**Advanced Distribution Planning Tool
Description and Certification Request**

INTRODUCTION

Distribution planning is a key component of the Company's efforts to modernize its grid operations. As described in Section V of the IDP, we undertake a multi-step distribution planning effort each year. This process evaluates projected peak load on each feeder and substation in our system, so that we can analyze and identify needed risk mitigation projects, and put forward a proposal for the upgrades we anticipate are necessary to accommodate customer needs. While some of this baseline distribution forecasting is performed efficiently within our current tool, there is also significant manual work and several bolt-on tools required to fulfill all of our historical distribution planning needs.

Recognizing that distribution planning needs were beginning to change and our existing tool could not accommodate all the analysis we would need or want to do going forward, we began assessing new options in 2015. Given market trends, widespread changes to our grid, and our forecasting software's lifecycle, it is now essential we implement a new, more capable, and dynamic forecasting tool. Such a tool will enable us to meet our planning and regulatory requirements and provide our customers with incremental benefits. Consistent with national trends, our customers are increasingly exercising more choice around their use of energy from our grid, choosing DER and beneficial electrification that can make load forecasting a much more complex undertaking than it was only a few years ago.

As a result of these changes, our distribution planning tools must accommodate additional data granularity to better assess how technologies interact with the grid and how they change l distribution system needs. In order to accommodate customer needs and other stakeholder requests for additional granularity and transparency, the Commission has implemented new planning analysis and reporting requirements the Company must meet. These requirements include conducting scenario forecasting and assessing non-wires alternatives (NWA) for certain upgrade needs we identify. Finally, the existing tool and its hosting server are out of date and its vendor will no longer support it in the near future. Considering these factors, it is time to implement a new solution.

After a thorough solicitation and assessment process, the Company selected a preferred advanced distribution planning tool that will enable us to meet the aforementioned customer needs and Commission requirements for distribution planning. While we are currently in the advanced stages of procuring that tool, as of November 1, 2019, we have not yet signed a contract. Thus, we refer to the tool in this certification request as the Advanced Planning Tool or APT. Beyond customer and compliance needs, the APT will enable us to deliver additional benefits via more efficient planning, enhanced load forecasting capabilities, and better integration with the Company's other planning efforts.

We have already begun to prepare our internal systems and processes to implement the APT. We expect to complete procurement in early 2020, and take the first several months of the year to integrate our data into the new tool and train employees on its use. This is an ambitious timeline, but it will allow us to begin using the APT in our distribution planning processes stating in 2020-2021. Our expected all-in upfront cost is approximately $9.3 million Xcel Energy-wide, and we estimate the proportional Northern States Power Company – Minnesota (NSPM) operating company share of these upfront costs will amount to approximately $4 million. Given the proposed contract structure, our annual costs to maintain the tool are low, and the upfront costs represent most of the total costs we expect over the tool's life.

While our benefit-to-cost assessment for the tool does not indicate direct positive returns, we believe the investment is essential to performing the more sophisticated analyses our evolving grid requires going forward. Continuing to use the existing tool is not feasible. We do expect O&M expenditures for APT will be comparatively lower than the existing tool, however; and while challenging to assess in advance, we also believe the tool may enable us to defer some distribution capital expenditures in the future. Finally, the tool will deliver additional qualitative value, beyond what is quantifiable, by improving analysis efficiency and precision.

Given these factors, the Company respectfully requests that the Commission certify our request to procure the APT for distribution planning purposes. As we discuss in more detail below, this investment meets the requirements for certification and is consistent with planning requirements and goals set forth in prior Commission Orders.

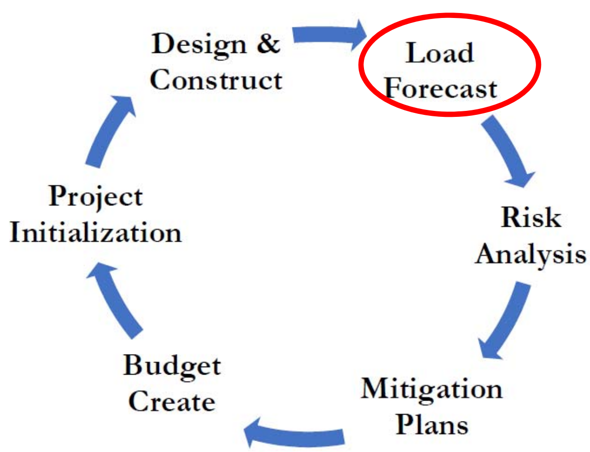
I. EXISTING DISTRIBUTION PLANNING PROCESS AND TOOLS

As discussed in detail in Section V of the IDP, our existing distribution planning process examines our distribution system's ability to serve customer peak load, identifies areas where there is a risk of overload or equipment failure, and makes plans to mitigate these potential overloads with additional or upgraded equipment. We complete this full cycle once per year, and the analysis examines projected conditions over a five-year forward-looking time horizon. As the starting point of our distribution planning process, load forecasting – and the tools we use to complete it – is an essential foundational step. Our current tool has served the Company well in the past; however, as distribution planning and needs change and software service offerings evolve, the tool has become out of date and can no longer effectively meet our system needs moving forward.

A. Load Forecasting as a Piece of the Distribution Planning Process

The process begins with load forecasting. Historically, the load forecasting step has included examining several key components of distribution system use, but remained primarily focused on expected peak load and overall utilization rates. These are two important components, because as peak load or utilization on specific feeders or substations increase and approach the equipment's capacity, there is a greater chance that deviations from expected load could result in overloads and outages.

Figure 1: Annual Distribution Planning Process



In the course of our current load forecasting process, we examine our most recent year's actual peak load and utilization data for each feeder and substation transformer, along with historical trends, and use this information to project load five years into the future. We also evaluate the potential effects of additional load growth drivers and incorporate them into our load forecast. These factors include weather, potential and planned development and new customer load, trends around DER adoption and electrification, and any circuit reconfigurations that may affect the forecast for specific locations on the grid. After completing these projections, our distribution team analyzes where forecasted peak load and utilization may exceed or approach limits for overloading in both normal and contingency conditions. Where these overloads are identified, the team evaluates potential upgrade solutions and prioritizes investments. These investment priorities then feed into our budget creation process. The team also then aggregates the forecast and coordinates with transmission planning staff, so that the Company uses consistent information across these planning processes.

B. Existing Load Forecasting Tool and Capabilities

Given the process described above, load forecasting is an essential foundational step in identifying potential pain points in the system, and balancing the need to stop potential outages before they happen with the need to manage costs to customers. The Company currently uses a tool called Distribution Asset Analysis (DAA) to facilitate its load forecasting efforts. This tool was specifically tailored to the Company's system by its vendor, Itron, and was first implemented in 2003. DAA allows us to use SCADA-based feeder and substation information, combined with customer billing data and weather data, to better examine loading conditions at each of these analysis points. Our ability to evaluate this previously disparate data within one tool helps us form the basis of our existing distribution load forecasting analysis.

There are, however, various other aspects of our distribution planning process for which DAA is not used, largely because it does not have the required functionality to perform them. For example, DAA itself cannot perform scenario analyses or aggregate feeder and substation specific forecasts. For these aspects of our distribution forecasting process, we use a combination of other tools and manual processes, as depicted in Table 1 below. In all, the combination of DAA and other tools and approaches has historically enabled us to meet our distribution planning and reporting regulatory requirements and operational needs.

Table 1: Distribution Forecasting Tools, by Planning Component

	Planning Process Component						
Tool	Forecast	Risk Analysis	Mitigation Plans	Budget Create	Initiate Construction - EDP Memo	Long-Range Plans	Hosting Capacity
Synergi Electric			X			X	X
DAA	X	X				X	
MS Excel		X		X		X	
CYMCAP		X					
GIS			X			X	X
SCADA	X						
WorkBook		X	X	X	X		
DRIVE							X

That said, distribution planning is changing, given customer trends, needs, and evolving regulatory requirements; DAA's usefulness as a planning tool has not kept pace with these changes. Customers now have many more options when it comes to their energy usage and are increasingly exercising those choices. These options include reducing consumption through home energy controls, increasing consumption through beneficial electrification, and feeding energy back onto the grid by installing DER. Further, the Commission has established grid planning priorities and requirements that are intended to ease the customer path to DER adoption and electrification, as well as encouraging utilities to examine options for grid upgrades beyond traditional "poles and wires" investments. DAA, as a forecasting tool, was not designed to support utility analysis in these tasks.

More specifically, the Commission has set forth several requirements for which the analysis possible within DAA falls short, and requires the Company to conduct various manual analyses. These include developing forecast scenarios that allow us to understand the grid impacts on varying levels of DER adoption, as well as evaluating non-wires alternatives for traditional poles and wires mitigation projects identified that are over $2 million in estimated cost.[1] Further, several of the Commission's objectives with regard to grid modernization are more difficult to meet given DAA's limitations. For example, one of the objectives of Grid Modernization Reports, as set forth by the Commission, is to ensure optimized utilization of electricity grid assets and resources to minimize total system costs. Given our existing tool only evaluates

[1] Per *Order Approving Integrated Distribution Planning Filing Requirements for Xcel Energy*. Docket No. E002/CI-18-251 (August 30, 3018).

annual peak load conditions, our existing forecasting tool simply does not provide the capability to meet these going forward needs.

It is also important to note that the DAA tool and its hosting server are both outdated and reaching the end of their useful life. DAA's vendor has informed us that it no longer provides ongoing updates or support for the tool beyond basic technical maintenance, and the Company is its only remaining customer for this tool.

For the foregoing reasons, DAA will no longer provide us the basic functionality we need to understand how customers are interacting with our distribution system, deliver additional value to customers by identifying potential benefits of DER in a given area, or keep pace with regulatory requirements in an efficient manner. Even if the tool were going to be available into the future, we would need a new distribution load forecasting tool that is better suited to evaluating more dynamic load conditions with more granularity, given the evolving nature of our distribution system and customer technology adoption. Further, as our advanced grid efforts continue, a more dynamic load forecasting tool will be able to grow with our capabilities, serving as an essential piece to enable new customer usage data insights, and providing additional value to customers in terms of programs and offerings.

II. NEW TOOL EVALUATION AND APT SELECTION

Recognizing that DAA's capabilities would not be sufficient in a future with more customer technology adoption and without continuing vendor support, we began evaluating options for a new tool in 2015. As we moved through this process and received bid responses to evaluate different options, new requirements from the Commission were also emerging that solidified much of what we recognized would be important tool attributes going forward. As a result of a careful evaluation process – including bid responses, initial evaluations, and vendor demonstrations – we determined that the APT is the best option for conducting the depth and breadth of analyses needed going forward. The tool's core benefits include the ability to: more efficiently and cost-effectively forecast distribution-level load; conduct more advanced scenario and NWA analyses; and better integration of our distribution planning with other Company planning processes. We believe this tool will position us well for the future of distribution planning, where its capabilities can grow with us and help us meet current and future Commission planning requirements.

A. Guiding Factors for Selecting a New Load Forecasting Tool

Overall, selecting a tool that enables us to provide customers with more value, meets our regulatory requirements, and eliminates manual data processing was of utmost importance in our evaluation process. Specifically, we see the following three key capabilities as essential to our selection process: forecast granularity and ability to support non-wires alternative investment analysis, ability to support scenario development, and integration with other resources and planning processes. We discuss each further below.

1. Forecast Granularity and Non-wires Alternative Investment Analysis

As noted above, our current tool is capable of evaluating annual peak load at a feeder or substation level. A tool that provides more granular analysis options, in terms of both time intervals and proximity to the customer end point, enables us to make more accurate decisions regarding investment needs and options. For example, with the introduction of DER onto the system, the differentials between minimum and maximum load during the day become both a more valuable and harder to predict data point. With more customers adopting DER and beneficial electrification, peak loading on a specific feeder may result in different levels of load, or at a different time of day than another feeder or than the system as a whole. In order to adequately assess the impact of DER on a given part of the grid, therefore, we need a tool that can forecast hourly load at the selected analysis point. Further, the most granular analysis point we have been able to utilize in distribution planning thus far is the feeder level, but there may be value in analyzing sub-feeder data. Each feeder is generally associated with approximately 1,500 to 8,000 endpoints, depending on the area's population density. However, as DER are often localized to a specific end point, being able to analyze load and generate distribution forecasts at a sub-feeder level may provide valuable insights for both necessary grid upgrades and future potential customer offerings.

Combined, a tool that enables these more granular analyses will provide important information and efficiencies in assessing potential non-wires alternatives to identified system upgrade needs. An annual peak load analysis alone cannot communicate whether an identified upgrade is a candidate for non-wires alternative; more granular hourly data is required to determine the magnitude of overloads at specific durations. Currently this analysis is completed by extracting historical peak day load curves from feeder data, scaling them to the forecast study year, and then manually evaluating the normal and contingency load conditions. We then use these results to conduct risk analyses and develop theoretical load conditions if certain DER solutions were applied. However, a tool that can evaluate and project hourly load data on a feeder or other specific point on the grid would facilitate more efficient evaluation of potential future overloads and whether a non-wires solution – such as DER, efficiency or energy storage – is a viable alternative to traditional upgrades. In short, we anticipate a tool with these capabilities would reduce manual work and better identify opportunities for DERs to provide value on our grid.

2. Scenario Development

The Commission's Order setting out the requirements for our integrated distribution plan includes DER scenario analyses. In accordance with these requirements, we evaluate scenarios with a minimum level of assumed DER adoption, as well as medium and high adoption scenarios (corresponding to Base+10 percent and Base+25 percent, respectively). The objective of these analyses is to understand whether substantially increased levels of DER at a given point on the grid would result in different system overload conditions and upgrade needs. Currently these scenarios are developed and evaluated outside our load forecasting tool, given our current tool is incapable of generating such an analysis. A tool that can provide these scenario forecasting capabilities intrinsically would contribute to more efficient forecasting processes and better assessment regarding how these increased adoption scenarios would affect specific feeders and substation transformers. This will be particularly important going forward as DER and beneficial electrification adoption increases in our service area.

3. Aggregation and Integration with Other Resources and Planning Processes

Finally, a key aspect of a new distribution forecasting tool is its ability to integrate data source inputs, as well as communicate effectively with our other planning processes. Any new tool in which we invest will need to be able to surpass the existing tool's capabilities; preferably in its ability to handle data inputs from various sources beyond the current set of inputs such as feeder-level SCADA data and existing customer usage inputs. External data layers, such as more targeted economic and weather forecasts or projected DER adoption trends will help us more effectively forecast load changes into the future. The tool we select also needs to be able to integrate potential internal future sources of data, such as interval data from our proposed AMI investments.

Further, forecast aggregation and integration with other company planning efforts is an essential benefit we considered when evaluating replacement tools. As previously discussed, our existing tool evaluates potential load growth on a feeder or substation. However, this level of growth must be defined by the planner responsible for analyzing that specific point on the grid, and the tool cannot effectively aggregate forecasts from each point of analysis to ensure a reasonable fit with Company-wide top-line forecasts. Moreover, the forecast outputs from a future tool must be easily accessible and usable within other company planning processes. Currently, our transmission planners scale distribution forecasts to the corporate level manually, for use in transmission planning processes and tools. We also have an existing regulatory requirement to align distribution planning to integrated resource planning more closely, particularly in terms of DER forecasts. As our resource planning tools evaluate generation resources at an hourly level, a similarly granular distribution forecasting tool will facilitate this integration more effectively than the current manual translation processes.

B. RFI Process, Evaluation, and Selection

Considering the needs outlined above, the Company took a multi-step approach to evaluating potential future tools. This includes information gathering and pre-screening, applying evaluation criteria to potential vendors subsequent bid proposals, inviting the top vendors to provide product demonstrations, and external vetting. We describe each of these steps in turn below.

1. Initial Screening and Evaluation Criteria Development

First, we independently researched available tools and their vendors, in addition to well-known technology companies that we believed may be able to develop a customized solution. This research resulted in seven distinct vendor options representing a broad range of companies; from large industrials providers to boutique solutions. After this research was complete, we issued a Request for Information from the selected vendors. This RFI included a questionnaire with over 300 questions that were designed to help us further screen the potential new tools. At the same time, we also assembled a cross functional team to use a list of scoring metrics and evaluate potential options throughout the information and bid process. This team included Company professionals from the Distribution team, as well as Enterprise Architecture, IT Security, and Sourcing. Solutions were evaluated across multiple metrics, including those in the non-exhaustive list of example scoring considerations in Table 2 below.

Table 2: Example Distribution Forecasting Tool Evaluation Metrics (Not Exhaustive)

Category	Scoring Criteria
Scope and Technical Requirements	Prior experience and customer references
	Ability of proposal to meet scope of work and timeline
	Functional requirements
	Technical requirements
	Security requirements
Cost/Pricing	Total price – base and alternate bids
	Proposal detail and cost transparency
	Implementation costs and maintenance costs
Commercial Terms	Negotiability of contract terms
Vendor Financials	Financial health of the vendor

Of the seven vendors invited to submit an informational bid, three responded. These responses were scored primarily according to the vendor's ability to demonstrate how the tool would meet the scope and technical requirements we outlined, as well as other factors. Pricing and commercial terms were evaluated in a subsequent round, after formal bids were received.

2. *Bid Evaluation and APT Selection*

Given the initial screening and bid evaluation described above, we eventually narrowed available distribution forecasting tool options to two potential products, as the third vendor failed to demonstrate their proposed solution met the project scope. At this point, we invited the vendors of each remaining product to provide a demonstration of their respective tools and discuss whether they were able to provide the core functionalities we identified. We designed the demonstration assessments to build on vendors' RFI responses, ensuring a vendor's tool could sufficiently meet the most important functional requirements we set out for our next distribution forecasting tool. The APT's vendor was able to show that the tool satisfies all of these the requirements, and it was the only vendor to do so. We describe the tool itself and its capabilities with respect to the three core guiding factors we identified further below. Further, the vendor showed that the tool would not require substantial customization for use with our other existing tools and analyses. Conversely, the other tool's vendor was unable to demonstrate most of the requirements during the course of our demonstration meeting, and would have required extensive customization to integrate. As a result, the APT was the preferred choice given its analysis capabilities and ease of integration.

In an effort to further validate this determination, we also reached out to industry experts after the demonstration phase to gauge experience with both tools. Specifically, we talked to existing APT customers in the utility industry to better understand their use cases and satisfaction with the tool and the vendor's services. We also conducted expert interviews through a third party to evaluate APT and whether there were viable alternate tools we missed the process of our evaluation. These experts confirmed that APT was one of the only solutions that could provide the functionality we need. It was based on all the aforementioned evaluations, in aggregate, that we determined APT is the appropriate tool for the next phase of the Company's distribution forecasting.

III. APT OVERVIEW AND PLANNED IMPLEMENTATION

The APT is a spatial load forecasting tool, which combines several layers of detailed electric infrastructure, weather, economic and other data layers to forecast how future load and energy demands on the grid may change and thus, where upgrades may be required. We describe the APT's capabilities relative to those benefits further below. Given our existing load forecasting tool has reached its end of life, we plan to begin procurement and implementation quickly. In fact, we are currently conducting contract discussions with the tool's vendor and have already begun our initial internal design work. We plan to finalize the contract in the near term and complete the software acquisition in early 2020. We anticipate full tool implementation for the Upper Midwest service areas will be complete in the third quarter of 2020, and Company-wide by 2021. Xcel Energy-wide we expect that procurement and implementation will cost approximately $9.3 million upfront – most of which will be capital investments. For NSPM, we expect the upfront investment will amount to approximately $4 million. As the tool will be a shared asset, other Xcel Energy operating companies will incur their proportional share of overall costs as well.

While our benefit-to-cost assessment for the tool does not indicate direct positive returns, we believe the investment is essential to performing the more sophisticated analyses our evolving grid requires going forward. Over the full seven year assumed financial life of the software, we expect a benefit-to-cost ratio of 0.35. Benefits of the tool include lower O&M costs for the APT as compared to our existing tool, even considering substantial added functionality, and some potential capital deferral benefits. However, the tool's benefits go beyond what can be shown in the CBA. The APT will provide multiple additional qualitative benefits that, while challenging to quantify in dollar terms, are tangible and substantial. We also expect to use the tool far beyond its seven year asset life – and given the low ongoing costs, customer benefits will continue to accrue into the future. In all, we believe the APT will provide substantial value in building a more robust distribution forecasting process that will better serve customer needs, and help us meet our regulatory requirements more efficiently.

A. Overview

The APT is a forecasting tool for distribution loads, which will replace – and surpass – our existing load forecasting tool in providing insight into potential future load on each of our feeders and substation transformers. The tool will do this by combining hourly historical load data with other Company and externally provided data layers, and using statistical methods to develop best-fit forecast analyses for every feeder and substation transformer on our system. The tool allows historical load data to be imported directly from SCADA systems, or at a more granular level from AMI.[2] The tool also can manage multiple data layers such as the Company's demand data and DER forecasts, as well as external geospatial and economic data such as housing starts and gross domestic product growth at a granular geographic level. The effect of each layer on the load forecast for a feeder or substation transformer can be disaggregated from the overall forecast, to provide information on the magnitude of impact resulting from any given factor.

The tool's vendor provides several combination options for licensing and deploying the software, which we carefully evaluated for fit, cost, and ease of use. Ultimately we chose to procure the tool as a hosted solution on a perpetual license. This means that the vendor will provide for our use of the tool on their servers, to which we will have access via the cloud. We determined using the APT as a hosted solution was an appropriate choice largely because it affords nearly instantaneous updates to the tool when the vendor makes improvements or adds new features. If we were to host the software on our own servers, update integration would need to be done on site, which can sometimes delay access to new or updated features up to several months. A hosted deployment option is also more cost effective for the Company in this instance, allowing us to avoid maintaining – and paying for – our servers for the software.

We chose a perpetual license primarily based on its cost-effectiveness over the duration we plan to use the tool. We believe the APT – with the vendor's continual updates – will provide the features we need far into the future, beyond the typical seven year asset life we use to assess software investments. Our internal analyses showed that a perpetual license option would be the most cost-effective if the Company uses this tool for eight years or more. To provide a point of comparison,

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[2] Note that the Company does not yet have AMI on its system, but APT could integrate the data from that infrastructure in the future, if available.

we have been using our current tool for 16 years thus far, and given the cost to acquire and integrate a new system, we do not anticipate making another change within eight years. At present, there are few to no alternatives that can provide comparable functionality, and emergent tools from other vendors remain in development phases. Especially given APT's continual updates and its "room to grow" with our advanced metering capabilities, we anticipate the upfront investment is the most prudent path forward. We further discuss the tool's total costs in Section D below

B. Capabilities and Benefits

The APT provides various functionalities and benefits that make it an appropriate choice for our future distribution system planning. As discussed previously, there are three key functions we used as guiding factors in tool evaluation and selection, to enable the range of analyses that will provide value to our customers and that meet our regulatory requirements. The APT has the demonstrated ability to provide all of these functions. We also anticipate it will facilitate additional process automation, reducing staff time dedicated to completing our forecasting and reporting requirements. We describe these capabilities in more detail below.

1. Forecast Granularity and Non-wires Alternative Investment Analysis

As noted previously, improved forecast granularity is a key enabling factor that will allow us to improve our analyses, in terms of both time intervals and proximity to the customer end point, and enable us to make more accurate decisions regarding investment needs and options. APT will be able to use historical distribution system SCADA and/or metering data, alongside in-built layers to generate statistically robust best-fit hourly load forecasts and shapes at the feeder and substation transformer level. Forecasting load shapes for each feeder and substation transformer, in particular ones that can be disaggregated from the effects of DER installed at a given point on the system, is an essential functionality for our future tool. It will enable more targeted N-0 and N-1 overload analyses, in terms of time, duration, and location. Further, where upgrade needs are identified, these hourly shapes will provide helpful insight that allows us to better analyze potential non-wires alternatives and distribution investment deferral analyses.

2. Scenario Development

As noted above, the Commission's Order setting out requirements for our distribution planning processes necessitate DER scenario analyses. We currently develop these scenarios manually outside our distribution forecasting tool, and because the tool only evaluates annual peak load conditions, it is difficult to get a full picture of how these higher DER adoption scenarios may affect a given feeder or substation across the full year. However, APT will allow us to integrate these forecasts more fully into our analyses. Our baseline DER forecasts will be integrated directly with hourly load forecasts, where the tool uses best-fit analyses to determine potential impact of DER at the feeder level. The tool will also make it easier to develop DER scenario analysis that can be applied at this more granular level, and allow us to test different adoption scenarios within the tool. All of this functionality allows us to conduct DER scenario analyses more efficiently, and will help us better assess how different levels of DER may change peak loads and load shapes on specific feeders throughout the service area.

3. Aggregation and Integration with Other Resources and Planning Processes

Finally, a key aspect of a new distribution forecasting tool is its ability to integrate data source inputs, as well as communicate effectively with our other planning processes. APT enables us to do both. The tool can be used to fit distribution system forecasts, via standard statistical modeling methods, to our corporate-level forecasts that we use in Transmission and Resource Planning, so that these forecasts can be consistent across planning functions. This is key in part because Transmission and Resource Planning already use models that conduct analyses on hourly load and generation shape data; and enabling distribution planning to analyze and forecast conditions on a similar time interval will enable all three planning processes to align better. The new tool will also provide modeling outputs that can be used in power flow modeling, which will support easier data handoffs between processes.

4. Additional Benefits

In addition to the benefits described above, the tool can also provide two additional capabilities that will support our ability to meet additional regulatory requirements: (1) inform customer energy choices and (2) perform increasingly granular analyses. First, because APT is capable of developing hourly load shapes on feeders and disaggregating the effects of DER from net load, it will help us conduct better informed Hosting Capacity Analyses (HCA) in the future. For example, daytime minimum load analyses required in the HCA are currently developed manually, by evaluating each feeder with a Community Solar Garden installation and manually removing the estimated effect of the CSG on the feeder's estimated load. With APT, the tool will provide hourly load shapes that will automatically disaggregate the effect of DERs in a particular area, so that we are able to assess daytime minimum load without additional manual work. Second, the tool can grow in its analysis capabilities in accordance with the granularity of the data we can provide, in particular with AMI and meter level interval data. When we implement AMI, APT will be able to integrate that sub-feeder level data and allow us to perform more precise forecasting and planning analyses. Overall, these added benefits support our determination that APT is the right tool to take our load forecasting capabilities into the next phase.

C. Implementation Action Plan

Now that we have determined the APT is the best tool available to suit our distribution forecasting needs for the foreseeable future, we plan to move quickly to procure and implement APT. After finalizing the procurement, design, implementation, testing, which will take place over the next several months – we plan to begin using the APT in our distribution planning processes by late 2020.

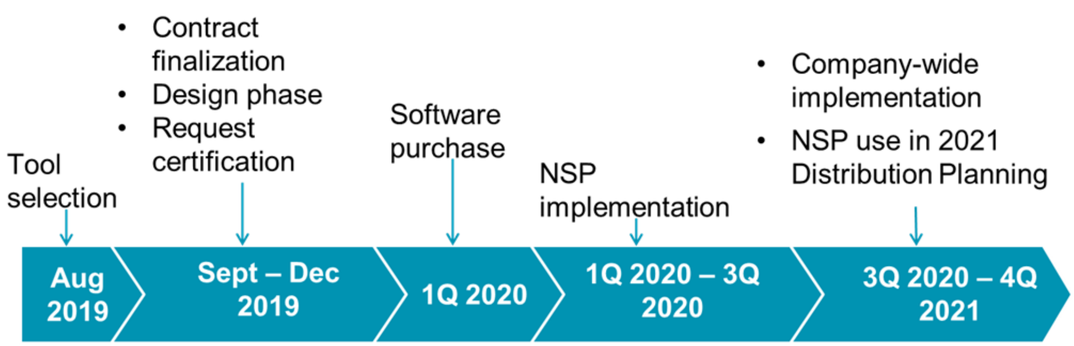
In order to prepare for tool implementation, we are currently conducting detailed design preparations. In this phase, we are undertaking activities such as developing an overall software implementation architecture, mapping functional requirements to test cases, and mapping from where each needed data stream will feed into the tool. We anticipate completing this phase by the end of the year. During this time we are also finalizing the contract details with the vendor, which will enable us to move through the purchasing process early in the first quarter of 2020.

After purchase is complete we will immediately begin partnering with the vendor on the detailed design. During this phase, we will firm up the scope of the project, including which modules/capabilities of the software we will use. We will also conduct a system architecture review, which will determine how APT and its integration will be implemented within the broader context of our IT system. This will also be followed by a data mapping effort, in which we will determine the source system and the location of the information for each level of data attribution that APT requires. Simultaneously, we will be reviewing the various requirements for the project, identifying test cases that would validate those requirements that will be conducted during the testing phase.

The project team will then begin migrating this data to the APT system to prepare for implementation for use in our Upper Midwest distribution system planning (NSPM and the Northern States Power Company-Wisconsin, or NSPW systems – collectively NSP). Given the effort and coordination required to migrate vast amounts of data into a new, more granular forecasting tool, we expect this phase will take several months. The implementation phase will include both internal work – such as necessary development to build data integration paths, prepare, migrate our data to the new system, and testing to ensure data is migrating correctly. During the testing phase, we will conduct the test cases identified in the design phase, to identify and resolve any defects. After the defects are resolved, training will begin, in which the vendor will prepare our distribution planning team (and other stakeholders as necessary) for using the system after go-live.

After the tool is tested and implemented for NSP, we plan to begin using it in our distribution planning process. In fact, we anticipate it will be fully operational in time to use it in our 2020-2021 distribution planning cycle. This timeline, while ambitious, will ensure that we can begin benefitting from its more granular analyses and draw key insights as soon as is practicable.

Figure 2: Planned APT Implementation Timeline[3]



After the tool is fully implemented in NSP, we will begin work to implement in our operating company affiliates Public Service of Colorado (PSCo) and Southwest Public Service (SPS).

D. Costs and Benefits

1. *Procurement and Implementation Costs*

Given the capabilities and benefits the APT will enable for our distribution planning processes, we are confident that the investment is in the interest of both customers and the Company. As discussed previously, we have already started internal work to prepare for implementing the tool. While the contracting process and implementation planning remains in progress, we believe the costs outlined below represent an appropriate estimate for the Commission to consider as part of our certification request.

We expect the full up-front cost to procure and implement the tool at the Xcel Energy level will be approximately $9.3 million. This includes costs related to the

[3] Note this implementation schedule remains fluid and subject to change.

tool's procurement – such as the license, a pre-paid five-year maintenance and support contract, internal systems integration activities, as well as the first year of ongoing O&M costs. Because the vendor portion of the cost details are market sensitive, we provide a non-public breakdown of the estimated costs in Section V and summary level costs in Table 3 below.

Table 3: Xcel Energy-Wide APT Procurement and Implementation Cost Estimate ($, Nominal Millions)

Cost Category	Cost
APT License	Please refer to Section V for the non-public detailed cost breakdown
Company Integration – Capital Costs	
Pre-Paid Maintenance and Support for five years	
Annual Software Hosting Fee	
Company O&M Costs	
Total Up Front Costs	**$9.3**

Further, we note that our maintenance costs for the APT will be lower than the amount we currently pay for our current tool that, comparatively, has limited functionality; on an annualized basis, this savings amounts to over $100,000 Xcel Energy-wide.

The upfront acquisition costs will be apportioned to Xcel Energy operating companies based on each company's number of distribution feeders.[4] In total, we expect NSPM-specific costs to amount to approximately $4.0 million in 2020, most of which will be capital. We outline the expected cost categories below, and provide the corresponding expected costs in Section V.

We further note that there are some minimal O&M-related costs that will recur each year, including the hosting server cost and Company internal support; we have also accounted for annualized maintenance and service contract costs beyond year five when our initial pre-paid period ends. These costs are factored into the cost-benefit analysis discussed below.

[4] While not an existing approved application methodology, we will propose this allocation method in our 2020 Cost Allocation Methodology filing.

Table 4: NSPM Jurisdictional Capital and O&M Budget – APT Procurement and Implementation ($2020 Millions)[5]

Cost Category	Upfront Budget	Discussion
Total Capital	Please refer to Section V	
APT Installation and License		Majority of costs incurred in 2020 for perpetual license and project/program management and contingencies.
Company IT System Integration		Costs incurred in 2019-2020, for initial business systems implementation and year 1 contingencies.
Total O&M	Please refer to Section V	
APT Software Maintenance		Pre-paid five-year maintenance service and ongoing software hosting, plus year 1 contingencies.
Company IT Maintenance and Support		Costs incurred in 2019-2020, for implementation and change management expenses, including year 1 contingencies.
Total Cost to Procure and Implement	$3.97	Total estimated capital and O&M

2. *Cost-Benefit Analysis*

The APT will become a foundational element of our increasingly robust distribution planning process, to meet the needs of an evolving grid. Considering the costs to be incurred and the directly quantified benefits, we expect this project to result in a benefit-to-cost ratio of approximately 0.35 for NSPM. We summarize the CBA below and provide the Company's full cost-benefit analysis as non-public Attachment D2 to this filing.

[5] Note that these costs include adjustments to present expected 2020 costs, based on the 2019 Company-wide cost estimates presented in Table 3.

Table 5: NSPM APT Benefit-to-Cost Ratio

Net Present Value Components	Total
Benefits ($ millions)	**1.3**
O&M Benefits	0.8
Other Benefits	-
Capital Benefits	0.5
Costs ($ millions)	**3.7**
O&M Expense	0.6
Change in Revenue Requirements	3.1
Benefit/Cost Ratio	**0.35**

We derived this ratio from our estimates of the approximately $3.7 million of present value revenue requirement the tool will represent, and $1.3 million of quantified present value benefits, on a net present value basis, over an assumed seven year asset life. The costs reflected in this calculation primarily relate to a change in capital revenue requirements associated with the software and ongoing maintenance costs described more extensively above.

The benefits relate to two key factors. First, the avoided ongoing subscription cost of our current distribution forecasting tool and a Microsoft Excel plug-in tool. Second, our estimated annual deferred capital value realized as a result of the tool's enhanced capabilities. As noted previously, the APT – with its enhanced functionality – will result in reduced maintenance costs of over $100,000 on an annualized basis. We also expect that the tool may provide some capital expenditure deferral opportunities. As the APT able to more accurately forecast the needs on the system through the incorporation of Distributed Generation, Energy Efficiency, and Corporate growth forecasts, we expect it may help us defer certain upgrades that would have otherwise been indicated with a less precise tool. We estimated this value based on the benefits of deferring one feeder upgrade for three years.

In addition to the quantifiable benefits discussed above, we believe that the qualitative benefits of an improved tool further supports our planned investment. Some of the additional benefits the APT offers as compared to our existing tools and process include:

- Hourly analysis for all measured points on the grid that examines the minimum and peak loading differentials, load shapes and more clearly shows the impact of DER;
- Improved load forecasting precision that can account for two-way power flows;

- Enables easier identification of opportunities for non-wires alternatives investments for projected overloads and contingencies;
- Processes forecasting scenarios within the tool, rather than requiring an outside, manual process;
- Enables analysis closer to the customer than the traditional feeder and substation analysis, to examine impacts of DER at a more granular level;
- Better integrates customer data, including from future AMI deployment;
- Aggregates forecasts to ensure better consistency with corporate-level forecasts, and better integration into other company planning processes

While it is difficult to quantify the benefits of the factors listed above, we believe they are substantive and should be considered when the Commission determines the prudence of our proposed investment. All these factors considered, we are confident that the APT is a valuable investment that will significantly improve our load forecasting capabilities overall, helping us to provide enhanced customer benefits in our distribution planning overall and to meet relevant regulatory requirements.

IV. REQUEST FOR CERTIFICATION

Given the above, we respectfully request that the Commission certify our request to procure APT for load forecasting purposes. In accordance with Minn. Stat. §216B.2425, we request the Commission certify the APT as a project necessary to modernize our distribution system. This statute requires utilities operating under multiyear rate plans, such as Xcel Energy, to identify in biennial reports:

> …investments that it considers necessary to modernize the transmission and distribution system by enhancing reliability, improving security against cyber and physical threats, and by increasing energy conservation opportunities by facilitating communication between the utility and its customers through the use of two-way meters, control technologies, energy storage and microgrids, technologies to enable demand response, and other innovative technologies.

The normal procedural schedule for certification under Minn. Stat. § 216B.2425 would require a determination by June 1, 2020. As also discussed in the IDP, we recognize that our request for certification of this advanced planning tool and our proposed AGIS investments in the General Rate Case does not align with that timing. In addition, the AGIS initiative includes large investments and is supported by a sizeable filing that may require analysis beyond the six-month certification timeframe, even if the General Rate Case is withdrawn. Thus, we offer to work with the

Commission and stakeholders to set an appropriate deadline and procedural schedule for consideration of these investments.

That said, we believe the APT will substantially facilitate our distribution planning process and enhance our hosting capacity analysis processes, therefore meeting the standard of an investment eligible for certification. For these reasons, we request that the Commission certify the APT; specifically because the tool will support grid modernization while enhancing reliability, and because it will facilitate increased conservation opportunities.

First, the APT is a foundational tool that will support distribution system modernization, thereby enhancing reliability. As discussed at length above, our current distribution forecasting relies on historical annual peak load data and does not enable hourly forecasts. Therefore, it does not provide sufficient visibility into, nor adequately account for, the timing of peak load throughout the day, intraday differential between minimum and peak load, or the duration of a potential feeder or substation overload. For each instance in which a potential overload or contingency condition is uncovered, we rely on historical data and manual analysis to determine the best mitigation method. As a direct improvement, the tool will significantly enhance our visibility into hourly forecasted load shapes, so that we may better identify and analyze potential issues and mitigation paths. It also enables better and more efficient DER scenario forecasting and enhanced integration with our other planning processes.

Second, the APT will better facilitate our evaluation and identification of increased conservation opportunities. One clear benefit of developing more granular load forecast capabilities, both in terms of time and spatial analysis, is that we will be able to better assess opportunities for non-wires alternatives to mitigate or eliminate identified needs. Understanding the timing and duration of an overload is essential to determining the viability of DER or energy efficiency solutions to fulfil the need. Further, because the APT enables analysis at a more granular level than feeder and substation, it could enable better us to better target those solutions. In addition to the improvements the tool will afford to our conventional distribution planning functions, we also believe the tool will better facilitate our hosting capacity analysis, because it enables analysis of daytime minimum loads and how they may change over the forecast period.

V. DETAILED COST INFORMATION

As noted above, the Company has not yet finalized the contract for the APT, and regardless whether they are being negotiated or in final form, the contractual cost terms are market sensitive and thus subject to trade secret protection. For that reason, we are providing additional detailed cost information in this separate section, with a request for trade secret designation for selected details.

As initially discussed in Table 3 above, the Company's expects that the total upfront cost to procure the APT would be approximately $9.3 million. A more detailed accounting of these costs is included in Table 6 below.

Table 6: Xcel Energy-Wide APT Procurement and Implementation Cost Estimate ($, Nominal Millions)

Cost Category	Cost
[PROTECTED DATA BEGINS	
APT License	
Company Integration – Capital Costs	
Pre-paid Maintenance and Support for Five Years	
Annual Software Hosting Fee	
Company O&M Costs	
PROTECTED DATA ENDS]	
Total Up Front Costs	**$9.27**

Further, we noted in Section III.D that APT will provide ongoing annual savings as compared to our current distribution forecasting tool. The vendor's pre-paid ongoing service agreement for APT technical support would effectively amount to approximately **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]**. This, in addition to the **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]** annual hosting fee, represents over $100,000 per year in savings as compared to the **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]** annual Xcel Energy-wide cost of DAA, which is the distribution forecasting tool APT replaces, and an additional **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]** associated with a Microsoft Excel plug-in tool, which will be included with the APT.

For NSPM specifically, the estimated upfront investments for the APT, adjusted to 2020 values are outlined in Table 7 below.

Table 7: NSPM Jurisdictional Capital and O&M Budget – APT Procurement and Implementation ($2020 Millions)

Cost Category	Upfront Budget ($2020 millions) [6]	Discussion
[PROTECTED DATA BEGINS		
Total Capital		
APT Installation and License		Majority of costs incurred in 2020 for perpetual license and project/program management and contingencies.
Company IT System Integration		Costs incurred in 2019-2020, for initial business systems implementation and year 1 contingencies.
Total O&M		
APT Software Maintenance		Pre-paid five-year maintenance service and ongoing software hosting, plus year 1 contingencies.
Company IT Maintenance and Support		Costs incurred in 2019-2020, for implementation and change management expenses, including year 1 contingencies.
PROTECTED DATA ENDS		
Total Cost to Procure and Implement	$3.97	Total estimated capital and O&M

[6] Note that these costs include adjustments to present expected 2020 costs, based on the 2019 Company-wide cost estimates presented in Table 6.

APT Cost Analysis for NSPM

	2019	2020	2021	2022	2023	2024	2025	2026	2027	TOTAL	NPV
CAPITAL ITEMS - SUMMARY											
APT Installation-License	[PROTECTED DATA BEGINS										
License-Vendors Project Management											
Vendor Project Management - Contingency											
TOTAL - Installation and License											
Company's IT Systems and Integration											
IT Hardware-Upgrade											
Business Systems NSPM Implementation											
IT Contingency											
TOTAL - Installation and License											
Program Management											
Engineering and Supervision (E&S)-electric distribution											
TOTAL - Program Management											
											PROTECTED DATA ENDS]
TOTAL CAPITAL	**$0**	**$3,592,890**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$3,592,890**	**$3,171,724**
O&M ITEMS - SUMMARY											
APT Maintenance-License	[PROTECTED DATA BEGINS										
Hosting Software Cost											
Pre-paid M&S											
Contingency											
TOTAL - License Maintenance											
Company's IT Systems											
Business Systems Maintenance and Support											
TOTAL - BS Maintenance											
Program Management											
Program/Change Management/Training											
Contingency											
TOTAL - Program Managememt											
											PROTECTED DATA ENDS]
TOTAL O&M	**$0**	**$374,697**	**$26,357**	**$26,980**	**$27,619**	**$28,274**	**$105,814**	**$108,094**	**$110,424**	**$808,259**	**$610,383**
GRAND TOTAL CAPITAL & O&M	**$0**	**$3,967,587**	**$26,357**	**$26,980**	**$27,619**	**$28,274**	**$105,814**	**$108,094**	**$110,424**	**$4,401,149**	**$3,782,107**

Note: Input values from the "CostInputs" tab are "budget values," which represent 2019 nominal dollars. These are not adjusted for inflation. The model on the "SumAPTCOSTS" tab adjusts the "input budget cost allocations" to real prices over time due to inflation. For instance, a 2020 budget allocation, currently in 2019 nominal dollars, will be converted to 2020 real dollars by the model.

APT Benefits Analysis for NSPM

	2019	2020	2021	2022	2023	2024	2025	2026	2027	TOTAL	NPV
O&M ITEMS - SUMMARY											
Avoided Cost From Current Systems	[PROTECTED DATA BEGINS										
DAA Annual Cost											
DSMore Annual Cost											
TOTAL - Avoided Cost Current Systems											
											PROTECTED DATA ENDS]
TOTAL O&M	**$0**	**$0**	**$155,556**	**$158,776**	**$162,063**	**$165,417**	**$168,842**	**$172,337**	**$175,904**	**$1,158,894**	**$799,381**
CAP ITEMS - SUMMARY											
Capital Deferred Projects Value											
Capital Deferred Projects Value	$0	$0	$96,328	$98,322	$100,357	$102,435	$104,555	$106,720	$108,929	$717,646	$495,017
TOTAL CAPITAL	**$0**	**$0**	**$96,328**	**$98,322**	**$100,357**	**$102,435**	**$104,555**	**$106,720**	**$108,929**	**$717,646**	**$495,017**
GRAND TOTAL QUANTIFIABLE BENEFITS	**$0**	**$0**	**$251,884**	**$257,098**	**$262,420**	**$267,852**	**$273,397**	**$279,056**	**$284,833**	**$1,876,540**	**$1,294,398**

APT Benefit to Cost Ratio

	Total ($M, net present value)
Benefits	**1.3**
Operational	1.3
Costs	**(3.7)**
O&M Expense	(0.6)
Change in Capital Revenue Requirement	(3.0)
Benefit/Cost Ratio	**0.35**

I. RISK SCORING METHODOLOGY

As part of our risk analysis and mitigation processes, discussed as part of our annual System Planning process in Section V of the IDP, Xcel Energy personnel enter projects throughout the year in the Risk Register/Workbook. Along with the description of the project, the originator must identify the primary business value driving the investment, and may also enter the benefit and any associated service quality metric impacts (i.e. customer minutes out, which impacts System Average Interruption Duration Index (SAIDI), System Average Interruption Frequency Index (SAIFI), and Customer Average Interruption Duration Index (CAIDI), etc.). After Distribution Operations and Risk Analytics review the projects to ensure the data is accurate, Business Area Finance sets-up all appropriate accounting structures.

Projects are then run through the risk model for scoring. This process involves a number of steps:

- A project's raw financial benefit is calculated based on a project's gross cash flow (generally, incremental revenue plus realized salvage value less incremental recurring costs, non-recurring costs (e.g. taxes), and capital expenditures) and avoided costs.
- A project's raw reliability benefit is calculated based on overload customer minutes out (considering mega volt-amperes (MVA) beyond threshold, customers per MVA, and annual hours at risk), contingency customer minutes out (considering peak load less available relief MVA, customers per MVA, time to restore, peak day hours out, and yearly failure rate of equipment at risk), and the number of customer complaints to the public utilities commission.
- The raw reliability benefit is converted into the same metric as the raw financial benefit using a conversion factor (e.g., $1.25/customer minute out) based on an algorithm.
- Jurisdictional factors (including discount rates, income tax rates, property tax rates, inflation rates, historical Commission complaints, historical Quality of Service plan (QSP) SAIDI data, and historical transformer failure data) are then applied to the financial benefit and reliability benefit.
- A benefit:cost ratio (also known as a Risk Score) based on the jurisdictional financial and reliability benefits and annualized costs of each project is calculated.

From these calculations the projects get prioritized – and based on the capital budget, the projects that will be funded in the current 5-year budget are selected.

Part II reflects all Distribution projects budgeted in the latest/most current available budget (July 2019) at the time of our IDP filing. Budgets are formally updated annually, and rebalanced on an ongoing basis. Project scopes and/or timelines are subject to change at any time based on (but not limited to) engineering studies, area considerations, design estimates, permitting feasibility, capital target changes, and emergent circumstances.

IDP Capacity is the only IDP category for which Risk Scores are applicable, because it is the only category for which we have the ability to objectively quantify the annual risk. Capacity projects are driven by feeder and transformer risks that can be quantified in terms of increased reliability. We use the risk score to help prioritize capacity projects; however, as discussed in our IDP filing, the risk score is not the only factor used to determine budget priority. For other budget categories that may not be driven by reliability, and for which the risks may not be objectively quantifiable, we prioritize projects based on other factors:

- *Mandates*. Government- or customer-driven work that is covered by our tariffs or involves relocating our facilities in public rights of way when in conflict with road projects, for example. This work category is not negotiable and has established timelines/due dates – and some portion may additionally be emergent in the current year, potentially requiring us to reprioritize/rebalance our budgets.

- *New Business*. Customer-driven work under our tariffs, including customer requests for changes or applications for new service. Like Mandates, this work category is not negotiable, has established timelines/due dates, and some portion may additionally be emergent in the current budget year.

- *Asset Health*. Programs or projects driven by engineering analyses to address aging infrastructure and improve system resilience. Our budget benefit/cost model does not effectively capture the value that a programmatic approach to asset health provides.

- *Blankets*. Blankets fund high volume, low dollar, current year, reactive work and can contain hundreds of smaller projects and therefore does not lend itself to risk-ranking.

- *Programs*. Also see Asset Health above. Programs are funded based on identified needs or risks outside of the budget risk scoring model. Programmatic work for the current year is typically defined in-year based on equipment failures that are occurring, or after the previous year's reliability results are available and analyzed. For example, our cable replacement program is based on in-year cable failures and customer impacts, and is driven by engineering and reliability needs, not a budgeting risk model. As noted in Asset Health, our budget benefit/cost model does not effectively capture the value that a programmatic engineering approach to cable failures provides.

Parts II and III contain information Xcel Energy maintains as Security Information, pursuant to Minn. Stat. § 13.37, subd. 1(a). The public disclosure or use of this information creates an unacceptable risk that those who want to disrupt our system for political or other reasons may learn which facilities to target to create a disruption of our service.

Part III contains information Xcel Energy maintains as trade secret data as defined by Minn. Stat. § 13.37, subd. 1(b). This information has independent economic value from not being generally known to, and not being readily ascertainable by, other parties who could obtain economic value from its disclosure or use.

Part III is marked as "Not-Public" in its entirety. Pursuant to Minn. Rule 7829.0500, subp. 3, the Company provides the following description of the excised material:

1. **Nature of the Material:** Calculations of expected Customer Minutes Out given electric distribution asset load and failure rate data
2. **Authors:** Electric Systems Performance and the Risk Analytics Department
3. **Importance:** Key values to determine the potential reliability of certain projects
4. **Date the Information was Prepared:** October 29, 2019

PROTECTED DATA SHADED

II. CAPACITY RANKINGS

Mitigation Title	Jurisdiction	Lifespan of Project	Total Annualized Costs ($M's)	Reliability Benefit - CMO (Electric)	Financial Benefit	Reliability Benefit	Financial Benefit	Total Weighted Benefit	Project Score
				[PROTECTED DATA BEGINS					
Reinforce Medford Junction MDF TR1	NSPM - ED	40	$0.158						**114.9**
Install Switch Coon Creek CNC073	NSPM - ED	40	$0.002						**52.9**
Reinforce Fair Park FAP TR1 & Fdr	NSPM - ED	40	$0.086						**49.7**
Install Feeder Tie Wilson WIL081	NSPM - ED	40	$0.020						**34.8**
Reinforce Osseo OSS062	NSPM - ED	40	$0.013						**33.1**
Extend Red Rock RRK063	NSPM - ED	40	$0.007						**18.1**
Load Transfer ESW062 to SMT061	NSPM - ED	40	$0.007						**15.0**
Extend Main Street MST074	NSPM - ED	40	$0.020						**14.3**
Reinforce Westgate WSG Feeders	NSPM - ED	40	$0.036						**10.8**
Reinforce Medicine Lake MEL074	NSPM - ED	40	$0.033						**10.6**
Install Hiawatha West HWW Feeder	NSPM - ED	40	$0.079						**10.3**
Install Midtown MDT Feeder	NSPM - ED	40	$0.125						**9.5**
Extend Saint Louis Park SLP085	NSPM - ED	40	$0.010						**8.4**
Install Feeder Tie Osseo OSS063	NSPM - ED	40	$0.007						**8.0**
Load Transfer CGR062 to CGR071	NSPM - ED	40	$0.063						**7.7**
Install Wilson WIL TR4 & Feeders	NSPM - ED	40	$0.974						**7.5**
Reinforce Savage SAV063 & SAV067	NSPM - ED	40	$0.072						**7.1**
Install Kohlman Lake KOL Feeder	NSPM - ED	40	$0.103						**6.9**
Install Stockyards STY TR3 & Feeders	NSPM - ED	40	$0.263						**6.3**

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Install Baytown BYT Feeders	NSPM - ED	40	$0.268						**6.2**
Install Fiesta City FIC Feeder	NSPM - ED	40	$0.066						**6.0**
Install Feeder Tie SOU083 to MDT074	NSPM - ED	40	$0.007						**5.4**
Reinforce Saint Louis Park SLP087	NSPM - ED	40	$0.010						**5.2**
Extend Saint Louis Park SLP092	NSPM - ED	40	$0.040						**4.8**
Reinforce Glenwood GLD Sub Equip	NSPM - ED	40	$0.046						**4.6**
Install Goodview GVW Feeder	NSPM - ED	40	$0.072						**4.0**
Install Chemolite CHE065 Feeder	NSPM - ED	40	$0.095						**3.9**
Install Wyoming WYO Feeder	NSPM - ED	40	$0.165						**3.9**
Install Feeder Tie EBL064	NSPM - ED	40	$0.010						**3.7**
Reinforce Basset Creek BCR062	NSPM - ED	40	$0.016						**3.7**
Reinforce Moore Lake MOL071	NSPM - ED	40	$0.036						**3.1**
Install Western WES TR3 & Feeders	NSPM - ED	40	$0.493						**2.8**
Reinforce Kasson KAN TR1 & Feeders	NSPM - ED	40	$0.188						**2.8**
Install Feeder Tie Crooked Lake CRL033	NSPM - ED	40	$0.073						**2.6**
Install Albany ALB TR	NSPM - ED	40	$0.194						**2.1**
Reinforce Terminal TER073	NSPM - ED	40	$0.072						**1.8**
Install South Washington ERU Sub	NSPM - ED	40	$0.373						**1.8**
Reinforce Veseli VES TR1 & Feeder	NSPM - ED	40	$0.171						**1.8**
Extend Terminal TER064	NSPM - ED	40	$0.010						**1.7**
Reinforce Burnside BUR TR2	NSPM - ED	40	$0.172						**1.6**
Reinforce Edina EDA062	NSPM - ED	40	$0.033						**1.3**
Reinforce Brooklyn Park BRP062	NSPM - ED	40	$0.012						**1.2**
Install Zumbrota ZUM TR & Feeder	NSPM - ED	40	$0.189						**1.2**

PROTECTED DATA SHADED

Reinforce Sibley Park SIP Sub Equip	NSPM - ED	40	$0.006						**1.1**
Install Viking VKG Feeder	NSPM - ED	40	$0.165						**1.0**
Install Rosemount RMT TR2 & Feeder	NSPM - ED	40	$0.358						**1.0**
Install Orono ORO TR2 & Feeder	NSPM - ED	40	$0.274						**0.9**
Install Goose Lake GLK TR3 & Feeders	NSPM - ED	40	$0.333						**0.8**
Install Cannon Falls Trans CTF TR2 & Fdr	NSPM - ED	40	$0.124						**0.7**
Install West Coon Rapids WCR TR	NSPM - ED	40	$0.137						**0.7**
Install Lindstrom LIN Feeder	NSPM - ED	40	$0.043						**0.7**
Install Hyland Lake HYL TR3 & Feeder	NSPM - ED	40	$0.291						**0.6**
Reinforce Tanners Lake TLK Sub Equip	NSPM - ED	40	$0.013						**0.6**
Reinforce Oakdale OAD073 & OAD075	NSPM - ED	40	$0.018						**0.5**
New MPK075-GPH061 Feeder Tie	NSPM - ED	40	$0.016						**0.5**
Install East Winona EWI TR2 & Feeder	NSPM - ED	40	$0.218						**0.4**
Install Louise LOU TR2 & Feeders	NSPM - ED	40	$0.332						**0.4**
Install Hiawatha West HWW TR2	NSPM - ED	40	$0.092						**0.1**
Reinforce St Cloud SCL TR2	NSPM - ED	40	$0.092						**0.1**
Install Midtown MDT TR2	NSPM - ED	40	$0.093						**0.1**

PROTECTED DATA ENDS]

III. Mitigation Calculation Examples

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2. **Authors:** Electric Systems Performance and the Risk Analytics Department
3. **Importance:** Key values to determine the potential reliability of certain projects
4. **Date the Information was Prepared:** October 29, 2019

IDP Requirement 3.A.29 requires the following:
Planned distribution capital projects, including drivers for the project, timeline for improvement, summary of anticipated changes in historic spending. Driver categories should include:
a. Age-Related Replacements and Asset Renewal
b. System Expansion or Upgrades for Capacity
c. System Expansion or Upgrades for Reliability and Power Quality
d. New Customer Projects and New Revenue
e. Grid Modernization and Pilot Projects
f. Projects related to local (or other) government-requirements
g. Metering
h. Other

	Mitigation	Mitigation Name	Risk Score Applied	2020	2021	2022	2023	2024	Grand Total
Age-Related Replacements and Asset Renewal				**$87,244,281**	**$79,537,631**	**$78,279,487**	**$79,652,481**	**$80,991,479**	**$405,705,358**
Accounting Correction	E114.017857	MN Elec Mixed Work Adjustment	NA	$9,099,917	$11,829,996	$11,829,996	$11,829,996	$11,829,996	$56,419,901
Blanket	E114.018176	MN - OH Rebuild Tap/Backbone/Sec Blkt	NA	$9,912,000	$10,142,000	$10,377,000	$10,618,003	$10,864,003	$51,913,006
	E114.018178	MN - OH Services Renewal Blanket	NA	$103,000	$105,003	$107,000	$109,000	$112,000	$536,003
	E114.018354	MN - OH Street Light Rebuild Blanket	NA	$822,000	$844,000	$865,000	$888,000	$888,000	$4,307,000
	E114.018274	MN - UG Conversion/Rebuild Blanket	NA	$6,758,000	$6,915,009	$7,075,009	$7,239,009	$7,407,009	$35,394,036
	E114.018275	MN - UG Services Renewal Blanket	NA	$2,903,009	$2,970,002	$3,039,009	$3,110,002	$3,182,000	$15,204,022
	E114.018355	MN - UG Street Light Rebuild Blanket	NA	$788,000	$809,002	$830,000	$852,000	$852,000	$4,131,002
	E141.017359	MPLS UG Network Vault Blanket	NA	$492,000	$504,000	$516,000	$516,000	$516,000	$2,544,000
	E151.016697	STP UG Network Vault Blanket	NA	$244,000	$250,004	$256,000	$256,000	$256,000	$1,262,004
Failure	E103.001736	MN Failed Sub Equip Replacement	NA	$2,300,000	$2,300,000	$2,300,000	$2,300,000	$2,300,000	$11,500,000
	E103.016837	MN Failed Sub TR Replacement	NA	$800,000	$1,600,000	$1,600,000	$1,600,000	$1,600,000	$7,200,000
	E103.019429	Reserve TR 115/13.8 kV 70 MVA	NA	$552,000					$552,000
	E103.013577	Reserve TR 115/34.5 kV 70 MVA	NA	$800,000					$800,000
	E103.012618	Reserve TR 69/13.8 kV 28 MVA	NA			$550,000			$550,000
Program	E103.017653	ELR MN Sub Batteries	NA	$54,000	$306,000	$180,000	$180,000	$180,000	$900,000
	E103.011890	ELR MN Sub Feeder Breakers	NA	$449,998	$2,550,000	$1,500,000	$1,500,000	$1,500,000	$7,499,998
	E103.012606	ELR MN Sub Fences	NA	$75,008	$425,008	$250,000	$250,000	$250,000	$1,250,016
	E103.012603	ELR MN Sub Regulators	NA	$60,000	$340,000	$200,000	$200,000	$200,000	$1,000,000
	E103.012586	ELR MN Sub Relays	NA	$90,000	$510,000	$300,000	$300,000	$300,000	$1,500,000
	E103.006458	ELR MN Sub Retirements	NA	$60,000	$340,000	$200,000	$200,000	$200,000	$1,000,000
	E103.013521	ELR MN Sub RTUs	NA	$31,340	$177,594	$104,467	$104,467	$104,467	$522,334
	E103.011891	ELR MN Sub Switches	NA	$30,000	$170,000	$100,000	$100,000	$100,000	$500,000
	E103.012612	ELR MN Sub TRs	NA			$2,000,004	$2,000,004	$2,000,004	$6,000,012
	E141.018795	ELR MPLS Network Protectors	NA	$250,004	$750,004	$1,000,000	$1,000,000	$1,000,000	$4,000,008
	E141.001664	ELR MPLS Vault Tops	NA		$1,000,000	$500,000	$1,000,000	$1,000,000	$3,500,000
	E151.018796	ELR STP Network Protectors	NA	$250,004	$750,004	$1,000,000	$1,000,000	$1,000,000	$4,000,008
	E151.013639	ELR STP Vault Tops	NA	$799,999	$700,006	$500,002	$1,000,000	$1,000,000	$4,000,007
	E114.018129	MN - Pole Replacement Blanket	NA	$28,900,000	$17,700,000	$17,700,000	$17,700,000	$17,700,000	$99,700,000
	E103.009150	SPCC NSPM Oil Spill Prevention	NA	$700,000					$700,000
Project	E144.013600	Convert Butterfield BTF 4kV	NA			$100,000	$2,700,000		$2,800,000
	E144.013622	Convert Lafayette LAF 4kV	NA				$100,000	$1,950,000	$2,050,000
	E144.018411	Rebuild Clara City CLC221	NA	$800,001	$599,999				$1,400,000
	E144.019617	Rebuild Sacred Heart SCH211	NA	$1,400,000					$1,400,000
	E144.017589	Rebuild Yellow Medicine YLM211 & YLM212	NA	$1,450,000	$1,450,000	$1,400,000			$4,300,000
	E141.017906	Replace Fifth Street FST Network RTU	NA	$200,000					$200,000

	Mitigation	Mitigation Name	Risk Score Applied	2020	2021	2022	2023	2024	Grand Total
Age-Related Replacements and Asset Renewal				**$87,244,281**	**$79,537,631**	**$78,279,487**	**$79,652,481**	**$80,991,479**	**$405,705,358**
	E141.012673	Replace Fifth Street FST Switchgear	NA	$2,470,001					$2,470,001
	E150.018891	Replace Linde LND TR1	NA	$1,100,000					$1,100,000
	E154.019464	T Rebuild West St Cloud to Millwood	NA	$1,500,000	$2,500,000	$900,000			$4,900,000
Working Capital	E114.018276	MN - Line Asset Health WCF Blanket	NA	$11,000,000	$11,000,000	$11,000,000	$11,000,000	$12,700,000	$56,700,000
New Customer Projects and New Revenue				**$35,598,000**	**$39,294,000**	**$39,323,000**	**$39,352,000**	**$39,352,000**	**$192,919,000**
Blanket	E114.018171	MN - OH Extension Blanket	NA	$3,290,000	$3,651,000	$3,651,000	$3,651,000	$3,651,000	$17,894,000
	E114.018172	MN - OH New Services Blanket	NA	$2,511,000	$2,788,000	$2,788,000	$2,788,000	$2,788,000	$13,663,000
	E114.018045	MN - OH New Street Light Blanket	NA	$352,000	$362,000	$371,000	$380,000	$380,000	$1,845,000
	E114.018268	MN - UG Extension Blanket	NA	$19,387,000	$21,499,000	$21,499,000	$21,499,000	$21,499,000	$105,383,000
	E114.018269	MN - UG New Services Blanket	NA	$8,330,000	$9,247,000	$9,247,000	$9,247,000	$9,247,000	$45,318,000
	E114.018046	MN - UG New Street Light Blanket	NA	$728,000	$747,000	$767,000	$787,000	$787,000	$3,816,000
Program	E114.018792	MN LED Post Top Conversion	NA	$1,000,000	$1,000,000	$1,000,000	$1,000,000	$1,000,000	$5,000,000
System Expansion or Upgrades for Capacity				**$44,375,021**	**$40,066,002**	**$32,338,001**	**$32,948,001**	**$37,908,008**	**$187,635,033**
Blanket	E114.018342	MN - New Business Network Blanket	NA	$1,282,000	$1,313,000	$1,345,001	$1,345,001	$1,345,001	$6,630,003
	E114.018181	MN - OH Reinforce Blkt Tap/Back/Sec	NA	$883,002	$883,002	$883,002	$883,002	$883,002	$4,415,010
	E114.018279	MN - UG Reinforce Blkt Tap/Back/Sec	NA	$460,000	$460,000	$460,000	$460,000	$460,000	$2,300,000
	E103.001735	MN-Sub Capacity Reinforcement	NA	$100,000	$100,000	$100,000	$100,000	$100,000	$500,000
Program	E103.018426	SUB MN Feeder Load Monitoring	NA	$880,000	$2,020,000	$2,500,000	$2,500,000	$3,750,000	$11,650,000
Project	E147.011058	Plymouth-Area Power Grid Upgrades	Non-Discretionary	$8,000,000	$7,900,000				$15,900,000
	E150.019059	T Reinforce Red Rock RRK TR2	Non-Discretionary	$670,003					$670,003
	E150.019885	Install Jamaica JAM Area Sub	Non-Discretionary	$2,800,000					$2,800,000
	E144.018970	Reinforce Medford Junction MDF TR1	114.9	$1,700,000					$1,700,000
	E147.019893	Install Switch Coon Creek CNC073	52.9	$30,000					$30,000
	E144.007793	Reinforce Fair Park FAP TR1 & Fdr	49.7	$1,300,000					$1,300,000
	E143.016730	Install Feeder Tie Wilson WIL081	34.8	$300,000					$300,000
	E147.017741	Reinforce Osseo OSS062	33.1	$200,000					$200,000
	E150.018967	Extend Red Rock RRK063	18.1	$100,000					$100,000
	E144.017637	Load Transfer ESW062 to SMT061	15.0	$100,000					$100,000
	E141.017739	Extend Main Street MST074	14.3	$300,000					$300,000
	E143.016724	Reinforce Westgate WSG Feeders	10.8	$550,000					$550,000
	E141.019911	Reinforce Medicine Lake MEL074	10.6	$500,000					$500,000
	E141.019924	Install Hiawatha West HWW Feeder	10.3	$1,200,000					$1,200,000
	E141.019929	Install Midtown MDT Feeder	9.5		$1,900,000				$1,900,000
	E141.019957	Extend Saint Louis Park SLP085	8.4	$150,000					$150,000
	E147.015637	Install Feeder Tie Osseo OSS063	8.0	$100,000					$100,000
	E150.019910	Load Transfer CGR062 to CGR071	7.7	$950,000					$950,000
	E141.010910	Install Wilson WIL TR4 & Feeders	7.6	$6,850,000	$7,950,000				$14,800,000
	E143.019055	Reinforce Savage SAV063 & SAV067	7.1	$1,100,004					$1,100,004
	E156.010177	Install Kohlman Lake KOL Feeder	6.9	$1,000,000	$600,000				$1,600,000
	E150.010914	Install Stockyards STY TR3 & Feeders	6.3		$4,000,000	$3,500,000			$7,500,000
	E156.015749	Install Baytown BYT Feeders	6.2		$2,100,000	$2,100,000			$4,200,000
	E154.016772	Install Fiesta City FIC Feeder	6.0		$1,000,000				$1,000,000
	E141.019930	Install Feeder Tie SOU083 to MDT074	5.4		$100,000				$100,000
	E141.019954	Reinforce Saint Louis Park SLP087	5.2		$150,000				$150,000

	Mitigation	Mitigation Name	Risk Score Applied	2020	2021	2022	2023	2024	Grand Total
Age-Related Replacements and Asset Renewal				**$87,244,281**	**$79,537,631**	**$78,279,487**	**$79,652,481**	**$80,991,479**	**$405,705,358**
	E141.019928	Extend Saint Louis Park SLP092	4.8		$600,000				$600,000
	E154.018960	Reinforce Glenwood GLD Sub Equip	4.6		$700,000				$700,000
	E144.002712	Install Goodview GVW Feeder	4.0		$1,100,000				$1,100,000
	E150.015662	Install Chemolite CHE065 Feeder	3.9		$1,440,000				$1,440,000
	E156.011061	Install Wyoming WYO Feeder	3.9		$2,500,000				$2,500,000
	E143.016727	Install Feeder Tie EBL064	3.7		$150,000				$150,000
	E147.019056	Reinforce Basset Creek BCR062	3.7		$250,000				$250,000
	E141.019958	Reinforce Moore Lake MOL071	3.1		$550,000				$550,000
	E151.012409	Install Western WES TR3 & Feeders	2.8		$100,000	$5,300,000			$5,400,000
	E144.013436	Reinforce Kasson KAN TR1 & Feeders	2.8			$2,850,002			$2,850,002
	E147.012463	Install Feeder Tie Crooked Lake CRL033	2.7			$1,250,000			$1,250,000
	E154.010157	Install Albany ALB TR	2.1		$100,000	$2,800,000			$2,900,000
	E141.019956	Reinforce Terminal TER073	1.8			$1,100,000			$1,100,000
	E150.012576	Install South Washington ERU Sub	1.8	$5,670,002					$5,670,002
	E144.018971	Reinforce Veseli VES TR1 & Feeder	1.8		$100,000	$2,650,004			$2,750,004
	E141.019955	Extend Terminal TER064	1.8				$150,000		$150,000
	E144.010920	Reinforce Burnside BUR TR2	1.6			$100,000	$2,600,000		$2,700,000
	E143.019054	Reinforce Edina EDA062	1.3				$500,000		$500,000
	E147.014465	Reinforce Brooklyn Park BRP062	1.2				$200,000		$200,000
	E144.000793	Install Zumbrota ZUM TR & Feeder	1.2			$100,000	$2,950,002		$3,050,002
	E144.016592	Reinforce Sibley Park SIP Sub Equip	1.1				$100,000		$100,000
	E143.017702	Install Viking VKG Feeder	1.0				$2,500,000		$2,500,000
	E150.010904	Install Rosemount RMT TR2 & Feeder	1.0	$4,400,008					$4,400,008
	E142.011721	Install Orono ORO TR2 & Feeder	0.9			$100,000	$4,000,000		$4,100,000
	E156.007927	Install Goose Lake GLK TR3 & Feeders	0.8				$700,000	$4,000,000	$4,700,000
	E144.008708	Install Cannon Falls Trans CTF TR2 & Fdr	0.7				$100,000	$1,895,003	$1,995,003
	E147.013379	Install West Coon Rapids WCR TR	0.7			$99,996	$1,979,996		$2,079,992
	E156.011752	Install Lindstrom LIN Feeder	0.7					$650,008	$650,008
	E143.019908	Install Hyland Lake HYL TR3 & Feeder	0.6				$100,000	$4,600,000	$4,700,000
	E156.011764	Reinforce Tanners Lake TLK Sub Equip	0.6					$200,000	$200,000
	E156.015811	Reinforce Oakdale OAD073 & OAD075	0.5					$275,004	$275,004
	E151.018961	New MPK075-GPH061 Feeder Tie	0.5					$250,002	$250,002
	E144.013520	Install East Winona EWI TR2 & Feeder	0.4				$100,000	$3,100,000	$3,200,000
	E153.010999	Install Louise LOU TR2 & Feeders	0.4			$100,000	$3,480,000		$3,580,000
	E141.009146	Install Hiawatha West HWW TR2	0.1	$1,400,000					$1,400,000
	E154.015728	Reinforce St Cloud SCL TR2	0.1	$1,400,002					$1,400,002
	E141.009145	Install Midtown MDT TR2	0.1				$100,000	$1,400,000	$1,500,000
Working Capital	E103.006881	Dist Subs Carryover-NSPM	NA		$1,500,000	$3,999,996	$5,100,000	$9,999,996	$20,599,992
	E114.018281	MN - Line Capacity WCF Blanket	NA		$500,000	$1,000,000	$3,000,000	$4,999,992	$9,499,992
Projects related to Local (or other) Government-Requirements				**$28,875,012**	**$29,446,025**	**$28,475,002**	**$28,958,009**	**$29,242,010**	**$144,996,058**
Blanket	E114.018173	MN - OH Reloc Tap/Backbone/Sec Blkt	NA	$8,468,000	$8,468,000	$8,468,000	$8,468,000	$8,468,000	$42,340,000
	E114.018271	MN - UG Reloc Tap/Backbone/Sec Blkt	NA	$5,408,000	$5,408,000	$5,408,000	$5,408,000	$5,408,000	$27,040,000
	E114.018273	MN - UG Service Conversion Blanket	NA	$649,009	$649,009	$649,009	$649,009	$649,009	$3,245,045
Program	E114.018479	MN - Pole Transfer 3rd Party Blanket	NA	$500,000	$500,000	$500,000	$500,000	$500,000	$2,500,000
Project	E143.019409	COMP Relocation EDINA SWLRT Road Project	NA	($457,997)	($582,993)	($462,998)			($1,503,988)
	E141.019410	COMP Relocation MPLS SWLRT Road Project	NA	($458,008)	($582,991)	($463,007)			($1,504,006)
	E141.018907	Relocation 4th Street Road Project	NA	$249,999	$300,001				$550,000
	E141.019319	Relocation 4th Street Road Project	NA	$3,577,000	$3,795,000				$7,372,000

	Mitigation	Mitigation Name	Risk Score Applied	2020	2021	2022	2023	2024	Grand Total
Age-Related Replacements and Asset Renewal				**$87,244,281**	**$79,537,631**	**$78,279,487**	**$79,652,481**	**$80,991,479**	**$405,705,358**
	E143.013574	Relocation EDINA SWLRT Road Project	NA	$908,002	$908,002	$259,998			$2,076,002
	E141.019412	Relocation Hennepin Ave Road Project (LINES)	NA	$3,033,000	$2,983,000	$1,061,000			$7,077,000
	E141.019422	Relocation Hennepin Ave Road Project (VAULTS)	NA	$615,000					$615,000
	E143.019345	Relocation Hwy 35 106th St to Cliff Rd	NA		($250,002)				($250,002)
	E141.019192	Relocation MPLS SWLRT Road Project	NA	$908,000	$908,000	$260,000			$2,076,000
Working Capital	E114.018175	MN - Mandate WCF Blanket	NA	$3,400,001	$4,345,999	$3,653,000	$3,933,000	$4,217,001	$19,549,001
	E141.017929	MPLS Mandates WCF	NA	$2,075,006	$2,597,000	$9,142,000	$10,000,000	$10,000,000	$33,814,006
System Expansion or Upgrades for Reliability and Power Quality				**$21,510,000**	**$114,689,901**	**$117,350,000**	**$117,349,933**	**$117,349,944**	**$488,249,778**
Program	E114.018471	MN - Feeder Cable Repl Blanket	NA	$5,000,000	$5,000,000	$5,000,000	$5,000,000	$5,000,000	$25,000,000
	E114.018180	MN - FPIP Blanket	NA	$600,000	$1,400,000	$1,500,000	$1,500,000	$1,500,000	$6,500,000
	E114.018179	MN - REMS Blanket	NA	$510,000	$1,190,000	$850,000	$850,000	$850,000	$4,250,000
	E114.018277	MN - URD Cable Replacement Blanket	NA	$15,400,000	$26,100,000	$22,000,000	$22,000,000	$22,000,000	$107,500,000
	E114.019275	MN Incremental System Investment	NA		$80,999,901	$88,000,000	$87,999,933	$87,999,944	$344,999,778
Other				**$38,255,280**	**$39,697,956**	**$43,162,921**	**$35,399,680**	**$35,098,111**	**$191,613,949**
Blanket	E103.002100	2002 Spec Cnstr - Sm Tool/Equipment Blanket for NSPM	NA	$789,595	$1,169,167	$1,169,167	$1,169,167	$1,169,167	$5,466,263
	E103.002265	Capitalized Locating Costs-Elec UG MN	NA	$400,000	$400,000	$400,000	$400,000	$400,000	$2,000,000
	C115.006786	Logistics-NSPM Tools Blanket	NA	$167,359	$247,850	$252,632	$252,632	$252,632	$1,173,105
	E153.011934	Logistics-NSPM Tools Blanket - SD	NA	$3,482	$4,353	$4,353	$4,353	$4,353	$20,893
	E103.001738	MN Subs tools & equip	NA	$233,309	$501,441	$501,441	$501,441	$501,441	$2,239,072
	E103.001041	MN-New Bus Transformer	NA	$21,537,000	$23,114,000	$22,104,000	$22,774,000	$23,431,000	$112,960,000
	E145.001206	ND-Electric Tools & Equip	NA	$53,105	$70,518	$70,518	$70,518	$70,518	$335,176
	E103.002099	NSPM Metering Sys-Tools & Equipment Blanket	NA	$34,822	$69,645	$69,645	$69,645	$69,645	$313,400
	E153.001257	SD-Tools & Equip	NA	$76,609	$101,855	$101,855	$101,855	$101,855	$484,029
	C103.002113	Tools & Equipment-Transportation Blanket	NA	$30,284	$90,055	$90,055	$90,055	$90,055	$390,504
	NA	Fleet Purchases	NA	$9,637,809	$12,797,349	$17,093,422	$9,095,459	$7,701,612	
Program	E103.018427	COMM MN Feeder Load Monitoring	NA	$348,223	$696,445	$870,557	$870,557	$1,305,835	$4,091,616
Project	E114.018553	AGIS - Planning and Forecasting Tool - MN	NA	$4,000,000					$4,000,000
	E150.012576	Install South Washington ERU Sub	NA	$87,056					$87,056
	E103.014467	Sub Fiber Communication Cutover	NA	$435,278	$435,278	$435,278			$1,305,835
	E144.019891	T Revenue Metering Mapleton	NA	$215,898					$215,898
	E144.019892	T Revenue Metering Minnesota Lake	NA	$205,451					$205,451
Metering				**$5,484,000**	**$4,290,000**	**$3,454,000**	**$2,338,000**	**$2,338,000**	**$17,904,000**
Blanket	E103.001040	MN-Electric Meter Blanket	NA	$5,484,000	$4,290,000	$3,454,000	$2,338,000	$2,338,000	$17,904,000
Grid Modernization and Pilot Projects				**$19,878,543**	**$49,293,082**	**$141,718,272**	**$152,381,221**	**$76,749,821**	**$440,020,938**
Program	NA	AGIS	NA	$10,350,543	$41,211,082	$131,903,272	$140,519,221	$61,990,821	$385,974,938
	E114.020058	MN Electric Vehicle Program	NA	$9,528,000	$8,082,000	$9,815,000	$11,862,000	$14,759,000	$54,046,000
Non-Investment				**($3,733,000)**	**($3,702,000)**	**($3,813,000)**	**($3,813,000)**	**($3,813,000)**	**($18,874,000)**
Blanket	E141.001140	Electric New Construction Contributions in Aid	NA	($3,733,000)	($3,702,000)	($3,813,000)	($3,813,000)	($3,813,000)	($18,874,000)
Grand Total				**$277,487,137**	**$392,612,596**	**$480,287,683**	**$484,566,325**	**$415,216,373**	**$2,050,170,114**

PROTECTED DATA SHADED

Mitigation #	Investment Summary Information	Risk Number	Risk Type N-0 or N-1	Parent Device	Risk Score	2019 Forecasted Demand kVA	2019 Forecasted Capacity kVA	2019 Forecasted Percent Loading	Planned Spending in 5 Year Budget
						[PROTECTED DATA BEGINS			
E141.009145	Install Midtown MDT TR2	2008.1458	1	MDT_TR02	0.08			54.40%	$ 1,500,000
E141.009146	Install Hiawatha West HWW TR2	2008.1457	1	HWW_TR02	0.12			73.39%	$ 1,400,000
E141.010910	Install Wilson WIL TR4 & Feeders	2016.0369	1	EDA067	7.53			93.94%	$ 14,800,000
E141.010910	Install Wilson WIL TR4 & Feeders	2016.0370	1	EDA073	7.53			93.74%	$ 14,800,000
E141.010910	Install Wilson WIL TR4 & Feeders	2020.0297	1	SLP082	7.53			75.38%	$ 14,800,000
E141.010910	Install Wilson WIL TR4 & Feeders	2012.0216	0	SOU063	7.53			103.95%	$ 14,800,000
E141.010910	Install Wilson WIL TR4 & Feeders	2020.0307	1	SOU063	7.53			103.95%	$ 14,800,000
E141.010910	Install Wilson WIL TR4 & Feeders	2008.0692	1	SOU064	7.53			89.26%	$ 14,800,000
E141.010910	Install Wilson WIL TR4 & Feeders	2020.0310	1	SOU072	7.53			103.46%	$ 14,800,000
E141.010910	Install Wilson WIL TR4 & Feeders	2008.0699	1	SOU075	7.53			106.70%	$ 14,800,000
E141.010910	Install Wilson WIL TR4 & Feeders	2016.0497	0	SOU075	7.53			106.70%	$ 14,800,000
E141.010910	Install Wilson WIL TR4 & Feeders	2011.0194	0	SOU082	7.53			110.86%	$ 14,800,000
E141.010910	Install Wilson WIL TR4 & Feeders	2012.0703	1	SOU082	7.53			110.86%	$ 14,800,000
E141.010910	Install Wilson WIL TR4 & Feeders	2016.0409	1	WIL_TR03	7.53			87.01%	$ 14,800,000
E141.010910	Install Wilson WIL TR4 & Feeders	2016.0410	1	WIL_TR04	7.53			89.20%	$ 14,800,000
E141.010910	Install Wilson WIL TR4 & Feeders	2016.0411	1	WIL_TR05	7.53			73.05%	$ 14,800,000
E141.010910	Install Wilson WIL TR4 & Feeders	2016.0390	1	WIL073	7.53			119.23%	$ 14,800,000
E141.010910	Install Wilson WIL TR4 & Feeders	2016.0391	0	WIL073	7.53			119.23%	$ 14,800,000
E141.010910	Install Wilson WIL TR4 & Feeders	2016.0394	1	WIL076	7.53			83.38%	$ 14,800,000

PROTECTED DATA SHADED

Mitigation #	Investment Summary Information	Risk Number	Risk Type N-0 or N-1	Parent Device	Risk Score	2019 Forecasted Demand kVA	2019 Forecasted Capacity kVA	2019 Forecasted Percent Loading	Planned Spending in 5 Year Budget
E141.010910	Install Wilson WIL TR4 & Feeders	2016.0396	0	WIL079	7.53			99.70%	$ 14,800,000
E141.010910	Install Wilson WIL TR4 & Feeders	2016.0400	1	WIL085	7.53			114.21%	$ 14,800,000
E141.010910	Install Wilson WIL TR4 & Feeders	2016.0401	0	WIL085	7.53			114.21%	$ 14,800,000
E141.010910	Install Wilson WIL TR4 & Feeders	2016.0402	1	WIL086	7.53			71.78%	$ 14,800,000
E141.010910	Install Wilson WIL TR4 & Feeders	2016.0403	1	WIL087	7.53			102.82%	$ 14,800,000
E141.010910	Install Wilson WIL TR4 & Feeders	2016.0404	0	WIL087	7.53			102.82%	$ 14,800,000
E141.010910	Install Wilson WIL TR4 & Feeders	2016.0406	1	WIL094	7.53			83.05%	$ 14,800,000
E141.010910	Install Wilson WIL TR4 & Feeders	2016.0407	1	WIL097	7.53			102.97%	$ 14,800,000
E141.010910	Install Wilson WIL TR4 & Feeders	2018.0936	0	WIL097	7.53			102.97%	$ 14,800,000
E141.010910	Install Wilson WIL TR4 & Feeders	2016.0408	1	WIL098	7.53			102.69%	$ 14,800,000
E141.010910	Install Wilson WIL TR4 & Feeders	2018.0937	0	WIL098	7.53			102.69%	$ 14,800,000
E141.017739	Extend Main Street MST074	2017.0160	0	MST075	14.27			104.44%	$ 300,000
E141.017739	Extend Main Street MST074	2017.0599	0	TER066	14.27			111.21%	$ 300,000
E141.019911	Reinforce Medicine Lake MEL074	2017.0168	0	MEL074	10.61			100.71%	$ 500,000
E141.019911	Reinforce Medicine Lake MEL074	2020.0267	1	MEL078	10.61			86.67%	$ 500,000
E141.019924	Install Hiawatha West HWW Feeder	2020.0233	1	ELP063	10.27			92.35%	$ 1,200,000
E141.019924	Install Hiawatha West HWW Feeder	2020.0345	1	HWW061	10.27			81.56%	$ 1,200,000
E141.019924	Install Hiawatha West HWW Feeder	2020.0248	1	HWW071	10.27			51.93%	$ 1,200,000
E141.019924	Install Hiawatha West HWW Feeder	2020.0249	1	HWW073	10.27			62.40%	$ 1,200,000
E141.019924	Install Hiawatha West HWW Feeder	2020.0251	1	HWW075	10.27			107.46%	$ 1,200,000

PROTECTED DATA SHADED

Mitigation #	Investment Summary Information	Risk Number	Risk Type N-0 or N-1	Parent Device	Risk Score	2019 Forecasted Demand kVA	2019 Forecasted Capacity kVA	2019 Forecasted Percent Loading	Planned Spending in 5 Year Budget
E141.019924	Install Hiawatha West HWW Feeder	2020.0346	1	SOU066	10.27			48.07%	$ 1,200,000
E141.019928	Extend Saint Louis Park SLP092	2017.0157	1	SLP092	4.77			88.91%	$ 600,000
E141.019929	Install Midtown MDT Feeder	2020.0347	1	ALD072	9.46			100.34%	$ 1,900,000
E141.019929	Install Midtown MDT Feeder	2020.0211	1	ALD083	9.46			68.05%	$ 1,900,000
E141.019929	Install Midtown MDT Feeder	2020.0212	1	ALD085	9.46			94.91%	$ 1,900,000
E141.019929	Install Midtown MDT Feeder	2017.0541	1	ALD092	9.46			100.82%	$ 1,900,000
E141.019929	Install Midtown MDT Feeder	2020.0331	0	ALD092	9.46			100.82%	$ 1,900,000
E141.019929	Install Midtown MDT Feeder	2020.0304	1	SLP096	9.46			85.10%	$ 1,900,000
E141.019930	Install Feeder Tie SOU083 to MDT074	2020.0314	1	SOU083	5.40			65.83%	$ 100,000
E141.019954	Reinforce Saint Louis Park SLP087	2020.0293	1	SLP074	5.17			104.33%	$ 150,000
E141.019955	Extend Terminal TER064	2020.0319	1	TER064	1.75			69.68%	$ 150,000
E141.019956	Reinforce Terminal TER073	2020.0283	1	MST075	1.84			84.16%	$ 1,100,000
E141.019956	Reinforce Terminal TER073	2020.0320	1	TER065	1.84			76.16%	$ 1,100,000
E141.019956	Reinforce Terminal TER073	2020.0343	1	TER082	1.84			80.80%	$ 1,100,000
E141.019956	Reinforce Terminal TER073	2020.0340	1	TER083	1.84			71.74%	$ 1,100,000
E141.019956	Reinforce Terminal TER073	2020.0342	1	TER085	1.84			35.79%	$ 1,100,000
E141.019957	Extend Saint Louis Park SLP085	2020.0299	1	SLP085	8.37			92.66%	$ 150,000
E141.019958	Reinforce Moore Lake MOL071	2020.0351	1	MOL061	3.13			79.46%	$ 550,000
E142.011721	Install Orono ORO TR2 & Feeder	2005.0539	1	ORO_TR01	0.87			80.24%	$ 4,100,000
E142.011721	Install Orono ORO TR2 & Feeder	2005.0766	1	ORO061	0.87			66.44%	$ 4,100,000
E142.011721	Install Orono ORO TR2 & Feeder	2005.1699	1	ORO062	0.87			81.83%	$ 4,100,000
E143.016724	Reinforce Westgate WSG Feeders	2016.0567	0	WSG061	10.78			104.81%	$ 550,000
E143.016724	Reinforce Westgate WSG Feeders	2016.0415	1	WSG066	10.78			88.49%	$ 550,000
E143.016724	Reinforce Westgate WSG Feeders	2016.0417	1	WSG071	10.78			96.97%	$ 550,000
E143.016724	Reinforce Westgate WSG Feeders	2016.0568	0	WSG074	10.78			108.59%	$ 550,000
E143.016727	Install Feeder Tie EBL064	2016.0363	1	EBL064	3.73			69.63%	$ 150,000
E143.016727	Install Feeder Tie EBL064	2016.0367	1	EBL076	3.73			35.35%	$ 150,000

PROTECTED DATA SHADED

Mitigation #	Investment Summary Information	Risk Number	Risk Type N-0 or N-1	Parent Device	Risk Score	2019 Forecasted Demand kVA	2019 Forecasted Capacity kVA	2019 Forecasted Percent Loading	Planned Spending in 5 Year Budget
E143.016730	Install Feeder Tie Wilson WIL081	2016.0397	1	WIL081	34.83			99.50%	$ 300,000
E143.017702	Install Viking VKG Feeder	2016.0376	0	EDP073	1.03			106.97%	$ 2,500,000
E143.017702	Install Viking VKG Feeder	2016.0564	1	EDP073	1.03			106.97%	$ 2,500,000
E143.017702	Install Viking VKG Feeder	2017.0451	0	HYL061	1.03			100.74%	$ 2,500,000
E143.017702	Install Viking VKG Feeder	2016.0418	1	WSG076	1.03			51.94%	$ 2,500,000
E143.019054	Reinforce Edina EDA062	2016.0385	1	NMC092	1.34			75.86%	$ 500,000
E143.019054	Reinforce Edina EDA062	2016.0386	1	NMC093	1.34			71.59%	$ 500,000
E143.019055	Reinforce Savage SAV063 & SAV067	2018.0919	0	SAV063	7.08			113.36%	$ 1,100,004
E143.019055	Reinforce Savage SAV063 & SAV067	2017.0453	0	SAV067	7.08			109.89%	$ 1,100,004
E143.019055	Reinforce Savage SAV063 & SAV067	2018.0921	1	SAV067	7.08			109.89%	$ 1,100,004
E143.019055	Reinforce Savage SAV063 & SAV067	2016.0388	1	SAV071	7.08			87.48%	$ 1,100,004
E143.019055	Reinforce Savage SAV063 & SAV067	2017.0560	1	SAV073	7.08			49.97%	$ 1,100,004
E143.019908	Install Hyland Lake HYL TR3 & Feeder	2020.0165	1	HYL_TR01	0.58			89.83%	$ 4,700,000
E143.019908	Install Hyland Lake HYL TR3 & Feeder	2020.0166	1	HYL_TR02	0.58			60.78%	$ 4,700,000
E143.019908	Install Hyland Lake HYL TR3 & Feeder	2018.0913	1	HYL062	0.58			66.84%	$ 4,700,000
E143.019908	Install Hyland Lake HYL TR3 & Feeder	2018.0917	1	HYL073	0.58			84.89%	$ 4,700,000
E143.019908	Install Hyland Lake HYL TR3 & Feeder	2018.0932	1	WIL092	0.58			84.45%	$ 4,700,000
E144.000793	Install Zumbrota ZUM TR & Feeder	2004.1114	1	ZUM_TR01	1.19			97.10%	$ 3,050,002
E144.000793	Install Zumbrota ZUM TR & Feeder	2011.0097	1	ZUM021	1.19			46.76%	$ 3,050,002
E144.000793	Install Zumbrota ZUM TR & Feeder	2011.0098	1	ZUM022	1.19			77.98%	$ 3,050,002
E144.002712	Install Goodview GVW Feeder	2009.0877	1	GVW021	4.02			89.69%	$ 1,100,000
E144.002712	Install Goodview GVW Feeder	2004.0812	1	GVW022	4.02			76.85%	$ 1,100,000
E144.002712	Install Goodview GVW Feeder	2004.0808	1	GVW023	4.02			103.67%	$ 1,100,000
E144.007793	Reinforce Fair Park FAP TR1 & Fdr	2008.0369	1	FAB_TR01	49.67			66.98%	$ 1,300,000

PROTECTED DATA SHADED

Mitigation #	Investment Summary Information	Risk Number	Risk Type N-0 or N-1	Parent Device	Risk Score	2019 Forecasted Demand kVA	2019 Forecasted Capacity kVA	2019 Forecasted Percent Loading	Planned Spending in 5 Year Budget
E144.007793	Reinforce Fair Park FAP TR1 & Fdr	2005.0479	1	FAB_TR02	49.67			90.66%	$ 1,300,000
E144.007793	Reinforce Fair Park FAP TR1 & Fdr	2007.0695	1	FAB061	49.67			55.41%	$ 1,300,000
E144.007793	Reinforce Fair Park FAP TR1 & Fdr	2007.0696	1	FAB063	49.67			71.40%	$ 1,300,000
E144.007793	Reinforce Fair Park FAP TR1 & Fdr	2007.0698	1	FAB073	49.67			49.48%	$ 1,300,000
E144.007793	Reinforce Fair Park FAP TR1 & Fdr	2011.0108	1	FAP_TR01	49.67			60.00%	$ 1,300,000
E144.007793	Reinforce Fair Park FAP TR1 & Fdr	2007.0693	0	FAP_TR02	49.67			128.69%	$ 1,300,000
E144.007793	Reinforce Fair Park FAP TR1 & Fdr	2011.0109	1	FAP_TR02	49.67			89.84%	$ 1,300,000
E144.007793	Reinforce Fair Park FAP TR1 & Fdr	2005.0741	1	FAP061	49.67			66.96%	$ 1,300,000
E144.007793	Reinforce Fair Park FAP TR1 & Fdr	2007.1920	1	FAP071	49.67			126.68%	$ 1,300,000
E144.007793	Reinforce Fair Park FAP TR1 & Fdr	2018.0090	0	FAP071	49.67			126.68%	$ 1,300,000
E144.008708	Install Cannon Falls Trans CTF TR2 & Fdr	2007.0757	1	CAF_TR01	0.71			114.23%	$ 1,995,003
E144.008708	Install Cannon Falls Trans CTF TR2 & Fdr	2013.1534	0	CAF_TR01	0.71			114.23%	$ 1,995,003
E144.008708	Install Cannon Falls Trans CTF TR2 & Fdr	2005.0386	1	CTF_TR01	0.71			94.17%	$ 1,995,003
E144.010920	Reinforce Burnside BUR TR2	2006.0285	1	BUR_TR01	1.62			33.01%	$ 2,700,000
E144.010920	Reinforce Burnside BUR TR2	2009.0884	1	REW021	1.62			80.11%	$ 2,700,000
E144.010920	Reinforce Burnside BUR TR2	2005.0433	1	REW023	1.62			85.14%	$ 2,700,000
E144.013436	Reinforce Kasson KAN TR1 & Feeders	2011.0111	1	KAN_TR02	2.77			79.47%	$ 2,850,002
E144.013436	Reinforce Kasson KAN TR1 & Feeders	2007.0707	1	KAN022	2.77			56.41%	$ 2,850,002
E144.013436	Reinforce Kasson KAN TR1 & Feeders	2007.0706	1	KAN031	2.77			111.33%	$ 2,850,002
E144.013436	Reinforce Kasson KAN TR1 & Feeders	2019.0012	0	KAN031	2.77			111.33%	$ 2,850,002
E144.013436	Reinforce Kasson KAN TR1 & Feeders	2008.0398	1	WEB_TR01	2.77			88.46%	$ 2,850,002

PROTECTED DATA SHADED

Mitigation #	Investment Summary Information	Risk Number	Risk Type N-0 or N-1	Parent Device	Risk Score	2019 Forecasted Demand kVA	2019 Forecasted Capacity kVA	2019 Forecasted Percent Loading	Planned Spending in 5 Year Budget
E144.013436	Reinforce Kasson KAN TR1 & Feeders	2005.0758	1	WEB021	2.77			104.19%	$ 2,850,002
E144.013436	Reinforce Kasson KAN TR1 & Feeders	2013.0155	0	WEB021	2.77			104.19%	$ 2,850,002
E144.013520	Install East Winona EWI TR2 & Feeder	2005.0562	1	EWI_TR01	0.42			79.53%	$ 3,200,000
E144.013520	Install East Winona EWI TR2 & Feeder	2008.1123	1	EWI022	0.42			79.65%	$ 3,200,000
E144.013520	Install East Winona EWI TR2 & Feeder	2019.0083	0	GVW023	0.42			103.67%	$ 3,200,000
E144.013520	Install East Winona EWI TR2 & Feeder	2014.0080	1	WIN_TR01	0.42			70.22%	$ 3,200,000
E144.013520	Install East Winona EWI TR2 & Feeder	2014.0081	1	WIN_TR02	0.42			92.22%	$ 3,200,000
E144.013520	Install East Winona EWI TR2 & Feeder	2014.0082	1	WIN_TR03	0.42			70.17%	$ 3,200,000
E144.013520	Install East Winona EWI TR2 & Feeder	2014.0084	1	WIN032	0.42			109.12%	$ 3,200,000
E144.013520	Install East Winona EWI TR2 & Feeder	2014.0087	0	WIN032	0.42			109.12%	$ 3,200,000
E144.013520	Install East Winona EWI TR2 & Feeder	2008.1152	1	WIN034	0.42			56.89%	$ 3,200,000
E144.016592	Reinforce Sibley Park SIP Sub Equip	2018.0091	1	SIP_TR01	1.13			80.29%	$ 100,000
E144.016592	Reinforce Sibley Park SIP Sub Equip	2018.0092	1	SIP_TR02	1.13			65.79%	$ 100,000
E144.017637	Load Transfer ESW062 to SMT061	2016.1294	0	ESW062	15.04			110.24%	$ 100,000
E144.018970	Reinforce Medford Junction MDF TR1	2019.0081	0	MDF_TR01	114.86			153.77%	$ 1,700,000
E144.018970	Reinforce Medford Junction MDF TR1	2005.0744	1	MDF021	114.86			110.88%	$ 1,700,000
E144.018971	Reinforce Veseli VES TR1 & Feeder	2008.0365	1	EKO021	1.76			110.07%	$ 2,750,004
E144.018971	Reinforce Veseli VES TR1 & Feeder	2013.1536	0	EKO021	1.76			110.07%	$ 2,750,004
E144.018971	Reinforce Veseli VES TR1 & Feeder	2013.1491	1	VES021	1.76			80.36%	$ 2,750,004

PROTECTED DATA SHADED

Mitigation #	Investment Summary Information	Risk Number	Risk Type N-0 or N-1	Parent Device	Risk Score	2019 Forecasted Demand kVA	2019 Forecasted Capacity kVA	2019 Forecasted Percent Loading	Planned Spending in 5 Year Budget
E147.011058	Plymouth-Area Power Grid Upgrades	2008.1167	1	GSL_TR04	Non-Discretionary			62.28%	$ 15,900,000
E147.011058	Plymouth-Area Power Grid Upgrades	2008.0378	1	GSL076	Non-Discretionary			61.74%	$ 15,900,000
E147.011058	Plymouth-Area Power Grid Upgrades	2007.0308	1	GSL341	Non-Discretionary			54.02%	$ 15,900,000
E147.011058	Plymouth-Area Power Grid Upgrades	2008.1166	1	GSL342	Non-Discretionary			88.17%	$ 15,900,000
E147.011058	Plymouth-Area Power Grid Upgrades	2009.0036	1	HOL_TR02	Non-Discretionary			59.28%	$ 15,900,000
E147.011058	Plymouth-Area Power Grid Upgrades	2014.0333	1	HOL061	Non-Discretionary			59.16%	$ 15,900,000
E147.011058	Plymouth-Area Power Grid Upgrades	2007.0544	1	HOL062	Non-Discretionary			89.80%	$ 15,900,000
E147.011058	Plymouth-Area Power Grid Upgrades	2013.0592	1	PKL_TR01	Non-Discretionary			80.41%	$ 15,900,000
E147.011058	Plymouth-Area Power Grid Upgrades	2013.0593	1	PKL_TR02	Non-Discretionary			79.99%	$ 15,900,000
E147.011058	Plymouth-Area Power Grid Upgrades	2013.0594	1	PKL_TR03	Non-Discretionary			71.20%	$ 15,900,000
E147.011058	Plymouth-Area Power Grid Upgrades	2014.0335	1	PKL062	Non-Discretionary			67.59%	$ 15,900,000
E147.011058	Plymouth-Area Power Grid Upgrades	2006.0128	1	PKL074	Non-Discretionary			103.71%	$ 15,900,000
E147.011058	Plymouth-Area Power Grid Upgrades	2014.0509	0	PKL074	Non-Discretionary			103.71%	$ 15,900,000

PROTECTED DATA SHADED

Mitigation #	Investment Summary Information	Risk Number	Risk Type N-0 or N-1	Parent Device	Risk Score	2019 Forecasted Demand kVA	2019 Forecasted Capacity kVA	2019 Forecasted Percent Loading	Planned Spending in 5 Year Budget
E147.011058	Plymouth-Area Power Grid Upgrades	2005.0781	1	PKL075	Non-Discretionary			104.22%	$ 15,900,000
E147.011058	Plymouth-Area Power Grid Upgrades	2012.0548	0	PKL075	Non-Discretionary			104.22%	$ 15,900,000
E147.011058	Plymouth-Area Power Grid Upgrades	2006.0129	1	PKL081	Non-Discretionary			77.26%	$ 15,900,000
E147.011058	Plymouth-Area Power Grid Upgrades	2006.0131	1	PKL083	Non-Discretionary			96.15%	$ 15,900,000
E147.011058	Plymouth-Area Power Grid Upgrades	2014.0326	0	PKL083	Non-Discretionary			100.04%	$ 15,900,000
E147.011058	Plymouth-Area Power Grid Upgrades	2006.0132	1	PKL084	Non-Discretionary			82.70%	$ 15,900,000
E147.012463	Install Feeder Tie Crooked Lake CRL033	2007.0542	1	CRL027	2.65			89.87%	$ 1,250,000
E147.012463	Install Feeder Tie Crooked Lake CRL033	2005.0773	1	CRL031	2.65			73.46%	$ 1,250,000
E147.012463	Install Feeder Tie Crooked Lake CRL033	2005.0774	1	CRL033	2.65			87.54%	$ 1,250,000
E147.012463	Install Feeder Tie Crooked Lake CRL033	2012.0527	1	CRL065	2.65			65.48%	$ 1,250,000
E147.013379	Install West Coon Rapids WCR TR	2013.0532	1	WCR_TR01	0.67			49.60%	$ 2,079,992
E147.013379	Install West Coon Rapids WCR TR	2013.0533	1	WCR_TR02	0.67			71.56%	$ 2,079,992
E147.013379	Install West Coon Rapids WCR TR	2010.0935	1	WCR_TR03	0.67			77.68%	$ 2,079,992
E147.013379	Install West Coon Rapids WCR TR	2013.0529	1	WCR311	0.67			53.48%	$ 2,079,992
E147.013379	Install West Coon Rapids WCR TR	2019.0260	1	WCR321	0.67			77.53%	$ 2,079,992
E147.013379	Install West Coon Rapids WCR TR	2020.0191	0	WCR322	0.67			101.29%	$ 2,079,992

PROTECTED DATA SHADED

Mitigation #	Investment Summary Information	Risk Number	Risk Type N-0 or N-1	Parent Device	Risk Score	2019 Forecasted Demand kVA	2019 Forecasted Capacity kVA	2019 Forecasted Percent Loading	Planned Spending in 5 Year Budget
E147.013379	Install West Coon Rapids WCR TR	2013.0531	1	WCR322	0.67			101.29%	$ 2,079,992
E147.014465	Reinforce Brooklyn Park BRP062	2012.0512	1	BRP073	1.21			77.89%	$ 200,000
E147.015637	Install Feeder Tie Osseo OSS063	2012.0532	1	OSS063	8.03			68.93%	$ 100,000
E147.017741	Reinforce Osseo OSS062	2012.0534	1	OSS065	33.06			82.88%	$ 200,000
E147.017741	Reinforce Osseo OSS062	2012.0538	1	OSS072	33.06			38.84%	$ 200,000
E147.017741	Reinforce Osseo OSS062	2017.0084	0	TWL079	33.06			102.97%	$ 200,000
E147.017741	Reinforce Osseo OSS062	2017.0086	1	TWL081	33.06			94.90%	$ 200,000
E147.019056	Reinforce Basset Creek BCR062	2018.0948	0	BCR062	3.69			100.95%	$ 250,000
E147.019056	Reinforce Basset Creek BCR062	2013.0546	1	PKL065	3.69			77.18%	$ 250,000
E147.019893	Install Switch Coon Creek CNC073	2014.0488	1	TWL089	52.92			68.37%	$ 30,000
E150.010904	Install Rosemount RMT TR2 & Feeder	2005.0576	1	RMT_TR01	1.02			36.50%	$ 4,400,008
E150.010904	Install Rosemount RMT TR2 & Feeder	2004.1089	1	RVA_TR01	1.02			82.61%	$ 4,400,008
E150.010904	Install Rosemount RMT TR2 & Feeder	2014.0188	1	RVA061	1.02			73.34%	$ 4,400,008
E150.010904	Install Rosemount RMT TR2 & Feeder	2007.0280	1	RVA062	1.02			86.46%	$ 4,400,008
E150.010914	Install Stockyards STY TR3 & Feeders	2013.1443	1	LOK062	6.33			91.62%	$ 7,500,000
E150.010914	Install Stockyards STY TR3 & Feeders	2008.0350	1	RLK066	6.33			84.64%	$ 7,500,000
E150.010914	Install Stockyards STY TR3 & Feeders	2013.1532	0	RLK071	6.33			97.38%	$ 7,500,000
E150.010914	Install Stockyards STY TR3 & Feeders	2013.1451	1	RLK071	6.33			97.38%	$ 7,500,000
E150.010914	Install Stockyards STY TR3 & Feeders	2013.1453	1	RLK073	6.33			67.90%	$ 7,500,000
E150.010914	Install Stockyards STY TR3 & Feeders	2005.1672	1	STY_TR2	6.33			63.63%	$ 7,500,000
E150.010914	Install Stockyards STY TR3 & Feeders	2008.1187	1	STY_TR1	6.33			64.76%	$ 7,500,000

PROTECTED DATA SHADED

Mitigation #	Investment Summary Information	Risk Number	Risk Type N-0 or N-1	Parent Device	Risk Score	2019 Forecasted Demand kVA	2019 Forecasted Capacity kVA	2019 Forecasted Percent Loading	Planned Spending in 5 Year Budget
E150.010914	Install Stockyards STY TR3 & Feeders	2018.0022	0	STY061	6.33			109.49%	$ 7,500,000
E150.010914	Install Stockyards STY TR3 & Feeders	2011.0091	1	STY061	6.33			109.49%	$ 7,500,000
E150.010914	Install Stockyards STY TR3 & Feeders	2005.1713	1	STY062	6.33			80.70%	$ 7,500,000
E150.010914	Install Stockyards STY TR3 & Feeders	2007.0281	1	STY063	6.33			85.69%	$ 7,500,000
E150.010914	Install Stockyards STY TR3 & Feeders	2008.0374	1	STY065	6.33			73.49%	$ 7,500,000
E150.010914	Install Stockyards STY TR3 & Feeders	2013.0131	0	STY071	6.33			107.80%	$ 7,500,000
E150.010914	Install Stockyards STY TR3 & Feeders	2005.1714	1	STY071	6.33			107.80%	$ 7,500,000
E150.010914	Install Stockyards STY TR3 & Feeders	2005.1715	1	STY072	6.33			67.98%	$ 7,500,000
E150.010914	Install Stockyards STY TR3 & Feeders	2007.0282	1	STY073	6.33			64.03%	$ 7,500,000
E150.012576	Install South Washington ERU Sub	2013.0140	1	AFT_TR01	1.80			73.82%	$ 5,670,002
E150.012576	Install South Washington ERU Sub	2013.0141	1	AFT_TR02	1.80			62.41%	$ 5,670,002
E150.012576	Install South Washington ERU Sub	2014.0077	1	AFT315	1.80			79.78%	$ 5,670,002
E150.012576	Install South Washington ERU Sub	2013.0133	0	AFT321	1.80			105.46%	$ 5,670,002
E150.012576	Install South Washington ERU Sub	2013.0143	1	AFT321	1.80			105.46%	$ 5,670,002
E150.012576	Install South Washington ERU Sub	2013.0142	1	AFT322	1.80			65.33%	$ 5,670,002
E150.012576	Install South Washington ERU Sub	2017.0107	1	RRK064	1.80			96.63%	$ 5,670,002
E150.012576	Install South Washington ERU Sub	2013.0134	1	WDY_TR01	1.80			82.25%	$ 5,670,002
E150.012576	Install South Washington ERU Sub	2013.0136	1	WDY_TR02	1.80			68.33%	$ 5,670,002
E150.012576	Install South Washington ERU Sub	2013.1468	1	WDY311	1.80			54.76%	$ 5,670,002

PROTECTED DATA SHADED

Mitigation #	Investment Summary Information	Risk Number	Risk Type N-0 or N-1	Parent Device	Risk Score	2019 Forecasted Demand kVA	2019 Forecasted Capacity kVA	2019 Forecasted Percent Loading	Planned Spending in 5 Year Budget
E150.012576	Install South Washington ERU Sub	2013.0138	1	WDY312	1.80			82.25%	$ 5,670,002
E150.012576	Install South Washington ERU Sub	2013.1469	1	WDY321	1.80			45.02%	$ 5,670,002
E150.012576	Install South Washington ERU Sub	2013.0137	1	WDY322	1.80			74.24%	$ 5,670,002
E150.015662	Install Chemolite CHE065 Feeder	2019.0214	1	CGR_TR01	3.90			82.86%	$ 1,440,000
E150.015662	Install Chemolite CHE065 Feeder	2019.0215	1	CGR_TR02	3.90			62.23%	$ 1,440,000
E150.015662	Install Chemolite CHE065 Feeder	2013.1439	1	CGR072	3.90			84.12%	$ 1,440,000
E150.015662	Install Chemolite CHE065 Feeder	2013.1441	1	CHE063	3.90			110.19%	$ 1,440,000
E150.015662	Install Chemolite CHE065 Feeder	2020.0186	0	CHE063	3.90			110.19%	$ 1,440,000
E150.018967	Extend Red Rock RRK063	2013.1436	1	CGR061	18.14			105.87%	$ 100,000
E150.018967	Extend Red Rock RRK063	2019.0082	0	CGR061	18.14			105.87%	$ 100,000
E150.019059	T Reinforce Red Rock RRK TR2	2020.0047	1	RRK_TR02	Non-Discretionary			99.16%	$ 670,003
E150.019885	Install Jamaica JAM Area Sub	2019.0532	0	JAM_TR01	Non-Discretionary			0.00%	$ 2,800,000
E150.019910	Load Transfer CGR062 to CGR071	2019.0235	0	CGR062	7.72			115.45%	$ 950,000
E151.012409	Install Western WES TR3 & Feeders	2010.0320	1	MPK078	2.82			82.38%	$ 5,400,000
E151.012409	Install Western WES TR3 & Feeders	2013.1524	1	UPP064	2.82			82.60%	$ 5,400,000
E151.012409	Install Western WES TR3 & Feeders	2013.1525	1	UPP065	2.82			83.87%	$ 5,400,000
E151.012409	Install Western WES TR3 & Feeders	2013.0167	1	WES_TR01	2.82			47.94%	$ 5,400,000
E151.012409	Install Western WES TR3 & Feeders	2013.0168	1	WES_TR02	2.82			63.40%	$ 5,400,000
E151.012409	Install Western WES TR3 & Feeders	2013.1544	0	WES064	2.82			89.13%	$ 5,400,000

PROTECTED DATA SHADED

Mitigation #	Investment Summary Information	Risk Number	Risk Type N-0 or N-1	Parent Device	Risk Score	2019 Forecasted Demand kVA	2019 Forecasted Capacity kVA	2019 Forecasted Percent Loading	Planned Spending in 5 Year Budget
E151.012409	Install Western WES TR3 & Feeders	2006.1178	1	WES064	2.82			89.13%	$ 5,400,000
E151.012409	Install Western WES TR3 & Feeders	2007.1177	1	WES065	2.82			77.93%	$ 5,400,000
E151.012409	Install Western WES TR3 & Feeders	2005.0139	1	WES072	2.82			82.35%	$ 5,400,000
E151.012409	Install Western WES TR3 & Feeders	2008.0202	1	WES073	2.82			92.30%	$ 5,400,000
E151.012409	Install Western WES TR3 & Feeders	2013.0160	0	WES073	2.82			92.30%	$ 5,400,000
E151.012409	Install Western WES TR3 & Feeders	2008.0203	1	WES074	2.82			90.54%	$ 5,400,000
E151.012409	Install Western WES TR3 & Feeders	2010.0342	1	WES075	2.82			81.89%	$ 5,400,000
E151.012409	Install Western WES TR3 & Feeders	2013.1546	1	WES076	2.82			78.87%	$ 5,400,000
E151.018961	New MPK075-GPH061 Feeder Tie	2018.0832	1	MPK075	0.48			87.84%	$ 250,002
E153.010999	Install Louise LOU TR02 and Feeders	2010.0419	1	LOU_TR01	0.38			55.82%	$ 3,580,000
E153.010999	Install Louise LOU TR02 and Feeders	2012.0595	1	LOU061	0.38			79.11%	$ 3,580,000
E153.010999	Install Louise LOU TR02 and Feeders	2018.0822	1	LOU062	0.38			93.31%	$ 3,580,000
E153.010999	Install Louise LOU TR02 and Feeders	2019.0071	1	LOU063	0.38			99.48%	$ 3,580,000
E154.010157	Install Albany ALB TR	2004.0942	1	ALB_TR02	2.05			115.49%	$ 2,900,000
E154.010157	Install Albany ALB TR	2006.0067	0	ALB_TR02	2.05			115.49%	$ 2,900,000
E154.010157	Install Albany ALB TR	2012.0102	1	ALB021	2.05			89.39%	$ 2,900,000
E154.010157	Install Albany ALB TR	2012.0103	1	ALB022	2.05			43.64%	$ 2,900,000
E154.015728	Reinforce St Cloud SCL TR2	2009.0415	1	SCL_TR01	0.12			67.67%	$ 1,400,002
E154.016772	Install Fiesta City FIC Feeder	2016.0249	0	MTV_TR02	5.95			110.34%	$ 1,000,000
E154.016772	Install Fiesta City FIC Feeder	2010.0959	0	MTV021	5.95			116.66%	$ 1,000,000
E154.016772	Install Fiesta City FIC Feeder	2016.0302	1	MTV021	5.95			116.66%	$ 1,000,000
E154.018960	Reinforce Glenwood GLD Sub Equip	2018.0825	1	GLD_TR01	4.56			66.25%	$ 700,000
E154.018960	Reinforce Glenwood GLD Sub Equip	2012.0131	1	GLD_TR02	4.56			37.52%	$ 700,000

PROTECTED DATA SHADED

Mitigation #	Investment Summary Information	Risk Number	Risk Type N-0 or N-1	Parent Device	Risk Score	2019 Forecasted Demand kVA	2019 Forecasted Capacity kVA	2019 Forecasted Percent Loading	Planned Spending in 5 Year Budget
E154.018960	Reinforce Glenwood GLD Sub Equip	2005.0076	1	GLD021	4.56			83.17%	$ 700,000
E154.018960	Reinforce Glenwood GLD Sub Equip	2009.0358	1	GLD031	4.56			78.69%	$ 700,000
E156.007927	Install Goose Lake GLK TR3 & Feeders	2005.0554	1	GLK_TR01	0.75			79.33%	$ 4,700,000
E156.007927	Install Goose Lake GLK TR3 & Feeders	2005.0555	1	GLK_TR02	0.75			80.95%	$ 4,700,000
E156.007927	Install Goose Lake GLK TR3 & Feeders	2013.0109	1	GLK061	0.75			90.40%	$ 4,700,000
E156.007927	Install Goose Lake GLK TR3 & Feeders	2013.0110	1	GLK062	0.75			74.63%	$ 4,700,000
E156.007927	Install Goose Lake GLK TR3 & Feeders	2013.0112	1	GLK064	0.75			79.95%	$ 4,700,000
E156.007927	Install Goose Lake GLK TR3 & Feeders	2013.0113	1	GLK071	0.75			81.88%	$ 4,700,000
E156.007927	Install Goose Lake GLK TR3 & Feeders	2013.0114	1	GLK072	0.75			68.00%	$ 4,700,000
E156.007927	Install Goose Lake GLK TR3 & Feeders	2013.0116	1	GLK074	0.75			87.77%	$ 4,700,000
E156.007927	Install Goose Lake GLK TR3 & Feeders	2012.0560	1	LLK071	0.75			66.91%	$ 4,700,000
E156.010177	Install Kohlman Lake KOL Feeder	2014.0455	1	LLK072	6.86			67.46%	$ 1,600,000
E156.010177	Install Kohlman Lake KOL Feeder	2007.0784	1	OAD061	6.86			90.62%	$ 1,600,000
E156.010177	Install Kohlman Lake KOL Feeder	2008.0733	1	OAD063	6.86			62.24%	$ 1,600,000
E156.010177	Install Kohlman Lake KOL Feeder	2012.0561	1	OAD064	6.86			37.81%	$ 1,600,000
E156.010177	Install Kohlman Lake KOL Feeder	2012.0562	1	OAD065	6.86			81.45%	$ 1,600,000
E156.010177	Install Kohlman Lake KOL Feeder	2012.0563	1	OAD072	6.86			92.67%	$ 1,600,000
E156.010177	Install Kohlman Lake KOL Feeder	2012.0564	1	OAD074	6.86			61.82%	$ 1,600,000
E156.010177	Install Kohlman Lake KOL Feeder	2012.0565	1	OAD075	6.86			96.36%	$ 1,600,000
E156.011061	Install Wyoming WYO Feeder	2005.0720	1	WYO021	3.87			97.15%	$ 2,500,000

PROTECTED DATA SHADED

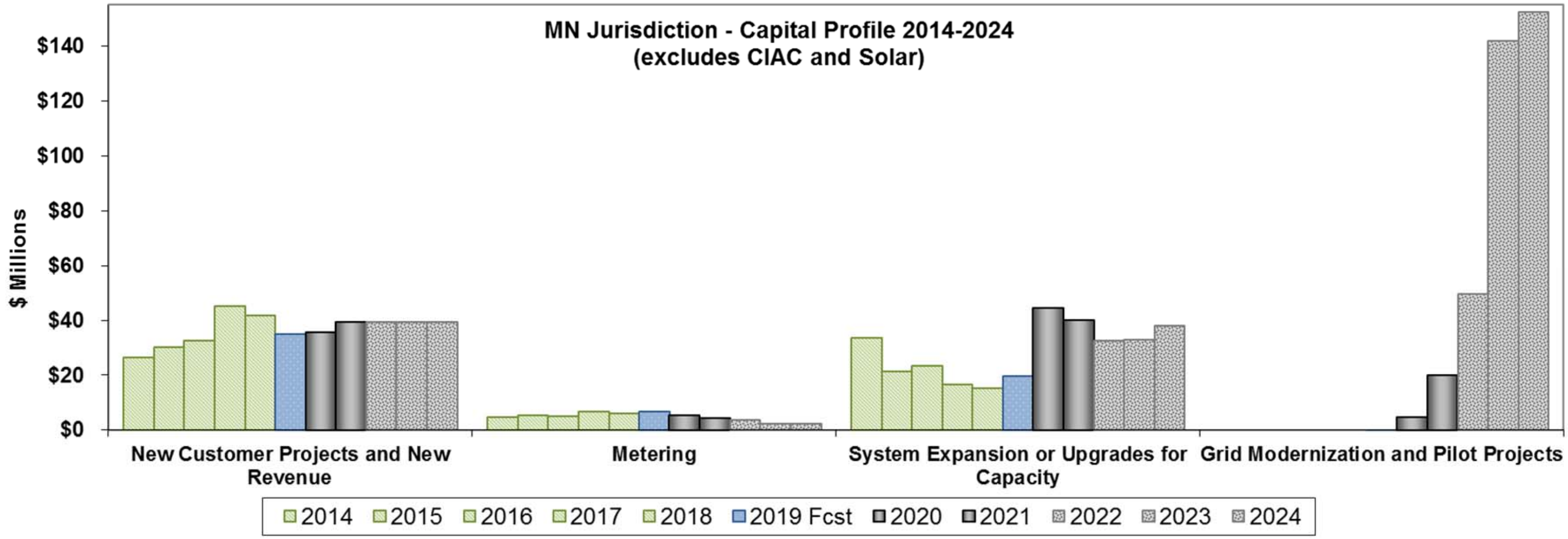
Mitigation #	Investment Summary Information	Risk Number	Risk Type N-0 or N-1	Parent Device	Risk Score	2019 Forecasted Demand kVA	2019 Forecasted Capacity kVA	2019 Forecasted Percent Loading	Planned Spending in 5 Year Budget
E156.011061	Install Wyoming WYO Feeder	2006.0229	1	WYO022	3.87			77.93%	$ 2,500,000
E156.011061	Install Wyoming WYO Feeder	2004.1268	1	WYO031	3.87			76.20%	$ 2,500,000
E156.011061	Install Wyoming WYO Feeder	2010.0166	1	WYO032	3.87			93.93%	$ 2,500,000
E156.011061	Install Wyoming WYO Feeder	2011.0158	1	WYO033	3.87			64.10%	$ 2,500,000
E156.011752	Install Lindstrom LIN Feeder	2006.0210	1	LIN022	0.66			56.55%	$ 650,008
E156.011752	Install Lindstrom LIN Feeder	2006.0211	1	LIN031	0.66			94.75%	$ 650,008
E156.011752	Install Lindstrom LIN Feeder	2005.0568	1	SCA_TR01	0.66			88.57%	$ 650,008
E156.011752	Install Lindstrom LIN Feeder	2008.0856	1	SCA021	0.66			90.71%	$ 650,008
E156.011764	Reinforce Tanners Lake TLK Sub Equip	2011.0177	1	TLK_TR01	0.57			71.03%	$ 200,000
E156.011764	Reinforce Tanners Lake TLK Sub Equip	2009.0399	1	TLK_TR02	0.57			55.03%	$ 200,000
E156.015749	Install Baytown BYT Feeders	2013.0135	1	AFT314	6.16			87.03%	$ 4,200,000
E156.015749	Install Baytown BYT Feeders	2016.0167	1	BYT072	6.16			75.40%	$ 4,200,000
E156.015749	Install Baytown BYT Feeders	2015.0574	1	HUG321	6.16			76.10%	$ 4,200,000
E156.015811	Reinforce Oakdale OAD073 & OAD075	2012.0572	1	TLK066	0.52			63.85%	$ 275,004

PROTECTED DATA ENDS]

Protected Data Justification

The shaded and marked columns in this spreadsheet contain information Xcel Energy maintains as Security Information, pursuant to Minn. Stat. § 13.37, subd. 1(a). The public disclosure or use of this information creates an unacceptable risk that those who want to disrupt our system for political or other reasons may learn which facilities to target to create a disruption of our service. Additionally, these fields for certain feeders contain information that if made public would be counter to our requirement to protect the anonymity of our customers' energy usage information unless we have the customers' consent to disclose it (Commission Order dated January 19, 2017 in Docket No. E,G999/CI-12-1344).

Figure 1: Distribution Capital Profile Trend (2014 to 2024)
State of Minnesota Electric Jurisdiction



New Business –

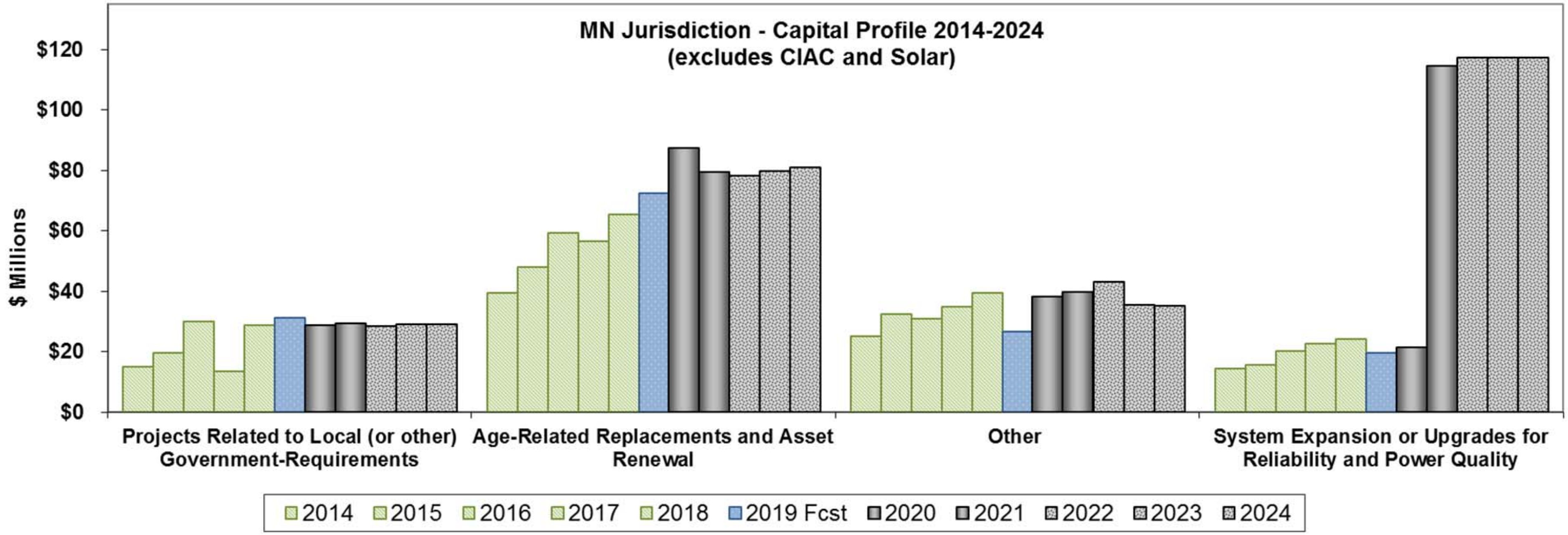
- Based on estimated cost per meter and growth assumptions. Analysis does not include 2019 results and will be refreshed in 2021-2025 budget create cycle.
- Growth assumptions based on historical results; National housing start data and known trends in service territories. National housing start data predicting growth uptick in 2020 and 2021, held growth consistent beginning in 2022 pending results in 2019 and 2020.
- 2017 and 2018 expenditures are elevated by the LED Conversion project (completed early 2019).

Metering – Includes meter purchases. No significant changes identified.

Capacity – Limited funds available for capacity projects through 2019. Uptick beginning in 2020 driven by increased funding availability and focus on overloads and contingency risk. Annual amounts will fluctuate based on needs in North and South Dakota, as well as timing of large projects.

Grid Modernization and Pilot Projects – Includes Advanced Grid Infrastructure and Security (AGIS) and Electric Vehicle (EV) Programs with AGIS starting in 2018 and EV starting in 2019.

Figure 2: Distribution Capital Profile Trend (2014 to 2024)
State of Minnesota Electric Jurisdiction



Projects Related to Local (or other) Government –

- Significant uptick in 2018 and 2019 driven by road projects in Minneapolis including 8th Street Relocation, 4th Street Relocation and Hennepin Avenue Relocation. Project schedules and final scopes greatly depend on city/government timelines, approvals and permitting.
- 2020 and beyond held consistent assuming elevated trend continues.

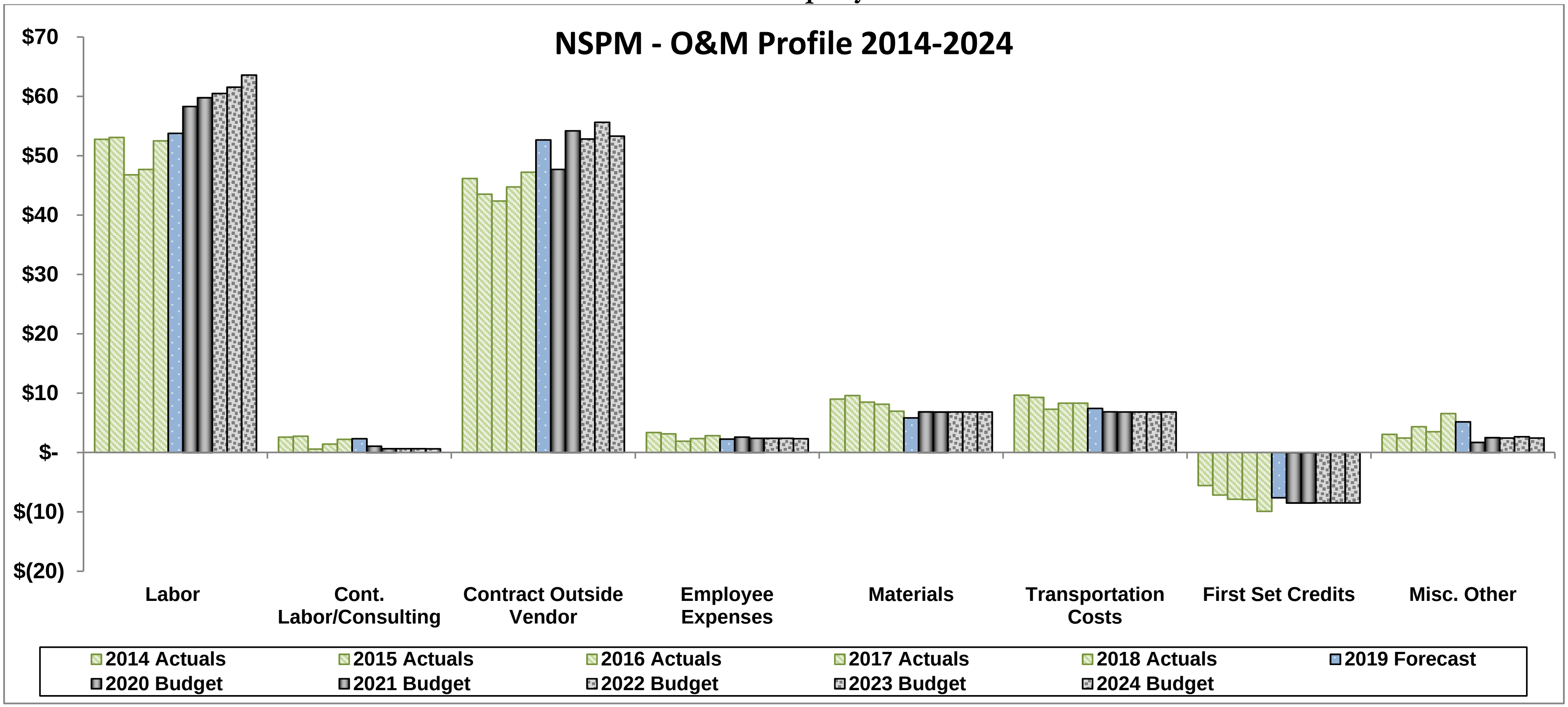
Other –

- Includes fleet, tools, communication equipment and transformer purchases. Transformer purchases and fleet purchases driving decrease in 2019.
- Uptick in 2020 includes increases to fleet, transformers and the Advanced Planning Tool. Other remains elevated in 2021 and 2022 with increased fleet needs anticipated.

System Expansion or Upgrades for Reliability and Power Quality –

- Cable replacement program is the main driver in this category. Cable replacement remains flat in 2020 due to limited funding.
- Elevated spend beginning in 2021 includes Incremental System Investment program currently starting at $81M in 2021.

Figure 1: Distribution O&M Profile Trend (2014 to 2024)
NSPM – Total Company Electric



1. Misc. Other: Includes bad debt, use costs, office supplies, janitorial, dues, donations, permits, etc.
2. The average Contract Outside Vendor annual expense related to Vegetation Management and Damage Prevention are $29.3M and $8.0M, respectively.
3. The average budgeted Contract Outside Vendor annual expense related to AGIS is $5.9M. There were no AGIS expenses from 2014-2017.

Non-Wires Alternatives Analysis

This attachment contains our non-wires alternatives analysis for the 2019 IDP. We provide an overview of our analysis and approach below. Section I provides the results for each project analyzed, Part II contains our assumptions, and Part III provides the load curves for each project.

OVERVIEW

As discussed in the IDP, we performed a non-wires alternatives analysis on the following projects. Using the screening process we described, the below table provides the list of capacity projects over $2 million that fall within the required timeline. Nine projects fit the screening criteria for further evaluation.

Table 1: Total Capacity Projects Exceeding $2 Million and Within the Timeline

Project	2020	2021	2022	2023	2024	Total
Install Hyland Lake HYL TR3 & Feeder	$0	$0	$0	$100,000	$4,600,000	$4,700,000
Install Goose Lake GLK TR3 & Feeders	$0	$0	$0	$700,000	$4,000,000	$4,700,000
Install Orono ORO TR2 & Feeder	$0	$0	$100,000	$4,000,000	$0	$4,100,000
Install East Winona EWI TR2 & Feeder	$0	$0	$0	$100,000	$3,100,000	$3,200,000
Install Zumbrota ZUM TR & Feeder	$0	$0	$100,000	$2,950,000	$0	$3,050,000
Reinforce Kasson KAN TR1 & Feeders	$0	$0	$2,850,000	$0	$0	$2,850,000
Reinforce Burnside BUR TR2	$0	$0	$100,000	$2,600,000	$0	$2,700,000
Install Viking VKG Feeder	$0	$0	$0	$2,500,000	$0	$2,500,000
Install West Coon Rapids WCR TR	$0	$0	$100,000	$1,980,000	$0	$2,080,000

For each of these projects we focused on the forecasted 2022 peak load curve for each feeder or transformer risk involved. We then applied focused demand response in an effort to reduce the load and followed that with energy storage and/or solar generation to make up the rest of the deficiency. In some instances, we had existing solar on particular feeders that we could utilize in the analysis as well.

We only considered Demand Response for the N-0 risks. This is partially due to the complexity of the N-1 analysis (combinations of feeders resulting in multiple configurations and customer make-ups) and the difficulty in obtaining necessary data such as individual customer loads. By focusing on the N-0 risks at this time, we are looking to develop a process, observe the value, and determine next steps for all risks.

Table 2 below highlights the nine projects, their costs, and the risk deficiencies that drive those costs. Comparing these analyses to traditional projects was difficult because in some instances, the NWA is not able to fully solve all of the risks that the traditional project solved. This was in part due to contingency situations where a NWA would have to act as a microgrid for large amounts of energy. The costs for such a solution would have been substantially greater. The NWA solutions also solved the risks up to 100 percent of the capacity rating, which means that any new load growth would create the need for an expanded or new NWA solution. In comparison, our traditional capacity projects contain "spare capacity" that allows us to accommodate some new growth in the near term.

Table 2: 2019 NWA Candidate Projects – Results Summary

Project Title	# of Risks	Aggregate Project Peak Demand (MW Overload)	Aggregate Project Energy Demand (MWh Overload)	Cost of NWA ($ M)	Cost of Traditional Project ($ M)
Reinforce Kasson TR1 and Feeders	7	14.14	126.69	$49.34	$2.85
Install West Coon Rapids WCR TR	4	18.59	167	$94.64	$2.08
Reinforce Burnside BUR TR2	3	9.76	92.59	$46.86	$2.7
Install Zumbrota ZUM TR & Feeder	3	2.8	28.25	$8.84	$3.05
Install Orono ORO TR2 & Feeder	3	9.62	59.35	$31.32	$4.10
Install Hyland Lake HYL TR3 & Feeder	5	11.31	52.49	$20.99	$6.20
Install Goose Lake GLK TR3&Feeders	8	20.94	155.77	$63.31	$4.70
Install Viking VKG Feeder	4	6.99	39.10	$15.64	$2.00
Install East Winona EWI TR2 & Feeder	9	9.2	98.16	$88.90	$3.2

I. PROJECT ANALYSIS RESULTS

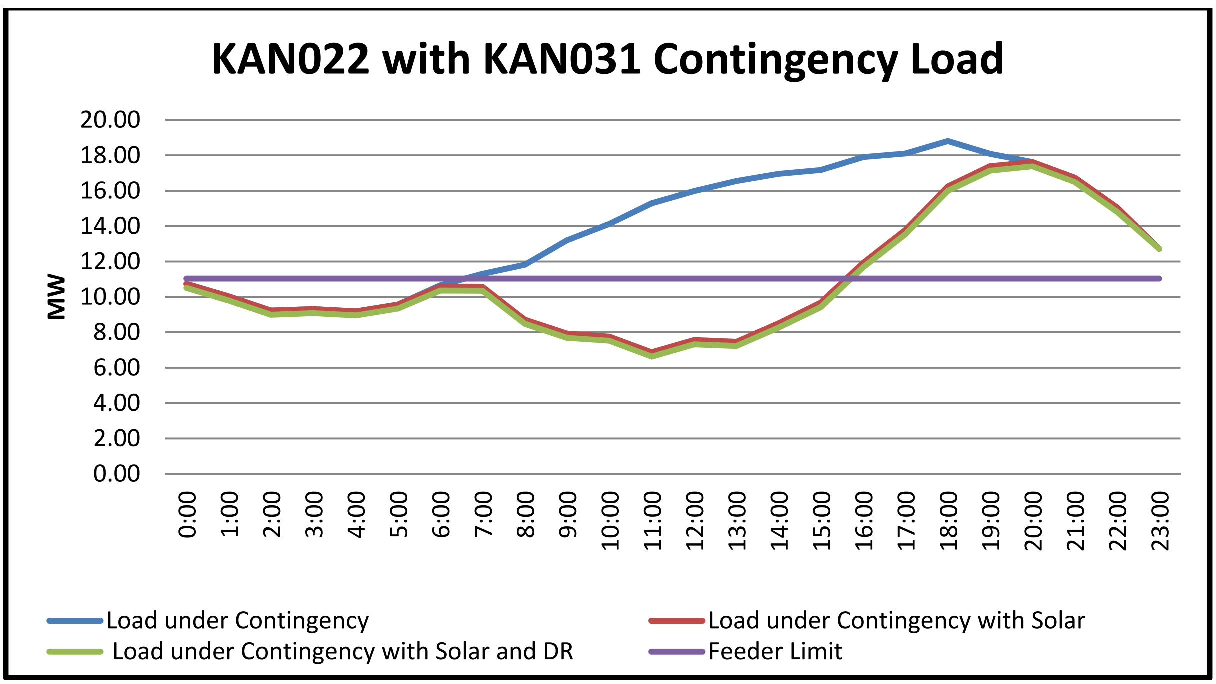
A. Reinforce Kasson TR1 and Feeders

This project has five feeder risks and two substation transformer risks. The transformer risks are both contingency risks while three of the feeder risks are due to contingencies and two are normal overloads. The traditional project that was budgeted to mitigate these issues included the upgrading of one substation transformer and the building of a new feeder.

The NWA solution for this project looked at existing solar generation on West Byron and both of the Kasson feeders (5MW on each of the three feeders) and combined it with energy storage and demand response potential. It assumed that two energy storage devices could be placed at key locations on the feeders to minimize the locations of deployment and solve all of the feeder risks. It was also assumed that the Kasson TR2 transformer risk and the West Byron TR1 risk could be mitigated by leveraging either one or both of those energy storage devices during a transformer contingency.

Figure 1 shows the amount of load at risk if feeder Kasson 31 (KAN031) were to be switched to Kasson 22 (KAN022) during contingency (this is the largest feeder risk for the project).

Figure 1: Kasson – KAN031 N-1 Contingency Load Risk



With solar contribution considered there would need to be energy storage installed that would be capable of reaching 6.6 MW at peak and discharging 31.5 MWH of energy throughout the day. This represents the largest energy storage device that would need to be deployed for this project and would also be used to mitigate the KAN031 N-0, Kasson TR2 N-1 and KAN022 N-1 risks. When observing the blue curve (total load under contingency) it's important to understand that there would not be enough available capacity under the feeder limit to charge an energy storage device for the amount of energy that is needed during discharge. Consequently, more solar needed to be added to this feeder so that the green curve (total load under contingency with solar and DR) could be realized and provide enough capacity for charging. This resulted in 15 MW of additional solar being added to the KAN031 feeder.

One other device would also be needed to mitigate two of the remaining three West Byron risks, but it would be smaller and result in less cost. Of particular interest is the fact that the combination of existing solar and demand response on WEB021 is sufficient to eliminate the WEB021 N-0 overload, which is the final risk.

Table 3: Reinforce Kasson TR1 and Feeders – Summary of DER Feeder Solutions

Capacity Risk	Overload Magnitude		Optimal DER Solution			Estimated Cost
	MW Overload	MWh Overload	Demand Response (MWh)	Solar PV (MW)	Battery Storage (MWh)	
N-1: Kasson, Loss of KAN022	Mitigated with optimal energy storage placement					
N-1: Kasson, Loss of KAN031	7.8	79.96	5.46	20	31.53	$42,611,398
N-0: KAN031	Mitigated with optimal energy storage placement					
N-1: West Byron, Loss of WEB021	5.71	45.32	15.7	5	16.82	$6,729,758
N-0: WEB021	0.6	1.41	15.7	5	0	$0
N-1: Kasson TR2	Mitigated with optimal energy storage placement					
N-1: West Byron TR1	Mitigated with optimal energy storage placement					
Total			21.16	25	48.35	$49,341,156

*Note: One of the WEB021 risks is counted in the total for DR and Solar

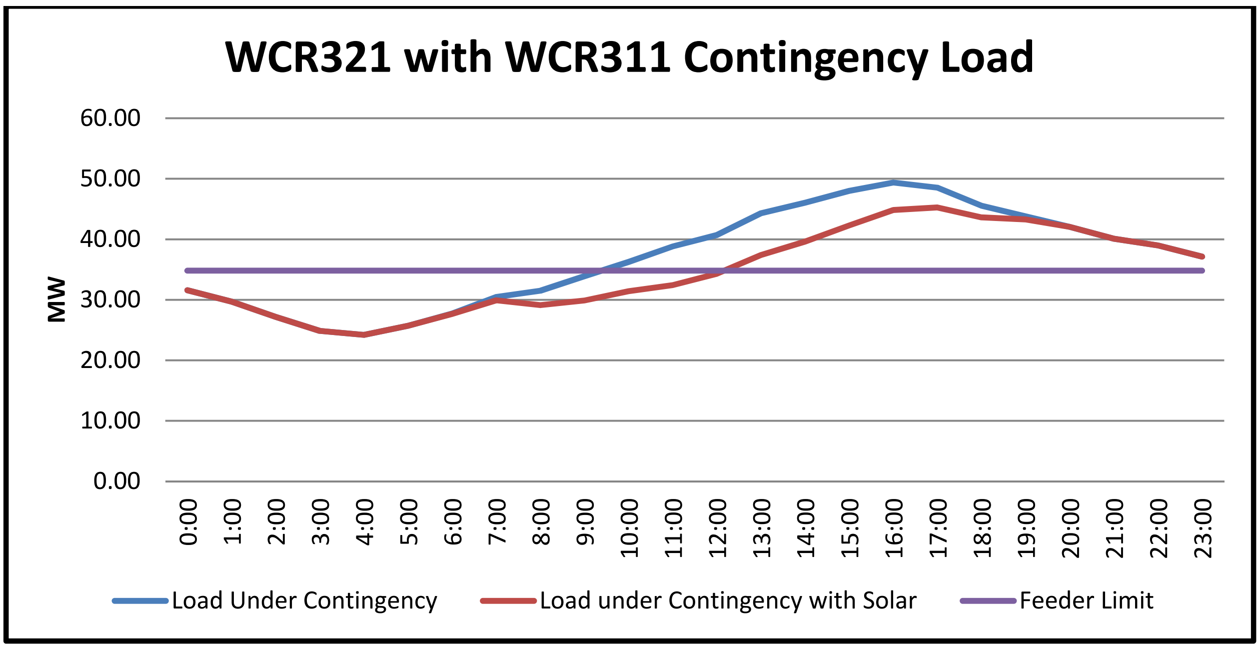
B. Install West Coon Rapids WCR TR

This project has three feeder risks and one substation transformer risk. The transformer risk is a contingency risk while two of the feeder risks are due to contingencies and the third is due to normal overloads. The traditional project that was budgeted to mitigate these issues was the installation of a new 13.8kV transformer in the substation.

