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August 1, 2017

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

**Re: Case No. U-17990 - In the matter of the application of Consumers Energy Company for authority to increase its rates for the generation and distribution of electricity and for other relief.**

Dear Ms. Kale:

Enclosed for electronic filing in the above-captioned case, please find **Consumers Energy Company's Electric Distribution infrastructure Investment Plan.** This is a paperless filing and is therefore being filed only in a PDF format. I have also included a Proof of Service showing electronic service upon the parties.

Sincerely,

Anne Uitvlugt

Digitally signed by
Anne M. Uitvlugt
Date: 2017.08.01
17:41:39 -04'00'

Anne M. Uitvlugt

cc: Hon. Dennis W. Mack, Administrative Law Judge
Parties per Attachment 1 to Proof of Service

Consumers Energy

# Electric Distribution Infrastructure Investment Plan (2018-22)

August 1, 2017

# TABLE OF CONTENTS — MAIN DOCUMENT

# TABLE OF CONTENTS — APPENDIX





**Draft Only and Subject to Major Revisions. Final Report Due January 31, 2017**

# 1. Executive Summary

At Consumers Energy, we are proud to serve nearly 1.8 million Michigan electric customers. It is our commitment to plan, build, maintain, and operate an electric distribution system that provides safe, reliable, and affordable electricity to our customers, both today and in the future. Customer expectations are quickly evolving and we must adapt to ensure that we can meet those expectations. Our ambitious, 15-year vision centers on five primary objectives for ensuring that our distribution system remains customer-driven:

- Optimizing system cost over the long-term
- Improving reliability and resiliency
- Enhancing cybersecurity and physical security and safety
- Reducing carbon footprint
- Enabling greater customer control

Over the past ten years, we have invested nearly five billion dollars into our electric distribution system, not only to maintain our current assets, but also to support a higher standard of reliability, resiliency and safety through infrastructure upgrades. We have taken the first steps towards our future vision through deployments like our distribution automation loop installations (2010-2017) and Advanced Metering Infrastructure (AMI) roll-out (2012-17), with much more to accomplish in order to reach our vision.

In the Commission order for Case No. U-17990, dated February 28, 2017, the Michigan Public Service Commission (MPSC) directed The Company to submit a five-year electric distribution investment plan, to inform the MPSC of our plan for modernizing the electric distribution system. We were directed to include: a detailed description, with supporting data, on distribution system conditions, including age of equipment, useful life, ratings, loadings, and other characteristics; system goals and related reliability metrics; local system load forecasts; maintenance and upgrade plans for projects and project categories including drivers, timing, cost estimates, work scope, prioritization and sequencing with other upgrades, analysis of alternatives (including AMI and other emerging technologies), and an explanation of how they will address goals and metrics; and benefit/cost analyses considering both capital and operations and maintenance (O&M) costs and benefits. The MPSC directed us to submit a draft plan to Staff by August 1, 2017 (this document) and the final plan by January 31, 2018.

Together, our draft and final submissions address all of the elements outlined by the MPSC. We present our future vision for the electric distribution system, compare and contrast that with the current state of the system, and outline our investment plan to bridge between the current state and the future. This draft focuses on our vision, current state of the system, and our categories of investment, but does not yet include forward-looking cost estimates. We look forward to working with the MPSC and the broader set of stakeholders to refine the details of our electric distribution infrastructure investment plan.

# 2. Vision of the Consumers Energy Electric Distribution System

## 2.1 A customer-driven future

Over the past century the electric distribution system has changed numerous times, affecting system requirements and the investments needed to meet those requirements. Today, the electric grid is evolving ever-faster as technological advances and financial innovations allow customers to change their electricity usage in new, meaningful, and sometimes unexpected ways. Customer expectations are becoming more varied and complex, which requires the system to become increasingly adaptable. For the residential segment, one customer may want to install distributed solar, while another may desire greater certainty in his/her monthly bill. For the commercial and industrial (C&I) segment, we are experiencing greater demand for a variety of options from lowering cost (e.g. demand response for peak shaving) to creating a brand that is more environmentally conscious (e.g. 100% renewable energy). More broadly, customers want some combination of the following objectives: lower cost, improved reliability and resiliency, enhanced security and safety, reduced carbon footprint, and more control over energy supply and consumption.

Additionally, there is a renewed focus on the critical state of U.S. infrastructure in general, from water to transportation to electricity, as the infrastructure ages. The American Society of Civil Engineering's 2017 Infrastructure Report Card[1] gives U.S. energy infrastructure a D+ grade, saying "the U.S. energy sector faces significant challenges as a result of aging infrastructure, including supply, security and reliability, and resiliency issues in the face of severe weather events, all posing a threat to public safety and the national economy." These acute infrastructure needs affect Michigan. Governor Snyder's 21st Century Infrastructure Commission report[2] identified a modern and dependable electric grid as a priority area for infrastructure improvement. The statewide storm events in March of 2017 further highlighted the need for increased reliability and resiliency.

Over the coming decades, five trends in customer expectations will meaningfully affect the attributes of the electric distribution system and thus the assets and capabilities required to operate it successfully:

i. **Reliability and resiliency**: Outage events are extremely costly, both to us when we respond and to our customers via lost productivity and damage. Following outage events across the country, from Hurricane Sandy in 2012 to the recent March storms in Michigan, customers increasingly focus on reliability and resiliency in their assessments of utility service provision.

ii. **Security**: Customers, governments, and utility executives are increasingly focusing on security threats, especially cybersecurity, as one of the most important issues facing utilities today, reflected through increasing security spending *[See Appendix A.5 – Figure 26]*. Recent events, including the December 2015 hacking of several Ukrainian electric distribution centers and the April 2013 sniper assault on a Pacific Gas & Electric transmission substation, have highlighted the real security threats present today. In fact, in Utility Dive's 2017 "State of the Electricity Utility" survey[3] of utility executives, physical and cyber

[1] https://www.infrastructurereportcard.org/

[2] http://www.michigan.gov/documents/snyder/21st_Century_Infrastructure_Commission_Report_555079_7.pdf

[3] http://www.utilitydive.com/library/2017-state-of-the-electric-utility-survey-report/

security threats topped the list as the most important concern for utility executives today *[See Appendix A.5 – Figure 27].*

iii. **Distributed energy resources (DERs)**: Customers will continue to pursue adoption of distributed energy resources (e.g. distributed generation, battery storage, electric vehicles) *[See Appendix A.1 – Figures 14 - 17]*. Adoption will accelerate as underlying costs continue to fall along normal experience curves *[See Appendix A.1 – Figures 18 – 19]*.

iv. **Renewable generation**: C&I customers across the country and within Michigan will continue to desire expanded renewable generation, driven by (A) falling costs of renewable energy and (B) increasing demand by end use customers for stronger corporate commitment to sustainability and environmental responsibility. Projections for wind energy costs suggest it could be competitive with traditional generation on an unsubsidized basis in Michigan over the next decade *[See Appendix A.2 – Figures 20 – 21]*. In addition, four of Michigan's largest corporations have recently publicly stated a desire for a greater percentage of their electricity to be renewable, with more coming forward each year *[See Appendix A.2 – Figure 22].*

v. **Data proliferation:** Our customers have a growing amount of data at their fingertips and increasingly leverage that data to make new, ever more powerful, real-time decisions. Customers can change the thermostat, monitor their homes, unlock the doors, and even do the laundry remotely. This new reality is evident in the electric sector as well. Customers can actively engage with the system via energy efficiency and demand response programs, and have the potential to control distributed generation and energy storage devices. Further into the future, this could unlock the potential for a more interactive relationship between utilities and their customers, supported by expanded data and the analytics to drive new insights and decision-making. Just as past technological innovations rapidly penetrated the market over the course of a single generation, these "grid edge" data-driven technologies are expected to become deeply integrated in the electric distribution system over the next two decades *(see Appendix A.4 – Figure 25)*.

In our five-year electric distribution infrastructure investment plan, we commit to building a more modern electric distribution system that integrates greener, more distributed sources of electric supply with grid enhancements that are engineered for customer value. More specifically, the plan focuses on meeting five primary objectives we have across our entire customer base:

- **Optimize system cost over the long-term**: We will meet all of our objectives in a manner that is most cost effective and equitable for our entire customer base over the long-term. We will not optimize costs for some customers in a manner that unfairly impacts other customers, and will not be short-sighted by minimizing cost in the short term only to bear a multiple of that cost in later years.

- **Improve reliability and resiliency:** We will harden the system, where necessary; improve visibility in order to more proactively operate the system; minimize outage occurrences; respond with speed and effectiveness to minimize outage duration; and better manage frequency and voltage.

- **Enhance cybersecurity and physical security and safety**: Our plan will introduce new technologies and new work processes to support the deployment and operation of those technologies. We will design the system to ensure that the security and safety of our customers – and our employees – is maintained and ultimately enhanced.

- **Reduce carbon footprint**: We will continue to look for opportunities to reduce waste in the system by building "at the right size and at the right time" (e.g. smaller, more modular, and more targeted investments) and exploring opportunities to promote lower carbon resources where economical (e.g. non-wires alternatives that integrate distributed generation).

- **Enable greater control**: We will continue to configure the system providing customers with the data, technology, and tools to take greater control over their energy supply and consumption. This will require a more robust communications network to facilitate two-way flows of information and further improve our own systems to gather more data and translate that data into information useful to our customers, our regulators, and ourselves.

Our plan focuses on meeting the expectations of customers while continuing to develop rate constructs, in conjunction with the MPSC, that reflect the value of our services and provide sustainable returns.

## 2.2 Implications for Consumers' Distribution Infrastructure Investment Plan

This customer-driven future requires a dynamic electric distribution system that integrates greener, more distributed sources of electric supply with grid enhancements that are engineered for customer value. When considering customer objectives and the changing ecosystem, we believe our system must incorporate the following capabilities:

- **Predictive and targeted resiliency**: Usage of predictive analytics, upgraded assets to better withstand "failure" events (e.g. storms), and the ability to island portions of the network to protect from malicious events and improve resiliency
- **System variability**: Ability to anticipate and manage increasing load changes due to large-scale distributed renewable resource penetration
- **Circuit-level planning**: Enhanced system planning to align investments with needs at a more granular level, leveraging the availability of additional data points in the system
- **Two-way communications**: Expanded communications network that can support increased two-way flows of information and energy
- **Advanced technologies:** Installation and usage of advanced technologies (e.g. drones, remote switching) to reduce costs and improve reliability
- **Data transparency**: Providing customers with education on energy usage and DER technologies along with access to AMI information to support informed decision-making
- **Heightened cybersecurity**: Ability to detect and mitigate increasingly sophisticated cybersecurity threats (e.g. phishing schemes, ransomware) as digital grid technology expands

Transitioning to this future system will occur in three phases over 15 years:

- **Phase 1 ("Complete the foundation", first 3-5 years to early 2020s)**: We will continue to update the system and develop new capacity through traditional infrastructure investments for immediate and important system needs (e.g. replacement cycles) while also developing critical infrastructure (e.g. distribution automation loops, AMI) as a foundation for next generation capabilities. We will also launch early pilots of our Advanced Distribution Management System (ADMS) platform which will enable initial use of volt-VAR optimization (VVO) to reduce energy waste and fault location, isolation, and service restoration (FLISR) to improve reliability for customers.

- **Phase 2 ("Enhance our capabilities", next 3-5 years to mid-2020s)**: Building upon the foundation laid in Phase 1, the focus will shift to enhancing our communications network and critical system planning capabilities and expanding our use of automation and conservation applications (e.g. FLISR, VVO) required to better optimize the design and operation of the electric distribution system. Additional pilots will be launched to test a greater suite of non-wires alternatives along with more modern opportunities to maintain the system (e.g. LiDAR for tree trimming, drones for pole inspections) in a lower cost way.

- **Phase 3 ("Optimize the future system", third 3-5 years to late 2020s)**: With the devices and applications deployed in prior phases, we expect to fully implement best practices that leverage the knowledge and capabilities acquired in the first two phases and improve asset management, grid analytics, and operational efficiency capabilities.

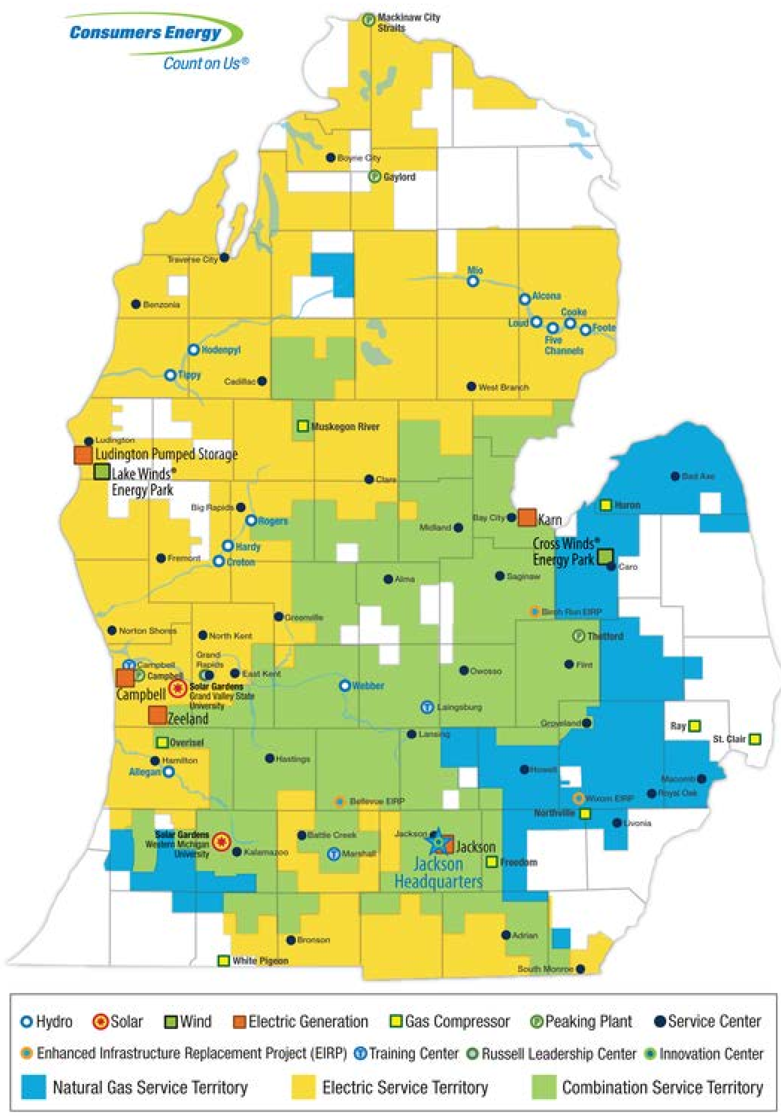
This transition will allow us to optimize cost to customers by investing at the right time; incorporate more mature technologies to ensure longevity; and meet customers' expectations through knowledge gained in early, limited-scale deployments.

We are already in the midst of Phase 1 and have made meaningful progress with investments such as our AMI deployment, distribution automation loops, and capacitator bank controller upgrades. Collectively, these investments are part of a continued focus on system upgrades that will meet our customers' evolving expectations. This five-year electric distribution infrastructure investment plan covers the period from 2018-2022 and marks the transition from Phase 1 to Phase 2.

# 3. Current state of the Consumers Energy electric distribution system

Our electric distribution system is an essential part of Michigan's infrastructure, serving 1.8 million customers across approximately 70,000 miles of distribution lines and 1,200 substations in the north, central, and western portions of Michigan from Monroe County to Mackinaw City *[See Figures 1 and 28, Appendix B.1 - Tables 16 - 17]*.

***FIGURE 1 - CONSUMERS ENERGY SERVICE TERRITORY***

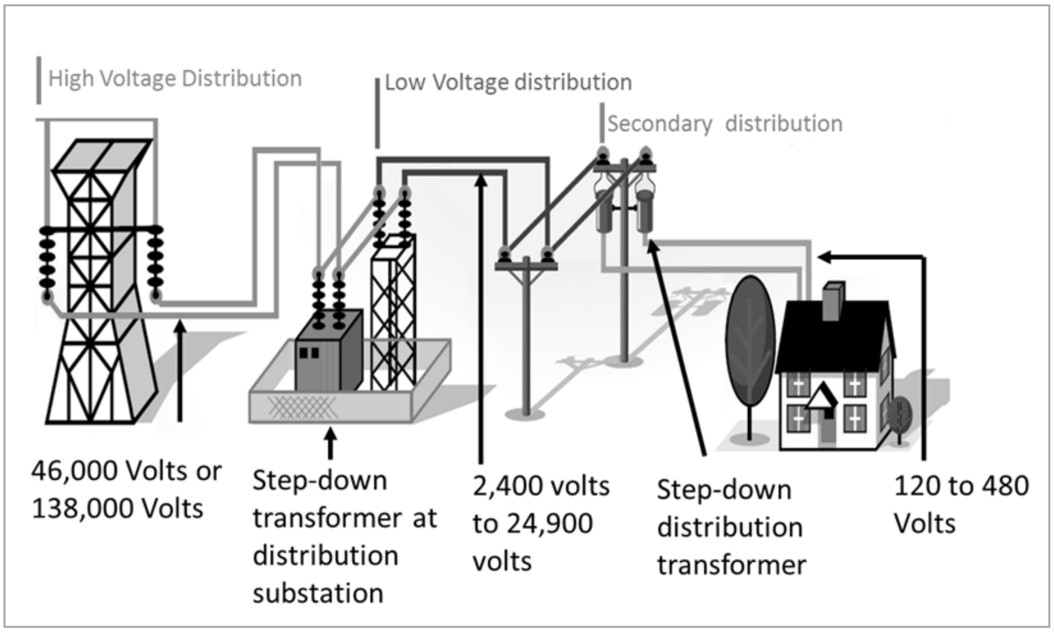



## 3.1 Consumers Energy electric distribution system overview

Our distribution system consists of more than 70,000 miles of wires on high-voltage distribution (HVD) and low-voltage distribution (LVD) systems, providing service to residential, commercial and industrial customers. The

Consumers Energy HVD system consists nearly entirely of 46,000 volt lines (96% of the total), but also includes radial 138,000 volt and 69,000 volt lines (4% and <1% respectively). The HVD voltage is stepped down, or reduced, at LVD substation transformers to primary voltages between 2,400 and 24,900 volts. LVD voltage is then further stepped down at the distribution transformer to a secondary voltage, serving businesses and residences at between 120 and 480 volts. The LVD system consists of 12 different voltages because Consumers Energy acquired several distribution systems from smaller distribution companies. 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.

***FIGURE 2 - DISTRIBUTION SYSTEM DIAGRAM***

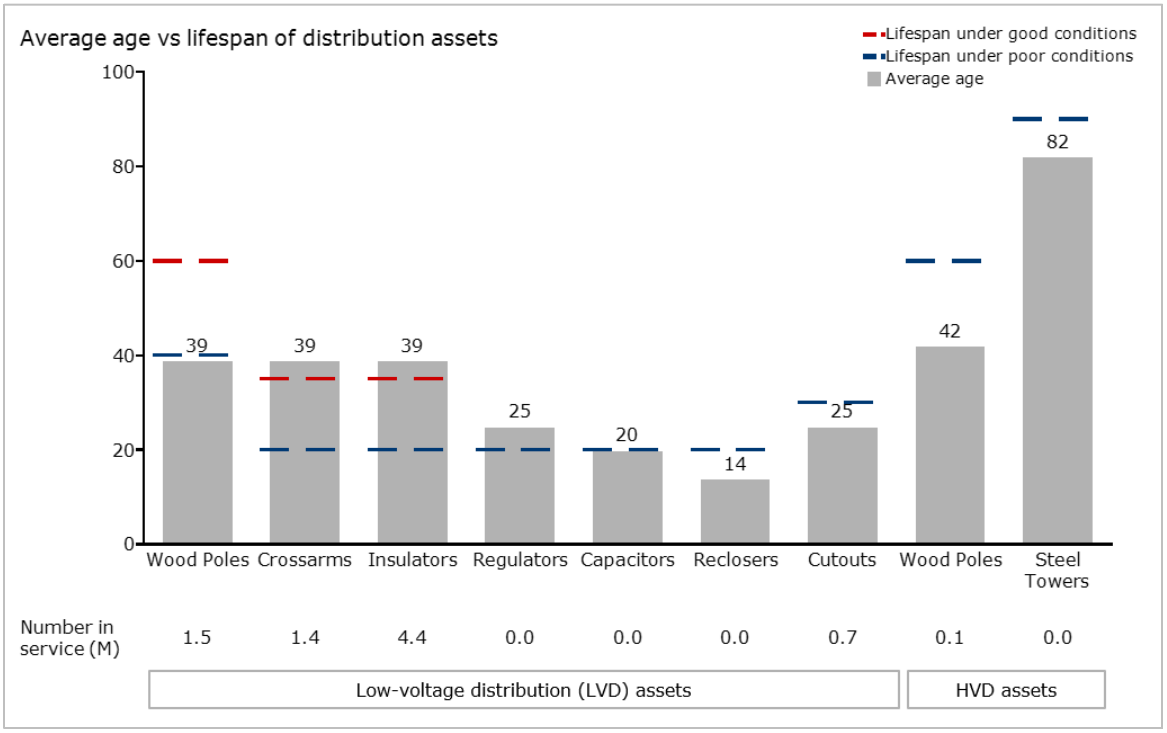



## Age of assets

Throughout more than a century of distributing electricity, our service area has expanded to incorporate new lines, pole-top equipment, and substations, among other assets, and much of that infrastructure has aged significantly. For example, of the more than 70,000 wood poles on the HVD system, approximately 30% are older than the expected life of sixty years *(see Appendix B.1 – Figure 29)*. A similar percentage applies to many other parts of the system, including crossarms, insulators, capacitors, and conductors *(see Figure 3 – Average Age of Distribution Assets and Appendix B.1 – Tables 18 - 19).* When compared to other major U.S. utilities, the age of our infrastructure as a portion of its expected lifespan is in the third quartile. (*see Figure 4 – Benchmarked Age of Assets*).

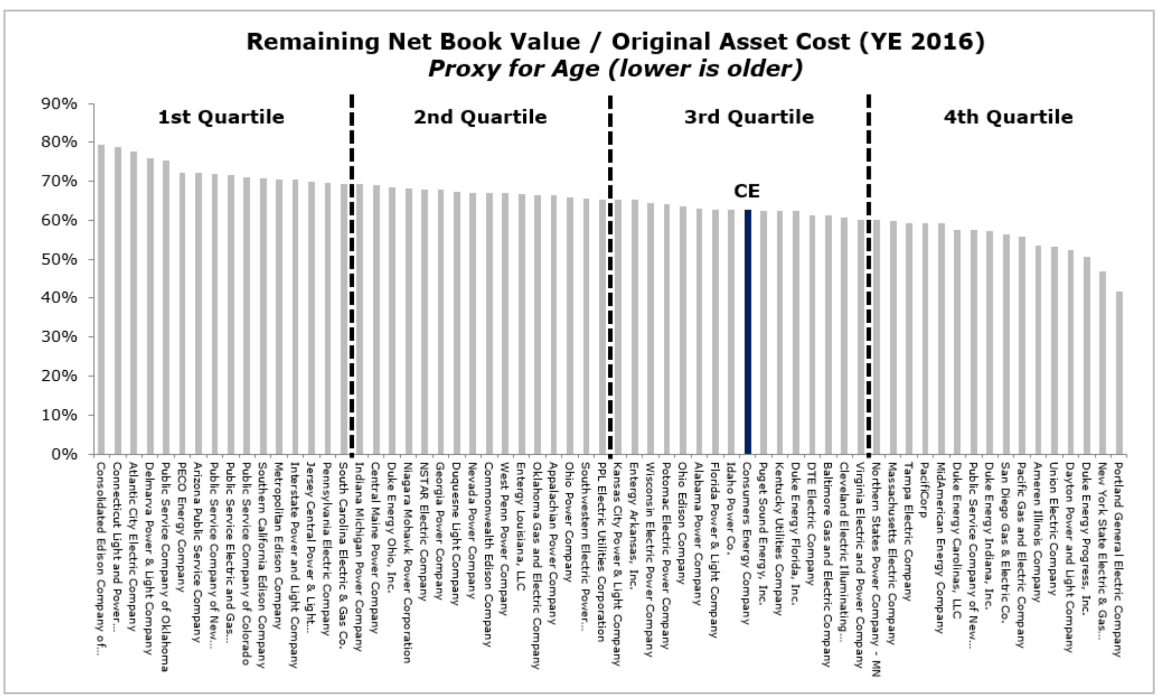
This age is not yet an urgent concern, as we are not yet at a point where the age of our assets creates critical reliability issues. Our inspection and repair programs, discussed in greater detail later in the report, diligently identify assets whose conditions have deteriorated, and we have programs in place to ensure timely and effective replacement.

***FIGURE 3 - AVERAGE AGE OF DISTRIBUTION ASSETS***




*Source: Consumers Energy*

***FIGURE 4 - BENCHMARKED AGE OF ASSETS***



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*Source: SNL FERC Form 1*

***Note: Figure X - Benchmarked Age of Assets** provides a snapshot of the average age of our total asset base in relation to other major U.S. utilities. The chart reflects the remaining book value of a company's assets divided by the original cost – intended to reflect the remaining life of the existing assets. This measurement includes all accounts listed in FERC Form 1 filings (Land and ROW, Structures, Station Equipment, Poles and Fixtures, OH Conductors, UG Conductors, Line Transformers, Services, Meters, Customer Installations, Leased Property, Street Lighting, and Retirement Costs).*

## 3.2 Historical reliability and resiliency performance

We assess our performance using industry standards and metrics from the Institute of Electrical and Electronics Engineers (IEEE), which benchmarks electric reliability across electric utilities using several key measures:

- System Average Interruption Duration Index (SAIDI): The primary overall electric system reliability indicator. SAIDI measures the annual number of minutes the average customer is without power across the entire electric system.
- Customer Average Interruption Duration Index (CAIDI): The average restoration time per outage (outage duration).
- System Average Interruption Frequency Index (SAIFI): The average number of interruptions per customer per year (outage frequency).

Below, we have included historical, benchmarked performance versus our peers *(see Figures 5 - 10).*

***FIGURE 5 - SAIFI: COMPARISON OF CONSUMERS ENERGY TO IEEE RELIABILITY SURVEY (2007 - 2016)***

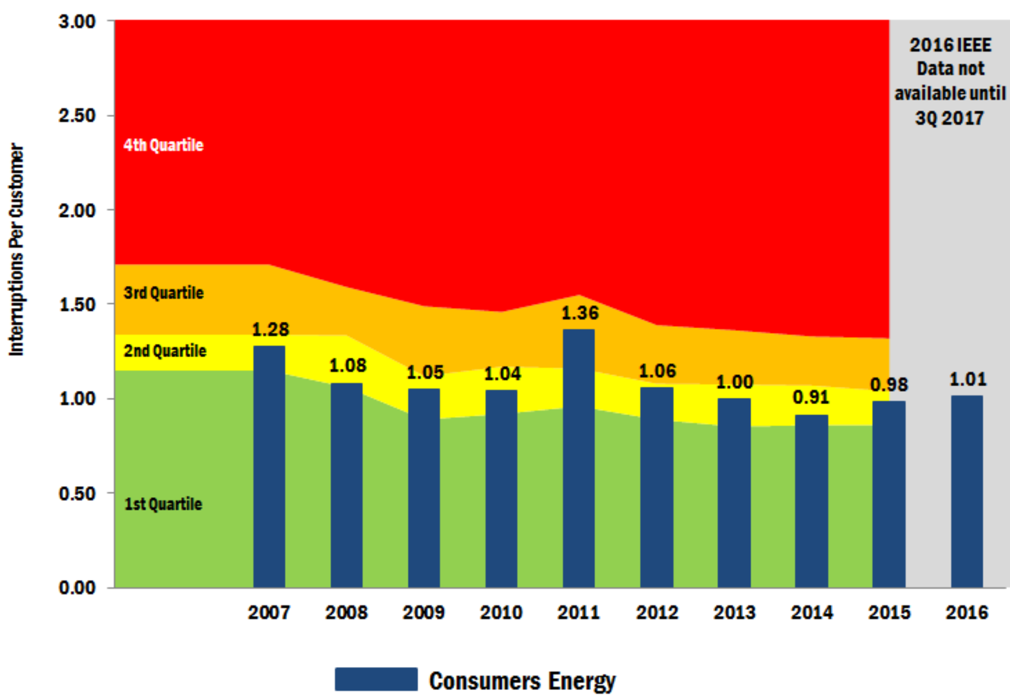
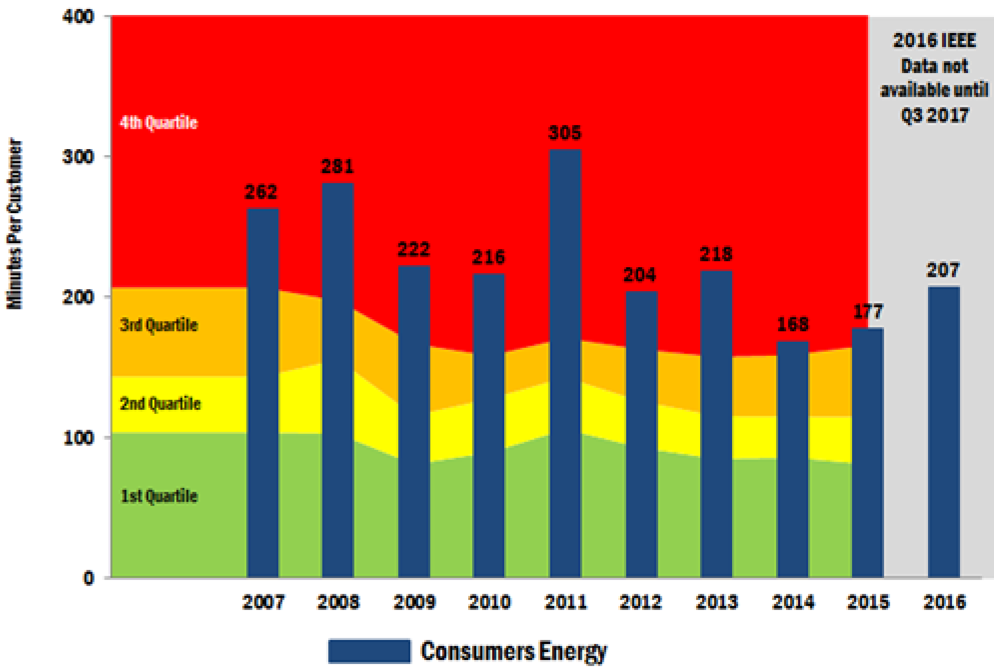


*FIGURE 6 - SAIDI: COMPARISON OF CONSUMERS ENERGY TO IEEE RELIABILITY SURVEY (2007 - 2016)*




Over the past ten years, our objective of improving customer experience has focused on reliability. While pursuing this, we have recently begun combining data on electric reliability performance and customer satisfaction to prioritize and plan reliability investments. Today we are seeing reliability improvements during business-as-usual operations, and particularly during weather events. These system improvements, layered with investments in technology to improve customer communications, have been foundational in how we plan for improving the overall customer experience. Additional information our reliability metrics, including circuit-level data is included in *Appendix B.2*; additional reliability benchmarking is included in *Appendix A.3*.

***FIGURE 7 - SAIDI RELIABILITY SCORES (2012 - 2016) - MAJOR EVENTS EXCLUDED***

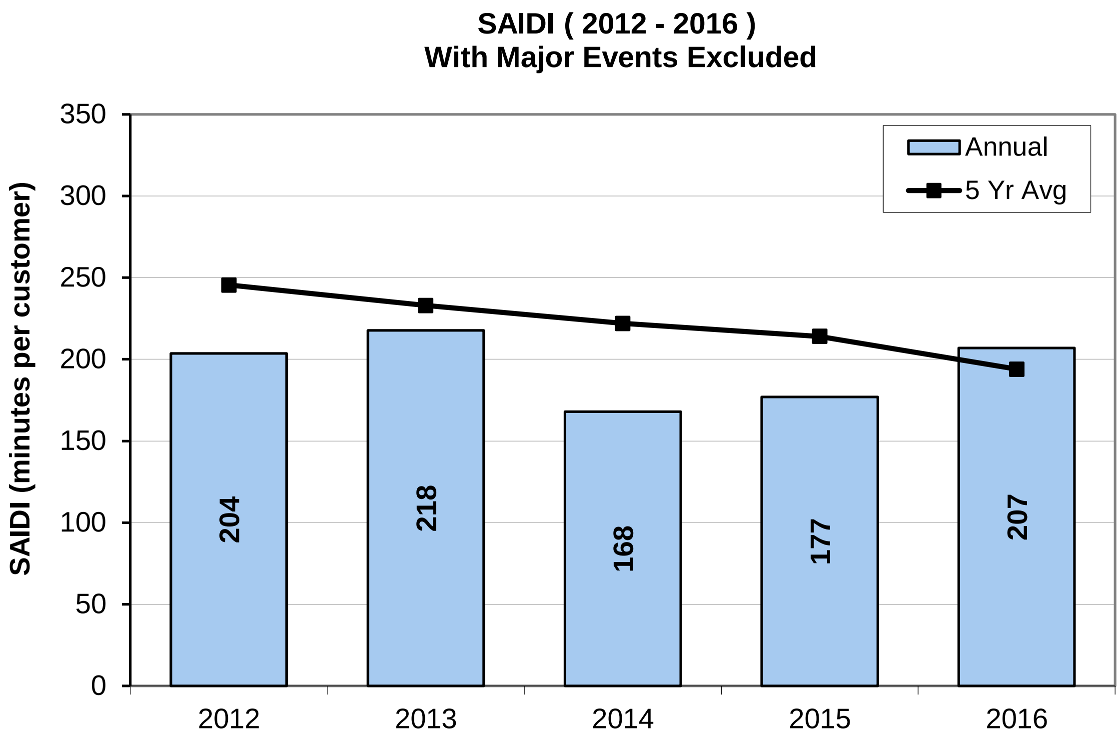



***FIGURE 8 - SAIFI RELIABILITY SCORES (2012 - 2016) - MAJOR EVENTS EXCLUDED***

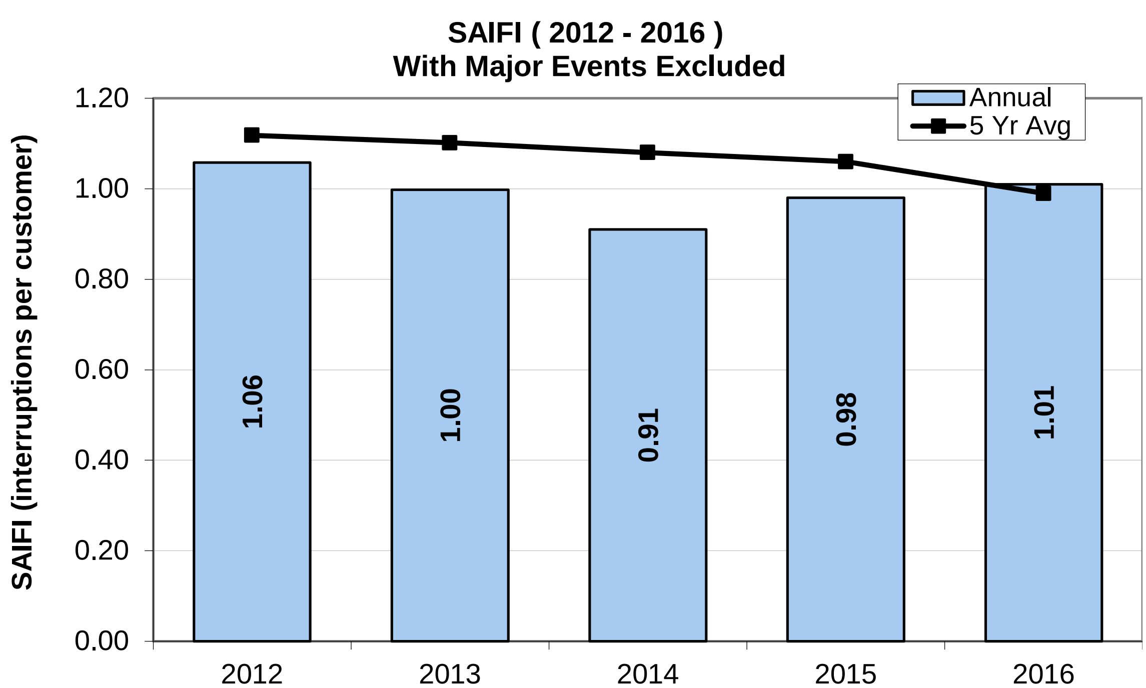





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*FIGURE 9 - SAIDI RELIABILITY SCORES (2012 - 2016) - MAJOR EVENTS INCLUDED*

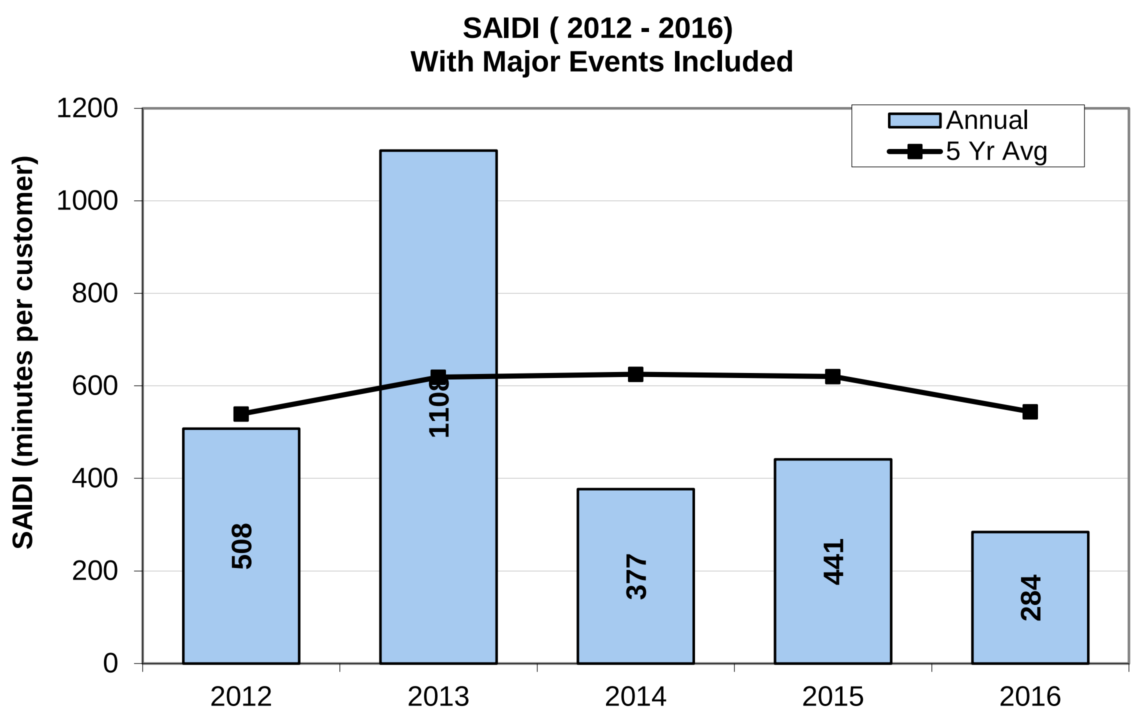
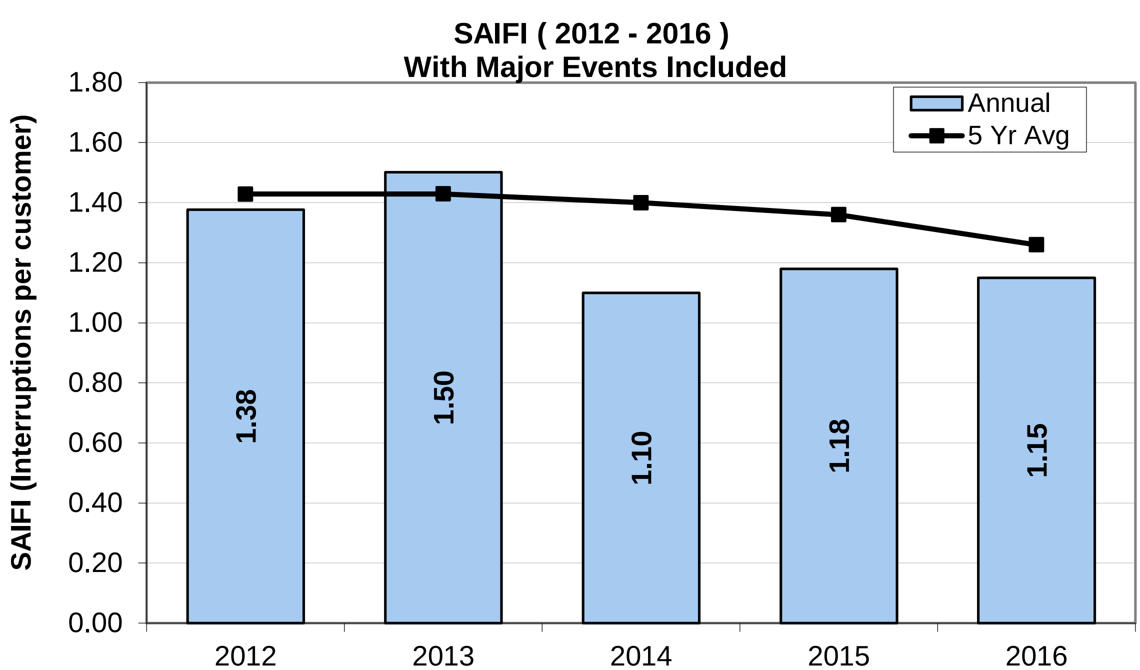



*FIGURE 10 - SAIFI RELIABILITY SCORES (2012 - 2016) - MAJOR EVENTS INCLUDED*



### Holistic approach to reliability and resiliency

Our recent efforts to improve system reliability and close the gap with many of our peer utilities are based on a holistic approach to improving the reliability of our worst performing circuits. This approach addresses reliability concerns through a multi-prong strategy, often consisting of repairs to both HVD and LVD assets along with forestry (tree trimming) efforts. This multi-prong strategy is monitored and managed through our Electric Reliability Rally Room, a physical collaboration area that promotes improved visibility and accountability. More information on our approach to reliability planning and the rally room is included in *Appendix E.3.*

## 3.3 Recent grid modernization investments

We recognized years ago that modernizing our infrastructure would improve customer satisfaction. We have been working more closely with the MPSC since 2010 to support the state's goal of updating and modernizing the electric distribution system to ensure long-term capacity, reliability, resiliency, and safety, and we look forward to building on that progress. Examples of our investments include:

- **Distribution automation loops (2010–2017)**: For years, we have been ramping up the deployment of distribution automation to improve reliability. These automated systems utilize specially programmed reclosers to immediately restore service as outages occur. Customers have saved over $4.6 million just in the first half of 2017 according to the Department of Energy ICE model[4]. Continued deployment of distribution automation in coming years will build on this success, and sets the stage for integration of even more advanced automation going forward.

