional years of actual spending, with each subsequent rate case filing as an exhibit supporting test year investments.

Appendix A – Grid Archetype Details and Supporting Figures

Figure 121

CIRCUIT CHARACTERISTICS FOR ARCHETYPE CLASSIFICATION - EXAMPLE

	LVD Archetypes							
LVD Focused Statistics	#1	#2	#3	#4	#5	#6	#7	TOTAL
SUMMARY STATISTICS								
# of Circuits	248	233	257	492	341	213	259	**2,043**
% of Total	*12%*	*11%*	*13%*	*24%*	*17%*	*10%*	*13%*	***100%***
CUSTOMER								
# of Customers	11,844	152,356	161,670	763,240	257,832	165,754	327,777	**1,840,473**
% of Total Customers	*1%*	*8%*	*9%*	*41%*	*14%*	*9%*	*18%*	***100%***
Average # of Customers/ Circuit	48	654	629	1551	756	778	1266	**901**
Residential Net Promoter Score (CMS Nov. Survey; Sum of respondents)	-	15%	21%	20%	12%	10%	10%	**15%**
Promoters	-	26	53	221	70	71	111	**552**
Neutrals	-	18	31	123	47	30	66	**315**
Detractors	-	17	29	127	50	56	85	**364**
# of Critical Customers (e.g., Hospital, Police, Telephone etc.)	69	188	120	276	125	40	103	**921**
% of Total Critical Customers	*7%*	*20%*	*13%*	*30%*	*14%*	*4%*	*11%*	***100%***
% of Circuits serving one or more Critical Customer	*23%*	*42%*	*25%*	*31%*	*25%*	*12%*	*27%*	***0***
# of Priority Customers (e.g., Major customers, Business centers)	446	1,053	806	1,848	919	445	725	**6,242**
% of Total Priority Customers	*7%*	*17%*	*13%*	*30%*	*15%*	*7%*	*12%*	***100%***
% of Circuits serving one or more Priority Customer	*65%*	*90%*	*83%*	*91%*	*71%*	*65%*	*75%*	***79%***
OPERATIONS								
Total Line Miles	577	3,348	2,390	11,134	15,281	10,149	17,467	**60,348**
Median Line Miles/ Circuit	1	12	9	20	42	48	60	**18**
Average Line Miles/ Circuit	2	14	9	23	45	48	67	**29**
Standard Deviation of Line Miles/ Circuit	4	10	5	13	22	20	35	**28**
Overhead Miles	289	2,387	1,556	7,622	14,138	9,249	15,693	**50,934**
Overhead Miles % of Total	*50%*	*71%*	*65%*	*68%*	*93%*	*91%*	*90%*	***84%***
Underground Miles	289	961	835	3,513	1,142	900	1,775	**9,414**
Underground Miles % of Total	*50%*	*29%*	*35%*	*32%*	*7%*	*9%*	*10%*	***16%***
Median Customers/ Line Mile	15	47	69	71	19	16	19	**31**

Figure 122

CALCULATIONS OF LVD ARCHETYPE ENVELOPE GUARDRAILS – ILLUSTRATIVE EXAMPLE

LVD Planned Capital Projects (Excludes forestry)
All spend values are loaded

Year	Illustrative
Total LVD Budget Allocation	$225M
Envelope Percent Change	20%

		LVD						
Archetype Metrics	**TOTAL**	**#1**	**#2**	**#3**	**#4**	**#5**	**#6**	**#7**
# of Circuits (LVD)	***2,163***	*422*	*224*	*260*	*476*	*337*	*258*	*186*
Spend/ Circuit (LVD)	**$104,022**	$43.9M	$23.3M	$27.0M	$49.5M	$35.1M	$26.8M	$19.3M
# of Customers (LVD Circuits)	**1,782,404**	*15,334*	*157,564*	*178,952*	*712,991*	*274,157*	*201,343*	*242,063*
Spend/ Customer (LVD)	**$126**	$1.9M	$19.9M	$22.6M	$90.0M	$34.6M	$25.4M	$30.6M
Total Line Miles (LVD)	**58,190**	*528*	*3,245*	*2,666*	*11,221*	*14,775*	*12,749*	*13,006*
Spend/ Line Mile (LVD)	**$3,867**	$2.0M	$12.5M	$10.3M	$43.4M	$57.1M	$49.3M	$50.3M
Yearly SAIDI Contribution (Excl. MED; Excluding HVD, '15-19)	***153***	*0.72*	*12.29*	*6.79*	*38.23*	*23.65*	*27.00*	*44.67*
Spend/ Minute of SAIDI Contribution	**$1,467,333**	$1.1M	$18.0M	$10.0M	$56.1M	$34.7M	$39.6M	$65.5M
Yearly SAIFI Contribution (Excl. MED; Excluding HVD, '15-19)	**0.76**	*0.00*	*0.07*	*0.04*	*0.22*	*0.12*	*0.13*	*0.19*
Spend/ Frequency Contribution	**$294M**	$1.1M	$19.5M	$11.1M	$63.7M	$34.4M	$38.6M	$56.6M
Guardrail Analysis								
Median Allocated Spend per Archetype	**$225M**	$2.1M	$20.7M	$11.8M	$59.5M	$36.8M	$40.9M	$53.3M
Median spend as a % of Total	***100%***	*0.9%*	*9.2%*	*5.3%*	*26.4%*	*16.3%*	*18.2%*	*23.7%*
Low Budget Spend Envelope (-20%)	**$180M**	$1.6M	$16.6M	$9.5M	$47.6M	$29.4M	$32.7M	$42.6M
Medium Budget Spend Envelope (Base)	**$225M**	$2.1M	$20.7M	$11.8M	$59.5M	$36.8M	$40.9M	$53.3M
High Budget Spend Envelope (+20%)	**$270M**	$2.5M	$24.8M	$14.2M	$71.3M	$44.1M	$49.1M	$64.0M

Figure 123

MONITORED CIRCUIT CHARACTERISTICS AND PRIORITY THRESHOLDS

	Threshold	Variable
Safety	≥2 / year	Car pole accidents/year (incl. MED); Tracking started 2016
	Ungrounded	Circuit primary voltage
	≥12 total	Total number of wiredown events requiring 911 on-scene (13-17, incl. MED)
	≥8 total	Total number of wiredown events requiring 911 on-scene (13-17, incl. MED)
	≥100	Customers/line mile
Reliability	≥0.001	Avg system SAIFI contribution (13-17, excl. MED)
	System: ≥46%	Avg percent of customers/year with ≥3 outages (13-17, incl. MED)
	Arch. 1: 10%	
	Arch. 2: 25%	
	System: ≥60%	Avg percent of customers/year with 1+ >5hr outages (13-17, incl. MED)
	Arch. 1: 21%	
	Arch. 2: 30%	
	≥18	Worst zone score
	=17	
	<0%	Residential net promoter score (NPS, panel survey)[1]
	N≥6	Number of respondents (NPS question, panel survey)[1]
	≥350 mins	Avg circuit CAIDI (13-17, excl. MED)
	≥1	Number of overloaded pieces of equipment (data)[1,3]
Cost	≥$400/inc	Average O&M restoration cost per incident (15-17 data, incl. MED)
	≥30%	Percent of non-MED incidents >5hrs (13-17)
	≥85	Total line miles
	≥50%	Percent of line miles underground
	≥40 mins	Average drive-time to service center / headquarters
	≥30%	Percent of non-MED incidents >5hrs (13-17)
Sust.	≤50%	Load factor coincident with 10 system peak hours
	≥$40K cost	Replacement cost of equipment almost overloaded
Control	≤50%	Load factor coincident with 10 system peak hours
	≥$40K cost	Equipment almost overloaded replacement cost
	=0%	Percent of control question responses ranked ≥9/10 (panel survey)
	N≥3	Number of respondents (Control question, panel survey)[1]

Appendix B – Environmental Justice Data and Maps

Circuit Reliability Statistics for EJ Circuits

The following data reflects 2022 performance on circuits serving EJ census tracts. Circuits have been excluded from the list if they had no outage data for 2022 and/or if they were single-customer circuits.

Figure 124

PERFORMANCE ON CIRCUITS SERVING EJ CENSUS TRACTS

SUBSTATION	CIRCUIT	Archetype	Circuit Length (Miles)	Customers Served	2022 Total Outage Count	2022 Total Outage Duration Minutes	2022 Total Customers Interrupted	2022 Total Customer Outage Minutes	2022 Non-MED Circuit SAIDI Score	2022 Non-MED Circuit SAIFI Score	2022 Circuit SAIDI Score with MED	2022 Circuit SAIFI Score with MED	Last Year Trimmed
DUNBAR	HULL	3	14.34	676	9	692	375	33656	49.79	0.55	49.79	0.55	2019
FOURTEENTH STREET	SOUTH WESTERN	4	15.43	2216	47	18548	1527	826519	127.11	0.51	372.98	0.69	1999
WEALTHY STREET	WATSON	1	3.77	126	3	508	360	80902	642.08	2.86	642.08	2.86	1999
MAUMEE	LENAWEE ST	4	14.55	1428	31	6316	4317	1242982	121.25	1.41	870.44	3.02	2016
LEE STREET	BLACK HILLS	1	2.89	71	5	1943	75	53198	749.27	1.06	749.27	1.06	1989
BEECHER	DISPOSAL	2	11.91	281	15	2030	131	23120	82.28	0.47	82.28	0.47	2020
DOEHLER JARVIS	GRIGGS STREET	4	9.84	2089	43	12444	2694	261891	104.79	1.26	123.05	1.27	2017
WEALTHY STREET	BUTTERWORTH	2	4.96	109	3	438	10	1158	10.63	0.09	10.63	0.09	2012
WEALTHY STREET	INDIANA	4	5.86	1818	32	7451	850	106620	34.40	0.45	58.65	0.47	2016
DOEHLER JARVIS	JEFFERSON	4	17.54	3941	79	16132	8756	1507776	148.83	1.55	370.36	2.17	2018
WEALTHY STREET	LOGAN	2	6.3	1026	7	2952	2078	655091	636.81	2.02	638.49	2.03	1994
MAPLE GROVE	WESTGATE	2	8.59	737	14	1796	804	140438	188.71	1.08	190.52	1.09	2020
HASKELITE	ANN STREET	3	5.35	617	14	1928	3911	266568	415.71	6.06	415.71	6.06	2010
FOURTEENTH STREET	TOBIAS STREET	2	7.94	693	8	3542	974	150114	220.36	1.47	220.36	1.47	1994
ALDRICH	COUNTY	3	4.34	319	6	2933	30	3565	11.17	0.09	11.17	0.09	2014
STEVENS	ALBANY	2	6.57	712	15	5262	130	22685	27.46	0.18	31.86	0.18	1999
DEWEY	CONVENTION CENTER	3	2.95	544	4	2344	608	141369	163.70	1.04	259.87	1.12	1999
FOURTEENTH STREET	LIBERTY STREET	4	8.61	1419	44	22175	734	657127	55.21	0.21	462.95	0.52	2017
RED ARROW	KEATS	4	9.08	1507	26	10003	505	240178	142.82	1.40	240.07	1.50	1998
MONA LAKE	AIRPORT	4	31.54	2593	73	14429	1174	284637	28.33	0.30	109.77	0.45	2008
WOOD STREET	AVENUE A	1	2.04	142	7	1256	129	28698	201.68	0.90	201.68	0.90	1994
WOOD STREET	MASON	3	9.72	625	42	22520	1853	506369	323.63	1.35	595.55	2.07	1997
WOOD STREET	CHIPPEWA	1	1.64	139	2	864	47	19927	143.36	0.34	143.36	0.34	1988
HARRIET	WITHERBEE	4	12.87	833	7	3836	859	310543	374.03	1.03	374.04	1.03	2016
ALDRICH	TRAVERSE	2	12.67	999	24	8762	787	115477	220.82	1.32	249.83	1.35	2022
MILBOURNE	DUPONT	3	7.87	784	33	23437	184	82264	86.61	0.22	104.93	0.23	2017
HARVEY STREET	DIAMOND	4	10.27	3462	41	9913	3958	2252874	14.42	0.12	650.74	1.14	2022
SQUIRE HILL	EDGEWATER	4	21.22	1449	33	13269	405	163537	145.42	0.41	154.66	0.41	1988
MICOR	LOSEY	1	7.49	171	9	3853	204	22408	115.43	1.17	131.04	1.19	2014
MUSKEGON HEIGHTS	HEIGHTS	2	9.57	1086	27	2906	573	82181	59.54	0.50	75.67	0.53	2018
MAPLE GROVE	HENRY STREET	2	16.82	1424	23	3890	428	77042	53.26	0.30	54.10	0.30	2014
KEATING	EAST BARNEY	2	9.49	628	15	2183	729	77543	123.48	1.16	123.48	1.16	2016