The NWA solution for this project assumed that three energy storage devices could be placed at key locations on the feeders to minimize the locations of deployment and solve all of the feeder risks. Additionally, 26MW of solar PV would need to be installed on one of the feeders in order to store enough energy below the feeder capacity to discharge during a severe over-capacity case. It was also assumed that the WCR TR3 transformer risk could be mitigated by leveraging all energy storage devices during a transformer contingency.

Figure 2 shows the amount of load at risk if feeder West Coon Rapids 322 (WCR322) were to be switched to West Coon Rapids 321 (WCR321) during contingency (this is the largest feeder risk for the project).

Figure 2: West Coon Rapids WCR322 N-1 Contingency Load Risk



With the additional solar solution considered, there would need to be energy storage installed that would be capable of reaching 12 MW at peak and discharging 86.3 MWH of energy throughout the day. It should be noted that demand response is not included in this N-1 mitigation solution. This is due to WCR322's size and the requirement of its load being split apart amongst several feeders during an outage scenario, which would lead to inaccurate analysis. This represents the largest energy storage device that would need to be deployed for this project and would also be used to mitigate the WCR311 N-1, and a portion of the WCR TR3 N-1 risks. Again, more solar must be added to this feeder so that the red curve (total load under contingency plus solar) could be realized and provide enough capacity for charging. This resulted in 26 MW of additional solar being added to the WCR321 feeder. Two other devices would also be needed to mitigate the remaining West Coon rapids risks, but would be smaller and result in less cost.

Table 4: Install West Coon Rapids WCR TR – Summary of DER Feeder Solutions

Capacity Risk	Overload Magnitude		Optimal DER Solution			Estimated Cost
	MW Overload	MWh Overload	Demand Response (MWh)	Solar PV (MW)	Battery Storage (MWh)	
N-1: West Coon Rapids, Loss of WCR311	Mitigated with optimal energy storage and solar PV placement					
N-1: West Coon Rapids, Loss of WCR322	14.73	144.41	0	26	86.3	$86,501,974
N-0: WCR322	0.98	2.29	64.9	0	0	$0
N-1: West Coon Rapids TR3*	2.88	20.3	0	0	20.3	$8,135,751
Total			64.9	26	106.6	$94,637,725

*Note: Part of the WCR TR3 Optimal DER Solution relies on optimal PV and energy storage placement

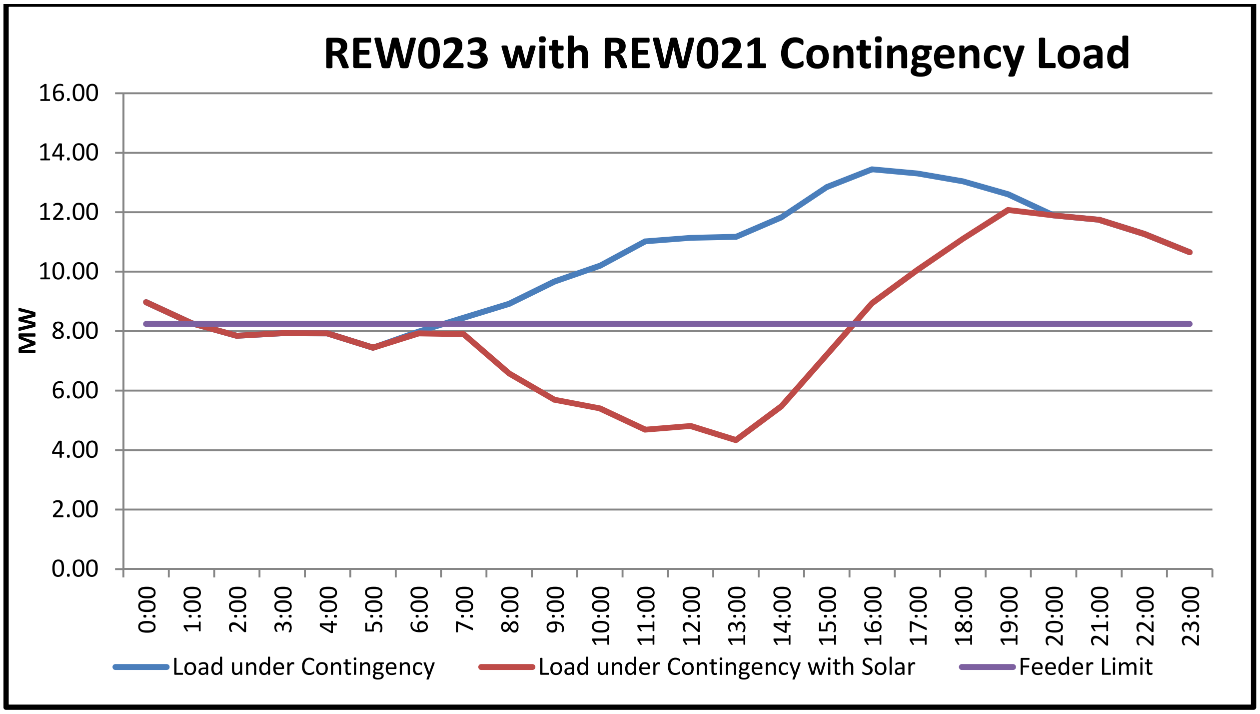
C. Reinforce Burnside BUR TR2

This project has two feeder risks and one substation transformer risk. All three of these risks are contingency risks. The traditional project that was budgeted to mitigate these issues included the upgrading of one substation transformer and the building of a new feeder.

The NWA solution for this project looked at existing solar generation on the Red Wing 23 (REW023) feeder (4.8 MW) and a feeder served by the Burnside TR1 (BURTR1) transformer (5 MW). Those amounts of existing generation were combined with energy storage potential. It assumed that two energy storage devices could be placed at key locations on the feeders to minimize the locations of deployment and solve all three of the risks.

Figure 3 shows the amount of load at risk if feeder REW021 were to be switched to REW023 during contingency (this is the largest risk for the project). Due to its geographic location and topography REW021 cannot be switched to any other feeders.

Figure 3: Red Wing – REW021 N-1 Contingency Load Risk



With solar considered there would need to be energy storage installed that would be capable of reaching 3.83 MW at peak and discharging 22.54 MWH of energy throughout the day. This represents the largest energy storage device that would need to be deployed for this project. It would also be used to mitigate the REW023 N-1 risk. When observing the blue curve (total load under contingency) it's important to understand that there would not be enough available capacity under the feeder limit to charge an energy storage device for the amount of energy that is needed during discharge. Consequently, more solar needed to be added to this feeder so that the red curve (total load under contingency plus solar) could be realized and provide enough capacity for charging. This resulted in 14 MW of additional solar being added to the REW021 feeder.

One other energy storage device would also be needed to mitigate the BURTR1 risk, but would be smaller and result in less cost.

Table 5: Reinforce Burnside BUR TR2 – Summary of DER Feeder Solutions

Capacity Risk	Overload Magnitude		Optimal DER Solution			Estimated Cost
	MW Overload	MWh Overload	Demand Response (MWh)	Solar PV (MW)	Battery Storage (MWh)	
N-1: Red Wing, Loss of REW021	5.2	53.79	0	18.8	22.54	$37,016,621
N-1: Red Wing, Loss of REW023	Mitigated with optimal energy storage and PV placement					
N-1: Burnside TR1	4.56	38.8	0	5	24.61	$9,842,961
Total			0	23.8	47.15	$46,859,581

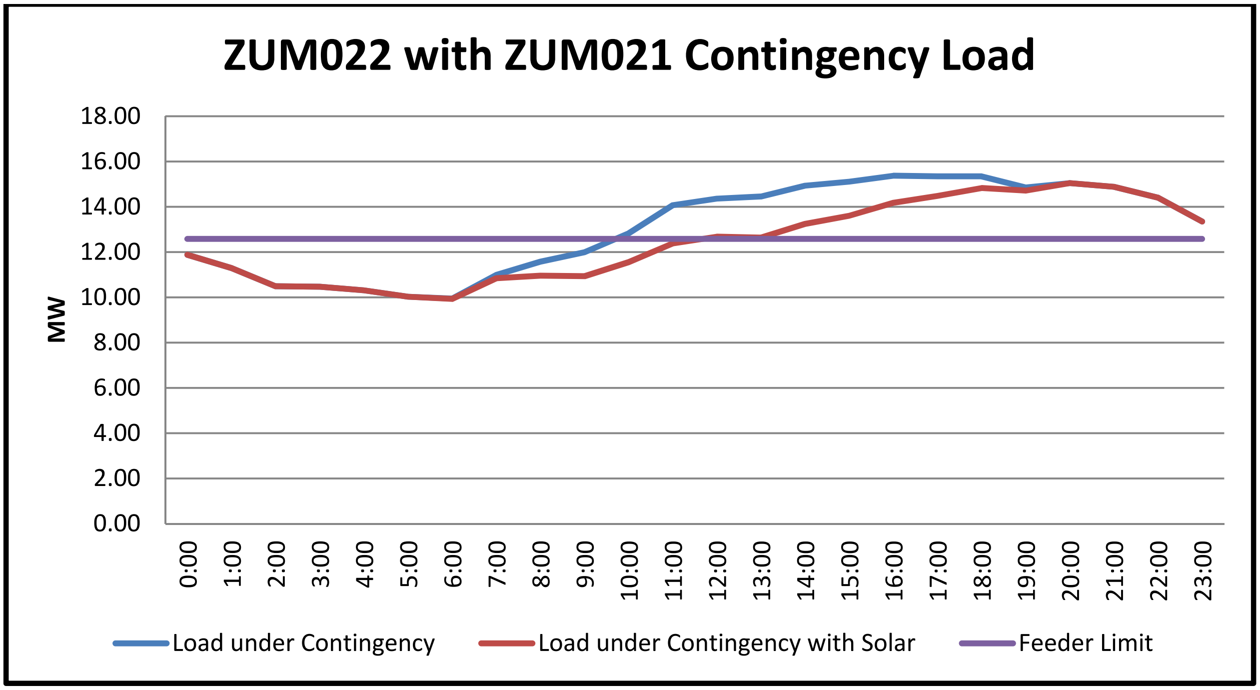
D. Install Zumbrota ZUM TR & Feeder

This project has two feeder risks and one substation transformer risk. All three of these risks are contingency risks. The traditional project that was budgeted to mitigate these issues included the addition of one substation transformer and the building of a new feeder.

The NWA solution for this project looked at existing solar generation on the Zumbrota 21 (ZUM021) feeder (2 MW) and the Zumbrota 22 (ZUM022) feeder (2 MW) and combined it with energy storage potential. It assumed that one energy storage devices could be placed at a key location so that both feeders could utilize it and minimize the locations of deployment. Also, we did not analyze the ability for the NWA to solve the transformer contingency risk. This is because Zumbrota TR1 (ZUMTR1) has no other transformers to shift any of its load to if it were to fail. It is the only transformer in the Zumbrota substation and has no other strong ties to other substation transformer via its feeders. This means that all of its peak load would have to be picked up in any NWA solution for an extended period of time. This would be extremely cost prohibitive and represent more of a large micro-grid type solution.

Figure 4 shows the amount of load at risk if feeder ZUM021 were to be switched to ZUM022 during contingency.

Figure 4: Zumbrota – ZUM021 N-1 Contingency Load Risk



With solar considered there would need to be energy storage installed that would be capable of reaching 2.47 MW at peak and discharging 17.1 MWH of energy throughout the day. It would also be used to mitigate the ZUM022 N-1 risk. When observing the blue curve (total load under contingency) it's important to understand that there would not be enough available capacity under the feeder limit to charge an energy storage device for the amount of energy that is needed during discharge. Consequently, more solar needed to be added to this feeder so that the red curve (total load under contingency plus solar) could be realized and provide enough capacity for charging. This resulted in 1 MW of additional solar being added to the ZUM021 feeder. As noted earlier, the end result would solve two of the three risks, with the third risk being too difficult and costly to accommodate.

Table 6: Install Zumbrota ZUM TR & Feeder – Summary of DER Feeder Solutions

Capacity Risk	Overload Magnitude		Optimal DER Solution			Estimated Cost
	MW Overload	MWh Overload	Demand Response (MWh)	Solar PV (MW)	Battery Storage (MWh)	
N-1: Zumbrota, Loss of ZUM022	Mitigated with optimal energy storage placement					
N-1: Zumbrota, Loss of ZUM021	2.8	28.25	0	2	17.1	$8,841,589
N-1: Zumbrota ZUMTR1	Single transformer – too costly to accommodate – risk not solved					
Total			NA	2	17.1	$8,842,000

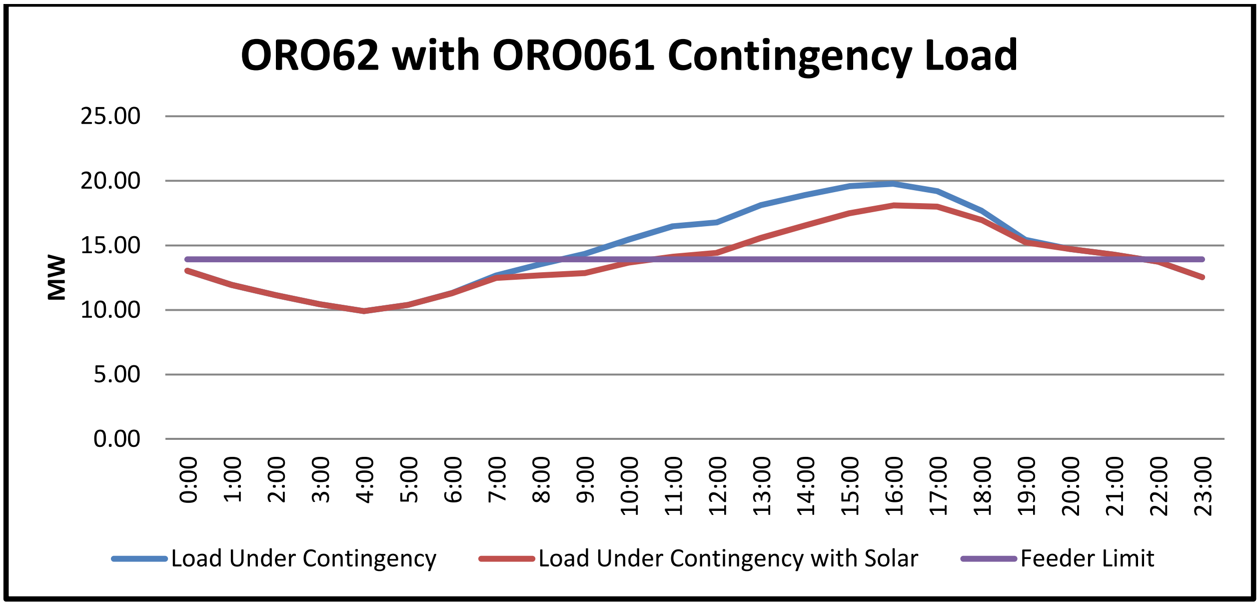
E. Install Orono ORO TR2 & Feeder

This project has two feeder risks and one substation transformer risk. All risks associated with this project are contingency risks, with no normal overloads. The traditional project that was budgeted to mitigate these issues was the installation of a new 13.8kV transformer in the substation and additional feeders.

The NWA solution for this project assumed that two energy storage devices could be placed at key locations on the feeders to minimize the locations of deployment and solve all of the feeder risks. Additionally, 5MW of solar PV would need to be installed on one of the feeders in order to store enough energy below the feeder capacity to discharge during a severe over-capacity case. Also, after analysis was completed, it was discovered that there was no ability for the NWA to solve the transformer contingency risk. This is because Orono TR1 (OROTR1) has no other transformers to shift any of its load to if it were to fail. It is the only transformer in the Orono substation and has no other strong ties to other substation transformer via its feeders. This means that all of its peak load would have to be picked up in any NWA solution for an extended period of time. This would be extremely cost prohibitive and represent more of a large micro-grid type solution.

Figure 5 shows the amount of load at risk if feeder Orono 61 (ORO061) were to be switched to Orono 62 (ORO062) during contingency (this is the largest feeder risk for the project).

Figure 5: Orono ORO061 N-1 Contingency Load Risk



With the additional solar solution considered, there would need to be energy storage installed that would be capable of reaching 4.18 MW at peak and discharging 22.32 MWh of energy throughout the day. This represents the largest energy storage device that would need to be deployed for this project. Again, more solar must be added to this feeder so that the red curve (total load under contingency plus solar) could be realized and provide enough capacity for charging. This resulted in 7 MW of additional solar being added to the ORO062 feeder. One other device would also be needed to mitigate the remaining ORO062 risks, but would be smaller and result in less cost.

Table 7: Install Orono ORO TR2 & Feeder –
Summary of DER Feeder Solutions

Capacity Risk	Overload Magnitude		Optimal DER Solution			Estimated Cost
	MW Overload	MWh Overload	Demand Response (MWh)	Incremental Solar PV (MW)	Battery Storage (MWh)	
N-1: Orono, Loss of ORO061	5.85	39.79	0	7	22.32	$22,927,307
N-1: Orono, Loss of ORO062	3.77	19.56	0	0	19.56	$8,390,112
N-1: Orono TR1	Single transformer – too costly to accommodate – risk not solved					
Total			0	7	41.88	$31,317,419

F. Install Hyland Lake HYL TR3 & Feeder

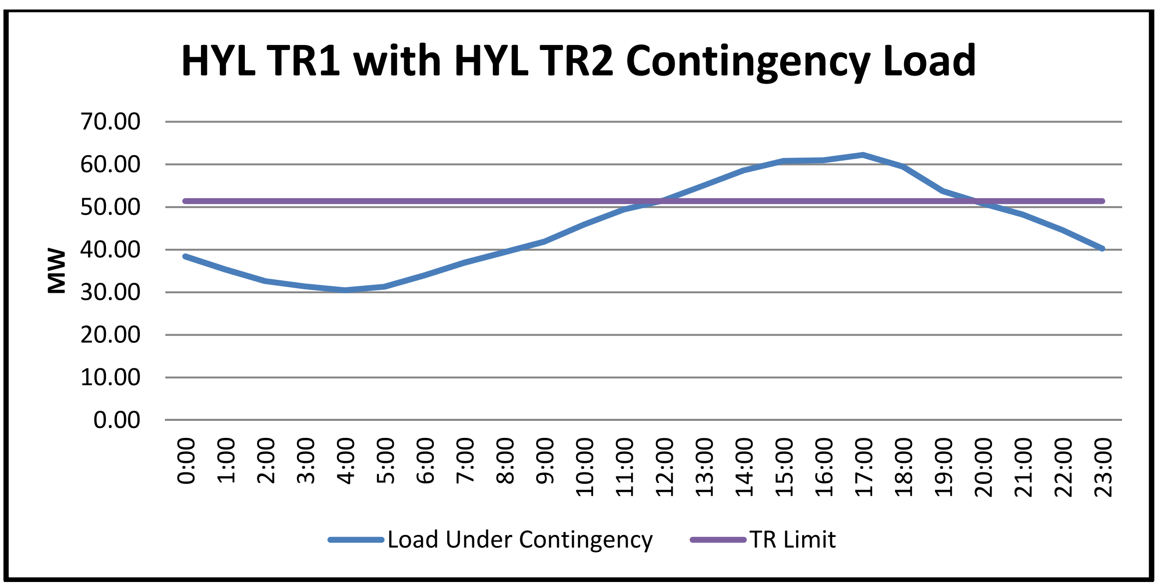
This project has three feeder risks and two substation transformer risks. The transformer risks and feeder risks are all due to contingencies. The traditional project in the budget involved installing one new substation transformer, one feeder bay, and one new feeder.

The NWA solution for this project involved placing three energy storage systems at strategic places on the feeders to mitigate risks and keep costs at a minimum.

It was assumed that two of these energy storage systems could be put at feeder ties to mitigate three of the feeder risks. The third energy storage system was assumed to be utilized at the substation transformer level to mitigate the transformer contingencies.

Figure 6 shows the amount of load at risk if the Hyland Lake substation transformer TR2 (HYL TR2) were to be switched to Hyland Lake transformer TR1 (HYL TR1) during contingency.

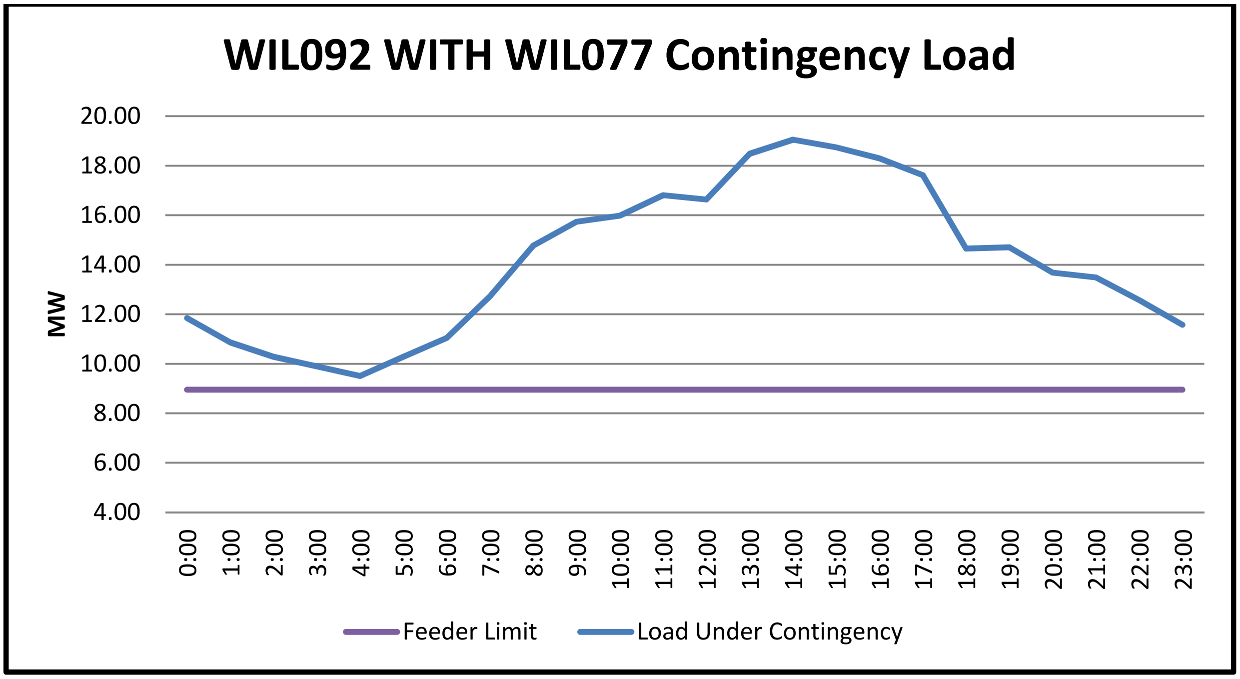
Figure 6: Install Hyland Lake HYL TR3 & Feeder – HYL TR1 N-1 Contingency Load Risk



In the current condition, there would need to be an energy storage system installed that could handle 51.39 MW at peak, discharging 10.85 MWh of energy throughout the day. This energy storage system would be the largest in magnitude (in MW) needed for the project and would mitigate both HYL TR1 and HYL TR2 N-1 risks.

Another feeder risk for this project is shown below in Figure 7. This figure shows the amount of load at risk if feeder Wilson 77 (WIL077) were to be switched to feeder Wilson 92 (WIL092) during contingency.

Figure 7: Wilson – WIL092 N-1 Contingency Load Risk



With this particular contingency, it is important to note that the load under contingency is above the feeder limit at all times. Due to the magnitude of the overload for this contingency, adding solar to mitigate the risk results in extremely high costs. Therefore, the remaining solution to this particular risk was to install an energy storage system capable of reaching 10.10 MW at peak and discharging 124.45 MWh of energy throughout the day. In order for the energy storage system to mitigate this contingency, it would have to be discharging through all hours of the day with no time to recharge. This isn't possible, so this particular contingency wasn't included in the NWA. Therefore, this NWA solution wouldn't be an equivalent to the traditional solution.

Table 8: Install Hyland Lake HYL TR3 & Feeder – Summary of DER Feeder Solutions

Capacity Risk	Overload Magnitude		Optimal DER Solution			Estimated Cost
	MW Overload	MWh Overload	Demand Response (MWh)	Incremental Solar PV (MW)	Battery Storage (MWh)	
N-1: Hyland Lake, Loss of HYL073	0.46	1.10	0.00	0.00	1.10	$441,758
N-1: Wilson, Loss of WIL077	Not able to solve risk with NWA solution					
N-1: Hyland Lake, Loss of TR2	10.85	51.39	0.00	0.00	51.39	$20,554,313
Total			0.00	0.00	52.49	$20,996,071

G. Install Goose Lake GLK TR3 & Feeders

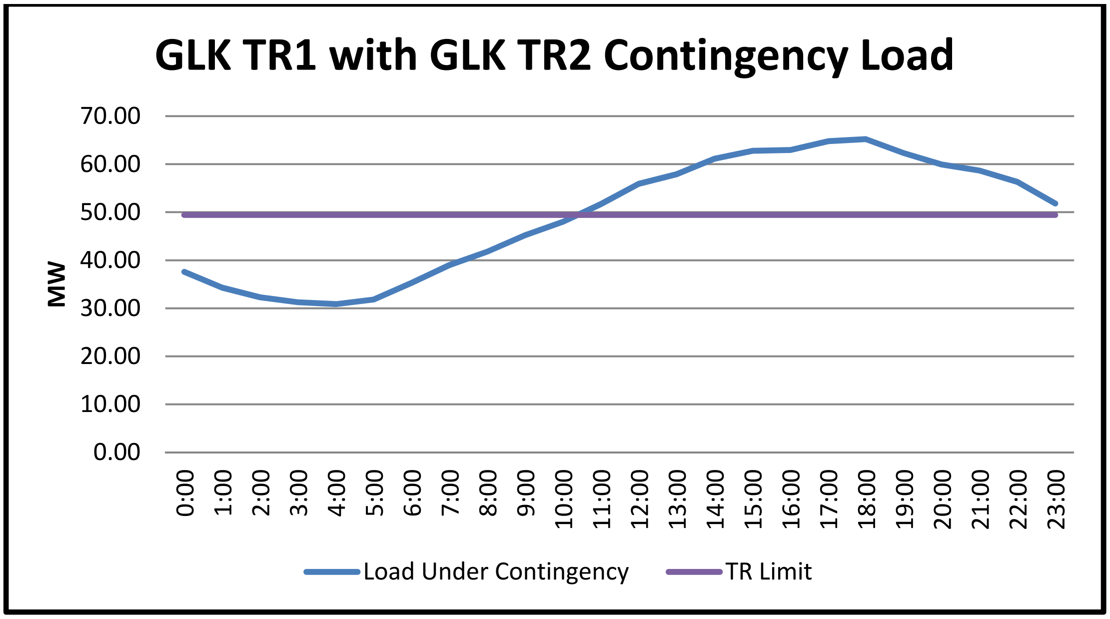
This project has six feeder risks and two substation transformer risks. The transformer risks and feeder risks are all due to contingencies. The traditional project in the budget involved installing one new substation transformer, one feeder bay, and one new feeder.

The NWA solution for this project involved placing four energy storage systems at strategic places to mitigate risks and keep costs at a minimum.

It was assumed that three of the energy storage systems could be put at feeder ties to mitigate all six of the feeder risks. The fourth energy storage system was assumed to be utilized at the substation transformer level to mitigate transformer contingencies.

Figure 8 shows the amount of load at risk if the Goose Lake substation transformer TR2 (GLK TR2) were to be switched to Goose Lake transformer TR1 (GLK TR1) during contingency.

Figure 8: Goose Lake TR2 N-1 Contingency Load Risk



In the current condition, there would need to be an energy storage system installed that could handle 15.82 MW at peak, discharging 129.27 MWh of energy throughout the day. This energy storage system would be the largest in magnitude (in MW) needed for the project and would mitigate both GLK TR1 and GLK TR2 N-1 risks.

Table 9: Install Goose Lake GLK TR3 & Feeders – Summary of DER Feeder Solutions

Capacity Risk	Overload Magnitude		Optimal DER Solution			Estimated Cost
	MW Overload	MWh Overload	Demand Response (MWh)	Incremental Solar PV (MW)	Battery Storage (MWh)	
N-1: Goose Lake, Loss of GLK065	Mitigated with optimal energy storage placement					
N-1:Goose Lake, Loss of GLK074	0.66	1.68	0.00	0.00	1.68	$1,188,477
N-1:Goose Lake, Loss of GLK063	Mitigated with optimal energy storage placement					
N-1:Goose Lake, Loss of GLK074	3.13	20.42	0.00	0.00	20.42	$8,402,552
N-1: Goose Lake GLKTR1	Mitigated with optimal energy storage placement					
N-1: Goose Lake GLKTR2	15.82	129.27	0.00	0.00	129.27	$51,706,037
N-1: Goose Lake, Loss of GLK073	Mitigated with optimal energy storage placement					
N-1: Ramsey, Loss of RAM071	1.33	4.40	0.00	0.00	4.40	$2,015,738
Total			0.00	0.00	155.77	$63,312,804

*Note: GLK074 has risks at two feeder ties and requires two mitigations

H. Install Viking VKG Feeder

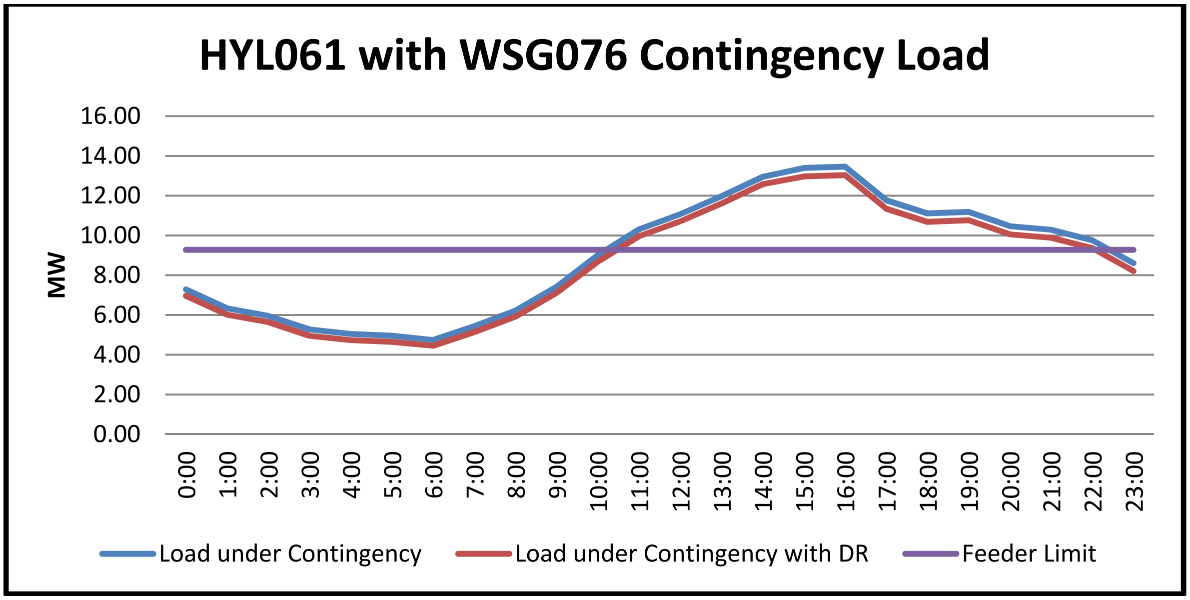
This project has four feeder risks, with two of them being due to contingencies and the other two being due to normal overloads. The traditional project in the budget involved installing one new feeder and feeder bay.

The NWA solution for this project involved placing two energy storage systems at strategic places on the feeders to mitigate risks and keep costs at a minimum.

It was assumed that both of these energy storage systems could be put at feeder ties to mitigate the contingencies and normal overload.

Figure 9 shows the amount of load at risk if the Westgate 76 feeder (WSG076) was switched to Hyland Lake 61 (HYL061) under contingency. This contingency is the highest risk in the project.

Figure 9: Hyland Lake – HYL061 N-1 Contingency Load Risk



In the current condition, there would need to be an energy storage system installed that could handle 3.76 MW at peak, discharging 21.69 MWh of energy throughout the day. This energy storage system would be the largest in magnitude (in MW) needed for the project and would mitigate both HYL061 N-0 and HYL N-1 risks.

Table 10: Install Viking VKG Feeder – Summary of DER Feeder Solutions

Capacity Risk	Overload Magnitude		Optimal DER Solution			Estimated Cost
	MW Overload	MWh Overload	Demand Response (MWh)	Incremental Solar PV (MW)	Battery Storage (MWh)	
N-1: Hyland Lake, Loss of WSG076	3.76	21.69	0.00	0.00	21.69	$8,677,622
N-1: Eden Prairie, Loss of WSG065	2.70	16.64	0.00	0.00	16.64	$6,656,069
N-0: Eden Prairie, Loss of EDP073	0.81	1.64	5.543	0.00	0.77	$309,744
N-0: Hyland Lake, Loss of HYL061	0.00	0.00	8.584	0.00	0.00	$0
Total			14.127	0.00	39.11	$15,643,435

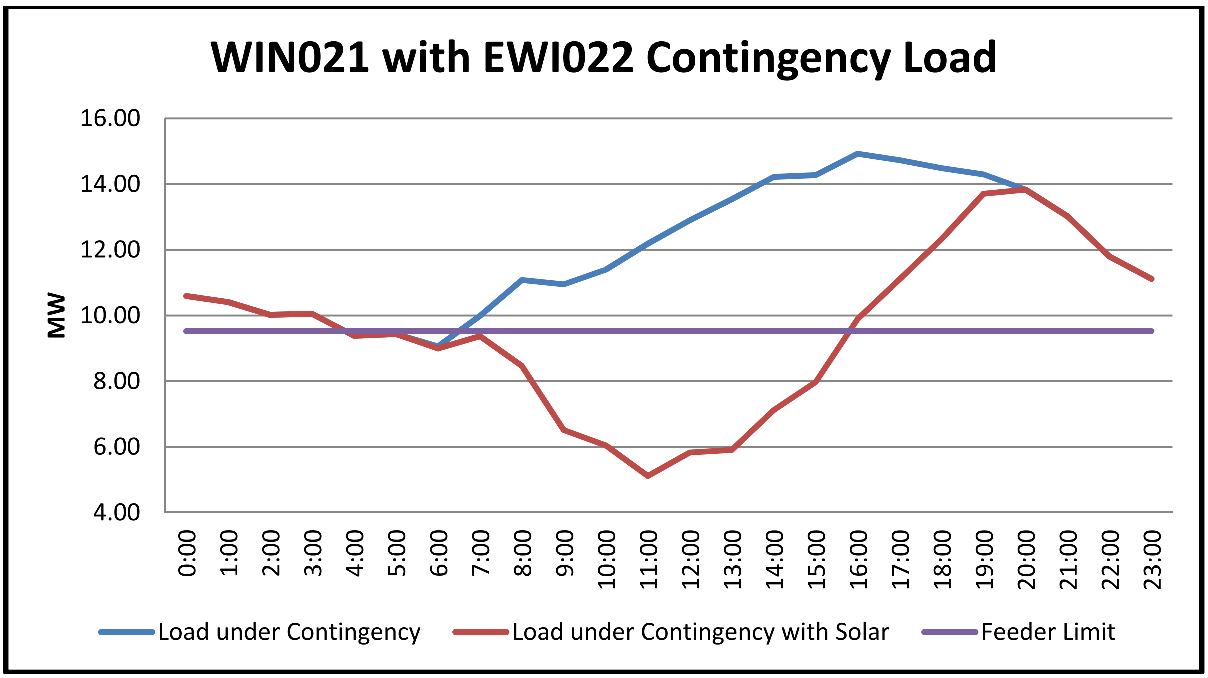
I. Install East Winona EWI TR2 & Feeder

This project has five feeder risks and four substation transformer risks. Three of the feeder risks are contingency risks and two are overloads. All four of the transformer risks are contingency risks. The traditional project that was budgeted to mitigate these issues included the addition of a second transformer and feeder at the East Winona Substation.

The NWA solution for this project considered PV and energy storage. With optimal placement of these resources only two feeder locations would be needed to solve all of the risks. The transformer risks were assumed to be solved by the feeder risks and were ignored in the analysis.

Figure 10 shows the amount of load at risk if feeder EWI022 were to be switched to WIN021 during contingency.

Figure 10: East Winona – EWI022 N-1 Contingency Load Risk



With solar considered there would need to be energy storage installed that would be capable of reaching 4.31 MW at peak and discharging 23.59 MWH of energy throughout the day. It would also be used to mitigate the WIN032 N-0 and N-1 risks. When observing the blue curve (total load under contingency) it's important to understand that there would not be enough available capacity under the feeder limit to charge an energy storage device for the amount of energy that is needed during discharge. Consequently, solar needed to be added to this feeder so that the red curve (total load under contingency plus solar) could be realized and provide enough capacity for charging. This resulted in 21 MW of additional solar being added to the EWI022 feeder. The end result would solve three of the five feeder risks, with the other two risks being mitigated with the WIN034 PV and energy storage solution indicated below.

Table 11: Install East Winona EWI TR2 & Feeder – Summary of DER Feeder Solutions

Capacity Risk	Overload Magnitude		Optimal DER Solution			Estimated Cost
	MW Overload	MWh Overload	Demand Response (MWh)	Solar PV (MW)	Battery Storage (MWh)	
N-1: Winona, Loss of WIN032	Mitigated with optimal energy storage placement					
N-1: Winona, Loss of WIN034	3.8	38.36	0	14	23.67	$37,467,286
N-1: East Winona, Loss of EWI022	5.4	59.8	0	21	23.59	$51,434,385
N-0: Winona, WIN032	Mitigated with optimal energy storage placement					
N-0: Goodview, GVW023	Mitigated with optimal energy storage placement					
Total			0	35	47.26	$88,901,671

II. ASSUMPTIONS

For all NWA studies, reasonable assumptions were made in order to streamline the process. Our goal in these studies is to reduce overloads and contingencies down to 100%. Therefore, any additional load growth in future years that could cause additional risk would require an additional risk analysis, associated mitigation, and NWA analysis. There is no "spare" capacity in these solutions.

When conducting an NWA analysis, we assumed that peak day conditions contain the highest magnitude of risk. Therefore, rather than doing analysis for potentially multiple overload events during the year, NWA studies were done utilizing available SCADA data containing peak day conditions. Historical 2018 peak days were selected and scaled to 2022 forecast peak values to accommodate the 3 year minimum that it would take to install a NWA solution in the field.

When approaching feeder and transformer risks, load that was not able to be offset by solar or demand response resulted in energy storage solutions. Unless extreme circumstances dictated otherwise, it was assumed that these energy storage systems would be available during risk hours to mitigate contingencies and overloads.

Minimum solar output curves utilized during the analyses ranged from 24-36% of peak output from 10AM to 4PM and to percentages less than that outside of that timeframe. These solar curves were obtained from the NREL PVWatts tool.

Demand response curves applied assumed peak at 6PM on associated feeders. Load curves were procured utilizing risks that had N-0 overloads. Risks containing N-1 contingencies were generally not considered for demand response due to the complexity of the N-1 analysis (combinations of feeders resulting in multiple configurations and customer make-ups) and the difficulty in obtaining necessary data, such as individual customer loads.

Battery storage systems were assumed to have no losses. In actuality during the charging and discharging of the system losses do occur, they are not 100% efficient.

It was also assumed that land would be available at key locations on feeders/transformers/substations that would enable the NWA solution.

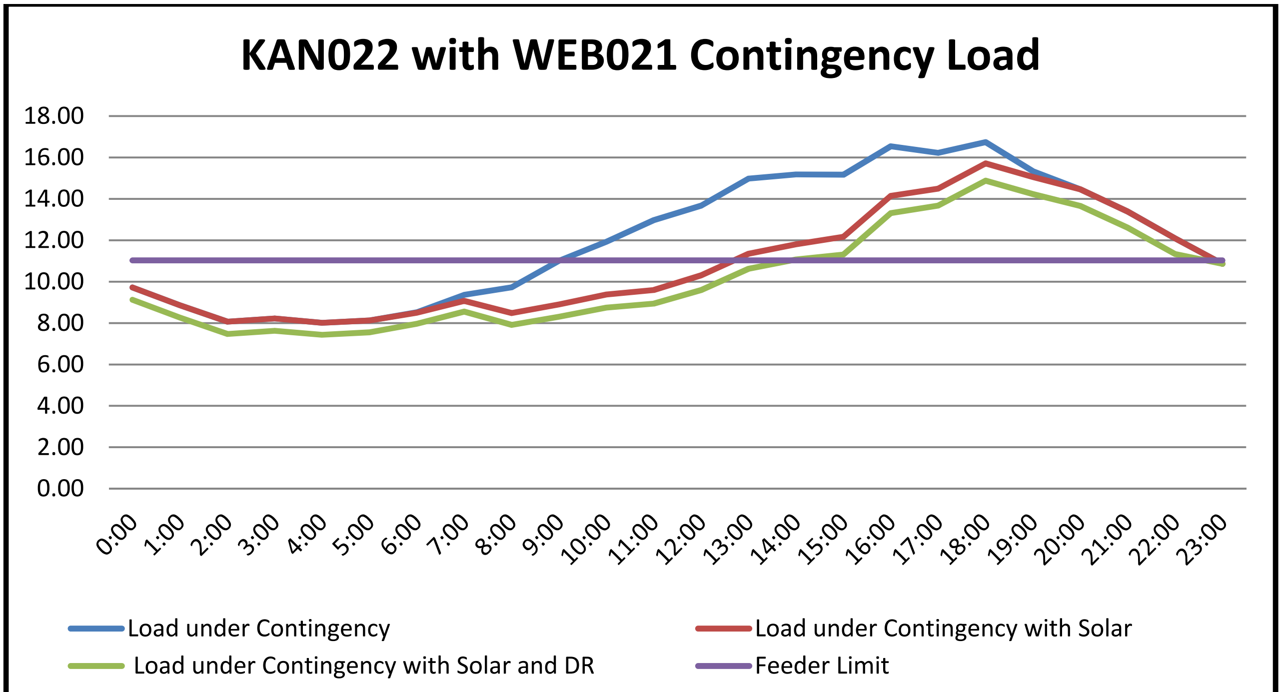
Table 12 below shows assumptions made in cost calculations during the studies.

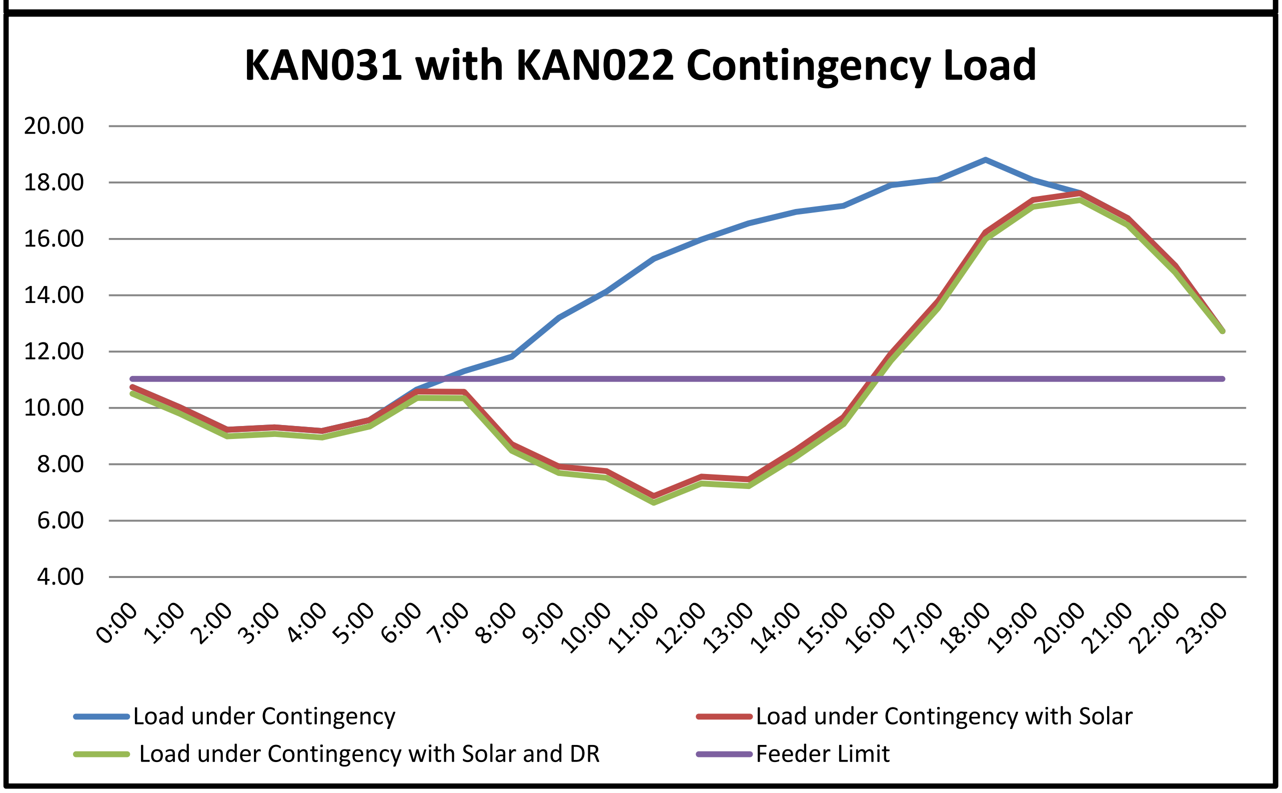
Table 12: Cost Assumptions in NWA Analysis

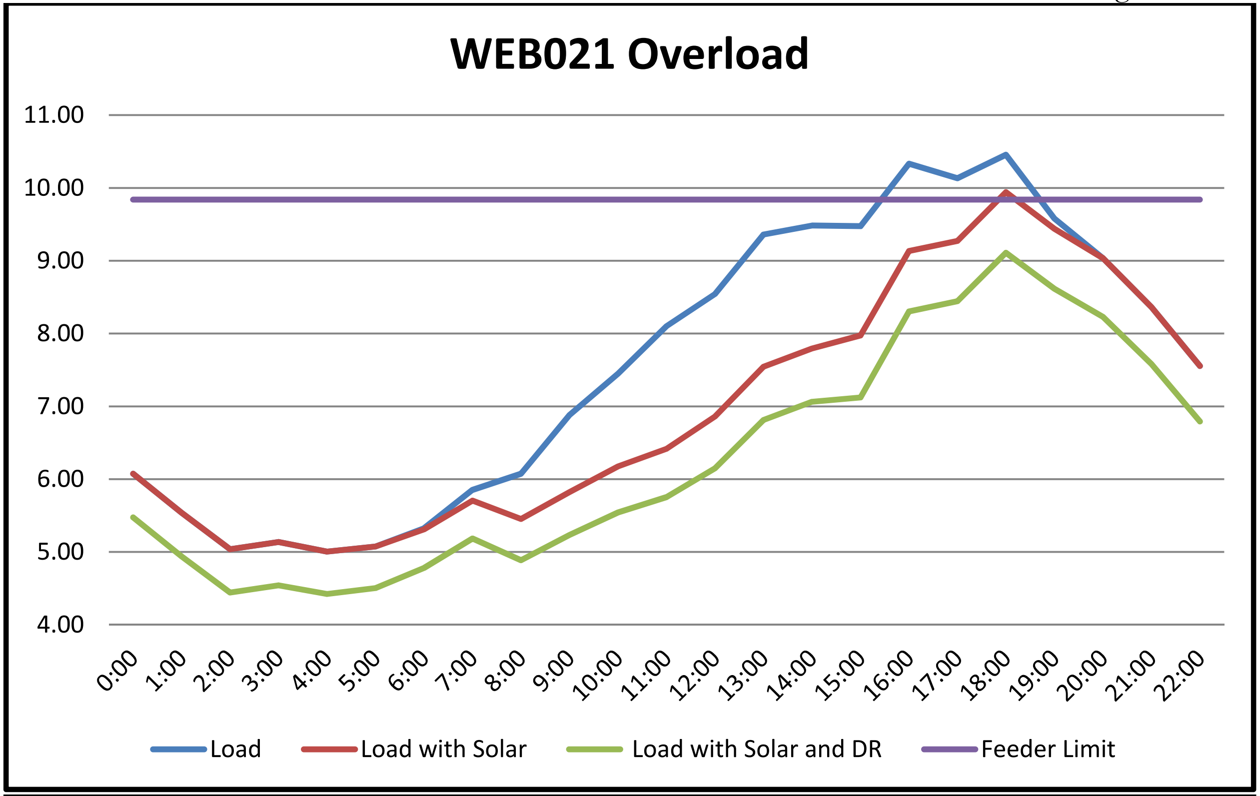
Assumption	Cost
Energy Storage Costs	$400,000/MWh
Solar PV Costs	$2,000,000/MW
O&M Costs	Not Included In Analysis
Land Costs	Not Included In Analysis
End of Life Replacement Costs	Not Included In Analysis

III. LOAD CURVES

A. Reinforce Kasson TR1 and Feeders



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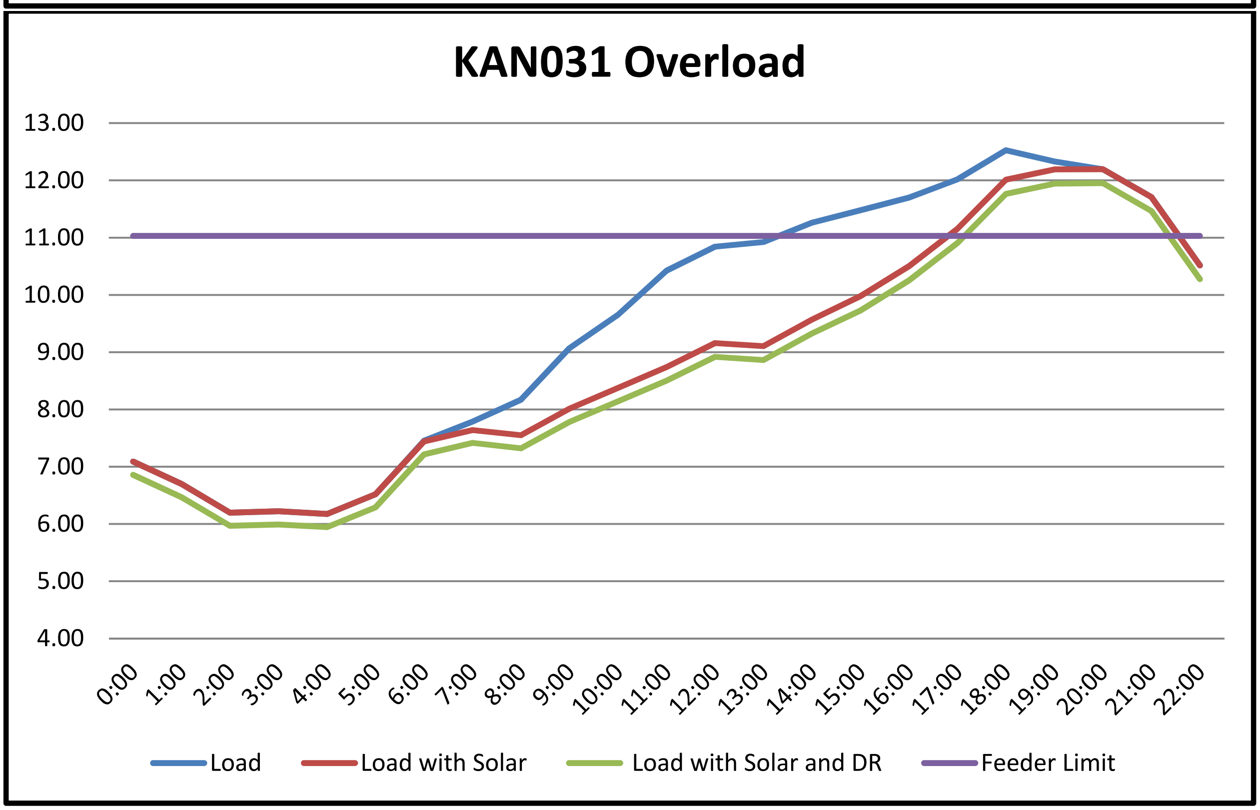
4.00
0:00 1:00 2:00 3:00 4:00 5:00 6:00 7:00 8:00 9:00 10:00 11:00 12:00 13:00 14:00 15:00 16:00 17:00 18:00 19:00 20:00 21:00 22:00
Load
Load with Solar
Load with Solar and DR
Feeder Limit


KAN031 Overload
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7.00
6.00
5.00
4.00
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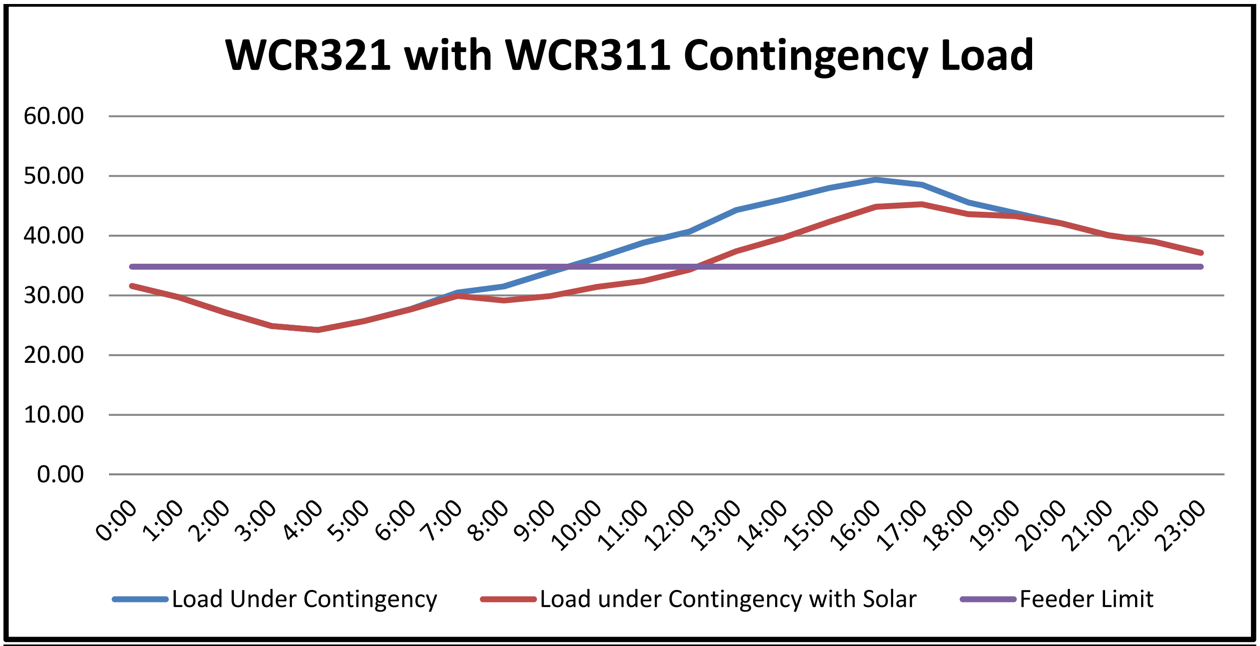
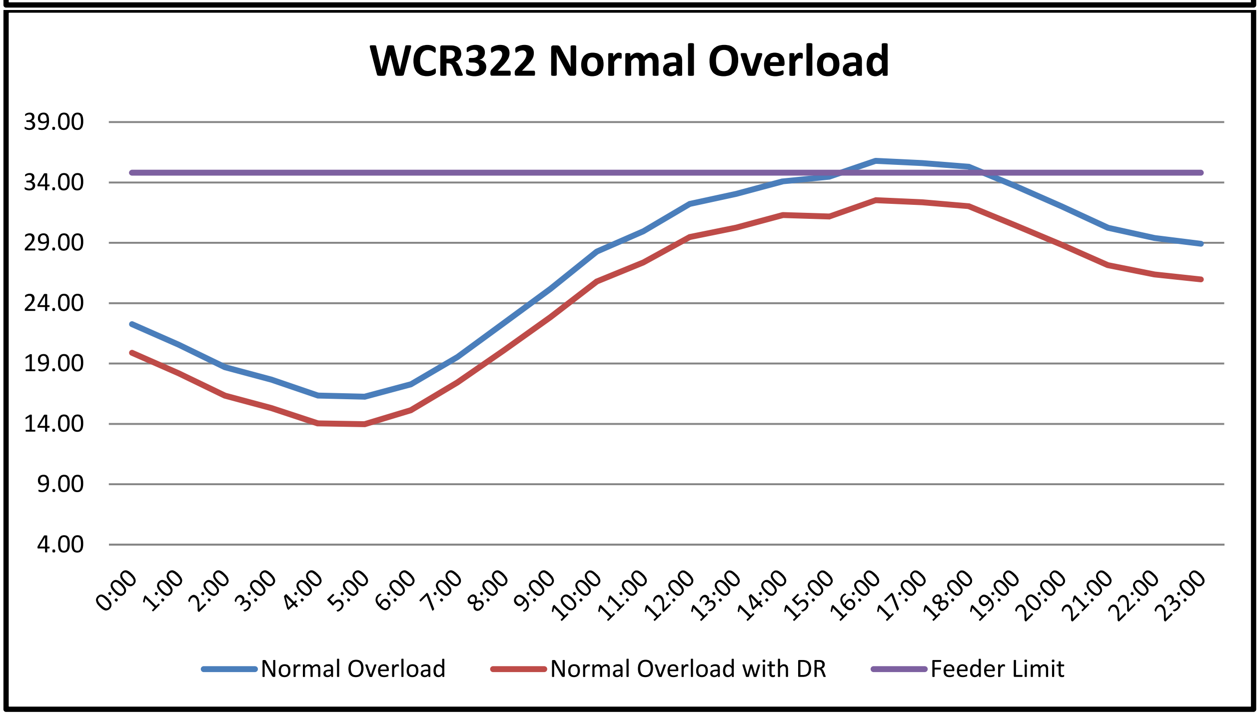
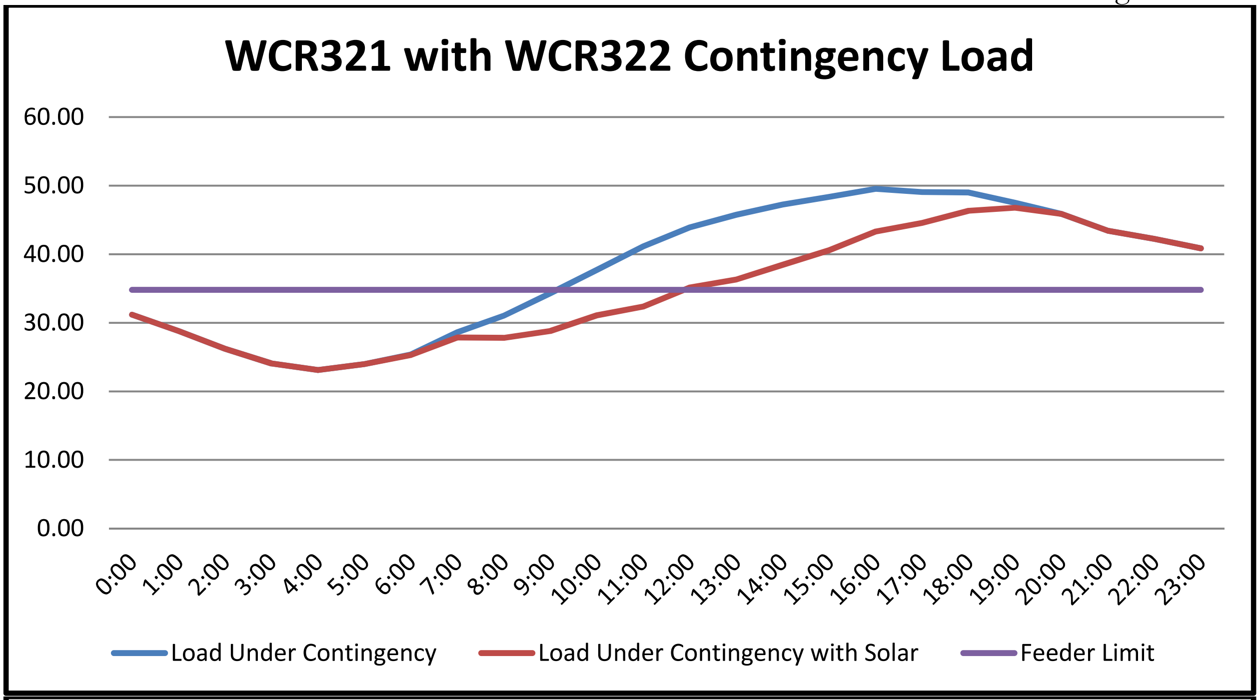
Load
Load with Solar
Load with Solar and DR
Feeder Limit

B. Install West Coon Rapids WCR TR






WCR321 with WCR322 Contingency Load
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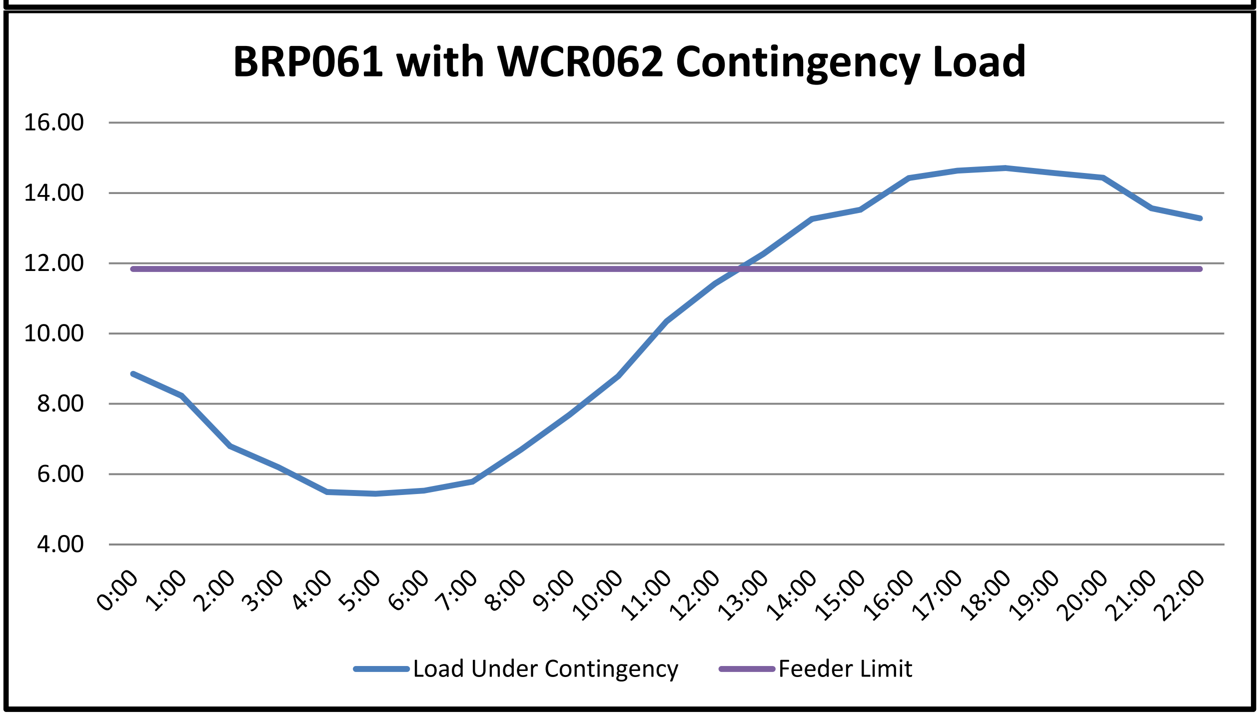
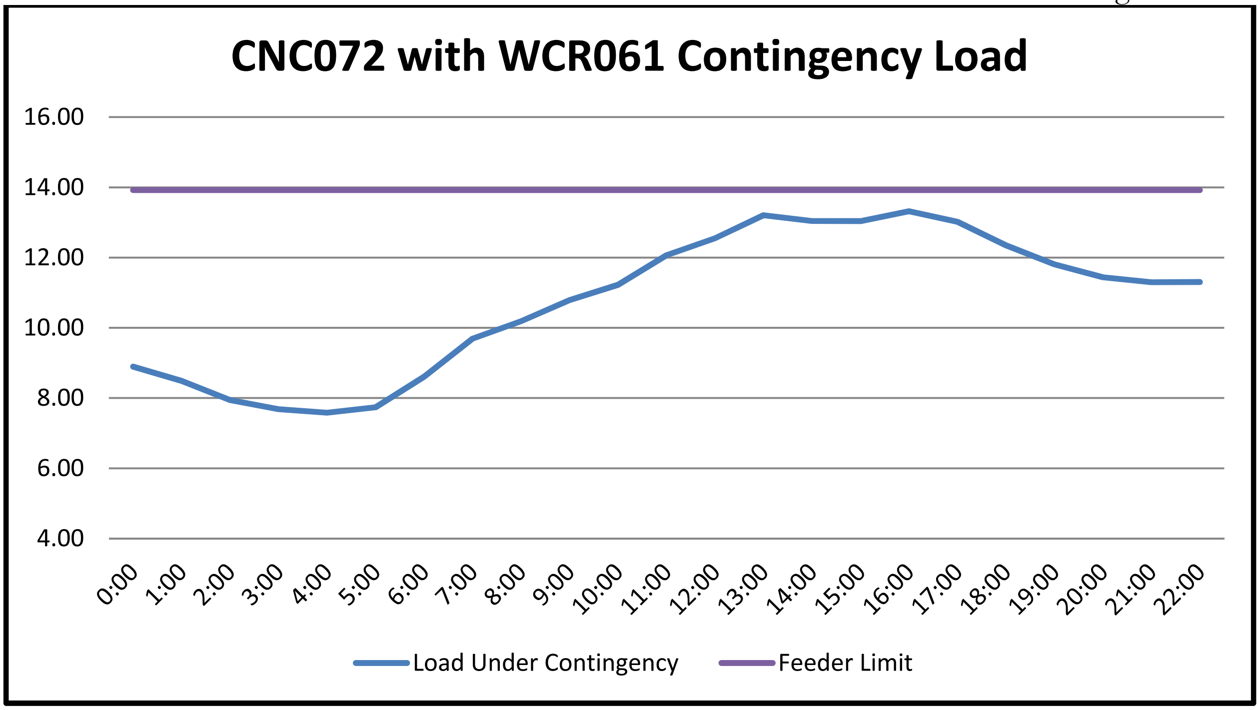
50.00
40.00
30.00
20.00
10.00
0.00
0:00 1:00 2:00 3:00 4:00 5:00 6:00 7:00 8:00 9:00 10:00 11:00 12:00 13:00 14:00 15:00 16:00 17:00 18:00 19:00 20:00 21:00 22:00 23:00
Load Under Contingency
Load Under Contingency with Solar
Feeder Limit


BRP061 with WCR062 Contingency Load
16.00
14.00
12.00
10.00
8.00
6.00
4.00
0:00 1:00 2:00 3:00 4:00 5:00 6:00 7:00 8:00 9:00 10:00 11:00 12:00 13:00 14:00 15:00 16:00 17:00 18:00 19:00 20:00 21:00 22:00
Load Under Contingency
Feeder Limit


CNC072 with WCR061 Contingency Load
16.00
14.00
12.00
10.00
8.00
6.00
4.00
0:00
1:00
2:00
3:00
4:00
5:00
6:00
7:00
8:00
9:00
10:00
11:00
12:00
13:00
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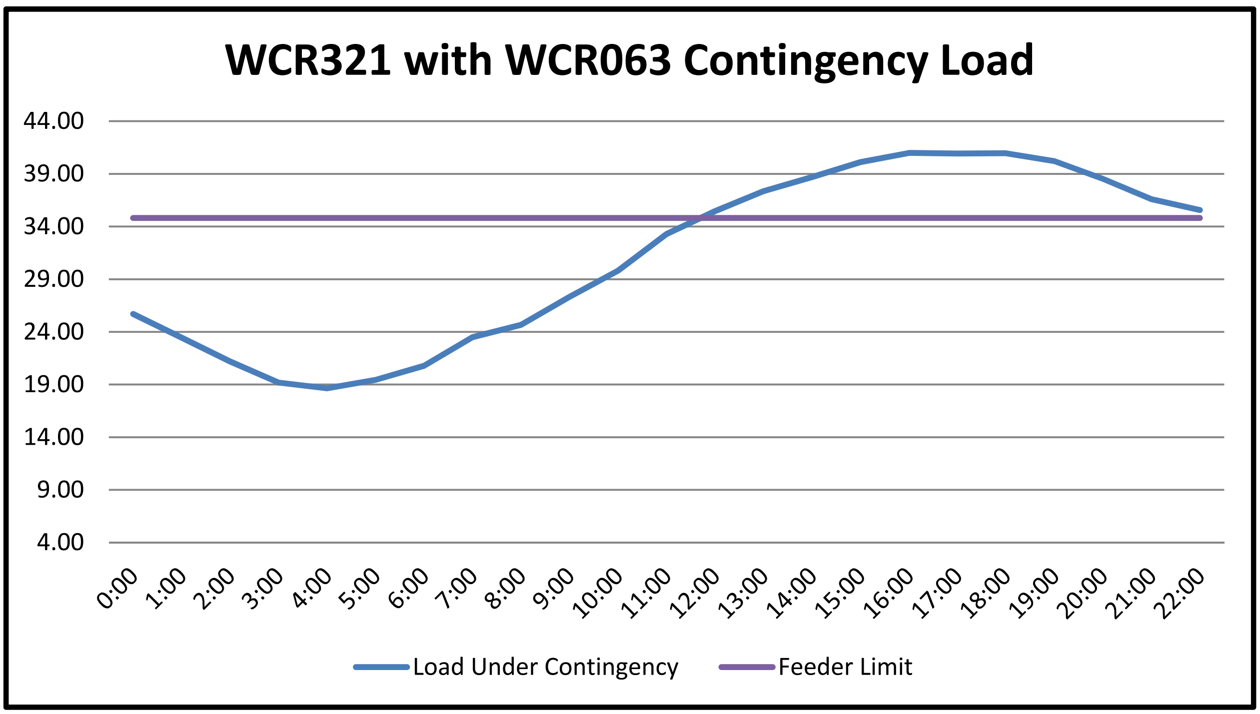
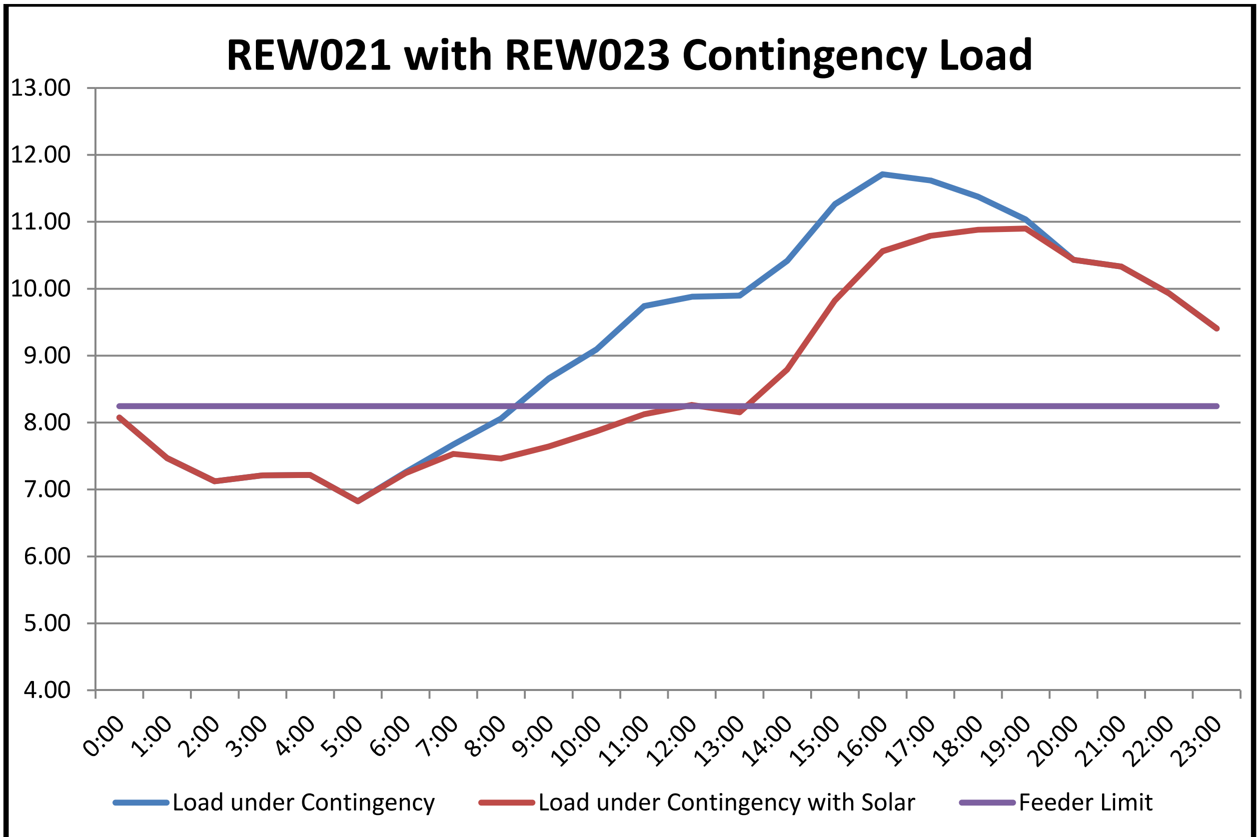
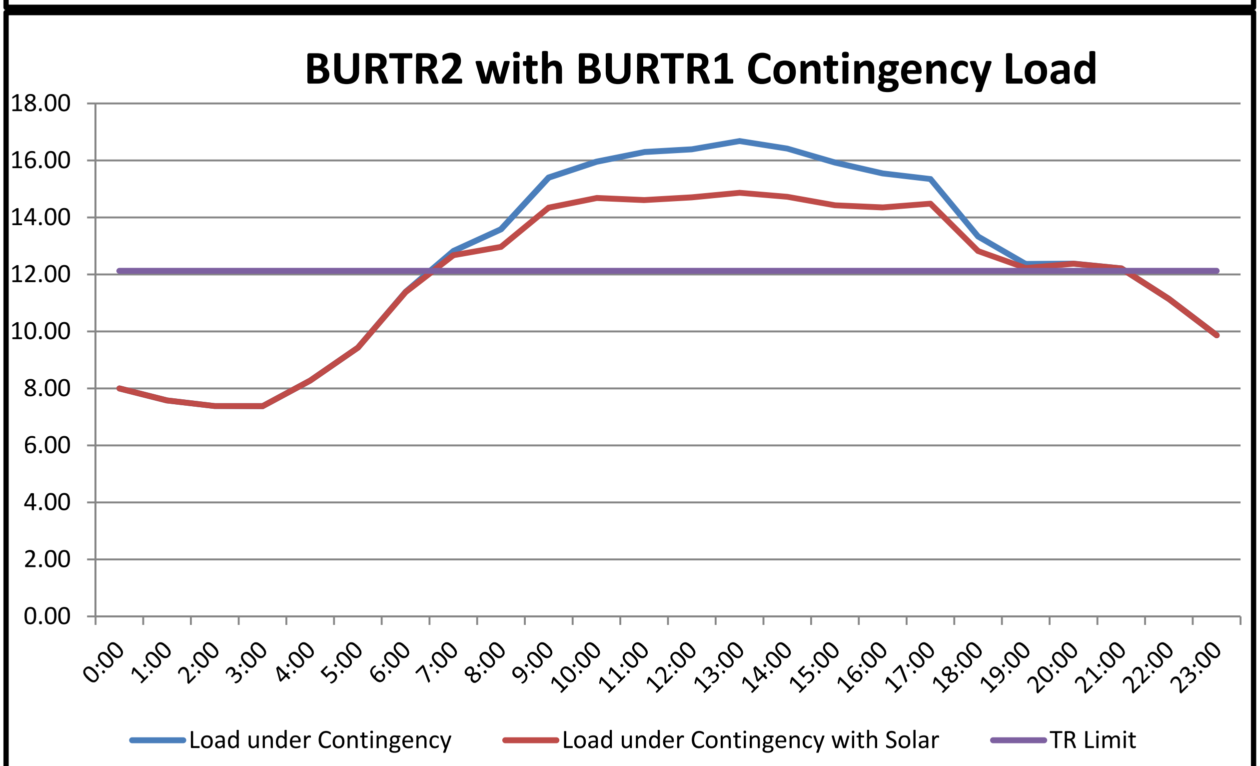
18:00
19:00
20:00
21:00
22:00
Load Under Contingency
Feeder Limit

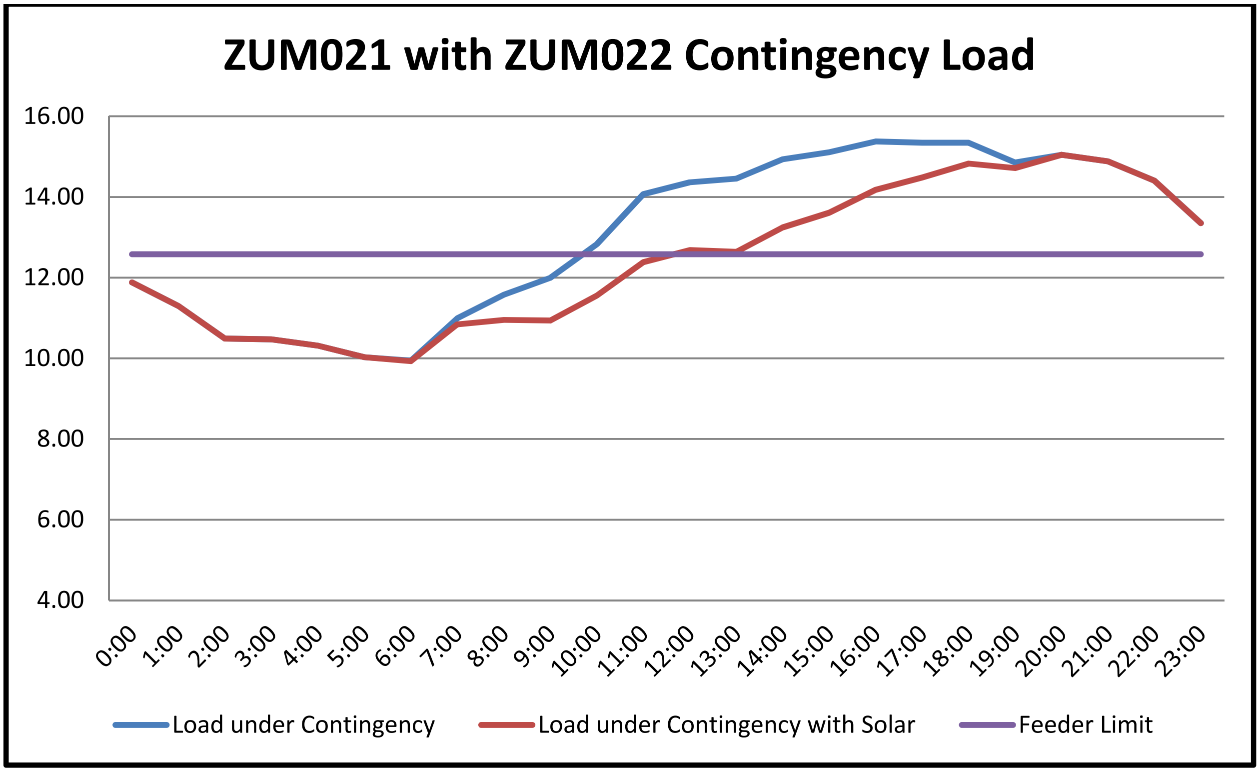

WCR321 with WCR063 Contingency Load
44.00
39.00
34.00
29.00
24.00
19.00
14.00
9.00
4.00
0:00
1:00
2:00
3:00
4:00
5:00
6:00
7:00
8:00
9:00
10:00
11:00
12:00
13:00
14:00
15:00
16:00
17:00
18:00
19:00
20:00
21:00
22:00
Load Under Contingency
Feeder Limit

C. Reinforce Burnside BUR TR2

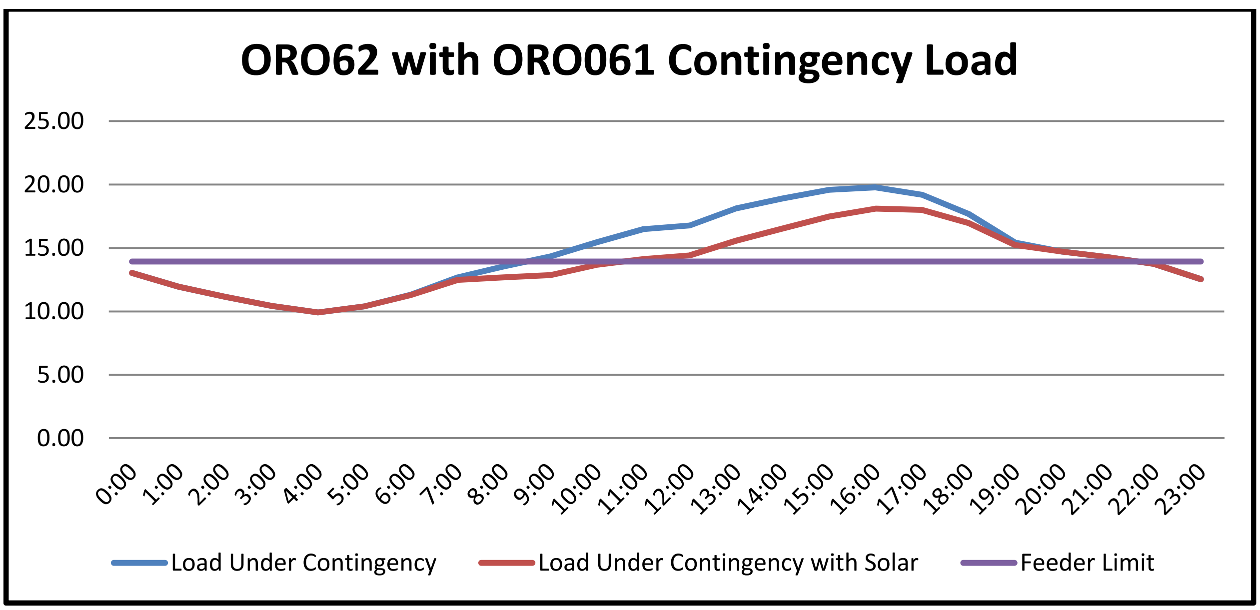


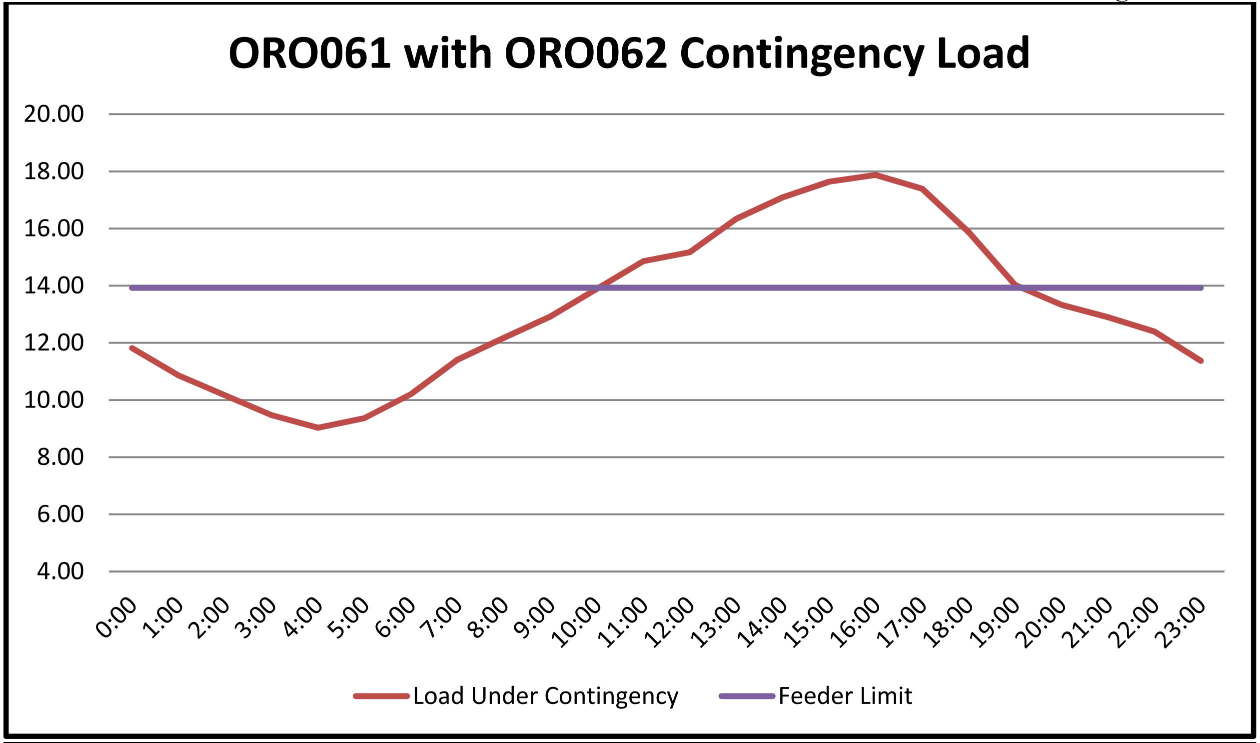


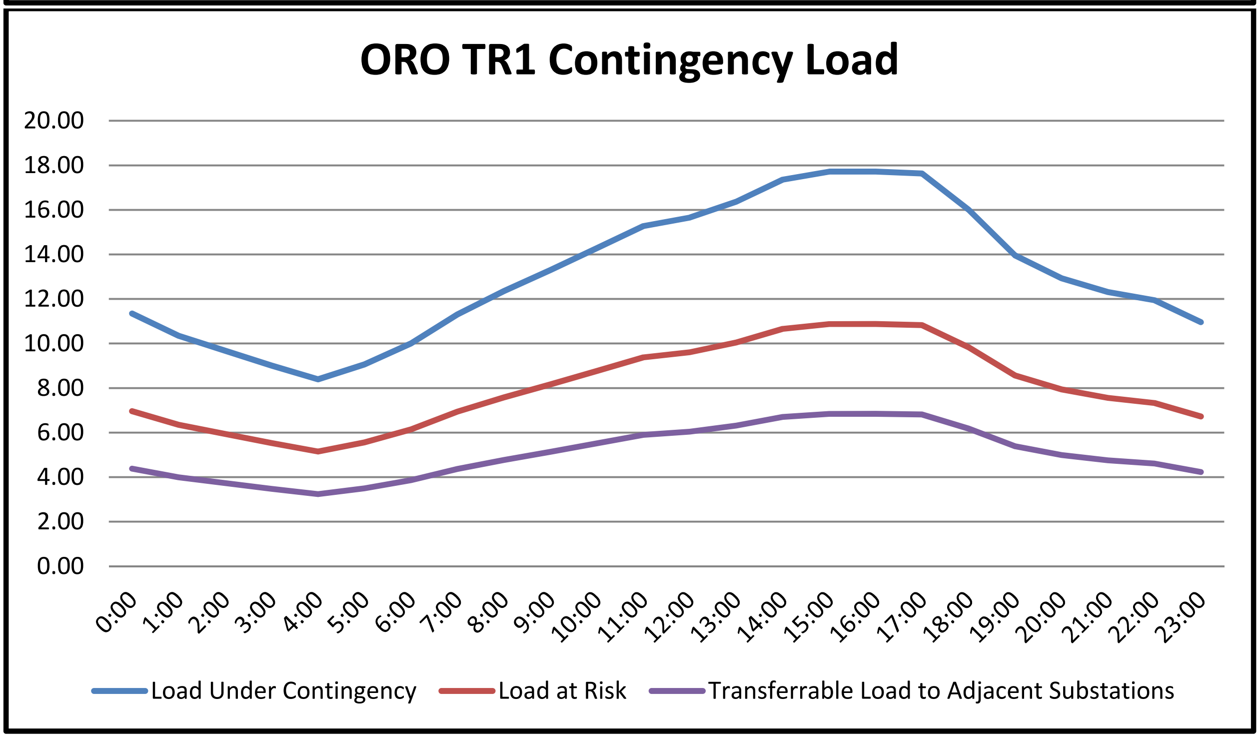
D. Install Zumbrota ZUM TR & Feeder



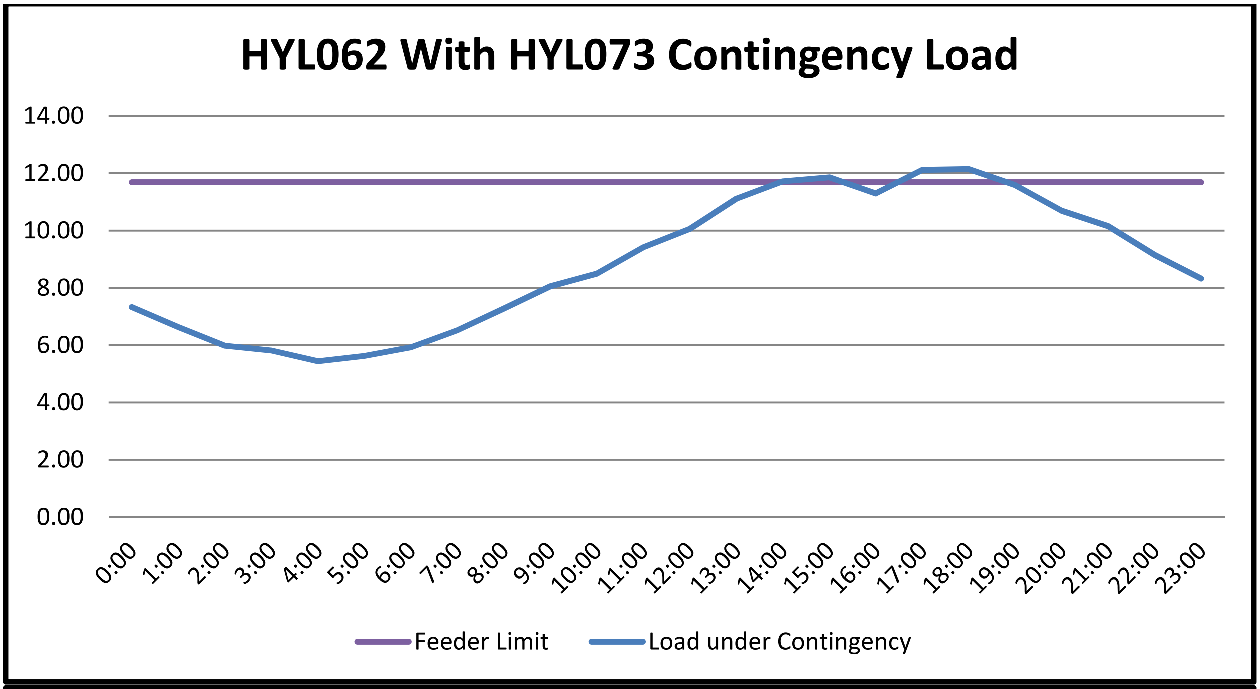
E. Install Orono ORO TR2 & Feeder

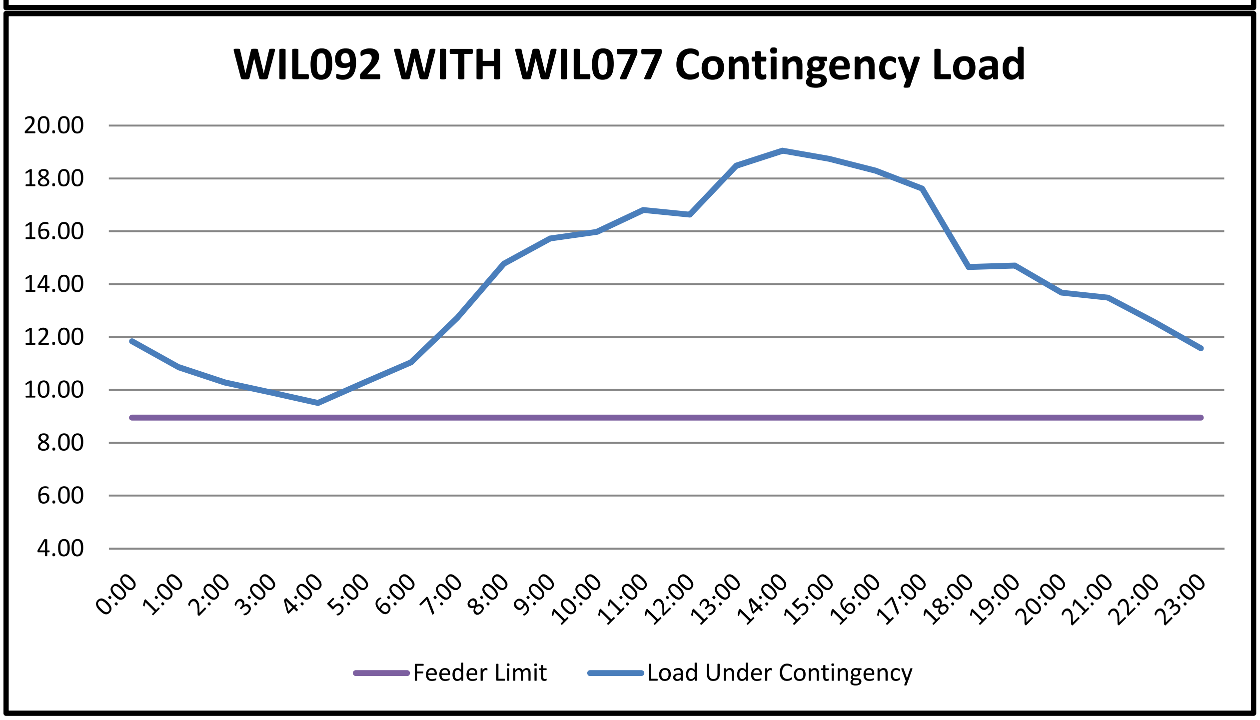


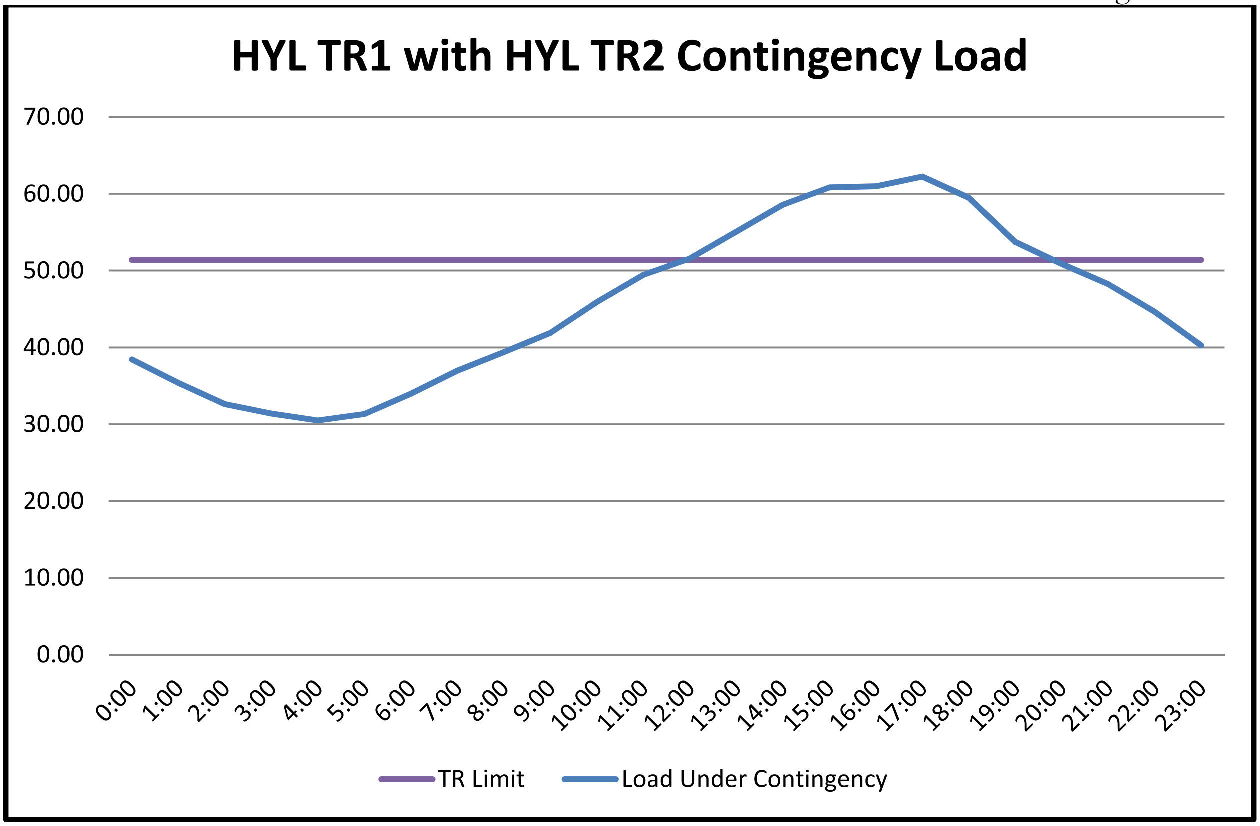

ORO061 with ORO062 Contingency Load
20.00
18.00
16.00
14.00
12.00
10.00
8.00
6.00
4.00
0:00
1:00
2:00
3:00
4:00
5:00
6:00
7:00
8:00
9:00
10:00
11:00
12:00
13:00
14:00
15:00
16:00
17:00
18:00
19:00
20:00
21:00
22:00
23:00
Load Under Contingency
Feeder Limit


ORO TR1 Contingency Load
20.00
18.00
16.00
14.00
12.00
10.00
8.00
6.00
4.00
2.00
0.00
0:00
1:00
2:00
3:00
4:00
5:00
6:00
7:00
8:00
9:00
10:00
11:00
12:00
13:00
14:00
15:00
16:00
17:00
18:00
19:00
20:00
21:00
22:00
23:00
Load Under Contingency
Load at Risk
Transferrable Load to Adjacent Substations

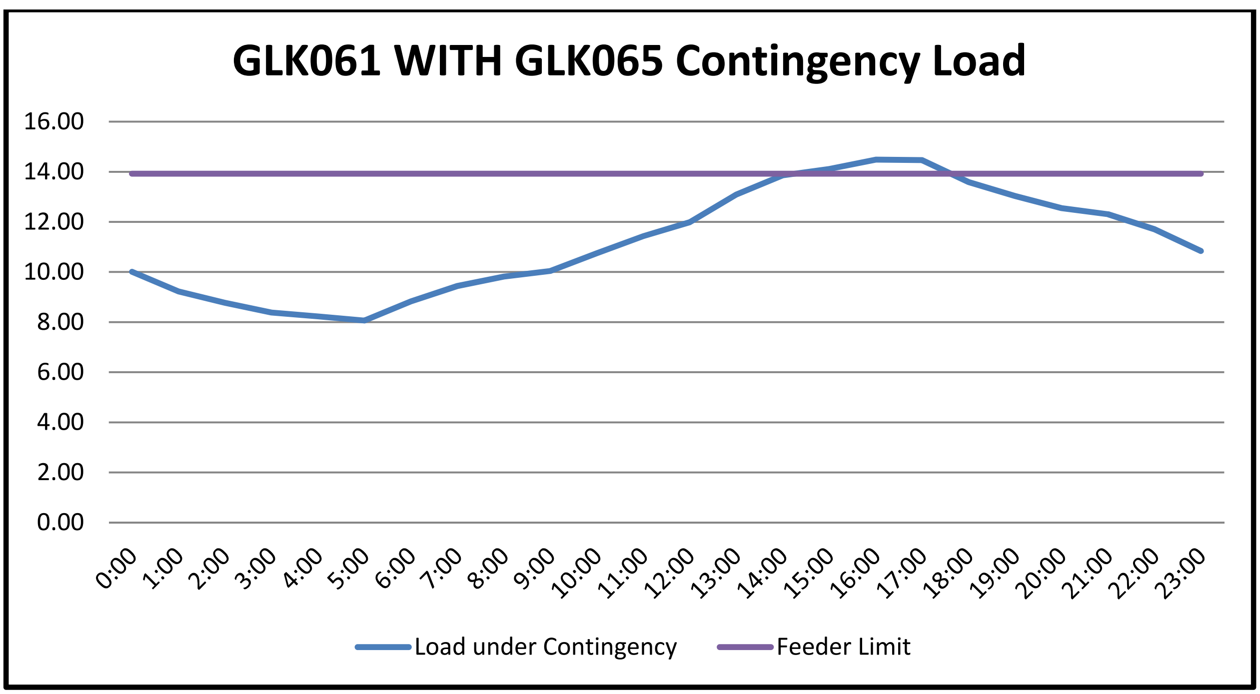
F. Install Hyland Lake HYL TR3 & Feeder

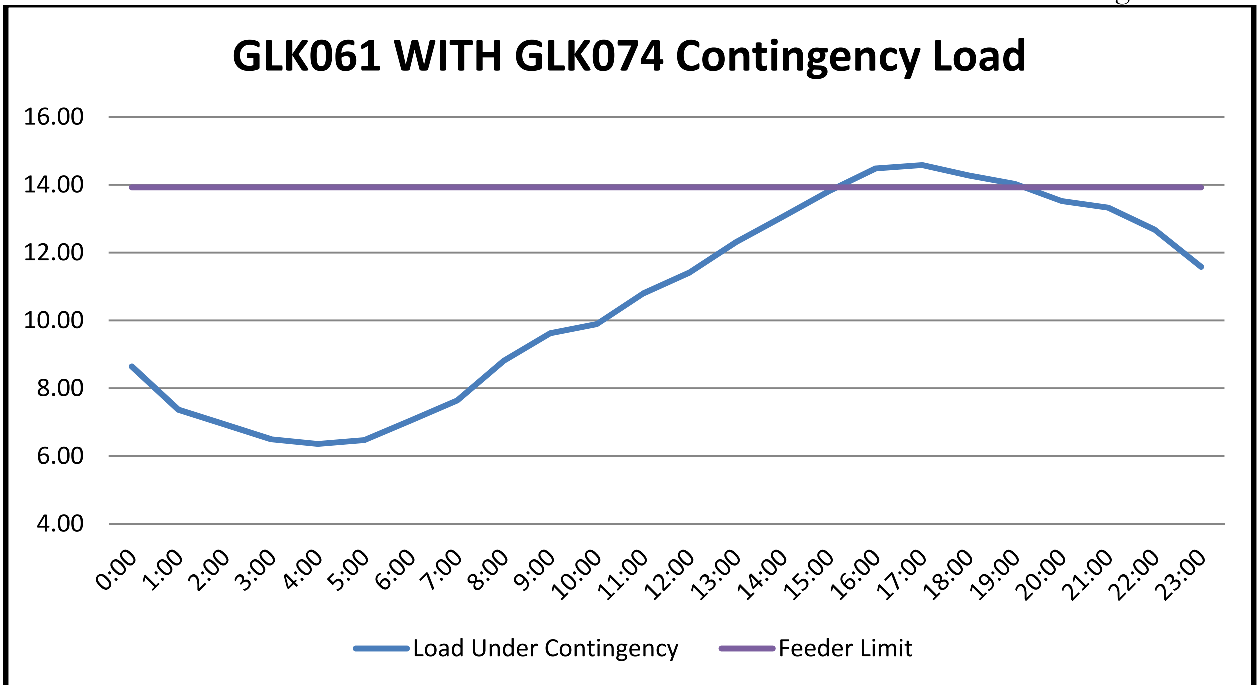


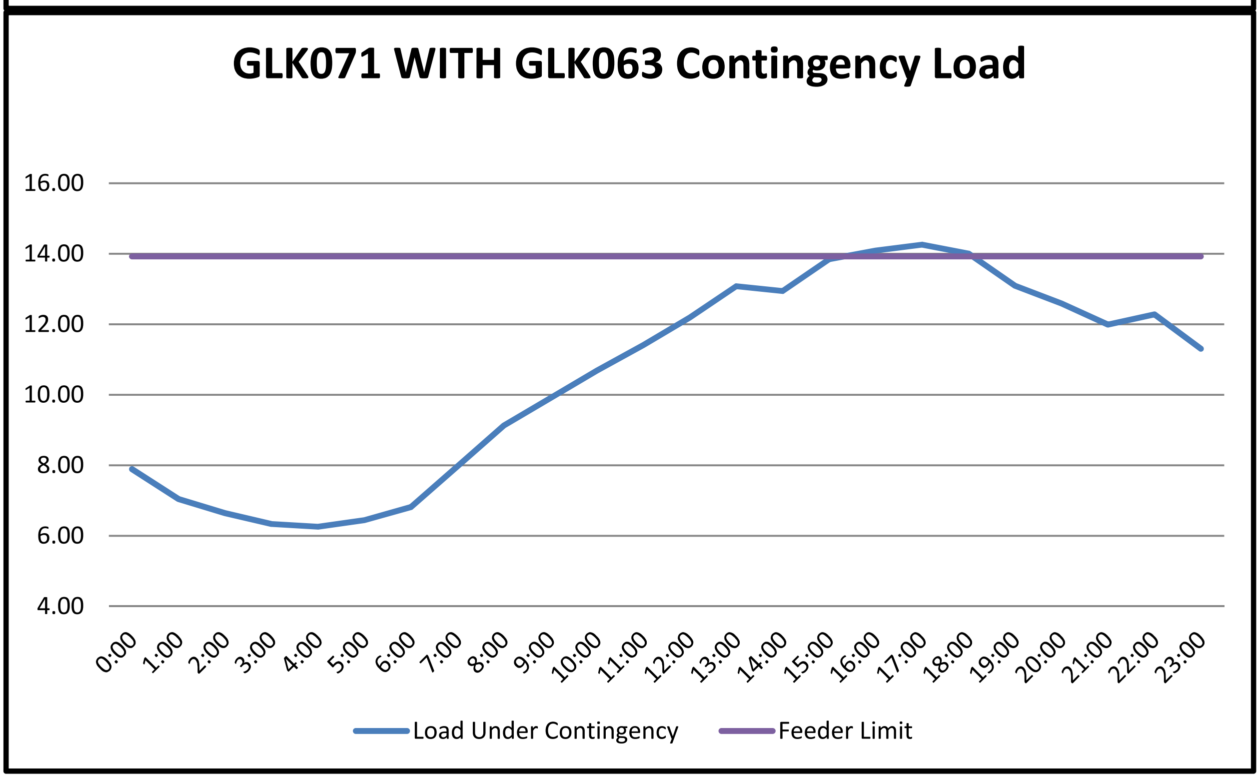


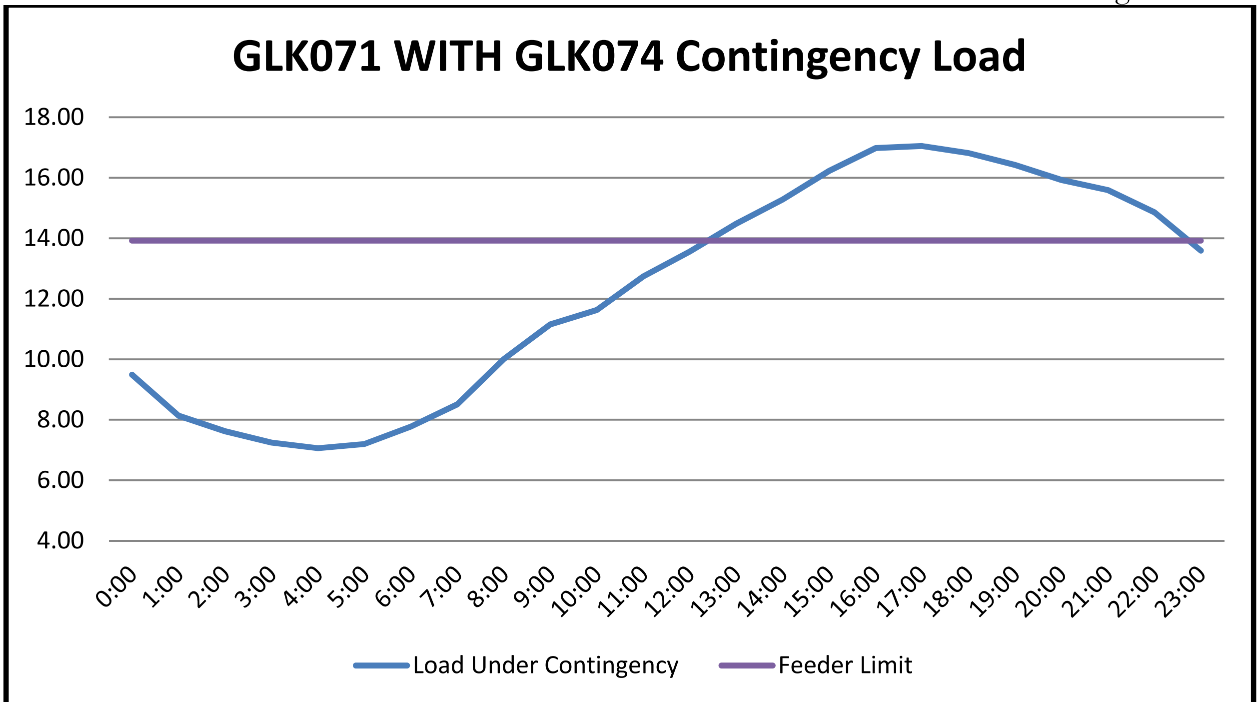


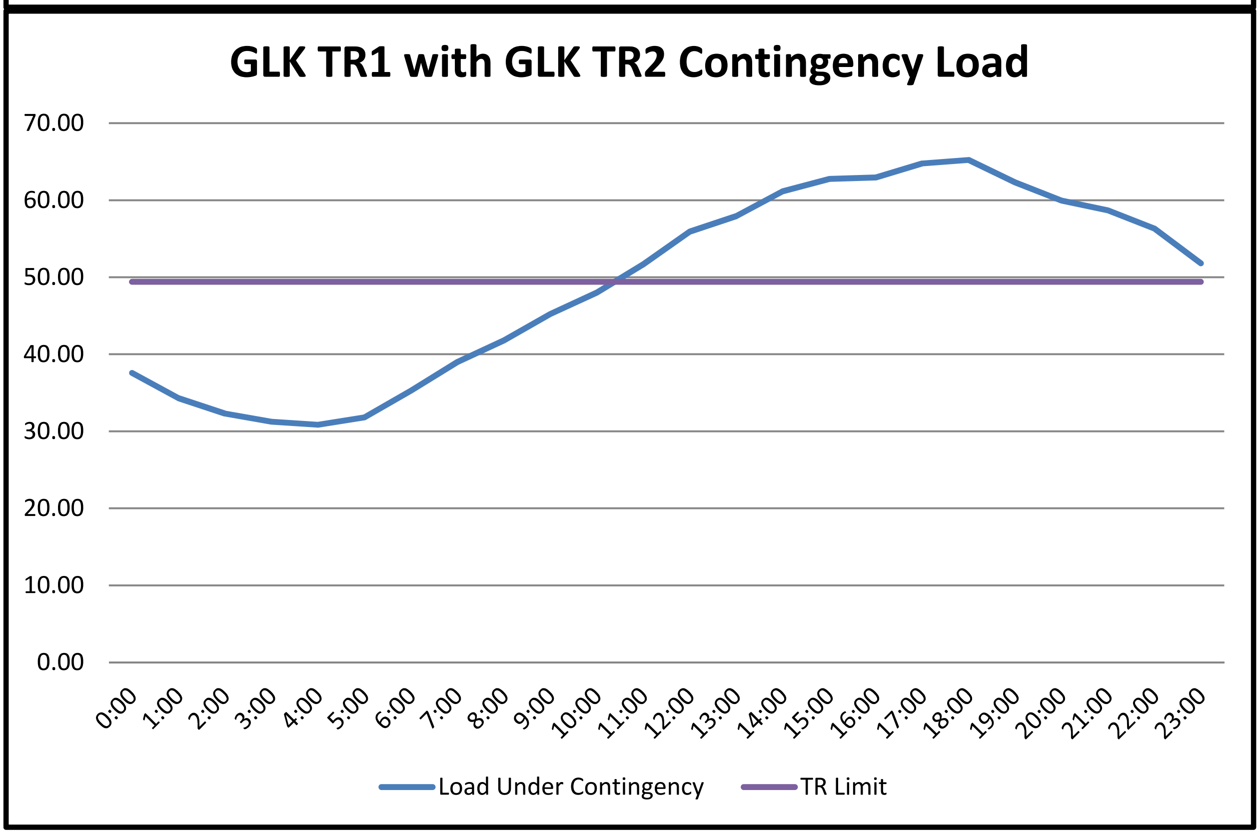
G. Install Goose Lake GLK TR3 & Feeders

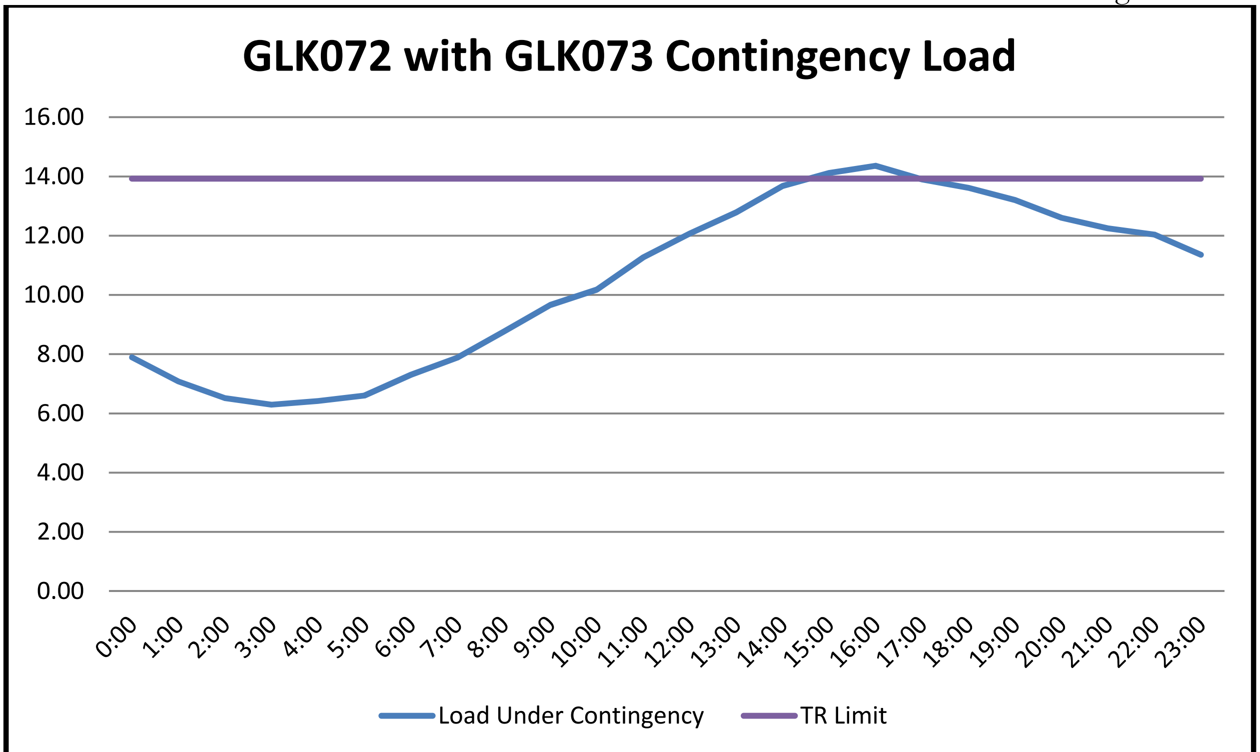



GLK061 WITH GLK074 Contingency Load
16.00
14.00
12.00
10.00
8.00
6.00
4.00
0:00 1:00 2:00 3:00 4:00 5:00 6:00 7:00 8:00 9:00 10:00 11:00 12:00 13:00 14:00 15:00 16:00 17:00 18:00 19:00 20:00 21:00 22:00 23:00
Load Under Contingency
Feeder Limit


GLK071 WITH GLK063 Contingency Load
16.00
14.00
12.00
10.00
8.00
6.00
4.00
0:00 1:00 2:00 3:00 4:00 5:00 6:00 7:00 8:00 9:00 10:00 11:00 12:00 13:00 14:00 15:00 16:00 17:00 18:00 19:00 20:00 21:00 22:00 23:00
Load Under Contingency
Feeder Limit


GLK071 WITH GLK074 Contingency Load
18.00
16.00
14.00
12.00
10.00
8.00
6.00
4.00
0:00
1:00
2:00
3:00
4:00
5:00
6:00
7:00
8:00
9:00
10:00
11:00
12:00
13:00
14:00
15:00
16:00
17:00
18:00
19:00
20:00
21:00
22:00
23:00
Load Under Contingency
Feeder Limit


GLK TR1 with GLK TR2 Contingency Load
70.00
60.00
50.00
40.00
30.00
20.00
10.00
0.00
0:00
1:00
2:00
3:00
4:00
5:00
6:00
7:00
8:00
9:00
10:00
11:00
12:00
13:00
14:00
15:00
16:00
17:00
18:00
19:00
20:00
21:00
22:00
23:00
Load Under Contingency
TR Limit


GLK072 with GLK073 Contingency Load
16.00
14.00
12.00
10.00
8.00
6.00
4.00
2.00
0.00
0:00
1:00
2:00
3:00
4:00
5:00
6:00
7:00
8:00
9:00
10:00
11:00
12:00
13:00
14:00
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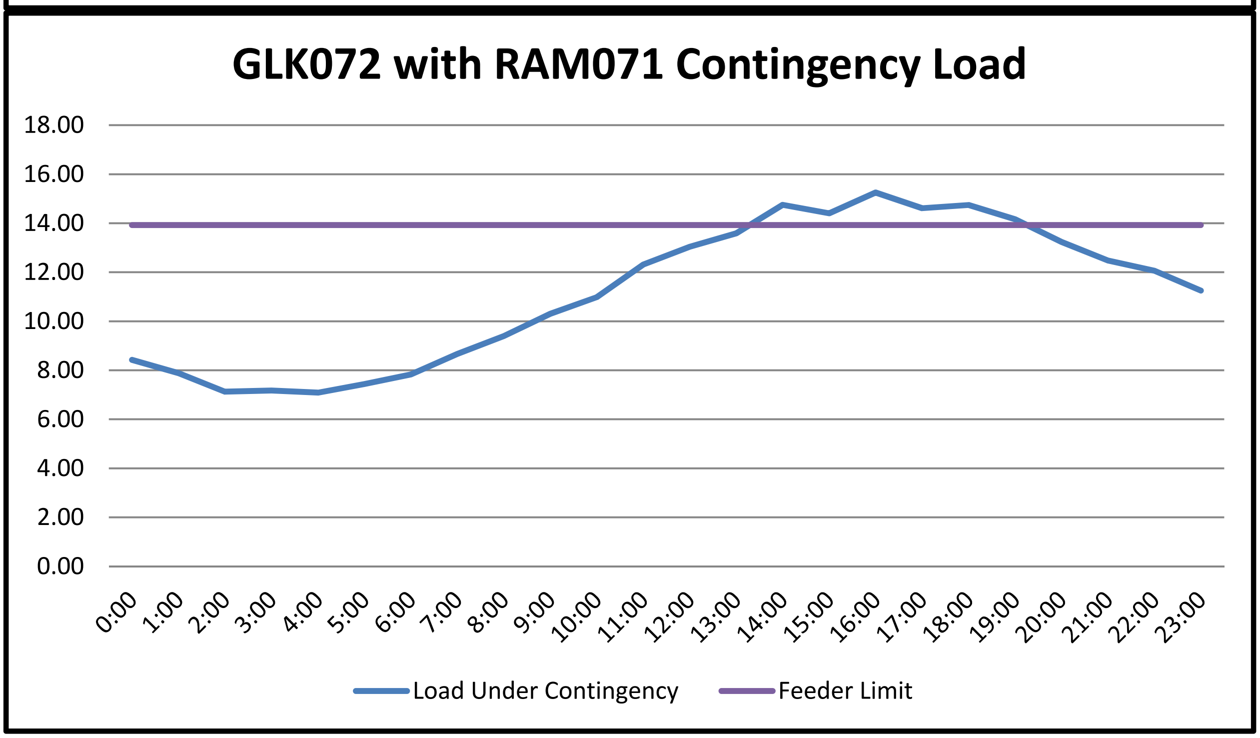
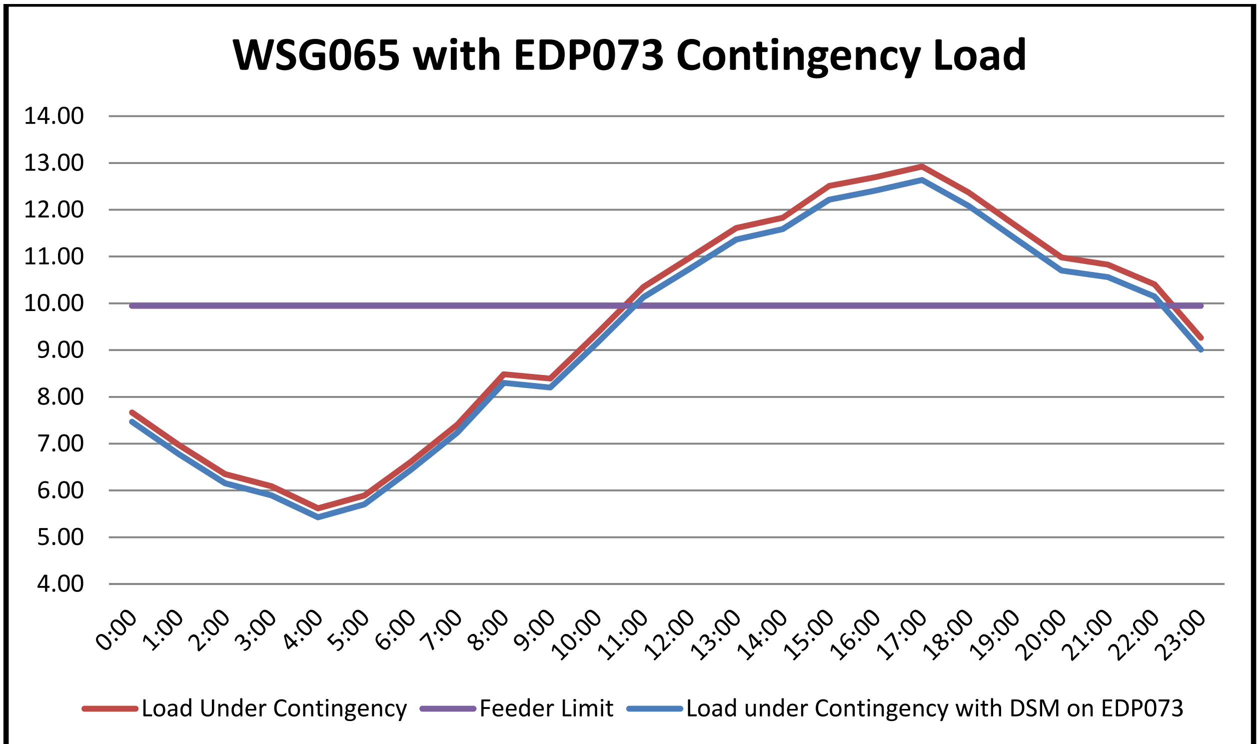
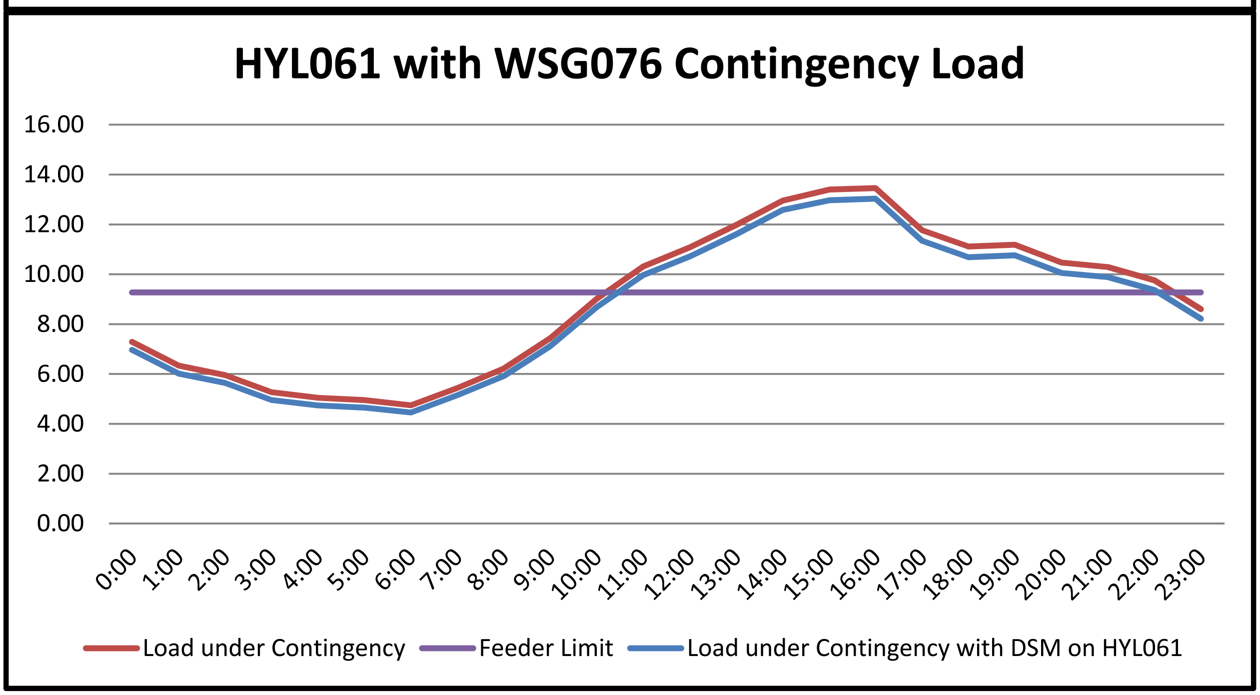
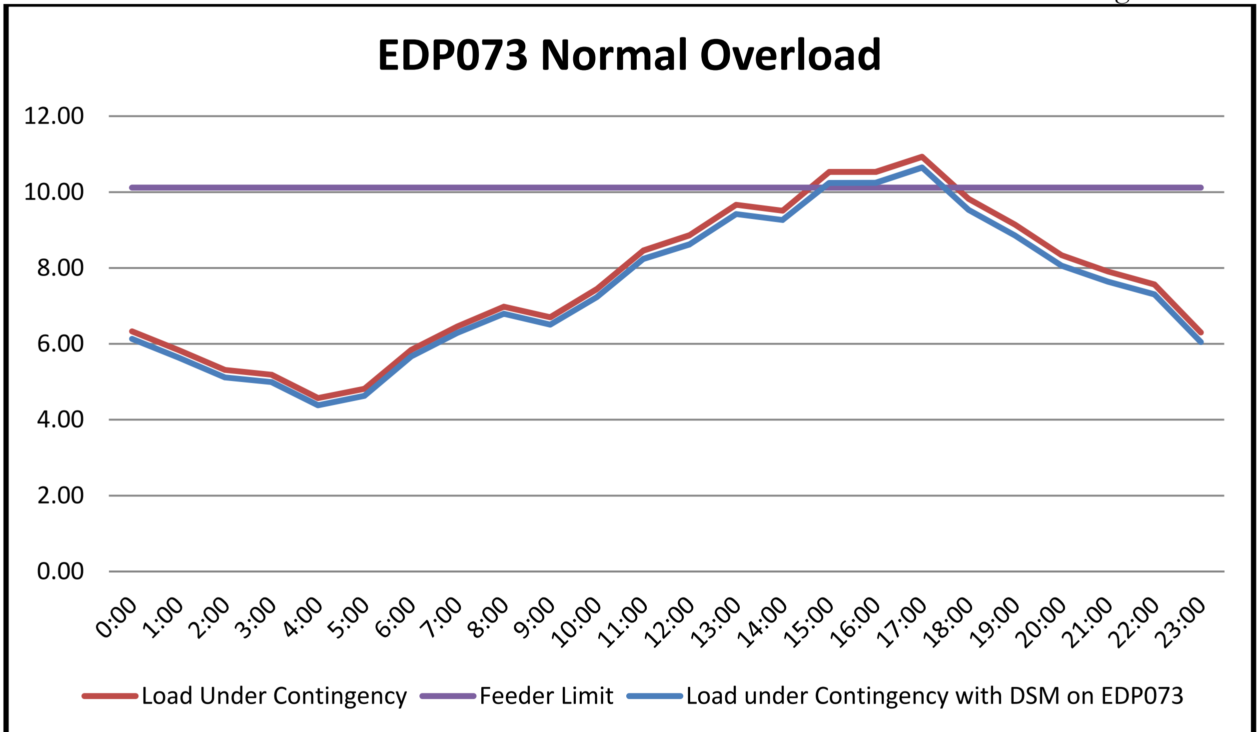
22:00
23:00
Load Under Contingency
TR Limit

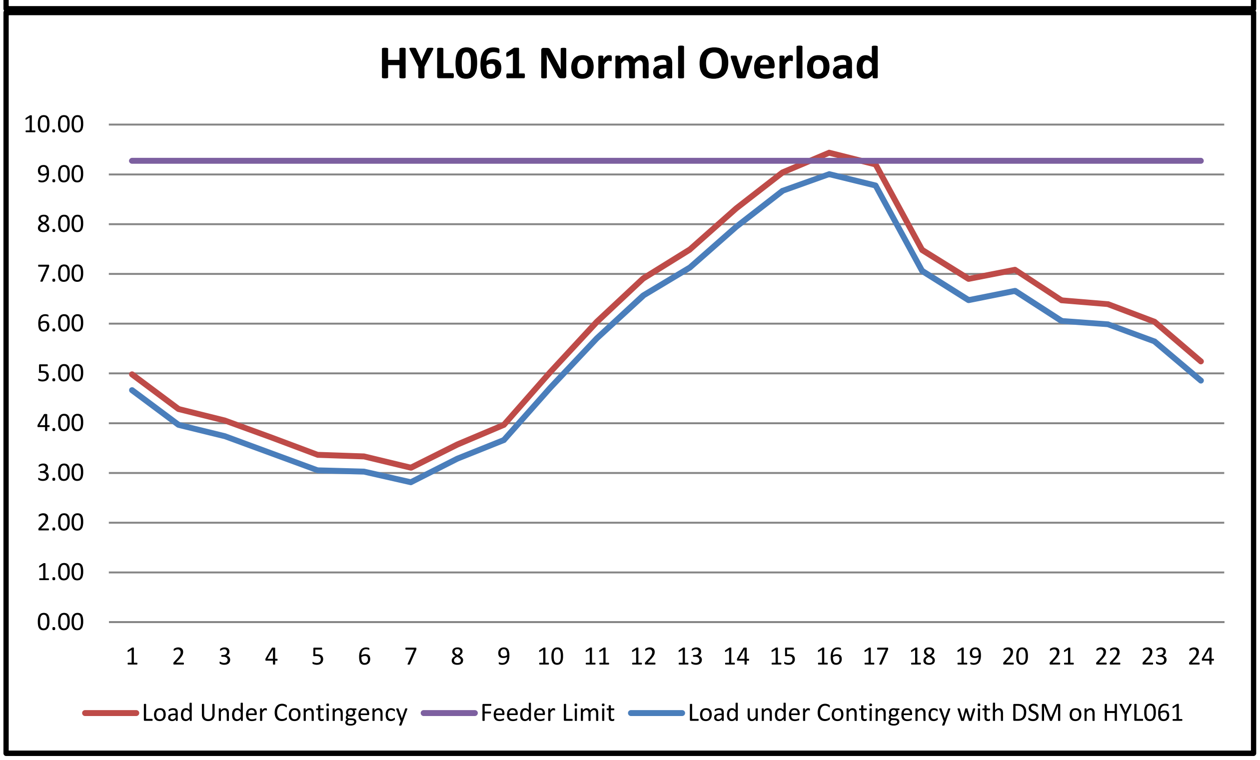

GLK072 with RAM071 Contingency Load
18.00
16.00
14.00
12.00
10.00
8.00
6.00
4.00
2.00
0.00
0:00
1:00
2:00
3:00
4:00
5:00
6:00
7:00
8:00
9:00
10:00
11:00
12:00
13:00
14:00
15:00
16:00
17:00
18:00
19:00
20:00
21:00
22:00
23:00
Load Under Contingency
Feeder Limit

H. Install New Viking VKG Feeder

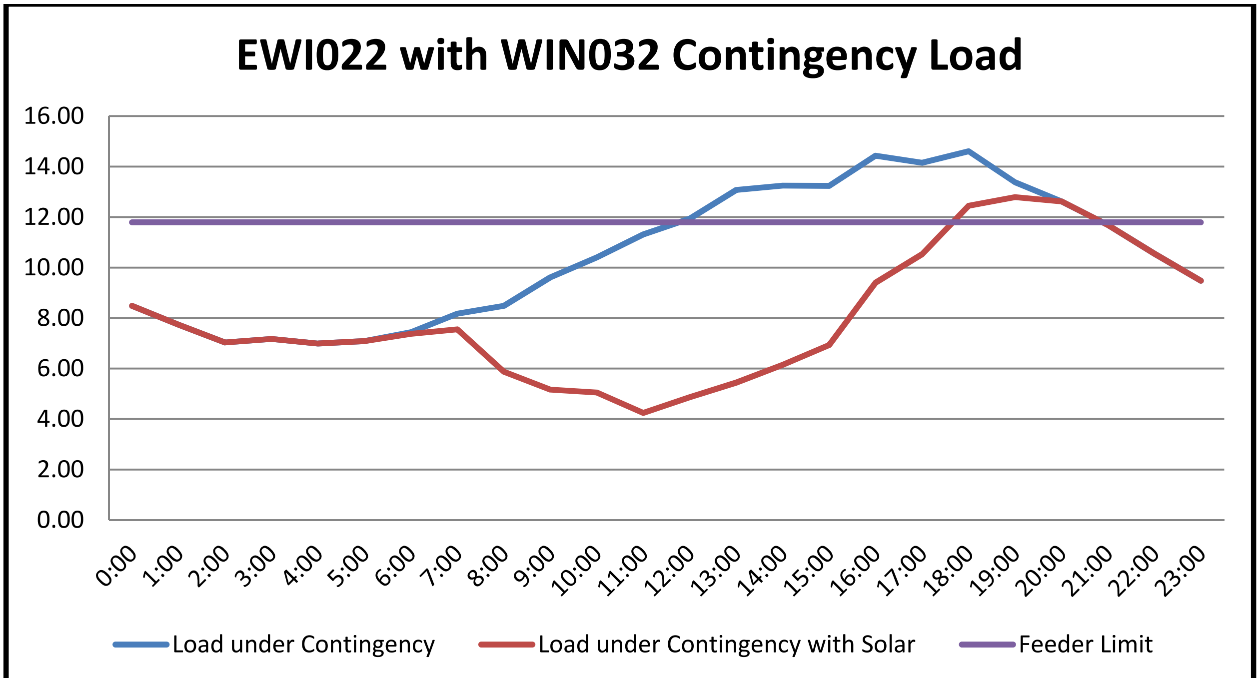


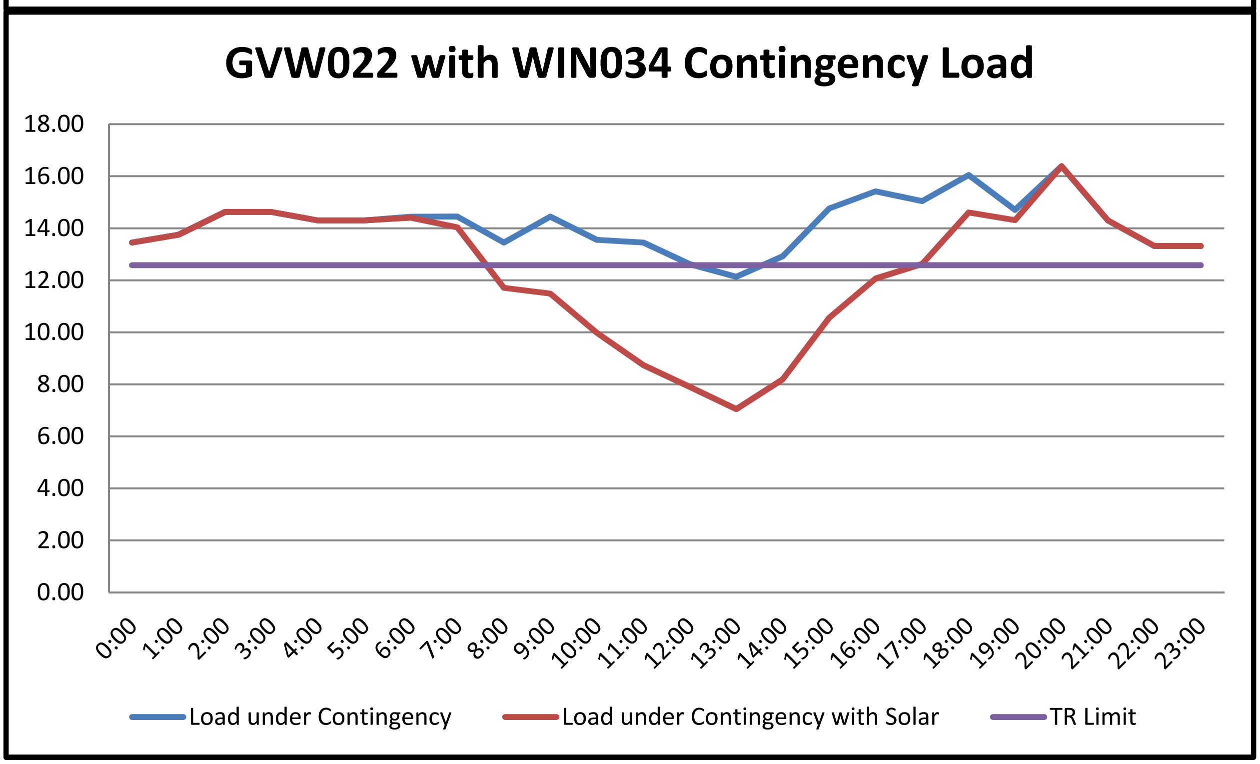


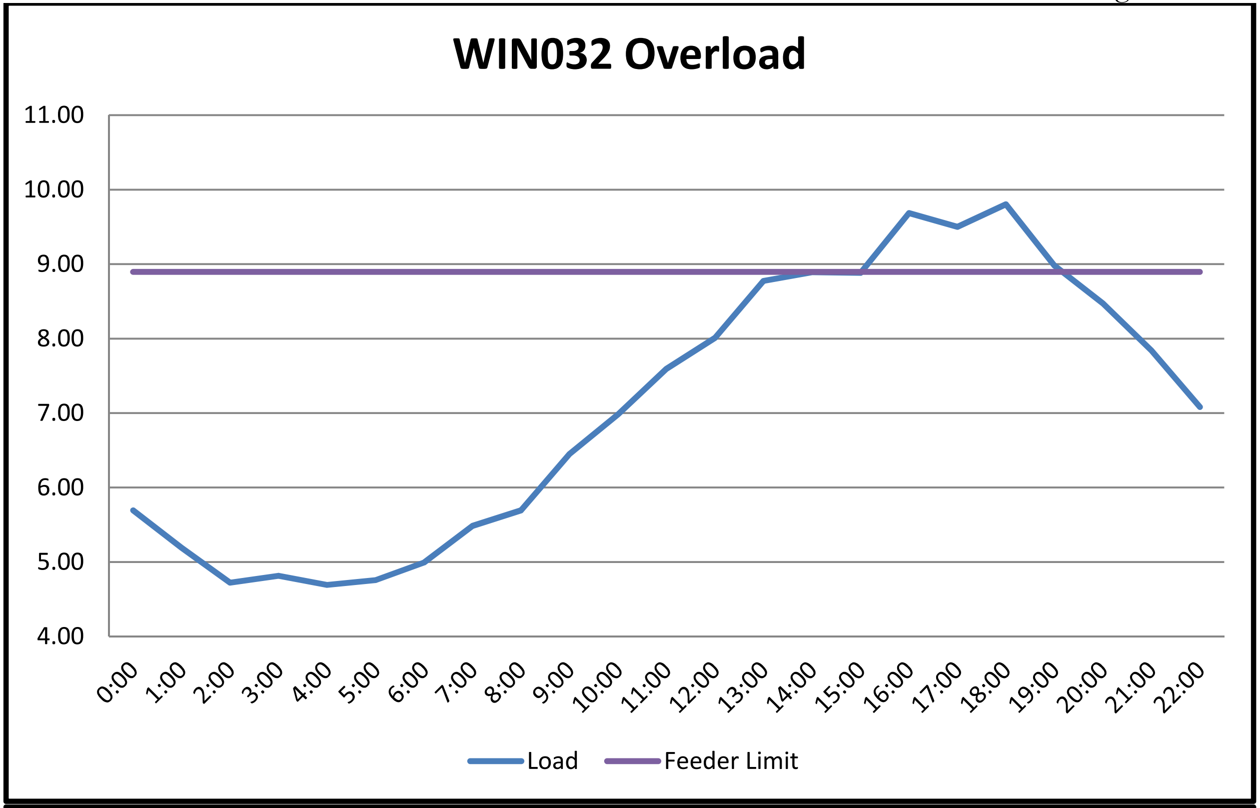

EDP073 Normal Overload
12.00
10.00
8.00
6.00
4.00
2.00
0.00
0:00
1:00
2:00
3:00
4:00
5:00
6:00
7:00
8:00
9:00
10:00
11:00
12:00
13:00
14:00
15:00
16:00
17:00
18:00
19:00
20:00
21:00
22:00
23:00
Load Under Contingency
Feeder Limit
Load under Contingency with DSM on EDP073

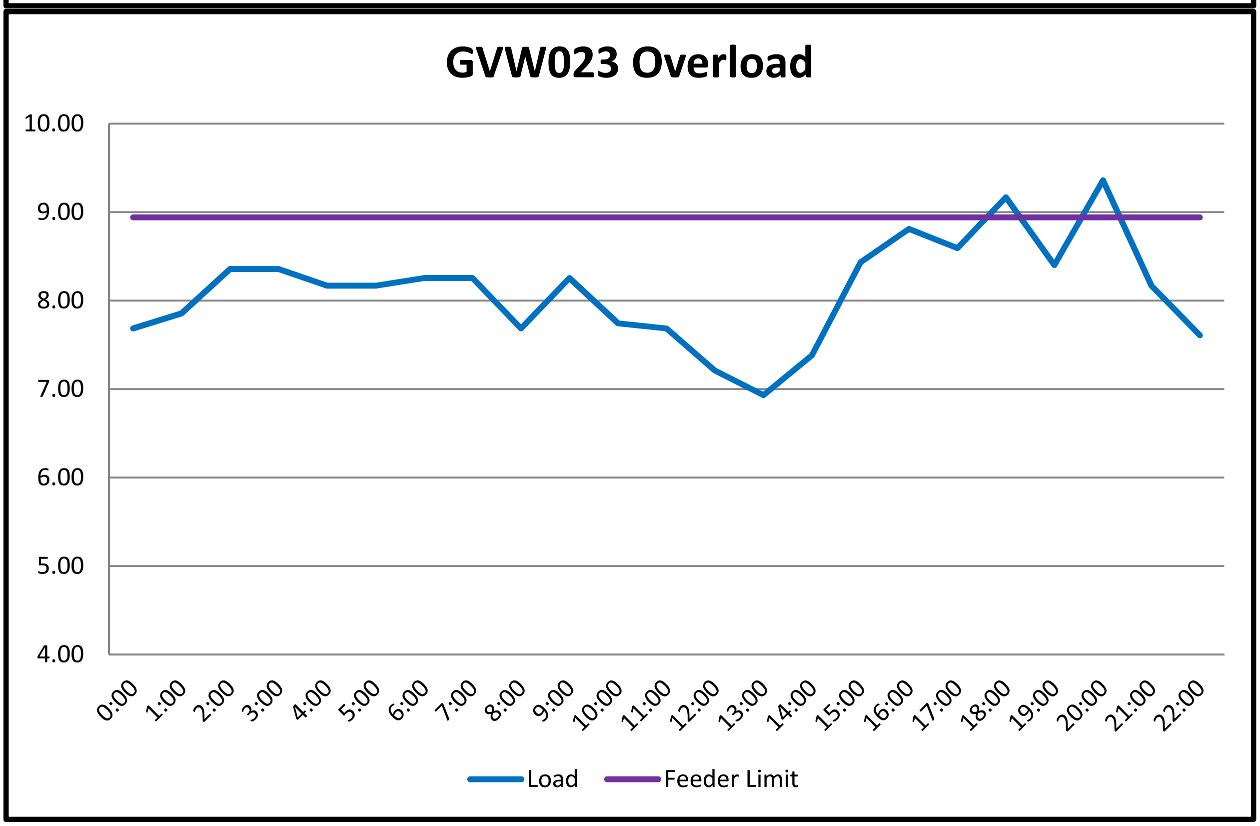

HYL061 Normal Overload
10.00
9.00
8.00
7.00
6.00
5.00
4.00
3.00
2.00
1.00
0.00
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Load Under Contingency
Feeder Limit
Load under Contingency with DSM on HYL061

I. Install East Winona EWI TR2 & Feeder






WIN032 Overload
11.00
10.00
9.00
8.00
7.00
6.00
5.00
4.00
0:00
1:00
2:00
3:00
4:00
5:00
6:00
7:00
8:00
9:00
10:00
11:00
12:00
13:00
14:00
15:00
16:00
17:00
18:00
19:00
20:00
21:00
22:00
Load
Feeder Limit


GVW023 Overload
10.00
9.00
8.00
7.00
6.00
5.00
4.00
0:00
1:00
2:00
3:00
4:00
5:00
6:00
7:00
8:00
9:00
10:00
11:00
12:00
13:00
14:00
15:00
16:00
17:00
18:00
19:00
20:00
21:00
22:00
Load
Feeder Limit

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Participation of Distributed Energy Resource Aggregations in Markets Operated by Regional Transmission Organizations and Independent System Operators	))))	**Docket No. RM18-9-000**

DATA REQUEST COMMENTS OF THE
MIDCONTINENT INDEPENDENT SYSTEM OPERATOR, INC.