- **AMI deployment (2012-2017)**: By the end of 2017 we will finish our five-year plan to install advanced metering infrastructure across our electric service territory. This investment is integral to meet evolving customer needs (e.g. two-way flows of information and energy).

- **Capacitor bank controller upgrades (2015–2017)**: Over the course of the last two and a half years, we have invested nearly $20 million to upgrade outdated capacitor controller equipment with new 4G cellular technology. A large portion of this program cost was dedicated to circuit conditioning and replacing failed infrastructure, improving power quality and reliability. Complementing the device deployment, we operationalized a LVD supervisory control and data acquisition (SCADA) system providing visibility into our distribution system in real-time. These upgrades enable applications like Volt-VAR Optimization and Conservation Voltage Reduction, which will contribute savings for our customers.

Our electric distribution infrastructure investment plan is a continuation of our efforts to update and modernize the system to meet the needs of today and to design a system that delivers greater value to customers by meeting their evolving needs and expectations in the future.

[4] http://www.icecalculator.com/

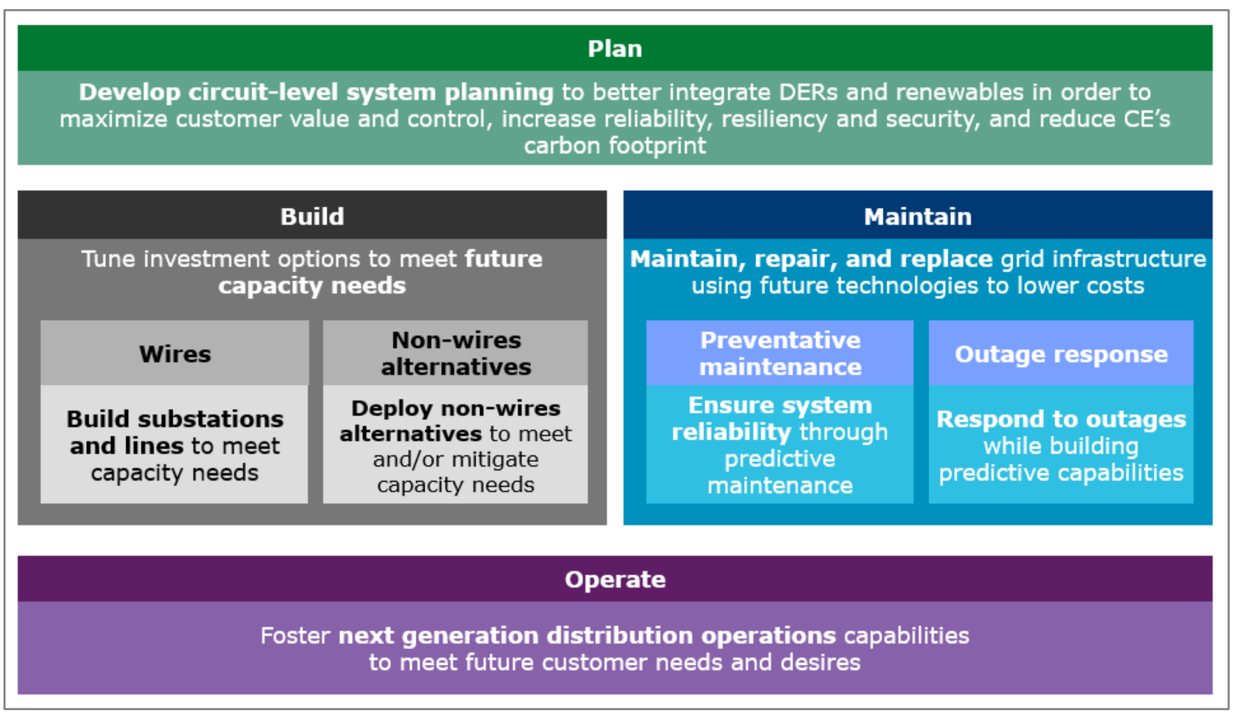
# 4. Electric Distribution Infrastructure Investment Plan

## 4.1 Electric Distribution Infrastructure Investment Plan Categories

As the distribution system operator, we perform four critical roles in meeting the expectations of our customers and the objectives that we set in Section 2.2 above. We group our investments into categories based on these roles.

1. **Plan**: We identify future supply-side and demand-side resource needs based on load forecasts and the acquisition of various resources. We will conduct system planning on an increasingly localized level to provide a more targeted set of investments and resources.
2. **Build**: We invest in the electric distribution system to ensure the entire system meets overall load and peak demand. As load changes we will consider a wider range of options, including non-wires alternatives, to meet future system demands in the most economical way possible.
3. **Maintain**: We perform traditional maintenance of our HVD and LVD networks with tree trimming, pole replacements, and general asset repair along with outage and restoration management. We will continue to expand the suite of available tools to perform these maintenance activities to cost effectively improve reliability, resiliency, and safety.
4. **Operate**: We manage the distribution system network every moment of every day to ensure a safe, reliable, and affordable electric system. We will continue to invest in technologies that provide greater visibility into the system and automation to deliver world class performance for our customers.

***FIGURE 11 - ELECTRIC DISTRIBUTION INFRASTRUCTURE INVESTMENT PLAN CATEGORIES***

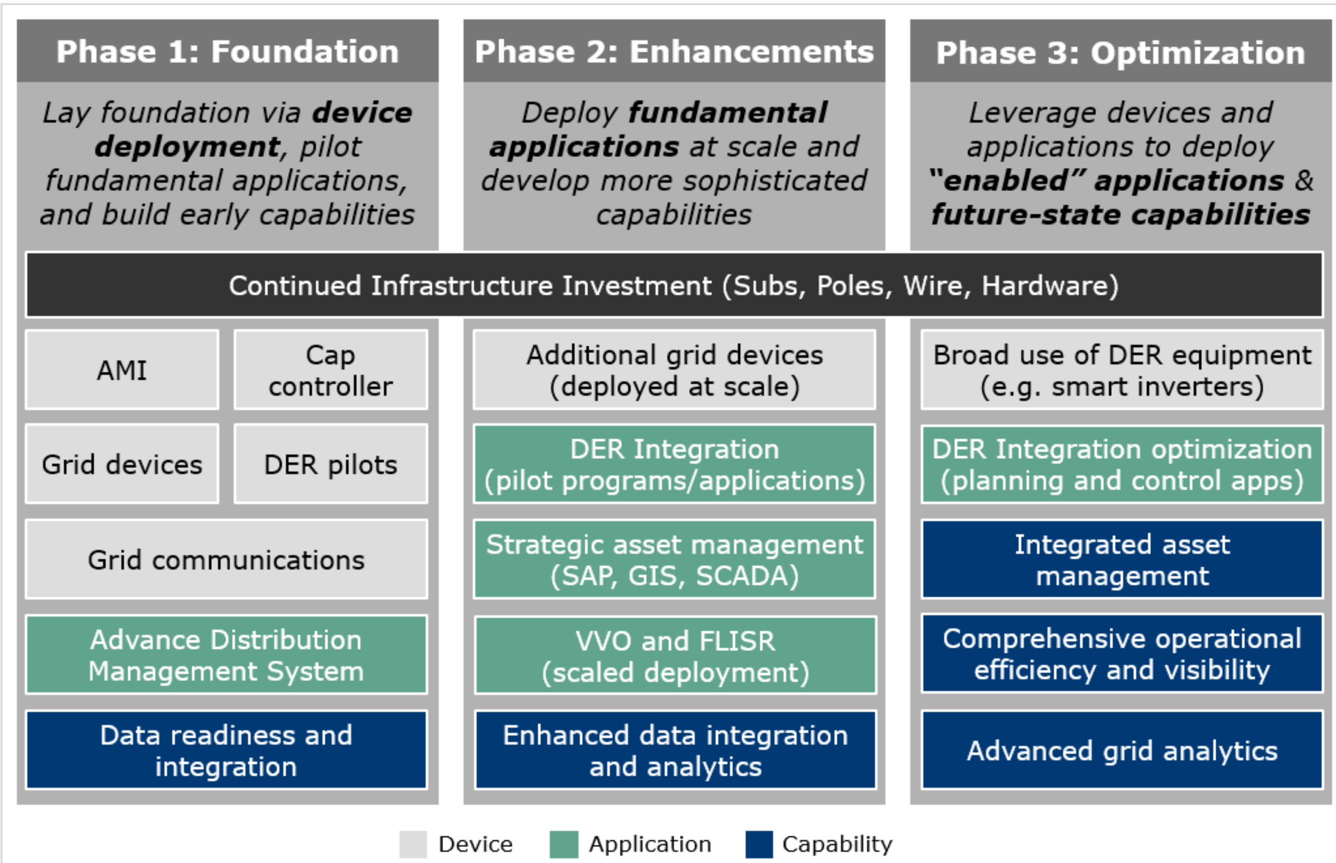



*Source: Consumers Energy*

## 4.2 Electric Distribution Infrastructure Investment Plan Roadmap

*Figure 12 – Investment Phasing Roadmap* illustrates how the three-phase 15-year investment plan discussed in Section 2.2 translates into investments in specific devices, applications, and capabilities. This roadmap is a preliminary outline of potential devices, applications, and capabilities that we expect to develop and deploy and will be continuously re-evaluated and may materially change over the course of the next 10-15 years.

***FIGURE 12 - INVESTMENT PHASING ROADMAP***




*Source: Consumers Energy*

Developing advanced planning capabilities goes beyond deploying devices and purchasing software licenses. Investments must be made in an informed optimal sequence, building a network of devices, applications, and capabilities. Our roadmap aims to do this in a way that also balances the proactive modernization of our grid infrastructure and the dispersal of infrastructure investment costs over multiple years to mitigate major rate changes and technology risks. However, investments could be pursued more rapidly if technological advances affect the relevant costs and benefits. As the investment phase continues, we will develop a framework to identify the benefits of pursuing a more aggressive modernization strategy.

## 4.3 Electric Distribution Infrastructure Investment Plan Details

Our five-year distribution investment plan provides visibility into the needs and priorities of our distribution system and applies to each of our four major roles. Each planned investment and expense is allocated to one of these four roles based on the primary means by which the investment or expense is expected to provide customer benefits. Many investments will create supplementary benefits for other roles. Additional information and data used to support our analysis is included in the Appendix, including a full summary of planned capital expenditures and O&M expenses in *Appendix G.1*.

### First Role: Plan

In system planning, we identify future infrastructure needs to ensure our system has adequate distribution capacity, can effectively integration of DERs where most valuable to the overall system, can effectively manage frequency and voltage regulation, and is able to proactively adapt to ensure reliability, resiliency, and safety. Our process relies on load forecasts, which have traditionally been the primary input in system planning. While the usage of load forecasts will likely continue, the way in which we create and use our forecasts will change as technologies and capabilities change, so that we keep up with significant and accelerating evolution in customer electricity usage.

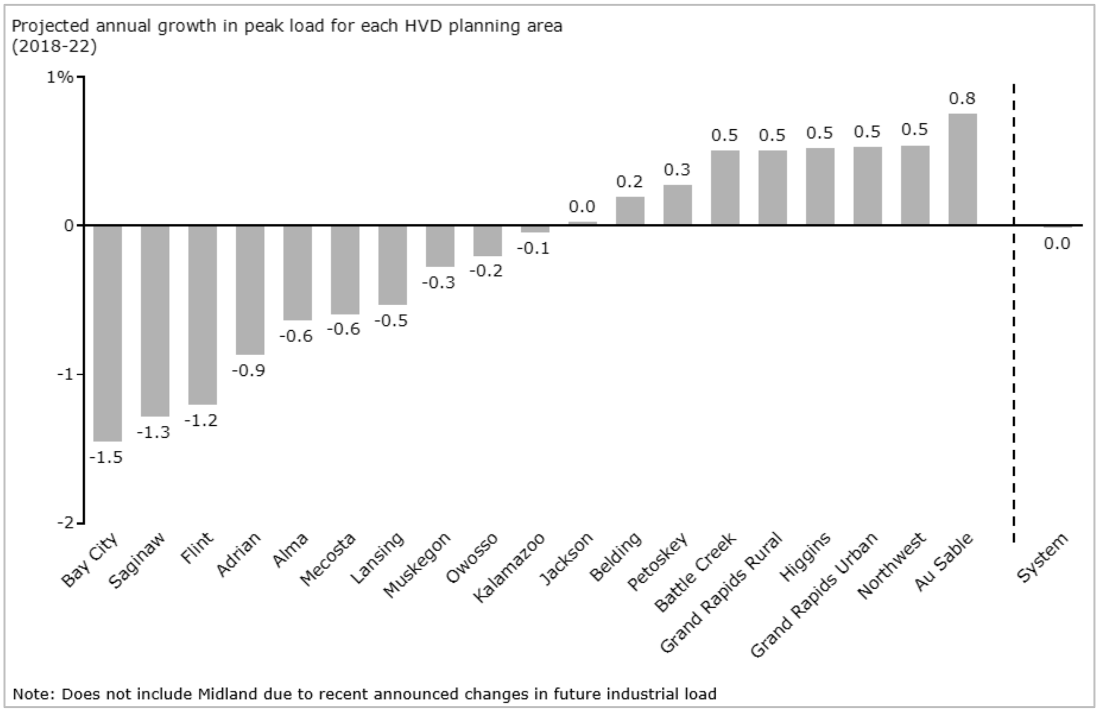
#### *Current approach to system planning*

We begin by building a forecast of future peak electric demand for our entire system, based on historical data, economic forecasts, industrial load forecasts, and weather data. We use a 65% confidence interval for our system-wide peak load forecast to incorporate any potential unanticipated load changes. Our HVD planning engineers allocate this system-wide forecast across 20 planning areas based on historical growth rates within each area. We then develop a power flow model of future load levels on the HVD system. This model is used to identify future system deficiencies, or planning criteria violations, indicating areas where future action may be needed to maintain reliability.

At the LVD level, we use a similar approach, relying on local substation peak load data to identify local substation, line, and load transfer needs. The source of local data varies by location. Real-time data (SCADA or Distribution SCADA -- DSCADA) is used where available. Where real-time data is unavailable, we incorporate historical data from manual readings into our distribution power flow planning tool, known as CYME.

While system-level projected peak demand is not expected to increase significantly in the near-term, we continue to use a robust forecasting process to accommodate pockets of growth activity (e.g. Battle Creek, Grand Rapids) *(see Figure 13 – Projected Load Forecast by HVD Planning Area* for an overview of our peak demand forecasts through 2022).

***FIGURE 13 - PROJECTED LOAD FORECAST BY HVD PLANNING AREA***




*Source: Consumers Energy*

***Note: Figure X – Projected Load Forecast by HVD Planning Area** provides a peak load forecast based upon our corporate forecast (at a 65% confidence interval) that is allocated based upon area-specific, historical growth over the past ten years.*

After identifying planning criteria violations and reliability concerns, our LVD planning team reviews the options for mitigating anticipated issues. More detail regarding the potential options we consider and our current process for determining the best solution is outlined in the *Build* section of this report.

Historically, sustained load growth created opportunities for utilities throughout the country to increase the size of the utility rate base to support future investments (both new construction and maintenance) without significantly affecting customer rates. As load growth slows (and even begins to reverse in some areas), the process of system planning faces a changing future.

Additional information related to load forecasting and capacity planning is included in *Appendices C.2, C.3, and C.4.*

## *Future of system planning*

In the future, planning will require significant changes to account for two-way power flows, widespread integration of distributed energy resources, dynamic changes that result from advanced automation and control schemes, and other emerging technologies. New tools, analysis methods and models with circuit-level data are critical for maximizing customer value and control, increasing reliability, and reducing our carbon footprint. Integrating these over the coming decade will provide immense planning benefits.

With a completely updated Geographic Information System (GIS) electric model and new integrated load flow software, we will be able to assess the system in real-time and make more up-to-date decisions regarding upgrades to facilities and operational capabilities, and we will be able to consider advanced system efficiency initiatives like volt-VAR optimization (VVO), conservation voltage reduction (CVR), and distributed energy resource (DER) integration. With expanded data from new grid-enabled devices (such as AMI meter data, DSCADA, reclosers, regulators, capacitors, and line sensors) we will be able to identify and fix the root causes of reliability and power quality issues more quickly and more accurately.

### *Key system planning investments and expenses*

A subset of our planned investments that will significantly impact our system planning capabilities includes:

**System Modeling Tools** – New planning tools will allow near-real time device measurement data and accurate system connectivity models, allowing us to perform near-real time distribution power flow studies, supporting future distribution investment plans. We will use this to increase system automation and to increase our ability to accommodate distributed energy resources while we study impacts to power quality and system reliability. This will streamline the expected increase in interconnection requests for distributed resources like solar and battery storage that will help reduce our emissions.

**Data Lake** – Our traditional database systems are not suited to the volume, variety, and velocity of the data sets that are provided by smart meters and grid devices. A data lake centralizes disparate data sources (asset, customer, outage, smart meter, DSCADA, etc.) into a single location. The raw data from content sources are combined into analytical data models to be processed using advanced data processing and analytical techniques. Data is prepared "as needed," reducing preparation costs when compared to the up-front processing required today. Planners, designers, and system operators can retain flexible access to the data lake and its content from both enterprise and operational data sources.

**Grid Analytics "Sprints"** – We will develop new grid analytics capabilities, including:

- Identifying worst circuits with mis-phasing issues for a particular phase
- Counting the number of service points with power quality issues per circuit

**External Planning Services** – With new on-line services, we will be able to streamline interconnection requests and offer additional planning services. Planning capacity and capabilities developed internally for load and distributed energy forecasting will be made available and shared with customers and third parties (e.g. project developers).

### *Total cost and scope of investments and expenses*

The largest, planning-specific capital expenditure focuses on the two grid analytics sprints related to mis-phasing and customer power quality, with a budgeted cost of $X *[to be included in final plan]* through 2022. In addition to capital expenditures, we are planning to spend $X-YM *[to be included in final plan]* from 2018-22 in O&M expenses to enhance our scheduling and dispatch, grid infrastructure, and data management. More details on the proposed capital expenditures and O&M expenses can be found in *Appendix C.1 –Tables 29 - 30.*

***TABLE 1 - PLAN - CAPITAL EXPENDITURES ($000)***

| Plan - Capital Expenditures | | | | |
|---|---|---|---|---|
| Investment Category | 2016 Actuals | 2017 YTD (June) | Five Year Estimate (2018-22) | Major investments |
| Grid Analytics | -- | -- | *Final Report* | Sprints (Mis-phasing, Customer power quality) and Data Lake |
| System Modeling | -- | -- | *Final Report* | System modeling tools, external planning services |
| **Total Plan CapEx** | -- | -- | *Final Report* | N/A |

***TABLE 2 - PLAN - O&M EXPENSES ($000)***

| Plan – O&M Expenses | | | | |
|---|---|---|---|---|
| Expense category | 2016 Actuals | 2017 YTD (June) | Five Year Est. (2018-22) | Major expenses |
| Scheduling and dispatch | $3,605 | $2,554 | *Final Report* | Long range planning, weekly planning, scheduling, dispatch and office support for field operations to execute their work activities. |
| Grid infrastructure | $5,067 | $3,214 | *Final Report* | Capacity and reliability planning, infrastructure inspections, system load analysis, agricultural services, Reliability First dues. |
| Data management | $536 | $388 | *Final Report* | Update geographic information system (GIS) records and applications |
| Distribution and customer operations staffing | $2,711 | $950 | *Final Report* | Salaries and expenses for management personnel. |
| Other* | $6,843 | $3,686 | *Final Report* | Substation and HVD line design and standards. |
| **Total Plan O&M** | ***$18,763*** | ***$10,792*** | *Final Report* | N/A |

**Other includes project management, regulatory and compliance, infrastructure standards, financial management, contract administration, etc.*

## Second Role: Build

Building incorporates both traditional assets and non-wires alternatives. We do both kinds of building in response to the needs identified by our planning.

### *Current approach to building and upgrading assets*

When planning criteria violations and reliability concerns are identified for a given planning area, we conduct distribution studies to consider solutions, comparing the benefits and costs of various options:

- Load transfer – rerouting load to a different substation or line
- Capacity increase – building or upgrading lines and equipment
- New LVD substation – new construction to split load and reduce circuit length
- Alternative LVD substation connection – reconnecting to a different HVD or transmission line

With planning criteria violations, we may also consider using non-wires alternatives (*see right*) to address the issue in a limited fashion. With reliability concerns, non-wires alternatives are not yet considered a viable option. NWAs are typically located at customer homes or businesses and are often unable to correct distribution reliability issues that occur (e.g. animal-related damage, pole failure).

> **Non-Wires Alternative (NWA)**
> *(or non-wires solution):*
>
> "Technologies that use non-traditional T&D solutions, such as **distributed generation, energy storage, energy efficiency, demand response,** and **grid software and controls**, to defer or replace the need for specific equipment upgrades, such as T&D lines or transformers, by reducing load at a substation or circuit level."
>
> *Navigant Research*

### *Right-sizing projects*

When we build or upgrade assets, we ensure assets are "right-sized" to alleviate the issue without building assets that are larger (and therefore more expensive) than they need to be. We do this using our load forecasts, future distribution automation plans, HVD system restrictions, site configurations, property size, and individual operational considerations of the local system. For example, substations located in relatively close proximity to each other, such as in urban areas, and substations with stout distribution tie-lines cancan more easily facilitate load transfers from other substations. Conversely, substations in rural areas with a long history of slow growth are built with equipment to meet the needs of the local system only, to minimize upfront equipment cost.

### *Prioritizing projects*

We prioritize projects to ensure we maximize the value delivered to our customers, due to natural economic constraints.

For capacity projects, we use equipment load data compared to its peak capability to prioritize investments. LVD planning criteria requires that a component of the distribution system have a projected load over its peak capability (typically 125%) for a minimum of one year prior to a capacity project being proposed. We consider previous year loadings and future customer growth to project future loadings on the distribution line system. In general, the greater the projected load over equipment's peak capability, the higher the priority is for upgrade. We evaluate 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 HVD systems. This procedure identifies HVD facilities that would overload or provide unacceptable low voltage during normal conditions both at the system peak load, and during situations where a single component fails at 80% of system peak load. We study outages of a single line, a single transformer, a single bus, and a single generator. We develop plans to eliminate both low voltage and loading above normal ratings for these conditions – testing proposed plans to ensure they address the concern.

We also use SCADA information to project future load on radial lines, and develop short circuit models of our HVD network to compare available short circuit current to the interrupting capability of the HVD interrupting equipment.

For reliability concerns, we use performance data on distribution lines and projected improvement to prioritize investments, primarily using SAIDI as our metric. The Reliability Analytics Engine ("RAE") tool helps analyze large amounts of outage data and produces a ranked list that incorporates line performance and opportunity for improvement. The ranked list is used to prioritize projects.

Our rankings include "backbone" areas that have a higher-than-normal outage history. Addressing these areas improves service to all customers on those circuits. The RAE also produces a bi-weekly repetitive outage report that is reviewed by our engineers, who evaluate potential actions to prevent future outages. We use our Electric Reliability Rally Room to coordinate efforts, better define areas of opportunity, align on the plan and prioritization, check performance against the plan, and adjust as necessary.

### *Installing and upgrading assets*

After we decide to move forward with a new or upgraded asset, we create a project outline with an initial construction timeline. Teams of engineers create designs for segments of the project, which are then integrated as a single plan. The project then moves to a construction planning and scheduling phase, which includes the procurement and assignment of construction resources, which can include outside contractors and/or our own employees. The high-level construction schedule is then finalized, allowing for construction to commence. Following the construction process, an equipment checkout is completed to ensure the equipment was installed properly. The equipment is then put into service. Additional information on the construction process is included in *Appendix D.2 – Figure 32.*

### *Future of building and upgrading assets*

The transition to multi-directional energy flows will require increased deployment of advanced protective devices with dynamic protective settings that respond when the energy resources mix changes. Current protective assets would not adequately support sustained, multi-directional flows.

More broadly, we will need to make significant system conditioning investments. We will need to reshape our infrastructure backbone, on which the wires' ability to carry current gradually declines moving away from the substation. If we make these changes, more consistent current could be carried to interconnection points with other circuits. Devices such as transformers and wires that have historically only served a single customer will need to be sized to instead accommodate multiple distributed resources. All of this will require us to build a different mix of new infrastructure.

### *System Conditioning*

Our system conditioning investments will systematically target limitations to reliability, reducing energy waste, and maintaining adequate voltage. Smart meters, which monitor voltage, have already improved visibility of voltage provided to customers. Going forward, we will finish the job of ensuring that all of our customers have voltage within acceptable ranges, as defined by applicable standards and industry best practices. We will further upgrade the backbone of the grid to allow bi-directional power flows, integrating alternate sources during system outages and expanding our capacity to connect distributed energy resources. System conditioning will address situations and opportunities on a proactive basis without waiting for customer-initiated inquiries. Addressing any remaining voltage issues will help us deploy future energy waste reduction programs based on conservation voltage reduction.

### *Evaluating traditional assets vs. non-wires alternatives*

Investments are classified as either traditional wires investments or non-wires alternatives (NWA), to ensure that non-wires alternatives are adequately considered as solutions. Our non-wires alternatives have focused on two programs:

| Demand Response | Energy Efficiency |
|---|---|
| Since 2010, we have partnered with more than 1,700 Michigan residences and businesses to reduce peak electric demand by approximately 52 MW (majority through our C&I program) | Since 2009, our portfolio of Energy Efficiency programs have saved customers more than $1B in reduced energy bills while reducing peak electric demand by approximately 400 MW |

Other utilities have similarly focused on demand response and energy efficiency for early-stage programs. One frequently-cited example, Consolidated Edison's Brooklyn Queens Demand Management program in New York City, reduced peak demand by nearly 50MW for a cost of approximately $150 million. More than 60% of the peak reduction was accomplished through demand response and energy efficiency programs, with the remainder spread out among energy storage, microgrid and solar projects.

As we deploy non-wires alternative pilot programs, including our Swartz Creek pilot project, we will better understand the benefits and risks of these alternatives. Today a primary benefit of many non-wires alternatives is modular sizing – the ability to alleviate minor capacity constraints via load reduction (energy efficiency) or peak shaving (energy storage, demand response). Pilot programs will provide insight into additional benefits of NWAs and better prepare us for future deployments.

Summary information for our plans to construct new infrastructure and upgrade existing infrastructure is included below. Additional context is also provided in *Appendix D.1.*

## *Overview of key investments and expenses*

### Traditional wires investments

Our infrastructure investment plan includes installation of 52 new substations and upgrades or capacity expansions at 23 substations over the next five years. Below are three examples of planned projects.

***TABLE 3 - SUBSTATION ADDITION EXAMPLE***

| New substation addition | |
|---|---|
| Location | Ash Road (Litchfield Area) |
| Major cause | Customer expansion |
| Local load | The group regulators at Litchfield were loaded to 97% of their capability in 2016. A single customer's expansion of 2.5MW in early 2018 will place the regulators at 116% of their capability. |
| Primary options considered | Expand the existing Litchfield substation<br>Build a new substation |
| Rationale | A long range study was completed in 2013 identifying a new substation as the best course of action when an overload occurs. The recommendation was reviewed and implemented to accommodate the customer's load addition. In addition to addressing the load addition, this solution offers a reliability improvement to all customers in the area, which was the primary reason for why the addition was chosen instead of an expansion at the existing substation. |

***TABLE 4 - SUBSTATION EXPANSION EXAMPLE***

| Substation expansion | |
|---|---|
| Location | Deerfield |
| Major cause | Customer expansion |
| Local load | The existing transformer in the substation was loaded to approximately 86% of capability in 2016. The customer's load addition of 1.8MW in late 2017 will place the transformer at 131% of capability in 2018. |
| Primary options considered | Expand the existing substation<br>Build a new substation<br>Energy efficiency / demand response |
| Rationale | The existing substation is a small substation that is group regulated. These substations were not built to the current minimum approach distance standards. Working in them without forcing an outage to customers is difficult. The substation expansion project will address the capacity the concerns and ultimately improves reliability to the area. The addition of a new substation was not necessary due to the relatively small nature of the load addition (about 1.5MW of peak load increase), but neither energy efficiency nor demand response were considered viable in this location to achieve sufficient peak load reduction. |

***TABLE 5 - SUBSTATION REBUILD EXAMPLE***

| Substation rebuild | |
|---|---|
| Location | Frontier |
| Major cause | Reliability issues from aging equipment (including a history of increasing outages) |
| Local load | The existing substation transformer was loaded to approximately 76% of its capability in 2016. No significant load growth is expected in the area from a single customer. A modest assumption of 2% growth per year places transformer capability at approximately 85% in 2022. |
| Primary alternative considered | N/A |
| Rationale | A long range plan was completed on the area with a total of four alternatives. These four alternatives were looking at different options for addressing reliability and loading concerns in the region. Common to all four alternatives was the rebuild of Frontier substation to current standards due to substation equipment age and layout. Implementing this portion of the long range plan offers an improvement to all customers and positions the company to implement the full plan in the future. |

We have identified 76 areas with capacity or reliability challenges that require new investments between 2018 and 2022, and all but one area (Swartz Creek) will be addressed through traditional assets. The new investments will consist mostly of new substation construction and capacity increases. As we progress through our five year plan, we will continue to look for opportunities to incorporate non-wires alternatives as system needs arise and change. The full list of expected new infrastructure builds is included in *Appendix D.5.*

Over the next five years, we plan to invest $X billion *[to be included in final plan]* in traditional infrastructure projects. The following table summarizes our major planned investments, the cost of each set of projects (to-be-added in our final submission), and an explanation of why each set is needed. Full detail on each investment (including annual cost estimates) is included in *Appendix D.1*.

***TABLE 6 - TRADITIONAL WIRES CAPITAL EXPENDITURES ($000)***

| Traditional "Wires" – Capital Expenditures | | | | |
|---|---|---|---|---|
| Investment category | 2016 | 2017 YTD (June) | Five Year Estimate (2018-22) | Major investments |
| New Business | $60,401 | $35,898 | Final Report | Equipment needed to serve new customers, including lines, transformers, and meters |
| Capacity – HVD | $20,965 | $10,668 | Final Report | High voltage lines and substations needed for increased load |
| Capacity – LVD | $35,780 | $17,788 | Final Report | Low voltage lines, substations, and transformers needed to meet increased load |
| Strategic Customers – HVD (Lines) | $27,864 | $2,846 | Final Report | HVD project to support new business needs for large industrial customers or increased load requirements for these customers. |
| Total "Wires" CapEx | $145,010 | $67,199 | Final Report | N/A |

**Non-wires alternatives**

Over the next five years, we plan to increase our investment in demand response and energy efficiency programs, and launch two battery storage pilot programs.

### *Demand response and energy efficiency programs*

We plan to invest $X million *[to be included in final plan]* in our C&I Demand Response program, expanding that portfolio from 50 MW to 150 MW. Similarly, our infrastructure plan includes $X million *[to be included in final plan]* in additional investment for our Energy Efficiency program, which we will bring our portfolio up to 780 MW of peak demand reduction and about 530 MWhs of energy production per year. In addition to distribution benefits, these programs contribute capacity in an environmentally sustainable way, because they reduce the need for additional electricity generation.

Our non-wires alternative pilot program at Swartz Creek demonstrates an opportunity to manage capacity constraints with demand response and energy efficiency. It uses our existing demand response and energy efficiency programs plus time of use rates and dynamic peak pricing, as shown in the following table:

***TABLE 7 - NON-WIRES ALTERNATIVE PILOT***

| Non-wires alternative (Pilot) | |
|---|---|
| Location | Swartz Creek |
| Major cause | General load growth |
| Local load | The substation transformer at Swartz Creek has experienced peak loadings of 92%, 94%, 80%, 79%, and 85% from 2012 through 2016. The load appears to be highly dependent upon the weather as no system changes (large transfers or large, new customers) have been observed. |
| Primary alternative considered | N/A |

| | |
|---|---|
| Rationale | A traditional substation capacity increase would be implemented after an observed overload. Swartz Creek substation was chosen for the NWA (pilot) due to historical loads that have been observed close to capacity, but never over. Piloting an NWA at this location was an opportunity to test an NWA solution's feasibility without risking the equipment or customer reliability due to an observed overload the prior year.<br><br>The company's NWA pilot at Swartz Creek substation will rely heavily on the existing Energy Efficiency and Demand Response programs in place. The pilot will also make use of the Time of Use and dynamic peak pricing rates that are offered. These programs and rates will be marketed in the community to show off the rebates and long-term cost savings that can be realized. The marketing plan utilized will reach both residential and business customers.<br><br>The NWA pilot is being run in coordination with the Natural Resources Defense Council (NRDC). |

More information on our demand response and energy efficiency programs can be found in *Appendix X*.

**Battery storage pilots**

Deployment of utility-scale battery storage projects continues to grow in the U.S., using battery energy storage systems (BESS) to defer transmission and distribution investments, reduce local peak loads, mitigate outages, improve renewable integration, and provide other ancillary services like frequency regulation. More detail on the ways in which a battery system can be used is included in *Appendix D.4.*

Beginning in 2018, we will deploy two battery energy storage systems in our service area: one at Western Michigan University and another in Grand Rapids at a new mixed use development location. Together, these systems will be used to improve our understanding of how batteries can benefit the grid across several of the use cases detailed above. This experience will help us learn how we can best integrate batteries into the grid at the distribution level. More details on these pilot projects can be found in *Appendix D.4.*

***TABLE 8 - NON-WIRES ALTERNATIVES CAPITAL EXPENDITURES ($000)***

| Non-wires Alternatives - Capital Expenditures | | | | |
|---|---|---|---|---|
| Investment category | 2016 | 2017 YTD (June) | Five Year Estimate (2018-22) | Major investments |
| Full-scale programs | $1,200 | $2,752 | *Final Report* | Demand response and energy efficiency |
| Pilot programs | -- | -- | *Final Report* | Battery storage pilots |
| **Total NWA CapEx** | $1,200 | $2,752 | *Final Report* | N/A |

***TABLE 9 - NON-WIRES ALTERNATIVES O&M EXPENSES ($000)***

| Non-wires Alternatives – O&M Expenses | | | | |
|---|---|---|---|---|
| Expense category | 2016 | 2017 YTD (June) | Five Year Estimate (2018-22) | Major expenses |
| Full-scale programs | $78,836 | $49,488 | *Final Report* | Demand response and energy efficiency |
| Pilot programs | -- | -- | *Final Report* | Battery storage pilots |
| **Total NWA CapEx** | $78,836 | $49,488 | *Final Report* | N/A |

### *Total cost and scope of investments and expenses*

Over the next five years, we expect to invest between $XM *[to be included in final plan]* in capital expenditures on traditional wires assets and non-wires alternatives to meet the needs of new customers and changing demand. As customer behavior, population growth, DER penetration and many other factors change, we will modify this plan to continue providing customers with low-cost and high-reliability service. Further detail regarding the cost of planned investments can be found in *Appendix D.1.*

***TABLE 10 - BUILD - CAPITAL EXPENDITURES ($000)***

| Build - Capital Expenditures | | | | |
|---|---|---|---|---|
| Investment category | 2016 | 2017 YTD (June) | Five Year Estimate (2018-22) | Major investments |
| "Wires" investments | $145,010 | $67,199 | *Final Report* | New business (lines, meters, transformers) and capacity increases (substations, upgrades) |
| Non-wires alternatives | $1,200 | *$2,752* | *Final Report* | Battery storage pilots, demand response and energy efficiency programs |
| **Total Build CapEx** | $146,210 | $69,952 | *Final Report* | N/A |

***TABLE 11 - BUILD - O&M EXPENSES ($000)***

| Build – O&M Expenses | | | | |
|---|---|---|---|---|
| Expense category | 2016 | 2017 YTD (June) | Five Year Estimate (2018-22) | Major expenses |
| "Wires" investments | -- | -- | *Final Report* | New business (lines, meters, transformers) and capacity increases (substations, upgrades) |
| Non-wires alternatives | $78,836 | $49,488 | *Final Report* | Battery storage pilots, demand response and energy efficiency programs |
| **Total Build O&M** | $78,836 | $49,488 | *Final Report* | N/A |

## Third Role: Maintain

We consistently maintain our distribution assets, an increasingly important role as assets age.

### *Current approach to repairing assets*

We regularly maintain our system to ensure all equipment is operating safely, effectively, and efficiently, using multiple programs that cover all poles, lines, pole-top equipment, and substation equipment. We also have a tree trimming and line clearing program. In addition to ensuring the safety and reliability of equipment operation, these programs reduce our customers' average outage duration (SAIDI). More information on our tree trimming program can be found in *Appendix E.6*.

### *Current approach to replacing and repairing assets*

Given the age of our distribution assets, we make investments to ensure equipment is safely operating, to upgrade deteriorated equipment, to reduce system outages (especially during adverse weather), and to build for the future need and demands of our customers. More information on the costs of replacing assets as well as which assets are proactively inspected and replaced can be found in *Appendices E.2, E.3, E.4, E.5, E.8, and E.9.*

### *Current approach to outage restoration*

Outages occur for many reasons, including weather, falling trees, and equipment failure *(see Appendix X – LVD Outage Causes).* When an outage occurs, we work to safely and quickly restore service through our restoration management program.

Storm restoration is the most wide-reaching component of this program and consists of several key activities including: monitoring weather to proactively identify threats, mobilizing office and field resources, securing down wires, assessing damage, repairing assets, communicating with public and government agencies, and performing a post-storm assessment to improve preparedness for future events. We use two platforms to coordinate these activities: (1) an outage management system, which allows us to identify where outages occur; and (2) a resource management system, which enables us to ensure crews respond quickly to outages.

We use a continuous feedback loop to find ways improve our restoration program, using the experience from each outage response to better prepare for future events. More detail on our restoration process is provided in *Appendices E.13, E.14 and E.15.*

### *Future of system maintenance*

As smart meters and distribution automation field devices provide more granular, real-time data, our maintenance operators will spend less time performing lengthy annual equipment inspections and more time proactively repairing assets before they fail based on real-time health information, predictive analytics, asset monitoring and on-line diagnostic capabilities.