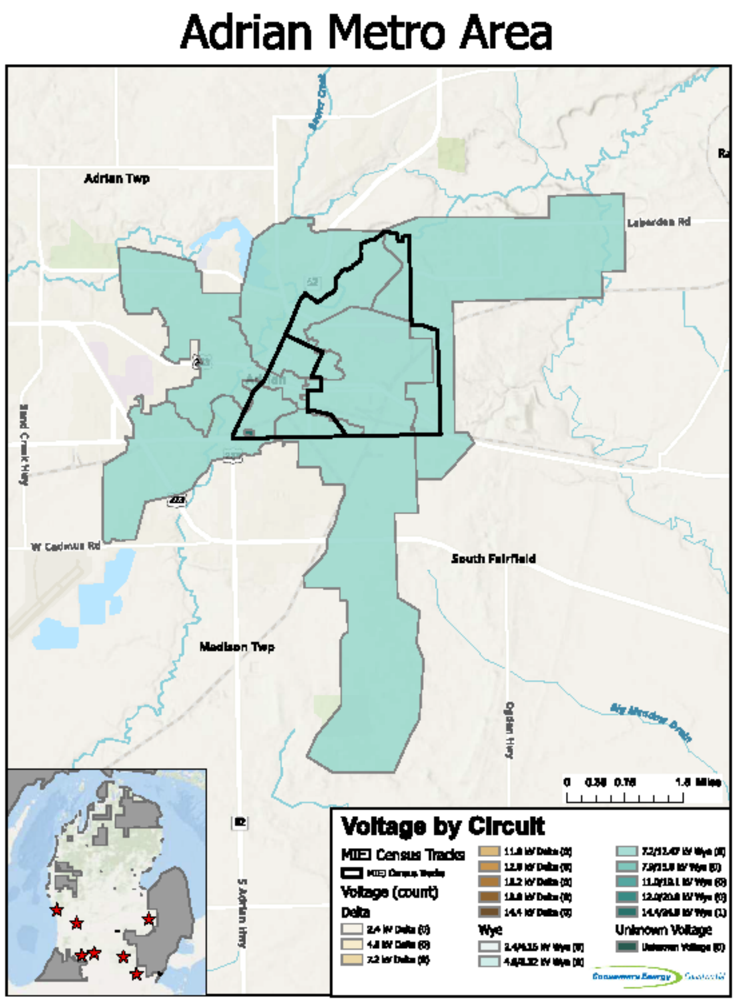
COOLEY	WESTNEDGE	3	3.14	480	6	2882	61	10995	17.49	0.06	21.36	0.06	1998
LIBERTY	LIBERTY	3	4.56	439	8	7430	879	143412	313.49	2.00	326.68	2.00	2021
MUSKEGON HEIGHTS	EAST CENTRAL	3	7.06	694	29	5218	311	38185	40.33	0.33	55.02	0.45	2016
ROBERTS STREET	BENDER	3	11.15	490	23	6831	602	95786	189.25	1.22	195.48	1.23	2002
ROBERTS STREET	FOOTE HOSPITAL	3	3.07	365	5	1185	48	11998	32.87	0.13	32.87	0.13	1988
FAIRBANKS	IONIA-ROWE	3			1	2261	16	36171			92.04	0.04	
MUSKEGON HEIGHTS	LEAHY	3	2.96	383	18	2744	160	14327	37.41	0.42	37.41	0.42	2018
ELM STREET	CHAMPION	3	7.08	1176	24	5966	1426	217236	164.60	1.09	184.72	1.21	2015
ELLSWORTH	WESTON	3	1.28	333	5	537	196	21823	65.53	0.59	65.53	0.59	1988
SUMMIT	SOUTH STREET	3	6.06	594	21	8631	1018	132931	152.94	1.54	223.79	1.71	2019
COMSTOCK	TUNIER	2	20.74	1097	42	16518	1862	504423	105.14	1.11	459.82	1.70	1997
RED ARROW	OGEMA	4	10.89	1600	45	23871	2402	1041339	54.83	0.40	659.52	1.55	2010
LEONARD	TAYLOR	4	10.16	1929	30	11540	12659	1612507	94.25	1.12	835.93	6.56	2022
COLLEGE PARK	MADISON	4	16.1	1938	31	3741	944	409155	20.27	0.18	209.99	0.46	2018
MICHIGAN	LYDIA	4	8.15	1693	35	12968	3955	1271090	21.62	0.93	750.78	2.34	2018
MICHIGAN	LOOKOUT	4	4.25	1046	33	21068	528	413401	49.54	0.20	395.22	0.50	2017
OAK STREET	COOPER STREET	4	17.29	1163	30	16383	1960	687446	422.00	1.58	591.10	1.69	2016
BEALS ROAD	BURTON HEIGHTS	2	5.44	467	24	3346	421	50196	111.46	0.93	111.46	0.93	1999
ABERDEEN	HOLLYWOOD	4	14.71	2452	48	7784	2216	504617	223.44	1.20	225.91	1.21	2019
LEONARD	IONIA	4	12.59	2905	141	21277	11429	1278854	405.64	3.88	440.23	3.93	1996
WEALTHY STREET	GODFREY	2	7.04	936	30	5352	2314	203262	213.01	2.44	217.16	2.47	2014
MAYNARD	BESTWALL	1	4	31	4	633	34	5253	169.46	1.10	169.46	1.10	1989
STEVENS	HYNES		0.98	22	1	283	1	283	12.87	0.05	12.87	0.05	NULL
MUSKEGON HEIGHTS	MUSKEGON	4	6.99	1015	29	4321	533	54806	41.14	0.49	54.30	0.53	2015
LEE STREET	CENTURY	3	6.48	1151	25	8273	989	370714	51.21	0.72	322.08	0.86	2014
KEATING	WOOD STREET	4	9.41	1564	44	5655	694	86242	51.88	0.44	55.14	0.44	2020
TERRACE	SHORELINE	1	3.56	107	1	497	107	53154	496.76	1.00	496.76	1.00	2000
TERRACE	MALL	3	6.42	1011	7	504	136	14499	14.34	0.13	14.34	0.13	1988
TERRACE	SPRING	3	8.71	897	19	2175	206	18012	20.08	0.23	20.08	0.23	2022
LEE STREET	KIRTLAND	4	12.98	2731	49	9340	1971	391222	55.13	0.55	143.28	0.72	2015
LEE STREET	LEE	2	5.43	658	19	3271	1339	203067	308.61	2.03	308.61	2.03	1992
ALBER	TERRITORIAL	4	11.36	1543	14	4333	3037	862536	558.68	1.97	559.31	1.97	2019
WESTERN AVENUE	WEST BUSINESS	2	7.1	988	18	4032	189	43720	14.86	0.08	43.93	0.19	2021
WESTERN AVENUE	DIVISION	3	3.85	639	4	433	42	5771	4.32	0.04	9.03	0.07	2010
MILLER ROAD	UTLEY ROAD	2	6.95	534	19	17470	711	186157	166.77	1.24	348.61	1.33	1999
MILLER ROAD	YALE STREET	3	9	1094	27	11135	256	95835	56.25	0.20	87.60	0.23	2015
CALKINS	FLUSHING ROAD	4	16.16	1019	18	8649	525	172209	13.88	0.06	123.70	0.44	1998
BALLENGER	BRADLEY	4	13.48	1925	39	17116	476	164440	28.00	0.19	85.42	0.25	2014
WYOMING PARK	WYOMING	4	10.7	1663	20	4667	280	58377	15.56	0.12	35.10	0.17	2012
BURLINGAME	ROBIN	4	12.63	2052	26	13444	1159	231179	202.74	1.53	247.95	1.56	2017
HARVEY STREET	FULLER	4	8.81	2522	24	10586	402	211347	4.34	0.08	83.80	0.16	2021
ATHERTON	HEMPHILL	3	8.42	696	6	1113	2698	209503	124.25	1.30	124.25	1.30	1998
JUDD ROAD	MANDEVILLE	3	9.11	1006	21	9930	258	63124	42.76	0.21	61.61	0.25	2017
LEITH STREET	WESTERN ROAD	4	17.69	1196	38	20078	3232	964486	637.33	2.60	806.43	2.70	2022

SLOAN	LONGFELLOW	4	14.49	1790	82	32917	6676	2542528	656.99	3.25	1420.43	3.73	2009
BALLENGER	TACKEN	4	15.26	1539	13	2927	156	20389	12.39	0.10	13.25	0.10	2022
BALLENGER	SALISBURY	4	6.11	950	33	16531	341	176744	120.94	0.31	186.05	0.36	2014
SLOAN	BALLENGER	2	5.02	271	4	451	20	3637	13.42	0.07	13.42	0.07	1996
BEALS ROAD	CLYDE PARK	4	20.42	3416	49	12952	4088	711150	203.42	1.19	208.18	1.20	2022
BURLINGAME	MICHAEL	3	8.88	1349	17	3968	4823	527439	184.62	2.05	185.20	2.05	2011
ROBERTS STREET	LEROY STREET	4	16.54	1571	36	19929	3289	1217301	222.88	1.55	774.48	2.09	2019
BOSTON SQUARE	KALAMAZOO	4	7.15	1551	33	7459	1869	904618	575.29	1.16	583.89	1.21	2022
MOSEL	ALLEN	3	7.49	447	14	10454	1284	653399	342.91	2.09	1461.61	2.87	NULL
DOEHLER JARVIS	COTTAGE GROVE	3	2.17	308	9	2414	459	90115	300.32	1.56	308.95	1.63	1988
STEVENS	Campau	3	2.53	339	13	2426	309	43948	129.64	0.91	129.64	0.91	2000
BOSTON SQUARE	NELAND	4	6.71	2024	21	4301	428	68216	35.38	0.22	59.95	0.32	2018
BOSTON SQUARE	HALL	4	10.49	2052	31	4603	2541	394272	33.54	0.22	192.14	1.24	2018
BOSTON SQUARE	MULICK PARK	4	5.06	990	18	4269	1533	250644	61.33	0.52	253.18	1.55	2019
DOEHLER JARVIS	SEYMOUR	4	6.38	1464	29	6000	1741	197959	124.27	1.17	134.61	1.19	2017
LAGRAVE	MAPLE	1	1.38	106	1	737	105	77331	729.54	0.99	729.54	0.99	2014
GLENDALE	HERCULES	4	9.9	1071	20	7350	760	201098	173.81	0.68	187.77	0.71	2014
MAPLE GROVE	SUMMIT AVENUE	4	14.54	2156	35	10871	1251	896871	33.96	0.15	415.99	0.58	2020
MAPLE GROVE	SHAW BOX	4	9.63	1077	17	4548	121	11104	6.41	0.09	9.98	0.10	2019
RAVINE	PATTERSON	4	14.69	1274	24	3661	1075	226285	177.62	0.84	177.62	0.84	2013
PALMER	WATER LIFT	4	4.87	782	23	7416	360	52108	52.39	0.40	66.63	0.46	2020
GETTY	MARQUETTE	4	27.05	3204	34	5906	338	52121	15.47	0.10	16.27	0.11	2018
GETTY	ALLEN	4	9.82	1430	14	3158	633	78446	53.65	0.44	54.86	0.44	2014
BISHOP	RAINBOW	4	16.43	973	24	7631	655	101191	102.04	0.67	104.00	0.67	2016
PARKWAY	VINE	4	7.88	1942	25	9482	394	54601	24.96	0.20	28.12	0.20	2020
HASKELITE	3 MILE	4	12.26	1002	16	2256	394	62430	61.13	0.38	62.31	0.39	2020
EAST MUSKEGON	QUARTERLINE ROAD	4	8.99	1116	16	4206	390	82510	72.71	0.35	73.93	0.35	2021
PHILLIPS	FACTORY	4	7.05	1574	32	17259	1691	234538	75.49	1.00	144.11	1.04	2019
PHILLIPS	MILWOOD	4	7.56	1369	29	17565	2819	1595014	353.27	1.44	1170.72	2.10	2020
COMSTOCK	SHIELDS	4	24.74	1186	50	17436	2330	967844	190.61	1.39	816.06	1.96	2016
PHILLIPS	ALCOTT	4	10.87	1335	45	13068	651	125060	70.69	0.48	93.68	0.49	2021
LIBERTY	WASHINGTON	2	9.72	697	28	13565	1333	151083	165.54	1.89	216.76	1.91	2022
COURT	KENT	2	9.51	832	13	7583	418	79821	97.35	0.58	97.35	0.58	2019
BEECHER	ANDERSON	4	10.62	1046	20	3268	3289	160348	125.79	2.13	153.30	3.14	2017
HARRIET	HARRIET	3	9.22	669	40	33643	232	193269	109.96	0.25	288.98	0.35	1988
LIBERTY	HAMBLIN	2	9.13	623	25	9934	1477	1193605	210.28	0.94	1915.90	2.37	2021
LEITH STREET	LEITH	4	17.05	2063	69	38352	555	307247	64.56	0.20	148.93	0.27	2014
WALNUT	GILKEY	4	9.53	1178	31	13582	678	315539	140.84	0.51	267.86	0.58	2006
AMPERSEE	WELDER	1	3.72	286	4	896	341	7751	27.10	1.19	27.10	1.19	1988
PARKWAY	SOUTH CENTRAL	3	6.33	918	16	12656	1175	132187	132.69	1.28	143.99	1.28	2017
BEECHER	TOLEDO ROAD	2	19.97	989	31	5685	1565	137019	137.26	1.58	138.54	1.58	2019
OAK STREET	STATE STREET	3	3.79	634	17	10310	1523	165266	161.91	2.38	261.60	2.41	2014
COOLEY	NORTH STREET	4	8.12	1356	29	4685	259	37408	24.59	0.19	27.59	0.19	2020
HASKELITE	BISSELL	4	12.07	1662	17	4544	945	297641	20.33	0.15	179.09	0.57	2020