The Midcontinent Independent System Operator, Inc. ("MISO") submits these comments in response to the data request issued by the Federal Energy Regulatory Commission ("Commission") in the above-captioned docket on September 5, 2019 ("Data Request"). On November 17, 2016, the Commission issued a Notice of Proposed Rulemaking concerning Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators ("NOPR").[1] On February 15, 2018, the Commission announced its intention to explore the NOPR's proposed distributed energy resources ("DER") aggregation reforms. The Commission conducted a technical conference on April 10 and 11, 2018 to discuss the status of DER rules and explore potential reforms. Following the technical conference and the Commission's review of comments submitted in response to the NOPR, the Commission issued the Data Request seeking information on Regional Transmission Organizations ("RTO") and Independent System Operator ("ISO") policies and procedures that affect the interconnection of DERs.

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[1] *Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators*, 157 FERC 61,121 (2016).

I. INTRODUCTION

MISO appreciates the opportunity to provide information about the rules pertaining to DER aggregators under MISO's currently-effective Tariff[2] and business practices. Generally, MISO supports efforts to remove barriers and better accommodate the participation of DER aggregations in MISO markets. However, there is much work to be done to accommodate the unique characteristics of DER units. As MISO noted in our comments filed in this docket, the MISO region currently does not have a high volume of DER installations (other than demand response resources) and MISO does not anticipate significant penetration levels in the near future.[3] DERs typically connect to distribution facilities and are subject to the rules of the directly connected local distribution provider ("Host Distribution Provider") rather than the MISO Tariff. MISO's historic involvement with distribution-level interconnections largely has been limited to coordinating with the Host Distribution Provider where MISO is identified as an affected system.

MISO's interconnection rules would apply to requests to connect directly to a facility that provides Wholesale Distribution Service ("WDS Facility") because such facilities are part of the MISO Transmission System for purposes of interconnection. To date, however, MISO has not received nor processed a request from a DER to interconnect to such a facility. Therefore, while MISO has complied with the Data Request by providing information about how MISO's existing interconnection rules would apply to DERs, the application of current rules to DERs remains untested in practice and MISO's responses consequently are to some degree hypothetical.

[2] MISO Open Access Transmission, Energy, and Operating Reserve Markets Tariff ("Tariff").

[3] Comments of the Midcontinent Independent System Operator, Inc. (filed June 26, 2018), Docket No. RM18-9-000 ("MISO Comments") at 2.

MISO is currently working with the Organization of MISO States ("OMS") and other MISO stakeholders to develop a DER participation model that accounts for the distinctive characteristics of the MISO region and promotes reliability on a least cost basis. Such a model likely will require carefully-considered adjustments to MISO's interconnection rules in order to address the unique challenges presented by DERs, such as defining a permissible geographic scope, refining study processes to account for changes to aggregations, and enhancing coordination procedures with the diverse distribution providers in the MISO region. MISO looks forward to developing regionally appropriate rules in close coordination with the Commission and MISO stakeholders. MISO also reiterates its request that the Commission's Final Rule provide more guidance as to the desired role of the distribution provider and latitude to RTOs and ISOs, and refrain from broad implementation of prescriptive DER requirements.

II. RESPONSES TO DATA REQUESTS

MISO provides the following response to each of the Commission's data requests below.

1. Under your RTO's/ISO's existing rules for small generator interconnection, if a DER seeks to participate in wholesale markets and plans to interconnect at the distribution level, please describe the step-by-step process by which that resource would interconnect to the system.

Attachment X of the MISO Tariff contains a single Generator Interconnection Procedure ("GIP") and Generator Interconnection Agreement ("GIA") for Interconnection Requests of all sizes rather than separate procedures for interconnecting small and large projects. Therefore, the process described in this Response is the same process applicable to all Generating Facilities interconnected to the MISO Transmission System. The process that a DER connected to distribution facilities must follow to inject electricity into the Transmission System participate in MISO wholesale markets varies depending on the characteristics of the distribution facility and whether the DER seeks to participate in

MISO's Resource Adequacy construct. If the distribution facility to which the DER will connect is part of the Transmission System within the meaning of MISO's Generator Interconnection Procedures, then the DER must submit an Interconnection Request in the form of Attachment X, Appendix 1 to the Tariff. MISO processes these Interconnection Requests through the Three Phase Definitive Planning Phase of MISO's GIP. This involves grouping for study of f Interconnection Requests based on queue priority in accordance with Section 4.1 and 4.2 of the GIP, processing these groups through the three phases of MISO's definitive planning phase as described in GIP Sections 7.1 through, 7.3.3.5, and negotiating and executing a MISO GIA in accordance with Sections 11.1 through 11.3 of the GIP.

If the distribution facility is not part of the Transmission System, then MISO's GIP usually will not apply. Instead, the DER would submit an interconnection request to the applicable distribution provider (the "Host Distribution Provider") and would be subject to any applicable study requirements and interconnection procedures required by the Host Distribution Provider. If the Host Distribution Provider, applying its study procedures, determines that the DER may have impacts on the MISO Transmission System, the Host Distribution Provider would inform MISO's interconnection group of those impacts. MISO, as an affected system, would then coordinate with the Host Distribution Provider and impacted Transmission Owner to study the DER's impacts on the MISO Transmission System to determine what facilities or other mitigation are required to remedy the adverse impacts. The DER would be responsible for the costs of any upgrades needed to address adverse impacts on the MISO Transmission System under a Facilities Construction Agreement ("FCA") or Multi-Party Facilities Construction Agreement ("MPFCA") conforming to the *pro forma* FCA or MPFCA contained in Tariff Attachment X, Appendix 8 (FCA) or Appendix 9 (MPFCA), respectively.

While a DER ordinarily is not required to adhere to MISO's GIP when connecting to facilities that are not part of the Transmission System, MISO's GIP would apply if the DER seeks to participate in MISO's Resource Adequacy construct and receive capacity payments. To inject electricity and participate in the Resource Adequacy construct as a Capacity Resource, the DER must be deliverable to load through the MISO Transmission System.[4] MISO provides two services that a DER must choose between for MISO to study the DER's deliverability: (1) External Network Resource Interconnection Service ("E-NRIS"); or (2) firm Transmission Service (either Point-To-Point or Network) from the DER unit to a particular load. If the DER elects to obtain E-NRIS, they must submit an Interconnection Request specifying that the DER is seeking E-NRIS and be studied through MISO's 3-phase DPP (described above). If the DER elects to obtain firm Transmission Service to be deliverable to specific load, then the Interconnection Customer must submit a Transmission Service Reservation ("TSR") and adhere to MISO's TSR study procedures.[5] The requirement to proceed through MISO's DPP for E-NRIS or the TSR study process would not relieve a DER of its obligation to adhere to the requirements of the Host Distribution Provider's interconnection process. MISO provides a set of instructions for interconnecting to non-MISO distribution facilities on its website for the benefit of customers.[6]

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4 *See* MISO Tariff, Module E-1, Section 69A.3.1.g.

5 *See* MISO Tariff, Module B.

6 *See* MISO instructions for Interconnection Requests to the Distribution System or non-MISO Transmission System within the MISO region, available at, https://cdn.misoenergy.org/Distribution_System_Interconnection_Request_Instructions108140.pdf.

a. What are the respective roles of the RTO/ISO and the distribution utility in that process?

Each of the roles of MISO and the Host Distribution Provider perform are described in response to Question 1, above.

b. How would the DER ascertain whether it must interconnect pursuant to a state-jurisdictional interconnection process or a Commission-jurisdictional process?

Interconnection customers that intend to connect generating units to transmission or distribution system elements that are a part of the Transmission System, as defined in Attachment X of the MISO Tariff, must go through MISO's interconnection process. This requirement is communicated through Sections 1 and 2 of Attachment X. Specifically, Section 2.1 provides that the MISO Generator Interconnection Procedures ("GIP") apply where the Generating Facility is proposed for interconnection to a Point of Interconnection on the Transmission System. Transmission System is defined in Section 1of Attachment X as facilities "owned by Transmission Owner and controlled or operated by Transmission Provider or Transmission Owner that are used to provide transmission service (including HVDC Service) or Wholesale Distribution Service under the Tariff."

While MISO has not yet encountered requests to connect DER resources to the Transmission System, there are two methods that DER could use to ascertain the process applicable to its interconnection request. First, the DER could contact the Host Distribution Provider to determine whether the MISO process or the Host Distribution Provider's process applies to a given facility. Second, the DER could obtain this information directly from MISO. Any DER (or other resources) registering for participation in MISO's Resource Adequacy construct would be informed of the need for study under MISO's GIP.

MISO maintains records of all facilities that comprise the Transmission System (*i.e.*, those facilities that have been transferred to MISO's functional control and those that are subject to an agency agreement).[7] In addition, MISO currently maintains a list on MISO's public website of those transmission facilities that are Transferred Transmission Facilities ("TTF") under MISO's functional control. While the TTF list does not currently include WDS facilities, the TTF list can be used by DERs and other Interconnection Customers to ascertain those transmission assets that have been transferred to MISO on MISO's public website.[8] Also, if the DER intends to connect to a distribution facility that is not included on the TTF list, the DER would need to determine whether that distribution facility has been identified as a WDS facility that is a part of the Transmission System, as defined in Attachment X of the Tariff. In this case, the DER would need to contact MISO directly and inquire whether the distribution facility is a WDS facility.

If the DER interconnection customer intends to connect the DER unit to facilities listed on MISO TTF list or a distribution facility that provides Wholesale Distribution Service, then the Interconnection Customer is required to follow the Generator Interconnection Procedures (Attachment X) of MISO Tariff. If DER is not interconnecting to such facilities, then the interconnection customer is required to follow the interconnection rules of the Host Distribution Provider.

c. How does your RTO/ISO define the physical boundaries of a distribution facility when determining whether a distribution facility to which a new DER seeks interconnection is already subject to an Open Access Transmission Tariff (OATT) for purposes of making wholesale sales?

7 MISO Transmission Owner's Agreement Appendices G and H.

8 The TTF list is available at: https://www.misoenergy.org/legal/transferred-transmission-facilities/#t=10&p=0&s=FileName&sd=asc.

As discussed in response to Question 1, above, MISO's Transmission System is defined as the aggregate of individual transferred transmission facilities, non-transferred facilities including those subject to an agency agreement and distribution facilities that provide Wholesale Distribution Service. A facility that is not turned over to MISO's functional control or subject to an agency agreement does not automatically become a part of the MISO Transmission System based on its geographic location. Geography therefore does not determine the boundaries of the MISO Transmission System. If a distribution facility is part of the MISO Transmission System as defined in Attachment X of the Tariff, then MISO's Tariff and GIP apply to such facility as described above. If the distribution facility is not part of the Transmission System, then the Host Distribution Provider's procedures control.

2. Does the interconnection process described in response to Question # 1 differ based on whether or not the DER is a Qualifying Facility, and if so, how?

MISO's interconnection process does not differ based on whether or not a DER is a Qualifying Facility ("QF"). If a QF is subject to MISO's GIP, the process would be the same for a QF as it is for any other Generating Facility subject to the GIP. However, not all QFs are subject to MISO's GIP. Under Commission precedent, a QF that sells all of its output to the utility to which it is interconnected or an on-site customer pursuant to the Public Utility Regulatory Policies Act of 1978 ("PURPA") is not subject to MISO's GIP. However, if a QF plans to sell any of its output over the MISO Transmission System then it would be required to adhere to MISO's GIP and obtain a GIA for interconnection service. Likewise, if a QF that previously sold all of its output to the utility to which it is interconnected becomes able to sell its output to third parties over the MISO Transmission System, as may be the case if a power purchase agreement expires, then such QF would need to submit an Interconnection Request and proceed through MISO's queue.[9]

3. Does the interconnection process described in response to Question # 1 differ if the DER seeking to participate in wholesale markets is interconnecting behind a retail customer meter (whether on the distribution or transmission system), and if so, how?

No, the interconnection process is the same regardless of whether the DER connects behind a retail customer meter.

4. Does the interconnection process described in response to Question# 1 allow studies for bi-directional service (i.e., both from a DER to the transmission system and from the transmission system to a distribution-connected wholesale customer)?

The Host Distribution Provider will determine whether bi-directional service is allowed. If the Host Distribution Provider determines that the DER may have a material impact on MISO's Transmission System, such Host Distribution Provider would inform MISO and the impacted Transmission Owner. MISO would then coordinate with the Host Distribution Provider to conduct DER studies to ensure reliability on the Transmission System. For requests that need to go through MISO's interconnection process, the interconnection study will include bi-directional analysis (*i.e.*, injection of power into Transmission System and withdrawal of power from Transmission System) as needed. In such cases, the Interconnection Customer is still required to procure Transmission Service under the Tariff to withdraw power from the Transmission System.

5. Under the interconnection process described in response to Question# 1, and assuming all of the individual DERs in the aggregation are new resources, which of the following would apply: (1) an aggregation of DERs located at multiple points of interconnection would be studied as one aggregated resource by your RTO/ISO and require only a single Generator Interconnection Agreement (GIA); (2) each individual DER would be studied individually and require its own GIA; (3) each DER would be studied individually with the aggregation still only requiring a single

[9] *Midwest Indep. Transmission Sys. Operator, Inc.*, 132 FERC ¶ 61,241, P 25 (2010), *reh'g denied*, 138 FERC ¶ 61,204 (2012).

GIA; or (4) a different approach (please describe if a different approach would be used).

As described in response #1, the interconnection of a DER often would be processed using the interconnection rules of the Host Distribution Provider. MISO has not yet received any interconnection requests from DERs. Attachment X of the Tariff defines "Generating Facility" as generating device(s) identified in the Interconnection Request. Therefore, an Interconnection Customer with multiple generating resources, such as wind turbines, has some ability to determine how many GIAs it will obtain based on how many Interconnection Requests it chooses to submit. While MISO generally discourages the splitting of projects into numerous GIAs for queue efficiency reasons, MISO is still evaluating whether this approach or another would be most appropriate for DERs.

Because DER aggregation of generation resources is new and, as a result, MISO has yet to process an Interconnection Request for a DER aggregator, MISO is still in the process of developing interconnection rules for such resources. These rules may address matters such as how wide an area can be aggregated as a single project for purposes of MISO's interconnection process.

6. **In contrast with the scenario in Question# 5, please assume that at least some of the individual DERs in a proposed aggregation are existing resources already interconnected and in service. If multiple existing and new DERs were able to aggregate at separate points of interconnection across your RTO/ISO to participate in wholesale markets as an aggregation rather than as individual resources, under what circumstances would your RTO's/lSO's existing interconnection procedures and study processes apply to the individual DERs in the aggregation? If multiple existing and new DERs were able to aggregate at separate points of interconnection across your RTO/1SO to participate in wholesale markets as an aggregation rather than as individual resources, under what circumstances would your RTO's/ISO's existing interconnection procedures and study processes apply to the aggregation? Would any revisions be needed to accommodate aggregations of DERs (existing and new) at multiple points of interconnection?**

a. Under existing tariff rules, which entity (i.e., the RTO/1SO or the distribution utility) would be responsible for processing the interconnection of the individual DERs seeking to join an aggregation?

If the individual DERs are directly connected to distribution facilities and not to the MISO Transmission System, under existing Tariff rules, the Host Distribution Provider will be responsible for processing the interconnection of the individual DERs seeking to join an aggregation. MISO has not yet received any requests to interconnect aggregations of DERs to the MISO Transmission System and has not yet developed rules that specifically address the challenges of such interconnections, including how the unit to be studied would be defined and studied.

b. For existing DERs that are currently not participating in wholesale markets and that interconnected under a state-jurisdictional process, under your current interconnection procedures would the DER's decision to participate in an aggregation trigger the RTO/ISO interconnection process? Would additional studies be necessary to ensure that participation in your RTO's/ISO's wholesale markets through an aggregation does not cause reliability problems on the transmission system? If so, what studies? If not, why not? For example, would the original state-jurisdictional interconnection process have already studied the DER in a variety of operational scenarios that eliminate the need for further studies prior to wholesale market participation in your region?

The above-described scenarios would not trigger MISO's interconnection process. As described in response #1, the Host Distribution Provider's interconnection process should have already studied the individual DER impact on the MISO Transmission System and MISO would have coordinated with the Host Distribution Provider and impacted Transmission owner to address such impacts. Aggregation without more interconnection service should not cause, and would not authorize, additional injection or impact on the Transmission System. This said, MISO notes that the study processes and assumptions used by individual Host Distribution Providers vary widely. If the Host Distribution Provider did not study the DER under a wholesale market participation scenario, and such market participation changes the characteristics and system impact of the DER from those under which it was originally studied, further studies by the Host Distribution Provider may be required.

c. If existing distribution-level DERs that are currently not participating in wholesale markets join aggregations and start making wholesale sales for the first time, how would that new wholesale use of existing DERs and their associated distribution facilities impact your assessment of whether those distribution facilities are subject to your OATT? Would Commission-jurisdictional interconnection procedures apply to subsequent requests to interconnect to those distribution facilities? Why or why not?

Under MISO's current Tariff definitions, once an existing DER begins participating in the MISO wholesale energy markets, the distribution facility to which that DER connects would be deemed as providing Wholesale Distribution Service within the meaning of MISO's Tariff. Because Attachment X of the MISO Tariff defines Transmission System as including facilities that provide Wholesale Distribution Service, any future DER interconnection to a Wholesale Distribution Service facility would be subject to the MISO Tariff and therefore required to proceed through the interconnection process established in Attachment X of the Tariff. MISO notes that these rules have not yet been applied given that MISO has thus far not received a request to interconnect a DER aggregation through MISO's interconnection process. As MISO continues developing its DER aggregator participation model, MISO may reexamine the scope and applicability of MISO's interconnection process under various scenarios.

d. For large and small generator interconnections subject to Order Nos. 2003 and 2006, the transmission provider is required to coordinate between the interconnection customer and "affected systems" (i.e., third-party transmission systems) to ensure that any needed affected system issues are resolved. With respect to new DERs seeking to interconnect to distribution facilities that are subject to a Commission-jurisdictional OATT, do the relevant small generator interconnection procedures in your region treat the transmission system to which the relevant distribution facilities are connected as an "affected system" in order to address any needed transmission upgrades at the initial interconnection stage?

MISO's Generator Interconnection Procedures (Attachment X) of the MISO Tariff covers requests for interconnection to the Transmission System as defined in Attachment X. MISO does not have two separate Generator Interconnection Procedures (GIP) for small and large interconnections. Therefore, any new DERs seeking to interconnect to distribution facilities are subject to the requirements of the Host Distribution Provider. MISO would coordinate with the Host Distribution Provider and the impacted Transmission Owner if the Host Distribution Provider determines that there is a material impact on the Transmission System caused by the new interconnection. After receiving such a notice, MISO would consult with the impacted Transmission Owner to review the assumptions used by the Host Distribution Provider. If MISO and the impacted Transmission Owner agree that adverse reliability impacts exist, the parties will engage the Interconnection Customer in a System Impact Study and, if upgrades are needed, a Facilities Study to resolve the constraint.

7. **If the individual DERs in an aggregation are seeking to interconnect to a combination of distribution facilities, some of which are subject to a Commission-jurisdictional OATT and some that are not subject to an OATT, would any, all, or only a subset of the DERs in the aggregation be required to go through the interconnection process you described in response to Question # 1 and to execute GIA(s) under your tariff? Please explain.**

   See response to Question 6(d), above.

8. **If available, please provide data on or estimates of the number of individual DERs in your region that are directly participating today in your RTO/ISO markets as compared to DERs in your region that are not participating in wholesale markets. If possible, please provide estimates by resource type and participation model (i.e., generator, demand response, etc.).**

   DERs Currently Participating in MISO Markets

Currently, MISO does not specifically track the DERs that are connected to the distribution system, and therefore the specific number and MW volume of such DERs that are participating in the MISO markets is not currently known. However, MISO does track the broader categories of Demand Response Resources ("DRRs"), Load Modifying Resources ("LMRs"), and Emergency Demand Response ("EDRs") that do participate in MISO's markets, whether located on the distribution or transmission system. Each of these resource types can be categorized as DERs, as defined in the Data Request,[10] but also includes other resources beyond the scope of this Data Request (*e.g.*, transmission-connected generators that are within the LMR definition). For purposes of generally estimating the DERs that may be participating in the MISO markets, MISO provides the following information about the DRRs that participate in MISO energy markets and the LMRs and EDRs that participate in MISO Resource Adequacy construct.

The inventory of DRR Type I that MISO believes are connected to distribution systems consist of 28 resources with a combined target demand reduction of 672.6 MW.[11] The largest of these DRR Type 1 resources has a target demand reduction of 195 MW, and the smallest DRR Type 1 resource has a target demand reduction of 3.1 MW.

The combined capacity of LMRs participating in MISO markets is 7326.5 MW, of which 9 resources comprising 180.8 MW are also registered as EDRs. Currently, there are 66 EDR resources totaling 2,163.3 MWs. MISO does not require Market Participants to identify the precise location of their LMR and EDR resources (*i.e.*, whether those resources are located on elements of the transmission system or distribution system). Accordingly, MISO does not track and actively monitor the precise location of LMR and EDR resources.

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10 For purposes of this data request, the Commission defines a DER as "a source or sink of power that is located on the distribution system, any subsystem thereof, or behind a customer meter. These resources may include, but are not limited to, electric storage resources, distributed generation, thermal storage, and electric vehicles and their supply equipment."

11 Demand Response Resource Type II is connected to MISO at the transmission level and is not included as a DER resource.

DERs Not Currently Participating in MISO Markets

MISO does not possess information on DER resources in the MISO region that are not participating in the MISO markets. However, the Organization of MISO States ("OMS") recently conducted a survey of utilities within the MISO footprint to estimate the quantity of DER's that are not currently participating in the MISO market. The data collected by OMS for 2019 is included in the 2019 OMS DER Survey Results.[12] A summary of the data included in that Survey is provided in the table below:

	Installations			Capacity (MW)		
DER Type	Residential	Non-Res	Total	Residential	Non-Res	Total
Solar PV	41,212	8,328	49,540	861	1,147	2,008
Wind	659	460	1,119	8	482	490
Electric Vehicle	4,101	-	4,101	0	-	0
Microturbine	-	4	4	-	9	9
Fuel Cell CHP	-	-	-	-	-	-
Fuel Cell Electric	-	-	-	-	-	-
Internal Combustion	1	385	386	0	634	634
Hydro	4	86	90	0	112	112
Gas Turbine	-	13	13	-	120	120
Battery Storage	37	9	46	246	3	250
Demand Response	137,210	1,796	139,006	118	131	249
Biodigesters	1	115	116	0	107	107
Other	14	31	45	0	718	718
Totals	183,239	11,227	194,466	1,234	3,464	4,698

9. Do you or the distribution utilities in your region have data on or estimates of how many distribution facilities, as defined in your answer to Question # l .c. above, are currently subject to an OATT compared to the total number of distribution facilities in the RTO/ISO footprint?

a. If yes, please provide this data or estimates.

12 *See* 2019 MOS DER Survey Results, *available at* https://www.misostates.org/images/stories/Other_Projects/2019_Survey_Results_Presentation_Public_002.pdf.

MISO does not currently track the number of distribution facilities in the MISO footprint that are currently subject to the MISO Tariff. MISO does not currently track the total number of distribution facilities that exist within its footprint. However, in order to accommodate changing customer needs, MISO will expand its tracking to include WDS facilities in anticipation of DERs. MISO would adjust the prominence of this information on its website based on evolving customer needs.

b. How is this information managed and updated?

See response to Question 9(a), above.

10. Is your RTO/ISO engaged in any ongoing discussion or coordination with state or local authorities regarding the interconnection process for DERs? If so, please describe this discussion or coordination.

Yes. Currently MISO is working with local authorities including States and distribution utilities to develop a guideline for the implementation of DER interconnection standard Institute of Electrical and Electronic Engineers ("IEEE") Standard 1547-2018. This new version of this IEEE standard added voltage and frequency ride-through requirements to support the reliability of the transmission system, and requires coordination between distribution authorities and Reliability Coordinators. To help this required coordination, MISO created a stakeholder process to develop a MISO region guideline for the implementation of IEEE Standard 1547-2018.

11. If a DER needs to transmit its output over distribution facilities to make sales into the RTO/ISO markets, are there any existing tariff provisions that govern such service? If so, please list and describe such provisions and describe whether that service is bi-directional.

No, there are no provisions in the MISO Tariff that provide rules for DERs that transmit output over distribution facilities to makes sales in the MISO markets.

IV. Notice and Service

Communications and correspondence regarding this filing should be directed to:[13]

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mblackwell@misoenergy.org

MISO has served all parties provided in the Commission's eService list for the above-referenced docket. In addition, MISO notes that it has served a copy of this filing electronically, including attachments, upon all Tariff Customers under the Tariff, MISO Members, Member representatives of Transmission Owners and Non-Transmission Owners, as well as all state commissions within the Region. In addition, the filing has been posted electronically on MISO's website at https://www.misoenergy.org/legal/ferc-filings/ for other parties interested in this matter.

[13] To the extent necessary, the Filing Parties respectfully request a waiver of Rule 203(b)(3) of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.203(b), to permit all of the persons listed to be placed on the official service list for this proceeding.

V. Conclusion

MISO appreciates the opportunity to respond to the Commission's questions in this proceeding.

Respectfully submitted,

/s/ Michael L. Kessler
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Attorneys for Midcontinent Independent System Operator, Inc.

Dated: October 7, 2019

CERTIFICATE OF SERVICE

I hereby certify that I have this day e-served a copy of this document upon all parties listed on the official service list compiled by the Secretary in the above-captioned proceeding, in accordance with the requirements of Rule 2010 of the Commission's Rules of Practice and Procedure (18 C.F.R. § 385.2010).

Dated this 7th day of October, 2019, in Carmel, Indiana.

/s/ Julie Bunn

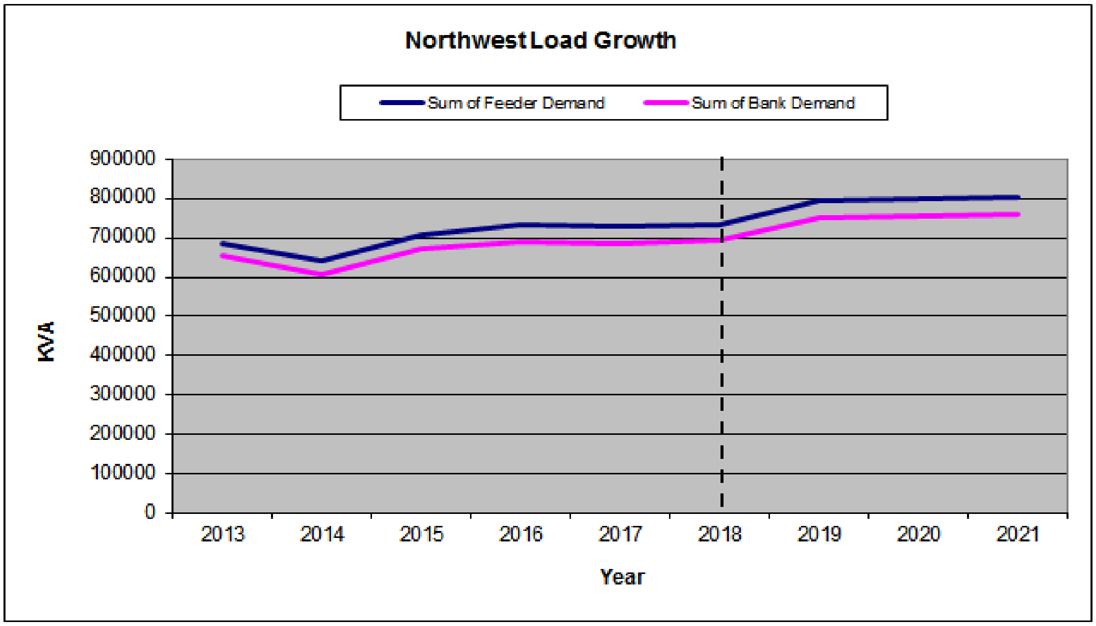
Julie Bunn
Midcontinent Independent
System Operator, Inc.
720 City Center Drive
Carmel, IN 46032

3.D.2 Action Plan Roadmap

Section	Requirement	Section or Reference
3.D.2	Xcel shall provide a 5-year Action Plan as part of a 10-year long-term plan for distribution system developments and investments in grid modernization based on internal business plans and considering the insights gained from the DER futures analysis, hosting capacity analysis, and non-wires alternatives analysis.	XIV.A.2 IX, X Attachment C
3.D.2	The 5-year Action Plan should include a detailed discussion of the underlying assumptions (including load growth assumptions)	XIV.A.1 V.B, IX, X
	and the costs of distribution system investments planned for the next 5-years (expanding on topics and categories listed above).	II.D, IX Attachment C
3.D.2	Xcel should include specifics of the 5-year Action Plan investments.	IX, X Attachment C
3.D.2	Topics that should be discussed, as appropriate, include at a minimum:	-
3.D.2 (i)	Overview of investment plan: scope, timing, and cost recovery mechanism	II, IX, XIV.A, XV Attachment C
3.D.2 (ii)	Grid Architecture: Description of steps planned to modernize the utility's grid and tools to help understand the complex interactions that exist in the present and possible future grid scenarios and what utility and customer benefits that could or will arise. (Footnote: https://gridarchitecture.pnnl.gov/)	IX, X Figure 73 Attachment C
3.D.2 (iii)	Alternatives analysis of investment proposal: objectives intended with a project, general grid modernization investments considered, alternative cost and functionality analysis (both for the utility and the customer), implementation order options, and considerations made in pursuit of short-term investments. The analysis should be sufficient enough to justify and explain the investment.	IX Attachment C
3.D.2 (iv)	System interoperability and communications strategy	IX, X Attachment C
3.D.2 (v)	Costs and plans associated with obtaining system data (EE load shapes, PV output profiles with and without battery storage, capacity impacts of DR combined with EE, EV charging profiles, etc.)	XI.F
3.D.2 (vi)	Interplay of investment with other utility programs (effects on existing utility programs such as demand response, efficiency projects, etc.)	Attachment C, Attachment M1
3.D.2 (vii)	Customer anticipated benefit and cost	V.D.2, IX.F-G, XVI Attachment C, Attachments M1-M5, Attachments O1-O4
3.D.2 (viii)	Customer data and grid data management plan (how it is planned to be used and/or shared with customers and/or third parties)	IX, X Attachment C, Attachment M1
3.D.2 (ix)	Plans to manage rate or bill impacts, if any	IX.G, XIV.A.3 Attachment C, Attachment M1
3.D.2 (x)	Impacts to net present value of system costs (in NPV RR/MWh or MW)	Attachment L

3.D.2 Action Plan Roadmap

Section	Requirement	Section or Reference
3.D.2 (xi)	For each grid mod project in its 5-year action plan, Xcel should provide a cost-benefit analysis <u>based on the best information it has at the time and include a discussion of non-quantifiable benefits. Xcel shall provide all information used to support its analysis.</u>	IX, X Attachment C, Attachments M1-M5, Attachments O1-O4, Workpapers (CBA)
3.D.2 (xii)	Status of any existing pilots or potential for new opportunities for grid mod pilots.	XIII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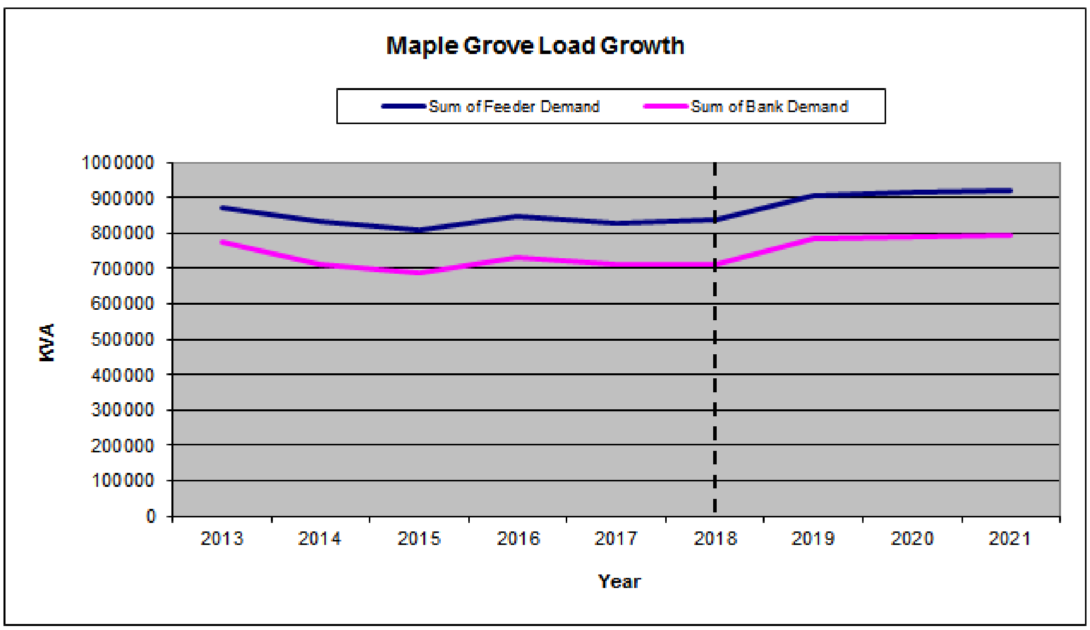
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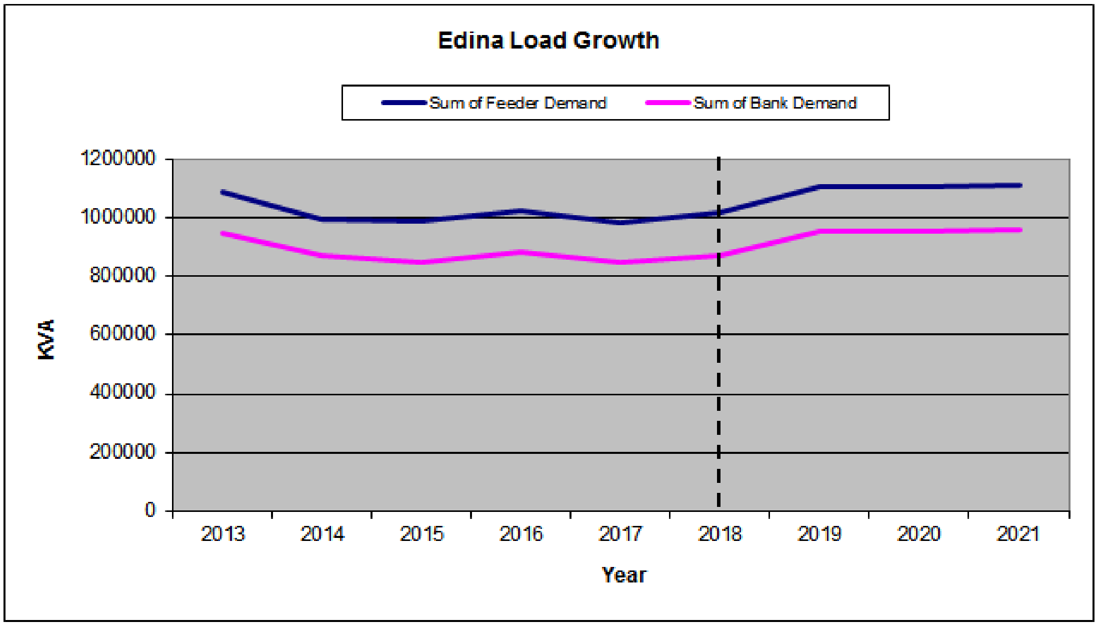
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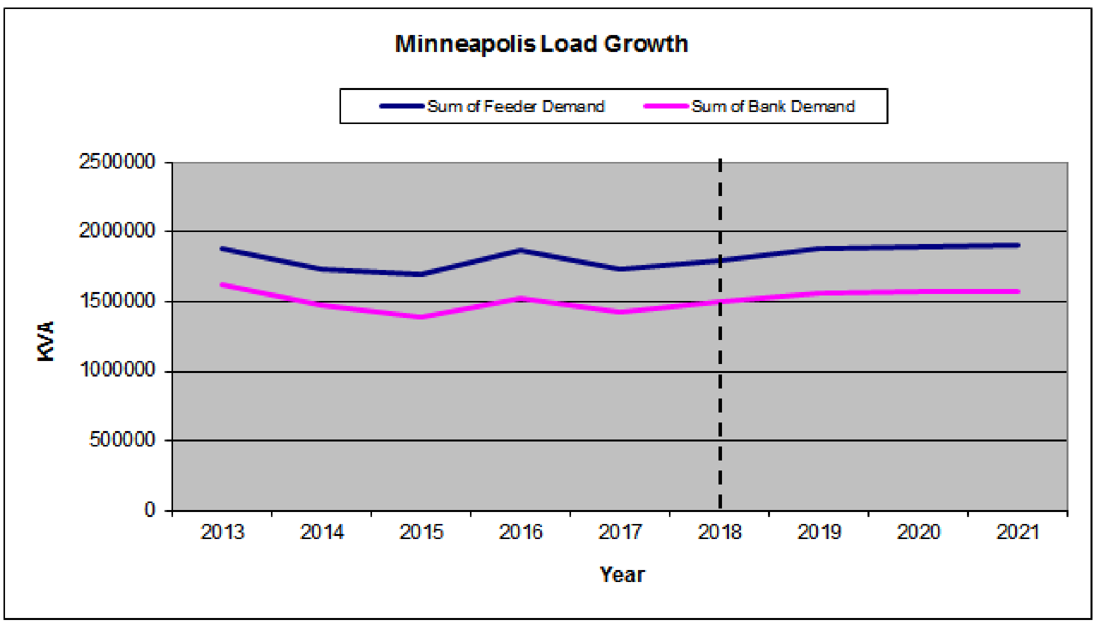
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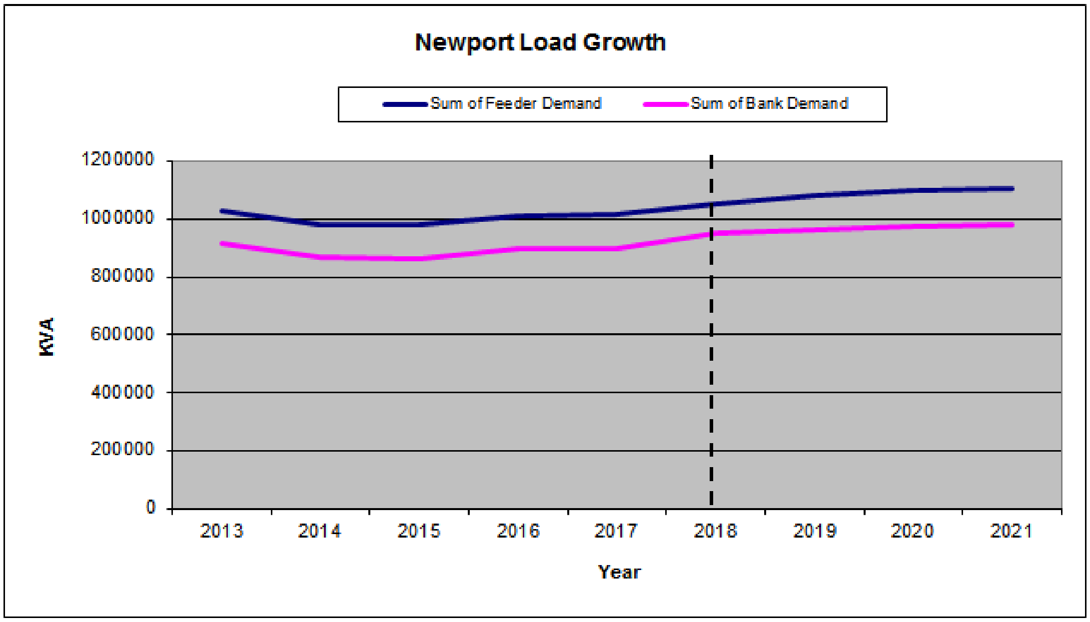
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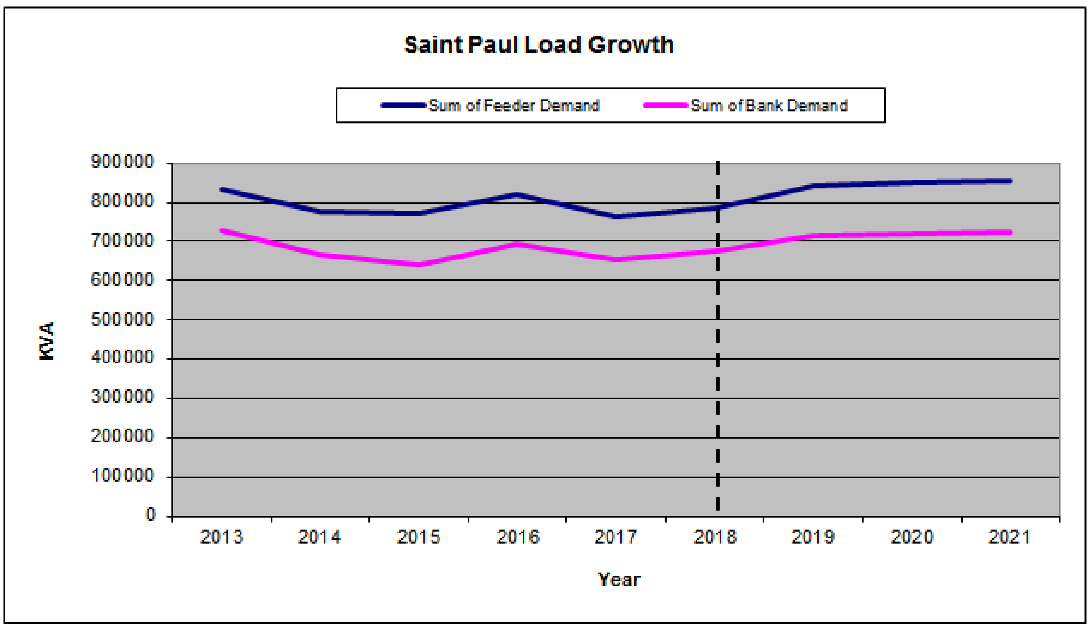
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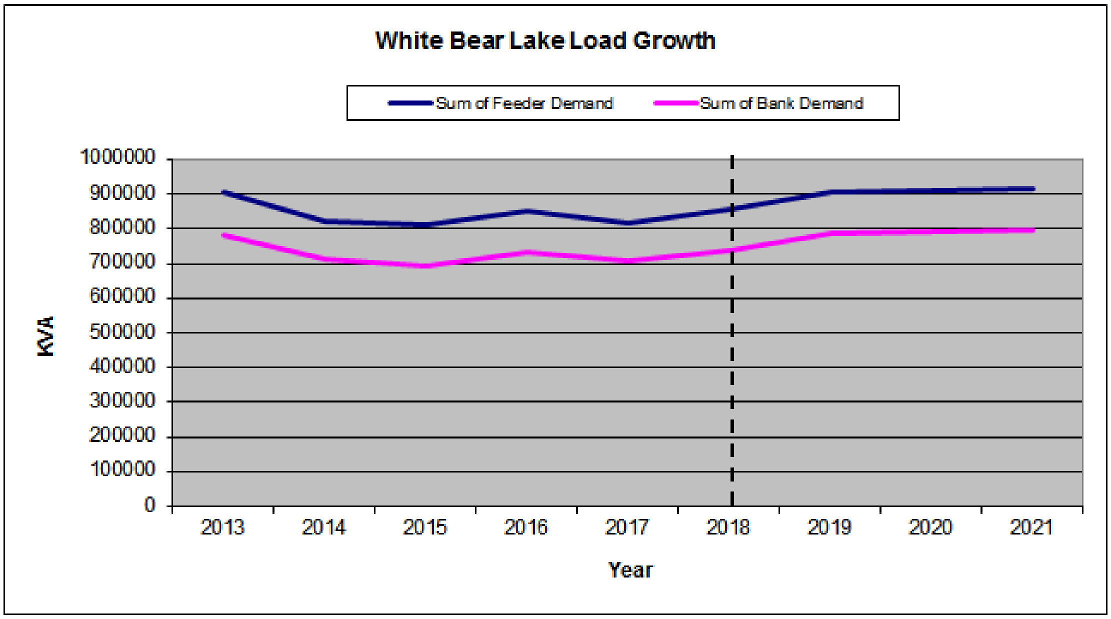
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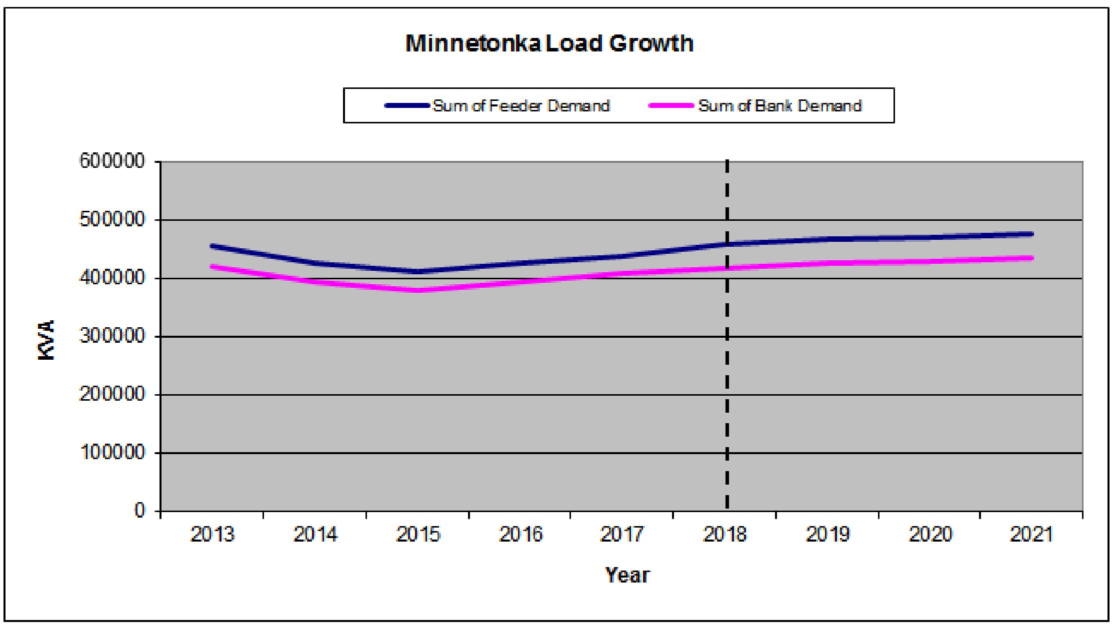
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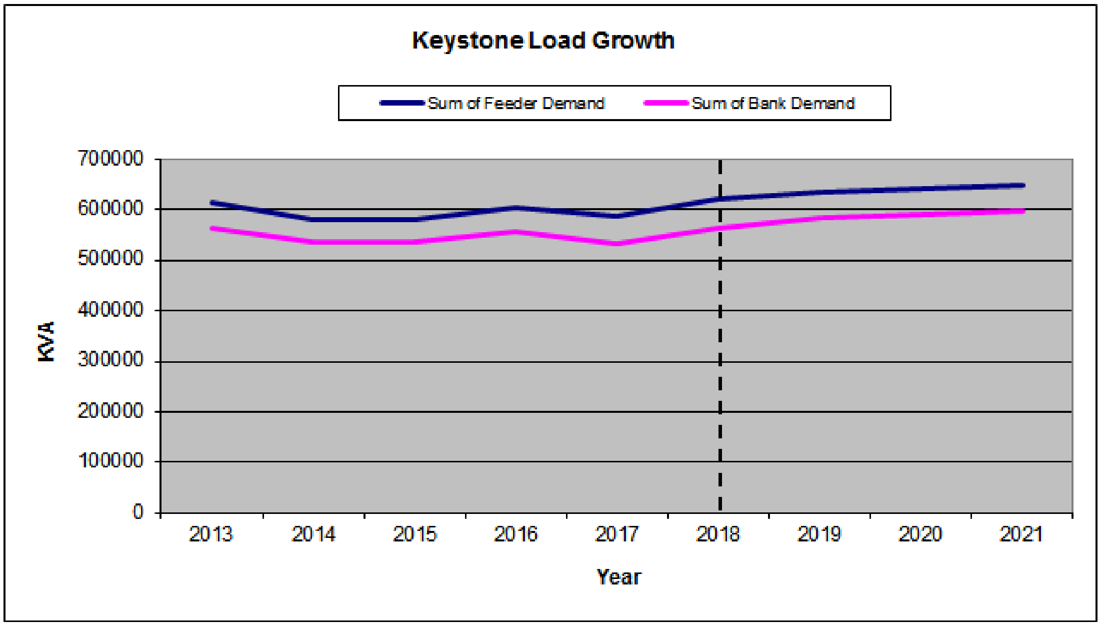
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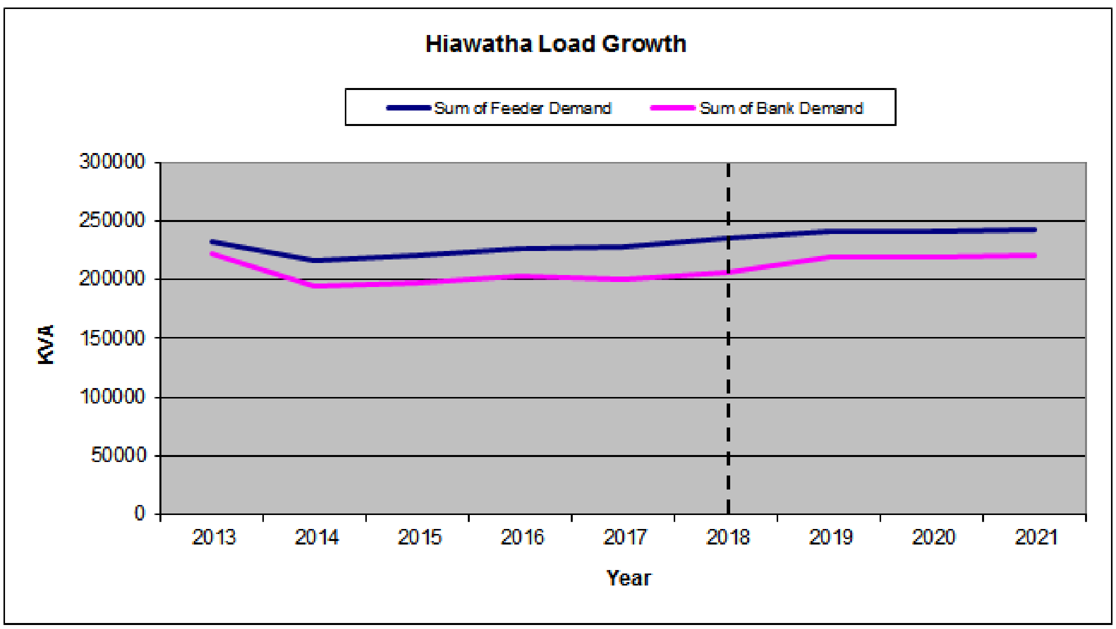
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IDP Requirement 3.D.2 requires that we provide:

Impacts to net present value of system costs (in NPV RR/MWh or MW)

As we noted in our July 20, 2018 Reply Comments in the Docket No. E002/CI-18-251 in which our IDP requirements were established, and consistent with our fulfillment with this requirement in our November 1, 2018, we understand this requirement to be a calculation similar to that provided in conjunction with an Integrated Resource Plan. Our comments continued, saying that there are differing characteristics associated with the distribution system that may make this complex to translate – and that we would provide some sort of distribution-level calculation – but at that time were working with various business units to ascertain how best to do so.

We took the same approach in this 2019 IDP as we took in our 2018 IDP, which is an approach similar to a jurisdictional cost of service – but for just the Distribution function of the Company. In general, a jurisdictional cost of service study includes the following financial data input sections: (1) capital structure; (2) cost of capital; (3) income tax rates; (4) rate base; (5) income statement; (6) income tax calculations; and (7) cash working capital computation.

We clarify that this "rate base" view of the Distribution function will not match the budget information we provide in this IDP, because the inputs to the NPV Revenue Requirements (RR) calculation are specific to just the distribution system located in Minnesota. As such, only costs that are direct-assigned to Distribution, and distribution assets located in the state of Minnesota are included. Common and general property in support of the Distribution function are not included in this view – but are represented in the distribution budget information provided elsewhere in this IDP. Similarly, other rate base is not included, and we are not including ratemaking treatments such as net operating losses.

Rate base primarily reflects the capital expenditures made by a utility to secure plant, equipment, materials, supplies and other assets necessary for the provision of utility service, reduced by amounts recovered from depreciation and non-investor sources of capital. It is generally comprised of the following major items:

- *Net Utility Plant.* Net utility plant represents the Company's investment in plant and equipment that is used and useful in providing retail electric service to its customers, net of accumulated depreciation and amortization.
- *Construction Work in Progress (CWIP).* In Minnesota, CWIP is included as part of the revenue requirement calculation for base rates. CWIP is the accumulation of construction costs that directly relate to putting a fixed asset into use.

- *Accumulated Deferred Income Taxes (ADIT).* Inter-period differences exist between the book and taxable income treatment of certain accounting transactions. These differences typically originate in one period and reverse in one or more subsequent periods. For utilities, the largest such timing difference typically is the extent to which accelerated income tax depreciation generally exceeds book depreciation during the early years of an asset's service life. ADIT represents the cumulative net deferred tax amounts that have been allowed and recovered in rates in previous periods.

- *Pre-Funded Allowance for Funds Used During Construction (AFUDC).* In Minnesota, AFUDC is included as part of the revenue requirement calculation for base rates. Specifically, during construction, AFUDC is calculated and included in the CWIP balance and is also included in operating income as an offset to the revenue requirement. AFUDC is added to the cost of related capital projects and is reflected in rate base when the related capital project is placed into service. Once a project is placed in service, the recording of AFUDC ceases and the total capital cost of the project including accumulated AFUDC is recovered through depreciation.

- *Other Rate Base*. Other Rate Base is comprised primarily of Working Capital. It also includes certain unamortized balances that are the result of specific ratemaking amortizations. Working Capital is the average investment in excess of net utility plant provided by investors that is required to provide day-to-day utility service. In general, it includes items such as materials and supplies, fuel inventory, prepayments, and various non-plant assets and liabilities.

Rate base is generally calculated as outlined in Table 1 below.

Table 1: High Level Rate Base Calculation

	Original Average Cost of Electric Plant in Service (Plant)
Less:	Average Accumulated Depreciation Reserve
Less:	Average Accumulated Provision for Deferred Taxes
Plus:	Average Construction Work in Progress
Plus:	Average Working Capital
Equals:	Rate Base

For this Distribution Function NPV RR, we calculated the growth in revenue requirements over the 5-year budget period to derive an NPV of $164.4 million (in 2019 dollars).

	Annual Revenue Requirement						
	Electric Distribution Minnesota						
	2019-2024						
	(000's)						
				MN Jurisdiction			
	Rate Analysis	2019	2020	2021	2022	2023	2024
1	Average Balances:						
2	Plant Investment	3,698,030	3,885,363	4,138,497	4,503,003	4,919,052	5,319,332
3	Depreciation Reserve	1,380,479	1,447,122	1,520,312	1,598,759	1,685,968	1,785,101
4	CWIP	36,528	40,228	61,610	64,700	61,746	46,153
5	Accumulated Deferred Taxes	611,278	601,876	593,636	588,408	586,479	586,813
6	Average Rate Base = line 2 - line 3 + line 4 - line 5	1,742,802	1,876,594	2,086,160	2,380,537	2,708,351	2,993,572
7							
8	Revenues:						
9	Interchange Agreement offset = -line 40 x line 52 x line 53						
10							
11	Expenses:						
12	Book Depreciation	107,797	112,921	119,261	130,072	142,192	152,924
13	Annual Deferred Tax	(9,527)	(9,278)	(7,202)	(3,254)	(603)	1,271
14	ITC Flow Thru	-	-	-	-	-	-
15	Property Taxes	49,951	48,941	51,442	57,029	64,927	71,009
16	subtotal expense = lines 12 thru 15	148,221	152,585	163,501	183,847	206,516	225,203
17							
18	Tax Preference Items:						
19	Tax Depreciation & Removal Expense	92,529	99,642	112,795	136,578	158,274	177,168
20	Tax Credits (enter as negative)	-	-	-	-	-	-
21	Avoided Tax Interest	1,629	2,133	2,895	2,449	1,751	1,909
22							
23	AFUDC	2,437	3,649	4,669	4,177	2,906	3,133
24							
25	Returns:						
26	Debt Return = line 6 x (line 44 + line 45)	36,250	39,221	43,601	50,229	60,125	67,056
27	Equity Return = line 6 x (line 46 + line 47)	93,937	100,585	111,818	127,597	145,168	161,054
28							
29	Tax Calculations:						
30	Equity Return = line 27	93,937	100,585	111,818	127,597	145,168	161,054
31	Taxable Expenses = lines 12 thru 14	98,270	103,644	112,059	126,818	141,589	154,194
32	plus Tax Additions = line 21	1,629	2,133	2,895	2,449	1,751	1,909
33	less Tax Deductions = (line 19 + line 23)	(94,966)	(103,290)	(117,464)	(140,755)	(161,180)	(180,301)
34	subtotal	98,870	103,071	109,308	116,109	127,327	136,857
35	Tax gross-up factor = t / (1-t) from line 50	0.403351	0.403351	0.403351	0.403351	0.403351	0.403351
36	Current Income Tax Requirement = line 34 x line 35	39,879	41,574	44,089	46,833	51,357	55,201
37	Tax Credit Revenue Requirement = line 20 x line 35 + line 20	-	-	-	-	-	-
38	Total Current Tax Revenue Requirement = line 36+ line 37	39,879	41,574	44,089	46,833	51,357	55,201
39							
40	Total Capital Revenue Requirements	315,850	330,316	358,340	404,329	460,260	505,382
41	= line 16 + line 26 + line 27 + line 38 - line 23 + line 9						
42	O&M Expense	110,471	114,249	132,140	127,086	128,511	128,884
43	Total Revenue Requirements	426,321	444,565	490,480	531,414	588,771	634,266
	Capital Structure	**Weighted Cost**	**Weighted Cost**	**Weighted Cost**	**Weighted Cost**	**Weighted Cost**	**Weighted Cost**
44	**Long Term Debt**	**2.0400%**	**2.0600%**	**2.0500%**	**2.0800%**	**2.2000%**	**2.2200%**
45	**Short Term Debt**	**0.0400%**	**0.0300%**	**0.0400%**	**0.0300%**	**0.0200%**	**0.0200%**
46	**Preferred Stock**	**0.0000%**	**0.0000%**	**0.0000%**	**0.0000%**	**0.0000%**	**0.0000%**
47	**Common Equity**	**5.3900%**	**5.3600%**	**5.3600%**	**5.3600%**	**5.3600%**	**5.3800%**
48	**Required Rate of Return**	**7.4700%**	**7.4500%**	**7.4500%**	**7.4700%**	**7.5800%**	**7.6200%**
49	**PT Rate**	**0.0000%**	**0.0000%**	**0.0000%**	**0.0000%**	**0.0000%**	**0.0000%**
50	**Tax Rate (MN)**	**28.7420%**	**28.7420%**	**28.7420%**	**28.7420%**	**28.7420%**	**28.7420%**
51	**MN JUR Direct**	**100.0000%**	**100.0000%**	**100.0000%**	**100.0000%**	**100.0000%**	**100.0000%**
52	Growth in Total Revenue Requirements	0	18,244	45,915	40,934	57,357	45,495
53	Present Value of Growth in Total Revenue Requirements	164,439					

Direct Testimony and Schedules
Michael C. Gersack

Before the Minnesota Public Utilities Commission
State of Minnesota

In the Matter of the Application of Northern States Power Company
for Authority to Increase Rates for Electric Service in Minnesota

Docket No. E002/GR-19-564
Exhibit___(MCG-1)

AGIS Customer Experience and Policy

November 1, 2019

Table of Contents

Schedules

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND OCCUPATION.

A. My name is Michael C. Gersack. I am Vice President of Innovation and Transformation for Xcel Energy Services Inc. (XES), which provides services to Northern States Power Company – Minnesota (NSPM or the Company).

Q. PLEASE SUMMARIZE YOUR QUALIFICATIONS AND EXPERIENCE.

A. I have more than 25 years of experience in the areas of customer operations, accounting, and finance. In my current position, I am responsible for leading our Innovation & Transformation Office that governs and drives the successful implementation of critical programs or projects that focus on efficiency, operational effectiveness and innovation, and enable the Company to continuously improve and transform. Our ITO includes the following Centers of Excellence: Project Management Office; Innovation; Process Management; Data Strategy and Governance; and Change Management. I was previously Vice President of Customer Care, where I was responsible for the overall business performance of our customer operations including meter reading, billing, credit, remittance processing, and customer contact center functions. Prior to this, I held various operational, accounting and financial positions supporting Xcel Energy's distribution, marketing, transmission, and customer service functions. Before joining Xcel Energy, I held similar positions with Kinder Morgan (KN Energy). My resume is provided as Exhibit___(MCG-1), Schedule 1.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony is to provide the overview of the Company's plans to transform the customer experience through the investments that are proposed as part of the Company's Advanced Grid Intelligence and Security (AGIS) initiative. My Executive Summary summarizes the Company's support for the AGIS initiative in my testimony and the testimony of other witnesses in this rate case. I also provide an overview of the Company's grid modernization efforts to date, outline the Company's strategic goals and identify the current state of the customer experience and the distribution system. I describe, at a high level, the work required to implement each component of the AGIS initiative for which we are requesting cost recovery in this proceeding, contemporaneous with the requests in our simultaneous Integrated Distribution Plan (IDP) filing. I outline the Company's proposed capital investments and operations and maintenance (O&M) costs for the core components of the AGIS initiative. I also summarize the timing of implementation of these components from both a system and customer perspective, and explain in detail the customer experience that will result from our work. I also discuss the Company's planned outreach efforts to help educate customers on what to expect from AGIS and how the new functionality will benefit them.

I also summarize the cost and benefits analysis that the Company has conducted with respect to the AGIS components, while also emphasizing the benefits that are qualitative and, by definition, non-quantifiable. I also provide a bill impact analysis for the components of the AGIS initiative. Lastly, I speak to the Company's plans for progress metrics and reporting with respect to the AGIS initiative.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. I present my testimony in the following sections:

- *Section II* – Executive Summary
- *Section III* – Grid Modernization Background
- *Section IV* – Drivers of the AGIS Strategy
- *Section V* – AGIS Components and Implementation Strategy
- *Section VI* – AGIS and the Customer Experience
- *Section VII* – Prudence of the AGIS Investments
- *Section VIII* – Bill Impacts
- *Section IX* – AGIS Metrics and Reporting
- *Section X* – Conclusion

II. EXECUTIVE SUMMARY

A. Introduction to the AGIS Initiative

Q. PLEASE EXPLAIN XCEL ENERGY'S APPROACH TO DISTRIBUTION SYSTEM PLANNING, IN GENERAL.

A. Xcel Energy has a 100-year track record of outstanding service to our customers and communities – delivering safe, reliable, and affordable energy. And while we remain focused on those fundamentals, we are also looking to the future and have a vision for an advanced grid that will provide both customer and operational benefits for many years to come. Our grid modernization plan is designed to maximize customer value, ensure the fundamentals of our distribution business remain sound, and maintain the flexibility needed as technology and our customers' expectations continue to evolve.

We are also constantly assessing our customers' experience, including what they want and need from their electric and gas utility. We have learned that customers want access to actionable information, more choice and greater control of their energy use – and they expect a smarter, simpler, and more seamless experience. In order to meet that need, we need a smarter grid. We therefore plan to integrate modern customer experience strategies with advanced grid platforms and technologies to enable intelligent grid operations, smarter networks and meters, and optimized products and services for our customers.

Q. WHAT IS AGIS?

A. The AGIS initiative is our long-term strategic plan to transform our electric distribution system to address aging meter technology, meet changing customer demands, enhance transparency into the distribution and to system data, to promote efficiency, and reliability, and to safely integrate more distributed resources. The AGIS initiative consists of multiple elements that work together to create a more modern and advanced distribution grid.

Q. WHAT ARE THE COMPONENTS OR ELEMENTS OF AGIS?

A. The core components of AGIS are the Advanced Distribution Management System (ADMS); Advanced Metering Infrastructure (AMI); and the Field Area Network (FAN). ADMS is underway, with costs being recovered in the TCR Rider. In this case, we propose to implement AMI, FAN, and two advanced applications that we believe will provide substantial benefits to customers: Integrated Volt-VAr Optimization (IVVO); and Fault Location Isolation and Service Restoration (FLISR). More specifically:

- *Advanced Distribution Management System (ADMS)* is the backbone of the AGIS initiative, consisting of a real-time operating system that enables enhanced visibility into the distribution power grid and controls advanced field devices.
- *Advanced Metering Infrastructure (AMI)* is the Company's proposed metering solution, consisting of an integrated system of advanced meters, communication networks, and data processing and management systems that enables secure two-way communication between Xcel Energy's business and data systems and customer meters.
- *Field Area Network (FAN)* is a private, secure, flexible two-way communication network that provides wireless communications across Xcel Energy's service area – to, from, and among, field devices and our information systems.
- *Fault Location, Isolation, and Service Restoration (FLISR)* is an ADMS application that improves customers' reliability experience, reducing the duration of outages and number of customers affected by them. FLISR takes the form of distribution automation and involves the deployment of automated switching devices that work to detect issues on our system, isolate them, and automatically restore power.
- *Integrated Volt VAr Optimization (IVVO)* is an ADMS application that uses specific field devices to optimize voltage as power travels from substations to customers, reducing system losses and may result in energy savings for customers.

Of course, protective cyber security and information technology (IT) support underlie all these components, as they are essential to operating a secure, technologically-advanced grid in today's world.

B. Drivers of the AGIS Initiative

Q. WHY IS THE COMPANY IMPLEMENTING AGIS AT THIS TIME?

A. NSPM has made incremental modernization efforts for the distribution system over many years, striving to maintain a grid that is as reliable and efficient as it could be with the technology it currently employs. However, our current one-way meters are nearing the end of their lives. With meter replacement a near-term reality, now is the right time to begin a more significant advancement of the grid through our AGIS initiative – of which AMI meters are the largest component. Other drivers impacting the timing of the AGIS transition include:

- The Company's strategic priorities to lead the clean energy transition, enhance the customer experience, and keep bills affordable;
- The Company's desire to meet the growing needs and expectations of our customers;
- Current distribution system needs; and
- Commission policy and direction, and stakeholder input relative to customer offerings, performance, and technological capabilities of the grid.

Q. BEFORE DISCUSSING EACH DRIVER IN TURN, PLEASE DESCRIBE THE COMPANY'S OVERALL APPROACH TO IDENTIFYING AND SELECTING THE COMPONENTS OF THE AGIS INITIATIVE.

A. Over the last several years, the Company has experienced a variety of converging needs and opportunities related to distribution grid modernization – some driven by internal system needs, others by industry direction, and still others by customers and other stakeholder considerations. The Company's extensive assessments of these multi-faceted needs, as well as the alternatives to meet them, are described in detail in the testimony of Company witnesses Ms. Bloch, Mr. Cardenas, and Mr. Harkness. As one example, Ms. Bloch and Mr. Cardenas explain the status of the current meters on our system, and Ms. Bloch discusses the extensive planning, information gathering, RFP processes, and consideration of alternate vendors, devices, systems, and programs that we undertook prior to landing on our current AMI plan. Mr. Harkness explains the work completed to select the appropriate IT solutions. We compared the capabilities, costs, benefits, and limitations of a variety of solutions, as well as the costs versus benefits of our preferred solutions, and ultimately propose an overall AGIS package that I believe delivers on the promise of grid advancement.

Q. PLEASE DISCUSS THE COMPANY'S STRATEGIC PRIORITIES AND HOW THEY ARE DRIVING THE AGIS INVESTMENTS.

A. We are working every day to lead the transition to a clean energy future, enhance our customers' experience with their utility, and keep bills low. The AGIS initiative advances each of these priorities. As I describe in more detail throughout my testimony, our customers can be partners in a more environmentally sound future, especially if they are empowered with better information and data to manage their energy usage and make conservation-friendly choices. AMI and the associated components of the AGIS initiative are critical to these efforts. Likewise, IVVO has the potential to act as a demand side management-type tool with carbon reduction and energy savings benefits without requiring any action from customers. Distributed energy resources (DER) are also a key to this clean energy future, and two-way communications on the distribution grid, down to the meter level, are necessary to accommodate increased levels of DER on the system. Thus, while the AGIS initiative provides direct benefits to all of our customers (beginning with implementation and over the long term), it also enables environmental benefits that will be provided for both customers and non-customers alike.

Further, customers are demanding more optionality and increasing levels of service from all their service providers – including us. The AGIS initiative is intended to create better interfaces with customers, provide them with better information and more choices, and thus improve their overall experience. Coupled with efforts to improve the digital platforms through which we interact with customers, improved energy management, control, conservation, and bill management are all available with a more interactive, advanced distribution system. And it goes without saying that continually enhancing our customers' reliability experience is at the core of quality electric service.

Finally, our proposed AGIS initiative offers our customers opportunities to better control and manage their monthly bills by providing more timely and granular energy usage data and enabling advanced rate design.

Q. WHAT ARE THE CHANGING CUSTOMER NEEDS AND EXPECTATIONS DRIVING THE COMPANY'S AGIS INVESTMENTS?

A. Influenced by other services, like Amazon, customers have come to expect more from their energy providers than in the past, including greater choices and levels of service, as well as greater control over their energy sources and their energy use. Customers also expect greater functionality and interaction in how those services are delivered. Technologies that customers can use to control their energy usage, such as smart thermostats, electric vehicle (EV) chargers, smart home devices, and even smart phones and energy-related digital applications, are evolving at a fast rate.

Q. HOW DOES AGIS ENABLE THE COMPANY TO MEET EVOLVING CUSTOMER EXPECTATIONS?

A. While Xcel Energy customers today have access to a multitude of energy efficiency and demand management programs, renewable energy choices, and billing options, there is a limit to what we can offer without taking advantage of the new technology that has emerged around grid advancement. Smart electric meters can now more easily and flexibly gather more detailed information about customer energy usage, which utilities can use to help customers better understand and manage their usage. Other advanced equipment on the grid can detect, communicate, and respond in real time to circumstances that would normally result in power outages. Grid operators can also get improved data to better and more proactively plan and operate the grid. These advancements form the foundation for a flexible grid environment that helps support two-way power flows from customer-connected devices or generating resources (such as rooftop solar) and provides utilities with a greater ability to adapt to future developments.

Q. WHAT ARE THE SYSTEM NEEDS THAT MAKE NOW THE RIGHT TIME FOR THE COMPANY TO IMPLEMENT THE AGIS INITIATIVE?

A. There are a variety of needs. Like other electric utilities, our current distribution system is based on one-way flow of information on much of our system, which means that beyond the distribution substation, the Company has little insight into the workings of the distribution system as it relates to outages, voltage levels experienced by the customer, and DER operations. Company witness Ms. Kelly Bloch describes this in further detail. Additional components that integrate with ADMS and advanced meters are necessary to better manage and shorten outages, and to maximize the voltage management on our system.

In addition, our current automated meter reading (AMR) technology in Minnesota is nearing end of life and our meter reading services vendor, Landis+Gyr (Cellnet) has informed the Company that it will no longer manufacture replacement parts for this system after 2022. In fact, we are the last Cellnet customer still using this technology. Further, our current contract with Cellnet for meter reading services expires at the end of 2025. While we have maximized the value of this AMR system that has provided efficient meter reading services for nearly 30 years, we now have the opportunity to transition to AMI, a proven meter technology. AMI will allow us the ability to expand the use of our meter system beyond basic billing functions for the benefit of our customers.

Q. TO WHAT EXTENT IS THE COMPANY'S AMI PROPOSAL ALIGNED WITH THE INDUSTRY?

A. AMR technology is becoming increasingly outdated and the progressively complex needs of the distribution system require movement to technology that can accommodate these needs. As stated in the United States Department of Energy (DOE), Office of Electricity's November 2018 Smart Grid System Report to Congress, "[f]rom 2007 to 2016, the number of advanced meters has grown ten-fold. About 70.8 million meters out of a total of 151.3 million meters were smart meters as of 2016, representing about 47 percent of U.S.

electricity customers. Bloomberg estimates that number has risen to 51 percent by the start of 2018. This is a significant increase compared to 14 percent of customers with smart meters in 2010 and only 2 percent in 2007."[1]

Xcel Energy has always performed well with respect to system reliability, management, and customer service, but in light of the prevalence of advanced meters and smart grid technologies, the Company must make similar investments to ensure continuing alignment with industry direction and customer expectations.

Q. ARE THERE BROADER INFRASTRUCTURE NEEDS THAT ARE FACTORED INTO THE COMPANY'S AGIS STRATEGY?

A. Yes. The DOE Smart Grid System Report has recognized the broader need for attention to distribution infrastructure nationwide:

> Our [country's] electric infrastructure is aging and it is being pushed to do more than it was originally designed to do. Modernizing the grid to make it "smarter" and more resilient through the use of cutting-edge technologies, equipment, and controls that communicate and work together to deliver electricity more reliably and efficiently can greatly reduce the frequency and duration of power outages, reduce storm impacts, and restore service faster when outages occur. Consumers can better manage their own energy consumption and costs because they have easier access to their own data. Utilities also benefit from a modernized grid, including improved security, reduced peak loads, increased integration of renewables, and lower operational costs.
>
> "Smart grid" technologies are made possible by two-way communication technologies, control systems, and computer processing. These advanced technologies include advanced

[1] https://www.energy.gov/sites/prod/files/2019/02/f59/Smart%20Grid%20System%20Report%20November%202018_1.pdf, as of October 1, 2019 (internal citations omitted) (DOE Smart Grid System Report).

> sensors… that allow operators to assess grid stability, advanced digital meters that give consumers better information and automatically report outages, relays that sense and recover from faults in the substation automatically, automated feeder switches that re-route power around problems, and batteries that store excess energy and make it available later to the grid to meet customer demand.[2]

It is consistent with these broader industry needs that we are implementing ADMS at this time and that our existing AMR meters are nearing the end of their life. And, as noted earlier, our customers are also demanding more optionality, environmentally-sound investments, more control over their energy usage, and better outage management and communications.

Q. HAS THE COMPANY CONSIDERED COMMISSION AND STAKEHOLDER INPUT IN FORMING ITS GRID STRATEGY?

A. Yes. We have applied Commission guidance and stakeholder feedback gleaned through regulatory proceedings and Commission- and Company-sponsored stakeholder processes around grid modernization, DER hosting capacity, integrated distribution system planning, our integrated resource plan, and performance metrics for the Company's electric operations. We also considered the Commission's guidance and stakeholder feedback associated with the Company's proposed Time of Use (TOU) pilot and our EV pilot proposals. All of this guidance and feedback helped shape our proposal in terms of the advanced grid capabilities, how we prioritized the advanced applications, and how we evaluated the costs and benefits of the various AGIS components.

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[2] https://www.energy.gov/oe/activities/technology-development/grid-modernization-and-smart-grid, as of Oct. 1, 2019.

Q. IN LIGHT OF COMMISSION POLICY DIRECTIONS, ARE THERE OTHER STRATEGIC REASONS WHY THE COMPONENTS OF THE AGIS INITIATIVE ARE IMPORTANT AT THIS TIME?

A. Yes. Various Commission policies and specific goals of each of the efforts described above are supported or enabled by advanced grid technologies. We have considered these policies, goals, and the stakeholder input as we developed our overall strategy and specific project plans for AGIS implementation. I discuss this further in Section IV, along with other drivers of our AGIS strategy.

Further, as the prevalence of DER continues to rise, the ability to manage these resources requires visibility into the grid and a more resilient and responsive grid. As the DOE Smart Grid Report stated, grid advancement is necessary to support "the increasing presence of renewable generation and the proliferation of customer- and merchant-owned DERs [that] are introducing significantly greater levels of variability and uncertainty in both the supply of electricity and the demand for it. Generation and load profiles, which have been predictable in the past, can now vary instantaneously and are subject to the behavior of consumers where DERs are present."[3] Enhanced grid management through ADMS, meters with two-way communications that act as sensors, and greater voltage optimization will all support our ability to host increasing levels of DERs.

Given these circumstances and the additional customer and system benefits enabled by advanced grid technology, the Company determined now is the appropriate time to pursue a targeted AGIS initiative that will address system

[3] DOE Smart Grid Report at p. 5.

needs, customer needs, and our overall strategic priorities as a Company to lead the clean energy transition, enhance the customer experience, and keep bills low.

C. AGIS Implementation

Q. WHAT PORTIONS OF THE AGIS INITIATIVE ARE UNDERWAY?

A. With the Commission's certification and approval of our first year of costs, the ADMS is underway and scheduled to go into service in 2020. We are also in the process of implementing our TOU pilot, consistent with the Commission's Order in Docket No. E002/M-17-775, certifying it as a distribution project under Minn. Stat. § 216B.2425 (*i.e.*, a grid modernization project). This pilot is intended to study time of use rates and how to maximize their value. This limited deployment of AMI meters and the FAN communications network in connection with the TOU pilot is a part of the overall AGIS initiative, and has been considered as we have developed plans for full deployment of advanced grid technologies. Likewise, we have conducted system research and testing around FLISR and IVVO, as discussed by Company witness Ms. Kelly Bloch.

Q. WHAT IS THE TIMING OF OVERALL AGIS IMPLEMENTATION?

A. Implementation of the components of the AGIS initiative will occur over several years and be substantially complete by 2024, with FLISR implementation expected to continue through approximately 2028. As such, a large portion of AMI, FLISR, IVVO, and FAN work will be undertaken and placed in service during the multi-year rate plan (MYRP) period, and are included in the Company's rate request. Our implementation timeline is set forth in Table 1, below:

Table 1

Program	Implementation Timeline
ADMS	In-service 2020
AMI	Meter roll-out 2021-2024
FAN	Deployment 2021-2024 (preceding AMI deployment by approximately six months)
FLISR	Limited testing 2020; Implementation 2020-2028
IVVO	Limited testing 2021; Implementation 2021-2024

That said, the grid modernization effort is ongoing by nature and we will continue to maintain the system as well as leverage evolving technology, platforms and optionality as appropriate over time. Likewise, we understand that the Commission's IDP requirements contemplate five- and ten-year outlooks. As such, our discussion of AGIS costs and benefits includes but also extends beyond the MYRP timeframe, and our cost-benefit analysis (CBA) (described in Section VI of my Direct Testimony) runs through the lifecycle of the assets based on the information currently known (as with any integrated long-range plan).

Given the longer term outlook required in the IDP filing, I also discuss potential future AGIS investments that are not planned for the MYRP. We are not seeking recovery or certification of these investments in this case and do not have an implementation schedule at this time. However, I discuss them to provide a view of potential future functionality that today's investment in the advanced grid will enable.

Q. PLEASE EXPLAIN IN MORE DETAIL HOW THE COMPANY'S RATE CASE DISCUSSION OF THE AGIS INITIATIVE AND IDP FILINGS INTERRELATE.

A. The Company is filing its IDP concurrently with this rate case filing. The IDP would typically include the Company's grid modernization report, while a rate case filing typically focuses on the test year or MYRP. In this case, however, while we focus on investments during the MYRP period as the elements for which are seeking cost recovery, we also introduce longer-range plans to provide context for our overall distribution system vision. For example, in my testimony, I discuss the core components of AGIS – AMI, the FAN, FLISR, and IVVO – and the Company's building block approach to deploying these components. I also discuss ADMS as part of our overall strategy and distribution planning, even though ADMS has been previously certified by the Commission, and the first year of costs were recently approved for recovery under our Transmission Cost Recovery (TCR) Rider.

Together, this filing and the IDP respond to the Commission's direction to bring the Company's overall vision into focus, including providing extensive detail regarding AGIS and distribution strategies as well as specifics around implementation and planned outcomes.

Q. WHAT ARE THE OVERALL ANTICIPATED COSTS OF THE AGIS INITIATIVE?

A. The Company anticipates incurring capital expenditures totaling $524 million and O&M costs totaling $152 million for the overall AGIS initiative, exclusive of ADMS.

Table 2

Total AGIS Capital Expenditures

NSPM – Total Company Electric

(Dollars in Millions)

	Rate Case Period			5-Year Period	10-Year Period
AGIS Program	**2020**	**2021**	**2022**	**2023-2024**	**2025-2029***
AMI	$14.0	$28.9	$144.0	$185.2	$15.0
FAN	$14.7	$37.3	$36.8	$3.8	$0.0
FLISR	$3.5	$8.6	$6.6	$18.8	$29.7
IVVO	$0.1	$6.5	$9.8	$18.6	$0.0
Total	**$32.3**	**$81.3**	**$197.2**	**$226.4**	**$44.7**

*Period may include additional assumptions, including inflation and labor cost increases, that are not part of the capital budget in periods 2020-2024.

Table 3

Total AGIS O&M

NSPM – Total Company Electric

(Dollars in Millions)

	Rate Case Period			5-Year Period	10-Year Period
AGIS Program	**2020**	**2021**	**2022**	**2023-2024**	**2025-2029***
AMI	$6.6	$16.4	$14.1	$25.2	$67.2
FAN	$0.1	$2.3	$1.5	$0.5	$8.6
FLISR	$0.2	$0.4	$0.3	$3.3	$2.5
IVVO	$0.0	$0.4	$0.8	$0.6	$0.8
Total	**$6.9**	**$19.5**	**$16.7**	**$29.4**	**$79.1**

*Period may include additional assumptions, including inflation and labor cost increases, that are not part of the capital budget in periods 2020-2024.

Q. WHAT ARE THE COMPANY'S SPECIFIC REQUESTS OF THE COMMISSION WITH RESPECT TO THE AGIS INITIATIVE?

A. We have two primary requests in this proceeding and in the IDP. First, we request approval to recover the costs of capital investments and O&M expense for the AGIS components that we propose to implement during the 2020-2022 term of the MYRP. We are proposing full AMI and FAN implementation, as well as implementation of FLISR and IVVO. The Company anticipates incurring the following capital additions and O&M costs for the AGIS initiative during the 2020-2022 period of the MYRP:

Table 4
Capital Additions for the AGIS Components (2020-2022, includes AFUDC)
$ in Millions – Minnesota

AGIS Component	2020	2021	2022
AMI	$16.0	$27.9	$119.8
FAN	$8.3	$21.3	$42.0
FLISR	$3.4	$8.4	$6.4
IVVO	-	$5.7	$8.6
Total	$27.7	$63.3	$176.8

Table 5
O&M for the AGIS Components (2020-2022)
$ in Millions – NSPM

Component	2020	2021	2022
AMI	$6.6	$16.4	$14.1
FAN	$0.1	$2.3	$1.5
FLISR	$0.2	$0.4	$0.3
IVVO	-	$0.4	$0.8
Total	$6.9	$19.5	$16.7

Second, because the AGIS implementation period extends beyond the term of our proposed MYRP, we are requesting that the Commission certify the AGIS projects overall, so that the Company would be allowed to request recovery of cost for 2023 and later in subsequent rider filings based on certification via this proceeding and/or the concurrent IDP filing. This is consistent with other requests for certification in the grid modernization and IDP filings, where certification does not guarantee cost recovery, but enables the opportunity for the Company to request recovery of costs in a subsequent rider filing. Certification of AGIS projects will provide a cost recovery option in the event the Company would not otherwise file a general rate case immediately following the conclusion of this MYRP period.

Q. DOES THE COMPANY PRESENT DETAILED SUPPORT FOR THESE COSTS, AND FOR THE QUANTITATIVE AND QUALITATIVE BENEFITS ASSOCIATED WITH THEM?

A. Yes. As I describe below, the Company presents a detailed cost-benefit analysis for each AGIS component – including both quantitative and qualitative support. Additionally, we provide detailed information to support the proposed investments for each year of the MYRP.

Q. WHY DOES THE COMPANY BELIEVE BOTH MYRP RATE RECOVERY AND CERTIFICATION FOR POTENTIAL TCR RECOVERY ARE APPROPRIATE?

A. We believe both MYRP cost recovery and certification are appropriate because of the extensive amount of support and analysis we are providing in this case – including everything required for both the MYRP and the IDP. The witnesses supporting the AGIS initiative provide support for costs during the MYRP term as well as for AGIS implementation beyond 2022. These witnesses discuss in detail the anticipated work to be done, the expected implementation timelines, and the reasonableness of underlying assumptions for planning and cost-benefit analysis purposes. Given the complete information we provide on overall AGIS implementation and costs, we believe granting cost recovery during the MYRP and certification of the AGIS projects beyond the MYRP is appropriate in this case.

D. Witness Support for the Proposed AGIS Initiative

Q. WHAT INFORMATION DO YOU PROVIDE IN THIS SECTION OF YOUR EXECUTIVE SUMMARY?

A. Below I describe the business areas involved in implementing the AGIS initiative, identify the witnesses supporting AGIS, and provide an overview of the topics covered by each. Because the large majority of information necessary to support the AGIS initiative in this rate case and in the concurrent IDP is contained in this rate case filing, this section of my Direct Testimony provides a roadmap to help navigate the extensive information and testimony we provide on the AGIS initiative.

We have made every effort here to identify the location of specific topics and information to aid the reader. Exhibit___(MCG-1), Schedule 2 is the AGIS Completeness List, which identifies specific filing requirements and where the information is located. In my testimony I provide a higher-level roadmap.

Q. WHAT AREAS OF THE COMPANY ARE INVOLVED IN IMPLEMENTING AND SUPPORTING THE AGIS INITIATIVE?

A. The AGIS initiative is supported by and affects many operating and customer service areas of our business. In particular:

- Our Distribution Operations business area is responsible for the planning, implementation, and operations of the various advanced grid components. At a high level, this can be thought of as installing, maintaining, operating, and protecting the foundational hardware and support components of AGIS on the distribution system.
- The Business Systems area is responsible for the hardware and software systems necessary to deploy and secure the AGIS components from an information technology (IT) perspective. Business Systems is also responsible for implementation of the IT platform that will enable the Company to interface with customers through various portals, and to provide customers access to additional information, products, and services that will be possible through the advanced grid initiative. Business Systems also works hand-in-hand with our security team to protect the Company's software systems from cyber attacks.
- Customer Care is responsible for meter reading, billing, credit, remittance processing, and customer contact center functions. The Customer Care team will manage customer questions and concerns as

the AGIS initiative is being deployed, as well as the new billing options and programs that will be made available.

Other customer-facing teams are also heavily involved. Customer Solutions is responsible for development and implementation of those customer-facing online and mobile applications, as well as new products and services, that will be enabled by the advanced grid capabilities. Our Customer Insights group is responsible for survey and research efforts necessary to determine the needs and preferences of our customers with respect to development of new products and services, as well as to measure customer satisfaction with new products, services, or advanced grid capabilities. Corporate Communications is responsible for the customer education and communications related to implementation of new technologies and products and services related to advanced grid capabilities. In short, the AGIS initiative will touch many areas of both NSPM and Xcel Energy as a whole.

Q. WHICH COMPANY WITNESSES ARE PROVIDING TESTIMONY IN THIS CASE TO SUPPORT THE COMPONENTS OF THE AGIS INITIATIVE?

A. As noted in the introduction to my direct testimony, the Company is presenting five witnesses who provide Direct Testimony and accompanying schedules supporting our request for approval of the capital and O&M budgets for the specific components of AGIS included in this case, as well as support for the broader Integrated Distribution Plan being filed concurrently with this case. These witnesses' respective topics are as follows:

- My testimony presents the overview of the AGIS initiative, the background on our efforts to date, an explanation of governance as it relates to the AGIS initiative, a discussion of the customer experience upon implementation, an explanation of our customer outreach and progress metrics proposals, and an overview of the cost-benefit analyses as well as customer bill impacts.

- *Kelly A. Bloch,* Regional Vice President of Distribution Operations, addresses the AGIS initiative from the Distribution perspective, and specifically identifies those costs and benefits that derive from the Distribution portion of the business. Her testimony details the business case for AMI, FLISR, and IVVO, and provides extensive discussion of these technologies, alternatives considered, and supporting cost and benefit detail.
- *David C. Harkness,* Senior Vice President of Customer Solutions for XES, addresses the AGIS initiative from the Business Systems (IT) perspective, focusing on integration of the hardware and software necessary for the AGIS elements to function together and with existing Company systems. Mr. Harkness also details the business case for the FAN strategy and project management, as well as alternatives considered and supporting cost detail. Mr. Harkness also discusses cyber security for the AGIS initiative, as well as the costs and benefits of the IT hardware and software systems necessary to deploy each of the AGIS components.
- *Christopher C. Cardenas,* Vice President of Customer Care for XES, explains the current status of the expiring Cellnet contract for wireless metering, meter change and billing impacts and options as AMI meters are deployed, and potential tariff changes the Company plans to pursue in the future. Mr. Cardenas also describes certain cost savings and customer benefits associated with moving away from our current meter reading system.

- *Ravikrishna Duggirala,* Director of Risk Strategy for XES, supports the Company's cost-benefit model for the individual core AGIS components as well as the overall AGIS initiative. Dr. Duggirala explains the structure of the model, how inputs received from other business areas were utilized, and the results of the analyses. Lastly, Dr. Duggirala explains the limitations of any cost-benefit modeling.

Q. CAN YOU IDENTIFY THE NSPM TESTIMONY SUPPORTING THE SELECTION OF AND COSTS FOR THE COMPONENTS OF THE AGIS INITIATIVE?

A. Yes. Because the costs of the AGIS initiative reside in our Distribution and Business Systems budgets, Ms. Bloch and Mr. Harkness support the costs of the AGIS components and most aspects of our initiative's development. As set forth in Table 6 below, Ms. Bloch supports the selection of meters and the FLISR and IVVO field devices and associated implementation; whereas Mr. Harkness describes the associated software, hardware, security, and overall IT integration.

Table 6

AGIS Program Witness Support

AGIS Program	Component	Witness
AMI	IT Integration and head end application	Harkness Direct, Section V(E)(3)
	Meters and deployment	Bloch Direct, Section V(D)
FAN	IT Integration and deployment	Harkness Direct, Section V(E)(4)
	Installation of pole-mounted devices	Bloch Direct, Section V(E)
FLISR	System development	Harkness Direct, Section V(E)(5)
	Advanced application and field devices	Bloch Direct, Section V(F)
IVVO	System development	Harkness Direct, Section V(E)(6)
	Advanced application and field devices	Bloch Direct, Section V(G)

In addition, I support program management for the AGIS initiative in Section V.D of my Direct Testimony, as well as the Company's customer outreach plans in Section VI.E of my Direct Testimony.

Q. PLEASE SUMMARIZE THE BENEFITS OF THE AGIS INITIATIVE AND PROVIDE THE WITNESS RESPONSIBLE FOR SUPPORTING EACH.

A. Overall, the AGIS initiative consists of multiple programs that work together to improve and update our distribution system in many ways. At a system-wide level, we will move from the predominantly one-way system that currently exists to an integrated system of centralized and decentralized energy resources that are connected and optimized through communications systems that share information from across the distribution grid. The advanced grid will leverage automation, real-time monitoring, and communication to locate and isolate disruptions in the system and improve safety, efficiency, and reliability of the system. The advanced grid will also enable greater customer choice by allowing customers to adopt new products, services, technologies, and applications, including access to timely energy usage data and more options for managing their usage. The advanced grid will be more secure, and address cyber and physical threats to the extent possible. Additionally, the advanced grid will allow the Company to manage the increasing amount of DER entering our system.

Ms. Bloch, Dr. Duggirala, and Mr. Cardenas support the benefits of AMI overall and with respect to specific individual benefits. While the IT work is necessary to both implement the AGIS initiative and ensure appropriate security measures, IT by itself does not provide independent benefits; therefore, Mr. Harkness's testimony is limited to a discussion of costs.

Benefits of the AGIS initiative are many and varied, but the types of benefit and supporting witnesses can be summarized as follows:

Table 7

Summary of Benefits for AGIS Components

Benefit	Supporting Witness
AMI	
Distribution System Management Efficiency	Bloch Direct, Section V(D)(4)(a)(1)
Outage Management Efficiency	Bloch Direct, Section V(D)(4)(a)(2)
Avoided Meter Purchases for Failed Meters	Bloch Direct, Section V(D)(4)(a)(3)
Avoided Capital for Alternative Meter Reading System	Bloch Direct, Section V(D)(4)(a)(4)
Avoided O&M Meter Reading Cost for Alternative Meter Reading System	Cardenas Direct, Section V(F)
Reduction in Field & Meter Services	Bloch Direct, Section V(D)(4)(b)(1)
Improved Distribution System Spend Efficiency	Bloch Direct, Section V(D)(4)(b)(2)
Outage Management Efficiency	Bloch Direct, Section V(D)(4)(b)(3)
Customer Outage Reduction	Bloch Direct, Section V(D)(4)(c)
Reduction in Energy Theft	Cardenas Direct, Section V(F)
Reduced Consumption Inactive Premise	Cardenas Direct, Section V(F)
Reduced Uncollectible/Bad Debt	Cardenas Direct, Section V(F)
Critical Peak Pricing	Duggirala Direct, Section II(B)(1)
TOU Customer Price Signals	Duggirala Direct, Section II(B)(1)
Reduced Carbon Dioxide Emissions	Duggirala Direct, Section II(B)(1)
Improved Customer Choice and Experience	Gersack Direct, Section VI and Schedule 3
Enhanced DER Integration	Bloch Direct, Section V(D)(4)(d)(1)
Environmental Benefits of Enhanced Energy Efficiency	Bloch Direct, Section V(D)(4)(d)(2)
Improved Safety to Both Customers and Company Employees	Bloch Direct, V(D)(4)(d)(3)
Improvements in Power Quality	Bloch Direct, V(D)(4)(d)(4)

Benefit	Supporting Witness
FLISR	
Customer Minutes Outage –Savings	Bloch Direct, Section V(F)(5)(a)(1)
Outage Patrol Time Savings	Bloch Direct, Section V(F)(5)(a)(2)
Improved ability to plan distribution system needs	Bloch Direct, Section V(F)(5)(b)
Overall Customer Satisfaction with Utility Service	Gersack Direct, Section VII(B)
IVVO	
Fuel savings (Energy Reduction)	Bloch Direct, Section V(G)(4)(a)(1)
Fuel Savings (Line Losses)	Bloch Direct, Section V(G)(4)(a)(2)
Avoided Capacity Costs	Bloch Direct, Section V(G)(4)(a)(3)
Reduced Carbon Dioxide Emissions	Duggirala Direct, Section II(B)(3)
Customer bill savings for customers with feeders with IVVO assets	Bloch Direct, Section V(G)(4)(b)
Greater Efficiencies from the Customer's Personal Electrical Devices	Bloch Direct, Section V(G)(4)(b)
Increased Hosting Capacity for Distributed Energy Resources.	Bloch Direct, Section V(G)(4)(b)

Q. DID THE COMPANY ALSO PREPARE COMPARISONS OF THE COSTS AND BENEFITS OF THESE COMPONENTS, OR ALTERNATIVES COMPARISONS?

A. Yes – we provide both. As noted above, the Company conducted a CBA for each of the AGIS components and on a consolidated basis. The CBA provides one point of reference to assess the investments in the broader context of the goals of AMI, FLISR, and IVVO implementation, the current qualitative benefits they offer, Commission policy goals, and the opportunities for future customer benefits. The witnesses noted above provide the inputs to the CBA for each component and for the consolidated AGIS initiative, and Dr. Duggirala presents the overall model.

Additionally, Dr. Duggirala presents "Least-Cost/Best-Fit" analyses with respect to the costs/benefits of AMI and manual reading or drive-by AMR solutions; as well as for the costs of FAN versus cellular communications and dedicated AMI network alternatives.

Q. WHAT DOES THE COMPANY CONCLUDE WITH RESPECT TO THE RELATIVE COSTS AND BENEFITS – BOTH QUANTITATIVE AND QUALITATIVE – FOR THE AGIS INITIATIVE?

A. The CBA results indicate that the consolidated quantifiable costs and benefits of the AGIS initiative total 0.87 in our baseline scenario, or 1.03 under a high benefit/no contingency scenario. Thus the combined components do not reach 1.0 (equal quantifiable benefits and costs) under our baseline scenario. However, the baseline benefit-to-cost ratio for the overall AGIS initiative approaches 1.0 even before we factor in qualitative benefits such as customer satisfaction and certain operational and power quality improvements, as well as safety enhancements.

We note that while the CBA, by itself, does not show that quantifiable benefits are equal to quantifiable costs, we would not necessarily expect that result. We are proposing an initiative to both replace fundamental components of our system that are approaching end of life, and to add capabilities for our customers now (and in the future) to address a future that includes greater DER, distributed intelligence, and greater customer engagement. We would not expect to save money (on a net basis) when investing in these kinds of technologies, but we believe the total value of the initiative significantly outpaces the cost of the investments. For these reasons, the AGIS investments are prudent based on the need for the investments to serve customers, as well as consideration of the customer-facing benefits, efficiencies, and system benefits they provide.

E. Roadmap to AGIS Policy Testimony

Q. WITH THAT BACKGROUND, PLEASE SUMMARIZE THE REMAINDER OF YOUR TESTIMONY.

A. In my testimony, I first provide background on grid modernization in Minnesota and discuss how our request in this case relates to our IDP filed concurrently with the Commission on November 1, 2019, in order to establish a backdrop for the Company's view of the future of the grid. I then identify the Company's overall strategic goals, focusing on the environment, the customer experience, and cost of service. I also identify customer expectations and wishes for the future of electric service based on extensive Company research, focusing on how these expectations relate to the future of the distribution system.

I then describe the Company's long-term strategic plan to use technological advances to transform our distribution system to meet changing customer demands, to enhance efficiency, and reliability, and security, to safely integrate more distributed energy resources, and explain how that plan is aligned with core Company goals. I highlight the reasons now is the right time to undertake these initiatives – including our meters nearing end of life and the expiration of our meter reading contract with Cellnet – and discuss the key goals of AGIS and how they are consistent with Xcel Energy's strategic priorities.

I then address the scope of the core components of AGIS that are included in this case, outlining the function, benefits, alternatives considered, timing of implementation, and costs of each. I defer to other Company witnesses to flesh out these components, costs, and benefit assumptions in more detail.

Next, I discuss in detail the current customer experience compared to what will be different when the distribution system is transformed and advanced. I also provide our customer and community outreach plan for the AGIS initiative, designed to educate and inform customers about our progress, impacts they will experience during and after implementation, and advanced grid capabilities that will provide the basis for additional opportunities and services for our customers. I also discuss indicators of progress and success, and how the Company will measure and report on progress and outcomes of the AGIS initiative.

Finally, I describe why AGIS, and thus the foundational elements included in this case, are in the public interest. I introduce the cost benchmarking and cost-benefit analyses we have undertaken, which are specifically supported and presented in detail in the Direct Testimony of Dr. Duggirala. I explain both the value and the inherent limitations of any cost-benefit analysis. I also summarize the quantitative and qualitative benefits of the AGIS initiative, explaining how the benefits of certain components of AGIS are not limited to quantifiable items; they will also update aging systems, improve our customers' overall experience and satisfaction, position the Company for future grid developments, and help achieve broader energy goals.

Q. Do you provide other information to support your own discussion of the Company's AGIS implementation strategy with respect to the customer experience?

A. Yes. Provided as Exhibit___(MCG-1), Schedule 3 is the Company's *Advanced Grid Customer Strategy*. This document the details the Company's AGIS strategy and plans to enhance the customer experience. The document includes, among other things, background on our customer surveys and research efforts that have informed our AGIS strategy, and details on the technologies and customer benefits of each AGIS component.

To help stakeholders further visualize our plans, the Company also prepared a brief video[4] entitled *Building the Future* to illustrate the advanced grid technologies and benefits and illustrate multiple situations where additional data and capabilities with respect to the distribution grid will facilitate a better, smoother, and more agile customer experience. While not as dynamic as the video itself, I have attached illustrations from this video as Exhibit___(MCG-1), Schedule 4 to my Direct Testimony.

Q. What are your recommendations with respect to the AGIS initiative?

A. I recommend that the Commission approve our proposed AGIS investments for the term of the MYRP, and certify the components of the Company's long-term AGIS plan (AMI, FLISR, IVVO, and the FAN) for potential future cost recovery in the TCR rider.

[4] https://youtu.be/HoQoHFdF7kc

III. GRID MODERNIZATION BACKGROUND

Q. CAN YOU PROVIDE SOME RECENT HISTORICAL CONTEXT FOR THE COMPANY'S MODERN ERA OF GRID MODERNIZATION EFFORTS AND UNDERTAKINGS IN MINNESOTA?

A. Yes. The Company's first grid modernization report was filed in 2015[5] in compliance with Minn. Stat. § 216B.2425, subds. 2(e) and 8, which required that in addition to the biennial distribution system plan required for all utilities, a utility under a multi-year rate plan would also be required to file a separate biennial grid modernization report. At that time, the new statutory language and requirements reflected the growing interest in ensuring the distribution system would be well positioned to meet future system needs while maintaining security, reliability, and safety. The statute also allowed the Company to request Commission certification of specific projects, for which the Company would then be allowed to include requests for cost recovery in filings under the Transmission Cost Recovery Rider (TCR Rider).

Q. DID THE COMPANY REQUEST AND RECEIVE CERTIFICATION FOR ANY INITIATIVES IN ITS FIRST GRID MODERNIZATION REPORT?

A. Yes. In the 2015 grid modernization report, the Company requested and received certification for the ADMS program. In its Order, the Commission approved certification of ADMS as consistent with statutory requirements. The Commission also noted that because of ADMS' foundational role in grid modernization, the Company should be provided with reasonable incentive to move forward, specifically through the opportunity to request cost recovery through the TCR Rider. The Company has begun ADMS implementation

[5] See Docket No. E002/M-15-962.

and the first year of costs were recently approved to be recovered under the TCR Rider.[6]

Q. DID THE COMPANY REQUEST AND RECEIVE CERTIFICATION FOR ANY INITIATIVES IN ITS SUBSEQUENT GRID MODERNIZATION REPORT?

A. Yes. In its 2017 Distribution Grid Modernization report,[7] the Company sought and received certification for a TOU rate under a new pilot program.[8] The TOU pilot implements new residential TOU rates in two communities in the Twin Cities metropolitan area, and provides participants with increased energy usage information, education, and support to encourage shifting energy usage to daily periods when the system is experiencing low load conditions. To support the TOU pilot, we will deploy both AMI meters and the necessary FAN communications in the participating communities.

The goals of the pilot program are to study adequate price signals to reduce peak demand, identify effective customer engagement strategies, understand customer impacts by segment, and support demand response goals. In its Order, the Commission certified the TOU pilot as consistent with statutory requirements, noting that the pilot program will allow the Company and its customers to learn more about the TOU rate. The limited deployment of FAN and AMI through the TOU pilot will also allow the Company an opportunity to measure and verify key assumptions regarding customer behavior in advance of the planned wider rollout of both initiatives. Customer engagement and installation of both FAN and AMI in connection with the TOU pilot began in 2019.

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[6] See the Commission's Order dated September 27, 2019 in Docket No. E002/M-17-797.
[7] See Docket No. E002/M-17-776.
[8] See Docket No. E002/M-17-775.

Q. DURING THE PERIOD YOU DISCUSS ABOVE, WERE THERE OTHER PROCEEDINGS ON GRID MODERNIZATION IN MINNESOTA?

A. Yes. In 2015, after enactment of the new grid modernization statute noted above, the Commission opened an investigatory docket on grid modernization[9] and issued the *March 2016 Staff Report on Grid Modernization*. Of various potential options outlined in the Staff Report, the Commission supported examining distribution system planning as the most reasonable and actionable way to assist in the forthcoming grid evolution. The Commission also supported the staff-proposed guiding principles as its Planning Objectives, as follows:

- Maintain and enhance the safety, security, reliability, and resilience of the electricity grid at fair and reasonable costs, consistent with the state's energy policies;
- Enable greater customer engagement, empowerment, and options for energy services;
- Move toward the creation of efficient, cost-effective, accessible grid platforms for new products, new services, and opportunities for adoption of new distributed technologies; and
- Ensure optimized utilization of electricity grid assets and resources to minimize total system costs.

During this proceeding, the Commission conducted a workshop seeking stakeholder input on a Minnesota-based distribution system planning framework. The Commission also accepted comments and replies seeking to understand how utilities currently plan their systems, the status of current-year

[9] See Docket No. E999/CI-15-556.

utility plans, and recommendations for improvements to present planning practices.

The Commission then established individual utility IDP dockets,[10] where Staff and the utilities worked on proposed IDP filing requirements, with a comment and reply period for stakeholder input. The Commission determined final IDP requirements for Xcel Energy at its August 9, 2018 hearing, and issued its Order on August 30, 2018. Like development of the IDP requirements, the Order acknowledges IDP as envisioned by the planning objectives will be an iterative process – set in motion with the Company's initial IDP.

Xcel Energy's first IDP was filed November 1, 2018, and is due annually thereafter. The biennial grid modernization reports discussed above are now combined with the annual IDP filings.

Q. HOW DOES THE COMPANY'S RATE CASE REQUEST RELATE TO THE COMPANY'S MOST RECENT IDP FILED ON NOVEMBER 1, 2019?

A. The annual IDP filing addresses distribution system planning overall. Through the IDP, the Company is also allowed to request certification of specific projects that meet statutory requirement for grid modernization projects, which then allows the Company to subsequently request recovery of the costs of those projects under the TCR Rider. This year, the Company is filing its IDP and this rate case concurrently on November 1, 2019. As such, while the IDP addresses the AGIS initiative in the discussion of overall distribution system planning, the Company is requesting approval to include in base rates the costs of the AGIS components implemented during the term of

[10] Xcel Energy's IDP filing requirements were developed in Docket No. E002/CI-18-251.

the multi-year rate plan. These components include AMI, the FAN, FLISR, and IVVO.

Further, because ADMS cost recovery has been approved under the TCR Rider, and the ADMS implementation process is at an advanced stage, we propose to continue recovery of the ADMS costs under the TCR Rider. While the costs of the TOU pilot were also certified for potential recovery under the TCR Rider, we are requesting that TOU pilot costs incurred during the MYRP be included in base rates to align with the stage of the pilot and future AMI efforts. Our testimony in this case and our IDP filing provide the support for these cost recovery proposals.

Additionally, through the IDP proceedings, the Commission has issued requirements around the level and types of information that are expected to be included in any future request to proceed with AGIS initiative components. As a result, this rate case testimony provides the 2020-2022 multi-year rate plan capital and O&M expenditures for the AGIS initiative in the broader context of our longer-term AGIS strategy. The information in this case also supports our request for certification of the AGIS projects for potential future rider recovery.

Q. HOW IS THE COMPANY ILLUSTRATING ITS COMPLIANCE WITH BOTH RATE CASE AND IDP REQUIREMENTS THROUGH ITS COMPLEMENTARY NOVEMBER 1, 2019 FILINGS?

A. In our last IDP filed in November 2018, we noted that we intended to bring the costs and benefits associated with specific grid modernization projects to the Commission for approval through either a future certification request in the grid modernization/IDP filings or through a general rate case. Several additional requirements have been established in the Commission's most recent TCR Order.

Our request for rate recovery for AGIS initiatives in this case includes the information required by the Commission, as noted in my testimony and the Direct Testimony of the other witnesses supporting AGIS projects in this case. In the attached Schedule 2, I provide the AGIS Completeness List, which identifies the filing requirements for future Xcel Energy grid modernization projects in Minnesota, and specifies where we have provided this information in our direct testimony in this case. This schedule also identifies where information is provided solely in the IDP rather than this rate case, to provide a holistic view of the information provided in the two complementary dockets.

IV. DRIVERS OF THE AGIS STRATEGY

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A. In this section of my testimony, I explain why the AGIS initiative is a necessary and appropriate step for the Company, as it is aligned not only with Xcel Energy's strategic priorities to meet customers' current and forward-looking expectations and service needs but also the needs of the existing NSPM distribution system as well as the objectives that emerged from the Commission-led grid modernization planning process. Indeed, the AGIS initiative supports Commission policy and reflects our previous work with stakeholders relative to customer offerings, performance, and technological capabilities of the grid. I further describe the current customer experience with the Company's electric service delivery. In this way, I establish the reasons we have developed and propose to continue pursuing the AGIS initiative.

Q. WHAT ARE THE SPECIFIC DRIVERS BEHIND THE NEED FOR AGIS IMPLEMENTATION AT THIS TIME?

A. The need to modernize the grid is driven by

- the Company's overall strategic priorities;
- changing customer needs and preferences;
- distribution system needs; and
- Commission policy and stakeholder input.

Our goal with AGIS implementation is to use new technologies to transform the customer experience to meet the increasing customer demands for additional energy usage data as well as new products and services that will provide opportunities for customers to use that information to control usage.

In addition, there are system needs related to aging technology that make now the right time for the Company to implement the elements of the AGIS initiative. We have already begun ADMS implementation and will need to replace our current AMR infrastructure in the near term to maximize that investment in ADMS and avoid end of life issues with our current meters.

Our AGIS initiative has also been informed by Commission policy and our previous work with stakeholders in various proceedings related to distribution grid planning, advanced rate design, and performance-based metrics.
In this section of my testimony, I discuss each of these drivers.

A. The Company's Strategic Priorities

Q. WHAT ARE THE COMPANY'S OVERARCHING STRATEGIC PRIORITIES FOR ITS CUSTOMERS AND ITS BUSINESSES?

A. As described by Company witness Mr. Gregory Chamberlain, Xcel Energy presently has three overall strategic priorities, which are as follows:

- Lead the Clean Energy Transition – Decarbonize the energy sector by retiring fossil fuel resources and replacing them with cost-effective and carbon-free resources.
- Enhance the Customer Experience – Deliver personalized products and services that meet our customer's lifestyle needs and offer them a personalized and contemporary customer experience.
- Keep Bills Low – Drive costs from generation, transmission, and distribution, and continue to deliver safe, reliable, affordable, and sustainable electric and gas services.

Q. HOW DOES AGIS IMPLEMENTATION SUPPORT EACH OF THESE STRATEGIC PRIORITIES?

A. First, AGIS will improve our ability to maximize environmental and conservation goals. By implementing the advanced grid technologies that provide for two-way communications, there will be significant improvement in the Company's ability to collect system data, manage distributed energy resources, and track outages and power quality issues. This insight into the distribution grid will enhance our ability to deliver on clean energy goals and support increased DER.

With two-way communications and an integrated distribution system with ADMS, we will be able to provide the kinds of data and insights to our customers that would facilitate their own efforts around and understanding of energy efficiency, cost management, and beneficial electrification. Similarly, AGIS will improve our outage and restoration performance in two ways. Specifically, two-way communication and fault location capabilities will allow the Company to: (1) provide timely and accurate communications to customers about outages and restorations; and (2) to isolate faults and restore power to customers in an automated fashion where possible.

While the short-term solution with the least impact on bills is to maintain the distribution system status quo ("do nothing"), this is not a realistic option for any extended period. First, technology is constantly evolving and improving, and customer expectations for interactions with their service providers – both utility and non-utility – are evolving as well. Second, the Company's grid, as currently constituted, cannot be maintained at status quo because certain components are near the end of life and will not be supported in the near future. Finally, the AGIS initiative brings long-term value for customers. Accordingly, my testimony recommends taking the longer, more strategic view, in order to position the Company to continue its environmental leadership, bring the customer experience in line with customer expectations, and help manage reliability and bill impacts over time.

Q. DOESN'T IMPLEMENTATION OF ADMS ACCOMPLISH THESE GOALS?

A. No, not by itself. ADMS helps with these issues, but it is only a start – ADMS is the necessary backbone for addressing the core issues facing our system. Even with ADMS, our current system is limited because it lacks the ability to manage two-way communications and does not provide the level of insight into the distribution system that will be necessary to enhance our ability to deliver on clean energy goals and support increased DER as we move into the future. Likewise, AMI meters themselves, supported by FAN communications, are a foundational aspect of better outage and usage data, but require additional technology to enable the Company and customers to use that data and integrate it with other utility systems. As such, a more comprehensive strategy is needed to serve the Company's strategic vision – which, in the end, is all about the quality of service to our customers.

Q. IS THE AGIS INITIATIVE THE COMPANY'S ONLY PLAN TO MEET THESE XCEL ENERGY STRATEGIC PRIORITIES?

A. No. As discussed by Company witness Mr. Chamberlain, the AGIS initiative is a key part of a broader strategic vision. The AGIS initiative is specific to the distribution grid and associated information technology systems, the utility customer's experience is affected by a much broader array of services and capabilities.

For example, in conjunction with the AGIS initiative, the Company is embarking on a Customer Experience transformation, which is intended to update the Company's digital channel platforms (MyAccount and the mobile application, for example), and our customer resource management systems to ensure a better, more modern customer experience. Mr. Harkness discusses the Customer Experience efforts in more detail in his Direct Testimony. These are not specific to the AGIS initiative, but rather complement it to bring the utility's interfaces up to date and meet existing and evolving customer expectations. In other words, the Company is thinking holistically about the customer experience, with AGIS serving an important piece of that strategy.

B. Changing Customer Needs and Preferences

Q. HOW ARE CHANGING CUSTOMER NEEDS AND PREFERENCES DRIVING THE NEED FOR AGIS IMPLEMENTATION?

A. The needs and preferences of customers continue to evolve in the digital age, with increasing dependence on information and the connectivity of digital devices. While incremental modernization efforts have taken place on the distribution system over many years, and we have used these investments to provide reliable power for decades, we (along with the broader industry, as noted earlier in my testimony) believe now is the right time to begin a more significant advancement of the grid. Technological advances now make it possible to meet growing customer expectations for a more robust, reliable, and resilient system, as well as customer desire for more insight and visibility into the energy choices they are making.

Q. CAN YOU PROVIDE SOME EXAMPLES OF THESE GROWING CUSTOMER EXPECTATIONS?

A. Yes. Customers are increasingly savvy when it comes to smartphone applications and sophisticated websites. They are accustomed to engaging electronically to manage their accounts, resources, and service needs across many industries. Without advanced meters that can provide regular usage data, it is not possible to bring the energy industry along that same curve by developing sophisticated energy management and conservation tools such as TOU rates, nor the applications and web-based tools that allow the customer to observe and manage their consumption. The improved interactions with the utility, outage response, and control over their energy usage and bills that our customers want begins with foundational advanced grid initiatives that we are seeking recovery of in this case. By way of example, approximately 2/3 (66 percent) of our NSPM customers surveyed over the past 12 months through August of 2019 said they want to be able to control their energy use when not at home. Customers expect to be able to turn lights on and off remotely, for example, but have no remote insight into how much energy they are actually using at this time. Further, 44 percent of NSPM customers over the same time period said they want alerts when their monthly usage or bill amount goes over a preset amount. These services require advanced metering and more timely usage data in order to provide these services and controls to our customers.

Q. DOES THE COMPANY CURRENTLY HAVE DIGITAL CHANNELS TO PROVIDE ENERGY USAGE INFORMATION TO CUSTOMERS?

A. Yes. Currently, the Company has a web portal, called MyAccount, where customers may obtain energy usage and billing information. We provide customers with energy usage information through the MyEnergy portion of MyAccount; however, the information in this portal is primarily limited to a comparison of monthly energy usage versus weather trends and general recommendations about how to reduce energy consumption. This portal also provides Green Button Download, which enables customers to download their energy usage data. While helpful information, it is not the sort of personalized data and insight our customers are seeking, and we have largely reached the limits on the level of data and customer engagement we can provide with our current systems.

Today, the Company receives energy usage data on a monthly basis, and this customer data is limited only to energy (kWh) consumption during the read period (typically the most recent 30 days). We cannot obtain data regarding the time when customers consume energy, the demand (kW) an individual places on the grid, or what end-use technologies contribute to the energy consumption. Customers receive information only on their aggregate monthly energy usage via a monthly bill.

Q. CAN YOU EXPAND ON HOW THE FUNCTIONALITY OF THE CURRENT GRID IMPACTS THE CUSTOMER EXPERIENCE?

A. Yes. First, the most direct impact that current system functionality has on the customer experience is during an outage. Today, the Company has limited insight into an outage on certain portions of our system. Typically, we cannot anticipate an outage and, in most of our service territory and for outages below the feeder level, do not know when an outage occurs unless a customer contacts us. We also have limited insight into what caused an outage after it is identified, cannot pinpoint the location of an outage easily or quickly, and cannot definitively notify a customer when an outage has been restored. Outages and the Company's ability to restore power and provide timely and accurate communications have a large impact on our customers' day-to-day lives and the quality of service they receive. This is a fundamental aspect of our service that we seek to improve through the AGIS initiative.

In addition, the lack of data detail and timeliness of energy usage information is an impediment to empowering customers to see and respond to their own energy usage, and therefore exercise more power over both conservation efforts and their bills. The current system limits the Company's ability to provide such information to customers to better inform their decisions about their own energy usage and its impacts. Our customers increasingly want additional information and energy options that are not provided with the basic functionality of our current systems.

Q. DOESN'T THE COMPANY CURRENTLY OFFER PROGRAMS FOR CUSTOMERS TO MAKE DECISIONS ABOUT THEIR ENERGY USAGE?

A. Yes, we do offer a significant number of optional programs for customers today, between our renewable choice and CIP/Demand Management programs, but these are essentially self-service programs. While we work hard to facilitate customer engagement in these programs, a customer must make an active effort to engage in the programs and manage the process. Further, the current system does not provide the information necessary to enable the Company to provide specific and personalized advice and recommendations to customers. Rather, we provide general recommendations that tend to work for the average customer under typical conditions – but we know that is not the reality and we are missing opportunities to enhance the customer experience. Each customer is different with respect to both goals and current situations, and we need more customer-specific data and data management tools to provide the level of service customers are seeking.

Q. HOW DID THE COMPANY DEVELOP ITS STRATEGY FOR MEETING THE CHANGING CUSTOMER NEEDS AND PREFERENCES YOU MENTIONED ABOVE?

A. First we worked to understand our customers' preferences and what they think about the benefits and value of an advanced grid investment. To that end, the Company conducted primary research through customer focus groups and surveys. To supplement these research efforts, the Company also reviewed secondary sources, such as the Smart Energy Consumer Collaborative and GTM Research, as well as other utility advanced grid plans. These research efforts are also discussed in detail in Schedule 3.

Q. CAN YOU PROVIDE ADDITIONAL INFORMATION ON THE SPECIFIC RESEARCH THE COMPANY CONDUCTED REGARDING CUSTOMER PREFERENCES AND INTEREST IN THE CAPABILITIES PROVIDED BY ADVANCED GRID TECHNOLOGIES?

A. Schedule 3 identifies the Company's primary research through customer surveys and focus groups, and its secondary research sources as well as other utility advanced grid plans. Below is a summary of surveys and studies that provided key findings to support our customer strategy with respect to the AGIS initiative.

- *Grid Edge Product Survey* – This survey was conducted to gauge customers' opinions and interest toward several proposed product and service concepts that may become available after AGIS deployment, as well as willingness to engage in new services and customers' levels of price sensitivity.
- *Advanced Meter Focus Groups* –The goal of these customer focus groups was to capture customer understanding, perception, and attitudes toward advanced meters, as well as to understand customer expectations of the services enabled by advanced metering. We also sought to understand customer preferences for communications around the deployment and implementation of new meters.
- *2018 MN Smart Meter Survey* – The objective of this survey was to quantify familiarity and perceived value of smart meters, gauging the potential value of AMI-related benefits to customers, preferences for

AMI enabled data, and communications about future smart meter plans.

- *Residential Relationship Study* – This monthly survey is intended to determine the pulse of our customers' opinions and satisfaction with service. Included in the monthly survey are questions which gauge customers' interest in new products and attitudes of and practices around energy usage.

In addition to Xcel Energy's research efforts described above, the following secondary sources were used to inform our customer strategy around advance grid capabilities:

- JD Power Electric Residential Study;
- E Source, *E Design 2020 Small Medium Business Ethnographic Research*;
- Department for Business, Energy & Industrial Strategy (U.K.), *Smart Meter Customer Experience Study: Post-Installation Survey Report*;
- U.S. Department of Energy, *Advanced Metering Infrastructure and Customer Systems: Results from the Smart Grid Investment Grant (SGIG) Program*;
- Smart Grid Consumer Collaborative, *Effective Communication with Consumers on the Smart Grid Value Proposition*;
- Smart Energy Consumer Collaborative, *Understanding Your SMB Customers: A Segmentation Approach*; and
- Chartwell, *Demand Reduction Programs for TOU Customers – Madison Gas & Electric Case Study.*

Q. WHAT ARE THE KEY TAKEAWAYS IDENTIFIED THROUGH THE COMPANY'S RESEARCH EFFORTS RELATED TO ADVANCED GRID CAPABILITIES?

A. Key takeaways from the Company's research include the following:

- *Safety and energy savings* are most highly rated in order of importance to customers.[11]
- *Technology:*
  - Customers care about technology and their interactions with their utility. They want to know how the advanced grid will provide benefits related to those technologies and interactions.[12]
- *Reliability:*
  - Addressing service interruptions is important to all customer classes.[13]
  - Customers expect that service interruptions will be less frequent, smaller in scope, and shorter in duration.[14]
- *Data and Information:*
  - Customers expect to receive detailed energy usage information from their utility.[15]
  - Provision of information is expected to be personal and frequent.[16]
  - Customers expect tools that will help them use information to make decisions about their energy usage.[17]

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[11] Grid Edge Product Survey; Advanced Meter Focus Groups.
[12] Xcel Energy Residential Relationship Study; E Design 2020 Small Medium Business Ethnographic Research.
[13] 2018 MN Smart Meter Survey; JD Power Electric Residential Study; E Design 2020 Small Medium Business Ethnographic Research.
[14] Advanced Metering Infrastructure and Customer Systems: Results from the Smart Grid Investment Grant Program.
[15] Advanced Meter Focus Groups; JD Power Electric Residential Study; 2019 E Source Gap and Priority Study; Colorado Time of Use Non-Participating Customer Survey.
[16] Advanced Meter Focus Groups; 2018 MN Smart Meter Survey; JD Power Electric Residential Study.
[17] 2018 MN Smart Meter Survey; Xcel Energy Residential Relationship Study; E Design 2020 Small Medium Business Ethnographic Research; Effective Communication with Consumers on the Smart Grid Value Proposition.

- Customers expect that more information will allow them to better identify opportunities and strategies to save energy and reduce their costs.[18]

- *Rate Design:*
  - Business customers have more awareness and familiarity with advanced rate designs.[19]
  - Residential customers expect the utility to provide them with rate comparison tools and information about new rate designs.[20]
- *Trust:*
  - Building trust is a key component to unlocking value for customers. [21]
  - Trust is best built by identifying solutions and showing results specific to the customers. [22]

Q. HOW WOULD YOU SUMMARIZE THESE TAKEAWAYS?

A. Customers want certain features of their electric service that are not possible without a more advanced grid. These include more detailed and timely information about their energy use, improved reliability and outage restoration, and the ability to remotely control their energy usage.

Q. CAN THE COMPANY'S CURRENT METERS AND SYSTEMS MEET THESE CUSTOMER EXPECTATIONS?

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[18] Advanced Meter Focus Groups; 2018 MN Smart Meter Survey; MN Time of Use Rate Study; E Design 2020 Small Medium Business Ethnographic Research.
[19] 2019 E Source Gap & Priority Study; 2018 MN Smart Meter Survey.
[20] Colorado Time of Use Non-Participating Customer Survey; MN Time of Use Rate Study; MN Time of Use Behavioral Focus Groups; 2018 MN Smart Meter Survey.
[21] MN Time of Use Behavioral Focus Groups; E Design 2020 Small Medium Business Ethnographic Research.
[22] E Design 2020 Small Medium Business Ethnographic Research; Advanced Meter Focus Groups.

A. Only to an extent. Without investments in the advanced grid through AMI, the FAN, and ADMS we will not have the tools necessary to meet these concrete customer expectations. Our system, as currently constituted, can only provide customers with the following limited information:

- Monthly, whole premise consumption data;
- General recommendations about how they use their energy – because we lack detailed customer energy usage profiles and disaggregation of their energy usage; and
- Limited information about the existence of an outage and the status of a restoration – because our systems do not report when all outages occur, cannot "self-heal," and cannot automatically identify the cause of an outage.

Q. WHAT DID YOU LEARN ABOUT CUSTOMERS' EXPECTATIONS FOR THE COSTS OF DEVELOPING THE SYSTEMS THAT WILL ACCOMPLISH THESE GOALS?

A. Generally, our research showed that customers need more information to understand the costs and benefits of our proposed investments in the advanced grid. Specifically:

- Customers believe certain safety features should be provided at no cost.[23]
- Customers need specific information about what the cost of the advanced grid is and how it will impact them.[24]
- Customer willingness to pay is tied to customer awareness of the technology and its benefits. Business customers are more familiar with the benefits and more willing to pay.[25]

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[23] Grid Edge Product Survey; Advanced Meter Focus Groups.
[24] Advanced Meter Focus Groups; Colorado Time of Use Non-Participating Customer Survey; Minnesota Time of Use Rate Study Grid Edge Product Survey.

Q. CAN YOU PROVIDE ADDITIONAL INFORMATION ABOUT CUSTOMERS' EXPECTATIONS WITH RESPECT TO COSTS?

A. Yes. In our MN Smart Meter Survey, we found that awareness of "smart meters" is low among our residential customers (15 percent) and twice as high among our business customers (30 percent). This same survey found that only 13 percent of residential customers and 36 percent of business customers understood that the cost of smart meters corresponds to more value than our existing meters. This low level of awareness indicates customers are not familiar with what a smart meter is or what the benefits are likely to be. This lack of awareness was also borne out in our Advanced Meter Focus Groups which found that customers were unclear about the basic functionality of advanced meters.

As I previously discussed, while many customers are interested in the benefits of advanced meters, such as control over their energy usage, more information about their energy usage, greater reliability, and environmental benefits, customers do not fully understand the technology or how advanced meters are critical to enabling these benefits. This leads us to conclude that customer education is needed for customers to understand AMI metering and how it relates to the needed technology and associated benefits. Our communications and education plan discussed in Section VI(E) was designed to address this need.

Q. DID THE COMPANY'S RESEARCH PROVIDE ANY OTHER INSIGHT RELATED TO CUSTOMER COMMUNICATIONS AND EDUCATION?

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[25] 2018 MN Smart Meter Survey; Advanced Meter Focus Groups; Grid Edge Product Survey.

A. Yes. Through our Advanced Meter Focus Groups, we also identified that customers would prefer to learn about the meters approximately 2-3 months prior to installation. Education and awareness information is also best provided through multiple channels as not all customers will receive or digest the information the same way. We have taken these considerations and built them into our Customer and Community Outreach plans which I detail below.

Q. HOW DID CUSTOMER CONSIDERATIONS AFFECT THE COMPANY'S DEVELOPMENT OF THE AGIS INITIATIVE?

A. As I noted above, customers expect more resources to help manage their energy usage and want more information about outages. Our investments in the advanced grid are specifically designed to deliver on these expectations. Our investments in AMI, the FAN, and ADMS will reduce the number of minutes customers are out, potentially reduce the number of outages that occur, and allow us to better communicate with our customers about the status of an outage restoration. Similarly, more granular energy usage information, including the timing of when energy is used, what the specific drivers of a customer's energy usage are, and personalized advice on how to change their behavior to reduce their energy usage are only enabled because we will have advanced meters capable of providing detailed interval energy usage data that is transmitted across the FAN at hourly or faster intervals.

Q. HOW DO YOU FACTOR IN THE CONSIDERATIONS OF CUSTOMER COST?

A. Keeping bills low is a priority for Xcel Energy, and keeping bills low starts with smart investments. I discuss the prudence of the AGIS investments and the cost-benefit analyses we conducted in Section VII of my testimony, and I discuss the estimated customer bill impacts in Section VIII. We took a conservative approach in our cost-benefit analyses to ensure that costs were not understated and expected quantifiable benefits were not overstated. However, in addition to considering costs and quantifiable benefits, we also considered the non-quantifiable customer benefits as we developed our strategy for investments in advanced grid technologies. For example, customer expectations for more detailed and timely information is one factor driving our customer strategy. Similarly, although not quantifiable, improvements in overall customer satisfaction, power quality, safety are important considerations. We have also considered the benefits of our advanced grid investments over the longer term, as they will provide the flexibility that will allow the Company to respond to evolving customer expectations and technology advancements in the future.

Q. WERE YOUR RESEARCH FINDINGS USED TO DEVELOP THE COMPANY'S ADVANCED GRID STRATEGY IN ANY OTHER RESPECT?

A. Yes. Results of our research efforts were also used to inform our customer education and communications plan related to the implementation of advanced metering. Our education plan and outreach efforts are discussed further in Section V.C of my testimony.

Q. WERE CUSTOMER NEEDS THE ONLY FACTORS IN THE COMPANY'S DEVELOPMENT OF THE AGIS STRATEGY?

A. No. We also leveraged our internal expertise with respect to utility distribution systems and the Company's systems, in particular, to determine the needs of our distribution grid. We have also looked to broader industry information, which reflects the degree to which advanced grid technology has matured in recent years and demonstrates a clear trend toward its adoption.

C. System Needs

Q. ARE THERE PARTICULAR DISTRIBUTION SYSTEM NEEDS THAT FURTHER CONTRIBUTED TO THE NEED FOR AN ADVANCED GRID INITIATIVE?

A. Yes. Our NSPM distribution grid has several intersectional needs that have driven the development of the AGIS initiative. Like other electric utilities, our current distribution system is based on aging technologies. While appropriate when implemented, multiple components of the distribution system either must be replaced in the near term or they have limited capabilities that simply do not meet the needs and expectations for the system going forward. Further, additional components that integrate with ADMS and advanced meters are necessary to better manage and shorten outages, and to maximize the voltage management on our system. I provide an overview of these needs in this section of my testimony.

Q. WHAT SPECIFIC SYSTEM REQUIREMENTS PROMPTED THE NEED FOR GRID MODERNIZATION?

A. Grid modernization is an issue facing most utilities in Minnesota in varying respects, as evidenced by the Commission's specific proceeding examining the issue. NSPM is no different. The current one-way flow of information on our system means that beyond the distribution substation, the Company has little insight into the workings of the distribution system as it relates to outages or voltage levels experienced by the customer. As further outlined by Company witness Ms. Bloch, the current system is not capable of the two-way communication necessary to identify outages, gather and manage customer data more frequently, support increasing levels of DER, nor optimize voltage levels and identify faults in an automated, responsive, and proactive way.

Q. CAN YOU PROVIDE SOME ADDITIONAL EXAMPLES OF THE EXISTING LIMITATIONS YOU HAVE IDENTIFIED WITH THE COMPANY'S CURRENT METERS?

A. Yes. Without two-way communications, we have limited visibility into what is happening with a particular meter. This means we are missing the ability to provide either timely energy usage data to our customers, or recommendations about how they use their energy. We cannot always identify meter tampering, the shift of a premise to a different user, or other issues without physically visiting a meter. And, as previously noted, we have limited information about the existence of an outage and the status of a restoration – because our systems do not report when an outage occurs.

Q. HOW DOES THE CURRENT SYSTEM LIMIT THE COMPANY'S ABILITY TO IDENTIFY AND RESPOND TO OUTAGES?

A. Because the Company does not have visibility into the system beyond the substation level, the Company primarily gains outage information through customer calling about an outage at the home or business. The Company then analyzes the locations of the outage calls to determine what aspect of the distribution system lost power. It can be frustrating for a customer to have to identify an outage, rather than relying on its electric utility to do so. Ultimately to obtain information regarding outages and storm damaged facilities, the Company must send workers into the field to gather this information manually.

In addition, this lack of two-way communication and fault location capabilities limits the Company's ability to isolate faults and restore power to customers in an automated fashion where possible. These are advanced grid capabilities that FLISR will provide.

Q. DOES THE COMPANY'S CURRENT COMMUNICATIONS NETWORK LIMIT THE CAPABILITIES OF ITS EXISTING DISTRIBUTION SYSTEM?

A. Yes. The Company's current communication network is the Wide Area Network (WAN). The WAN provides high-speed, two-way communications capabilities and connectivity in a secure and reliable manner between Xcel Energy's core data centers and its service centers, generating stations, and substations. However, the WAN is not able to provide communications to support AMI meters or facilitate the operation of FLISR and IVVO. Leveraging the existing WAN, the primary function of FAN mesh network is to enable the communications between the intelligent devices deployed across the distribution system – up to and including meters at customers' homes and businesses. These advanced applications cannot be supported with the Company's current communication network.

Further, the WAN does not allow the Company to monitor and manage impacts of distributed energy resources (for example, solar resources) and other events occurring on the grid in a timely manner. The FAN, however, provides capabilities to monitor and assess impacts closer to the field devices themselves, enhancing the Company's ability to integrate more distributed resources

Q. DOES THE LIMITED AMOUNT OF INSIGHT INTO THE DISTRIBUTION SYSTEM IMPACT OTHER OPERATIONS?

A. Yes. The limited visibility and control of devices on the system also translates to a lack of ability to efficiently manage the voltage level on the system. The current system design does not inform the Company if the end-use customer is outside of an allowable voltage range; therefore, like the need for outage notifications from customers noted above, the Company can only obtain information on voltage variation if the customer calls to complain about conditions that indicate their voltage may be outside of the range. Additionally, lacking the ability to efficiently manage and optimize voltage levels diminishes our DSM options. The addition of the IVVO component of ADMS will address these limitations.

Q. ARE THERE CURRENT SYSTEM LIMITATIONS THAT AFFECT THE INTEGRATION OF DER ON THE COMPANY'S SYSTEM?

A. Yes. Currently, Xcel Energy does not have the granularity necessary to dynamically forecast the impact of distributed resources, such as private solar and batteries, on the system and our customers. Additionally, the system was designed for known system loads, and while we are able to host significant DER on most of the grid, limitations exist – especially when larger quantities of distributed generation are proposed.

Q. WILL INVESTMENTS IN AGIS IMPROVE THE INTEGRATION OF DERS ON THE COMPANY'S SYSTEM?

A. Yes. Investments in AMI, ADMS, IVVO, and the FAN will improve DER integration and enable the Company to better manage DER. The investment in these AGIS components will provide us the tools to understand the details of how and when customers use and produce energy. We can then use this information to better analyze and operate the local distribution system.

Q. HOW WILL AMI (AND ADMS) ENABLE GREATER DISTRIBUTED GENERATION INTEGRATION?

A. AMI will provide the detailed data on the flow of energy to and from customers, as well as voltage, current, and power quality data from the AMI meter to ADMS. With this information, as Ms. Bloch discusses, system operators will be able to facilitate the integration of greater amounts of distributed generation on to the system.

Additionally, with this data, we will be able to identify any voltage problems caused by solar DERs or a potential transformer overload due to DERs. Coupled with IVVO capabilities, this will allow the Company to enable distributed resources while at the same time maintaining reliability and power quality for each of our customers.

Further, AMI will enable the creation of more accurate load profiles which are used by ADMS to create better system models for planning and operational purposes.

Finally, AMI meters have bi-directional capabilities that can be utilized by our DER net metered customers, without the need for installation of a different meter, which is currently the case.

Q. HOW WILL IVVO INCREASE THE SYSTEM'S ABILITY TO HOST DER?

A. As DER penetration increases, the Company will need to manage the DER's influence on voltage through distribution system voltage control. IVVO will enable the Company to optimize voltage across a feeder where DER is present, and potentially high-voltage situations may occur as a result of DER injection. In this way, IVVO will support the ability for additional distributed resources to be hosted on the system.

Q. HOW WILL THE FAN INCREASE THE SYSTEM'S ABILITY TO HOST DER?

A. As the underlying network that supports the two-way communications of the advanced grid, the FAN supports the AMI meter and IVVO capabilities described above that enable additional DER on the system.

Q. ARE THERE ADDITIONAL CIRCUMSTANCES THAT ARE DRIVING THE NEED FOR GRID MODERNIZATION?

A. Yes. On top of the considerations above, we are facing aging systems even for their current functionality. For example, our Automated Meter Reading (AMR) contract is coming to an end in at the end of 2025, and we have a number of AMR meters that are nearing the end of their useful lives in the early 2020s. All of these considerations factor into the need for a more advanced, responsive grid.

Q. CAN YOU OUTLINE THE AMR CONTRACT EXPIRATION THAT RESULTS IN THE NEED TO REPLACE AMR IN THE NEAR TERM?

A. Yes. Our present AMR system has delivered substantial value for customers since it was implemented in the mid-1990s. Our vendor has announced that they will no longer be manufacturing replacement parts for this proprietary system past 2022. Further, our current AMR meter reading contract expires in 2025 with the possibility to extend this contract for one additional year at a substantial cost. Company witness Mr. Cardenas provides additional details on our current AMR contract in his testimony.

Q. IS THIS CONSISTENT WITH THE STATE OF AMR TECHNOLOGY ACROSS THE UNITED STATES?

A. Yes, very much so. At the same time our AMR technology is reaching the end of its life, the AMI technology and market have matured, which has driven many other vendors to also discontinue support of AMR. According to the U.S. Energy Information Administration, AMI adoption surpassed AMR in 2012, and the gap has widened as AMR rollouts have remained flat.[26] The state of the industry, combined with the state of our existing technology, requires us to make choices now about how to move forward with our metering options.