This proactive approach will rely on an integrated view of asset conditions and operational service quality. We will also invest in analytics to take advantage of new and existing data sources including GIS, line sensor data, and weather data. Combined with more granular information, this will help us extend the life of our equipment, reduce, technical losses, and improve our operational performance.

We will also improve our outage response through the use of predictive analytics to better prepare for weather events and prioritize tree trimming to reduce both the frequency and duration of outages. Improvements in asset management will also reduce the number and severity of outages caused by equipment failure.

### *Key maintenance investments and expenses*

In 2016, we spent $300,000 on distribution maintenance and reliability; we plan to spend approximately $X million *[to be included in final plan]* each year throughout our five-year plan.

Other key investments include LVD, HVD, and substation maintenance, relying primarily on traditional infrastructure. We are making focused investments to upgrade our distribution system to enable grid modernization. For example, obsolete equipment such as reclosers, regulators, and transformers are being replaced with new technologies that are compatible with DSCADA. More detail on these investments can be found in *Appendix E.1.*

### *Total cost and scope of investments and expenses*

Over the next five years, Consumers expects to spend $X million *[to be included in final plan]* in capital expenditures to repair and replace existing distribution assets. The largest portion of expenditures will continue to focus on rehabilitating existing equipment and responding to failures on distribution lines.

***TABLE 12 - MAINTAIN - CAPITAL EXPENDITURES ($000)***

| Maintain - Capital Expenditures | | | | |
|---|---|---|---|---|
| Investment category | 2016 Actuals | 2017 YTD (June) | Five Year Estimate (2018-22) | Major investments |
| Reliability | $113,866 | $45,517 | *Final Report* | Proactive rehabilitation of poor performing LVD lines, pole inspection and replacements, pole-top replacements, sectionalizing, etc. |
| Demand failures | $116,539 | $81,888 | *Final Report* | Respond to failures on distribution lines including poles, pole-top equipment, voltage improvement, service restoration, etc. |
| Cost of removal | $41,618 | $36,061 | *Final Report* | Retirement only projects and labor costs to remove assets associated with the investments in LVD New Business, Reliability, Capacity, Demand Failures, and Asset Relocations. |
| Asset relocations | $19,504 | $11,804 | *Final Report* | Respond to requests (internal or external) to relocate distribution lines. |
| Technology | $3,533 | $941 | *Final Report* | Budget for projects that may be required in order to maintain compliance. Incudes control house upgrades to meet National Electric Safety Code (NESC). |
| Other* | $3,982 | $2,160 | *Final Report* | Conversion of Mercury Vapor streetlights to the streetlight of the community's choice (e.g. High Pressure Sodium, LED). |
| **Total Maintenance CapEx** | $297,254 | $177,470 | *Final Report* | N/A |

**Other includes streetlight maintenance (mercury vapor / LED)*



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***TABLE 13 - MAINTAIN - O&M EXPENSES ($000)***

| Maintain – O&M Expenses | | | | |
|---|---|---|---|---|
| Expense category | 2016 | 2017 YTD (June) | Five Year Estimate (2018-22) | Major expenses |
| Reliability | $53,906 | $27,829 | *Final Report* | Vegetation management along LVD and HVD electric system rights-of-ways. |
| Repair and restoration | $53,390 | $40,256 | *Final Report* | Respond and make necessary repairs for no light calls, outages, wire downs, emergency orders, and hazards. |
| Field operations | $18,606 | $11,119 | *Final Report* | Supervision and leadership for electric operations. |
| Meter services | $14,574 | $2,637 | *Final Report* | Meter maintenance, customer requested work, theft investigation, mixed meter investigation, routine exchanges. |
| Other* | $8,684 | $4,201 | *Final Report* | Credits associated with purchase of pre-capitalized assets (e.g. distribution transformers). |
| **Total Maintenance O&M** | ***$149,159*** | ***$86,042*** | *Final Report* | N/A |

**Other includes DCO accruals, joint pole rental, IT projects, unallocated emergency funds, and WMIP*

## Fourth Role: Operate

We actively manage the distribution system at all times to ensure reliability. System operators are critical to the customer experience, minimizing system cost and improving reliability and resiliency, while allowing customers more control over their energy supply and consumption.

### *Current system operations*

Today, we operate our system with power flow analysis tools, customer call triangulation, and SCADA, which reduces reliance on customer call triangulation by providing access to system status. 100% of our HVD substations are SCADA enabled, and 25% of our LVD substations are DSCADA enabled. When SCADA alerts our operators of a disturbance, they run a power flow analysis to determine optimal mitigation strategies. It takes an average of four hours of analysis to run the CYME report and interpret the results. For several years, we have been increasing the number of substations and circuits that have this real-time visibility and automation, and recently integrated AMI events to improve outage visibility.

System operators currently have limited capability to perform switching order creation and validation processes, resulting in delays due to the lengthy manual processes required. Operators are also limited in their interactions with distributed energy resources. Without appropriate monitoring and control capabilities, there could be safety and reliability concerns for the operators as distributed energy resources are increasingly deployed.

### *Future of system operations*

We have opportunities to increase our situational awareness and automate many manual processes, shifting operations from being reactive to proactive.

Similar to our challenges in system planning, system operations will become increasingly more complex as our system becomes more modular and distributed, but new digital capabilities will enable a real-time view of the system. The integrated advanced distribution management system (ADMS) will provide system operators with enhanced operational capabilities and better tools to assess, monitor, analyze and control the distribution system and connected distributed energy resources as these resources become more and more important to our customers. Increasing field deployments of distribution and substation automation, and sensors and AMI meters throughout the distribution system, will increase situational awareness and system control.

### *Key operations investments*

Our plan sets a foundation of devices, applications, and capabilities, then builds on that foundation in our three phases of implementation as previously described. Over the next five years, we will continue to deploy foundational components, including grid communications, substation and line automation, the installation of operational applications platforms, and will continue to prepare our electric system model to accurately represent what is on our system for enhanced operations.

**Grid Communication** – We will develop a robust, standards-based field communications network that will provide a reliable, high-speed, high-capacity, wired and wireless communications platform based on internet protocol to connect all substations and distribution grid devices. More detail provided in *Appendix F.2*.

**Substation and Line Automation** – This will include control and monitoring devices such as DSCADA, distribution automation, device controllers, and line sensors that are used to sense the operating conditions of the distribution system and make adjustments to optimize power flow and performance and avoid outages. More detail provided in *Appendix F.3*.

**Unified System Control Center** – Many utilities have identified significant operational and reliability savings associated with centralizing their operations on a single campus. This allows for improved communications, tightly integrated processes, and ease of access to shared support services. We are in the process of consolidating our System Control Center (SCC) personnel and developing a Distribution Control Center (DCC). We are developing five year plans to review consolidating these functions with the Work Management Center (WMC) and the Smart Energy Operations Center (SEOC).

In addition, we will review the benefits of consolidating operations support functions such as Operating Technologies, Data Center, Security, Real-Time Engineering, Applications Support and other shared operations support functions.

**Advanced Distribution Management System (ADMS)**: This operational platform will integrate core systems for a comprehensive solution to improve reliability, cost, and grid performance. ADMS will enable an entire ecosystem of grid management applications, including Volt-VAR optimization; conservation voltage reduction; and fault location, isolation, and service restoration. More detail provided in *Appendix F.5*.

**Communications Device Management System:** This operational platform will enable system-wide communications by collecting information from multiple grid device technologies and telecom providers into a single view, letting us see overall communications and grid device system health. More detail provided in *Appendix F.5*.

**Data Management**: An accurate system model and processes to maintain the integrity of model data provides the foundation for ADMS and other distribution applications. To prepare, we are improving data accuracy, installing data quality tools, and improving business processes by collecting data from distribution circuits. Maintaining this data will ensure the electric system model continues to reflect an accurate view of the distribution system.

As we automate manual processes, decision support will improve from hours to minutes. By 2021, we will have greater visibility and control of the distribution system and we will improve the performance of the system. Beyond the five-year horizon, we will continue to invest in short-term planning capabilities and more closely coordinate operations and planning, and will continue integrating distributed energy resource equipment and supporting technology.

### *Total cost and scope of investments:*

From 2018 through 2022, we expect to spend $X million *[to be included in final plan]* in capital expenditures to bolster our grid operations capabilities. The largest category, grid modernization, includes significant investment in grid communications equipment as well as line and substation automation devices. More information on these investments can be found in *Appendix F.1*.

***TABLE 14 - OPERATE - CAPITAL EXPENDITURES ($000)***

| Operate - Capital Expenditures | | | | | |
|---|---|---|---|---|---|
| Investment category | | 2016 | 2017 YTD (June) | Five Year Estimate (2018-22) | Major investments |
| Grid Modernization | Total Grid Modernization | $18,518* | $8,253* | *Final Report* | Various – see below |
| Grid Modernization | Grid Analytics - Sprints | *Final Report* | *Final Report* | *Final Report* | Outage analysis |
| Grid Modernization | Grid Communications Modernization | *Final Report* | *Final Report* | *Final Report* | Modernizing the communications technology through standards based communication and replacement of frame relay and analog multi-drop technologies |
| Grid Modernization | Grid Modernization Applications | *Final Report* | *Final Report* | *Final Report* | Implementation of Advance Distribution Management System (ADMS) for Grid Management, data readiness of the electric system model, and Communication Device Management Software |
| Grid Modernization | Lines Automation, Monitoring & Control | *Final Report* | *Final Report* | *Final Report* | Implementation of distribution automation loops, reclosers, line regulators, and line sensors |
| Grid Modernization | Substation Automation, Monitoring & Control - LVD | *Final Report* | *Final Report* | *Final Report* | Implementation of Distribution SCADA and Distribution SCADA upgrades |
| SCADA | | $407 | $348 | *Final Report* | Capital repair/replacement of systems necessary to support HVD & Distribution SCADA, including Substation RTU's, Servers, and Test Equipment |
| System control | | $2 | $6 | *Final Report* | System control room upgrades and projects to mitigate System Operating Limitations (SOL's). |
| **Total Operations CapEx** | | **$18,927** | **$8,607** | *Final Report* | N/A |

**Note: Total Grid Modernization includes ALL investments in that category, including grid modernization efforts for Plan and Build purposes; final report will have grid modernization fully allocated among framework buckets*

***TABLE 15 - OPERATE - O&M EXPENSES ($000)***

| Operate – O&M Expenses | | | | |
|---|---|---|---|---|
| Expense category | 2016 | 2017 YTD (June) | Five Year Estimate (2018-22) | Major expenses |
| Smart Energy MTC | $0 | $3,522 | *Final Report* | Smart meter software maintenance and backhaul costs |
| System control | $3,754 | $2,478 | *Final Report* | Real time operation and monitoring of the electric system |
| Meter services | $1,133 | $485 | *Final Report* | New technology evaluation, meter upgrades, and verification of meter accuracies for all customer classes (residential, commercial, industrial) |
| **Total Operations O&M** | **$4,887** | **$6,485** | *Final Report* | N/A |

# 5. Conclusion

This draft Electric Distribution Infrastructure Investment Plan outlines our vision for the future of our electric distribution system and our five-year plan to move towards this end-state. The future of the electric distribution system is customer-driven and requires a dynamic electric distribution system that integrates greener, more distributed sources of electric supply with grid enhancements that are engineered for customer value. Our investment plan lays out a roadmap to deliver that vision and will be adapted for technology and customer expectation evolutions to ensure we deliver upon our five primary objectives:

- Optimizing system cost over the long-term
- Improving reliability and resiliency
- Enhancing cybersecurity and physical security and safety
- Reducing carbon footprint
- Enabling greater customer control

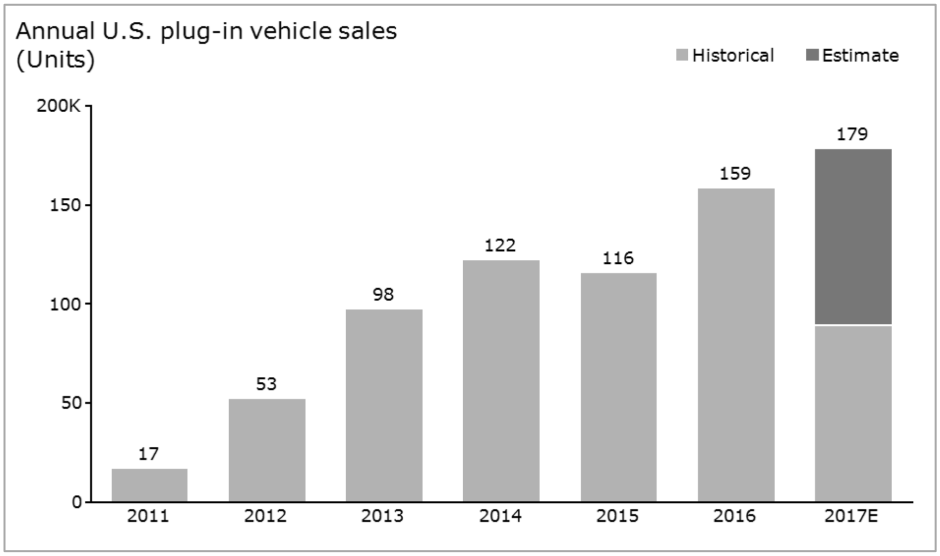
With much of our system ready for replacement, we have numerous opportunities to make progress on these objectives. Our five-year investment plan will both reinvigorate our distribution system through traditional investments and set the foundation for future technologies.

In our final plan, to be submitted in January 2018, we will provide additional detail for our planned investments and expenses. We look forward to working with the MPSC and the broader set of stakeholders to refine the details of our electric distribution infrastructure investment plan and ensure our plan effectively delivers on our stated objectives.

# APPENDIX — VISION OF THE CE ELECTRIC DISTRIBUTION SYSTEM

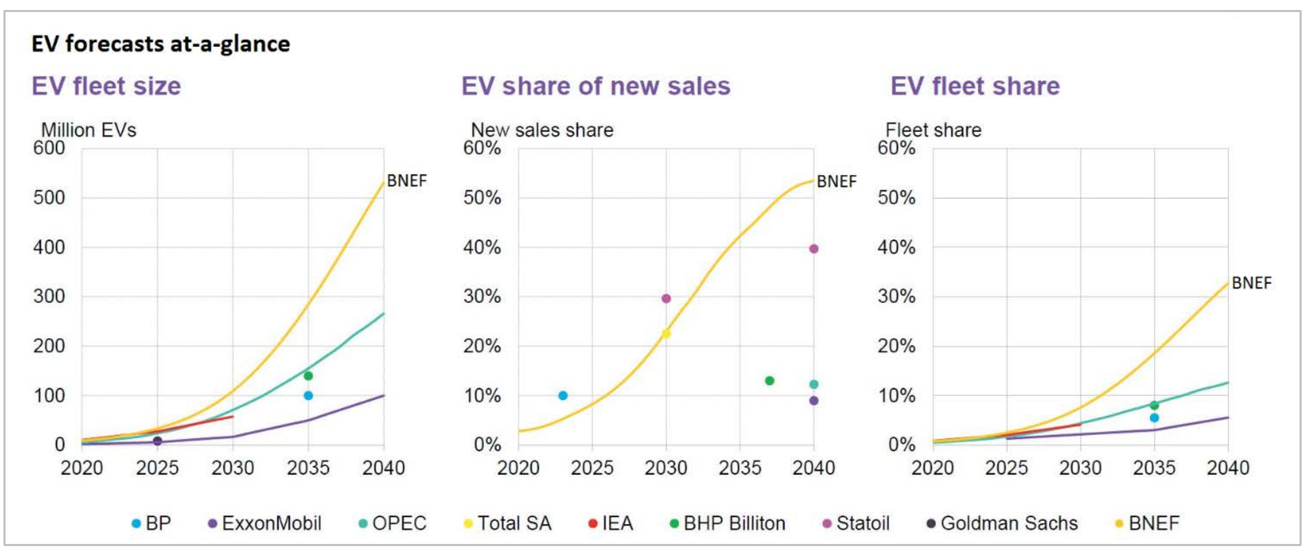
## A.1 Distributed energy resources (DERs) Figures

***FIGURE 14 — HISTORICAL US ELECTRIC VEHICLE SALES***



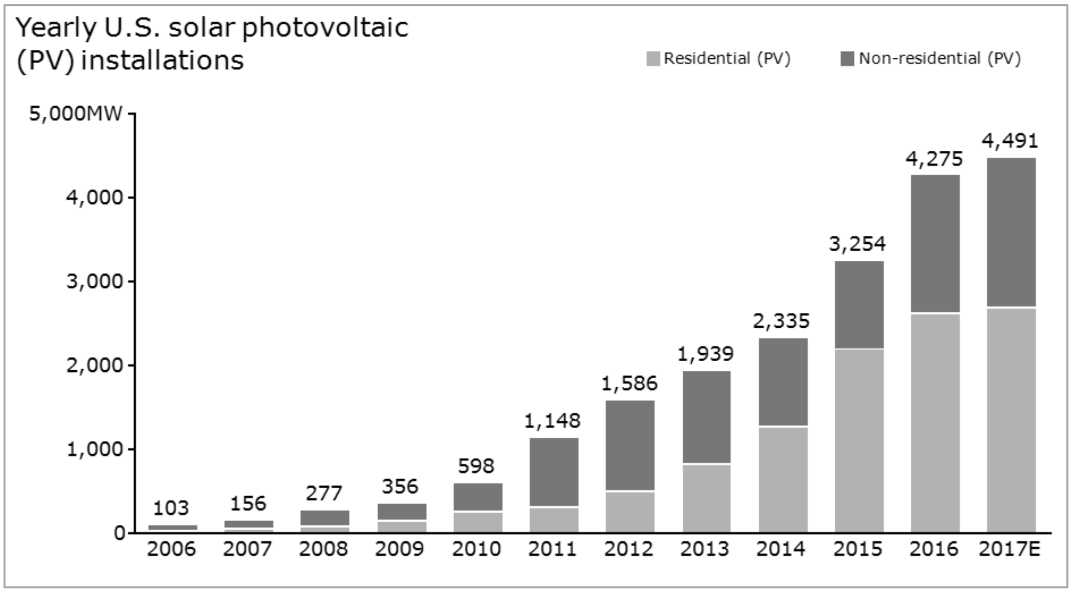

*Sources: Inside EVs, Forbes*

***FIGURE 15 — HISTORICAL US ELECTRIC VEHICLE SALES***



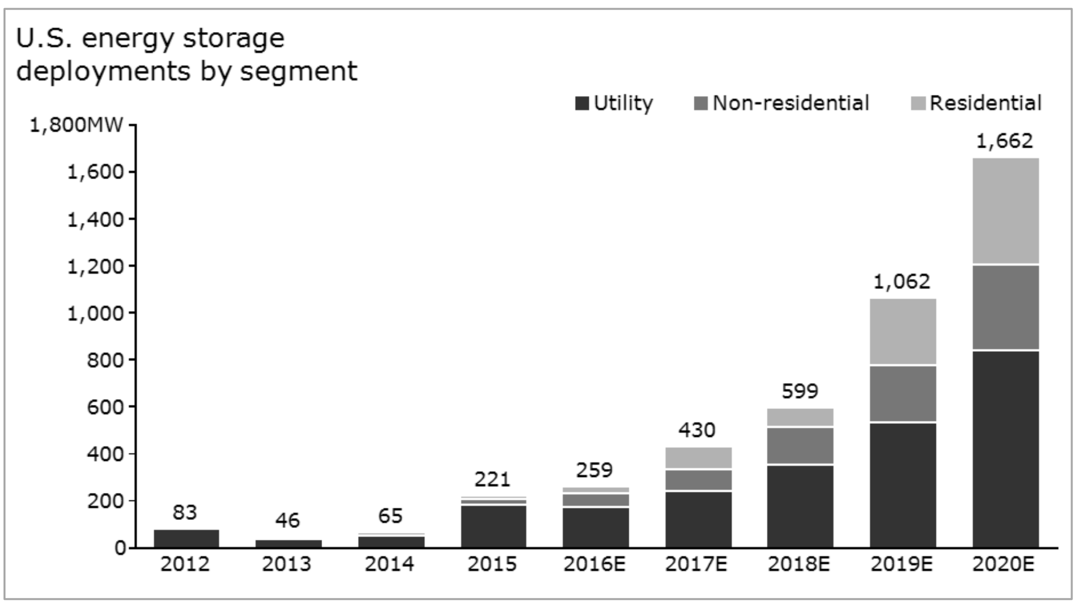

*Sources: Bloomberg New Energy Finance; Organization websites*

***FIGURE 16 — HISTORICAL US SOLAR PV INSTALLATIONS***



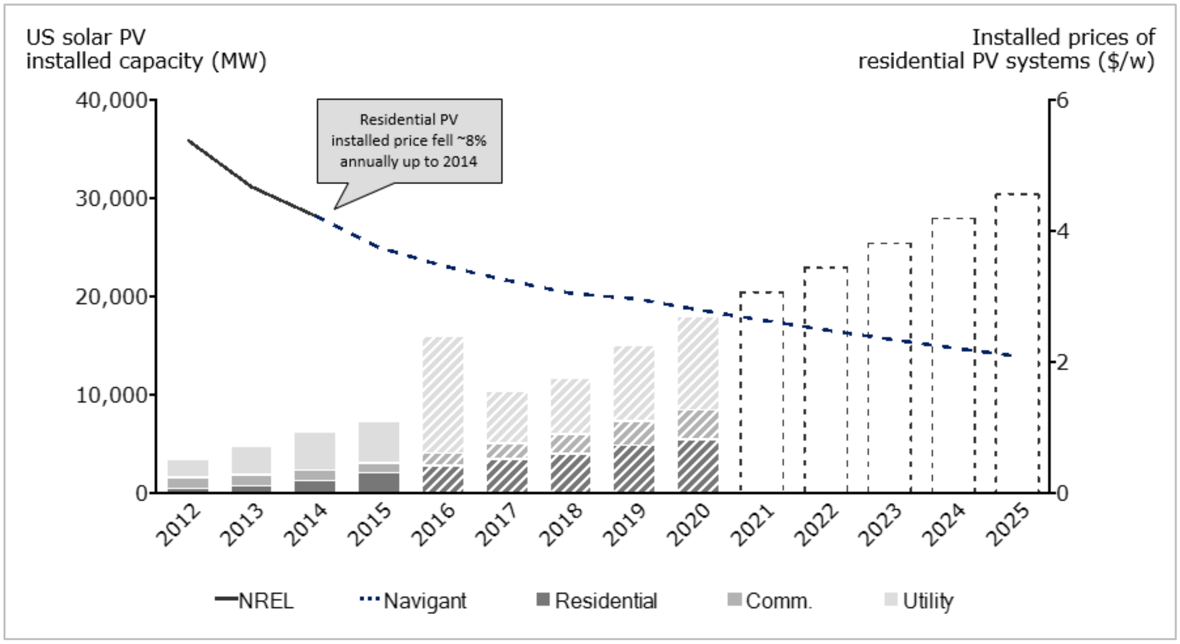

*Source: Solar Energy Industry Association (SEIA)*

***FIGURE 17 — HISTORICAL AND FORECASTED US ENERGY STORAGE DEPLOYMENTS***



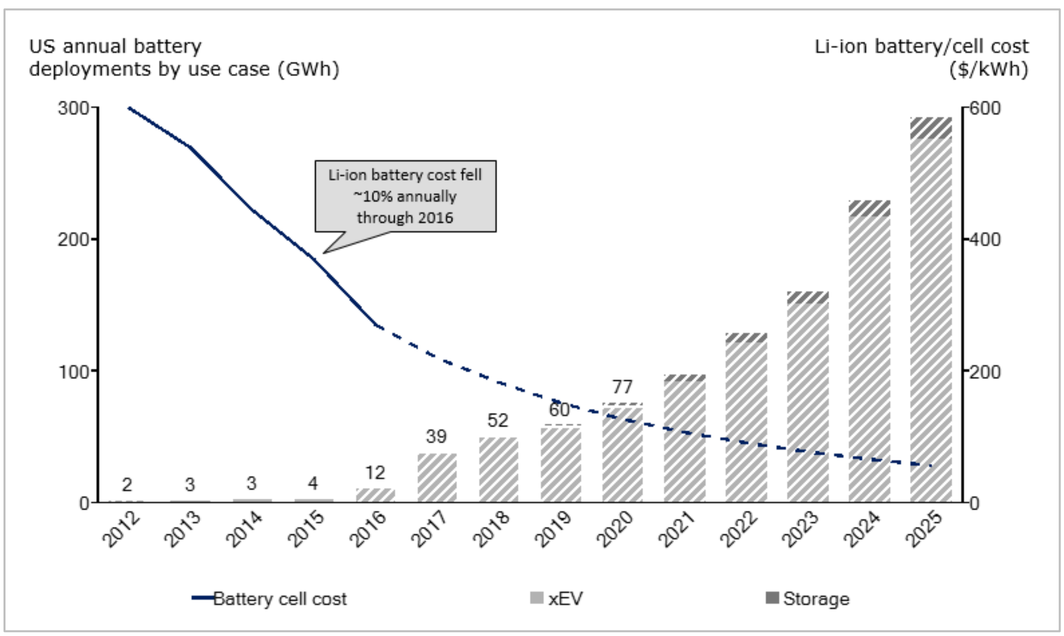

*Sources: Massachusetts DOER State of Charge Report; GTM Research*

***FIGURE 18 — DISTRIBUTED SOLAR COST PROJECTIONS***




*Note: Hashed bars from 2016 to 2020 are forecasts, while 2021-2025 are illustrative projections using similar forecasted trends*
*Sources: NREL, Navigant, Deutsche Bank, Goldman Sachs, Business Insider; Greentech Media; SEIA; Bain & Company*

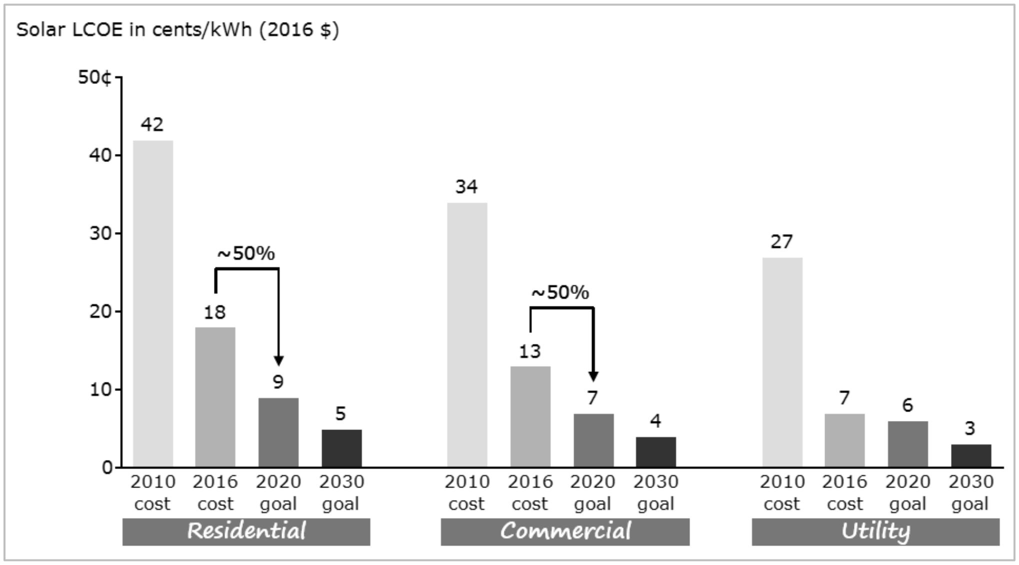
***FIGURE 19 — LITHIUM ION STORAGE COST PROJECTIONS***




*Note: xEV includes annual sales of plug in hybrids and pure battery EVs. Does not include other lithium ion battery usage in traditional battery markets (including consumer electronics) or e-bikes*
*Sources: BNEF; EIA; NREL; Greentech Media, IEA, Deutsch Bank, JP Morgan; Bain & Company*

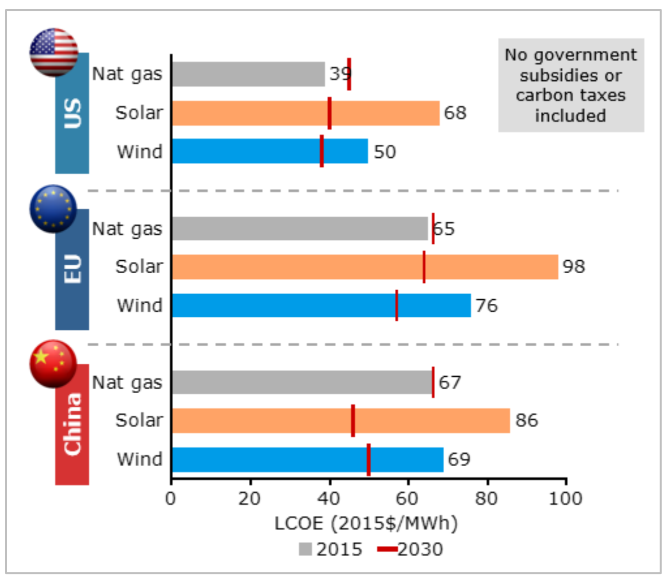
# A.2 Renewable generation Figures

***FIGURE 20 — SOLAR LCOE PROJECTIONS***




*Note: Levelized cost of electricity (LCOE) progress and targets are calculated based on average U.S. climate and without the ITC or state/local incentives; Utility-scale PV uses one-axis tracking; "2020 goals" represent average costs for conventional electricity sources)*
*Source: U.S. Department of Energy "SunShot Initiative"*

***FIGURE 21 — WIND LCOE PROJECTIONS***




*Note: 2030 LCOEs for different resources and regions use average of high and low cases*
*Sources: BNEF; IRENA; IEA; Greentech Media; Bain & Company*

***FIGURE 22 — MICHIGAN COMPANIES WITH RENEWABLE GENERATION GOALS & INVESTMENTS***

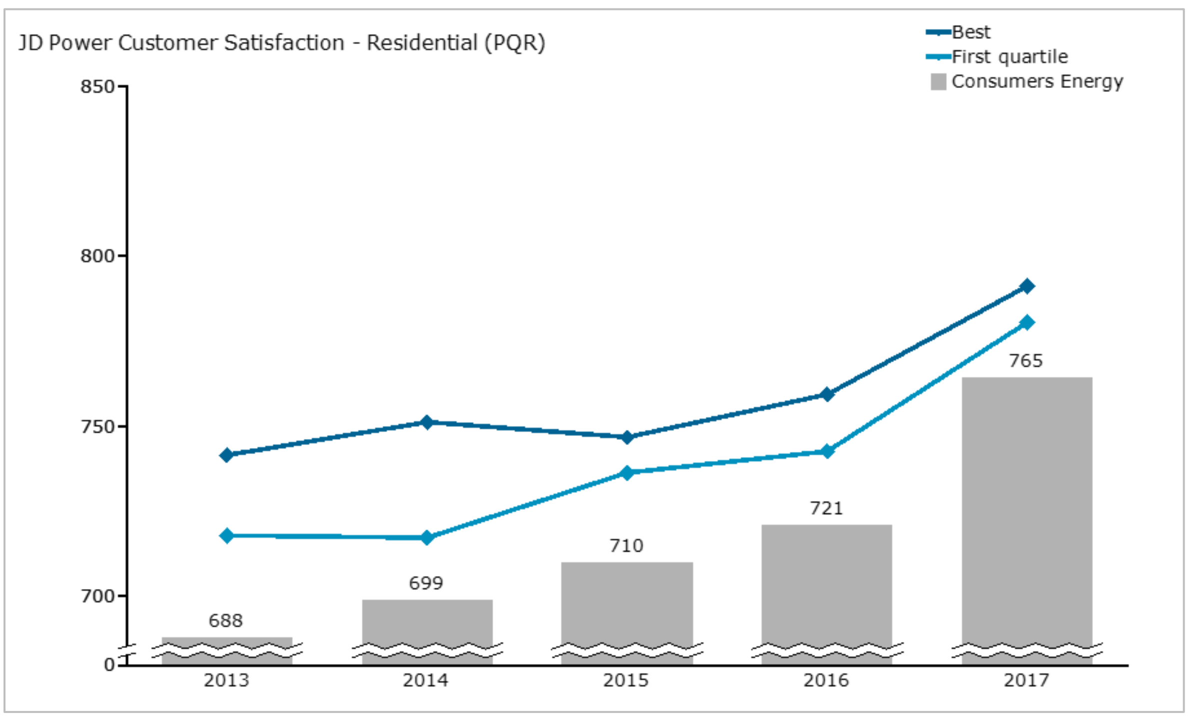
***Michigan-headquartered companies with renewable generation (2017)***

| GM | Ford | Dow | Whirlpool |
|---|---|---|---|
| *Target of 100% renewable generation by 2050* | *Renewable provides nearly 20% of energy generation today* | *Target of 750MW of renewable generation by 2025* | *Built six wind turbines in Ohio for ~$14M* |

*Sources: Company press releases; Advanced Energy Economy*

# A.3 Reliability and resiliency Figures

***FIGURE 23 — JD POWER: POWER QUALITY & RELIABILITY SATISFACTION — RESIDENTIAL CUSTOMERS***

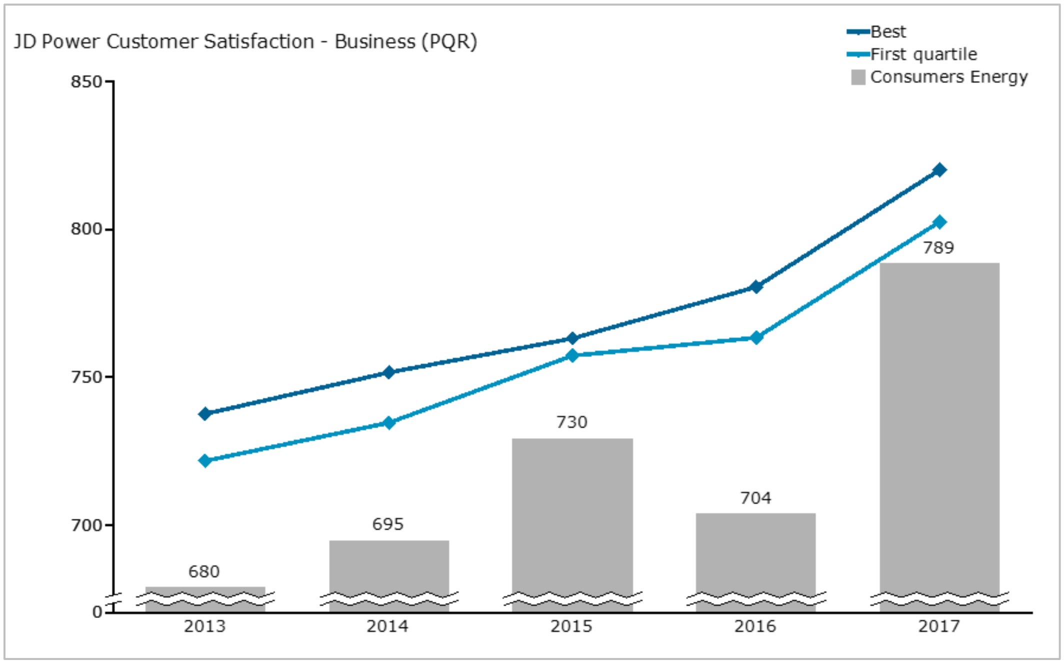



*Source: JD Power*

***FIGURE 24 — JD POWER: POWER QUALITY & RELIABILITY SATISFACTION — BUSINESS CUSTOMERS***



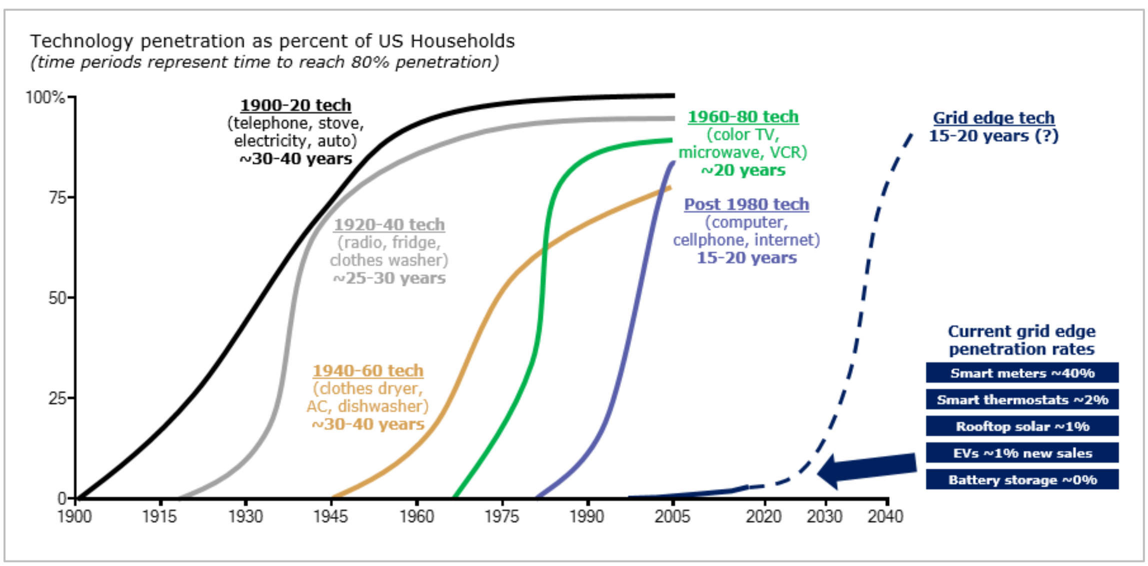
**Draft Only and Subject to Major Revisions. Final Report Due January 31, 2017**




*Source: JD Power*

## A.4 Data Proliferation Figures

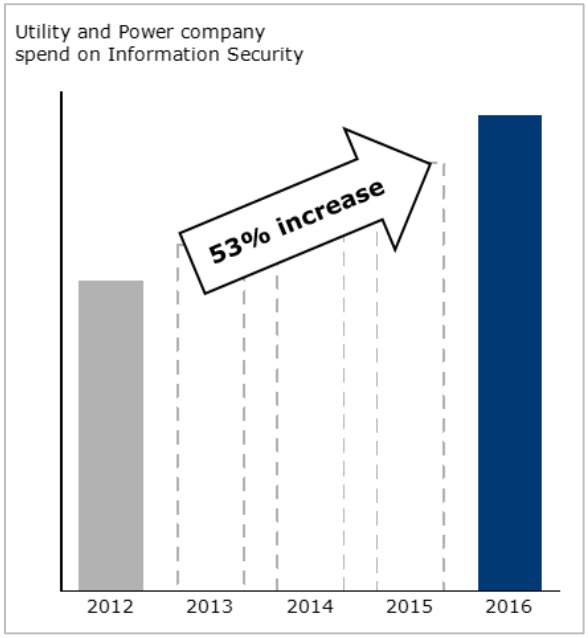
***FIGURE 25 — HISTORICAL TECHNOLOGY PENETRATION CURVES***




*Source: NY Times; IEA; GTM; DOE; HIS; Berg Insight*

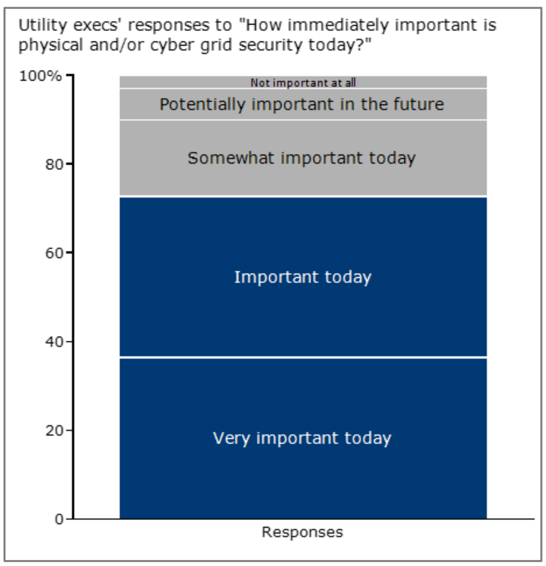
## A.5 Security Figures

***FIGURE 26 — INFORMATION SECURITY SPENDING BY POWER AND UTILITY BUSINESSES (2012 — 2016)***




*Source: PwC "Global State of Information Security Survey — 2017"*

***FIGURE 27 — EXECUTIVE RESPONSES TO STATE OF ELECTRIC UTILITY SURVEY***



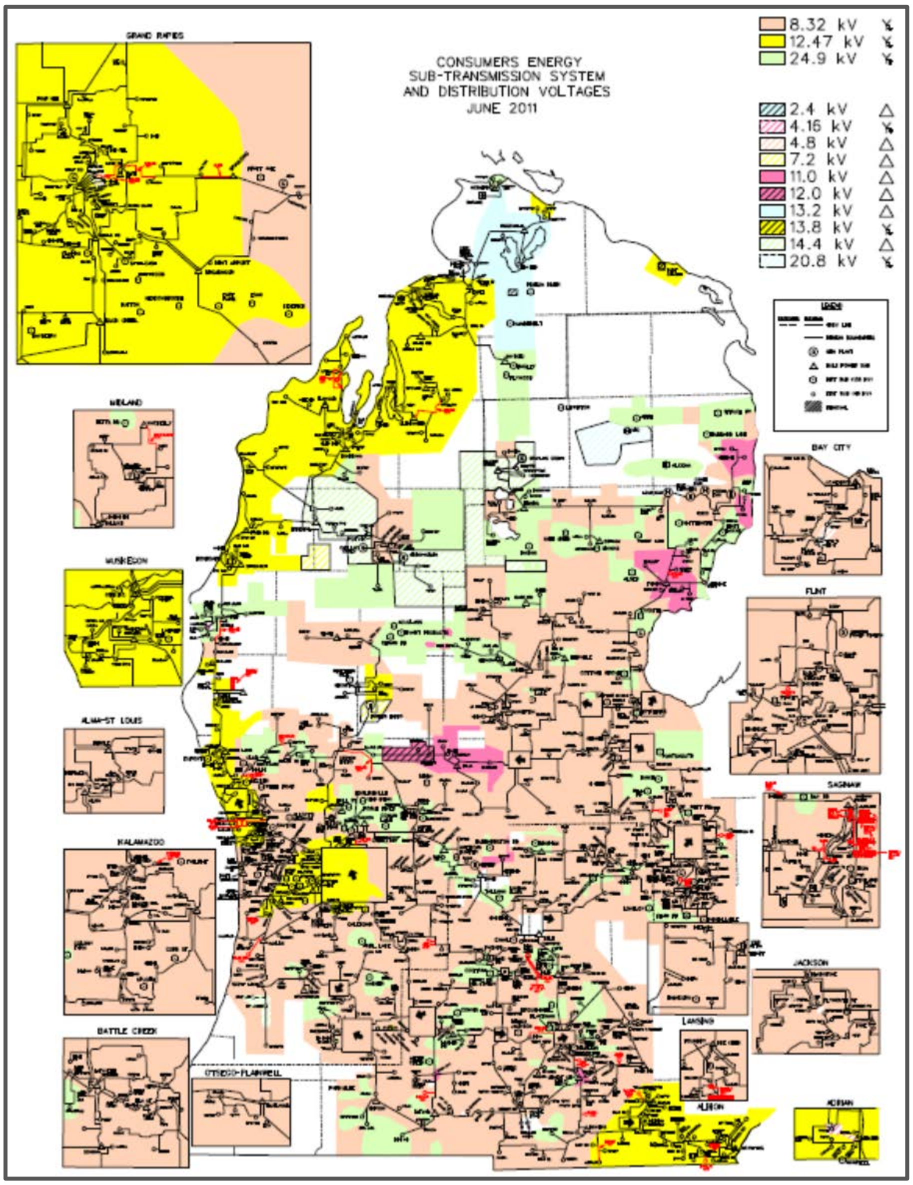

*Source: Utility Dive "State of the Electric Utility Survey - 2017"*

# APPENDIX — CURRENT STATE

## B.1 Distribution System Overview

### Distribution System Voltage Map

***FIGURE 28 — DISTRIBUTION SYSTEM VOLTAGE MAP***






**Draft Only and Subject to Major Revisions. Final Report Due January 31, 2017**

## System Miles/Composition

***TABLE 16 — DISTRIBUTION SYSTEM LINES OVERVIEW***

| Distribution System Lines Overview | | | |
|---|---|---|---|
| Distribution System | Total Miles | Overhead Miles | Underground Miles |
| Low Voltage (LVD) | 67,139 | 56,607 | 10,532 |
| High Voltage (HVD) | 4,641 | 4,624<br>4,430 Miles 46 kV<br>192 Miles 138 kV<br>2 Miles 69 kV | 17 |

***TABLE 17 — DISTRIBUTION SYSTEM SUBSTATIONS OVERVIEW***

| Distribution System Substations Overview | | |
|---|---|---|
| Distribution System | Total | Type(s) |
| Low Voltage (LVD) | 1,110 | 862 general distribution<br>207 Consumers Energy owned dedicated customer substations<br>41 customer-owned dedicated substations<br>4 Consumers Energy-owned substations providing wholesale distribution service to rural co-op and municipal systems<br>30 customer-owned substations providing wholesale distribution service to rural co-op and municipal systems |
| High Voltage (HVD) | 121 | 138/46 kV Substations |

## System Condition, Age & Useful Life

The table below provides the number of different types of assets we have in service, and their average age, according to our accounting records. For accounting purposes, the age of electric distribution assets are determined statistically. Additional equipment is always recorded in the current year, at year end. Retirements are processed statistically using curves that model when a particular asset is available to be retired. For example, when a pole is set to be retired, we use an application to choose a vintage of pole to take out of service. Average age can vary based on field conditions (i.e. soil, weather, grade/slope, wind patterns, etc.), location, and materials used by the manufacturer (i.e. wood type, porcelain, polymer, interrupting media, etc.). For example, poles deteriorate at a faster rate in wet soil conditions than dry non-acidic soil conditions, and porcelain is more susceptible to freeze/thaw conditions than polymer.