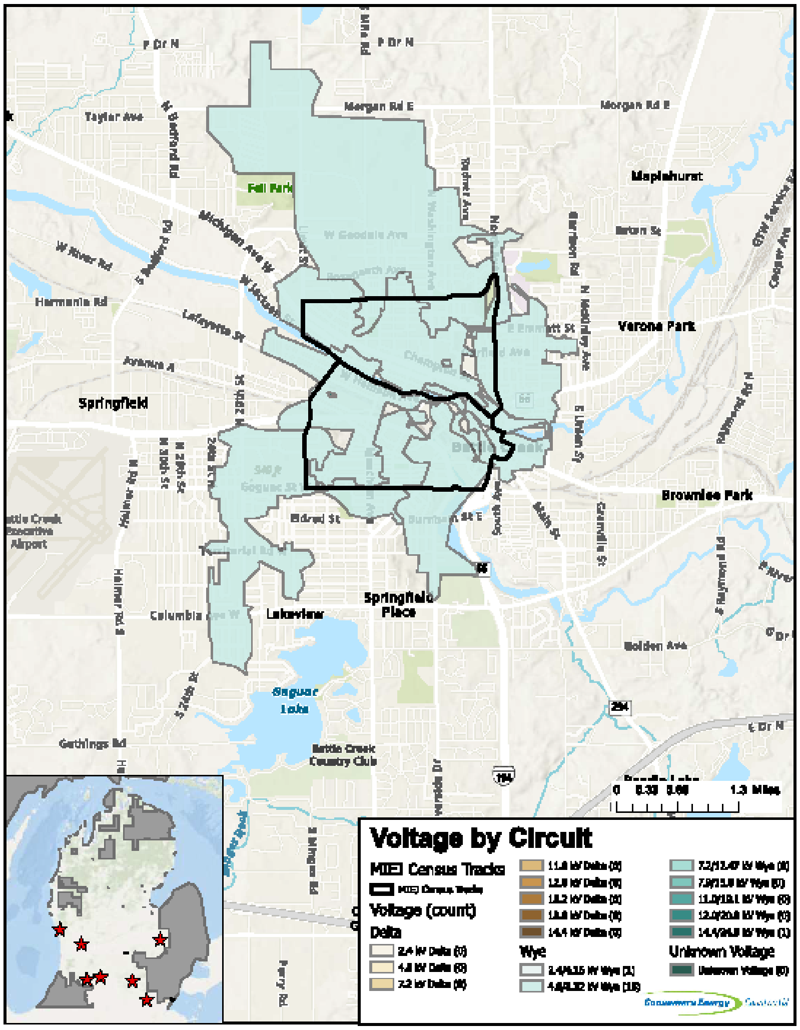
DEWEY	SEATING	4	16.07	3797	67	32534	13358	6208906	62.07	1.15	1635.21	3.52	2018
NORTH LANSING	LABORATORY	3	15.77	637	21	6046	436	102184	16.61	0.27	160.41	0.68	2014
IRON STREET	DORT HIGHWAY	3	7.67	507	18	8734	206	82840	46.45	0.22	136.32	0.25	2016
LEONARD	NEWBERRY	2	3.56	555	6	4620	1588	1090753	775.45	1.95	1965.32	2.86	1996
PALMER	REED	2	6.71	320	20	4463	1445	682260	697.53	2.38	2132.06	4.52	2014
PALMER	HEALY	2	6.01	231	3	987	462	195999	848.48	2.00	848.48	2.00	1988
DEWEY	BRIDGEWATER	3	3.73	434	5	2861	552	561628	3.87	0.28	1294.07	1.27	1988
WEALTHY STREET	NORTHWEST	2	15.53	2888	55	12790	5054	1200213	131.67	1.15	415.59	1.75	2017
NORTH MUSKEGON	SANITARIUM	3	8.9	602	13	2967	254	68885	11.86	0.09	114.43	0.42	2016
OAK STREET	PLYMOUTH	3	3.71	300	3	817	19	6671	22.24	0.06	22.24	0.06	2014
AMPERSEE	BORGESS	3	5.11	720	21	5217	635	115836	158.00	0.88	160.88	0.88	2021
AMPERSEE	NORTH COMMERCIAL	3	6.78	467	7	5296	432	522095	79.95	0.07	1117.98	0.93	2014
ELM STREET	VAN BUREN	1	1.42	68	2	619	107	28827	423.93	1.57	423.93	1.57	2012
ELM STREET	MONROE	1	2.29	44	1	13	2	25	0.57	0.05	0.57	0.05	2012
HASKELITE	RICHMOND	2	4.37	870	13	1689	1816	162388	186.12	2.08	186.12	2.08	2020
EASTWOOD	TEXEL	4	12.45	1764	88	18273	4270	576315	243.90	2.36	326.71	2.42	2018
EASTWOOD	EAST	4	6.8	1056	5	3723	84	34563	4.65	0.07	32.73	0.08	2014
WALKER	ROSALIE	4	28.45	3015	46	13536	931	316410	23.11	0.12	104.95	0.31	2021
DEWEY	WIDDICOMB	4	3.83	1032	24	6107	4632	1744776	347.37	2.98	1700.89	4.66	2022
MICOR	WELLWORTH	3	11.55	356	4	838	365	77331	217.22	1.03	217.22	1.03	2014
COOLEY	EXCHANGE	1	3.12	130	1	266	1	266	2.05	0.01	2.05	0.01	1988
HASKELITE	FISHER BODY	1	3.79	94	4	1126	8	3656	38.89	0.09	38.89	0.09	1998
ELLSWORTH	HOUSEMAN	1			1	1736	1	1736			41.32	0.02	
LIBERTY	RALSTON	1			1	63	1	63					
LOVELL	GIBSON	2	5.65	405	11	2423	732	348518	242.76	1.18	860.54	1.81	2014
KEATING	LAKETON	2	11.98	770	16	1362	138	9967	12.94	0.18	12.94	0.18	2020
LAGRAVE	COLLEGE	3	2.09	169	3	1989	8	3807	14.30	0.04	22.53	0.05	2006
BRIDGE STREET	HUPP AVENUE	3	6.33	564	10	7408	663	196619	140.41	1.08	348.61	1.18	2022
BRIDGE STREET	WATER STREET	3	8.22	598	8	7479	115	166058	20.58	0.12	277.69	0.19	2014
STADIUM	NORMAL	3	3.94	919	5	1070	68	2931	4.00	0.11	4.00	0.11	2016
SUMMIT	FRANCIS STREET	4	10.96	1487	42	17546	1814	157328	58.92	1.19	105.80	1.22	2019
PARKWAY	BALCH	1	2.2	127	2	672	34	7194	56.65	0.27	56.65	0.27	2020
ROBERTS STREET	DETTMAN	2	12.29	1115	15	3995	85	9947	6.53	0.08	8.92	0.08	2000
WAGER	FLINT PARK	4	11.47	1011	12	2139	114	13490	259.15	0.63	469.61	0.75	2006
MAUMEE	MAPLE ST	4	15.48	1736	34	8725	1125	251815	75.97	0.63	145.05	0.65	2016
WAGER	PARKLAND	2	18.2	1157	46	21291	1323	411604	338.63	1.14	355.75	1.14	2011
WAGER	MARENGO	2	5.44	190	15	3719	550	152764	489.56	1.03	798.58	2.88	1988
LOVELL	HENRIETTA	1	1.06	69	4	1700	11	2094	30.35	0.16	30.35	0.16	1988
LOVELL	FINE ARTS	1	1.16	96	1	509	1	509	5.30	0.01	5.30	0.01	1988
LEITH STREET	FRANKLIN	4	9.28	794	21	5217	141	25384	31.11	0.18	31.97	0.18	2021
FOURTEENTH STREET	LIPPINCOTT STREET	4	11.02	1135	37	11714	672	140025	120.07	0.59	123.37	0.59	2022
GOODALE	HUBBARD	4	16.6	1319	21	6438	403	189710	24.51	0.21	143.83	0.31	2017
FOUNTAIN	SOUTH	3	5.95	455	3	2307	6	2402	0.73	0.01	5.28	0.01	2012
FOUNTAIN	DOWNTOWN	1	1.02	44	2	318	20	3173	27.80	0.23	72.12	0.45	1988

BALK STEEL	HANSEN BALK	1			1	76	1	76					
MOSEL	PITCHER	3	5.5	592	12	1872	742	80735	136.47	1.26	136.47	1.26	NULL
BROADWAY	PHILLIPS	4	17.48	1729	51	8269	3463	572138	327.80	1.99	330.91	2.00	2022
SINCLAIR	HERITAGE HILL	4	5.72	1698	27	7942	591	0	59.68	0.35	61.51	0.35	1988

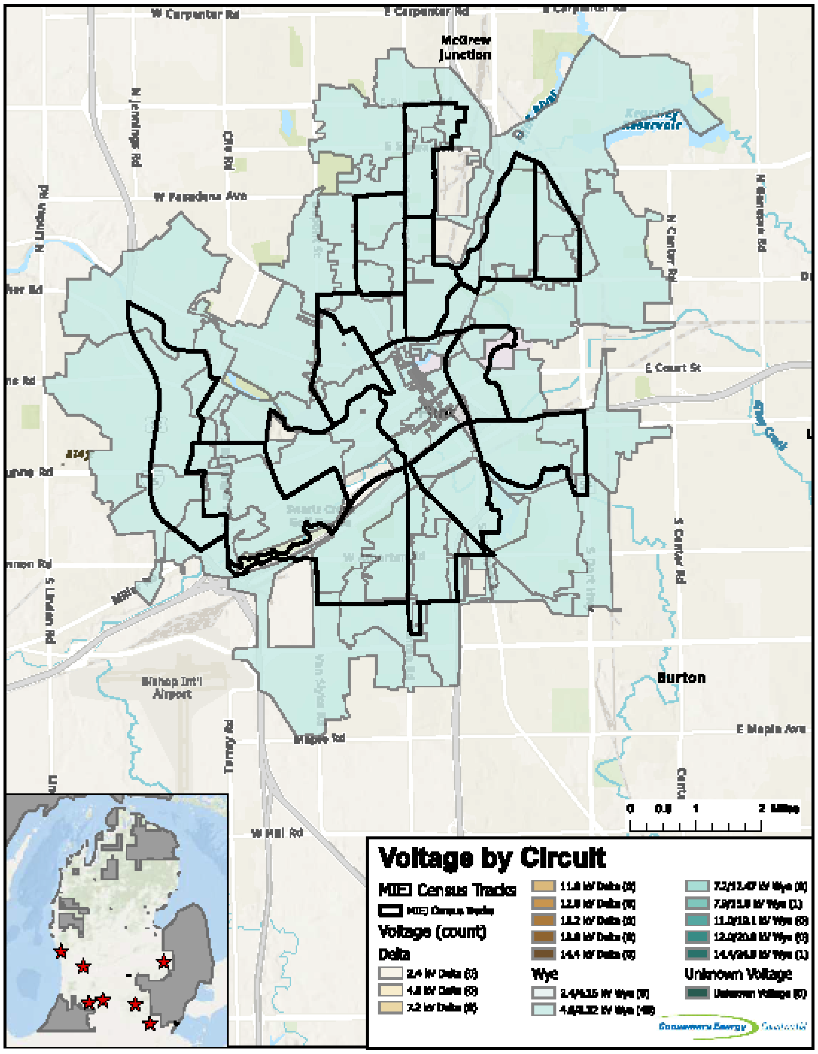
Circuit Voltage Overlaid on EJ Census Tracts