Q. WHAT DO YOU CONCLUDE WITH RESPECT TO THE CURRENT STATE OF THE COMPANY'S DISTRIBUTION GRID?

A. The technology available to operate electric grids has significantly advanced, at the same time our customers' expectations have increased substantially. It is now possible to implement equipment and systems that will provide the Company with real-time visibility into the grid that we currently lack. While the Company has implemented some of these technologies, it is time to expand the advancing technology to our entire electric grid. As I discuss in the next section of my testimony, the Company's AGIS initiative comprises the Company's strategy for meeting these needs in the years ahead.

D. Commission Policy and Stakeholder Input

Q. HOW HAVE COMMISSION POLICY AND STAKEHOLDER INPUT INFORMED DEVELOPMENT OF THE COMPANY'S GRID STRATEGY?

[26] Source: https://www.eia.gov/todayinenergy/detail.php?id=34012. Ms. Block provides additional discussion in her testimony.

A. Since 2015, the Company has provided information and engaged in extensive stakeholder processes around grid modernization, DER hosting capacity, and integrated distribution system planning. Additionally, the Company's residential TOU pilot was informed by and incorporated stakeholder input in that proceeding. Further, the docket initiated to identify performance metrics and potential incentives for the Company's electric utility operations included a robust stakeholder process. Reporting on some of the metrics identified will be enabled or enhanced through the advanced grid capabilities resulting from AGIS implementation. I discuss each of these topics below, highlighting the Commission policies, goals, and stakeholder input that the Company has considered in developing our AGIS implementation strategy.

Q. PLEASE DESCRIBE THE COMMISSION POLICIES AND GOALS AROUND GRID MODERNIZATION AND INTEGRATED DISTRIBUTION SYSTEM PLANNING.

A. The Company filed its first grid modernization report in 2015 in compliance with a new Minnesota statute.[27] In March 2016, the Commission released the *Staff Report on Grid Modernization* (Staff Report). The Staff Report outlined a phased process and potential options for the Commission to pursue in its investigation into the state's grid modernization efforts. At that time, the Commission supported distribution system planning as the most reasonable and actionable way for the Commission to assist in the forthcoming grid evolutions. The Commission agreed with the creation of a comprehensive, coordinated, transparent, and integrated distribution system planning process in Minnesota and agreed with the staff proposed principles to guide further work as follows:

[27] Minn. Stat. § 216B.2425, subds. 2(e) and 8.

- Maintain and enhance the safety, security, reliability, and resilience of the electricity grid at fair and reasonable costs, consistent with the state's energy policies;
- Enable greater customer engagement, empowerment, and options for energy services;
- Move toward the creation of efficient, cost-effective, accessible grid platforms for new products, new services, and opportunities for adoption of new distributed technologies; and
- Ensure optimized utilization of electricity grid assets and resources to minimize total system costs.

Q. WHAT STAKEHOLDER PROCESSES INFORMED THE DEVELOPMENT OF GRID MODERNIZATION PLANS AND THE IDP PROCESS?

A. The Commission conducted a comprehensive stakeholder process that included written comments and workshops, where it solicited input and explored many topic areas and aspects of grid modernization and distribution system planning. After issuing the Staff Report, the Commission conducted a workshop and initiated a comments and replies process seeking to understand how utilities currently plan their systems, the status of current-year utility plans, and recommendations for improvements to present planning practices.

The Commission then established individual utility IDP dockets,[28] where Staff and the utilities worked on proposed IDP filing requirements, with a comment and reply period for stakeholder input. From this process, the Commission determined final IDP requirements for Xcel Energy.[29] In

[28] Xcel Energy's IDP filing requirements were developed in Docket No. E002/CI-18-251.
[29] See the Commission's August 30, 2018 Order in Docket No. E002/CI-18-251.

addition to the grid modernization principles listed above, the final IDP Planning Objectives include:

- Provide the Commission with the information necessary to understand Xcel Energy's short-term and long-term distribution system plans, the costs and benefits of specific investments, and a comprehensive analysis of ratepayer cost and value.

The Company's 2019 IDP is being filed concurrently with this rate case. As part of the annual IDP process, the Company engages with stakeholders to share at a minimum, its budgets and investment plans, DER and load forecasts, and its 5-year action plan. The Company additional held stakeholder workshops leading up to its 2019 IDP to discuss its non-wires alternatives analysis and its advanced grid cost-benefit analysis CBA framework.

Q. HOW DOES THE COMPANY'S AGIS STRATEGY INCORPORATE THE POLICIES, GOALS, OBJECTIVES, AND STAKEHOLDER INPUT DESCRIBED ABOVE?

A. Our AGIS implementation strategy and project components are closely tied to what we have heard from the Commission and stakeholders through the grid modernization and IDP efforts and as such, considers the inherent Planning Objectives, filing requirements, and stakeholder input. For example, we have added an IVVO component to our proposal, which is a direct result of the feedback we received in response to our recent grid modernization reports. Our AGIS testimony in this case addresses the Planning Objectives described above, and provides the necessary information to demonstrate the costs and operational and customer benefits of each AGIS component, as well as the long-term value of advanced grid capabilities in supporting Commission policies and objectives including those related to carbon reductions and additional DER integration.

Q. WHAT IS THE COMPANY'S UNDERSTANDING OF COMMISSION POLICIES AND GOALS AROUND HOSTING CAPACITY AND DER INTEGRATION.

A. As articulated in the IDP Planning Objectives noted above, we understand that distribution grid planning should move toward the creation of efficient, cost-effective, accessible grid platforms for new products, new services, *and opportunities for adoption of new distributed technologies*. The statute noted above also requires Xcel Energy to file hosting capacity reports in conjunction with its grid modernization reports (now submitted with the annual IDP filings). In the Company's first hosting capacity report,[30] we noted that we recognize hosting capacity as a key element in the future of distribution system planning and anticipate advanced grid capabilities will have the potential to further enable DER integration. As such, we continue to engage with stakeholders on hosting capacity and integration of increased DER.

Q. HOW DOES THE COMPANY'S AGIS STRATEGY INCORPORATE THE COMMISSION POLICY AND STAKEHOLDER INPUT AROUND OPPORTUNITIES FOR ADOPTION OF NEW DISTRIBUTED TECHNOLOGIES?

A. Our AGIS implementation strategy is designed to support further DER integration on our system, specifically through ADMS coupled with the detailed data provided by AMI meters and the IVVO voltage control capabilities (all supported through the two-way communications enabled by the FAN). As I discussed earlier in Section C, these components will provide the Company the visibility needed to understand and integrate additional DER

[30] See the Distribution System Study filed December 1, 2016, in Docket No. E002/M-15-962.

on a feeder and tools to manage any voltage issues once DER (like solar generation) is installed on a feeder. In this way AGIS supports further DER integration on our system.

Q. WHAT IS THE COMPANY'S UNDERSTANDING OF COMMISSION POLICIES AND GOALS AROUND TOU RATES?

A. We believe the Commissions policies around TOU rates are partially articulated in several of the IDP Planning Objectives, including: *Enable greater customer engagement, empowerment, and options for energy services.* In addition, TOU rates support policy objectives on carbon reduction and goals to reduce peak demand on the system. As articulated in our TOU pilot proceeding, the goals of the pilot program are to study adequate price signals to reduce peak demand, identify effective customer engagement strategies, understand customer impacts by segment, and support demand response goals.

Q. WHAT STAKEHOLDER PROCESSES INFORMED THE DEVELOPMENT OF THE COMPANY'S TOU PILOT PROGRAM?

A. The Company met with key stakeholders to gather feedback and present preliminary plans in advance of its final residential TOU pilot proposal. Xcel Energy established a framework and identified preliminary objectives as the basis of a stakeholder process through which the Company received input on the design of the pilot and made further refinements. Stakeholder input informed the features of the Company's pilot, including the criteria for participation, the design of the customer experience, the desired learnings from the study, and other important elements that shaped the Company's approach.

Q. HOW DOES THE COMPANY'S AGIS STRATEGY ADDRESS THE COMMISSION POLICIES AND STAKEHOLDER INPUT AROUND TOU RATES?

A. The pilot will implement new residential TOU rates in two geographic areas, providing participants with increased energy usage information, education, and support to encourage shifting energy usage to daily periods when the system is experiencing low load conditions. TOU rates for our residential customers are enabled through deployment of both AMI meters and the necessary FAN communications in the participating communities. The limited deployment of these AGIS components in connection with the TOU pilot began in 2019.

Q. WHAT ARE THE COMMISSION'S STATED GOALS WITH RESPECT TO PERFORMANCE METRICS AND POTENTIAL INCENTIVES?

A. In the docket initiated to identify performance metrics and potential incentives for the Company's electric utility operations, the Commission initially set forth the following regulatory policy goals in its January 8, 2019 Order,[31] to promote the public interest by ensuring:

- Environmental protection;
- Adequate, efficient, and reasonable service;
- Reasonable rates; and
- Opportunity for utilities to earn a reasonable return.

The outcomes identified in the order were: affordability; reliability, including both customer and system-wide perspectives; customer service quality, including satisfaction, engagement and empowerment; environmental performance, including carbon reductions and beneficial electrification; and cost-effective alignment of generation and load, including demand response.

[31] See Docket No. E002/CI-17-401.

Q. WHAT STAKEHOLDER PROCESSES INFORMED THE DEVELOPMENT OF THE PERFORMANCE METRICS?

A. The Commission conducted a robust stakeholder process, including two meetings, with a goal of engaging stakeholders in discussing potential metric topics. The Commission also accepted comments and replies seeking input on proposed metrics, measurement of metrics, alignment with outcomes, goals, and principles established in the January order. After determining the metrics in a September 2019 Order, the Commission also required the Company to continue to collaborate with interested parties proposals for calculating, verifying, and reporting each of the metrics.

Q. CAN YOU HIGHLIGHT SOME OF THE STAKEHOLDER INPUT ON DEVELOPMENT OF THE PERFORMANCE METRICS?

A. Yes. The Department of Commerce (Department) indicated in its June 4, 2019 Reply Comments that its policy objectives largely align with the goals and objectives set forth by the Commission.[32] Additionally, the Department expressed interests in: decarbonization and beneficial electrification; rate stability; and responding to customer desires.

Q. WHAT ARE THE STATED OUTCOMES AND METRICS RESULTING FROM THIS PROCEEDING?

A. In its Order dated September, 18, 2019, the Commission set forth metrics in the following categories:

- Environmental performance, including carbon reductions and beneficial electrification;

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[32] See Department of Commerce Reply Comments, June 4, 2019, Docket No E002/CI-17-401.

- Reliability, including both customer and system-wide perspectives;
- Affordability;
- Customer service quality, including satisfaction, engagement, and empowerment; and
- Cost effective alignment of generation and load, including demand response.

Q. HOW DOES AGIS IMPLEMENTATION SUPPORT THE COMMISSION'S POLICY GOALS AND INCORPORATE STAKEHOLDER FEEDBACK DESCRIBED ABOVE?

A. Among other things, the Company's AGIS proposal provides foundational capabilities to develop and offer flexible, advanced rates and new products and services that we expect will contribute to improved environmental performance, increased customer satisfaction, engagement and empowerment, and cost-effective alignment of generation and load. It will also improve our overall reliability and the customer reliability experience – and improve the efficiency of the system, which may also result in energy savings for customers. For example, while the Commission established desired goals, outcomes, and principles for the metric design in its January 2019 Order (described above), in later determining specific metrics (September 2019 Order), the Commission recognized that additional work and technology infrastructure, particularly the installation of AMI, may be needed before certain reliability metrics could be widely implemented. The metrics identified in the Commission's Order include MAIFI, locational reliability, and power quality – all of which would enabled by our AGIS proposal in this case.

Q. WHAT OTHER COMMISSION AND STAKEHOLDER INPUT INFLUENCED THE COMPANY'S AGIS PROPOSAL?

A. In May 2019, the Company held a stakeholder workshop focused on the cost-benefit analysis framework for its advanced grid investments. We have incorporated the key aspects of the feedback we received from stakeholders, as follows:

- Clearly articulate the assumptions and the level of certainty/ uncertainty behind them;
- Articulate the dependencies (or non-) between different advanced grid investments;
- Consider framing in concert with the performance metrics proceeding outcomes;
- Prioritize investments – i.e., what comes after the foundational components;
- Demonstrate innovation and creativity around the customer value proposition; and,
- Differentiate between easy-to-quantify and hard-to-quantify benefits for customers.

In addition, the Commission's September 27, 2019 Order in our most recent TCR Rider proceeding[33] provided additional guidance for the cost-benefit analyses for any future requests for cost recovery for AGIS investments. We have addressed these requirements in our CBAs presented with this filing.

Q. CAN YOU SUMMARIZE HOW COMMISSION POLICY AND STAKEHOLDER INPUT INFORMED DEVELOPMENT OF THE COMPANY'S GRID STRATEGY?

A. Yes. These topics have been a particular focus not only for the Company but for the Commission and stakeholders in Minnesota. The Commission policies

[33] Docket No. E002/M-17-797.

and goals developed through these proceedings focus on the future of distribution systems and how advanced grid capabilities will support Commission and state policy goals, including carbon reduction and DER integration, and provide benefits for customers.

V. AGIS COMPONENTS AND IMPLEMENTATION STRATEGY

A. AGIS Component Selection

Q. IN LIGHT OF THESE DRIVERS, PLEASE SUMMARIZE THE COMPANY'S VISION FOR THE FUTURE OF THE ELECTRIC DISTRIBUTION GRID.

A. The Company envisions moving from the predominantly one-way system that currently exists to an integrated system of centralized and decentralized energy resources that are connected and optimized through communications systems that share information from across the distribution grid. The advanced grid will leverage automation, real-time monitoring, and communication to locate and isolate disruptions in the system and improve safety, efficiency, and reliability of the system. The advanced grid will enable greater customer choice by allowing customers to adopt new products, services, technologies, and applications, including access to timely energy usage data and more options for managing their usage. Additionally, the advanced grid will provide timely and accurate information that will allow the Company to manage the increasing amount of DER entering our system. This will be accomplished through the Company's AGIS initiative, which consists of multiple programs that work together to improve and update our distribution system.

Q. CAN YOU PROVIDE AN OVERVIEW OF THE COMPONENTS OF THE AGIS INITIATIVE IN MORE DETAIL?

A. Yes. The components of our AGIS plan include:

- *Advanced Distribution Management System (ADMS)* provides the foundational system for operational hardware and software applications. It acts as a centralized decision support system that assists control room personnel, field operating personnel, and engineers with the monitoring, control and optimization of the electric distribution grid. In turn, ADMS provides greater visibility into an increasingly complex electric distribution grid and operating advanced grid applications. The result is near real-time calculations of the state of the network, including factors such as voltages, currents, real and reactive power, amps, voltage drops, and losses.

  ADMS was initially certified by the Commission in 2016 as part of our 2015 Biennial Grid Modernization Report,[34] and the first year of ADMS costs have been approved for recovery under our TCR Rider.[35] Likewise, ADMS would be necessary regardless of other components of AGIS due to the need for a modern, integrated, two-way distribution system and the increasing use of distributed energy resources (DERs). ADMS also includes the Geographic Information System (GIS), which is a foundational data repository that provides location and specification information for all of the physical assets that make up the distribution system. ADMS uses this information to maintain the as-operated electrical model and advanced applications.

[34] See Docket No. E002/M-15-962.
[35] See Docket No. E002/M-17-797.

- *Advanced Meter Infrastructure (AMI)* is a system of advanced meters, communication networks, and data processing and management systems that enables secure two-way communication between Xcel Energy's business and operational data systems and customer meters. AMI provides a central source of information that is shared through the communications network with many components of an intelligent grid design. AMI enables near real-time monitoring and communication between the meter and ADMS about, among other things, energy usage and outages. The AMI meter itself functions as a sensor that, along with other intelligent field devices, will provide the Company with the necessary information to continually monitor and make the necessary adjustments to the system. AMI is a necessary first step to better customer data, enhanced customer service, and the addition of applications and services for future energy management and optionality.
- *Field Area Network (FAN)* is the communications network that will enable communications between the existing communications infrastructure at the Company's substations, ADMS, meters, and the new intelligent field devices associated with advanced grid applications. With its embedded communication module, the AMI meter itself is a part of the FAN communication network.
- *Fault Location Isolation and Service Restoration (FLISR)* is also an additional component of ADMS. FLISR is wholly different from IVVO, however, in that it involves software and automated switching devices that locate and isolate faults, thereby reducing the frequency and duration of customer outages. Specifically, these automated switching devices detect feeder mainline faults, isolate the fault by opening section switches, and

restore power to unfaulted sections by closing tie switches to adjacent feeders as necessary.

- *Integrated Volt-VAr Optimization (IVVO)* is an application that is built onto ADMS. IVVO automates and optimizes the operation of the distribution voltage regulating and VAr control devices, to in turn reduce electrical losses, electrical demand, and energy consumption. In addition to automating and improving voltage management and power quality, IVVO provides increased distribution system capacity to host DER.

Q. WHY DID THE COMPANY OBTAIN APPROVAL FOR ADMS BEFORE SETTLING ON OTHER AGIS COMPONENTS?

A. Implementation of ADMS is the foundation for all other advanced grid components. ADMS will enable the Company to implement advanced grid technologies necessary in the near term, and will allow the Company to take advantage of future capabilities that will result from rapid advances in smart grid technologies. Specifically, ADMS is a necessary upgrade to our distribution system that will utilize an enhanced distribution grid model to consolidate substations, feeders, taps, and services into a single user interface that more accurately represents the entire distribution grid. GIS is an integral part of ADMS, and ADMS will maintain the as-operated GIS electrical model and advanced applications in near real-time. This model will provide the Company with greater visibility into the distribution system and provide information about the system at a more granular level. ADMS will allow the Company to monitor and control power flow from substations to the edge of the grid. The improved capability over today's systems will enable multiple grid performance objectives to be realized over the entire grid.

Q. WHY IS THE COMPANY PROPOSING TO MOVE FROM AMR TO AMI TECHNOLOGY?

A. As previously noted, there are several reasons. First, we needed to explore options to address the expiration of the Cellnet contract and the pending obsolescence of our AMR meters. We explored multiple metering options, as described by Company witness Ms. Bloch. Operationally, AMR meters have limited functionality and are not considered modern technology. In contrast, advanced meters provide substantial near real-time data that can be used to improve the Company's ability to monitor, operate, and maintain the distribution grid. Advanced meters can be used to verify power outages and service restoration. Improved reliability monitoring can lead to improved outage response, proper protection system analysis and ultimately reduce or eliminate outages. Advanced meters can also provide improved voltage monitoring and management, support better load studies and analysis resulting in improved planning and design, and be used to support additional systems such as an ADMS with applications like IVVO that will promote energy efficiency and peak shaving and FLISR that will allow us to locate, isolate, and remedy faults much faster than our current system options. Additionally, as described in our past TOU pilot filings, advanced meters will also unlock the potential for new rate designs that cannot be supported by the Company's current AMR meters. The benefits of AMI meters are discussed in more detail in the Direct Testimony of Ms. Bloch.

Q. WHY IS THE COMPANY PROPOSING TO IMPLEMENT FLISR TECHNOLOGY?

A. The Company is implementing FLISR because it will continue to improve reliability for our customers. FLISR is a technology that, in most cases, will allow the Company to understand when a fault event occurred and allow the

Company to reconfigure the system more quickly than we are able to today. This application reduces the number of customers that experience an outage for a prolonged period of time in the event of a fault.

Q. WHY IS THE COMPANY PROPOSING TO IMPLEMENT IVVO TECHNOLOGY?

A. The current distribution system has the capability to monitor voltages at the substation but does not have the capability to allow the Company to constantly monitor voltage levels throughout its feeders to the customer premise. As a result, the Company must often operate the system at a higher voltage than what would otherwise be required to ensure the appropriate voltage at the end of a long feeder. The Company's proposed IVVO application will allow voltage to be monitored along the entire length of the feeder and at selected end points (rather than only at the substation). This insight into the voltage levels will allow the Company to utilize lower voltages across the entire feeder at most times. This will result in reduction in distribution electrical losses; reduction in electrical demand; reduction in energy consumption; and increased capacity to host DER. Fundamentally, the IVVO is a demand side management (DSM) tool that controls voltage without requiring behavioral changes from customers.

Q. WHY IS THE COMPANY PROPOSING TO IMPLEMENT THE FAN?

A. The integrated components of our AGIS initiative require an integrated, secure communication system that involves the FAN and the advanced meters. The mesh network allows the advanced meter to communicate its measurement data, power status, voltage current, usage history, and peak demand information back to the Company. Additionally, the FAN integrates with IVVO and FLISR because the advanced meters voltage information and service interruption information is communicated to the Company via the FAN.

Below I provide an overview of the individual components of the AGIS initiative.

1. AMI

Q. WHAT ARE THE UNDERLYING COMPONENTS OF AMI, AT A HIGH LEVEL?

A. The AMI infrastructure itself consists of new meters and associated hardware and software. The components of the advanced meter include: (1) the meter itself (responsible for measurements and storage of interval energy consumption and demand data); (2) an embedded two-way radio frequency communication module (responsible for transmitting measured data and event data available to backend applications); (3) embedded Distributed Intelligence capabilities; and (4) an internal service switch (to support remote connection and disconnection of service).

The AMI meters measure, store, and transmit meter data, including energy usage data from customer locations. The advanced meters can also measure values such as voltage, current, frequency. Additionally, these meters detect outage and restoration events, detect tampering and energy theft events, and perform meter diagnostics.

Q. WHAT IS THE DISTRIBUTED INTELLIGENCE COMPONENT OF THE ADVANCED METER?

A. Distributed Intelligence is an operating system that allows for the installation of a wide-range of potential applications – including grid-facing applications, or those the utility operates and with which the customer interfaces. These applications will have the potential to enhance the customer experience not only by improving the energy usage information and control that a customer has but by introducing new ways to manage the grid.

Today, the potential for applications is broad and we're working with our meter vendor to better define the long-term vision for how the Distributed Intelligence platform will be deployed. Potential use cases for these new applications include:

- Virtual Energy Audits: A remote assessment of the customer's energy usage conducted and compared to an expected baseline with recommendations on how to improve performance;
- Virtual Sub-Metering: The replacement of on-site metering equipment for end-use technologies such as electric vehicles that are on a separate electric rate;
- Smart Thermostat Support: The meter can communicate with the customer's smart thermostat to optimize the operation of the air conditioner; and
- Green Notifications: Messaging provided to the customer that notifies them of periods of high renewable energy on the system that will allow them to cycle their energy usage to align with cleaner energy.

The contract with our meter vendor includes the license costs for four applications. Working with our meter vendor we will identify the appropriate applications for mass deployment. These applications may be customer-facing, similar to those described above, or grid-facing, meaning Xcel Energy interacts with the applications. For these customer-facing applications, we envision engaging the customer through the portal currently called MyAccount. Applications may also be made available as customers participate in new products and services such as our energy efficiency offerings.

Q. HOW IS THE COMPANY PROCURING AND INSTALLING THE ADVANCED METERS?

A. Xcel Energy issued a Request for Proposal (RFP) in March 2018 to select a meter vendor that could provide an AMI meter, project management, and installation services. The Company selected Itron, and a contract was executed on September 1, 2019. Itron was selected for a number of reasons, including that they provided the lowest cost and best overall value for an offering that included distributed intelligence technology and met Xcel Energy's deployment schedule. Ms. Bloch describes the AMI RFP and selection process in her testimony. By selecting Itron, we also ensure a single vendor solution, as Itron was previously selected to provide the FAN network and AMI software, as discussed by Mr. Harkness.

The Company and Itron are committed to working together during AMI implementation to ensure our customers receive excellent service, and will provide coordinated support and address all customer inquiries and any issues that may arise. Mr. Cardenas discusses these plans, as well as customer service tracking and reporting, in his testimony.

Q. WHAT WORK IS REQUIRED TO IMPLEMENT AMI METERS?

A. We must install the AMI meter hardware, as well as software necessary to integrate the "smart meters" across the NSP system. This requires meter development and installation in coordination with our meter contractor, Itron.

Additionally, as Company witness Mr. Harkness describes, new metering technology requires integration with multiple existing Company systems, as well as security protections. This work is complex and requires multiple years of planning, design, and implementation, such that we cannot wait until our AMR technology is no longer supported to begin the process. Further, even as it stands, we are behind our industry peers in taking steps to move away from AMR and to AMI technology.

Once meters and associated software and hardware are implemented, additional work is needed to build the digital platforms for our customers.

Our work around meter installation and use of the associated capabilities also requires customer education, outreach, and support, as I describe in Section V.C. of my testimony.

Q. WHAT IS THE COMPANY'S CURRENT PLAN FOR AMI IMPLEMENTATION IN CONNECTION WITH THE TOU PILOT?

A. We have begun the limited AMI deployment for our TOU pilot. Installation of AMI in connection with the pilot began in 2019 and will be completed during the first quarter of 2020, with TOU pilot launch scheduled for April 2020.

Q. WHAT IS THE COMPANY'S PLAN FOR FULL AMI IMPLEMENTATION FOR ALL CUSTOMERS?

A. Our present AMI plan for Minnesota is to complete the installation of AMI meters in 2024, in anticipation of the end of the support for AMR meters and the end of our present service agreement. Company witnesses Ms. Bloch, Mr.

Harkness, and Mr. Cardenas describe the implementation plan in more detail. I note that our TOU pilot is not intended to validate our plan for full roll-out of AMI to all customers. Rather, the TOU pilot is intended to study the TOU rate and its impacts specifically, particularly with respect to the more timely information and advanced rate design options provided by advanced meters. In other words, it is not necessary for us to conclude the TOU pilot prior to full implementation of AMI.

2. FAN

Q. WHY IS A FAN THE RIGHT TYPE OF COMMUNICATIONS NETWORK FOR THE COMPANY AND ITS CUSTOMERS?

A. The FAN is a private, Company-owned network that will securely and reliably address the need for increased communication capacity that arises from distribution grid advancements. The advantages of the FAN over other alternatives include that a Company-owned network solution enhances security against cyber threats by reducing the use of third party networks, the use of public networks (*i.e.*, cellular), and the reliance on external entities for communications support. Further, developing the FAN as an internal private network allows us to implement our cyber security measures into the design at all levels. In addition, the private network solution allows NSPM to utilize the network's full bandwidth and all capacity is dedicated to the Company's use, which is particularly critical during emergency and outage situations. The FAN also integrates with the communication systems used for current components of our distribution system. Overall, the FAN provides for greater security and efficiency and avoids requiring the Company to incur monthly usage fees that would otherwise be paid to private vendors.

Q. IS OUR SELECTION OF THE FAN APPROACH CONSISTENT WITH WHAT OTHER UTILITIES HAVE DONE?

A. Yes. Our proposed FAN is consistent with developments within the electric utility industry, and current industry standards that have been adopted by vendors, organizations, and other electric utility companies. We actively participate with industry standards organizations and alliances – such as the Electric Power Research Institute (EPRI) and the Institute of Electrical and Electronics Engineers (IEEE) – to ensure that our requirements and assumptions are aligned with the standards and products being deployed throughout the industry. Mr. Harkness discusses this further in his testimony.

Q. WHAT ARE THE UNDERLYING COMPONENTS OF THE FAN, AT A HIGH LEVEL?

A. The FAN will consist of two separate wireless technologies: (a) a lower-speed Wireless Smart Utility Network (WiSUN) mesh network; and (b) a high-speed point-to-multipoint Worldwide Interoperability for Microwave Access (WiMAX) network.

The WiSUN component transfers information between meters and transmits data over the mesh network to an access point device that transitions the data from the mesh network to the WiMAX tier of the FAN or in some cases directly to the Company's Wide Area Network (WAN) currently in place. I also note that in addition to their metering function, the advanced meters will have embedded communication modules that will allow the devices to communicate as part of the WiSUN network.

Q. CAN YOU SUMMARIZE THE WORK AND TIMELINES FOR FAN IMPLEMENTATION?

A. Deployment of the FAN occurs slightly ahead of AMI installation to provide the necessary communications for advanced meter operations. We have already begun the limited deployment in connection with the TOU pilot, which will be completed in the first quarter of 2020. We anticipate full FAN deployment will begin in 2020 to ensure network readiness when AMI meters and other devices are deployed. Mr. Harkness and Ms. Bloch provide details related to the FAN device installation.

During the installation of FAN equipment, Business Systems will work concurrently on integration of the FAN with the Company's other systems. The IT integration work is described in the testimony of Mr. Harkness. To support the TOU pilot, Business Systems has begun to deploy WiMAX base stations in three substations, and the equipment necessary to enable the functioning of those base stations. Business Systems has also conducted field coverage studies to ensure the FAN will provide adequate coverage for both the TOU pilot as well as full deployment of meters and other devices in those areas. Work related to full FAN deployment will continue in 2020, and full FAN implementation is expected to be completed in 2024.

Q. ARE THERE OTHER BENEFITS OF IMPLEMENTING THE FAN?

A. Yes. Having a secure two-way communication network on the system provides for communications not only between ADMS and AMI, but it allows for communications between and among any other new intelligent field devices associated with advanced grid applications. Like ADMS, the FAN is a support network that enables other components of the AGIS initiative (AMI, IVVO, FLISR) to provide customer benefits. Company witness Mr. Harkness describes the strategy and costs for the FAN in more detail.

3. FLISR

Q. HOW WILL THE FLISR COMPONENT WORK WITHIN THE AGIS INITIATIVE?

A. Implementation of FLISR will enable automated capabilities to locate and isolate faults, thereby reducing the frequency and duration of customer outages. FLISR also results in cost savings by enabling the Company to more efficiently restore power with the use of fewer resources. While we currently have small-scale automation programs across our distribution system, those systems are becoming outdated and have limited ability to communicate with other components of our system. In contrast, FLISR will be fully integrated with ADMS and will be able to use the FAN network communications. Additionally, while the Company continually focuses on process improvements, these efforts around outage restoration and communications are likely to result in only limited incremental improvement in those areas. FLISR, on the other hand, will transform the process by which the Company is made aware of and responds to outages, as well as the customer experience related to outages and system reliability. Ms. Bloch discusses FLISR implementation and benefits further in her testimony.

Q. WHAT ARE THE COMPONENTS OF FLISR, AT A HIGH LEVEL?

A. There are four principal components of FLISR:

- Reclosers are pole-mounted reclosing and switching devices that have monitoring, communication, and control capabilities.
- Automated overhead switches are overhead remote switching devices that serve to isolate faults on the system.

- Automated switch cabinets are pad mounted switching devices that perform functions similar to the automated overhead switches but for underground feeders.
- Substation relays function primarily to monitor the status of the distribution system and initiate a command to open the breaker in the event of a fault on the system. These relays can also capture important fault information which will be sent to ADMS.

Q. CAN YOU SUMMARIZE THE WORK AND TIMELINES FOR FLISR IMPLEMENTATION?

A. In 2020, we plan limited installation of FLISR for testing purposes. FLISR will be deployed to a small area in conjunction with ADMS to validate capabilities. Following testing, we will begin FLISR roll-out using selected, targeted deployment to maximize benefits and reduce installation costs. The current FLISR project will cover 208 feeders benefiting approximately 350,000 customers by 2028. Ms. Bloch provides additional implementation details in her testimony.

Q. WHAT OTHER BENEFITS ARE PROVIDED THROUGH IMPLEMENTATION OF FLISR?

A. In addition to the improved system reliability and customer satisfaction and cost reductions discussed above, FLISR also provides benefits through increased visibility into the distribution systems. The ability to see system load in real-time and operate devices remotely has benefits for operating the system during our peak summer season and for construction purposes. This visibility also provides improved data for system planning purposes that, when combined with other system data, can enhance planning and design for the future. Ms. Bloch describes these benefits in more detail.

4. IVVO

Q. WHY IS THE COMPANY PROPOSING TO IMPLEMENT THE IVVO COMPONENT OF THE AGIS INITIATIVE?

A. IVVO serves to automate the optimization of distribution system voltage, providing capabilities that are not available on our current system. Managing the overall voltage profile of distribution system feeders provides benefits in reducing line losses, demand, and energy consumption, while ensuring that voltage levels are adequate for providing safe and reliable power to customers. Voltage management is becoming increasingly important because customers' energy consumption is more dynamic than ever, with on-site solar, batteries, electric vehicles, smart appliances, smart thermostats, and many more electronic devices. The voltage optimization capabilities of the advanced grid will enable not only improved power quality and cost savings attributed to the benefits noted above, but will also increase our ability to host distributed energy resources (DER).

Q. WHAT ARE THE COMPONENTS OF IVVO, AT A HIGH LEVEL?

A. There are four primary components of IVVO:

- Capacitors, a stock component used by the Company. We were able to use our existing equipment standards to support deployment.
- Secondary static VAr compensators (SVC) are a relatively new technology introduced to Xcel Energy's distribution system, and have been successfully tested implemented in our Colorado service territory.

- Voltage and current sensing devices are essentially meters that will be installed on feeders to provide monitoring of voltage and current.
- Load tap changers (LTC) are installed at the substation and function as the local controller to raise or lower the voltage, to optimize voltage levels based on the demand of the demand of the substation transformer.

The Grid Edge Management System (GEMS) is a software application that will be used to communicate between ADMS and the SVCs to improve customer voltages and achieve full value of IVVO implementation.

Q. CAN YOU SUMMARIZE THE WORK AND TIMELINES FOR IVVO IMPLEMENTATION?

A. In 2021, we plan limited installation of IVVO for testing purposes on seven distribution feeders (one transformer area). This will occur as part of the installation of ADMS in that area. Following testing, we plan to begin full implementation of IVVO on 189 feeders serving approximately 224,000 customers. This work is anticipated to be completed in 2024.

Q. WOULD THE COMPANY BE ABLE TO ACHIEVE THE BENEFITS DESCRIBED ABOVE WITHOUT IMPLEMENTATION OF IVVO?

A. To some extent, yes. While there are alternative paths to achieve certain of the benefits described above, IVVO consolidates capabilities that will result in benefits in a variety of areas. For example, energy savings could be increased through DSM programs. These are voluntary programs that require customers to take affirmative actions in order to reduce their energy usage. In contrast, IVVO enables continuous energy savings on all feeders across our system where IVVO has been installed. Further, pursuing DSM programs exclusively without IVVO implementation, we would be forgoing increased DER hosting capacity. Company witness Ms. Bloch describes IVVO alternatives, selection process, and benefits in more detail.

B. Overall AGIS Implementation

Q. WHAT IS THE CURRENT STAGE OF THE AGIS INITIATIVE IMPLEMENTATION?

A. Overall, the deployment of AGIS has already begun with the implementation of the ADMS system and deployment of the FAN and AMI meters to support the time-of-use pilot. ADMS implementation is expected to be complete in the second quarter on 2020.

Q. CAN YOU PROVIDE A SUMMARY TIMELINE VIEW OF AGIS DEPLOYMENT?

A. Yes. Table 8 below provides an overview of the deployment timeline for the various components of the AGIS initiative.

Table 8

Deployment Timeline

Program	Implementation Timeline
ADMS	In-service 2020
AMI	Meter roll-out 2021-2024
FAN	Deployment 2021-2024 (preceding AMI deployment approximately six months)
FLISR	Limited testing 2020; Implementation 2020-2028
IVVO	Limited testing 2021; Implementation 2021-2024

Q. CAN YOU ILLUSTRATE THE IMPLEMENTATION PLAN FOR AGIS IN MORE DETAIL, BOTH THROUGH THE END OF THE MYRP AND FOR THE OVERALL PLANNING AND IMPLEMENTATION HORIZONS?

A. Yes. The AGIS Implementation and Customer Experience Timeline provided as Exhibit___(MCG-1), Schedule 5 illustrates AGIS implementation for the period 2019 through 2030.

Q. HOW DOES AGIS IMPLEMENTATION IN MINNESOTA ALIGN WITH OTHER JURISDICTIONS SERVED BY THE COMPANY?

A. AGIS is an enterprise-wide initiative in several respects, as our ADMS is serving several jurisdictions and our planning for other components of the AGIS initiative is being conducted on an enterprise-wide basis. For example, we are taking into account the needs of multiple jurisdictions we serve when planning for IT needs and undertaking vendor selection and negotiations for the components of the AGIS initiative. We will therefore have shared assets between jurisdictions, as is typical for an initiative like this. However, we also must also tailor our AGIS initiative planning to the unique requirements and needs of each area we serve – both from regulatory and operational perspectives. For example, we were required to obtain a Certificate of Public Convenience and Necessity to pursue certain components of the AGIS initiative in Colorado, whereas we have different IDP and rate case requirements in Minnesota. The jurisdictions we serve will also have varying requirements for implementation of certain attributes of the system (like remote connections, as discussed by Mr. Cardenas). Our approach for this rate case is tailored to the Minnesota jurisdiction.

C. Alternatives to the AGIS Initiative

Q. DID THE COMPANY CONSIDER ALTERNATIVES TO THE AGIS INITIATIVE?

A. Yes. The Company has considered alternatives for the various components of the AGIS initiative on many levels. By that I mean that we have not only considered options as part of our overall strategic planning, but also compared options within that plan for each component and device through information gathering, vendor discussions, Requests for Information, Requests for Proposals, and vendor contract negotiations. With respect to the component-based alternatives, we have considered not only whether to move forward with AMI vs. AMR or a FAN versus a cellular network, but also different types of AMI meters and systems, different device options, and different functionalities, and different support and security considerations. While I discuss system-wide and policy options, the individual technical alternatives to each individual AGIS component – as well as the process to whittle down our options to specific systems, vendors, and devices – are discussed by Company witnesses Mr. Harkness and Ms. Bloch.[36]

Q. DID THE COMPANY CONSIDER TAKING NO ACTION AS ONE ALTERNATIVE TO PURSUING THE AGIS PROGRAMS?

A. Yes. From an overall system perspective, theoretically one alternative is to do nothing and maintain the current distribution system. However, the Company has determined that "doing nothing" is not a viable option.

Q. WHY IS TAKING NO ACTION NOT CONSIDERED A VIABLE OPTION?

A. There are several reasons. First, NSPM does not have the option to avoid investments in the distribution system because, as I describe above, the Company's existing technology is reaching the end of its life and will need to be replaced. Replacement parts will no longer be available after 2022 and our meter reading contract expires in 2025. Given that we need metering to function as a business and that vendors are choosing not to support or continue to manufacture AMR meters, there is truly no "do nothing" option. We believe this reality is understood by the Commission and our other regulators and stakeholders. Indeed, the Company has previously received Commission permission to implement ADMS as a reasonable initial approach to modernizing the distribution grid; as such, a foundational piece of grid advancement is already underway. It does not make sense to stop there.

Second, AMR meters do not provide the functionality needed for a modern utility. The communication technology currently employed is limited to

[36] The Company's RFPs related to the AGIS projects are provided on the AGIS supporting files compact disk provided with Vol. 2B.

supporting only the current infrastructure, and many of these communications networks have reached technical obsolescence. Additionally, the current system does not provide visibility into the grid or the ability to manage and optimize voltage that would enable increased DER, which is anticipated to continue to increase at a rapid rate.

Third, the "do nothing" approach ignores customers' stated expectations. For example, customers want the ability to access timely energy usage information in order to empower them to make decisions that affect their power usage. AMI metering is necessary to accomplish this objective. As a further example, few customers are likely aware of how heavily we must rely on them to identify outage locations or how manual our fault location is or how voltage is maintained at levels to avoid systemic power quality issues rather than at optimized levels. AMI, FLISR, and IVVO go a long way to addressing these issues, and will improve service to customers who care about choice, reliability, outage restoration, and energy conservation.

Q. DID THE COMPANY CONSIDER SIMPLY EXTENDING USE OF THE CURRENT METERS FOR SOME LONGER PERIOD OF TIME?

A. Yes. As Ms. Bloch describes, while the Company could conceivably continue to maintain its existing AMR meters, many of these meters were installed in the 1990s are between 20 to 30 years old. Due to their age, we expect that these meters may begin to experience mechanical issues in the coming years and we will not be able to get meter replacement parts after the end of 2022.

Further, with our Cellnet meter reading contract expiring at the end of 2025, we need to have an advance plan for either new meters or new meter reading that could be implemented by that time.

Q. DID THE COMPANY CONSIDER DSM PROGRAMS AS ALTERNATIVES TO THE RELEVANT COMPONENTS OF AGIS?

A. Yes, but AGIS and other DSM programs are not mutually exclusive, and the technology of the AGIS initiative is necessary to some forms of DSM. For example, IVVO is an efficient way to lower voltage on the electric grid because it creates benefits without customer action, and does not rely on a subset of customers to voluntarily act to lower voltage at peak periods. Further, as Ms. Bloch describes in more detail, the ability to monitor voltage across the entire grid enables lower voltage. It can be likened to a 'wholesale level' of DSM. Similarly, AMI meters are necessary to eventually facilitate providing timely, automated usage information for customers and time-of-use rates. The technology we plan to employ through AGIS is necessary to these DSM efforts but does not preclude other efforts. In fact, they complement our CIP and demand response efforts.

Q. DID THE COMPANY CONSIDER A SYSTEM-WIDE APPROACH TO UPGRADING THE DISTRIBUTION SYSTEM THAT DOES NOT REQUIRE THE IMPLEMENTATION OF INTEGRATED APPLICATIONS?

A. Yes. Ultimately each component of the AGIS initiative could have been completed through a stand-alone application. For example, the Company considered the use of independent sensors to measure voltage instead of AMI and advanced meters. However, AMI and advanced meters were selected over independent sensors because AMI is not a stand-alone system and, as Ms.

Bloch describes, the advanced meters provide a multitude of benefits in addition to being voltage sensors. While independent sensors only perform the specific function of measuring voltage, advanced meters provided the capabilities necessary for the Company to achieve visibility into an individual customer's status. AMI and advanced meters constitute the only solution that provides the Company with the visibility into the status of the electric grid at the customer level.

Similarly, the components of IVVO and FLISR were chosen based on their ability to interact with each other and provide an integrated solution to address voltage and fault regulation and correction. Because independent components could not achieve the same outcomes, stand-alone options were discarded.

Q. DID NSPM CONSIDER OTHER SYSTEM-WIDE APPROACHES?

A. Yes. We also evaluated the options of implementing only certain aspects of AGIS, and could focus on the implementation of AMI and the FAN at this time and defer FLISR and/or IVVO to a later date.

We do not recommend this approach, however. As described later in my testimony and in Ms. Bloch and Mr. Harkness's testimony, all of the components of the AGIS initiative essentially layer on top of each other with each one providing a solid foundation for the next. For example, the deployment of FAN, which will enable two-way communications with devices in the field, is a necessary foundational element that must be in place before AMI meters can be fully functional. Likewise, AMI meters must be in place to support applications like IVVO and FLISR. The ADMS provides the foundation for all of these elements. Consequently, our overall distribution advancement program consists of a strategically-developed set of components that are designed to function together.

Q. COULD IVVO AND FLISR BE DELAYED INTO THE FUTURE, TO PACE INVESTMENTS DIFFERENTLY THAN THE COMPANY HAS PROPOSED?

A. Yes, this is a possible path, although we do not recommend it. While FLISR and IVVO are additional capabilities rather than replacements for aging technology, we believe there will be some incremental cost efficiencies due to implementing them at the same time as AMI and the FAN. Perhaps just as importantly, the costs of these devices and installation are more likely to increase in the future due to inflation, so there is little to be gained from delay. We would likely be delaying the benefits of this work and at the same time creating higher costs at the time of implementation, losing the value of the work already done to investigate and plan for these components, or both.

Q. ARE THERE OTHER ALTERNATIVES THAT WOULD PROVIDE THE SAME RESULTS AS THE AGIS APPROACH?

A. No. As I describe above, the other available options are individual technologies that would not promote an integrated system. The ADMS provides a network model of the electric distribution grid that enables and indeed is essential to integrating each component of an advanced grid to work with each other. A FAN communication network keeps that model updated. To try to update the distribution grid with independent systems would create an environment in which it would be virtually impossible to manually integrate the information gathered by each system. The components selected as part of the AGIS initiative are the correct components to bring NSPM's distribution grid into the future.

Q. WHAT WOULD THE COMPANY DO IF ITS AGIS PROPOSALS ARE NOT APPROVED?

A. For metering in particular, we would have some very difficult choices to make. We would need to manage the meters we have farther into the future, potentially without access to repair parts and without vendor support. In doing so, we would risk falling behind our peers in several areas, and the experience and satisfaction of our customers will suffer as a result. We would need to make investments in our existing meters to keep them going longer, which could include hiring meter readers when the Cellnet contract expires. We considered purchasing the Cellnet technology, but determined the contract would be at market value of the system including field devices, plus costs for professional services to support the aging software. Additionally, the software is almost 20 years old and not designed to run on newer servers, and we would not be able to purchase replacement meters or modules after 2022. This solution does not address many of our concerns.

Q. ARE THERE OTHER ADVANCED GRID COMPONENTS THAT MAY BE IMPLEMENTED IN THE FUTURE?

A. Yes. While it is not possible to anticipate all possible technological innovations that may be available in the future, the Company is already looking to maximize the AGIS investments beyond what can be delivered on "Day 1". For example, we know that we will have the option to build additional customer applications and interfaces once we observe how our customers begin to use our AGIS "Day 1" capabilities. Beyond the foundational AGIS components necessary to add future capabilities, we are planning to implement the Distributed Energy Resources Management System (DERMS) in the 2024-2025 timeframe to further expand our ability to host and manage distributed energy resources.

Q. WHAT IS DERMS?

A. DERMS is a control system that will provide improved awareness of DER impacts to power-flow on the grid. DERMS allows for the integration of DER and demand response with full visibility and control, and at the same time enables the Company to maximize localized and system-wide benefits and value for our customers. DERMS will be important to support and manage DERs as they continue to grow, but is not as immediately critical to system management as replacing our meters or improving our outage response. Rather, it is a building block we expect and anticipate adding in the future.

Q. WHY IS THE COMPANY NOT BRINGING FORWARD A DERMS PROJECT RIGHT NOW?

A. While DERMS will become necessary in the near future, more time is needed for research and development activities to occur in this space. The Company will continue monitoring developments, monitoring operational and market needs, begin crafting requirements, and refine our forecasting to deploy DERMS. The penetration of DER, while increasing, has not yet reached the point where a DERMS is required. We expect that the needs of Minnesota will align with the further maturation of DERMS product offerings, such that a future investment in this functionality will ultimately prove prudent and beneficial to all.

Q. IN SUM, WHY ARE AMI, THE FAN, FLISR, AND IVVO THE RIGHT PACKAGE FOR THE COMMISSION TO APPROVE AT THIS TIME?

A. Given the need to replace our existing AMR meters that are nearing end of life, now is the right time to implement AMI and the FAN communications network. These technological advances now make it possible to meet growing customer expectations for a more robust, reliable, and resilient system, as well as customer desire for more insight and visibility into the energy choices they are making. Further, implementing FLISR and IVVO at this time will enable the reliability and energy reduction benefits at a lower cost than if the Company waits to deploy these systems in the future. The Company's targeted AGIS initiative will address system needs, customer needs, and our overall strategic priorities as a Company to lead the clean energy transition, enhance the customer experience, and keep bills low.

D. AGIS Governance

1. Governance Structure

Q. WHAT IS THE COMPANY'S GOVERNANCE STRUCTURE FOR THE AGIS INITIATIVE?

A. A robust governance structure is necessary for any project of this size and scope, especially considering the technical and integrated nature of AGIS, the various operating and customer service areas of our business that support the initiative, and the coordination necessary to deliver value for our customers as we implement AGIS in Minnesota. The Company has established a tiered governance structure for the AGIS initiative to provide the necessary controls and oversight that will enable us to achieve the desired customer and business outcomes. The program sponsors are responsible for approval of the overall strategy and funding as well as the overall program results. The program sponsors have instituted an executive level Integration Council, to ensure alignment of the enterprise vision and drive cross-workstream integration of the AGIS initiative. This council resolves execution issues and risks, and provides enterprise visibility to the design, program management, change management, and benefits realization anticipated from AGIS implementation. Any proposed changes are individually documented and brought to a change control meeting composed of program management leadership. The program management leaders can approve administrative and low impact changes to the initiative. Any significant changes to costs, benefits, scope, schedule, or resources are elevated to the Integration Council for review and approval to provide a consistent approach across the initiative.

Q. HOW WILL THIS STRUCTURE ENSURE APPROPRIATE OVERSIGHT OF AGIS IMPLEMENTATION?

A. Any significant changes to costs, benefits, scope, schedule, and resources are elevated to the Integration Council from the program management leadership team to provide a consistent approach across the initiative. Program leaders ensure that when risks and issues are identified that could affect costs, benefits, scope, schedule, or resources, they are documented and resolved. Any risks, issues or changes that meet predetermined thresholds are then elevated to the Integration Council and, if necessary, to the sponsors for appropriate resolution. This hierarchy of approvals ensures that scope, schedule and costs are documented and controlled in order to align with customer and Company check as the initiative proceeds.

2. *Program Management*

Q. WHAT IS PROGRAM MANAGEMENT?

A. Program management is an organizational effort designed to coordinate all projects necessary to incorporate the AGIS initiative into the current distribution system. Large, complex projects like AGIS must have established program management controls in order to ensure the effective use of resources, and thus optimal costs for the scope and benefits intended. There are various aspects of program management, some that are specific to a particular business area, and other applicable across all functional areas involved in implementation.

Coordination of projects through program management is driven through common project planning, governance, budgeting, and execution metrics methodology. Program management also provides essential corporate resources to ensure that the various individual AGIS projects are completed successfully. The program management team will coordinate the work required for the individual projects that will build the assets that make up the overall AGIS initiative. The program management team is also responsible for financial analysis and control, accounting, contract management, resource management, initiative governance, communications, and administrative assistance for each individual project and the overall AGIS initiative. The program management team will also track results, identify and determine if remedial action is necessary to keep the AGIS initiative on track, and monitor interdependencies between individual projects.

Given the size of this initiative, significant program management oversight is needed on a frequent and ongoing basis due to the highly interrelated and interdependent nature of the many components of the AGIS initiative at the individual project level. The project planning life cycle in broken into phases; Strategy, Planning, Initiation, Blueprinting, Design, Build, Test, Deploy, Warranty. Once a project has been initiated, each phase of the project's health is peer reviewed on a weekly basis. The weekly review includes, schedule, milestone, issues, risk, and budget. The Project Management office conducts a peer review of the overall AGIS budget on a monthly basis and provides the results to the Integration Council. Exhibit___(MCG-1), Schedule 6 provides the project management costs discussed in this section.

Q. PLEASE DESCRIBE THE COSTS ASSOCIATED WITH AGIS PROGRAM MANAGEMENT.

A. The AGIS budget includes program management costs for AMI and IVVO for 2019 through 2025, when advanced meter deployment and installation of IVVO devices will be substantially completed. The program management costs are discussed together below. Schedule 6 provides program management costs separately for AMI and IVVO.

We have estimated the total of AGIS program management capital costs for the MYRP period 2020-2022 will be approximately $20.3 million, or $30.0 million for 2019 through 2025. These capital expenditures are for work necessary throughout the development, deployment, and conclusion of implementing the AGIS components. We have estimated approximately $10.7 million will be attributable to operations and maintenance (O&M) expenses during the MYRP period (or $21.1for 2019-2025). These O&M costs related to strategic program oversight, as well as incremental corporate services and larger change management needs obtained in direct support of the initiative.

Q. WHAT ASPECTS OF PROGRAM MANAGEMENT ARE INCLUDED IN THE AGIS BUDGET?

A. Program management costs include:

- Change Management;
- Environment/Release Management;
- Finance;
- Project Management Organization;
- Security;
- Supply Chain;
- Talent Strategy; and
- Delivery and Execution Leadership.

Change management makes up the largest portion of the program management costs in the AGIS budget.

Q. WHAT IS CHANGE MANAGEMENT?

A. Change management is a systematic approach to effectively executing and managing fundamental organization and process changes, such as when an electric utility implements a significant change to the distribution grid. The implementation of the AGIS initiative will impact and transform the job functions for many of the Company's employees. In order to manage this transformation and properly engage employees and external stakeholders to ensure a successful transition, a comprehensive change management plan is necessary. In the context of change management, stakeholders include any person, process, or entity that is affected by the implementation of the AGIS initiative. The three main elements of change management– prepare, manage and sustain – each involve significant detailed analysis, action and documentation. The AGIS initiative has a dedicated team to ensuring that there is an appropriate overall change management plan in place, and that the plan is resourced and thoughtfully executed.

Q. WHAT ARE THE COSTS ASSOCIATED WITH AGIS CHANGE MANAGEMENT.

A. We have estimated change management costs for 2020-2022 to be approximately $10.2 million. Approximately $4.4 million of that estimate will be capitalized. These capital costs are for work throughout the development, deployment, and conclusion of on implementing the AGIS components. Specific tasks that will be capitalized are those that relate directly to design and deployment of assets, such as, but not limited to, the development of key design decisions, training development, functional alignment, integration reviews, program architecture documentation, technical change management, managing quality, and performing independent deliverable reviews. Approximately $7.5 million will be attributable to O&M expenses. These O&M costs are related to strategic program oversight, communications and customer training, as well as incremental corporate services obtained in direct support of the initiative.

Q. PLEASE DESCRIBE THE OTHER COSTS RELATED TO AGIS PROGRAM MANAGEMENT AND HOW THOSE COSTS WERE DEVELOPED.

A. The other program management costs associated with AGIS implementation are described in below. As a general note, these functions will be performed using a combination of internal employees and external consultants, and the costs forecasts related to work performed by internal employees is incremental to the general corporate budget forecasts. These costs were estimated based upon experience in deployment of the AGIS technology in Colorado, focused on the incremental requirements related to Minnesota functionality and scalability performance. I also note below where additional considerations were used in developing the specific cost forecasts.

- *Environment/Release Management:* These costs are related to performance and operating tests on the AGIS technology prior to deployment. This includes identification and remediation of issues in the software/hardware deployment and performance testing on the scalability requirements of certain AGIS technology.
- *Finance:* These costs include providing forecasting, budgeting, and reporting on the financial performance of the projects and the AGIS initiative. This includes internal reporting on monthly metrics and providing support in regulatory filings. While these costs were estimated based upon the current required financial needs in supporting AGIS implementation in Colorado, current Minnesota jurisdictional reporting requirements were also considered.
- *Project Management Organization:* These costs are related to governance activities for the projects and the overall AGIS initiative. This includes reporting on current project status, requirements for project change requests, and control of policies and guidelines designed to effectively govern the projects and AGIS initiative.
- *Security:* These costs are for work related to identifying security threats and issues on the AGIS technology prior to deployment. This includes identification and remediation of security threats in the software/hardware deployment and continuing requirements for effective cyber security programs. Security requirements for the AGIS

initiative follow the corporate strategy and process as outlined in Mr. Harkness' testimony.

- *Supply Chain:* These costs include providing centralized supply chain support, including negotiation of large strategic contracts. Costs were estimated based upon experience in providing support for the Colorado AGIS initiative, and are specific to the expectations of contracts required in Minnesota
- *Talent Strategy:* These costs include providing support in staffing and alignment of the project and initiative teams. This includes alignment with long term strategic priorities and staffing levels designed around the implementation of the AGIS technology.
- *Delivery and Execution Management:* These costs include project and initiative leadership through the design, build, and deployment phases of the AGIS initiative. Delivery and Execution Leadership will provide the oversight and alignment of the project and initiative objectives to the strategic priorities of the Company and the Commission.

Q. ARE PROGRAM MANAGEMENT COSTS REASONABLE?

A. Yes. The Company determined the costs based on the need to build a program management team that will consist of internal employees, as well as the engagement of consultants. This approach is based on the Company's experience with program management, and is consistent with its recent experience implementing the new general ledger and work and asset management systems. The costs identified in my testimony are those that were allocated to the AGIS components.

Q. DID THE COMPANY DEVELOP CONTINGENCIES FOR PROGRAM MANAGEMENT?

A. Yes. The contingency for 2019 through 2025 for both program and change management is $1.3 million in capital and $1.0 million for O&M, or approximately 5 percent of total costs. These contingencies are less than the overall contingencies estimated for design, deployment, and operations of the other components of the initiative. They reflect the uncertainty around the costs that will be necessary for program management, which may not be fully known until the AGIS program is approved and final requirements for implementation in Minnesota are known. Until design and engineering are complete, contingencies are necessary to account for the unknowns that are likely to develop during the processes and through the installation and operations phase. The contingencies for program management are consistent with the contingencies proposed for the overall AGIS initiative, as described further in Section VII.

VI. AGIS AND THE CUSTOMER EXPERIENCE

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A. In this section, I discuss the overall NSPM customer experience currently, compared to what will be different for customers upon AGIS implementation. To illustrate the impacts and customer benefits, I provide a timeline and discussion of how advanced grid capabilities will be rolled out and experienced by customers. In addition, I describe future opportunities that will be made possible by the AGIS initiative and discuss to what extent additional regulatory proceedings may be necessary to implement those opportunities.

I then discuss our customer and community outreach strategy for AMI and the associated functions, and present our Customer Education and Communication Plan related to the roll-out of AGIS initiatives over the implementation period.

Schedule 3 provides additional discussion and details related to the Company's customer strategy with respect to the advanced grid capabilities and implementation, including background on our customer surveys and research efforts that have informed our AGIS strategy, and details on the technologies and customer benefits of each AGIS component. The document also provides timeline discussions of the customer experience from pre-deployment, through the deployment and installation phase, and post-deployment when new customer products and services will be implemented. The document also discusses our customer outreach and education plan, as well as data privacy and security considerations.

A. The Customer Experience

Q. WHAT IS THE COMPANY'S VISION FOR THE FUTURE CUSTOMER EXPERIENCE?

A. The Company's vision is to further empower customers with timely and relevant information so they are more aware of their energy usage and its impacts, and can make better decisions about how and when they use energy. This will give customers greater opportunity to control their energy costs and reduce their environmental impact, two issues that rate highly with customers. In the future, the customer experience will require less direct engagement from customers yet will be a stronger partnership between customers and Xcel Energy. To meet this vision, we need to understand our customers' needs, design products and services to meet their individual needs, and seamlessly execute in ways that meet customer priorities.

Q. HOW WILL AGIS IMPLEMENTATION ENHANCE THE CUSTOMER EXPERIENCE COMPARED TO THE CAPABILITIES OF TODAY'S DISTRIBUTION SYSTEM?

A. First, the advanced grid will be able to provide data and information that is simply not available with our current system and AMR technology. This is not just an incremental step compared to the data provided by our current metering and distribution system technologies; rather, the advanced grid will provide vastly different information with a level of granularity that can impact customers' energy usage decisions, as well as increase reliability and improve the safety and security of the grid.

Q. CAN YOU SUMMARIZE HOW EACH OF THE CORE ELEMENTS OF AGIS IMPACT THE CUSTOMER EXPERIENCE?

A. Yes. Each of the core elements of AGIS (AMI, the FAN, ADMS, FLISR, and IVVO) adds to the customer experience in a specific way, but each is also interdependent upon the others to ensure that maximum benefits can be realized.

AMI provides the customer-level data that will enable an improved customer experience. AMI provides the timely and detailed energy usage data needed to better inform customers thereby empowering them to better manage their energy costs. AMI also provides additional outage information, because the Company will know when a meter stops communicating through the FAN, which is an indication that an outage has occurred. Once contact with an advanced meter in lost, we can proactively notify a customer that an outage has occurred. Additionally, we can tell when a meter is back in service, which allows us to send accurate notifications to customers about the resolution of an outage.

The FAN can be viewed as the nervous system of the AGIS system as it transmits information both to and from the advanced meter. This two-way communication is necessary to allow the meter to transmit data about energy usage or outages back to the Company's meter data management and ADMS systems.

FLISR and IVVO, which are additions to the ADMS, help us improve service reliability and quality. FLISR is a critical investment to improve the outage experience because FLISR devices can identify outages and can be used to proactively restore power through automatic switching and help isolate outages so field service crews can be more efficiently dispatched. FLISR is expected to reduce the duration of many outages thereby minimizing the impact customers experience.

Power quality, the level of voltage on the system, generally affects all customers because unnecessarily high voltage on the system or a feeder both wastes energy and can have a detrimental effect on customer's end-use technologies. ADMS and the IVVO application will allow us to better manage the voltage levels on our system thereby reducing energy usage and the associated cost and improving the voltage range on our grid, which improves the efficiency and life of customer technologies.

Q. HOW DOES THE TOU PILOT INFORM THE EVOLUTION OF THE CUSTOMER EXPERIENCE?

A. As previously noted, the TOU pilot will be underway in 2020 and is expected to conclude in 2022. The goals of the TOU pilot are to study adequate price signals to reduce peak demand, identify effective customer engagement strategies, understand customer impacts by segment, and support demand response goals. Learnings from this pilot will inform the design of future advanced rates the Company would propose, such as a full TOU rate for residential customers, or other pricing options.

While we do not yet know the pilot outcomes with respect to the pilot rate design and price signals yet, with this pilot, we are developing a digital platform to provide more granular and timely information to customers about their energy usage. We have partnered with a third-party to reimagine how we deliver this energy usage information to our customers. For TOU pilot customers, we intend to provide at least hourly interval data to customers on a prior day basis. This will allow customers to see how their energy usage tracks throughout the day as well as the cost of their energy during that time. We will offer disaggregation information that identifies the appliances or devices using energy in a home so customers can make more informed decisions about how their behavior impacts energy usage, and the best places are to start making changes. We expect to explore how to maximize advanced rate designs that benefit from more timely usage information coming from the advanced meter. We also expect to include demand response messaging that will proactively alert customers about high demand days and encourage them to take actions to change their behavior helping them save money on their bills and also reduce constraints on the grid.

These new services to be offered through the TOU pilot will be used as a template for the information to be available to customers via the web portal once an AMI meter has been installed. In other words, even though a full residential TOU rate may not be implemented to coincide with deployment of the first AMI meters in 2021, we will use the initial experience with our TOU pilot customers to better inform how we deliver new information to our customers and what channels and strategies work the best. In the future, the TOU pilot learnings will inform our rate design based on feedback we receive from TOU customers and operational results of the pilot.

Q. HOW DOES THE AGIS DEPLOYMENT TIMELINE ALIGN WITH THE ROLL-OUT OF NEW OR ENHANCED PRODUCTS AND SERVICES FOR CUSTOMERS?

A. As a general overview, impacts to the system and the customer experience will evolve as we implement AGIS components and take full advantage of the advanced grid capabilities over time. Our customer experience investments are beginning today. We are actively researching and designing new products and services that will be enabled by AGIS investments and innovating on existing products and services that can be improved by AGIS. We are also talking to our customers about what their expectations are now and in the future and how we can best meet those expectations.

Schedule 5 provides our AGIS implementation timeline, illustrating the products and services we anticipate deploying. Complimentary to this is Exhibit___(MCG-1), Schedule 7, which provides a summary of the products and services identified in the timeline. Schedule 7 also identifies how these products and services align with the Company's strategic priorities to lead the clean energy transition, enhance the customer experience, and keep bills low.

Generally, we consider implementation of new offerings in three phases:

- *Day 1*, coincident with the installation of advanced meters beginning in 2021. The Day 1 experience described below encompasses the capabilities that will be enabled and new information that will be available to customers once an advanced meter has been installed. I note, however, that the Day 1 experience for the first customer to receive an advanced meter in 2021 will be different than for a customer who receives an advanced meter later in the deployment phase. This is because the Company will be rolling out new products and services in the near term during the actual meter deployment phase. The Day 1 experience will be more robust and further enhanced with later meter deployments as we implement new products and services.
- *Near Term*, through 2025, describes the period when the Company will be developing, requesting Commission approvals (where necessary), and implementing new products and services for customers.
- *Long Term*, through 2030, describes future products and services the Company envisions implementing to realize additional capabilities that are enabled by the advanced grid. The Company will be flexible during this period, and any new products and rate design will be informed by prior experience, changing customer needs and expectations, and evolving technologies.

Q. WILL FUTURE FILINGS BE REQUIRED RELATED TO NEW PRODUCTS AND SERVICES TO ENABLE SOME ADVANCED GRID BENEFITS?

A. Yes. We recognize that many new products, services, or rate offerings – such as a full residential time of use rate – will require additional filings with the Commission and may involve a stakeholder engagement process to inform development. I discuss these additional capabilities and rate offerings below, including outlines of the development and approval processes.

B. Day 1

1. Overview

Q. PLEASE FURTHER DEFINE THE DAY 1 PERIOD.

A. As stated above, Day 1 coincides with the beginning of advanced meter deployment in 2021. Some of the services and information will be available to customers immediately upon installation of the AMI meter, while others will be implemented and available as additional meters are installed, as the Company initiates new product and service offerings, and as additional devices are deployed, building a larger base for advanced grid operations.

Q. PLEASE SUMMARIZE THE COMPANY'S VISION FOR THE DAY 1 EXPERIENCE.

A. The Day 1 experience will be heavily focused on "getting the basics right." Basics include things like accurately billing customers with the data received from the smart meter, ensuring the Company's website and customer portal are correctly displaying the interval data received from the smart meter, and ensuring there is a robust communications with customers about meter installations. These foundational elements of AGIS implementation also double as the primary touchpoints of service we have with customers.

While focusing on getting the basics right we also intend to deploy new products and services in areas where the cost-benefit is the highest or where the satisfaction value is highest for our customers. In particular, the Day 1 experience will be include an improved outage experience, an enhanced digital experience, and new energy savings programs. I discuss each of these projects below.

2. *Outages and Reliability*

Q. WHAT ARE CUSTOMER EXPECTATIONS WITH RESPECT TO OUTAGE DATA AND SYSTEM RELIABILITY?

A. As noted earlier, our customer research efforts show that:

- addressing service interruptions is important to all customer classes;
- customers expect more accurate and timely information related to outages; and
- customers expect that service interruptions will be less frequent, smaller in scope, and shorter in duration.

a. Outage Notification

Q. HOW DO CUSTOMERS RECEIVE OUTAGE NOTIFICATIONS TODAY?

A. Today, we have a mobile app, and customers can receive outage notifications that include estimated restoration times. Customers also receive confirmations when our records reflect that the outages have been resolved, and they can receive these via their preferred communication channel, wither text, email, or phone. While we have made advances on our grid and with the service we offer our customers – and these and other products and services have provided our customers with significant value over many years – we have room for improvement in our communications with customers and especially with restoration time estimates.

Q. HOW DOES AGIS IMPLEMENTATION ENABLE THE COMPANY TO PROVIDE TIMELY OUTAGE INFORMATION?

A. The AMI meters detect outage and restoration events, this real-time information is then transmitted through the meter's radio frequency communication module, through the FAN, and is received by the AMI operating software system that is used to send and receive information from an AMI-capable meter. With AMI, the Company will know when momentary or nested outages[37] occur because the advance meters will no longer communicate through the FAN back to the Company.

This improved awareness will allow for the Company to proactively notify customers of an outage, instead of relying on customers to notify the Company. In addition, with improved awareness and expected reduced restoration scopes (as discussed in the next section), the Company will be able to provide customers with more timely and accurate information about their outages. Today, customers are provided general updates and asked to confirm if their power has been restored. With the advanced grid capabilities, the Company can remotely confirm restoration of power.

Q. HOW WILL THE COMPANY COMMUNICATE OUTAGE NOTIFICATIONS TO CUSTOMERS?

A. As part of the Day 1 experience, we do not anticipate significant changes to *how* customers receive outage notifications; the significant difference will be in the Company's ability to proactively communicate with customers, provide more timely notifications, and provide more accurate restoration time estimates. By default, all customers with a valid email address in our system

[37] Storms often result in multiple failures. When we repair and reenergize a section, but a subset remains out due to a second fault, that outage is referred to as a "nested" outage.

will receive outage notifications via email. However, we will take steps to encourage customers to update their preferences in order to receive notifications in the way they prefer most. We will also begin enabling notifications through our mobile application for customers that prefer this communication channel.

b. System Reliability Improvements

Q. WHAT CAPABILITIES RELATED TO OUTAGE RESTORATION DOES THE ADVANCED GRID PROVIDE?

A. As described in the previous section, through ADMS, AMI, the FAN, and FLISR implementation, AGIS enables outage identification in real time and enhances capabilities for faster outage resolution. These improvements will begin as we begin to install FLISR devices in 2020. Customers on FLISR-enabled feeders will begin to see improvements, with improvement growing as we install FLISR on additional feeders over time.

Q. HOW DO THESE AGIS CAPABILITIES IMPROVE SYSTEM RELIABILITY EXPERIENCED BY CUSTOMERS?

A. First, as noted above, AMI can provide initial notice of an outage to the Company. This immediate notification can play a role in reduced response times. Once an outage has been noted, ADMS supports operators in determining optimal solutions faster during outage restoration through utilization of the network model, load flow calculations, and advanced analysis tools. ADMS, in conjunction with automated grid components, can improve reliability in terms of both reducing the number of outages and minimizing outage time. The FLISR application, which calculates the possible locations of the outage cause and including automated switching devices, can reduce the frequency and duration of customer outages. These automated switching devices detect feeder mainline faults, isolate the fault by opening section switches, and restore power to unfaulted sections by closing tie switches to adjacent feeders as necessary

Q. WILL THE IMPACT OF ADVANCED GRID BE REFLECTED IN THE COMPANY'S RELIABILITY METRICS?

A. Yes. Operationally, we expect improvements in the System Average Interruption Duration Index (SAIDI) when AGIS is fully implemented and the Company adapts its process to more efficiently respond to outages. However, because our current system is unable to track momentary service interruptions, there is a likelihood that the number of outages may increase as the advanced grid technology will enable the Company to track momentary outages. This may increase the System Average Interruption Frequency Index (SAIFI). I also note that because we will now be able to capture momentary outages that otherwise would go unnoticed if not observed and reported by a customer, we will be able to report MAIFI statistics, which are another measure of service quality for our customers.

Q. DOES THE COMPANY CURRENTLY REPORT ON THESE RELIABILITY METRICS?

A. Yes. We report service quality and reliability metrics under Minn. Rule 7826 and as required by our tariff governing service quality.[38] I also note that SAIFI and SAIDI have penalties attached according to established thresholds and past performance. With SAIFI and SAIDI impacts and the ability to report MAIFI as a result of AGIS implementation, new baselines for these metrics may need to be established over time through a Commission-

[38] See the Company's Minnesota Electric Rate Book, Section 6, General Rules and Regulations, Subsection 1.9, Service Quality.

approved process. I provide an overview of our service quality tariff and metrics in Section VIII, identifying how the Company expects AGIS may affect our performance and reporting under the Minn. Rule 7826 and our service quality tariff. Specific information as it relates to reliability performance is discussed in detail in the Direct Testimony of Ms. Bloch. The other service quality metrics related to billing and customer service are discussed in detail in the Direct Testimony of Mr. Cardenas.

3. *Digital Experience Improvements*

a. Customer Portal

Q. PLEASE DESCRIBE THE CURRENT CUSTOMER PORTAL EXPERIENCE?

A. Today, customer's access the customer portal through MyAccount. MyAccount provides customers with the ability to enroll in certain programs, review their usage and bill information, receive updates on outages, and personalize their communications preferences.

This experience covers many of the primary interactions a customer will have with Xcel Energy. However, the information provided in the customer portal is limited by the information that we have available today. As I have discussed above, our current system and metering technology is limited in the detail and timeliness of the data it provides. As we upgrade our system we will integrate this new information into an enhanced customer portal experience.

Q. HOW WILL THE PORTAL EXPERIENCE CHANGE?

A. The enhanced customer portal will provide customers with more detailed energy usage information. At a minimum, customers will be able to see in the portal their hourly intervals available the next day. This display of AMI-enabled energy usage data will also be supplemented with new tools such as disaggregated energy usage details and opt-in alerts and notifications that are personalized to the customer's energy usage and billing preferences. These initial enhancements to the customer portal will help empower customers with better information about their energy usage and more tools to make decisions that can help them control their energy usage. Over time, we expect to further enhance the detail and quality of this data with new products and services and more frequent updates to displayed data. Ultimately, the Company believes that on-demand meter reads through the customer portal will be added.

Q. WHAT IS THE COMPANY DOING TO PREPARE FOR THE PORTAL ENHANCEMENTS ON DAY 1?

A. We are currently conducting a full review of the look, feel, and organization of the customer portal. Generally, we are exploring ways to streamline customer use of the portal, to keep customers engaged, and present relevant information more directly. We are also working to better align the mobile and web experiences so that customers do not experience significantly different interactions between the two. Company witness Mr. Harkness addresses this in his Direct Testimony.

In summary, on Day 1, we expect to provide customers with a better portal experience that displays more detailed information that is more relevant to each customer, and keeps them more engaged and knowledgeable about their energy usage. It will also allow customers to opt-in to new types of notifications and communications.

b. Notifications and Communications

Q. WHAT ARE CUSTOMER EXPECTATIONS WITH RESPECT TO ENERGY USAGE DATA?

A. As noted earlier, key findings from research efforts show that customers expect that more energy usage data will allow them to better identify opportunities and strategies to save energy and reduce their costs. Customers also expect:

- to receive detailed information from their utility;
- that provision of information is personal and frequent; and
- that the Company will provide tools to help them use information to make decisions about their energy usage.

Q. HOW DOES THE CURRENT SYSTEM LIMIT THE TRANSFER OF ENERGY USAGE INFORMATION BETWEEN THE COMPANY AND THE CUSTOMER?

A. Our current distribution system and metering technology primarily allow for one-way communication that can generally only provide customers with usage information on a monthly basis through the Company's billing system.

Q. HOW DOES AGIS ENABLE ACCESS TO AND USE OF TIMELY ENERGY USAGE DATA?

A. The AGIS components necessary to enable timely energy usage are ADMS (as the foundational component necessary to enable advanced meter applications), AMI, and the FAN. Implementation of AMI and FAN will provide the real-time energy usage data and the foundation for new products and services that will enable customers to use that data to make decisions about their energy usage. The FAN, as the communication system for the advanced grid, will allow for transmission of data both to and from the meter.

This data can be built into digital experience channels to provide customers with more timely and accurate updates about their energy usage, thereby providing the ability for customers to better manage their energy usage and costs.

Q. WHAT ARE THE COMPANY'S PLANS WITH RESPECT TO THE CAPABILITIES OF THE ADVANCED GRID TO SUPPORT NEW INFORMATION AND DATA?

A. As part of the Day 1 experience, the Company will provide customers with more information about their energy usage. As discussed above, much of this information will be provided through the enhanced customer portal as digital experiences like the customer portal are the way customers increasingly interact with data and information. Some ways that we will share this data and information may include energy usage dashboards, energy usage alerts, and advisory tools..

Q. PLEASE SUMMARIZE THE COMPANY'S VISION FOR DASHBOARDS, ALERTS, AND ADVISORY TOOLS.

A. Dashboards will allow customers to customize the information that they see when they access their account through the web or mobile device. Customers will be able to see how devices use energy and what impact that has on their consumption, how their energy trends over time, and how their energy compares to external factors such as the weather. Dashboards can also incorporate comparisons such as to aggregated customers, like our Home Energy Reports do today, or to an individual customer's historic energy usage. These dashboards will be an enhancement to the dashboard service the Company currently offers, MyEnergy, by allowing for customization as well as incorporating more detailed data made available through AMI.

Alerts are a new function made available because of our ability to receive timely data through AMI and the FAN. Customers will be able to set thresholds for their usage or bills and the Company will proactively send alerts to customers when their energy usage is on track to exceed those thresholds. Alerts may also include helpful and personalized advice for customers to help them change their behavior before it's too late and they receive a unexpectedly high bill. Other types of alerts will focus on behavioral changes customers can make as we notify them of high peak energy usage days, such as a critical peak day. While these alerts may or may not have a financial incentive associated with them, providing customers with the information is likely to induce some type of behavioral change due to other intrinsic factors such as care for the environment.

Finally, advisory tools will analyze a customer's energy usage data and identify ways that customers can change their behavior or act to reduce their energy usage or more efficiently use energy. For example, one advisory tool may analyze a customer's energy usage relative to the costs associated with an advanced rate such as a time-of-use rate. The "advisor" may integrate with other products and services, such as disaggregation which is discussed below, to provide recommendations targeted towards specific appliances that the customer regularly uses. Alternatively, the advisor may suggest new rates or programs that help the customer manage their energy usage through price signals or direct control.

Provision of this data and enhanced communications with customers will not require additional filings for approval by the Commission. However, we will keep the Commission and stakeholders informed of customer usage and satisfaction with these new capabilities. I discuss our proposed AGIS metric and reporting in Section VII.

4. Energy Savings Programs

Q. HOW WILL AGIS INVESTMENTS ENABLE OR ENHANCE NEW DEMAND-SIDE MANAGEMENT (DSM) PROGRAMS?

A. The more detailed and timely data that our AGIS investments provide can help enable or enhance programs in a number of ways. First, as we have more information we can use that to update our program designs and marketing tactics. We will have better insight into how and when customers use their energy which will allow us to better market and segment our customers. This means our communications will be more relevant as I discussed above. Just as important will be new products and services that support our DSM goals. These may include, Home Area Networks, Green Button Connect My Data, and traditional energy efficiency, demand response, and demand management programs.

Q. WHAT ARE THE COMPANY'S PLANS WITH RESPECT TO THE GREEN BUTTON CONNECT AND HAN PRODUCTS?

A. Green Button Connect (GBC) and Home Area Network (HAN) functionality are enabled by the advanced meter and are two products that may be included in the Day 1 experience. GBC allows customers to share their energy usage data seamlessly with their approved third-parties. This is an enhancement to the existing system, Green Button Download, because it allows a customer to share their data regularly with a third-party without needing to take proactive action to share that data. For customers with third-party services that help them manage their energy usage this will allow them to work with their chosen third-party to more effectively manage their energy.

HANs vary in the benefits they provide and can be as simple as a dashboard that communicates with the meter to provide real-time energy usage or more complicated networks of devices that are receiving energy usage data from the meter and adjusting operations based on that information.

Q. WHAT ARE THE COMPANY'S PLANS WITH RESPECT TO TRADITIONAL DSM PROGRAMS?

A. We are developing multiple new programs for Day 1 deployment. These include:

- virtual energy audits;
- whole facility monitoring and continuous commissioning; and
- Enhanced Saver's Switch.

Virtual energy audits will provide customers reports of their energy usage relative to a baseline or general customer comparison. This audit is similar to the "Neighbor Comparison" that is provided with the Company's "Home Energy Reports" but because of new capabilities from AGIS – specifically AMI and the FAN, we can provide this service more frequently for customers. We can also rely on the more detailed data provided by service such as disaggregation to provide more specific details on how their energy usage compares to a baseline.

Whole facility monitoring programs will use the detailed data provided by AMI to better integrate with energy management systems. This will allow customers to get more timely and accurate feedback on how adjustments to their business processes and energy management systems impact their energy usage. For customers on certain types of advanced rates, this more timely and accurate feedback can be critical to ensuring they don't have an unexpectedly high bill or fail to meet energy curtailment requirements during demand response events.

Finally, Enhanced Saver's Switch is an upgrade to the existing Saver's Switch technology that allows for two-way communication between the Company and the Saver's Switch. This two-way communication utilizes the FAN to more reliably send signals to the switch and the switch can then send a signal back indicating it is active and receiving messages. This will result in more accurate forecasts or demand response savings and can enabled improved maintenance of the switch system to focus on disabled or broken switches first. While this program may not have a direct impact on customers like an audit or monitoring program may, the improvement in switch responsiveness will have indirect benefits because we can more accurately forecast the resources we need to require helping avoid high cost peak generation.

C. Near Term

1. Overview

Q. PLEASE SUMMARIZE THE COMPANY'S VISION FOR THE NEAR TERM CUSTOMER EXPERIENCE.

A. As defined above, the near term encompasses the period through 2025. During this time, we plan to:

- Continue innovating on existing products and services;
- Begin offering new advanced rate designs;

- Expand the capabilities of the advanced meter to utilize the Distributed Intelligence platform discussed earlier in my testimony; and
- Better integrate DERs on the system.

Continual innovation has long been a core requirement of our customer programs; however, with the rapid pace of technology advancements – including Distributed Intelligence – and the increasing amount and sophistication of data we have it will become more important. We will need to reconsider the ways our customers interact, what the most effective way to interact with them is, and how to use the data we must most cost-effectively offer products and services. I will discuss the other plans in more detail below.

2. Advanced Rate Designs and Billing Options

Q. WHAT ARE THE COMPANY'S PLANS WITH RESPECT TO THE CAPABILITIES OF THE ADVANCED GRID TO SUPPORT ADVANCED RATE DESIGNS?

A. The Company generally supports advanced rate designs, such as a TOU rates, because advanced rate designs can help customers manage their energy usage and environmental impacts. As our customer research has shown, managing costs and minimizing environmental impacts are important factors in customer satisfaction.

We have long experience with time-of-use and other advanced rate designs in Minnesota and across our other service territories. However, beginning in April 2020, we will pilot a new time-of-use rate with residential customers in two areas in the Twin Cities metropolitan area. This pilot will provide us with an opportunity to better understand how customer react to a four-part rate (off peak, two shoulder peaks, and an on-peak period) as well as test tools and resources that may help customers adjust their energy usage to keep their bills low and better control their energy costs. The learnings from this pilot, with respect to both the rate and new products and services, will help inform our plans for advanced rates in the future. In addition, the Company is proposing a new time-of-use rate for the commercial and industrial customers served under the current General Time-of-Day tariff. Implementation of this General TOU rate will require the installation of AMI meters. Company witness Mr. Lon M. Huber provides details on this proposed rate in his testimony.

Q. WHAT OTHER TYPES OF ADVANCED RATE DESIGNS OR BILLING OPTIONS MIGHT BE ENABLED BY THE AGIS INVESTMENT?

A. One billing option the Company is investigating is the option for customers to "pre-pay." A pre-pay system allows a customer to purchase a set amount of energy each month which can help customers manage within a budget. Because our investments in AMI and the FAN will provide more detailed and timely energy usage information a customer can monitor their usage towards the "pre-pay" amount regularly. Similarly, the Company can track the usage, relative to the budget, and send the customer regular notifications about their energy usage balance and ways to reduce their reduce to remain on the budget.

Other advanced rate designs may include critical peak pricing or technology specific rates. Critical peak pricing can be used to signal when energy prices are extremely high – for example, on a hot summer day. During these periods the energy price may increase significantly, and the price signal sent to customers would encourage them to shift their energy usage to a non-peak period or pay a higher price. There are a variety of peak demand rate design structures the Company may explore, such as peak time rebates. Similarly, technology specific rates may encourage customers to not use certain end-uses during periods of the day when demand is higher. For example, an EV TOU rate may encourage customers to charge electric vehicles off peak but may also include incentives or signals for customers to not charge at the same time. Investments in the FAN and AMI will allows us to send and receive the data we need in order to manage these types of rates and provide customers with detailed information about how to respond to these signals.

Q. WHAT ARE THE COMPANY'S PLANS RELATED TO THE CAPABILITIES OF THE ADVANCED GRID TO SUPPORT REMOTE CONNECTION AND DISCONNECTION SERVICES?

A. As I noted above, the advanced grid enables remote connection and disconnection capabilities. There are both customer benefits and costs savings related to these capabilities. However, any changes to our provision of these services to customers will require filings with the Commission for approval. These proceedings will allow for full review of the proposed services by the Commission and stakeholders. Mr. Cardenas addresses remote connection and disconnection and the necessary future filings in his testimony.

3. Distributed Intelligence

Q. PLEASE SUMMARIZE THE DISTRIBUTED INTELLIGENCE PLATFORM.

A. Distributed Intelligence refers to the Linux-based operating system built directly into the meter. This operating system provides the meter with the ability to conduct localized computing, analysis, and data processing. This work is done through applications that are installed by Xcel Energy on the meter. These applications may be customer-facing, meaning the customer directly interacts with them, or grid-facing – meaning, Xcel Energy interacts with the applications. Ms. Bloch discusses the technology behind the DI platform further in her Direct Testimony.

Q. WHAT ARE SOME OF THE FUNCTIONALITIES OR APPLICATIONS THAT HAVE BEEN ENVISIONED FOR THE DI PLATFORM?

A. We are actively considering a number of potential applications such as:

- Virtual Submetering – this application meters an end-use technology, such as an EV, in lieu of a physical submeter installation. This virtual metering reduces costs and can allow for submetered technologies to be billed on a different rate than the primary meter.
- Smart Feeder Restoration – when there is insufficient capacity to immediately restore all of the service to a feeder this application will sequentially restore power to critical loads (*e.g.* a hospital or fire station) first.
- Power Quality Analysis – this application can provide a regular or on-demand analysis of the quality of the power coming into a premise and on-site. If anomalies in the quality are detected it can advise the customer on next steps to address the potential anomalies.
- Green Notifications – this application may alert customers about the status of carbon free electricity on the system. This type of notification, relying on system data, would encourage customers to shift their energy usage during these periods to reduce their carbon footprint.

Because the Distributed Intelligence platform is a newer technology, we continue to research and collaborate with our vendor partner we expect to identify additional use cases and applications for use with the DI platform. We also expect to have robust engagement with other third-parties to develop additional use cases.

Q. HOW WILL APPLICATIONS FOR THE DI PLATFORM BE DEPLOYED?

A. Application deployment will be managed by Xcel energy in order to ensure that all applications meet our strict cybersecurity and technical requirements. Because these applications are installed directly on the meter there is serious risk to allowing open access to the meter. However, we are committed to offering a broad suite of applications that offer customer and grid benefits. How these applications are made available will vary as some may be offered as standalone products while others are offering as a package with participation in other programs. Grid facing applications will not be made available to customers but instead managed internally by Xcel Energy departments that need the functionality they provide for grid management.

4. DER Integration

Q. WHAT IS THE COMPANY'S CURRENT EXPERIENCE WITH THE INTEGRATION OF DERS?

A. Today, we interface with all types of DERs – DSM, EVs, solar, and batteries. In some cases, we have over 20 years of experience managing DERs on our system and have developed effective policies to ensure DERs provide customer and grid benefits without impacting safety and reliability. Without quality, granular data, we must manage the integration of DER conservatively. Access to more granular data will result in a more accurate analyses of DER impacts and a more refined approach to DER integration.

Q. HOW WILL THE AGIS INVESTMENTS IMPROVE THE COMPANY'S ABILITY TO INTEGRATE DERS?

A. AGIS investments will allow us to better understand the grid and impacts that DERs have to it. With this information we can conduct more accurate analyses of the impacts of DERs and track the impacts in near real time. This will allow us to integrate more DERs and in the future manage DERs in a collaborative way to ensure we maximize their benefit to the system. AGIS investments that are critical to this are the ADMS platform and AMI. In the future DERMS may also help integrate and manage DERs more efficiently.

Q. WHAT BENEFITS WILL DER INTEGRATION HAVE FOR CUSTOMERS?

A. In addition to better system management which will yield lower operating costs we also expect that we will be able to accommodate more DERs on the system providing customers with more access to new technologies that have environmental, energy saving, and customer satisfaction benefits. With our commitment to a 100 percent carbon free future we fully realize the value that DERs can provide to meeting this ambitious goal and we can only meet this goal by maximizing the value that all potential resources can provide. Ms. Bloch discussed DER integration, including our plans for EVs, further in her Direct Testimony.

D. Long Term

Q. PLEASE DESCRIBE THE CUSTOMER EXPERIENCE DURING THE LONGER TERM PERIOD (THROUGH 2030).

A. We cannot definitively say what will happen during this period because of the unknowns with technological advancement and how customer expectations will change. However, at this time we envision a transformation in how we do business with our customers. This will be punctuated by more sophisticated products and services that begin to integrate multiple customer systems into broader grid management. This aggregation of systems will allow for more flexibility in grid management.

We will work with our customers to become an orchestrator of the grid helping individuals and communities achieve broad energy goals. This orchestration role will relieve the customer of much of the burden of management around their energy goals. Xcel Energy will understand, in greater detail, our customers' expectations and goals and will work with third-parties to achieve those goals with minimal effort from customers.

Q. WHAT IS THE ROLE THAT THE AGIS INVESTMENTS WILL PLAY IN SUPPORTING CHANGES TO THE CUSTOMER EXPERIENCE DURING THIS PERIOD?

A. ADMS, the FAN, and AMI provide the foundational tools we need to help manage the grid and integrate increasing levels of DERs on the system. As new applications in ADMS and the DI platform are introduced we can more efficiently manage the grid because the computing power is more local thereby reducing the response time to a system need. The functional ability of our AGIS components to process information more quickly, more reliably, and more accurately will support not only support these customer experience investments but remain capable of supporting investments over the long term.

In the future, additional AGIS investments may be necessary to further the integration of more DER as customers introduce more electric end-use technologies (EVs, electrically heated homes, and other DERs) to the grid. One such investment may be in the aforementioned DERMS.

Q. WHAT DO YOU BELIEVE WILL BE THE OUTCOME IF THE COMPANY DOES NOT MAKE INVESTMENTS IN ADVANCED GRID CAPABILITIES?

A. Without advanced grid capabilities, the Company's ability to meet evolving customer expectations will be limited. Although we have and will continue to strive to provide the services and information our customers expect, our current system technology does not support two-way communications, or the granular energy usage data that will enable the Company to roll out advanced rates, and realize the energy and cost savings they can provide.

Q. OVERALL, CAN YOU SUMMARIZE WHAT WILL BE DIFFERENT FOR CUSTOMERS UPON IMPLEMENTATION OF AGIS?

A. Upon the implementation of AGIS, customers will begin to see benefits in reduced outage times and new products and services to help control their energy usage. With reduced outage times will also come the ability to better inform customers about the status of their outage. Not knowing why you're out and when you will be restored is frustrating for customers. With the investments in AGIS we'll be able to provide customers with more accurate timelines for restoration keeping them better informed about their status. We'll also be able to proactively identify and restore customers rather than wait for a customer to contact us as our current technology requires.

With new products and services, we'll be able to offer customers a range of new ways to control their energy usage. Advanced rate designs, such as time-of-use, critical peak, and technology specific rates will be possible without additional metering. We will also be able to use the more detailed data provided by the customer's meter to personalize the recommendations and information we provide them. This will help customers make more informed decisions about what steps to take rather than rely on general energy efficiency recommendations that we provide today and may not always be actionable or insightful to an individual.

Over time, we'll also be able to use our advancements in AGIS to better align programs and use the Distributed Intelligence platform to provide new, seamless interactions. Better alignment and new ways of engaging customers can keep them more involved in their energy usage and give them more control in ways – such as a mobile devices – that are increasingly prioritized.

Even with uncertainty around the long-term future customer experience, the Company remains committed to understanding customers' preferences and considerations regarding the benefits and value of advanced grid investment as technologies evolve and new technologies become available over time. Our investments in how we understand and work with our customers, combined with the foundational investments in the grid through our AGIS initiative, will provide us with the resources we need to adapt quickly to changes in technology and customer expectations.

E. Customer and Community Outreach

Q. HAS THE COMPANY DEVELOPED A DETAILED PLAN FOR CUSTOMER AND COMMUNITY OUTREACH RELATED TO AGIS IMPLEMENTATION?

A. Yes. The Company has developed a detailed Customer Education and Communication Plan (Communication Plan), which is provided as Exhibit___(MCG-1), Schedule 8. This plan details the communications strategies, messages, and tactics to be executed in three phases to match the customer's experience as we implement advanced grid capabilities.

Q. HOW WAS THE EDUCATION PLAN DEVELOPED?

A. We developed our Communication Plan based on (1) the Company's experience with advanced meter pilots and advanced grid technology initiatives for NSPM as well as other Xcel Energy operating companies; (2) examination of communication and outreach best practices among other utilities with advanced grid and advanced meter deployment experience; and (3) customer research efforts.

Q. WHAT SPECIFIC RESEARCH DID THE COMPANY CONDUCT TO DEVELOP ITS AGIS OUTREACH STRATEGY?

A. Xcel Energy has conducted qualitative customer research through focus groups in Minnesota and throughout the service territory of its other operating companies. The results of this research have informed message development and the strategic updates to this plan. Objectives of this research included exploring customers' understanding of advanced meters, perceived benefits and drawbacks of advanced meters, both positive and negative expectations about moving to advanced meters, what barriers may arise and how to address them, and customer preferences for information and communication methods.

Q. WHAT ARE THE KEY LESSONS LEARNED, BEST PRACTICES, AND TAKEAWAYS FROM THE CUSTOMER RESEARCH EFFORTS?

A. The lessons learned, best practices, and results of our customer research efforts are outlined in the Communication Plan. Key takeaways that we have considered in the development of our AGIS outreach strategy include:

- Customers want to hear from Xcel Energy about the transition to the new meters at least two or three months in advance of installation via a multi-channel approach.
- Customers believe the new meters could help them save money by providing more detailed usage information, which they perceive as empowering.
- The potential cost of the new meters is the top barrier that Xcel Energy needs to address.

I note that our research also shows that customers better understand the term "smart meter" as opposed to "advanced meter" or "AMI." We therefore used "smart meter" in our customer education planning to make the information more accessible, whereas "AMI" is used throughout our AGIS discussions because it is the more correct technical and industry term.

Q. PLEASE OUTLINE THE COMPANY'S EDUCATION PLAN.

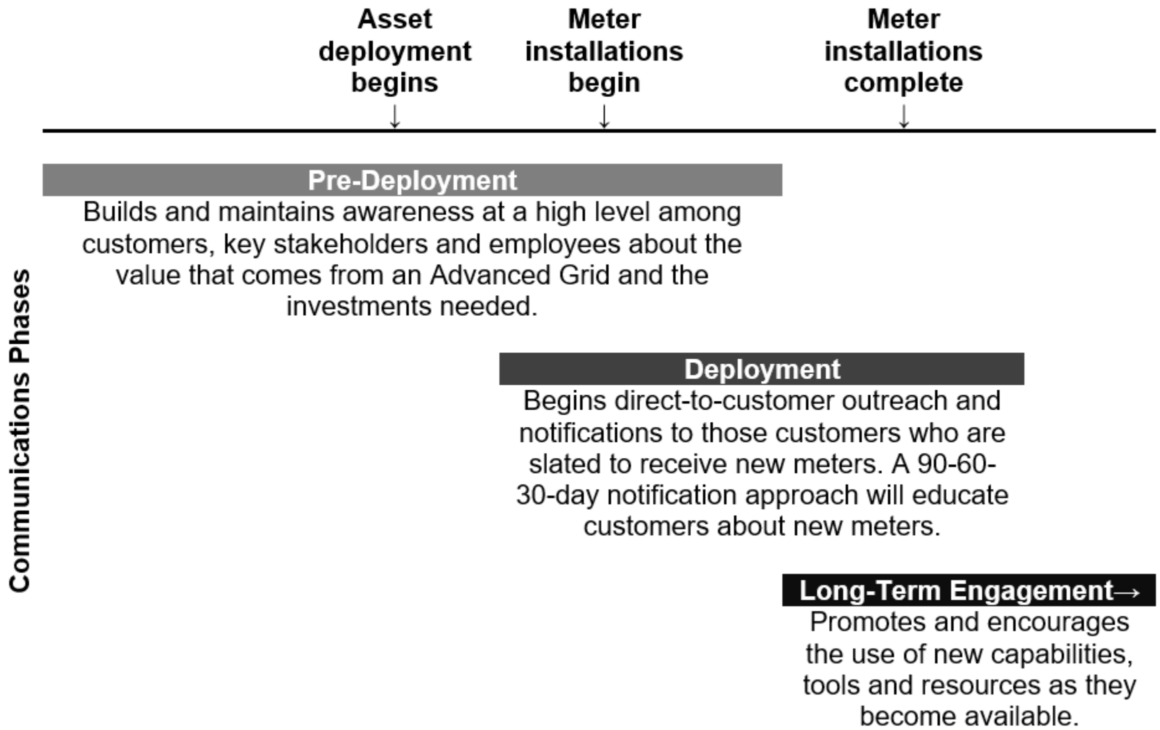
A. Our comprehensive Communication Plan provides the strategies, messaging, and tactics that will be executed in three phases to match the customer journey as we move through AMI meter installation and implementation of advanced grid capabilities. While the Communication Plan focuses primarily on the customer experience, the plan also details our efforts with respect to other key audiences that will help support customer awareness, understanding, and engagement through this transition. These audiences include: (1) community leaders and elected officials; (2) our Customer Care agents; and (3) all Company employees. Our plan also identifies how we will communicate with different customer groups, and details any communications considerations relative to specific customer segments, such as low-income or non-English speaking customers.

The overall goals of the plan are to:

- Ensure a smooth, integrated experience for all customers;
- Provide customers with relevant, up-to-date, practical information about new meters and programs through multiple channels; and
- Minimize confusion through proactive, multi-channel communications.

Our phased approach will coincide with meter deployment and advance grid capabilities as they are phased in over the next five years.

Figure 1



1. Pre-Deployment Phase

Q. PLEASE DESCRIBE THE PRE-DEPLOYMENT PHASE OF THE COMPANY'S EDUCATION PLAN.

A. The pre-deployment phase focuses on building and maintaining awareness of advanced grid capabilities at a high level among customers, key stakeholders, and employees. This will include communication and education about the value that comes from an advanced grid and the investments needed. Advanced grid will be presented as one of the Company's platforms for bringing innovative technological solutions to enhance the customer experience. The pre-deployment phase is designed to set the stage for meter installation, and will in late 2020, before AMI installations will begin, and continuing through mid-2023 in order to maintain awareness.

Q. WHAT ARE THE KEY OBJECTIVES DURING PRE-DEPLOYMENT?

A. Key objectives during this phase include:

- Create customer and stakeholder awareness about the overall benefits of the advanced grid;
- Explain why we are making this investment, focusing on tangible customer benefits;
- Educate and train employees to equip them with tools and resources necessary to engage with customers and stakeholders;
- Build customer interest in the change by explaining the benefits of advanced meters and the tools and options they enable; and
- Proactively address customer concerns and questions.

Q. WHAT ARE THE COMPANY'S SPECIFIC PLANS FOR COMMUNICATIONS AND EDUCATION EFFORTS RELATED TO ADVANCED GRID AWARENESS?

A. The Company has developed an integrated, expansive, and multi-channel approach to build awareness of advanced grid capabilities and to set the stage for AMI meter installations. We will build awareness by leveraging a variety to channels in order to reach as many customers as possible. Channels include XcelEnergy.com, social media, traditional media outreach, mass advertising, and community events. The attached Education Plan provides the details of the messages, communication channels, and materials that are being developed for each of the four key audiences.

2. Deployment Phase

Q. PLEASE DESCRIBE THE COMPANY'S EDUCATION PLAN DURING THE DEPLOYMENT PHASE.

A. The deployment phase focuses on education related to AMI meter installation. During this phase, we will begin direct-to-customer outreach and notifications to those customers who are slated to receive new meters. A 90-60-30-day notification approach will educate target audiences on the new meters, how they will be deployed and installed, and their benefits. While messaging and content will focus on meter installation, all communications will speak to the broader value and benefits of the advanced grid. This phase will also set the stage for the communications plan over the longer term by collecting customer information and preferences that can be used as new capabilities are enabled and to create deeper long-term customer relationships.

Q. WHAT ARE THE KEY OBJECTIVES OF THE DEPLOYMENT PHASE?

A. Key objectives during this phase include:

- Provide practical and timely information and notifications about the deployment, installation, and opt-out processes;
- Provide clear information on the opt-out process and associated costs, including how to take action;
- Leverage a messaging hierarchy to reiterate high-level benefits of advanced metering; and
- Further develop tools and resources for employees to use during proactive discussions with customers and stakeholders.

Q. WHAT ARE THE COMPANY'S SPECIFIC PLANS FOR COMMUNICATIONS AND EDUCATION EFFORTS RELATED TO METER INSTALLATIONS?

A. Communication efforts during this phase will provide practical, specific information to customers about meter deployment. Customers will receive notifications about their new meters 90 days, 60 days, and 30 days prior to meter installation through various channels to ensure all customers receive adequate notification. Where possible, materials will be personalized with the most relevant and up-to-date deployment information. The communications plan also provides for a phone call seven days before installation, and a follow-up communication after installation. The attached Education Plan provides the details related to timing and methods for the installation notifications, and the details of the messages, communication channels, and materials that are being developed for each of the four key audiences. The Education Plan also includes sample materials for meter installation communications.

Q. HOW WILL THE EDUCATION PLAN INCORPORATE DETAILS WITH RESPECT TO CUSTOMER INTERACTIONS WITH THE METER INSTALLATION VENDOR?

A. The Company and the meter installation vendor will work together to provide coordinated support and address all customer inquiries and any issues that may arise. The meter installation vendor will be a key point of contact for the Company's customers during the meter installation process and will have a dedicated call center phone number for Xcel Energy's customers. Mr. Cardenas provides additional detail in his testimony. We will work closely with Customer Care to ensure the communications and materials we will provide to customers prior to and during the installation will include clear directions and contact information so any questions or issues will be resolved as quickly as possible.

Q. ALTHOUGH AMI TECHNOLOGY AND ADVANCED GRID CAPABILITIES WILL ENABLE THE NEW AND ENHANCED PRODUCTS AND SERVICES FOR CUSTOMERS, WILL CUSTOMERS BE ABLE TO OPT OUT OF RECEIVING AN ADVANCED METER?

A. Yes. The Company believes that customer should have the choice to opt-out of receiving an advanced meter. However, the Company can provide the greatest benefits for our customers by deploying advanced meters consistently across our service territory. The Company will provide information on the benefits enabled by advanced metering while also providing clear information on the opportunity to decline the installation of an advanced meter or have an advanced meter removed at any time.

Q. HAS THE COMPANY DEVELOPED A FRAMEWORK FOR CUSTOMER OPT-OUTS?

A. Yes. We have developed a framework under which a customer may opt-out of advanced meter installation. In his testimony, Mr. Cardenas details the opt-out framework that the Company will propose in a separate filing submitted to the Commission. Once the opt-out provisions are finalized and approved by the Commission, we will ensure the process details, costs, tariff sheets, and any other necessary information and materials are incorporated into our customer communications plan.

Q. GIVEN THE BENEFITS OF AMI, HOW DOES THE COMPANY PROPOSE TO MINIMIZE THE POTENTIAL FOR CUSTOMER OPT-OUTS FOR ADVANCED METERS?

A. It is important to have a concentration of advanced meters to achieve the benefits of better identifying outage locations and of making time-of-use or other conservation-incentive rates widely available. It is also necessary to broadly deploy advanced meters to capture the benefits of reduced home visits and fewer meter reading costs. The Company's customer education and awareness campaign is designed to address many of the questions or concerns that customers have with advanced meters including privacy and safety. Communications will also discuss the benefits that an advanced meter provides including opportunities to reduce energy costs and improve their environmental impact. Customer care representatives will also be trained to address customer questions and concerns. The Company believes the most effective way to reduce the potential for customer opt-outs is to provide proactive, informative education to ensure customer questions and concerns are fully understood and addressed by the Company.

Q. WILL CUSTOMERS BE ABLE TO OPT OUT OF TARGETED MARKETING THAT MAY BE ENABLED BY THE ADVANCED GRID TECHNOLOGIES?

A. Yes. With advanced metering technology, the Company will be able to provide customers with enhanced energy usage data, including interval data, and will have the ability to disaggregate some end-use technologies from the customer's total energy usage. This information can be used to better market products and services that save money to customers and to improve a customer's awareness of their energy usage. However, we recognize that some customers may not want to receive targeted marketing, and the Company will provide customers the choice to opt-out of receiving this information. This option is similar to a customer's choice to opt-out of the Company's current Home Energy Report or to select how they receive notifications today. In the future, the Company expects to be able to provide customers more choice around how they receive communications to better reflect their preferences.

3. Long Term Engagement Phase

Q. PLEASE DESCRIBE THE COMPANY'S EDUCATION PLAN OVER THE LONGER TERM.

A. After AMI deployment, will promote and encourage the use of new advanced grid capabilities, tools, and resources as they become available. Communications will not only highlight the features of new tools and resources, but the broader benefits they can provide, such as:

- *Economic benefits:* With more information on energy consumption and more choices about how and when they use energy via possible future rate options, consumers may be able to save money as a result of advanced grid-enabled programs and technologies.
- *Environmental benefits*: The advanced grid enables the incorporation of greater amounts of renewable generation, gives customers more opportunities to make more environmentally conscious choices, and can also reduce the need to rely on fossil fuel generation.
- *Reliability benefits:* Grid-side intelligence offered by advanced grid technology can reduce the frequency and duration of outages while providing better information for customers when outages do occur.

This phase will also leverage customer information and preferences gathered during the deployment phase to provide a seamless experience for all customers via their preferred channels.

Q. WHAT ARE THE KEY OBJECTIVES OF POST-DEPLOYMENT CUSTOMER COMMUNICATIONS?

A. Key objectives during this phase include:

- Educate customers on new capabilities, tools, and resources as they become available.
- Develop and execute a customer campaign to follow the customer journey and encourage adoption of new capabilities, tools and resources.
- Leverage a messaging hierarchy to reiterate high-level benefits of the advanced grid and advanced metering.
- Evaluate and refine messages and tactics to continuously improve and ensure the best possible customer experience.

Q. WHAT ARE THE COMPANY'S SPECIFIC PLANS FOR COMMUNICATIONS AND EDUCATION EFFORTS RELATED CUSTOMER ENGAGEMENT IN ADVANCED GRID CAPABILITIES?

A. A multi-channel approach will reach customers via their preferred channels and include tailored messages to move them along in the engagement journey. The attached Education Plan provides the details of the messages, communication channels, and materials that are being developed for each of the four key audiences. In addition, I note that we will also develop the necessary materials and communications plans for any advanced rate design or service offerings that will be enabled by advanced grid capabilities. As discussed above, such offerings – such as a full residential time of use rate – will go through an approval process at the Commission and may involve a stakeholder engagement process to inform development.

4. Customized Communications

Q. WHAT ARE THE COMPANY'S PLANS FOR CUSTOMIZED COMMUNICATIONS FOR FIXED AND LOW-INCOME CUSTOMERS?

A. Customized communications will recognize and proactively address cost concerns among low-income households, seniors, and vulnerable customer populations. We will engage community leaders, influencers, and representatives of these communities in the development and deployment of our educational efforts. Messages will address how customers on fixed or limited budgets can take advantage of personal energy use information that may allow them to better manage their energy costs. Outreach will also focus on increasing these customers' participation rates in energy efficiency and conservation programs, and cross-marketing the state's energy assistance programs. Communication and education materials that could be customized for this segment of customers may include:

- FAQs and fact sheets to address specific concerns and needs.
- Talking points and scheduled briefings with consumer advocacy groups and nonprofit groups who serve these populations.
- Customized presentations for community relations staff to share with their community leaders.
- Outreach to organizations serving seniors, low-income, and other vulnerable customer segments, with an emphasis on providing ready-to-use materials that can be distributed via their communication channels, online resources, events, meetings, and social media platforms.

Q. WHAT ARE THE COMPANY'S PLANS FOR CUSTOMIZED COMMUNICATIONS FOR NON-ENGLISH SPEAKING CUSTOMERS?

A. According the U.S. Census Bureau's American Community Survey (ACS), in 2017, 11.3 percent of Minnesotans spoke a language other than English at home. After English, the most common language spoken at home is Spanish, with close to 200,000 speakers.[39] As such, the Company's website (xcelenergy.com) will include material related to the advanced grid in Spanish.

Q. WHAT ARE THE COMPANY'S PLANS FOR CUSTOMIZED COMMUNICATIONS FOR CUSTOMERS WITH LIFE-SUPPORTING EQUIPMENT?

A. Prior to any direct communication regarding meter installation, the Customer Contact Center will proactively reach out to customers who rely on life-supporting equipment in their homes. These customers will have the option to opt out of the new meter, or make an installation appointment and have a bridge installed to avoid a service interruption.

Q. WHAT ARE THE COMPANY'S PLANS TO ENSURE COMMUNICATIONS ARE ACCESSIBILE FOR ALL CUSTOMERS?

A. The Company has a number of options in place to assist customers and ensure accessibility for all.

- Deaf or hearing-impaired customers can dial 711 to be connected with the state transfer relay service. This service allows callers to communicate with text-telephone (TTY) users. This service is available 24/7 and is confidential.
- The company's Contact Center can make outbound calls using TTY technology.
- Any residential customer may request a large print bill statement.
- Customer emails and our website and online tools are continually reviewed, and we make improvements to ensure accessibility.

[39] U.S. Census Bureau, 2013-2017 American Community Survey 5-Year Estimates, https://factfinder.census.gov/bkmk/table/1.0/en/ACS/17_5YR/B16001/0400000US27.

Q. WHAT ARE THE COMPANY'S PLANS FOR COMMUNICATION AND EDUCATION EFFORTS FOR COMMERCIAL AND INDUSTRIAL (C&I) CUSTOMERS?

A. We expect our broad awareness communications will be applicable to small C&I customers as well, but we will also provide customized 90, 60, and 30-day meter install notifications for those customers. The content of these communications will vary depending on the customer's current tariff to ensure they receive the most relevant information. The Company has dedicated account managers for large C&I customers, who will help ensure a smooth experience before, during, and after meter installation.

Q. WHAT ARE THE COMPANY'S PLANS TO ENSURE CUSTOMERS ARE INFORMED OF THEIR CHOICES RELATIVE TO OPTING-OUT OF ADVANCED METER INSTALLATION?

A. As I discussed earlier, the Company believes customers should have the choice to opt-out of receiving an advanced meter. To that end, our communications and education materials will clearly inform customers of the opt-out process, the associated costs, and how to take action. The Company will clearly provide customers with the opportunity to decline the installation of an advanced meter or have an advanced meter removed at any time.

As also noted earlier, we have developed a framework under which a customer may opt-out of advanced meter installation; however, we are not seeking approval of specific opt-out provisions at this time. Mr. Cardenas discusses the opt-out framework in his testimony. We will work with Customer Care as these opt-out provisions and options are finalized to develop the communication channels and materials to clearly present these options to customers.

Q. HOW DOES THE COMPANY PROPOSE TO MINIMIZE THE POTENTIAL FOR CUSTOMER OPT-OUTS FOR ADVANCED METERS?

A. As discussed throughout my testimony, the Company can provide the greatest benefits for our customers by deploying advanced meters consistently across our service territory, thus it is in our customers' interests for us to minimize opt-outs for advanced meter installation. Our Education Plan is designed to address many of the questions or concerns that customers have with advanced meters, including privacy and safety. Communications will also discuss the benefits that an advanced meter provides, including opportunities to reduce energy costs and improve their environmental impact. Customer Care representatives will also be trained to address customer questions and concerns. The Company believes the most effective way to reduce the potential for customer opt-outs is to provide proactive, informative, and meaningful education to ensure customer questions and concerns are fully understood and addressed by the Company.

Q. HOW WILL THE COMPANY DETERMINE WHETHER THE CUSTOMER COMMUNICATION EFFORTS HAVE BEEN SUCCESSFUL?

A. In Section VIII below, I discuss our proposed progress metrics, which will be based on operational metrics as well as customer surveys. I also discuss how we will report the information on our customer communications and education efforts.

Q. ARE THE COSTS RELATED TO EXECUTION OF THE EDUCATION PLAN INCLUDED IN THIS CASE?

A. Yes. The costs related to the AGIS Education Plan total approximately $6.3 million over the implementation timeline discussed above. These costs are included in the overall AGIS program management budget in Distribution Operations, as presented in Ms. Bloch's testimony. I also discuss the development of program management cost forecasts in Section V.D.2.

VII. PRUDENCE OF THE AGIS INVESTMENTS

Q. WHAT INFORMATION DO YOU PROVIDE IN THIS SECTION OF YOUR TESTIMONY?

A. In this section I provide an overview and summarize the results of the Company's analyses of the quantitative and qualitative cost and benefits of the various components of the AGIS initiative, as well as of the consolidated program. I also discuss the purpose and limitations of a strictly quantitative cost-benefit analysis and present the qualitative benefits of AGIS implementation that should also be considered. Company witness Dr. Duggirala provides a detailed discussion of the Company's cost-benefit analyses in his Direct Testimony, both with respect to the Company's cost-benefit model and least-cost/best fit analyses.

A. The Company's Cost Benefit Analysis

1. Overview of AGIS Cost-Benefit Analysis

Q. DID THE COMPANY UNDERTAKE A COST-BENEFIT ANALYSIS TO ASSESS THE QUANTITATIVE COSTS AND BENEFITS OF THE AGIS INITIATIVE?

A. Yes. The Company conducted separate detailed cost-benefit analyses (CBAs) for each of the following components of the AGIS initiative: AMI, FLISR, and IVVO, with costs of the FAN (which is a supporting component that does not provide standalone measurable benefits) incorporated into each analysis of the other components. The Company provides resulting benefit-to-cost ratios for each of these components individually, as well as a total AGIS CBA, both with and without contingency amounts. While the Company expects to use some component of the contingency amounts, by definition the total amount of contingency the Company will use is not fully predictable at this time. Therefore, we show totals with and without contingency to illustrate the outer boundaries of benefit-to-cost ratio ranges.

Q. WHAT IS THE PURPOSE OF THE CBA?

A. A CBA is one tool to evaluate potential quantifiable costs and benefits of the core AGIS components, including AMI, FLISR, and IVVO, and supporting FAN costs. It can capture most costs (which are in themselves quantifiable), but only compares quantifiable projected benefits, such as O&M and capital expenditures savings and known quantifiable societal benefits.

Q. DOES THE COMPANY RELY PRIMARILY OR EXCLUSIVELY ON CBAS TO APPROVE OR REJECT PROJECTS LIKE THE AGIS INITIATIVE?

A. No. While we utilize CBAs as one tool to assess larger projects, we are always cognizant of the limits of a CBA. A cost-benefit model cannot capture other benefits that cannot be quantified, such as customer satisfaction, power quality, improved safety, and the like. As a result, the CBA is a useful tool but does not provide a complete picture of the costs and benefits of any given program.

Those modeling limitations become even more pronounced where, as here, a large portion of the costs of the AGIS initiative are unavoidable because they are associated with addressing aging metering assets that are central to core utility functioning. Given the issues with our existing meters noted earlier in my testimony and discussed in detail in the testimony of Mr. Cardenas and Ms. Bloch, the question is less whether to pursue a metering solution at all, and more whether to pursue more current technology to align with the industry and system needs, which can also offer our customers functionality they have come to expect from their service providers.

Q. WHAT IS THE COMPANY'S OVERALL APPROACH TO THE AGIS CBA?

A. Our overall approach for the CBA is to provide a customer-focused, conservative look at the AGIS investments. In other words, we have incorporated estimated customer benefits enabled by the advanced grid, but have used conservative estimates to avoid overstating these benefits. Likewise, we have include our current cost estimates, both with and without contingencies, to provide the range of results for consideration. The CBA covers the life of the proposed assets, rather than just the MYRP period, in order to examine values for the overall AGIS initiative beyond the MYRP term. Dr. Duggirala provides further discussion on the CBA design.

Q. PLEASE DESCRIBE THE OUTPUTS OF THE CBA AT A HIGH LEVEL.

A. At a high level, the CBAs present the net present value of costs and benefits on a 2019 base year net present value (NPV) basis. From a benefit-to-cost ratio perspective, a ratio greater than one (1) indicates the quantifiable benefits that can be converted to dollar values exceed the costs, and vice-versa. Of course, as previously noted, the benefit-to-cost ratio excludes qualitative benefits and other considerations such as the business's dependence on the systems being evaluated. As a result, it is not surprising that some of our benefit-to-cost ratios for AGIS components exceed 1.0, while others do not.

Q. HOW DID THE COMPANY DEVELOP THE COST INPUTS FOR THIS ANALYSIS?

A. At a high level, the Company developed the cost inputs by relying on subject matter experts in our various areas of the Company to assess the hardware, software, labor, and processes necessary to implement the various programs of the AGIS initiative. Cost development was based on such items including, but not limited to, RFPs, contracts, labor rates, company experience, and other pricing efforts.

Q. WHAT BUSINESS AREAS DEVELOPED COST INPUTS FOR THE CBA?

A. Primarily, our Distribution and Business Systems organizations developed the cost inputs for the CBA. The overall AGIS budget is split between these two business areas, as they are responsible for implementing the technologies and systems for the AGIS initiative. Information supporting the capital investments and O&M expenses related to the AGIS initiative is provided in the direct testimony of Ms. Bloch and Mr. Harkness. Their testimonies address both the specific costs included the multi-year rate plan period as well as the development of cost inputs for the CBA.

Q. ARE THERE COSTS NECESSARY FOR AGIS IMPLEMENTATION THAT ARE RELATED TO AREAS OF OPERATION OTHER THAN DISTRIBUTION AND BUSINESS SYSTEMS?

A. Yes. Like any other project of this size and scope, the AGIS initiative touches many areas of our business, and there are costs necessary for overall program management that are not developed by Distribution or Business Systems. For example, in Section D.2. above, I provided the costs for Program Management. Other program management cost inputs that are necessary for delivery of the overall AGIS project were developed for business areas such as Supply Chain, Finance, and Human Resources. These program management costs are all reflected in the Distribution or Business Systems budgets, either by direct assignment to, or allocation among, the appropriate AGIS components. I also identified the costs for execution of our Customer Education and Communications Plan as we install AMI meters and implement advanced grid capabilities. While these costs were developed by Corporate Communications, they are accounted for in the overall AGIS budget within Distribution.

Q. PLEASE FURTHER DESCRIBE THE CONTINGENCY AMOUNTS INCLUDED IN THE CBAS.

A. The costs associated with AMI, FAN, FLISR, and IVVO installation, and the necessary IT integration, include contingency amounts, which are detailed further in the Direct Testimony of Company witnesses Mr. Harkness and Ms. Bloch. These estimates appropriately reflect corresponding risk allowances and contingencies for inherent uncertainties associated with budget estimates at the current stage of project development and approval. Consistent with our conservative approach, we have reflected these contingencies in our CBAs.

Q. WHY DOES THE COMPANY BELIEVE THAT UTILIZING SUCH CONTINGENCIES IS APPROPRIATE?

A. Using contingencies is consistent with project planning practices, especially for large technology projects that implement new technologies and require major changes to enterprise IT systems. Further, the size, scope, and complexity of the AGIS initiative, as well as the multi-year implementation schedule, warrants the use of budget contingencies. While we have undertaken initial planning, benchmarking, and research, and have based our budget estimates on all known design and installation details, there remain uncertainties with respect to specific Minnesota requirements that will not be known until after Commission approval of the projects, and unknowns that may develop through the installation phases.

Further, while we believe the budgets including contingency amounts appropriately account for certain costs that may be incurred but are currently unknown, we do not look at the contingency amounts as additional budget dollars that can simply be used in any way for project implementation. Rather, use of any of the contingency amounts would only occur if cost changes are determined to be necessary, and changes have gone through the appropriate review and approval processes described in Section V.D of my Direct Testimony. As described, the Company has implemented a robust AGIS governance process to ensure the project is implemented and provides value for our customers.

Q. WHAT IS THE CONTINGENCY PERCENTAGE FOR THE AGIS INITIATIVE OVERALL?

A. The AGIS initiative capital budget forecast for the period 2020-2025 includes an overall contingency percentage of approximately 26 percent, with individual component contingencies varying depending on the complexity, size, and scope of work (as discussed by Ms. Bloch and Mr. Harkness).

Q. IS THIS CONSISTENT WITH CONTINGENCY LEVELS FOR OTHER COMPANY PROJECTS AND THOSE USED ACROSS THE INDUSTRY?

A. Yes. The Company includes contingency amounts for large projects that are appropriate to the stage of development and scope of the project. A 26 percent overall contingency AGIS at this stage of project development is very much in line with industry standards for large technical and IT projects that span multiple years, and is appropriate for the complexity, size, and integrated nature of the AGIS project.

Q. ARE THERE INDUSTRY GUIDELINES FOR ESTABLISHING CONTINGENCY AMOUNTS FOR CAPITAL PROJECT ESTIMATES?

A. Yes. The Association for the Advancement of Cost Engineering (AACE International) is the leading professional society for cost estimators, cost engineers, schedulers, project managers, and project control specialists. AACE International recommends a combination of project and process contingencies for large capital projects. Project contingency recommendations are based on the level of project definition at the time the estimate is developed, with a range of recommended contingencies between 5 and 50 percent. Process contingency recommendations are based on the programmatic or technical uniqueness and complexity of the project, with a recommended range of contingencies between 0 and 40 percent (or more).

Q. HOW DO THE CONTINGENCY BUDGETS FOR EACH OF THE AGIS COMPONENTS FACTOR INTO THE OVERALL CONTINGENCY AMOUNT?

A. As previously noted, contingency levels vary between the individual AGIS components because they are based on the current stage of project development, outstanding contract finalizations, and the specific scope of work and integrations necessary for the individual projects. The overall capital contingency levels for each of the AGIS components for the period 2020-2025 are shown in the Table 9 below.

Table 9

AGIS Project Contingencies			
AGIS Program	**Business Systems**	**Distribution**	**Combined**
AMI	37%	26%	27%
FAN	45%	0%	39%
FLISR	24%	12%	14%
IVVO	10%	10%	10%

Q. ARE THESE CONTINGENCY LEVELS FLAT WITHIN EACH AGIS COMPONENT?

A. No. Just as the overall contingency levels vary between the different AGIS components, the contingency levels also vary between the Distribution and Business Systems budgets for the same AGIS component. This is due to the differences between IT and Distribution work, and helps to ensure reasonable contingency amounts that are tailored to the individual components and work to be done. For example, IT projects generally have a higher contingency for several reasons, including the unknowns around the integrations with new and legacy systems, and necessary security controls that may evolve over the course of project implementation, to name a few. Mr. Harkness and Ms. Bloch discuss the reasons contingencies for their work on each AGIS component is needed and why these estimate are reasonable given the specific project scopes and stages of project development.

Q. DOES THE INCLUSION OF A CONTINGENCY AMOUNT IN A CBA OR INITIAL BUDGET MEAN 100 PERCENT OF THE CONTINGENCIES MUST BE CONSUMED THROUGH THE PROJECT?

A. No. In this case, the Company worked to develop a conservative budget to provide a fair view of potential costs and benefits. If the Company does not utilize all of the contingencies in order to realize the benefits of the advanced grid, the benefit-to-cost ratio of these programs will only improve.

Q. HOW WILL THE COMMISSION BE INFORMED OF PROJECT COSTS AND WHETHER CONTINGENCY AMOUNTS ARE BEING USED, AND TO WHAT EXTENT, DURING THE COURSE OF THE MULTI-YEAR RATE PLAN?

A. The Company is requesting approval in this proceeding to recover these amounts in base rates, but also for certification of these programs to provide the opportunity for the Company to request cost recovery in the TCR Rider after the end of the MYRP. Annual filings will enable the Commission to see what amounts are being spent and on what items. Likewise, the Company has proposed a capital true-up through Company witness Ms. Amy Liberkowski, and is proposing regular AGIS filings with the Commission as I describe later in my testimony. Each of these methods will provide the Commission with insight into the progress and costs around the AGIS initiative.

Q. HOW DID THE COMPANY DEVELOP THE BENEFIT INPUTS FOR THIS ANALYSIS?

A. Benefits inputs were developed by synchronizing the programs' technical capabilities, Company expectations, prior experience, alternatives, and Commission approved values where available. Where applicable, Ms. Bloch and Mr. Harkness discuss quantifiable benefits for Distribution and Business Systems, respectively. Mr. Cardenas identifies benefits related to customer care, such as reduced bad debt expense and meter reading. Dr. Duggirala discusses certain broader AMI benefits around load flexibility.

Q. WHAT TIME PERIOD DOES THE COMPANY'S CBA EXAMINE?

A. While implementation of the foundational AGIS components is expected to be completed by approximately 2025, the CBA examines the time periods that match either the expected life of the installed asset (AMI meters), or the period up to full book depreciation of the assets (IVVO and FLISR components). For AMI, the CBA covers is a 15-year project life, which is the expected life of the advanced meter equipment. The CBAs for IVVO and FLISR cover a 20-year project life, after which the equipment will be fully depreciated. Company witness Ms. Bloch describes the meter and device useful lives in her Direct Testimony.

Q. EARLIER YOU IDENTIFIED AMI, FLISR, AND IVVO AS INCLUDED IN THE CBA. HOW DO THE OTHER ASPECTS OF THE AGIS INITIATIVE – NAMELY, ADMS, THE TOU PILOT, AND THE FAN – FACTOR INTO THE CBA?

A. As I noted earlier, ADMS was separately certified for implementation via the Company's TCR Rider. In the certification proceedings, ADMS was approved as necessary regardless of any future advanced grid initiatives the Company would undertake. Further, the purpose of the CBA is primarily to provide one tool to evaluate the potential costs and quantifiable benefits of potential future grid modernization functionality. As such, ADMS costs are not part of the CBA.

However, installation of the FAN is necessary for AMI, FLISR, and IVVO implementation, respectively. The FAN does not provide benefits in its own right; therefore, all FAN costs are accounted for in the CBAs, where the associated portion of FAN is allocated into the costs for those individual components.

Finally, although the TOU pilot was previously approved, some of the work completed for the pilot will carry over to the broader AGIS initiative. Therefore, we have included TOU pilot costs in the AMI and consolidated CBA. However, the primary purpose of the TOU pilot is not to bring quantifiable benefits or cost-savings to customers, but rather to learn more about the capabilities and how to maximize the value of advanced metering technology. As such, the TOU pilot has a minor impact on the cost side of the benefit-to-cost ratio for AMI and the overall initiative (about 0.2 points), but no material quantifiable benefits.

Q. WHAT ARE THE RESULTS OF THE COMPANY'S AGIS CBA?

A. As discussed in detail in Dr. Duggirala's testimony, AMI, FLISR, and IVVO have the following approximate quantitative benefit-to-cost ratios for each component, shown here with and without contingency amounts:

Table 10

AMI Benefit-to-Cost Ratio

NSPM-AMI-NPV	Total ($MM)
Benefits:	446
O&M Benefits	53
Other Benefits	203
CAP Benefits	190
Costs:	(538)
O&M Expense	(179)
Change in Revenue Requirements	(359)
Benefit/Cost Ratio	**0.83**
Benefit/Cost Ratio (no contingencies)	**0.99**

Table 11

FLISR Benefit-to-Cost Ratio

NSPM FLISR- NPV	Total ($MM)
Benefits:	**103**
O&M Benefits	0
Customer Benefits	103
Costs:	**(79)**
O&M Expense	(5)
Change in Revenue Requirements	(74)
Benefit/Cost Ratio	**1.31**
Benefit/Cost Ratio (no contingencies)	**1.53**

Table 12

IVVO Benefit to Cost Ratio

<u>NSPM IVVO- NPV</u>	**Total ($MM)**
Benefits:	**22**
Other Benefits	19
CAP Benefits	3
Costs:	**(39)**
O&M Expense	(2)
Change in Revenue Requirement	(37)
Benefit/Cost Ratio (CVR 1.25% energy; 0.7% capacity)	**0.57**
Benefit/Cost Ratio (no contingencies)	**0.61**
Low Benefit Sensitivity:	
Benefit/Cost Ratio (CVR 1% energy; 0.6% capacity)	0.46
Benefit/Cost Ratio (no contingencies)	0.49
High Benefit Sensitivity:	
Benefit/Cost Ratio (CVR 1.5% energy; 0.8% capacity)	0.67
Benefit/Cost Ratio (no contingencies)	0.72

Q. WHY DO YOU SHOW AN ADDITIONAL RANGE OF IVVO BENEFIT-TO-COST RATIOS?

A. As Ms. Bloch and Dr. Duggirala explain, the Company is deploying IVVO to a core area, and does not have widespread data on the likely results of IVVO implementation. However, we understand that many of our stakeholders are particularly interested in IVVO deployment. Our engineers feel confident they can achieve 1.0 percent energy savings and may be able to achieve 1.5

percent through voltage optimization; in light of the uncertainty and interest, we have utilized a 1.25 percent mid-range energy savings level to show a range of potential outcomes. Our baseline benefit-to-cost ratio overall assumes 1.25 percent energy savings, 0.7 percent capacity savings, and that we will need to utilize the IVVO contingency amounts.

Q. WHAT ARE THE RESULTS OF THE CBA FOR THE AGIS INITIATIVE ON A CONSOLIDATED BASIS?

A. On a consolidated basis, the CBA results show a benefit-to-cost ratio for the overall AGIS initiative of between 0.86 and 1.03, with 0.87 as our baseline benefit-to-cost ratio, as set forth in Table 13 below.

Table 13

AGIS Initiative Combined Cost-Benefit Ratio

NSPM -AMI, FLISR, IVVO-NPV	**Total ($MM)**
Benefits:	**571**
O&M Benefits	53
Other Benefits	222
Customer Benefits	103
Capital Benefits	193
Costs:	**(656)**
O&M Expense	(186)
Change in Revenue Requirement	(470)
Baseline Benefit-Cost Ratio (IVVO CVR 1.25% energy, 0.7% capacity, with contingencies)	**0.87**
High Benefit/No Contingency Sensitivity (IVVO CVR 1.5% energy/0.8% capacity, no contingency)	1.03
Lower Benefit/With Contingency Sensitivity (IVVO CVR 1.0% energy/0.6% capacity, with contingencies)	0.86

Q. WHAT DOES THIS COMBINED RATIO INDICATE?

A. These ratios indicate that the quantifiable costs and benefits of the AGIS initiative do not reach 1.0 (equal benefits and costs) in their own right, but approach 1.0 even before we factor in qualitative benefits such as customer satisfaction, power quality, safety, and the like. In other words, the CBA, by itself, does not show that quantifiable benefits are equal to quantifiable costs; however, we would not necessarily expect it to when we are proposing this equipment not to avoid investments or to increase efficiency, but rather to replace a fundamental component of our system that is approaching obsolescence while adding capabilities for our customers and for a future that includes greater DER, distributed intelligence, artificial intelligence, and greater customer engagement with all facets of their life. We would not expect to save money (on a net basis) when investing in these kinds of technologies. I discuss the purpose and limitations of the CBA, as well as the unquantifiable qualitative benefits, further in the next section of my testimony.

2. Role of the CBA in AGIS Evaluation

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A. In this section of my testimony, I expand upon the purpose and limitations of a CBA from a policy perspective. While Dr. Duggirala discusses this subject from the perspective of the model itself, I provide the broader business considerations around the efficacy – and limitations – of any quantitative assessment tool.

Q. WHY IS IT IMPORTANT FOR THE COMMISSION TO EVALUATE QUALITATIVE BENEFITS AND FUTURE CUSTOMER OPTIONS THAT COULD NOT BE BUILT INTO A CBA?

A. We recognize that it is difficult to put a numeric value on future opportunity and non-monetary benefits, and that evaluating these possibilities can be a challenge. However, the trends in the utility industry and the efforts of other states to advance their distribution grids, described in this testimony and in industry-wide resources like the Department of Energy's Smart Grid effort, verify the importance of bringing utilities' distribution grids into the future. Without AGIS, the Company will soon be behind in managing to customer expectations, supporting DER, employing future technologies, maintaining reliability goals and expectations, and fully capturing DSM opportunities.

AGIS is therefore both a fundamental part of the Company's strategic plans to meet and exceed customer expectations as well as a standalone requirement for a robust and resilient distribution grid.

Q. SHOULD THE DECISION OF WHETHER TO APPROVE COST RECOVERY OF THE AGIS COMPONENTS DEPEND SOLELY ON THE OUTCOME OF THE QUANTITATIVE CBA?

A. No. That would be an overly-narrow perspective that does not take into account the broader context of AMI, IVVO, and FLISR, the place of AGIS in the Company's overall strategic plans, or future opportunities that the advanced grid can create for customers. Company witness Dr. Duggirala discusses both the purpose and limitations of a quantitative CBA in his testimony. More specifically, a CBA can only capture that which can be quantified or measured. Most costs, by definition, can be quantified. Other benefits of a project, including customer satisfaction, the secondary effects of lost productivity, business, or consumables on customers due to electric outages, and human health and safety are not fully quantifiable or quantifiable at all.

Q. IS THE OUTCOME OF A CBA THE ONLY STANDARD BY WHICH COST RECOVERY MUST BE JUDGED IN MINNESOTA?

A. No. Certainly balancing the costs and benefits of any project is an important consideration, which we do not discount. However, it is not the only consideration. In Minnesota, the Commission has approved project costs based on the need for the investments to serve customers, customer-facing benefits, efficiencies, system benefits, avoiding obsolescence, and for other reasons. The test is always whether the investment is just and reasonable – not whether dollar savings are greater than the price of the project.

Q. ULTIMATELY, WHAT DO YOU RECOMMEND IS THE PROPER PERSPECTIVE ON THE CBA?

A. I recommend that the Commission review the CBA, but do so in the broader context of the goals of AMI, FLISR, and IVVO implementation, the current qualitative benefits they offer, Commission policy goals, and the opportunities for future customer benefits.

B. Qualitative Benefits of AGIS

Q. IF THE COMMISSION SHOULD NOT RELY SOLELY ON A CBA TO ASSESS A PROJECT'S REASONABLENESS AND VALUE, WHAT SHOULD IT RELY UPON?

A. The Commission should consider a wide variety of factors, that include (but may not be limited to):

- The overall need for the proposed investments for the utility to run its business (as described above in my testimony, and in the testimony of Ms. Bloch and Mr. Cardenas);
- The value of the investments in meeting Commission policy goals (described in my testimony and Ms. Bloch's and Dr. Duggirala's testimony);
- The benefits of the investment – both qualitative and quantitative – to the utility's customers (described in each piece of the AGIS testimony);
- The cost impact of the investments on the customer (discussed later in my testimony);
- The alternatives available to and considered by the Company (discussed earlier in my testimony on a holistic level, and discussed by Ms. Bloch

and Mr. Harkness with respect to the alternatives to individual components, component types, and vendors); and

- The amount and quality of due diligence undertaken by the Company in selecting both the investments it is pursuing and the vendors and project scoping proposed (discussed throughout our AGIS testimony).

Q. CAN YOU PROVIDE AN OVERVIEW OF THE QUALITATIVE BENEFITS TO BE CONSIDERED AS PART OF THE EVALUATION OF THE AGIS COMPONENTS?

A. Yes. From a policy perspective, the unquantifiable benefits of advancing the distribution grid are difficult to overstate. Safety, reliability, and customer satisfaction are vital to our role as a public utility. Each is enhanced by the AGIS initiative, as I describe earlier in my testimony and as Ms. Bloch and Mr. Cardenas describe in more detail. A more automated, insightful, and transparent grid supports greater customer empowerment and employee safety, as discussed by Company witness Ms. Bloch. Similarly, Ms. Bloch also explains that the advanced technologies associated with the AGIS initiative support ongoing quality SAIDI and SAIFI measurements, along with improved ability to measure MAIFI. Nor can the utility keep up with greater customer demand for distributed energy resources without investing in the advanced grid technologies necessary to support these resources.

In addition, giving customers choice and control over their energy usage by providing greater insight to customers; giving customers greater input into the types of energy they use by supporting distributed energy resources; and empowering customers to make good choices about their impact on the environment are important pieces of both building customer satisfaction and managing electric demand.

Perhaps most importantly, there are simply limitations to our current system that frustrate customers and cannot be resolved without aspects of the AGIS initiative. In many cases, without AMI metering technology we have limited ability to identify outages without relying on the customer. The AGIS initiative will allow us to improve reliability by automating fault response and identifying more issues beyond the substation. Two-way communication and additional devices will allow us to enhance voltage optimization and better support distributed energy resources. It further allows us to look to the future, and to emerging capabilities like distributed intelligence, more customer application and interface technology, and additional energy sources through a modernized distribution grid. All of these benefits relate largely to customer satisfaction and future-proofing the distribution grid – benefits that are difficult or impossible to quantify.

Q. HOW DOES CUSTOMER OPTIONALITY FURTHER SUPPORT APPROVAL FOR THE AGIS INITIATIVE, INCLUDING THE PROJECT COSTS IN THIS CASE?

A. As noted earlier in my Direct Testimony, empowering customer choice is a key driver of the AGIS initiative as a whole. Digital metering and technologies enable new programs and tools for customers that give them more power over their energy usage. Some of these options, such as the opportunities to receive regular updates about their electricity usage and to tailor their electric usage to reduce their electricity costs, are discussed above. But customer choice goes beyond TOU rates or remote connect/disconnect options.

With AMI, the Company has the option to implement budgeting tools and high usage alerts that notify customers if they exceed or approach certain thresholds; to create internet portals that provide greater insight into energy consumption and peak demand; and to develop mobile apps that allow near real-time information access.

AMI will also support the two-way flow of energy via net metering, further supporting customers' abilities to invest in DER options such as rooftop solar and potential energy storage or battery options, if they should choose to do so.

Q. HAS THE COMPANY INCORPORATED ANY ASSUMPTIONS ABOUT THESE FUTURE OPTIONALITIES INTO ITS ASSESSMENT OF AMI, FLISR, AND IVVO?

A. Yes. As I discussed earlier, the Company envisions implementing a full residential time of use rate by 2024. We anticipate continuing discussion of those options in the Company's TOU pilot proceeding, as we will build on those pilot results and learnings, and engage stakeholders in developing a full residential time of use rate offering. Likewise, the implementation of the advanced meters and associated infrastructure provide an opportunity for customer web portals to access energy usage data on a near real-time basis, and we anticipate building such portals as part of the AGIS initiative. Estimated anticipated reduced consumption and benefits associated with time-of-use rates are incorporated into the Company's CBA.

Q. WHAT ARE OTHER BENEFITS ASSOCIATED WITH TOU RATES?

A. There are several key, quantifiable benefits associated with a time-of-use rate structure. TOU rates result in direct benefits for our customers, by giving customers the tools necessary to keep their bills low. Additionally, TOU rates can help to further goals shared by the Company and stakeholders, such as furthering the clean energy transition in Minnesota. With TOU rates providing customers energy price signals, customers are empowered with information necessary to shift usage to off-peak times – when energy costs are lower and system generation tends to be less carbon intensive. In addition to these direct benefits for all of our customers who have an AMI meter, the environmental benefits enabled by AGIS will be realized for both customers and the public.

In the CBA, we did not quantify reductions in carbon dioxide emissions from shifting customers away from consumption during peak periods (and therefore away from reliance on peaking units) toward more average periods, when we can rely more heavily on renewable resources. Instead, we focused on a conservative estimate of benefits we could measure, resulting in significant savings as a result of load flexibility benefits.

Q. HAS THE COMPANY SUMMARIZED THE CAPABILITIES OF CERTAIN AGIS COMPONENTS IN RELATION TO THE RELATIVE COSTS AND BENEFITS IN ANY OTHER WAY?

A. Yes. Dr. Duggirala compares the capabilities of AMI provided by Ms. Bloch to other alternatives, such as manual reading and AMR solutions, while also factoring in incremental cost and benefit information for alternatives (compared to the Company's current metering solution) where available. This "Least-Cost/Best-Fit" analysis further underscores the significant additional capabilities and higher net costs/benefits of AMI as compared to other metering solutions for which we have pricing information. It also demonstrates that while we do not have specific pricing information for all options (such as manual read meters), the capabilities of older technology are sufficiently limited and outdated as to be incomparable.

Dr. Duggirala presents a similar comparison of FAN alternatives, including a cellular or dedicated AMI communications network alternative. Mr. Harkness explains why those alternatives are not preferable solutions as compared to the FAN, and Dr. Duggirala summarizes the comparisons in his testimony. In short, a cellular alternative is expected to have approximately the same per-device costs plus additional O&M costs, with less Company control and less security than the FAN. A dedicated AMI alternative would not allow us to utilize the FAN for multiple type of devices, limiting the functionality of the solution. Overall, the capabilities of a secure, flexible, and reliable Field Area Network make this the preferable solution.

C. Summary of Prudence of AGIS Investments

Q. PLEASE SUMMARIZE THE COMPANY'S OVERALL APPROACH AND THE RESULTS OF THE AGIS CBA.

A. The AGIS CBA provides a customer-focused, conservative look at the AGIS investments. It incorporates conservative estimates of quantifiable customer benefits enabled by the advanced grid. It also incorporates our current cost estimates, both with and without contingencies, to provide a range of results for consideration. Our CBA shows individual and composite benefit-to-cost ratios that approach 1.0 (or exceed 1.0 in the case of FLISR), even before taking into account unquantifiable benefits.

Q. HOW DOES THE COMPANY'S CBA INFORM THE OVERALL ASSESSMENT OF THE PRUDENCE OF THE AGIS INVESTMENTS?

A. By evaluating the costs and quantifiable benefits of AGIS implementation, the Company's AGIS CBA is one tool that informs assessment of the overall prudence of the AGIS strategy and investments. However, a cost-benefit model is limited in that it cannot capture other benefits that cannot be quantified, such as customer satisfaction, power quality, and improved safety.

The CBA results underscore that our AGIS program is reasonable given the need to replace aging technology, bring our distribution grid into the future, meet customer needs and offer greater customer choice, and take advantage of opportunities to use technology to support demand side management, peak demand reductions, and build a more resilient, responsive grid. With those qualitative considerations and benefits, the Company believes the value of the AGIS initiative and its respective components substantially exceed the costs.

Q. ULTIMATELY, WHAT DO YOU RECOMMEND WITH RESPECT TO THE PRUDENCE OF THE AGIS INVESTMENTS?

A. I recommend that the Commission approve the Company's proposed investments in the AGIS initiative as prudent, and certify them for future cost recovery for the reasons described throughout my testimony – including in this section – and in the testimony of Ms. Bloch, Mr. Harkness, Mr. Cardenas, and Dr. Duggirala.

VIII. BILL IMPACTS

Q. PLEASE DESCRIBE HOW AGIS INVESTMENTS WILL IMPACT CUSTOMER BILLS.

A. Keeping customer bills low is a core strategy of the Company and is a central consideration of the AGIS initiative. As I previously described, the combined

AGIS investment will provide significant value to our customers – some of which we can quantify and some that we can't.

Q. WHAT TYPE OF IMPACT WILL AGIS INVESTMENT HAVE ON CUSTOMER BILLS?

A. The impact to a customer's bill will result from the increased revenue requirement due to our investments and O&M spending necessary to implement the AGIS initiative.

Q. HOW DID THE COMPANY APPROACH ITS ASSESSMENT OF THE BILL IMPACT OF AGIS?

A. The Company performed a revenue requirement analysis for 2020 through 2024 to illustrate the incremental revenue requirement and estimated bill impact of AGIS implementation. The AGIS revenue requirement calculation is provided as Exhibit___(MCG-1), Schedule 9.[40] While we did not perform an exhaustive class cost of service model for this subset of investments and O&M expenses, this analysis provides the annual cost of the AGIS initiative overall, and provides an estimate of a monthly bill impact for a typical residential customer.