***TABLE 18 — LVD LINE EQUIPMENT***

| LVD Line Equipment (as of 7/05/17) | | | |
|---|---|---|---|
| LVD Lines Equipment | Number in Service | Average Age (Years) | Expected Life (Years) |
| Wood Poles | 1,490,311 | 39 | 40-60 |

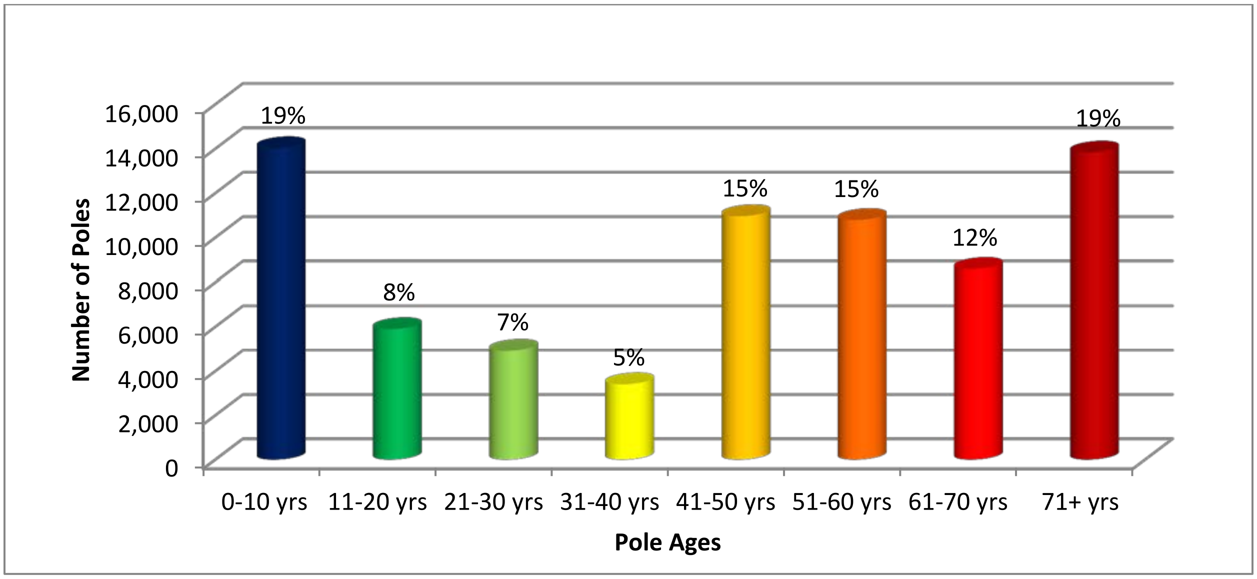
| | | | |
|---|---|---|---|
| Crossarms | 1,388,596 | 39 | 20-35 |
| Insulators | 4,401,534 | 39 | 20-35 |
| Regulators | 7,955 | 25 | 20 |
| Capacitors | 15,977 | 20 | 20 |
| Reclosers | 10,806 | 14 | 20 |
| Cutouts | 673,296 | 25 | 30 |
| Overhead Primary Conductor | 805,843,847 | 51 | N/A |
| Underground Conductor | 54,399,920 | 30 | 30-40 |

## HVD Condition, Age & Useful Life

***TABLE 19 — HVD LINES EQUIPMENT***

| HVD Line Equipment | | | | | |
|---|---|---|---|---|---|
| HVD Lines Equipment | Miles | # in Service | Average Age (Years) | Expected Life (Years) | % of Population past Expected Life |
| HVD Wood Poles | 4462 | 72,400 | 42 | 60 | 31% |
| HVD Steel Poles | 2 | 30 | 32 | 60 | 0% |
| HVD Steel Towers | 160 | 2,070 | 82 | 90 | 43% |
| HVD UG | 17 | | 23 | 30 | 6% |
| HVD Air Break Switches | -- | 1,004 | -- | 25-30 | -- |
| HVD Motor-operated Air Break Switches | -- | 306 | -- | 25-30 | -- |
| HVD Shielded OH Lines with Standard Conductor | 3581 | -- | -- | 50 | -- |
| HVD Shielded OH Lines with Non-standard Conductor (#2 or smaller ACSR, or Copper) | 360 | -- | -- | 60 | 100% |
| HVD Unshielded OH Lines | 683 | -- | -- | 60 | 100% |

***FIGURE 29 — HVD WOOD POLE AGES***




# B.2 Reliability and Outage Metrics

## <u>Reliability Summary</u>

Statistics outlined below illustrate performance of the LVD and HVD systems over a five year period including Major Event Days. Overall we have improved customer experience with our investment strategy, based on system System Average Interruption Duration Index (SAIDI), System Average Interruption Frequency Index (SAIFI), and Customers Experiencing Multiple Interruptions (CEMI) values. Individual circuit performance data and LVD and HVD outage cause data show that several areas still need reliability investment to improve customer experience and to improve system resiliency to weather. LVD system performance continues to be driven by tree-related outages, due to an average ten year full circuit trimming cycle and equipment-related outages, due to aging infrastructure. HVD system performance is primarily driven by equipment failures, due to aging infrastructure. We are dedicated in improving our response to customer outages through restoration process improvement and technology system enhancements, and we are making progress. 88% of customers were restored in under eight hours in 2016.

### SAIDI & SAIFI

The following table provides our rolling five-year average SAIDI and SAIFI indices. These indices were calculated for all conditions, and to exclude Major Event Days ("MED") using the methodology in IEEE Standard 1366-2012.

***TABLE 20 — SAIDI AND SAIFI INDICES***

| SAIDI and SAIFI indices (five year rolling average) | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| Year | All Conditions | | | | Excluding Major Event Days | | | |
| | SAIDI | | SAIFI | | SAIDI | | SAIFI | |
| | Annual | 5 Yr. Avg. | Annual | 5 Yr. Avg. | Annual | 5 Yr. Avg. | Annual | 5 Yr. Avg. |
| 2012 | 508 | 539 | 1.38 | 1.43 | 204 | 245 | 1.06 | 1.12 |
| 2013 | 1108 | 619 | 1.50 | 1.43 | 218 | 233 | 1.00 | 1.10 |
| 2014 | 377 | 625 | 1.10 | 1.40 | 168 | 222 | 0.91 | 1.08 |
| 2015 | 441 | 620 | 1.18 | 1.36 | 177 | 214 | 0.98 | 1.06 |
| 2016 | 284 | 544 | 1.15 | 1.26 | 207 | 194 | 1.01 | 0.99 |

## Circuit-level SAIDI and SAIFI performance

Below we've included an overview of our circuit-level performance for SAIDI and SAIFI metrics. Each histogram provides a glimpse into the variability of our system performance. For example, the vast majority of our circuits achieved an average SAIDI score of less than 0.5 minutes per customer between 2012 and 2016, with more than 40% achieving SAIDI average scores of 0.1 minutes or lower. Similarly, three-quarters of our circuits achieved SAIFI performance of 1.5 interruptions per customer. The circuit-level analysis also points to opportunities to improve reliability by focusing on our worst performing circuits, which are outlined in the next section.

***FIGURE 30 — CIRCUIT-LEVEL SAIDI PERFORMANCE (2012-16)***

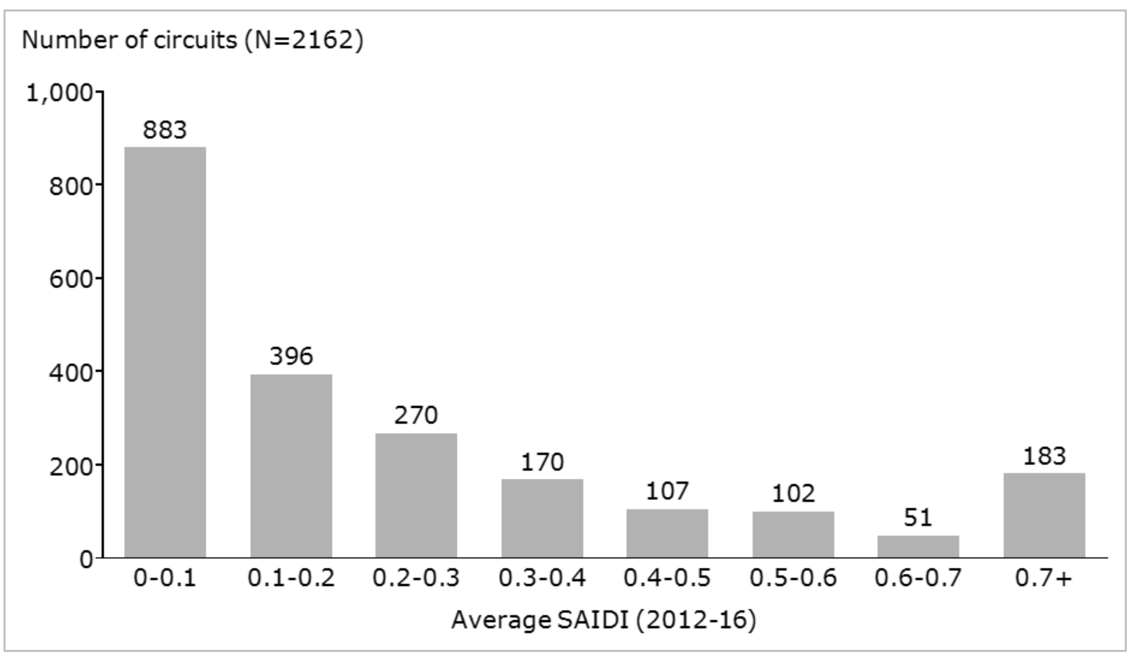
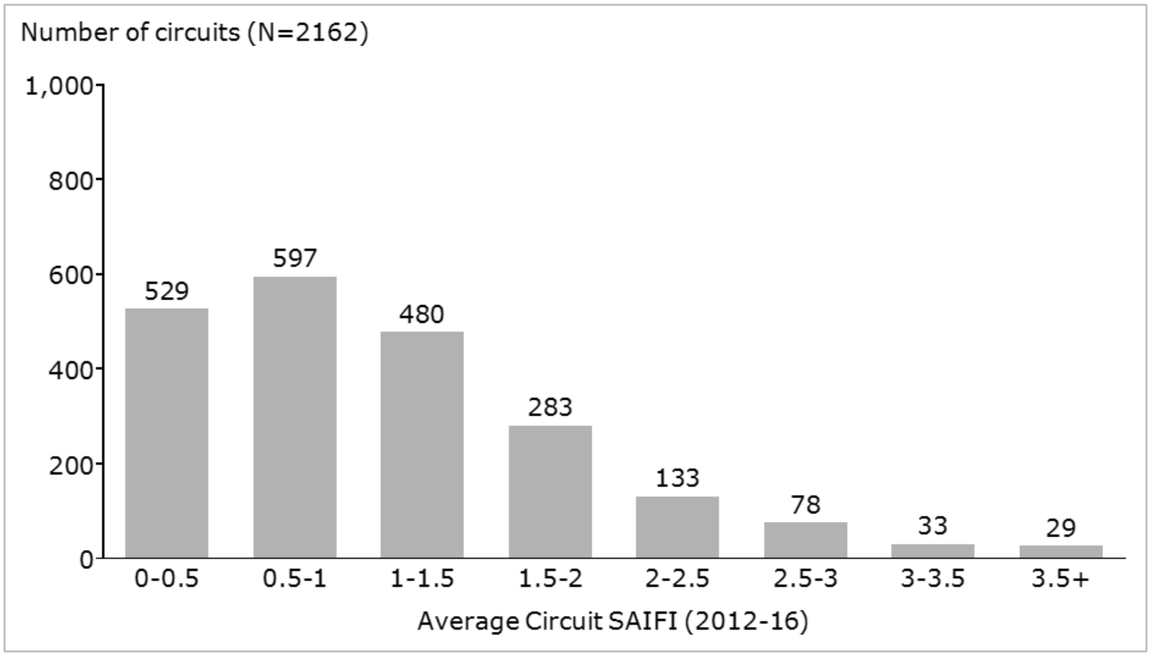


***FIGURE 31 — CIRCUIT-LEVEL SAIFI PERFORMANCE (2012-16)***




## Ten Poorest Performing SAIDI and SAIFI Circuits

The tables below show average performance from 2012 — 2016 for the ten poorest-performing SAIDI and SAIFI circuits. System SAIDI is defined as cumulative customer minutes on a circuit, divided by average customer base. System SAIFI is defined as cumulative customers interrupted on a circuit, divided by the average customer base. Circuit SAIDI is defined as cumulative customer minutes, divided by the average customer count on that circuit. Circuit SAIFI is defined as cumulative customers interrupted divided by the average customer count on that circuit. This data uses all conditions to show the customer experience by each circuit. Some of the circuit performance was driven by catastrophic storm conditions. For example, the Glen Lake substation's Arbor circuit was impacted by a catastrophic storm in August 2015, which produced localized wind speeds in excess of 80mph and hail 1-2" in diameter in northern Michigan.

***TABLE 21 — TEN POOREST-PERFORMING SAIDI CIRCUITS***

| Ten Poorest-Performing SAIDI Circuits | | | | | | | |
|---|---|---|---|---|---|---|---|
| Substation | Average Customer Count | Cumulative Outages | Cumulative Customers Interrupted | Cumulative Customer Minutes | Circuit SAIDI | Circuit SAIFI | System SAIDI |
| GLEN LAKE | 1741 | 61 | 3,723 | 4,605,849 | 2645.52 | 2.1387 | 2.57 |
| DELTON | 1400 | 60 | 5,388 | 4,503,999 | 3217.14 | 3.8487 | 2.51 |
| ALGER | 4104 | 134 | 9,333 | 4,477,764 | 1091.07 | 2.2741 | 2.50 |
| IRISH ROAD | 2709 | 44 | 5,504 | 4,165,096 | 1537.50 | 2.0318 | 2.32 |
| RANGER LAKE | 2407 | 79 | 5,871 | 4,054,942 | 1684.65 | 2.4390 | 2.26 |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| BACKUS | 5583 | 100 | 9,016 | 3,610,233 | 646.65 | 1.6149 | 2.01 |
| OBERLIN | 1748 | 61 | 4,349 | 3,480,972 | 1991.40 | 2.4881 | 1.94 |
| DEAN ROAD | 2278 | 65 | 5,359 | 3,424,743 | 1503.40 | 2.3523 | 1.91 |
| GERRISH | 2062 | 55 | 5,354 | 3,307,082 | 1603.82 | 2.5963 | 1.85 |
| PENINSULA | 2160 | 85 | 5,426 | 3,205,758 | 1484.15 | 2.5121 | 1.79 |

***TABLE 22 — TEN POOREST-PERFORMING SAIFI CIRCUITS***

| Ten Poorest-Performing SAIFI Circuits | | | | | | | |
|---|---|---|---|---|---|---|---|
| Substation | Average Customer Count | Cumulative Outages | Cumulative Customers Interrupted | Cumulative Customer Minutes | Circuit SAIDI | Circuit SAIFI | System SAIFI |
| ALGER | 4104 | 134 | 9,333 | 4,477,764 | 1091.07 | 2.2741 | 0.0052 |
| BACKUS | 5583 | 100 | 9,016 | 3,610,233 | 646.65 | 1.6149 | 0.0050 |
| LAKE CITY | 1924 | 92 | 7,853 | 1,946,167 | 1011.52 | 4.0816 | 0.0044 |
| HONOR | 2245 | 93 | 6,723 | 2,902,908 | 1293.05 | 2.9946 | 0.0038 |
| HOUGHTON HEIGHTS | 3334 | 79 | 6,630 | 2,569,875 | 770.81 | 1.9887 | 0.0037 |
| LEVELY | 1975 | 77 | 6,218 | 1,942,274 | 983.43 | 3.1482 | 0.0035 |
| WEALTHY STREET | 2874 | 35 | 6,101 | 1,562,569 | 543.69 | 2.1229 | 0.0034 |
| EASTON | 2653 | 60 | 5,880 | 1,883,441 | 709.93 | 2.2164 | 0.0033 |
| RANGER LAKE | 2407 | 79 | 5,871 | 4,054,942 | 1684.65 | 2.4390 | 0.0033 |
| GETTY | 3174 | 41 | 5,672 | 1,756,776 | 553.49 | 1.7869 | 0.0032 |

## CEMI

Data for Customers Experiencing Multiple Interruptions ("CEMI") is provided in the table below, with interruptions by year. 17% more customers experienced zero outages in 2016 compared to 2012, indicating improvement in reliability and customer service. The number of customers experiencing ten outages or more has decreased significantly since 2012, also showing continuous reliability improvement.

***TABLE 23 — CEMI (CUSTOMERS EXPERIENCING MULTIPLE INTERRUPTIONS) BY YEAR***

| CEMI — Customer Experiencing Multiple Interruptions | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | Number of interruptions | | | | | | | | | | |
| Year | 0 | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10+ |
| 2012 | 621.8K | 532.2K | 308.9K | 160.7K | 83.4K | 39.7K | 19.4K | 9.2K | 4.2K | 2.3K | 2.6K |
| 2013 | 549.9K | 522.3K | 336.K | 192.5K | 102.8K | 42.4K | 20.4K | 11.1K | 4.8K | 2.9K | 1.6K |

| | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 2014 | 687.1K | 570.8K | 318.1K | 131.3K | 51.1K | 18.5K | 6.5K | 2.5K | .6K | .7K | .5K |
| 2015 | 743.K | 533.8K | 273.5K | 137.K | 64.4K | 26.3K | 14.5K | 7.1K | 3.4K | 1.K | 1.4K |
| 2016 | 730.3K | 544.9K | 276.5K | 135.K | 66.5K | 29.3K | 13.1K | 5.5K | 3.1K | 1.7K | .7K |

## CELID

Data for Customers Experiencing Long Interruption Duration ("CELID") for various time durations is provided in the table below for the last five years. The data is representative of all the outages on the system; it does not exclude any major event days or accommodations for hazards on the system. Continuous improvements to restoration processes, such as proactive planning, practice tabletop exercises, and technology upgrades have increased the percentage of customers restored within each of the CELID target timeframes from 2012 to 2016. 88% of customers are restored within 8 hours of their outage start time.

***TABLE 24 — CELID (≤120 HOURS)***

| CELID — Customers Experiencing Long Interruption Duration | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| Year | Incidents | Customers | % of Customers Less than or equal to… | | | | | | |
| | | | 8 Hrs | 24 Hrs | 48 Hrs | 60 Hrs | 72 Hrs | 96 Hrs | 120 Hrs |
| 2012 | 43,150 | 2,459,330 | 83.59% | 94.19% | 98.23% | 98.96% | 99.47% | 99.98% | 100.00% |
| 2013 | 49,728 | 2,693,036 | 71.54% | 85.99% | 92.76% | 94.97% | 96.28% | 97.85% | 99.11% |
| 2014 | 38,710 | 1,971,112 | 84.11% | 94.90% | 99.25% | 99.68% | 99.96% | 100.00% | 100.00% |
| 2015 | 39,708 | 2,126,178 | 84.72% | 93.88% | 97.88% | 98.80% | 99.36% | 99.87% | 99.99% |
| 2016 | 39,781 | 2,085,976 | 88.43% | 98.89% | 99.98% | 100.00% | 100.00% | 100.00% | 100.00% |

***TABLE 25 — CELID (≥120 HOURS)***

| CELID — Customers Experiencing Long Interruption Duration | | | |
|---|---|---|---|
| Year | Incidents | Customers | % of Customers Greater Than or Equal to… |
| | | | 120 Hrs |
| 2012 | 43,150 | 2,459,330 | 0.00% |
| 2013 | 49,728 | 2,693,036 | 1.24% |
| 2014 | 38,710 | 1,971,112 | 0.00% |
| 2015 | 39,708 | 2,126,178 | 0.01% |
| 2016 | 39,781 | 2,085,976 | 0.00% |

## Outage Summary

The following tables show the average number of outages, customers, and customer minutes from 2012 to 2015 for the LVD and HVD systems, including all conditions in order to show overall customer experience. When we began using a new Service Suite work order management system, employees received device training for cause code fields, to improve consistency in outage reporting.

### LVD

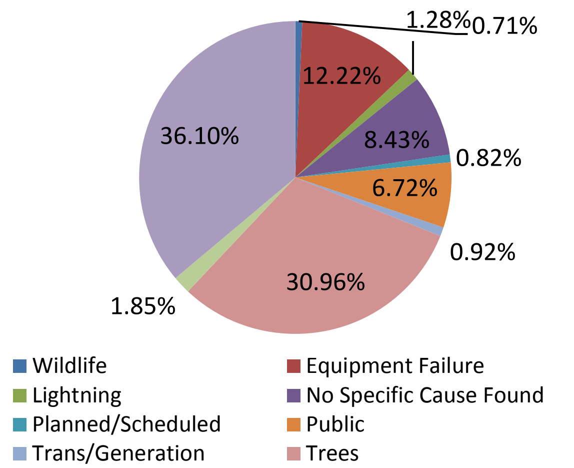
In 2016, LVD tree-related customer outage minutes increased by 22% from their 2012-2015 averages. Weather continued to be the second-largest cause of outages on the LVD system. Equipment failure continued to be the third-largest cause of outages, with a slight improvement in 2016 compared to 2012-2015 averages.

***TABLE 26 — LOW VOLTAGE DISTRIBUTION OUTAGE SUMMARY***

## Low Voltage Distribution Outage Summary

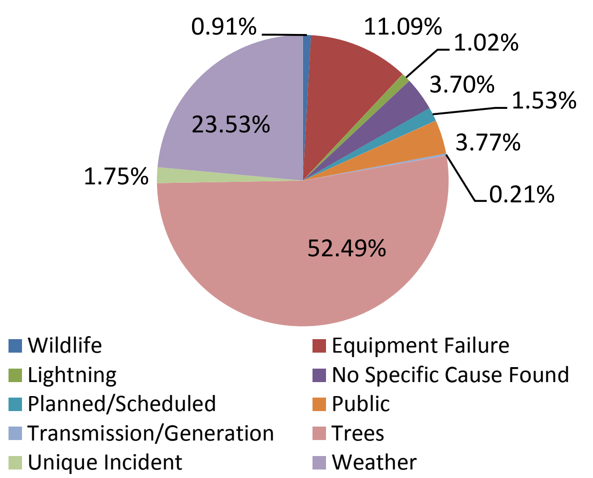
Average of years 2012—2015

| Cause | Outages | Customers | Minutes |
|---|---|---|---|
| Wildlife | 2.4K | 42.7K | 6.8M |
| Equipment Failure | 7.3K | 300.9K | 115.9M |
| Lightning | 1.7K | 65.3K | 12.1M |
| No Specific Cause Found | 3.4K | 132.K | 79.9M |
| Planned/Scheduled | 1.6K | 44.K | 7.7M |
| Public | 3.1K | 184.1K | 63.7M |
| Transmission/ Generation | 1.2K | 46.4K | 8.7M |
| Trees | 9.7K | 469.9K | 293.6M |
| Unique Incident | 3.1K | 72.5K | 17.6M |
| Weather | 7.9K | 363.8K | 342.4M |
| Total | 41.4K | 1.7M | 948.5M |




2016

| Cause | Outages | Customers | Minutes |
|---|---|---|---|
| Wildlife | 3.8K | 35.9K | 3.9M |
| Equipment Failure | 7.2K | 245.4K | 48.M |
| Lightning | .6K | 22.3K | 4.4M |
| No Specific Cause Found | 4.8K | 100.7K | 16.M |
| Planned/Scheduled | 1.2K | 67.9K | 6.6M |
| Public | 1.2K | 101.4K | 16.3M |
| Transmission/ Generation | .1K | 4.8K | .9M |
| Trees | 14.1K | 725.5K | 227.4M |
| Unique Incident | 1.3K | 62.8K | 7.6M |
| Weather | 5.1K | 272.6K | 102.M |
| **Total** | 39.2K | 1.6M | 433.3M |




*Pie charts are based Customer Minutes and include MEDs



**Draft Only and Subject to Major Revisions. Final Report Due January 31, 2017**

## HVD

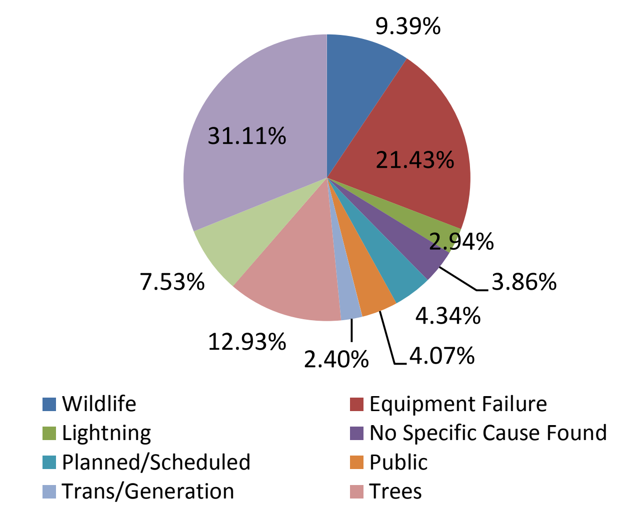
HVD outages in 2016 were caused primarily by equipment failure, weather, and wildlife. Unfortunately, customer minutes due to equipment failure in 2016 increased by 8% from 2012-2015 averages. Improvements in coding conditions have decreased weather by 7% and wildlife coding is up by 3%. Tree related outages were down by 3% from 2012-2015 averages and is not the number one driver on the HVD system due to a rigorous four year line clearing cycle.

***TABLE 27 — HIGH VOLTAGE DISTRIBUTION OUTAGE SUMMARY***

**High Voltage Distribution Outage Summary**

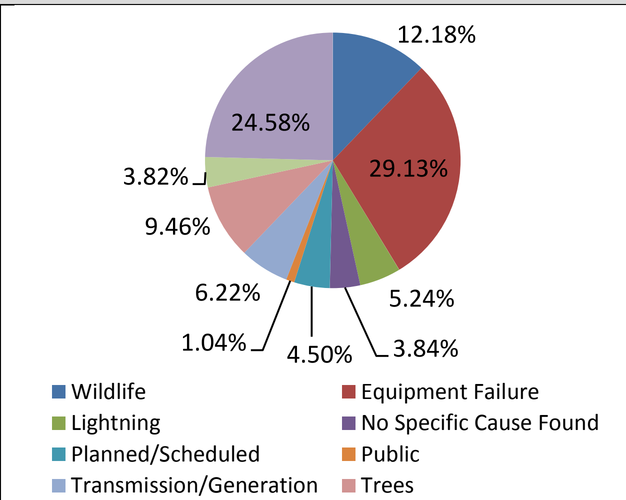
Average of years 2012—2015

| Cause | Outages | Customers | Minutes |
|---|---|---|---|
| Wildlife | 74 | 75.6K | 12.6M |
| Equipment Failure | 189 | 148.1K | 28.8M |
| Lightning | 17 | 15.1K | 4.M |
| No Specific Cause Found | 49 | 36.7K | 5.2M |
| Planned/Scheduled | 35 | 32.5K | 5.8M |
| Public | 42 | 30.9K | 5.5M |
| Transmission/ Generation | 16 | 13.K | 3.2M |
| Trees | 50 | 40.3K | 17.4M |
| Unique Incident | 75 | 67.9K | 10.1M |
| Weather | 136 | 102.2K | 41.9M |
| Total | **681** | 562.3K | 134.5M |




2016

| Cause | Outages | Customers | Minutes |
|---|---|---|---|
| Wildlife | 81 | 54.6K | 9.8M |
| Equipment Failure | 191 | 149.8K | 23.4M |
| Lightning | 8 | 6.3K | 4.2M |
| No Specific Cause Found | 16 | 15.7K | 3.1M |
| Planned/Scheduled | 33 | 28.8K | 3.6M |
| Public | 11 | 7.5K | .8M |
| Transmission/ Generation | 57 | 42.3K | 5.M |
| Trees | 59 | 55.8K | 7.6M |
| Unique Incident | 24 | 21.9K | 3.1M |
| Weather | 84 | 64.K | 19.8M |
| **Total** | **564** | 446.7K | 80.5M |




*Pie charts are based Customer Minutes and include MEDs

# APPENDIX — PLAN

## C.1 Detailed investment list

***TABLE 28 — PLAN — CAPITAL INVESTMENT SUMMARY (2016-22)***

| Capital Investment Summary (2016-22, $K) | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| All Investments | 2016 Actuals | 2017 YTD (June) | 2018 Plan | 2019 Plan | 2020 Plan | 2021 Plan | 2022 Plan | Five Year Total |
| Grid Analytics | -- | -- | *Estimates for 2018-22 will be included in the final report* | | | | | |
| System Modeling | -- | -- | | | | | | |
| ***Total*** | -- | -- | | | | | | |

***TABLE 29 — PLAN — O&M EXPENSE SUMMARY (2016-22)***

| O&M Expense Summary (2016-22, $K) | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| All Investments | 2016 Actuals | 2017 YTD (June) | 2018 Plan | 2019 Plan | 2020 Plan | 2021 Plan | 2022 Plan | Five Year Total |
| ***Scheduling & Dispatch*** | | | *Estimates for 2018-22 will be included in the final report* | | | | | |
| Scheduling & Dispatch | 5,067 | 3,214 | | | | | | |
| ***Grid Infrastructure*** | | | | | | | | |
| Grid Infrastructure | 2,711 | 950 | | | | | | |
| ***Distribution & Customer Ops Management*** | | | | | | | | |
| Distribution & Customer Ops Management | 536 | 388 | | | | | | |
| ***Data Management*** | | | | | | | | |
| Geospatial Mgmt & Data Quality - Elec | 3,316 | 971 | | | | | | |
| ***Other O&M*** | | | | | | | | |
| Engineering - HVD | 611 | 285 | | | | | | |
| Infrastructure Attachments and Standards | 450 | 520 | | | | | | |
| Financial Management & Controls-Elec | 722 | 552 | | | | | | |
| Distribution Performance | 399 | 489 | | | | | | |
| Regulatory & Compliance-Elec | 227 | 276 | | | | | | |
| Project Management-Elec | 529 | 277 | | | | | | |
| Agreements - LVD & HVD | 360 | 151 | | | | | | |
| CES | 229 | 166 | | | | | | |
| Contract Administration | 5,067 | 3,214 | | | | | | |
| ***Total*** | 18,763 | 10,792 | | | | | | |

# C.2 Load/Peak Forecasting

## Low Voltage Distribution (LVD)

The LVD Planning program's purpose is to provide adequate distribution infrastructure to meet current and projected distribution customer loads for the following year. LVD planners use CYME, a power flow software, to identify system capacity issues and develop remediation plans on an annual basis. They then use CYME reports to develop imbalance remediation plans, and test the plans within CYME to ensure they meet future needs.

All planning activities are based on peak load conditions. We look for situations where a component of the distribution system has a projected load well over its peak capability (typically 125% of the capability), based on our standards for the equipment. Previous year loadings and future customer growth (average of 3%) are used to project future loadings on the distribution infrastructure.

The loading standards for equipment are established by the manufacturer, or by a recognized industry source like IEEE, and indicate the optimal operation of the equipment. Evaluation of each piece of equipment depends on its use. All equipment has a defined set of operating parameters that, if violated, can negatively impact its strength and durability. For example, equipment that uses oil is rated based on a maximum temperature. If that temperature is exceeded, the equipment can break down, leading to a shorter lifespan.

# C.3 Capacity Planning Overview

## Low Voltage Distribution (LVD)

LVD project construction prioritized to address the highest overloads prior to lower overloads, considering actual and projected overloads, including known new business loads. We discussed determination of LVD overloads in Appendix C.2.

For 2017 LVD line capacity projects were modeled in the third quarter of 2016 and prioritized for construction in the fourth quarter of 2016. Similar criteria will be used for future projects.

## High Voltage Distribution (HVD)

### Lines and Substations

Because the HVD system is backbone infrastructure, capacity projects must be completed on an as-needed basis to maintain reliability.

HVD lines and substations are planned based on criteria violations (overloaded equipment or low voltage), changes in standards, operational requirements, and coordination with the needs of transmission, LVD substations, other utilities, and generation. These upgrades include new 138/46 kV substations, HVD line extensions to 138/46 kV substations, reconductoring HVD lines (replacing conductor), interconnection facilities, and other HVD line and substation equipment upgrades. This may include obtaining rights of way for new lines and substations.

We evaluate 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 HVD systems. This process identifies HVD facilities that would overload or provide unacceptably low voltage during base (normal) conditions at system peak load and during single (N-1 equipment out of service) outage conditions at 80% of system peak load. We study single line, single transformer, single bus, and single generator outages. We develop to eliminate unacceptably low voltage, and loadings above line and equipment ratings. We test proposed plans in the models to assure they fulfill the designed purpose. We also use SCADA information to project future load on radial lines, and develop and use short circuit models of our HVD network to compare available short circuit current to the interrupting capability of the HVD interrupting equipment.

### Timing

The 2017 HVD line capacity projects were scheduled in prior years or by the fourth quarter of 2016. Capacity projects that require outages to construct must be scheduled during non-summer months (September 15 — May 15) to allow optimal system integrity during peak summer loading. Some projects are sequential, requiring phase 1 to be completed prior to beginning construction on phase 2, etc.

# C.4 Capacity Planning Investments

Capacity investments are directed at preventing line and equipment overload due to excessive demand beyond its threshold. These investments are divided into the following categories:

## Low Voltage Distribution (LVD)

### Power Flow Software

We use CYME, a power flow software, to determine power flow, voltages, and system protection for current and future states of the system. We also use CYME for evaluating potential circuit tie points and proposing automation loop concepts.

### Electric System Model

We use Geographic Information System (GIS) for our model of record. Engineers import their substation interconnection model and prepare a set of studies for overloading, low voltage, and protection issue review. We model individual substations and circuits, with loads aggregated on the low-side bus of the substation transformers. We review and update these models on an annual basis based on maximum load information and used as the basis for submitting system improvement concepts. Maximum loads are the highest loads experienced on the system at the point of analysis, excluding anomalies.

## High Voltage Distribution (HVD)

### Capacity

Capacity investment includes capital investment to: (1) ensure that the HVD system can serve forecasted electric peak demand with all HVD facilities in service; (2) ensure that single facilities of the HVD system can be taken out of service during non-peak demand periods for maintenance and construction, without loading the remaining HVD facilities beyond equipment ratings or reducing voltage to unacceptably low levels.