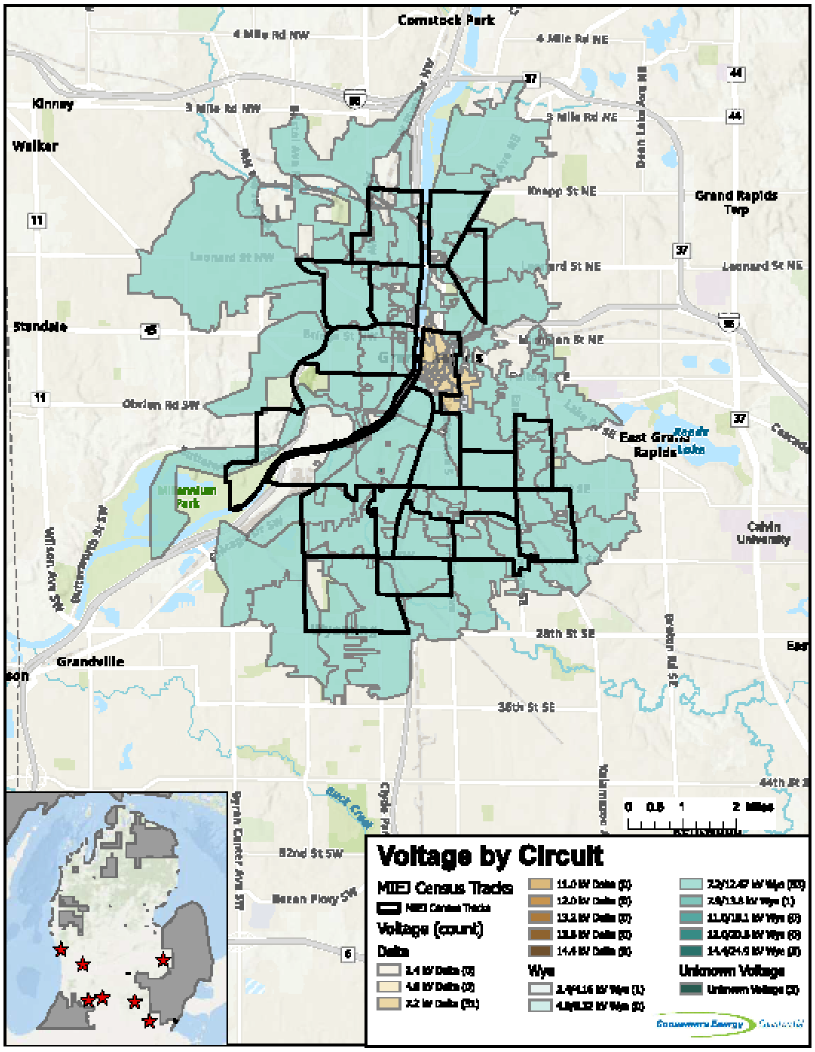
Battle Creek Metro Area



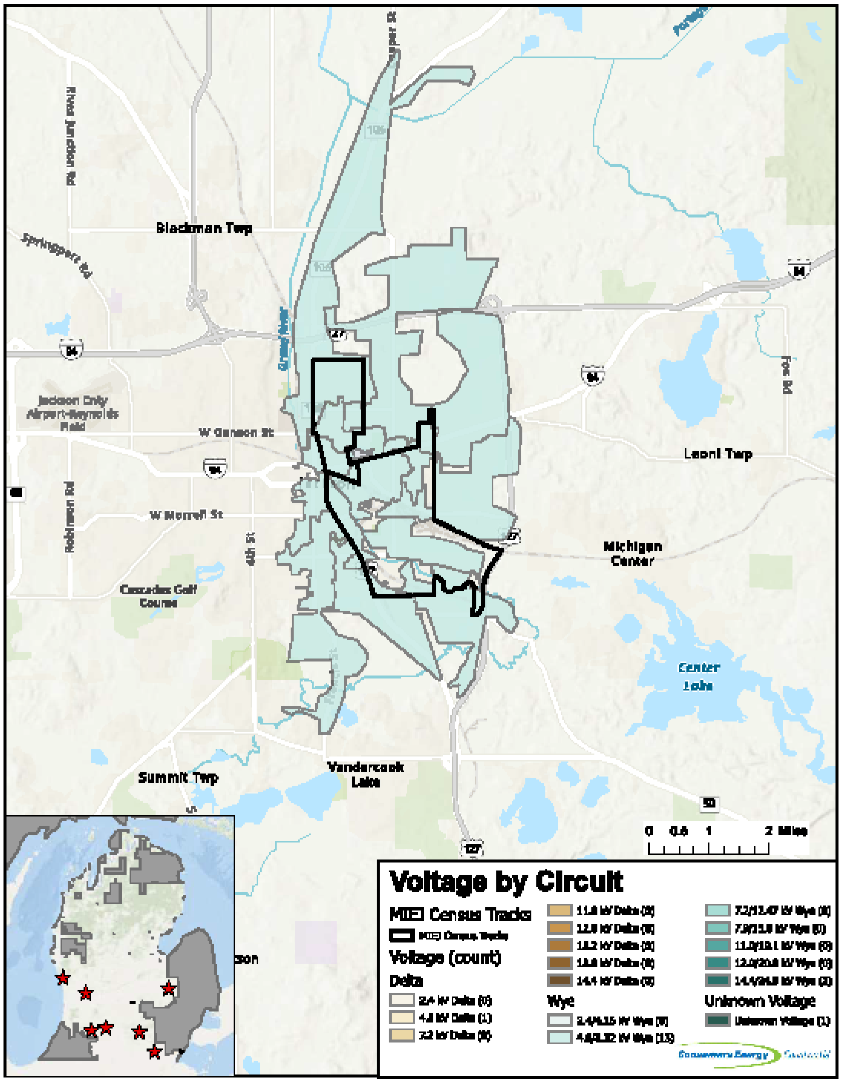
Flint Metro Area



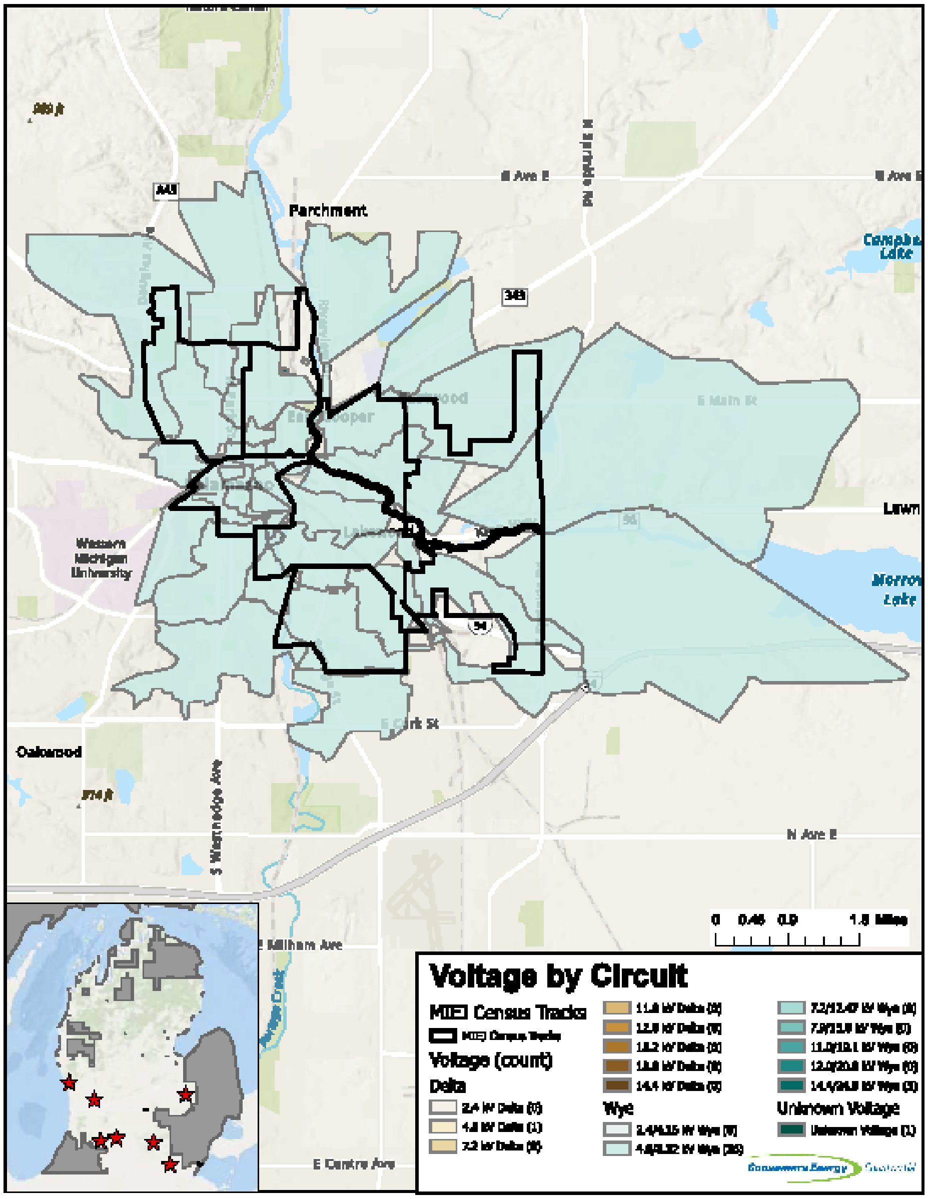
Grand Rapids Metro Area



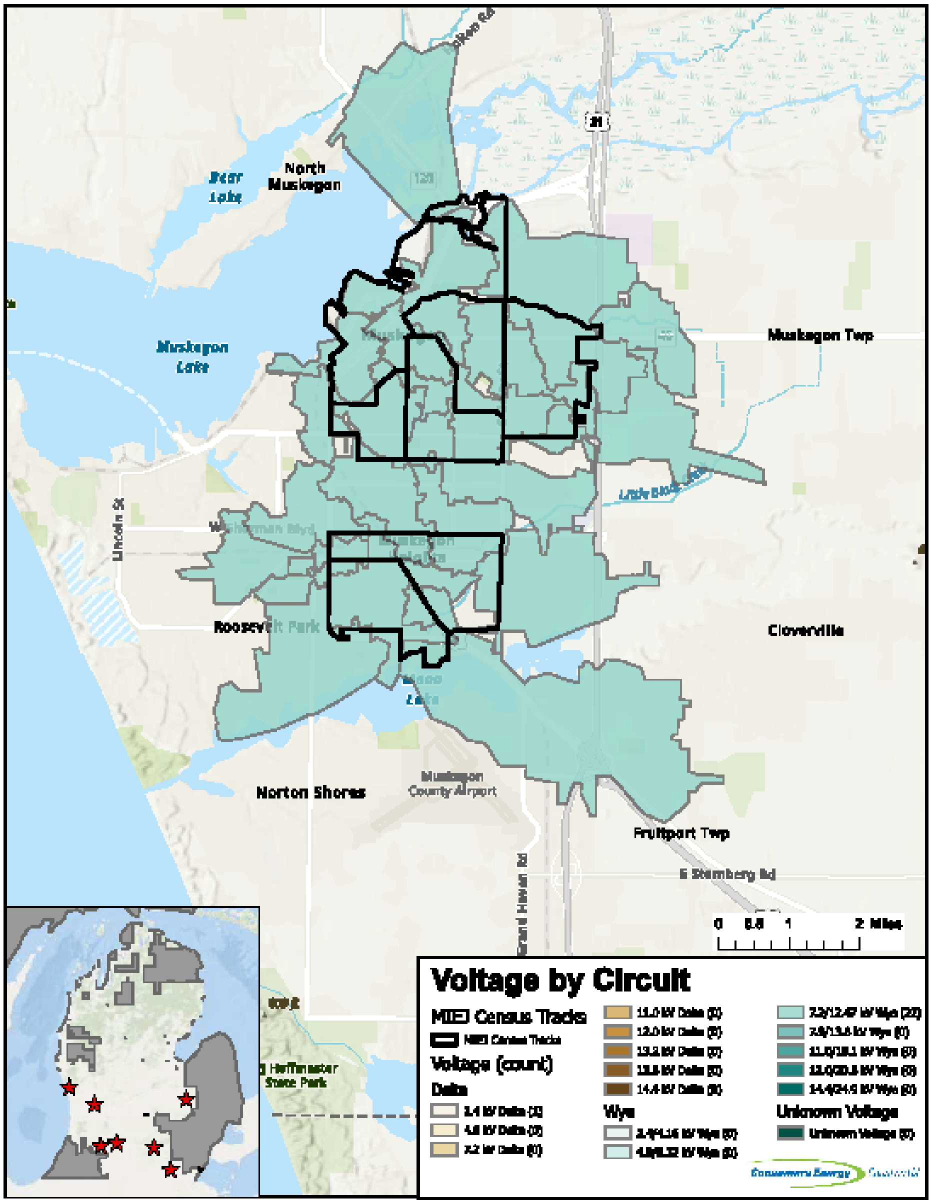
Jackson Metro Area