Q. HOW DID THE COMPANY SPECIFICALLY CALCULATE THE ESTIMATED BILL IMPACT FOR A TYPICAL RESIDENTIAL CUSTOMER?

A. We estimated the bill impact by utilizing a series of allocation assumptions applied to the AGIS costs, using allocators consistent with our 2020 proposed Class Cost of Service Study. Appropriate allocators were applied to distribution capital, distribution O&M, and the remaining costs, to develop an

[40] The costs included in 2019 are related to the Company's TOU pilot. As described in Section VI, the costs of implementing AMI and FAN in connection with the TOU pilot (in 2019 and 2020) have been included in the AGIS CBA to provide a complete picture of advanced grid investments and costs. We have also included these costs in our bill impact assessment.

estimated residential class revenue requirement. We then divided the estimated residential class revenue requirement by the sales forecast for each year, as provided in Company witness Ms. Janell Marks' testimony. This results in an estimated overall cost per kilowatt hour (kWh). We then calculated an estimated bill impact based on the average monthly residential customer usage of 675 kWh. This assessment shows an estimated 2024 AGIS bill impact of approximately $2.87 per month for an average residential customer.

While this calculation is not a full class cost of service assessment, it does illustrate an estimated bill impact for a residential customer. We recognize that bill impacts will vary by customer class; however, we believe this approach is informative for purposes of comparing the bill impact of the AGIS initiative to the alternative investment that would be necessary to continue to provide service to our customers.

Q. WHAT ALTERNATIVE INVESTMENT AND COSTS WOULD BE NECESSARY IF THE COMPANY DOES NOT IMPLEMENT THE AGIS INITIATIVE?

A. As described earlier, it is not feasible for the Company to continue to use its current AMR meters because they are nearing end of life, and the Company's contract with Cellnet for meter reading service and support expires at the end of 2025. As such, the Company would, at a minimum, need to invest in new meters and provide meter reading services in order to continue to provide electric service to our customers. This means that even without AGIS implementation, there would be an incremental impact to customers' bills for an alternative metering service.

Q. HOW DID THE COMPANY CALCULATE THE BILL IMPACT OF THE ALTERNATIVE TO AGIS IMPLEMENTATION?

A. In addition to the AGIS revenue requirement, the Company developed a reference case scenario to represent an alternative to our AGIS investments. The reference case reflects the necessary investments and costs if the Company were to pursue a basic AMR drive-by meter reading alternative. Ms. Bloch and Mr. Cardenas discuss AMR meters and provide details on the costs of this alternative. The Company calculated the bill impact by using the revenue requirements for the AMR drive-by alternative and calculated the estimated bill impact as described above. The reference case revenue requirement calculation is provided as Exhibit___(MCG-1), Schedule 10. This assessment shows an estimated bill impact for the AMR drive-by alternative of approximately $1.51 per month for an average residential customer.

Q. COULD YOU COMPARE THE TWO CASES?

A. Yes. We provide the overall bill impact of the AGIS initiative, but the key comparison is the difference between the estimated bill impact of AGIS implementation versus the basic alternative, as shown in Table 14 below. This Table illustrates the incremental cost of pursuing our AGIS investments, compared to the investments that would otherwise be necessary but would not enable all the quantitative and qualitative benefits of the advanced grid. Table 14 also illustrates that costs of AGIS will be spread over the implementation period, which reasonably manages the cost impact for our customers.

Table 14

Estimated Residential Monthly Bill Impact

	2020	2021	2022	2023	2024
AGIS	$0.44	$1.33	$1.84	$2.58	$2.87
Reference Case	$.01	$0.19	$0.62	$1.18	$1.51
Difference	$0.43	$1.14	$1.22	$1.40	$1.36

Q. OVERALL, DO YOU BELIEVE THE AGIS INVESTMENTS ARE A GOOD VALUE FOR CUSTOMERS?

A. Yes. While there are costs associated with new technology, the combined AGIS investment will provide significant value to our customers immediately on Day 1 and over the long term.

IX. AGIS METRICS AND REPORTING

Q. WHAT INFORMATION DO YOU PROVIDE IN THIS SECTION OF YOUR TESTIMONY?

A. In this section, I discuss progress metrics and proposed reporting on the AGIS program. Our intent is to provide the Commission and stakeholders comprehensive information on deployment progress for monitoring purposes, and performance and achievement of customer and system benefits as we implement the advanced grid initiatives.

The AGIS initiative will be implemented over a number of years, beginning with customer outreach and education efforts, followed by deployment of the systems and technologies, and then the roll-out of new products and services enabled by the AGIS initiative. Our efforts will also include development and implementation of future products and services that will capture additional benefits of the advanced grid capabilities as customer preferences and technologies evolve over time. This section discusses our proposed progress metrics and reporting chronologically as we move through these phases of AGIS implementation.

Because we are the first Minnesota utility to propose implementation of these advanced grid components through a broad advanced grid initiative, we believe comprehensive reporting will contribute to and inform the ongoing discussions of distribution planning and the advanced grid among Minnesota stakeholders. Our proposed progress metrics and reporting are discussed below and are also summarized in Exhibit____(MCG-1), Schedule 11.

Q. ARE YOU PROPOSING A SEPARATE PERIODIC REPORT SPECIFICALLY RELATED TO AGIS?

A. Yes. We propose to file an annual report on the AGIS initiative that will include various progress metrics that relate to different areas of our business that are involved in AGIS implementation. We propose to file the AGIS report on May 1 each year, to include reporting for the prior calendar year. Our first AGIS report would be filed May 1, 2022. I note that the content of the report and relevant metrics will change over time as we move through the phases of AGIS implementation.

Q. WILL OTHER PERIODIC REPORTING BE IMPACTED BY THE AGIS INITIATIVE?

A. Yes. AGIS may also impact certain service quality metrics that are included in reporting that is already in place. Specifically, the Company reports service quality metrics under our established Service Quality tariff[41] as well as the Minnesota Rules governing utility service quality.[42] We propose to continue reporting the service quality metrics in those reports, and intend to address any AGIS impacts to service quality metrics or thresholds in those separate proceedings.

Q. DO YOU PROPOSE SPECIFIC METRICS RELATED TO FUTURE OPERATIONAL CAPABILITIES OR PRODUCTS AND SERVICES THAT WILL BE ENABLED BY AGIS?

A. Not at this time. I discuss below some of the types of information that the Company anticipates filing in the future. However, are currently developing operational reporting solutions, so final details concerning specific metrics and calculations are not yet available. In addition, we recognize that specific metrics or potential performance thresholds might be further developed through later Commission proceedings as the Company proposes new products or services enabled by the advanced grid. For example, the Company would seek approval for a full residential time of use rate in a future proceeding, where detailed metrics and reporting would be informed by stakeholder input and approved by the Commission. We propose to report on metrics developed in those proceedings in the separate future dockets.

A. Customer Education and Outreach Metrics

Q. WHAT INFORMATION DO YOU PROPOSE TO TRACK AND REPORT WITH RESPECT TO THE COMPANY'S CUSTOMER EDUCATION AND OUTREACH EFFORTS?

A. Because education and awareness are key to customer engagement with advanced grid offering and capabilities, we intend to measure the impact of

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[41] See the Company's Minnesota Electric Rate Book, Section 6, General Rules and Regulations, Subsection 1.9, Service Quality.

[42] See Minn. Rule 7826, Electric Utility Standards on safety, reliability, and service quality.

our communications and education efforts around installation of the advanced meters. To answer key questions and assess the overall effectiveness of our efforts, we will track and report on:

- Customer responses on the adequacy and clarity of our communications prior to installation of advanced meters.

Q. HOW WILL THE COMPANY MEASURE THIS PERFORMANCE?

A. We plan to conduct quarterly customer surveys to ensure our surveys are timely and follow soon after the distribution of meter installation communications. The surveys will continue as installation efforts proceed across our service territory.

Q. HOW DOES THE COMPANY EXPECT TO USE THESE SURVEY RESULTS?

A. We intend to closely monitor these results and modify our communication materials or education plans if these results indicate a modification may be warranted.

In addition to these survey results, we will be tracking the number of customer who elect to opt out of an advanced meter installation. To the extent the opt-out percentage may be related to the efficacy of our customer materials or education efforts, we will also take that into consideration as we continue to proceed with meter installation across our service territory.

Q. HOW AND WHEN WILL YOU REPORT ON THE PROGRESS METRICS RELATED TO CUSTOMER EDUCATION AND OUTREACH EFFORTS?

A. We intend to begin these surveys in 2021 as we begin AMI installation and will report this information in our annual AGIS report beginning in 2022.

B. Installation and Deployment Metrics

Q. WHAT INFORMATION DO YOU PROPOSE TO TRACK AND REPORT WITH RESPECT TO DEPLOYMENT AND INSTALLATION OF SYSTEMS AND TECHNOLOGIES?

A. We intend to track and report on installation for all AGIS components. This includes the timing of installation and the following statistics:

- AMI – Number of meters installed;
- FAN – Percentage of FAN deployed;
- FLISR – Number of feeders with FLISR enabled;
- IVVO – Number of feeders with IVVO enabled; and
- Number of customers electing to opt out of AMI installation.

Q. HOW DOES THE COMPANY EXPECT TO USE THIS INFORMATION RELATED TO INSTALLATION AND DEPLOYMENT OF AGIS COMPONENTS?

A. We will track these installation progress metrics to monitor our performance compared to our deployment plan for each component and our forecasted opt-out percentages. We intend to report these metrics to keep the Commission and stakeholders informed of our progress as we install and deploy AGIS equipment and systems.

Monitoring the percentage of customers opting out of advanced meter installation may provide information relative to our customer materials or education efforts. We will take that into consideration as we continue to roll-out meter installation across our service territory and develop future products and services that will utilize AMI capabilities.

Q. HOW AND WHEN WILL YOU REPORT THE INSTALLATION PROGRESS METRICS?

A. We intend to measure these installation metrics semi-annually for our internal monitoring purposes, and will report these progress metrics in our annual AGIS report beginning in 2022. This reporting would continue until deployment is completed.

Q. ARE THERE OTHER METRICS YOU INTEND TO REPORT DURING THE INSTALLATION AND DEPLOYMENT PHASE?

A. Yes. We intend to track and report:

- Number of calls to our Customer Contact Center regarding the AMI meter installations; and
- Number of complaints regarding AMI installation.

In addition to tracking our call center metrics, we have developed a robust plan with our meter installation vendor (Itron) around customer communications and service quality, as they will have direct contact with and will receive calls directly from our customers related to meter installation. Mr. Cardenas discusses our plans for the meter installation vendor service quality tracking and reporting. We would include these metrics in our reported information as well. Mr. Cardenas provides details on the tracking mechanism, categories, and methods of reporting for both the Company's and Itron's call centers, as well as any customer complaints.

Q. HOW AND WHEN WILL YOU REPORT THE COMPANY'S AND ITRON'S CALL CENTER METRICS AND ANY COMPLAINTS REGARDING AMI INSTALLATION?

A. As discussed by Mr. Cardenas, these metrics are related to and may impact metrics we report under our established Service Quality tariff and the Minnesota Rules on service quality. We intend to begin reporting this information as part of our annual service quality reporting beginning in 2022. I note, however, that for completeness and monitoring purposes, we would also include this information in our annual AGIS report.

C. Post-Implementation Metrics

Q. WHAT INFORMATION DO YOU PROPOSE TO TRACK AND REPORT ONCE AGIS IS IMPLEMENTED?

A. Post-implementation, we propose to track and report operational metrics related to AGIS components, certain service quality metrics, and customer engagement and satisfaction as it related to AGIS capabilities. In the near term, this would include metrics related to advanced grid capabilities and services that do not require future regulatory proceedings to enable.

Q. WHAT OPERATIONAL METRICS DO YOU PROPOSE TO REPORT?

A. We propose to report the following operational metrics:

- Avoided customer minutes out on FLISR-enabled feeders; and
- Energy reduction due to IVVO (that result in associated cost reduction and reduction in CO_2 emissions).

Q. HOW DOES TRACKING AND REPORTING CUSTOMER MINUTES OUT REFLECT THE IMPACT OF FLISR?

A. We are currently able to track customer minutes out (CMO) as one measure of system reliability. The automated restoration provided by FLISR will reduce customer minutes out (CMO) for customers located on FLISR-enabled feeders. As we begin to install FLISR devices, we will be able to compare CMO to past performance, indicating the extent to which FLISR has reduced CMO. Ms. Bloch provides additional information on the benefits of FLISR, including how the value of reduced CMO is quantified. I note that this reliability metric is not included in our service quality reporting. Other reliability metrics will continue to be addressed in our existing service quality reports, where calculation methodologies and performance thresholds are defined.

Q. HOW WILL THE COMPANY TRACK AND CALCULATE THE ENERGY REDUCTION DUE TO IVVO, THE ASSOCIATED COST REDUCTION, AND VALUE OF REDUCED CO_2 EMISSIONS?

A. IVVO is expected to result in energy reductions due to the voltage reductions enabled by IVVO. In other words, lowering the voltage on a feeder would result in lower energy usage, which would result in lower costs. In addition, line losses are generally a percentage of energy, so reduced energy also results in reduced line losses (and associated costs). Reduced energy usages also means reduced CO_2 emissions. As we begin to install IVVO devices, energy reductions will be calculated based on the voltage on the IVVO-enabled feeder compared to the overall system voltage. With the energy reduction will come cost savings to customers and a reduction in CO_2 emissions. Ms. Bloch provides additional information on the benefits of IVVO, including how the value of these benefits are quantified.

Q. HOW AND WHEN WILL YOU REPORT THESE OPERATIONAL METRICS?

A. We intend to report these operational metrics in our annual AGIS report. With FLISR and IVVO installation beginning in 2021, we would be able to begin this reporting for specific feeders in 2022. This reporting would continue throughout the FLISR and IVVO deployment phases as we install the devices on additional feeders.

Q. WHAT SERVICE QUALITY METRICS DO YOU PROPOSE TO REPORT?

A. As noted above, certain service quality metrics related to call center response time, meter reading, billing, and reliability may be impacted by AGIS implementation. Ms. Bloch and Mr. Cardenas discuss service quality metrics in their testimony. We propose to report those metrics and address any impacts under the already established reporting structures for our service quality tariff and the Minnesota service quality rules. However, for completeness and monitoring purposes we would include the following information in the annual AGIS report beginning in 2022:

- Percentage of customers with advanced meters that receive estimated bills; and
- Percentage of customers with advanced meters that have made a complaint about inaccurate meter readings.

Q. WHAT CUSTOMER SATISFACTION AND ENGAGEMENT METRICS DO YOU PROPOSE TO REPORT?

A. We propose to report the following metrics in our annual AGIS report beginning in 2022:

- Customer satisfaction with outage-related communications;
- Number of customers with an advanced meter with an active web portal account (MyAccount); and
- Number of unique visits to MyAccount.

Q. WHY DOES THE COMPANY BELIEVE THESE METRICS ARE IMPORTANT?

A. First, the improved visibility into the system and the ability of AMI meters to detect outage and restoration events enables the Company to provide proactive and more timely and accurate communications on outages and expected restoration times. We believe it is important to understand our customers' views on these benefits enabled by the advanced grid as well as to obtain feedback to improve our outage communications.

Second, the majority of the new information on energy usage provided by advanced metering will be available to customers via the web portal and MyAccount. Tracking our customers' use of the web portal will be useful in determining how to improve presentation of data and how to engage customers in the future as we develop new products and services enabled by the advanced grid.

D. Longer-Term Reporting

Q. WHAT TYPES OF AGIS-RELATED OPERATIONAL INFORMATION DOES THE COMPANY ANTICIPATE REPORTING IN THE FUTURE?

A. As Mr. Harkness discusses in his testimony, we are currently developing operational reporting solutions, with final details on specific reporting and metrics calculations not yet finalized. Although reporting details are not finalized, some examples of metrics we anticipate being able to report are:

- Theft / tamper detection and reduction;
- Reduction in trips due to customer equipment damage;
- Reduction in "OK on Arrival" outage field trips;
- Reduction in field trips for voltage investigations;
- Patrol time reduction; and
- Outage management efficiency.

Q. WHAT TYPES OF INFORMATION DO YOU ANTICIPATE REPORTING RELATED TO NEW PRODUCTS AND SERVICES ENABLED BY THE ADVANCED GRID?

A. For those new products and services that will require separate Commission approval for implementation, we expect the reporting details and timing will be determined in those separate proceedings, with stakeholder input and at the direction of the Commission. Future reporting will be determined in separate proceedings for any advance rates – like a full residential time-of-use rate – or for other new products such as Green Button Connect. Some examples of the types of reporting we would anticipate for new products and services are:

- TOU rate – avoided generation/peak demand;
- TOU rate – deferral of capital investments due to demand reduction;
- Remote disconnect – reduced consumption on inactive meters;
- Remote disconnect – reduced uncollectible / bad debt expense;
- Percentage of customers with AMI that have selected pre-pay billing;
- Percentage of customers with AMI that receive high bill alerts; and
- Percentage of customers with AMI that have one or more active advanced applications.

X. CONCLUSION

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. Our distribution grid is the foundation of the service we provide our customers. We are at a point where investment in new technologies to further modernize our grid will return significant value to our customers. Our proposed AGIS initiative supports the Company's vision for an advanced grid that will provide both customer and operational benefits for many years to come and has been informed by:

- The Company's strategic priorities to lead the clean energy transition, enhance the customer experience, and keep bills low;
- The Company's desire to meet the growing needs and expectations of our customers;
- Current distribution system needs; and
- Commission policy and stakeholder input relative to customer offerings, performance, and technical capabilities of the grid.

Our AGIS initiative will enhance transparency into the distribution system and provide detailed and timely data to promote efficiency, reliability, and enable increased distributed resources on our system. AGIS will also enhance our customers' experience by providing access to actionable information, more choices, and greater control of their energy use.

I recommend that the Commission approve our AGIS initiative, including recovery the costs of the capital investments and O&M expense for the AGIS components that we propose to implement during the 2020-2022 term of the MYRP. I also recommend that the Commission certify our proposed AGIS projects overall, so that the Company would have the opportunity to request cost recovery for these programs between rate cases in subsequent rider filings.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

Statement of Qualifications

Michael C. Gersack
Vice President, Customer Care
Xcel Energy
1800 Larimer Street, Suite 1500, Denver, Colorado

Current Responsibilities (2019 - Present)

Vice President Innovation and Transformation

Previous Positions

Xcel Energy Inc., Minneapolis

2010 - 2018 Vice President, Customer Care
2007 - 2010 Managing Director, Revenue Cycle Operations
2006 - 2007 Managing Director, Customer Care
2004 - 2006 Managing Director, Customer Care Business Operations
2002 - 2004 Managing Director, Retail Finance, Customer and Field Operations
2000 - 2002 Director, Accounting and Financial Analysis, Retail Operations
1999 - 2000 Manager, Retail Operations Accounting

Kinder Morgan

1998 – 1999 Controller, Enable (joint venture)
1997 – 1998 Manager, Retail Accounting
1996 – 1997 Business Unit Consultant

Energy and Resource Consulting Group

1994 – 1996 Senior Analyst

Education

Bachelor of Science and Masters Degrees in Accounting, University of Denver

Business / Industry Activities

Certified Public Accountant

AGIS Grid Modernization Requirements - 2019

Planning Objectives: The Commission is facilitating comprehensive, coordinated, transparent, integrated distribution plans to:
· Maintain and enhance the safety, security, reliability, and resilience of the electricity grid, at fair and reasonable costs, consistent with the state's energy policies;
· Enable greater customer engagement, empowerment, and options for energy services;
· Move toward the creation of efficient, cost-effective, accessible grid platforms for new products, new services, and opportunities for adoption of new distributed technologies; and,
· Ensure optimized utilization of electricity grid assets and resources to minimize total system costs.
· Provide the Commission with the information necessary to understand Xcel's short-term and long-term distribution system plans, the costs and benefits of specific investments, and a comprehensive analysis of ratepayer cost and value.

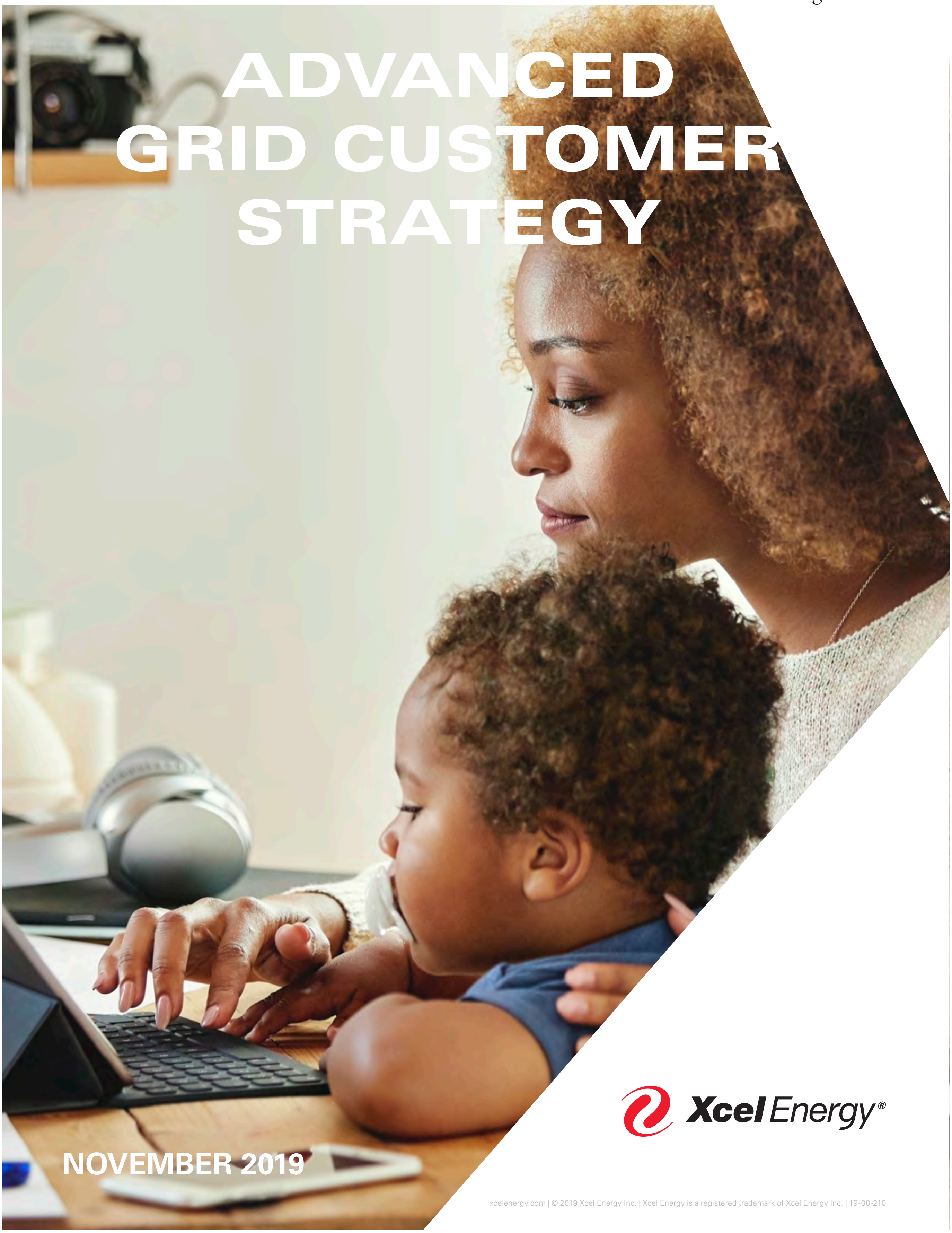
Source	Requirement/Description	IDP	Rate Case: AGIS
Docket No. E002/CI-18-251 Aug. 30, 2018 Order (Updated to include changes from Jul 16, 2019 Order)	**A. Baseline Distribution System and Financial Data: Financial Data**		
	26. Historical distribution system spending for the past 5-years, in each category: a. Age-Related Replacements and Asset Renewal b. System Expansion or Upgrades for Capacity c. System Expansion or Upgrades for Reliability and Power Quality d. New Customer Projects and New Revenue e. Grid Modernization and Pilot Projects f. Projects related to local (or other) government-requirements g. Metering h. Other	IDP II (C)	Addressed in IDP
	28. Projected distribution system spending for 5-years into the future for the categories listed above, itemizing any non-traditional distribution projects	IDP II (C)	Gersack II(C) AGIS Expenditures 2020-2029 Gersack V(D)(2) AGIS PM Costs 2020-2029 Bloch V(A) AGIS - Distribtuion 2020-2029 Bloch V(D)(5) AMI - Distribution 2020-2029 Bloch V(E)(3) FAN - Distribution 2020-2029 Bloch V(F)((6) FLISR - Distribution 2020-2029 Bloch V(G)(7) IVVO - Distribution 2020-2029 Harkness V(E)(3)(c)(4) AMI - IT 2020-2029 Harkness V(E)(4)(e)(4) FAN - IT 2020-2029 Harkness V(E)(5)(c) FLISR - IT 2020-2029 Harkness V(E)(6)(c) IVVO - IT 2020-2029 Harkness V(E)(7) AGIS - IT 2020-2029 Duggirala Schedules 2, 3, 4
	29. Planned distribution capital projects, including drivers for the project, timeline for improvement, summary of anticipated changes in historic spending. Driver categories should include: a. Age-Related Replacements and Asset Renewal b. System Expansion or Upgrades for Capacity c. System Expansion or Upgrades for Reliability and Power Quality d. New Customer Projects and New Revenue **e. Grid Modernization and Pilot Projects** f. Projects related to local (or other) government-requirements g. Metering h. Other	IDP II (C) and Attachments F1 nd G1	Gersack II(B) Exec Summary - Drivers Gersack IV Drivers of AGIS Strategy Gersack II(C) Exec Summary - Implementation Gersack V(A) Component Implementaion Gersack V(B) Overall Timeline/Implementation Bloch V(A) Projects and Timeline Block V(B) Drivers (Limitations of System) Bloch V(D) AMI Bloch V(E) FAN Bloch V(F) FLISR Bloch V(G) IVVO Harkness V(B)(E) AGIS Overview Harkness V(E)(3) AMI Harkness V(E)(4) FAN Harkness V(E)(5) FLISR Harkness V(E)(6) IVVO
	30. Provide any available cost benefit analysis in which the company evaluated a non-traditional distribution system solution to either a capital or operating upgrade or replacement	IDP VI and Attachment H	Addressed in IDP

Source	Requirement/Description	IDP	Rate Case: AGIS
Docket No. E002/CI-18-251 Aug. 30, 2018 Order (Updated to include changes from Jul 16, 2019 Order)	**D. Long-Term Distribution System Modernization and Infrastructure Investment Plan**		
	2. Xcel shall provide a 5-year Action Plan <u>as part of a 10-year long-term plan</u> for distribution system developments and investments in grid modernization based on internal business plans and considering the insights gained from the DER futures analysis, hosting capacity analysis, and non-wires alternatives analysis. The 5-year Action Plan should include a detailed discussion of the underlying assumptions (including load growth assumptions) and the costs of distribution system investments planned for the next 5-years (expanding on topics and categories listed above). Xcel should include specifics of the 5-year Action Plan investments. Topics that should be discussed, as appropriate, include at a minimum:	IDP XIV	Gersack II Exec Summary Gersack IV Drivers of AGIS Strategy Gersack V AGIS Components and Implementation Gersack VI Customer Experience
	· Overview of investment plan: scope, timing, and cost recovery mechanism	IDP II, IX and XIV and Addressed in Rate Case	Gersack II Exec Summary
	· Grid Architecture: Description of steps planned to modernize the utility's grid and tools to help understand the complex interactions that exist in the present and possible future grid scenarios and what utility and customer benefits that could or will arise.	IDP XIV and Addressed in Rate Case	Gersack V AGIS Components and Implementation Bloch V(D) AMI Bloch V(E) FAN Bloch V(F) FLISR Bloch V(G) IVVO Harkness V(E)(3) AMI Harkness V(E)(4) FAN Harkness V(E)(5) FLISR Harkness V(E)(6) IVVO Harkness V(D) Cyber Security Cardenas V(F) Quantifiable Benefits Gersack VI Customer Experience (Benefits)
	· Alternatives analysis of investment proposal: objectives intended with a project, general grid modernization investments considered, alternative cost and functionality analysis (both for the utility and the customer), implementation order options, and considerations made in pursuit of short-term investments. The analysis should be sufficient enough to justify and explain the investment.	Addressed in Rate Case	Gersack V(C) Alternatives to AGIS Bloch V(D)(6) AMI Alternatives Bloch V(F)(7) FLISR Alternatives Bloch V(G)(6) IVVO Alternatives Harkness V(E)(4)(g) FAN Alternatives
	· System interoperability and communications strategy	IDP IX, X and Addressed in Rate Case	Bloch V(D)(7) AMI Interoperability Bloch V(F)(8) FLISR Interoperability Bloch V(G)(7) IVVO Interoperability Harkness V(E)(4) FAN Overview Harkness V(E)(4)(b) FAN Interoperability Harkness V(E)(3)(b) AMI Integration
	· Costs and plans associated with obtaining system data (EE load shapes, PV output profiles with and without battery storage, capacity impacts of DR combined with EE, EV charging profiles, etc.)	IDP XI (F)	Addressed in IDP
	· Interplay of investment with other utility programs (effects on existing utility programs such as demand response, efficiency projects, etc.)	Addressed in Rate Case	Gersack VI(B)(4) Energy Savings Programs
	· Customer anticipated benefit and cost	Addressed in Rate Case	Gersack VII Prudence of AGIS Investments (CBA) Duggirala Overall CBA Costs, Benefits, Results Gersack VIII Bill Impacts *Costs and Benefits are also discussed throughout Bloch V (AGIS), Harkness V (AGIS), and Cardenas V (AGIS)*
	· Customer data and grid data management plan (how it is planned to be used and/or shared with customers and/or third parties)	Addressed in Rate Case	Gersack VI Customer Experience (overall) Gersack VI(B)(3) Digital Experience (web portal) Gersack Schedule 3 Customer Strategy (Appendix B: Data Access, Privacy, Governance) Harkness V(D) Cyber Security
	· Plans to manage rate or bill impacts, if any	IDP IX and Addressed in Rate Case	Gersack VIII Bill Impacts
	· Impacts to net present value of system costs (in NPV RR/MWh or MW)	IDP XIV and Attachment L	Addressed in IDP

Source	Requirement/Description	IDP	Rate Case: AGIS
Docket No. E002/CI-18-251 Aug. 30, 2018 Order (Updated to include changes from Jul 16, 2019 Order)	**· For each grid modernization project in its 5-year Action Plan, Xcel should provide a cost-benefit analysis <u>based on the best information it has at the time and including a discussion of non-quantifiable benefits. Xcel shall include all information used to support its analysis.</u>**	IDP IX and Addressed in Rate Case	Gersack VII(A) CBA Gesack VII(B) Qualitative Benefits Duggirala II(B) Quantitative Inputs Duggirala II(C) Results Duggirala IV Qualitative Benefits
	· Status of any existing pilots or potential for new opportunities for grid modernization pilots	IDP XIII	Gersack III Grid Mod Background (Res TOU Pilot) Gersack IV(C)(2) Advanced Rate Design/Billing Options
	3. In addition to the 5-year Action Plan, Xcel shall provide a discussion of its vision for the planning, development, and use of the distribution system over the next 10 years. The 10-year Long-Term Plan discussion should address long-term assumptions (including load growth assumptions), the long-term impact of the 5-year Action Plan investments, what changes are necessary to incorporate DER into future planning processes based on the DER futures analysis, and any other types of changes that may need to take place in the tools and processes Xcel is currently using.	IDP XIV and Addressed in Rate Case	Gersack II Exec Summary Gersack V AGIS Implementation Gersack VI(D) Customer Experience (Long Term) Bloch D(4)(d)(1) AMI Benefits (DER) Bloch G(4)(b) IVVO Benefits (DER)
Docket No. E002/CI-18-251 July 16, 2019 Order	**8. Provide all information, analysis and assumptions used to support the cost/benefit ratio for AMI, FAN, and FLISR; and IVVO and CVR cost-benefit analysis as part of its 2019 IDP filing or other future filings.**	IDP IX (F) and Addressed in Rate Case	Duggirala Overall - CBA testimony points to the other witnesses who provide detailed cost and benefit forecasts.
Docket No. E002/M-17-797 Sept. 27, 2019 Order	**9. If and when Xcel requests cost recovery for Advanced Grid Intelligence and Security investments, the filing must include a business case and comprehensive assessment of qualitative and quantitative benefits to customers, considering, at a minimum, the following:**	IDP IX and Addressed in Rate Case	Gersack II Exec Summary Gersack III Grid Mod Background Gersack IV(D) Commission Policy and Stakeholder Input Gersack V(A) AGIS Components Gersack V(B) Overall Implementation Gersack VII(A) CBA Quantified Benefits Gersack VII(B) Qualitative Benefits Bloch V(D) AMI Bloch V(E) FAN Bloch V(F) FLISR Bloch V(G) IVVO Harkness V(E)(3) AMI Harkness V(E)(4) FAN Harkness V(E)(5) FLISR Harkness V(E)(6) IVVO
	A. Scope of Investment 1. Investment Description		
	a. Detailed description of proposed investment and project life		
	b. If multiple components, overview of costs and descriptions of each		
	i. Include purpose and role		
	ii. Explain known and potential future use cases for each component		
	iii. Explain known and potential value streams and how each component fits with state policy, statues, rules and Commission orders		
	iv. Describe beneficiaries of each investment (who, how many, over what time period)		
	c. Articulation of principles, objectives, capability, functionalities, and technologies enabled by investment; and		
	d. Interrelation and interdependencies with other existing or future investments, including overlapping costs: scope, amount, timing.		
	2. Alternatives considered	Addressed in Rate Case	Gersack V(C) Alternatives to AGIS Bloch V(D)(5) AMI Cost Development (RFP discussion) Bloch V)D)(6) AMI Alternatives Bloch V(F)(6) FLISR Cost Development Bloch V(F)(7) FLISR Alternatives Bloch V(G)(5) IVVO Cost Development Bloch V(G)(6) IVVO Alternatives Harkness V(E)(4)(e) FAN Cost Development Harkness V(E)(4)(g) FAN Alternatives AGIS Supporting files, Vol. 2B (on disc)
	a. If a Request for Proposal was used provide:		
	i. The RFP issued, including list of all services or assets scoped in the RFP		
	ii. Provide summary of responses		
	iii. Provide assessment of bids and factors used for selection		
	iv. The scope of offerings or services included in the selected bid		
	b. If not, what was used.		
	3. Costs	IDP IX and Addressed in Rate Case	Duggirala II(A) Model Structure and Requirements Duggirala Schedules 2, 3, 4, 5
	a. Provide sufficient information to determine what is included in the investment in each of the following categories:		
	i. Direct Costs (product, service, customer, project, or activity)		
	ii. Indirect Costs		
	iii. Tangible Costs		
	iv. Intangible Costs		
	v. Real Costs		
	b. If needed, provide the utility's definition of each category and whether internal or external labor costs are included in the category and the instant petition. If the costs are not included in the petition, include information on where and when those costs will be sought to be recovered.	Addressed in Rate Case	Duggirala II(A) Model Structure and Requirements
	c. If there is overlap or costs included in both categories, outline the overlapping costs and explain.	Addressed in Rate Case	Duggirala II(A) Model Structure and Requirements Duggirala Schedules 2, 3, 4, 5
	d. For each of the cost categories outline whether the investment has been partially approved or included in previous or on-going docket riders, rate cases, or other cost recovery mechanisms or note all costs are included in the instant petition.	IDP II (C)	Gersack II(C) Exec Summary - AGIS Implementation Gersack III Grid Mod Background Bloch V(C) Grid Mod Efforts to Date Harkness V(E)(2) Grid Mod Efforts to Date

Source	Requirement/Description	IDP	Rate Case: AGIS
Docket No. E002/M-17-797 Sept. 27, 2019 Order	**4. Detailed Analysis of the type of proposed or multiple cost effectiveness analysis utilized:**	Addressed in Rate Case	Duggirala III
	a. Least-cost, best-fit (Xcel proposes in IDP Reply comments)		
	b. Utility Cost-test; and		
	c. Integrated Power System and Societal Cost test		
	B. Provide a cost benefit analysis for (1) each investment component with overlapping costs or benefits in isolation and (2) each bundled components, as appropriate	IDP IX and Addressed in Rate Case	Duggirala II(C) CBA Results AGIS Supporting files, Vol. 2B (on disc) Gersack VII(A)(1) CBA Overview
	1. Provide Discount Rate Used and Basis; and	Addressed in Rate Case	Duggirala II(A) Model Structure and Requirements
	2. Identify cost categories and benefit categories used (explain metrics), including an explaination of how benefits can be monitored over time and proposal for reporting to Commission:	Addressed in Rate Case	Duggirala II(B) Quantitative Inputs Gersack IX Metrics and Reporting
	a. Identify quantitative costs and qualitative costs: i. Use quantitative methods to address qualitative benefits to the extent possible. ii. Explain system used to assess value and priorities to qualitative benefits (points and/or weighting); and iii. Identify sensitivity ranges on estimates or value	Addressed in Rate Case	Duggirala Overall CBA Costs, Benefits, Results
	b. Include a long-term bill impact analysis	IDP IX and Addressed in Rate Case	Gersack VIII Bill Impacts
	c. Include a reference case/scenario without the project (or group of projects); and	IDP IX and Addressed in Rate Case	Duggirala II(A) Model Structure and Requirements Gersack VIII Bill Impacts
	d. Apply the following principles to ensure the investment analysis has:	Addressed in Rate Case	*The Company has incorporated these priciples throughout its analyses, including:* Gersack V AGIS Components and Implementation Bloch V(D) AMI Bloch V(E) FAN Bloch V(F) FLISR Bloch V(G) IVVO Harkness V(E)(3) AMI Harkness V(E)(4) FAN Harkness V(E)(5) FLISR Harkness V(E)(6) IVVO Cardenas V(F) Quantifiable Benefits Gersack VI Customer Experience (Benefits) Duggirala Overall CBA Costs, Benefits, Results
	i. compared with traditional resources or technologies;		
	ii. clearly accounted for state regulatory and policy goals;		
	iii. accounted for all relevant costs and benefits, including those difficult to quantify;		
	iv. provided symmetry across relevant costs and benefits;		
	v. applied a full life-cycle analysis;		
	vi. provided a sufficient incremental and forward-looking view;		
	vii. is transparent;		
	viii. avoided combining or conflating different costs and benefits;		
	ix. discuss customer equity issues, as needed;		
	x. assessed bundles and portfolio where reasonable; and		
	xi. addressed locational and temporal values.		

ADVANCED GRID CUSTOMER STRATEGY



NOVEMBER 2019

Xcel Energy®

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EXECUTIVE SUMMARY

The electric utility industry is in a time of significant change. Increasing customer expectations and technological advances have reshaped what customers expect from their energy service provider, and how those services are delivered. Technologies that customers can use to control their energy usage, such as smart thermostats, electric vehicle (EV) chargers, smart home devices, and even smart phones, are evolving at a fast rate. Influenced by other services, customers have come to expect more now from their energy providers than in the past, including greater choices and levels of service, as well as greater control over their energy sources and their energy use.

At the same time, major industry technological advances provide new capabilities for utility providers to manage the electric distribution grid and service to customers. Electric meters are now equipped to gather more detailed information about customer energy usage, which utilities can leverage to help customers better understand and manage their usage. Other advanced equipment on the grid can sense, communicate, and respond in real time to circumstances that would normally result in power outages. Grid operators can also get improved data to better and more proactively plan and operate the grid. These advancements form the foundation for a flexible grid environment that helps support two-way power flows from customer-connected devices or generating resources (such as rooftop solar) and provides utilities with a greater ability to adapt to future developments.

Xcel Energy has a 100-year track record of outstanding service to our customers and communities – delivering safe, reliable and affordable energy. At our core, is keeping the lights on for our customers, safely and affordably. We are also planning for the future – and have a vision for where we and our customers want the grid to go. We are taking a measured and thoughtful approach to ensure our customers receive the greatest value, and that the fundamentals of our distribution business remain sound.

Today, Xcel Energy customers have access to a multitude of energy efficiency and demand management programs, renewable energy choices, billing options, a mobile app, and outage notifications that include estimated restoration times. Customers also receive confirmations when our records reflect that the outages have been resolved – and they receive these via their preferred communication channel – text, email, or phone. We have made advances on our grid and with the service we offer our customers – and these and other products and services have provided our customers with significant value over many years.

However, technologies are advancing, as are customer expectations. Customers want access to actionable information, more choice and greater control of their energy use – and they expect a smarter, simpler and more seamless experience. Enhancing the customer experience is critically important, and is one of our three strategic priorities, along with leading the clean energy transition and keeping bills low. We plan to integrate modern customer experience strategies with advanced grid platforms and technologies to enable intelligent grid operations, smarter networks and meters, and optimized products and services for our customers.

While we have made incremental modernization efforts on the distribution system over many years, the time is now to begin a more significant advancement of the grid. This modernization begins with foundational advanced grid initiatives that both provide immediate benefits and new customer offerings while also enabling future systems and customer value. The foundational investments in our AGIS initiative include:

- *Advanced Distribution Management System (ADMS).* A real-time operating system that enables enhanced visibility into the distribution power grid and controls advanced field devices.

- *Field Area Network (FAN).* A private, secure two-way communication network that provides wireless communications across Xcel Energy's service area – to, from, and among, field devices and our information systems.
- *Advanced Metering Infrastructure (AMI).* AMI is an integrated system of advanced meters, communication networks, and data processing and management systems that enables secure two-way communication between Xcel Energy Energy's business and operational data systems and customer meters.
- *Fault Location, Isolation, and Service Restoration (FLISR).* A form of distribution automation that involves the deployment of automated switching devices that work to detect issues on our system, isolate them, and restore power thereby decreasing the duration of and number of customers affected an outage.
- *Integrated Volt VAr Optimization (IVVO).* An application that uses selected field devices to decrease system losses and optimize voltage as power travels from substations to customers.

We are taking a measured and thoughtful approach to advancing the grid to ensure our customers receive the greatest value, the fundamentals of our distribution business remain sound, and we maintain the flexibility needed as technology and our customers' expectations continue to evolve.

A. Customer Strategy

This multi-year initiative aims to transform the customer experience by implementing capabilities, technologies, and program management strategies to enable the best-in-class customer experience that our customers now expect. Our customer strategy is focused on shifting the customer experience dynamic to one where little action is required from customers around their basic service and where we offer personalized "packages" that customers can select from to meet their needs – similar to what customers experience when purchasing cable and internet services today. These packages may include options such as demand-side management, renewable energy, rate design, and non-energy services.

Figure 1. Customer Strategy Informed by Customer Expectations

Our implementation of the Advanced Distribution Management System in early 2020 is preparing the grid for increasing levels of DER. It is also paving the way for further grid advancement with Advanced Metering Infrastructure and our ability to leverage the underlying and necessary Field Area Network to reduce customers' energy costs through Integrated Volt-Var Optimization, improve customers' reliability experience through Fault Location Isolation and Service Restoration, and more.

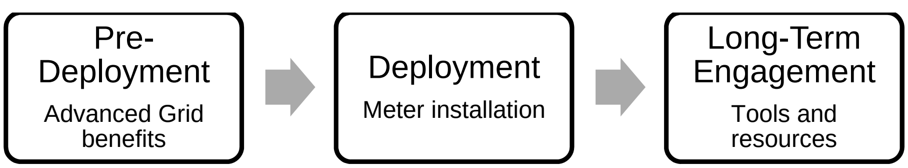
Customers will have access to granular energy usage data from our AMI through a customer portal, which we expect to pair with informed insights and helpful tips on how to change their behavior to save energy. Further, the AMI we propose includes a Distributed Intelligence platform, which provides a computer at each customer's home that can "connect" usage information from the customer's appliances for further insights – and be updated with new software applications, much like customers can currently update their mobile devices with applications.

Figure 2. Customer Value through Lifecycle

	Awareness	Start/Stop/ Transfer	Billing & Payments	Ongoing Use	Support & Service	Lifestage & Lifestyle
What do customers expect?	A **trusted, responsible source** helping customers learn more about environmental initiatives, energy programs and regulations	An **intuitive, frictionless** experience that doesn't contribute to the stress of moving	**Flexibility** and **options** (i.e., variety of payment methods), **transparency** around monthly costs	**Monthly usage insights** allowing customers to manage costs; a **robust offering of energy efficiency programs** aligned to customers' interests	**Increased visibility** during electric outages and delivery of other services; a service organization that **advocates for the customer**	A **go-to resource** for information and solutions regarding **renewable energy** and **smart homes** Energy management technology
Examples – AGIS Enabled Experience	**Integrated communication plan** across channels and timeline.	**Remote Connect / Disconnect** **Real-time meter reads**	**Bill forecasting** **Bill prepayment**	High bill alerts Energy usage goals TOU alerts Disaggregation	**Outage ERT accuracy** **Arch detection**	Distributed Energy Resources Home automation/remote monitoring
Examples – Customer Value	A feeling of comfort with the changes and timely and relevant communications.	Avoid gaps in service Easier moving experience	Increased bill predictability. Payment flexibility. Better understanding of their monthly bill.	Timely alerts and messages to guide their energy use and add predictability to their bill.	More timely and accurate ERT messages. Predictable home health and safety.	EV, Battery, Solar installation readiness and reduced friction Control over usage in the home.
Examples – Business Value	Customer satisfaction Reduced call volume	Reduced truck rolls Accurate meter reads Reduced call volume	Customer satisfaction Reduced B&P call volume	Customer satisfaction Energy savings More predictable load	Customer satisfaction Reliability Reduced call volume	Customer satisfaction Reliability

During this transition to the advanced grid, we will take exceptional care of our customers to educate, inform, and ensure a smooth implementation. We are already developing processes that will ensure accurate, timely bills as customers change over to AMI. We are also developing dedicated, hands-on customer care processes that will provide our customers a single point of contact during implementation – and that will phase customer communications relative to our geographic deployment of AMI meter installation. Meter deployment and advanced meter capabilities will be phased in over the next several years, communications strategies, messages and tactics will be executed in three phases to match the customer journey.

Figure 3. Customer Communications Journey Phases



For example, our customer communications will begin pre-implementation to educate on the possibilities enabled by AMI, as well as customers' ability to opt-out of an AMI meter. As the AMI installation date gets closer, we will inform customers about what to expect with the AMI meter changeover at their homes or businesses. Finally, we will communicate post-AMI installation to reinforce early AMI messaging regarding possibilities and options – also providing practical steps to take advantage of the customer portal or other new or enhanced services available day one.

B. Customer Research

To develop the customer strategy, Xcel Energy committed to understanding customers' preferences, considerations, and thoughts regarding the benefits and value of an advanced grid investment. We gathered this information through primary research, such as focus groups and surveys. We also supplemented our research with information from secondary sources including the Smart Energy Consumer Collaborative, and GTM Research and other utilities' advanced grid plans.

Our key takeaways from these sources are as follows:

- *Consumers care more about technology and enabling improvements than process*. Safety and energy savings rated most highly.
- *Addressing service interruptions are important to all customer classes*. Improved reliability will allow the Company to focus more on other customer priorities.
- *Customers expect that service interruptions will be less frequent in scope and duration*.
- *Customers expect to receive detailed information from their utility*. They expect this information to be personal and frequent.
- *Customers expect more tools and information for them to make decisions about their energy usage*. Customers indicated more information allowed them to better identify opportunities and strategies to save energy and reduce their costs.
- *Business customers have more awareness and familiarity with advanced rate designs*. Residential customers expect the utility to provide them with rate comparison tools and information about new rate designs.
- *Building trust is a key component to unlocking value.* Trust is best built by identifying solutions and showing results specific to the customers
- *Customers expect that there will be a cost associated with the advanced meter but that the meter will also provide benefits over time.*

We have incorporated customer feedback and insights into our customer transition and communication plans – and the work we are doing to develop new and enhanced products and services as enabled by the advanced grid.

C. Advanced Grid Initiative

Fundamentally, we must act to replace our current Automated Meter Reading (AMR) service because our current vendor is sun-setting its AMR technology in the mid-2020s. While this system has provided value to customers for many years through efficient meter reading, we have an opportunity now to seize AMI technologies that are becoming available to maximize value for our customers. As we deploy advanced grid infrastructure, platforms, and technologies we expect three outcomes: (1) a transformed customer experience, (2) improved core operations, and (3) facilitation of future capabilities, which we discuss below.

Transformed customer experience. Our planned advanced grid investments combine to provide greater visibility and insight into customer consumption and behavior. We will use this information to transform the customer experience through new programs and service offerings, engaging digital experiences, enhanced billing and rate options, and timely outage communications.

We will offer options that give customers greater convenience and control to save money, provide access to rates and billing options that suit their budgets and lifestyles, and provide more personalized and actionable communications. As our system more efficiently manages energy flows, we can save customers money by reducing line losses and conserving energy. Smarter meters will be the platform that enables smarter products and services and contributes to improved reliability for our customers. Our customers will have more information to make more effective decisions on their energy use.

We will know more about our customers and our grid – and we will use that information to make more effective recommendations and decisions and continually use new information to develop new solutions. This will serve to help keep our bills low, as customers save money through both their actions and ours. It will also help ensure that our transition to a carbon-free system occurs efficiently – and harnesses the vast potential of all energy resources, from utility-scale to local distributed generation.

Improved core operations and capabilities. Smarter networks will form the backbone of our operations, and our investments will more efficiently and effectively deliver the safe and reliable electricity that our customers expect. We will have the capability to communicate two ways with our meters and other grid devices, sending and receiving information over a secure and reliable network in near-real time.

Our current service is reliable; however, we need to continue to invest in new technologies to maintain performance in the top third of U.S. utilities, particularly as we deliver power from more diverse and distributed resources and as industry standards continue to improve. Our advanced grid investments provide the platform and capabilities to manage the complexities of a more dynamic electric grid through additional monitoring, control, analytics and automation.

Our systems will more efficiently and effectively restore power when outages do occur using automation without the need for human intervention. For those outages that cannot be restored through automation, our systems will be better at identifying where the outage is and what caused it – benefitting customers through less frequent, shorter, and less impactful outages; more effective communication from the Company when they are impacted by an outage; and reduced costs from our more efficient use and management of assets.

Facilitation of future capabilities. The backbone of our investments will also support new developments in smart products and services; in the short term by supporting the display of more frequent energy usage data through the customer portal – and over the long term, allowing for the implementation of more advanced price signals. Designing for interoperability enables a cost-effective approach to technology investments and means we can extend our communications to more grid technologies, customer devices, and third-party systems in a stepwise fashion, which unlocks new offerings and benefits that build on one another. We have planned our advanced grid investments in a building block approach, starting with the foundational systems, in alignment with industry standards and frameworks. By doing so, we sequence the investments to yield the greatest near- and long-term customer value, while preserving the flexibility to adapt to the evolving customer and technology landscape. By adhering to industry standards and designing for interoperability, we are well positioned to adapt to these changes as the needs of our customers and grid evolve.

In planning our advanced grid initiative, we have considered the long-term potential of our ability to meet our obligations to serve and our customers' expectations and needs – ensuring we extract cost-effective value from our investments and remain nimble enough to react to a dynamically changing landscape. The principles we applied to our advanced grid planning include the ability to remotely update hardware and software, security and reliability, and flexible, standards-based service components. We are planning our grid advancement with the future in mind, and to provide both immediate and increasing value for our customers over the long-term.

We are on the forefront of many of the issues and changes underway in the industry and have developed our advanced grid initiative and our customer strategy to address them and harness value for our customers. In addition to transforming the customer experience, these foundational investments will allow us to advance our technical abilities to deliver reliable, safe, and resilient energy that customers value. These foundational investments also lay the groundwork for later years. The secure, resilient communication networks and controllable field devices deployed today through these investments will become more valuable in the future as additional sensors and customer technologies are integrated and coordinated.

Now is the time to modernize the interface where we connect directly with our customers – the distribution system. Technologies have evolved and matured; our peers have successfully implemented these technologies; and, the industry landscape is evolving. We must ensure our system has the necessary capabilities to meet our customers' expectations and needs – and, the flexibility to adapt to an uncertain future.

D. Reporting Metrics

Recognizing the significant investment that the advanced grid initiative requires as well as the fact that we are the first utility in Minnesota to take on this holistic effort, we propose to report on several metrics. These metrics will not only help measure the success of or areas of improvement within the advanced grid initiative, they will also provide progress reports to the Commission and share information and learnings with stakeholders. The proposed metrics are defined in four categories:

1. *Customer Awareness* – measuring the effectiveness of the communications on educating customers about the advanced grid and the potential benefits it entails.
2. *Customer Engagement* – measuring the adoption rates of customers in new products and services that are enabled or enhanced by the advanced grid.
3. *Customer Satisfaction* – measuring how satisfied customers are with the deployment or and services associated with the advanced grid.
4. *System Benefits* – measuring the energy savings benefits associated with products and services enabled or enhanced by the advanced grid.

Reporting of these metrics can keep stakeholders informed of the progress and value that the advanced grid is bringing to customers and also identify areas where Xcel Energy can focus additional resources to improve results. Each metric would have a specific baseline in a steady state. The steady state would occur within 1-2 years of the completion of mass deployment of advanced meters.

E. Conclusion

Xcel Energy's advanced grid initiative supports our vision of a customer experience where customers' needs and preferences are met and the customer effort level is low. We understand what our customers expect and will deliver on those expectations with a seamless experience that both improves their comfort and satisfaction while reducing costs and improving the efficiency of the entire system.

I. INTRODUCTION

Xcel Energy has a 100-year track record of outstanding service to our customers and communities – delivering safe, reliable and affordable energy. Currently, Xcel Energy customers have access to a state-of-the-art storm center, approximately 40 different energy efficiency and demand management programs, multiple renewable energy choices, billing options such as Average Monthly Payment, and a customer portal – MyAccount – that provides them digital access to their energy usage, energy savings recommendations, and benchmarking comparisons with similar customers. We also provide customers with outage notifications that include estimated restoration times – and confirmations when the Company's information reflects that the outages have been resolved. These have provided our customers with significant value over many years.

However, technologies are advancing, as are customer expectations. While we have done a great job meeting our customers' needs over time by maximizing the value of our existing infrastructure and technologies – customers want access to more actionable information, more choice and greater control of their energy use – and they expect a smarter, simpler and more seamless experience. Today, connected devices, such as Wi-Fi thermostats, Amazon's Alexa, and Google Home are becoming more prevalent in customer homes – influencing their perceptions about the ease of getting information conducting transactions. Distributed energy resources (DER) are becoming more cost-effective for customers – and forecasts indicate the potential for rapid growth in electric vehicles and home energy management systems. While there are no guarantees that these forecasts will be realized or that customers see promise in the potential value these technologies may unlock, we expect and want to play a role in spurring adopting of these technologies and ensuring their value is realized. We also look to these technologies to shape the way that we provide service to our customers.

Enhancing the customer experience is critically important, and is one of our three strategic priorities, along with leading the clean energy transition and keeping bills low. We plan to integrate modern customer experience strategies with advanced grid platforms and technologies to enable intelligent grid operations, smarter networks and meters, and optimized products and services for our customers. Combining enhanced experiences with smarter capabilities is a powerful and winning combination for the customers and communities we serve.

Now is the time to modernize the interface where we connect directly with our customers – the distribution system. Technologies have evolved and matured; our peers have successfully implemented these technologies; and, the industry landscape is evolving. We must ensure our system has the necessary capabilities to meet our customers' expectations and needs – and, the flexibility to adapt to an uncertain future.

II. ADVANCED GRID CUSTOMER STRATEGY

More than a century after the introduction of commercial electricity, the electricity grid and the role of the utility are being reimagined. We are on the cusp of advancing our grid with investments in the things that customers truly value. These investments will allow us to provide comprehensive and customized energy solutions that will help bring about the flexible, distributed, consumer-driven energy system of the future. While we have been incrementally advancing the grid over time, we are poised to embark and intend to complete a transformational set of investments in concert with our over 3 million Upper Midwest customers over the next five years.

Our advanced grid investments will provide the foundation for new products and services or the enhancement of existing products and services. These investments include a communications backbone that will allow us to transmit data to and from advanced meters at every customer's home or business in near real time. We will have more information about customer energy usage that will improve the quality and accuracy of our product and service recommendations. We will build this data into digital experience channels to provide customers with more timely and accurate information about their energy usage. These experiences will drive increased satisfaction and savings for customers as they have better information and as our recommendations become more relevant and actionable. Customers will feel like Xcel Energy is a partner in their energy usage – not just a provider.

The advanced meters we will implement will provide a distributed intelligence platform that is essentially a "computer" at customers' homes and businesses. This computer uses a Linux-based operating system to conduct localized, at the meter computing, analysis, and data processing that provide customers with new tools to help manage their energy usage and provide Xcel Energy with new tools to manage the grid more efficiently.

Automated sensors and controls on the grid will use the advanced grid communications backbone to smooth out the voltage and avert outages for some customers and shorten outages for others. We will delight our customers by knowing and acting without them having to call or take any other action when they lose power. The number of sensors and devices in the field will allow the Company an unprecedented level of information to continually monitor and adjust what will be a dynamic system that includes increasing amounts of distributed energy resources and electric technologies. We will have more information about our distribution grid that will improve our planning and operations – driving efficiencies, lowering costs, providing better service, and increasing customer satisfaction.

A. Customer Strategy

If we want to ensure that our customers benefit from the greater value and opportunity presented by an increasingly complex and challenging energy system, we know we must move away from the traditional one-directional customer relationship. We must instead operate in partnership with customers.

We aspire to be the preferred, trusted provider for our customers by delivering low-cost and reliable electricity and innovative, energy-efficient solutions. We understand that placing the customer at the center of everything we do is vital to the successful realization of the future electric system. Our strategy is therefore focused on shifting the customer experience dynamic to one where little action is required from customers around their basic service – and where we offer personalized "packages" that include options and opportunities in areas such as energy savings and renewable energy, lifestyle-oriented rate designs, and non-energy services – to meet individualized needs and wants.

With the impending introduction of advanced meters, greater system data availability and energy technologies, customers can increasingly decide when and how to consume electricity. Many customer experience improvements will come through foundational changes to our processes and technology – and our investment in the advanced grid will play a critical role in helping us meet our customers' expectations throughout their Xcel Energy journey.

Our advanced grid strategy is driven by our strategic priorities:

- Enhance the customer experience;
- Keep bills low; and
- Lead the clean energy transition.

These strategic priorities are driven by our customers' expectations which are informed by the routine experiences they have outside of the relationship with their energy provider. These customer expectations shape our guiding principles creating the future customer experience:

Figure 4. Customer Experience Guiding Principles

With the advanced grid, there are significant possibilities for Xcel Energy and its customers, but there are also unknowns. Our vision is that the long-term customer experience is one where customers' needs and preferences are met, and that the level of effort our customers need to take is low. We will understand what our customers expect and deliver on those expectations with a seamless experience that improves their comfort and happiness, while reducing costs and improving the efficiency of the entire system. We discuss our customer research in more detail below.

Through innovation, we will provide our customers with data-driven insights that help identify and deliver the best options, and we will work in collaboration to give them greater control to support their energy goals. We will make this easy by focusing on outcomes, responding with speed, and utilizing digital tools to improve the customer journey experience.

Our commitment to the customer experience is not just an evolution of the current experience. In all of our interactions, we are relying on our broad and in-depth customer research to better understand customer needs, preferences, and expectations and then develop the appropriate processes, products and services, and experiences needed to satisfy those expectations. The following section reviews the research we have done related to customer interest in and knowledge and awareness of advanced meters and the benefits of the advanced grid.

B. Customer Research

To develop our customer strategy, we gathered information about customers' considerations, preferences, and thoughts through primary research such as focus groups and surveys. We also supplemented this research with insights from secondary sources, such as the Smart Energy Consumer Collaborative, GTM Research, and other utilities' advanced grid plans.

Our key takeaways from these sources are as follows:

- *Consumers care more about their technology and enabling improvements from the advanced grid than process*. Safety and energy savings rated most highly. Customers have strong feelings about the cost of the advantages available through advanced meters.
- *Addressing service interruptions is important to all customer classes*. Improved reliability will allow the Company to focus more on other customer priorities.
- *Customers expect that service interruptions will be less frequent and of shorter duration*.
- *Customers expect to receive detailed information from their utility*. They expect this information to be personal and frequent.
- *Customers expect more tools and information for them to make decisions about their energy usage*. Customers indicated more information allowed them to better identify opportunities and strategies to save energy and reduce their costs.
- *Business customers have more awareness and familiarity with advanced rate designs*. Residential customers expect the utility to provide them with rate comparison tools and information about new rate designs.
- *Building trust is a key component to unlocking value.* Trust is best built by identifying solutions and showing results specific to the customers
- *Customers understand that their rates will increase in order to cover the expense of advanced meters but expect that the benefits of the meters will result in their costs being net neutral over time.*

In terms of messaging regarding implementation, customers told us our messaging should be short, specific, and positive. Messages should focus on the benefits of the project not on the process – and begin 2-3 months in advance of any implementation, which will give customers time to conduct their own research if they want. Customers want communications through multiple channels, including those that align with their preferences (email, text, phone). Finally, communications should be clear about any customer costs associated with the installation.

1. Primary Customer Research

The following studies have helped to inform our AGIS plans and deployment.

- *Grid Edge Product Survey* – This survey was conducted in March 2019 with the intent to gauge customers' opinions and interest toward several proposed product and service concepts that may become available after AGIS deployment. Beyond testing for concept interest, willingness to purchase and price sensitivity were also observed.
- *Advanced Meter Focus Groups* – Four residential customer focus groups were held in January 2019 which the goal of capturing customer understanding, perception, and attitudes toward advanced meters, as well as to understand customer expectations of the services enabled by advanced metering. Also included in these focus groups

were learning customer preferences for communications around the deployment and implementation of new meters.

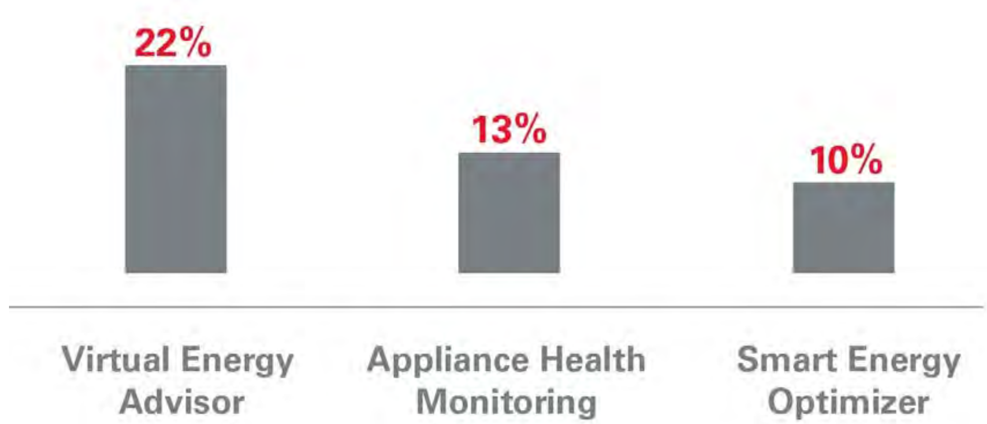
- *2018 MN Smart Meter Survey* – 500 residential and 100 business customers were surveyed in August 2017 with the objective of quantifying familiarity and perceived value of smart meters, gauging the potential value of AMI-related benefits to customers, preferences for AMI enabled data, and communications about future smart meter plans.
- *Residential Relationship Study* – The *Residential Relationship Study* has been conducted monthly since April 2018 in order to determine the pulse of Xcel Energy Energy's customers' opinions and satisfaction with service. Included in the monthly survey are questions which gauge customers' interest in new products and attitudes of and practices around energy usage.
- *Electric Residential Study* – Xcel Energy subscribes to this study, conducted by JD Power, to benchmark the company against peer utilities, to measure customer satisfaction, and to analyze data about customer electric use in their homes.

a. Grid Edge Product Survey

We conducted this_survey focused on Xcel Energy residential customers in March 2019; we collected 5,119 survey completions, so consider these results robust. We tested multiple product concepts enabled by AMI. Of these concepts we have identified three, listed below, that we believe deliver significant customer value and help achieve our customer driven strategic priorities.

- *Appliance Health Monitoring*: A service that can help customers gain insight into the performance and health of their electric appliances. Xcel Energy would also provide a list of vendors that can offer expert advice and repair options to the subscriber.
- *Virtual Energy Advisor*: This product concept monitors energy consumption in the home via Amazon Echo or Google Home so that customers can control home appliances/electronics from anywhere.
- *Smart Energy Optimizer*: This product concept would connect to customers' smart home devices via Amazon Echo or Google Home and manage them based on a set budget.

Figure 5. Product/Concept Interest (Top 3 Box)



Key findings of this survey include:

- The product concepts were new at the time of the survey and do not exist in any form today, so education to build awareness and willingness to subscribe is likely necessary.
- Customers under age 45 have higher interest in AMI enabled concepts that are technology driven. 39% of customers under 45 expressed top 3 box interest in a home Virtual Energy Advisor.
- There were no significant differences seen between the larger states (Minnesota and Colorado) and smaller states (Texas, New Mexico, and Wisconsin).

b. Advanced Meter Focus Groups

These focus groups were conducted in Colorado among residential customers in January 2019. In preparation for advanced meter implementation in the coming years, our objective was to understand customer expectations, attitudes, and communications preferences around advanced meters. Key findings of these focus groups include:

- Customers believe that advanced meters will help them save money through detailed, incremental usage data.
- Customers are unclear about the basic functionality of smart or advanced meters and need to be informed before new meters are implemented.
- Customers want to be made aware of advanced meter installation 2-3 months in advance through a multi-channel approach.
- Customers under age 45 prefer to seek out information on a Frequently Asked Questions (FAQ) page or through online media tools.
- A major concern for customers is the potential for increased cost to them for new meters.

c. Minnesota Smart Meter Survey

We conducted this survey in August 2018 among residential and business customers with the intent of identifying customer familiarity with smart meters, value assigned to AMI enabled benefits, and willingness to pay for those benefits. We also sought to understand customer preferences for accessing smart meter data. Key findings include:

- Residential customers value smart meter benefits for power restoration, personalized information, monetary incentives, grid automation/monitoring, and rate comparison tools.
- Awareness is low. Only 15% of residential customers state that they are familiar with smart meters.
- Willingness to pay is tied to awareness of the benefits; 13% of residential customers would be willing to make a small monthly payment to receive advanced meter benefits.
- Digital channels are preferred among residential customers for accessing their advanced meter data.
- Business customers are much more familiar with advanced meters (30%) and are more likely to be willing to pay (36%) for advanced meter benefits.

d. Xcel Energy Residential Relationship Study

This is a proprietary study conducted by Xcel Energy on a monthly basis to determine the pulse of the customer including satisfaction, attitudes, interest in new products or services. In May 2019, we added questions on grid edge products in the survey. Key findings include:

- 43% of respondents would like to be alerted when their energy usage/dollar amount is over a preset amount.
- Energy efficient products and appliances that help reduce energy usage are a popular concept: 42% of respondents currently have or use them, and 35% of respondents are interested in such products.
- Current use of Wi-Fi connected smart thermostats and smart plugs that allow Wi-Fi control of appliances or lighting is still relatively low at 14% and 8% respectively.
- 66% of respondents want to have control of their energy use when not at home.
- 34% of respondents are interested in receiving a notification through a phone app when electricity is available from renewable sources, while 4% currently have or use this type of service.
- Customers are currently lacking the tools to know why their bill may be high; 57% of respondents have the perception that their Xcel Energy bills have increased in the past three years.

e. JD Power Electric Residential Study

Xcel Energy subscribes to this study, which analyzes survey responses from utility customers around the country. JD Power surveys customers regarding their in-home electric usage, perceptions of their utility, and satisfaction their utility. Findings from year-end 2018 include:

- Xcel Energy ranked in the 2nd quartile among its peers for efforts to help manage monthly usage.
- Xcel Energy ended 2018 near the 1st quartile for keeping customers informed about an outage.
- Xcel Energy ranks at the 51st percentile in terms of providing pricing options that meet the needs of customers, which is right at threshold for 2nd quartile.
- Customers want detailed information about their monthly bills and can benefit from advanced meter data. Diagnostics from the study indicate:
    - 91% view their monthly payment amount.
    - 39% view their kilowatt hours used.
    - 27% view price per usage level.
    - 51% review their usage compared to the prior month.
    - 40% review their usage compared to the prior year.

f. Colorado Time of Use Non-Participating Customer Survey

We conducted this survey in December 2017 among customers that were only participating in a traditional rate plan. The objective of this survey was to gain insight in to how customers learn about new pricing plans and how we can improve communications around these plans. Key findings include:

- Familiarity with advanced pricing plans is low:
    - 58% of respondents reported that they would need more specific information about rate plans, including rules and guidelines.
    - 39% said they would need additional examples of practices that would help them save while on a new rate plan.
    - 27% of respondents answered that they did not know enough about new rate plans to switch from their current rate plan.

- In order to learn more about the new rate plans, 46% of respondents answered that they were likely to visit the Xcel Energy website to obtain information.

g. Minnesota Time of Use Rate Study

Similar to the TOU customer survey in Colorado, we conducted this study during the summer of 2017 with Minnesota residential customers to learn more about the level of familiarity, customer opinions, and customer attitudes regarding new rate plans. This study also took a more detailed look at customer habits and practices with energy use willingness to switch to a Time of Use rate plan. Key findings from this study include:

- 93% of respondents had tried to save money on their bills by reducing electricity use in the past; however, 61% had never tried to save money on their bills by shifting use to a different time of day.
- 31% glance at the various costs and other information on their bill; 18% spend several minutes or more reviewing their bill to further understand their costs.
- 60% of respondents either had never heard of the term "time of use rate" or had heard it but did not know what it meant.
- 43% of respondents expressed interest (top 3 box on a 10 point scale) in using less energy during the weekday peak time.
    - The most common reasons for wanting to shift usage out of peak periods was wanting to save money (61% of respondents) and wanting to help protect the environment (43% of respondents).
- Customers largely prefer to receive information about new "Peak and Off-Peak" pilot programs through email.
- Through advanced metering, the information most valued by customers was month-to-month peak usage comparisons, and proportion of on-peak vs. off-peak energy use comparisons.

h. Minnesota Time of Use Behavioral Focus Groups

These focus groups were held in May 2019 among residential customers to gain insight into current customer behavior, and potential future behavior concerning their energy usage. Key findings include:

- Customers are most willing to shift usage of appliances that have the least impact on their quality of life, such as dishwashers and laundry washers/dryers. Customers are less likely to shift energy usage of appliances that have a large impact on their quality of life.
- Most were willing to change some behavior if electric rates went up during peak times.
- Daily schedules, convenience, and comfort are the main barriers to adapting new usage patterns.
- Economic motivators are top of mind, though customers describe environmental motivators as important.
- The younger cohort had more of a tendency to acknowledge social pressures as a motivator for change.
- Third party coverage and reporting is the most trustworthy when it comes to learning about time-of-use plans.
- Online tools and savings tips should be personalized to customers to make them more actionable.

2. *Secondary and External Customer Research*

In addition to conducting primary research, we also rely on external resources to supplement advanced grid planning, which can be seen as having a larger scope since the tendency is to study a topic industry wide rather than by a single utility. Secondary and external customer research serves to provide insight from national and international research organizations and other utilities that have or are in the process of deploying advanced grid plans. We have used the following sources and insights in our advanced grid planning.

a. E Source: *E Design 2020 Small Medium Business Ethnographic Research*

E Source conducted this research in 2018 in order to help utilities understand how to better engage with small and midsize business (SMB) customers through effective programs, services and offerings.[1] In the 2018 study, objectives included developing a better understanding of the SMB landscape, detailing SMB customer wants and needs, and determining ways that utilities can actively partner with these customers for increased satisfaction. Key findings from this research include:

- Utilities should build partnerships with business customers by building trust first.
- Improved infrastructure and availability of data will help SMB customers better monitor their energy usage and find ways to conserve on energy costs.
- Since business customers spend a significant portion of their budget each year on energy costs, bills and charges should be as transparent as possible, and utilities should be easily accessible if there is a question/concern about billing.
- Business owners define their relationship with a utility based on power reliability. Outages have a significant impact on this relationship.
- Businesses need utilities to guide them toward the tools that will allow them to be actively and passively energy efficient.

b. Department for Business, Energy & Industrial Strategy (U.K.): *Smart Meter Customer Experience Study: Post-Installation Survey Report*

The United Kingdom Department for Business, Energy & Industrial Strategy (BEIS) conducted a survey in 2017 focusing on customer experiences before, during, and immediately after smart meters were installed in residential homes. The BEIS also developed steps in the customer journey toward making changes to energy consumption. Findings from this research include:

- 80% of customers surveyed were satisfied with their smart meter; 50% were very satisfied with their smart meter (score 9 or 10 on a 10 point scale).
- Customers that proactively requested smart meter installation were among the most likely to be satisfied and highly likely to recommend smart meters to others.
- Making energy use visible was the primary motivation among respondents for having a smart meter installed.
- Respondents most commonly recalled receiving information in advance of the installation from energy suppliers.
- 67% of households that received an in-home display for their meter reported using it at least once a week to view the amount of energy being used.

[1] ESource is an industry organization focused on advancement of the efficient use of energy. They help utilities and large energy users with critical problems involving energy efficiency, utility customer satisfaction, program design, marketing, customer management, and sustainability by providing syndicated research and counsel.

c. U.S. Department of Energy: *Advanced Metering Infrastructure and Customer Systems: Results from the Smart Grid Investment Grant Program*

The Smart Grid Investment Grant (SGIG) Program, developed under the U.S. DOE is a project aimed at modernizing the electric grid, has invested heavily in deployment of AMI and customer systems technologies. This report outlines key findings from SGIG projects that have implemented AMI and customer systems technologies. This research aids the DOE in accelerating grid modernization and informing decision makers. Key findings from this report include:

- AMI deployment has resulted in reduced cost for metering and billing from fewer truck rolls, labor savings, more accurate and timely billing, fewer customer disputes, and improvements in operational efficiencies.
- New customer tools allow for more control over electricity consumption, costs, and bills.
- Customer bill savings and lower capital expenditures results in reduced peak demand and improved asset utilization.
- Outages are less frequent, restored faster, and less of an inconvenience for customers.

d. Smart Grid Consumer Collaborative: *Effective Communication with Consumers on the Smart Grid Value Proposition*

The Smart Grid Consumer Collaborative (SGCC), now known as the Smart Energy Consumer Collaborative (SECC), conducted a customer survey in 2016 with the intent of capturing feedback that will help utilities effectively communicate with customers about smart grid implementation and values. This report outlines the messaging and methods to which customers were most receptive. Findings from this report include:

- Messages should be short, specific, and positive.
- References to increasing benefits rather than reducing harmful elements are better received by customers.
- Consumers are more interested in tech enabled improvements, less interested in how a utility achieves results.
- Smart grid benefits for consumers are generally grouped in three broad categories: environmental benefits, economic benefits, and reliability benefits.

e. Smart Energy Consumer Collaborative (SECC): *Understanding Your SMB Customers: A Segmentation Approach*

The SECC conducts utility industry research on a wide variety of subjects and customer segments. The SECC conducted this research using segmentation to more clearly define utility-customer relationships and how utilities can be a more active partner for SMB customers. Key findings from this research include:

- During the course of this research, five segments emerged:
    - o *Established and Engaged* – Always on the lookout for ways to use energy more effectively and are already partnered with service providers to do so. (15% of SMB market)
    - o *Motivated Yet Inactive* – Interested in the idea of energy efficiency, although they have not yet taken the first steps. (17% of SMB market)

  - *Interested if Incented* – Energy efficiency is not top of mind. Engaging in new programs and services will require a compelling incentive. (27% of SMB market)
  - *Saving and Satisfied* – Have already taken steps to use energy more efficiently and only passively interested in doing more. (13% of SMB market)
  - *Decidedly Disengaged* – Have no interest in the idea of energy efficiency and feel there isn't much they can do. (28% of SMB market)
- Size of business matters to engaging with utility in energy efficiency. Across all segments, half of SMBs with more than 50 employees surveyed would "definitely" engage with their utility, if the utility reaches out, on energy efficiency.
- Small- and mid-sized customers vary widely within their industries in terms of size of building, number of employees, and wants and needs from their energy provider.
- 92% of the Established and Engaged have interacted with their utility on energy usage data.
- 68% of the Established and Engaged have interacted with their utility around rate adjustments.
- 86% of the Motivated Yet Inactive segment is interested in usage rates relevant to their business.

f. Chartwell: *Demand Reduction Programs for TOU Customers – Madison Gas & Electric Case Study*

Madison Gas & Electric began an On Demand Savings (ODS) pilot program for commercial & industrial (C&I) customers in 2015, originally targeting 30 customers.[2] The intent of this pilot was to allow C&I customers to monitor their energy use in real time, reduce overall energy use, and implement practical load shedding or load shifting strategies to reduce their on-peak demand and improve their operational efficiency. The pilot sought to do this by identifying a customers' unique demand profile to suggest the best load shedding and cost saving strategies through use of AMI-enabled technology to provide data to both the customer and utility. Key findings from this report include:

- Customers participating in the initial pilot from 2015-2016 averaged 9% savings in monthly demand charges.
- Between June and September 2016, the average monthly savings was 2,760 kW.
- The average monthly kWh savings for participating customers was 4.5% in the same time period.
- The initial pilot found that nearly 70% of participants changed their thinking about how they use their building automation systems after participating in the pilot program.

g. E Source: *2019 E Source Gap & Priority Study*

Xcel Energy subscribes to this annual study from E Source to better understand small, mid-sized, and large commercial and industrial customers' needs – and how we are meeting those needs. In this study, SMB and large C&I customers are asked about their participation and interest in various energy efficiency programs, utility programs or services, and demand response services that can be offered by their utility. Key findings from this study include:

[2] The pilot has since been expanded to 50 C&I customers.

- 24% of large C&I customers surveyed currently participate in energy data analytics, strategic energy management, and behavior programs; another 32% are interested in participating in these types of programs.
- 31% of large C&I respondents currently use some form of energy management system, and 25% are interested in this technology.
- 21% of large C&I respondents currently participate in an Xcel Energy power monitoring program or service and 32% are interested in participating.
- Participation in energy data analytics, strategic energy management, and behavior programs is less common among mid-sized businesses. Only 4% currently participate in these types of programs and 19% are interested in participating.

C. Research Applied to our Advanced Grid Implementation

In summary, we have taken the following insights away from this research to shape our advanced grid customer strategy and implementation.

1. Customer Value and Expectations

Customers care more about technology and enabling improvements than process. They have strong feelings about the costs and benefits of advanced meters; however, their awareness and understanding of the costs and benefits may be limited, which has an impact on their perceptions.

Addressing service interruptions is important to all customer classes. Customers expect that service interruptions will be less frequent and of shorter duration. Customers expect to receive detailed information from their utility. This information is expected to be personal and frequent. Customers believe that improved reliability will allow the Company to focus more on other customer priorities.

Customers expect more tools and information for them to make decisions about their energy usage. They indicated that more information would allow them to better identify opportunities and strategies to save energy and reduce their costs.

Business customers have more awareness and familiarity with advanced rate designs. Residential customers expect their utility to provide them with rate comparison tools and information about new rate designs.

Building trust is a key component to unlocking value. Trust is best built by identifying solutions and showing results specific to the customers.

Customers understand that their rates will increase in order to cover the expense of advanced meters but expect that the benefits of the meters will result in their costs being net neutral over time.

2. Customer Education and Outreach

Messaging should be short, specific, and positive. Messages should focus on the benefits of the project, not on the process. Messaging should begin 2-3 months in advance of any implementation. Early messaging gives customers time to conduct their own research, if they want. Messaging should be done through multiple communications channels and align with customer preferences.

Customers under the age of 45 tend to prefer digital communications whereas customers over 45 tend to prefer phone and mail communications. They expect communications to be clear about what the direct and indirect customer costs are. If customers believe there is a direct charge for the meter at the time of installation they are less likely to support deployment. Benefits can broadly be grouped as environmental, economic, and reliability.

III. ADVANCED GRID INTELLIGENCE AND SECURITY INITIATIVE

While we have made incremental modernization efforts on the distribution system over many years, we must replace our current Advanced Meter Reading (AMR) service. The current vendor of this service will stop supporting and producing the parts required to maintain the system after 2022. While this system has provided value to customers for many years through efficient meter reading, it has limited capability to improve other aspects of our operations.

The need to replace these meters provides us with an opportunity to modernize our distribution system. This modernization begins with foundational advanced grid initiatives that both provide immediate benefits and new customer offerings while also enabling future systems and customer value. The core investments in our AGIS initiative include:

- Advanced Distribution Management System (ADMS);
- Advanced Metering Infrastructure (AMI); and
- Field Area Network (FAN).

In addition, ADMS is already underway and will provide the capability to implement two advanced applications that we believe will provide substantial benefits to customers and are included in our AGIS initiative:

- Fault Location Isolation and Service Restoration (FLISR); and
- Integrated Volt-VAr Optimization (IVVO).

These core investments will provide us with the tools and information we need to improve the management of the grid, meet growing customer expectations, and develop a platform that can provide long term flexibility and value.

To ensure we have made investments that will serve our customers over the long term, we have also planned into our technology the ability to conduct remote upgrades, applied industry leading security practices, and adopted flexible, standards-based service components to ensure interoperability between systems. The following sections will detail our AGIS investment strategy, our commitment to security, and the broad benefits we will deliver for all our customers.

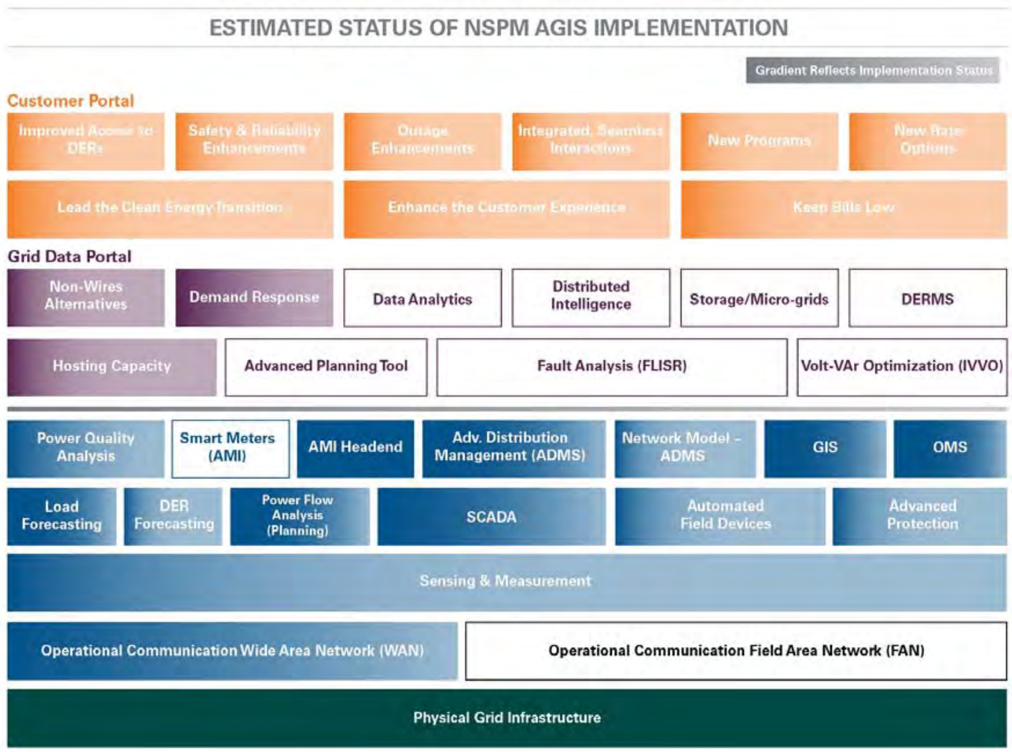
A. Technology Strategy

Unlocking the customer and operational value enabled by AGIS will evolve over time and begins with building a solid foundation. The U.S. DOE's Next Generation DSPx, Volume III provides a good reference for how to consider both the elements of a modern grid and their costs.[3]

We have taken the DOE's DSPx model and adapted it, as shown in Figure 6 below, to reflect the investments and capabilities that are part of our AGIS vision. This vision is also defined by the feedback and interactions we have had with a broad array of stakeholders and the Minnesota Commission.

[3] The DSPx report was sponsored by the U.S. DOE's Office of Electricity Delivery and Energy Reliability. *See Modern Distribution Grid, Volume III: Decision Guide*, U.S. Department of Energy Office of Electricity Delivery and Energy Reliability (June 2017).

Figure 6. Xcel Energy Advanced Grid Approach



The DSPx model begins with the "core components" as the foundation for our advanced grid roadmap. Building on that foundation enables advanced applications that will ultimately support our commitment to enhanced customer experience, keeping bills low, and leading the clean energy transition.

Our implementation of systems and hardware has already begun. As detailed below, this begins with the solid foundation and backbone in ADMS, which is expected to go into service in Minnesota in 2020 – and a limited implementation of the FAN and AMI to support the Minnesota Time of Use (TOU) pilot. This is followed by the deployment of smarter meters with more grid capabilities as we expand the FAN to support the mass deployment of advanced meters. During this timeframe of mass meter deployment, we will begin to implement other advanced grid components such as IVVO and FLISR and implement new products and services to help customers manage their energy usage and keep their bills low.

B. Step 1: Solid Foundation and Backbone

1. Advanced Distribution Management System

ADMS provides the foundational system for advanced grid operational hardware and software applications. The ADMS acts as a centralized decision support system that assists control room personnel, field operating personnel, and engineers with the monitoring, control and optimization of the electric distribution grid. This centralized platform provides greater awareness to our system and our customers. This capability is becoming critical as customer interest in solar, battery storage, electric vehicles, and other emerging technologies continues to grow – increasing the complexity of the electric distribution grid. ADMS also supports advanced applications such as IVVO and FLISR, which can provide further benefits for our customers.

A critical supporting element of the ADMS system is the Geospatial Information System (GIS). This foundational data repository is integrated with ADMS to provide location and other information for all the physical assets that comprise the distribution system. The ADMS uses this information to maintain the as-operated electrical model and operate the advanced applications.

2. *Field Area Network*

The FAN is a private, secure two-way communication network that provides wireless communications across Xcel Energy's service area – to, from, and among field devices and our information systems. It serves multiple business value streams that include, but are not limited to ADMS, IVVO, FLISR, and AMI – and will support future technologies that will unlock additional value for customers. Comprehensive geographic coverage allows Xcel Energy to grow and expand automation opportunities to the benefit of our customers. The FAN can enable future applications that may provide significant advances in situational awareness, operational efficiency, and asset lifecycle management. The FAN may allow for such applications as sensors that monitor assets, heat/temperature, pressure, flow, thermal energy, air quality, acoustic transmissions, vibration, cathodic measurements, environmental, tower lights, and security events.

We began limited implementation of the FAN in 2019 to support the TOU Pilot in Minnesota beginning in 2020. Additional build-out of the FAN to support AMI, FLISR, and IVVO will continue through 2023, which will lay the foundation for the future as we continue to innovate and improve our systems to ensure that we meet customer expectations as they evolve over the next decade or longer.

C. Step 2: Smarter Meters and Grid Capabilities

1. *Advanced Meter Infrastructure*

AMI is a foundational element of the AGIS plan because it provides a central source of information that is shared through the FAN with many components of an intelligent grid design. AMI is traditionally known as an integrated system of advanced meters, communication networks, and data processing and management systems. In the past, advanced meters were integrated with a proprietary communications network, and utilities selected a solution that would have trade-offs between meter functionality and communications capabilities. As discussed in above, the FAN we are implementing uses industry standard protocols, rather than a meter vendor's proprietary network. This not only provides important interoperability benefits to the Company and our customers, it also allowed the Company to select the best available advanced meter technology available.

The advanced meter itself is made up of several components – a metrology component (responsible for measurements and storage of interval energy consumption and demand data), an embedded two-way communication module (responsible for transmitting measured data and event data available to external applications), embedded Distributed Intelligence (DI) capabilities, and an internal service switch (to support remote connect and disconnect of single-phase service).

The core function of AMI is to measure customer energy usage so we can provide timely, accurate bills for utility service. New meters are a necessary replacement for our existing AMR, because of the impending discontinuance of our current Cellnet service in 2025. However, the new AMI meters go beyond the historic ability of our AMR meters because they facilitate two-way communications capabilities and more granular customer energy usage detail. This more detailed energy usage data will allow us to provide new rate and billing options. It will also inform many of the customer experiences that we have planned, to better inform and engage our customers.

Additionally, the advanced meters we will deploy will have the ability to conduct localized computing, analysis and data processing. This capability, called Distributed Intelligence (DI), is a Linux-based operating system that conducts localized, at the meter analysis and computing. At a high level, the DI platform allows Xcel Energy to install applications on the meter – similar to how applications are installed on a smart phone. These applications may be customer-facing, meaning the customer directly interacts with them, or grid-facing, meaning Xcel Energy interacts with the applications. Any applications available on the meter will be required to meet our strict technology and data security approvals and controls. Some of the potential use cases for these applications include:

- Improved grid and customer safety and awareness;
- Improved energy usage control and savings;
- Improved insight into power quality;
- Smarter insights about customer data and information; and
- Smarter controls to better manage and integrate customer and utility systems.

Xcel Energy is leading the nation in the deployment of the DI platform. We are working with Itron, our meter vendor to plot a vision for the design, development, and implementation of new meter applications that our customers will manage and interact with through a customer portal. Itron has already begun building a number of applications that can be enabled on the meter. We expect third parties will also develop applications that we can leverage to improve the customer experience – and we will actively partner with those that we believe offer new and innovative ways to transform our business to provide valuable services to our customers. Customers will be able to

AMI provides Xcel Energy and customers with access to timely, accurate, consistent, and granular energy usage data that is necessary to develop personalized insights and that supports informed decision making. With these insights and other data, customers are empowered to make energy usage decision based on their preferences that can reduce their bills. Additionally, the advanced meters will detect and report power outages and when power is restored, detect tampering and energy theft events, and perform meter diagnostics. Finally, the advanced meters will enhance our planning and operational capabilities by measuring values such as voltage, current, frequency, real and reactive power, and certain power quality events such as sags and swells.

In sum, the system visibility and data delivered by the advanced meters we have selected will improve reliability, enable advanced rate designs, and afford opportunities to improve the efficiency of several aspects of our business, and expand our ability to offer customer-facing products and services as a result of the DI platform. We began limited deployment of the AMI meters in 2019 to support the TOU Pilot in Minnesota beginning in 2020. We expect to begin mass deployment of AMI in 2021, with installations continuing through 2024. The following table lists the approximate number of installations per year.

Table 1. Minnesota AMI Implementation Plan

Year	Installation Estimate
2019/2020	17,500 (TOU Pilot)
2021	100,000 – 130,000
2022	550,000 – 650,000
2023	530,000 – 600,000
2024	30,000 – 60,000

In addition to the installation of meters, our AMI implementation requires certain functionalities be implemented to support the metering technology. These implementations will involve the following activities:

- *Systems integration.* This involves integrating a number of existing systems with the new advanced metering headend and meter data management system.
- *Enhanced capabilities*. This includes development of enhanced data reporting through the customer portal, operational analytics, outage management, Green Button Connect My Data, and Home Area Network functionality.
- *Meter deployment*. As we transition to actual meter deployments, we will deploy the DI platform, events processing, and enable FAN functionality.

We will also be continuing to build and refine our next steps with both advanced grid technologies and customer products and services that will leverage those investments.

2. Robust Customer portal

Our customer research tells us that customers want more information and need that information to make better decisions. Investments in AMI and the FAN will allow us to meet, and exceed, that expectation by providing us with detailed and timely data. We share that data with our customers through various digital channels including mobile and web applications. Customers will be more informed by this data by increasing their awareness about how and when they use energy. They can then apply that information to how they behave with energy – adjusting their usage to align with lower energy costs or more environmentally friendly periods of generation.

The portal will also offer other features to support customer efforts to save money and control their energy usage including access to DI applications. Applications will be made available, by Xcel Energy, through the customer portal. Applications may be part of the default meter package or customers can opt-in to certain applications. Potential applications could include (but not be limited to) energy usage dashboard with summary information about their energy usage, personalized insights about their energy usage with recommendations on how to save, and disaggregation tools that distill what end-use technologies are using energy.

The customer portal will also allow customers to share their energy usage with third-parties. We understand that our customers have relationships with third-parties and that those relationships provide energy savings and customer experience benefits. We will employ Green Button services to facilitate this exchange of information.

Currently, Xcel Energy employs Green Button Download My Data to facilitate data sharing. This tool allows only one-time data sharing with third-parties. If a customer wishes to share their data using Green Button Download My Data, they log into MyAccount, click Download My Data, and then send the file to the third-party. There is no automated connection for sharing data. Conversely, the Green Button Connect My Data (CMD) standard allows access to third parties to present the data in their application.

In the future, we will enable data sharing through both the Download function and the Green Button CMD tool. The Green Button Alliance[4] identifies awareness as one of the important factors necessary for customers to be able to change their energy use behaviors and defines CMD as “a way to download or connect to your utility-usage data (electricity, gas, water) to gain better insight of waste and inefficiencies; allowing you to make adjustments to use fewer resources and even save money.”

[4] https://www.greenbuttonalliance.org/about#mission

Data sharing is conducted in a secure environment and only at the authorization of the customer. Personally Identifiable Information (PII) is required to be transmitted in a secured transmission that is separate from the secured data stream used to transmit a customer's energy-usage information (EUI). The receiving application is then required to logically connect the separate data streams. CMD's capabilities expand beyond just consumption data and include the abilities to provide payment data (generation and distribution charges, tariff name, demand charges, third-party charges, administrative adjustments, etc.), summarize billing data across multiple locations, and even to generate monthly billing statements.

3. *Outage Management*

Customers have come to expect a high level of service from Xcel Energy and outages are one of the critical moments in our customer's experience. With increasing dependence on mobile devices and Wi-Fi outages, even for short duration outages have a significant impact on customer's experience and this experience filters into their broader experience and expectations from Xcel Energy. Long or recurring outages reduce customers' trust in the quality service Xcel Energy and have negative repercussions when customers consider participation in other products and services.

Currently, in most of our service territory and for outages below the feeder level, customers inform the Company that they have an outage. Once aware of the outage, the Company dispatches field workers to investigate the outage and make necessary repairs. Upon completion, the Company sends a follow up communication indicating that the Company believes the customer's outage has been addressed but encouraging the customer to follow up if the outage persists. We know customers generally expect the Company to know when they are out of power and when their service has been restored.

To improve this experience, we will use the benefits of improved grid awareness, provided by ADMS, AMI, and the FAN, and additional insights into the scope of the outages (provided by FLISR, and discussed below) to provide customers with more timely and accurate information about their outage. Immediately after receiving an advanced meter, customers will receive improved communications about outages should they occur. With AMI, the Company will know when momentary or sustained outages occur because the advanced meters will communicate through the FAN back to Xcel Energy. This improved awareness will allow the Company to proactively notify customers of an outage, instead of relying on customers to make contact, which we expect will be satisfying for customers – and may additionally play a role in reduced outage response times.

We expect we will also be able to provide customers with more accurate estimates of restoration timelines and reduce the time field personnel are required to identify, diagnose, and repair an outage by utilizing the abilities of FLISR to restore power automatically thereby reducing the scope of an outage. We will also proactively notify customers of when their power has been restored by verifying the status of an advanced meter remotely. These actions will transform a customer experience currently dependent on significant communication from our customers and evaluation by our field crews to a more streamlined process where customers are informed but not actively engaged.

Operationally, improvements in reliability should be expected as the AGIS project is fully implemented and Xcel Energy updates its processes to more efficiently respond to outages.[5]

[5] While the customer experience is expected to improve, the Company's reported performance related to certain reliability indices may decline due to the Company's increased visibility into outages and events occurring on the system.

Figure 7. Residential Customer Journey – Outage Notification & Restoration

4. Improved and Actionable Billing Information

Advanced meters enable Xcel Energy to more frequently and granularly track energy usage. The FAN also allows the Company to send and receive more timely energy usage data. The combination of timely and detailed data will enable advanced rate designs, discussed further in the next section, as well as products and services that complement our existing energy efficiency and demand management programs. An example of a new service the Company expects to offer that is enabled only by investments in AMI and the FAN is High Usage Alerts, which we expect to offer upon deployment of the advanced meters.

Optional, high usage alerts will provide messaging to customers when their energy usage is expected to surpass preset limits set by the customer. Proactive messaging to customers, prior to the end of their billing cycle, will offer both a customer experience benefit and energy savings benefit. The customer experience benefit is keeping customers informed of their energy usage so they can change their behavior and avoid a surprisingly high bill. The energy savings benefit is a direct result of this behavior change as customers take actions to shift or reduce usage in order to save money.

Figure 8. Residential Customer Journey – Billing and Payment Options

5. Remote Reconnection and Disconnection

The AMI meters will be equipped with the ability to remotely disconnect or reconnect electric service, which offers potential benefits to our operations and thus customer costs, and the customer experience. We recognize using this functionality in Minnesota will require regulatory approval. We expect to engage stakeholders as a precursor to a regulatory filing where we would propose to use this functionality initially in conjunction with tenancy changes and customer requests associated with seasonal use properties to capture benefits associated with unbillable energy use.

Today, when tenancy changes occur, the meter is not automatically disconnected and any energy costs associated with the unoccupied premise are considered losses. With advanced meters capable of remote disconnection, the Company could disconnect the meter; thereby eliminating energy costs at an unoccupied premise (*e.g.* a vacant retail location) and upon new tenancy could remotely reconnect service. This eliminates the need for the Company to send field personnel to the location to disconnect and reconnect the devices, improving employee safety, reducing or eliminating the cost for the new tenant customer to reconnect, and reducing or eliminate any unbillable energy use.

Similarly, customers with seasonal homes may want to disconnect service if there are long periods where the home is unused. For example, a summer home that is not used during cold weather months beginning in the late fall through late spring. In lieu of a customer paying for a field employee to visit the customer's site and disconnect and then reconnect the meter, the customer could schedule a remote disconnection aligned with their winterization and reconnection aligned with their opening. This would save the customer the cost of the two trip charges each year, as well as any stray energy usage at an otherwise winterized premise.

In the future, use of remote capabilities associated with non-payment would offer efficiencies and thus reduced costs. For customers dealing with payment issues, the Company makes every effort to engage with them and set up a payment plan that will work with their budget and personal circumstances. When payment plans fail and disconnection for non-payment is appropriate, the Company incurs significant costs to physically disconnect and reconnect service at the customer's home or business. These costs are ultimately borne by both the affected customer, in terms of a reconnection charge, and the entire Minnesota customer base in the form of higher field collection costs and bad debt expense.

We clarify that we are *not* seeking approval of any remote connection or disconnection services at this time. Instead, we intend to engage stakeholders to develop a framework that will inform a proposal for regulatory approval, which we believe will be the best way to align stakeholder interests and ultimately reduce costs to our customers.

D. Step 3: Smart Applications

1. Fault Location Isolation and Service Restoration

Customer satisfaction depends on how well a company's products or services meet customer expectations, and reliability is one of the foundational components for meeting customer expectations. As electricity becomes more and more entwined with every aspect of day-to-day life, the issue of reliability becomes increasingly important to customers.

FLISR is a form of distribution automation that involves the deployment of automated switching devices that work to detect issues on our system, isolate them, and automatically restore power – thereby decreasing the duration and number of customers affected by an outage. Fault Location Prediction (FLP) is a subset application of FLISR that utilizes equipment information to locate a precise location for an issue on our system. The combination of FLISR and FLP will enhance our ability to detect issues on our system and restore power to customers. FLISR and FLP rely on three primary components to operate:

- ADMS, for the central control and logic
- FAN, for wireless communications to and among field devices
- Specific intelligent field devices

The common industry metrics to track reliability performance are System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI). While these metrics measure the overall performance of the system, they do not capture the reliability *experience* of each individual customer, because they typically exclude outages from major events such as storms, which can be a significant contributor to a customer's overall reliability experience. FLISR and FLP are expected to improve customers' overall reliability experience – and, in particular, outages occurring as a result of storms or other severe events.

Today, aside from the limited number of early versions of automated switches on our system, crews manually patrol distribution lines to identify the failure location and manually close and open switches to restore power to customers. FLISR and FLP will automate restoration for most customers on the feeder – preventing a sustained outage – and reduce the length of the outage for other all customers on the feeder by providing field crews a more precise location for the failure.

FLISR and FLP have the greatest impact when implemented on the worst performing feeders, where the investment will return the greatest value in terms of reliability improvement for the customers connected to those feeders. In Minnesota, we intend to implement FLISR and FLP on approximately 200 feeders between 2021 and 2028, directly improving reliability for over 250,000 customers, where we expect the number of sustained outages on these

2. *Integrated Volt VAr Optimization*

Integrated Volt-VAr Optimization, or IVVO, is an advanced application that automates and optimizes the operation of the distribution voltage regulating devices and VAr (reactive power) control devices to achieve operating objectives. These objectives can provide:

- Reduction of distribution electrical losses
- Reduction of electrical demand
- Reduction of energy consumption
- Increased ability to host Distributed Energy Resources

IVVO is an advanced application within ADMS that leverages field devices and the FAN to modify how the Company controls the voltage of the system and enables the Company to optimize the voltage of the system in ways that were not possible previously. Our implementation of IVVO will enable energy and demand savings for customers without requiring any action on their behalf.

The concept of voltage/VAr management or control is essential to electrical utilities' ability to deliver power within appropriate voltage limits so that consumers' equipment operates properly – and to deliver power at an optimal power factor to minimize system losses. These concepts are affected by a variety of technical factors throughout the distribution network, the complexity and dynamic nature of which make the task of managing electrical distribution networks challenging. While voltage regulation and VAr regulation are often referenced in combination (i.e. Volt/VAr control), they are easier to understand if described as two separate, but interrelated concepts.

Voltage Regulation. Feeder voltage regulation refers to the management of voltages on a feeder with varying load conditions. Regardless of nominal operating voltage, a utility distribution system is designed to deliver power to consumers within a predefined voltage range. Under normal conditions, the service and utilization voltages must remain within an industry standard range. When customer load is high, the source voltage at the beginning of the feeders is at the higher end of the range, and the voltages delivered to customers at the end of the feeders are at the lower end of the range.

VAr Regulation. Nearly all power system loads require a combination of real power (watts) and reactive power (VArs). Real power must be supplied by a generator while reactive power can be supplied either by a generator with VAr capabilities, or a local VAr supply, traditionally a capacitor. Delivery of reactive power from a remote VAr supply results in additional feeder voltage drop and losses due to increased current flow, so utilities prefer to deliver reactive power from a local source. Since demand for reactive power is higher during heavy load conditions than light load conditions, VAr supply on a distribution feeder is typically regulated or controlled by switching capacitors on during periods of high demand and off during periods of low demand. As with voltage control, there are both feeder design considerations and operating considerations.

The ADMS that we are in the process of implementing can run the IVVO application in several different operating modes: Voltage Control, Peak Reduction, VAr Control, and Conservation Voltage Reduction (CVR), which we explain below.

- *Voltage Control mode* functions to optimize voltage on the feeder around standard operating voltages – maintaining adequate service voltage for all customers. This mode is generally a secondary operating mode of IVVO, and only used to establish the voltage boundaries within which the other operating modes must stay within. As penetration of DER grows, Voltage Control will become more common as a primary control mode to manage the expanded range of distribution system voltage caused by DER. Traditionally, with only load on a feeder, the Voltage Control objective was to raise voltage at times of heavy load in order for voltage to remain within the acceptable range. With DER causing reverse power flow and raising voltages during times of light loading, voltage control schemes must now both raise and lower voltage.
- *Peak Reduction mode* serves to reduce load only during peak load events. It is a manually triggered mode that reduces system voltage to a targeted value to reduce load on the system for a short duration – typically one or two hours. This peak reduction tool can be used in large operating regions, such as Minnesota as a whole, or tactically by feeder, substation, or other targeted area.
- *VAr Control mode* seeks to reduce system losses and save energy by optimizing power factor on each distribution feeder.
- *CVR mode* seeks energy savings through reduced operating voltages. CVR mode first flattens the load profile along the feeder using capacitors, and then uses the Load Tap Changer (LTC) or Voltage Regulators inside the substation to lower voltage on the feeder. This lowered operating voltage results in small energy savings for most customers on a feeder.

Customer's end-use devices are designed to operate over a range of voltages. Historically, the voltage on the distribution system is toward the high end of the range, which causes devices to consume more energy. The need to have more dynamic voltage management has become more important because customers' energy consumption is more dynamic than ever. Residential customers can have on-site solar, batteries, electric vehicles, smart appliances, smart thermostats, and many more electronic devices.

Since 2010, we have been doing VAr Control through our SmartVAR program in Minnesota, which has provided benefits to the grid and our customers. SmartVAR will be transitioned to our ADMS as that is implemented. Over time, we intend to transition this to IVVO, which will allow for more dynamic voltage control that can improve end-use efficiencies while still maintaining voltage within the acceptable range. This will reduce the voltage level on our system, which we expect will result in energy savings for customers, translating directly into avoided energy costs that our customers would otherwise incur.

Implementing IVVO for our customers requires ADMS to be operational, the FAN and AMI to be deployed, and implementation of some supporting information systems including a Grid Edge Management System (GEMS). As these supporting technologies are deployed, we will implement IVVO on distribution feeders with the highest return and highest probability of success. In total, we intend to deploy IVVO between 2021 and 2024 on over 180 feeders serving over 200,000 customers.

3. Improved Power Quality

Power quality, specifically the voltage levels on the distribution system, can have a significant impact on the customer experience. Some of our customers have highly sensitive processes and technologies that perform better at lower voltage levels. Investments in AMI and ADMS with IVVO will help us improve our service quality for customers and therefore improve their customer experience. With AMI, we can monitor the voltage level at a customer's location and identify if voltage levels are too high or low. If voltage levels are determined to be out of line or adjustments can be made, the ADMS and IVVO applications will be used for these adjustments.

Other power quality improvements will include identifying potential power quality issues, such as flickering lights, before they become a negative experience for the customer. Using AMI, we can remotely identify these potential issues rather than send field personnel to conduct a diagnosis. This remote sensing capability reduces the time to address an issue and the likelihood of a customer call or formal complaint. This proactive service reduces the burden on customers to make us aware of issues in our service and helps improve customer satisfaction.

4. Distributed Intelligence

As discussed in more detail in the summary of our Advanced Metering Infrastructure investments above, we are at the leading edge of the deployment of the DI platform. With mass meter deployment rapidly approaching we are working with our meter vendor partner to develop conceptual uses for the DI platform that make grid management more efficient. This process will involve ongoing ideation, iteration, and reinvention to ensure that we continually create value from our investment. At this time, we have identified the following grid-facing use cases:

- *Real-Time Granular Voltage Optimization* – Use the edge processors / radios to intercommunicate and 'shout' who is the lowest voltage (compared to only receiving voltage from dedicated meters on the secondary).
- *Undocumented / Unregistered DER Alerts* – Detect if there is a DER behind the meter, even if it is not back feeding.
- *Grid Configuration Status* – Better, real-time grid configuration status, e.g. knowing which phase and transformer every meter is connected to. Edge computing would build on this by providing insights to loads / DERs per feeder / phase which could directly or indirectly (notification to third party or targeted message to premise owner) dispatched to improve grid balancing.
- *Distributed Transformer Load Management* – Modulating customers' devices on a secondary that are contributing to a high load situation on a distribution transformer.

- *Locate Momentary Grid Disturbances* – Uses the high granularity disaggregation capabilities across multiple meters to triangulate the location of a grid disturbance by analyzing the amplitude of the disturbance waveform. Edge meters could detect the anomaly and shout out who has the highest amplitude.
- *Meter By-Pass Detection* – Enhanced functionalities that complement the base capabilities of AMI to detect and remotely disconnect when a meter by-pass is detected.
- *Smart Feeder Restoration* – Occasionally during outage restoration utilities face the situation where capacity is insufficient to restore the next section of a feeder. Smart Feeder Restoration enables the restoration of critical loads, deferring the re-energization of other loads until full capacity is restored, for example, prioritizing restoration for a hospital or a fire station before.. This ability provides for resiliency during emergency situations.

We are also working with our vendor partner to develop customer facing applications that we will make available to customers in the future. Many of these applications are complimentary to many of our existing demand-side management and customer choice programs. They may provide customers with more information about their energy usage through services such as disaggregation, virtual energy audits, or real-time monitoring. Alternatively, they may also provide new services that our current meters and customers programs do not provide such as advanced notifications and alerts about the composition of your energy usage, internet outages, or emergency notifications. The broad categories of how we will transform the customer experience and the types of products and services will offer are detail further in Section IV of this document.

E. Broad Customer and Grid Benefits

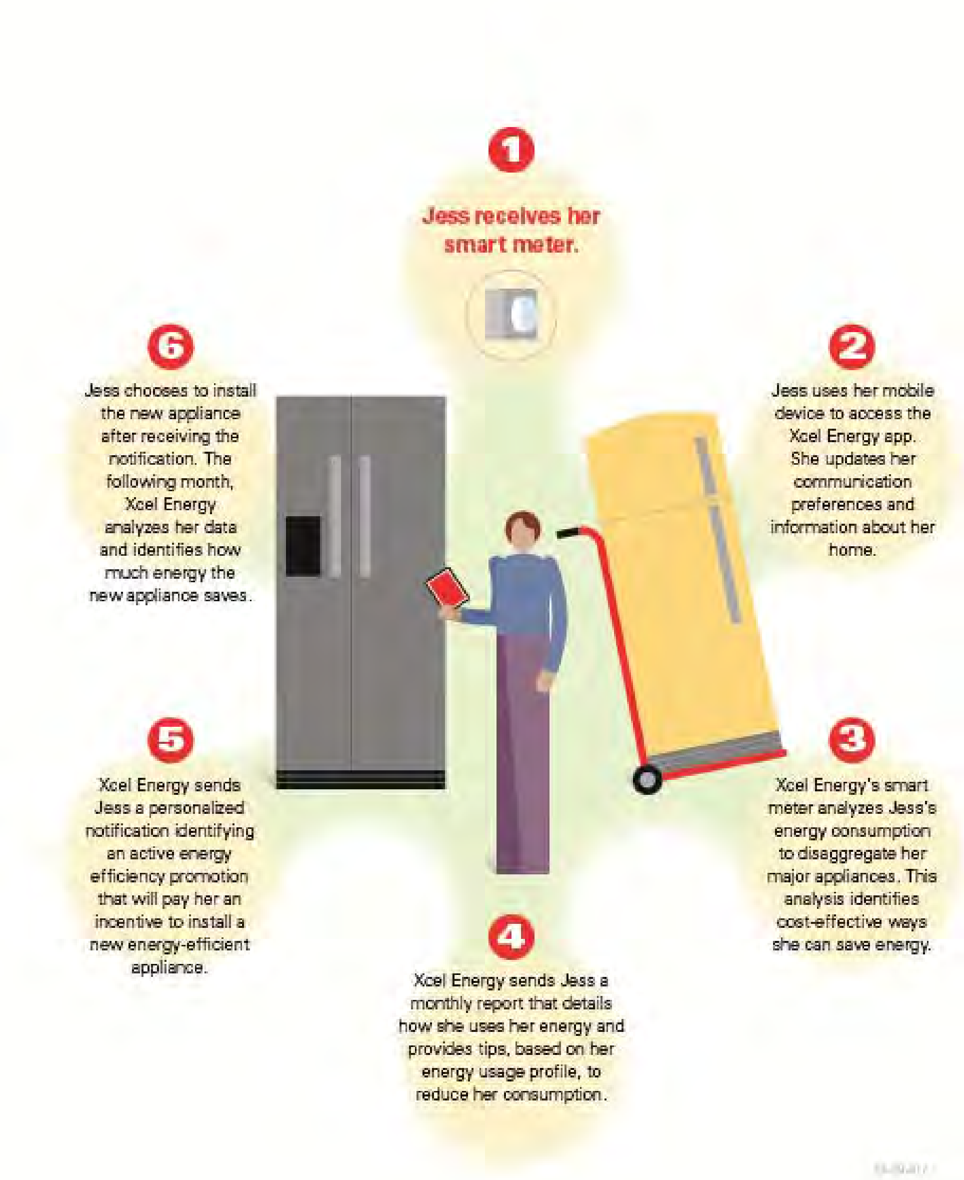
1. Improved Energy Efficiency Options

Today, to encourage customers to make informed energy saving decisions and reduce their monthly bill, we provide general recommendations and energy savings steps they can take – upgrading to a new air conditioner, turning off unused appliances, and installing high efficiency lighting. These messages and tips are general and will not be relevant to all customers. For example, customers who have already replaced an air conditioner or other major appliance – or customers interested in changing their behavior with their air conditioner to save money.

Transforming this customer experience involves targeted deployment of new products and services that build upon foundational advanced grid investments. With more granular data from advanced meters, we will be able to improve our marketing to and segmentation of our customers. This will help identify cost efficiencies in our programs and improve our communications with customers. For example, combining AMI data with disaggregation tools through Distributed Intelligence, we can better target market our customers and provide them more relevant communications about their energy usage. From a customer experience perspective, the more relevant information we share with them the more likely they will be to act upon it.

These might include improved insights and recommendations to customers regarding their energy usage, due to the availability of more granular usage information. These might also include end-use disaggregation – or programs/services that allow the customer to extract end-use and/or appliance level data from their aggregate household usage. These might also include more targeted opportunities for behavioral demand response advanced rate designs. These new products would leverage the benefit of near-real-time, interval-level usage data provided by advanced metering to help customers reduce bills and better achieve their energy goals. The following figures provide an illustrative customer journey that integrates new benefits from the advanced grid.

Figure 9. Residential/Small Business Customer Journey – Insights and Recommendations



2. Demand Response

As part of our Minnesota operations we are committed to delivering resources to help manage the generation, transmission, and distribution systems during both peak and non-peak periods. We define demand response as:

- *Traditional Demand Response* (DR) provides a temporary reduction to system peak. Often these products are referred to as dispatchable resources because the utility may control them directly. This peak reduction has a similar impact on our system as a combustion turbine (CT) because it can be brought on- and off-line quickly for short periods of time as an operational reserve.
- *Non-Traditional DR* provides the opportunity for our customers to plan for and manage their electric demand differently. Compared to traditional methods of peak demand reduction during the hottest days of year, these methods allow customers to shift portions of their electric loads to lower-cost periods of the day when carbon-free generation is highest.

One example of non-traditional DR that will be enabled by our advanced grid investments is Behavioral Demand Response. This is a new product we are developing where the Company provides energy savings messages to customers when energy usage is high. The Company can message customers with general or personalized opportunities, using data provided through advanced meters, to reduce their energy usage. Customers can monitor the impact these decisions have on their energy usage because of timely data communication hat is made possible by AMI and the FAN. To engage customers, incentives may be offered on top of their energy savings based upon actions the take. In this case, the Company also expects a customer satisfaction improvement because customer's not only save money but are also more informed and in control of their energy usage – two key takeaways identified through our customer research.

One example of traditional demand response that will be enabled by our advanced grid investments is a two-way communicating Saver's Switch. Two-way communication through the FAN provides a more reliable signal than our current use of the Cellnet system and allows us to monitor the status of the Saver's Switch. This proactive identification allows us to improve our maintenance cycles to ensure high levels of response when these switches are called for system needs.

3. Advanced Rate Design

The deployment of advanced meters will provide the information and communications capabilities necessary for the Company to provide customers with more pricing options to improve customer choice and control over their electric bills. AMI will make Time-of-Use (TOU) pricing a feasible option for all customers. By recognizing cost differences throughout the day, between weekdays and weekend days and other types of days, TOU pricing provides both customer and grid rewards for shifting energy usage away from system peaks or making better use of renewable energy resources when they are abundant on the grid. Customers may realize these benefits through reduced energy costs and perhaps a reduced carbon footprint; the Company may realize benefits in the form of avoided infrastructure investments and increased system productivity through a higher load factor.

Advanced rate designs improve the customer experience by giving customers more information and control over their energy usage. Our customer research shows that energy costs are a primary concern for all customers – but also that other factors are important, including a customer's environmental impact, their ability to control their usage and the presentation of options/choice programs. Advanced rates can create opportunities to reduce customers' bills and minimize customers' environmental impact by giving them better signaling about the cost of their energy usage. For example, higher prices during "on-peak" periods are typically correlated with more expensive and carbon intensive forms of generation whereas "off-peak" periods are typically correlated with renewable energy resources.

Advanced meters include two-way communication capabilities in contrast to the limitations of our current AMR meter infrastructure. This provides the Company the ability to communicate with the meter and any appliances or devices that a customer may choose to "connect" to their meter. With the advanced meters capable of measuring energy usage in short time intervals such as every 15 minutes, it is possible to develop dynamic pricing options that recognize cost differences between different types of days and that provide focused customer incentives for reducing energy usage during the highest system peak times of the year. Dynamic pricing can also be combined with TOU pricing for an even more robust signal to customers.

The advanced meter's ability to capture and transmit regular energy usage intervals enables us to partner advanced rates with energy usage notifications to provide a more robust customer experience and more opportunities for customers to keep their bills low. More targeted and personalized information about their energy usage empowers customers to control costs and minimize their environmental impact.

The ability to provide a seamless, timely, and detailed view of a customer's energy usage data is highly contingent upon the implementation of advanced meters and the supporting infrastructure, such as the FAN. Without investments in these new technologies we do not have the ability to effectively and efficiently meet customer expectations for increased control, new opportunities to engage with the energy usage, transparency of costs, and impacts of their energy usage.

4. DER Integration

The adoption of DER, including community solar gardens, behind the meter solar, batteries, electric vehicles, energy efficiency and DR is not likely to slow in the future as costs decline and awareness of the potential benefits of these resources becomes more widespread. As customers adopt increased levels of DER, it is incumbent upon Xcel Energy to improve its ability to accurately forecast the growth of these resources, the impacts they will have on the distribution system, and the cost to implement these resources.

Furthermore, our customer research has shown that customer's increasingly look to their utility for expert advice and are interested in engaging with the utility as an orchestrator, helping to manage their energy bills and achieve their energy goals. However, in order to achieve individual goals, collective efforts are necessary to maximize efficiency and effectiveness at the individual level.

The increasing prevalence of DER necessitates a more comprehensive integration of DER into the day-to-day operation and planning of the grid to ensure the safe and reliable management and monitoring of the distribution system. While DER can, and currently is being interconnected, this is accomplished with limited visibility and control, which prevents the Company from fully optimizing the system benefits DER can provide. For instance, energy storage could be used to regulate the amount of energy on the system during peak solar production times. In this circumstance, a battery can "absorb" the energy when demand is lower and then dispatch energy from the battery onto the system as demand increases later in the day. Alternatively, ADMS can improve our control and dispatching of demand response (DR) resources. This will help us more precisely manage the level of demand by dispatching the right amount of DR in the appropriate locations.

Investments in AMI and ADMS coupled with the FAN – and in the future, a Distributed Energy Resource Management System (DERMS) – will allow for Xcel Energy integrate DERs into the day-to-day operation and better manage DER. Currently and by necessity, Xcel Energy takes a conservative approach to the forecasted impact of resources because we do not have the granularity necessary to dynamically forecast the impact of resources such as batteries and solar. With more granular data we can better refine our estimations of the impact of new resources and better integrate more resources on the grid.

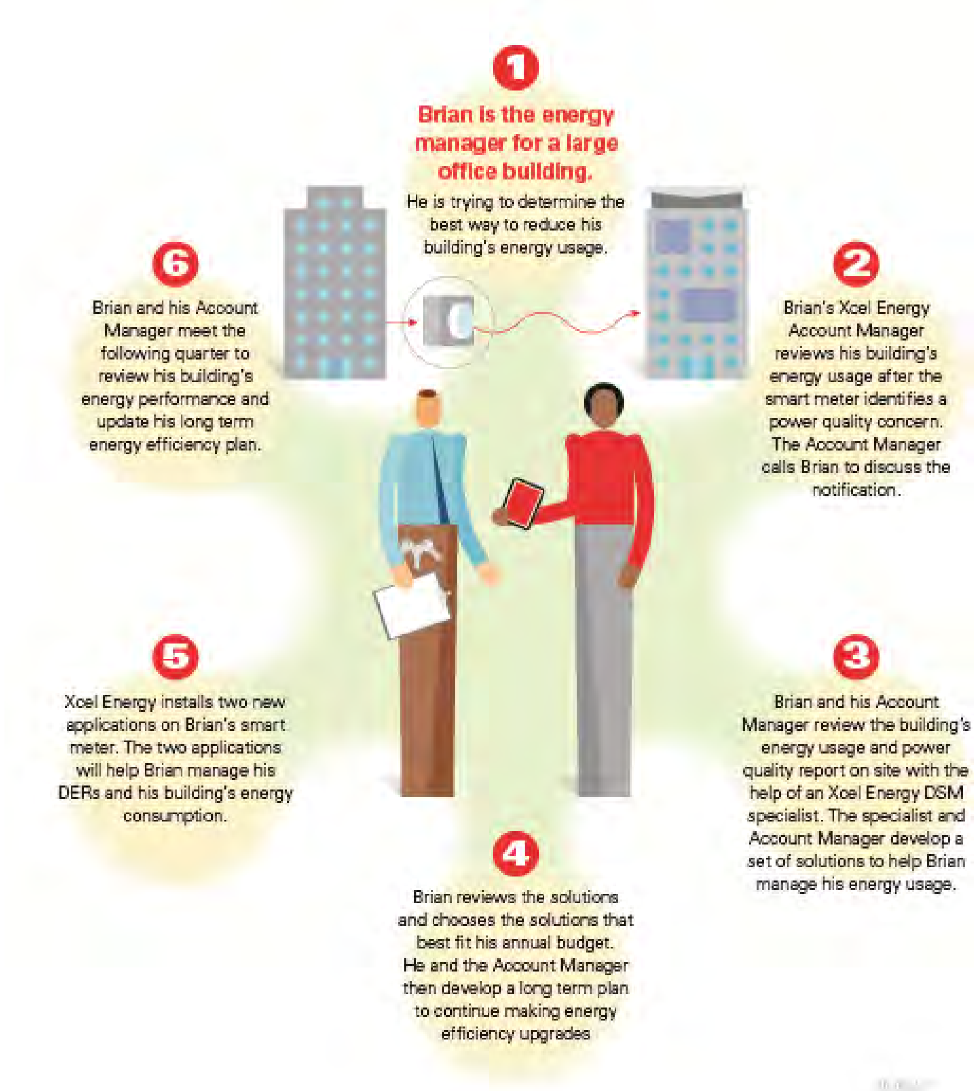
In the near term, Xcel energy is investing in an advanced planning tool which will significantly improve our distribution planning capability. The future of DER has uncertainty, and the new tool will allow for planners to explore the impacts of varying DER adoption, along with a host of other factors such as land use planning, weather, socio-economics, and more. This investment will help us identify barriers & opportunities as we and plan the grid of the future.

Figure 10. Residential Customer Journey – EV Integration with New Rate Designs

The next step in optimizing DER integration will be provided by a DERMS. Currently in the industry, interested stakeholders are identifying use cases and blueprinting how such systems may work. In the short term, we will work with the industry to define what and how a DERMS might work to provide the most benefit to our customers. By engaging in these discussions, we can help steer the future of DERMS in ways that will provide our customers with the most benefit. In the future, we plan to implement a DERMS, but only after we have successfully laid the foundational pieces of the advanced grid such as ADMS and AMI. If the technological capability continues to progress, we believe that a DERMS deployment will fit into our advanced grid plans around 2025.

Microgrids are another type of DER integration that will be improved by investments in AMI, FAN, ADMS and DERMS. Microgrids are effectively one large DER and the use of these advanced grid investments will allow the system to make more informed decisions, sometimes automatically, about what resources are needed, when they are needed, and the most efficient way to utilize those resources. As cost-effective opportunities present themselves, our distribution investments will allow for more efficient grid services, such as absorbing excess solar energy to be discharged at later periods, while also enabling backup needs power in the case of an emergency.

Figure 11. Commercial Customer Journey – DER and System Integration



F. Security

The Company has a dedicated Enterprise Security Services (ESS) business unit that encompasses both cyber and physical security, security governance and risk management, and enterprise resilience and continuity services. This combination of services is designed to cover analysis of vendor risks, alignment of the technology with security standards, secure solution design and deployment, integration with Company solutions including user access management and system monitoring and incident response, as well as threat analysis and planning for continuity of business operations in the event of a disruption. The Company's security risk management program provides Company leaders with information about threats and the level of security risks, so that mitigations and responses can be planned that are proportional to the risk.

Overall, while the implementation of the AGIS initiative solves certain existing issues, it also presents different challenges to security than a less advanced grid, and requires its own comprehensive security strategy. It starts with identification and protection of all components of the intelligent grid, both for the protection of customers and for the reliable and safe delivery of energy to customers. First, devices in the field must be protected. Unlike internal business technology, the distribution components are out in the field and at customers' residences; devices can only be hardened so much, and security must also rely on other controls. For example, detective controls at strategic locations to provide early notification of suspicious behavior or anomalous activity.

Additionally, although even legacy distribution systems and meters are vulnerable to physical tampering and disabling, adding a communications network – that provides additional capabilities and services to our customers, as well as greater insight into our system – also enhances the potential impact of a security compromise. The addition of a Company-owned FAN is a prudent approach to this concern. A private network allows Company to better control the integrity of the devices on its network and the data exchanged with those devices. The alternative – a public network – would expose the devices to increased risk because the Company would not be in control of the network.

1. *AGIS Security Approach*

As part of our AGIS initiative, we are designing security controls for each component and system implemented. These security risks can be organized into three primary areas: compromise of meters and devices; exploitation of the communications channels; and security lapses once data is within the corporate environment. There are also security risks related to the web portal, as well as future customer applications and new products and services that will be enabled by the advanced grid.

Figure 12. Key Security Components

First, advanced meters and other networked devices have an integrated network interface card (NIC) that enables them to connect to the FAN. We leverage both physical and cyber security controls to protect NICs from unauthorized access. Second, a compromise of the FAN communications protocols that carry "traffic" to and from the meters and field devices could lead to disruption or alteration of information needed for grid management. Therefore it is paramount to protect the integrity of the communication devices and channels that allow the advanced grid to perform at expected levels. It is also important to implement the correct level of monitoring and alerting, configured to identify potentially anomalous activity, so that both proactive and reactive responses are appropriate and efficient. Third, the primary risk to systems and information that reside within the Company's corporate environment is from unauthorized access – where a criminal or unqualified employee accesses sensitive data or issues commands to the grid. There are many controls in place to prevent and detect such behavior.

We have based on our controls on a security controls governance framework, which leverages industry best practices including the National Institute of Standards and Technology (NIST), Cyber Security Framework (CSF). The Company's security policies and standards incorporate regulatory compliance requirements and security controls designed to protect against CIA (Confidentiality, Integrity and Availability) breaches. This framework serves as the basis for project security requirements as well as periodic internal security technology control assessments.

2. Cyber Security Overview

Our cyber security program may best be described in terms of the five categories of controls outlined in the NIST CSF: identify, protect, detect, respond, recover. Combining these adds multiple layers of protection and detection including defenses at each endpoint and throughout the network. Controls within these layers include:

- *Asset management* – maintain an inventory and securely configure assets, so we know what to protect as well as what is authorized to access our networks ["Identify"];
- *Protection* – user access controls, encryption, digital certificates and other controls to ensure the confidentiality, integrity and availability of data ["Protect"];
- *Vulnerability management* – in addition to scanning equipment for known security vulnerabilities, the Company monitors emerging threats ["Detect"];
- *Monitoring and alerting* – identify potentially anomalous activity so that both proactive and reactive responses are appropriate and efficient ["Detect"];
- *Incident response* – analyze information using playbooks and escalate to the Enterprise Command Center, the Company's 24x7 watch floor operation designed to prepare for, respond to, and recover from any potential hazard that may impact customers, Company assets, operations, or its reputation ["Respond"]; and
- *Disaster recovery and business continuity planning* – to efficiently maintain and restore grid operations in the event of a cyber attack ["Recover"].

We will apply these controls to identify and protect all components of the intelligent grid and help ensure the reliable and safe delivery of energy to our customers.

Endpoint Protection is the installation and/or enablement of protective and detective cyber security controls to thwart malware and external influences from causing unexpected, unwanted or invalid behavior at an endpoint. These were specified as cyber security controls in the AMI vendor selection process, as they are essential to protect the devices and the data that are handled by AMI meters and headend servers.

Access Control is to confirm that only necessary and authorized users have access to the individual devices. This not only includes the devices that are installed on the consumer's premises, but also the devices that facilitate communication and control of the data flowing to the consumer. There are potentially many avenues of compromise with respect to unauthorized access to devices. This is a key consideration and will be addressed through strong authentication methods, which include multi-factor authentication methods.

Authentication is a method by which a user affirms their identity. In its simplest form, it involves a user ID and password. Where technically feasible, Xcel Energy requires multi-factor authentication so that a user must not only know their password, they must also possess a physical or logical token. This minimizes the ability of an unauthorized user to steal passwords and access our assets and information.

Authorization is the process of determining and configuring the minimum level of access required by a user or an automated system. Granting undue permissions to devices that comprise the intelligent electric distribution system could lead to unauthorized or inadvertent changes and instability. Complying with a least-privilege principle ensures that only necessary and authorized individuals have the ability to make administrative changes.

System and Patch Management addresses the periodic manufacturer updates to software and firmware to improve performance, add features, or address security vulnerabilities. A robust system patch management process incorporates asset inventories, secure receipt of patches from the vendor, testing and deployment to the field. The Company's threat intelligence and vulnerability management teams monitor for and inform support teams of known security vulnerabilities that require patching. Keeping current with vendor patches helps reduce the possibility that a criminal can use a known exploit to compromise our systems or data.

Data validation is a final defensive layer between the various endpoints. As data is sent from endpoints at consumer premises, data validation at the head-end must take place. If data values received from the consumer endpoint do not fall within a range of expected values, then either the data must be assumed compromised and discarded, or secondary validation must take place to measure the integrity of the data received. This validation will provide yet another level of detection and protection for the intelligent electric distribution system.

3. FAN Security

The equipment that makes up the FAN deploys the endpoint protections discussed above. Additional key controls for FAN include the use of firewalls to restrict which systems can interact and what ports and protocols they can use; encryption to minimize the opportunity to intercept and alter data traffic; monitoring and log review as well as response to suspected security events.

Firewalls are placed in multiple areas of the network between the customer meter and the company data center/head end. By default, all traffic through a firewall is blocked, and authorized only after a thorough review and change process. With a firewall, any unauthorized, unregistered devices that attempt to join the network or communicate to/from devices are blocked.

Encryption uses complex mathematical algorithms to obscure data prior to and during its travels through the communications network. It also prevents data from being altered. Only authorized parties to the transaction (sender and receiver) have the "keys" to encrypt and decrypt data.

4. AMI Data Protection

As we have described, our Company and AGIS security approach is one of "defense in depth." The advanced meters will be physically sealed and monitored to detect tampering. Meter communications will be encrypted to protect the privacy of our customers, as will the other communications that travel on the company's private FAN from and between the authorized devices that have been registered onto the network. Firewalls control the information that travels in and out of the corporate network. The AMI head-end will validate the integrity of the data received. We will actively monitor the communications path between the meters and the Company data centers to promptly detect and respond to any anomalous activity. Additional monitoring of the head-end system will trigger alerts for investigation.

5. Company Systems Security

The Company systems comprising and supporting AGIS reside in data centers with physical access protections – only authorized users are able to enter these locked facilities on company property. Data accessed from the control centers travels from the systems in the company data centers over the corporate network. At the control center, application users must follow the same rules for authentication, authorization, and least privilege.

Data from the intelligent electric distribution network passes through multiple defense-in-depth controls on its way back to the systems in the corporate data centers. Communications will pass through multiple firewalls to ensure that only authorized devices are communicating on authorized ports/protocols. Additionally, a protocol-aware Intrusion

Detection System/Intrusion Prevention System (IDS/IPS) will inspect the traffic to ensure tampering has not been performed on the data packet. Once the data has been delivered to the systems responsible for consuming this information, only authorized processes will have the ability to act upon this information.

The Company segments its networks, so that critical operational systems and information are kept separate from business data and operations including email. This segmentation adds a significant barrier should a criminal compromise a corporate user's account. In addition to using firewalls between networks, the Company requires the use of multi-factor authentication when accessing systems from outside the control center.

We take our responsibility to protect the privacy and security of our customers, grid, and information systems seriously. We have based on our controls on a security controls governance framework, which leverages industry best practices. We will take a defense-in-depth approach that will apply controls at many levels to identify and protect all components of the intelligent grid and help ensure the reliable and safe delivery of energy to our customers. See Appendix B for a summary of our data access, privacy and governance framework.

IV. TRANSFORMED CUSTOMER EXPERIENCE

Rather than simply evolving from our current state, we are revisiting our entire customer experience. Today, customers expect the we *know them* and take a personalized approach to their relationship with us; they expect that we keep them *informed* and use our expertise to *advise* them about what to do and then *enable* them to take those actions; and finally that we *deliver seamless* experiences for them reducing the burden on them to take action.

Figure 13. Customer Experience Priorities

In order to *know* our customers, *inform, advise, and enable* them, and *deliver seamlessly* we are taking time to understand the customer's journey and experience in our program design and execution. This process starts with a commitment to understanding customers' preferences, considerations, and thoughts regarding the benefits and value of an advanced grid investment from their point of view. As detailed above, we conduct robust customer research and continually update that research to ensure we are reactive to our customer's perceptions. It also requires our organization to improve the skills and competencies needed to continuously evolve and iterate our programs more quickly and leverage technology to make interactions more streamlined and enjoyable.

Our investments in the advanced grid will help us meet customer expectations. We have categorized how we expect to meet these expectations in three broad, but interconnected, categories. The categories are at the foundation of how we think about making investments in our customers every day.

- Enhance the Customer Experience

ENHANCE THE CUSTOMER EXPERIENCE

Outages

BEFORE ADVANCED GRID	AFTER ADVANCED GRID
Detecting an outage: The current Electric Management System alerts system operators only to larger system outages. Xcel Energy depends on customers to notify us about outages in their neighborhoods or individual homes.	**Detecting an outage:** System alerts operators to almost all outages. After major storm repairs are completed, we'll send signals to newer meters to verify that power has been restored.*
Identifying outage location: With no specific location pinpointed, linemen drive or walk along the line – which could be many miles – until they identify the cause of the outage.	**Identifying outage location:** New technology pinpoints where problem has occurred, allowing grid operators to dispatch linemen to specific location. The result is improved restoration times.
Restoring power: When an object or tree comes in contact with a power line, every customer served by that line – and other lines connected to it – loses power.	**Restoring power:** Smart devices on the grid can perform automated switching – or keep additional, connected power lines in service – while linemen work on the impacted power line, minimizing the number of affected customers.
	*Customers should continue to contact us to report an electric outage at 1.800.895.1999.

Setup and Billing

BEFORE ADVANCED GRID	AFTER ADVANCED GRID
Customer billing information: Customers receive their monthly energy use after the end of their monthly billing cycle.	**Customer billing information:** Through advance metering, customers may access their energy usage the next day.
Accurate Billing: Sometimes customer bills have to be estimated due to access or safety issues until their meters can physically be read.	**Accurate Billing:** New advanced meters send energy usage information directly to us so customer bills are rarely estimated.
Remote connect/disconnect capability: A technician has to physically connect or disconnect service at a customer's home or office.	**Remote connect/disconnect capability:** With advanced meters, a customer's service can be remotely connected or disconnected.

- Cleaner, more reliable energy

LEAD THE CLEAN ENERGY TRANSITION

Reliability

BEFORE ADVANCED GRID	AFTER ADVANCED GRID
System monitoring: Grid operators rely on linemen and a limited number of alarms to alert them to trouble on a power circuit.	**System monitoring:** Grid operators receive real-time information from line sensors, intelligent substations, and communication devices so they can proactively prevent and respond to grid issues.

Distributed Energy Resources

BEFORE ADVANCED GRID	AFTER ADVANCED GRID
Hosting Capacity: Customer-owned rooftop solar can shutdown at times of over voltage on feeders.	**Hosting Capacity:** Increased situational awareness and control enables both increased hosting capacity for new installations and enhanced uptime for existing systems.
Openness to New Technology: Finite utility ability to manage diverse resources limits customer ability to adopt new technology.	**Openness to New Technology:** Improved measurement, visibility and control allows customers to select advanced applications such as batteries and electric vehicles.

- Keep Bills Low

KEEP BILLS LOW

Customer Choice and Control

BEFORE ADVANCED GRID	AFTER ADVANCED GRID
Customer options: Customers have limited choices.	**Customer options:** An Advanced Grid opens the door for more energy-related products and services, including rate design choices for customers such as time-of-use rates, and more energy- and cost-savings programs.

In the following sections, we provide more details on the types of products and services we will offer in the future that fit within these categories. These products and services are currently in development and we have provided an expectation of when we expect to begin delivering on these products and services. However, it is important to reiterate that the anticipated delivery dates are not the final states of these offerings. We will continually innovate and iterate these offerings and incorporate new benefits and opportunities as they become available to us. This may include adapting offerings to incorporate DI capabilities, transitioning traditional opportunities to DI applications, or integrating new technology that is not yet in the market.