# APPENDIX — BUILD

## D.1 Detailed investment list

***TABLE 30 — BUILD — CAPITAL INVESTMENT SUMMARY (2018-22)***

| Capital Investment Summary (2018-22, $K) | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| All Investments | 2016 Actuals | 2017 YTD (June) | 2018 Plan | 2019 Plan | 2020 Plan | 2021 Plan | 2022 Plan | Five Year Total |
| ***New Business*** | | | *Estimates for 2018-22 will be included in the final report* | | | | | |
| Lines New Business - LVD | 43,039 | 23,420 | | | | | | |
| Transformers New Business - LVD | 8,852 | 5,434 | | | | | | |
| Metering New Business - LVD | 5,266 | 5,643 | | | | | | |
| Metro New Business | 3,243 | 1,402 | | | | | | |
| ***Capacity - LVD*** | | | | | | | | |
| Lines Capacity - LVD | 14,517 | 10,143 | | | | | | |
| Substations Capacity - LVD | 18,044 | 5,727 | | | | | | |
| Transformers Capacity - LVD | 3,219 | 1,918 | | | | | | |
| ***Capacity - HVD*** | | | | | | | | |
| Lines & Subs Capacity - HVD | 20,965 | 10,668 | | | | | | |
| ***Strategic Customers*** | | | | | | | | |
| Lines Strategic Customers - HVD | 27,864 | 2,846 | | | | | | |
| ***Non-Wires Alternatives*** | | | | | | | | |
| Demand Response | 1,200 | 2,752 | | | | | | |
| ***Total*** | 146,210 | 69,952 | | | | | | |

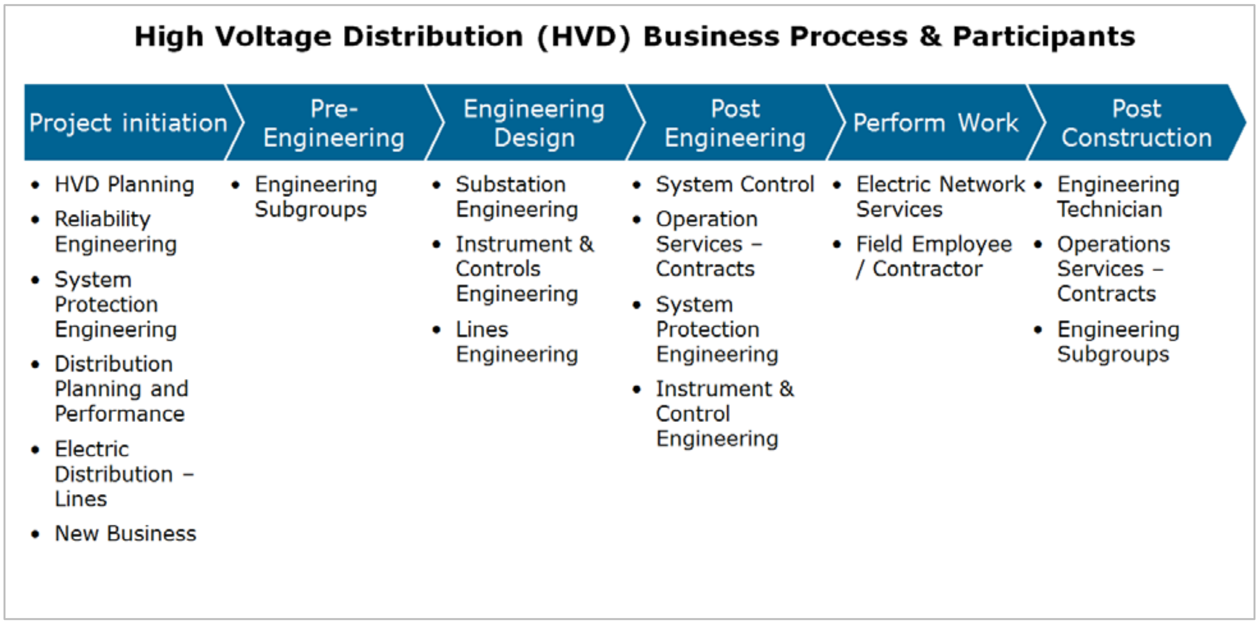
***TABLE 31 — BUILD — O&M EXPENSE SUMMARY (2016-22)***

| O&M Expense Summary (2016-22, $K) | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| All Expenses | 2016 Actuals | 2017 YTD (June) | 2018 Plan | 2019 Plan | 2020 Plan | 2021 Plan | 2022 Plan | Five Year Total |
| ***Non-Wires Alternatives*** | | | *Estimates for 2018-22 will be included in the final report* | | | | | |
| Energy Efficiency | 77,216 | 46,063 | | | | | | |
| Demand Response | 1,620 | 3,425 | | | | | | |
| ***Total*** | 78,836 | 49,488 | | | | | | |

## D.2 Business Process

When we build or upgrade an asset, we follow a standard process that includes numerous groups within our organization. This figure below illustrates a high-level overview of our process for bringing a HVD project from approval to operation.

***FIGURE 32 — HVD BUSINESS PROCESS OVERVIEW***




## D.3 Traditional Assets Overview

When we identify a capacity constraint, reliability concern, or planning criteria violation, we conduct a distribution study, comparing the benefits and costs of several traditional options: load transfer (to a less loaded substation or line), capacity increase (lines or equipment upgrade), new LVD substation (to split load), or an alternative connection (to a different HVD or transmission line)

When we build or modify substations, we "right-sized" them based on load forecast, future distribution automation plans, HVD system restrictions, site configuration, property size, and individual operational considerations of the local system. For example, substations located in relatively close proximity to each other (such as urban areas) or substations with stout distribution tie-lines are built with more capacity to facilitate load transfers and improve overall system reliability. Conversely, substations in rural areas with a long history of low growth are built with equipment to meet the needs of the local system only while minimizing upfront equipment cost.

## D.4 Non-Wires Alternatives Overview

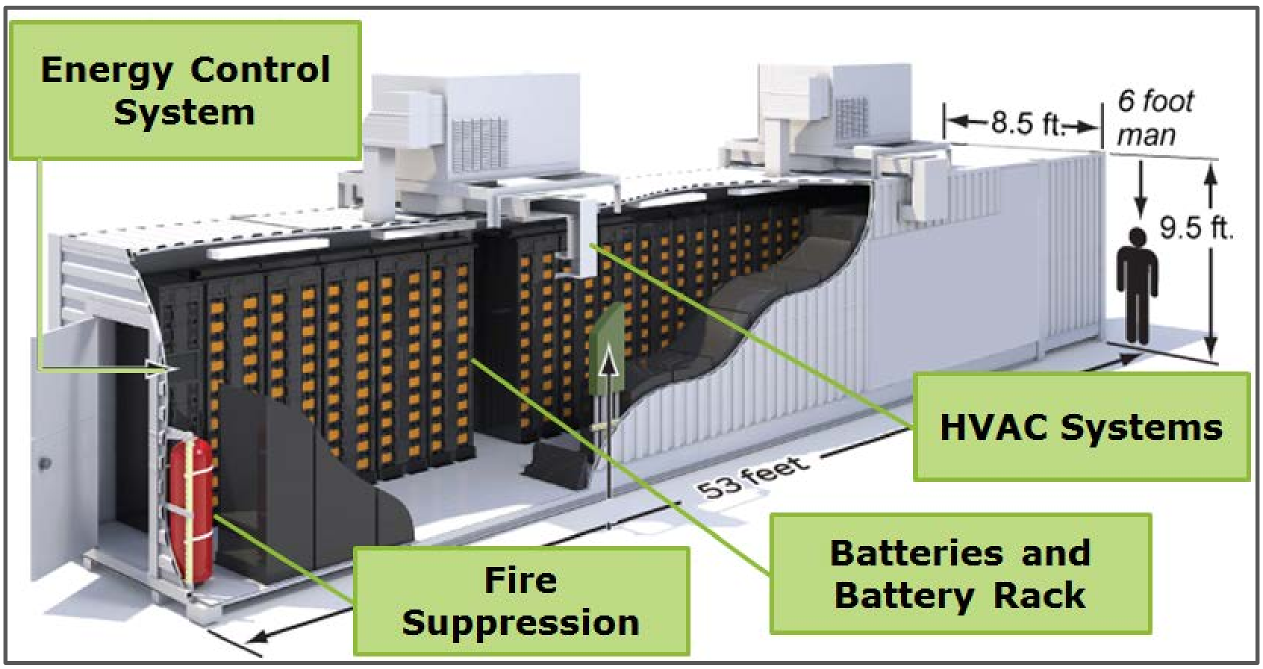
In addition to traditional options, non-wires alternatives (NWA) are becoming more popular. We are beginning to incorporate NWA, such as energy efficiency (EE), demand response (DR), distributed generation (DG), and battery energy storage systems (BESS), into the option pool. We are piloting an NWA project at the Swartz Creek substation to defer a capacity project and learn more about NWA integration.

Today, in general NWA are not considered viable alternatives to address planning criteria violations or reliability issues, and their ability to replace traditional capacity options is limited. However, NWA are now an integral part of the supply planning process and part of the Company's supply plan. NWA programs are part our annual load monitoring, and we will watch them closely as they continue to penetrate the electric system.

## Battery Storage

Battery energy storage systems (BESS) are becoming an integral part of a national strategy to modernize the electric system. BESS can take many shapes and sizes depending on the specifications of the battery and the chosen application. Batteries under 10MW generally are built in containers up to the size of a semi-trailer. Batteries that are 10MW and larger are typically housed in a building that is configured similarly to a data center. Inside, racks are filled with batteries and large HVAC systems for climate control.

***FIGURE 33 — EXAMPLE OF A BATTERY ENERGY STORAGE SYSTEM***




*Source: GE*

### Research Partnership

WE are determining how to use BESS to benefit our customers. We recently partnered with Michigan State University (MSU) to research the present state of BESS and its applications, vendors, engineering, and materials. The partnership has focused on state-of-the-science applications of utility-scale distribution systems.

### Pilots

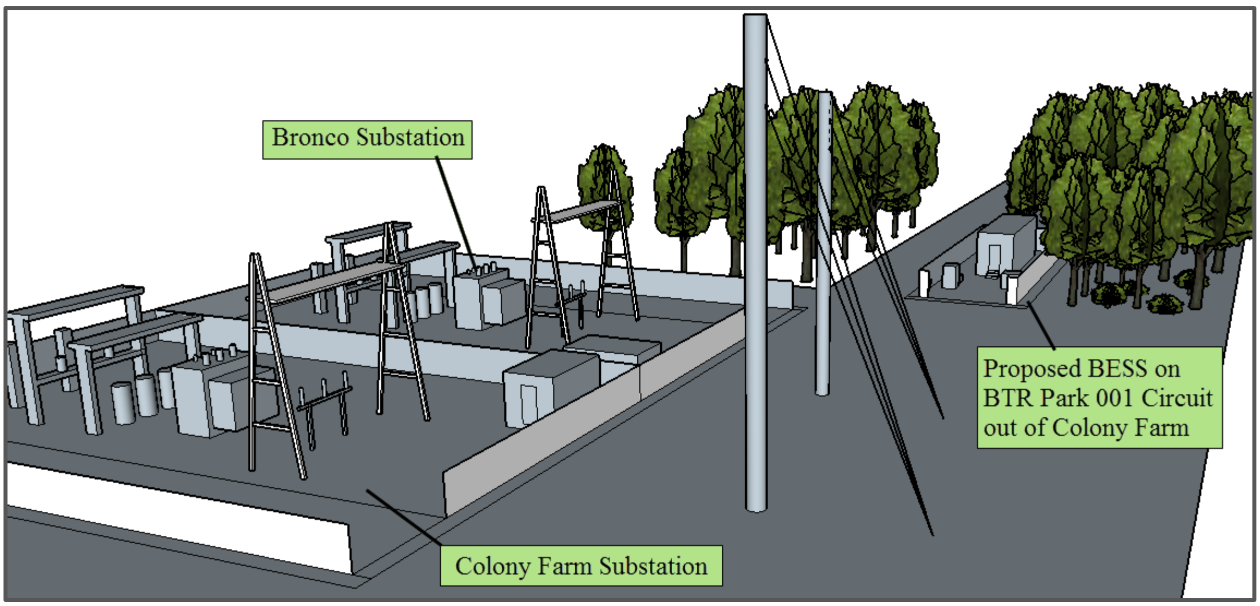
The MSU research, in part, helped us develop BESS pilot projects that will be installed on our system in 2018, to test battery capabilities, provide benefits to the circuit, and learn about how to integrate batteries into the grid at the distribution level. We are planning two installations in 2018, in Kalamazoo and Grand Rapids, detailed below:

### *WMU Solar Farm BESS (Kalamazoo)*

We will install a 1MW/1MWhr BESS on the circuit that serves WMU's Solar Garden array, which also has residential, commercial, and industrial customers connected to it.

The footprint of the BESS will be approximately 25'x75' and will consist of a packaged set of equipment including battery, battery charger, battery management controls, inverter, and other hardware. This BESS will provide storage capabilities to support outage mitigation, demand response, and other use cases. Figure 2 shows a rendering of the BESS in relation to our Colony Farm Substation and WMU Bronco Substation.

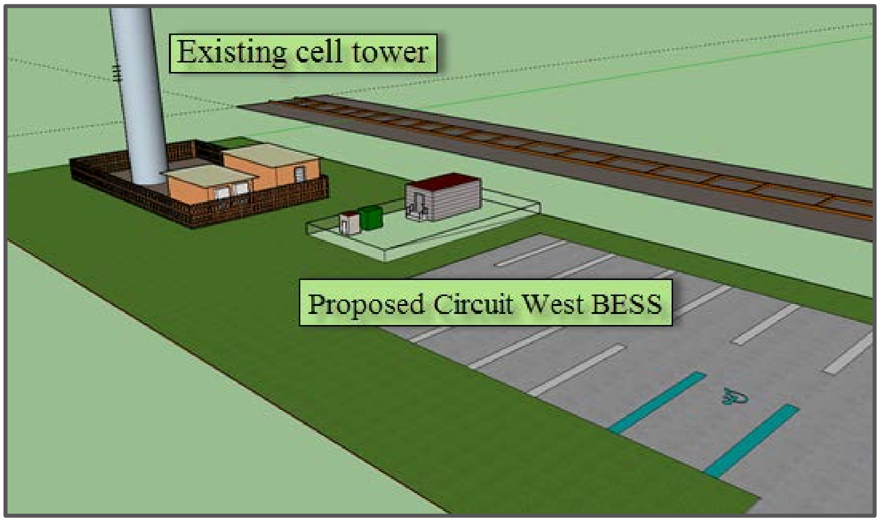
***FIGURE 34 — RENDERING OF WMU SOLAR FARM BESS***




### *Circuit West BESS (Grand Rapids)*

We will also install a BESS at the new Circuit West location in Grand Rapids. The battery will be sized between 0.25 and 0.75 MW, with a footprint of approximately 30'x60'. It will be connected to the grid on a circuit with commercial and residential customers, along with a Solar Garden array. Figure 3 is a rendering of what the BESS may look like in the Circuit West development.

***FIGURE 35 — RENDERING OF CIRCUIT WEST BESS***




## Benefits

BESS is emerging as a flexible energy supplement, capable of producing the following benefits:

***TABLE 32 — BATTERY STORAGE BENEFITS***

| Battery Storage Benefits | |
|---|---|
| Benefit | Description |
| Upgrade Deferrals | Batteries can be used to delay or avoid investments that would otherwise be necessary to maintain capacity to serve all load requirements. For example: when a transformer is replaced, the new transformer is sized to accommodate future load growth, and thus a large portion of the investment may be underutilized for some of the new equipment's life. Rather than replacing the transformer, a battery can be installed to offload it during peak periods, thus potentially extending its operational life by several years. |
| Peak Shaving | Rather than designing the grid to meet the load on the one peak day in the summer, we may be able to use batteries in areas with large load swigns to reduce the impact to distribution feeders where the load can be supported by the BESS during peak hours. |
| Outage Mitigation | A BESS that is "islanded" can support customer loads for a period of time when there is a loss of power. Locations with less reliable power supply could be augmented by a BESS to impact reliability metrics. |
| Integration with Renewables | A BESS can be used to store the excess energy from intermittent distribution generation and discharge it when the generation is insufficient. This can reduce variability and firm up renewable capacity, therefore enabling more penetration of renewables on the system. |
| Frequency Regulation | Batteries can provide frequency response in areas where there is a significant amount of integrated variable generation (renewables). The pairing of batteries with these sources mitigates distribution system frequency fluctuations resulting from unexpected cloud cover or variations in wind speed. |

## Demand response programs

We use demand response program to manage loads and stresses on the electrical system, reducing peak demand and saving our customers money in avoided capacity expenses. However, these programs do more than help solve capacity needs. They also provide rewards to customers who use energy more efficiently and provide economic benefits for Michigan. Peak demand reduction is reached with programs targeting residential and commercial and industrial customer classes.

Demand response resources that are registered with the Midcontinent Independent System Operator (MISO) can qualify as load modifying resources (LMRs) if they can reduce demand with no more than 12 hours advance notice and sustain reduction for a minimum of four consecutive hours. The resources must be capable of being interrupted at least the first five times during the summer season when directed by MISO to do so for emergency purposes. The capability to reduce demand to a targeted reduction level and measurement and verification (M&V) protocol must be documented and approved by MISO. Demand response programs curtail on-peak loads or shift load from peak periods to off-peak periods, either by controlling the load directly, such as with air conditioning (AC) cycling, or by motivating and incentivizing customers to take action to modify their load on their own.

## Residential

We launched an AC cycling pilot with 1,754 customers, enrolling 1.9645 MWs in 2016. We used a planning value of 1.12 kW per participant in this pilot, established by using an average of savings of 1.01 kW per participant in a 2010 pilot and a Stone & Webster engineering analysis of 1.25 kW per participant.

We also launched two time of use (TOU) pilots to a group of 37 employees, enrolling 0.0233 MWs in 2016. We used a planning value of 0.63 kW per participant in the program for 2016, established using a combination of results from the 2010 pilot savings of 15% or 0.33 kW per participant and other Brattle Group evaluations of similar programs that demonstrated impacts in the range of 10% - 50% per participant. We chose a middle ground, and used results from a ComEd pilot to determine the 23.5% or 0.63 kW per participant. The TOU pilots began open enrollment in 2017, providing customers with two additional pricing options that combine daily TOU rate structures with extra price incentive for customers to reduce consumption during summer hours of peak system demand.

With these options, we are shifting our marketing approach for residential demand response from individual programs to a portfolio approach, called Peak Power Savers®. The portfolio will offer customers these direct control and behavioral demand response pilots:

- AC Peak Cycling
- Critical Peak Time of Use
- Peak Rewards Time of Use

## Commercial and Industrial

Our commercial and industrial (C&I) demand response program provides a flexible energy resource that can reduce power supply costs for all customers. Each business customer that signs up for the program is contracted for a specified load reduction. We work with individual customers at their facility to set up an energy reduction plan that will be implemented when a demand response event is called. When customers in the portfolio initiate their plan, it reduces stress on the grid.

Over the next five years, we forecast $20 million of investment in our C&I Demand Response program, increasing our C&I demand response portfolio from 50 MW to 150 MW.

Demand response programs promote cost-effective green energy using Michigan resources, because they manage capacity without needing additional electricity generation or expensive capacity contracts.

## Forecasts

### *Customer Enrollments*

The following table shows the forecasted cumulative enrollment at year end from 2017-2021 for our residential and commercial and industrial demand response programs. The MW enrollment numbers represent delivery at the customer level. The last section of the table provides Zonal Resource Credits (ZRCs) expected to be awarded by MISO for the planning year specified. A new Grid Infrastructure (GI) contract was added in 2017 increasing the forecasted customer-level MWs at year end from 62MW to 112MW. The plan maximizes the available demand response based on the potential studies for our residential and commercial and industrial programs.

***TABLE 33 — 2017-2021 DEMAND RESPONSE ENROLLMENT FORECAST***

| 2017-2021 DEMAND RESPONSE ENROLLMENT FORECAST | | | | | |
|---|---|---|---|---|---|
| Cumulative Enrollment at Year End (Customers) | | | | | |
| Residential | | | | | |
| Tariff & Sheet No. | 2017 | 2018 | 2019 | 2020 | 2021 |
| DLM; Sheet No. D - 11.00 - 11.10 | 26,700 | 61,700 | 96,700 | 131,700 | 178,500 |
| RDP & RDPR; Sheet No. D - 11.10 - 11.30 | 28,560 | 87,703 | 145,251 | 201,610 | 228,569 |
| Commercial & Industrial | | | | | |
| Rate GDP, GI Provision | 18 | 18 | 18 | 18 | 18 |
| C&I Demand Response Program | 110 | 225 | 350 | 350 | 350 |
| Cumulative Enrollment at Year End (Customer-Level MW) | | | | | |
| Residential | | | | | |
| Tariff & Sheet No. | 2017 | 2018 | 2019 | 2020 | 2021 |
| DLM; Sheet No. D - 11.00 - 11.10 | 30 | 69 | 108 | 148 | 200 |
| RDP & RDPR; Sheet No. D - 11.10 - 11.30 | 18 | 55 | 92 | 127 | 144 |
| Commercial & Industrial | | | | | |
| Rate GDP, GI Provision | 112 | 112 | 112 | 112 | 112 |
| C&I Demand Response Program | 50 | 100 | 150 | 150 | 150 |
| MISO Zonal Resource Credits (ZRCs) for Planning Year | | | | | |
| Residential | | | | | |
| Tariff & Sheet No. | 2017 | 2018 | 2019 | 2020 | 2021 |
| DLM; Sheet No. D - 11.00 - 11.10 | 12 | 47 | 89 | 131 | 177 |
| RDP & RDPR; Sheet No. D - 11.10 - 11.30 | 7 | 32 | 70 | 107 | 137 |

| Commercial & Industrial | | | | | |
|---|---|---|---|---|---|
| Rate GDP, GI Provision | 127 | 126 | 126 | 126 | 126 |
| C&I Demand Response Program | 56 | 113 | 169 | 169 | 169 |

### *Financial Forecast*

The following table shows forecasted financial investments at year end from 2017-2021 for our residential and commercial and industrial demand response programs.

***TABLE 34 — 2017-2021 DEMAND RESPONSE FINANCIAL FORECAST***

| 2017-2021 DEMAND RESPONSE FINANCIAL FORECAST | | | | | |
|---|---|---|---|---|---|
| Annual O&M Budget Forecast | | | | | |
| | | | Residential | | |
| Tariff & Sheet No. | 2017 | 2018 | 2019 | 2020 | 2021 |
| DLM;<br>Sheet No. D - 11.00 - 11.10 | $2,444,609 | $3,129,807 | $3,136,191 | $3,140,575 | $3,218,885 |
| RDP & RDPR;<br>Sheet No. D - 11.10 - 11.30 | $2,360,609 | $3,191,807 | $3,137,191 | $2,911,575 | $2,170,846 |
| Commercial & Industrial | | | | | |
| GI Rate | $13,819 | $13,819 | $13,819 | $13,819 | $13,819 |
| C&I DR Program | $ 2,801,664 | $ 3,434,864 | $ 3,909,064 | $ 2,309,424 | $ 2,231,024 |
| Incentive Payments (PSCR) * | $1,300,000 | $2,800,000 | $4,500,000 | $4,650,000 | $4,650,000 |
| Total | $8,664,037 | $9,991,433 | $9,355,619 | $9,250,969 | $8,642,550 |
| Annual Capital Budget Forecast | | | | | |
| | | | Residential | | |
| Tariff & Sheet No. | 2017 | 2018 | 2019 | 2020 | 2021 |
| DLM;<br>Sheet No. D - 11.00 - 11.10 | $5,997,173 | $8,304,570 | $8,444,444 | $8,579,760 | $11,653,200 |
| RDP & RDPR;<br>Sheet No. D - 11.10 - 11.30 | $ - | $ - | $ - | $ - | $ - |
| Commercial & Industrial | | | | | |
| GI Rate | $ - | $ - | $ - | $ - | $ - |



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| | | | | | |
|---|---|---|---|---|---|
| C&I DR Program | $468,750 | $468,750 | $468,750 | $ - | $ - |
| Total | $6,623,173 | $8,930,570 | $9,070,444 | $8,579,760 | $11,653,200 |
| *This row assumes PSCR incentive payments will be recovered in Power Supply Costs Recovery (PSCR). The incentive payments assume $25/MWh for a 50MW program and $30/MWh for a 100 or 150MW program. | | | | | |

We will continue offering economic demand response programs to its customers. These offerings have increased since the last capacity self-assessment filing, and will continue with the deployment of advanced meter technology throughout the state. We will continue to use these resources to balance short-term deployment and scalability with long-term supply resource planning and reliability, all to the benefit of customers.

### Energy Efficiency Programs

Energy efficiency ("EE") programs focus on improving customers' overall energy usage by reducing energy waste, helping stabilize volatile energy prices and solidify energy security. It also helps customers save money, providing a boost for Michigan's economy. Since 2009, our EE programs have saved customers more than $1 billion on their energy bills, created or saved more than 5,700 Michigan jobs, added $1.8 billion in net economic growth to the Michigan economy, helped over 80,000 low income customers make their energy bills more affordable, and helped avoid over five million tons of carbon dioxide greenhouse gas emissions.

We offer a comprehensive portfolio of electric and natural gas EE programs and incentives to customers. In particular, we offer programs and incentives to residential customers who install more efficient lighting, appliances, insulation, air-conditioning, and windows. Similarly, we offer programs and incentives to business customers that improve production processes and reduce energy waste — such as agriculture initiatives, building operator certification, and smart buildings retro-commissioning. Over the next five years, we plan to continue investing in cost-effective energy efficiency programs to help its customers further reduce electric and gas energy waste.

## D.5 New Substation Builds and Upgrades Plan

The following areas are locations that have LVD substation projects underway or have future plans to address area load growth:

***TABLE 35 — NEW SUBSTATION BUILDS AND UPGRADES (2018-2022)***

| New Substation Builds and Upgrades (2018-2022) | | | | |
|---|---|---|---|---|
| Location / Area | Substation | Project Type | Why does it need to be built? | Target Completion |
| Battle Creek (city and greater area of) | Fort Custer | Capacity increase | Area load growth | 2017-2018 |
| | Fellowship | New Substation | Will be constructed when an actual overload occurs | 2020 |
| | Capital Avenue | New Substation | Will be constructed when an | 2020 |

| New Substation Builds and Upgrades (2018-2022) | | | | |
|---|---|---|---|---|
| Location / Area | Substation | Project Type | Why does it need to be built? | Target Completion |
| | | | actual overload occurs | |
| | Renton/Fort Custer II | Rebuild/New Substation | Industrial park and area load growth along I-94 corridor | 2021 |
| Grand Rapids (city and greater area of) | Forest Grove | New Substation | Jamestown Sub regulator overload, industrial customer load additions, area growth | 2018 |
| | Hawthorne | New Substation | Will be constructed when an actual overload occurs | 2019 |
| | Ironwood | New Substation | Will be constructed when an actual overload occurs | 2020 |
| | Lagrave | Replace TB1 with LTC TB | Lagrave Sub regulator overload | 2018 |
| | Peach Ridge | Rebuild Substation | Peach Ridge Sub overload | 2017-2018 |
| | Candlestone | New Substation | Will be constructed when an actual overload occurs | 2022 |
| | Egan | New Substation | Will be constructed when an actual overload occurs | 2020 |
| | Stevens | New TB2 | Will be constructed when an actual overload occurs | 2019 |
| | Harvey Street | Capacity Increase | Transformer overload due to alternate service/reserve capacity | 2019 |
| Kalamazoo (city and greater area of) | Kromdyke | New Substation | Customer load addition, area growth and airport runway expansion | 2018-2019 |
| | Ridgeview | New Substation | Galesburg Sub regulator overload, area load growth, reliability improvement | 2017 |
| | Pavilion | Capacity increase | Industrial customer load addition and area growth | 2017-2018 |
| | Oakwood | Upsize 1-6 Regulator | Additional capacity for load transfers for the MDOT bridge project | 2018 |
| Holly Area | Fish Lake | New general distribution Substation | New substation due to loading at Holly sub. | 2017 |
| Clio Area | Field Rd | New general distribution Substation | New substation due to loading at Clio sub. | 2017 |
| Fenton Area | Fausett | New general distribution Substation | New substation to improve reliability. | 2018-2020 |
| | Long Lake | Capacity Increase | Long Lake substation group | 2017-2018 |

| New Substation Builds and Upgrades (2018-2022) | | | | |
|---|---|---|---|---|
| Location / Area | Substation | Project Type | Why does it need to be built? | Target Completion |
| | | | regulator loading concerns. | |
| | Case Lake | New Substation | Will be constructed when an actual overload occurs or for reliability improvement | 2019 |
| Tittabawassee Township Area | Freeland | Expand existing sub or build a new general distribution sub | New substation due to load growth in the township. | 2018-2020 |
| Lincoln Area | Lincoln | Convert and expand Substation | Lincoln three-phase regulator loading issues and Reliability improvement for the area | 2018-2019 |
| Litchfield Area | Ash Road | New Substation | New substation due to customers expanding in the industrial park | 2018 |
| Lakeshore Area | Buchanan | New Substation | Ottawa Beach Sub regulator overload, reliability improvement | 2017-2018 |
| Whitehall | Benston | New Substation | Tanium Sub regulator overload, reliability improvement | 2017-2018 |
| Ludington | Washington | New TB2 | Washington Sub TB1 overload with distribution automation operation | 2018 |
| Au Sable Area | Rea Rd | New Substation | Reliability improvement | 2017 |
| | Monument | New Substation | Reliability improvement | 2018 |
| | Alcona Dam Distribution | New Substation | Reliability improvement | 2020 |
| | Five Channels Distribution | New Substation | Reliability improvement | 2021 |
| | Fairview Distribution | New Substation | Reliability improvement | 2022 |
| Grayling Area | Grayling | Rebuild Substation | Grayling sub group regulator loading | 2017 |
| | Beaver Creek Distribution | New Substation | Reliability improvement | 2019 |
| Newaygo | Butterfield | New Substation | Retire Newaygo Sub - end of life | 2018 |
| Kaleva | High Bridge | New Substation | Retire Kaleva Sub - end of life | 2018 |
| Boyne Area | Walloon | Rebuild Substation | Reliability improvement | 2018 |
| Traverse City (city and greater area of) | Chums Corner | New Substation | Will be constructed when an actual overload occurs | 2020 |
| | Devils Dive | New Substation | Will be constructed when an actual overload occurs or for reliability improvement | 2022 |

| New Substation Builds and Upgrades (2018-2022) | | | | |
|---|---|---|---|---|
| Location / Area | Substation | Project Type | Why does it need to be built? | Target Completion |
| Indian River Area | Haakwood | New Substation | Will be constructed when an actual overload occurs or for reliability improvement | 2019 |
| Cheboygan Area | Laperell | New Substation | Will be constructed when an actual overload occurs or for reliability improvement | 2019 |
| Hudsonville Area | Eagle | New Substation | Will be constructed when an actual overload occurs | 2020 |
| Arcadia Area | Jensen | New Substation | Will be constructed when an actual overload occurs or for reliability improvement | 2022 |
| Coopersville Area | Dennison | New Substation | Will be constructed when an actual overload occurs | 2019 |
| Gaylord | Dickerson | New Substation | Will be constructed when an actual overload occurs | 2019 |
| Moline Area | Huckleberry | New Substation | Will be constructed when an actual overload occurs | 2019 |
| Muskegon Area (city and greater area of) | Hunter | New Substation | Will be constructed when an actual overload occurs | 2019 |
| | Peterson | New Substation | Reliability improvement | 2019 |
| | Pontaluna | New Substation | Will be constructed when an actual overload occurs | 2020 |
| Hastings Area | Lower Lake | New Substation | Reliability improvement | 2021 |
| Lake City Area | Star City | New Substation | Reliability improvement | 2019 |
| McBain Area | Stoney Corners | New Substation | Will be constructed when an actual overload occurs | 2019 |
| Cedar Springs Area | Red Hawk | New Substation | Will be constructed when an actual overload occurs | 2022 |
| Stanton Area | Penny Lake | New Substation | Will be constructed when an actual overload occurs | 2022 |
| Breedsville Area | Violet | New Substation | Reliability improvement | 2019 |
| Grand Haven Area | West Olive | New Substation | Will be constructed when an actual overload occurs | 2022 |
| Kalkaska Area | Leetsville | New Substation | Will be constructed when an actual overload occurs | 2022 |
| Manistee | Channel | New Substation | Will be constructed when an actual overload occurs | 2022 |
| Central Lake | Central Lake | Capacity Increase | Will be constructed when an actual overload occurs | 2019 |
| Lakeview | Tamarack | Rebuild & Convert Substation | Will be constructed when an actual overload occurs | 2019 |

| New Substation Builds and Upgrades (2018-2022) | | | | |
|---|---|---|---|---|
| Location / Area | Substation | Project Type | Why does it need to be built? | Target Completion |
| Rogers City | Port Calcite | Capacity Increase | Will be constructed when an actual overload occurs or obsolete regulator fails | 2019 |
| Kingsley | Paradise | New Substation | Will be constructed when an actual overload occurs | 2022 |
| Allendale | Pearline | New TB2 | Will be constructed when an actual overload occurs | 2021 |
| Holt | Sycamore Creek | New substation | Will be constructed when an overload occurs | 2020 |
| Gladwin | Buckeye | New substation | Will be constructed when an overload occurs | 2021 |
| Lambertville | Douglas | New substation | Will be constructed when an overload occurs | 2021 |
| Tawas | East Tawas | New TB2 | Will be constructed when an overload occurs | 2019 |
| Mt Pleasant Area | Gilmore | New substation | Will be constructed when an overload occurs | 2020 |
| Breckenridge Area | Edgewood | Capacity Increase | Will be constructed when an overload occurs or for reliability improvement | 2020 |
| Riverdale | Riverdale | Capacity Increase | Will be constructed when an overload occurs or for reliability improvement | 2019 |
| Frontier area | Frontier | Capacity Increase | Reliability improvement | 2018 |
| | Cross Lake | New Substation | Reliability improvement | 2022 |
| Deerfield | Deerfield | Capacity Increase | Deerfield TB1 overload due to Customer Expansion | 2018 |
| Birch Run Area | Dehmel | New Substation | Will be constructed when an overload occurs or for reliability improvement | 2021 |

# APPENDIX — MAINTAIN

## E.1 Detailed investment list

***TABLE 36 — MAINTAIN — CAPITAL INVESTMENT SUMMARY (2016-22)***

| Capital Investment Summary (2016-22, $K) | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| All Investments | 2016 Actuals | 2017 YTD (June) | 2018 Plan | 2019 Plan | 2020 Plan | 2021 Plan | 2022 Plan | Five Year Total |
| ***Reliability*** | | | | | | | | |
| Lines Reliability - LVD | 48,617 | 20,166 | | | | | | |
| Lines Reliability - HVD | 37,825 | 10,330 | | | | | | |
| Substations Reliability - LVD | 11,135 | 7,732 | | | | | | |
| Repetitive Outages - LVD | 8,353 | 3,486 | | | | | | |
| Substations Reliability - HVD | 3,850 | 1,993 | | | | | | |
| Metro Reliability | 2,518 | 77 | | | | | | |
| System Protection | 1,569 | 1,733 | | | | | | |
| ***Demand Failures*** | | | | | | | | |
| Lines Failures - LVD | 66,860 | 48,745 | | | | | | |
| Transformers Failures - LVD | 14,754 | 8,630 | | | | | | |
| Lines & Subs Failures - HVD | 13,206 | 7,562 | | | | | | |
| Substations Failures - LVD | 9,399 | 6,705 | | | | | | |
| Metering Failures - LVD | 7,272 | 9,158 | | | | | | |
| Metro Failures | 5,047 | 1,089 | *Estimates for 2018-22 will be included in the final report* | | | | | |
| ***Cost of Removal*** | | | | | | | | |
| Cost of Removal - LVD | 33,427 | 25,358 | | | | | | |
| Cost of Removal - HVD | 8,191 | 10,703 | | | | | | |
| ***Asset Relocations*** | | | | | | | | |
| Lines Relocations - LVD | 14,362 | 9,169 | | | | | | |
| Metro Relocations | 4,854 | 2,584 | | | | | | |
| Lines Relocations - HVD | 288 | 51 | | | | | | |
| ***Technology*** | | | | | | | | |
| Tools | 3,377 | 636 | | | | | | |
| Computer & Equipment | 76 | 298 | | | | | | |
| Substation Fall Protection | 80 | 6 | | | | | | |
| ***Other*** | | | | | | | | |
| Streetlight-Mercury Vapor / LED | 2,193 | 1,258 | | | | | | |

| | | | |
|---|---|---|---|
| ***Total*** | 297,254 | 177,470 | |

***TABLE 37 — MAINTAIN — O&M EXPENSE SUMMARY (2016-22)***

| O&M Expense Summary (2016-22, $K) | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| All Investments | 2016 Actuals | 2017 YTD (June) | 2018 Plan | 2019 Plan | 2020 Plan | 2021 Plan | 2022 Plan | Five Year Total |
| ***Reliability*** | | | *Estimates for 2018-22 will be included in the final report* | | | | | |
| Forestry | 50,782 | 26,288 | | | | | | |
| Substations Reliability - LVD | 1,794 | 872 | | | | | | |
| Substations Reliability - HVD | 957 | 627 | | | | | | |
| Lines Reliability - LVD | 56 | 5 | | | | | | |
| Lines Reliability - HVD | 317 | 37 | | | | | | |
| ***Repair and Restoration*** | | | | | | | | |
| Service Restoration | 35,504 | 30,632 | | | | | | |
| Staking / Street / Service Calls | 7,262 | 3,605 | | | | | | |
| Corrective Maintenance | 3,483 | 2,476 | | | | | | |
| Substations Demand - LVD | 3,321 | 1,465 | | | | | | |
| Substations Demand - HVD | 2,150 | 1,198 | | | | | | |
| Alma Equipment Repair | 1,136 | 526 | | | | | | |
| Lines Demand — HVD | 533 | 354 | | | | | | |
| ***Field Operations*** | | | | | | | | |
| Supervision / Admin-Staff | 6,063 | 3,475 | | | | | | |
| Training | 4,174 | 3,209 | | | | | | |
| Facilities Building Opers & Maint | 4,198 | 2,050 | | | | | | |
| Field Operations Expenses | 2,360 | 1,446 | | | | | | |
| Tools | 1,811 | 939 | | | | | | |
| ***Meter Services*** | | | | | | | | |
| Meter Services | 2,992 | -847 | | | | | | |
| Meter Reading | 11,582 | 3,484 | | | | | | |
| ***Other O&M*** | | | | | | | | |
| O&M Assoc w/Construction | 7,228 | 3,685 | | | | | | |
| DCO Accruals | 5,801 | 2,653 | | | | | | |
| Joint Pole Rental | 1,789 | 903 | | | | | | |
| Transformer Credits | -6,134 | -3,041 | | | | | | |
| ***Total*** | 149,159 | 86,042 | | | | | | |



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# E.2 Annual replacement spend for each asset class & average per unit

***TABLE 38 — ANNUAL REPLACEMENT SPEND & AVERAGE COST PER ASSET***

| Annual Replacement Spend & Average Cost Per Asset ($K) | | | |
|---|---|---|---|
| Asset Class | Asset | Annual Replacement Spend (5yr Average) | Average Replacement Cost Per Asset |
| LVD Lines | | $145,500 | |
| | Underground Conductor | - | $194 / mile |
| | Overhead Conductor | - | $37 / mile |
| | Pole | - | $3.5 |
| | Cross Arm | - | $1.5 |
| | Cutout, Arrestor, Insulator | - | $0.8 |
| HVD Lines | - | $38,400 | - |
| | Line Rebuilds | | $300 / mile |
| | Pole | | $12.0 |
| | Cross Arm | | $3.5 |
| | Cutout, Arrestor, Insulator | | $2.0 |
| LVD Subs | - | $30,800 | - |
| | Full Animal Mitigation | | $60 / site |
| | Polycarbonate | | $20 / site |
| HVD Subs | - | $17,200 | - |
| | Switch | | $50 |
| | Bushing | | $115 |
| | Breaker | | $100 |
| | Station Potential Transformers | | $15 |

# E.3 Reliability Planning Process and Timing

## Holistic Approach

Starting in 2016, we improved collaboration across our operations, LVD, HVD and forestry groups to improve circuits holistically, aiming to make all improvements, such as all line upgrades and forestry clearing, in the same timeframe to prevent having to address the same circuit multiple times. For example, the year-end SAIDI for Ranger Lake substation Goodar circuit in 2015 was 0.32. In 2016, when work was done, it had a year end SAIDI of 0.26, a 19% improvement. After the work was completed, in 2017 the SAIDI is 0.06, an 82% improvement.