Kalamazoo Metro Area

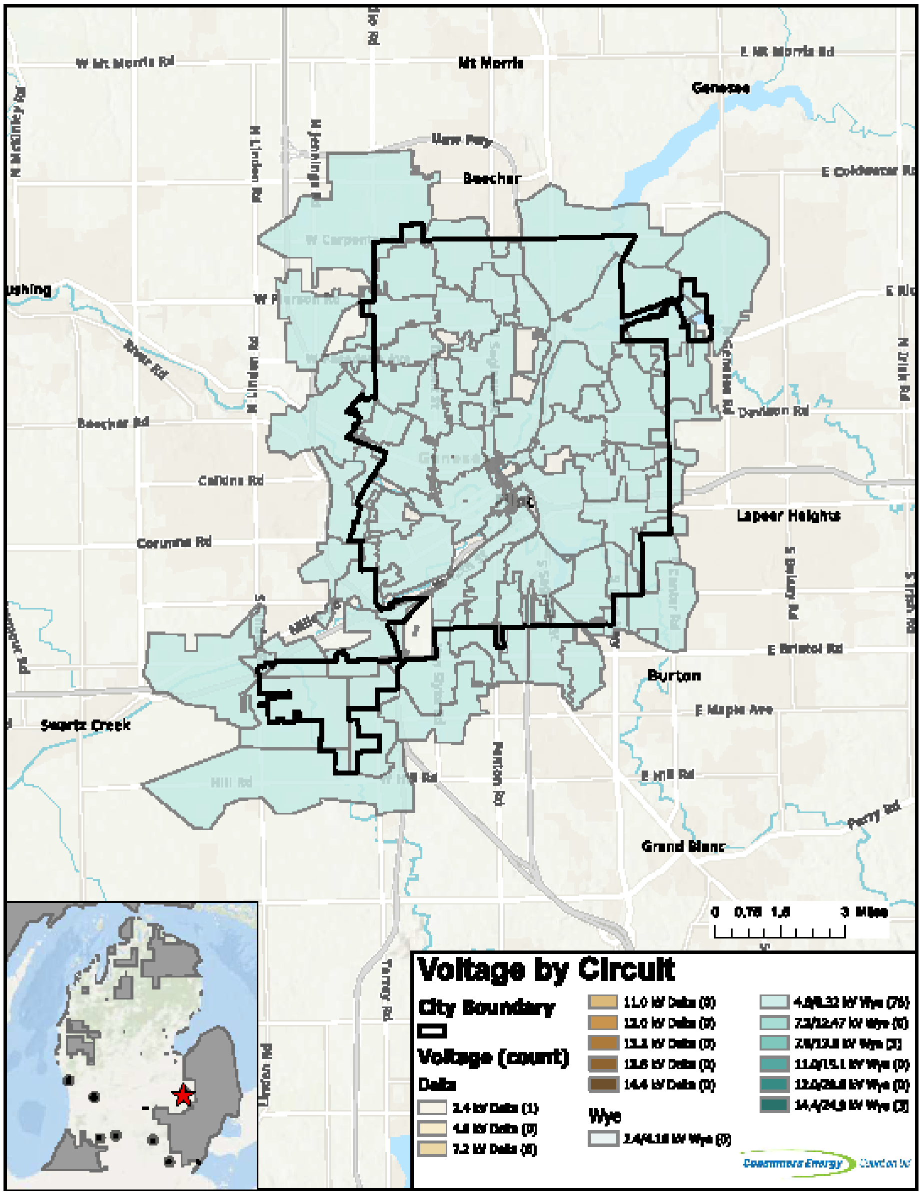


Muskegon Metro Area

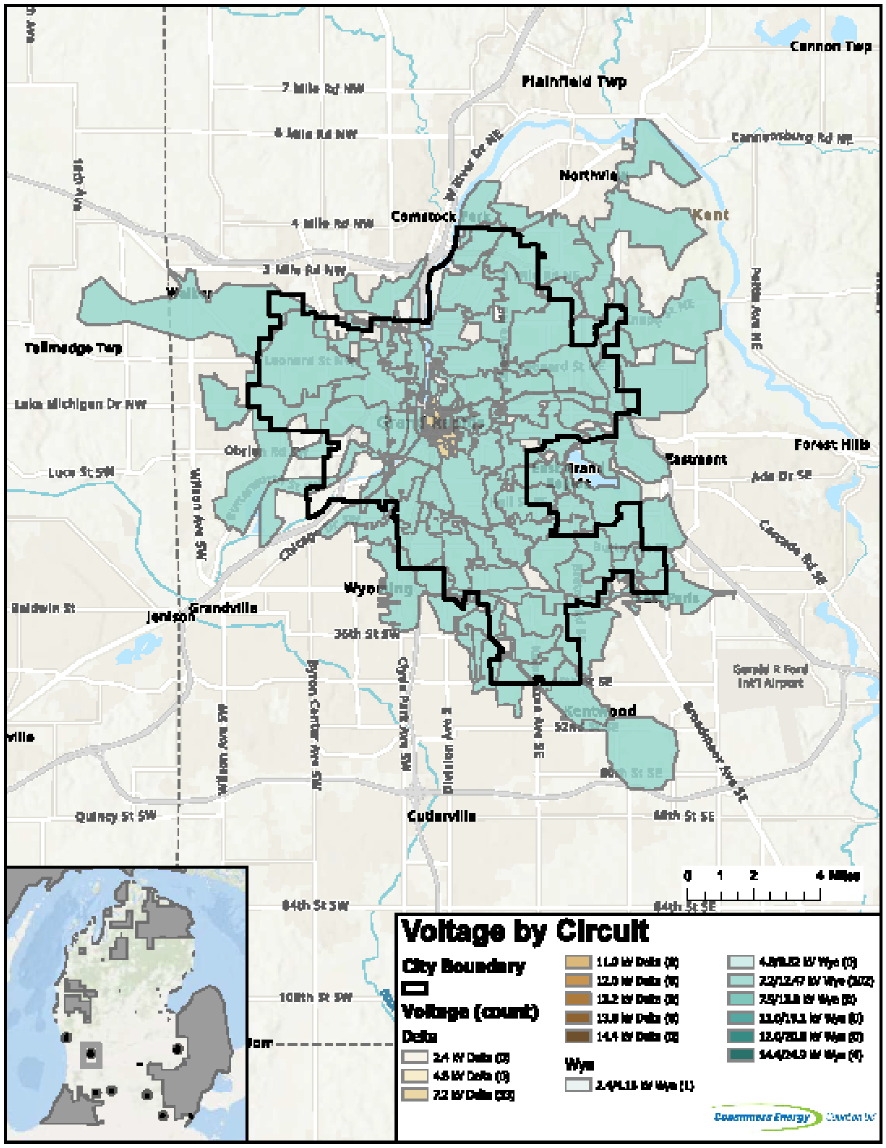


Circuit Voltage Overlaid on Designated Cities

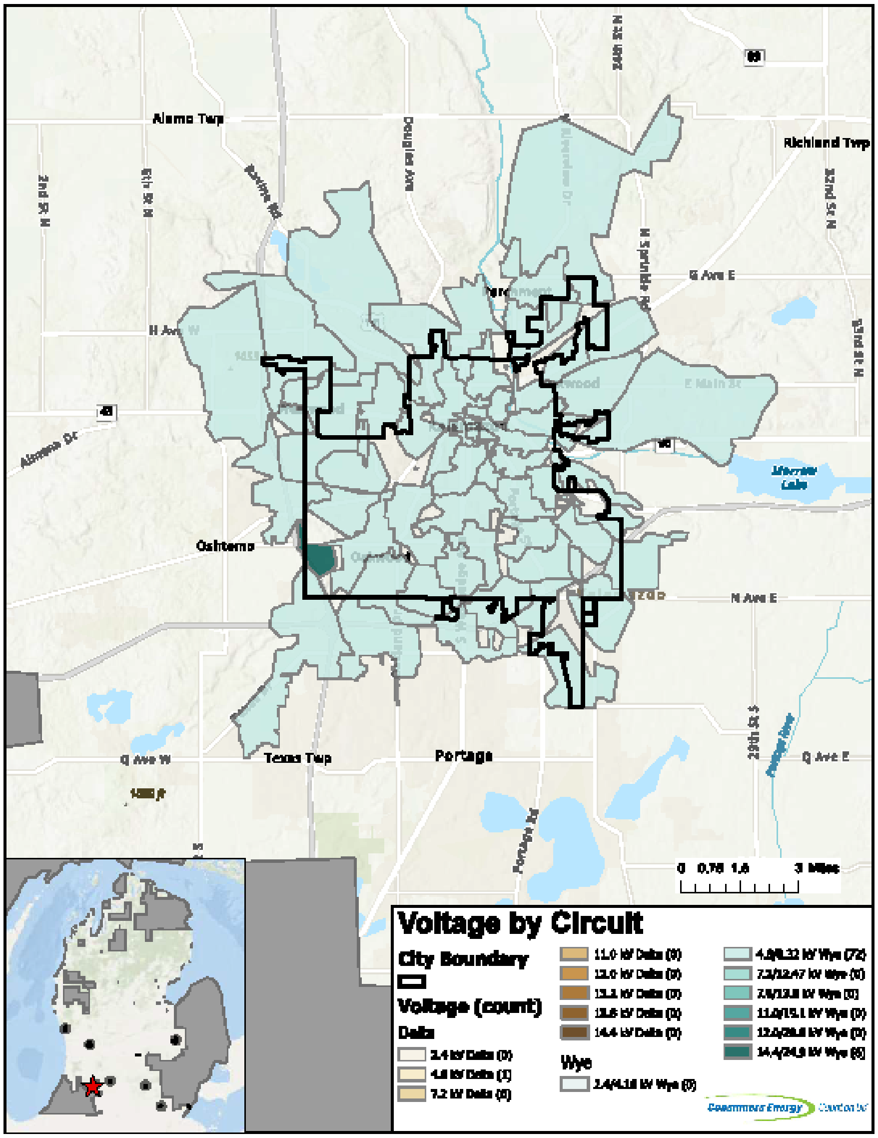
City of Flint



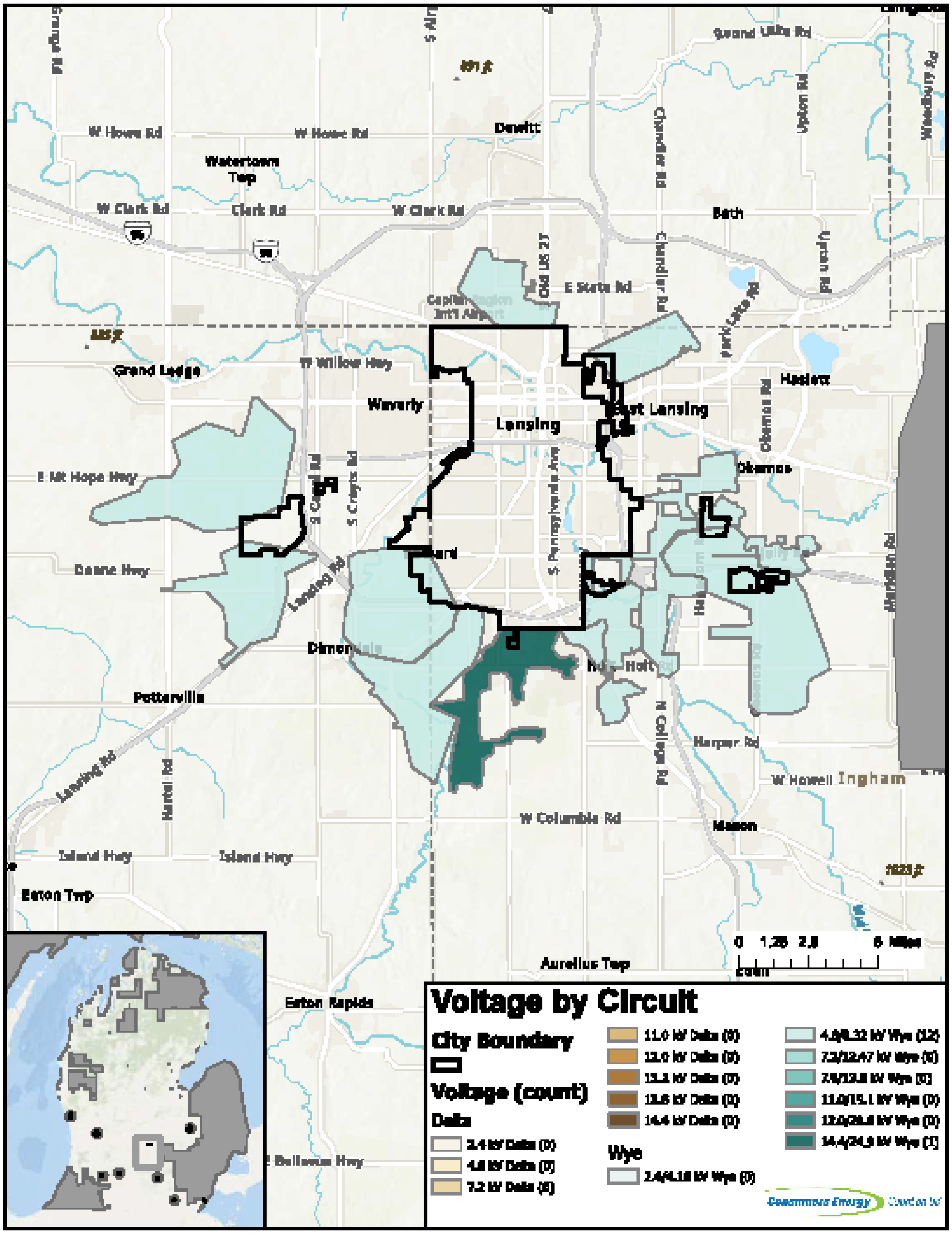