A. Enhance the Customer Experience

Outage Enhancements

Product or Service	Customers Affected	Timing
Enhanced Outage Notifications More accurate alerts informing customers about outages in a timely, relevant way. These could include proactive messaging about an outage status, automatic restoration, and restoration confirmation.	Residential Small Business Large C&I	Day 1
Smart Premise Restoration Sequentially restore power to various devices inside the home or business after an outage to reduce the likelihood of voltage or overloading issues, protecting customer system performance as power is restored.	**Residential** **Small Business** **Large C&I**	Future

Integrated, seamless interactions

Product or Service	Customers Affected	Timing
Green Button Download My Data For customers who prefer to perform their own analysis or use their granular usage information for other purposes, data in the standard Green Button protocol will be made available through the Download My Data feature in the customer web portal.	**Residential** **Small Business** **Large C&I**	Day 1
Enhanced Web and Mobile Applications Customer account information along with options to view and pay bills, visualize energy usage and trends, and manage outages will be presented to customers in an integrated and highly personalized format. This is made possible by granular information and analytics as well as a robust customer preference center.	**Residential** **Small Business** **Large C&I**	Day 1
Energy Usage Dashboard Within the new web and mobile customer portals, energy usage dashboards will informs customer about the energy usage of both the overall facility as well as individual devices in a home or business. Compares data to a comprehensive database of similar products to alert to opportunities to save energy and money. Dashboards can be customized to both residential and C&I customer needs (e.g. multi-site data).	**Residential** **Small Business** **Large C&I**	Day 1
Energy Usage Alerts and Notifications Alerts allow customers to be notified with important information in a timely, relevant way. These could include high usage alerts, TOU peak period, Peak Day notification, or goal-based alerts.	**Residential** **Small Business** **Large C&I**	Near Term
Green Button Connect My Data For customers who would like to automatically transmit their usage information to third parties, Green Button Connect My Data will also be available in the customer web portal for ongoing automated transfers.	**Residential** **Small Business** **Large C&I**	Near Term
Personalized Notifications Communication systems will be enhanced to provide timely information to customers in a form that is personalized to their lifestyle and preferences.	**Residential** **Small Business** **Large C&I**	Near Term
Artificial Intelligence Enabled Notifications As artificial intelligence technologies mature and become widely adopted in the market, meters will have the ability to leverage these capabilities to provide heightened interactions which will be customized to the unique needs of each customer.	**Residential** **Small Business** **Large C&I**	Future

Safety & Reliability Enhancements

Product or Service	Customer Affected	Timing
Power Quality Analysis With detailed information collected by the meter relating to power delivery, customers can more accurately and frequently assess their power quality. Over time, analytics of the power quality information can help flag and diagnose potential power quality related items so that customers can proactively manage any possible issues.	**Residential** **Small Business** **Large C&I**	Near Term
Emergency and Safety Notifications The meter will be able to provide customers with emergency management notifications via its analytics and communications capabilities. This can help customers identify potential risks to their energy management systems, security monitoring, and be aware of local emergency notifications that may apply to their general safety and security.	**Residential** **Small Business** **Large C&I**	Near Term
Enhanced Microgrid Integration Where the capability exists for portions of the grid to operate independently of the rest of the surrounding system, the advanced distribution management system will more seamlessly be able to manage the connection of these microgrids.	**Residential** **Small Business** **Large C&I**	Future
Smart Safety Disconnect Detects when a smart inverter has malfunctioned or was improperly installed and has not disconnected from the grid when incoming power has been lost. In this situation, the disconnect inside the meter is automatically tripped to protect the rest of the grid and the customer.	**Residential** **Small Business** **Large C&I**	Future

Product or Service	Customers Affected	Timing
Outage Notifications Alerts allow customers to be notified with important information in a timely, relevant way. These could include proactive messaging about an outage, automatic restoration, and restoration confirmation.	Residential Small Business Large C&I	Day 1
Smart Premise Restoration Sequentially restore power to various devices inside the home or business after an outage to reduce the likelihood of voltage or overloading issues, protecting customer system performance as power is restored.	**Residential** **Small Business** **Large C&I**	Future

B. Lead the Clean Energy Transition

Product or Service	Customers Affected	Timing
Enhanced Access to Battery Storage and Electric Vehicles Through the enhanced visibility and control of the distribution system, greater utilization of storage elements on the grid, including electric batteries and electric vehicles, will be possible. This capability promises to help ensure safe, reliable energy for all customers.	**Residential** **Small Business** **Large C&I**	Near Term
Green Notifications and Controls Customers would be notified when the percentage of electricity generated by renewable services in their area exceeds a certain threshold.	**Residential** **Small Business** **Large C&I**	Near Term
Enhanced DER Enablement Through the enhanced visibility and control of the distribution system, customers will be able to integrate distributed generation resources more seamlessly and potentially at higher levels within a given area.	**Residential** **Small Business** **Large C&I**	Near Term
Demand Management Optimization With more granular consumption information, new demand management programs can be created to enable customers to shift and shed load to respond to needs of the grid on an increasingly real-time basis. With new communication capabilities, the meter will be able to communicate directly with smart devices within homes and businesses. As analytics such as disaggregation and virtual submetering evolve, demand response routines can increase sophistication through optimizing sequence among various demand response resources.	**Residential** **Small Business** **Large C&I**	Near Term

C. Keep Bills Low

New Energy Saving Programs

Product or Service	Customers Affected	Timing
Virtual Energy Audits Provides an on-demand or periodic assessment of the energy usage/efficiency of a premise based on actual performance versus expected performance based on various parameters (i.e. size, year, build, occupancy, devices, etc.). With disaggregation and other analytics capabilities made possible by AMI, these audit results will improve over time to provide more accurate and relevant information. Audits may also be used to monitor the health and status of appliances to identify opportunities for customer to reduce maintenance costs and improve energy efficiency.	**Residential** **Small Business** **Large C&I**	Day 1
Whole Facility Monitoring C&I customers with long-term sustainability goals can more easily track progress at the whole facility and sub-system level through integrations between meters and customer-operated energy management systems. This information can be used to verify savings over time for the purposes of demand side management or can be used to alert customers when demand or energy usage projections are expected to exceed threshold amounts over a given period of time.	**Small Business** **Large C&I**	Near Term
Enhanced Control Options for Behind the Meter Systems From the smart home to intelligent buildings, AMI meters will be able to communicate more seamlessly with devices and systems within the customer facility. Customers can use this capability to participate in demand response programs as well as to manage facility energy consumption in a more accurate and robust way.	**Residential** **Small Business** **Large C&I**	Near Term
Enhanced Automated Demand Response As the grid evolves, distribution system management can utilize expanded automated demand response capabilities which respond to real time needs of the distribution grid.	**Residential** **Small Business** **Large C&I**	Future

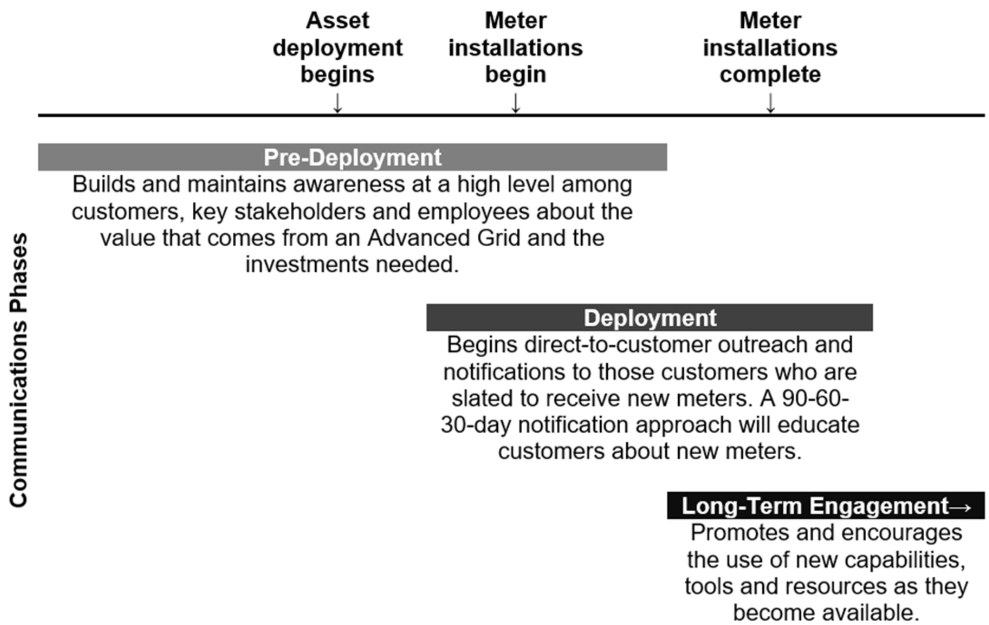
New rate options

Product or Service	Customers Affected	Timing
Rate Advisor With granular usage information and analytics capabilities made possible by AMI, the company will provide a multi-channel approach to educate customers and proactively offer ways to optimize energy usage and cost under existing and new, future rates schemes.	**Residential** **Small Business** **Large C&I**	Near Term
Time Varying Rates With more granular consumption data and more sophisticated meters, rate schedules can be created to better reflect the actual costs on the system at specific times of day. Customers can take advantage of these price signals to manage costs.	**Residential** **Small Business** **Large C&I**	Near Term
Virtual Submetering Instead of installing physical submeters, which are costly and take special wiring and their own communications channels, the main meter could act as a virtual submeter through disaggregation capabilities at the meter.	**Residential** **Small Business** **Large C&I**	Near Term
Smart Rates New rate opportunities including pre-pay and technology specific rates. Rates may rely on local management of the premise level grid or local identification of events. For example, when an EV is plugged in, this could be detected and an EV rate is automatically applied. Another example, would be a flat billing rate with use of the Premise Level Grid Management System (PLGMS) to stay within the agreed to usage levels.	**Residential** **Small Business** **Large C&I**	Future

V. CUSTOMER COMMUNICATIONS STRATEGY AND PLANNING

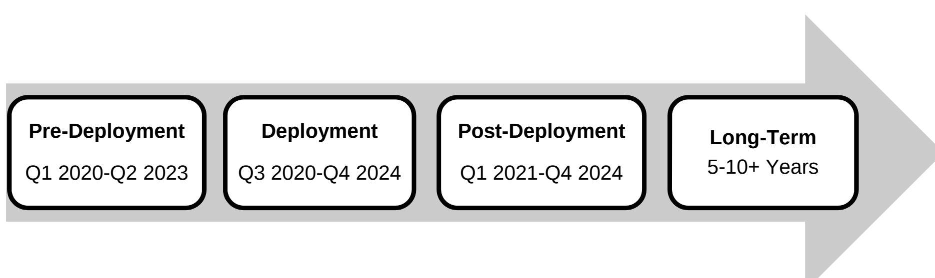
Because meter installation and advanced meter capabilities will be geographically staged over a multi-year timeframe, we will stage our customer communications to align with the value we expect customers to realize through this advanced grid journey.

Figure 14. Customer Communication Phased Implementation



We know from our research that it is important to not overwhelm customers with new products and services as part of their initial experience with advanced meters. For example, our research to-date indicates that customers are not familiar with and don't fully understand how time-of-use pricing works and how to change their behavior to account for this type of pricing. Therefore, as billing becomes ever more complex it is important that customers understand the complexities of their billing before they are introduced to new products and services that may or may not help them control their energy usage.

Figure 15. Customer Communications and Value Realization



A. Pre-Deployment

In this pre-implementation phase, we are building awareness among customers and key stakeholders about the value that comes from an advanced grid and the investments needed. We are communicating the value AGIS is expected to bring to our customers and communities and working to anticipate customers' information needs and questions and clearly outline how to take action – including how to "opt out" of receiving an advanced meter (see Appendix A for our proposed Opt-Out Framework).

We will also be setting the stage for Day One with customers – and with advanced grid infrastructure, as we will begin installing the FAN approximately six months in advanced of AMI meter deployment.

Table 2. Customer Communications Timeline and Summary

	90 days before meter install	**60 days before meter install**	**30 days before meter install**	**7 days before meter install**	**Day of install**	**Post-install**
All customers	Mailer: intro	Mailer: your meter is coming soon	Mailer: meter installation FAQs	Phone call: your meter is coming next week	Install technician door knock	Mailer: success or attempt
					Door hanger: success or attempt	
Opted-in customers (only customers who have opted into these channels will receive these notifications)	Email: what to expect during meter installation	Email: Your meter is coming soon	Email: Your meter is coming soon	Text notification		Email: success or attempt
			My Account banner: Your meter is coming this month	App push notification		My Account banner: success or attempt
Mass communication	Targeted online, print, and out of home advertising			Hyper-targeted social media advertising		
	Community outreach: meter install schedule by neighborhood, informational content about new meters					

This is a critical period where we are working to ensure the foundational customer experience is exceptional, and that customers will not only be satisfied but also active and excited for what comes next.

B. Deployment

Deployment represents the point at which customers have an advanced meter and begin to realize tangible value from our advanced grid investments. Our customer communications will become more specific – with messaging regarding the specific service improvements customer should expect to see, such as:

Improved reliability and faster outage restoration

- New digital energy grid technologies will help us prevent outages to you and your neighbors and, in some cases, enable us to automatically reroute power to shorten or prevent any service interruptions.

- Advanced grid technologies can detect outages at your home or on the larger electric system, helping reduce the time you are without service.
- You'll receive quicker notifications when service is out and more accurate information on when power will be restored.

More options to protect the environment and use new technologies

- The advanced grid will help us provide you with even more clean energy because it will allow us to maximize the use of renewable energy sources such as solar, wind, and hydro.
- Energy use data in near real-time will give you the ability to choose how and when you use technology such as batteries and electric vehicles.

Security you can trust

- Energy use data will be securely transferred electronically from the advanced meter, eliminating the need for manual meter reading or estimates, which also helps reduce costs.
- Protecting your data is extremely important to us. We use multiple layers of defense to ensure all data is secure and protected.

For customers who have received new meters, we will seek feedback to ensure satisfaction with the process. We will also continue to raise awareness about advanced meter features and engage them to take advantage of new capabilities and functions. In this phase, we will focus more on the available Home Area Network and available online tools and resources, such as the online energy usage portal. We will begin to introduce them to more products and services that help reduce energy usage and offer non-energy benefits. Finally, we will also be measuring customer awareness, understanding, interest, participation and satisfaction with the advanced meters and their associated features.

C. Long-Term Engagement

This phase will promote and encourage the use of new Advanced Grid capabilities, tools and resources as they become available. Communications will not only highlight the features of new tools and resources, but also the broader benefits they can provide. This phase will leverage customer information and preferences gathered in Phase II to provide a seamless experience for all customers via their preferred channels.

Key objectives during this phase include:

- Leverage a messaging hierarchy that reiterates high-level benefits of the project while educating customers on new capabilities, tools and resources as they become available.
- Develop and execute a customer nurturing campaign to follow the customer journey and encourage adoption of new capabilities, tools and resources.
- Evaluate and refine messages and tactics to continuously improve and ensure the best possible customer experience.

VI. CONCLUSION

Our distribution grid is the foundation of the service we provide our customers. As our current system ages and technology advances, we are at a point where modernization will return significant value to our customers. Making these investments in our system will enhance transparency into the distribution and to system data, to promote efficiency, and reliability, and to safely integrate more distributed resources. Underlying these goals are the following drivers:

- The Company's strategic priorities to lead the clean energy transition, enhance the customer experience, and keep energy prices affordable;
- The Company's desire to meet the growing needs and expectations of our customers;
- Current distribution system needs; and
- Commission policy and direction, and stakeholder input relative to customer offerings, performance, and technological capabilities of the grid.

If we delay the implementation of a smarter and more advanced grid, we will increasingly find ourselves unable to meet customer expectations and unable to benefit from the advanced in technology includes the benefits brought by DERs. As discussed above, our investments will:

- Provide customers with new products and services to manage their energy use;
- Improve our management and integration of DERs;
- Improve the outage restoration process and the accompanying customer experience; and
- Help maintain stable and reasonable costs for our customers.

APPENDIX A: CUSTOMER OPT OUT FRAMEWORK

The Company believes customers should have the choice to opt-out of receiving an advanced meter. We will therefore provide eligible customers with the opportunity to decline the installation of an advanced meter before initial installation or a request to have an advanced meter removed at any time. However, opt-out requires the Company to maintain its abilities to manually read meters, which involves maintaining supporting information systems and incremental meter reading personnel – meaning the Company will lose both its current efficiencies of reading the meters through AMR and future efficiencies of reading these meters through AMI. Therefore, we believe any opt-out framework should be based on the cost-causation principle to ensure other customers are not subsidizing customers who choose to opt-out of AMI. We outline a framework below that we intend to socialize with stakeholders to gather feedback before proposing an Opt-Out Tariff for inclusion in our Minnesota Electric Rate Book.

Because of the inefficiencies created by the opt-out option, we will work to minimize the numbers of customers choosing to opt-out – starting with our pre-AMI deployment customer education and awareness campaign, which will address many of the questions or concerns that customers typically have with advanced meters, including privacy and safety. Our communications will also discuss the benefits that an advanced meter provides, including opportunities to reduce energy costs and improve their environmental impact. As our pre-deployment communications get underway with customers, our customer service representatives will also be trained to address customer questions and concerns in a transparent and understanding manner.

To ensure no cross-subsidization and consistent with cost-causation principles, we propose that customers opting-out of AMI incur the costs to provide the services necessary to maintain billing and meter reading activities to support that choice. If an eligible customer chooses to decline installation of an AMI meter, that customer will receive a meter that will be capable of recording the customer's interval energy usage – but the meter will not contain a communications network interface card, and therefore the usage must be retrieved manually by a Company meter reader. This will be a change from the current meter reading and billing experience for customers, because we have used an AMR system that, except for unusual circumstances, has nearly negated the need for meter reading field personnel for most customers for approximately 20 years.

We propose that customers be able to decline the installation of AMI at with no upfront charge – only incurring an ongoing cost-based charge to support the ongoing manual meter reading and related processes. If however a customer requests an AMI meter to be removed after its initial installation, we propose to charge a service fee that covers the costs of a field representative to remove the AMI meter and replace it with a non-AMI meter. The ongoing charge for these customers would be the same as for those who decline the installation at the time of initial deployment.

As noted previously, we intend to engage stakeholders with this basic framework along with proposed cost-based upfront and ongoing fees – with a goal of developing a detailed Tariff proposal to submit to the Commission for approval.

APPENDIX B: DATA ACCESS, PRIVACY, GOVERNANCE

The Customer Data and Information Strategy enables the framework for maintaining the integrity and security of our data and information assets throughout its lifecycle. This strategy encompasses the creation, storage, usage, sharing, and disposal phases of data assets. The strategy also ensures Xcel Energy data and information provides business value, minimizes risk, and complies with legal and regulatory requirements.

A. Culture

Xcel Energy's data is managed as an asset of the business. We leverage data to drive more understanding within the business about how data can be employed to improve operational performance, evaluate industry options, and help customers make better decisions. We have robust data privacy and security standards for all data that varies based on the type of data. Our customer strategy is informed by these standards, and as new products, services, and experiences are identified they will comply with these standards. At this time, the expectation is that any customer-specific data derived from AGIS will be treated similar to the way customer-specific data is treated today. The primary difference in the data AGIS will capture is expected to be the granularity of the data – i.e. today's monthly consumption compared to the 5- and 15-minute interval data from AMI.

Everyone who works for Xcel Energy understands their responsibilities for maintaining the integrity and quality of our data assets, complying with data requirements, and keeping the data safe and secure. To ensure that all employees understand the criticality and responsibility of securing data, all employees are required to complete information management training annually.

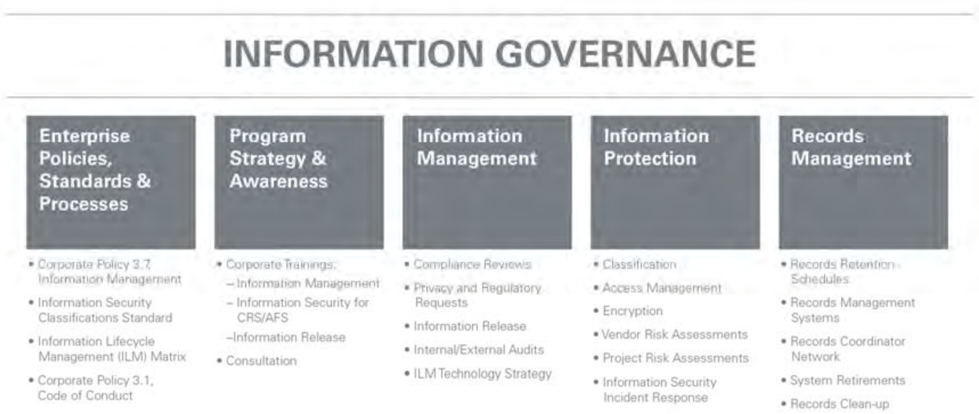
B. Information Governance Framework

Xcel Energy's Enterprise Security Services (ESS) oversees and provides leadership of the information governance policies, procedures, processes and standards. This includes strategic oversight of the creation, collection, use, protection, retention and disposal of all company information in all formats.

Compliance with is a corporate and individual responsibility, and compliance is monitored and evaluated through the corporate governance framework.

The key areas of Information Governance are as follows:

Figure 16. Xcel Energy Information Governance



C. Information Management and Protection

Customers trust that the information Xcel Energy creates, collects, and uses as part of its work to provide regulated utility service to customers is handled properly to avoid the potential for loss, misuse, or harm. Information Management is the policies and procedures that support data quality, data logistics and data integration covering the following lifecycle stages: (1) creation and collection; (2) use; (3) release; (4) disposition.

1. Creation and Collection

Company information is data, facts, and figures generated or received in connection with the transaction of business, and that is categorized as a Record or a Non-Record. Distinguishing between records and non-records is essential to the decision-making process regarding the use, release, and disposition of the information.

- Records are any documentary material, regardless of format, that have been finalized and / or identified on a records retention schedule.
- Non-Records are any documentary material, regardless of format, that has not been identified as a record; non-records include copies of records.

All Company information whether it is a record or non-record is classified into four information security categories based on its value or potential risk. We describe these categories and how we classify customer information below:

Confidential Restricted (CRI). CRI includes information where unauthorized disclosure (inside or outside the company), alteration or destruction has the potential for significant harm to the company, its employees, shareholders or its customers, including: damage to reputation; damage to Bulk Electric System (BES); legal, regulatory, or other sanctions. Data in this classification requires the strongest level of protection. Distribution of CRI must be limited to those with a business need to know and distribution of CRI to any third party must be approved through the approved data release process. Customer CRI includes Personally Identifiable Information (PII), such as Social Security Number (SSN), Driver's license or other government-issued identification numbers, financial account number, any individually identifiable information received directly from a financial institution, individually identifiable biometric data (including, fingerprints, voice print, retina or iris image), first name (or initial) and last name (whether in print or signature) in combination with any one of the following; Date of birth, Mother's maiden name, Digitized or other electronic signature, or DNA profile.

Confidential (CI). CI includes information where unauthorized disclosure (inside or outside the company), alteration or destruction has the potential for harm to the company including: damage to reputation; material productivity loss; impede the organization's operations to the BES; legal, regulatory, or other sanctions. Data in this classification requires protection and may only be distributed to those with a business need to know and distribution of CI to any third party must be approved through the approved data release process. Examples of customer CI include details regarding a customer's account or other Xcel Energy-assigned numbers, energy usage, current charges, and billing records.

Internal (I). Internal information includes information where unauthorized disclosure (inside or outside the company), alteration or destruction is unlikely to cause harm to the company, such as: damage to reputation; significant inconvenience or productivity loss; damage to BES; legal, regulatory, or other sanctions. Data in this classification may not be shared outside the company without prior approval from the information owner. Customer internal information includes aggregated customer energy usage data (CEUD) aggregated to the 15/15 threshold or whole building CEUD aggregated to the 4/50 threshold.

Unsecured (U). Information that may or must be available to the public. Unsecured information includes Xcel Energy's website, and the following documents once published and made available to the general public: SEC filings and FERC filings, brochures, advertisements, press releases, annual reports, bill board advertising, current billing rates. In terms of customer information, once aggregated CEUD is authorized, it becomes unsecured information (example: the Community Energy Reports on the xcelenergy.com website).

2. *Use*

Our Privacy Policy outlines the ways that we may use the information we obtain about our customers, as follows:[6]

- Assist in establishing an account with Xcel Energy
- Provide, bill, and collect for Xcel Energy products and services
- Communicate with customers, respond to their questions and comments, and provide customer support
- Provide customers access to their information via the My Account site
- Administer customers participation in events, programs, surveys, and other offers and promotions
- Operate, evaluate and improve Xcel Energy's business and the regulated products and services we offer (including developing new products and services, analyzing our products and services, optimizing customer experience on websites, managing our energy distribution system and our communications, reducing costs and improving service accuracy and reliability, and performing accounting, auditing and other internal functions)
- Create aggregated or de-identified energy usage data
- Protect against and prevent fraud, unauthorized transactions, claims and other liabilities, including past due accounts
- Manage risk exposure
- Comply with applicable legal and regulatory requirements

Internally, we base our use parameters on the information security category assigned to the type of information. Employee access to customer CRI or CI is limited to only those

[6] The Xcel Energy Privacy Policy in its entirety can be found at:
https://www.Xcel Energyenergy.com/staticfiles/xe/Admin/Xcel Energy%20Online%20Privacy%20Policy.pdf

employees and contract workers with approved access to our customer system (Customer Resource System or CRS).

Employees with access to customer CRI and/or CI are prohibited from accessing viewing for a non-business reason; accessing or transferring it for personal gain, advantage or any other personal reason; giving access to or transferring it without first obtaining appropriate approvals; downloading, uploading, or saving it on a personally owned computing device; and accessing it from a public computer.

3. Release

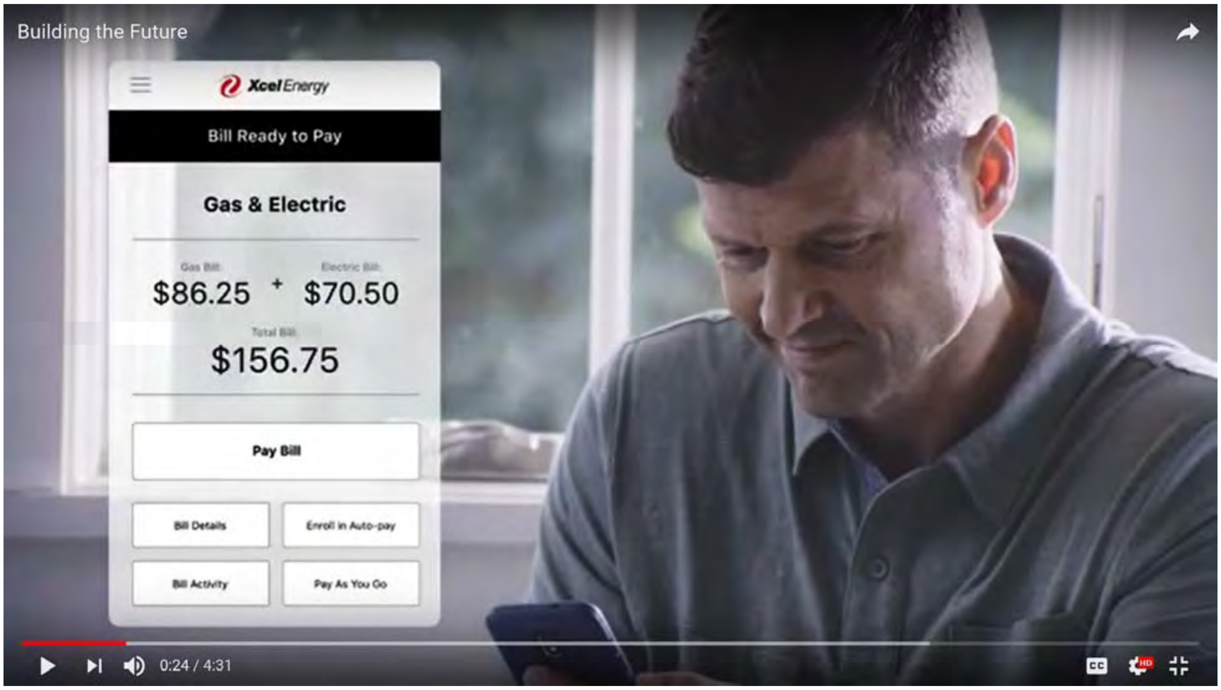
Xcel Energy will only release customer CRI pertaining to an individual to that individual once the identity of the individual has been validated. We will release customer CI to the customer of record upon validating the customer's identity, or to a third party upon receiving a documented and verified consent from the customer of record. We may also disclose customer CI as required or permitted by law or applicable regulations, including to a federal, state or local governmental agency with the power to compel such disclosure, or in response to a subpoena or court order.

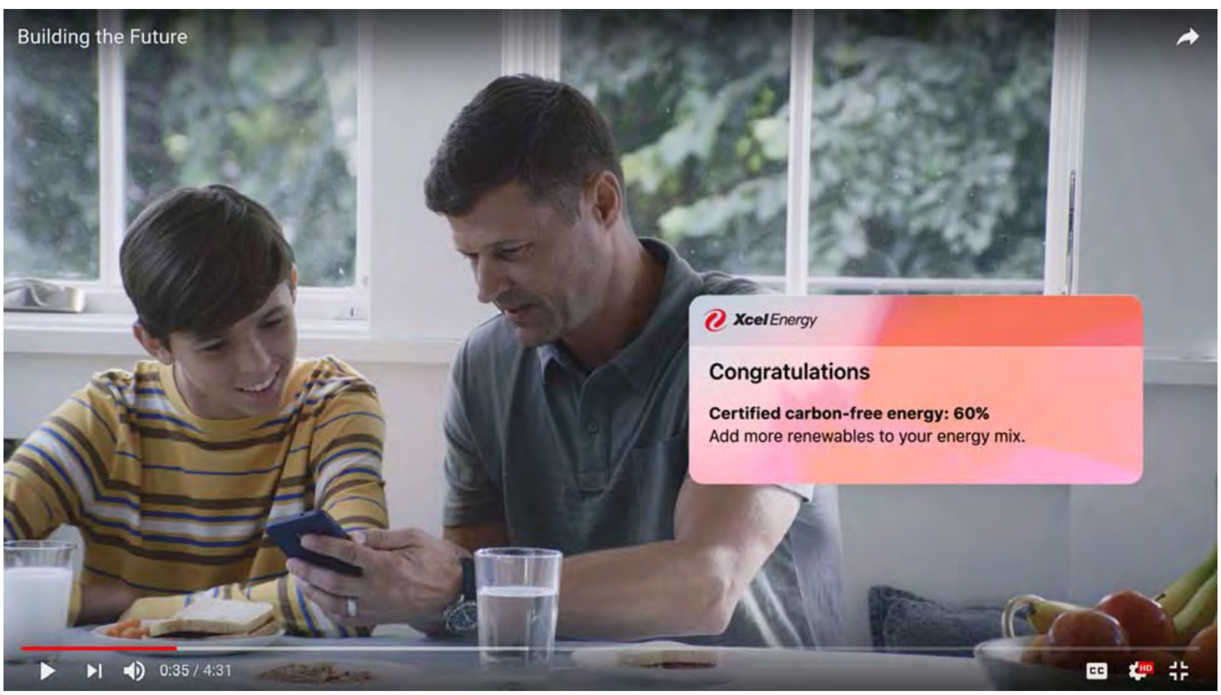
We also release customer information to our contracted agents, when it is necessary for our agent to perform the service(s) specified in an Agreement.[7] All of our contracted agents go through a security vendor risk assessment (SVRA) screening process intended to provide transparency into security-related risk(s) that could potentially be introduced to Xcel Energy as a direct result of utilizing a third-party vendor's product, service, application, etc. All newly proposed vendor arrangements are subject to the (S)VRA process before a contract is signed. Suppliers are assessed by multiple ESS teams (Security Risk Management, Physical Security, Enterprise Resilience, and Information Governance) to ensure security risk is addressed holistically. We prohibit these service providers from using or disclosing the information we provide them, except as necessary to perform specific services on our behalf or to comply with legal requirements.

4. Disposition

The disposition phase of the information management lifecycle consists of disposal requirements as defined in a records retention schedule. Customer account and billing information, and data from our meters are retained for six years.

[7] Contracted Agents are entities with whom we have a contractual relationship to support our provision of regulated utility service, or that directly provide regulated utility service to our customers on our behalf.





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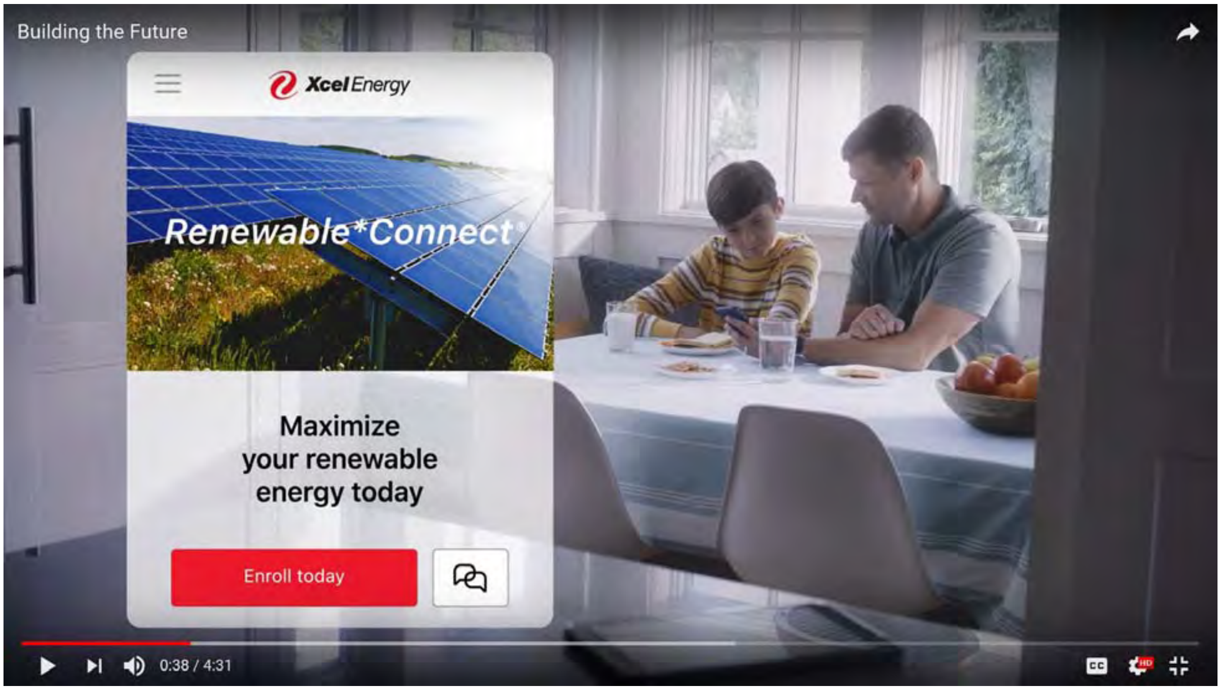

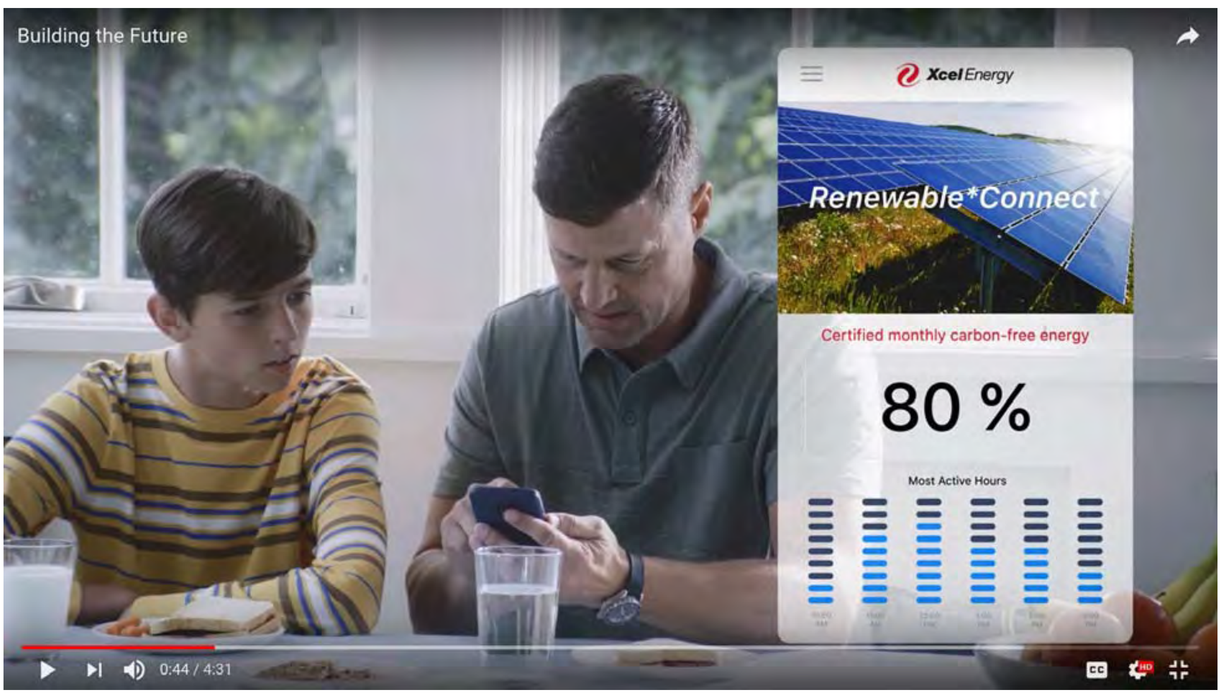

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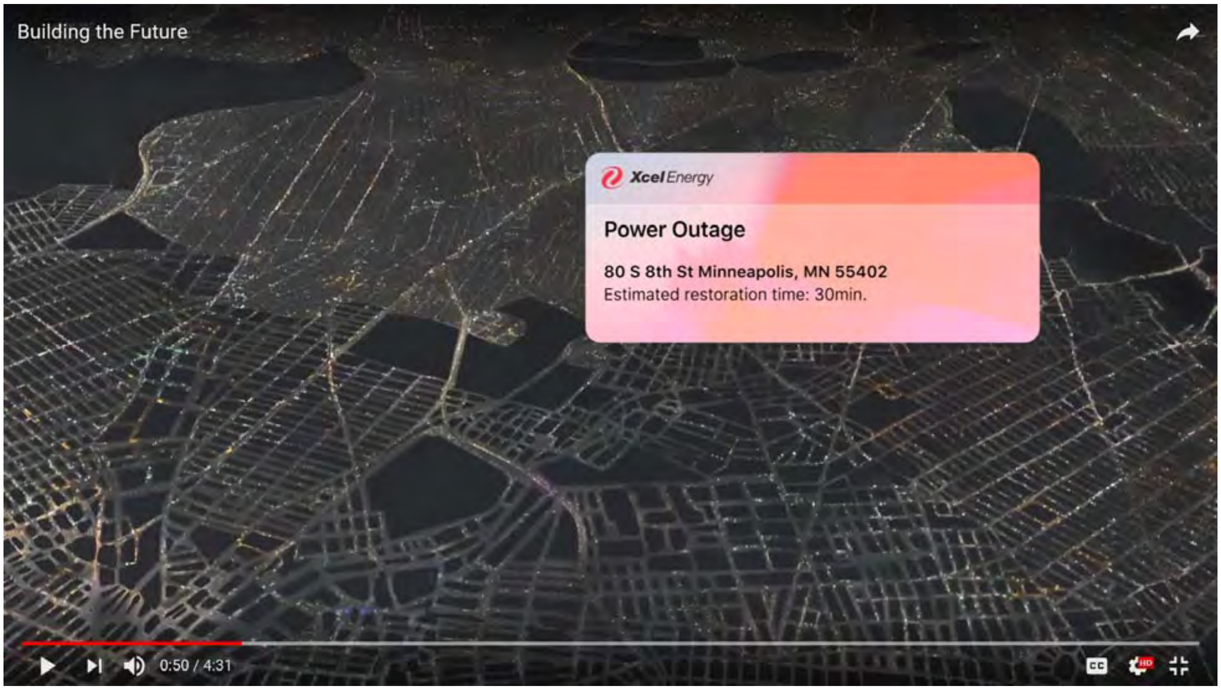

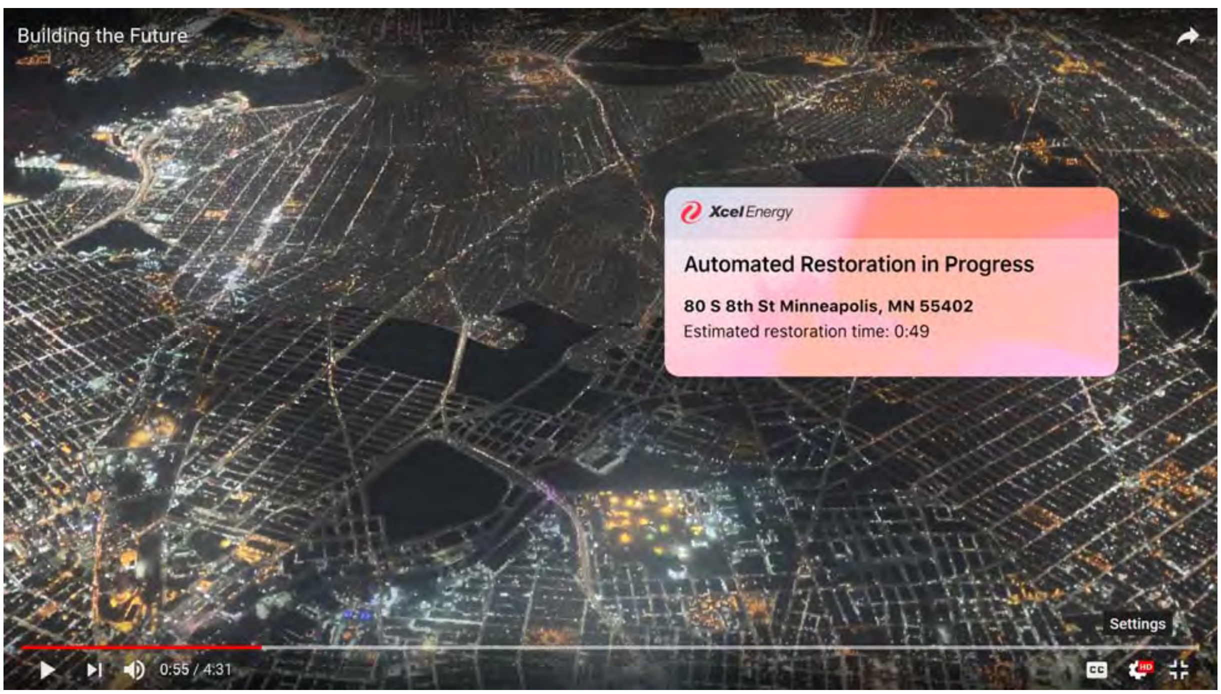

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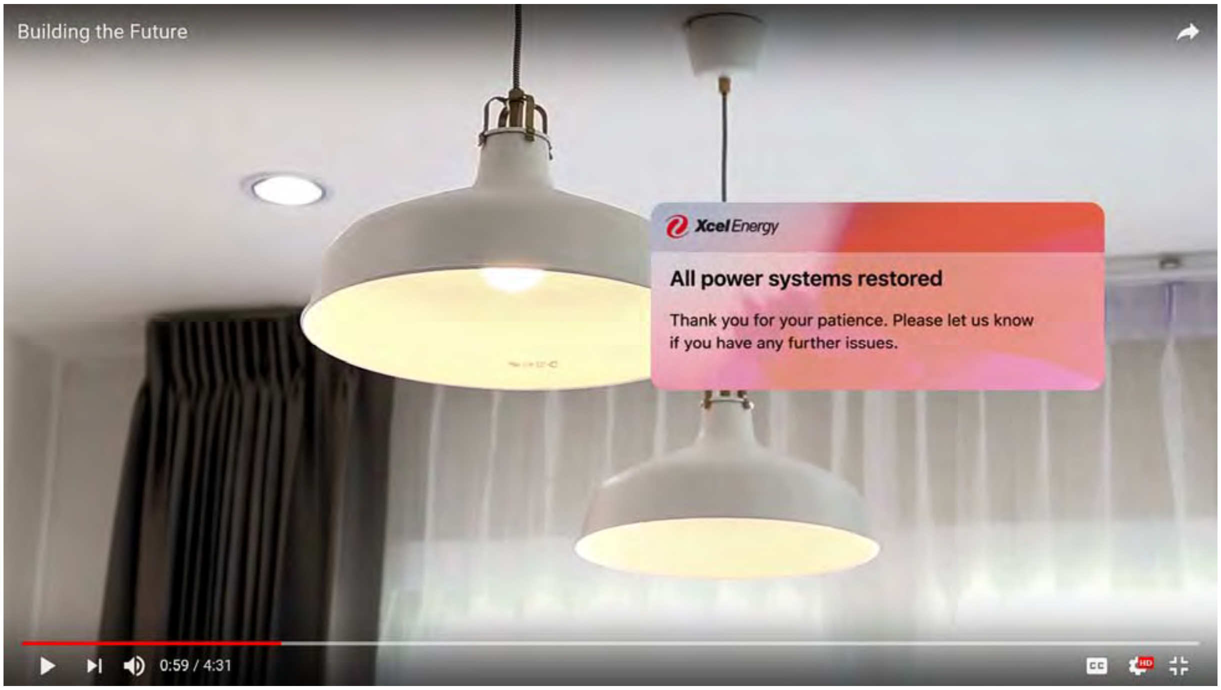

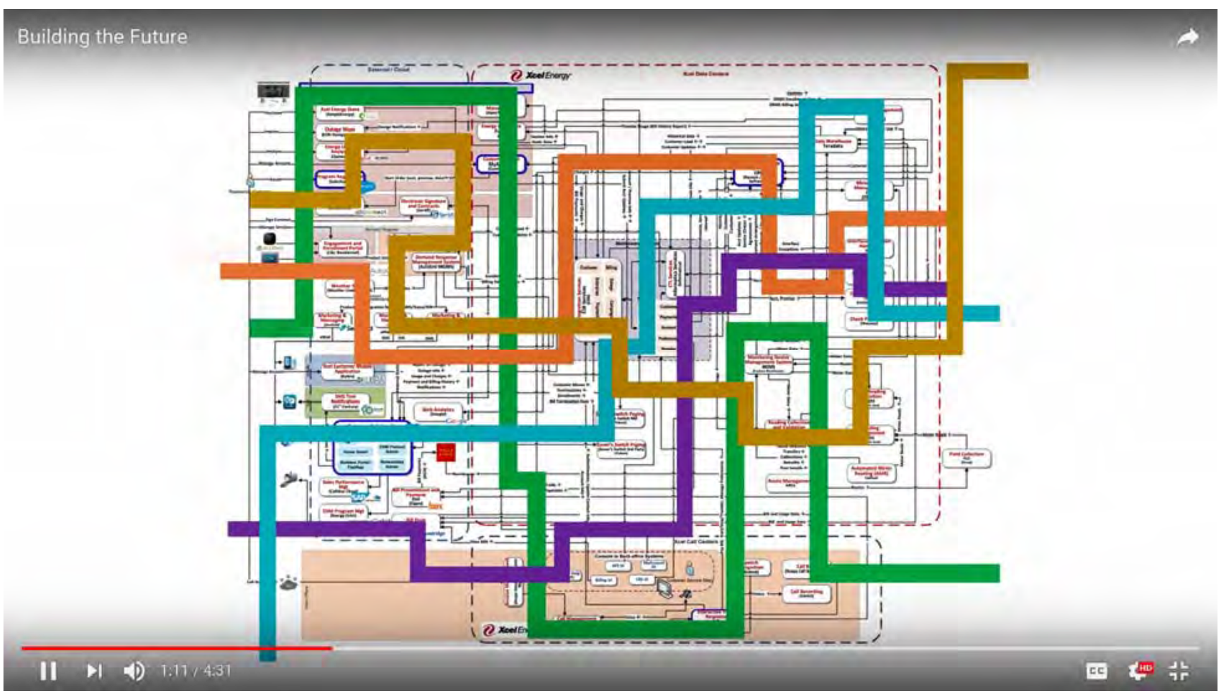

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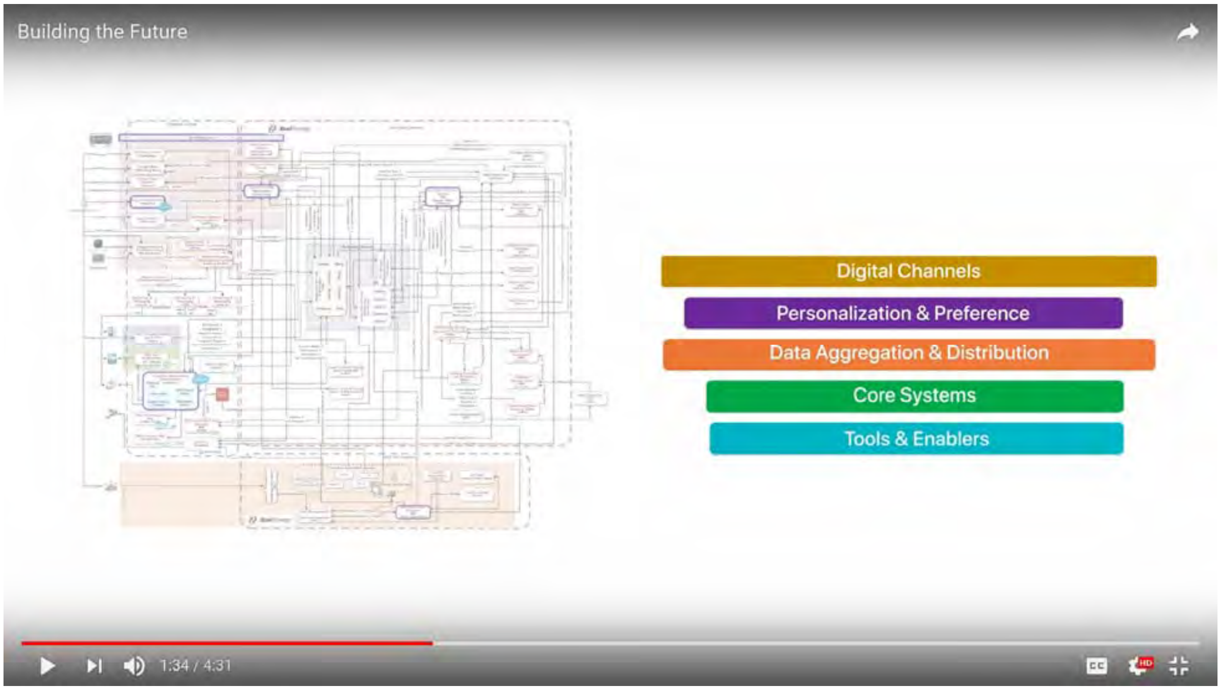

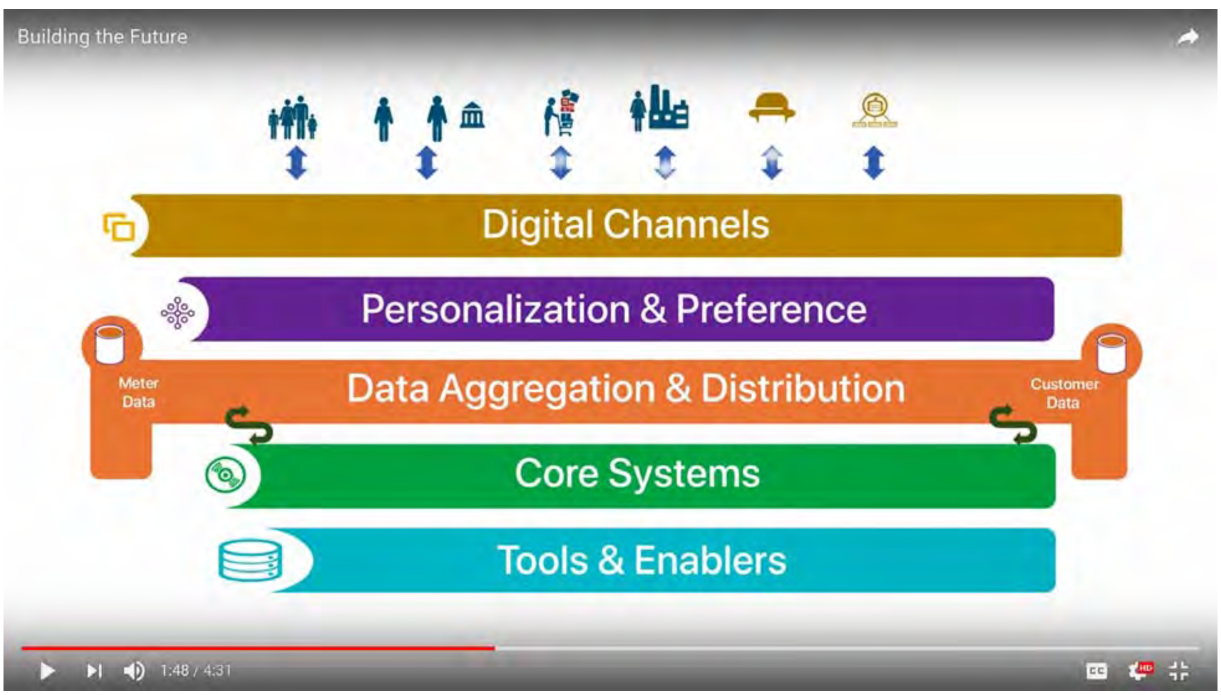

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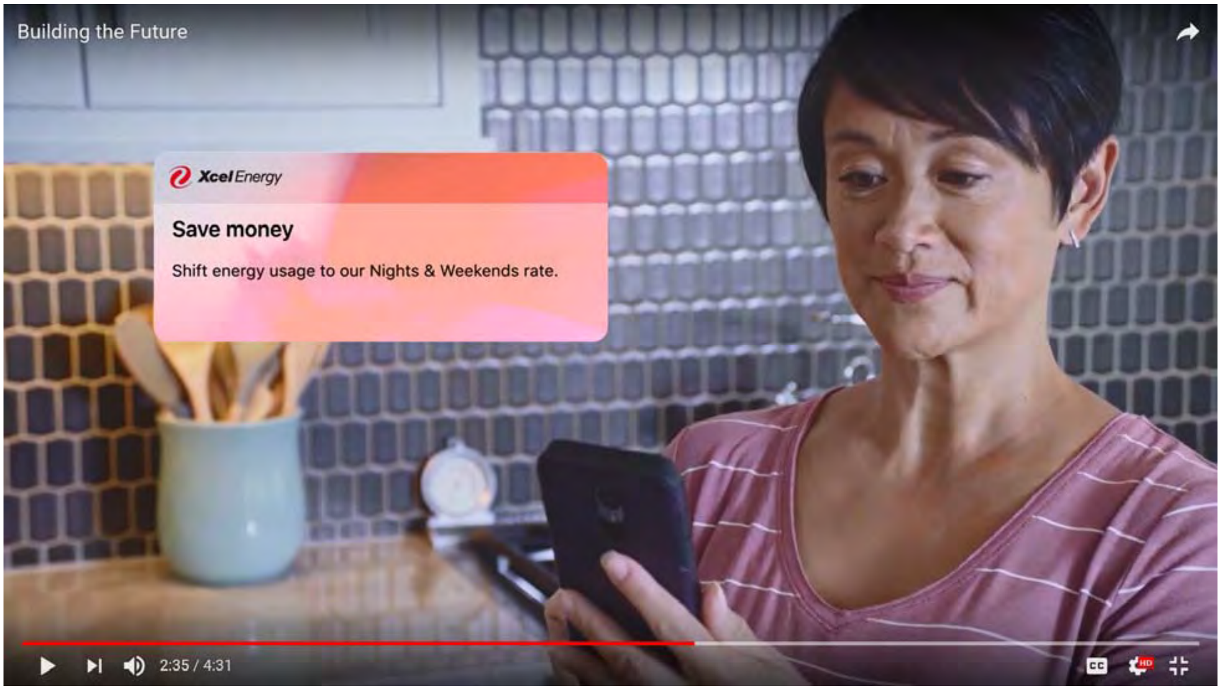

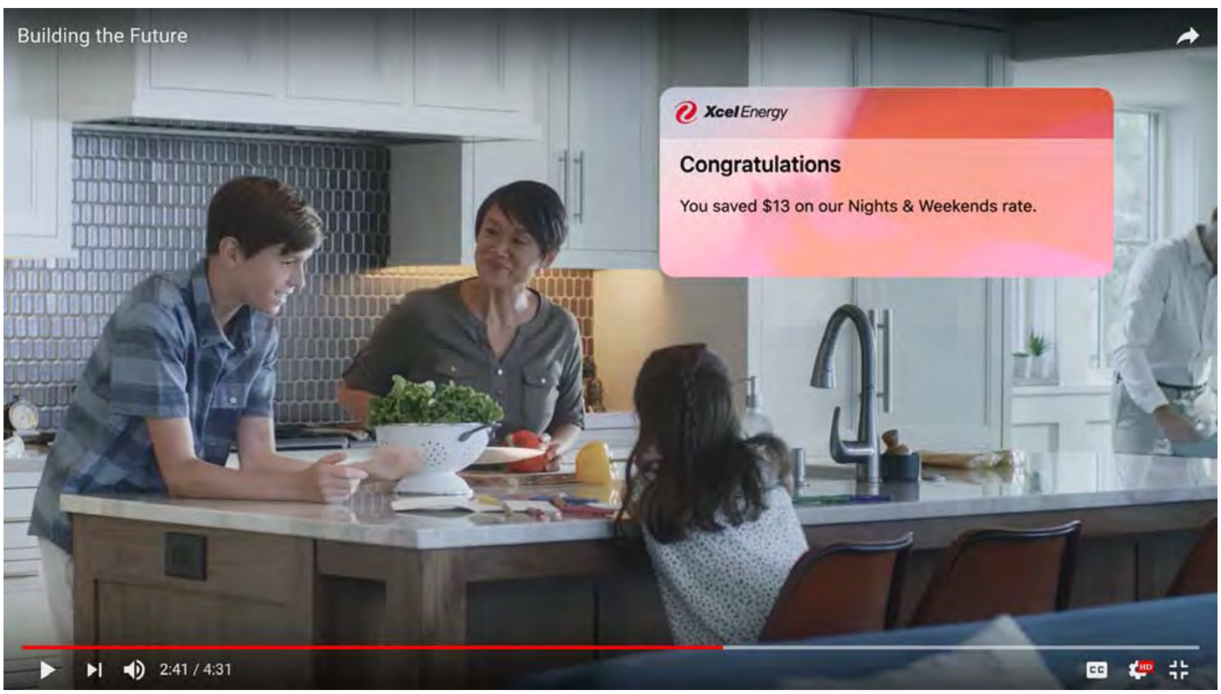

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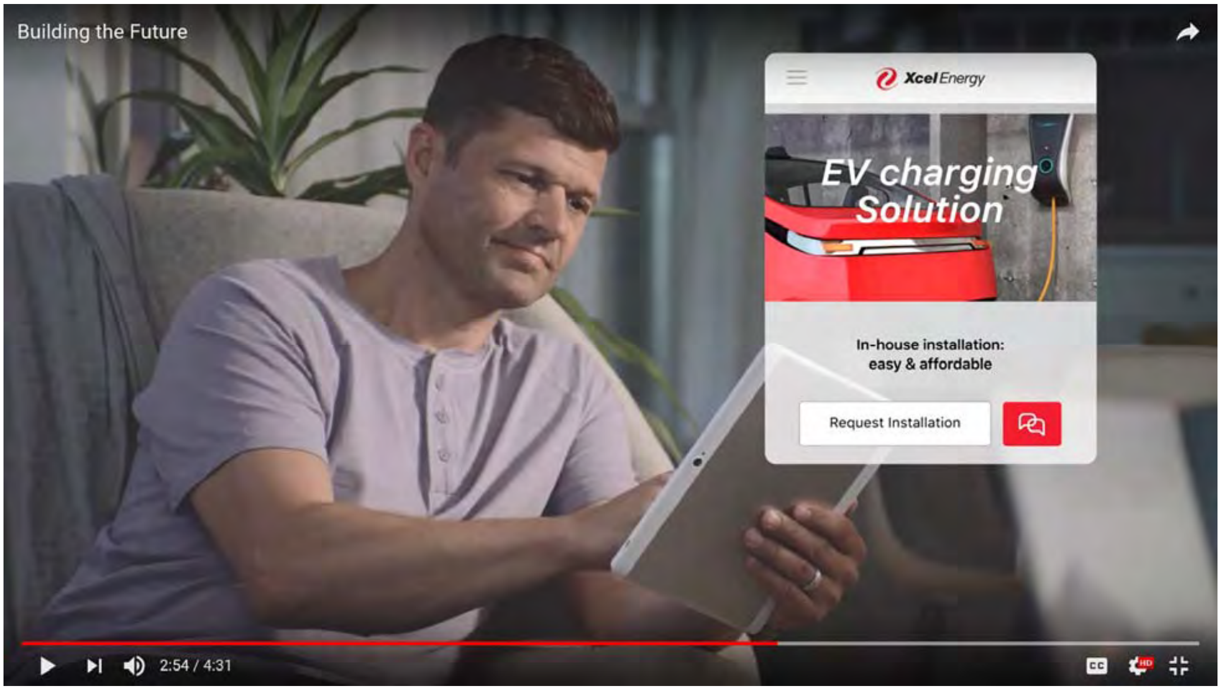

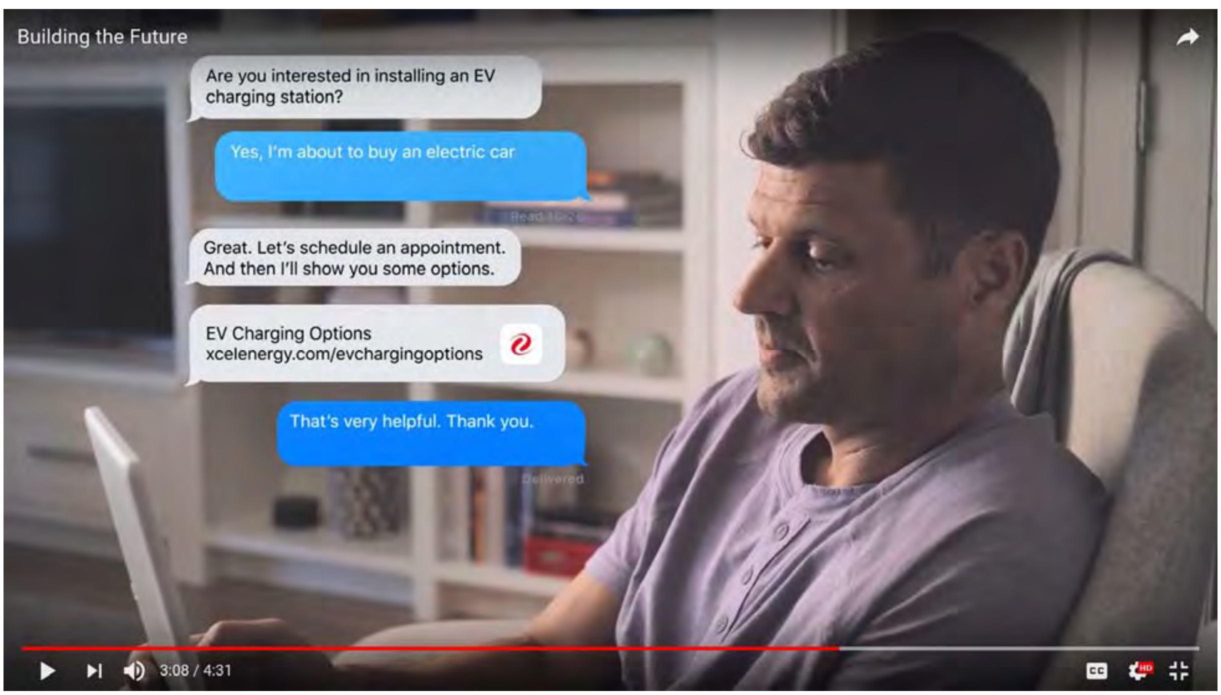

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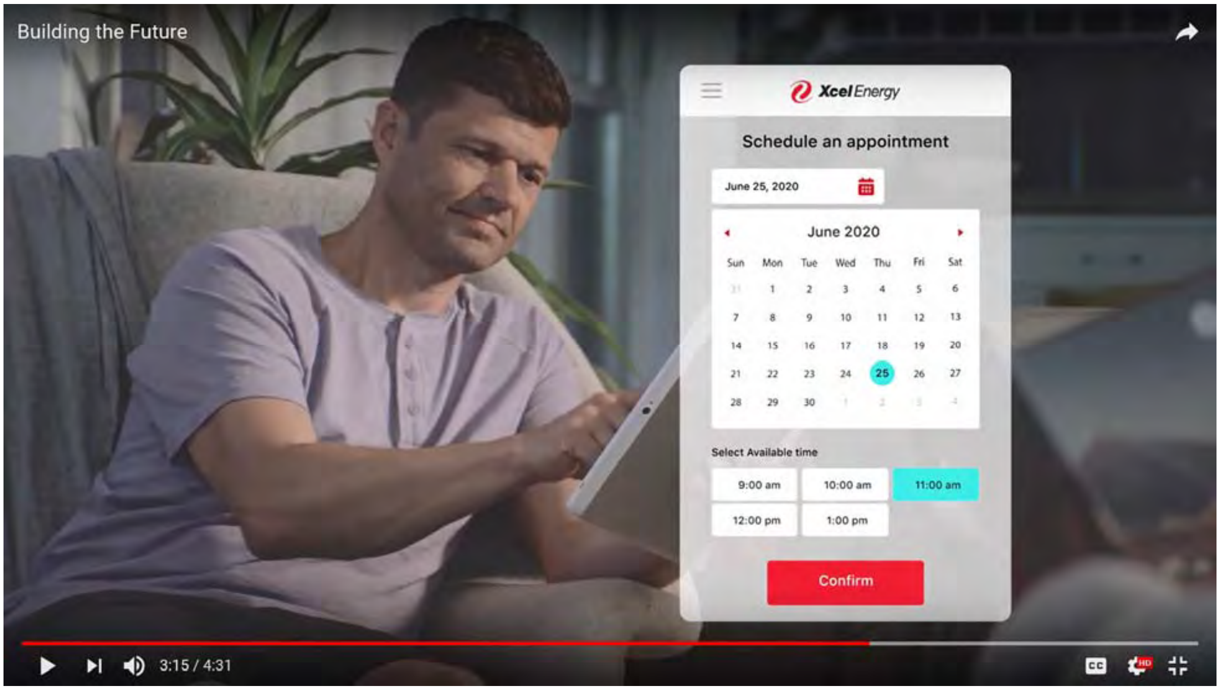

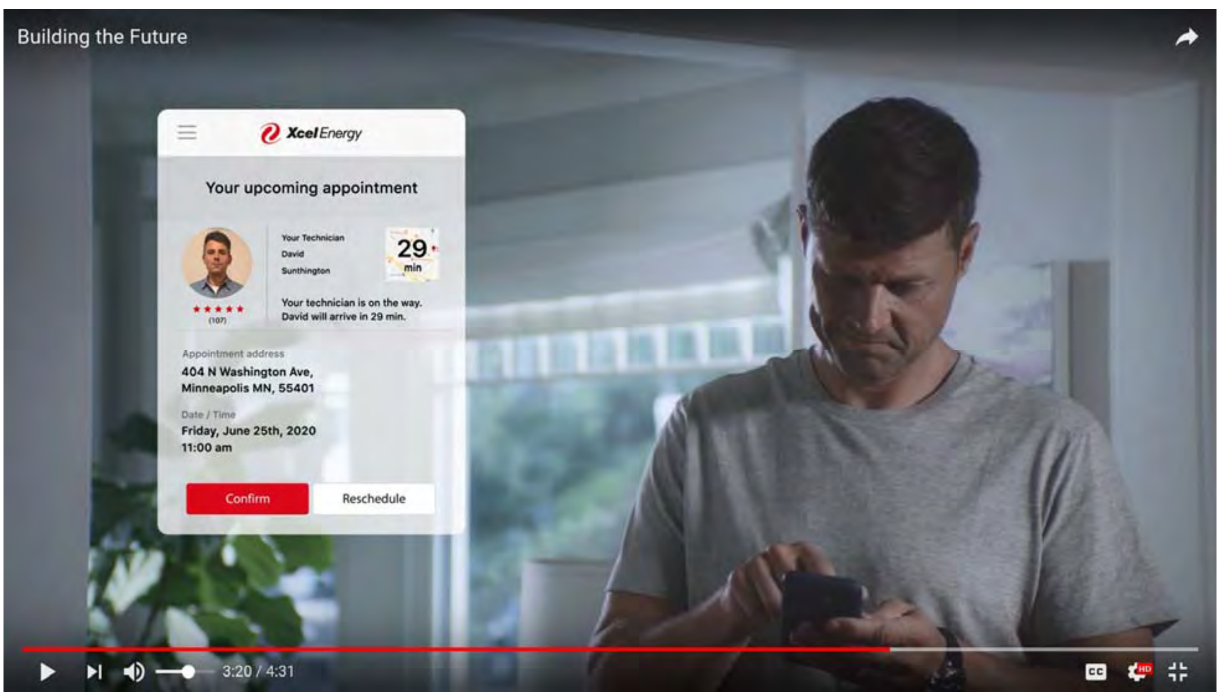

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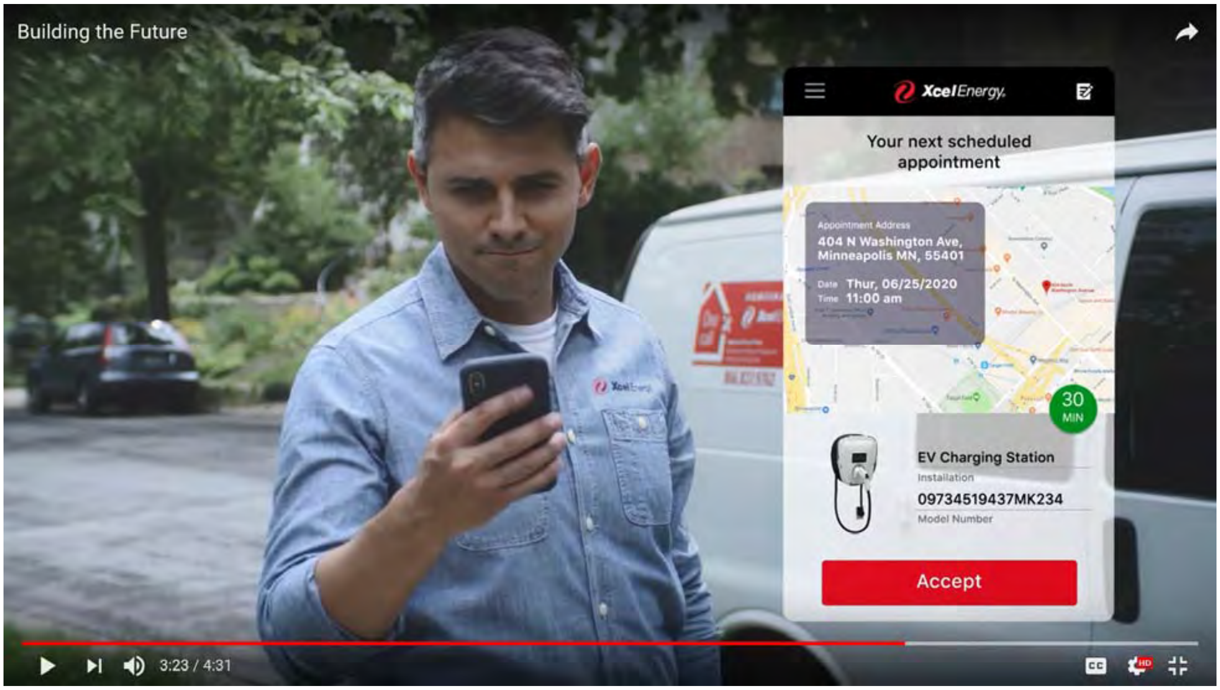

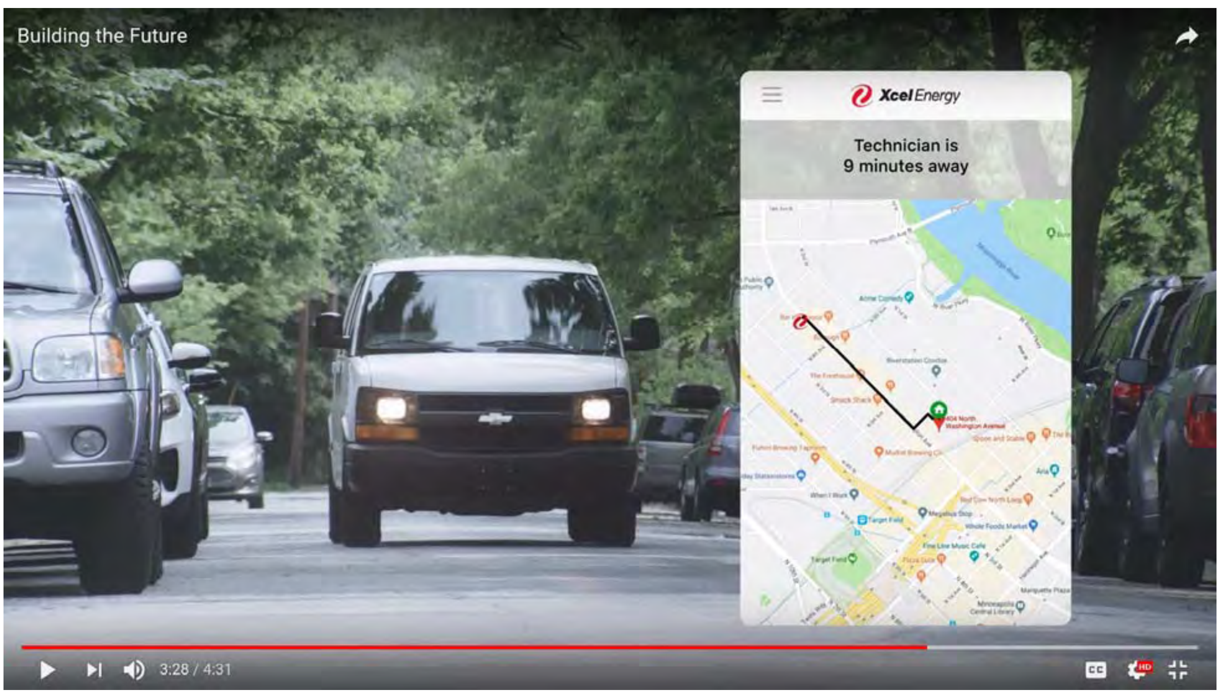

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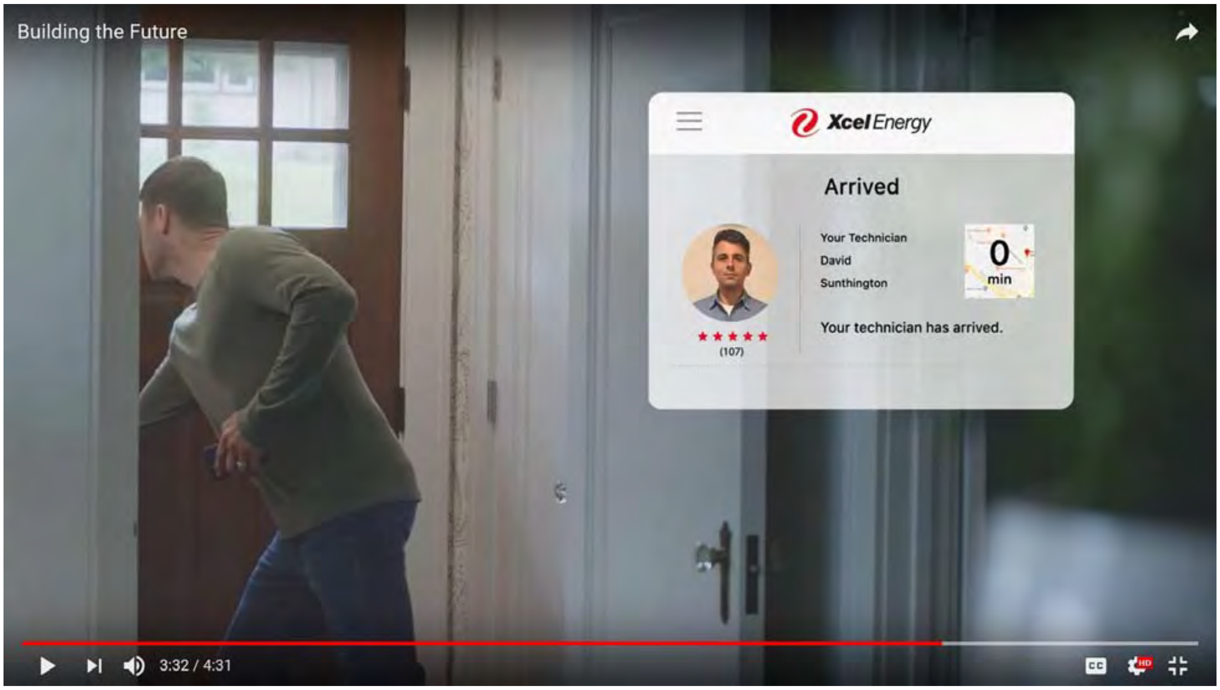

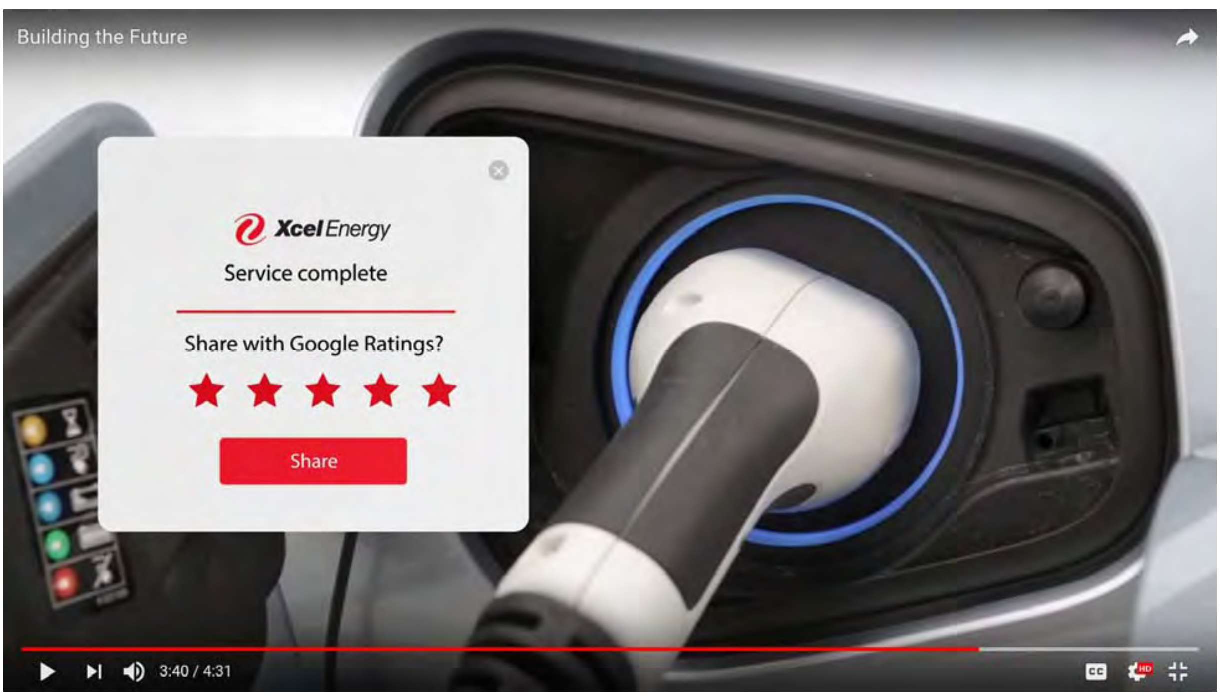

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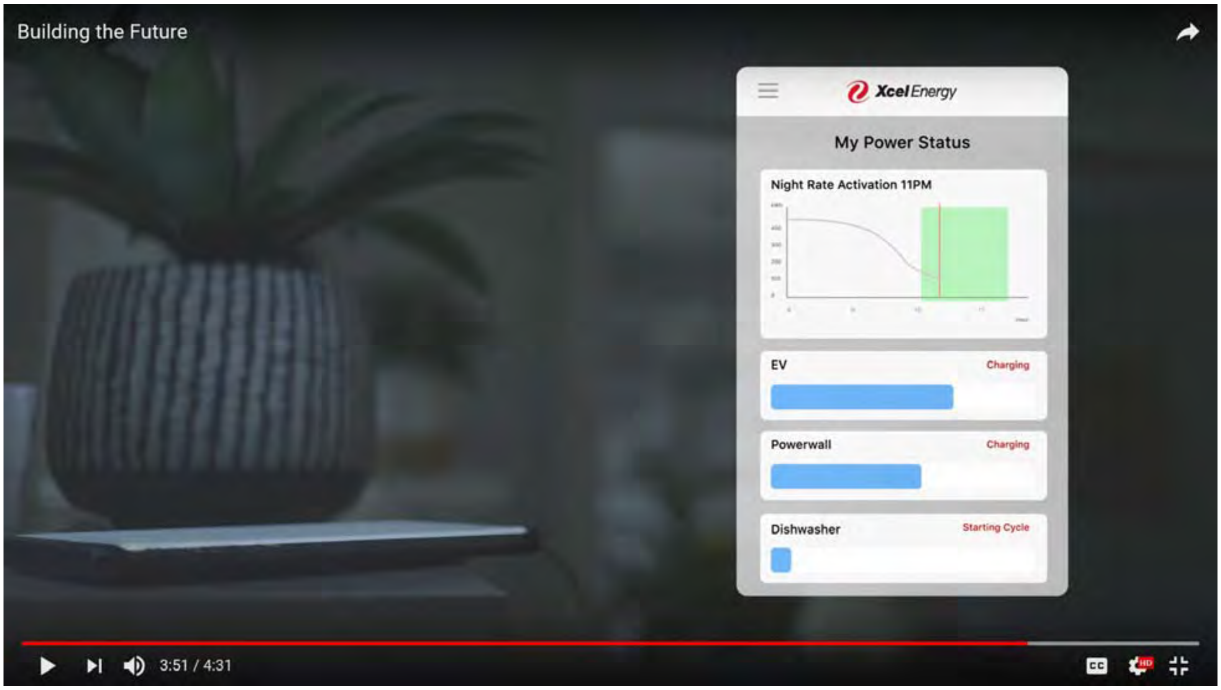

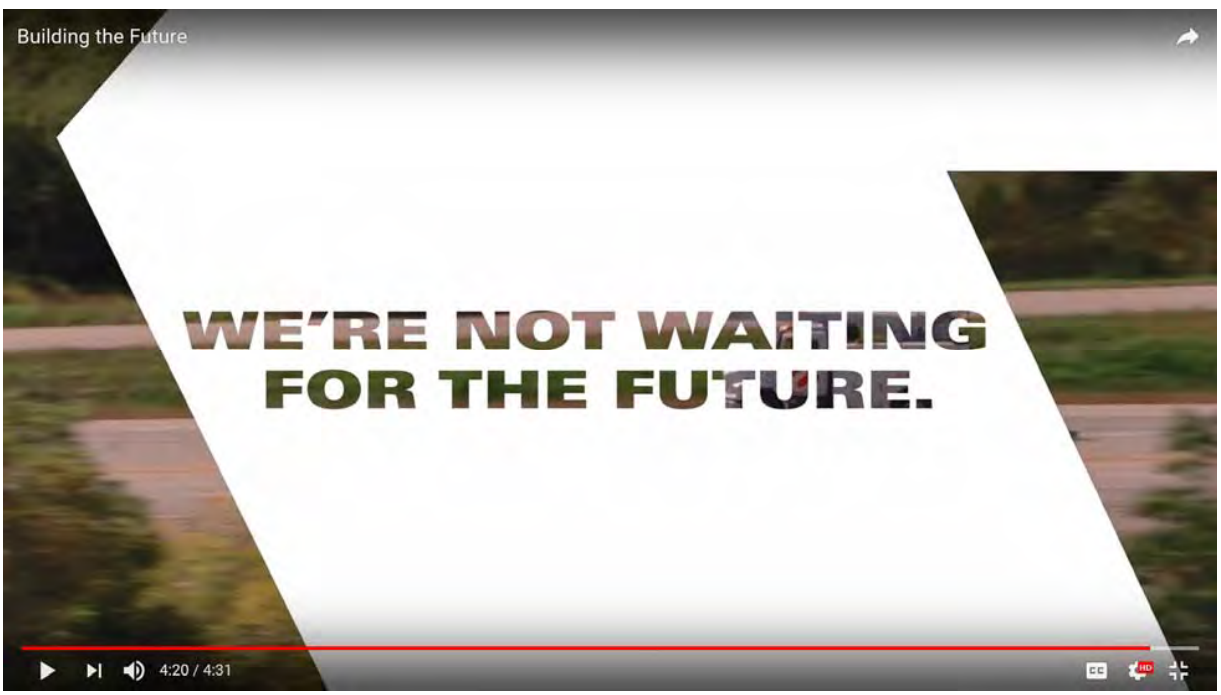

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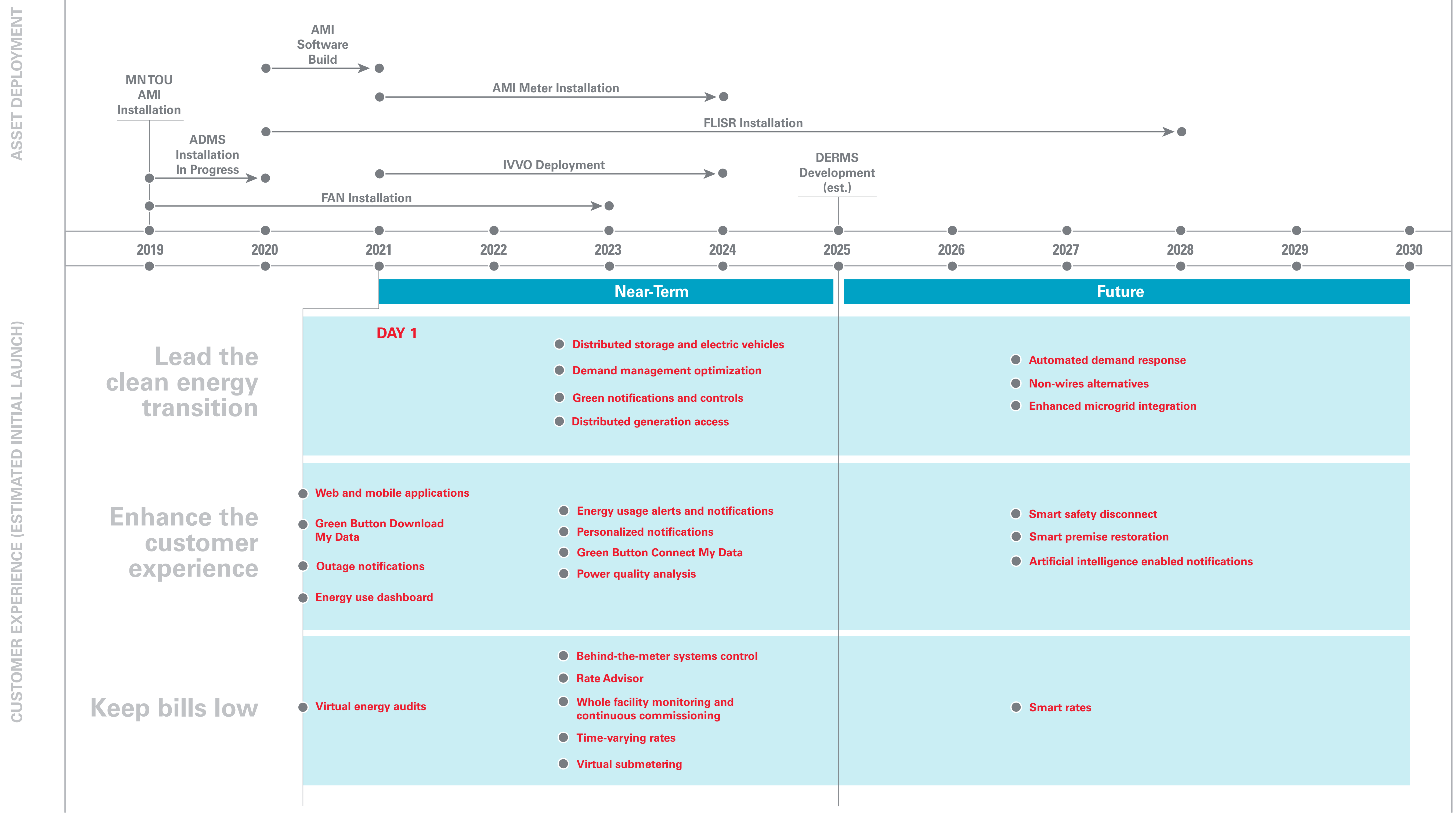
Northern States Power Company
AGIS Implementation and Customer Experience Timeline

AGIS IMPLEMENTATION & CUSTOMER EXPERIENCE TIMELINE



Northern States Power Company
AGIS Program Management Costs

Docket No. E002/GR-19-564
Exhibit___(MCG-1), Schedule 6
Page 1 of 2

AMI

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	TOTAL	NPV
Total Meters Deployed	*10,131*	*7,368*	*121,800*	*630,000*	*590,000*	*40,700*	*13,755*	*13,890*	*14,027*	*14,164*	*14,304*	*14,444*	*14,586*	*14,729*	*14,874*	*15,020*	*15,168*	***1,558,960***	
CAPITAL COSTS																		***TOTAL DISCOUNTED***	***NSPM-NPV***
Program Management																			
Change Management	0	1,000,000	1,035,500	1,072,260	1,110,325	1,149,742	1,190,558	0	0	0	0	0	0	0	0	0	0	**6,558,386**	**4,950,734**
Environment/Release Management	0	28,071	2,064,464	2,318,348	1,044,303	355,017	99,666	0	0	0	0	0	0	0	0	0	0	**5,909,870**	**4,617,070**
Finance	0	109,959	193,798	194,658	145,467	0	0	0	0	0	0	0	0	0	0	0	0	**643,882**	**516,017**
PMO	0	288,790	506,590	508,944	381,346	0	0	0	0	0	0	0	0	0	0	0	0	**1,685,670**	**1,350,955**
Security	0	1,105,737	1,144,991	1,185,638	1,227,728	0	0	0	0	0	0	0	0	0	0	0	0	**4,664,093**	**3,748,708**
Supply Chain	0	477,703	487,591	497,685	507,987	0	0	0	0	0	0	0	0	0	0	0	0	**1,970,966**	**1,585,917**
Talent Strategy	238,852	349,325	361,726	185,901	0	0	0	0	0	0	0	0	0	0	0	0	0	**1,135,803**	**977,689**
Delivery and Execution Leadership	0	374,158	1,294,786	1,314,010	667,319	0	0	0	0	0	0	0	0	0	0	0	0	**3,650,273**	**2,916,840**
Contingency	11,943	186,687	354,472	363,872	254,224	75,238	64,511	0	0	0	0	0	0	0	0	0	0	**1,310,947**	**1,033,197**
TOTAL - Program Management	***250,795***	***3,920,430***	***7,443,919***	***7,641,315***	***5,338,699***	***1,579,997***	***1,354,735***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***27,529,891***	***21,697,127***
TOTAL CAPITAL	**250,795**	**3,920,430**	**7,443,919**	**7,641,315**	**5,338,699**	**1,579,997**	**1,354,735**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**27,529,891**	**21,697,127**
O&M ITEMS																			
Program Management																			
Change Management	0	1,825,114	2,157,971	3,067,323	3,176,213	2,991,329	1,608,666	0	0	0	0	0	0	0	0	0	0	**14,826,616**	**11,214,681**
Environment/Release Management	0	0	22,405	23,200	24,024	24,877	11,794	0	0	0	0	0	0	0	0	0	0	**106,300**	**78,991**
Finance	0	32,456	112,027	167,045	216,218	0	0	0	0	0	0	0	0	0	0	0	0	**527,746**	**410,061**
PMO	0	79,772	275,346	410,574	531,437	0	0	0	0	0	0	0	0	0	0	0	0	**1,297,129**	**1,007,876**
Talent Strategy	37,760	58,651	60,733	0	55,000	0	0	0	0	0	0	0	0	0	0	0	0	**212,144**	**177,898**
Delivery and Execution Leadership	0	217,284	510,624	714,661	897,539	0	0	0	0	0	0	0	0	0	0	0	0	**2,340,109**	**1,829,448**
Contingency	1,888	110,664	156,955	219,140	245,022	150,810	81,023	0	0	0	0	0	0	0	0	0	0	**965,502**	**735,948**
TOTAL - Program Management	***39,648***	***2,323,940***	***3,296,060***	***4,601,944***	***5,145,453***	***3,167,016***	***1,701,483***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***20,275,545***	***15,454,901***
TOTAL O&M	**39,648**	**2,323,940**	**3,296,060**	**4,601,944**	**5,145,453**	**3,167,016**	**1,701,483**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**20,275,545**	**15,454,901**
GRAND TOTAL CAPITAL & O&M	**290,443**	**6,244,371**	**10,739,979**	**12,243,259**	**10,484,152**	**4,747,013**	**3,056,219**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**47,805,436**	**37,152,028**

Northern States Power Company
AGIS Program Management Costs

IVVO

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	TOTAL	NPV
Feeders enabled with IVVO	0	0	26	43	61	59	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**189**	
CAPITAL COSTS																						
Program Management																						
Organizational Change Management	0	0	468,823	850,715	651,244	553,937	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**2,524,720**	**1,909,732**
TOTAL - Program Management	***0***	***0***	***468,823***	***850,715***	***651,244***	***553,937***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***				***2,524,720***	**1,909,732**
TOTAL CAPITAL	**0**	**0**	**468,823**	**850,715**	**651,244**	**553,937**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**2,524,720**	**1,909,732**
O&M ITEMS																						
Business Program Management																						
Organizational Change Management	0	0	156,274	283,572	217,081	184,646	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**841,573**	**636,577**
TOTAL - Program Management	***0***	***0***	***156,274***	***283,572***	***217,081***	***184,646***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***841,573***	**636,577**
TOTAL O&M	**0**	**0**	**156,274**	**283,572**	**217,081**	**184,646**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**841,573**	**636,577**
GRAND TOTAL CAPITAL & O&M	**0**	**0**	**625,097**	**1,134,287**	**868,325**	**738,583**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**3,366,293**	**2,546,309**

Products and Services Enabled or Enhanced by AGIS

KEEP BILLS LOW

New Energy Saving Programs

Product or Service	Customers Affected	Timing
Virtual Energy Audits Provides an on-demand or periodic assessment of the energy usage/efficiency of a premise based on actual performance versus expected performance based on various parameters (i.e. size, year, build, occupancy, devices, etc.). With disaggregation and other analytics capabilities made possible by AMI, these audit results will improve over time to provide more accurate and relevant information. Audits may also be used to monitor the health and status of appliances to identify opportunities for customer to reduce maintenance costs and improve energy efficiency.	**Residential** **Small Business** **Large C&I**	Day 1
Whole Facility Monitoring C&I customers with long-term sustainability goals can more easily track progress at the whole facility and sub-system level through integrations between meters and customer-operated energy management systems. This information can be used to verify savings over time for the purposes of demand side management, or can be used to alert customers when demand or energy usage projections are expected to exceed threshold amounts over a given period of time.	**Small Business** **Large C&I**	Near Term
Enhanced Control Options for Behind the Meter Systems From the smart home to intelligent buildings, AMI meters will be able to communicate more seamlessly with devices and systems within the customer facility. Customers can use this capability to participate in demand response programs as well as to manage facility energy consumption in a more accurate and robust way.	**Residential** **Small Business** **Large C&I**	Near Term
Enhanced Automated Demand Response As the grid evolves, distribution system management can utilize expanded automated demand response capabilities which respond to real time needs of the distribution grid.	**Residential** **Small Business** **Large C&I**	Future

New rate options

Product or Service	Customers Affected	Timing
Rate Advisor With granular usage information and analytics capabilities made possible by AMI, the company will provide a multi-channel approach to educate customers and proactively offer ways to optimize energy usage and cost under existing and new, future rates schemes.	**Residential** **Small Business** **Large C&I**	Near Term
Time Varying Rates With more granular consumption data and more sophisticated meters, rate schedules can be created to better reflect the actual costs on the system at specific times of day. Customers can take advantage of these price signals to manage costs.	**Residential** **Small Business** **Large C&I**	Near Term
Virtual Submetering Instead of installing physical submeters, which are costly and take special wiring and their own communications channels, the main meter could act as a virtual submeter through disaggregation capabilities at the meter.	**Residential** **Small Business** **Large C&I**	Near Term
Smart Rates New rate opportunities including pre-pay and technology specific rates. Rates may rely on local management of the premise level grid or local identification of events. For example, when an EV is plugged in, this could be detected and an EV rate is automatically applied. Another example, would be a flat billing rate with use of the Premise Level Grid Management System (PLGMS) to stay within the agreed to usage levels.	**Residential** **Small Business** **Large C&I**	Future

ENHANCE THE CUSTOMER EXPERIENCE

Outage Enhancements

Product or Service	Customers Affected	Timing
Enhanced Outage Notifications More accurate alerts informing customers about outages in a timely, relevant way. These could include proactive messaging about an outage status, automatic restoration, and restoration confirmation.	Residential Small Business Large C&I	Day 1
Smart Premise Restoration Sequentially restore power to various devices inside the home or business after an outage to reduce the likelihood of voltage or overloading issues, protecting customer system performance as power is restored.	**Residential** **Small Business** **Large C&I**	Future

Integrated, seamless interactions

Product or Service	Customers Affected	Timing
Green Button Download My Data For customers who prefer to perform their own analysis or use their granular usage information for other purposes, data in the standard Green Button protocol will be made available through the Download My Data feature in the customer web portal.	**Residential** **Small Business** **Large C&I**	Day 1
Enhanced Web and Mobile Applications Customer account information along with options to view and pay bills, visualize energy usage and trends, and manage outages will be presented to customers in an integrated and highly personalized format. This is made possible by granular information and analytics as well as a robust customer preference center.	**Residential** **Small Business** **Large C&I**	Day 1
Energy Usage Dashboard Within the new web and mobile customer portals, energy usage dashboards will informs customer about the energy usage of both the overall facility as well as individual devices in a home or business. Compares data to a comprehensive database of similar products to alert to opportunities to save energy and money. Dashboards can be customized to both residential and C&I customer needs (e.g. multi-site data).	**Residential** **Small Business** **Large C&I**	Day 1
Energy Usage Alerts and Notifications Alerts allow customers to be notified with important information in a timely, relevant way. These could include high usage alerts, TOU peak period, Peak Day notification, or goal-based alerts.	**Residential** **Small Business** **Large C&I**	Near Term
Green Button Connect My Data For customers who would like to automatically transmit their usage information to third parties, Green Button Connect My Data will also be available in the customer web portal for ongoing automated transfers.	**Residential** **Small Business** **Large C&I**	Near Term
Personalized Notifications Communication systems will be enhanced to provide timely information to customers in a form that is personalized to their lifestyle and preferences.	**Residential** **Small Business** **Large C&I**	Near Term
Artificial Intelligence Enabled Notifications As artificial intelligence technologies mature and become widely adopted in the market, meters will have the ability to leverage these capabilities to provide heightened interactions which will be customized to the unique needs of each customer.	**Residential** **Small Business** **Large C&I**	Future

Safety & Reliability Enhancements

Product or Service	Customer Affected	Timing
Power Quality Analysis With detailed information collected by the meter relating to power delivery, customers can more accurately and frequently assess their power quality. Over time, analytics of the power quality information can help flag and diagnose potential power quality related items so that customers can proactively manage any possible issues.	**Residential** **Small Business** **Large C&I**	Near Term
Emergency and Safety Notifications The meter will be able to provide customers with emergency management notifications via its analytics and communications capabilities. This can help customers identify potential risks to their energy management systems, security monitoring, and be aware of local emergency notifications that may apply to their general safety and security.	**Residential** **Small Business** **Large C&I**	Near Term
Enhanced Microgrid Integration Where the capability exists for portions of the grid to operate independently of the rest of the surrounding system, the advanced distribution management system will more seamlessly be able to manage the connection of these microgrids.	**Residential** **Small Business** **Large C&I**	Future
Smart Safety Disconnect Detects when a smart inverter has malfunctioned or was improperly installed and has not disconnected from the grid when incoming power has been lost. In this situation, the disconnect inside the meter is automatically tripped to protect the rest of the grid and the customer.	**Residential** **Small Business** **Large C&I**	Future

LEAD THE CLEAN ENERGY TRANSITION

Product or Service	Customers Affected	Timing
Enhanced Access to Battery Storage and Electric Vehicles Through the enhanced visibility and control of the distribution system, greater utilization of storage elements on the grid, including electric batteries and electric vehicles, will be possible. This capability promises to help ensure safe, reliable energy for all customers.	**Residential** **Small Business** **Large C&I**	Near Term
Green Notifications and Controls Customers would be notified when the percentage of electricity generated by renewable services in their area exceeds a certain threshold.	**Residential** **Small Business** **Large C&I**	Near Term
Enhanced DER Enablement Through the enhanced visibility and control of the distribution system, customers will be able to integrate distributed generation resources more seamlessly and potentially at higher levels within a given area.	**Residential** **Small Business** **Large C&I**	Near Term
Demand Management Optimization With more granular consumption information, new demand management programs can be created to enable customers to shift and shed load to respond to needs of the grid on an increasingly real-time basis. With new communication capabilities, the meter will be able to communicate directly with smart devices within homes and businesses. As analytics such as disaggregation and virtual submetering evolve, demand response routines can increase sophistication through optimizing sequence among various demand response resources.	**Residential** **Small Business** **Large C&I**	Near Term

Advanced Grid Customer Education & Communications Plan

1 Summary and Customer Vision

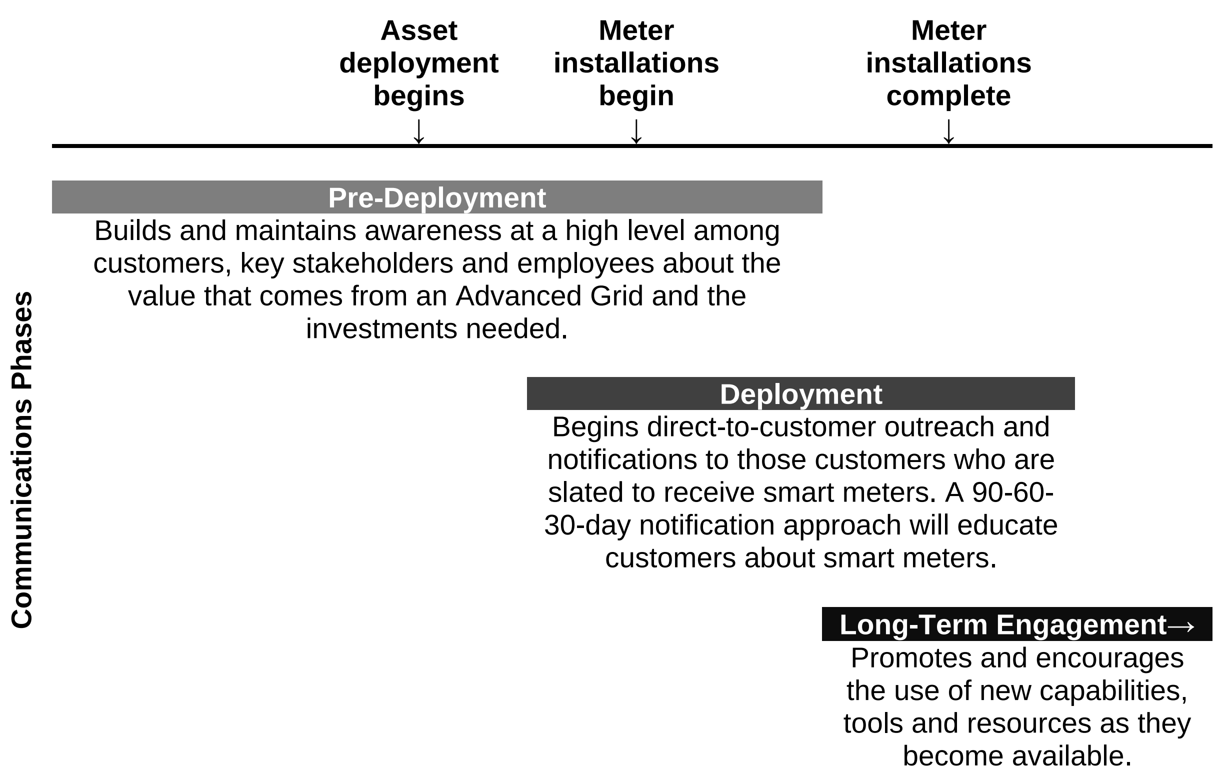
The electric utility industry is in a time of significant change. Increasing customer expectations and technological advances have reshaped what customers expect from their energy service provider, and how those services are delivered and communicated. Enhancing the customer experience is critically important, and is one of our three strategic priorities, along with leading the clean energy transition and keeping bills low. As outlined in the Advanced Grid Customer Strategy (Schedule 3), we plan to integrate modern customer experience strategies with advanced grid platforms and technologies to enable intelligent grid operations, smarter networks and meters, and optimized products and services for our customers.

This Customer Education & Communications Plan is an integral part of our customer experience transformation and Xcel Energy's Advanced Grid initiative.

2 Education and Communications Phases

Meter deployment and smart meter capabilities will be phased in over the next five-plus years. Communications strategies, messages and tactics will be executed in three phases to match the customer journey.

Figure 1. Communications phases



2.1 Pre-Deployment Phase – Advanced Grid Benefits

This phase builds and maintains awareness at a high level among customers, key stakeholders and employees about the value that comes from an Advanced Grid and the investments needed. Advanced Grid will be presented as one of the company's platforms for bringing innovative tech solutions to transforming the customer experience.

Key objectives during this phase include:

- Create customer and stakeholder awareness about the overall benefits of the advanced grid.
- Explain why we are making this investment, focusing on tangible customer benefits.
- Educate and train employees to equip them with tools and resources necessary to engage with customers and stakeholders.
- Build customer interest in the change by explaining the benefits of smart meters and the tools and options they enable.
- Proactively address customer concerns and questions.

2.1.1 Pre-Deployment Tactics

An integrated, expansive, and multi-channel awareness-building approach, as shown in Table 1, is required to set the stage for smart meter installation communication in the Deployment phase.

Table 1. Pre-deployment tactics

Audience	Messages	Channels	Materials
All customers	• Overview of Advanced Grid initiative • Intro to smart meters • Customer benefits • Privacy and security	• xcelenergy.com and blog • Email • Social media • Media outreach • Out of home advertising • Online and print advertising • Bill onserts • Community events and meetings	• Info sheets and brochures • Videos
Community leaders and elected officials	• Overview of Advanced Grid initiative • Intro to smart meters • Customer benefits • Deployment plans and processes • Privacy and security	• In-person meetings and discussions with Community Relations Managers • Community events and meetings • Email	• Presentations • Info sheets and brochures • Videos • Talking points
Customer Care agents	• Overview of Advanced Grid initiative • Intro to smart meters • Customer benefits • Deployment plans and processes • Privacy and security	• Web-based training • In-person training • Email • Customer Care Quick Reference program	• FAQs • Info sheets and brochures • Videos • Talking points
All employees	• Overview of Advanced Grid initiative • Intro to smart meters • Customer benefits • Deployment plans and processes • Privacy and security	• Intranet • Email • In-person meetings or presentations	• Internal news articles • Presentations • Info sheets and brochures • Videos • Talking points

2.1.2 Pre-Deployment Phase Success Metrics

We will measure customer awareness during this phase through existing measures of advertising/awareness campaign recall and through tracking and reporting of customer responses to the following statements:

- Communications on the advanced grid meter installation and initiative were clear and easy to understand.
- Communications encouraged me to seek additional information if needed.

2.2 Deployment Phase – Smart Meter Installation

This phase will begin direct-to-customer outreach and notifications to those customers who are slated to receive smart meters. A 90-60-30-day notification approach will educate target audiences on smart meters, how they will be deployed and installed, and on smart meter benefits. While messaging and content will focus on meter installation, all communications will speak to the broader value and benefits of the Advanced Grid.

This phase will also set the stage for the Long-Term communications phase by collecting customer information and preferences that can be used as new capabilities are enabled and to create deeper customer relationships.

Key objectives during this phase include:

- Provide practical and timely information and notifications about the deployment, installation and opt-out processes.
- Provide clear information on the opt-out process and associated costs, including how to take action.
- Leverage a messaging hierarchy to reiterate high-level benefits of advanced metering.
- Further develop tools and resources for employees to use during proactive discussions with customers and stakeholders.

2.2.1 Deployment Tactics

Most tactics in this phase will be hyper-targeted toward customers with practical information about smart meter deployment. Customers will receive notifications about their smart meters 90 days, 60 days, and 30 days prior to meter installation through various channels to ensure all customers receive adequate notification, as shown in Table 2 below. Where possible, materials will be personalized with the most relevant and up-to-date deployment information.

Table 2. 90-60-30-day communications approach

	90 days before meter install	**60 days before meter install**	**30 days before meter install**	**7 days before meter install**	**Day of install**	**Post-install**
All customers	Mailer: intro	Mailer: your meter is coming soon	Mailer: meter installation FAQs	Phone call: your meter is coming next week	Install technician door knock	Mailer: success or attempt
					Door hanger: success or attempt	
Opted-in customers (only customers who have opted into these channels will receive these notifications)	Email: what to expect during meter installation	Email: Your meter is coming soon	Email: Your meter is coming soon	Text notification		Email: success or attempt
			My Account banner: Your meter is coming this month	App push notification		My Account banner: success or attempt
Mass communication	Targeted online, print, and out of home advertising		Hyper-targeted social media advertising			
	Community outreach: meter install schedule by neighborhood, informational content about new meters					

Table 3 describes the 90-60-30-day communications and the additional tactics used during the deployment phase to ensure a consistent and useful customer experience.

Table 3. Deployment tactics

Audience	Messages	Channels	Materials
All customers	• Smart meter benefits • Meter installation logistics • Opt-out information • New tools and how to sign up for My Account • Low income protections	• Postcard/mailer (90 days) • Direct mailers and email if available(60 days and 30 days) • Phone call (7 days) • My Account • xcelenergy.com and blog • Targeted email • Targeted social media • Media outreach • Targeted online, print, and out of home advertising • Community events and meetings	• Mailings and emails • Info sheets and brochures • Educational videos • Door hangers • FAQs
Community leaders and elected officials	• Smart meter benefits • Meter installation logistics • Opt-out information • Specific meter deployment plans and schedules • Low income protections	• In-person meetings and discussions with Community Relations Managers • Community events and meetings • Email	• Presentations • Info sheets and brochures • Educational videos • Talking points • Deployment plans
Customer Care agents and Meter Installation Vendor	• Smart meter benefits • Meter installation logistics • Opt-out information • Specific meter deployment plans and schedules • Low income protections	• Web-based training • In-person training • Email • Customer Care Quick Reference program	• FAQs • Info sheets and brochures • Educational videos • Talking points • Deployment plans
All employees	• Smart meter benefits • New tools • Meter installation logistics	• Intranet • Email • In-person meetings or presentations	• Internal news articles • Presentations • Info sheets and brochures • Educational videos • Talking points

2.2.1.1 Pilot example communications

The Minnesota time of use pilot used a 90-60-30-day communication approach to support smart meter installations:

Figure 2. Minnesota pilot 60-day postcard

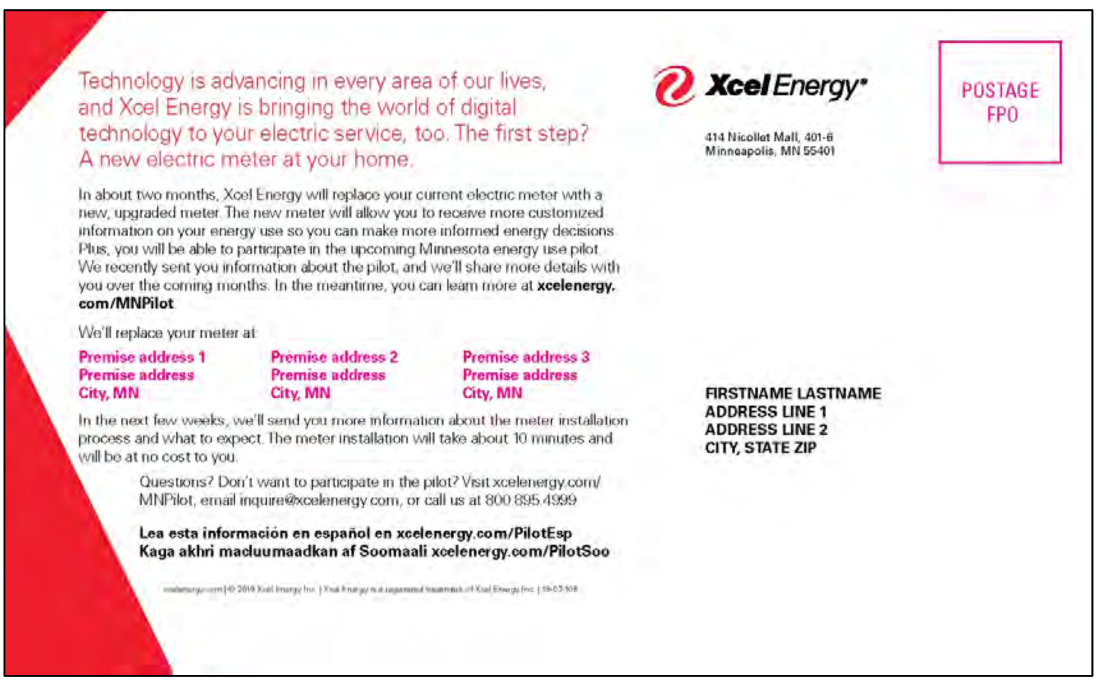


Figure 3. Minnesota pilot 30-day letter and meter FAQs

Xcel Energy

YOU'RE GETTING A
NEW ELECTRIC METER
IMPORTANT INFO INSIDE

414 Nicollet Mall
Minneapolis, MN 55401

IMPORTANT! Electric meter upgrades are coming soon to your neighborhood.

Sample A. Sample
Mailing Address 1
Mailing Address 2
City, MN ZIP-1234

In about 30 days, Xcel Energy will replace your existing electric meter with an upgraded meter. It is part of Xcel Energy's effort to build a smarter, more resilient energy grid that can better serve you for decades to come. The new meter will also allow you to participate in the upcoming Minnesota energy use pilot. We recently sent you information about the pilot, and we'll share more details with you in the coming months. In the meantime, you can learn more at **xcelenergy.com/MNPilot**.

Xcel Energy

What is different about my new meter?

Your new meter allows for two-way communication between your electric meter and Xcel Energy. The new meters will enable many benefits, including improved outage detection and response, future web tools to help you make more informed decisions about your energy use, and future programs and services to help you save energy and money.

How does the new meter work?

Compared to traditional meters, new electric meters have many benefits. Your current meter tells you and Xcel Energy how much electricity you're using, but it does not show **when** you're using electricity. The new meters measure your energy use every five minutes. This way you can see how much energy you use and when you use it. This information can help you better understand how you are using energy and help you make more informed decisions. Plus, these new meters will help us better manage the energy grid, reduce the need for added generation, and react to power outages more quickly.

What are the benefits of a new meter?

Your new meter and the larger advanced grid will enable…

2.2.2 Deployment Phase Success Metrics

To answer key questions and assess the overall effectiveness of our efforts, we will track and report customer responses to the following statements:

- Communications on the advanced grid meter installation and initiative were clear and easy to understand.
- Communications answered all of my questions about the meter installation.
- Communications encouraged me to seek additional information if needed.

2.3 Long-Term Engagement Phase – Tools and Resources

This phase will promote and encourage the use of new Advanced Grid capabilities, tools and resources as they become available. Communications will not only highlight the features of new tools and resources, but also the broader benefits they can provide. This phase will leverage customer information and preferences gathered in Phase II to provide a seamless experience for all customers via their preferred channels.

Key objectives during this phase include:

- Leverage a messaging hierarchy that reiterates high-level benefits of the project while educating customers on new capabilities, tools and resources as they become available.
- Develop and execute a customer nurturing campaign to follow the customer journey and encourage adoption of new capabilities, tools and resources.
- Evaluate and refine messages and tactics to continuously improve and ensure the best possible customer experience.

2.3.1 Long-Term Engagement Tactics

A multi-channel approach will reach customers via their preferred channels and include tailored messages to move them along in the engagement journey. Where possible, we will use available data to segment outreach about specific tools and resources. For example, a unique campaign could target only those customers who have not enrolled in My Account.

Table 4. Long-term engagement tactics

Audience	Messages	Channels	Materials
All customers	• New tools and how to use them or sign up for My Account • Savings tips and tricks • Testimonials and case studies	• xcelenergy.com and blog • Email • Direct mail • My Account • Social media • Media outreach • Bill onserts • Community events and meetings	• Mailings and emails • Info sheets and brochures • Instructional videos • Case studies • Savings tips
Community leaders and elected officials	• Customer benefits • Testimonials and case studies • Successes and results	• In-person meetings and discussions with Community Relations Managers • Community events and meetings • Email	• Presentations • Info sheets and brochures • Videos • Talking points
Customer Care agents	• New tools and how to use them or sign up for My Account • Savings tips and tricks	• Web-based training • In-person training • Email • Customer Care Quick Reference program	• FAQs • Info sheets and brochures • How-to videos • Talking points
All employees	• Customer benefits • Testimonials and case studies • Successes and results	• Intranet • Email • In-person meetings or presentations	• Internal news articles • Presentations • Info sheets and brochures • Videos • Talking points

2.3.2 Long-Term Phase Success Metrics

The success of long-term communications will largely be measured by the number of customers who enroll in optional programs and services. We will measure:

- The percentage of customers with a smart meter that have one or more active applications
- The percentage of customers with a smart meter that receive high usage alerts

- The percentage of customers with a smart meter that select pre-pay billing
- The number of customers with a smart meter that have My Account
- The number of monthly, unique visits to My Account
- The percentage of customers with a smart meter that access personalized insights

3 Best Practices and Research Results

To build on the company's experience with smart meter pilots and advanced grid technology initiatives through its service territory, Xcel Energy also has examined communication and outreach best practices among other utilities with advanced grid and smart meter deployment experience. We supplemented this research with insights from additional sources, such as the Smart Energy Consumer Collaborative and GTM Research.

Many of these best practices and lessons learned are outlined below, and they have been taken into consideration in the development of this communication plan.

- Treat advanced grid/smart meter implementation as a change management program for employees. Engage with employees throughout the lives of all activities and initiatives.
- Train employees to be ambassadors in the community and leverage employees' existing relationships and involvement in their communities to help disseminate important information. Aim for transparency and a high level of engagement between the customer and customer-facing employees.
- Educate customers before their smart meter deployment by staging communications ahead of key customer contact leading up to the actual installation.
- Use social media to approach smart meter installation as a new technology rollout across specific geographic locations and targeted customer segments.
- Focus communication directly on customers. Do not assume they understand the concept of kilowatt hours, how the utility measures electricity, on- versus off-peak usage, etc. Avoid industry terms and jargon and instead use simple language and a call to action that customers can easily understand.
- Set realistic expectations on smart meter functionality.
- Build an extensive set of FAQs to address issues and concerns. Through active employee change management and education, ensure front-line employees who work directly with customers use these messages and anticipate questions so they can clear up concerns and address issues in an accurate and timely manner.
- Collect customer success stories to make smart meter/advanced grid benefits tangible and understandable.
- Ensure full integration and coordination of field operations, communication/marketing, customer care, and billing.
- Identify customer concerns quickly, elevate to the appropriate level as needed, and resolve concerns swiftly.

3.1 Market Research Results

Xcel Energy has conducted qualitative customer research through focus groups in Minnesota and throughout its service territory.[1] The results of this research have informed message development and the strategic updates to this plan.

The objectives of research were to:

- Explore customers' current understanding of smart meters.
- Understand the perceived benefits and drawbacks of smart meters.
- Explore both positive and negative expectations consumers have about Xcel Energy moving customers to smart meters.
- Explore reactions to different ways of describing smart meters.
- Understand what barriers may arise and how to address them (pre- or post-meter installation).
- Understand how customers want to be communicated with about smart meters, including what they want to know and how they want to receive the information.
- Identify any differences between younger (under age 45) and older customers (45+) on these topics.

At a high level, the key findings of this research were:

Expectations of New Meters

- Customers believe the new meters could help them save money by providing more detailed usage information, which they perceive as empowering.
- That said, they have questions about the new meter's basic functionality that need to be addressed to convince them of the true utility in these devices.
- They are also concerned about possible out of pocket costs, with many wondering whether the new meters could either cost them money upfront or over the long-run.

Communicating the Change

- Customers want to hear from Xcel Energy about the transition to the new meters at least two or three months in advance of installation.
- They want to be contacted via a multi-channel approach, which would include paper mail, mass media, email and phone.
- Younger customers (<45) are more likely to say they would seek information on an FAQ page or watch an online video about the process.
- Overall, customers want the communications to have a high degree of transparency.

[1] Eight Minnesota focus groups were held April 16–17 and May 15–16, 2019. Four Colorado focus groups, held Jan. 22–23, 2019, also informed this plan. All focus group sessions were moderated by an independent third party consultant.

Addressing Barriers

- The potential cost of the new meters is the top barrier that Xcel Energy needs to address. Another way to address barriers is by clearly conveying the reasons why the new meters will benefit customers in the long-run, and by clearly presenting why the company is advancing this technology.

3.2 Customer Messaging and Development

Xcel Energy has developed a carefully constructed message framework using best practices and its own market research. This message framework is essential for successful completion of this plan and the overall transition to smart meters.

Xcel Energy typically develops messages using the following process:

Research

Market research lays the groundwork for message development, incorporating customer message testing, customer panels, focus groups, and utility peer research.

Understanding the Audience

While we will be raising awareness among all our Minnesota customers, smart meter messages will target specific customer market segments to ensure maximum effectiveness and tap into the benefits that customers care about the most.

Language and Tone

Messages will be developed using simple, straight-forward language and practical information that customers can easily understand and act upon. Xcel Energy has worked with its advertising agency of record – Carmichael Lynch – to explore and validate the language and terminology that resonates most with customers.

3.2.1 Overarching Messaging Themes: Customer Benefits & Value Propositions

Because of the significant investment other utilities have made in the advanced grid, consumers today are seeing the benefits. The Smart Energy Consumer Collaborative (SECC) is an independent nonprofit organization consisting of commercial, utility and advocacy organizations that collects information about customers' views and understanding of smart meters and grids. According to SECC's study titled *Effective Communication with Consumers on the Smart Grid Value Proposition*, three distinct value propositions of advanced grids have emerged:

Economic benefits: With more information on energy consumption and more choices about how and when they use energy via possible future rate options, consumers may be able to save money as a result of advanced grid-enabled programs and technologies.

> Example messaging theme: Smart meters and the smart grid provide superior energy usage information, which can help consumers save money by enabling them to better manage their electricity use.

Environmental benefits: The advanced grid enables the incorporation of greater amounts of renewable generation, gives customers more opportunities to make more environmentally conscious choices, and can also reduce the need to rely on fossil fuel generation.

> Example messaging theme: The smart grid helps reduce greenhouse gas emissions by making it easier to connect renewable energy sources to the electricity grid.

Reliability benefits: Grid-side intelligence offered by advanced grid technology can reduce the frequency and duration of outages while providing better information when outages do occur.

> Example messaging theme: A smart grid senses problems and reroutes power automatically. This prevents some outages and reduces the length of those that do occur. It strengthens the resiliency of the power network that serves you.

3.2.2 Sample Customer Messaging

Based on best practices and research results, the company has drafted sample customer messaging.

Elevator speech

Technology is advancing in every area of our lives, and Xcel Energy is bringing the world of digital technology to your electric service too. The next generation of our energy grid—the advanced grid — will help us serve you better. The advanced grid will give customers more of what they expect from Xcel Energy – clean, reliable energy, new ways to save money, and a better experience for you and all of our customers.

New technologies to help you save energy and money

- You will have more access to useful information about your household energy use, which can help you make informed energy decisions that save energy and money.

- You'll also have online tools to help understand your data and make decisions that will help save energy and money.
- In the future, the advanced grid will make it possible for you to choose pricing plans and energy savings options that work best for you.

Improved reliability and faster outage restoration

- New digital energy grid technologies will help us prevent outages to you and your neighbors and, in some cases, enable us to automatically reroute power to shorten any service interruptions.
- Advanced grid technologies can detect outages at your home or on the larger electric system, helping reduce the time you are without service.
- You'll receive quicker notifications when service is out and more accurate information on when power will be restored.

More options to protect the environment and use new technologies

- The advanced grid will help us provide you with even more clean energy because it will allow us to maximize the use of renewable energy sources such as solar, wind, and batteries.
- Energy use data in near real-time will give you the ability to choose how and when you use technology such as batteries and electric vehicles.

Security you can trust

- Energy use data will be securely transferred electronically from the smart meter, eliminating the need for manual meter reading or estimates, which also helps reduce costs.
- Protecting your data is extremely important to us. We use multiple layers of defense to ensure all data is secure and protected.

3.2.3 Addressing Concerns

Our communication materials will attempt to address key issues and possible smart meter concerns, including but not limited to:

- **Radio frequency (RF) emissions**. Smart meters emit low levels of electro- magnetic radiation through their RF communications. Xcel Energy will educate customers to alleviate unfounded concerns around health impacts and interference with other wireless devices.
- **Privacy and security**. The company will assure customers that we take their data privacy seriously by providing information about our data privacy policies. We will also clearly outline steps we take to protect customers' energy use information and personally identifiable information.
- **Accuracy**. Messages will also address the measurement accuracy of smart meters, and let customers know how to contact us if they have billing questions related to their meter readings. Call center agents will be trained to answer questions and assist customers.

- **Deployment expectations**. Communications will help make it easy for customers to properly identify our company employees and know what to expect when meter installers are working at their home or business. This includes special instructions for customers with medical conditions that may have equipment in their homes.
- **Opt-out policies**. The company will address opt-out policies for smart meter technology, and let customers know the proper channels for inquiring about available alternatives.

4 Customer Segments and Communications Considerations

Customers are interested in smart meters and functionality, but broad deployment will require the company to manage expectations and address customer concerns. Success requires the company to anticipate and respond to situations that could affect customers, stakeholders, or the community during smart meter deployment.

While individual customer issues will receive attention, Xcel Energy will also track issues on a broader scale. The company will actively monitor sources where customer issues or concerns may originate, including but not limited to:

- Customer care call centers (both residential and business inquiries)
- Inquiries to company executives, regional leaders, and front-line managers
- Inquiries to field and other employee personnel
- Xcel Energy Community Relations, Account Management, and State and Government Affairs teams
- Media relations
- Minnesota Public Utilities Commissioners and staff
- Community groups and consumer advocacy groups
- Letters, phone calls, social media posts, and emails from customers

We will use existing processes and procedures for handling issues escalated through our Customer Care team.

4.1 Commercial & Industrial Customers

We expect our broad awareness communications will be applicable to small C&I customers as well, but we will also provide customized 90, 60, and 30-day meter install notifications for those customers. The content of these communications will vary depending on the customer's current tariff to ensure they receive the most relevant information. Dedicated account managers for large C&I customers who will help ensure a smooth experience before, during, and after smart meter installation.

4.2 Fixed and Low-Income Customers

Customized communications will recognize and proactively address cost concerns among low-income households, seniors, and vulnerable customer populations. We will engage community leaders, influencers, and representatives of these communities in the development and deployment of our educational efforts. Messages will address how customers on fixed or limited budgets can take advantage of personal energy use information that may allow them to better manage their energy costs. Outreach will also focus on increasing these customers' participation rates in energy efficiency and conservation programs, and cross-marketing the state's energy assistance programs. Communication and education materials that could be customized for this segment of customers may include:

- FAQs and fact sheets to address specific concerns and needs.
- Talking points and scheduled briefings with consumer advocacy groups and nonprofit groups who serve these populations.
- Customized presentations for community relations staff to share with their community leaders.
- Outreach to organizations serving seniors, low-income, and other vulnerable customer segments, with an emphasis on providing ready-to-use materials that can be distributed via their communication channels, online resources, events, meetings, and social media platforms.

4.3 Non-English-Speaking Customers

The company's service area is expansive and includes a diverse audience spread across the state. According the U.S. Census Bureau's American Community Survey (ACS), in 2017, 11.3 percent of Minnesotans spoke a language other than English at home. Behind English, the most common language spoken at home is Spanish, with close to 200,000 speakers.[2] Spanish materials will be available on xcelenergy.com.

4.4 Customers with Life-Supporting Equipment

Prior to any direct communication regarding smart meter installation, the Contact Center will proactively reach out to customers who rely on life-supporting equipment in their homes. These customers will have the option to opt out of the smart meter, make an installation appointment or get a bridge installed to avoid a service interruption.

4.5 Communications Accessibility

The company has a number of options in place to assist customers and ensure accessibility for all.

- Deaf or hearing-impaired customers can dial 711 to be connected with the state transfer relay service. This service allows callers to communicate with text-telephone (TTY) users. This service is available 24.7 and is confidential.
- The company's Contact Center can make outbound calls using TTY technology.
- Any residential customer may request a large print bill statement.
- Customer emails and our website and online tools are constantly being improved to ensure accessibility.

[2] U.S. Census Bureau, 2013-2017 American Community Survey 5-Year Estimates, https://factfinder.census.gov/bkmk/table/1.0/en/ACS/17_5YR/B16001/0400000US27.

4.6 Customer Choice and Opting Out

The company believes customers should have the choice to opt out of receiving a smart meter. All direct customer communications will clearly overview all customer options and explain the steps required to decline initial installation of a smart meter or request to have their smart meter removed. Communications will include information about any costs associated with opting out of the smart meter.

5 Budget

The forecasted costs (**Table 5**) related to the execution of this plan total approximately $6.3 million. These estimates are based on actual expenses to date for the Minnesota time of use pilot and for meter deployment in our Colorado service territory. We also gathered additional estimates from vendors to inform the forecast of specific costs. This budget includes external resources and support for this program (i.e., goods and services), but does not include internal resources (i.e., communications personnel).

Table 5. Education & communications plan forecasted budget

Tactic	**Estimated cost per piece**	**Estimated cost for all MN customers**
90-day mailer	$0.90	$1,170,000.00
60-day postcard	$0.80	$1,040,000.00
30-day letter	$1.00	$1,300,000.00
Smart meter info sheet	$0.08	$104,000.00
Door hanger success	$0.40	$520,000.00
Door hanger sorry we missed you	$0.40	$520,000.00
Email	$0.00	$3,900.00
Targeted digital advertising		$25,000.00
Paid social		$85,000.00
Mass advertising		$350,000.00
Video production		$20,000.00
Home network/tools education mailer	$0.90	$1,170,000.00
Total	**$4.48**	**$6,307,900.00**

Northern States Power Company
AGIS Rate Impact Analysis

Docket No. E002/GR-19-564
Exhibit___(MCG-1), Schedule 9
Page 1 of 1

Annual Revenue Requirement
Summary of AGIS
2019-2024
($s)

	10364000	State of Minnesota Jurisdiction					
	Rate Analysis	2019	2020	2021	2022	2023	2024
1	Average Balances:						
2	Plant Investment	6,580,245	29,009,905	76,532,529	175,653,195	300,960,249	370,657,038
3	Depreciation Reserve	343,659	1,762,406	5,573,184	12,132,579	22,633,577	39,470,175
4	CWIP	6,077,959	4,923,865	10,920,662	11,207,715	4,295,266	1,139,888
5	Accumulated Deferred Taxes	215,274	1,186,806	3,367,552	7,591,449	13,587,298	18,886,510
6	Average Rate Base = line 2 - line 3 + line 4 - line 5	12,099,271	30,984,558	78,512,455	167,136,882	269,034,640	313,440,240
7							
8	Revenues:						
9	Interchange Agreement offset = -line 40 x line 52 x line 53	-	-	-	-	-	-
10							
11	Expenses:						
12	Book Depreciation	789,251	2,284,099	6,556,439	12,248,284	17,750,252	20,715,373
13	Annual Deferred Tax	429,201	1,513,864	2,847,628	5,600,166	6,391,532	4,206,892
14	ITC Flow Thru	-	-	-	-	-	-
15	Property Taxes	-	-	-	-	-	-
16	subtotal expense = lines 12 thru 15	1,218,453	3,797,963	9,404,067	17,848,450	24,141,784	24,922,265
17							
18	Tax Preference Items:						
19	Tax Depreciation & Removal Expense	2,312,376	7,589,079	16,657,950	32,098,686	40,379,438	35,533,814
20	Tax Credits (enter as negative)	-	-	-	-	-	-
21	Avoided Tax Interest	24,950	128,118	132,406	187,323	60,166	649
22		-	-	-	-	-	-
23	AFUDC	77,380	626,878	276,556	431,934	120,184	56,678
24							
25	Returns:						
26	Debt Return = line 6 x (line 44 + line 45)	251,665	647,577	1,640,910	3,526,588	5,972,569	7,021,061
27	Equity Return = line 6 x (line 46 + line 47)	652,151	1,660,772	4,208,268	8,958,537	14,420,257	16,863,085
28							
29	Tax Calculations:						
30	Equity Return = line 27	652,151	1,660,772	4,208,268	8,958,537	14,420,257	16,863,085
31	Taxable Expenses = lines 12 thru 14	1,218,453	3,797,963	9,404,067	17,848,450	24,141,784	24,922,265
32	plus Tax Additions = line 21	24,950	128,118	132,406	187,323	60,166	649
33	less Tax Deductions = (line 19 + line 23)	(2,389,756)	(8,215,957)	(16,934,506)	(32,530,620)	(40,499,622)	(35,590,492)
34	subtotal	(494,203)	(2,629,104)	(3,189,766)	(5,536,311)	(1,877,415)	6,195,507
35	Tax gross-up factor = t / (1-t) from line 50	0.403351	0.403351	0.403351	0.403351	0.403351	0.403351
36	Current Income Tax Requirement = line 34 x line 35	(199,337)	(1,060,452)	(1,286,596)	(2,233,078)	(757,258)	2,498,965
37	Tax Credit Revenue Requirement = line 20 x line 35 + line 20	-	-	-	-	-	-
38	Total Current Tax Revenue Requirement = line 36+ line 37	(199,337)	(1,060,452)	(1,286,596)	(2,233,078)	(757,258)	2,498,965
39							
40	Total Capital Revenue Requirements	1,845,551	4,418,982	13,690,093	27,668,564	43,657,168	51,248,699
41	= line 16 + line 26 + line 27 + line 38 - line 23 + line 9						
42	O&M Expense	1,077,012	5,996,154	16,923,400	14,264,833	13,185,267	12,340,661
43	Total Revenue Requirements	2,922,563	10,415,136	30,613,493	41,933,397	56,842,434	63,589,359

	Capital Structure	**Weighted Cost**	**Weighted Cost**	**Weighted Cost**	**Weighted Cost**	**Weighted Cost**	**Weighted Cost**
44	**Long Term Debt**	**2.0400%**	**2.0600%**	**2.0500%**	**2.0800%**	**2.2000%**	**2.2200%**
45	**Short Term Debt**	**0.0400%**	**0.0300%**	**0.0400%**	**0.0300%**	**0.0200%**	**0.0200%**
46	**Preferred Stock**	**0.0000%**	**0.0000%**	**0.0000%**	**0.0000%**	**0.0000%**	**0.0000%**
47	**Common Equity**	**5.3900%**	**5.3600%**	**5.3600%**	**5.3600%**	**5.3600%**	**5.3800%**
48	**Required Rate of Return**	**7.4700%**	**7.4500%**	**7.4500%**	**7.4700%**	**7.5800%**	**7.6200%**
49	**PT Rate**	**0.0000%**	**0.0000%**	**0.0000%**	**0.0000%**	**0.0000%**	**0.0000%**
50	**Tax Rate (MN)**	**28.7420%**	**28.7420%**	**28.7420%**	**28.7420%**	**28.7420%**	**28.7420%**
51	**NA**	**86.6960%**	**86.6960%**	**86.6960%**	**86.6960%**	**86.6960%**	**86.6960%**
52	**MN JUR Direct**	**100.0000%**	**100.0000%**	**100.0000%**	**100.0000%**	**100.0000%**	**100.0000%**
53	**IA Demand**	**100.0000%**	**100.0000%**	**100.0000%**	**100.0000%**	**100.0000%**	**100.0000%**

Northern States Power Company
Reference Case Rate Impact Analysis

Docket No. E002/GR-19-564
Exhibit___(MCG-1), Schedule 10
Page 1 of 1

Annual Revenue Requirement
Summary of AMR
2019-2024
($s)

10364000

	Rate Analysis	2019	2020	2021	2022	2023	2024
				State of Minnesota Jurisdiction			
1	Average Balances:						
2	Plant Investment	-	-	16,069,221	63,779,109	126,994,134	172,463,867
3	Depreciation Reserve	-	-	(273,703)	358,641	4,319,457	8,264,698
4	CWIP	434,960	2,162,643	1,727,683	-	-	-
5	Accumulated Deferred Taxes	-	-	250,835	1,135,177	2,495,094	3,662,003
6	Average Rate Base = line 2 - line 3 + line 4 - line 5	434,960	2,162,643	17,819,771	62,285,292	120,179,582	160,537,166
7							
8	Revenues:						
9	Interchange Agreement offset = -line 40 x line 52 x line 53	-	-	-	-	-	-
10							
11	Expenses:						
12	Book Depreciation	-	-	964,592	3,828,093	7,621,538	10,348,936
13	Annual Deferred Tax	-	-	501,671	1,267,010	1,452,827	880,989
14	ITC Flow Thru	-	-	-	-	-	-
15	Property Taxes	-	-	-	-	-	-
16	subtotal expense = lines 12 thru 15	-	-	1,466,263	5,095,104	9,074,365	11,229,924
17							
18	Tax Preference Items:						
19	Tax Depreciation & Removal Expense	-	-	2,747,099	8,329,070	12,780,553	13,473,681
20	Tax Credits (enter as negative)	-	-	-	-	-	-
21	Avoided Tax Interest	17,140	83,696	-	-	-	-
22							
23	AFUDC	26,243	145,389	-	-	-	-
24							
25	Returns:						
26	Debt Return = line 6 x (line 44 + line 45)	9,047	45,199	372,433	1,314,220	2,667,987	3,596,033
27	Equity Return = line 6 x (line 46 + line 47)	23,444	115,918	955,140	3,338,492	6,441,626	8,636,900
28							
29	Tax Calculations:						
30	Equity Return = line 27	23,444	115,918	955,140	3,338,492	6,441,626	8,636,900
31	Taxable Expenses = lines 12 thru 14	-	-	1,466,263	5,095,104	9,074,365	11,229,924
32	plus Tax Additions = line 21	17,140	83,696	-	-	-	-
33	less Tax Deductions = (line 19 + line 23)	(26,243)	(145,389)	(2,747,099)	(8,329,070)	(12,780,553)	(13,473,681)
34	subtotal	14,341	54,225	(325,697)	104,525	2,735,438	6,393,144
35	Tax gross-up factor = t / (1-t) from line 50	0.403351	0.403351	0.403351	0.403351	0.403351	0.403351
36	Current Income Tax Requirement = line 34 x line 35	5,784	21,872	(131,370)	42,160	1,103,342	2,578,682
37	Tax Credit Revenue Requirement = line 20 x line 35 + line 20	-	-	-	-	-	-
38	Total Current Tax Revenue Requirement = line 36+ line 37	5,784	21,872	(131,370)	42,160	1,103,342	2,578,682
39							
40	Total Capital Revenue Requirements	12,033	37,600	2,662,466	9,789,975	19,287,319	26,041,539
41	= line 16 + line 26 + line 27 + line 38 - line 23 + line 9						
42	O&M Expense	1,868	73,380	903,542	2,005,631	2,987,832	2,807,656
43	Total Revenue Requirements	13,901	110,980	3,566,008	11,795,606	22,275,151	28,849,194

	Capital Structure	Weighted Cost	Weighted Cost	Weighted Cost	Weighted Cost	Weighted Cost	Weighted Cost
44	**Long Term Debt**	**2.0400%**	**2.0600%**	**2.0500%**	**2.0800%**	**2.2000%**	**2.2200%**
45	**Short Term Debt**	**0.0400%**	**0.0300%**	**0.0400%**	**0.0300%**	**0.0200%**	**0.0200%**
46	**Preferred Stock**	**0.0000%**	**0.0000%**	**0.0000%**	**0.0000%**	**0.0000%**	**0.0000%**
47	**Common Equity**	**5.3900%**	**5.3600%**	**5.3600%**	**5.3600%**	**5.3600%**	**5.3800%**
48	**Required Rate of Return**	**7.4700%**	**7.4500%**	**7.4500%**	**7.4700%**	**7.5800%**	**7.6200%**
49	**PT Rate**	**0.0000%**	**0.0000%**	**0.0000%**	**0.0000%**	**0.0000%**	**0.0000%**
50	**Tax Rate (MN)**	**28.7420%**	**28.7420%**	**28.7420%**	**28.7420%**	**28.7420%**	**28.7420%**
51	**NA**	**86.6960%**	**86.6960%**	**86.6960%**	**86.6960%**	**86.6960%**	**86.6960%**
52	**MN JUR Direct**	**100.0000%**	**100.0000%**	**100.0000%**	**100.0000%**	**100.0000%**	**100.0000%**
53	**IA Demand**	**100.0000%**	**100.0000%**	**100.0000%**	**100.0000%**	**100.0000%**	**100.0000%**

AGIS Progress Metrics Summary

Proposed Reporting Annually May 1

First AGIS Report May 1, 2022

	Description	AGIS Report (Service Quality potential impacts and reporting noted)
Customer Outreach and Education	Survey results of customers on the adequacy and clarity of communications prior to installation of advanced meters.	AGIS
Installation and Deployment	Number of advanced meters installed.	AGIS
	Percentage of FAN deployed.	AGIS
	Number of feeders with FLISR enabled.	AGIS
	Number of feeders with IVVO enabled.	AGIS
	Number of customers electing to opt-out of AMI installation.	AGIS
	Number of calls to Customer Contact Center and meter installation vendor regarding meter installation.	AGIS / SQ
	Number of complaints regarding AMI installation.	AGIS / SQ
Post-Deployment	Avoided Customer Minutes Out due to FLISR installation.	AGIS / SQ
	Energy Reduction (MWh) due to IVVO that result in cost savings and CO_2 emissions reduction.	AGIS
	Percentage of customers with advanced meters that receive estimated bills.	AGIS / SQ
	Percentage of customers with an advanced meter that have made a complaint of inaccurate meter readings.	AGIS / SQ
	Survey of customer satisfaction with outage related communications.	AGIS
	Number of customers with an advanced meter with an active web portal account.	AGIS
	Number of monthly, unique visits to the web portal (My Account).	AGIS

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Direct Testimony and Schedules
Kelly A. Bloch

Before the Minnesota Public Utilities Commission
State of Minnesota

In the Matter of the Application of Northern States Power Company
for Authority to Increase Rates for Electric Service in Minnesota

Docket No. E002/GR-19-564
Exhibit___(KAB-1)

Distribution

November 1, 2019

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Schedules

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I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND OCCUPATION.

A. My name is Kelly A. Bloch. I am the Regional Vice President, Distribution Operations for Xcel Energy Services Inc. (XES), the service company affiliate of Northern States Power Company, a Minnesota corporation (NSPM) and an operating company of Xcel Energy Inc. (Xcel Energy).

Q. PLEASE SUMMARIZE YOUR QUALIFICATIONS AND EXPERIENCE.

A. I have over 28 years of experience in the utility industry. I joined Public Service Company of Colorado, another operating company of Xcel Energy, in 1991 and have served in various engineering roles since that time. In my current role, I am responsible for the electric and natural gas distribution design and construction activities for the Company's service areas in the states of Minnesota, North Dakota, South Dakota, Michigan, and Wisconsin. My resume is attached as Exhibit___(KAB-1), Schedule 1.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. I present and support the Company's capital and operations and maintenance (O&M) budgets for the Distribution business area, for purposes of determining electric revenue requirements and final rates in this proceeding. I also support the Company's Advanced Grid Intelligence and Security (AGIS) Initiative, which is a portfolio of grid modernization investments to improve reliability, shorten the duration of power outages, integrate renewables, and empower customers with more information to control and track their energy use. I further discuss the assumptions used in the Company's Minimum System Study and Zero Intercept Analysis, provide information regarding the

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cost savings achieved from the LED street light conversion project, and discuss methods to measure losses on the distribution system.

Q. PLEASE PROVIDE A SUMMARY OF YOUR TESTIMONY.

A. The Distribution organization is responsible for operating, maintaining, and constructing the distribution system that is the critical final link in delivering electricity to our customers to power their homes and businesses.

Traditionally, much of Distribution's investments and efforts have been focused on maintaining the reliability, resiliency, and health of our existing distribution facilities. We regularly evaluate the health of the key components of our distribution system and make the necessary investments to ensure these facilities are safe and reliable. This includes replacing aging poles, wires, underground cables, and substation transformers. Throughout the term of this multi-year rate plan, we are continuing and increasing our investments in these established asset health and reliability programs.

At the same time, we are placing greater focus on the portion of our system that is closest to our customers, including tap lines and the secondary system. To better address the needs of this portion of our system we will launch the Incremental System Investment (ISI) Initiative in 2021. The ISI Initiative will expand some of our existing programs, such as our cable replacement program, as well as adding new programs, such as a targeted undergrounding program. This initiative would provide several benefits to customers including making our system more resilient and reliable, reducing O&M, and enabling increased adoption of distributed energy resources (DER). It will also improve safety for both our workers and our customers.

While our traditional areas of investment are important to maintaining the reliability and condition of the basic elements of our system, the electric industry is also undergoing a fundamental change. As aging distribution infrastructure approaches the end of its useful life, emerging technologies promise enhanced functionalities and operational efficiencies. Technological and manufacturing advances have also driven down the costs of solar panels and electric vehicles placing them within the reach of the average customer. The pervasive nature of electronics in our society and the unlimited access to data that they provide has further elicited changes in customer expectations.