## Prioritization

We evaluate reliability projects based on estimated avoidance of outage minutes for the customers impacted by the project. Projects are prioritized using cost-benefit ratio analysis, input by engineers and program managers based on their experience and knowledge of the system, availability and location of resources, and funding. We then use the Reliability Analytics Engine ("RAE") to aggregate and analyze large amounts of outage data. The RAE provides prioritization methodologies to improve specific targeted funding in areas that affect reliability the most. It also produces a bi-weekly repetitive outage report, which system engineers review. Based on predefined criteria, potential actions are evaluated to prevent the next outage, such as pole-top maintenance, sectionalizing, system upgrades like addressing aerial spacer cables, replacing conductors, and localized tree clearing.

## Timing

The planning process occurs in the current year for the following year construction, closer to construction time, so that timely data is available. Planning too far in advance can result in using stale data, potentially limiting benefits to customers. Proactive reliability projects that are identified too far in advance might be addressed by system improvements completed using other capital or O&M programs (e.g. Demand Failures) in the interim.

## Electric Reliability Rally Room

We use out electric reliability rally room to monitor the progress and SAIDI benefit of projects. Many reliability initiatives and actions span many of our departments. The rally room provides a collaboration area for a core team to coordinate efforts and identify any barriers. This process incorporates lessons from daily and weekly operating reviews, providing frequent checkpoints and flexibility.

We use Lean tools to transform problem definition, target setting, measuring progress, and developing corrective actions. We base decisions on visual displays of key performance data. Visual management allows quick action on countermeasures and promotes accountability while facilitating cross-functional communication and honest discussion.

# E.4 Pole Inspection and Replacement Programs

## HVD and LVD Pole Inspection Program

We started our pole inspection program in 2010, planning to use a 12-year cycle using our own employees. We expanded the program to all pole configurations using trained contractors starting in August 2011. This program continued in 2015, using trained contractors and moving towards a 12-year inspection cycle for both LVD and HVD poles.

As part of the inspection program, we evaluate the results of both LVD and HVD pole inspections to determine if a pole replacement is required, with further evaluation to determine if an entire pole line should be replaced and potentially relocated to improve reliability.

The table below details the type and number of inspections completed on both LVD and HVD poles and lines.

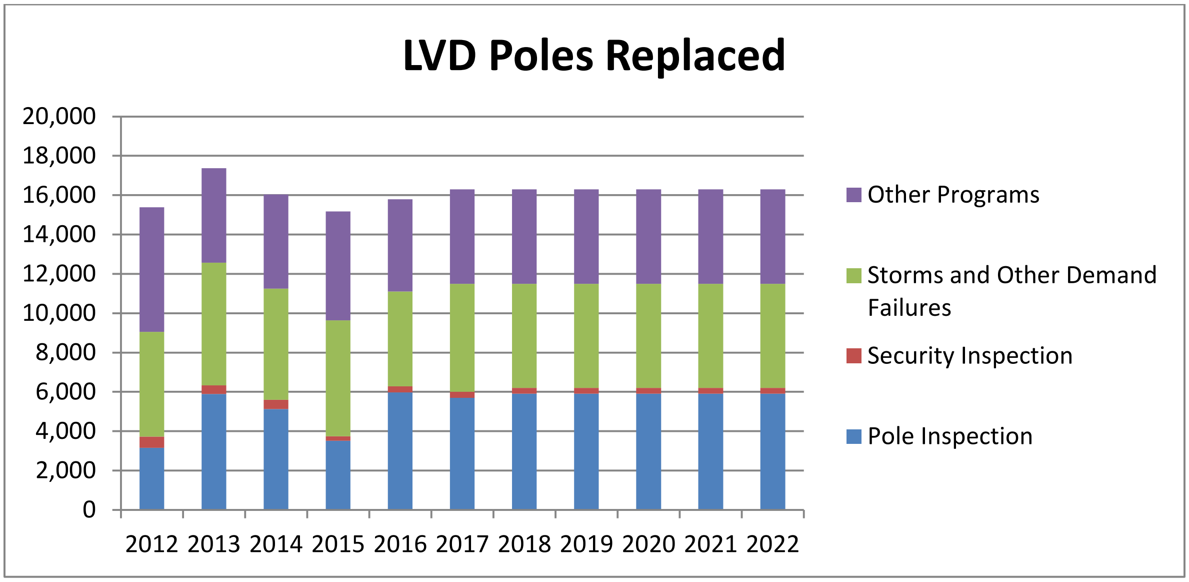
*TABLE 39 — HVD AND LVD POLE INSPECTIONS*

| HVD and LVD Pole Inspections | | | | | |
|---|---|---|---|---|---|
| Inspection Type | Year | Number of Poles Inspected | Number of Poles Identified for Replacement | Number of Poles Replaced[1] | Number of Poles Treated |
| HVD Pole Inspections[1] | 2012 | 8,580 | 1,282 | 321 | 1,043 |
| | 2013 | 552 | 74 | 967 | 60 |
| | 2014 | 11,704 | 2219 | 788 | 905 |
| | 2015 | 932 | 78 | 888 | 67 |
| | 2016 | 7,675 | 915 | 1,217 | 823 |
| LVD Pole Inspections | 2012 | 34,792 | N/A | 3,158 | N/A |
| | 2013 | 129,805 | 8,523 | 5,896 | N/A |
| | 2014 | 83,753 | 5,814 | 5,130 | N/A |
| | 2015 | 66,407 | 8,090 | 3,518 | N/A |
| | 2016 | 0 | 0 | 5,969 | N/A |
| LVD Overhead Line Inspections[2] | 2012 | 245,000 | N/A | 574 | N/A |
| | 2013 | 233,600 | N/A | 429 | N/A |
| | 2014 | 228,900 | N/A | 470 | N/A |
| | 2015 | 159,420 | N/A | 224 | N/A |
| | 2016 | 187,260 | N/A | 312 | N/A |
| Total | 2012 | 288,372 | N/A | 4,053 | 1,043 |
| | 2013 | 363,858 | 8,597 | 7,292 | 60 |
| | 2014 | 324,357 | 8,033 | 6,388 | 905 |
| | 2015 | 226,759 | 8,168 | 4,630 | 67 |
| | 2016 | 194,935 | 915 | 7,498 | 823 |

[1] Only includes poles replaced due to pole inspection.
[2] Estimate of LVD poles inspected are based on average number of poles per mile for urban and rural circuits.

The average rejection rate for LVD poles that are inspected under the pole inspection program is 9%. Below is a table that represents the number of poles that have been replaced due to pole inspection and other programs.

***FIGURE 36 — LVD POLES REPLACED***




### Testing Criteria

We provide our contractors with pole evaluation guidelines. Poles are tested from the ground line to six feet above ground line. A bore test is done if the initial pole test indicates signs of decay, there is visual decay present, insects appear to be in the pole, the pole has been backfilled or is discolored, or to determine the condition of a pole that was previously reinforced. The bore test is done at the weakest point. Shell thickness determines whether or not a pole needs replacement. If a pole does need replacement, we categorize the need as "immediate" or as "a planned future replacement" and mark the pole with a red tag.

## Replacement Programs

We are making investments to prevent or reduce the duration of outages due to deteriorated equipment. Investments are divided into the following categories.

### LVD Replacement Program

#### *General*

We will direct investment in LVD lines primarily at underperforming distribution circuits. System improvement work will include: (1) lightning protection; (2) equipment replacements and upgrades, such as poles, cross-arms, switches and conductor; and (3) line segmentation to minimize the number of customers impacted during an outage.

#### *Poles*

We do not keep installation date records of LVD poles, But the average failure rate of LVD poles is 3% per year. Each interruption contributes 0.01 SAIDI minutes (excluding MEDs) per LVD pole failure. By increasing the failed pole replacement rate, we will reduce future SAIDI impact (including MEDs). So far, we have prevented an average of 45 SAIDI minutes annually through the pole replacement.

We will increase pole replacements to an annual average of 8,000 poles per year by 2019. This will cost approximately $28 million dollars annually.

### HVD Replacement Program

#### *General*

We will direct investment in HVD lines at: (1) complete overhead line rebuilds including conductor and structure replacements on the worst performing line sections; (2) pole-top rehabilitation, which includes replacing deteriorated cross-arms, lightning arrestors, switches, and insulators; (3) deteriorated underground lines replacement; and (4) installation of motor operated air break devices to again minimize customer outages and outage duration.

#### *Poles*

We have been replacing approximately 1,200 HVD poles per year, combining those replaced per the pole inspection program, those replaced during line rebuild projects, and demand failures. This equates to an approximately 60 year replacement rate, which would be adequate for a uniform distribution of pole ages with an expected life of 60 years. However, over 31% of HVD poles are presently past the 60 year expected life, meaning we will need to replace 2,200 HVD poles per year (1,000 more in addition to the present 1,200 per year) for the next 20 years to have no HVD poles greater than 60 years old at the end of 20 years.

Estimated cost for proactive replacement is $10,000/pole (including pole top) or $3,500/pole top only. Estimated cost for reactive replacement is $14,000/pole (including pole top) or $5,000/pole top (only). At 17 HVD poles per mile, proactively replacing one mile of HVD poles costs approximately $170,000.

# E.5 Line Inspection and Replacement Programs

## LVD Line

The LVD overhead line inspection program is completed on a six-year cycle, evaluating all equipment on a structure through a visual inspection process. The circuits are assessed with driving inspections to identify public safety hazards and failed, end of life, defective, and obsolete equipment. The following construction prioritization criteria are used and addressed in the timeline described:

- “Priority 2” imminent failures are repaired/replaced within 5 business days;
- “Priority 1, 3 and 4” anomalies are typically repaired/replaced within 2 years of the inspection year.

### Items Identified during LVD Assessments

The following table provides the types of hazards found during LVD system assessments. The hazards are listed by the priority code for the anomaly.

***TABLE 40 — LVD SYSTEM ASSESSMENT HAZARDS***

| LVD System Assessment Hazards | |
|---|---|
| Code | Description |
| P1 - Public Safety | |
| P1A | Safety Code Violation |
| P1B | Unusual Public Hazard |
| P2 - Imminent Failure | |
| P2A | Floating Phase / Neutral |
| P2B | Broken / Severely Cracked Crossarm |
| P2C | Damaged / Cracked Cutout |
| P2D | Damaged / Cracked Insulators |
| P2E | Pole: Needing immediate Replacement |
| P3 - Failure Expected Before Next Inspection (Less Than 6yrs) | |
| P3A | Pin Pulling from Crossarm / Pole |
| P3B | Cracked Crossarm |
| P3C | Broken Guy - Leaning Pole |
| P3D | Pole: Damaged |
| P4 - Heightened Risk of Failure | |
| P4A | Broken/Missing Crossarm Braces |
| P4B | Failed Arrester |
| P4C | Broken Guy - Non-Leaning Pole |
| P4D | Damaged Equipment (Transformers, Reclosers, Etc.) |
| P4E | Lightning/Flashover Burn Marks |
| P4F | Poorly Sagged Line |
| P4G | Pin Through Crossarm |
| P5 - Out of Standard | |
| P5A | Short Crossarm |
| P5B | Brown Arresters |
| P5C | Non-Standard Insulators (14.4 kV Only) |
| P5D | Missing Guy Guards |

## HVD Lines

Periodic inspection of equipment helps determine if assets are in need of repair or replacement ensures components will operate as intended when called upon, and maximizes the value of those assets over their lifetimes. Equipment near the end of life can be replaced before it fails. Such inspections and replacements are more economical, safer and can save customer outage minutes. Maintenance on certain components is mandated by NERC compliance standards.

## HVD Line Equipment

Below is a Pareto chart of HVD line equipment failures that have resulted in SAIDI minutes over the past five years and table listing the HVD line equipment, number installed, average age, expected life, and percent past the expected life.

***FIGURE 37 — HVD LINES — EQUIPMENT SAIDI CAUSES***

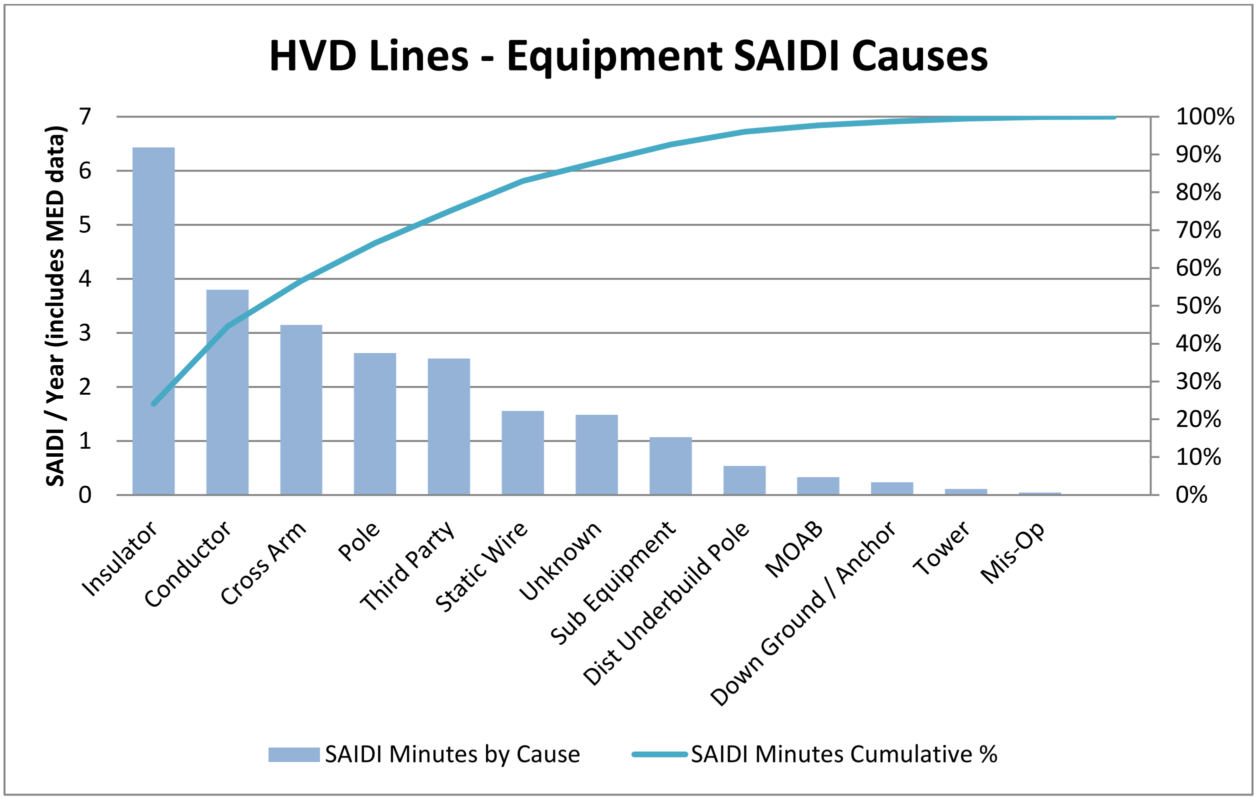


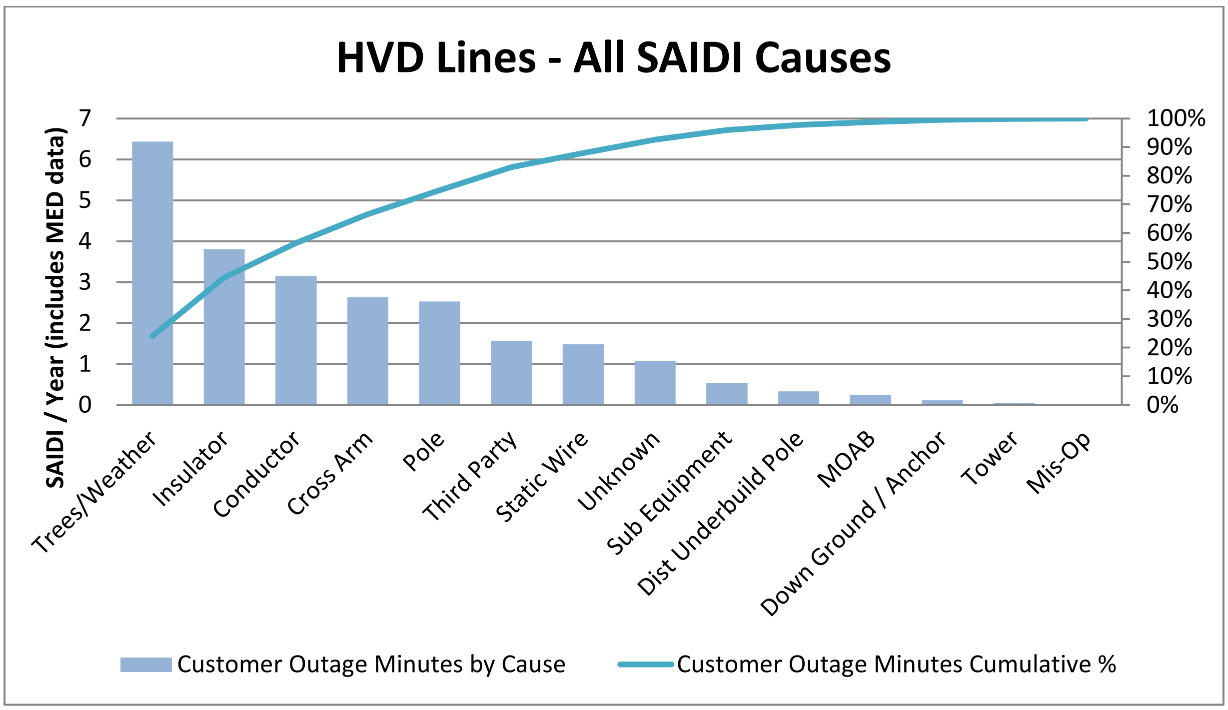

***TABLE 41 — HVD LINES EQUIPMENT***

| HVD Lines Equipment | | | | | |
|---|---|---|---|---|---|
| Cause | Average # of Failures Per Year | Average # of Failures Causing a Customer Outage Per Year | Average SAIDI Minutes Per Year | % of HVD Lines SAIDI Minutes | SAIDI Minutes Cumulative % |
| Insulator | 36 | 20 | 6.4 | 26.9% | 26.9% |
| Conductor | 18 | 10 | 3.8 | 15.9% | 42.8% |
| Cross Arm | 30 | 10 | 3.1 | 13.2% | 56.0% |
| Pole | 23 | 9 | 2.6 | 11.0% | 66.9% |

| | | | | | |
|---|---|---|---|---|---|
| Third Party | 20 | 9 | 2.5 | 10.6% | 77.5% |
| Static Wire | 7 | 5 | 1.6 | 6.5% | 84.0% |
| Unknown | 11 | 6 | 1.5 | 6.2% | 90.2% |
| Sub Equipment | 11 | 5 | 1.1 | 4.5% | 94.7% |
| Dist Underbuild Pole | 3 | 1 | 0.5 | 2.2% | 96.9% |
| MOAB | 2 | 1 | 0.3 | 1.4% | 98.3% |
| Down Ground / Anchor | 2 | 1 | 0.2 | 1.0% | 99.3% |
| Tower | 1 | 1 | 0.1 | 0.5% | 99.8% |
| Mis-Op | 1 | 1 | 0.0 | 0.2% | 100.0% |

In addition to equipment issues, weather and trees have caused an average of over 7 SAIDI minutes per year over the last 5 years.

***FIGURE 38 — HVD LINES SAIDI CAUSES***




## Helicopter Inspection Program

### *Consumers Energy Helicopter Electric Operations Overview*

We have approximately 4,400 miles of 46kV lines and 400 miles of 138kV lines we currently fly one or two patrols of the HVD system per year. The cost of each helicopter patrol, covering the helicopter itself, a pilot, and an observer, is approximately $350,000.

We estimate that seven million customer minutes are saved with each helicopter patrol, equivalent to 3.87 SAIDI minutes. A complete patrol requires about 45 flying days.

We contract with Bijan Air in Ann Arbor, Michigan, for these patrols. We conduct two types of helicopter patrols: 1) visual inspections and 2) visual inspections with the infrared or corona camera.

***TABLE 42 — HELICOPTER PATROL INSPECTION TYPES***

| Helicopter Patrol Inspection Types | | |
|---|---|---|
| Type of Patrol | Crew | Priority |
| Visual Inspection | Two or three person crew<br>• Pilot<br>• Observer (must be Union member)*<br>• Trainer if observer is not fully trained | Look for anomalies<br>• Deterioration of/damage to wood pole, cross arms and braces<br>• Damage to insulators<br>• Damaged or floating conductors<br>• Forestry concerns (primarily danger trees)<br>• Damage on LVD underbuild<br>• Damaged/missing/slack guy wires<br>• Third party concerns (deer stands, construction in right of way, etc.)<br>• Blown arresters<br>• Evidence of tracking |
| Visual Inspections w/Infrared or Corona | Three person crew<br>• Pilot<br>• Fully trained observer<br>• Technician to run corona and/or infrared camera** | Monitoring equipment detects hot spots on lines |
| *Current Observer contracted through Michels Power<br>**Trained internal Consumers Energy employee | | |

The corona/infrared camera is mounted to the underside of the helicopter. The output of the camera is monitored by a technician onboard the helicopter. Infrared inspection detects hot spots on the lines. These are typically splices and switches. Hot spots usually indicate a degraded or corroded condition that will likely result in failure.

Corona inspections detect cracked insulators. We are rolling out this brand new technology to proactively identify cracking in Victor-type pin insulators of 1970s-1990s vintage that are prone to failure. Results of the corona inspections so far have been mixed. We are working to evaluate when inspections are most effective.



**Draft Only and Subject to Major Revisions. Final Report Due January 31, 2017**

***TABLE 43 — HVD SYSTEM PATROL FINDINGS CRITERIA***

| HVD System Patrol Findings Criteria | | |
|---|---|---|
| Priority | Description | Repair Timeline |
| 1* | Imminent Failure | 24 hours |
| 2* | | 5 to 10 days |
| 3* | | 4-6 months |
| 4 | | Repair not required but condition tracked |
| *SAP repair orders are created for all Priority 1, 2 and 3 findings only | | |

In 2016, Consumers identified the following:

- 5 Priority 1 anomalies
- 38 Priority 2 anomalies
- 231 Priority 3 anomalies
- 8 Priority 4 anomalies
- 258 forestry issues

## Biannual Ground Patrol

Approximately 400 miles of the system is unsafe to fly over because it is difficult to land quickly and safely in the event of an emergency. Most of these “no fly-lines” are in urban areas. To inspect these lines, biannual ground patrol is completed and may include infrared and/or corona inspection.

## Annual Testing

Motor operated air break switches (MOABs) allow us to sectionalize HVD lines and restore a portion of the customers who would otherwise be affected by a line outage. The controls of the MOABs require power to operate and since they are called on to operate when power to the line they are attached to is lost, batteries provide control circuit power. Periodic battery replacement ensures that power is always available to operate the device. MOABs are tested annually to ensure they are in proper working order and the batteries are replaced every three years, or sooner, as needed.

## HVD Line Rebuild

Approximately 1,100 miles (24%) of our HVD wood pole lines are either unshielded or utilize otherwise non-standard conductors such as #2-7s ACSR or copper conductors that have been obsolete for over 60 years. There lines are common candidates for rebuilding. If one of these lines has many poles that need to be replaced, it would also be candidate for rebuilding, as opposed to simply replacing the poles. Rebuilding an HVD line costs approximately $250,000 - $400,000 per mile, depending on the area, forestry, and on the associated right of way needs.

Over the last five years we have rebuilt an average of 23 miles, or 2.1% of the total, of HVD line per year. Rebuilding 110 miles (10% of 1,100) per year would replace all of these lines within 10 years and would cost an estimated additional $28 million per year, but would reduce yearly SAIDI by approximately 12 minutes or more. An average of 24 SAIDI minutes (non-MED) per year is attributed to HVD lines.

### HVD Pole Top Rehabilitation

Poor performing lines with standard shielded construction are likely candidates for pole top rehabilitation, replacing cross-arms and insulators. This would include a pole inspection of the line and replacement of any deteriorated poles. Rehabilitating an HVD line costs approximately $100,000 per mile, depending on the number of rejected poles, the area, forestry, and the pole rejection rate.

## Towers

We not have a program to replace aging towers. The average tower age is 82 years, and 43% of towers are past the 90-year expected life.

## Underground (UG) Cable

We do not have a program to replace aging UG cable. The average cable age per mile is 23 years, and 6% of UG cable is past the 30-year expected life.

## Insulators

We do not have a program to replace aging line insulators, other than as replaced on poor performing lines through rebuilding or pole top rehabilitation. However, beginning in 2017, we began using corona camera technology combined with helicopter inspection of the HVD lines to identify insulators that are in the pre-failure stage, so we can replace these prior to an outage occurring.

## “Run Until Fail” Equipment

### LVD

We do not participate in an active inspection process on reclosers, transformers, regulators, capacitors, internal switchgear, or primary meter equipment, due to high cost and cumbersome nature. Inspecting this equipment would require qualified electrical line workers to remove equipment from service and send it to a certified lab for testing. As a result, the equipment would have to be replaced while the original equipment was out for testing.

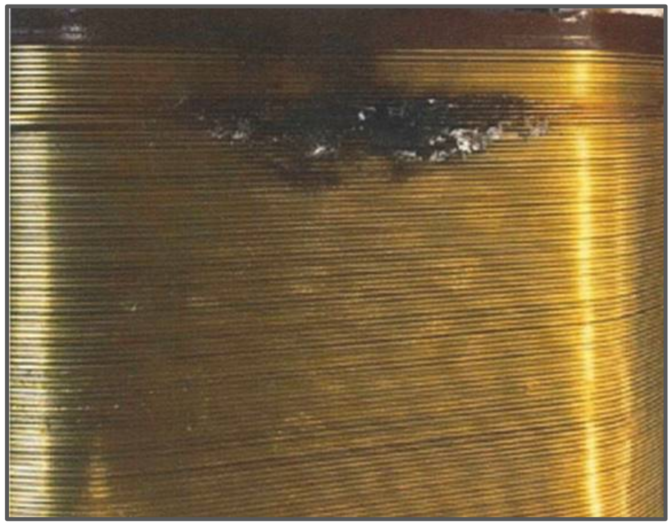
### HVD

We do not replace HVD lines and equipment simply due to age. Unless an operational problem or an inherent failure mode is identified for a particular manufacturer or vintage of HVD conductor or equipment, we do not have a systematic program to replace aging lines, cross arms, insulators, or other pole top equipment, other than as associated with the pole replacement program. HVD lines equipment is inspected from time to time when we perform system wide helicopter flyover inspections (walking inspection for no-fly zones) to identify failing equipment that can be identified visually, using infrared camera technology, or in the future using corona camera technology. Equipment identified as imminently failing is repaired or replaced.

## Proactive Line Equipment Replacement

Data management systems, paired with technical analytics can transform increasing amounts of raw data into useful information, providing operational visibility. Figure 1 shows an internally faulted distribution line transformer that was proactively replaced based on AMI data, even though the transformer was still serving load without customer complaint. Condition based maintenance will actively monitor the health of devices and target maintenance to control costs while extending equipment life.

***FIGURE 39 — INTERNALLY FAULTED DISTRIBUTION LINE TRANSFORMER***



This effort includes a transformer lifecycle data from AMI voltage and other sources to proactively replace transformers. In 2015, we had over 5,350,000 customer outage minutes attributed to distribution transformers. Of those, nearly two million minutes related to equipment failure alone, affecting over 6,500 customers. Currently, we do not have a method to detect failed or failing distribution transformers outside of outage reporting, but with installation of smart meters, can use meter data to detect failing or malfunctioning devices and coordinate the replacement of the transformer.

# E.6 Tree Trimming Program

## Clearing Benefits

### LVD

Clearing trees benefits customers by reducing outages and decreasing the amount and degree of damage from catastrophic storms. Clearing the rights of way allows easier access to lines, resulting in faster restoration when an outage occurs. For the three major distribution voltages used on our LVD system, the benefit of clearing is demonstrated in the graphs below.

***FIGURE 40 — SYSTEM SAIFI IMPROVEMENT POST CLEARING***

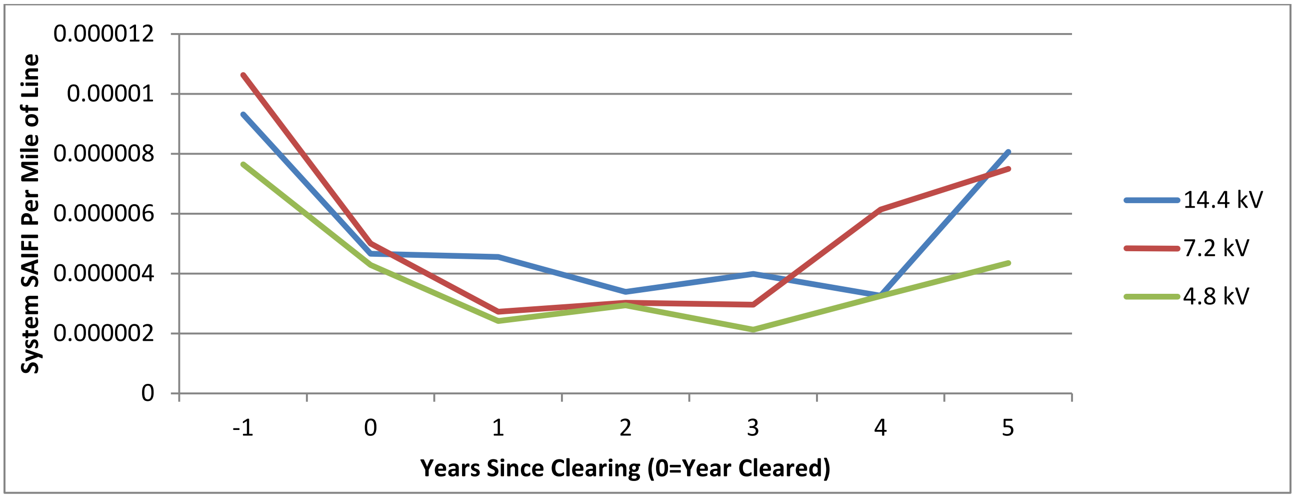
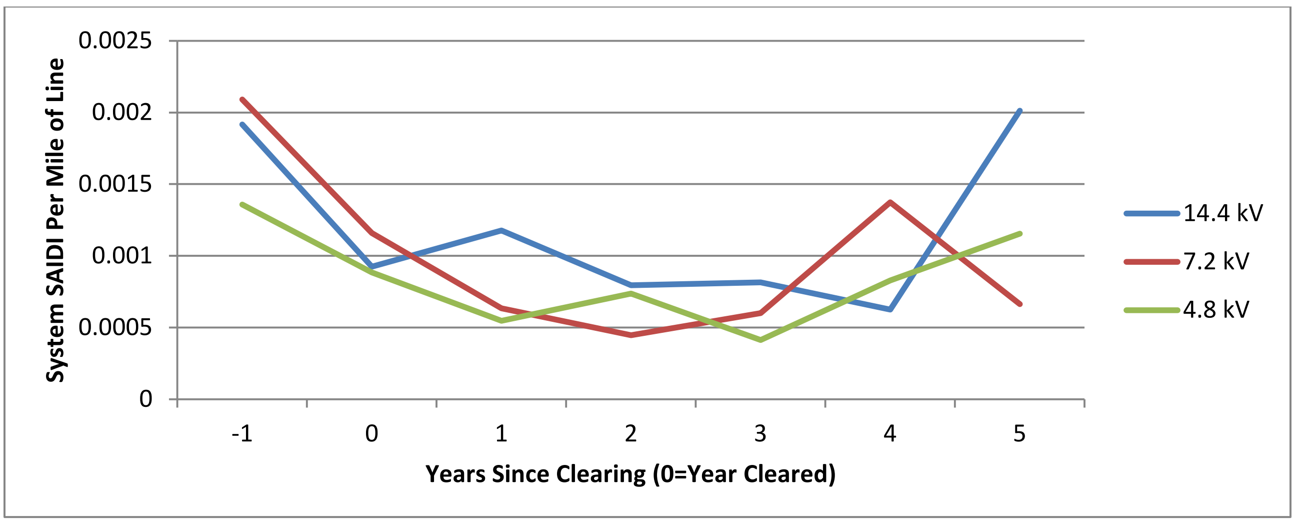



***FIGURE 41 — SYSTEM SAIDI IMPROVEMENT POST CLEARING***




## HVD

HVD system tree trimming reliability benefits are difficult to quantify due to the infrequency of tree related outages occurring on this system, with an average of only 15 annual outages on the HVD system due to trees. Most HVD tree-related outages occur from trees growing outside of the normally cleared right of way area. When an outage occurs it most often impacts several substations with multiple LVD circuits at each substation. An outage to a HVD line impacts many more customers than a typical LVD outage, so clearing widths are wider, trimming clearances are greater and clearing cycles are shorter. During high load periods, or when maintenance has temporarily removed a section of the HVD system from service, an outage on an HVD line can have localized cascading potential.

## Scope of Work and Costs

### LVD

#### *Full Circuit Clearing*

We are seeking to move our clearing cycle to a seven-year effective cycle, accounting for the three main LVD voltage groups. While individual circuits may be scheduled for clearing earlier or later than shown in the table below, it provides average miles of each voltage class that would be cleared each year under a seven year program. We are currently clearing on a cycle that exceeds ten years.

*TABLE 44 — LVD CLEARING SCHEDULE*

| LVD Clearing Schedule | | | | | |
|---|---|---|---|---|---|
| Voltage Group | System Miles | 14% Clearing Program | Effective Cycle (Years) | 10% Clearing Program | Effective Cycle (Years) |
| 11.0-14.4 kV | 16,100 | 3,200 | 5 | 2,680 | 6 |
| 7.2 kV | 9,300 | 1,325 | 7 | 1,030 | 9 |
| 2.4-4.8 kV | 30,600 | 3,455 | 9 | 1,890 | 16 |

It costs approximately $10,000 per mile, including hazard tree removal program costs, for full circuit clearing.

This is higher than our historical line clearing costs for several reasons. First, there is a shortage of skilled labor, including qualified tree trimmers, requiring the use of more expensive out-of-state crews on a temporary basis. Second, environmental requirements like the use of wetland mats, time of year restrictions on work, and other issues have added costs. Finally, in 2016 we began removing hazardous trees outside of LVD rights of way due to the mortality of ash trees from the emerald ash borer (EAB), accounting for an approximate 10% increase in the per mile cost.

We expect that as cycle time decreases from current levels to a stable seven-year effective cycle, the line clearing cost per mile will also decrease, as density of trees on the system is reduced.

#### *Partial Circuit Clearing*

We also perform several clearing programs not focused on clearing full circuits, clearing trees at customer requests, clearing sections of circuits to reduce repetitive outages, and clearing first zone three-phase sections when outage data indicates excessive outages are occurring in this zone.

### HVD

#### *Full Circuit Clearing*

The HVD system is on an approximate four year scheduled clearing cycle. Consumers Energy plans to maintain this level of clearing for the HVD system into the foreseeable future.

***TABLE 45 — HVD CLEARING SCHEDULE***

| HVD Clearing Schedule | | |
|---|---|---|
| Voltage | System Miles | 25% Clearing Program |
| 23kV | 35 | 9 |
| 46kV | 4,780 | 1,195 |
| 138kV | 168 | 42 |
| **Total** | **4,983** | **1,246** |

YTD 2017, HVD full circuit clearing cost is approximately $11,700 per mile.

EAB-killed trees along the HVD system have increased full circuit clearing costs. We believe HVD per mile clearing costs will decline over time as hazardous EAB trees are removed.

### *Partial Circuit Clearing*

Besides clearing on a scheduled four-year cycle, we inspect lines for vegetation conditions one year prior to being cleared. This permits us to address fast growing trees that are encroaching on conductors before full clearing takes place. Aerial inspection of HVD lines also records and reports questionable tree conditions. These inspections occur approximately once per year and capture changing tree conditions such as leaning or uprooting trees.

## Specifications

Clearing specifications fall into two categories:

- Specimen trees in maintained landscapes.
- Trees or brush growing in unmaintained landscape areas, or non-specimen trees in maintained landscapes.

Specimen trees are planted trees or naturally seeded trees that have been actively maintained in a landscape area, such as lawns, city streets, or developed areas of parks such a picnic areas and sports fields. Specimen trees are generally trimmed to remove branches and attain sufficient clearance to conductors to permit the line to operate without interference for several years. They may be removed if they present a hazardous condition or removal is preferable to repeated trimming over the expected life span of the tree. When trimmed, the following table reflects applicable clearances. Clearances are measured from the conductor to the closest point of the tree. For aerial spacer cables, an exception can be allowed to permit trees to grow no closer than three feet from conductors. For a system neutral conductor functioning as both primary and secondary neutral that is located on the pole in the secondary zone, clearance falls into the service/secondary category.

***TABLE 46 — SPECIMEN TREES IN MAINTAINED LANDSCAPES***

| Specimen Trees in Maintained Landscapes | | | | |
|---|---|---|---|---|
| Description | Voltage | Minimum Clearance for Trees Trimmed | | |
| | | Top | Side | Overhang |
| Service/Secondary | <750 volts | 2 feet | 2 feet | 2 feet |
| Primary Open Wire | 2.4-14.4 kV | 10 feet | 10 feet | 10-20 feet* |
| Primary Aerial Spacer Cable | 2.4-14.4 kV | 6 feet | 6 feet | 6 feet |
| HVD | 46 kV | 15 feet | 15 feet | No overhang allowed |
| HVD | 138 kV | Not Applicable | 20 feet | No overhang allowed |

Unmaintained areas are all other areas such as forested areas, agricultural fields and fencerows, and old fields. They rarely include specimen trees. Trees and brush growing in these areas are cleared to the width of the right of way. Similarly, non-specimen trees growing in or near maintained landscapes are removed to the width of the right-of-way.

For HVD lines, the clearing width is wider and fewer specimen trees are permitted. For 46 kV lines, public street specimen trees may be permitted, but specimen trees on private property growing directly below conductors are generally removed. For 138 kV lines, all specimen trees growing directly below conductors are removed. Specimen trees that require only side trimming to attain minimum clearance are permitted within the right of way clearing width.

***TABLE 47 — ROW WIDTH AND CLEARING FOR NON-SPECIMEN TREES***

| ROW Width and Clearing for Non-Specimen Trees | | | | | |
|---|---|---|---|---|---|
| Description | Voltage | ROW Width from Centerline | Clearing | Hazard Zone Width (each side of ROW) | Clearing |
| Service/ Secondary | <750 volts | 15' | Removal when needed | none | Removal when needed on case by case basis |
| Primary Open Wire | 2.4-14.4 kV | 15' | Non-specimen trees removed, specimen trees removed if hazardous or cost/benefit justifies removal | 20' | Hazard trees removed when work can be safely accomplished by crews with standard equipment |

| | | | | | |
|---|---|---|---|---|---|
| Primary Aerial Spacer Cable | 2.4-14.4 kV | 15/5 '* | Non-specimen trees removed, specimen trees removed if hazardous or cost/benefit justifies removal | 20' | Hazard trees removed when work can be safely accomplished by crews with standard equipment |
| HVD | 46 kV | 40' | Non-specimen trees removed, specimen trees removed if hazardous or cost/benefit justifies removal | 40' | Hazard trees removed when work can be safely accomplished by crews with standard equipment |
| HVD | 138 kV | 45-66' | Non-specimen trees removed. Specimen trees removed if hazardous or within the wire zone or cost/benefit justifies removal | 40' | Hazard trees removed when work can be safely accomplished by crews with standard equipment |
| *ROW width for aerial spacer cable is 15 feet from centerline on the bracket side of the pole and 5 feet from centerline on the non-bracket side of the pole. | | | | | |

We do not grind or remove stumps of trees removed for line clearing, nor do we remove tree debris from customers' properties during or after emergency restoration work.

We follow guidelines for line clearing work to prevent the spread of oak wilt disease as published by the Michigan Oak Wilt Coalition. These guidelines limit certain work or require additional precautions throughout most of the year.

Several threatened or endangered species exist within or along our rights of way including the Karner blue butterfly, Mitchell satyr butterfly, Indiana bat, Northern long-eared bat, Massasauga rattlesnake, and many other species of concern. Each of these species requires adjustments to line clearing practices or timing to protect individuals of the species or their habitats.

## Gaps in Current Program

The largest gap in the current program is funding to achieve a reasonable level of tree-caused interruptions for our customers. We believe that the optimal cost to benefit cycle is the effective seven year cycle described above.