City of Grand Rapids



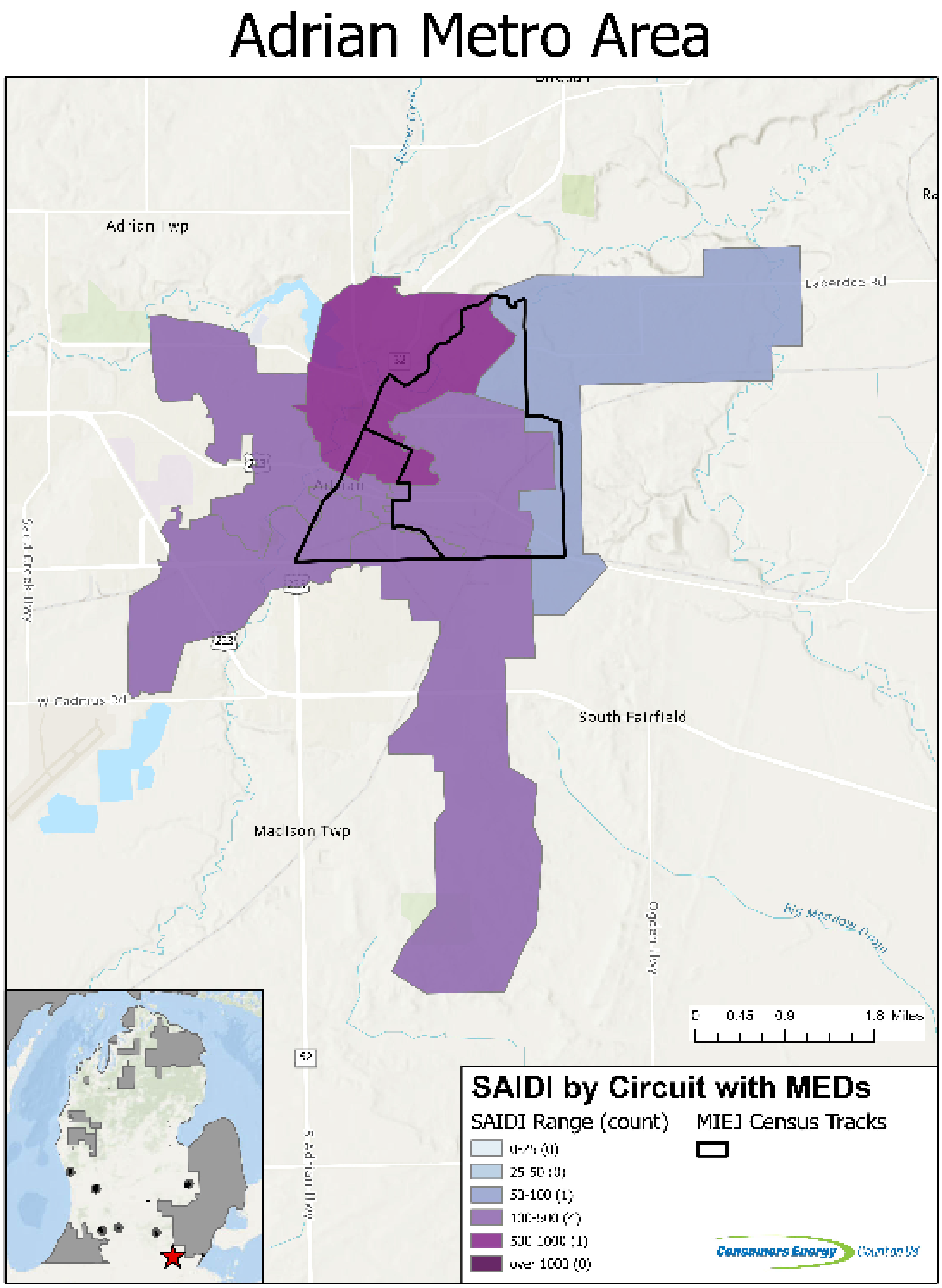
City of Kalamazoo



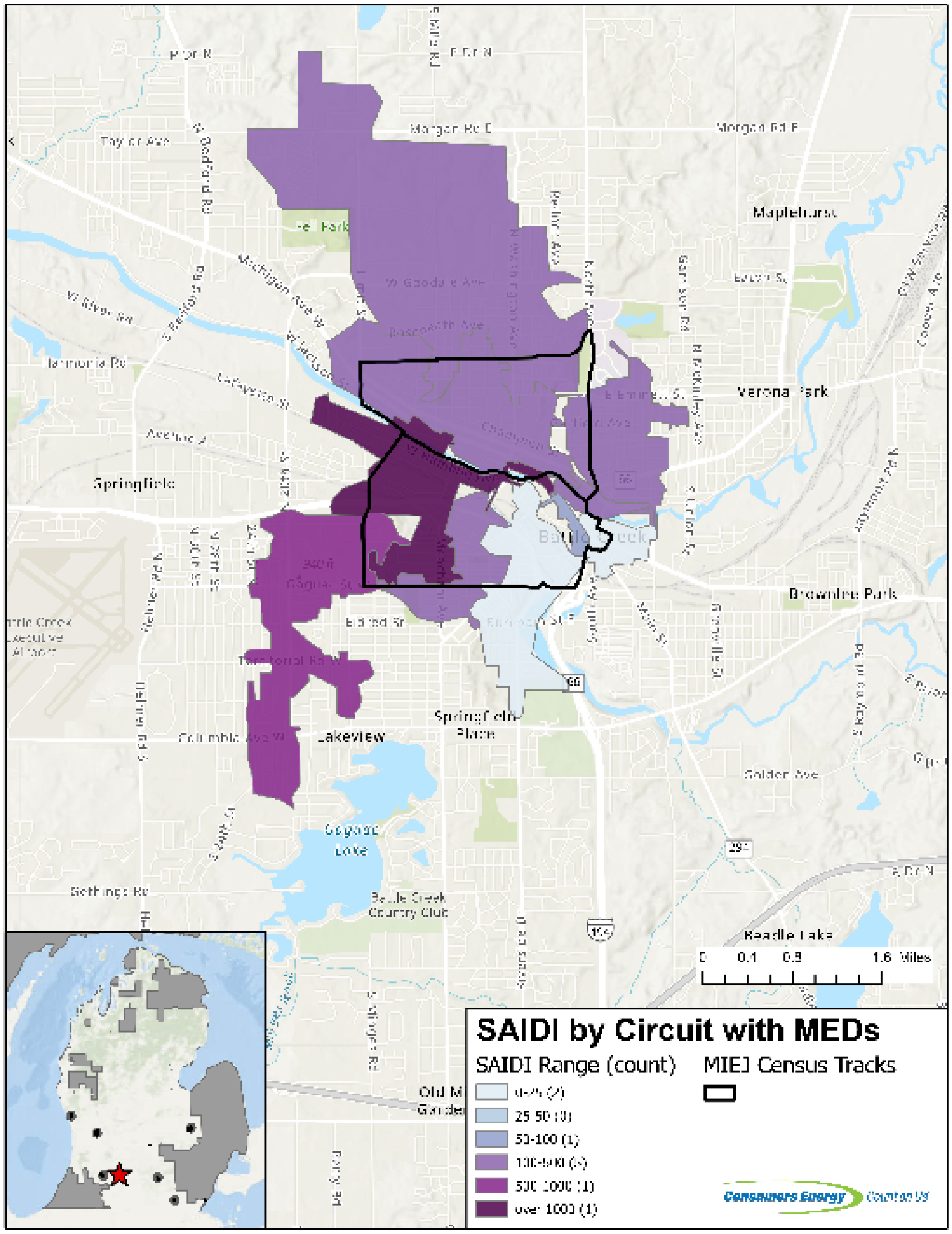
City of Lansing



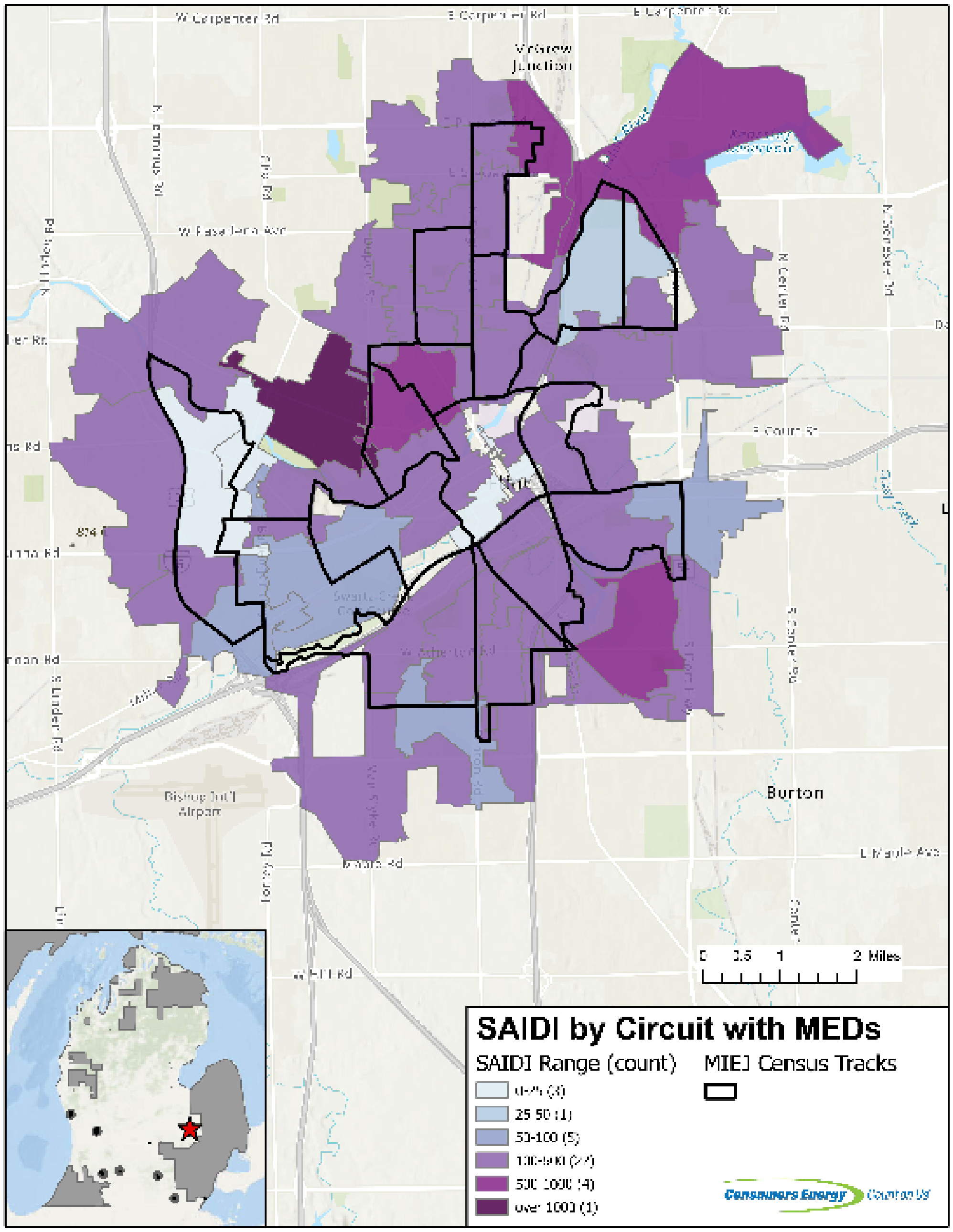
All-Weather SAIDI Overlaid on EJ Census Tracts