Our current investment in our distribution facilities has not kept pace with these technological advances or our customers' demands. Our current distribution system was designed to facilitate a basic one-way flow of both electricity and information, with limited monitoring points beyond the substation. As a result, we have limited insight into our customers' energy experience. This limits our ability to timely respond to outages as in many outage situations we rely on customers calling to let us know their power is out. We are also unable to provide timely energy use information to customers or to detect voltage issues absent a customer complaint. The majority of our current distribution system lacks intelligent and automated devices that would facilitate a quicker response to outages on the system. Our electric system is also not equipped to accommodate the amount of distributed generation and electric vehicle charging that is anticipated in the coming years.

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We have begun to address these limitations and transition to an advanced grid by taking a strategic building block approach. We have focused first on foundational elements that are needed to support fundamental applications. For example, we are in the process of implementing an Advanced Distribution Management System (ADMS). The ADMS is foundational to advanced grid capabilities that will provide visibility and control necessary for enhanced distribution planning and DER integration. We are also in the process of implementing a residential Time of Use (TOU) pilot (TOU pilot), as well as installing Advanced Metering Infrastructure (AMI) meters and two-way communication via a Field Area Network (FAN) in a limited area of the Twin Cities metro.

Now is the time to take the next major step towards an advanced grid. During the term of the multi-year rate plan, we propose to implement further elements of the Company's AGIS initiative including a full AMI and FAN implementation across our service territory, a targeted installation of Integrated Volt VAr Optimization (IVVO) for voltage monitoring and control, and Fault Location, Isolation, and Service Restoration (FLISR), for improved reliability.

It is an opportune time to make these investments as our current Automated Meter Reading (AMR) meters that have served our customers since the 1990s are at the end of their service contract and will no longer be supported by the vendor past the mid-2020s. In addition, AMI technology has advanced to the point where the technology has been well-tested by other utilities, and its two-way communication and command capabilities will provide multiple benefits for our customers and our operation of the grid.

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With this background, my Direct Testimony starts by describing the workings of the Distribution organization and the services that we provide to our customers. I will identify the key categories of capital investments undertaken by Distribution and describe how the Distribution business area prepares and manages its capital budget. I explain that we are proposing capital additions of approximately $235.3 million for 2020, $350.0 million for 2021, and $463.1 million for 2022 on a State of Minnesota Electric Jurisdiction basis. These capital additions are spread across investments in our traditional budget groupings of Asset Health and Reliability, New Business, Capacity, Mandates, and Tools and Equipment. I provide information about the key capital projects in each of these categories over the term of the multi-year rate plan.

I also discuss the Distribution O&M budgets for 2020 to 2022, which are driven by internal and contract labor costs, fleet, and materials. I also explain why our O&M budgets are reasonable and reflects expenditures that are needed to ensure that our distribution system is safe and reliable.

Next, I discuss Distribution's key role in implementing the AGIS initiative that includes installing the new AMI meters, FAN devices, FLISR devices, and IVVO devices that are necessary to achieving the goals of a more advanced, intelligent, and automated distribution grid. My testimony on AGIS complements that of Company witness Mr. Michael C. Gersack who provides the policy goals of AGIS and that of Mr. David C. Harkness who describes that integration of the AGIS components into the Company's existing systems.

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In addition, I address the Company's Electric Vehicle (EV) programs, and discuss the EV capital and O&M expenses included under the Distribution budget for 2020 to 2022. Further, I provide information regarding the cost and cost savings related to the Light Emitting Diode (LED) street light conversion project. I then provide information supporting the assumptions used in the Company's Minimum System Study and Zero Intercept Analysis. Finally, I discuss methods to determine electric losses on the distribution system.

Q. HOW HAVE YOU ORGANIZED YOUR TESTIMONY?

A. My testimony is organized into the following sections:

- *Section I* – Introduction
- *Section II* – Distribution Overview
- *Section III* – Capital Investments
- *Section IV* – O&M Budget
- *Section V* – AGIS Initiative
- *Section VI* – Electric Vehicle Programs
- *Section VII* – LED Street Lights
- *Section VIII* – Minimum System Study and Zero Intercept Analysis
- *Section IX* – Distribution System Losses
- *Section X* – Conclusion

Only the testimony necessary to support the Company's Advanced Grid Intelligence and Security (AGIS) Initiative have been included in the Integrated Distribution Plan (IDP) filing. Accordingly, we have excised non-AGIS pages from this attachment.

V. AGIS INITIATIVE

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A. This section of my testimony is focused on describing the work that the Distribution organization will be completing as part of the Company's AGIS initiative. The AGIS initiative is a multi-year project that will transform our distribution system into an intelligent and highly automated system. Our vision for this future distribution system is one that incorporates and leverages technology throughout our system to gather and utilize data to better meet our customers' electric needs and enable increased levels of DER.

Q. HOW IS THIS SECTION OF YOUR TESTIMONY ORGANIZED?

A. First, I will provide an overview of the AGIS initiative and the different components of this initiative. I will also describe the current limitations of the distribution system and how these limitations are, in part, driving the need for the AGIS initiative. Specifically, there is a need to bring our electric distribution system in line with current technologies to improve management and operation of the distribution system, support increasing DER, and to keep pace with our peers in terms of reliability performance.

Next, I will discuss in detail the four AGIS components that the Company is seeking recovery for in this rate case: (1) AMI; (2) FAN; (3) FLISR; and (4) IVVO and describe the work that the Distribution organization is undertaking to install these components. I also provide detailed support for recovery of both the capital and O&M costs associated with this work during the term of the multi-year rate plan. As discussed by Mr. Gersack, the Company is requesting approval to recover the costs of the capital investments and O&M

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expense for the components of AGIS that we propose to implement during the term of the multi-year rate plan, and is also requesting that the Commission certify these projects so the Company may request recovery of costs for 2023 and later in subsequent rider filings (subject to all other requirements of rider recovery). Accordingly, while I focus this discussion somewhat on the term of the multi-year rate plan, I also provide support for the Distribution portions of the broader AGIS initiative, consistent with the Company's Integrated Distribution Plan (IDP) being filed concurrently with this rate case.

Finally, I provide support for the cost estimates and benefit calculations utilized in cost-benefit analysis (CBA) model presented in the Direct Testimony of Company witness Dr. Ravikrishna Duggirala. My testimony is organized by the following topic areas. I note that a detailed discussion of FAN is provided by Mr. Harkness.

- <u>Overview of AGIS</u>
- <u>Limitations of Current Distribution System</u>
- <u>Grid Modernization Efforts to Date</u>
  - ADMS
  - TOU pilot
- <u>AMI</u>
  - Overview of AMI
  - Interrelation of AMI with other AGIS components
  - AMI Implementation
  - Benefits of AMI

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- Distribution's Costs of AMI
- Alternatives to AMI
- Interoperability
- Minimization of Risk of Obsolesce

- <u>FAN</u>
  - Overview of FAN
  - FAN Implementation
  - Distribution's Costs of FAN
- <u>FLISR</u>
  - Overview of FLISR
  - Prior Certification Request for FLISR
  - FLISR Implementation
  - Benefits of FLISR
  - Costs of FLISR
  - Alternatives to FLISR
  - Interoperability
  - Minimization of Risk of Obsolescence
- <u>IVVO</u>
  - Overview of IVVO
  - Interrelation of IVVO with other AGIS Components
  - IVVO Implementation
  - Benefits of IVVO
  - Costs of IVVO
  - Alternatives to IVVO
  - Interoperability

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- Minimization of Risk of Obsolescence

- AGIS Distribution Overall Costs and Implementation

Q. WHAT OTHER COMPANY WITNESSES ARE DISCUSSING THE AGIS INITIATIVE?

A. Mr. Gersack provides an overview of and policy support for the Company's AGIS initiative and certain Program Management costs. Specific information on the IT integration and cyber security support for AGIS is provided by Mr. Harkness. Company witness Mr. Christopher C. Cardenas provides information on how AGIS impacts Customer Care, including the Company's existing meter contract and how AGIS will impact meter reading, customer billing, and the Company's plan for customers selecting to opt-out of AMI meters. The cost-benefit analysis (CBA) model prepared by the Company is discussed by Dr. Duggirala.

A. Overview of AGIS

Q. WHAT IS THE AGIS INITIATIVE?

A. The AGIS initiative is a comprehensive plan to advance Xcel Energy's distribution system. This modernization will start with implementing foundational advanced grid initiatives that provide immediate benefits for customers while also enabling future systems and capabilities. AGIS will help to bring about an intelligent, automated, and interactive electric distribution system that will allow operators more visibility into the system, customers greater access to timely energy information, and enable future products and services for our customers.

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Q. WHAT ARE THE FOUNDATIONAL COMPONENTS OF AGIS?

A. The foundational components of AGIS are the Advanced Distribution Management System (ADMS), including the Geospatial Information System (GIS); Advanced Metering Infrastructure (AMI); the Field Area Network (FAN); Fault Location Isolation and Service Restoration (FLISR); and Integrated Volt-VAr Optimization (IVVO).

Q. PLEASE BRIEFLY DESCRIBE EACH OF THESE FOUNDATIONAL COMPONENTS.

A. A brief description of these foundational components is as follows:

- *Advanced Distribution Management System (ADMS)* provides the foundational system for operational hardware and software applications. It acts as a centralized decision support system that assists control room personnel, field operating personnel, and engineers with the monitoring, control and optimization of the electric distribution grid. The ADMS project includes investment to significantly improve the Company's existing Geospatial Information System (GIS), which is a foundational data repository, with data necessary to support the ADMS. ADMS uses this information to maintain the as-operated electrical model and advanced applications.
- *Advanced Meter Infrastructure (AMI)* is an integrated system of advanced meters, communication networks, and data processing and management systems that enables secure two-way communication between Xcel Energy's business and operational data systems and customer meters. AMI provides a central source of information that is shared through the communications network with many components of an intelligent grid design.

- *Field Area Network (FAN)* is the communications network that will enable communications between the existing communications infrastructure at the Company's substations, ADMS, AMI, and the new intelligent field devices associated with advanced grid applications.
- *Fault Location Isolation and Service Restoration (FLISR)* involves software and automated switching devices as an additional component of the ADMS, that reduce the frequency and duration of customer outages. These automated switching devices detect feeder mainline faults, isolate the fault by opening section switches, and restore power to unfaulted sections by closing tie switches to adjacent feeders as necessary.
- *Integrated Volt-VAr Optimization (IVVO)* is an additional application within ADMS, which automates and optimizes the operation of the distribution voltage regulating and VAr control devices to reduce electrical losses, electrical demand, energy consumption, and provides increased distribution system capacity to host DER.

Q. HAS THE COMPANY SOUGHT AND RECEIVED COMMISSION APPROVAL FOR ANY OF ITS GRID MODERNIZATION INVESTMENTS?

A. Yes, two advanced grid investments have been certified in the Company's biennial grid modernization reports. In the 2015 Biennial Grid Modernization Report, the Company sought certification of its proposed ADMS investments, which was subsequently certified by the Commission on June 28, 2016 for cost recovery under the TCR Rider.[6] The implementation of ADMS is currently on track to be completed in April 2020. The Company is not seeking cost recovery for ADMS in this case as these costs will remain in the

[6] *In the Matter of the Xcel Energy's 2015 Biennial Distribution Grid Modernization Report*, Docket No. E002/M-15-962, ORDER CERTIFYING ADVANCED DISTRIBUTION MANAGEMENT SYSTEM (ADMS) PROJECT UNDER MINN. STAT. 216B.2425 AND REQUIRING DISTRIBUTION STUDY (June 28, 2016).

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TCR Rider. I discuss ADMS here as it is a foundational component of the AGIS initiative and this background is helpful to understanding how other AGIS components operate in conjunction with ADMS.

In addition, the Company sought and obtained Commission certification for a proposed TOU pilot on August 7, 2018.[7] The TOU pilot requires the installation of AMI meters and associated FAN components to provide customers with pricing specific to the time of day energy is used. The Company proposes TOU Pilot costs incurred during the MYRP be included in base rates. I discuss Distribution's support for these costs below.

Q. WHAT ACTIVITIES WILL THE DISTRIBUTION BUSINESS UNIT PERFORM TO IMPLEMENT AGIS?

A. There are three primary functions that Distribution will perform to implement the AGIS initiative:

- *Installation*: At a high level, Distribution will be responsible for installing and configuring the field devices such as the AMI meters, reclosers, capacitors, sensors, and communications equipment to implement AMI, FAN, FLISR, and IVVO.
- *Operation*: Distribution will also operate the ADMS and its applications such as FLISR and IVVO. Specifically, Distribution operates the associated equipment for these applications, such as switches, reclosers, and capacitors. The Distribution Control Center will be the primary users, with the newly created Grid Management team ensuring its accuracy, availability, and effectiveness. Our Grid Management team

[7] *In the Matter of Xcel Energy's Residential Time of Use Rate Design Pilot Program*, Docket No. E002/M-17-775, ORDER APPROVING PILOT PROGRAM, SETTING REPORTING REQUIREMENTS, AND DENYING CERTIFICATION REQUEST (Aug. 7, 2018).

will monitor system performance and data integrity to ensure the improvements made to GIS data continue to provide accurate ADMS solutions.

- *Maintenance*: The Distribution Business unit will provide maintenance for the field-based equipment. When possible, maintenance activities such as firmware upgrades will be performed remotely. We note that several types of equipment reside on poles in the "power zone," and require the specialized skills of qualified line workers to access.

Q. WHICH COMPONENTS OF AGIS WILL YOU DISCUSS IN YOUR TESTIMONY?

A. The capital and O&M investments for AGIS are divided between Distribution and Business Systems. I provide primary support for the costs and implementation related to the AMI meters, procurement and installation of pole-mounted FAN devices, and the procurement and installation of the intelligent field devices required for FLISR and IVVO.

As explained by Mr. Harkness, Business Systems has primary responsibility for the IT infrastructure and IT services that will integrate the various components of the AGIS to allow these new application and field devices to communicate with and deliver data to the Company's existing applications. Mr. Harkness will also discuss the cyber security measures that the Company will implement to protect the advanced distribution network as well as the underlying data that it gathers. Table 29 below summarizes which witness support the specific components of the AGIS initiative.

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Table 29

AGIS Program Witness Support

AGIS Program	Component	Witness
AMI	IT Integration and head end application	Harkness Direct, Section V(E)(3)
	Meters and deployment	Bloch Direct, Section V(D)
FAN	IT Integration and deployment	Harkness Direct, Section V(E)(4)
	Installation of pole-mounted devices	Bloch Direct, Section V(E)
FLISR	System development	Harkness Direct, Section V(E)(5)
	Advanced application and field devices	Bloch Direct, Section V(F)
IVVO	System development	Harkness Direct, Section V(E)(6)
	Advanced application and field devices	Bloch Direct, Section V(G)

Q. CAN YOU PROVIDE AN OVERVIEW OF THE DEPLOYMENT TIMELINE FOR THE AGIS COMPONENTS?

A. Table 30 below provides an overview of the deployment timeline of the various AGIS components. I provide more detailed timelines below as part of my discussion of each individual AGIS component.

Table 30

AGIS Foundational Program	Anticipated Deployment Timeline
AMI	AMI Meter install for TOU pilot: 2019-2020 AMI Meter install for Mass Deployment: 2021-2024
FAN	FAN installation for TOU pilot: 2019-2020 FAN installation for AMI mass deployment: 2020-2023
FLISR	Limited testing in 2020; FLISR device install: 2020-2028
IVVO	Limited testing in 2021; IVVO device install: 2021-2024

Q. HOW ARE AGIS COSTS PRESENTED IN YOUR TESTIMONY?

A. The AGIS costs presented in my testimony are provided at either the NSPM Total Company electric level or the Minnesota electric jurisdiction level. This differs from cost presentation in the non-AGIS sections of my testimony, where all Distribution costs are presented at the Minnesota electric jurisdiction level. The reason for this difference within my testimony is that we wanted to present AGIS costs consistently across the various pieces of AGIS testimony. The heading for each cost table states how costs are being presented.

Q. WHAT TYPES OF CAPITAL COSTS IS DISTRIBUTION INCURRING TO IMPLEMENT THE AGIS INITIATIVE?

A. The capital costs for Distribution to implement each of the AGIS programs (AMI, FAN, FLISR, and IVVO) generally include material and equipment, labor, and vendor services.

Q. WHAT ARE THE DISTRIBUTION CAPITAL COSTS FOR THE AGIS INITIATIVE THAT YOU ARE SUPPORTING IN THIS CASE?

A. Distribution's AGIS capital additions I am supporting in this rate case are shown in the following table.

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Table 31

AGIS Capital Additions – Distribution State of MN Electric Jurisdiction (Includes AFUDC) (Dollars in Millions)			
AGIS Program	**2020**	**2021**	**2022**
AMI	$1.8	$22.2	$110.9
FAN	$2.8	$5.4	$0.0
FLISR	$3.1	$8.0	$5.8
IVVO	$0.0	$4.1	$6.7
Total	**$7.7**	**$39.7**	**$123.4**
There may be differences between the sum of the individual AGIS program amounts and Total amounts due to rounding.			

These AGIS capital additions are also set forth in Exhibit___(KAB-1), Schedule 2 to my Direct Testimony. I provide additional details and support for Distribution's capital costs below, organized by AGIS component.

For the years beyond 2020-2022, I discuss at a higher level the anticipated work to be done and the reasonableness of underlying assumptions for Integrated Distribution Plan (IDP) and CBA model purposes. Exhibit___(KAB-1), Schedules 4, 5, and 6 to my Direct Testimony also includes currently anticipated expenditures used in our CBA beyond 2022.

Q. WHAT TYPES OF O&M COSTS WILL DISTRIBUTION INCUR TO IMPLEMENT THE AGIS INITIATIVE?

A. Distribution's AGIS related O&M costs include labor, contractor, vendor services, and materials.

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Q. WHAT ARE DISTRIBUTION'S O&M COSTS FOR AGIS IMPLEMENTATION THAT ARE INCLUDED IN THE COST OF SERVICE IN THIS CASE?

A. The forecasted AGIS O&M expenses for Distribution are shown in the table below. I provide additional details and support for the Distribution O&M costs below, organized by AGIS component.

Table 32

AGIS O&M – Distribution NSPM – Total Company Electric (Dollars in Millions)			
AGIS Program	**2020**	**2021**	**2022**
AMI	$2.3	$3.3	$5.0
FAN	$0.1	$0.2	$0.4
FLISR	$0.1	$0.3	$0.2
IVVO	$0.0	$0.4	$0.8
Total	**$2.6**	**$4.2**	**$6.5**
There may be differences between the sum of the individual AGIS program amounts and Total amounts due to rounding.			

Exhibit___(KAB-1), Schedules 4, 5, and 6 to my Direct Testimony also includes currently anticipated expenditures used in our CBA beyond 2022.

Q. TO WHAT EXTENT ARE THE DISTRIBUTION CAPITAL COSTS PRESENTED ABOVE CONSISTENT WITH THE INFORMATION PROVIDED IN THE COMPANY'S TRANSMISSION COST RECOVERY RIDER (TCR) FILINGS AND ITS 2018 IDP FILING?

A. The TCR filings presented information on only ADMS, as that is the only certified project for which the Company has sought cost recovery to date. Project costs for the TOU pilot in the Company's 2017 Grid Modernization report and the foundational AGIS projects in the Company's 2018 IDP filing were presented at a higher level because the Company was not yet proposing cost recovery of those initiatives at that time. Further, these filings were based on information available at that time, whereas the current rate case and 2019 IDP filings present more up-to-date information. Lastly, as I describe later, the Company's plan for FLISR has been updated since these prior filings. As a result, this rate case presents the most current information on costs as our planning and data have evolved.

Q. WHAT IS THE DIFFERENCE BETWEEN THE COST ESTIMATES IN THE MYRP AND THE LONGER TERM COST ESTIMATES?

A. While these cost assumptions in the longer term estimates are reasonable and well-supported based on the information available today, they are not intended to reflect specific budgets as in a standard rate case budget. Rather, they are subject to refinement like all costs that will be incurred several years into the future. This is consistent with Mr. Robinson's discussion of all Company projections that represent work to be completed in the longer-term. However, I believe these cost estimates are reasonable, and I explain the support for them as part of my discussion of each AGIS component.

Q. WHAT SORT OF GOVERNANCE IS IN PLACE TO MANAGE THE COSTS AND IMPLEMENTATION OF THE AGIS PROJECTS?

A. Distribution employs standard processes and procedures for selecting technologies to be deployed in the Company's environment as well as the execution of large capital projects. These include long established processes in the area of competitive vendor sourcing and pricing negotiations. In addition, the AGIS program has a dedicated Project Management Office to govern all areas within the program. Mr. Gersack discusses overall AGIS governance in his testimony.

B. Limitations of the Current Distribution System

Q. HOW WAS XCEL ENERGY'S DISTRIBUTION SYSTEM ORIGINALLY DESIGNED, AND HOW DOES THIS DESIGN LIMIT THE CAPABILITIES AND OPERATION OF THE SYSTEM?

A. Xcel Energy's distribution system was originally designed to accommodate primarily a one-way flow of electricity and information from the utility to the customer with limited monitoring points. This design limits the amount of information and visibility that the Company has regarding the workings of the system and the customer experience beyond the distribution substation level. The system was also designed to rely heavily on manual and local control schemes to operate and lacks connectivity to easily share information between different portions and components of the system. These different system limitations can be categorized as:

- Limited Visibility;
- Manual Control; and
- Limited Connectivity.

1. Limited Visibility

Q HOW DOES THE LACK OF VISIBILITY BEYOND THE SUBSTATION IMPACT OPERATION OF THE SYSTEM AND THE CUSTOMER EXPERIENCE?

A. Since the existing distribution system only measures limited data on a small number of points on the distribution system (primarily at substations), the Company has little insight into the flow of power, voltages, and the operation of equipment on the system beyond the substation. Thus, the Company has

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little insight into the customer experience – the voltage that the customer is receiving, whether the power is out or has been restored, or any abnormality that might be detectable. To obtain information regarding the numerous distribution system components beyond the substation, such as meter readings, current flow, or voltage levels, the Company has to send workers out into the field to gather this information.

Q. HOW DOES THIS LACK OF VISIBILITY BEYOND THE SUBSTATION LEVEL IMPACT THE COMPANY'S ABILITY TO IDENTIFY OUTAGES?

A. Since we do not have visibility into the system beyond the substation level, we rely on customers notifying us via phone or website/app of outages. Our Outage Management System (OMS) then aggregates the outage call information and determines which portion(s) of the distribution system lost power. Once we know the portion of the system that is out, we must patrol the lines to find the source of the problem. This increases the time and expenses associated with responding to outages, and leaves our customers without power for longer periods of time.

Q. HOW DOES THIS LACK OF VISIBILITY IMPACT THE COMPANY'S ABILITY TO MONITOR AND CONTROL VOLTAGE LEVELS ON THE SYSTEM?

A. Because the Company does not have visibility into the system beyond the substation level, the Company does not have insight into voltage issues on the system or the ability to efficiently manage the voltage level on the system. Similar to outage information, we rely on customers to report either high or low voltage issues. To maintain required voltage levels, the Company keeps the voltage level at the substation that is at a high end of the appropriate voltage level at all times. This helps ensure that under any conditions the last customer on the system will have voltage within the acceptable range. However, operating the system at higher voltage levels is more costly as it uses more energy and because many end use devices do not operate efficiently at higher voltage levels.

Q. HOW DOES THE LACK OF VISIBILITY IMPACT THE DISTRIBUTION SYSTEM'S ABILITY TO ACCOMMODATE DISTRIBUTED GENERATION?

A. We do not have the ability to accurately measure the amount of distributed generation that is flowing onto or leaving the system. Rather, we rely on conservative estimates to quantify the amount of distributed generation entering and leaving the grid. Because we must ensure adequate voltage and protection at all times, such conservative estimates, coupled with the inability to modify voltages or system configuration, can limit the accommodation of DER. This is because the output of distributed generation sources is highly variable and can lead to operational complexities such as protection or voltage regulation concerns. For example, when there are high levels of distributed generation on a feeder, protective equipment such as reclosers or substation breakers may not operate as intended because they are unable to differentiate between loads, distributed generation, and a system fault. Should this occur, there is a risk that a faulted portion of the system would remain energized and present a hazard. While Minnesota currently has low levels of distributed generation relative to some other states, it will be important for the distribution system to have the capability to accommodate increasing levels in the future.

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Q. HOW DOES THE LACK OF VISIBILITY AND INFORMATION IMPACT THE CUSTOMER EXPERIENCE?

A. The current AMR system is largely limited to providing the Company with customer usage information necessary to support customer billing. As a result, we cannot provide customers with timely power usage information to enable them to manage their electric usage more efficiently. Additionally, while the system does measure voltage to quantify energy use, it is unable to provide that data through the communication network, and thus cannot alert the Company of either high or low voltage issues.

2. Manual Control

Q. HOW DOES THE LIMITED NUMBER OF REMOTELY CONTROLLED DEVICES BEYOND THE SUBSTATION IMPACT OPERATION OF THE SYSTEM?

A. The current distribution system's operation relies on mostly manual and local control schemes that require human intervention to complete an operation. For example, field switches are manually operated switches for nearly all feeders. If there is a fault on any feeder segment, the circuit breaker will open at the substation. When this occurs, a field crew has to patrol the feeder to find the location of the fault. This process can be time consuming, especially if visibility is poor or if sections of the line are not adjacent to roads. After the crew locates the fault, they manually open immediate upstream and downstream connecting switches to isolate the faulty feeder section. Then, after the faulted section of the feeder is repaired, the switches are manually closed to restore service to the feeder. Automating this process will reduce customer outage durations, enable quicker responses to faults, and reduce crew field time.

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3. *Limited Connectivity*

Q. HOW DOES THE COMPANY CURRENTLY COMMUNICATE WITH SUBSTATIONS, FIELD DEVICES, AND METERS?

A. For many years, the Company has communicated with its substation through leased telephone circuits with widely varying capabilities, especially in rural areas, or through expensive microwave installations. Connecting field devices (switches, etc.) with communications networks has been limited due to the expense and complexity of managing these circuits. Although, we have been able to successfully operate the system for many years under these conditions, advancements in technology can now support communications between the intelligent devices deployed across the distribution system – up to and including meters at customers' homes and businesses. These advanced applications cannot be supported with the Company's current communication network. These improvements will allow the Company access to information to better manage the system and respond to outages, and to provide our customers with access to near real-time data on their energy usage. Further, the rise of small-scale DER located on the grid edge (i.e., near or behind customer meters), has created a need for improvements to accommodate these resources.

4. *Xcel Energy's Vision for the Future of the Distribution Grid*

Q. CAN YOU DESCRIBE XCEL ENERGY'S VISION FOR THE FUTURE OF THE DISTRIBUTION GRID?

A. Our vision for the future distribution grid is one that utilizes advances in technology to improve our monitoring and operation of the grid for the benefit of our customers. Our AGIS investments will provide us timely and accurate information about what is happening on all portions of the grid from

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our substations down to each individual customer's meter. These investments will also have the necessary automation and intelligence to address any problems quickly and efficiently. In some cases, these insights will alert us to situations likely to result in an outage (such as overloaded equipment) before an outage occurs. The increased number of field sensors and devices will also provide the Company with the necessary information to continually monitor and make the necessary adjustments to the system to support increasing amounts of DER and other electric technologies such as EVs.

Additionally, as discussed by Mr. Gersack, the advanced grid investments will provide the foundation for new programs and service offerings, engaging digital experiences, enhanced billing and rate options, and timely outage communications. Further, as discussed by Mr. Harkness, the advanced grid will include security protocols that will detect and remedy cyber and physical threats to our system.

Q. WHY IS IT IMPORTANT TO MAKE THE PROPOSED AGIS INVESTMENTS AT THIS TIME?

A. As discussed in the next section, while the Company has taken certain steps to modernize the grid, now is the time to build on these foundational investments and to begin a more significant advancement of the grid through our AGIS initiative. The need for these AGIS investments is the result of a number of factors including system needs, the maturity of technology, changing customer needs and expectations, and increasing amounts of DER that is anticipated in the near future. Together, these factors drive the need to make the proposed AGIS investments in modernizing our distribution system. These investments will greatly enhance our distribution system's performance and our ability to meet our customers' needs and expectations for their electric service provider now and in the future.

C. Grid Modernization Efforts to Date

Q. WHAT HAS BEEN XCEL ENERGY'S APPROACH TO GRID MODERNIZATION?

A. Our strategy for grid modernization has been a building block approach. That is, we have focused our efforts first on developing the core components that form the foundation to build upon to construct and enable more advanced components. This building-block approach, starting with the foundational systems, is in alignment with industry standards and frameworks including the Department of Energy's Next Generation Distribution Platform (DSPx) framework.[8] This approach also allows us to sequence our investments to yield the greatest near-term and long-term customer value while preserving the flexibility to adapt to the evolving customer and technology landscape.

Q. WHAT STEPS HAS THE COMPANY TAKEN TO UPDATE THE DISTRIBUTION SYSTEM IN RECENT YEARS?

A. One of the steps that we have taken is utilizing our equipment replacements as an opportunity to deploy new equipment that has the greater functionality necessary for a modern grid. An example of this strategy is replacement of electro-mechanical relays with solid-state relays that are not only communication-enabled but are also capable of providing fault data that an ADMS system can use to calculate probable fault location. This allows for faults on our system to be more quickly identified thus improving our response time. Additionally, we are replacing voltage regulators that have

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[8] *See* Modern Distribution Grid, Volume III: Decision Guide, U.S. Department of Energy Office of Electricity Delivery and Energy Reliability (June 2017).

reached the end of their service life with regulators that have controls that identify reverse-power flow and react accordingly, which will facilitate integration of distributed generation onto the system. Beginning in 2015, we have deployed power line sensors on our system that aid our efforts to locate faults more quickly – improving our responsiveness to outage events, and thus the customer reliability experience.

The Company has also installed autonomous, proprietary automated switching systems on portions of its 34.5 kV system. Since these system use a proprietary, single-purpose communication network, they must be specifically designed for the portion of the grid they cover, and the system must be re-programmed when system topology changes. Where these devices have been installed, these systems have improved system reliability, proving the value of the FLISR concept. Going forward, we plan to leverage ADMS's broader FLISR capabilities, bringing reliability benefits customers served by our larger 13.8 kV systems.

Q. HAS THE COMPANY PREVIOUSLY SOUGHT AND RECEIVED COMMISSION CERTIFICATION OF GRID MODERNIZATION INVESTMENTS?

A. Yes, as mentioned above two advanced grid investments have been submitted for certification in biennial grid modernization reports and approved by the Commission. In its 2015 Biennial Grid Modernization Report, the Company outlined the ADMS initiative, which was submitted for certification and subsequently approved on June 28, 2016. In its 2017 Biennial Grid Modernization Report, the Company outlined its AMI and TOU pilot program and certification was approved in the Commission's August 7, 2018 Order.

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1. ADMS

Q. WHAT IS ADMS?

A. ADMS is the foundational software platform for operational hardware and software applications used to operate the current and future distribution grid. ADMS is foundational because it provides situational awareness and automated capabilities that sustain and improve the performance of an increasingly complex grid. Specifically, ADMS acts as a centralized decision support system that assists the control room, field operating personnel, and engineers with the monitoring, control and optimization of the electric distribution grid. ADMS does this by utilizing the as-operated electrical model and maintaining advanced applications which provide the Company with greater visibility and control of an electric distribution grid that is capable of automated operations. In particular, ADMS incorporates Distribution Supervisory Control and Data Acquisition (D-SCADA) measurements and advanced application functions with an enhanced system model to provide load flow calculations everywhere on the grid, accurately adjusting the calculations with changes in grid topology and insights from sensors. This allows the Company to improve the monitoring and control of load flow from substations to the edge of the grid, which enables multiple performance objectives to be realized over the entire grid.

Q. HOW DOES ADMS ENABLE OTHER GRID MODERNIZATION COMPONENTS?

A. Implementing ADMS will enable management of the complex interaction among outage events, distribution switching operations, IVVO and FLISR in the near-term, while preparing the Company to implement advanced applications like Distributed Energy Resource Management System (DERMS) in the future.

The GIS data improvement needed to enable ADMS also furthers grid modernization efforts related to DER. Specifically, this effort will help DER adoption by improving the GIS model which is used for system planning and for hosting capacity analysis. The data collection and improvements will reduce the amount of time that planning engineers spend preparing each model for analysis. The verification and population of additional data attributes will also help our designers validate capacity necessary for EVs.

Q. WHAT IS THE TIMING FOR IMPLEMENTATION OF ADMS?

A. ADMS software has an expected in-service date of April 2020 when the system will be tested and go live to control a subset of the distribution system. The plan is to continue to expand the modeled system over the next several years, enabling additional benefits of ADMS including coordination with the FLISR and IVVO deployments.

Q. IS THE COMPANY SEEKING TO RECOVER ANY COSTS RELATED TO ADMS IN THIS RATE CASE?

A. No. The Company has sought recovery for the costs for ADMS in the TCR Rider and proposes to keep ADMS in the TCR Rider through the multi-year rate plan period.

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2. TOU Pilot

Q. WHAT IS THE TOU PILOT?

A. The TOU pilot implements new residential TOU rates for select customers in the Twin Cities metropolitan area, providing customers with pricing specific to the time of day energy is consumed. This pilot requires installation of AMI meters to measure and record customer usage in detailed, time-based formats and requires installation of FAN communication to transmit this data to the Company and customers.

Q. HOW MANY CUSTOMERS ARE PARTICIPATING IN THE TOU PILOT?

A. As part of this pilot, we will deploy approximately 17,500 advanced meters to residential customers in Eden Prairie and Minneapolis. We will also deploy FAN communications to these same areas.

Q. WHAT IS THE TIMING OF IMPLEMENTATION FOR THE TOU PILOT?

A. Our back-office work on AMI and FAN necessary for the TOU pilot began in 2018. In 2019, we commenced installations of both FAN devices and AMI meters and expect this work to be completed during the first quarter of 2020. The TOU pilot – with the new rate structures for participants – is expected to begin in April 2020.

Q. WHAT IS THE PURPOSE OF THIS TOU PILOT?

A. The primary aim of this TOU pilot is to study the impact of rigorously designed price signals and technology-enabled data on customer usage patterns to inform future consideration of a broader TOU rate deployment in Minnesota. The purpose of this pilot is not to study the use of AMI meters

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because, as I discuss later in my testimony, this technology is proven and widely used by other utilities.

Q. IS THE COMPANY SEEKING TO RECOVER ANY COSTS RELATED TO TOU PILOT IN THIS RATE CASE?

A. Yes. For 2020 and going forward, the Company proposes to recover the costs associated with the TOU pilot as part of this rate case. These costs for Distribution are shown in 35 below.

Table 33

AMI TOU Pilot-Distribution State of MN Electric Jurisdiction (Dollars in Millions)			
TOU Pilot-Distribution	**2020**	**2021**	**2022**
Capital Additions	$1.8	$0.0	$0.0
O&M Expenses	$0.3	$0.0	$0.0

I note that the residential TOU pilot costs are part of the Company's overall AGIS initiative (specific to AMI and the FAN). The TOU costs reflect the estimated portion of the total AMI components that are necessary to implement the residential TOU pilot. In his testimony, Mr. Harkness provides the Business Systems costs necessary to implement the TOU pilot.

Q. WHAT HAS BEEN THE IMPACT OF THESE SYSTEM UPDATES AND PILOT PROGRAMS ON THE OPERATION OF THE DISTRIBUTION SYSTEM?

A. While some of these investments (i.e., the automated devices discussed above) have had a positive impact on customer reliability, these improvements have not corrected the fundamental issues with the operation of the current system – lack of visibility and wide-spread automation. Xcel Energy's

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distribution system currently lacks real-time visibility into the condition of its entire distribution grid and the customer experience beyond the substation level. As a result, if a customer is experiencing an outage, the Company still primarily relies on the customer to report the outage to know that an outage occurred. In addition, the distribution system continues to lack automated controls that allow the Company to adjust and control individual pieces of equipment from a central location.

The state of technology has reached a point where it is feasible to implement equipment and systems that will provide the Company with the visibility and automation required to operate with increasing levels of DER and higher customer expectations around reliability and information about their power use. While the Company has implemented some of these technologies in a few pilot areas, it is now time to expand this technology to larger portions of our electric grid. In the next section of my testimony, I will describe the foundational components of the AGIS initiative that we plan to implement during the term of the multi-year rate plan.

D. AMI

1. Overview of AMI

Q. WHAT IS AMI?

A. AMI is an integrated system of advanced meters, communications networks, and data management systems that enables secure two-way communication between customer meters and utilities' business and operational systems that enable benefits for both the customer and the utility. AMI meters are able to measure and transmit voltage, current, and power quality data and can act as sensor, providing timely monitoring at the customer's point of service that has a variety of uses for customers and business operations.

AMI is a key element of the AGIS initiative because it provides a central source of information that interacts with many of the other components of the AGIS initiative. The system visibility and data delivered by AMI provides customer benefits in reliability and ability for remote connection, enables greater customer offerings for rates, programs, and services. AMI also enhances utility planning and operational capabilities. Access to timely, accurate and consistent data from the AMI system will provide insights for customers to make informed decisions about their energy sources and usage of reliable and sustainable energy.

The Company plans to deploy approximately 1.3 million AMI meters in Minnesota starting in the third quarter in 2021 and continuing through 2024. This mass deployment of AMI meters builds off the limited AMI meter installation that will be completed in late 2020 as part of the TOU pilot. Xcel Energy will own and operate the AMI meters and the FAN communication network.

Q. DESCRIBE THE ADVANCED METERS.

A. The advanced meters are the key endpoint component of an AMI system that measures, stores, and transmits meter data, including energy usage data from customer locations. The advanced meters can also measure values such as voltage, current, frequency, real and reactive power, and certain power quality events such as sags and swells. Additionally, these meters can detect outage

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events, restoration events, tampering, energy theft events, and perform meter diagnostics.

Q. HAS XCEL ENERGY SELECTED A SPECIFIC ADVANCED METER?

A. Yes. Xcel Energy has selected the Itron Riva Generation 4.2 advanced meter. This meter will be installed for mass deployment in Minnesota starting in 2021. For the TOU pilot, Xcel Energy will install a different AMI meter, a Landis+Gyr Focus meters equipped with Itron Gen 5 NICs, because the Riva Generation 4.2 advanced meter will not be ready for installation until 2021. The meters installed for the TOU pilot will be replaced by Itron with the Riva Generation 4.2 during the mass deployment at no cost to Xcel Energy. The RFP process that was used to select this meter and vendor are described in greater detail below. This specific meter is the latest model in Itron's Riva family of meters so a photo of this specific meter is not currently available. A photo of a similar model (the OpenWay® Riva CENTRON meter) from the Itron Riva family of meters is provided below in Figure 8.

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Figure 8

Q. WHAT IS THE SERVICE LIFE OF THESE ADVANCED METERS?

A. We have assumed a service life for the advanced meters of 15 years in Minnesota for purposes of depreciation and the CBA. The actual physical life of these advanced meters will likely exceed this 15 year service life.

Q. WHAT ARE THE COMPONENTS OF ADVANCED METERS?

A. The components of the advanced meter include: (1) the meter itself (responsible for measurements and storage of interval energy consumption and demand data); (2) an embedded two-way radio frequency communication module (responsible for transmitting measured data and event data available to backend applications); (3) embedded Distributed Intelligence capabilities (described below); and (4) an internal service switch (to support remote connection and disconnection).

Q. WHAT ARE THE FUNCTIONS OF THE ADVANCED METER ITSELF?

A. The primary purpose of the advanced meter is the same as our existing meters – to measure the amount of electricity used by our customers for billing purposes. However, the advanced meters have additional capabilities and can be remotely configured to measure bi-directional and/or time-of-use energy consumption in kilowatt hours (kWh) and demand in kilowatts (kW). An advanced meter that is configured for bi-directional energy measurement measures energy provided by the Company to the customer and also measures net energy provided from customers (i.e., customers with solar panels) to the Company. Energy consumption data for billing purposes can be recorded by advanced meters in intervals as short as five minutes, or longer intervals if desired. The advanced meters also provide granular data regarding voltage and outages as explained further below.

Q. HOW OFTEN WILL AMI METERS COLLECT AND TRANSMIT DATA TO THE COMPANY?

A. The AMI meters will collect and transmit data to the Company a minimum of six times per day or every four hours. However, there are several instances when the meters will communicate more often than every four hours. Some examples of this more frequent communication include:

- Individual meters can be read on an on-request basis. For example, a Customer Care employee may request and collect the meter data while on the phone assisting a customer.
- Through the internet portal or smartphone application, as described by Mr. Harkness, a customer could request an on-demand meter reading. This request will provide a customer with near real-time energy information.[9]
- AMI meters will transmit data when an event occurs such as a power outage, power restoration, power quality event, or a diagnostic event.

[9] The terms "near real time" refer to the fact that there is a slight delay (under ten seconds) between the time the data is pulled and when it is received by the customer.

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The length of time between the data transmission and the event depends on the type of the event.

- AMI meters selected along the distribution feeders to provide data to ADMS will be configured for five minute interval data, and will transmit data to the head-end application every five minutes to make that information available to ADMS. The interrelation between AMI and ADMS is discussed further below.

Q. WHAT ARE THE OTHER CAPABILITIES OF THE ADVANCED METERS?

A. In addition to the ability to measure, store, and transmit interval meter data, advanced meters also have the capability to:

- Measure and transmit voltage, current, and power quality data;
- Detect and transmit meter power outage and restoration events;
- Detect and report meter tampering events;
- Perform and transmit meter diagnostics pertaining to the correct functioning of the meter and communications module;
- Support electric vehicle interconnections;
- Support customer-facing energy conservation technologies (i.e., smart thermostats);
- Support Distributed Intelligence; and
- Support remote connect/disconnect functions for customers taking single-phase service (generally, residential and some small business customers).[10]

[10] The only AMI meters available in the marketplace with remote connection/disconnection switches are single-phase meters.

Q. WHAT ARE THE CAPABILITIES OF THE ADVANCED METER'S TWO-WAY RADIO FREQUENCY COMMUNICATION MODULE?

A. The radio frequency communication module will utilize the Company's communication network (i.e., the FAN) to provide two-way communication between the meter and the AMI head-end application. The AMI head-end application is the operating system that is used to send data requests and commands to an advanced meter, and receive data from the meter. These communications include:

- Transmitting the measurements, alarms, and events performed by the meter to the head-end application;
- Receiving commands from the head-end application to send specific meter measurements, alarms, and events, configure the meter to measure specific sets of energy parameters or time-of-use intervals and data recording intervals;
- Remotely performing meter firmware upgrades;
- Receiving commands from the head-end application to open or close the internal service switch and communicate its status.

Q. WILL THE TWO-WAY RADIO MODULE WITHIN THE AMI METERS HAVE THE ABILITY TO COMMUNICATE WITH OTHER DEVICES?

A. Yes. While the primary purpose of the two-way radio is to capture and transmit customer billing data and service quality data from the AMI meter to the Company, there is also a second radio within the meter that is Wi-Fi compatible and can be configured to communicate with a customer's Home Area Network (HAN) and HAN devices.

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Q. WHAT IS A HAN?

A. The HAN is a network contained within a customer's home or business that connects a customer's HAN devices together as well as to customer's AMI meter. A HAN device can be as simple as an in-home energy display that provides real-time energy data. HAN devices can also include thermostats, home security systems, energy display devices, and smart appliances, that when connected through the HAN, these devices can communicate with each other to support energy management functions.

Q. HOW DOES THE COMPANY INTEND TO UTILIZE THE HAN FUNCTIONALITY OF THE AMI METERS?

A. As discussed by Mr. Gersack, HANs vary in the benefits they provide and can be as simple as a dashboard that communicates with the meter to provide real-time energy usage or more complicated networks of devices that are receiving energy usage data from the meter and adjusting operations based on that information. The Company will continue to build and refine our next steps with both advanced grid technologies and customer products and services that will leverage AMI capabilities.

Q. WHAT IS DISTRIBUTED INTELLIGENCE?

A. Distributed intelligence or "grid edge computing" refers to the distribution of computing power, analytics, decisions, and action away from a central control point and closer to localized devices or platforms where it is actually needed, such as advanced meters or other "smart" devices on the grid. Since data no longer has to traverse long distances over increasingly constrained networks, these technologies improve the computational speed, efficiency, and capabilities derived from these platforms. Distributed intelligence capabilities

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in advanced meters and other edge devices opens up a broad array of new uses that will fundamentally transform how customers will use energy in their homes and businesses, as well as how Xcel Energy will be able to optimize its AGIS investments.

Q. WHAT ARE THE EMBEDDED DISTRIBUTED INTELLIGENCE CAPABILITIES OF THE ADVANCED METER SELECTED BY THE COMPANY?

A. Our advanced meters will provide a distributed intelligence platform that is a computer at customers' homes and businesses. This computer uses a Linux-based operating system to conduct localized, at the meter computing, analysis, and data processing that provide customers with new tools to help manage their energy usage and provide Xcel Energy with new tools to manage the grid more efficiently. This capability also allows for the installation of a wide-range of potential applications. In other words, this Distributed Intelligence capability allows for the installation of applications on the meter – similar to how applications are installed on a smart phone. These applications may be customer-facing, meaning the customer directly interacts with them, or grid-facing, meaning Xcel Energy interacts with the applications.

Q. WHAT ARE THE POTENTIAL USES OF THIS DISTRIBUTED INTELLIGENCE CAPABILITY?

A. The Distributed Intelligence capabilities allow the AMI meter to run multiple applications at the same time and without the need for instructions from the Company's back-office applications or control room. This type of capability is beneficial because it allows the AMI meters to communicate directly with each other regarding issues, analyze those issues, and to solve problems directly rather than communicating these issues to a back-office system and

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then waiting for instructions on how to solve the problem. The potential use cases for these applications include:

- Improved and security and awareness,
- Energy usage control and savings,
- Smarter insights about customer energy data and information,
- Smarter controls to better manage and integrate different systems, and
- Identification and alarming for operational issues.

Q. CAN YOU PROVIDE AN EXAMPLE OF HOW THESE DISTRIBUTED INTELLIGENCE CAPABILITIES COULD BE USED BY THE DISTRIBUTION ORGANIZATION?

A. Xcel Energy is leading the nation in the deployment of Distributed Intelligence in the AMI meters. As a leader in this space, we are working with our meter vendor to design, develop, and implement new applications. Our meter vendor has already begun building a number of applications that can be enabled on the meter. While the specific use of these Distributed Intelligence capabilities will depend on the particular applications employed, I will provide an example of how these capabilities could be utilized to manage demand during peak times to avoid transformer overloads. During a hot summer afternoon when energy use is rising due to air conditioning use, the AMI meters at each customer location would analyze this data in real time. These meters would then share their individual data with the other meters served by a common distribution transformer, calculating and comparing the total load to the capacity of the transformer. The AMI meters would be able to discern when the transformer is approaching overload conditions and determine the most appropriate course of action, which could be reporting, alarming, modulating, or possibly shutting off controllable loads to keep the transformer below its rated capacity. The same concept would help with the integration of

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electric vehicles, as well. Finally, a transformer's capacity may be challenged by additional PV, as more of our distribution transformers begin to see their peak not from load, but from PV generation in the afternoon when solar production is strong, but loads are low.

Q. WHAT IS THE PURPOSE OF THE INTERNAL SERVICE SWITCH?

A. The internal service switch has the ability to remotely connect or disconnect power to the customer's electric service upon command from the head-end data application. I note that remote connection/disconnection of residential or small commercial customers would require revisions to our existing tariff and Xcel Energy is not currently seeking Commission approval to enable this capability.

Q. HOW IS AMI DIFFERENT THAN THE METERING SYSTEM USED TODAY?

A. The Company currently has an AMR system that has been in place since the mid-1990s. Meter readings are collected and provided to the Company via a proprietary network by Landis+Gyr (Cellnet), our current meter reading services vendor. We have served our customers for 20-30 years via this AMR system. However, AMR is now dated technology and much of the industry has or is moving to AMI meters.

Q. WHAT ARE THE LIMITATIONS OF THE CURRENT AMR SYSTEM?

A. The AMR system in general is a fixed network, one-way communication system with limited functionality that is primarily related to meter reading for billing purposes. As a result, the AMR system has a number of limitations including:

- Inability to measure and record voltage, current, or power quality;

- Lack of real-time view of a customer's metering data;
- Meter readings are transmitted via a single path communication system that precludes the ability to collect necessary data if there is an obstruction on that single communication path; and
- Cannot be reprogrammed or upgraded remotely such that on-site performance of these tasks is required.

These limitations of the current AMR system preclude us from having much visibility into our customer's energy experience, this visibility is invaluable for how we operate and plan our system. As discussed by Mr. Gersack, the AMR system also limits the customer offerings we can currently provide.

Q. WHY IS IT IMPORTANT TO MOVE FROM AMR TO AMI AT THIS TIME?

A. In addition to the limited functionality of this outdated technology, now is an opportune time to replace this legacy system as we are nearing the expiration of our current AMR meter reading service contract with Cellnet. The current Cellnet contract expires at the end of 2025, with an option to extend it through 2026 at a significantly increased cost. As we are the last remaining customer of the Cellnet system, a contract extension past 2026 is highly unlikely. In addition, Cellnet will stop manufacturing replacement components for the AMR system, including communication modules necessary for meter reading, in 2022. Given that the Cellnet system is a proprietary system, replacement parts are not commercially available from other vendors. As a result, as these meters age and require repair, we will not be able to purchase the necessary replacement components after 2022.

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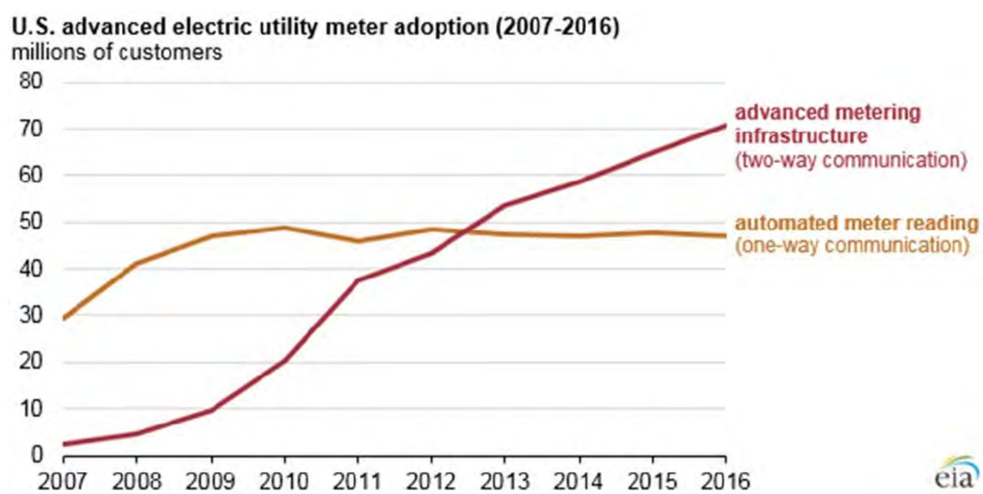
The expiration of our Cellnet contract comes at fitting time given the current state of the AMI market and its technology. AMI has advanced to the point where it is established meter technology that has widespread adoption. Installation of AMI meters has doubled since 2010 and since the end of 2016 nearly half of all U.S. electric customer accounts have AMI meters. According to the United States Energy Information Administration, and as shown in Figure 9, AMI adoption surpassed AMR in 2012, and the gap has widened as AMR deployment has remained flat.

Figure 9[11]

AMI vs. AMR Installations



In sum, it is the culmination of these several factors: (1) aging and outdated technology with limited functionality; (2) the expiration of the existing Cellnet meter reading contract; and (3) difficulty of obtaining vendor in the future for the AMR system that is driving the need to convert to AMI.

[11] https://www.eia.gov/todayinenergy/detail.php?id=34012.

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2. Interrelation of AMI with other AGIS Components

Q. CAN YOU SUMMARIZE THE ROLE OF AMI IN THE OVERALL AGIS INITIATIVE?

A. AMI is a central source of information with which virtually all components of AGIS interact and as such AMI is critical to support certain benefits of the advanced grid such as TOU rates and associated price signals, more efficient distribution management system, and greater customer control over energy usage.

Q. HOW WILL AMI INTERACT WITH ADMS?

A. AMI will also provide the ADMS with timely real and reactive power measurement data that will be used in load flow and IVVO calculations. Further, AMI meters will provide voltage measurements at various points on the distribution system to support IVVO calculations. The information collected by the AMI meters will allow the Company through IVVO to reduce the overall voltage on the system.

The AMI meters will report a power outage or "last gasp" event to the AMI head-end application and report a power-on event when the power is restored. This information will flow from the head-end application to ADMS that will improve the calculations for the fault location and restoration applications.

Q. HOW WILL AMI INTERACT WITH THE FAN?

A. The AMI meters have an integrated network interface card (NIC) that enables them to connect to the WiSUN portion of the FAN network. This enables the transmission of data and commands between the AMI meters and the Company. The meters can also act as a repeater for other mesh network devices, enabling two-way communication between the meters and the mesh network. This function provides increased communication reliability between the AMI meters and the head end application. For example, if the communication signal is weak between the AMI meter and the access point device, the meter may have a stronger communication path to the access point by having another meter (or several meters), act as a repeater to facilitate the communication.

Q. HOW WILL THE AMI METER INTERACT WITH FLISR?

A. The last gasp and power-on information that advanced meters will provide will be available on ADMS which will utilize this data to develop more accurate model and forecasting tools for FLISR. This transfer of data will enable the Company to more precisely locate faulted sections of feeders, which reduces patrol times, and improve FLISR switching plans, which minimizes the outage impact to customers.

Q. HOW WILL THE AMI METERS INTERACT WITH IVVO?

A. As noted above, advanced meters provide voltage information to ADMS from strategic points on the distribution system. The ADMS combines voltage information provided by the AMI meters to calculate voltage levels across the grid. This voltage data becomes more precise and accurate as the number of AMI meters providing this data increases. This voltage information is then used by the IVVO application to operate voltage control devices on the grid, optimizing the voltage levels on the grid while keeping the voltage within the desired bandwidth. Without the AMI meters acting as sensors, the Company would need to deploy stand-alone sensors to implement IVVO. I discuss this further in the alternatives section below.

3. AMI Implementation

Q. WHAT IS THE AMI DEPLOYMENT TIMELINE?

A. We plan to install approximately 1.3 million AMI meters throughout our Minnesota service territory as part of the AGIS initiative starting in the third quarter of 2021. This deployment builds off the limited installation of 17,500 AMI meters planned to be installed in late 2019 as part of the TOU pilot. By the end of 2023, we anticipate that over 90 percent of the meter installations will be complete. Table 34 below provides a summary of the number of meters we anticipate installing per year from 2021 through 2024.

Table 34

AMI Meter Installation by Year

Year	2021	2022	2023	2024
Number of AMI Meters Installed	100,000 to 130,000	550,000 to 650,000	530,000 to 600,000	30,000 to 60,000

Q. PLEASE PROVIDE ADDITIONAL DETAILS REGARDING WHERE THE AMI METERS WILL BE INSTALLED EACH YEAR?

A. Figure 10 below shows the anticipated deployment schedule for AMI. As shown below, the first meters installed as part of the mass deployment starting in third quarter 2021 are adjacent to and will build off the TOU pilot areas. From there, the deployment will continue to expand outward through 2023 with the final deployments scheduled in our Sioux Falls and Fargo service areas for 2024.

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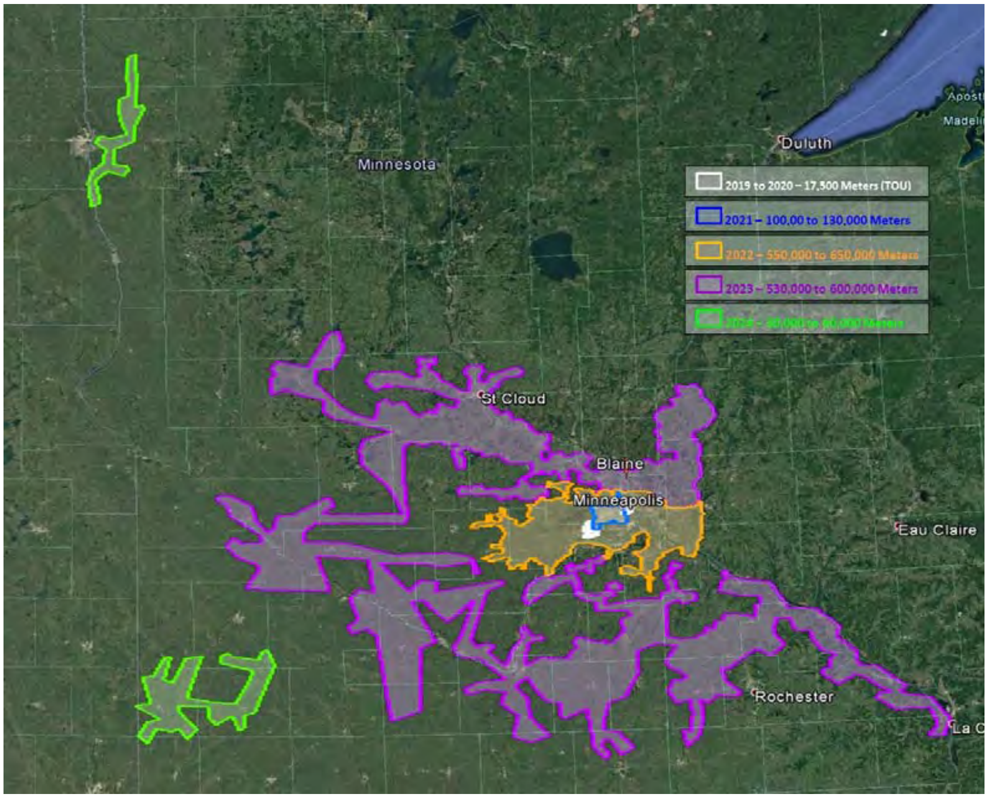
Figure 10



Q. HOW WILL THE AMI METERS BE INSTALLED?

A. The exchange of AMI meters in the field will be performed by trained and qualified contractors under the management and direction of Company employees.

Q. HOW LONG WILL IT TAKE TO INSTALL EACH INDIVIDUAL METER?

A. The time to install each meter will vary depending on the type of service and meter that each customer has but in most cases we expect that the meter exchange for a residential customer to take less than 15 minutes.

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Q. WILL INSTALLATION REQUIRE A CUSTOMER'S ELECTRICITY TO BE TURNED OFF?

A. Depending on the type of meter socket the customer has, they may experience a brief outage during installation. Customers do not need to be present during installation. We will provide customers with information about the timing of their AMI installation and what to expect during installation prior to installation. Mr. Gersack will discuss our communications and customer outreach plan in further detail.

Q. WILL THE INSTALLATION AND DEPLOYMENT OF AMI METERS BE INTEGRATED WITH THE COMPANY'S EXISTING INFORMATION TECHNOLOGY?

A. Yes. The advanced meters will be integrated with the Company's information technology system. AMI is data intensive with meter readings, energy usage interval profiles, power outage and restoration events, power quality information and other data transmitted and collected frequently. All data from the AMI meters comes into the head-end application and, depending on what the data is, it will need to be integrated and made available to the applicable business system in an accurate and timely manner. IT integration is explained in more detail by Mr. Harkness.

4. *Benefits of AMI*

Q. WHAT TYPES OF BENEFITS DOES XCEL ENERGY ANTICIPATE WILL BE ACHIEVED FROM AMI INSTALLATION?

A. There are four categories of benefits that we expect from implementation of AMI: (1) quantifiable capital benefits, (2) quantifiable O&M benefits, (3) other quantifiable benefits, and (4) non-quantifiable benefits. The quantifiable benefits of AMI were utilized by Dr. Duggirala in the CBA model prepared by the Company to calculate the benefit-to-cost ratios for each AGIS element.

Q. CAN YOU PROVIDE AN OVERVIEW OF THESE FOUR CATEGORIES OF BENEFITS?

A. With respect to quantifiable capital savings, we expect to see benefits in the areas of distribution system management efficiency, outage management efficiency, and avoided meter purchases. With respect to O&M savings, I will discuss quantitative benefits in the categories of field and meter service costs, distribution system management, outage management savings, as well as customer outage reductions. We also anticipate O&M savings in avoided meter reading costs, reduced customer calls, reduction in field and meters services, and improved distribution system spend efficiencies.

With respect to other quantifiable benefits, we anticipate reduction in energy theft, reduced consumption on inactive premises, reduced uncollectible and bad debt expense, load flexibility savings, and carbon emissions benefits. These other quantifiable benefits are discussed by Mr. Cardenas and Dr. Duggirala. Table 35 summarizes the quantifiable benefits of AMI.

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Table 35

AMI CAPITAL BENEFITS		
AMI Capital Benefits	**Description of Benefit**	**Witness**
Distribution System Management Efficiency	More efficient use of capital dollars to maintain the distribution system.	Direct Testimony of Ms. Bloch, Section V(D)(4)
Outage Management Efficiency	Improved capital spend efficiency during outage events.	
Avoided Meter Purchases	AMI meters have a lower failure rate as compared to AMR meters. By purchasing new AMI meters, the Company avoids the need to replace failing AMR meters.	
Avoided investment of an alternative meter reading system	Avoided capital cost of a drive-by meter reading system, instead of the AMI investment, since current Cellnet system requires replacement	
AMI O&M BENEFITS		
AMI O&M Benefits	**Description of Benefit**	**Witness**
Avoided O&M Meter Reading Cost	O&M cost component of a drive-by meter reading system alternative to AMI, since current Cellnet system requires replacement	Direct Testimony of Mr. Cardenas, Section V(F)
Reduction in Field and Meter Services	Reduction in O&M costs related to addressing meter and outage complaints and connections.	Direct Testimony of Ms. Bloch, Section V(D)(4)
Improved Distribution System Spend Efficiency	Increased efficiency of distribution maintenance costs.	Direct Testimony of Ms. Bloch, Section V(D)(4)
Outage Management Efficiency	Improved O&M efficiency during outage events.	Direct Testimony of Ms. Bloch, Section V(D)(4)

Table 35 (continued)

OTHER QUANTIFIABLE BENEFITS OF AMI		
Other Benefits of AMI	**Description of Benefit**	**Witness**
Reduction in Energy Theft	Easier identification of energy theft and an associated reduction in the amount of theft.	Direct Testimony of Mr. Cardenas, Section V(F)
Reduced Consumption Inactive Premise	Expedited ability to turn off power quickly when determined premise has been vacated.	Direct Testimony of Mr. Cardenas, Section V(F)
Reduced Uncollectible/Bad Debt	Decreased loss due to uncollectible/bad debt.	Direct Testimony of Mr. Cardenas, Section V(F)
Reduced Outage Duration	Direct benefit to customers associated with reduced outage duration	Direct Testimony of Ms. Bloch, Section V(D)(4)
Critical Peak Pricing	Customer demand savings in response to new rate structures.	Direct Testimony of Dr. Duggirala, Section II(B)(1)
TOU Customer Price Signals	Difference in energy prices paid by consumers in response to new rate structures.	Direct Testimony of Dr. Duggirala, Section II(B)(1)
Reduced Carbon Dioxide Emissions	Difference in emissions of generation assets due to shifted load.	Direct Testimony of Dr. Duggirala, Section II(B)(1)

A summary of the calculations for all of the quantifiable AMI benefits is provided in Exhibit___(KAB-1), Schedule 7. There are also a number of benefits that are not readily quantifiable. I address three of these non-quantifiable benefits: (1) enhanced DER integration; (2) improved safety for both customers and employees; and (3) improved power quality. Other non-quantifiable benefits are discussed by Mr. Gersack, Dr. Duggirala, and Mr. Harkness.

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Q. WHEN WILL CUSTOMERS BEGIN TO SEE THE BENEFITS OF AMI?

A. There is a relationship between when benefits will start to be realized based on when AMI meters are being installed in the field and when back office functionality is enabled via data processing and management systems and integrations with other systems. In general, most benefits will start to be fully realized after full-deployment of AMI meters in 2024. Partial benefits will begin to be realized in the 2023 timeframe.

a. Capital Benefits

Q. WHAT ARE THE CAPITAL BENEFITS FOR AMI THAT YOU PROVIDE SUPPORT FOR IN YOUR TESTIMONY?

A. I describe and provide support for calculation of the following capital benefits of AMI:

- Improved distribution system management efficiency;
- Improved outage management efficiency;
- Avoided meter purchases due to reduced failure rate of new meters; and
- Avoided capital investment of an alternative meter reading system to the existing Cellnet meter reading system.

(1) Distribution System Management Efficiency

Q. WHAT DISTRIBUTION SYSTEM MANAGEMENT EFFICIENCIES WILL BE GAINED AS A RESULT OF AMI?

A. AMI will provide a wealth of information about the workings of the distribution system. This AMI data can be aggregated at varying levels of the distribution system including tap, transformer, and service lines amongst other distribution system equipment. This data will be used by the Company to prioritize distribution grid improvements and more efficiently plan and design the system. Through the aggregated AMI data, we will have greater insights into the nature of the load - specifically load profiles, which will help us evaluate risk. The voltage insights will help us prioritize areas for investments in tap, transformer, and secondary wire replacement. For instance, the AMI data can be aggregated at the transformer level to identify overloaded transformers as well as determining the optimal transformer for replacement transformers. We will also have tools to better understand system losses which will help us evaluate opportunities for investment to minimize these losses. The Company estimated that AMI meters will provide a 1 percent reduction in capital expenditures for Asset Health and Reliability projects and Capacity projects.

Q. HOW WAS THIS BENEFIT CALCULATED?

A. The Company examined past projects in the Asset Health and Reliability and Capacity categories and determined that 1 percent was a reasonable estimate of the capital expenditure reduction that will result from the data provided AMI meters. In addition, the Company's 1 percent estimated benefit is consistent with the percentage utilized in the CBA performed by Ameren Illinois in 2012 when it sought approval for its AMI deployment (Ameren Business Case).

To calculate this benefit, the Company utilized an average of the actual capital expenditures in the capital budget categories of Asset Health and Reliability and Capacity over a five-year period 2014 through 2018. This average capital expenditure was then multiplied by 1 percent to calculate the reduction in capital expenditures resulting from AMI.

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(2) Outage Management Efficiency

Q. DESCRIBE THE IMPROVEMENT IN OUTAGE MANAGEMENT EFFICIENCY THAT WILL BE ACHIEVED FROM THE INSTALLATION OF AMI METERS.

A. AMI will enable increased outage management efficiencies by providing automated outage notification and restoration confirmation (power-on information) to the Company's Outage Management System (OMS). Power loss information is identified by an AMI meter's last gasp. Outage notification from the AMI meters will provide the Company with a timelier and more accurate scope of an outage. The automated outage information provided by the AMI meters will then assist the Company in restoring power more quickly. AMI will also enable more efficient outage restoration because the AMI will provide more detailed outage location information that will reduce the time and expense in locating the outage. Overall, because of these increased outage management efficiencies, AMI enables quicker response and restoration to customer outages to minimize inconveniences or economic losses that could be experienced by the customer.

Q. HOW DID XCEL ENERGY QUANTIFY THESE OUTAGE MANAGEMENT EFFICIENCY BENEFITS?

A. Xcel Energy estimates that AMI will result in a 10 percent reduction in storm-related capital costs due to the efficiencies gained from the information provided by the AMI meters. To develop this percentage, the Company examined historic storm-related capital expenditures in light of the improve outage information that AMI will provide and determined that a 10 percent reduction was a reasonable, if not conservative, estimate of expected reduction that will result from the data provided AMI meters.

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The Company utilized an average of the storm-related capital expenditures for the five-year period between 2014 and 2018. This average storm-related capital expenditure was then multiplied by 10 percent to calculate the benefit resulting from AMI deployment.

(3) Avoided Meter Purchases

Q. DESCRIBE THE AVOIDED METER PURCHASE BENEFIT THAT WILL RESULT FROM DEPLOYMENT OF THE AMI METERS?

A. AMI meters will have a lower failure rate as compared to our existing AMR meters. As a result, there is a cost savings associated with not having to replace these failed AMR meters. The benefit from avoided AMR meter purchases, however, is partially offset by the cost of ongoing replacement of AMI meters due to normal failure rates.

Q. HOW DID THE COMPANY CALCULATE THE BENEFIT ASSOCIATED WITH AVOIDED METER PURCHASES?

A. Based on historical data from 2014 to 2018, Company calculated that the average percentage failure rate of our current AMR meters is approximately 1.92 percent per year. In contrast, the AMI meter vendor provided an estimated failure rate of 0.5 percent per year for the new AMI meters based on their own experience and testing.

The total failure cost associated with replacing a failed meter has three components: meter cost, installation cost, and total number of failed meters per year. The total failure cost for replacing AMR meters was based on our current actual meter and installation costs. The total failure cost for replacing

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AMI meters was based on the meter and installation costs included in our contract with our selected meter vendor. The difference between total AMR failure costs and the total AMI failure costs was used to determine the cost savings associated with AMI.

(4) Avoided Cost of Alternative Meter Reading System

Q. DESCRIBE THE BENEFIT ASSOCIATED WITH AVOIDING AN INVESTMENT IN AN ALTERNATIVE METER READING SYSTEM?

A. As mentioned above, our current meter reading contract is set to expire in 2025 (or 2026 with a costly extension) and the Company will need to find a replacement meter reading system. One option is to replace the current AMR Cellnet meter reading system with another basic AMR meter reading alternative such as a drive-by system. Since the deployment of AMI will eliminate the need to replace the existing AMR Cellnet meter reading with an alternative drive-by meter reading system, these avoided costs are a benefit of AMI.

Q. HOW DID THE COMPANY DETERMINE THE COSTS FOR AN ALTERNATIVE DRIVE-BY SYSTEM?

A. PSCo employs an AMR drive-by system in Colorado and as a result, the Company was able to utilize actual costs of that system to estimate the upfront and projected capital and ongoing operating costs to deploy a similar system in Minnesota. To translate the costs from Colorado to Minnesota, the Company also prepared an analysis of possible routes for the drive-by meter reading system to better estimate these costs. The capital cost components include meters, meter installation, other deployment costs, vehicles, equipment and material, and project management. We also estimated reasonable O&M costs

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that include meter reading labor, vehicles, equipment maintenance, customer claims, and contingencies.

Q. HOW DID THE COMPANY CALCULATE THE AVOIDED COST BENEFIT ASSOCIATED WITH NOT HAVING TO DEPLOY AN ALTERNATIVE DRIVE-BY SYSTEM?

A. The total costs of this AMR drive-by system was assumed as the benefit of AMI as these costs would not be incurred if AMI is deployed.

b. O&M Benefits

Q. WHAT ARE THE O&M BENEFITS FOR AMI THAT YOU PROVIDE SUPPORT FOR IN YOUR TESTIMONY?

A. I describe and provide support for calculation of the following O&M benefits of AMI:

- Reduction in O&M for field and meter services;
- Improved efficiency in distribution maintenance; and
- Improved outage management efficiency.

The O&M benefit associated with implementing AMI as opposed to a drive-by meter reading system (i.e., avoided O&M for drive-by meter reading costs) that I mentioned in the prior section above is discussed by Mr. Cardenas.

Q. IN GENERAL, WHAT O&M BENEFITS DOES THE COMPANY ANTICIPATE AS A RESULT OF IMPLEMENTING AMI METERS?

A. AMI will enable Xcel Energy to perform several functions remotely that otherwise require a field visit to the customer premise. As a result, O&M cost savings will be realized through reductions in field personnel trips to repair

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damaged equipment, to confirm power has been restored after an outage, to reconnect and disconnect customers, and for voltage investigations.

(1) Reduced Field and Meter O&M Expenses

Q. WHAT ARE THE TYPES OF FIELD AND METER SERVICE EXPENSES THAT WILL BE REDUCED BY IMPLEMENTING AMI?

A. Since AMI meters will have the ability to provide billing, power, and voltage information to the Company on command, there will be a reduced need to send personnel to the field to gather this information. This will result in O&M savings in several areas:

- *Reduction in Outage Trips due to Customer Equipment Damage*: Our current AMR system requires crews to be dispatched to verify outages. Sometimes these outages are due to damaged customer equipment and not utility damaged equipment. Under the new AMI system, AMI meters will have two-way communications to the meter and the Company can verify whether there is power at the meter thus pointing to a likely customer problem. This would help reduce field trips while also assisting customers in identifying the likely cause of the outage.
- *Cost Savings from Remote Connect Capability*: AMI enables remote connection and disconnection of residential type service without the need to dispatch crews. This will result in personnel and transportation cost savings due to the reduction in field visits.
- *Reduction in "Ok on Arrival" Outage Field Visits*: AMI will allow the Company to test for loss of voltage at the service point and detect both outage conditions and to know when restoration is complete. As a result, AMI implementation will help eliminate unnecessary field trips

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to customer premises that result in field personnel finding no electric service issues upon arrival.

- *Reduction in Field Visits for Voltage Investigations*: When notified of a potential voltage problem, the Company currently sends a technician to investigate. AMI enables the elimination of unnecessary trips when proper voltage can be verified remotely, and helps us prioritize and dispatch the most appropriate crews if the voltage is outside of the appropriate range.

Q. HOW DID THE COMPANY CALCULATE THE O&M SAVINGS ASSOCIATED WITH THE REDUCTION IN FIELD TRIPS DUE TO DAMAGED CUSTOMER EQUIPMENT?

A. To calculate this O&M savings, Company first determined the average number of trips per year between 2014 and 2018 for damaged customer equipment. This average was 1,796 trips per year. The Company also determined that AMI would result in a 50 percent reduction in the number of trips per year for damaged customer equipment. To determine the cost benefit from this 50 percent reduction in the number of trips, the Company utilized the average O&M costs for a trip based on historic cost estimates from 2014 to 2018. To calculate the benefit amount, the Company applied a 50 percent reduction to the average number of trips and then reduced this amount by 50 percent and multiplied this by the average O&M cost. The cost of each trip is the sum of dispatch savings (wages multiplied by time saved) plus crew savings (same as dispatch), and overhead savings. To estimate the cost savings the Company multiplied the reduced number of trips by the estimated trip costs.

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Q. HOW DID THE COMPANY DETERMINE THAT AMI WOULD RESULT IN A 50 PERCENT REDUCTION IN THE NUMBER OF TRIPS DUE TO DAMAGED CUSTOMER EQUIPMENT?

A. The Company examined historic data for trips required due to damaged customer equipment and determined that 50 percent was a reasonable, if not conservative, estimate of this reduction. AMI will allow the Company to, in most cases, to determine remotely whether there is power at the meter thus pointing to a likely customer equipment issue. The only times when a field trip may still be required are when there are network communication issues, weather issues, or an issue inside the meter that will prevent us from remotely obtaining the necessary information to fix the issue. We expect that these situations will be limited and as a result the 50 percent reduction is conservative. By way of comparison, the Ameren Business Case assumed a 90 percent reduction in damaged customer equipment field trips due to AMI.

Q. HOW DID THE COMPANY CALCULATE THE COST SAVINGS FROM THE REMOTE CONNECTION CAPABILITY PROVIDED BY AMI?

A. An average of 4,416 residential disconnect and reconnect trips per year were completed by the Company between 2014 and 2018. To derive these benefits, the Company estimated that AMI will reduce the labor costs for these trips by approximately 70 percent for manual disconnections and 95 percent for manual reconnections. The Company believes that 70 percent is a reasonable reduction for disconnects as manual disconnection may still be required in approximately 30 percent of cases such as when the Company does not have accurate customer contact information or where a customer has opted out of AMI. The Company believes that 95 percent is a reasonable reduction for reconnection as manual reconnection may be required in cases where there is

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a poor communication connection to the AMI meter. The labor costs used to calculate these benefits were based on prevailing wage, overheads, and fleet costs. To estimate the cost savings the Company multiplied the reduced number of trips by the estimated labor costs.

Q. WILL THE COMPANY NEED COMMISSION APPROVAL TO ENABLE THE REMOTE RECONNECT AND DISCONNECT CAPABILITIES OF THE AMI METERS?

A. Yes, I understand that enabling these capabilities will require Commission approval. These regulatory filings are discussed by Mr. Cardenas. While these capabilities will require regulatory approval, the ability to remotely connect and disconnect customers is a benefit of AMI meters and as a result is included in the CBA.

Q. HOW DID THE COMPANY CALCULATE THE COST SAVINGS ASSOCIATED WITH "OK ON ARRIVAL" OUTAGE FIELD VISITS?

A. Between 2014 and 2018, there was approximately average of 7,464 trips per year where field crews found no issues with a customer's electric service upon arrival. The Company assumed that these trips would be reduced by approximately 50 percent as a result of AMI. This 50 percent reduction is reasonable, if not conservative, given that the AMI meter will allow the Company the ability to remotely determine whether or not power is on at an individual meter. There will of course be relatively rare instances where the Company will not perform this remote diagnostic test due to either network connection or weather issues. The labor costs used to calculate these benefits were based on prevailing wage, overheads, and fleet costs. To estimate the cost savings the Company multiplied the reduced number of trips by the estimated labor costs.

Q. HOW DID THE COMPANY CALCULATE THE COST SAVINGS ASSOCIATED WITH THE REDUCTION IN FIELD VISITS FOR VOLTAGE INVESTIGATIONS?

A. There was an average of 2,858 trips per year from 2014 to 2018 for voltage investigations. The Company assumed that AMI would reduce these voltage investigation trips by 50 percent. This 50 percent reduction is reasonable given that the Company will be able to obtain detailed voltage information remotely from AMI meters. In certain cases, the Company may still need to go to a customer premise to investigate voltage information due to either a poor communication connection or in cases where the voltage information is inconclusive. The labor costs used to calculate these benefits were based on prevailing wage, overheads, and fleet costs. To estimate the cost savings the Company multiplied the reduced number of trips by the estimated labor costs.

(2) Improved Distribution Maintenance Efficiency

Q. WHAT ARE THE IMPROVED EFFICIENCIES IN DISTRIBUTION MAINTENANCE FROM AMI THAT WILL RESULT IN O&M BENEFITS?

A. AMI data can be aggregated at varying levels of the distribution system that include the tap, transformer, and service lines amongst other distribution system equipment. This data will be used by Distribution to prioritize grid improvements and more efficiently plan and design the system. This data can then be used to determine optimal timing for installation and replacement of distribution assets as well as optimizing inventory levels. As discussed in the capital benefits section above, the Company estimated that these efficiencies will provide a 1 percent reduction in capital expenditures for Asset Health and Reliability projects and Capacity projects. This benefit is the O&M portion of this benefit which the Company determined would amount to a 0.1 percent

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reduction in the O&M expenditures for Asset Health and Reliability and Capacity projects. To determine this 0.1 percent, the Company examined past O&M costs for these types of projects.

(3) Outage Management Efficiency

Q. HOW WILL AMI REDUCE O&M COSTS DURING OUTAGES?

A. AMI enables an automated outage information system that allows the Company to deploy crews more efficiently to outage areas, especially during storm outages, ensuring verification that all customers in an area have been restored before dispatching the crew to the next location.

Q. HOW DID THE COMPANY CALCULATE O&M SAVINGS FROM THE IMPROVED EFFICIENCIES IN OUTAGE MANAGEMENT AS A RESULT OF AMI?

A. The Company utilized the average yearly O&M costs for storm related activities from 2014 to 2018 ($2,100,000) and then calculated 10 percent reduction in these costs due to AMI. As discussed, AMI will enable quicker responses to outages by our field crews as they will have more detailed information as to the location of the outage thus reducing time and expense. This 10 percent reduction is reasonable based on the Company's review of historic O&M storm information. This 10 percent reduction is also in alignment with the Ameren Business Case. Ameren serves customers in a similar area of the country we expect our storm expense O&M reductions to be similar.

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c. Other Benefits of AMI

Q. OTHER THAN THE CAPITAL AND O&M BENEFITS THAT YOU DISCUSS ABOVE, ARE THERE OTHER QUANTIFIABLE BENEFITS OF AMI?

A. Yes. The other quantifiable benefits include:

- Reduced consumption on inactive meters,
- Reduced uncollectible/bad debt expense,
- Reduced theft/meter tampering,
- Load flexibility benefits associated TOU rates (peak demand reduction, customer energy price savings, and reduced emissions).
- Reduced outage duration.

The majority of these other benefits of AMI are discussed by other Company witnesses. Mr. Cardenas discusses the first three benefits and Dr. Duggirala discusses the load flexibility benefits. I will discuss the last benefit (reduced outage duration).

Q. HOW WILL AMI REDUCE THE LENGTH OF OUTAGES?

A. AMI meters send a last gasp message to the utility before the meter loses power. Not all last gasp messages make it, but usually enough messages are received to help the utility adequately determine which customers are affected. This outage data helps utility personnel respond more quickly to fix problems with the end result being that customers' power is restored more quickly. Another benefit of AMI meters is verification of power restoration. Restoration verification is accomplished when a meter reports in after being reenergized. This will provide automated and positive verification that power has been restored to all customers, there are no nested outages, and all associated trouble orders are closed before restoration crews leave the areas.

This reduces costs, increases customer satisfaction, and further reduces outage duration.

Q. HOW DID THE COMPANY CALCULATE THE CUSTOMER BENEFIT ASSOCIATED WITH THIS REDUCTION IN OUTAGE DURATION?

A. The Company estimated that AMI meters will help reduce outage length resulting in direct benefits for customers. Three main improvement areas were evaluated for Customer Minutes Out (CMO) reduction: (1) better identification of nested outages during storm events; (2) reduction in response time for single customer events; and (3) faster response to tap level events. For each activity, the Company determined the value of these CMO based on the Interruption Cost Estimate (ICE) Calculator developed by Lawrence Berkeley National Laboratory (LBNL).[12]

Q. WHAT IS THE ICE CALCULATOR?

A. The ICE Calculator estimates the value of an interruption from a customer viewpoint. LBNL bases the value for commercial and industrial customers on their costs due to an outage, and for residential customers, the amount that they would be willing to spend to avoid an outage. It incorporates studies, analyses, and econometric models to determine these values and is widely used by utilities and government agencies across the country to estimate the costs of service interruptions and the value of reliability improvements.

[12] The ICE Calculator is available at: https://icecalculator.com/home.

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Q. HOW DID XCEL ENERGY CALCULATE THE VALUE OF THE BENEFIT RELATED TO BETTER IDENTIFICATION OF NESTED OUTAGES DURING STORM EVENTS?

A. During a large storm event, when a customer can experience multiple outage issues, it can be difficult to determine if all customers' power has been restored in an area after identifying and completing outage work at a single location. The ability to check which customers' power has been restored by automatically "pinging" their AMI meter will improve efficiencies in restoration work.

To calculate this benefit, we utilized outage data on Major Event Days (MEDs) (as this data typically captures large storms) for the years 2015-2017. CAIDI was determined to be 572 minutes for a storm day. The CAIDI value was inserted into the Customer Minute Out (CMO) value calculator. The result is a dollar savings per CMO of $0.65. The average annual number of CMO during major event days was 115,264,755 minutes. It is estimated that the ability to automatically ping AMI meters would reduce the number of CMO by 0.5 percent. This was multiplied by the $0.65 to calculate the total annual benefit of $374,610 which when divided by the number of meters for an estimated benefit of $0.30 per customer per year.

Q. HOW DID XCEL ENERGY CALCULATE THE VALUE OF THE REDUCTION IN RESPONSE TIME FOR SINGLE CUSTOMER EVENTS?

A. Today, when a single customer contacts Xcel Energy about an outage, it is frequently an outage issue on the customer's side of the meter or not an outage at all. First, Xcel Energy attempts to contact the customer and verify the outage. Frequently, this verification fails and the when the first responder arrives at the customer site the issue is then identified as a non-Xcel Energy outage event. Often while Xcel Energy is responding to the first event another single customer outage is in the queue, waiting for work on the first event to be completed. Installation of AMI will allow the Company to determine the first event is a non-Xcel Energy outage event, allowing Xcel Energy to more quickly respond to the other event.

The benefit of this reduced wait time was calculated based on single customer outage event data for 2015-2017 using only non-MEDs data. The average CAIDI for these events was 184 minutes. These outages added up to a total of 3,147,220 CMO for three years. It was estimated that half of the time the CMO could be reduced by 20 percent for an annual savings of 104,907 CMO. The CAIDI value was inserted into the CMO value calculator. The result is a savings per CMO of $0.75. This $0.75 was multiplied by the annual CMO reduction of 104,907 CMO to calculate the total annual savings of $78,680, which when divided by the number of meters equate to an estimated benefit of $0.06 per customer per year.

Q. HOW DID XCEL ENERGY CALCULATE THE VALUE RELATED TO A FASTER RESPONSE TO TAP LEVEL EVENTS?

A. Xcel Energy prioritizes outage events by the number of customers impacted by an outage. On a typical day, when an incoming outage is identified as a single customer event, work in progress continues and response to the single customer event waits until existing work is complete. Typically a multi-customer event is initially identified as a single customer event. Only when the outage event is identified as a multi-customer event, is work reprioritized. AMI will provide greater visibility into outages and will allow work to more quickly be reprioritized allowing for a faster response time to larger outage events.

The benefit of this faster response time was calculated using data from multi-customer events from 2015-2017 for non-MEDs. The average annual number of customers experiencing an outage or 396,883 customers was multiplied by three minutes (the estimated average time for more than one customer to report an outage) for an annual CMO savings of 1,190,649 minutes. The CAIDI value for multi-customer events, 271 minutes, was inserted into the CMO value calculator. The result is a savings for a per customer minute out of $0.70. This $0.70 was multiplied by the annual CMO reduction of 1,190,649 CMO to calculate the total annual savings of $833,454, which when divided by the number of meters equate to an estimated benefit of $0.67 per customer per year.

Q. HOW DID XCEL ENERGY CALCULATE THE TOTAL OUTAGE REDUCTION BENEFIT?

A. The total dollar value for each of these three categories of benefits was summed for a total benefit of $1.03 per customer. The Company then calculated the total outage reduction benefit by multiplying this $1.03 value by the total number of meters to be deployed.

d. Non-Quantifiable Benefits

Q. WHAT ARE THE ANTICIPATED NON-QUANTIFIABLE BENEFITS OF AMI?

A. Xcel Energy anticipates qualitative benefits in several areas, including:

- Improved customer choice and experience, leading to customer empowerment and satisfaction;

- Enhanced distributed energy resource integration;
- Environmental benefits of enhanced energy efficiency;
- Improved safety to both customers and Xcel Energy employees; and
- Improvements in power quality.

I will discuss the last four of these non-quantifiable benefits, and Mr. Gersack discusses the first benefit related to improved customer choice and experience.

(1) Distributed Energy Resource Integration

Q. HOW WILL AMI ENABLE GREATER DISTRIBUTED GENERATION INTEGRATION?

A. AMI will provide more timely and more granular data on the flow of energy to and from our customers. With this load flow information, and with voltage, current, and power quality data provided from AMI to ADMS, system operators will be able to facilitate the integration of greater amounts of distributed generation on to the system. In addition, the bi-directional capabilities of the AMI meters will allow the ability to perform net metering for our DER customers without the need to change out the existing meter.

Additionally, the AMI system will capture voltage and usage data which can be compared with nameplate or operational limits of our equipment. Using this data, we will be able to identify problems such as solar causing high secondary voltage, or transformer overload due to either a strong presence of EVs (load) or high reverse flows (such as solar generation). It is our intention to leverage AMI data for this purpose, which will allow us to enable DER while at the same time maintain reliability and power quality for each of our customers.

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Further, AMI will enable the creation of more accurate load profiles which are used by ADMS to create better system models for planning and operational purposes. Initially, ADMS will be using relatively few profiles to represent typical customer loads. Once AMI has been in place for a year, we will create more refined profiles which will significantly improve our models. This data will then support planning and operational modeling, enabling us to more accurately identify problems (or the lack thereof) as more load or DER hosting is contemplated for the system.

Finally, AMI meters have bi-directional capabilities that can be utilized by our DER net metering customers. Currently, when a customer who is eligible for net-metering adds generation, we replace the meter with to enable bi-directional flow. With AMI we will be able to effect this change remotely saving the cost of a meter change.

(2) Energy Efficiency

Q. WHAT ARE THE POTENTIAL ENVIRONMENTAL BENEFITS OF AMI?

A. AMI is expected to result in greater energy efficiency by the customer and the Company. As previously stated, AMI will provide the customer more information on energy usage and will enable the Company to offer additional time-based rates or other offerings that allow more customer choice in controlling their energy usage and costs. To the extent these energy efficiency gains reduce the need for generation they will contribute to lower energy emissions.

(3) Safety Improvements

Q. HOW WILL AMI IMPROVE SAFETY FOR BOTH CUSTOMERS AND XCEL ENERGY EMPLOYEES?

A. AMI enables the meters to be read, remotely disconnected and reconnected, and enables remote diagnostics of the customer's service, thereby minimizing safety risks for Company representatives and the customer. For example, AMI will allow us to more rapidly assist emergency personnel by remotely shutting off power to a burning building as opposed to dispatching a truck to perform the disconnection. In addition, while AMR meters can do some level of automated reading, they cannot minimize meter diagnostic and connect/disconnect visits to the same extent as AMI meters. AMI provides several remote functions that eliminate or minimize the need for the Company to visit the meter, which minimizes the intrusiveness to the customer and potentially reduces safety concerns of unknown people accessing their property. Reducing these visits also reduces employee safety risks associated with customer pets and traversing unfamiliar properties.

(4) Power Quality Improvements

Q. HOW WILL AMI PROVIDE IMPROVEMENTS IN POWER QUALITY?

A. AMI will monitor and provide power measurement and voltage data at more points within the distribution system, which will be used in load flow and IVVO calculations to enable improvements in power quality. This will help ensure voltage is within acceptable limits from the substation all the way to the customer's point of service. In other words, better monitoring of power quality reduces the potential for out-of-range voltages that may interfere with electronic devices in customers' homes or businesses. Additionally, timely power outage and restoration will enable improved outage management and contribute to improved power quality to our customers overall.

5. AMI Costs

Q. PLEASE DESCRIBE THE WORK THAT DISTRIBUTION WILL UNDERTAKE IN 2020, 2021, AND 2022 TO IMPLEMENT AMI.

A. Xcel Energy plans to install 1.3 million advanced meters between 2021 and 2024. The Distribution Business Area will be primarily responsible for the purchase and installation of these meters. Distribution will support the installation of the new AMI meters as well as removal, retirement, and disposal of the existing AMR meters, but the installation and removal work will primarily be done by the meter vendor. Distribution will also test and configure all AMI hardware to ensure that it is working properly and is able to integrate with other products and applications.

Q. WHAT ARE DISTRIBUTION'S COSTS FOR THE FULL AMI DEPLOYMENT?

A. Distribution's costs for AMI are broken down by capital additions and O&M costs through the term of multi-year rate plan in Tables 36 and 37 below. I will describe these costs in further detail below.

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Table 36

AMI Capital Additions – Distribution State of MN Electric Jurisdiction (Includes AFUDC) (Dollars in Millions)			
AGIS Program	**2020**	**2021**	**2022**
AMI	$1.8	$22.2	$110.9

Table 37

AMI O&M – Distribution NSPM – Total Company Electric (Dollars in Millions)			
AGIS Program	**2020**	**2021**	**2022**
AMI	$2.3	$3.3	$5.0

a. Distribution Capital Costs for AMI

Q. WHAT ARE THE PRINCIPAL CAPITAL COSTS ASSOCIATED WITH IMPLEMENTATION OF AMI?

A. Distribution's capital costs associated with implementing AMI are: (1) the meters; (2) meter installation; (2) vendor project management; (3) AMI operations; and (4) testing equipment.

Q. WAS DISTRIBUTION PRIMARILY RESPONSIBLE FOR DEVELOPING THE COSTS FOR AMI?

A. Distribution is responsible for the costs associated with acquiring and installing the AMI meters. I describe how we developed our forecast for these costs in more detail in my Direct Testimony. Business Systems is responsible for developing the forecasts for the head-end application, other software and hardware to support AMI data processing, and integrations required by those technologies, and Mr. Harkness will address the development of those costs.

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Q. WHAT ARE THE PRIMARY COMPONENTS OF DISTRIBUTION'S AMI CAPITAL FORECAST?

A. Distribution's AMI capital forecast has five key components: (1) AMI meter purchase; (2) AMI meter installation; (3) vendor project management; (4) AMI operations (external and internal); and (5) testing equipment.

Q. HOW DID DISTRIBUTION DEVELOP THE COSTS FOR THE AMI METERS AND INSTALLATION?

A. The costs for the AMI meters and installation are based on the meter contract with our AMI meter vendor, Itron Inc. (Itron). Additional overheads such as taxes are also included in these estimates.

Q. DESCRIBE THE PROCESS USED TO SELECT THE AMI METER VENDOR.

A. Xcel Energy issued a Request for Proposal (RFP) in March 2018 to select an electric AMI meter vendor that could provide an AMI meter, project management, and installation services. As part of the RFP process, potential vendors were asked to review the Company's priorities and vision for its AMI solution including the capabilities desired by the Company for this technology. The vendors were then asked to provide precise and detailed responses to numerous technical questions regarding their AMI meter offerings related to the following:

- Technical standards of the their meter;
- Capabilities of their meter;
- Compatibility of their AMI meter with other components of the AGIS initiative;
- Data and cybersecurity safeguards;

- Plan and schedule for technology development, integration, and AMI deployment; and
- Itemized pricing information for their AMI meter and installation.

We received responses to this RFP from four different companies.

Q. HOW DID XCEL ENERGY EVALUATE THESE RFP RESPONSES?

A. Xcel Energy evaluated these responses on a number of factors including: (1) total cost; (2) schedule requirements; (3) core metrology; (4) customer benefits and capabilities; (5) integration with the selected NIC from Silver Springs (which was purchased by Itron, Inc.); (6) future proofing/new technology; (7) commercial terms and conditions; and (8) security.

Q. WERE THERE OTHER CAPABILITIES THAT THE COMPANY DESIRED FOR THE NEW AMI METERS?

A. Yes. The Company was also interested in making sure that the selected AMI meter could support distributed intelligence capabilities. As discussed above, these are computing capabilities within the AMI meter that allows the meter to run different applications. These capabilities were an important consideration as the Company understood the customer facing, operational, and future proofing benefits that these capabilities could provide.

Q. DID XCEL ENERGY SELECT AN AMI METER AND INSTALLATION VENDOR FROM THESE RFP RESPONSES?

A. Yes. Based on an assessment and comparison of the capabilities, price, and schedule commitments provided in the RFP responses from these four different meter vendors, Xcel Energy selected a meter vendor. Xcel Energy

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issued a Limited Notice to Proceed to that meter vendor in December 2018. However, in late March 2019, Xcel Energy learned that the meter vendor that was initially selected would not be able to integrate the selected NIC and meet the Company's meter deployment schedule set forth in the Limited Notice to Proceed. As a result, Xcel Energy requested that the initially selected vendor provide a schedule for deployment for AMI meters that incorporated the vendor's own NIC and network.

Q. WHAT RESPONSE DID THE COMPANY RECEIVE TO THIS REQUEST?

A. The initial meter vendor's response indicated that it would not be able to integrate their own NIC and network into the meters without a significant increase in cost and a risk of further schedule delays. However, the Company also received a comprehensive proposal from another meter vendor that responded to the initial RFP. This meter vendor was able to meet the Company's requested deployment schedule with the necessary NIC integration, offered the necessary meter capabilities, and offered favorable price and contractual terms. As a result, in May 2019, Xcel Energy selected Itron as its meter vendor and a contract was executed on September 1, 2019 (Meter Contract).

Q. WHY DID XCEL ENERGY SELECT ITRON AS ITS METER VENDOR?

A. The primary factors in the decision were:

- Lowest cost/best overall value for an offering that included distributed intelligence / edge technology;
- Lowest risk solution / least complexity;
- Met Xcel Energy's deployment schedule;

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- Single vendor solution (Itron is already under contract for the mesh network and the head-end software);
- Met or exceeded Xcel Energy's core metrology requirements, including distributed intelligence capabilities; and
- Most favorable overall commercial terms and conditions, including for edge technology/distributed intelligence.

A summary of our analysis supporting the selection of Itron is attached is Exhibit___(KAB-1), Schedule 10.[13]

Q. HOW DID DISTRIBUTION DEVELOP ITS CAPITAL FORECAST FOR THE AMI VENDOR PROJECT MANAGEMENT COSTS?

A. The forecast for AMI vendor project management is set forth in the Meter Contract. The Company's estimates also include internal overheads.

Q. HOW DID DISTRIBUTION DEVELOP ITS CAPITAL FORECAST FOR AMI OPERATIONS RELATED TO INTERNAL AND EXTERNAL PERSONNEL?

A. Cost estimates for internal and external personnel were developed based on the role and number of required personnel required to perform necessary tasks to enable installation and deployment of the AMI meters. The necessary positions include analysts, program and project managers, engineers, and electricians. The cost estimates were determined using average pay scales for the needed positions combined with an estimate the amount of work required by each of these roles during the AMI installation and deployment. The

[13] The Company's RFPs related to the AGIS projects are provided on the AGIS supporting files compact disk provided with Vol. 2B.

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Company then determined the appropriate allocation between capital and O&M for these costs based on the type of work being performed.

Q. HOW DID DISTRIBUTION DEVELOP ITS CAPITAL FORECAST FOR TESTING EQUIPMENT?

A. These cost estimates were based on quotes obtained and purchases that were made from our existing vendors for this testing equipment. This testing equipment is standard off-the-shelf equipment and we leveraged our relationships with existing vendors to obtain the best cost for this equipment.

b. Distribution O&M Costs for AMI

Q. WHAT ARE DISTRIBUTION'S O&M COSTS ASSOCIATED WITH AMI?

A. The primary components of Distribution's AMI O&M expense relate to: (1) AMI operations (internal and external); and (2) customer claims.

Q. HOW DID THE COMPANY DEVELOP THE BUDGET FOR AMI OPERATIONS?

A. The development of these costs was discussed earlier in the capital section.

Q. HOW DID THE COMPANY DEVELOP THE BUDGET FOR CUSTOMER CLAIMS?

A. Based on input from industry experts, Company estimated approximately $100,000 for small claims from customers associated with meter installations. This total was then spread across the deployment years based on the number of meters deployed in each particular year.

c. Distribution Contingency for AMI

Q. DOES DISTRIBUTION'S AMI FORECASTS INCLUDE CONTINGENCY AMOUNTS?

A. Yes. The use of contingencies is consistent with project planning practices, especially for large projects. We believe it is appropriate to include a contingency amount at this stage given that the project will be implemented over multiple years, as well as the complexity, size, and integrated nature of this project. Mr. Gersack discusses the overall AGIS project contingencies in his testimony.

Q. WHAT IS THE AMOUNT OF DISTRIBUTION'S CONTINGENCY FOR AMI?

A. The Distribution's AMI budget forecast for the period 2020-2025 includes capital contingency amounts of approximately 26 percent.

Q. CAN YOU PROVIDE MORE INFORMATION ABOUT THE DISTRIBUTION CONTINGENCY ASSOCIATED WITH AMI?

A. Yes. The level of contingency is based on our current risk assessment of items that may impact the final costs of the project. While the Meter Contract dictates much of Distribution's costs for AMI meters and installation, there are still certain unknowns that could impact our final costs. These include: (1) customer access issues; (2) issues with existing electrical wiring to the meter box; and (3) changes to the deployment schedule. Given that the scope of our AMI meter deployment is vast and requires that we replace all of the electric meters throughout our entire service territory, it is important that we have sufficient contingency to account for these potential risks.

Q. PLEASE DESCRIBE THESE POTENTIAL RISKS THAT YOU IDENTIFIED?

A. Customer access issues involve difficulties associated with obtaining access to a customer's meter to remove the existing meter and install a new meter. This could involve a meter located in the basement of a home or a meter located outside that is guarded by an unfriendly dog. These types of access issues could result in increased costs due the increased labor and expense associated with multiple visits that are required perform the necessary work. Issues with existing electrical wiring to the meter box could also lead to increased costs due to the increase in labor and material costs associated with repairing such issues. Given that the existing meters at many customer locations are between 20-30 years old, it is difficult to know at this time the number of such issues that may arise with the existing electrical wiring. Finally, there may be changes to the deployment schedule that could impact final costs.

Q. HOW DID THE COMPANY DEVELOP AN APPROPRIATE CONTINGENCY AMOUNT TO ACCOUNT FOR THESE POTENTIAL RISKS?

A. Based on our assessment of these risks and their potential financial impact we set an overall contingency amount for AMI and then allocated that amount to each year of the AMI deployment based on the amount of work being completed in each year.

Q. DOES THE COMPANY BELIEVE THE CONTINGENCIES WILL BE USED?

A. Yes, to some extent. While the Company does not necessarily anticipate using all of the contingencies, we believe that some amount of contingency will be used based on experience with prior projects. Contingency amounts are included to avoid the need for tradeoffs in schedule and/or scope and functionality. In this way, we can ensure implementation of the project will

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help maximize benefits for our customers. As Mr. Gersack discusses, there are strict controls on when and how the contingency amounts may be used. The overall AGIS governance structure provides for review and approval of any project changes that will affect the scope, costs, or benefits of implementation. Any changes from budgeted amounts and any specific use of budget contingencies will need approval according to the established AGIS governance processes.

d. AMI Expenditures 2020-2029

Q. WHAT ARE DISTRIBUTION'S CAPITAL EXPENDITURE AND O&M FORECASTS FOR AMI FOR 2020 THROUGH 2029?

A. The tables below provide the Distribution's AMI capital expenditure and O&M forecasts for 2020 through 2029.

Table 38

AMI Capital Expenditures – Distribution NSPM - Total Company Electric (Dollars in Millions)					
	Rate Case Period			5-year Period	10-year Period
AGIS Program	**2020**	**2021**	**2022**	**2023-2024**	**2025-2029***
AMI	$2.6	$22.3	$133.9	$179.5	$14.1
*Period may include additional assumptions, including inflation and labor cost increases that are not part of the capital budget in periods 2020-2024.					

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Table 39

AMI O&M Expenditures – Distribution NSPM – Total Company Electric (Dollars in Millions)					
	Rate Case Period			**5-Year Period**	**10-Year Period**
AGIS Program	**2020**	**2021**	**2022**	**2023-2024**	**2025-2029***
AMI	$2.3	$3.3	$5.0	$10.0	$15.7
*Period may include additional assumptions, including inflation and labor cost increases that are not part of the capital budget in periods 2020-2024.					

6. Alternatives to AMI

Q. WHAT ALTERNATIVES TO AMI DID THE COMPANY EVALUATE?

A. The Company considered several alternatives to AMI. These alternatives were to: (1) extend the life of the existing AMR meters; (2) replace existing AMR meters as they fail with AMI meters; (3) utilize a different AMR solution with limited TOU capabilities; (4) utilize an AMR drive-by solution; or (5) return to non-AMR, manually read meters. I note that none of these alternatives provide the same benefits and functionality for our customers that are provided by the full deployment of AMI proposed by the Company. AMI meters are essential to an advanced grid that provides our customers and the Company with the data and information to improve our customers' energy experience, and improve reliability, safety, and security of the grid.

a. Extend life of existing AMR meters

Q. CAN YOU DESCRIBE THE CURRENT AMR METERS THAT ARE INSTALLED IN MINNESOTA?

A. The majority of Xcel Energy's electric meters in Minnesota are part of a one-way, transmit-only Radio Frequency (RF) fixed network AMR system. This system mostly provides total energy and demand information once a day based on the type of meter installed. The meter is affixed with a Cellnet module that transmits meter pulse data multiple times a day to pole-mounted network components. While the current AMR system has some ability to support more complex rate designs, such as limited TOU rates, and provides non-usage data, such as a "last gasp" when the power goes out, these meters do not have two-way communication capabilities. Without two-way capabilities, we must dispatch a meter technician to reconfigure a meter's TOU intervals each time a customer wants to change their rate.

Q. WHAT DID THE COMPANY CONCLUDE AFTER EVALUATING THE POSSIBILITY OF EXTENDING THE LIFE OF THE EXISTING AMR METERS?

A. Our current AMR system has been in place since the mid-1990s and has provided substantial value for customers since its installation. However, as I mentioned above, our Cellnet meter reading and vendor support contract expires at the end of 2025. We have the ability to extend this contract for one additional year but at a significant cost increase as compared to prior years. We are the last remaining customer on the Cellnet system such that our ability to extend this meter reading and vendor support contract beyond 2026 is highly unlikely. As a result, our ability to continue to use the Cellnet system for meter reading beyond 2026 would require us to purchase the existing meter reading network, software, and meter modules from Cellnet.

Even if we purchased this system from Cellnet, it would be challenging to continue to operate and maintain this aging system in good working order because Cellnet will stop manufacturing replacement parts for this system in 2022. As this system is proprietary, there are no other vendors that we can utilize to provide replacement parts for this system. As a result, as these meters age and require repair, we will not be able to purchase the necessary replacement components. Given the inability to find replacement parts for the existing Cellnet meters, Xcel Energy determined that trying to extend the life of these meters beyond the end of the Cellnet contract was simply not a reasonable or prudent alternative.

b. Replacing AMR meters one at a time

Q. DID THE COMPANY CONSIDER REPLACING AMR METERS WITH AMI METERS ONE AT A TIME AS THEY FAIL?

A. Yes, but the Company determined that installing the 1.3 million AMI meters at the same time to all of our Minnesota customers was the best option for several reasons. First, deploying all of the AMI meters at once reduces the cost of installation of each individual meter as there are efficiencies of scale in such a large deployment. Second, the AMI mesh technology that allows the AMI meters to communicate with each other and the utility requires a certain density of meters in a particular area to sustain reliable communications. AMI meters communicate within a mesh to an access point device, and the data is then transmitted to Company. If the Company were to replace meters one at a time, we would need to replace enough meters in a particular area to comprise a sufficient AMI mesh network otherwise communications could be comprised. We would also still need to install portions of the FAN communications network at that time.

Given the complexity associated with the installation of the communication network, the Company determined that best approach was a mass deployment of AMI meters that could be synchronized with the FAN deployment. Third,

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AMI is an integral component to the overall AGIS initiative. For instance, AMI meters serve as sensors at the customer premise that provide vital information to FLISR and IVVO on power status and voltage level. Without AMI, the Company would need to employ independent sensors that would not be able to match the performance of AMI meters given that they could not be located at the customer's point of service like AMI meters.

c. AMR alternatives

Q. DID THE COMPANY EVALUATE INSTALLING A DIFFERENT TYPE OF AMR METER SYSTEM?

A. Yes. There are several different types of AMR metering systems: (1) two-way RF system; (2) one-way RF system (currently in use in most of Xcel Energy's Minnesota service territory); and (3) a drive-by system. Xcel Energy evaluated each of these AMR systems and a manual read meter alternative and compared their capabilities to the AMI system.

Q. WHAT DID THE COMPANY CONCLUDE AFTER EVALUATING THESE DIFFERENT METER SOLUTIONS?

A. The Company concluded none of these alternative meter systems could match the features and capabilities of the AMI system. Although both the AMI and AMR systems provide billing data, the AMI system provides additional features and information that can be used to support advanced TOU rates, improve outage information, support demand response and distributed generation, and provide timely usage information that consumers can use to save money by managing their use of electricity. A summary comparison of the different meter options to AMI is provided in Table 40 below.

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Table 40

Comparison of Metering Capabilities

Feature/ Capability	AMI	AMR (One-way System)	AMR (Limited two-way system)	AMR Drive-by System	Manual Read
TOU data	● Would support more complex TOU rates and meters can be remotely programmed to capture TOU data	◐ The system supports two tier rates only and meters cannot be remotely programmed to capture TOU data	◐ Xcel Energy billing systems support only two TOU rates and meters cannot be remotely programmed to capture TOU data.	◔ Limited capability. Some meters could support one TOU bin in addition to other metering quantities.	○ Not supported
Interval data	● Capable of measuring and recording more complex interval data sets; supports more interval data lengths	◔ Can only be used for load research purposes and not for billing as data is not revenue grade quality; limited to traditional energy interval data	◐ Data can be used for billing; limited to traditional energy data; limited to 5 or 15 minute interval lengths	○ Not supported	○ Not supported
Real time notification of power outages	● Real-time availability of outage information	◐ Outage notification but not in real-time	◐ Outage notification sent up to meter head-end system	○ Not supported	○ Not supported
Fast response to customer inquires	● Real-time access to customer metering data and diagnostic information	◔ Limited access to customers metering data and meter diagnostic information	◔ Lack of real-time view of customer's metering data and no access to meter real time diagnostic information	○ Not supported	○ Not supported
Support integrated systems that offer customers options for energy conservation and cost management programs	● Technology supports customer side technologies such as smart thermostats, load control devices, etc.	◔ Limited and uncoordinated technology that can allow for such customer facing solutions.	○ Not supported	○ Not supported	○ Not supported

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Table 40 (continued)

Feature/ Capability	AMI	AMR (One-way System)	AMR (Limited two-way system)	AMR Drive-by System	Manual Read
Ability to remotely upgrade metering devices e.g. firmware upgrade, meter configuration changes	● AMI offers the platform to remotely perform such functions.	○ Not supported	○ Not supported	○ Not supported	○ Not supported
Availability of real-time data e.g. voltage, current, power, etc. that are vital for distributed energy resource monitoring	● AMI offers the foundation that makes the availability of such data possible.	○ Not supported by AMR system. Costly to extend standalone communication systems to all distributed energy resources	○ Not supported by AMR system. Costly to extend standalone communication systems to all distributed energy resources	○ Not supported	○ Not supported
Availability of power quality events e.g. momentary outages for each customer, sags, swells, etc. that are essential for system reliability improvement	● AMI offers the foundation that makes the availability of such data possible.	○ Not supported	○ Not supported	○ Not supported	○ Not supported
Remote availability of meter diagnostic data useful for remote troubleshooting	● Data available with full AMI systems.	◔ Feature supported to a limited extent.	◔ Feature supported to a limited extent.	◔ Feature supported to a limited extent.	○ Not supported
Remote reconnection/ disconnection	● System supports remote reconnect/disconnect of residential type customers and limited small commercial customers	○ Not supported	○ Not supported	○ Not supported	○ Not supported
Electric vehicle interconnects	● Allows EVs to utilize TOU pricing and provides load data to detect potential voltage issues.	○ Not supported	○ Not supported	○ Not supported	○ Not supported

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Table 40 (continued)

Feature/ Capability	AMI	AMR (One-way System)	AMR (Limited two-way system)	AMR Drive-by System	Manual Read
Detect unsafe field metering conditions	● Provides service condition information such as temperature and service quality that can be used to detect unsafe conditions such as hot sockets.	○ Current AMR systems do not provide temperature information	○ Current AMR systems do not provide temperature information	○ Current AMR systems do not provide temperature information	○ Not supported
Reliable methods for detecting energy theft	● AMI offers the platform that can be used to detect energy theft conditions.	◔ Limited capability	◔ Limited capability	○ Not supported	○ Not supported

Legend for Capabilities				
Full	**Most**	**Partial**	**Minimal**	**None**
●	◕	◑	◔	○

As shown in this table, none of the other metering options come close to matching the capabilities provided by AMI. Moreover, these meter alternatives does not provide the same quantifiable and non-quantifiable benefits that I outlined above.

Q. WHAT DID THE COMPANY CONCLUDE AFTER EVALUATING THE DIFFERENT AMR ALTERNATIVES?

A. While the AMR alternatives performing similarly to AMI in terms of basic meter reading capabilities, they cannot match the advanced TOU information, two-way capabilities, or functions provided by AMI. As the distribution system evolves with increasing amounts of DER, and customers' expectations require timely energy usage data and the ability to connect their smart devices to their meter, we must have the facilities to meet these needs. AMI is the correct technology to meet both our current and our future system and customer needs. The industry has also recognized the superiority of the AMI technology and vendors and suppliers of AMR systems and replacement parts are becoming harder to find.

Q. WHY DID THE COMPANY REJECT THE OPTION OF REVERTING TO DRIVE-BY AMR METERS?

A. Of the three types of AMR solutions, the drive-by solution is the most antiquated because such meters cannot be read remotely. Instead a drive-by AMR solution only provides meter readings when a meter reader drives by. Drive-by AMR meters would also have higher O&M costs as compared to AMI meters due to the need to perform drive-by meter readings which require additional personnel and fleet vehicles. For purposes of the CBA, the Company calculated the capital and O&M costs of a drive-by alternative. While these costs are lower than the costs for AMI, the drive-by system does not provide any of the benefits attributed to AMI as shown in Table 40 above.

d. Manual Read Meters

Q. WHY DID THE COMPANY REJECT THE OPTION OF REVERTING TO NON-AMR MANUAL READ METERS?

A. Reverting to manually read meters is not reasonable alternatives because reverting to non-AMR meters would require the replacement of well over a million meters but would not provide any of the benefits of the AMI meter such as timely energy usage data, outage information, or voltage information. In addition, manual read meters would have higher meter reading costs as compared to AMI meters due to the need to send personnel out into the field to perform manual monthly readings. Such manual meter reading is a less than ideal option as it would require hiring hundreds of meter readers along with the purchase of vehicles and equipment to perform these manual reads. Manual reading also has a lower read rate and an increase in the number of billing exceptions per read as compared to both AMR and AMI.

e. AMI Opt out

Q. WILL XCEL ENERGY OFFER INDIVIDUAL CUSTOMERS AN ALTERNATIVE TO AN AMI METER?

A. Yes. The Company will develop and offer customers the ability to opt out of having an AMI meter at the start of AMI deployment in 2021. This program will provide customers with the option to have a non-AMI digital meter installed and have it manually read on a monthly basis for billing purposes. This is discussed in further detail by Mr. Cardenas.

Q. WHAT DO YOU CONCLUDE ABOUT THE ALTERNATIVES TO AMI?

A. All of the variations of continuing the current outdated AMR technology provide limited benefits compared to AMI. AMI will provide customers more timely energy information and more control over how and when they use energy in their homes and businesses. It will enable the Company to provide an improved customer experience over AMR when addressing customers' concerns with their meter reading, billing, power outages, quality of service, and connections of service.

Further, AMI is much more than a meter reading technology; it is foundational component of overall AGIS initiative because it provides a

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central source of information with which many components of the advanced grid interact. For instance, AMI meters serve as important end of feeder sensors for IVVO and repeaters for the FAN communication network that increase the dependability of this network. The system visibility and data delivered by AMI provides customer benefits for reliability and enhances utility planning and operational capabilities. Although AMI offers many more customer benefits than AMR, our opt-out program plans will also provide customer choice for those who choose not to have an AMI meter installed.

7. Interoperability

Q. WHAT IS INTEROPERABILITY AND WHY IS IT AN IMPORTANT CONSIDERATION FOR THE COMPANY'S AGIS INVESTMENTS?

A. Interoperability is the ability for systems and different products from different vendors to work together seamlessly. For our AGIS investments, this means that each of the individual devices selected for this initiative will work together to perform the necessary task such as an on-demand meter reading.

Q. WHY IS INTEROPERABILITY AN IMPORTANT CHARACTERISTIC FOR THE AMI METERS?

A. Our AMI meters must be able to communicate and take direction from several different AGIS components, even if those components were manufactured by different vendors, as well as the Company's existing technology. For instance, since our AMI meters also serve as mesh network devices that transmit data from other field devices, it was important to ensure that the selected AMI meters had an interface that was capable of supporting multiple communication modules by multiple suppliers.

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Q. HOW DOES THE AMI METER SELECTED BY THE COMPANY FACILITATE INTEROPERABILITY WITH THE OTHER AGIS COMPONENTS?

A. The Company's RFP that was issued to select the AMI meter vendor required the meter to have several interoperability characteristics. These included that the meter must be built to the industry ANSI C12 standard and have an interface capable of supporting multiple communication modules. The RFP process is discussed in greater detail above.

8. Minimization of Risk of Obsolescence

Q. WHAT STEPS DID THE COMPANY TAKE TO MINIMIZE THE RISK OF OBSOLESCENCE OF THE SELECTED AMI TECHNOLOGY?

A. One of the issues with new technology is that it is ever changing and new technology can be obsolete shortly after deployment. In evaluating different AMI technology, the Company put an emphasis on "future proofing" the capabilities to minimize the risk of obsolescence. Specifically, the Company sought and selected AMI technology that had the following characteristics:

- Over the air (OTA) firmware and meter configuration upgrades without field visits or meter replacement;
- Enhanced memory size to support potential future use cases that would require certain meter configurations;
- Flexible, standard service components that are common in the industry such that any future technology would be adapted to this industry standard;
- Architecture for ease of integration with existing and future systems; and
- Reduction in technology design and development costs due to the (re)use of standard interfaces.

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Q. PLEASE EXPLAIN HOW THESE CHARACTERISTICS REDUCE THE RISK THAT THE SELECTED AMI TECHNOLOGY WILL BECOME OBSOLETE IN THE NEAR FUTURE?

A. We can predict that future needs will require our technologies to have more memory and better communications throughput. Among the possible changes are currently anticipated are advances in Distributed Intelligence, cybersecurity updates, and the ability to add more logic or intelligence in the meter. Based on this, the AMI meter specifications identified above will be essential in ensuring that hardware and technology deployed can be upgraded in the field without the need for a wholesale meter replacement.

E. FAN

1. Overview of FAN

Q. WHAT IS THE FAN?

A. The FAN is a private, Company-owned wireless communications network. The primary function of FAN is to enable secure and efficient two-way communication of information and data between our existing communication infrastructure located at our substations and new or planned intelligent field devices – up to and including meters at customers' homes and businesses. Through the substation infrastructure's connectivity to the Company's existing Wide Area Network (WAN), the FAN enables back-office applications to directly communicate with field devices providing usage information for both our customers and the Company.

The implementation of FAN is a joint effort with Business Systems, and Mr. Harkness provides detailed discussion of FAN and addresses the IDP filing requirements related to FAN in his testimony.

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Q. WHAT ARE THE PRINCIPAL TECHNOLOGIES THAT WILL BE USED BY THE FAN?

A. To provide communication between the substation and field devices, the FAN will use two wireless technologies: (1) Wireless Smart Utility Network (WiSUN) mesh network; and (2) a Worldwide Interoperability for Microwave Access (WiMAX) network.

Q. WHAT IS THE PURPOSE OF THE WISUN AND WIMAX NETWORK?

A. The WiSUN mesh network will communicate directly with the AMI infrastructure (including the advanced meters) and the Distribution Automation (DA) field devices used for IVVO and FLISR.

The WiMAX network will provide redundant, reliable, and secure connectivity between the WiSUN network and the Company's WAN. The field devices and the WiSUN access points connect to the WiMAX base stations (mostly located at the Company's substations) via wireless communication modules that are integrated into these devices.

Through the substation's connectivity to the WAN, the FAN (including the WiMAX network and the downstream WiSUN mesh network (will enable the Company's advanced applications (such as ADMS and AMI, and the sub-applications including FLISR and IVVO) to communicate with the field devices that implement those applications and sub-applications. Figure 11 provides an illustration of the principal components of the FAN. The WiSUN and WiMAX technologies are discussed in more detail by Mr. Harkness.

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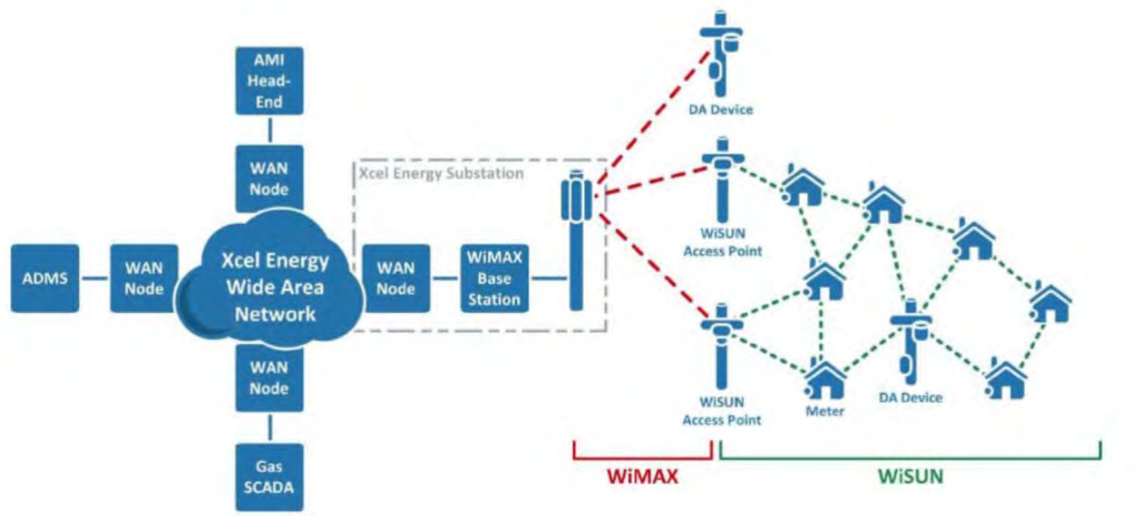
Figure 11

FAN Overview



Q. DESCRIBE THE COMPONENTS OF THE WISUN NETWORK.

A. The WiSUN mesh network is the key network structure that will communicate directly with the AMI infrastructure and most DA field devices. The core infrastructure for WiSUN will consists of three main device types:

- *Access Points*: device that will link the Company's endpoint devices that are enabled with wireless communication modules with the rest of the Company's communication network. The access points will wirelessly connect directly to backhaul (which is an intermediate link in the communications network – WiMAX, in this case) to pass data between the mesh network and the WAN. The access points will be located primarily on distribution poles and other similar structures.
- *Repeaters*: are range extenders that are used to fill in coverage gaps where devices would be otherwise unable to communicate. The mesh network design of WiSUN means that additional nodes on the network provide

devices more options to communicate with their access point. Repeaters will be located primarily on distribution poles.

- *Endpoint Devices*: include AMI meters and DA field devices, such as the intelligent FLISR and IVVO field devices, that have built-in radios. The AMI meters will be located on customer premises; the field devices will be co-located with either pole-mounted or pad-mounted distribution devices.

Q. DESCRIBE THE COMPONENTS OF THE WIMAX NETWORK.

A. The WiMAX network will consist of two main components: (1) base stations; and (2) customer premise equipment (CPE).[14]

Base stations will serve as the key communication points between the substation WAN and the WiSUN mesh network. At substations there will be a base station with up to three radios that will communicate with the WAN and multi-directionally with CPEs out in the field of operations. Where possible, the base stations at the substations will be mounted on existing poles or structures.

The CPEs will further enable the back office applications to communicate wirelessly with any device accessible to that access point's connections to the mesh network. CPEs will be mounted on distribution poles in the field of operation.

[14] CPE is an industry term that refers to specific equipment. The "customer" in CPE refers to Xcel Energy or a similarly situated entity using this equipment and does not refer to Xcel Energy's customers.

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Q. HOW WILL THE FAN DEVICES OPERATE IN THE EVENT OF A POWER OUTAGE?

A. The core infrastructure on both WiSUN and WiMAX is backed up by batteries to enable continued functionality and operations in the case of a power failure to that device – a situation where the continued functionality of those networks is critical. These battery systems also self-monitor and will automatically report any issues to ensure prompt repair. Specific devices will also have battery power, either supplied by the device itself or through a supplemental battery system, to enable continued operations during an outage. For example, the FLISR devices, that are critical during a distribution outage, will have battery power.

Q. HOW DOES THE FAN ASSIST THE OTHER AGIS COMPONENTS IN MANAGING OUTAGES?

A. As discussed above, the core infrastructure of both WiMAX and WiSUN will have battery backup as will other devices that are critical for outage operations. This means that the Distribution Control Center will still have visibility into the current status of the grid and remote control capabilities for devices like reclosers. Although AMI meters will not have battery backup, they will have energy storage adequate to send "last gasp" messages (that is, a final message transmitted by the meter upon detection of an outage) over the FAN to let the head-end system know that particular customers do not have power service. Once those customers have been reenergized, those meters will once again be able to communicate on the FAN and the head-end system will be able to remotely verify that customers have been reconnected. The additional visibility will also aid with the restoration of nested outages[15] by showing that certain customers remain without power even when the

[15] Storms often result in multiple failures. When we repair and reenergize a section, but a subset remains out due to a second fault, that outage is referred to as a "nested" outage.

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surrounding issue was resolved. This will help the control center identify those situations and reduce restoration times.

2. FAN Implementation

Q. WHAT WORK WILL DISTRIBUTION PERFORM TO SUPPORT INSTALLATION OF THE FAN?

A. The implementation of the FAN will be a joint effort between Business Systems and Distribution. Distribution will be responsible for the installation of the FAN devices (primarily access points, repeaters, and CPEs) that will be located on distribution poles. Distribution will also be responsible for installation of the WiMAX base stations. Business Systems will be responsible for installation of WiMAX base stations at the substations. Business Systems will also be responsible for the design of the network systems for WiMAX and WiSUN, the security of these networks, and configuring the software and hardware components of FAN.

Q. HOW WILL THESE FAN DEVICES BE INSTALLED BY DISTRIBUTION?

A. The access points, repeaters, and CPEs will be mounted primarily on distribution poles to provide adequate height for the radio signal to propagate. In certain instances, the distribution pole will need to be modified or replaced to support a particular device and Distribution will be responsible for completing this modification or replacement. In areas where Xcel Energy has underground service, arrangements will be made to mount the devices on street lights or other structures with appropriate height.

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Q. HAS THE COMPANY ALREADY DEPLOYED FAN DEVICES IN MINNESOTA?

A. To support the TOU pilot, the Company deployed limited FAN infrastructure in 2019 in the small geographic area overlaying the AMI meter deployment (Eden Prairie and Minneapolis). Business Systems has begun to deploy WiMAX base stations in three substations and Distribution has begun to deploy of access points (APs) and repeaters that will be connected to those base stations.

Q. WHAT IS THE FAN IMPLEMENTATION SCHEDULE TO SUPPORT THE FULL AMI DEPLOYMENT STARTING IN 2021?

A. For any given geography, FAN availability will precede AMI meter deployment by approximately 3-6 months, to ensure that meters will have a fully operational network to use when they are installed. To support this, we will need to begin FAN installation approximately 12-18 months ahead of AMI meter deployment to allow adequate time for permitting, material sourcing, and construction. Based on the current schedule for the full AMI meter deployment, we anticipate FAN deployment will begin in mid-2020 to ensure network readiness for when AMI meters

3. FAN Costs

Q. WHAT DISTRIBUTION CAPITAL AND O&M COSTS ARE NECESSARY FOR FAN IMPLEMENTATION IN 2020, 2021, AND 2022?

A. As discussed above, the work that Distribution will be performing to support the implementation of FAN is limited to the procurement and installation of pole-mounted FAN devices. Mr. Harkness discusses Business Systems' FAN costs which include the costs for the WiSUN and WiMAX components. Tables 41 and 42 below provide Distribution's capital additions and O&M

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costs for FAN implementation for 2020 through 2022 and I will describe these costs in further detail below.

Table 41

FAN Capital Additions – Distribution State of MN Electric Jurisdiction (Includes AFUDC) (Dollars in Millions)			
AGIS Program	**2020**	**2021**	**2022**
FAN	$2.8	$5.4	$0.0

Table 42

FAN O&M – Distribution NSPM – Total Company Electric (Dollars in Millions)			
AGIS Program	**2020**	**2021**	**2022**
FAN	$0.1	$0.2	$0.4

a. Distribution's Capital Costs

Q. WHAT ARE THE PRIMARY COMPONENTS OF DISTRIBUTION'S FAN CAPITAL FORECAST?

A. These capital costs include FAN devices, installation, and project management, as well as preparation costs.

Q. HOW DID DISTRIBUTION DEVELOP THESE CAPITAL COST ESTIMATES FOR FAN?

A. To estimate the device costs and installation costs for FAN, Engineering performed a preliminary Radio Frequency Network Study. The purpose of this study was to determine the location and number of access points, repeaters, and CPEs that would be required to facilitate a reliable FAN communication network for the AMI meter and the distribution automation devices. The study concluded that approximately 550 access points, 3,000 repeaters, and 2,500 CPEs will be required for the FAN coverage area.

Q. WHAT WAS THE NEXT STEP IN DEVELOPING THE CAPITAL COST ESTIMATES?

A. After determining the number of devices, the price for each device was derived from prices included in contracts that resulted from several RFP processes. These RFPs are described by Mr. Harkness. The labor costs to install each device are based on a combination of contractor and internal labor.

Q. HOW DID DISTRIBUTION DETERMINE THE LABOR COSTS FOR THE INSTALLATION OF THE FAN DEVICES?

A. Our labor estimates are based on our prior experience with installing FAN devices for both FAN rollout in Colorado and the limited deployment of FAN in Minnesota to support the TOU pilot. This work provides a reasonable point of reference for the labor estimates for the FAN deployment in Minnesota.

b. Distribution's O&M Costs

Q. WHAT ARE THE PRIMARY COMPONENTS OF DISTRIBUTION'S O&M COSTS FOR FAN?

A. The FAN's O&M costs will include costs for infrastructure and hardware, operations (including equipment and personnel), and preparation costs. These costs include the field level support for fixing broken and damaged equipment, additional personnel to monitor and manage the FAN, other preparation work that is designated as O&M, hardware and software maintenance, and training. Personnel will include both Company employees and contractors, which will be used based on workload, location, and timing. Most incremental work will be performed by contractors.

Q. HOW DID DISTRIBUTION DETERMINE THE O&M COSTS FOR FAN?

A. The projected costs associated with project employees are based on typical Company wages, and contractor costs are costs of contractors at estimated wage scales. The costs to fix and replace broken and damaged equipment are based on expected failure and damage rates for these devices.

c. Distribution Contingency for FAN

Q. DOES DISTRIBUTION'S FAN FORECAST INCLUDE CONTINGENCY AMOUNTS?

A. No. There is no contingency amount included in Distribution's FAN costs because Distribution has limited scope of defined work related to FAN.

d. FAN Expenditures 2020 to 2029

Q. WHAT ARE THE DISTRIBUTION'S CAPITAL EXPENDITURE AND O&M FORECASTS FOR THE FAN FOR 2020 THROUGH 2029?

A. The tables below provide Distribution's capital expenditures and O&M forecasts for the FAN for 2020 through 2029.

Table 43

FAN Capital Expenditures – Distribution NSPM – Total Company Electric (Dollars in Millions)					
	Rate Case Period			5-Year Period	10-Year Period
AGIS Program	**2020**	**2021**	**2022**	**2023-2024**	**2025-2029**
FAN	$3.2	$6.2	$0.0	$0.0	$0.0

Table 44

FAN O&M Expenditures – Distribution NSPM – Total Company Electric (Dollars in Millions)					
	Rate Case Period			5-Year Period	10-Year Period
AGIS Program	**2020**	**2021**	**2022**	**2023-2024**	**2025-2029**
FAN	$0.1	$0.2	$0.4	$0.3	$0.4

F. FLISR

1. Overview of FLISR

Q. WHAT IS FLISR?

A. FLISR (Fault Location, Isolation and Service Restoration) is a form of distribution automation that involves the deployment of automated switching devices that work to detect feeder mainline faults, isolate them, and restore power to unfaulted sections – decreasing the duration and number of customers affected by any individual outage. The FLISR application relies on three primary components to operate: (1) ADMS, for the central control and logic; (2) intelligent field devices to detect faults and operate field equipment; and (3) the FAN, for wireless communications to each device. Fault Location Prediction (FLP) is a subset application of FLISR that indirectly considers and leverages sensor data from the field devices to locate a faulted section of a

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feeder and reduce patrol times necessary to locate a fault. The FLISR system is expected to reduce outage durations for customers and improve overall system reliability performance metrics, such as SAIDI and SAIFI. It should be noted that while outage durations will decrease, a customer may see an increase in the number of momentary (less than 5 minutes) outages as FLISR isolates the faulted section.

Q. WHAT ARE FAULTS ON THE DISTRIBUTION SYSTEM?

A. Faults are failures of the electrical system, which result in abnormal power flows. The distribution system is designed to detect such conditions and de-energize the affected portions of the system in order to limit damage and ensure safety. Faults can be either temporary or permanent. A permanent fault is one where permanent damage is done to the system and a sustained outage (i.e., greater than five minutes) is experienced by the customer. Permanent faults may be the result of insulator failures, broken wires, equipment failure (e.g., cable failure, transformer failure), and public damage (e.g., an automobile accident impacting a utility pole). Temporary faults are those where customers experience a momentary interruption (i.e., less than five minutes). Causes of temporary faults are transient in nature. Some examples are lightning, conductors slapping in the wind, animal contact, and tree branches that fall across conductors and then fall or burn off.

Q. HOW DOES XCEL ENERGY CURRENTLY IDENTIFY AND ISOLATE FAULTS ON THE DISTRIBUTION SYSTEM?

A. The Company does have a SCADA system that informs operators of most feeder and substation-level outages. When the outage does not impact a full feeder or where SCADA capability does not yet exist (many rural systems),

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Xcel Energy must rely on calls from customers to inform the Company of an outage. As customers call to report outages, the service locations are identified in our Outage Management System (OMS). Initially, each outage is identified as affecting a single customer. But as outages for customers served by common elements accumulate, the outage "escalates", and points to the most probable location for us to initiate our repair activities. The Control Center Operator then uses aggregated information from all current outages, prioritizes, and dispatches field personnel to effect the most efficient restoration. When dispatched, crews patrol the feeder to identify the cause of the fault then proceed to manually open switches to isolate the fault. Next, they manually close other switches to restore service to as many customers as possible. Finally, they affect the repairs and restore power to the customers.

Q. WHAT IS OUTAGE TIME FOR A TYPICAL FEEDER-LEVEL FAULT?

A. The average time to restore a feeder-level fault in Minnesota has been 124.9 minutes (5-year average, not storm-normalized). NSPM feeders serve, on average, 1,219 customers. The average customer count for the feeders selected for the proposed FLISR deployment is 1,687.

Q. ARE THERE DEVICES ON THE XCEL ENERGY SYSTEM THAT CURRENTLY ASSIST WITH FAULT ISOLATION AND SERVICE RESTORATION?

A. Yes. We currently have small-scale automation programs across our distribution system. We have been installing intelligent switches for a number of years on much of our 34.5 kV system in Minnesota. Like FLISR, these devices act to isolate the faulted section of the system and restore power to unfaulted sections of the feeder when possible. These intelligent switches have improved the reliability for over 114,000 Minnesota customers. If the device is successful at isolating the fault to one portion of the line, customers upstream of the device are spared from a sustained outage.

We have also been installing faulted circuit indicators, powerline sensors, and replacing certain relays on the system to aid our ability to quickly find a fault so we can begin restoring service to interrupted customers.

Q. WHAT ARE THE LIMITATIONS OF THE THESE EXISTING DEVICES?

A. While the existing sensing devices provide important benefits, they are not as flexible as the fault location devices that are now available. For instance, faulted circuit indicators do not provide the fault magnitude, which ADMS can use to locate the probable location of the fault. Also, many of the earlier systems rely on proprietary communications systems, which means they lack the ability to communicate seamlessly with other devices on our system. While these early intelligence devices have been beneficial for our customers and our operations, we intend to implement newer FLISR technologies going forward – eventually replacing some of the current devices.

Q. CAN YOU DESCRIBE IN MORE DETAIL HOW FLISR OPERATES?

A. Yes. There are three basic steps to the operation of FLISR. First, the system identifies the faulted section and, where possible, calculates the probable location within that section. Second, the system isolates the fault by opening devices in the field. Finally, the system restores the service to as many customers as possible through additional automated field switching.

In the first step, when a fault occurs, the FLISR protective devices will open, or sectionalize the feeder to isolate the fault. Depending on the devices and

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the situation, the device may attempt to reenergize the affected area first, in case the fault was only temporary in nature. Once the fault is cleared (de-energized), data will be sent from those intelligent field devices to ADMS. ADMS will then run the FLISR application which will analyze the situation, select appropriate switching device near the fault, and generate a switching plan to restore service to other customers. In doing so, ADMS will take into account not only device and feeder loading, but surrounding substation loading as well. ADMS will then execute the proposed switching plan and notify the operator of the need to send a crew to the isolated section to manually investigate the fault event. This process is expected to take less than five minutes from the occurrence of an outage to operator notification. ADMS will also be able to run the FLP algorithm and predict which segment within a FLISR section the fault exists, which will reduce expected patrol times by crews. Figure 12 below shows how FLISR isolates that impacted feeder section to restore power to other sections of the line.

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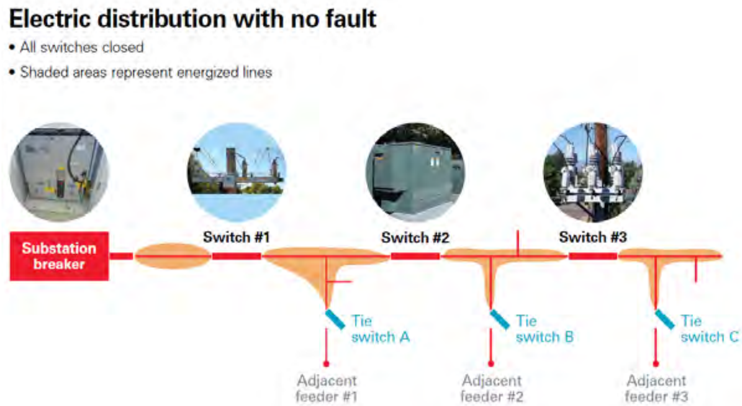
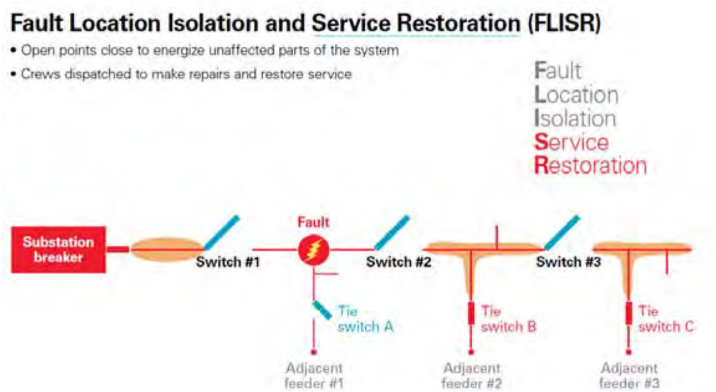
Figure 12

FLISR Feeder Configuration – Prior to Fault



FLISR Feeder Configuration – Service Restored



Q. HOW WILL FLISR IMPACT THE COMPANY'S RELIABILITY PERFORMANCE?

A. We expect that FLISR will improve our overall reliability performance and a customer's overall outage experience. However, our performance in certain reliability metrics may decline after FLISR is installed. For instance, FLISR will help some customers avoid sustained outages. Sustained outages are tracked by the SAIFI metric (annual average number of sustained service interruptions per customer served) and shorter duration outages (less than five minutes) are tracked by the Momentary Average Interruption Frequency Index (MAIFI) metric. In essence, we expect that FLISR will transform outages that would have been sustained outages into momentary outages. In addition, with AMI meters, we will be better able to track these momentary outages for all of our customers.

As a result, with FLISR, we expect that customers will experience fewer sustained outages thus improving our SAIFI performance while our MAIFI performance will decline. We also expect that FLISR will cause our Customer Average Interruption Duration Index (CAIDI) performance to decline. CAIDI is a measure of the length of time the average customer can expect to be without power during an interruption. CAIDI performance declines when the outages are more heavily concentrated on problems that take a longer time to fix. As FLISR's automatic switching will restore power quickly to customers not along the faulted section, the result will be a sustained outage that impacts fewer customers. This will negatively impact our CAIDI performance but will be a more positive outage experience for our customers because FLISR will minimize widespread extended outages on the system.

Q. PLEASE DESCRIBE HOW FLP OPERATES AND HOW IT WILL IMPROVE CUSTOMERS' OUTAGE EXPERIENCES.

A. Feeders enabled only with FLP will operate in a slightly different manner from FLISR-enabled feeders. Should a fault occur, FLP devices upstream of the fault will capture an event occurring and will communicate relevant measurements pertaining to the fault (such as current, voltage, and phase indication) to ADMS. ADMS will compare these measurements to the impedance model and will generate expected fault locations. ADMS will then notify the operator of these locations (with a level of certainty for each location), and the operator will dispatch a crew directly to the expected faulted section (as opposed to having the patrol the entire feeder line, as in the current situation) to isolate the faulted section. This reduction in patrol time will result in reduced outage durations for our customers.

Xcel Energy is proposing to install up to two sets of three-phase advanced powerline sensors along each feeder targeted for FLP deployment. At the substation where the feeder originates, we will use either an intelligent relay or install one set of sensors. Existing remote fault indicators and new intelligent device telemetry will be incorporated into the FLP deployment. If an existing device is in the correct location to employ FLP functionality, this will obviate the need for a new device. Other existing devices will enhance FLP's capabilities by providing additional data to improve FLP algorithm performance.

Q. WHAT ARE THE COMPONENTS OF FLISR?

A. There are four principal components of FLISR:

- Reclosers;
- Automated overhead switches;
- Automated switch cabinets; and
- Substation Relaying.

There are two main components to FLP:

- Powerline sensors; and
- Substation Relaying.

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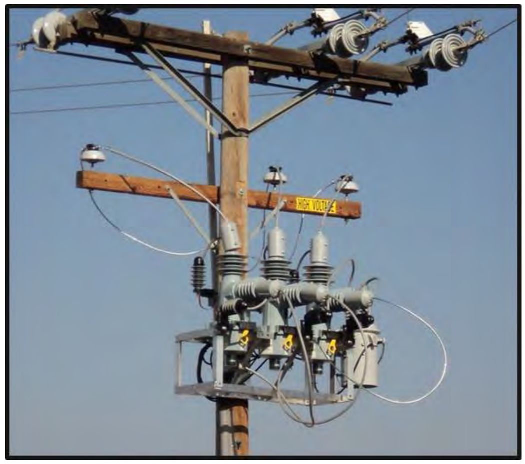
Q. WHAT ARE RECLOSERS AND HOW DO THEY OPERATE?