We are also reviewing the clearing specifications for our 14.4 kV primary system. Typically, lower voltage circuits are converted to 14.4 kV to alleviate power quality issues, reduce line loss and increase capacity, instead of extending the 46 kV HVD system and adding of new substations to achieve similar results. The 14.4 kV system is much more sensitive to tree and branch contact than lower voltages, and reliability data suggests that clearing to current specifications does not provide the same immediate improvement in reliability nor length of time of benefit. A wider right of way or changes to line design for 14.4 kV lines may be necessary to ensure that the 14.4 kV system performs at the same level as the lower voltages that we use.

As seen with the emerald ash borer, the process of adjusting clearing specifications and costs to new pests in Michigan's trees and forests is a slow one. Our customers experience outages due in part to a slow process before changes are approved. More flexibility would improve our ability to maintain reliability.

### Alternatives to Mitigate Tree Outages

We are installing aerial spacer cables when rebuilding primary lines in areas of heavy tree density, such as along county road rights of way running through Department of Natural Resources land. This type of conductor and bracketed spacing reduces the area requiring clearing, and the coated conductor is much more resistant to tree-caused faults than an open wire conductor. It is similar in installation expense to an underground primary, but it can be used in more areas with less disruption to existing infrastructure, and is easier and faster to repair when a fault occurs.

A second alternative on the secondary system is to replace the existing open wire secondary with triplex conductors. Similar to aerial spacer cables, triplex conductors offer a compact footprint and are more resistant to tree contact than open wire. Fewer customers are impacted by a secondary outage than a typical primary outage, but in urban settings where secondary is used this is also an alternative.

Finally, the grid modernization program will help reduce the impact of tree-caused outages to our customers. While not completely eliminating or reducing tree outages, it will provide benefits.

## E.7 System Protection Investments

### HVD System Protection

Investment in HVD system protection will be directed at replacing obsolete, high maintenance relays and sequence of events recorders with digital devices. Adding new digital devices that have fault monitoring capabilities will improve reliability, fault monitoring capability, and offset future O&M costs. This program targets replacement of relays that are reaching end of life. The failure of a relay to trip properly under fault conditions can lead to severe system consequences, including extending the size and length of outages experienced by customers, or increasing the likelihood of major equipment or conductor damage. This program also supports the replacement of relays due to NERC requirements (mis-operation or unplanned operation).

The relay replacement program is used for the budgeted capital replacement of defective, old, and obsolete protective relays. We target specific electromechanical relays for replacement with digital relays. These electromechanical relays are either unreliable and require high maintenance or have been reported by our electric field lab to be un-maintainable. Failure of these relays to operate correctly will cause either an over-trip (unnecessary outages) or a non-trip (damage to the electrical components) for an electrical system fault. Relays may also be targeted for replacement as a result of a change in the electric system configuration that requires relay enhancements to meet an acceptable level of protection performance in a given area.

Digital relays are cheaper to purchase, require less panel space, have increased setting and application flexibility, require less periodic maintenance (as they have self-diagnostics and monitoring functions) and provide detailed fault analysis data used by operations for more rapid restoration of the electric system.

In 2017, we have 6,634 protective relays on the HVD electrical system, 57% of which are electromechanical devices, 7% solid state, and 36% digital.

Currently, about 16% of the total relay population is older than the designated design life (27% for EM relays). As the relay population continues to age, more money will need to be spent on O&M. As we spend more capital dollars replacing old EM relays with digital, we will reduce O&M dollars. If we fail to continue to replace these old relays on a scheduled basis, system performance will suffer and O&M costs will continue to rise in order to keep these aging devices functioning.

# E.8 Substation Inspections

Periodic evaluation of substation equipment allows for identification of equipment near the end of life so that those items can be replaced before they fail. Such inspections and replacements are more economical, safer and can save customer outage minutes. Maintenance on certain components is mandated by NERC compliance standards.

## LVD Substations - Proactive Inspections

***TABLE 48 — LVD SUBSTATION INSPECTION CADENCE***

| LVD Substation Inspection Cadence | | |
|---|---|---|
| Inspection Task | Cadence | Components Checklist |
| All Station Components | Bi-Monthly | Visual Inspection<br>Routine Patrol Inspections |
| Entire Substation | Bi-Annually | Infrared Inspection of entire substation |
| Protective relays and communication systems | Depends on relay model & failure history | Maintenance & Testing Performed |
| Station Batteries | Monthly | Voltage Check |
| | Annually | Equalization |
| | Annually | Specific Gravity Reading |
| | 4 Years** | Complete Inspection |
| Power transformers | Bi-Monthly | Visual inspection (including fans and pumps) |
| | Periodic | Combustible gas test (Follow-Up dissolved gas analysis tests, if warranted) |
| | Annually | Diagnostic dissolved gas analysis of transformer oil* |
| Motor Operated Air Break Switches (MOABS) (decoupled) | Annually | Testing |
| | 4 Years | Battery replacement** |
| Regulators | Set cadence not yet established | Limited program of dissolved gas analysis |

| | | |
|---|---|---|
| NERC Circuit Breakers & Switches | Annually | Testing |
| NERC Current and Voltage Sensing Devices | 10 Years | Inspection |
| *For Power transformers with Load Tap Changers Only<br>**Or periodically as needed | | |

***TABLE 49 — LVD SUBSTATION RUN-TO-FAIL COMPONENTS***

| LVD Substation Run-to-Fail Components | |
|---|---|
| Substation Components | Run-to-Fail Mode (Monthly Visual Inspection Only) |
| Power transformers | -- |
| Station power transformers | Yes |
| Regulators | -- |
| Reclosers | Yes |
| Circuit Breakers (oil, gas, vacuum and air) | -- |
| Circuit switchers/Transrupters | -- |
| Lightning arresters | -- |
| Insulators | -- |
| Capacitors | -- |
| Fuses | -- |
| Station batteries | -- |
| Air break switches | Yes |
| Disconnect switches | Yes |
| 138kV bus three phase bus selector switches | Yes |
| Load break switches | Yes |
| Line switches (hydraulic and stored energy mechanism) | Yes |
| Spring operated ground switches | Yes |
| Bypass switches | -- |
| Braid and hot line clamps | -- |
| Yard | -- |

## HVD Substations — Proactive Inspections

***TABLE 50 — HVD SUBSTATION INSPECTION CADENCE***

| HVD Substation Inspection Cadence | | |
|---|---|---|
| Inspection Task | Cadence | Components Checklist |
| All Station Components | Monthly | Visual Inspection |
| Entire Substation | Annually | Infrared Inspection of entire substation |
| Protective relays and communication systems | Depends on relay model & failure history | Maintenance & Testing Performed |
| Station Batteries | Monthly | Voltage Check |
| | Annually | Equalization |
| | Annually | Specific Gravity Reading |
| | 4 Years** | Complete Inspection |
| Power transformers | Annually | Diagnostic Dissolved Gas Analysis of Transformer Oil* |
| | | Periodic combustible gas test/dissolved gas analysis tests |
| Motor Operated Air Break Switches (MOABS) (decoupled) | Annually | Testing |
| | 4 Years | Battery replacement |
| NERC Circuit Breakers & Switches | Annually | Testing |
| NERC Current and Voltage Sensing Devices | 10 Years | Inspection |
| *For Power transformers with Load Tap Changers Only<br>**Or periodically based on battery condition once battery reaches 15+ years in age | | |

***TABLE 51 — HVD SUBSTATION RUN-TO-FAIL COMPONENTS***

| HVD Substation Run-to-Fail Components | |
|---|---|
| Substation Components | Run-to-Fail Mode<br>(Monthly Visual Inspection Only) |
| Power transformers | Yes — Non-NERC current & potential transformers |
| Station power transformers | Yes |
| 46kV three-phase regulators | Yes |
| Circuit Breakers (oil, gas and vacuum) | Yes |
| Circuit switchers/Transrupters | Yes |
| Lightning arresters | -- |
| Insulators | -- |

| | |
|---|---|
| Capacitors | Yes — Coupling capacitor potential devices |
| Fuses | - |
| Station batteries | -- |
| Air break switches | Yes |
| Disconnect switches | Yes |
| 138kV bus three phase bus selector switches | Yes |
| Load break switches | Yes |
| Line switches (hydraulic and stored energy mechanism) | Yes |
| Spring operated ground switches | Yes |
| Braid and hot line clamps | -- |
| Yard | -- |

# E.9 Substation Maintenance and Reliability Programs

Below is a Pareto chart and table of substation equipment failures that have resulted in SAIDI minutes over the past three years.

***FIGURE 42 — HVD & LVD SUBSTATIONS EQUIPMENT FAILURES***

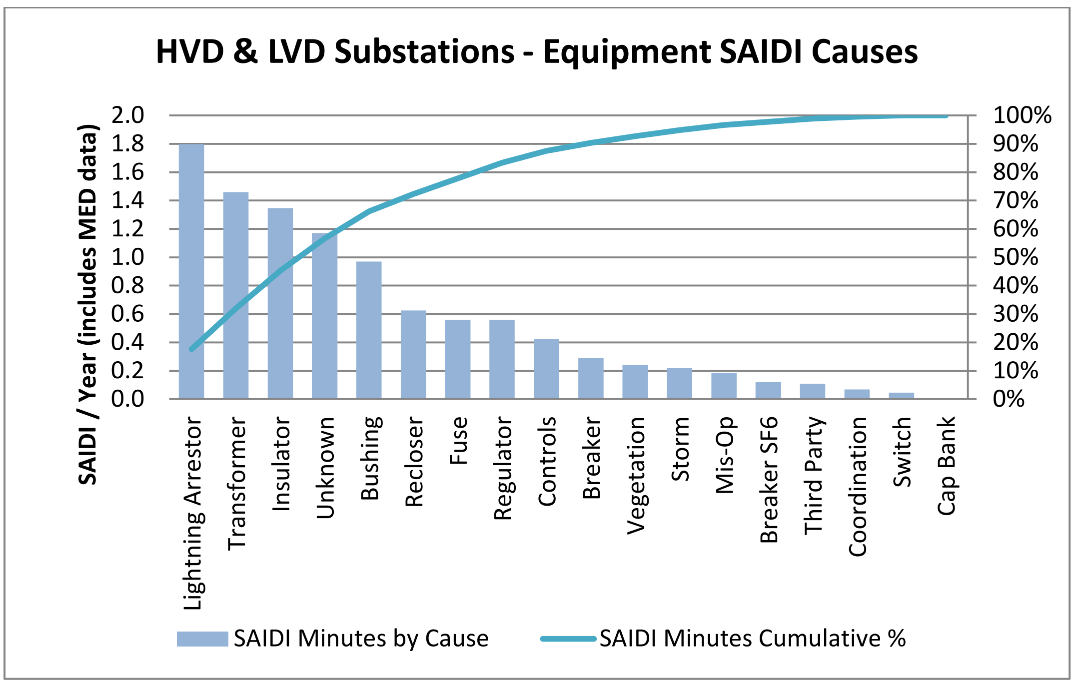
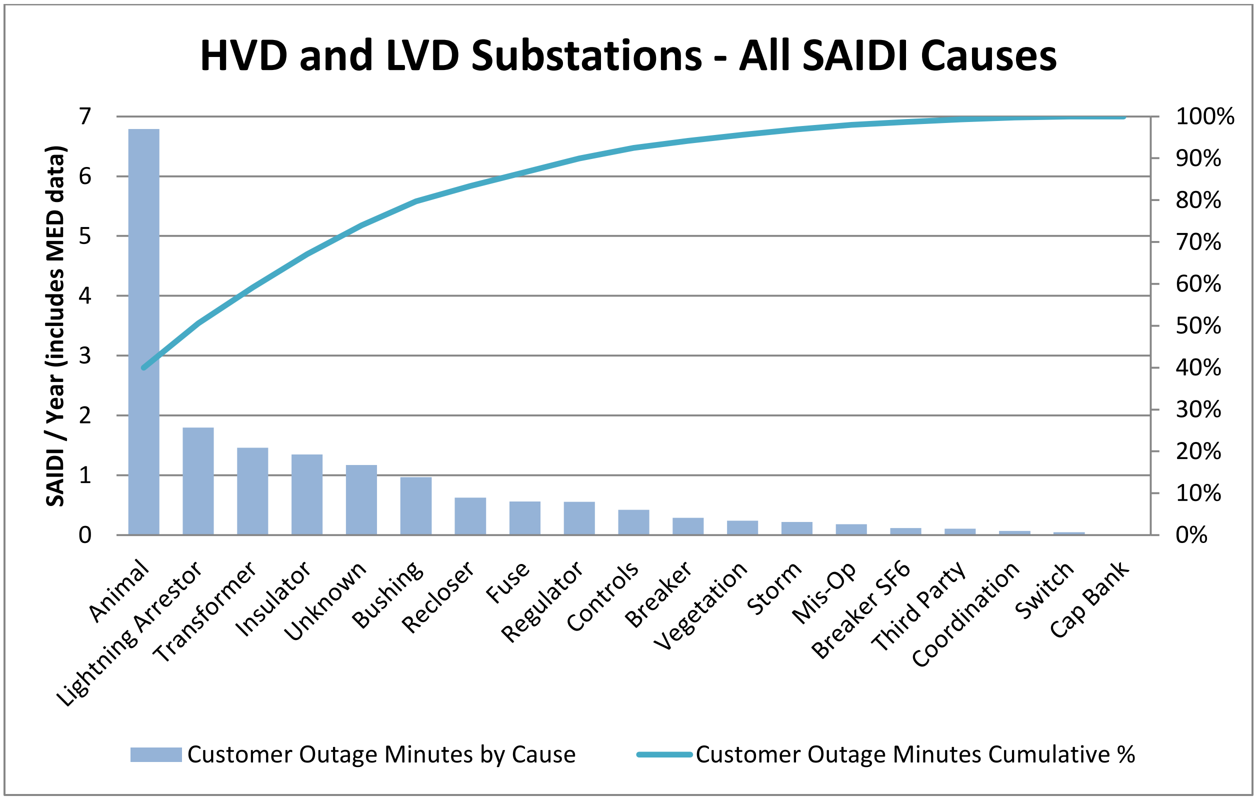


***TABLE 52 — HVD & LVD SUBSTATIONS EQUIPMENT FAILURES***

| HVD & LVD Substations Equipment Failures | | | | | |
|---|---|---|---|---|---|
| Cause | Average # of Failures Per Year | Average # of Failures Causing a Customer Outage Per Year | Average SAIDI Minutes Per Year | % of Substation SAIDI Minutes | SAIDI Minutes Cumulative % |
| Lightning Arrestor | 14 | 10 | 1.8 | 17.6% | 17.6% |
| Transformer | 10 | 5 | 1.5 | 14.3% | 32.0% |
| Insulator | 12 | 7 | 1.3 | 13.2% | 45.2% |
| Unknown | 10 | 7 | 1.2 | 11.5% | 56.7% |
| Bushing | 2 | 1 | 1.0 | 9.5% | 66.2% |
| Recloser | 3 | 3 | 0.6 | 6.1% | 72.3% |
| Fuse | 10 | 2 | 0.6 | 5.5% | 77.8% |
| Regulator | 5 | 5 | 0.6 | 5.5% | 83.3% |
| Controls | 7 | 3 | 0.4 | 4.1% | 87.5% |
| Breaker | 19 | 1 | 0.3 | 2.9% | 90.3% |
| Vegetation | 5 | 4 | 0.2 | 2.4% | 92.7% |
| Storm | 2 | 2 | 0.2 | 2.1% | 94.8% |
| Mis-Op | 3 | 1 | 0.2 | 1.8% | 96.6% |
| Breaker SF6 | 28 | 0 | 0.1 | 1.2% | 97.8% |
| Third Party | 7 | 2 | 0.1 | 1.1% | 98.9% |
| Coordination | 4 | 1 | 0.1 | 0.7% | 99.5% |
| Switch | 9 | 2 | 0.0 | 0.5% | 100.0% |
| Cap Bank | 21 | 0 | 0.0 | 0.0% | 100.0% |

In addition to equipment causes, animal intrusions have resulted in an average 6.8 SAIDI minutes per year over the last three years. We have invested over $2 million in 2016 and $4 million in 2017 on substation animal mitigation, reducing animal caused SAIDI minutes. SAIDI minutes due to animal intrusions in 2016 were 5.0, and through the first half of 2017 they are 1.5.

***FIGURE 43 — HVD AND LVD SUBSTATIONS SAIDI CAUSES***




## Substation Investment Plan

We will direct investment in LVD and HVD substations at: (1) targeted replacement of specific equipment, such as oil circuit breakers, substation lightning arresters, and transformer bushings; (2) complete substation rebuilds; (3) animal mitigation; (4) new mobile substations; and (5) protective relay replacements. We expect to purchase two mobile substations in 2017 and 2018. Protective relay equipment is critical to protect major HVD system assets (transformers, lines, etc.) from damage due to faults on the system, and is used to automatically isolate and reconfigure the HVD system after faults, reducing customer outages and outage duration.

Below is a table listing LVD substation equipment, number installed, average age, expected life, and percent past the expected life.

***TABLE 53 — LVD SUBSTATION EQUIPMENT SUMMARY***

| LVD Substation Equipment | | | | |
|---|---|---|---|---|
| Asset | Number in Service | Average Age | Expected Life (Years) | % of Population past Expected Life |
| Transformers (non-LTC) | 1,152 | 35.3 | 50 | 28.7 |
| LTC Transformers | 107 | 33.3 | 50 | 17.8 |
| Transformers with ABB O+C transformer bushings | 394 | 19.8 | 50 | 2.8 |
| Transformers with GE type U transformer bushings | 60 | 45.8 | 50 | 41.3 |
| Circuit Switchers | 121 | | 25-30 | |
| Obsolete Circuit Switchers (S&C Mark II, Mark III, & Mark IV) | 2 | | 25-30 | |
| Oil Circuit Breakers | 22 | 56.2 | 50 | 95.5 |
| SF6 Gas Circuit Breakers | 4 | 19 | 30 | 0 |
| Air Magnetic Circuit Breakers | 7 | 39.7 | 30 | 71.4 |
| Vacuum Circuit Breakers | 15 | 10 | 30 | 0 |
| Single Step Voltage Regulators | 5,405 | | 20 | |
| 46 kV gang-operated switches | 1,249 | | 50 | |
| Obsolete 46 kV gang-operated switches | 73 | | 50 | 100 |
| Batteries | 121 | 7.6 | 15 | 10.7 |
| Reclosers | 2511 | | 20 | |
| Transformer bushings | 8157 | | 40 | |
| Capacitor Banks | 7 | 13.3 | 20 | |
| Lightning Arrestors | | | | |

Below is a table listing HVD substation equipment, number installed, average age, expected life, and percent past the expected life.

***TABLE 54 — HVD SUBSTATION EQUIPMENT SUMMARY***

| HVD Substation Equipment | | | | |
|---|---|---|---|---|
| Asset | Number in Service | Average Age (Years) | Expected Life (Years) | % of Population past Expected Life |
| Transformers (non-LTC) | 166 | 44.8 | 50 | 45.8 |
| LTC Transformers | 6 | 18 | 50 | 0 |
| Transformers with ABB O+C transformer bushings | 52 | 33.6 | 50 | 17.3 |
| Transformers with GE type U transformer bushings | 1 | 63 | 50 | 100 |
| Circuit Switchers | 223 | | 25-30 | |
| Obsolete Circuit Switchers (S&C Mark II, Mark III, & Mark IV) | 14 | | 25-30 | |
| Oil Circuit Breakers | 346 | 48.5 | 50 | 46.5 |
| SF6 Gas Circuit Breakers | 539 | 12 | 30 | 0.4 |
| Vacuum Circuit Breakers | 3 | 5.3 | 30 | 0 |
| 46 kV gang-operated switches | | | 50 | |
| Obsolete 46 kV gang-operated switches | 70 | | 50 | 100 |
| 46 kV disconnect switches | | | 35-45 | |
| Batteries | 160 | 6.8 | 15 | 1.9 |
| Relays (electro-mechanical) | 3,797 | 24 | 40 | 26.6 |
| Relays (solid-state) | 450 | 21 | 30 | 5.3 |
| Relays (digital) | 2,387 | 7 | 25 | 0 |
| Transformer Bushings | 1,694 | | 40 | |
| Capacitor Banks | 207 | 20.6 | 20 | |
| Lightning Arrestors | | | | |

## E.10 Substation Ratings and Loadings Information

We rate HVD lines and substation equipment based on manufacturer nameplate ratings with adjustments based on industry standards. For example, we calculate substation transformer capability based on the nameplate rating (self-cooled or force-cooled as applicable) and actual unit design and test data into the Transformer Capability Program (based on IEEE/ANSI standard C57.91, "IEEE Guide for Loading Mineral-Oil-Immersed Transformers"). This allows peak load ratings for transformer peaks as high as 130% of nameplate or more, taking such things as ambient temperature and load cycles into account.

# E.11 Review of Obsolete Assets

***TABLE 55 — SUBSTATION OBSOLETE EQUIPMENT REPLACEMENT PLAN***

| Substation Obsolete Equipment Replacement Plan | | | | | | |
|---|---|---|---|---|---|---|
| Asset Type | Aging/Obsolete Asset | Approx. # | Replace With | Timeframe for replacement | Average Unit Cost (Loaded) | System Benefits |
| Reclosers | ME | 20 | Nova TS/VWE/VSA | As Issues develop, DSCADA or major projects | $50,000 | Eliminate unpredictable operations |
| | VXE | 112 | Nova TS/VWE/VSA | As Issues develop, DSCADA or major projects | $50,000 | DSCADA Compatibility, eliminate unpredictable operations |
| | Nova1 | 111 | Nova TS/VWE/VSA | As Issues develop, DSCADA or major projects | $50,000 | DSCADA Compatibility, eliminate unpredictable operations |
| | hydraulic(L, V4L, 4E, 4H) | 557 | Nova TS/VWE/VSA | As Issues develop, DSCADA or major projects | $50,000 | DSCADA compatibility (good functional design, just no communication capability) |
| | Recloser Controllers not DSCADA compatible | *unknown* | Form 6 | DSCADA projects | $3,000 | DSCADA compatibility |
| Regulators | Regulators not DSCADA compatible | *unknown* | New VR-32 or VR-1 regulators | DSCADA projects | $60,000 | DSCADA compatibility |
| | Regulator Controllers not DSCADA compatible | *unknown* | Form 6B, 7 or GE2011C controls | DSCADA projects | $3,000 | DSCADA compatibility |
| Transformers | Allis Chalmers | 104 | Non-AC unit | Targeting all replacements by 2022 | $500,000 | 0.8 SAIDI savings per unit (one time) |
| | Ferranti-Packard | 34 | Non-FP unit | No Program | $500,000 | 1.1 SAIDI savings per unit (one time) |



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| | | | | | | |
|---|---|---|---|---|---|---|
| Trf Bushings | GE Type U | 121 | | Targeting all replacements by 2022 | | |
| | ABB O+C | 394 | | No Program | | |
| Animal Mitigation | Non-Animal Mitigation Substation | 291 | Full Animal Mitigation | Varying # of projects each year, targeting full mitigation by 2027 | $60,000 | Average savings 0.015 SAIDI/year/substation, Avoid 0.21 SAIDI per incident |
| Substation Design | Two-legged erecticon & low-profile rolled steel | 36 | | As issues develop, major projects | $1,200,000 | Minimum Approach Distance (MAD working clearance issues), DSCADA compatibility |
| | 138kV Fusing | 14 | Transrupter or Circuit Switcher | As issues develop, project schedule allows | $300,000 | Reduced trf damage from ferroresonance, reduced outage time (need 3ph device to operate) |

# E.12 Demand Failures Program

This program includes expenditures incurred in connection with customer outage restoration and the repair or replacement of equipment including pole-top rehabilitation due to unanticipated or imminent failure. This provides both immediate customer benefit via service restoration and longer-term customer benefit associated with having new equipment providing service. In addition, this program includes a projection to enhance the credit available for customers who request conversion of existing street lighting to Light Emitting Diode (“LED”) fixtures.

We balance workload between planned and demand/emergent work, maintaining flexibility to accommodate customer demand requests and storm event failures.

## Categories

The Demand Failures Program is broken down into the following categories:

***TABLE 56 — DEMAND FAILURES PROGRAM CATEGORIES***

| Demand Failures Categories | |
|---|---|
| Category | Description |
| LVD Lines Demand Failures | Respond to Failures on the Electric Lines Distribution Systems throughout the state. This includes projects during storm restoration and response to 15kV underground failures. |
| HVD Lines Demand Failures | Replace failed 46-138 kV line and substation equipment to restore customer service and maintain reliability of electrical service. Funding will allow replacement of highest priority failed HVD substation equipment and failed HVD poles and switches, as well as HVD cross arms and insulators. This program is also responsible for the replacement of known failing SF6 breakers. |
| LVD Substation Failures | Respond to Failures in the Electric Distribution Substations throughout the state. |
| Distribution Metering | Consists of capital expenditures for meters purchased that are allocated to the Demand Failures Program based upon the projection of meters that will be utilized in the program (as opposed to those utilized in other programs). |
| Distribution Transformers | Consists of the purchase costs of distribution transformers and the associated first set of expenses. The purchase costs are then allocated to the Distribution Transformer programs in New Business, Demand Failures, and Capacity. |
| Streetlight - Mercury Vapor ("MV") | This program provides for the conversion of 160,000 original MV streetlights to the High Intensity Discharge ("HID") streetlight of the community's choice (i.e. High Pressure Sodium, LED). This program was initiated to address the cease in manufacturing of MV streetlight fixtures and in an effort to do so, engaged all our streetlight communities as well as the MPSC to develop a 10-year plan starting in 2011 for complete conversion. Currently, this program is on track to be completed by the end of 2019. The Company is proposing a tariff change that would affect this category beginning in 2018 as described in section XX below. |
| Metro Demand Failures | Respond to Failures on the Electric Metropolitain Underground Systems throughout the state. Replace failed metropolitan underground equipment, replace infrastructure deemed a risk to public safety and maintain the inherent redundancy of Metro underground systems within the Company's service territory. |

## Prioritization

To prioritize repair and resource allocation, we categorize damage as follows:

***TABLE 57 — DEMAND FAILURES PROGRAM REPAIR PRIORITIZATION***

| Repair Prioritization | | | | |
|---|---|---|---|---|
| | Timeframe to Address | | | |
| | 24 Hours | 10 Days (Includes weekends) | 14 Days (Includes weekends) | Timeframe? |
| Criteria | Service restoration, emergency, public safety, or imminent system integrity problem requiring immediate action to correct the situation or damage. Priority 1 defects are imminent failures or present an immediate threat to public safety and are not subject to reclassification | Damage is believed to be sufficient to cause public safety or system integrity problem if left unattended beyond 10 calendar days. | Damage is sufficient enough to cause concern for public safety or system integrity before next scheduled routine patrol | Damage or defect out-of-standard but not likely to present public safety or system integrity problem prior to next scheduled routine patrol. |
| Example(s)* | A wood pole which is burnt off or broken or energized conductor with less than acceptable clearance. | Cracked crossarm which could fail, a broken down ground that could contact energized conductor, or a loose down guy which could contact energized conductor. | Broken crossarm brace supporting an undamaged crossarm, a loose or broken down guy on a structure with more than one down guy or a broken down ground that has failed in the clear. | Missing guy guard or missing structure number. |

*Examples provided are not a comprehensive list of the criteria necessary to address damages within given timeframe. Examples are provided for clarity of understanding only.

# E.13 Repetitive Outages Program

The repetitive program addresses areas of consistently recurring customer outages on a reactive and proactive basis. Investments are targeted at improving same circuit repetitive interruptions, based on the definition in R460.702(s) of the MPSC Quality and Reliability Standards for Electric Distribution Systems. We also use the Customers Experiencing Multiple Interruptions index to address repetitive outages. Repetitive outage areas require investments to upgrade poles, conductors, and other facilities to improve reliability.

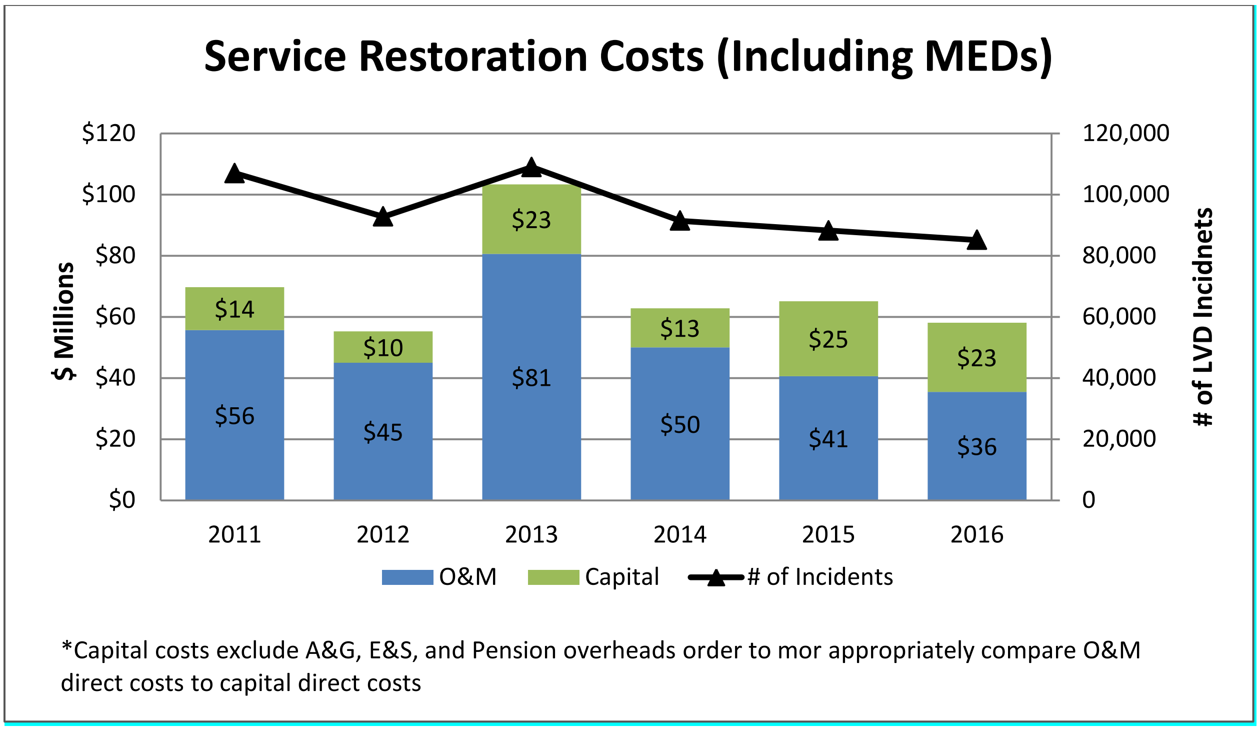
# E.14 Causes of restoration/storm costs

Costs associated with restoration during storm and non-storm environments include, but are not limited to, the following:

- Investigating and responding to outages, no-light calls, downed wires, and other customer safety hazards and incidents
- Damage assessment
- Repair and replacement of equipment due to unanticipated or imminent failure
- Clearing fallen trees and branches during restoration activity
- Office support for coordinating restoration and dispatching crews, wire guards, and wire evaluators
- Mutual assistance from other utilities and contractors during restoration activity

The chart below illustrates our restoration costs from 2011 to 2016 relative to the number of outage management system incidents (no light, bright/dim light, wire down, tree on line, and other hazards).

***FIGURE 44 — SERVICE RESTORATION COSTS (INCLUDING MEDS)***




With the exception of 2013, which included a major ice storm in December, restoration costs have averaged slightly over $62 million per year. Starting in early 2015, we reconfigured our work order system to allow for plant unitization of pole-top hardware such as cross-arms, lightning arrestors, and cut-out switches. The reconfiguration allows more restoration work to be charged to capital than in previous years. Incident count reduced from about 107,000 in 2011 to about 85,000 in 2016. Restoration costs per incident grew less than 1% annually from 2011 through 2016.

Starting in 2011, we made several changes to improve our response to customer outages. Restoration pre-planning prior to expected weather events, and regular weekend pre-planning, were instituted to proactively establish response approaches based on anticipated weather impacts. We frequently consider and schedule weekend work assignments to perform necessary work and to have line crews available for outage response during these non-standard work hours. Office and line crew resources are mobilized in some cases prior to weather events in areas of expected impact. We enhanced our wire down process by creating a new wire evaluator role to increase flexibility of response resources during storms. We initiate mobilization of additional contractor line crews earlier during, or prior to, weather events to increase resource availability in the initial phase of restoration. In the recent March 2017 wind storm we formally implemented our Incident Command System ("ICS") at the statewide level to delineate job responsibilities and organizational structure. ICS helps ensure the safety of responders and the public, the achievement of restoration objectives, and effective and efficient use of resources.

We insure for the cost to restore major overhead electric distribution lines, poles, towers, and pole-mounted equipment following a major storm. Our policy insures for all direct physical loss and damage to insured property unless excluded. Some of the losses or damages that are not covered are: insurrection, rebellion, or civil war; employee theft; faulty workmanship, material, construction or design; deterioration, corrosion or erosion, wear and tear. The insurance premium for this policy has averaged $2.4 million over the last three years. We expect this to increase over the next five years due to increasing exposure values, increased storm frequency and severity, and changes in the insurance market in this sector. Yearly premiums could range from $2.5 million to over $3 million. Our current policy deductible is $15 million, but the deductible is subject to change, which could impact future utilization of the policy.

# E. 15 Restoration management programs

## Storm restoration overview

Storms can cause great challenges for our customers including the loss of power, heat, and in some cases water; damage to homes and neighborhoods; damage to equipment; and interruption to businesses. To help restore power, our process relies on several key activities:

- Continuous monitoring of weather to identify system threats
- Preparation and planning for weather events and their impact on customers
- Mobilizing office and field resources, including Mutual Assistance resources if necessary;
- Executing the restoration plan, including:
    - Wire down management
    - Damage assessment
    - Restoration and repair
- Notifying and communicating throughout the event with public and governmental agencies as well as emergency managers
- Performing post-storm assessment to improve capabilities for future events

We rely on multiple weather services and a contracted weather vendor service for on-call meteorologist support to identify significant weather events. Based on the predicted weather impact, potential outages, and system hazards, we use a pre-planning tool to proactively secure necessary leadership, line and forestry crews beyond the pre-established first response teams.

The first step in our restoration philosophy is to ensure public and employee safety by securing wire down hazards. We use wire evaluators and wire guards to do this. Wire evaluators are trained to identify electrical utility hazards, while wire guards are trained to barricade a downed wire and stay on site to keep the public away and safe. We offer annual certification training and conduct annual recertification for wire guards and wire evaluators. Our Public Safety Outreach Team is a conduit to help prioritize safety concerns from fire chiefs, police chiefs, and emergency managers during service restoration.

Our outage management system allows us to identify where outages exist, but does not provide the whole picture on what kind and how much damage there may be to poles, lines, and equipment. Damage assessment becomes a critical next step for a successful storm operation. Damage assessment teams are immediately mobilized and coordinated across the state and sent to areas where damage is likely to be most severe. Unmanned aerial vehicles (UAVs) have the potential to improve damage assessment. UAVs can provide more information, quicker, and with less risk than traditional damage assessment. We are beginning to test UAVs for this application to determine the capabilities of the technology. Once UAVs have been proven successful in testing, we will determine how they could potentially be integrated into our standard damage assessment procedures.

## Restoration Systems and Platforms

The outlined restoration processes are supported by two major platforms:

- Outage Management System, integrated with Advanced Metering Infrastructure
- Resource Management System

### Outage management system

Customer outages, wire downs, hazards and other key information are received into our map-based outage management system (OMS) via our Voice Response Unit (VRU), customer service representatives, or our website. OMS processes this information and, based on the timing of receipt, produces a probable location of where the electric system fault originated or where a protective device may have operated to clear the fault, based on algorithmic modeling. This information is used to locate the problem, communicate information to customers, assign and manage resources to address downed wires and restore power outages in a more informed, efficient and timely manner. Recently we augmented OMS with the capability to receive advanced metering outage information, which provides timely outage information and additional analysis capabilities to quickly locate outage locations.

### Resource management system

During restoration, we perform progress analyses utilizing a resource management system (RMS). This system is critical for managing resource procurement and allocation among service territories, and tracking resource movements across the state based on the current work in the OMS. The RMS compares available crew resources to OMS demand to establish crew deficiencies or surpluses. This enables us to better understand our resourcing and make critical decisions as to when we engage Mutual Assistance.

## Communicating during outages

Various communication avenues allow us to keep customers informed and safe. Receiving timely and accurate Estimated Time of Restoration (ETR) is important to customers and the steps taken during restoration processes allow us to proactively determine what the ETR should be and communicate it through customer's preferred channel (voice, email, text). Along with providing ETR information, we also use other communication avenues such as:

- An online outage map for customers to get information on any outages in the territory
- Online and phone outage reporting
- Press releases, wire down ads, and social media to communicate pertinent information, specifically the danger of downed wires

- Public Service Announcements with severe wind, thunderstorm, and winter storm information

## Continuous improvement

We use a cycle of preparedness to help ensure continuous improvement in restoration process capabilities. Restoration management is responsible for the continuous cycle of planning, updating restoration process documentation, maintaining resources and tools necessary for activation and execution, and taking corrective action. Our Learning and Development program manages restoration training and employee records as part of the preparedness cycle. Lessons learned and standardization and evaluation of processes continue to be critical components of our ongoing improvement strategy.

# APPENDIX — OPERATE

## F.1 Detailed investment list

***TABLE 58 — OPERATE — CAPITAL INVESTMENT SUMMARY (2016-22)***

| Capital Investment Summary (2016-22, $K) | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| All Investments | 2016 Actuals | 2017 YTD (June) | 2018 Plan | 2019 Plan | 2020 Plan | 2021 Plan | 2022 Plan | Five Year Total |
| Grid Modernization | 18,518 | 8,253 | *Estimates for 2018-22 will be included in the final report* | | | | | |
| System Control Projects | 2 | 6 | | | | | | |
| SCADA | 407 | 348 | | | | | | |
| ***Total*** | 18,927 | 8,607 | | | | | | |

***TABLE 59 — OPERATE — O&M INVESTMENT SUMMARY (2016-22)***

| Operate - O&M Expense Summary (2016-22, $K) | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| All Investments | 2016 Actuals | 2017 YTD (June) | 2018 Plan | 2019 Plan | 2020 Plan | 2021 Plan | 2022 Plan | Five Year Total |
| Smart Energy MTC - Elec | 0 | 3,522 | *Estimates for 2018-22 will be included in the final report* | | | | | |
| System Control & Monitoring | 3,754 | 2,478 | | | | | | |
| Meter Tech & Mgmt Sys Support | 1,133 | 485 | | | | | | |
| ***Total*** | 4,887 | 6,485 | | | | | | |

## F.2 Grid Communications

There are two main drivers for Grid Communications investments. First, telecommunication carriers are quickly retiring the analog services that currently provide SCADA and circuit protection functionality for our electric grid. Second, we need to support situational awareness to manage the growing number of system automation deployments and DER equipment.

We will develop a communications network that enables reliable wired and wireless communications to generating facilities, substations and pole top devices. A robust, standards based internet protocol (IP) field communications architecture will provide a long-term communications platform that supports the requirements of our plan.

Grid Communications investments are usually large and long-term; therefore, it is essential that they include as much future-proofing as possible. As the rate of change increases, especially when it comes to telecommunication investments, the design must be standards-based, standardized, and modular, which is precisely what our program enables. This will help minimize the risk of technology manufactured with proprietary standards, “one-off” communication installations, and allows providers to install equipment without having to escort them in the field.

## Substation Communications Upgrade

This project is due to the two drivers mentioned for Grid Communications. The project will implement the Grid Communications design, allowing multiple applications to use the same network instead of having a single communications circuit per application. This includes substation telemetry, automation applications, Internet protocol (IP) cameras, phones, and physical security equipment.

We have has approximately 230 HVD substations with telecommunications. Similar to our aging grid infrastructure, our telecommunications to these substations are aging and becoming obsolete. The telecommunications service providers have communicated their intention to sunset this technology by 2018, so we will replace the existing analog multi-drop circuits with dedicated high-speed open standards-based communications and modern cybersecurity.

The project scope includes a number of key decisions that are very site specific, but one overarching principle for all the sites is to have a modular design that can handle changes. Consistent engineering standards are used wherever possible, but on some occasions our substations have constraints that require deviations. For instance, we have facilities where an outdoor H-frame is not allowed due to zoning, or the physical footprint of the site does not provide enough space. The following features are also included in the project scope.