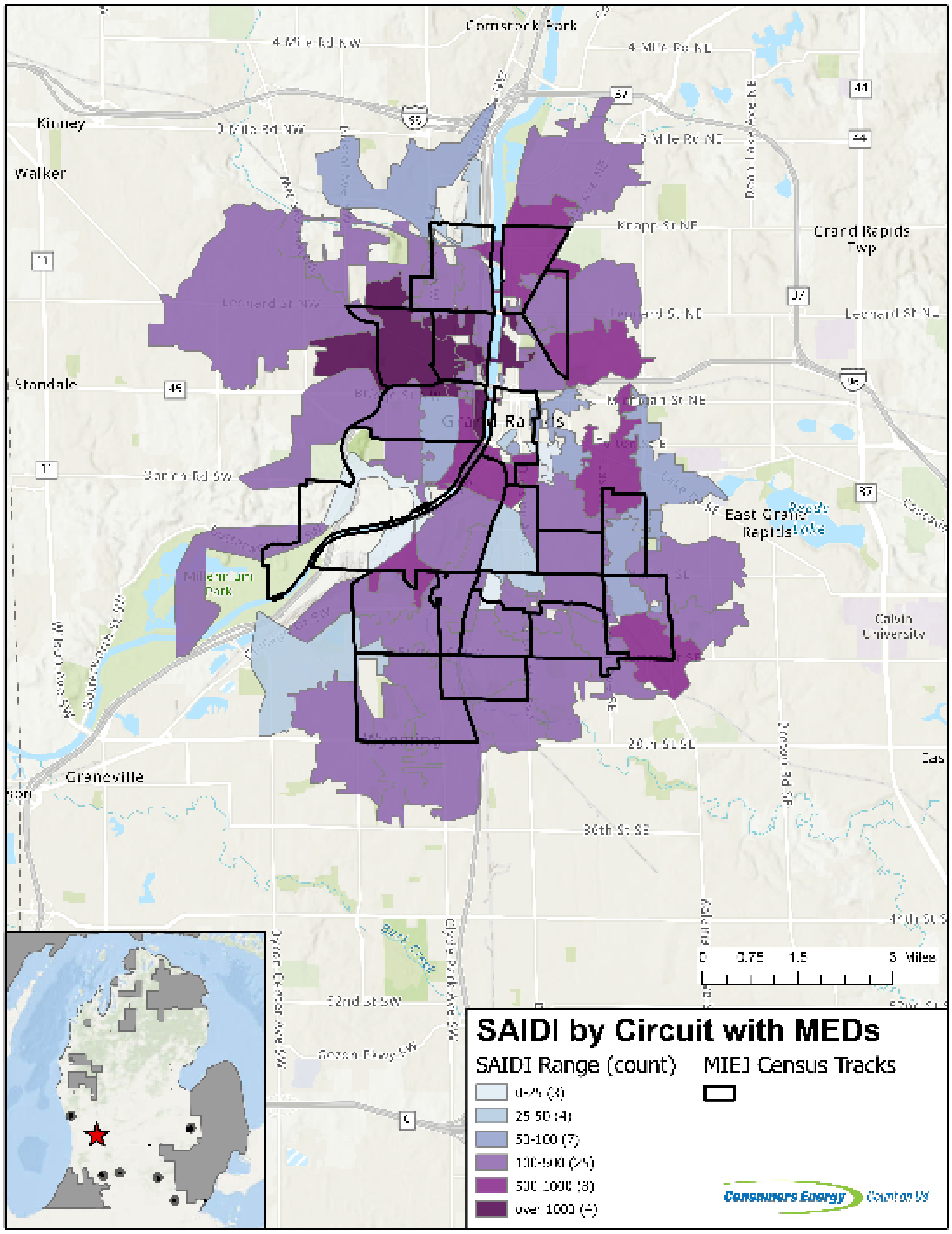
Battle Creek Metro Area



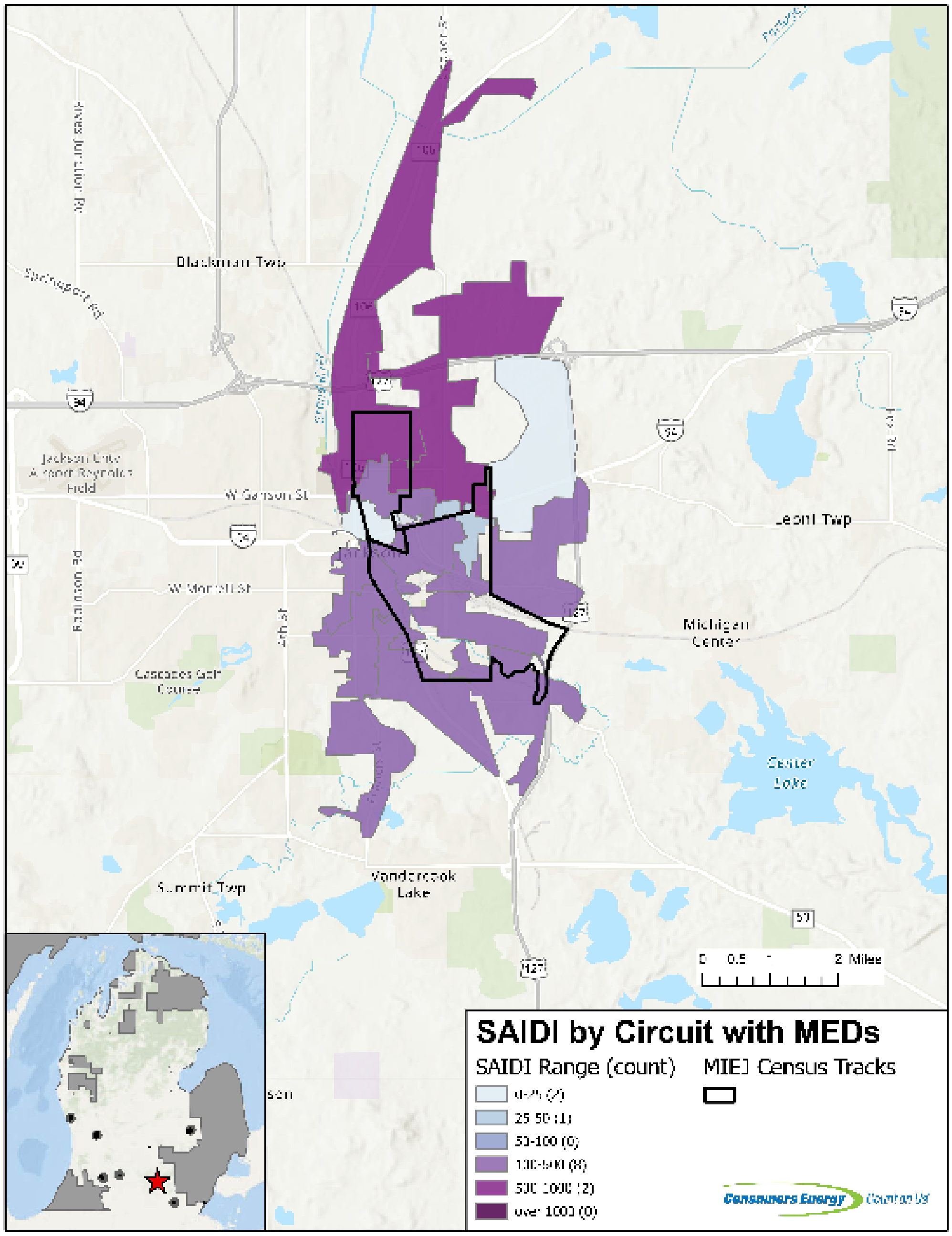
Flint Metro Area



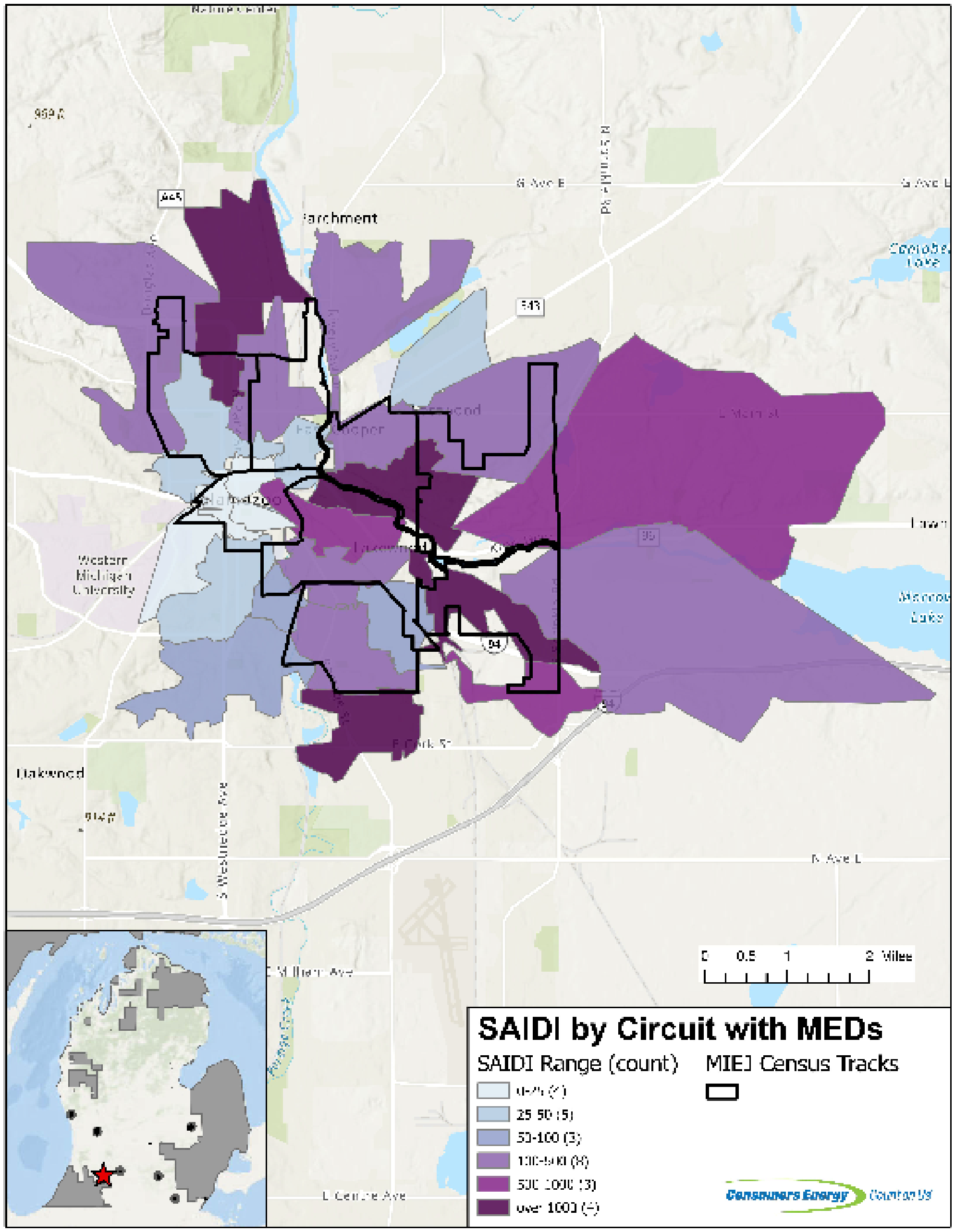
Grand Rapids Metro Area



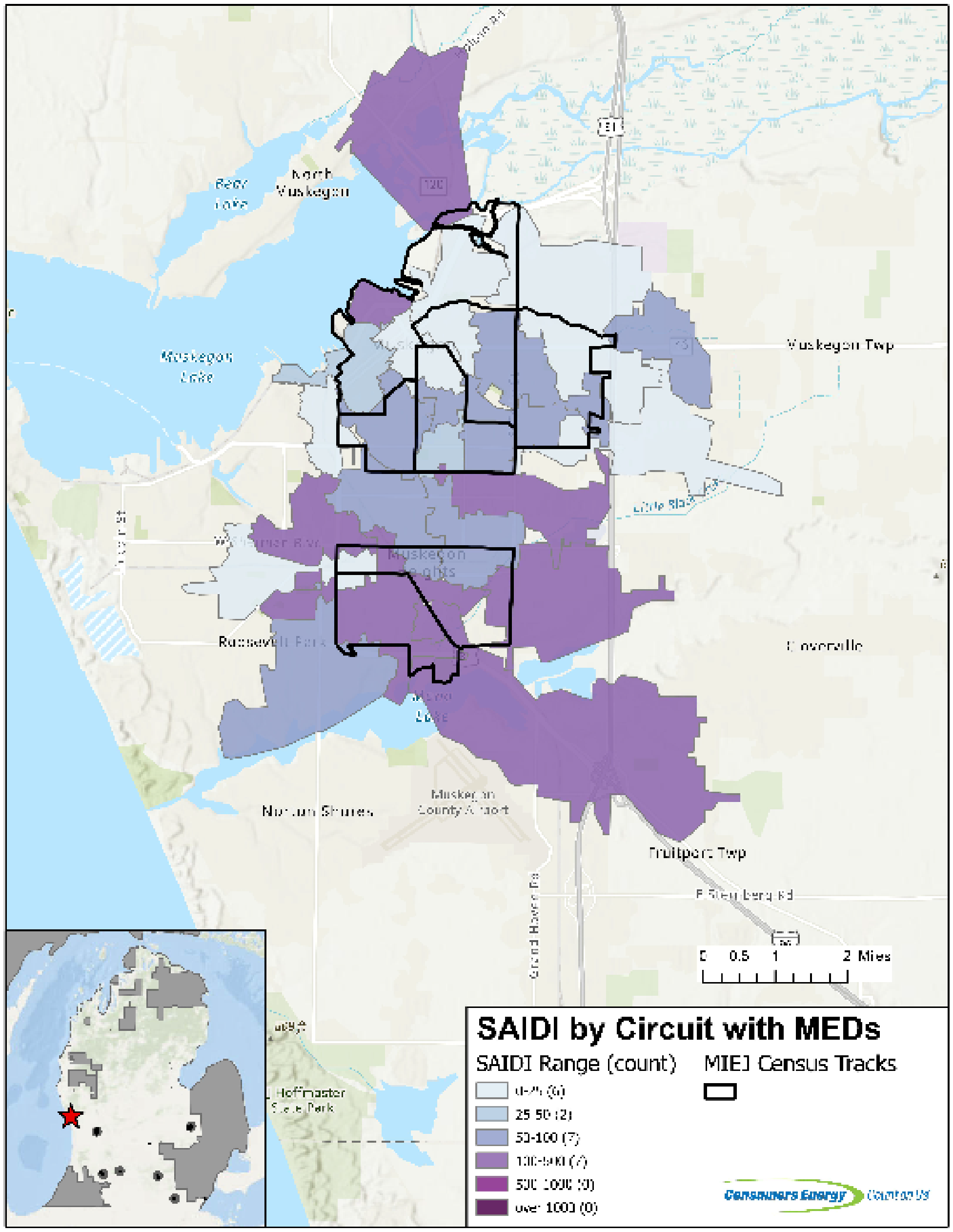
Jackson Metro Area



Kalamazoo Metro Area

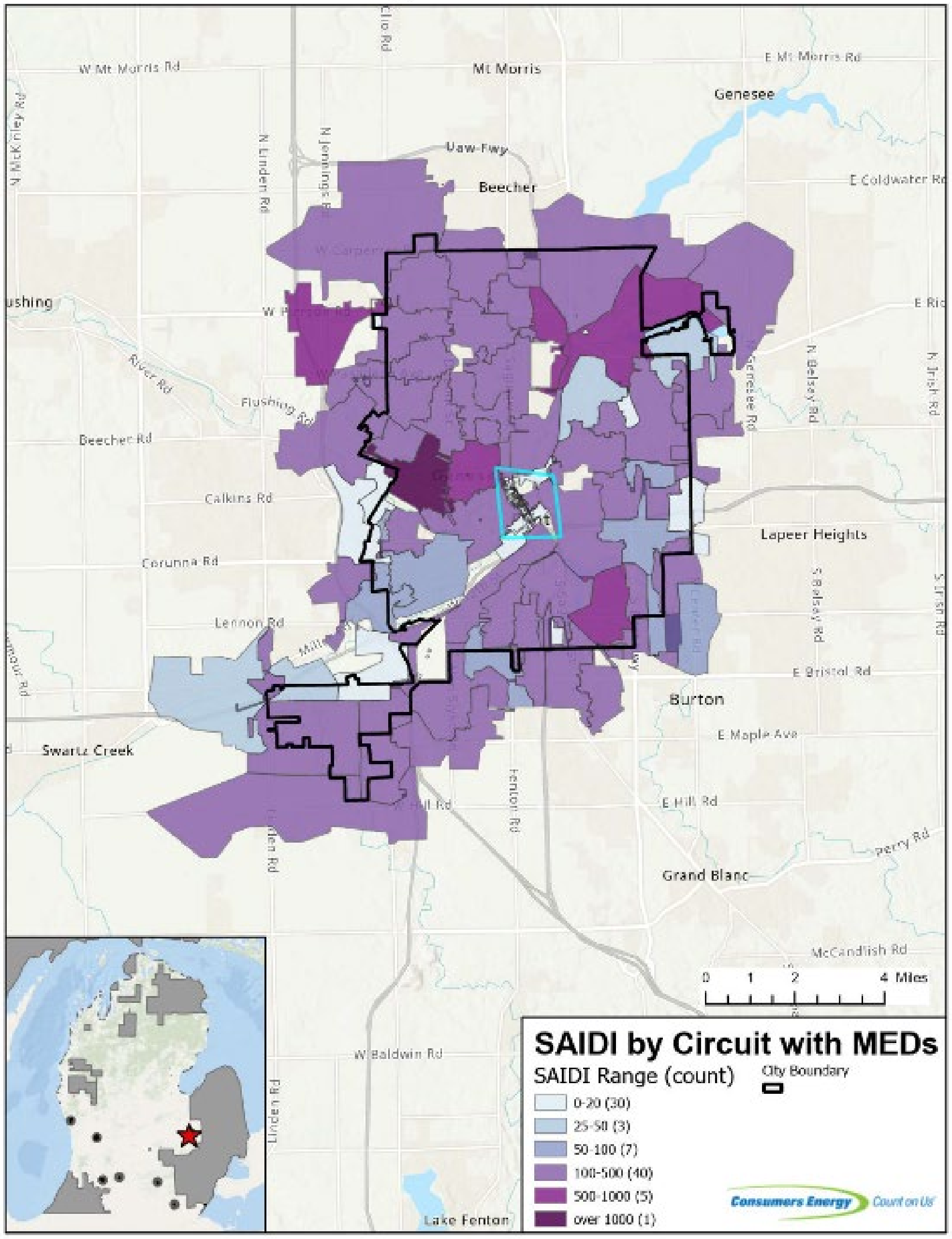


Muskegon Metro Area

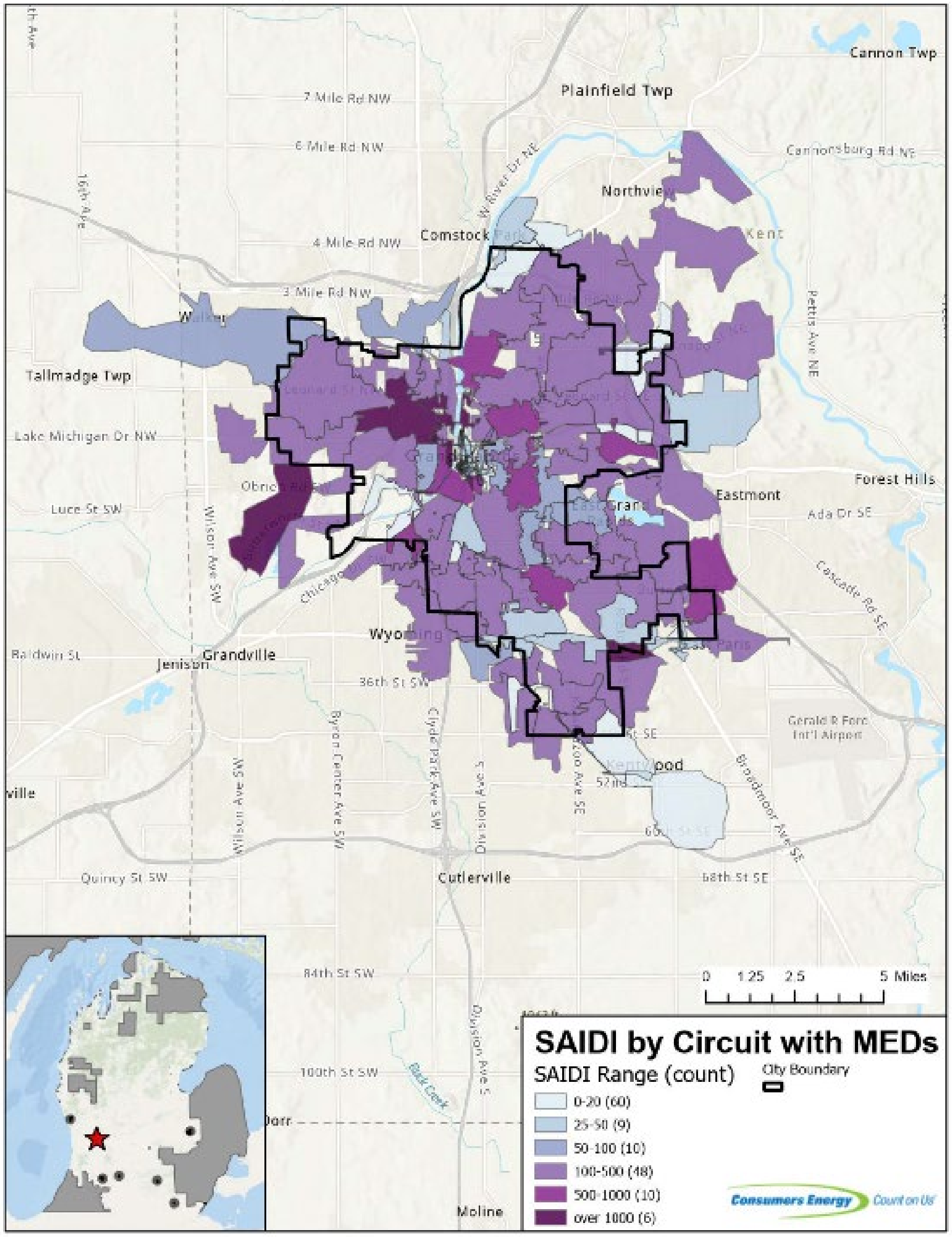


All-Weather SAIDI Overlaid on Designated Cities

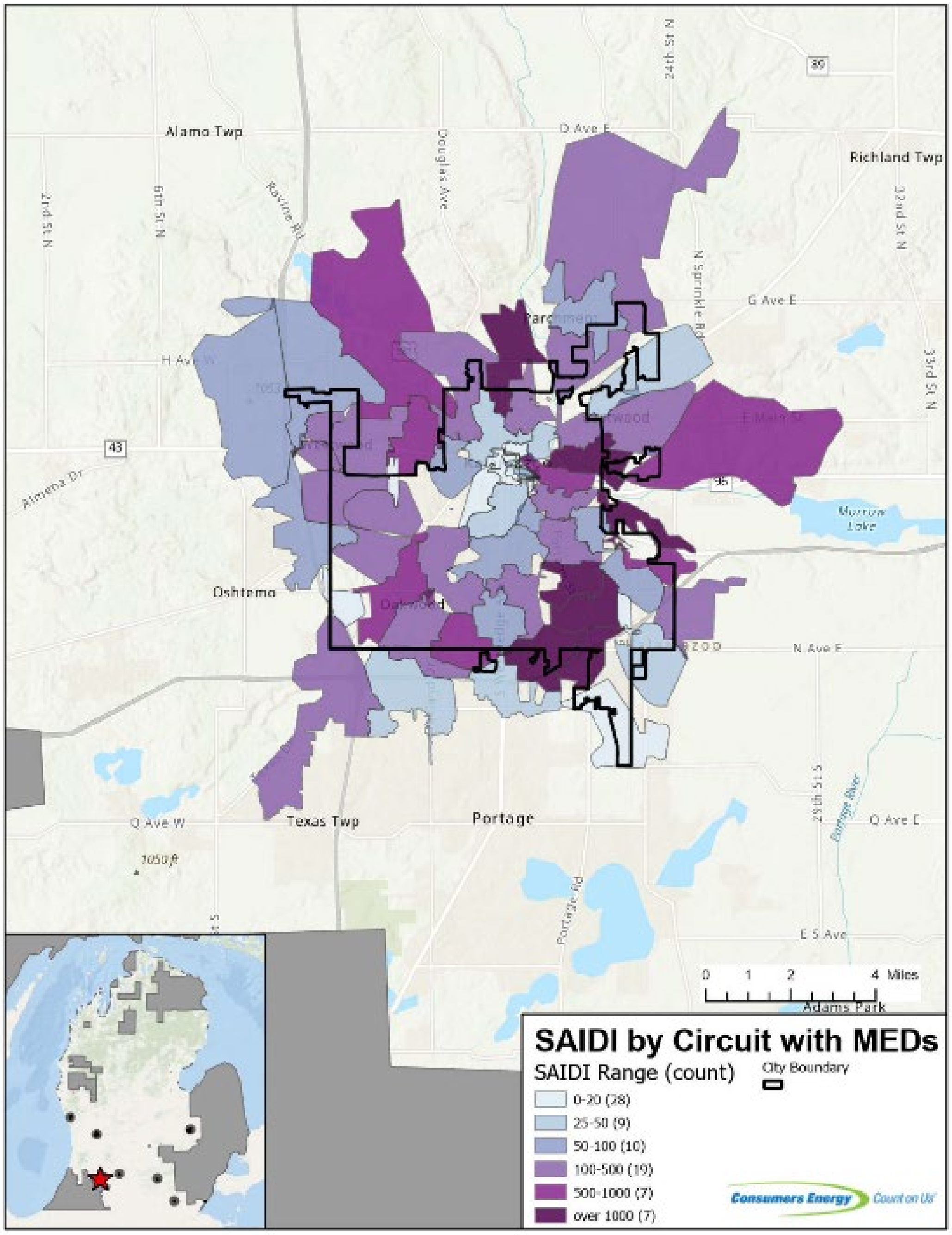
City of Flint



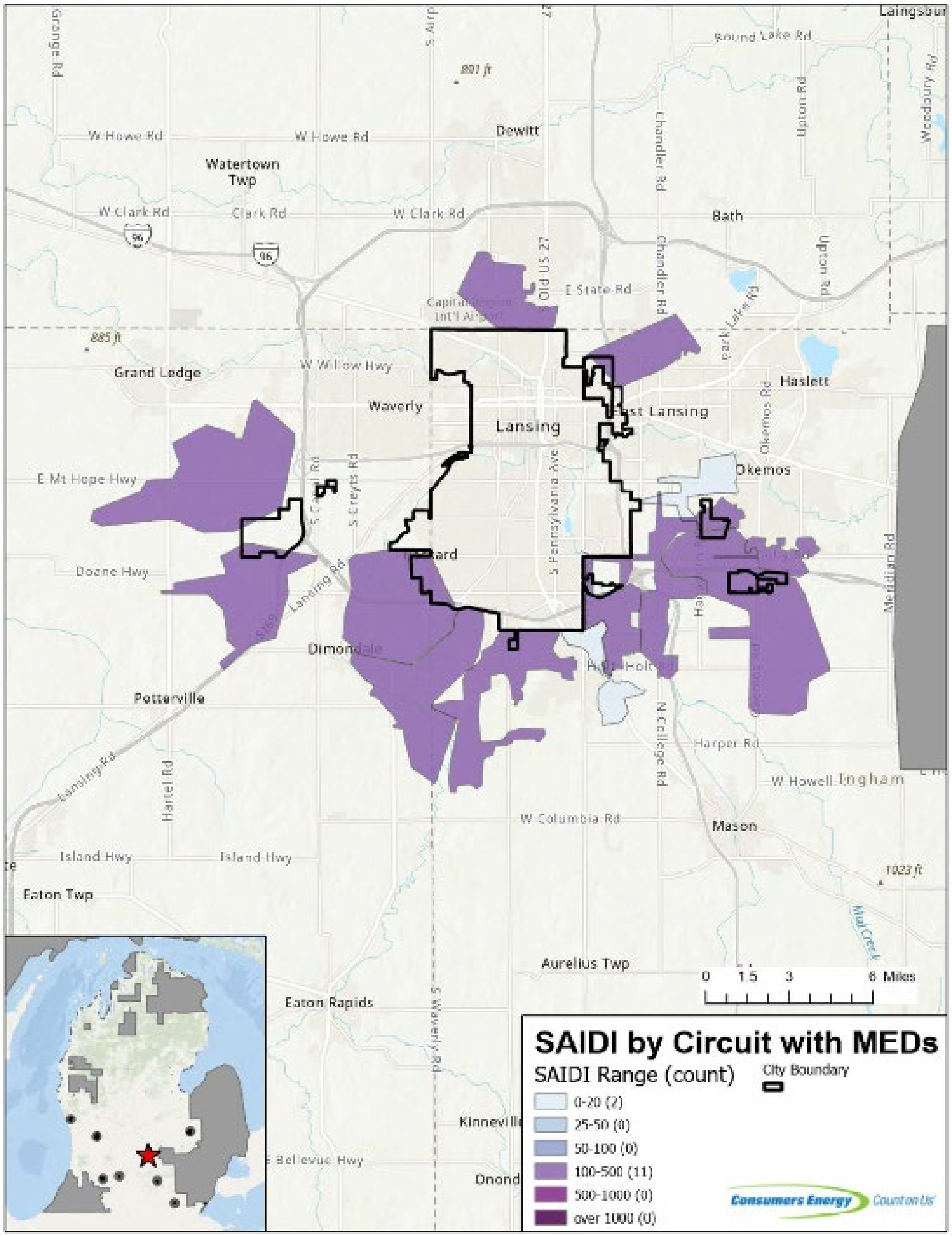
City of Grand Rapids



City of Kalamazoo



City of Lansing



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

STATE OF MICHIGAN)
) SS
COUNTY OF JACKSON)

Crystal L. Chacon, being first duly sworn, deposes and says that she is employed in the Legal Department of Consumers Energy Company; that on September 27, 2023, she served an electronic copy of **Consumers Energy Company's Electric Distribution Infrastructure Investment Plan ("EDIIP") 2024-2028** upon the persons listed in Attachment 1 hereto, at the e-mail addresses listed therein.

Crystal L. Chacon

Crystal L. Chacon

Subscribed and sworn to before me this 27th day of September, 2023.

Melissa K. Harris

Melissa K. Harris, Notary Public
State of Michigan, County of Jackson
My Commission Expires: 06/11/2027
Acting in the County of Hillsdale

ATTACHMENT 1 TO CASE NO. U-20147

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ATTACHMENT 1 TO CASE NO. U-20147

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Counsel for Residential Customer Group ("RCG") and Great Lakes Renewable Energy Association ("GLREA")		
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