- **Shared fenced area (CE, ITC & Telecommunications)** — By constructing a shared fenced area we can increase safety at the substation by enabling communications work without entering substation control houses. This design principle will also facilitate quicker communication circuit restoration by eliminating the need for our personnel to coordinate access and escort telecommunication technicians.
- **New control house** - At sites where working space issues exist and cannot be easily mitigated, we will build new control houses. The new houses will support communications equipment plus enough space to consolidate grid equipment in the future.
- **Communications catalog** — To ensure success beyond the initial project a communications catalog is being developed to insure communications in the field and substation adheres to a company standard. The catalog will deliver a single reference source for all substation and line device related communication options.

*TABLE 60 — SUBSTATION COMMUNICATION 5 YEAR DEPLOYMENT SUMMARY*

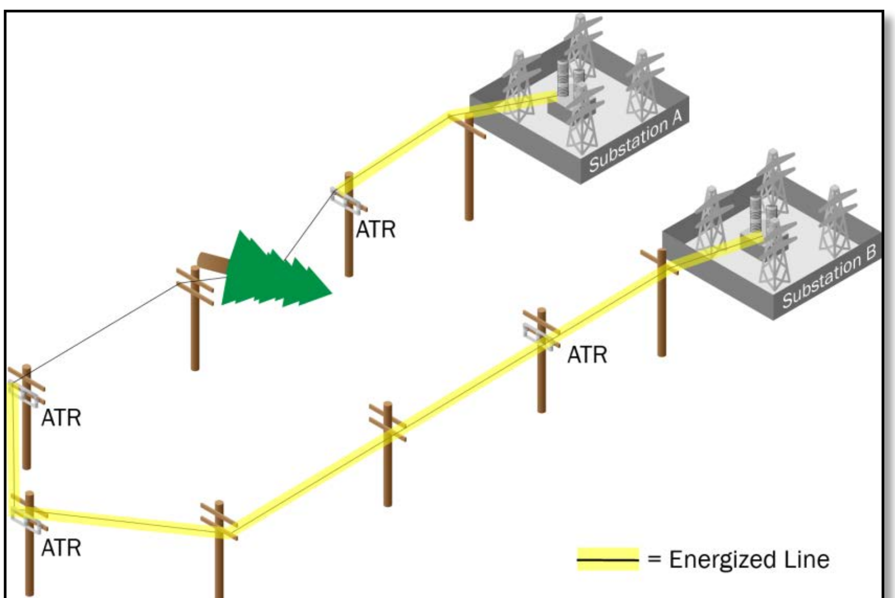
| Substation Communications Upgrade 5 Year Deployment Summary | | |
|---|---|---|
| | Number of Substations | Cost (k) |
| 2016 Actual | | $1,334 |
| 2017 Actual (Q1-Q2) | 4 | $1,866 |
| 2017 Plan (Q3-Q4) | 130 | $12,260 |
| 2018 Plan | 106 | $14,888 |

# F.3 Distribution Line Automation ("DLA" or "DA")

Distribution automation loops (DA loops) are specially designed systems installed between two LVD feeders. They use devices called automatic transfer reclosers (ATRs) to transfer load automatically in the event of an outage, reducing customer outages and improving system reliability by isolating a faulted section of a feeder. Our DA reclosers' “Loop Scheme” software is designed to operate even when communications are down. This ensures the systems provide the greatest benefit, even in catastrophic storms.

***FIGURE 45 — INSTALLED AUTOMATIC TRANSFER RECLOSER***

***FIGURE 46 — DISTRIBUTION AUTOMATION LOOP FUNCTIONALITY MODEL***



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We have been deploying DA loops since 2010. Since 2015, our DA loops have documented over 8.1 million in customer minutes savings. Continuation of DA loop deployment positions us for both increased reliability savings and implementation of more advanced automated switching systems through an Advance Distribution Management System (ADMS).

***TABLE 61 — DISTRIBUTION AUTOMATION LOOP DEPLOYMENT SUMMARY***

| DA Loop 5 Year Deployment Summary | | | | | | |
|---|---|---|---|---|---|---|
| | Based on current LTFP | | | If more funding … | | |
| | Number of loops | % of circuits looped (cum) | Cost (k) | Number of loops | % of circuits looped (cum) | Cost (k) |
| 2016 Actual | 19 (include previous years) | 1.5% | $1,430 | | | |
| 2017 Actual (Q1-Q2) | 6 | 2.0% | $309 | | | |
| 2017 Plan (Q3-Q4) | 12 | 3.0% | $3,953 | | | |
| 2018 Plan | 10 | 3.8% | $8,933 | 20 | 4.6% | $17,866 |
| 2019 Plan | 17 | 5.2% | $16,422 | 30 | 7.1% | $28,980 |
| 2020 Plan | 20 | 6.8% | $17,520 | 40 | 10.3% | $35,040 |
| 2021 Plan | 22 | 8.6% | $19,932 | 45 | 14.0% | $40,770 |
| 2022 Plan | 28 | 10.9% | $25,368 | 45 | 17.7% | $40,770 |

***TABLE 62 — DISTRIBUTION AUTOMATION LOOP BENEFITS***

| DA Loop Benefits | | |
|---|---|---|
| | Customer minutes saved | Cumulative customer minutes saved |
| 2015 and earlier years | 2.861M | 2.861M |
| 2016 | 1.871M | 4.732M |
| 2017 (as of 6/30/17) | 3.385M | 8.117M |

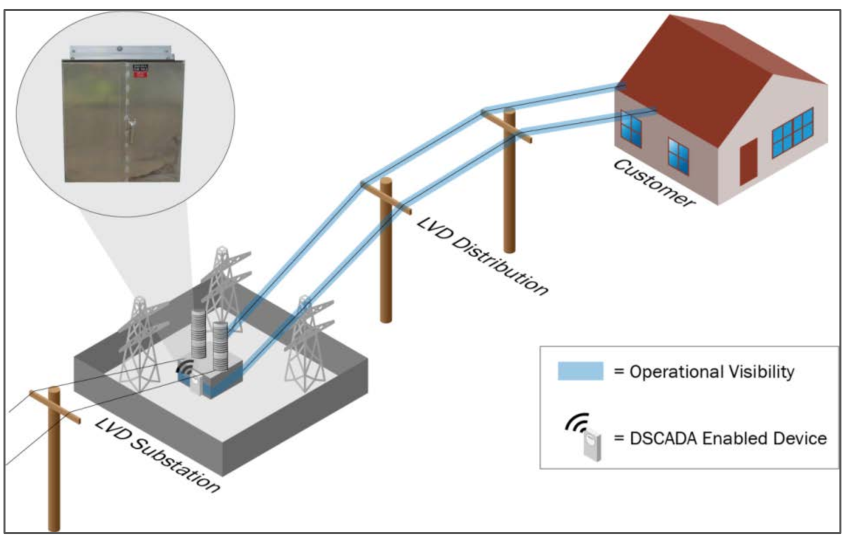
Individual DA loop projects are prioritized based on circuit reliability metrics (SAIFI, SAIDI, and CAIDI), historic OMS outage data, GIS system model information, and historic loading information from various sources. These selection criteria are used to identify advantageous locations for future automation and to prioritize funding to candidate locations.

DA loop projects typically include some amount of system conditioning such as replacing conductors, protective device modifications, line regulator upgrades, or minor substation upgrades. All projects include the installation of ATRs equipped with two-way communication to HVD and LVD SCADA systems. ATRs are capable of fault interruption in addition to the voltage monitoring necessary to perform their designed load transfers.

# F.4 Distribution Supervisory Control and Data Acquisition ("DSCADA")

DSCADA expands the existing HVD SCADA system to LVD substations, to enhance operational visibility between the existing HVD SCADA in the bulk power substations and our Advanced Metering Infrastructure (AMI) metering at our service delivery points. This will allow us to more quickly and effectively address system outages and improve real time system operation. Enhanced visibility and control enables advanced programs such as Volt-VAR Optimization (VVO), Conservation Voltage Reduction (CVR), and Fault Location, Isolation, and Service Restoration (FLISR).

***FIGURE 47 — DSCADA OPERATIONAL VISIBILITY ILLUSTRATION***




We have been upgrading distribution substations with DSCADA communications for several years. To date, over 240 distribution substations are DSCADA enabled. This is the foundation for many advanced distribution applications: it enables efficiency savings from VVO and CVR, and reliability and productivity benefits from DA loop operations and switching operations in a future Advance Distribution Management System (ADMS). DSCADA on its own provides significant reliability benefits via immediate visibility into system problems, as well as remote control capabilities. DSCADA saves customer minutes by, enabling quicker response to system outages rather than waiting for customers to call in an outage. System controllers are able to remotely operate substation equipment and are notified on a real time basis of when substation reclosers are locked out. When a circuit locks out, system controllers dispatch a substation area operator to the substation and contact the appropriate work management center to dispatch a crew to investigate the cause. In 2017, since remote control has been enabled at DSCADA sites, we have documented 1.2 million customer minutes saved and 77 avoided truck rollouts.

***TABLE 63 — DSCADA DEPLOYMENT SUMMARY***

| DSCADA 5 Year Deployment Summary | | | | | | |
|---|---|---|---|---|---|---|
| | Based on current LTFP | | | If more funding … | | |
| | Quantity | % of substations (cum) | Cost (k) | Quantity | % of substations (cum) | Cost (k) |
| 2016 Actual | 205 (includes all previous years) | 18.5% | $4,069 | | | |
| 2017 Actual (Q1-Q2) | 38 | 21.9% | $4,292 | | | |
| 2017 Plan (Q3-Q4) | 32 | 24.8% | $2,864 | | | |
| 2018 Plan | 50 | 29.4% | $7,444 | 75 | 31.6% | $11,166 |
| 2019 Plan | 50 | 33.9% | $8,050 | 100 | 40.7% | $16,100 |
| 2020 Plan | 65 | 39.7% | $9,490 | 100 | 49.7% | $14,600 |
| 2021 Plan | 70 | 46.1% | $10,570 | 100 | 58.7% | $15,100 |
| 2022 Plan | 80 | 53.3% | $12,080 | 100 | 67.8% | $15,100 |

The DSCADA deployment plan concentrates on distribution devices located in our approximately 1,000 distribution substations. While this plan does not specifically address expanded SCADA capabilities on the HVD or LVD systems, both are parts of an overarching Grid Modernization plan.

The DSCADA plan will be deployed by field areas but will require flexibility to ensure the funding is used in the most cost effective manner. The DSCADA additions are part of a much larger capital system improvement program and, as such, will be integrated into our overall plan to take advantage of synergies with other substation projects that impact DSCADA devices. Some of these projects include recloser upgrades, and substation voltage conversions. On a go-forward basis, DSCADA will be included on new substations and major rebuilds as part of standard substation design.

# F.5 Foundational Platforms: Operational

Operational platforms will provide advance applications that rely on near real-time data from connected grid devices, real-time operational systems and enterprise systems, enabling advanced analysis, visualization, and control capabilities to manage distribution system resources and networked devices that operate and monitor the system. These platforms require a well-developed integration strategy, placing an emphasis on common data objects to define standard interfaces that can be implemented with various vendors' operational platforms and existing company systems. The operational platforms include:

## Advance Distribution Management System (ADMS)

ADMS is the integration of four key software application components that include Supervisory Control and Data Acquisition (SCADA), Distribution Management System (DMS), Outage Management System (OMS), and Distributed Energy Resource Management System (DERMS) on a single platform.

ADMS is widely-used due to its single model capability. It enables more than a single application; it enables an entire eco-system of Grid Management applications that work as a comprehensive solution improving reliability, cost, and grid performance. We have chosen an ADMS strategy to maximize grid device deployments and enable increased Grid Management capabilities.

Data management for model connectivity and asset information will enable future Advanced Distribution Management System (ADMS) functions and our operational and asset analytics needs. ADMS must have accurate data to correctly model the distribution system, so we will establish the right foundation to ensure model data quality, accuracy and availability for ADMS, analytics and other electric GIS enabled applications. We are focusing on data readiness and collecting distribution circuit data, implementing data quality tools, and improving business processes to maintain the data to ensure ADMS and analytics delivers the capabilities to the business.

This approach enables electric connectivity model sharing (a single model serves DMS, OMS and DERMS functions), avoids the need for complex interfaces between separate systems, and allows a single user interface for optimizing grid performance and outage restoration.

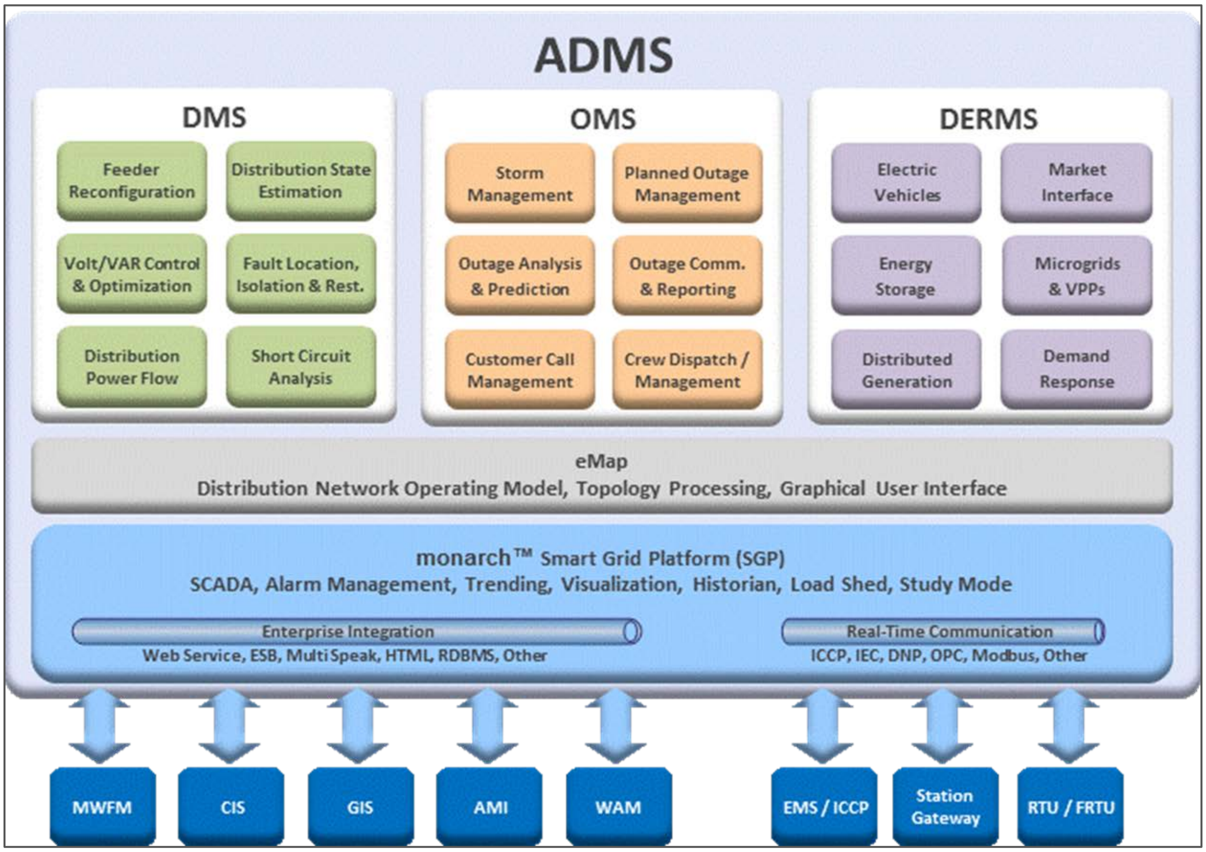
Common industry reasons for investing in ADMS include:

- **Resilience/Reliability**: Creates ability to withstand or recover quickly from outage events including natural disasters
- **Distributed Resources**: Allows for the accommodation and management of larger quantities of distributed energy resources
- **Replacement**: Updates old IT systems that can no longer be maintained or do not have the ability to integrate with new technologies
- **Regulatory**: Meets specific requests to accommodate efficiency and reliability requirements

*Source: DOE "Insights into Advanced Distribution Management Systems", February 2015*

Below is a conceptual overview of an ADMS platform using a single system model for enabling integrated functional components for advance grid management.

*FIGURE 48 — ADMS CONCEPTUAL OVERVIEW*




*Source: OSI, Inc*

## Communications Device Management System

Grid devices have a diverse set of requirements for optimal performance, often demanding multiple communication platforms. We are working to deploy a device management system that can integrate with multiple device-specific software systems, permitting links to telecommunications carrier-based web applications and vendor specific platforms like Cisco and RedLion, and will position us for future integration with cloud based service providers. This will provide real-time operational visibility across our communications fleet independent of the hardware manufacturer. With operational visibility focused on start-of-day monitoring, issue prioritization/tracking, device health and long-term trending, we will improve overall grid performance

# F.6 Foundational Platforms: Grid Asset Analytics

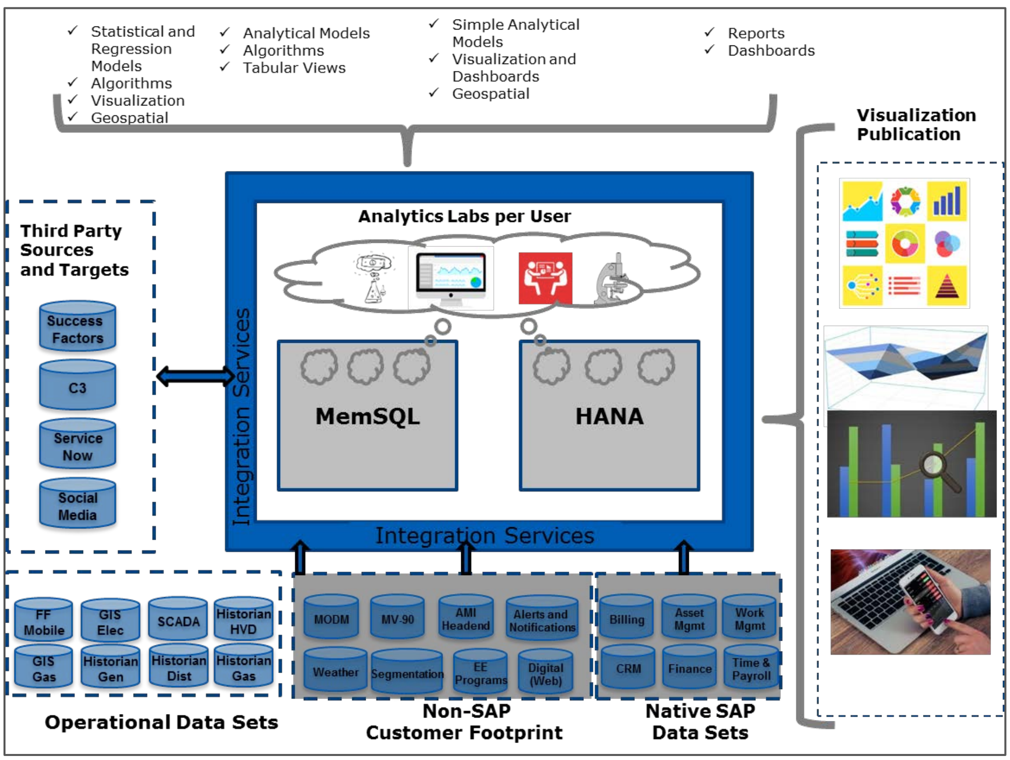
Grid asset analytics platforms include:

## Data Lake

This analytics platform will let us model and visualize connected sources of operational and enterprise data with consistent meaning and quality. We are implementing "Data Lake" architecture to enable this. We have nearly completed our smart meter deployment and plan to add additional smart equipment to the system. The data that these smart devices generate has to be collected, stored, and processed to ensure that the raw data can be turned into meaningful information to inform decision-making.

We have constructed a data repository, referred to as the "Data Lake", capable of storing, retrieving, and processing large amounts of data. There are four key benefits that the data lake provides. First, it provides a system capable of handling high-volume queries, taking the processing load off critical production systems. Second, part of the value of the Data Lake is in its integration of data from disparate systems. As data is ingested into the Data Lake, it is transformed and stored in a standardized manner. This provides a consistent and common framework for the analytics that will be done in the Data Lake. Third, like other corporate systems, the security model provides strict controls for who can access what data. However, the Data Lake also provides a secure space for users to create and explore for relationships in the data without exposing the information to other users or having to offload the data. And finally, the Data Lake is designed to be independent of any particular reporting or data visualization application. This allows users the freedom to turn the raw data into information and to present that information in a manner that is most meaningful to the decision-maker. Below is a conceptual architecture of the Data Lake approach:

***FIGURE 49 — DATA LAKE MODEL***




*Source: Consumers Energy*

## Analytic Development

The first wave of analytics development focuses on transformer based operational insight. The transformer data analytics development is focusing on transformer loading, voltage, and geographic alignment for our existing 500,000 distribution transformers. Expected outcomes include determining overloaded and under loaded conditions to fine-tune service quality; identifying assets with abnormal voltage patterns due to transformer damage or excessive load; and correct modeling of meter-to-transformer installations.

The second wave of analytics development will focus on mis-phasing issues related to individual circuits. This will identify areas with imbalance or model discrepancies based on meter data and events associated with each phase of individual circuits. Expected outcomes include corrections to the circuit model for modeling errors; and identification of circuits that need corrective actions.

The third wave of analytics development will focus on power quality issues. This will identify circuits that display unbalanced load and voltage profiles and extend voltage and load monitoring across the entire circuit. Expected outcomes include identification of circuits that need corrective actions to provide better service quality.

The fourth wave of analytics development will focus on outage analytics. This will look at outage and momentary trends and history to determine systemic issues with electric reliability. Expected outcomes include identification of repetitive outages; and determination of root cause and corrective actions.

# APPENDIX — INVESTMENT SUMMARIES

## G.1 Capital expenditures

***TABLE 64 — CONSOLIDATED CAPITAL INVESTMENT SUMMARY (2016-22)***

| Capital Investment Summary (2016-22, $K) | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| All Investments | 2016 Actuals | 2017 YTD (June) | 2018 Plan | 2019 Plan | 2020 Plan | 2021 Plan | 2022 Plan | Five Year Total |
| ***Plan*** | | | *Estimates for 2018-22 will be included in the final report* | | | | | |
| Grid Analytics | -- | -- | | | | | | |
| System Modeling | -- | -- | | | | | | |
| ***Plan Subtotal*** | -- | -- | | | | | | |
| ***Build*** | | | *Estimates for 2018-22 will be included in the final report* | | | | | |
| ***New Business*** | | | | | | | | |
| Lines New Business - LVD | 43,039 | 23,420 | | | | | | |
| Transformers New Business - LVD | 8,852 | 5,434 | | | | | | |
| Metering New Business - LVD | 5,266 | 5,643 | | | | | | |
| Metro New Business | 3,243 | 1,402 | | | | | | |
| ***Capacity - LVD*** | | | | | | | | |
| Lines Capacity - LVD | 14,517 | 10,143 | | | | | | |
| Substations Capacity - LVD | 18,044 | 5,727 | | | | | | |
| Transformers Capacity - LVD | 3,219 | 1,918 | | | | | | |
| ***Capacity - HVD*** | | | | | | | | |
| Lines & Subs Capacity - HVD | 20,965 | 10,668 | | | | | | |
| ***Strategic Customers*** | | | | | | | | |
| Lines Strategic Customers - HVD | 27,864 | 2,846 | | | | | | |
| ***Non-Wires Alternatives*** | | | | | | | | |
| Demand Response | 1,200 | 2,752 | | | | | | |
| ***Build Subtotal*** | **146,210** | **69,951** | | | | | | |
| ***Maintain*** | | | *Estimates for 2018-22 will be included in the final report* | | | | | |
| ***Reliability*** | | | | | | | | |
| Lines Reliability - LVD | 48,617 | 20,166 | | | | | | |
| Lines Reliability - HVD | 37,825 | 10,330 | | | | | | |
| Substations Reliability - LVD | 11,135 | 7,732 | | | | | | |
| Repetitive Outages - LVD | 8,353 | 3,486 | | | | | | |
| Substations Reliability - HVD | 3,850 | 1,993 | | | | | | |

| | | | |
|---|---|---|---|
| Metro Reliability | 2,518 | 77 | |
| System Protection | 1,569 | 1,733 | |
| ***Demand Failures*** | | | |
| Lines Failures - LVD | 66,860 | 48,745 | |
| Transformers Failures - LVD | 14,754 | 8,630 | |
| Lines & Subs Failures - HVD | 13,206 | 7,562 | |
| Substations Failures - LVD | 9,399 | 6,705 | |
| Metering Failures - LVD | 7,272 | 9,158 | |
| Metro Failures | 5,047 | 1,089 | |
| ***Cost of Removal*** | | | |
| Cost of Removal - LVD | 33,427 | 25,358 | |
| Cost of Removal - HVD | 8,191 | 10,703 | |
| ***Asset Relocations*** | | | |
| Lines Relocations - LVD | 14,362 | 9,169 | |
| Metro Relocations | 4,854 | 2,584 | |
| Lines Relocations - HVD | 288 | 51 | |
| ***Technology*** | | | |
| Tools | 3,377 | 636 | |
| Computer & Equipment | 76 | 298 | |
| Substation Fall Protection | 80 | 6 | |
| ***Other*** | | | |
| Streetlight-Mercury Vapor / LED | 2,193 | 1,258 | |
| ***Maintain Subtotal*** | **297,254** | **177,470** | |
| ***Operate*** | | | |
| Grid Modernization | 18,518 | 8,253 | *Estimates for 2018-22 will be included in the final report* |
| System Control Projects | 2 | 6 | |
| SCADA | 407 | 348 | |
| ***Operate Subtotal*** | **18,927** | **8,607** | |
| ***Total*** | **462,391** | **256,028** | |



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## G.2 O&M expenses

***TABLE 65 — CONSOLIDATED O&M EXPENSE SUMMARY (2016-22)***

| O&M Expense Summary (2016-22, $K) | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| All Investments | 2016 Actuals | 2017 YTD (June) | 2018 Plan | 2019 Plan | 2020 Plan | 2021 Plan | 2022 Plan | Five Year Total |
| ***Plan*** | | | *Estimates for 2018-22 will be included in the final report* | | | | | |
| ***Scheduling & Dispatch*** | | | | | | | | |
| Scheduling & Dispatch | 3,605 | 2,554 | | | | | | |
| ***Grid Infrastructure*** | | | | | | | | |
| Grid Infrastructure | 5,067 | 3,214 | | | | | | |
| ***Distribution & Customer Ops Management*** | | | | | | | | |
| Distribution & Customer Ops Management | 536 | 388 | | | | | | |
| ***Data Management*** | | | | | | | | |
| Geospatial Mgmt & Data Quality - Elec | 2,711 | 950 | | | | | | |
| ***Other O&M*** | | | | | | | | |
| Engineering - HVD | 3,316 | 971 | | | | | | |
| Infrastructure Attachments and Standards | 611 | 285 | | | | | | |
| Financial Management & Controls-Elec | 450 | 520 | | | | | | |
| Distribution Performance | 722 | 552 | | | | | | |
| Regulatory & Compliance-Elec | 399 | 489 | | | | | | |
| Project Management-Elec | 227 | 276 | | | | | | |
| Agreements - LVD & HVD | 529 | 277 | | | | | | |
| CES | 360 | 151 | | | | | | |
| Contract Administration | 229 | 166 | | | | | | |
| ***Plan Subtotal*** | 18,763 | 10,792 | | | | | | |
| ***Build*** | | | *Estimates for 2018-22 will be included in the final report* | | | | | |
| *Energy Efficiency* | 77,216 | 46,063 | | | | | | |
| *Demand Response* | 1,620 | 3,425 | | | | | | |
| ***Build Subtotal*** | 78,836 | 49,488 | | | | | | |
| ***Maintain*** | | | *Estimates for 2018-22 will be included in the final report* | | | | | |
| ***Reliability*** | | | | | | | | |
| Forestry | 50,782 | 26,288 | | | | | | |
| Substations Reliability - LVD | 1,794 | 872 | | | | | | |
| Substations Reliability - HVD | 957 | 627 | | | | | | |
| Lines Reliability - LVD | 56 | 5 | | | | | | |



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| | | | |
|---|---|---|---|
| Lines Reliability - HVD | 317 | 37 | |
| ***Repair and Restoration*** | | | |
| Service Restoration | 35,504 | 30,632 | |
| Staking / Street / Service Calls | 7,262 | 3,605 | |
| Corrective Maintenance | 3,483 | 2,476 | |
| Substations Demand - LVD | 3,321 | 1,465 | |
| Substations Demand - HVD | 2,150 | 1,198 | |
| Alma Equipment Repair | 1,136 | 526 | |
| Lines Demand — HVD | 533 | 354 | |
| ***Field Operations*** | | | |
| Supervision / Admin-Staff | 6,063 | 3,475 | |
| Training | 4,174 | 3,209 | |
| Facilities Building Opers & Maintenance | 4,198 | 2,050 | |
| Field Operations Expenses | 2,360 | 1,446 | |
| Tools | 1,811 | 939 | |
| ***Meter Services*** | | | |
| Meter Services | 2,992 | -847 | |
| Meter Reading | 11,582 | 3,484 | |
| ***Other O&M*** | | | |
| O&M Associated w/Construction | 7,228 | 3,685 | |
| DCO Accruals | 5,801 | 2,653 | |
| Joint Pole Rental | 1,789 | 903 | |
| Transformer Credits | -6,134 | -3,041 | |
| ***Maintain Subtotal*** | 149,159 | 86,042 | |
| ***Operate*** | | | |
| Smart Energy MTC - Elec | 0 | 3,522 | |
| System Control & Monitoring | 3,754 | 2,478 | *Estimates for 2018-22 will be included in the final report* |
| Meter Tech & Mgmt Sys Support | 1,133 | 485 | |
| ***Operate Subtotal*** | 4,887 | 6,485 | |
| ***Total*** | **251,646** | **152,808** | |

# APPENDIX — GLOSSARY

| Term or Acronym | Definition |
|---|---|
| Advanced Distribution Management System (ADMS) | The software platform that supports the full suite of distribution management and optimization. An ADMS includes functions that automate outage restoration and optimize the performance of the distribution grid. |
| Advanced Metering Infrastructure (AMI) | Advanced metering infrastructure (AMI) is an integrated system of smart meters, communications networks, and data management systems that enables two-way communication between utilities and customers. Customer systems include in-home displays, home area networks, energy management systems, and other customer-side-of-the-meter equipment that enable smart grid functions in residential, commercial, and industrial facilities. |
| BESS | Battery Energy Storage Systems |
| C&I | Commercial & Industrial |
| CAIDI | The average restoration time per outage (outage duration |
| Capability Margin | The difference between net electrical system capability and system maximum load requirements (peak load); the margin of capability available to provide for scheduled maintenance, emergency outages, system operating requirements and unforeseen loads. |
| Capacitor | An electrical device that adjusts the leading current of an applied alternating current to balance the lag of the circuit to provide a high power factor. |
| Capacity | The load that a power generation unit or other electrical apparatus or heating unit is rated by the manufacture to be able to meet or supply. |
| CELID | Customers Experience Long Interruption Duration |
| CEMI | Customer Experiencing Multiple Interruptions |
| Circuit | A device, or system of devices, that allows electrical current to flow through it and allows voltage to occur across positive and negative terminals. |
| Conservation Voltage Reduction (CVR) | Conservation Voltage Reduction (CVR) is a proven technology for reducing energy and peak demand. CVR is implemented by controlling the voltage on a distribution circuit to the lower end of a tolerance band, either defined by ANSI C84.1 (114–126 volts) or another target range. Conservation then occurs on the circuit when certain end-use loads draw less power when voltage is lowered. |
| CYME | A distribution power flow planning tool |
| Data Lake | Centralizes disparate data sources (asset, customer, outage, smart meter, DSCADA, etc.) into a single location. |
| Data Proliferation | The prodigious amount of data, structured and unstructured, that businesses and governments continue to generate at an unprecedented rate and the usability problems that result from attempting to store and manage that data. |



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| Term or Acronym | Definition |
|---|---|
| Demand | The rate at which electricity is delivered to or by a system, part of a system, or piece of equipment expressed in kilowatts, kilovoltamperes, or other suitable unit, at a given instant or averaged over a specified period of time. |
| Demand Charge | A charge for the maximum rate at which energy is used during peak hours of a billing period. That part of a power provider service charged for on the basis of the possible demand as distinguished from the energy actually consumed. |
| Demand Failures | Typically defined as an outage or interruption of service |
| Demand Response | A change in the power consumption of an electric utility customer to better match the demand for power with the supply |
| Dispatchability | The ability to dispatch power. |
| Distributed Energy Resources (DERs) | Smaller power sources that can be aggregated to provide power necessary to meet regular demand. As the electricity grid continues to modernize, DER such as storage and advanced renewable technologies can help facilitate the transition to a smarter grid. |
| Distributed Generation | A term used by the power industry to describe localized or on-site power generation. |
| Distribution | The process of distributing electricity; usually defines that portion of a power provider's power lines between a power provider's power pole and transformer and a customer's point of connection/meter. |
| Distribution Automation (DA) loops | Specially designed systems installed between two LVD feeders that use automatic transfer reclosers to transfer load automatically in the event of an outage, reducing customer outages and improving system reliability by isolating a faulted section of a feeder. |
| Distribution Line | One or more circuits of a distribution system on the same line or poles or supporting structures' usually operating at a lower voltage relative to the transmission line. |
| Distribution System | That portion of an electricity supply system used to deliver electricity from points on the transmission system to consumers. |
| DSCADA | Distribution Supervisory Control and Data Acquisition |
| Energy Efficiency | The goal to reduce the amount of energy required to provide products and services. For example, insulating a home allows a building to use less heating and cooling energy to achieve and maintain a comfortable temperature. |
| Energy Storage | The process of storing, or converting energy from one form to another, for later use; storage devices and systems include batteries, conventional and pumped storage hydroelectric, flywheels, compressed gas, and thermal mass. |
| ETR | Estimated Time of Restoration |

| Term or Acronym | Definition |
|---|---|
| FERC | This is an independent regulatory agency within the U.S. DOE that has jurisdiction over interstate electricity sales, wholesale electric rates, natural gas pricing, oil pipeline rates, and gas pipeline certification. It also licenses and inspects private, municipal, and state hydroelectric projects and oversees related environmental matters. |
| FLISR | Fault location, isolation, and service restoration |
| Frequency Regulation (FR) | Ancillary service that allows the grid to remain as close as possible to its nominal frequency (60 Hz in the U.S.). Often discussed with relation to a gap between power generation and demand on the grid that causes the grid frequency to move away from its nominal value. |
| GI | Grid Infrastructure |
| GIS | A geographic information system (GIS) is a system designed to capture, store, manipulate, analyze, manage, and present spatial or geographic data. |
| Grid | A common term referring to an electricity transmission and distribution system. |
| Grid-Connected System | Independent power systems that are connected to an electricity transmission and distribution system (referred to as the electricity grid) such that the systems can draw on the grid's reserve capacity in times of need, and feed electricity back into the grid during times of excess production. |
| High-voltage distribution (HVD) | Portion of the distribution system consisting of 46,000-69,000 volt lines |
| IEEE | Institute of Electrical and Electronics Engineers |
| Incident Command System (ICS) | Statewide program to help ensure the safey of responders and the public, the achievement of restoration objectives, and effective and efficient use of resources. |
| Kilovolt-ampere (kVa) | A unit of apparent power, equal to 1,000 volt-amperes; the mathematical product of the volts and amperes in an electrical circuit. |
| Kilowatt (kW) | A standard unit of electrical power equal to one thousand watts, or to the energy consumption at a rate of 1000 Joules per second. |
| LiDAR | LIDAR—Light Detection and Ranging—is a remote sensing method used to examine the surface of the Earth. LIDAR data is often collected by air. |
| LMRs | Load Modifying Resources |
| Load | The power required to run a defined circuit or system, such as a refrigerator, building, or an entire electricity distribution system. |
| Load Forecast | An estimate of power demand at some future period. |
| Load Leveling | The deferment of certain loads to limit electrical power demand, or the production of energy during off-peak periods for storage and use during peak demand periods. |

| Term or Acronym | Definition |
|---|---|
| Low-voltage distribution (LVD) | Portion of the distribution system serving businesses and residences at between 120-480 volts |
| Major Event Day (MED) | Designates a catastrophic event which exceeds reasonable design or operational limits of the electric power system and during which at least 10% of the customers within an operating area experience a sustained interruption during a 24-hour period. |
| Maximum Loads | The highest loads experienced on the system at the point of analysis, excluding anomalies |
| Megawatt (MW) | One thousand kilowatts, or 1 million watts; standard measure of electric power plant generating capacity. |
| MISO | Midcontinent Independent System Operator |
| NERC | North American Electric Reliability Corporation |
| On-site Generation | Generation of energy at the location where all or most of it will be used. |
| Outage | A discontinuance of electric power supply. |
| Peak Clipping/Shaving | The process of implementing measures to reduce peak power demands on a system. |
| Peak Demand/Load | The maximum energy demand or load in a specified time period. |
| Peaking Capacity | Power generation equipment or system capacity to meet peak power demands. |
| Reconductoring | Process in which the conductoring is replaced |
| Reliability | This is the concept of how long a device or process can operate properly without needing maintenance or replacement. |
| Renewable Energy | Energy derived from resources that are regenerative or for all practical purposes can not be depleted. Types of renewable energy resources include moving water (hydro, tidal and wave power), thermal gradients in ocean water, biomass, geothermal energy, solar energy, and wind energy. Municipal solid waste (MSW) is also considered to be a renewable energy resource. |
| Restoration | Return of normal service after an outage or interruption |
| SAIDI | The primary overall electric system reliability indicator. SAIDI measures the annual number of minutes the average customer is without power across the entire electric system. (SAIDI = SAIFI*CAIDI) |
| SAIFI | The average number of interruptions per customer per year (outage frequency). |
| SCADA | An acronym for Supervisory Control and Data Acquisition. SCADA generally refers to an industrial computer system that monitors and controls a process. In the case of the transmission and distribution elements of electrical utilities, SCADA will monitor substations, transformers and other electrical assets. |
| UAVs | Unmanned Aerial Vehicles |

| Term or Acronym | Definition |
|---|---|
| Volt-VAR Optimization (VVO) | Volt/VAR optimization (VVO) is a process of optimally managing voltage levels and reactive power to achieve more efficient gird operation by reducing system losses, peak demand or energy consumption or a combination of the three. During the process, voltage control devices at a substation and on the circuit can be used to shrink the voltage drop from the substation to the end of the line and reduce the service voltage to customers while maintaining the voltage within defined limits. The efficiency gains are realized primarily from a reduction in the system voltage. This results in less energy being consumed by end-use equipment served by the distribution system. |
| ZRC's | Zonal Resource Credits |
| Voltage | The amount of electromotive force, measured in volts, that exists between two points. |

# LIST OF TABLES





**Draft Only and Subject to Major Revisions. Final Report Due January 31, 2017**

# LIST OF FIGURES

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

| | | |
|---|---|---|
| In the matter of the application of<br>CONSUMERS ENERGY COMPANY<br>for authority to increase its rates for<br>the generation and distribution of<br>electricity and for other relief. | )<br>)<br>)<br>)<br>)<br>) | Case No. U-17990 |

**PROOF OF SERVICE**

STATE OF MICHIGAN )
) SS
COUNTY OF JACKSON )

Samantha J. O'Rourke, being first duly sworn, deposes and says that she is employed in the Legal Department of Consumers Energy Company; that on August 1, 2017, she served an electronic copy of **Consumers Energy Company's Electric Distribution Infrastructure Investment Plan** upon the persons listed in Attachment 1 hereto, at the e-mail addresses listed therein. She further states that she also served a hard copy of the same document to the Hon. Dennis W. Mack, Administrative Law Judge, at the address listed in Attachment 1 by depositing the same in the United States mail in the City of Jackson, Michigan, with first-class postage thereon fully paid.

Digitally signed by Samantha O'Rourke
Date: 2017.08.01 17:42:25 -04'00'

Samantha J. O'Rourke

Subscribed and sworn to before me this 1st day of August, 2017.

Digitally signed by Tara L. Hilliard
Date: 2017.08.01 17:42:42 -04'00'

Tara L. Hilliard, Notary Public
State of Michigan, County of Jackson
My Commission Expires: 09/12/20
Acting in the County of Jackson

**ATTACHMENT 1 TO CASE NO. U-17990**

**Administrative Law Judge**

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