A. Reclosers are pole-mounted reclosing and switching devices. The Company currently has reclosers on the distribution system, but only a few of these reclosers have communications to enable remote operations capabilities. The new devices employed by the Company will perform the same functions of existing reclosers but have enhanced monitoring, communications and control capabilities. The devices are able to identify and interrupt a fault event and then report the fault current to ADMS, which can then use that information to execute FLP to determine the location of the fault. The reclosers will be able to "re-close" after a fault event to determine if a fault still exists. If the fault does not persist, the recloser will reclose and restore service. If the recloser determines that there is a permanent fault after multiple attempts to reclose, the device will communicate the fault information to ADMS, which will inform the Company of the need to dispatch a crew to the fault location. In addition, the reclosers will be controlled by ADMS when there is a permanent fault to automatically restore service. Figure 13 is a picture of a recloser on a distribution pole.

Figure 13

Recloser on Distribution Pole



Q. WHAT IS AN AUTOMATED OVERHEAD SWITCH?

A. These switches are overhead remote supervisory sectionalizing and motor operated switching devices. When a fault occurs, a feeder breaker senses the fault and opens. Although the overhead switches do not communicate directly with the feeder breaker, local controllers on switches on both sides of the fault will sense the loss of voltage and open, isolating the fault. However, unlike a recloser, the overhead switches do not have the capability of reclosing to determine whether the fault is permanent in nature. Instead, overhead switches rely on the feeder breakers for the reclosing functionality. Although automated overhead switches lack the reclosing functionality, they are more compact and less expensive than reclosers, making them the preferred choice for space-constrained locations or where localized reclosing capability is not required.

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Q. WHAT ARE AUTOMATED SWITCH CABINETS?

A. Automated switch cabinets are pad mounted sectionalizing and switching devices. Each cabinet has motor-operated, remote-controlled devices that the Company will use for switching underground feeders. They will perform functions similar to the automated overhead switches for our underground feeders. Each cabinet has two or more switches inside, providing the safe and reliable switching capabilities required for FLISR.

Q. WHAT IS THE FUNCTION OF THE POWERLINE SENSORS?

A. Powerline sensors are equipment placed on distribution lines to continuously monitor the grid and send information back to the utility for analysis and response. Sensors are available to measure such attributes as current, voltage, power factor, and faults. Specifically for FLISR, this technology will allow Xcel Energy the ability to detect disturbances on the grid and use this information to identify fault locations, isolate faults, and analyze the unique patterns of these events to predict the likelihood of future outages. Finally, we hope to leverage the equipment in the future to detect defective equipment before it fails.

Q. WHAT IS THE FUNCTION OF THE SUBSTATION RELAYS?

A. Substation-based relays, historically referred to as the feeder's overcurrent relays, provide the logic for when and why a breaker opens. The purpose of these relays is to monitor and, if warranted, to initiate commands to the feeder breaker to de-energize systems which have been compromised. This is to protect the public, utility personnel, and to minimize damage to public or private property or utility equipment. Modern relays are multi-functional and have multiple protection functions programmed into them. These relays can also capture important fault information which will be sent to ADMS for the fault location application.

Q. WHAT IS THE SERVICE LIFE OF THESE FLISR DEVICES?

A. The service life of each of the FLISR devices is 20 years for depreciation purposes.

2. Prior Certification Request for FLISR

Q. HAS THE COMPANY PREVIOUSLY BROUGHT FLISR FORWARD FOR COMMISSION APPROVAL?

A. Yes. The Company previously sought certification of FLISR under the Grid Modernization Statute[16] in its 2017 Biennial Grid Modernization Report.[17]

Q. WHAT ACTION DID THE COMMISSION TAKE ON THIS CERTIFICATION REQUEST?

A. The Commission denied this certification request without prejudice finding that the Company "had not fully demonstrated that FLISR is 'necessary to modernize the transmission and distribution system by enhancing reliability…" as required by the Grid Modernization Statute.[18] The Commission also found that the Company's cost calculations "emphasize the value of reliability but do not adequately assess that value and do not quantify estimated cost savings to ratepayers."[19]

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[16] Minn. Stat. § 216B.2425.

[17] *In the Matter of Xcel Energy's 2017 Biennial Distribution Grid Modernization*, Docket No. E002/M-17-775, XCEL ENERGY'S 2017 BIENNIAL DISTRIBUTION GRID MODERNIZATION REPORT (Nov. 1, 2017).

[18] *In the Matter of Xcel Energy's 2017 Biennial Distribution Grid Modernization*, Docket No. E002/M-17-775, ORDER APPROVING PILOT PROGRAM, SETTING REPORTING REQUIREMENTS, AND DENYING CERTIFICATION REQUEST at 7, (Aug. 7, 2018).

[19] *Id.*

Q. HOW DOES THE COMPANY'S CURRENT FLISR PROPOSAL DIFFER FROM THE ONE THAT THE COMPANY SOUGHT APPROVAL FOR IN 2017?

A. Our FLISR proposal is slightly revised from that proposed in 2017 in our Grid Modernization Report. We revised our plan with the insights gained from the deployment of FLISR devices in PSCo, resulting in a slightly smaller footprint. The current FLISR proposal will cover 208 feeders, serving 267,182 customers, and require 655 devices (switches and reclosers). This is slightly smaller than the previous proposal which was slated to cover 238 feeders, 290,122 customers, and require 809 switches and reclosers. The reason for the change is that we now have a better understanding of the labor and material costs for the installations and integration of FLISR into ADMS which was gained from our PSCo deployment. Even with this slightly reduced footprint, the benefits of FLISR remain strong and FLISR is a cost-effective way to improve system reliability.

Q. DID THE COMPANY ADDRESS THE COMMISSION'S OTHER CONCERNS RELATED THE RELIABILITY BENEFITS OF FLISR AND THE QUANTIFICATION OF THE COST SAVINGS TO RATEPAYERS?

A. Yes. As described in greater detail below and by Dr. Duggirala, the Company has prepared a comprehensive CBA for each of the AGIS components, including FLISR. This CBA quantifies the reliability benefits for our customers that will result from implementation of FLISR and compares those benefits to the cost of the FLISR investment. As discussed by Dr. Duggirala, the benefits of FLISR are expected to exceed the cost of FLISR, with an expected benefit-to-cost ratio of approximately 1.31 to 1.53.

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3. Interrelation of FLISR with other AGIS Components

Q. HOW DOES FLISR INTERACT WITH THE OTHER AGIS COMPONENTS?

A. In addition to its own intelligent field devices, the FLISR application relies on two primary elements to operate: (1) ADMS, for the central control and logic; and (2) the FAN, for wireless communications to each device.

Q. HOW WILL FLISR AND THE SENSING DEVICES INTERACT WITH ADMS?

A. ADMS will maintain an impedance model of the NSP distribution system. Real-time current, voltage, and status data will be used to run load flow and state estimation applications on that model, providing awareness of system conditions for that feeder and surrounding feeders.

ADMS will provide for remote monitoring and control of FLISR and FLP devices. When a fault occurs on a FLISR or FLP-enabled feeder, any device that senses the fault will send a signal to ADMS, notifying the system of the event. Devices that are capable will also send fault current magnitude during the event. ADMS will use both sets of data, comparing fault current data against the impedance model to generate an expected fault location. If that feeder is FLISR-enabled, ADMS will generate a switching plan to isolate the faulted section based on system conditions, and will issue commands to field devices on the feeder and adjacent feeders so that non-faulted sections can be automatically restored.

Q. HOW WILL FLISR INTERACT WITH FAN?

A. FAN enables the communication that allows the FLISR field devices to communicate with ADMS and their head-end systems. Specifically, the WiMAX system of the FAN which will be used by the FLISR switches is the backbone of the same system proposed to communicate with AMI and with IVVO devices.

Q. WILL FLISR AND FLP MAKE USE OF AMI METERS?

A. Yes, indirectly. FLP considers outage prediction results from a separate outage prediction application in situations where multiple possible fault locations are indicated. The outage prediction application utilizes data from AMI meters. In this way, FLISR and FLP indirectly use AMI data when determining the location of an outage.

Q. HOW WILL FLISR INTERACT WITH IVVO?

A. Both IVVO and FLISR require ADMS to make accurate power flow calculations. ADMS will consume and use information from all the types of sensors on the system. Thus, where IVVO's capacitors provide powerline sensing, FLISR will benefit from this data. Similarly, IVVO calculations benefit from the data provided by FLISR's reclosers. Further, as more data is provided to ADMS by both FLISR and IVVO devices, this information will enhance the ADMS system model, creating greater benefits for both FLISR and IVVO as well as other applications.

4. FLISR Implementation

Q. WHAT IS THE DEPLOYMENT STRATEGY FOR FLISR?

A. The deployment strategy for FLISR is a selective, targeted deployment. In general, we plan to target areas for FLISR where the electric system is predominately overhead, has high customer density, and has a history of outages that is more frequent than the rest of the distribution system. There are two primary criteria that drove our FLISR feeder selection, both of which

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are based on historic reliability information: (1) feeder SAIDI performance; and (2) the combination of the number of feeder mainline outages and the number of customers impacted over a period of time.

Q. WERE THERE OTHER CONSIDERATIONS IN THE DEVELOPMENT OF THE DEPLOYMENT STRATEGY FOR FLISR

A. Yes, FLISR, like other advanced grid applications requires communications capabilities to each sensor and switching device. For Xcel Energy, this communications platform is the FAN. As a result, the FLISR implementation must be completed in concert with the FAN implementation.

Q. WHERE WILL FLISR FIRST BE DEPLOYED IN MINNESOTA?

A. FLISR will be deployed to a small two-feeder area in South Minneapolis in 2020 to validate the ADMS capabilities. Nearly 4,400 customers will benefit from the new capability. The location overlays the TOU pilot geographic area, providing efficiencies to both of the projects thereby leveraging the initial, underlying FAN infrastructure.

Q. WHAT IS THE COMPANY'S APPROACH TO EXTENDING FLISR BEYOND THE AREA COVERED BY THE TOU PILOT?

A. The Company's approach is a balance between addressing the poorest performing feeders in terms of reliability and deploying the technology in a concentrated enough manner to allow it to be as effective as possible. Addressing the highest priority, poorest performing feeders first provides the greatest benefit for our customers as measured by a reduction in "customer minutes out of power" or CMO. As this project progresses through its 10-year deployment, we will continue to deploy FLISR using this prioritization method. Since feeder performance varies from year to year, it is expected that some adjustments to the initial deployment plan may occur, while keeping with the concept of maximizing the reliability value of the investment.

However, because FLISR relies on ties to adjacent feeders, the application is most effective and can have the largest impact on reliability and operations when deployed on multiple distribution feeders in the same geographic area. This concentrated deployment allows for normally open tie switches to be shared between two automated feeders, thus reducing the cost of deployment and also increasing operational flexibility.

Therefore, the deployment plan we propose for Minnesota is focused around deploying in this concentrated geographic approach – first identifying areas where a number of feeders have experienced the lowest levels of reliability over the past several years, and building out from there.

Q. HOW DID THE COMPANY DETERMINE THE FEEDER LOCATIONS FOR THE FLISR DEPLOYMENT?

A. The Company analyzed the reliability improvement potential for 980 feeders, and, when factoring in implementation and operational costs, developed a benefit/cost curve which was utilized to determine the size of the FLISR deployment. This deployment plan calls for the automation of 208 feeders in the greater Minneapolis/St. Paul metropolitan area, which provides potential for a 21.3 minute SAIDI reduction. For perspective, 208 feeders comprise about 27 percent of our metro feeders, which serve 40 percent our metro area customers.

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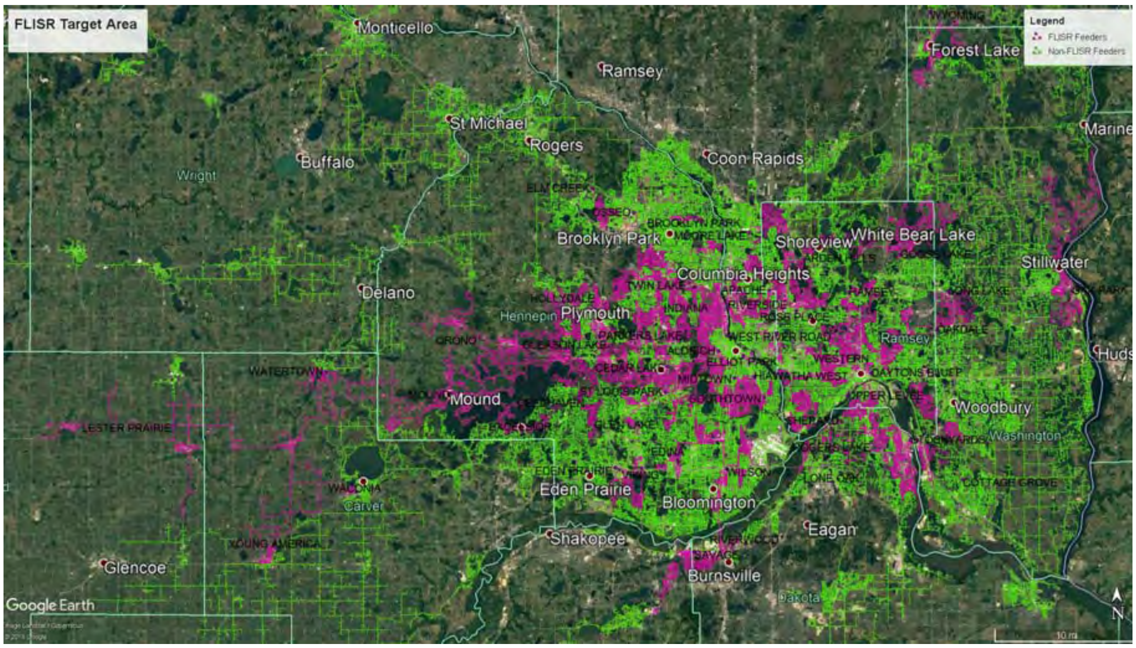
Q. WHERE ARE THESE 208 FEEDERS LOCATED?

A. These selected feeders are located throughout the greater Minneapolis/St. Paul area and are shown in magenta in Figure 14 below.

Figure 14



Q. WILL FLISR BE DEPLOYED OUTSIDE OF THE GREATER METROPOLITAN AREA?

A. Over time, we expect to bring FLP (Fault Location Prediction) and full FLISR capabilities to additional areas as we continue to evaluate reliability and cost-effective solutions.

Q WHAT IS TIMING FOR THE DEPLOYMENT OF THE FLISR DEVICES?

A. We plan to deploy FLISR devices (reclosers, switches, and substation relays) at a relatively steady rate through 2028. The device installation rate is shown in Table 45 below. By the end of 2028, FLISR devices will be installed on 208 feeders, benefiting nearly 350,000 customers.

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Table 45

FLISR Device Installation

FLISR Devices	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	Total
Field Devices	6	41	108	60	88	90	67	67	67	67	661
Feeders Impacted	2	13	34	19	28	28	21	21	21	21	208

5. Benefits of FLISR

Q. WHAT ARE THE BENEFITS OF IMPLEMENTING FLISR?

A. FLISR has both quantifiable benefits and non-quantifiable benefits. The most significant quantifiable benefit of FLISR is improved reliability for our customers, which we have estimated in two parts: (1) customer savings due to a reduction in CMO; and (2) patrol time savings due to the need to patrol a smaller portion of the system to find faults. These quantifiable benefits of FLISR were utilized by Dr. Duggirala in the CBA model prepared by the Company to calculate the benefit-to-cost ratio for FLISR.

We also expect to achieve certain non-quantifiable operational efficiencies due to the increased visibility and information provided by the FLISR field devices. One of these benefits is the reduction in field trips for our employees to effect non-outage switching, enabled by the FLISR automated devices. Additionally, all remotely operable switches will necessarily have sensors which will provide operating data at strategic points along the feeders. This data will be useful in the refining planning models and hosting capacity analysis, allowing the planning engineer to more accurately distribute load along the feeders.

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Q. WHEN WILL CUSTOMERS BEGIN SEEING BENEFITS OF FLISR?

A. Customers connected to feeders modeled in ADMS will begin seeing reliability benefits in steps. First, when faults occur on feeders that are modeled within ADMS, the algorithms will develop switching plans faster, which will result in faster outage restoration. At the same time, if fault magnitude information is available, the system will calculate the fault's probable location which will reduce patrol time. Second, for feeders equipped with automated devices, the operators will use remote capabilities to open and close switches, further improving the response time. This is referred to as "advisory mode." And third, when the Company is has sufficient experience and confidence, the full automated capability of FLISR will be employed, bringing the full benefit of fast, automated switching to our customers. As such, we expect that benefits will begin in 2022 and continue to increase through 2028 as additional FLISR devices are deployed and when the fully automated capabilities are utilized.

a. Quantifiable Benefits

Q. HOW WILL FLISR PROVIDE RELIABILITY BENEFITS?

A. Overall, implementing FLISR allows the Company to more efficiently restore power to our customers with the use of fewer resources and will improve our customer's outage experience. Specifically, if there is a fault on a feeder that is automated with FLISR, we will be able reduce the number of customers who experience a sustained outage by two-thirds and will shorten the duration of certain sustained outages that affect a substantial portion of our customers.

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Q. HOW WILL FLISR REDUCE THE NUMBER OF CUSTOMERS WHO EXPERIENCE SUSTAINED OUTAGES?

A. FLISR will allow us to restore service to two-thirds of customers affected by an outage within minutes of a fault. In the event of a fault, the FLISR protective devices will reclose, or sectionalize the feeder, and send data to ADMS. ADMS will then step through the FLISR sequence. The first step is fault location, identifying the location of the fault to, at minimum, between two telemetered devices. Next, FLISR will proceed to isolation, in which ADMS will send open commands to any additional devices necessary to isolate the faulted section of feeder. Last, FLISR will execute supply restoration, which will generate a switching plan to restore load to all possible customers.

Restoration can be done manually or automatically within the system. Restoration considers not only device and feeder loading - but surrounding feeder and substation loading as well. ADMS will then execute the proposed switching plan and notify the operator of the need to send a crew to the isolated section to investigate the fault event. This process is expected to take from 15-45 seconds from start to finish and by design, restore power to approximately two-thirds of the customers on that feeder. After the service restoration step, system operators will send a crew to the isolated section to investigate the fault event, make repairs, and restore service to the remaining customers.

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Q. HOW WILL FLISR REDUCE THE OUTAGE DURATION FOR CUSTOMERS ON A FEEDER WITH A FAULT?

A. FLISR will also provide better fault location identification that will improve restoration times for those customers served by feeder experiencing a fault. Specifically, ADMS will run the FLP algorithm and predict where within a FLISR section the fault exists, which will reduce patrol times for Xcel Energy crews. As a result, crews will be able to move on to subsequent outages more quickly.

Figure 15 below illustrates how FLISR will improve restoration times for both customers on the healthy section of the feeder and those on feeder with a fault. The first timeline below shows the sequence of activities that currently take place, along with their approximate timeframes. The second timeline depicts the anticipated sequence of activities with fully-functional FLISR. The comparison is significant, a reduction in outage duration from 45-75 minutes to only 5-10 minutes for those customers not connected to the faulted section. Also, due to the fault location information, FLISR will also reduce the patrol time required for our crews to locate the fault from 15-20 minutes to 5-10 minutes. For those customers on the faulted sections, this is expected to result in quicker service restoration.

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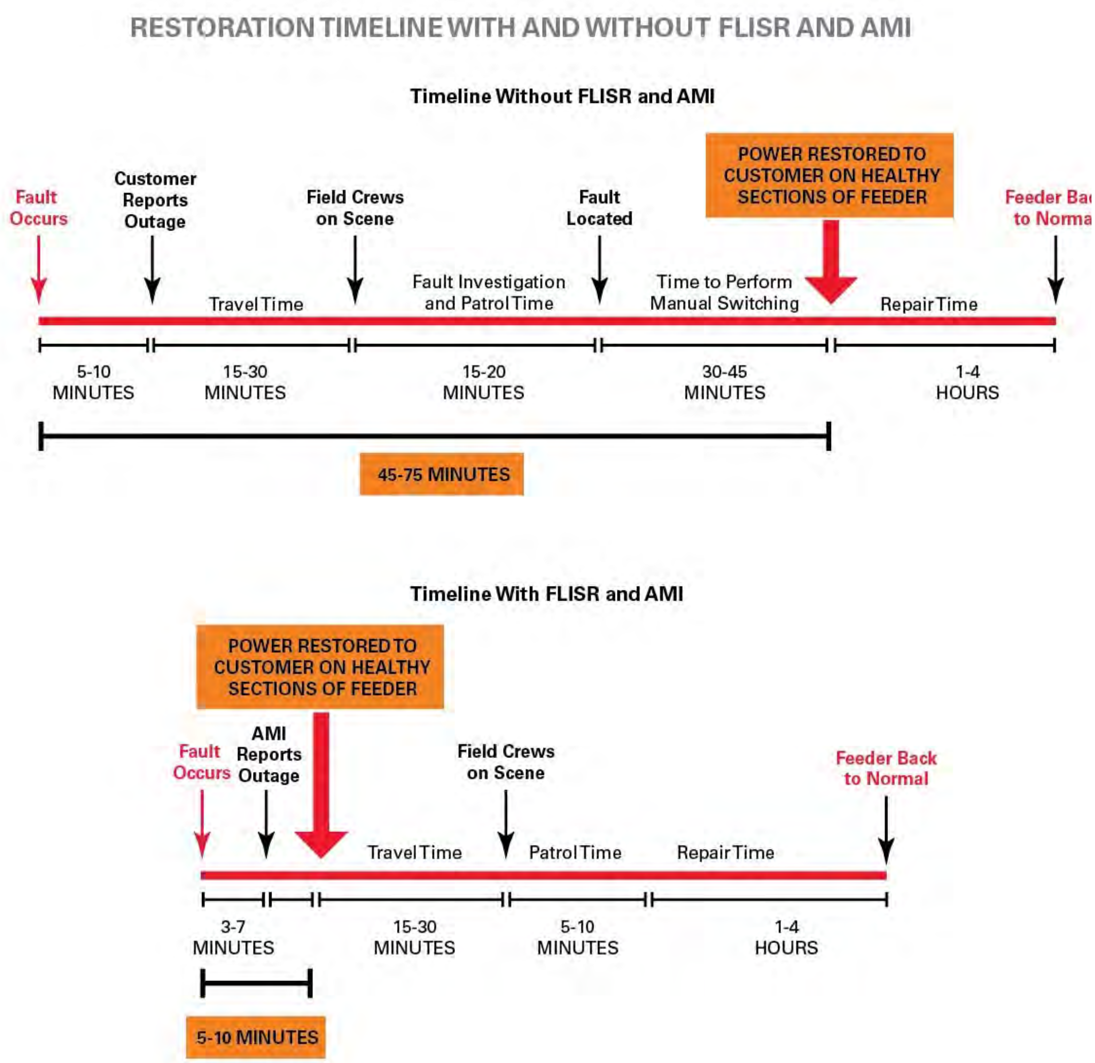
Figure 15



Q. HOW DID THE COMPANY QUANTIFY THESE RELIABILITY BENEFITS?

A. The Company quantified these reliability benefits in terms of: (1) customer benefit due to outage duration reductions and (2) reduced patrol time for crews to respond to outages. A summary of the calculations for these quantifiable FLISR benefits is provided in Exhibit___(KAB-1), Schedule 8.

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(1) Customer Benefit of Reduced Outage Duration

Q. HOW DID THE COMPANY QUANTIFY THE VALUE ASSOCIATED WITH A REDUCTION IN THE DURATION OF A CUSTOMER'S DUE TO FLISR?

A. Sustained electric power outages and blackouts cost the United States approximately $44 billion annually, according to a 2018 study by Lawrence Berkeley National Laboratory (LBNL).[20] The automated restoration provided by FLISR will reduce CMOs for customers located on FLISR-enabled feeders. FLP will also reduce CMOs through more effective identification of fault events and improved dispatching of crews for restoration. To determine the value of this reduction in CMOs, Xcel Energy used the ICE Calculator developed by LBNL.

Q. HOW DID THE COMPANY UTILIZE THE ICE CALCULATOR TO VALUE A REDUCTION IN CMOS FOR ITS CUSTOMERS?

A. To calculate the value of a CMO, each FLISR feeder was divided into two classes, residential and commercial/industry, to determine the value lost during an outage. On average, the cost-per-CMO of a mainline outage for the proposed FLISR feeders is approximately $0.72. The Company then calculated anticipated benefits from FLISR using this cost-per-CMO.

Q. HOW DID THE COMPANY PERFORM THIS CALCULATION?

A. We performed studies on the historic SAIDI performance of each feeder to establish a baseline of reliability, using a rolling five-year average. We derived a cumulative CMO for each the FLISR feeders using actual reliability data over the 2010 to 2017 period. We calculated an annual average CMO for each of the feeders to compare to after FLISR is deployed.

[20] *Improving the Estimated Cost of Sustained Power Interruptions to Electricity Customers* (June 2018), available at: http://eta-publications.lbl.gov/sites/default/files/copi_26sept2018.pdf.

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To quantify FLISR benefits, we applied the value for each CMO to the number of customers impacted by mainline feeder events – again using historic data. For the comparative future state once FLISR is deployed, we assumed that in a mainline fault event:

- All but one section of the customers on the feeder will see their power restored in less than one minute, which eliminates a sustained outage for the majority of customers on the feeder,
- An improvement of at least 50 percent from historic performance,
- Efficiencies associated with sharing tie switches between two automated feeders, such that each feeder acts as the back-up for the other, and
- A 25 percent reduction in the identified benefits, to represent a conservative but realistic estimate of the percentage of time that FLISR may not be available during an outage for some reason.[21]

The formula utilized to determine the annual CMO savings for each feeder is shown in Figure 16.

Figure 16

$$CMO\ Saved = (Average\ Annual\ CMO) * \frac{(Number\ of\ Sections - 1)}{Number\ of\ Sections} * (1 - Scale\ Factor)$$

[21] The system might not be available for switching for a variety of reasons, including communication failures or devices out of service for maintenance.

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To determine the cost-per-CMO for a particular feeder, we divided the cost of the devices to automate that feeder with FLISR by the number of expected CMO saved to determine the cost-per-CMO saved.

(2) Outage Patrol Time Savings

Q. HOW DID THE COMPANY QUANTIFY THE REDUCTION IN OUTAGE RESPONSE TIME DUE TO FLISR?

A. A primary benefit of FLISR is the ability to see the real-time load across many critical points on the distribution system – and the ability to operate those devices remotely. Since FLISR and other remotely-controlled devices will allow us to identify and thus restore the root cause of an outage faster, our crews will be able to get to the next outage faster – increasing crew productivity and reducing the duration of each subsequent outage event from what it would have been without the increased system visibility. Once our system is widely automated, the cascading benefits from this will have a meaningful impact on reliability for all customers, whether they are on a FLISR feeder or not.

The Company estimates that FLISR will reduce the field time that crews spend responding to outages by an average of 10 minutes per outage. The actual time reduction will differ by situation. In some cases, damage reports will allow us to locate the problem immediately and the patrol time saving benefit from FLISR will be small. In many others, there will be substantial reduction of patrol time resulting from the ability to pin-point the fault location, which will focus our crews on either the calculated location or on a smaller portion of the feeder. This 10 minute reduction is our best estimate of the average savings due to the ability of FLISR to pinpoint the fault location.

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Q. HOW DID THE COMPANY QUANTIFY THE BENEFIT ASSOCIATED WITH THIS REDUCTION IN THE FIELD TIME REQUIRED TO RESPOND TO AN OUTAGE?

A. The Company calculated the CMO saved through this improvement in patrol time, and using the ICE calculator, assigned a value.

b. Non-Quantifiable Benefits

Q. ARE THERE OTHER BENEFITS OF FLISR THAT THE COMPANY WAS UNABLE TO QUANTIFY?

A. Yes. One of the benefits that the Company was unable to quantify is the value of the data provided by FLISR for purposes of planning the system. FLISR provides key data at critical points along the system, which is fed into historical systems and can be leveraged by engineering to make decisions about how to plan and design the future grid. System planning uses historic measured load at a single point on the feeder to allocate that load across the feeder. With multiple FLISR devices on each feeder, the granularity of these data measurements will be enhanced across the feeder. The increased system visibility will also improve our reliability management efforts by increasing the quality and amount of the information we are able to analyze. In addition, these FLISR devices can capture momentary or transient fault and disturbance information, providing the ability to proactively identify potential issues on the distribution system.

6. FLISR Costs

Q. WHAT ARE DISTRIBUTION'S COSTS TO IMPLEMENT FLISR?

A. Distribution's principal costs of implementing FLISR are related to the costs for the FLISR devices and their installation. FLISR costs are broken down by capital additions and O&M costs through the term of multi-year rate plan in Tables 46 and 47 below. I will describe each of these costs in further detail below.

Table 46

FLISR Capital Additions – Distribution State of MN Electric Jurisdiction (Includes AFUDC) (Dollars in Millions)			
AGIS Program	**2020**	**2021**	**2022**
FLISR	$3.1	$8.0	$5.8

Table 47

FLISR O&M – Distribution NSPM – Total Company Electric (Dollars in Millions)			
AGIS Program	2020	2021	2022
FLISR	$0.1	$0.3	$0.2

a. Distribution's Capital Costs

Q. WHAT ARE THE PRINCIPAL CAPITAL COSTS ASSOCIATED WITH IMPLEMENTING FLISR?

A. The capital costs associated with FLISR are: 1) asset costs; 2) asset installation; and 3) communications.

Q. WHAT IS INCLUDED IN THE ASSET COST CATEGORY?

A. This includes the capital costs for the FLISR devices (i.e., switches, reclosers, powerline sensors, and relays).

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Q. HOW DID THE COMPANY ESTIMATE THE COSTS OF THESE DEVICES?

A. The Company has experience in the use and installation of many of the devices involved in the FLISR deployment. As a result, we were able to use historical costs to develop the capital cost estimates for these devices. Our recent costs and experiences in Colorado provide confirmation that these costs estimates are reasonable.

Q. HAS THE COMPANY SELECTED THE VENDORS TO SUPPLY THE FLISR DEVICES?

A. Yes. The Company selected the vendors for the FLISR devices through our established Equipment Standards process. The process by which our materials are selected to become "standard" does involve periodic review, so as the market evolves, the Company will revisit the vendors selected to provide these devices and based on this review, these vendors may change. In addition, the Company's foresight into the needs for automation of certain devices had led to selecting devices in the past that were capable of the automation needed to implement FLISR. This is the case for reclosers, switch cabinets, and overhead switches.

Q. WHAT IS INCLUDED IN THE ASSET INSTALLATION AND LABOR COST CATEGORY?

A. The asset installation costs for FLISR include the capitalized costs for installing and commissioning FLISR devices (switches, reclosers, sensors, and relays).

Q. HOW DID THE COMPANY ESTIMATE THESE COSTS?

A. The Company has experience in the use and installation of many of the devices involved in the FLISR deployment. We were able to use historical

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installation and labor costs to develop the capital cost estimates. Our recent costs and experiences in Colorado provide confirmation that these cost estimates are reasonable.

Q. WHAT IS INCLUDED IN THE COMMUNICATION COST CATEGORY?

A. The communications installation costs for FLISR include costs to install and communications endpoints associated with the FLISR equipment to ensure reliable and secure communications.

Q. HOW DID THE COMPANY ESTIMATE THESE COSTS?

A. The Company has experience in the use and installation of many of the devices involved in the FLISR deployment. We were able to use historical costs to develop the capital cost estimates. Our recent costs and experiences in Colorado provide confirmation that these costs estimates are reasonable.

b. Distribution's O&M Costs

Q. WHAT ARE DISTRIBUTION'S O&M COSTS ASSOCIATED WITH IMPLEMENTING FLISR?

A. Distribution's O&M costs for FLISR will include costs in the following categories: (1) capital support; (2) on-going asset/device support; (3) device replacement; (4) on-going communications network; and (5) training.

Q. WHAT IS INCLUDED IN THE CAPITAL SUPPORT COST CATEGORY AND HOW WERE THESE COSTS ESTIMATED?

A. This category includes expenses related to equipment installations that are appropriately deemed O&M. One example is certain switching activities

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(operations) necessary to safely install new equipment. The Company used actual, average installation times to develop these cost estimates.

Q. WHAT IS INCLUDED IN THE ON-GOING ASSET/DEVICE SUPPORT COST CATEGORY AND HOW WERE THESE COSTS ESTIMATED?

A. This category includes labor and repairs to maintain assets in good working order. The Company estimated the annual support costs by multiplying per-unit support cost estimates by the quantity of devices in service each year.

Q. WHAT IS INCLUDED IN THE COMPONENT REPLACEMENT COST CATEGORY AND HOW WERE THESE COSTS ESTIMATED?

A. This category includes material and labor to replace batteries for certain devices on a five-year schedule. The Company estimated these costs as by multiplying per-unit replacement cost by the quantity of devices expected to be in need of battery replacement for each year.

Q. WHAT IS INCLUDED IN THE ON-GOING COMMUNICATIONS NETWORK COST CATEGORY AND HOW WERE THESE COSTS ESTIMATED?

A. This category includes costs to maintain communications to the field devices. The Company estimated these costs based on historical time to troubleshoot device communication issues and an estimate of the quantity of devices which typically have required such maintenance.

Q. WHAT IS INCLUDED IN THE TRAINING COST CATEGORY AND HOW WERE THESE COSTS ESTIMATED?

A. This category includes training costs for the FLISR program. The Company estimated these costs based on the labor costs of the employees requiring

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FLISR training (control center, engineering, line crews, etc.) and the time required to train them.

c. Distribution Contingency for FLISR

Q. PLEASE DESCRIBE THE FLISR CONTINGENCY AMOUNTS INCLUDED IN THE FORECAST.

A. Distribution's FLISR budget forecast for the period 2020-2025 includes capital contingency amounts of approximately 12 percent. This smaller contingency percentage (compared to the contingency for AMI) is considered adequate because the cost projections for devices and installation were developed based on historical costs, and we believe we have fairly accurately estimated the quantity of equipment and cost of installation of the FLISR devices.

d. FLISR Expenditures 2020-2029

Q. WHAT ARE THE CAPITAL EXPENDITURE AND O&M FORECASTS FOR FLISR FOR DISTRIBUTION FOR 2020 THROUGH 2029?

A. The tables below provide Distribution's capital expenditures and O&M related to FLISR through 2029.

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Table 48

FLISR Capital Expenditures – Distribution NSPM – Total Company Electric (Dollars in Millions)					
	Rate Case Period			5-Year Period	10-Year Period
AGIS Program	**2020**	**2021**	**2022**	**2023-2024**	**2025-2029**
FLISR	$3.1	$8.1	$5.9	$16.0	$26.3

Table 49

FLISR O&M Expenditures – Distribution NSPM – Total Company Electric (Dollars in Millions)					
	Rate Case Period			5-Year Period	10-Year Period
AGIS Program	**2020**	**2021**	**2022**	**2023-2024**	**2025-2029**
FLISR	$0.1	$0.3	$0.2	$3.2	$2.4

7. *Alternatives to FLISR*

Q. WHAT ALTERNATIVES TO FLISR DID THE COMPANY EVALUATE?

A. There are no real alternative technologies that provide the same reliability benefits as FLISR. As a result, the Company evaluated the following alternatives: (1) maintaining the current system; (2) implementing FLISR without the other AGIS components; and (3) delaying the deployment of FLISR.

Q. WHAT DID XCEL ENERGY CONCLUDE AFTER EVALUATING THE POSSIBILITY OF MAINTAINING THE CURRENT SYSTEM?

A. Maintaining the current system means our ability to improve system reliability would be limited to process improvements related to our outage response

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procedures, which can only provide very limited incremental improvement. This is because absent FLISR, our ability to isolate, locate, and resolve faults is limited due to: (1) a lack of intelligent field devices that interact with the FAN and ADMS to restore service to a majority of customers on the faulted circuit; and (2) a lack of visibility and information regarding where the fault may have occurred on the feeder and the type of fault occurring. Given the limitations of the current system, we determined that FLISR was necessary to improving our customers' outage experience.

Q. DID THE COMPANY CONSIDER IMPLEMENTING FLISR BY ITSELF WITHOUT THE OTHER AGIS COMPONENTS?

A. Yes. We specifically considered installing FLISR without AMI. Such an installation was proposed by the Company in our 2017 Grid Modernization Report. However, as we pointed out in that filing, the FLISR application relies on three primary components to operate: (1) ADMS, for central logic and control; (2) FAN, for wireless communications to each device; and (3) FLISR field devices. As a result, even if FLISR is implemented without AMI, some portion of the FAN infrastructure would still need to be deployed to provide the necessary communication capabilities from the Company's back-office applications to each sensor and switching device. The FAN infrastructure required for FLISR is the same infrastructure that will support AMI and IVVO. Thus, while FLISR could be implemented as a standalone project with limited FAN deployment, there are efficiencies gained by deploying FLISR at the same time as AMI and IVVO as these programs require the same FAN communication infrastructure.

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Q. DID THE COMPANY EVALUATE THE POSSIBILITY OF DELAYING THE DEPLOYMENT OF FLISR?

A. Yes. However, the Company determined that such a delay would only defer the realization of the reliability benefits provided by FLISR. Further, delaying the deployment of FLISR has likely effect of increasing its costs due to inflation as well as potential increases in labor and material costs.

8. Interoperability

Q. HOW DOES THE COMPANY'S FLISR PROJECT ENSURE AND FACILITATE INTEROPERABILITY OF THIS TECHNOLOGY?

A. The Company plans to implement FLISR components that are vendor-neutral, non-proprietary, standards-based, and interoperable. This will allow the Company the ability to switch equipment vendors at any time and the new devices will be able to easily operate with the existing FLISR system and devices.

9. Minimization of Risk of Obsolescence

Q. HOW DOES THE COMPANY'S FLISR INVESTMENT PROTECT AGAINST OBSOLESCENCE?

A. Xcel Energy has always maintained an outlook that our assets must provide customer value over a long time period, a philosophy that has driven us to install quality equipment at the best price we can negotiate. That philosophy remains foundational to our goal of providing long-term value to our customers. Through our selection and sourcing procedures we select equipment from vendors which are well-established, financially viable, and show visionary leadership. While we cannot guarantee the longevity of any

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specific vendor, these attributes help to ensure the products will remain supported.

For electronic equipment, we specify equipment which can be remotely upgraded with new firmware as functionality or security needs dictate. Our requirement to leverage open standards is foundational to the concept that we will not become dependent on any single vendor, but that we will be free to integrate components from different vendors, should subsequent evaluations direct. In addition, we work closely with manufacturers to ensure they are building security into their equipment.

Specifically with FLISR, we have selected equipment and controls that adhere to these principles and are highly configurable. The recloser and switch controls, in particular, are sourced from industry leaders and can be used autonomously or in concert with the FLISR control system. The switches and reclosers themselves use state of the art, proven designs and technology.

G. IVVO

1. Overview of IVVO

Q. WHAT IS IVVO?

A. Integrated Volt-VAr Optimization, or IVVO, is an advanced application that automates and optimizes the voltage of the distribution system using equipment installed at the substation and along the feeder. Voltage optimization is accomplished by "flattening" a feeder line's voltage profile or, in other words, narrowing the bandwidth of the voltage from the head-end of the feeder to the tail-end via control of capacitors and other voltage regulating devices for voltage support. With IVVO, voltage can be monitored along the

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feeder and at select end points (rather than only at the substation), allowing the head-end voltage to be lowered to achieve a variety of operational outcomes such as:

- Reduction of distribution electrical losses;
- Reduction of electrical demand;
- Reduction of energy consumption; and
- Increased ability to host DER.

Q. CAN YOU PROVIDE ADDITIONAL DETAILS AS TO HOW IVVO WILL BE OPERATED?

A. The ADMS that we are in the process of implementing is capable of running the IVVO application in several different operating modes: Voltage Control, Peak Reduction, VAr Control, and Conservation Voltage Reduction (CVR).

- *Voltage Control mode* functions to optimize voltage on the feeder around standard operating voltages – maintaining adequate service voltage for all customers. This mode is generally a secondary operating mode of IVVO, and only used to establish the voltage boundaries within which the other operating modes must stay within. As penetration of DER grows, Voltage Control will become more common as a primary control mode to manage the expanded range of distribution system voltage caused by DER. Traditionally, with only load on a feeder, the Voltage Control objective was to raise voltage at times of heavy load in order for voltage to remain within the acceptable range. With DER causing reverse power flow and raising voltages during times of light loading, voltage control schemes must now both raise and lower voltage.

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- *Peak Reduction mode* serves to reduce load only during peak load events. It is a manually triggered mode that reduces system voltage to a targeted value to reduce load on the system for a short duration – typically one or two hours. This peak reduction tool can be used in large operating regions, such as Minnesota as a whole, or tactically by feeder, substation, or other targeted area.
- *VAr Control mode* seeks to reduce system losses and save energy by optimizing power factor on each distribution feeder.
- *Conservation Voltage Reduction (CVR) mode* seeks to save energy through reduced operating voltages. CVR mode first flattens the load profile along the feeder using capacitors, and then uses the Load Tap Changer (LTC) or Voltage Regulators inside the substation to lower voltage on the feeder. This lowered operating voltage results in small energy savings for most customers on a feeder.

Q. WHAT ARE THE PHYSICAL COMPONENTS OF IVVO?

A. There are four principal utility equipment components of IVVO:

- Capacitors;
- Secondary static VAr compensators (SVC);
- Voltage and current sensing devices; and
- Load Tap Changers (LTC).

Q. WHAT ARE CAPACITORS AND WHY ARE THE NEEDED?

A. Electric loads like motors require two types of power to operate: active and reactive power. Distribution line capacitors provide local VAr support or reactive power. By doing so, they help to limit both voltage drop and line losses across the distribution system. Capacitors are currently switched on

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and off using the SmartVAr program with a goal of improving power factor and reducing losses. With IVVO, these existing capacitor banks will continue to be used; however the control will be changed from SmartVAr to ADMS. We expect to add, on average, about half of a capacitor bank per feeder to the existing fleet to ensure proper IVVO performance. The Company plans to install 96 capacitors for this purpose.

Q. HOW DOES IVVO DIFFER FROM SMARTVAR?

A. The Company's legacy SmartVAr system currently controls 2,329 capacitor banks on 897 feeders within the NSPM footprint. This system is delivering good value by maintaining high power factor, which reduces distribution system losses. The IVVO program improves on SmartVAr by offering additional capabilities and control modes such as the CVR mode.

Q. WILL IVVO REPLACE THE SMARTVAR SYSTEM?

A. Ultimately, yes. As we enable IVVO, we will change control of 417 of these capacitors (on 189 feeders) from SmartVAr to ADMS to achieve the benefits of energy savings through reduced voltage. To consolidate control systems and enable the enhanced benefits ADMS has to offer, our plan is to move control from SmartVAr to ADMS for the remaining devices/feeders in the future.

Q. WHAT ARE SVCS AND WHY ARE THEY NEEDED?

A. The SVCs are electronic secondary capacitors that provide fast, variable voltage support to help stabilize and regulate the voltage. Each device is able to act in less than a cycle (a cycle is defined as 1/60 of a second since the United States AC frequency is 60 Hz), as opposed to a traditional utility

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capacitor device that operates on 60-90 second time delay. These devices provide dynamic voltage response for load, and are located closer to customers - or nearer the edge of the grid - than the Company's existing capacitors.

The devices' capabilities will enhance the system's ability to respond to the variability of renewable DERs such as solar facilities and other intermittent distributed resources. The Company will strategically place approximately 270 SVC devices along feeders that need additional voltage support. In the event that IVVO function is limited by localized low voltage, SVCs are a tool that can readily be employed to improve IVVO performance, and thus its benefits.

Q. PLEASE EXPLAIN WHY THE COMPANY IS PROPOSING BOTH PRIMARY AND SECONDARY CONNECTED (SVC) CAPACITANCE.

A. Capacitance can be added either at the primary or secondary level. While the cost-per-kVAr is substantially less when applied on the primary level, applying it on the secondary level can alleviate localized low voltage and thereby increase the depth to which CVR mode can be operated. To that end, we have found deploying SVCs on select low voltage sites to be helpful. Applying this technology is optional, but has the potential to increase energy savings. We plan to analyze the feeders where IVVO is proposed and, if warranted, install these devices selectively to mitigate potential voltage issues. Once in operation, we will deploy additional units as warranted.

Q. HOW ARE THE SVCS CONTROLLED BY THE ADMS?

A. The aggregating software Grid Edge Management System (GEMS) will be used to communicate between the ADMS and the SVCs to achieve full value.

GEMS is a software application developed by Varentec to monitor and control Varentec's "Edge of Network Grid Optimization" (ENGO) devices. These all-in-one ENGO devices are used to control and improve customer voltages in conjunction with an IVVO scheme.

The Company will install these devices with FAN NICs which will allow these devices to communicate through the GEMS system. The benefits of communicating through GEMS are:

- Ability to change devices voltage setpoints;
- Provides ADMS with VAr and voltage data from ENGOs;
- Ability to update firmware;
- Ability to query devices for operational history; and
- Enable control to help validate benefits.

Q. DID THE COMPANY CONSIDER INSTALLING SVCS WITHOUT GEMS?

A. Yes. SVCs can be installed as stand-alone devices. However, without GEMS we would not have any insight into their operational data, we would not be aware of failures, and we would not be able to quantify their effect or benefit. Further through GEMS, SVCs provide voltage data to ADMS which helps ADMS make better decisions to optimize voltage.

Q. WHAT IS THE FUNCTION OF THE LOAD SENSING DEVICES?

A. IVVO requires end-of-line voltage sensing to monitor the voltage and ensure it is compliant with ANSI Standard C84.1. The Company intends to use the newly installed AMI meters as "bellwether" sensing devices to provide near real-time voltage sensing. When located at the edge of system (i.e., at the customer premise) where voltage is predictably lowest, these sensors will

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ensure that IVVO does not lower the voltage to the degree that customers would experience voltage below the acceptable standard. The plan is to configure, on average, 10 meters per feeder to provide this data. We will be able to reassign meters as bellwether meters as necessary should load or feeder topology change.

Q. WHAT IS THE FUNCTION OF THE LOAD TAP CHANGERS (LTC)?

A. This is equipment that is installed on the substation transformer to enable voltage regulation. Substation transformers equipped with LTCs provide voltage regulation by varying the transformer ratio or tap. LTCs typically have 16 taps above and below neutral (33 taps total) and each tap adjusts the transformer turns ratio by 0.375 percent. LTCs are currently monitored and locally controlled based on the local bus voltage. LTCs raise or lower the voltage by tapping up or down based on the settings of the local controller and the demand of the substation transformer. The LTCs themselves will be used, but the controls for some of the legacy units will be upgraded to allow ADMS to control the setpoints. As part of IVVO, we will upgrade nine of the 30 LTC controls to accomplish this. The new LTCs may also require substation Remote Terminal Unit (RTU) upgrades due to the increased SCADA data demands of new LTC controls and FLISR relays. We are budgeting to replace 7 RTUs as part of IVVO.

Q. WHAT IS THE FUNCTION OF THE PRIMARY POWERLINE SENSORS?

A. Primary powerline sensors measure current, voltage, power factor, fault magnitude, and other attributes. Primary powerline sensors are also capable of providing fault current data that is useful to FLISR and FLP in detecting the location of faults on the system.

Q. HOW WILL THE INFORMATION OBTAINED FROM THE POWERLINE SENSORS BE UTILIZED BY ADMS AND IVVO?

A. ADMS uses real-time data to fine-tune its system solutions. The primary input to this will be the feeder load and voltage information, normally delivered via SCADA from the RTU in the substation. ADMS will also use all additional data available from primary powerline sensors, meters at larger DER sites, and secondary meters at large customer locations. ADMS will use the measurements – power, reactive power, and voltage - to improve power flow calculation accuracy and display the measurements and results geospatially. Where possible, we will install new capacitors and switches with primary powerline sensors. Where existing capacitors and switches will not be replaced, we will strategically install stand-alone powerline sensors to provide the data required for ADMS.

Q. WHAT IS THE COMPANY'S INSTALLATION PLAN FOR THE POWERLINE SENSORS?

A. We plan to install 180 sets of sensors on the 189 feeders selected for IVVO to ensure that we have accurate load flow to operate IVVO. Taking into account the powerline sensors, sensors installed with new capacitor banks, and sensors at FLISR devices, there will be roughly two sensor points per feeder in addition to the feeder breaker.

2. *Interrelation of IVVO with other AGIS Components*

Q. HOW WILL IVVO INTERACT WITH ADMS?

A. IVVO will be an advanced application within ADMS. ADMS will operate as a centralized system that monitors inputs from devices such as substation RTUs, capacitor banks, AMI meters, LTCs, and other distribution automation devices. ADMS will take the inputs from these devices and compute the most efficient way for the system to operate and respond to changes. IVVO, through ADMS, will implement automated activities such as opening and closing of capacitors, and sending new settings to LTCs and SVCs. ADMS will also compute the most efficient way for the system to operate based on both manual switching and FLISR (e.g., for construction and maintenance activities and outages). The LTC control devices will take direction from ADMS, which will make decisions based on knowledge about the entire system, rather than only about voltage at the local bus. As a centralized system, ADMS will be able to control the distribution devices to work in unison and dynamically react to an increasingly complex system in a safe, efficient, and reliable manner.

Q. HOW WILL IVVO INTERACT WITH AMI?

A. AMI meters used as bellwether meters are the least cost method to provide voltage inputs to ADMS at key locations across the grid. For IVVO to be successfully and safely operated, voltage endpoints are necessary at 10 end points on each feeder; without AMI, this data would need to be gathered in other ways. Our preliminary analysis for Minnesota shows the use of voltage sensors would be approximately ten times the cost per unit of an AMI meter. Thus, the AMI initiative is a critical part of IVVO deployment to minimize the cost of providing end of line voltage data.

Q. HOW WILL IVVO INTERACT WITH THE FAN?

A. IVVO will leverage the FAN for communication with its field components, principally capacitors and static VAr compensators. The FAN will also support communications from distribution powerline sensors, necessary for

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ADMS to calculate the power flows that are fundamental to IVVO operations. And as mentioned above, bellwether AMI meters will communicate via the FAN.

Q. HOW WILL IVVO INTERACT WITH FLISR?

A. First, IVVO and FLISR share the common need for accurate ADMS calculations. There is a mutual benefit when sensors installed on equipment necessary for FLISR (i.e., reclosers) and IVVO (i.e., capacitors) exist on the same feeders. The additional system inputs enhance ADMS accuracy.

Second, IVVO will react to system changes initiated by FLISR. When systems are reconfigured, the load may change significantly and the voltage controls must respond quickly. This capability exists within ADMS.

3. IVVO Implementation

Q. WHAT IS THE IMPLEMENTATION PLAN FOR IVVO?

A. The implementation plan for IVVO is a targeted, core deployment within the western Twin Cities metropolitan area which coincides with our initial ADMS deployment. This implementation will start in 2019 and continuing through 2024.

Q. WHERE AND WHEN WILL IVVO DEVICES BE DEPLOYED FIRST?

A. As part of the installation of ADMS, we plan to start by implementing IVVO on the seven-feeder system emanating from our Hiawatha West substation in Southeast Minneapolis. This system will support the testing of ADMS in the second quarter of 2020. The system's existing capacitors and LTC controls will be augmented with powerline sensors in late 2019 and early 2020 to

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enable this work. The Company will install approximately 35 SVCs, which will operate autonomously to provide localized voltage support.

Q. WHAT IS THE NEXT STEP IN THE CORE DEPLOYMENT OF IVVO?

A. Xcel Energy proposes to then implement IVVO at 13 substations (serving 224,000 customers). These 13 substations contain 30 transformers and serve 189 feeders. The Company will capture data and install and configure equipment, ensure the accuracy of the calculations, and then enable continuous IVVO functionality. IVVO will be enabled by substation transformer area (each substation contains 1-3 distribution transformers, and each transformer typically serves 4-7 feeders). This work will occur between 2021-2024, with these areas enabled roughly in a linear fashion beginning in 2022. The SVCs and controlling software (GEMS) would be deployed with IVVO. A detailed IVVO device implementation schedule is provided in the table below.

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Table 50

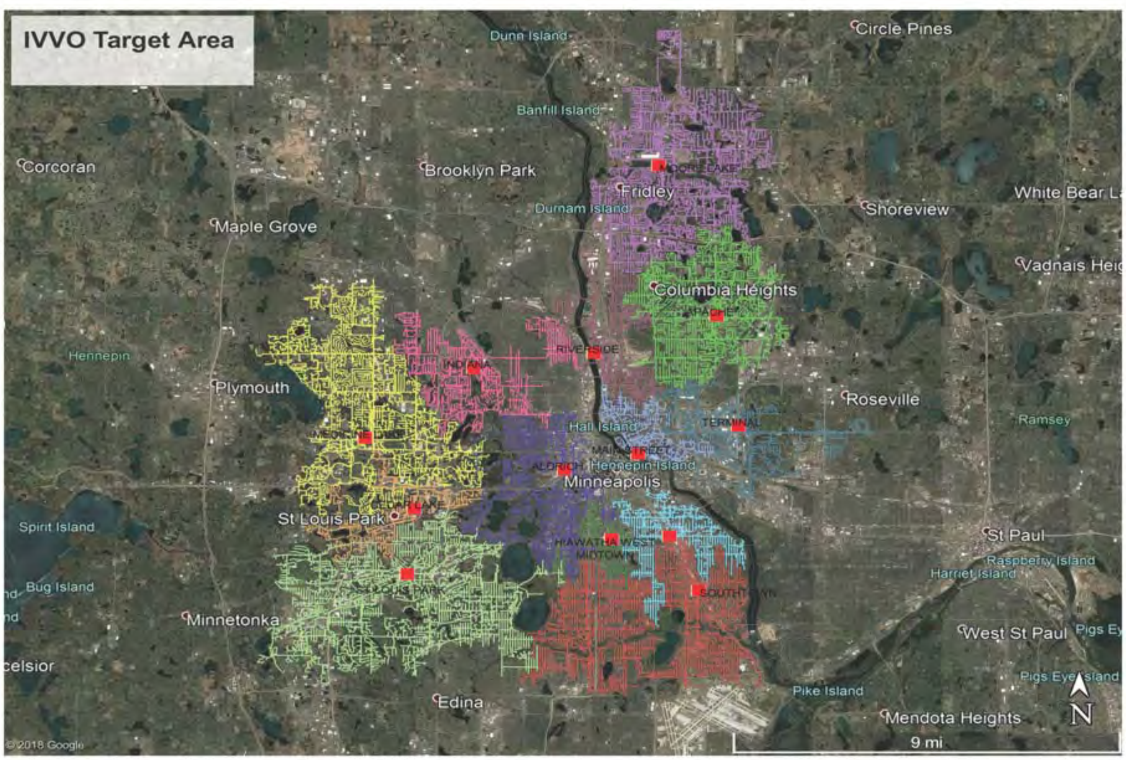
IVVO Device Implementation Schedule

VVO Devices	2019	2020	2021	2022	2023	2024	Total
Capacitors	0	0	16	32	23	25	96
ENGOS	35	0	35	82	82	71	270
Line Sensors	20	0	40	49	46	45	180
LTC Controls	0	0	1	3	3	1	8
Bellwether meters	0	0	0	945	945		1,890

Q. WHERE ARE THESE 13 SUBSTATIONS LOCATED?

A. These substations are located throughout the Minneapolis/St. Paul area and are depicted by the red circles on Figure 17 below.

Figure 17



Q. HOW DID XCEL ENERGY DETERMINE THE SCALE AND SCOPE FOR THE CORE DEPLOYMENT OF IVVO?

A. The Company sought to optimize the value, providing maximum energy savings while minimizing investment. To select the specific substations and feeders for this core deployment, the following factors influenced this selection:

- *ADMS overlay*. The Company chose to implement in the region controlled by our Metro West control center, which is the first control center to operate ADMS in Minnesota as part of the ADMS project.
- *LTC costs*. Because one LTC controller is required per transformer, and the Company uses larger power transformers in the metro area serving many feeders, the IVVO substation investment per customer is lowest in metropolitan area. Indeed, 22 of the 30 transformers chosen already had been equipped with the appropriate LTC controller. Similarly, the chosen substations generally had newer RTUs which support the functionality.
- *Customer Density*. The selected feeders are typical for urban and suburban feeders, having a slightly greater customer density than the average feeder.
- *Load Density*. The load density for the selected feeders is slightly lower than the system average. This lower density makes them good candidates for achieving a flattened voltage profile, which gives us a greater opportunity to achieve IVVO results. The Company is interested in observing how the adoption of EVs by customers served from these feeders affects the load density and IVVO.
- *Uniformity of feeder length*. IVVO benefits are generally restricted by the longest feeder served by each transformer. This is because longer

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feeders have greater voltage drop and, without additional investments, this limits the potential reduction. The feeders in the core deployment area are generally of uniform length for each transformer area.

Q. WILL XCEL ENERGY EXPAND THE DEPLOYMENT OF IVVO TO OTHER AREAS OF ITS SYSTEM AFTER 2024?

A. As I noted, Xcel Energy has determined that a core deployment of IVVO within the Twin Cities metro area is the best first step that allows us to maximize the benefits of IVVO while testing the functionality of IVVO for broader deployment. As the Company learns more about the benefits and costs of IVVO from this core deployment, we will consider implementing IVVO more broadly in the future.

Q. WHEN WILL CUSTOMERS BEGIN SEEING BENEFITS OF IVVO?

A. Customers connected to feeders with IVVO will begin seeing benefits as soon as their substation transformer area is tuned and IVVO is implemented. Thus, the customers on the initial seven feeders will see benefits starting in 2020. Customers impacted by the subsequent deployment will see benefits starting between 2022 and 2024. Of course all our customers indirectly benefit from the lowered energy requirements due to the overall energy efficiency and demand reduction. As discussed later in my testimony, this reduction provides cost savings as well as environmental benefits.

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4. Benefits of IVVO

Q. HAS XCEL ENERGY IDENTIFIED BENEFITS THAT WILL BE GAINED FROM DEPLOYING IVVO?

A. Yes. We have identified a range of benefits, both quantifiable and non-quantifiable. In terms of quantifiable benefits, these include reduction in energy consumption, reduced electric losses, and avoided capacity costs. These quantifiable benefits of IVVO were utilized by Dr. Duggirala in the CBA model prepared by the Company to calculate the benefit-to-cost ratios for IVVO. I also describe qualitative benefits that were not quantified by the Company, but that will result from deployment of IVVO.

a. Quantifiable Benefits of IVVO

Q. CAN YOU PROVIDE A SUMMARY DESCRIPTION OF THE QUANTIFIABLE BENEFITS OF IMPLEMENTING THE IVVO TECHNOLOGY?

A. There are four areas of quantifiable benefits of IVVO:

- *Reduction of Energy Consumption.* Flattening the voltage profile along a feeder and operating in the lower range of 114V to 120V reduces energy consumption for certain devices, like incandescent lighting or motors such as those found in air conditioners, dryers, and refrigerators. Ensuring these types of devices are operated in the lower voltage range makes them more energy efficient. The industry term used to describe operating in the lower voltage range is CVR (Conservation Voltage Reduction). Studies have shown that the CVR benefit varies with the load type, climate zone, and feeder characteristics. The amount of energy efficiency or demand reduction that is achievable is highly dependent on a number of factors, including various attributes and the configuration of the distribution system, and customer attributes such as customer density, load characteristics, and the mix of residential and commercial customers.

- *Reduction of Distribution Electrical Losses*. IVVO models in ADMS can turn the capacitors installed along the distribution circuit on and off in an optimal manner to limit the reactive power flowing on the distribution system. This improves the efficiency of the system, reduces system losses, slightly decreases energy generation needs, and reduces carbon emissions. Because power factor improvements have largely been achieved through our existing SmartVAr program in Minnesota, we expect this incremental benefit through IVVO to be modest.
- *Avoided Capacity Costs*. A by-product of reduced energy consumption is the corollary reduction of demand. By not having to provide that capacity, the benefit can be shown as a deferral of capital investments in generation, transmission, and distribution to serve peak demand.
- *Carbon Emissions Reduction*. Another by-product of reduced energy consumption is the corollary reduction in generation which in turn results in reduced CO_2 emissions. The Company valued this reduction in CO_2 emissions using Commission approved values.

I will discuss the first three benefits (reduction in consumption, losses, and avoided capacity) and Dr. Duggirala will discuss the last benefit (carbon emissions reduction). A summary of the calculations for all of the quantifiable IVVO benefits is provided in Exhibit___(KAB-1), Schedule 9.

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(1) Energy Savings

Q. CAN YOU GENERALLY DESCRIBE HOW THE IMPLEMENTATION OF IVVO WILL RESULT IN ENERGY SAVINGS?

A. Customer's end-use devices are designed to operate over a range of voltages. Historically, the voltage on the distribution system is toward the high end of the range, which causes devices to consume more energy. IVVO when operated in CVR mode will allow the Company to lower the voltage on the feeder while still keeping it within acceptable limits. This lowered operating voltage results in small energy savings for most customers on a feeder.

Q. CAN YOU PROVIDE AN EXAMPLE OF HOW IVVO WILL RESULT IN ENERGY SAVINGS?

A. One example of how IVVO will result in electricity savings is incandescent lighting, where the power consumed is directly proportional to the voltage. (For such a load, the formula $P=V^2/R$ applies, where P=power, V=voltage, and R=resistance). As shown in Figure 18, a 70W incandescent light bulb will consume around 77W at a higher voltage level of 126V and around 66W at a lower voltage level 114V. This type of load can be referred to as a constant-impedance load.

But other loads react differently, and power demand is influenced less by a reduction in voltage. For instance, the effect of a change in voltage on the demand for compact fluorescent light bulbs is shown in Figure 19 below. Analysis show the impact of voltage change on demand for CFLs is roughly half of that for the incandescent bulb (Figure 18). While the focus in on the reduction of real power, the graphics below depict the effect of change in reactive power for the benefit of understanding the impact.

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Other loads, especially electronics and most LEDs, respond even less to changes in voltage - exhibiting a constant-power behavior. Lastly, we note that energy savings is function of power over time, and that the benefit analysis does endeavor to takes this factor into account.

Figure 18

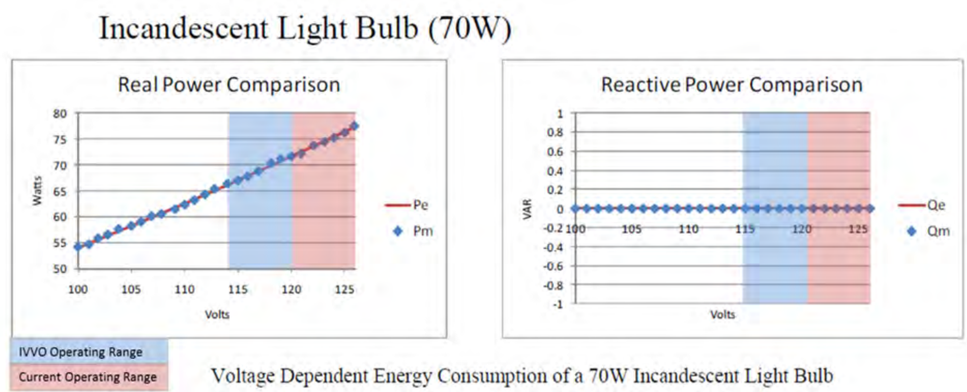
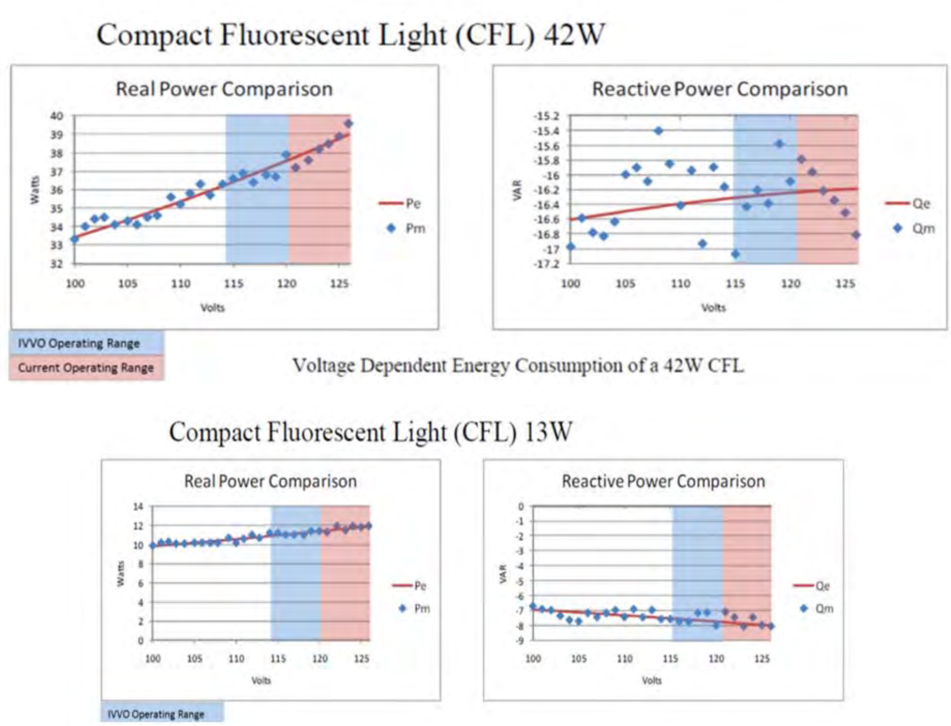


Figure 19



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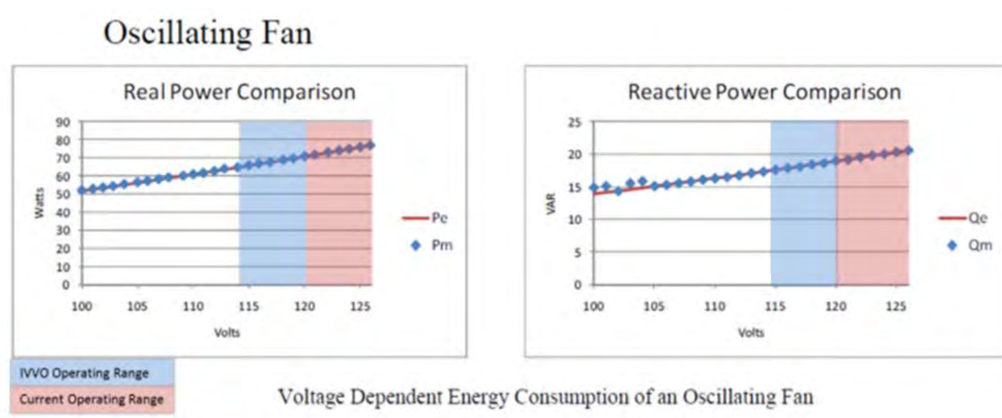
Q. ARE THERE OTHER BENEFITS ASSOCIATED WITH OPERATING ELECTRICAL DEVICES AT A LOWER VOLTAGE?

A. Yes. Some motors, such as those found in air conditioners, dryers, refrigerators, and oscillating fans operate more efficiently at a lower voltage (114V to 120V). A higher voltage (120V to 126V) generates more heat, which makes these motors less efficient. Figure 20 shows the reduced voltage level and energy consumption for an oscillating fan with IVVO.

Figure 20



Voltage Dependent Energy Consumption of an Oscillating Fan

Q. HOW DID XCEL ENERGY DETERMINE THE ENERGY SAVINGS LEVEL THAT IT ANTICIPATES ACHIEVING FROM THE CORE DEPLOYMENT OF IVVO IN MINNESOTA?

A. Xcel Energy developed the energy savings level based on information learned from pilot programs (one in Minnesota and two in Colorado) and then translating these results into a reduction that would be achievable for the Minnesota area where IVVO will be deployed based on an examination of the system characteristics core deployment area and engineering judgment.

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Q. PLEASE DESCRIBE THE IVVO PILOT PROGRAMS THAT YOU MENTIONED.

A. These pilot programs were the: 1) the Wilson Substation pilot that was conducted in 2014-2015 in Bloomington, Minnesota and 2) two pilot projects conducted by PSCo in 2011-2012 to estimate the energy savings for their IVVO deployment in Colorado.

Q. WHAT WAS THE WILSON SUBSTATION PILOT?

A. The purpose of the Wilson Substation pilot was to test and measure the impact of voltage reduction on energy use for Minnesota customers served by this substation in Bloomington. Due to equipment issues, the most substantial testing was done in October 2014 and February 2015. The pilot used the test method of alternating the Load Tap Changer set point between two settings – the normal setpoint and one 3 percent lower. As has been done nationally with many other pilot studies, testing was done day-on, day-off, and weekend-on, weekend-off to test the system's response to reduced voltage.

To determine the impacts, we compared on-days to off-days, and on-weekends to off-weekends. We also filtered out abnormalities in the data including abnormal feeder conditions and attempted to compare similar days to each other. The results of the Wilson pilot identified a CVR factor of between 0.88 and 0.91.

Q. WHAT IS A CVR FACTOR AND HOW DOES IT TRANSLATE INTO A REDUCTION IN ENERGY CONSUMPTION?

A. CVR factor is a term commonly used to refer to the ratio between voltage reduction and energy load consumption for a portion of the Distribution system. Generally, a CVR factor of 1.0 means that for a 1 percent drop in

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voltage, there is a 1 percent drop in energy consumption. As a result, the Wilson pilot results suggest that a 3 percent reduction in voltage would result in an over 2 percent reduction in energy consumption.

Q. WHAT ARE THE ISSUES WITH USING THE RESULTS OF THE WILSON PILOT TO THE PREDICT THE ENERGY SAVINGS FROM THE PROPOSED IVVO CORE DEPLOYMENT?

A. The biggest issue is that this pilot was conducted on only a small portion of our system (one substation), and the results may not accurately predict benefits on other areas of our system. This is because CVR factors vary widely across our system and can range from as low as 0.4 to as high as 1.5.

Q. WHY IS THERE SUCH A RANGE OF CVR FACTORS ACROSS THE MINNESOTA SYSTEM?

A. This is not an exhaustive list but some of the factors that can impact the CVR factor include: (1) length of feeders; (2) conductor sizing; (3) type, size, and location of different loads; and (4) type, size, and location of DER. The type of load on feeder has a significant impact on the CVR factor. For instance, commercial and industrial load tend to have lower CVR factors while highly resistive load such as old lighting (i.e., non-LED) tends to have higher CVR factors. With the transition to LED lighting, as well as the use of additional constant power devices, we expect that CVR factors will decline in the future across our system.

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Q. ARE THERE OTHER FACTORS THAT IMPACT THE USEFULNESS OF THE WILSON PILOT RESULTS IN PREDICTING ENERGY SAVINGS FROM THE PROPOSED CORE DEPLOYMENT OF IVVO?

A. Yes. The Wilson pilot does not account for the declining use per customer that we have seen and expect to continue to see in the future due to energy efficiency and conservation measures. This declining use per customer reduces the potential benefits of IVVO.

Q. CAN YOU PROVIDE ADDITIONAL DETAILS ABOUT THE IVVO PILOTS PERFORMED BY PSCO?

A. PSCo conducted two pilots in 2011 and 2012 to test IVVO at two substations, the Englewood Substation and the National Center for Atmospheric Research (NCAR) Substation, through its participation in the Electric Power Research (EPRI) Green Circuits program.

Q. WHAT WERE THE RESULTS OF THESE TWO COLORADO PILOTS?

A. The results of the NCAR pilot found that voltage could be lowered on average about 2.5 percent with corresponding energy savings of about 2.5 percent in 2011. The results from the Englewood Substation showed a voltage reduction of 1.5 percent and a CVR factor of 1.7 in 2011 and 2.7 in 2012, which would result in estimated energy savings of 2.55 percent and 4.05 percent. The results for both the NCAR Substation and the Englewood Substation pilots was higher than the nation-wide average for field trials with other utilities that showed an energy reduction range of 1.6 percent to 2.7 percent.

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Q. DOES THE COMPANY BELIEVE THAT THE SAME LEVEL OF ENERGY SAVINGS FROM THESE TWO COLORADO PILOTS COULD BE ACHIEVED IN MINNESOTA?

A. It is unlikely. There are key differences between the Minnesota and Colorado distribution systems that will impact the effectiveness of IVVO such that the same level of energy savings is not likely to materialize in Minnesota. These key differences include:

- *Standard substation bus voltage is lower in Minnesota:* In PSCo, the standard bus voltage is 125V, which is at the very high end of the ANSI C84.1 standard for distribution voltage. This higher starting voltage allows for the potential for greater voltage reduction to be done by IVVO which then results in greater energy savings without compromising service quality. In contrast, the standard bus voltage for the Minnesota service territory is typically 123.5V. This lower starting point reduces the potential energy savings that can be achieved in Minnesota from IVVO.
- *As compared to Minnesota, Colorado uses shorter feeders with larger conductors to support a denser load*: Large conductor size has lower impedance, which means that the voltage drop across the feeder is reduced which allows the Colorado system to achieve better results. In addition, the higher load density on each feeder means that the net impact from IVVO on a per-feeder basis will be greater than it will be in Minnesota.
- *Minnesota has a greater proportion of overhead construction as compared to Colorado*: Overhead construction inherently has greater voltage drop than underground construction. As a result, there is less opportunity for IVVO to further reduce voltage in Minnesota.

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Q. HOW DID XCEL ENERGY DETERMINE THE ENERGY SAVINGS LEVEL FOR MINNESOTA BASED ON THESE PILOT PROGRAMS?

A. We examined the results of the various pilot programs discussed above and accounted for the limitations of this data. We also evaluated the characteristics of the area of the system that is planned for the core deployment for IVVO. For example, we evaluated the average feeder head-end voltage, typical loads, line design, and customer density. We also took into account that fact that IVVO may not be available at all times of the day due to abnormal configurations or maintenance.

Q. WHAT LEVEL OF ENERGY SAVINGS DOES XCEL ENERGY BELIEVE IS ACHIEVABLE HERE IN MINNESOTA?

A. Ultimately, we believe that 1.0 percent is the most readily achievable energy savings level, but we are not setting a limit on these savings at this time. After the IVVO devices are deployed, the Company will lower the voltage to the extent that the system allows and seek to achieve the maximum savings within each substation transformer area. To account for the potential for higher energy savings once the IVVO devices are deployed, we identified 1.5 percent as the higher end of the range of energy savings that may be achievable. For purposes of the CBA, we utilized the mid-point of the range between 1.0 percent and 1.5 percent energy savings or 1.25 percent as our reference case. However, we also present as sensitivities in the CBA that utilize the lower (1.0 percent) and upper (1.5 percent) ends of the identified range.

Q. WILL THE ENERGY SAVINGS FROM IVVO RESULT IN OTHER BENEFITS?

A. Yes. There will be environmental benefits associated with the increased energy efficiency. Improved energy efficiency can result in reduced demand for

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electric generation and thus a reduction in carbon emissions caused by certain types of generation. The reduction in carbon emissions, in turn, will provide environmental and societal benefits. The Company's calculation of these benefits is described by Dr. Duggirala.

(2) Electrical Loss Reductions

Q. HOW WILL IVVO REDUCE ELECTRICAL LOSSES ON THE DISTRIBUTION SYSTEM?

A. For any conductor in a distribution network, the current flowing through it can be broken down into two components – active and reactive power. Active power is measured in watts or kilowatts (one thousand watts) and is the energy required to perform actual work. Reactive power is measured in "VAr" or "kVAr" (one thousand VAr); it does not do real work but uses the current-carrying capacity of the distribution lines and equipment, and contributes to the power loss. Reactive power compensation devices (such as capacitors) are designed to reduce the unproductive component of the electric current, thereby reducing current magnitude, and thus, reducing energy losses.

For Xcel Energy's system, ADMS will turn the system's capacitors installed along the distribution circuit on and off in an optimal manner to limit the reactive power flowing on each portion of the distribution system. This improves the efficiency of the system and reduces system losses.

Q. HOW, SPECIFICALLY, IS THE ADMS CONTROL METHOD AN IMPROVEMENT ON SMARTVAR?

A. ADMS is able to calculate the reactive power needs of each section of line and optimize for the circuit. SmartVAr does optimize power factor as measured at the substation, but uses a pre-selected sequence to energize the capacitors.

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The ADMS method is superior and will result in additional loss reduction, relative to SmartVAr.

Q. WHAT ARE THE ELECTRICAL LOSSES SAVINGS THE COMPANY ANTICIPATES ACHIEVING FROM IVVO?

A. The initial deployment of IVVO at 13 substations is expected to reduce annual electrical losses by 225 MWh in 2022, rising to approximately 900 MWh in 2025. This improvement, incremental to the SmartVAr program, is due to the additional capacitance deployed as part of the IVVO program

Q. HOW DID THE COMPANY CALCULATE THE ESTIMATED ELECTRICAL LOSS SAVINGS ANTICIPATED FROM IVVO?

A. As with the calculation of energy use reduction described above, we leveraged our extensive analysis for PSCo to calculate the potential for loss reduction in NSPM. The energy loss reduction quantified for purposes of the CBA is achieved through improvement to the power factor of the feeder. Studies were completed in PSCo which found the reduced losses from improving the power factor by 4.5 percent (from 95 percent to 99.5 percent). We note that the available reduction in NSPM is less than Colorado, because our typical power factor in Minnesota – the "starting point" for these calculations - was higher (98 percent) than that in PSCo (95 percent). We calculated the portion of the reduced line losses that we expect in Minnesota to be 34 percent of what was expected in PSCo.

(3) Avoided Capacity Costs

Q. HOW DID XCEL ENERGY ESTIMATE THE AVOIDED CAPACITY COSTS THAT WILL RESULT FROM IVVO?

A. Xcel Energy is projecting that IVVO will reduce the NSP system's peak demand by 0.7 percent, which is directly attributable to the energy reduction achievable at system peak. Since the Company will be conducting a targeted, core deployment of IVVO, this 0.7 percent reduction was applied to core IVVO deployment area's contribution to the system peak load. The value of benefit was calculated using avoided Transmission, Distribution, and Generation capacity values for each year through 2038.

b. Non-Quantifiable Benefits

Q. ARE THERE OTHER BENEFITS OF IVVO THAT ARE NOT QUANTIFIABLE?

A. Yes. For those customers whose feeders are equipped with IVVO, we anticipate fewer voltage-related complaints due to the more active voltage control throughout. This will save operating labor to investigate and resolve complaints reactively. In addition, these customers will experience higher energy efficiencies from their personal electrical devices. This improved efficiency will result in lower bills for those customers. However, since the Company is not proposing to implement IVVO for the entirety of its service territory at this time, and these voltage and efficiency benefits would not apply to all customers, the Company chose not to quantify them for the CBA. Another benefit that we did not quantify is the increase in the system's ability to host DER that will result from IVVO.

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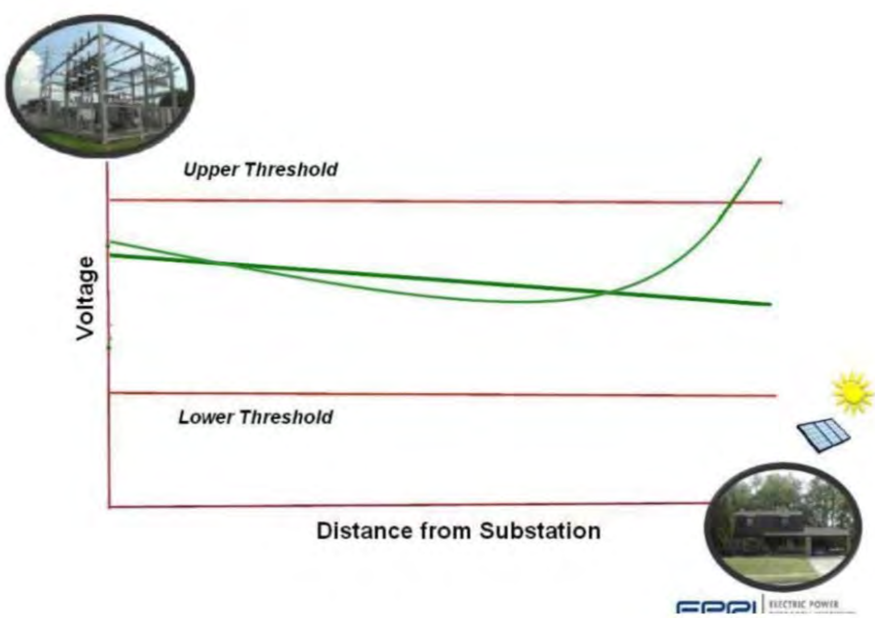
Q. HOW WILL IVVO INCREASE THE SYSTEM'S ABILITY TO HOST DER?

A. As penetration of DER grows, the Company will need to manage the DER's influence on voltage through distribution system voltage control. Traditionally, with one-way flows on a feeder, the voltage control objective was to raise voltage at times of heavy load to manage voltage within the acceptable range.

As shown in Figure 21 below, DER which injects power into the system, such as solar generation, increases the voltage on the edge of the grid, which will be most noticeable during times of lower energy use. By increasing the voltage at the end of the feeder, such DERs can cause over-voltage issues impacting both the DER and other customers. By lowering the voltage and reducing potential over-voltage impacts from solar DERs, IVVO will support the ability for additional solar to be hosted on the system.

Figure 21



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Q. HAS THE COMPANY PREVIOUSLY STUDIED THE ABILITY OF IVVO TO IMPROVE HOSTING CAPACITY?

A. Yes. In our 2018 Hosting Capacity Study,[22] we studied the impact of lowering the voltage the substation bus voltage on the hosting capacity of five feeders. In that analysis we found increases in capacity between 0 and 700 kW.[23] IVVO, however, will apply its more robust control algorithms and system controls to provide greater average improvement in hosting capacity although some feeders will gain significantly, while others may remain constrained by voltage or thermal ratings.

The EPRI publication, "Value of a Distribution Management System for Increasing Hosting capacity: Centralized vs. Autonomous Control of Distributed Energy Resources" published in December 2018, provides some insight into how the ADMS can provide an increase in Hosting Capacity through voltage control.

Q. WHY IS XCEL ENERGY UNABLE TO QUANTIFY THE INCREASE IN HOSTING CAPACITY THAT WILL BE ENABLED BY IVVO?

A. Hosting capacity can be constrained by factors other than voltage, such as thermal or protection issues. Each feeder is unique in its topology and the distribution of loads along the feeder, both of which have a significant impact on the hosting capacity. And finally, the distribution of DER along the feeder has a significant impact on the hosting capacity. Consequently a robust hosting capacity analysis needs to be conducted on every feeder where IVVO is installed in order to accurately quantify the system wide impact. While it is

[22] XCEL ENERGY'S 2018 DISTRIBUTION SYSTEM HOSTING CAPACITY STUDY, Docket No. E002/18-684 (Nov. 1, 2018).
[23] *Id.* at 26.

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true that most feeders' hosting capacity may be constrained by high voltage at low load times, other constraints can appear as voltage is lowered on a given feeder, making it hard to approximate what could ultimately be gained. Due to these factors, the Company is unable to quantify and generalize the increase in hosting capacity which can be attributed to IVVO.

5. IVVO Costs

Q. WHAT ARE DISTRIBUTION'S CAPITAL AND O&M COSTS RELATED TO IMPLEMENTATION OF IVVO?

A. The table below provides the Distribution capital additions and O&M costs for IVVO implementation for 2020 through 2022.

Table 51

IVVO Capital Additions – Distribution State of MN Electric Jurisdiction (Includes AFUDC) (Dollars in Millions)			
AGIS Program	**2020**	**2021**	**2022**
IVVO	$0.0	$4.1	$6.7

Table 52

IVVO O&M – Distribution NSPM – Total Company Electric (Dollars in Millions)			
AGIS Program	2020	2021	2022
IVVO	$0.0	$0.4	$0.8

a. Distribution's Capital Costs

Q. WHAT ARE DISTRIBUTION'S CAPITAL COSTS ASSOCIATED WITH THE IVVO IMPLEMENTATION?

A. Distribution's principal capital costs for IVVO are the costs for the IVVO devices and their installation. There are four categories of capital costs for IVVO: 1) device costs; 2) device installation; 3) labor and external contracting; and 4) communications.

Q. WHAT IS INCLUDED IN THE DEVICE DOST CATEGORY?

A. The capital device cost category includes material and equipment costs for the IVVO devices (capacitors, SVCs, voltage sensing devices, and LTC controls).

Q. HOW DID THE COMPANY ESTIMATE THE COSTS OF THE IVVO DEVICES AND THEIR INSTALLATION?

A. As many of the devices involved in the IVVO deployment are not new to the Company, we were able to use historical costs to develop the capital cost estimates to implement the IVVO. With respect to the new SVC devices, Xcel Energy used our recent costs and experiences for PSCo. For installation, the Company will use primarily contract labor. The projected labor and installation costs were developed using contractor wage scales.

Q. HOW DID THE COMPANY GO ABOUT SELECTING VARENTEC AS THE VENDOR FOR SVCS?

A. As mentioned above, the Company determined that SVCs are a cost-effective way to complement an IVVO installation and mitigate localized voltage problems. The Company completed its RFP process and selected Varentec as its supplier of SVCs in 2018 to support our Colorado IVVO activities. We

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evaluated three different vendors based on a variety of factors including cost per unit, number of devices deployed across different utilities, support capabilities, and technical capabilities, ultimately selecting Varentec's ENGO unit as the best amongst these factors. Contract negotiations were completed in the third quarter of 2018, and we received our first shipment of SVC units late in the same quarter.

Q. HOW DID THE COMPANY SELECT THE POWERLINE SENSOR EQUIPMENT AND VENDOR FOR IVVO?

A. The market for powerline sensors that integrate into capacitor controls and provide the accuracy necessary for IVVO is small. The Company researched the available products' ability to meet our criteria, field tested samples. Ultimately we selected an upgraded sensor that performed well in these field tests. Since further improvements in this technology are anticipated, the Company will continue to monitor this evolving space and modify our vendor selection if appropriate.

Q. HOW DID THE COMPANY SELECT THE VENDORS FOR THE OTHER IVVO DEVICES?

A. Primary capacitors and LTC controllers are a stock commodity within the Company, and we were able to use our existing equipment standards to support this deployment. The equipment selected for our standards undergoes periodic review, using the RFP process when appropriate.

Q. WHAT IS INCLUDED IN THE DEVICE INSTALLATION COST CATEGORY

A. The device installation capital costs for IVVO include costs for installing the IVVO devices, including any supporting internal and contract labor.

Q. WHAT IS INCLUDED IN THE LABOR AND EXTERNAL CONTRACTING COST CATEGORY?

A. This category captures costs for commissioning IVVO devices and their circuits and enabling benefits through ADMS's functionality. It includes standing up the GEMS system and enablement of AMI bellwether functionality.

Q. HOW DID THE COMPANY ESTIMATE THESE CAPITAL COSTS?

A. The projected labor and installation costs were developed using contractor wage scales.

Q. WHAT IS INCLUDED IN THE COMMUNICATION COST CATEGORY?

A. The communications installation capital costs for IVVO include costs to install and commissioning equipment to ensure reliable, secure communications.

Q. HOW DID THE COMPANY ESTIMATE THESE COSTS?

A. The Company has experience in the use and installation of many of the devices involved in the IVVO deployment. We were able to use historical costs to develop the capital cost estimates. Our recent costs and experiences in PSCo provide confirmation that the estimates in use are reasonable.

b. Distribution's O&M Costs

Q. WHAT ARE THE O&M COSTS ASSOCIATED WITH IMPLEMENTING IVVO?

A. The O&M costs include O&M costs in support of capital deployment, asset and device support, minor device replacement, and training.

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Q. WHAT IS INCLUDED IN THE O&M IN SUPPORT OF THE CAPITAL DEPLOYMENT COST CATEGORY AND HOW WERE THESE COSTS DETERMINED?

A. This category includes expenses related to equipment installations that are appropriately deemed O&M. One example is certain switching activities (operations) are necessary to safely install new equipment. The Company used actual, average installation experience to estimate these costs.

Q. WHAT IS INCLUDED IN THE ON-GOING ASSET/DEVICE SUPPORT COST CATEGORY AND HOW WERE THESE COSTS DETERMINED?

A. This category includes labor and repairs to maintain assets in good working order. The Company estimated these costs as a percentage of the number of installed IVVO assets.

Q. WHAT IS INCLUDED IN THE DEVICE REPLACEMENT COST CATEGORY AND HOW WERE THESE COSTS DETERMINED?

A. This category includes material and labor to replace assets (components which are not property units) in good working order. The Company estimated these costs as a percentage of installed IVVO assets.

Q. WHAT IS INCLUDED IN THE ON-GOING COMMUNICATIONS NETWORK COST CATEGORY AND HOW WERE THESE COSTS DETERMINED?

A. This category labor and incidental material to maintain communications link to IVVO assets. The Company estimated these costs as a percentage of the installed IVVO assets.

Q. WHAT IS INCLUDED IN THE TRAINING COST CATEGORY AND HOW WERE THESE COSTS ESTIMATED?

A. This category includes training costs for the IVVO program. The Company estimated these costs based on number of employees, the time to train them, and wage scales.

c. Distribution Contingency for IVVO

Q. PLEASE DESCRIBE THE IVVO CONTINGENCY AMOUNTS INCLUDED IN THE FORECAST.

A. Distribution's IVVO budget forecast for the period 2020-2025 includes capital contingency amounts of approximately 10 percent. This smaller contingency (compared to AMI) is considered adequate because the cost projections for devices and installation were developed based on historical costs and we believe we have fairly accurately estimated the quantity of equipment and cost of installation of the IVVO devices.

d. IVVO Expenditures 2020-2029

Q. WHAT ARE DISTRIBUTION'S CAPITAL EXPENDITURES AND O&M FORECASTS FOR IVVO FOR 2020 THROUGH 2029?

A. The tables below provide Distribution's capital expenditures and O&M forecasts for IVVO for 2020 through 2029.

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Table 53

IVVO Capital Expenditures – Distribution NSPM – Total Company Electric (Dollars in Millions)					
	Rate Case Period			5-Year Period	10-Year Period
AGIS Program	**2020**	**2021**	**2022**	**2023-2024**	**2025-2029**
IVVO	$0.1	$4.6	$7.6	$14.3	$0.0

Table 54

IVVO O&M Expenditures – Distribution NSPM – Total Company Electric (Dollars in Millions)					
	Rate Case Period			5-Year Period	10-Year Period
AGIS Program	**2020**	**2021**	**2022**	**2023-2024**	**2025-2029**
IVVO	$0.0	$0.4	$0.8	$0.5	$0.8

6. Alternatives to IVVO

Q. WHAT ALTERNATIVES TO IVVO DID THE COMPANY EVALUATE?

A. The Company evaluated four alternatives to IVVO: (1) maintaining the status quo; (2) implementing IVVO without the other AGIS components; (3) implementing IVVO without SVC devices,; and (4) delaying the deployment of IVVO.

Q. DESCRIBE THE STATUS QUO ALTERNATIVE AND WHY THAT ALTERNATIVE WAS REJECTED.

A. One alternative to implementing IVVO is to maintain the status quo, and this relies on the SmartVAr system to maintain good power factor. There are two primary drawbacks to staying with the status quo of SmartVAr which are: 1) forgoing the benefits of reduced energy usage; and 2) forgoing increased

DER hosting capacity. Those benefits are unavailable through SmartVAr because it is incapable of enacting CVR and enabling the system to operate at the lower levels which enable those specific benefits. Given that these two benefits are important to stakeholders, the Company, and its customers, maintaining the status quo is not a reasonable alternative.

Q. DID THE COMPANY CONSIDER IMPLEMENTING IVVO WITHOUT THE OTHER AGIS COMPONENTS?

A. Yes, however such a deployment would not be as efficient and as cost-effective as the proposed integrated deployment. This is because IVVO relies heavily on both the AMI meters and the FAN to operate. The AMI meters provide voltage sensing functions – measuring and transmitting voltage, current, and power quality data – that allow the Company access to more granular voltage data at the customer meter that makes IVVO more effective. IVVO also relies on the FAN infrastructure to communicate this data back to the Company.

Q. COULD THE COMPANY USE INDEPENDENT SENSORS RATHER THAN USING AMI METERS AS SENSORS?

A. Yes, but these sensors would not be nearly as cost-effective as the AMI meters. If independent sensors were utilized, the Company would need to install at minimum nine sensors per feeder and strategically locate these sensors to provide voltage sensing at the end of the line. Since these sensors would not be located at the customer meter, we would need to assume a conservative level of voltage drop from the sensor to the customer meter to ensure that voltages stay within required limits. This would limit our ability to optimize voltage levels as compared to using AMI meters that will provide

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precise voltage information at the service point. There would also be a significant additional cost associated with deploying independent sensors in place of AMI meters. We did estimate the additional cost for PSCo to use independent meters. Using those insights, we would anticipate a cost for the proposed NSPM deployment of over $4 million. The opportunity to leverage AMI meters provides the greater value.

Q. DESCRIBE THE ALTERNATIVE TO IMPLEMENT IVVO WITHOUT SVCS?

A. While IVVO could be implemented without any SVC devices, the SVCs will enable greater voltage reduction where deployed, thereby resulting in greater energy savings. In addition, the SVCs involved in the Company's proposed IVVO solution will increase the system's capacity to host renewables on the distribution system. SVCs will provide fast, variable voltage support that will help stabilize and regulate the voltage at the edge of the grid, near customers and DERs. Solar resources, in particular, are variable, intermittent, and non-coincident with peak demand, requiring more localized voltage support that is faster-acting than traditional utility devices. SVCs, as part of the IVVO solution, will help provide fast, variable voltage support limiting the impacts from solar and increasing the hosting capacity.

Q. DID THE COMPANY EVALUATE THE POSSIBILITY OF DELAYING THE DEPLOYMENT OF IVVO?

A. Yes. However, the Company determined that such a delay would likely result in a reduction in the energy savings benefit that will be achievable with IVVO. As a mentioned above, the transition to LED lighting and lower energy use per customer reduces the energy savings benefits of IVVO. These trends are expected to continue in the future, thus reducing IVVO's energy savings benefit. Further, delaying the deployment of IVVO has likely effect of increasing its costs due to inflation as well as potential increases in labor and material costs.

7. *Interoperability*

Q. HOW DOES THE COMPANY'S IVVO PROJECT ENSURE AND FACILITATE INTEROPERABILITY OF THIS TECHNOLOGY?

A. The Company plans to IVVO components that are vendor-neutral, non-proprietary, standards-based, and interoperable. This will allow the Company the ability to switch equipment vendors at any time and the new devices will be able to easily operate with the existing IVVO system and devices.

8. *Minimization of Risk of Obsolescence*

Q. HOW DOES THE IVVO TECHNOLOGY SELECTED BY THE COMPANY MINIMIZE THE RISK OF OBSOLESCENCE?

A. Xcel Energy has consistently sought to deploy assets that provide customer value over a long time period, a philosophy that has driven us to install quality equipment at the best price we can negotiate. That philosophy remains foundational, in our selection and sourcing procedures, where criteria include financial viability and long-term performance. The equipment itself must be robust to survive in a harsh outdoor environment and meet industry established testing standards to ensure longevity. While we cannot guarantee the longevity of any specific vendor, these attributes help to ensure the products will remain supported.

For electronic equipment, we specify equipment which can be remotely upgraded with new firmware as functionality or security needs dictate.

Requiring interfaces to follow open protocols (e.g., DNP3, WiSUN) that are not vendor specific helps ensure interoperability between manufacturers. Standard physical interface requirements allow newer devices to connect and interface with controls that are well over 20 years old. We evaluate the equipment's physical and cybersecurity capabilities and require upgradability to help protect from unknown future cybersecurity threats. We are working with manufacturers to ensure they are building such security into their equipment.

Specifically with IVVO, we have selected equipment and controls that adhere to these principles and are highly configurable.

H. AGIS Distribution Overall Costs and Implementation

Q. OVER WHAT TIME PERIOD WILL THE FOUNDATIONAL COMPONENTS OF AGIS BE IMPLEMENTED?

A. The Company began implementation of ADMS, as well as limited deployment of AMI and the FAN in support of the Company's residential TOU pilot, in 2019. Full deployment of AMI, the FAN, and IVVO will begin in 2021 and will be substantially completed in 2024. FLISR implementation will also begin in 2021 and will be accomplished over a longer time period, through 2029.

Q. WHAT ARE THE TOTAL DISTRIBUTION COSTS FOR THE AGIS COMPONENTS?

A. The tables below show the total capital expenditure and O&M IT integration costs, by component, for 2020-2029.

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Table 55

AGIS Capital Expenditures – Distribution NSPM - Total Company Electric (Dollars in Millions)					
	Rate Case Period			5-Year Period	10-Year Period
AGIS Program	**2020**	**2021**	**2022**	**2023-2024**	**2025-2029***
AMI	$2.6	$22.3	$133.9	$179.5	$14.1
FAN	$3.2	$6.2	$0.0	$0.0	$0.0
FLISR	$3.1	$8.1	$5.9	$16.0	$26.3
IVVO	$0.1	$4.6	$7.6	$14.3	$0.0
Total	**$9.0**	**$41.2**	**$147.4**	**$209.8**	**$40.4**
*Period may include additional assumptions, including inflation and labor cost increases, that are not part of the capital budget in periods 2020-2024					

Table 56

AGIS O&M – Distribution NSPM – Total Company Electric (Dollars in Millions)					
	Rate Case Period			5-Year Period	10-Year Period
AGIS Program	**2020**	**2021**	**2022**	**2023-2024**	**2025-2029***
AMI	$2.3	$3.3	$5.0	$10.0	$15.7
FAN	$0.1	$0.2	$0.4	$0.3	$0.4
FLISR	$0.1	$0.3	$0.2	$3.2	$2.4
IVVO	$0.0	$0.4	$0.8	$0.5	$0.8
Total	**$2.6**	**$4.2**	**$6.5**	**$13.9**	**$19.3**
Period may include additional assumptions, including inflation and labor cost increases, that are not part of the capital budget in periods 2020-2024					

Q. WHAT IS YOUR RECOMMENDATION FOR THE COMMISSION WITH RESPECT TO THE DISTRIBUTION COMPONENTS OF THE AGIS INITIATIVE?

A. I recommend that the Commission approve our request to recover Distribution's capital investments and O&M expense for the foundational components of AGIS that we propose to implement during the 2020-2022 term of the rate case. Our proposal includes full AMI implementation, IVVO and FLISR as part of our broader grid resiliency efforts, and the FAN components necessary to support AMI and the advanced grid applications. We also recommend that the Commission certify these projects to provide the opportunity for the Company to request recovery of costs for 2023 and later in subsequent rider filings. Approval of the costs necessary to implement the AGIS initiative will advance the Company's electric distribution system, provide customers with more choices, and enhance the way the Company serves its customers.

VI. ELECTRIC VEHICLE PROGRAMS

A. Overview of the Electric Vehicle Programs

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A. In this section of my testimony I will describe the Company's EV programs and discuss the EV capital and O&M expenses included in the budget for 2020 to 2022.

Q. WHY HAS THE COMPANY INVESTED IN EV PROGRAMS?

A. EVs are becoming more prevalent as costs of ownership have decreased and consumers have become increasingly focused on utilizing greener energy. Customers have indicated that they want increased access to electricity as a transportation fuel, especially electricity generated from renewable resources.

Only the testimony necessary to support the Company's Advanced Grid Intelligence and Security (AGIS) Initiative have been included in the Integrated Distribution Plan (IDP) filing. Accordingly, we have excised non-AGIS pages from this attachment.

Statement of Qualifications

Kelly A. Bloch
Regional Vice President, Distribution Operations
825 Rice Street, St. Paul, Minnesota

Ms. Bloch has more than 28 years of experience in the utility industry where she has compiled a diverse background. She joined Public Service Company of Colorado in 1991 and served in various engineering roles in the four operating companies at Xcel Energy: Manager of Capacity Planning for Xcel Energy, Manager of Distribution Planning for Public Service, Manager of System Planning and Strategy, and Senior Director Electric Distribution Engineering, in addition to her current role.

Ms. Bloch is currently the Regional Vice President, Distribution Operations, for Northern States Power Minnesota and Northern States Power Wisconsin. She is responsible for the electric and natural gas distribution design and construction activities for the Company's service areas in the states of North Dakota, South Dakota, Minnesota, Wisconsin and Michigan.

Resume

Kelly A. Bloch
Regional Vice President, Distribution Operations
825 Rice Street, St. Paul, Minnesota

Education:

Bachelor of Science Electrical Engineering
South Dakota State University

Employment:

Xcel Energy Services

2015-Present	Vice President, Distribution Operations NSPM
2014-2015	Sr. Director, Electric Distribution Engineering
2012-2014	Manager, System Planning and Strategy
2005-2009	Manager, Distribution Capacity Planning
2002-2005	Sr. Engineer, Distribution Capacity Planning

Public Service Company of Colorado

2009-2012	Manager System Planning
1993-2002	Sr. Engineer, Distribution Reliability Assessment
1991-1993	Distribution Standards Engineer

Northern States Power Company
Capital Plant Additions: 2020-2022

Distribution Ops - Capital Additions
State of MN Electric Jursidiction
Includes AFUDC

Capital Budget Groupings	WBS Level 2 #	Description	MN Allocated 2020	MN Allocated 2021	MN Allocated 2022
ASSET HEALTH & RELIABILITY	11662320	Tap Cable Injection	(80.45)	(0.01)	-
CAPACITY	A.0000226.009	SUB Plymouth-Area Power Grid Upgrad	-	(12,464,926.37)	-
CAPACITY	A.0000226.010	LINES Hollydale Feeder Install	-	(6,221,593.46)	-
CAPACITY	A.0000390.014	LINE Install Wilson WIL TR4 & Feede	-	(9,487,780.20)	-
CAPACITY	A.0000390.015	SUB Install Wilson WIL TR4 & Feeder	-	(8,252,961.84)	-
CAPACITY	A.0000718.003	LINE Install Stockyards STY TR3 & F	-	-	(3,953,411.66)
CAPACITY	A.0000718.004	SUB Install Stockyards STY TR3 & Fd	-	-	(3,624,386.19)
NEW BUSINESS	A.0005500.028	Edina-Oh Extension	(2.02)	(0.01)	-
NEW BUSINESS	A.0005501.001	MNUG Extension-MN	(919.14)	(1.99)	-
NEW BUSINESS	A.0005501.044	South Dakota/MN - UG Extension	1.38	-	-
CAPACITY	A.0005502.016	LINE Install Feeder Tie CRL033	-	-	(1,142,341.86)
CAPACITY	A.0005502.023	Install Kohlman Lake KOL Feeder	-	(1,614,018.35)	-
CAPACITY	A.0005502.024	LINE Install Wyoming WYO Feeder	-	(1,918,575.70)	-
CAPACITY	A.0005502.082	Mntka-Oh Reinforcements	(70.78)	(2.42)	-
CAPACITY	A.0005502.083	Edina-Oh Reinforcements	194.31	6.35	-
CAPACITY	A.0005502.090	St Paul-Oh Reinforcements	466.63	15.26	-
CAPACITY	A.0005503.021	Install Baytown BYT Feeders	-	-	(4,414,837.78)
CAPACITY	A.0005503.058	Maple Grv-Ug Reinforcements	937.02	5.36	-
CAPACITY	A.0005503.061	Newport-Ug Reinforcements	(12.78)	(0.08)	-
CAPACITY	A.0005503.063	St Paul-Ug Reinforcements	81.58	0.46	-
CAPACITY	A.0005503.156	LINE Install Chemolite CHE065 Feede	-	(901,567.26)	-
NEW BUSINESS	A.0005504.001	MNOH Services-MN	(3.83)	-	-
NEW BUSINESS	A.0005505.001	MNUG Services-MN	65.55	0.04	-
NEW BUSINESS	A.0005506.001	MNOH Street Lights-MN	(130.52)	-	-
NEW BUSINESS	A.0005507.001	MNUG Street Lights-MN	0.04	-	-
ASSET HEALTH & RELIABILITY	A.0005508.001	MNOH Rebuilds-MN	(423.23)	(0.10)	-
ASSET HEALTH & RELIABILITY	A.0005508.028	Northwest - Overhead Rebuilds	(102.96)	(0.02)	-
ASSET HEALTH & RELIABILITY	A.0005508.081	North Dakota/MN - OH Rebuilds	235.78	0.05	-
ASSET HEALTH & RELIABILITY	A.0005509.001	MNUG ConvrsnsRebuilds-MN	7,246.41	5.54	-
ASSET HEALTH & RELIABILITY	A.0005509.013	ELR STP Vault Tops	(654,689.19)	(684,776.83)	(511,851.26)
ASSET HEALTH & RELIABILITY	A.0005509.014	ELR MPLS Vault Tops	(73.57)	(737,521.21)	(584,781.20)
ASSET HEALTH & RELIABILITY	A.0005509.105	Replace 7 CM2 Network Protecto	(3,698.56)	(54.06)	(0.77)
ASSET HEALTH & RELIABILITY	A.0005512.008	MPLS UG Network Vault Blanket	(465,581.92)	(476,880.36)	(488,249.16)
ASSET HEALTH & RELIABILITY	A.0005512.012	STP UG Network Vault Blanket	(230,899.34)	(236,549.78)	(242,232.14)
FLEET, TOOLS & COMM	A.0005516.030	Scrap Sale Credits-MN	(38.31)	-	-
CAPACITY	A.0005517.023	Substation Land - MN	(110.45)	(0.07)	(0.01)
ASSET HEALTH & RELIABILITY	A.0005518.003	NSPM-Poor Perf Fdr Replace Blk	16.35	0.01	-
ASSET HEALTH & RELIABILITY	A.0005518.052	REMS-Maple Grove	(0.23)	(0.01)	-

Northern States Power Company
Capital Plant Additions: 2020-2022

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Exhibit___(KAB-1), Schedule 2
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Capital Budget Groupings	WBS Level 2 #	Description	MN Allocated 2020	MN Allocated 2021	MN Allocated 2022
ASSET HEALTH & RELIABILITY	A.0005521.001	MN Failed Sub Equip Replacement	(2,162,471.74)	(2,139,017.98)	(2,139,000.01)
ASSET HEALTH & RELIABILITY	A.0005521.014	SPCC NSPM Oil Spill Prevention	(672,571.32)	-	-
ASSET HEALTH & RELIABILITY	A.0005521.015	MN Infratructure Invest - Sub	(4,691.21)	(1,410.40)	(594.57)
ASSET HEALTH & RELIABILITY	A.0005521.051	ELR MN Sub Feeder Breakers	(397,252.34)	(2,211,012.49)	(1,492,777.24)
ASSET HEALTH & RELIABILITY	A.0005521.052	ELR MN Sub Switches	(34,184.85)	(143,203.00)	(101,617.44)
ASSET HEALTH & RELIABILITY	A.0005521.091	ELR MN Sub Relays	(90,245.03)	(429,599.03)	(304,852.24)
ASSET HEALTH & RELIABILITY	A.0005521.092	ELR MN Sub Regulators	(80,780.63)	(286,415.98)	(203,234.85)
ASSET HEALTH & RELIABILITY	A.0005521.093	ELR MN Sub Fences	(72,212.23)	(358,000.81)	(254,043.59)
ASSET HEALTH & RELIABILITY	A.0005521.094	ELR MN Sub TRs	-	-	(873,257.12)
ASSET HEALTH & RELIABILITY	A.0005521.095	Reserve 26/13kV 28 MVA XFMR-MN	-	-	(513,151.62)
ASSET HEALTH & RELIABILITY	A.0005521.096	SUB Replace Fifth Street FST Switch	(7,564,590.01)	-	-
ASSET HEALTH & RELIABILITY	A.0005521.103	ELR MN Sub Retirements	(55,515.13)	(286,395.61)	(203,234.84)
ASSET HEALTH & RELIABILITY	A.0005521.129	Rewind/Replace Failed Transfor	(7,994.46)	(582.08)	(42.25)
ASSET HEALTH & RELIABILITY	A.0005521.131	reserve 70 MVA 115/34.5 kV tra	(744,000.00)	-	-
ASSET HEALTH & RELIABILITY	A.0005521.212	Replace Failed Substation Transform	(659,127.21)	(1,406,772.63)	(1,498,198.90)
CAPACITY	A.0005522.001	Dist Subs Capacity WCF-NSPM	-	(685,805.90)	(2,402,293.80)
CAPACITY	A.0005522.005	Minnesota-Sub Capac Reinforcem	(87,844.46)	(99,669.29)	(99,683.05)
CAPACITY	A.0005522.033	SUB Reinforce Fair Park FAP TR1 & F	(970,304.11)	-	-
CAPACITY	A.0005522.195	SUB Install Rosemount RMT TR2 & Fee	(3,768,005.43)	-	-
CAPACITY	A.0005522.277	SUB Install Wyoming WYO Feeder	-	(503,890.13)	-
CAPACITY	A.0005522.279	SUB Install Chemolite CHE065 Feeder	-	(543,995.79)	-
CAPACITY	A.0005522.281	Reinforce SCL TR2 to 70MVA	(2,940,275.81)	-	-
FLEET, TOOLS & COMM	A.0005549.006	NSPM-Dist Sub Communication Eq	(9,140.52)	(7.35)	(0.01)
ASSET HEALTH & RELIABILITY	A.0005549.020	ELR MN Sub RTUs	(29,310.07)	(149,595.22)	(106,156.47)
ASSET HEALTH & RELIABILITY	A.0005550.002	NSPM-Accelerated URD Cable Rep	1,145.21	16.07	-
ASSET HEALTH & RELIABILITY	A.0005550.005	NSPM-Accelerated URD Cable Rep	12.07	-	-
FLEET, TOOLS & COMM	A.0005553.001	Fiber Communication Cutover -	(195,120.48)	(435,445.46)	(673,977.10)
FLEET, TOOLS & COMM	A.0005560.002	VAR Network Devices	(1,003.29)	-	-
SOLAR	A.0005566.014	Aurora Solar Sub Reinforcement	375.58	104.22	28.92
SOLAR	A.0005566.015	SE Solar Garden Extensions - E	(2,767,041.32)	(201,470.08)	(14,624.39)
SOLAR	A.0005566.017	Extend facilities to serve NW	(351,665.87)	(25,597.73)	(1,857.65)
SOLAR	A.0005566.018	Solar Garden Ext Newport - Ext	-	-	3,185,751.25
SOLAR	A.0005566.020	Solar Gardens Communications - CSG	(37,757.75)	(2,749.16)	(199.56)
SOLAR	A.0005566.021	MN-Solar Garden Sub Comm	(54,036.86)	(3,933.84)	(285.52)
SOLAR	A.0005566.022	MN-Solar Garden Sub Work	(647,806.83)	(194,386.62)	(58,180.87)
SOLAR	A.0005566.023	Solar Garden Ext - WBL	(176,360.78)	(12,840.94)	(932.09)
SOLAR	A.0005566.025	Northwest Solar Gardens Ext	-	-	2,758,785.67
SOLAR	A.0005566.026	Solar Garden Ext - Shorewood	202,559.90	13,919.81	956.57
SOLAR	A.0005566.027	Solar Garden Ext - Edina	(14,289.29)	(1,040.06)	(75.48)
SOLAR	A.0005566.028	Solar Garden Ext - MPLS	(4,616.94)	(336.17)	(24.40)
ASSET HEALTH & RELIABILITY	A.0005585.001	MINNESOTA MAJOR STORM RECOVERY	584,294.17	448.04	-
FLEET, TOOLS & COMM	A.0005585.003	NSM - MN CAPITALIZED ELECTRIC LOCA	(404,579.83)	(400,003.50)	(400,000.01)

Northern States Power Company
Capital Plant Additions: 2020-2022

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Capital Budget Groupings	WBS Level 2 #	Description	MN Allocated 2020	MN Allocated 2021	MN Allocated 2022
ASSET HEALTH & RELIABILITY	A.0005585.004	MN Mixed Work Adjustment	(8,062,596.00)	(10,481,376.00)	(10,481,376.00)
FLEET, TOOLS & COMM	A.0006059.002	MN-Dist Electric Tools and Equip	(782,491.08)	(1,158,639.42)	(1,158,639.42)
FLEET, TOOLS & COMM	A.0006059.003	ND-Dist Electric Tools and Equip	(52,625.15)	(69,883.06)	(69,883.06)
FLEET, TOOLS & COMM	A.0006059.004	SD-Dist Dist Tools and Equip	(75,917.76)	(100,938.42)	(100,938.42)
FLEET, TOOLS & COMM	A.0006059.014	MN-Dist Subs Tools and Equip	(258,897.58)	(462,592.57)	(496,399.39)
FLEET, TOOLS & COMM	A.0006059.020	MN-DistLogistics	(104,263.52)	(172,765.98)	(185,678.54)
FLEET, TOOLS & COMM	A.0006059.021	SD-Dist Logistics	(3,482.23)	(4,352.78)	(4,352.78)
FLEET, TOOLS & COMM	A.0006059.024	MN-Dist Tools Common	(48,388.60)	(77,102.84)	(87,431.41)
FLEET, TOOLS & COMM	A.0006059.473	Logistics - NSPM - Tools - ND	(7,551.86)	(13,337.74)	(14,344.26)
FLEET, TOOLS & COMM	A.0006059.474	Nspm Metering Sys-Tools & Equi	(34,509.73)	(69,019.47)	(69,019.47)
FLEET, TOOLS & COMM	A.0006059.477	Logistics - Fencing - NSPM	(5,299.98)	(8,262.71)	(8,766.02)
FLEET, TOOLS & COMM	A.0006059.478	Logistics - Security Equipment	(16,362.36)	(28,269.12)	(34,058.33)
FLEET, TOOLS & COMM	A.0006059.479	Logistics Security Eqiupment N	(5,034.57)	(8,262.51)	(8,766.02)
NEW BUSINESS	A.0006062.001	Distribution CIAC MN Elec	3,733,000.00	3,702,000.00	3,813,000.00
NEW BUSINESS	A.0010003.001	MN - OH Extension Blanket	(3,205,655.32)	(3,618,136.46)	(3,650,997.74)
NEW BUSINESS	A.0010003.002	MN - UG Extension Blanket	(19,496,373.27)	(21,133,978.85)	(21,498,205.43)
NEW BUSINESS	A.0010003.003	MN - OH New Services Blanket	(2,229,455.56)	(2,746,603.91)	(2,787,909.90)
NEW BUSINESS	A.0010003.004	MN - UG New Services Blanket	(8,116,058.18)	(9,135,122.14)	(9,246,914.28)
NEW BUSINESS	A.0010003.005	MN - OH New Street Light Blanket	(360,976.13)	(361,320.38)	(370,388.18)
NEW BUSINESS	A.0010003.006	MN - UG New Street Light Blanket	(728,878.94)	(745,976.97)	(765,923.13)
CAPACITY	A.0010003.007	MN - New Business Network Blanket	(1,232,000.00)	(1,261,793.00)	(1,292,546.00)
MANDATES	A.0010011.001	MN - OH Relocation Blanket	(7,444,549.18)	(7,451,840.49)	(7,451,841.00)
MANDATES	A.0010011.002	MN - UG Relocation Blanket	(5,060,457.54)	(5,159,229.66)	(5,159,230.00)
MANDATES	A.0010011.003	MN - UG Service Conversion Blanket	(566,718.75)	(587,348.65)	(587,349.00)
MANDATES	A.0010011.004	MN - Mandate WCF Blanket	(1,932,892.37)	(3,739,880.81)	(3,739,247.15)
ASSET HEALTH & RELIABILITY	A.0010019.001	MN - OH Rebuild Blanket	(8,302,858.41)	(8,967,162.52)	(9,175,079.68)
ASSET HEALTH & RELIABILITY	A.0010019.002	MN - UG Conversion/Rebuild Blanket	(5,831,219.27)	(6,516,178.44)	(6,667,444.82)
ASSET HEALTH & RELIABILITY	A.0010019.003	MN - OH Services Renewal Blanket	(86,711.25)	(92,777.64)	(94,557.28)
ASSET HEALTH & RELIABILITY	A.0010019.004	MN - UG Services Renewal Blanket	(2,919,771.21)	(2,799,073.42)	(2,863,909.96)
ASSET HEALTH & RELIABILITY	A.0010019.005	MN - OH Street Light Rebuild Blanke	(566,596.88)	(606,602.74)	(621,772.35)
ASSET HEALTH & RELIABILITY	A.0010019.006	MN - UG Street Light Rebuild Blanke	(654,185.24)	(605,903.18)	(621,651.96)
ASSET HEALTH & RELIABILITY	A.0010019.007	MN - Network Renewal Blanket	(7,653.45)	(16.66)	(0.03)
ASSET HEALTH & RELIABILITY	A.0010019.008	MN - Pole Blanket	(25,447,453.55)	(16,584,625.12)	(15,682,420.32)
ASSET HEALTH & RELIABILITY	A.0010019.009	MN - Line Asset Health WCF Blanket	(6,173,317.44)	(9,632,830.45)	(9,742,415.20)
MANDATES	A.0010019.010	MN - Pole Transfer (3rd Party) Blan	(461,559.45)	(440,005.26)	(440,000.00)
ASSET HEALTH & RELIABILITY	A.0010027.001	MN - URD Cable Replacement Blanket	(15,092,000.00)	(25,578,000.00)	(21,560,000.00)
ASSET HEALTH & RELIABILITY	A.0010027.002	MN - Feeder Cable Replacement Blank	(4,900,000.00)	(4,900,000.00)	(4,900,000.00)
ASSET HEALTH & RELIABILITY	A.0010027.003	MN - REMS Blanket	(499,800.00)	(1,166,200.00)	(833,000.00)
ASSET HEALTH & RELIABILITY	A.0010027.004	MN - FPIP Blanket	(588,000.00)	(1,372,000.00)	(1,470,000.00)
CAPACITY	A.0010035.001	MN - OH Reinforcement Blanket	(830,905.00)	(830,905.00)	(830,905.00)
CAPACITY	A.0010035.002	MN - UG Reinforcement Blanket	(455,402.00)	(455,402.00)	(455,402.00)
CAPACITY	A.0010035.004	MN - Line Capacity WCF Blanket	-	(298,011.67)	(763,047.87)

Northern States Power Company
Capital Plant Additions: 2020-2022

Capital Budget Groupings	WBS Level 2 #	Description	MN Allocated 2020	MN Allocated 2021	MN Allocated 2022
CAPACITY	A.0010061.004	Load Transfer CGR062 to CGR071	(966,740.27)	-	-
MANDATES	A.0010069.003	MPLS Mandates WCF	(1,611,601.42)	(2,402,785.93)	(7,592,406.15)
NEW BUSINESS	A.0010069.004	MN LED Post Top Conversion	(1,000,000.00)	(1,000,000.00)	(1,000,000.00)
MANDATES	A.0010069.012	Relocation Hwy 35 106th St to Cliff	-	328,240.91	-
ASSET HEALTH & RELIABILITY	A.0010077.001	Replace Fifth Street FST Network RT	(194,920.61)	-	-
ASSET HEALTH & RELIABILITY	A.0010077.012	Rebuild Clara City CLC221	-	(2,220,077.41)	-
ASSET HEALTH & RELIABILITY	A.0010077.022	T Rebuild West St Cloud to Millwood	-	-	(5,451,608.08)
ASSET HEALTH & RELIABILITY	A.0010077.024	Rebuild Sacred Heart SCH211	(2,044,132.60)	-	-
CAPACITY	A.0010093.008	TER065, extend TER073 to provide lo	(21,883.36)	-	-
CAPACITY	A.0010093.010	Extend Main Street MST074	(300,645.01)	-	-
CAPACITY	A.0010093.015	LINE Reinforce Westgate WSG Feeders	(250,708.70)	-	-
CAPACITY	A.0010093.017	Install Feeder Tie EBL064	-	(149,485.32)	-
CAPACITY	A.0010093.019	Install Feeder Tie Wilson WIL081	(299,351.29)	-	-
CAPACITY	A.0010093.023	Add 3rd feeder to Goodview Bank #2	-	(571,979.66)	-
CAPACITY	A.0010093.024	Install new feeder tie from FAP	(386,389.02)	-	-
CAPACITY	A.0010093.028	LINE Reinforce Kasson KAN TR1 & Fee	-	-	(337,134.86)
CAPACITY	A.0010093.031	Load Transfer ESW062 to SMT061	(95,459.39)	-	-
CAPACITY	A.0010093.038	Reinforce Osseo OSS062	(199,443.89)	-	-
CAPACITY	A.0010093.044	LINE Install Albany ALB TR	-	-	(96,121.35)
CAPACITY	A.0010093.048	LINE Install Fiesta City FIC Feeder	-	(477,251.18)	-
CAPACITY	A.0010093.065	Install Feeder Tie Osseo OSS063	(99,783.76)	-	-
CAPACITY	A.0010093.070	LINE Reinforce Veseli VES TR1 & Fee	-	-	(334,767.96)
CAPACITY	A.0010093.071	Reinforce Basset Creek BCR062	-	(250,670.65)	-
CAPACITY	A.0010093.072	Extend Red Rock RRK063	(95,452.31)	-	-
CAPACITY	A.0010093.074	Reinforce Glenwood GLD Sub Equip	-	(703,119.43)	-
CAPACITY	A.0010093.076	LINE Reinforce Medford Junction MDF	(960,008.86)	-	-
CAPACITY	A.0010093.077	Extend Saint Louis Park SLP092	-	(609,059.57)	-
CAPACITY	A.0010093.078	LINE Install Midtown MDT Feeder	-	(1,421,139.05)	-
CAPACITY	A.0010093.079	Install Feeder Tie SOU083 to MDT074	-	(101,509.96)	-
CAPACITY	A.0010093.081	Reinforce Terminal TER073	-	-	(1,117,271.40)
CAPACITY	A.0010093.082	Extend Saint Louis Park SLP085	(152,643.21)	-	-
CAPACITY	A.0010093.083	Reinforce Moore Lake MOL071	-	(558,304.63)	-
CAPACITY	A.0010093.086	Reinforce Medicine Lake MEL074	(508,810.67)	-	-
CAPACITY	A.0010093.087	LINE Install Hiawatha West HWW Feed	(712,334.93)	-	-
CAPACITY	A.0010093.088	Reinforce Saint Louis Park SLP087	-	(152,264.90)	-
CAPACITY	A.0010093.089	Install Switch Coon Creek CNC073	(29,018.63)	-	-
CAPACITY	A.0010093.090	LINE Install Rosemount RMT TR2 & Fe	(822,170.18)	-	-
CAPACITY	A.0010101.001	SUB MN Feeder Load Monitoring	(850,825.38)	(1,880,579.09)	(2,436,069.03)
FLEET, TOOLS & COMM	A.0010101.002	COMM MN Feeder Load Monitoring	(356,672.79)	(669,020.94)	(857,305.75)
FLEET, TOOLS & COMM	A.0010101.006	COMM Revenue Metering to Mapleton	(220,589.23)	-	-
FLEET, TOOLS & COMM	A.0010101.007	T Revenue Metering Minnesota Lake	(209,919.07)	-	-
ASSET HEALTH & RELIABILITY	A.0010125.002	Replace End of Life Substation Batt	(52,698.36)	(257,757.27)	(182,911.32)

Northern States Power Company
Capital Plant Additions: 2020-2022

Capital Budget Groupings	WBS Level 2 #	Description	MN Allocated 2020	MN Allocated 2021	MN Allocated 2022
ASSET HEALTH & RELIABILITY	A.0010125.014	ELR MPLS Network Protectors	(268,754.76)	(680,373.93)	(934,270.67)
ASSET HEALTH & RELIABILITY	A.0010125.015	ELR STP Network Protectors	(311,178.20)	(680,384.86)	(934,270.67)
ASSET HEALTH & RELIABILITY	A.0010125.016	Replace Linde LND TR1	(2,060,335.98)	-	-
ASSET HEALTH & RELIABILITY	A.0010125.020	Reserve XFMR 115-13.8 kV at 70 MVA	(514,797.27)	-	-
CAPACITY	A.0010133.007	SUB Reinforce Westgate WSG Feeders	(301,515.93)	-	-
CAPACITY	A.0010133.011	Install Breaker for New Goodview Ba	-	(502,352.30)	-
CAPACITY	A.0010133.016	SUB Reinforce Kasson KAN TR1 & Feed	-	-	(2,523,080.47)
CAPACITY	A.0010133.033	SUB Install Albany ALB TR	-	-	(2,846,874.78)
CAPACITY	A.0010133.038	SUB Install Fiesta City FIC Feeder	-	(502,353.58)	-
CAPACITY	A.0010133.055	SUB Install Feeder Tie CRL033	-	-	(50,076.09)
CAPACITY	A.0010133.063	Reinforce Savage SAV063 & SAV067	(1,122,935.84)	-	-
CAPACITY	A.0010133.064	SUB Reinforce Medford Junction MDF	(1,685,074.28)	-	-
CAPACITY	A.0010133.065	SUB Reinforce Veseli VES TR1 & Feed	-	-	(2,437,165.04)
CAPACITY	A.0010133.066	T Reinforce Red Rock RRK TR2	(865,433.04)	-	-
CAPACITY	A.0010133.067	Install Hiawatha West HWW TR2	-	-	(1,590,036.42)
CAPACITY	A.0010133.070	SUB Install Midtown MDT Feeder	-	(507,549.67)	-
CAPACITY	A.0010133.071	SUBS New Substation for Airgas	(2,849,339.70)	-	-
CAPACITY	A.0010133.072	SUB Install Hiawatha West HWW Feede	(508,810.67)	-	-
MANDATES	A.0010143.002	Relocation EDINA SWLRT Road Project	-	-	(2,349,124.45)
MANDATES	A.0010143.005	Relocation MPLS SWLRT Road Project	-	-	(3,543,828.22)
MANDATES	A.0010143.006	COMP Relocation EDINA SWLRT Road Pr	-	-	1,389,378.98
MANDATES	A.0010143.007	COMP Relocation MPLS SWLRT Road Pro	-	-	1,382,228.91
CAPACITY	A.0010144.002	Crosstown new 13.8kv Sub(REPLACED)	-	(208,161.81)	-
ASSET HEALTH & RELIABILITY	A.0010145.002	LINE Replace Fifth Street FST Switc	(854,677.56)	-	-
CAPACITY	A.0010148.002	Install new South Washington ERU Su	(5,902,148.43)	-	-
CAPACITY	A.0010148.003	Install New Fdrs - South Washington	(503,498.02)	-	-
FLEET, TOOLS & COMM	A.0010148.004	COMM Install South Washington ERU S	(86,653.17)	-	-
CAPACITY	A.0010149.001	SUB Install Western WES TR3 & Feede	-	-	(4,081,660.82)
CAPACITY	A.0010149.002	LINE Install Western WES TR3 & Feed	-	-	(1,402,130.53)
ASSET HEALTH & RELIABILITY	A.0010151.001	YLM211 and YLM212 Rebuild OH lines	-	-	(4,131,951.98)
MANDATES	A.0010154.001	VAULT Relocation 4th Street Road Pr	-	(571,464.53)	-
MANDATES	A.0010154.002	LINE Relocation 4th Street Road Pro	-	(7,601,627.45)	-
CREMENTAL SYSTEM INVESTME	A.0010162.003	MN Incremental System Investment	-	(50,678,063.39)	(84,022,979.27)
MANDATES	A.0010167.001	LINE Relocation Hennepin Ave Rd Pro	-	-	(11,475,386.78)
MANDATES	A.0010167.002	VAULT Relocation Hennepin Ave Rd Pr	(736,199.75)	-	-
ELECTRIC VEHICLE PROGRAM	A.0010180.001	MN Electric Vehicle Program	(9,824,077.10)	(8,310,160.74)	(10,098,761.52)
AGIS	D.0001723.046	GIS Cleanup for ADMS - NSPM	(1,743,793.59)	(871,788.29)	(871,814.20)
AGIS	D.0001900.016	FAN - AGIS - NSPM	(2,834,530.53)	(5,381,531.24)	(0.21)
AGIS	D.0001901.043	AMI-DIST-NSPM-MN Full AMI	-	(22,195,456.14)	(98,698,576.32)
AGIS	D.0001901.044	AMI-DIST-NSPM-MN TOU	(1,844,215.32)	-	-
AGIS	D.0001902.009	FLISR - AGIS - NSPM	(3,062,045.76)	(7,972,873.80)	(4,390,857.96)
AGIS	D.0001904.040	IVVO-Comm-Dist Blanket-NSPM	-	(4,096,092.93)	(5,876,285.01)

Northern States Power Company
Capital Plant Additions: 2020-2022

Capital Budget Groupings	WBS Level 2 #	Description	MN Allocated 2020	MN Allocated 2021	MN Allocated 2022
FLEET, TOOLS & COMM	D.0001907.026	AGIS-Planning & Fcst Tool-MN	(4,033,853.60)	-	-
AGIS	D.0001908.001	AGIS-Dist-Capital-Line-Contingency-	-	-	(2,002,580.52)
AGIS	D.0001908.002	AGIS-Dist-Capital-Subs-Contingency-	-	-	(838,500.84)
AGIS	D.0001908.038	AGIS-Dist-Capital-Line-AMI-Contin-N	-	-	(12,228,126.24)
AGIS	D.0001908.040	AGIS-Dist-Capital-Line-FLISR-Contin	-	-	(1,409,982.60)
NEW BUSINESS	D.0005014.004	MN Elec Distribution Transformers	(21,364,700.00)	(22,929,089.00)	(21,927,168.00)
NEW BUSINESS	D.0005014.021	MN-Electric Meter Blanket	(5,133,023.00)	(4,015,440.00)	(3,232,944.00)

Northern States Power Company
AMI & FAN Expenditures

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	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	TOTAL	NPV
Total Meters Deployed	*10,131*	*7,368*	*121,800*	*630,000*	*590,000*	*40,700*	*13,755*	*13,890*	*14,027*	*14,164*	*14,304*	*14,444*	*14,586*	*14,729*	*14,874*	*15,020*	*15,168*	***1,558,960***	
CAPITAL COSTS																		***TOTAL DISCOUNTED***	***NSPM-NPV***
AMI Meters																			
AMI Meters Purchase	1,408,513	1,024,373	13,875,456	71,769,600	67,212,800	4,636,544	1,771,935	1,826,384	1,882,506	1,940,352	1,999,976	2,061,432	2,124,776	2,190,067	2,257,364	2,326,730	2,398,226	**182,707,036**	**132,855,955**
AMI Meter Installation	620,017	450,922	5,054,700	26,145,000	24,485,000	1,689,050	645,500	665,335	685,779	706,852	728,573	750,961	774,036	797,821	822,337	847,606	873,652	**66,743,140**	**48,567,278**
RTU's (Return to Utility- Estimate 3% of installed meters)	0	0	303,282	1,568,700	1,469,100	101,343	0	0	0	0	0	0	0	0	0	0	0	**3,442,425**	**2,619,423**
Vendors deployment Project Management	0	381,182	733,817	1,198,410	1,223,217	624,270	0	0	0	0	0	0	0	0	0	0	0	**4,160,897**	**3,204,164**
AMI Operations (Internal Personnel)	843,677	983,487	1,869,203	2,046,398	2,186,980	1,903,327	0	0	0	0	0	0	0	0	0	0	0	**9,833,071**	**7,716,691**
AMI Operations (External Personnel)	0	0	658,073	1,372,663	1,365,055	637,919	0	0	0	0	0	0	0	0	0	0	0	**4,033,710**	**3,053,879**
Shop & Lab equipment (AMI Field Test, Lab equip)	0	25,888	217,401	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**243,288**	**203,171**
Distribution Contingencies	442,320	441,341	3,497,637	16,031,519	15,083,091	1,477,238	0	0	0	0	0	0	0	0	0	0	0	**36,973,146**	**28,259,602**
TOTAL - AMI Meters	3,314,527	3,307,193	26,209,569	120,132,290	113,025,244	11,069,690	2,417,435	2,491,719	2,568,285	2,647,205	2,728,549	2,812,393	2,898,813	2,987,889	3,079,701	3,174,336	3,271,878	***308,136,713***	***226,480,162***
Communications Network																			
FAN Infrastructure Distribution	100,005	650,501	1,279,994	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**2,030,499**	**1,729,867**
FAN Distribution WiMax	322,537	2,097,993	4,128,233	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**6,548,763**	**5,579,166**
TOTAL - Communications	***422,543***	***2,748,494***	***5,408,226***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***8,579,263***	***7,309,033***
TOTAL CAPITAL	**3,737,070**	**6,055,686**	**31,617,795**	**120,132,290**	**113,025,244**	**11,069,690**	**2,417,435**	**2,491,719**	**2,568,285**	**2,647,205**	**2,728,549**	**2,812,393**	**2,898,813**	**2,987,889**	**3,079,701**	**3,174,336**	**3,271,878**	**316,715,976**	**233,789,195**
O&M ITEMS																			
Communications Network																			
FAN Network Infrastructure Distribution	0	0	130,976	298,507	271,352	225,136	105,810	54,000	55,118	56,259	57,424	58,612	59,826	61,064	62,328	63,618	64,935	**1,624,966**	**1,036,835**
FAN Network Distribution Contingency	0	0	59,854	136,414	124,004	102,885	48,354	24,677	0	0	0	0	0	0	0	0	0	**496,189**	**363,768**
TOTAL - Communications	***0***	***0***	***190,831***	***434,922***	***395,356***	***328,021***	***154,164***	***78,678***	***55,118***	***56,259***	***57,424***	***58,612***	***59,826***	***61,064***	***62,328***	***63,618***	***64,935***	***2,121,155***	***1,400,602***
AMI Operations (Personnel)																			
	0	2,029	36,563	40,759	42,206	43,704	47,708	1,040,317	1,077,248	1,115,491	1,155,090	1,196,096	1,238,558	1,282,526	1,328,056	1,375,202	1,424,022	**12,445,575**	**5,756,644**
AMI Operations (External Personnel)	0	187,968	214,121	468,050	1,576,002	1,300,659	1,409,575	1,475,931	1,545,439	1,600,302	1,657,112	1,715,940	1,776,856	1,839,934	1,905,252	1,972,888	2,042,926	**22,688,954**	**11,693,307**
Customer Claims	0	663	1,719	48,916	48,843	7,423	0	0	0	0	0	0	0	0	0	0	0	**107,565**	**81,001**
Total AMI- O&M Dist Contingency	0	29,259	38,605	78,357	249,204	207,032	224,422	387,502	403,894	418,232	433,079	448,454	464,374	480,859	497,929	515,606	533,910	**5,410,717**	**2,687,292**
TOTAL - AMI Operations	0	219,920	291,008	636,082	1,916,255	1,558,818	1,681,704	2,903,750	3,026,581	3,134,024	3,245,282	3,360,490	3,479,787	3,603,319	3,731,237	3,863,696	4,000,857	***40,652,811***	***20,218,244***
TOTAL O&M	**0**	**219,920**	**481,839**	**1,071,003**	**2,311,611**	**1,886,839**	**1,835,869**	**2,982,428**	**3,081,699**	**3,190,283**	**3,302,706**	**3,419,102**	**3,539,613**	**3,664,383**	**3,793,565**	**3,927,314**	**4,065,792**	**42,773,966**	**21,618,846**
GRAND TOTAL CAPITAL & O&M	**3,737,070**	**6,275,606**	**32,099,634**	**121,203,293**	**115,336,855**	**12,956,529**	**4,253,304**	**5,474,147**	**5,649,984**	**5,837,488**	**6,031,254**	**6,231,494**	**6,438,425**	**6,652,272**	**6,873,267**	**7,101,650**	**7,337,670**	**359,489,942**	**255,408,042**

Northern States Power Company
FLISR & FAN Expenditures

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	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	TOTAL	NPV
CAPITAL ITEMS - SUMMARY																						
FLISR Assets																						
Asset Cost	0	2,456,519	6,604,776	3,745,275	5,606,776	5,852,901	4,447,353	4,539,413	4,633,379	4,729,290	0	0	0	0	0	0	0	0	0	0	**42,615,682**	**29,507,829**
Asset Installation	0	661,457	1,804,228	1,037,932	1,576,342	1,669,400	1,286,894	1,332,579	1,379,886	1,428,872	0	0	0	0	0	0	0	0	0	0	**12,177,590**	**8,386,388**
Device related Vendor Project Management + Other Labor	0	15,533	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**15,533**	**13,712**
Asset Contingency	0	0	0	1,499,386	1,866,899	919,536	604,982	617,505	630,288	643,334	0	0	0	0	0	0	0	0	0	0	**6,781,930**	**4,638,594**
TOTAL - Assets Cost	***0***	***3,133,508***	***8,409,004***	***6,282,593***	***9,050,018***	***8,441,837***	***6,339,229***	***6,489,497***	***6,643,552***	***6,801,496***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***61,590,735***	***42,546,523***
Communications Network																						
FAN Infrastructure Distribution	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**	**0**
FAN Distribution WiMax	60,476	393,374	774,044	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**1,227,893**	**1,046,094**
TOTAL - Communications	60,476	393,374	774,044	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	***1,227,893***	**1,046,094**
TOTAL CAPITAL	**60,476**	**3,526,882**	**9,183,048**	**6,282,593**	**9,050,018**	**8,441,837**	**6,339,229**	**6,489,497**	**6,643,552**	**6,801,496**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**62,818,628**	**43,592,617**
O&M ITEMS - SUMMARY																						
Deployment																						
O&M in support of capital deployment	0	85,389	229,582	130,186	194,892	203,447	154,590	157,790	161,056	164,390	0	0	0	0	0	0	0	0	0	0	**1,481,321**	**1,025,692**
TOTAL - Asset Operations	***0***	***85,389***	***229,582***	***130,186***	***194,892***	***203,447***	***154,590***	***157,790***	***161,056***	***164,390***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***1,481,321***	1,025,692
Ongoing Support																						
On-going Asset/Device support	0	9,416	34,927	50,006	72,532	96,468	115,512	135,303	155,864	177,218	180,886	184,630	188,452	192,353	196,335	200,399	204,547	208,781	213,103	217,514	**2,834,248**	**1,296,703**
Component Replacements	0	2,742	10,171	14,562	21,121	28,092	33,637	39,400	45,387	51,606	52,674	53,764	54,877	56,013	57,173	58,356	59,564	60,797	62,056	63,340	**825,333**	**377,600**
On-going Communications Network costs	0	7,324	27,166	38,894	56,414	75,031	89,843	105,236	121,227	137,836	140,689	143,601	146,574	149,608	152,705	155,866	159,092	162,386	165,747	169,178	**2,204,415**	**1,008,547**
Vendor costs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**	**0**
Training	0	10,355	10,723	11,103	11,497	11,906	12,328	12,766	13,219	13,688	14,174	14,677	15,199	15,738	16,297	16,875	17,474	18,095	18,737	19,402	**274,254**	**137,195**
Other	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**	**0**
Asset Contingency	0	1,974	7,321	10,482	15,204	20,221	24,213	28,361	32,671	37,147	37,916	38,701	39,502	40,320	41,154	42,006	42,876	43,763	44,669	45,594	**594,092**	**271,804**
TOTAL - Assets Cost	***0***	***31,810***	***90,308***	***125,047***	***176,769***	***231,717***	***275,533***	***321,066***	***368,368***	***417,495***	***426,339***	***435,374***	***444,604***	***454,032***	***463,663***	***473,502***	***483,554***	***493,822***	***504,312***	***515,028***	***6,732,342***	3,091,849
Communications Network																						
FAN Network Infrastructure Distribution	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**	**0**
FAN Network Distribution Contingency	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**	**0**
TOTAL - Communications	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**	**0**
TOTAL O&M	**0**	**117,199**	**319,890**	**255,232**	**371,660**	**435,164**	**430,123**	**478,856**	**529,425**	**581,885**	**426,339**	**435,374**	**444,604**	**454,032**	**463,663**	**473,502**	**483,554**	**493,822**	**504,312**	**515,028**	**8,213,663**	**4,117,541**
GRAND TOTAL CAPITAL & O&M	**60,476**	**3,644,080**	**9,502,937**	**6,537,826**	**9,421,678**	**8,877,001**	**6,769,352**	**6,968,353**	**7,172,977**	**7,383,381**	**426,339**	**435,374**	**444,604**	**454,032**	**463,663**	**473,502**	**483,554**	**493,822**	**504,312**	**515,028**	**71,032,291**	**47,710,158**

Northern States Power Company
IVVO & FAN Expenditures

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	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	TOTAL	NPV
Feeders enabled with IVVO	0	0	26	43	61	59	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**189**	
CAPITAL COSTS																						
Assets/Devices																						
Device costs	0	0	1,512,735	2,824,978	2,704,856	2,267,749	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**9,310,319**	**6,996,776**
Device Installation costs	0	0	357,063	773,839	777,449	679,695	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**2,588,046**	**1,936,047**
Xcel Personnel	0	0	132,317	272,663	277,896	283,603	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**966,479**	**720,811**
Xcel Distribution Personnel [ADMS IVVO Integration]	0	0	306,666	525,184	771,477	772,672	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**2,375,999**	**1,760,061**
External resources (Consultants, contractors etc.)	0	0	187,008	434,397	443,389	342,887	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**1,407,681**	**1,054,169**
E&S	0	103,550	750,582	777,228	804,819	833,391	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**3,269,570**	**2,482,269**
Varentec Engineering (ENGO,caps,ami)	0	0	416,731	425,358	434,163	443,150	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**1,719,402**	**1,299,884**
Continguency	0	0	107,914	269,162	256,986	175,088	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**809,149**	**607,879**
TOTAL - Business Assets/Devices	***0***	***103,550***	***3,771,016***	***6,302,808***	***6,471,034***	***5,798,235***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***22,446,644***	**16,857,896**
Communications Network																						
FAN Infrastructure Distribution	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**	**0**
FAN Distribution WiMax	20,159	131,125	258,015	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**409,298**	**348,698**
TOTAL - Communications	20,159	131,125	258,015	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	***409,298***	**348,698**
TOTAL CAPITAL	**20,159**	**234,675**	**4,029,031**	**6,302,808**	**6,471,034**	**5,798,235**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**22,855,942**	**17,206,594**
O&M ITEMS																						
O&M in support of capital deployment	0	0	17,731	37,764	33,658	34,745	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**123,898**	**92,683**
TOTAL - On-going Asset/Device support Costs	***0***	***0***	***17,731***	***37,764***	***33,658***	***34,745***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***				***123,898***	**92,683**
Assets/Devices																						
On-going Asset/Device support	0	0	0	0	7,991	25,537	40,714	57,063	59,089	61,187	63,359	65,608	67,937	70,349	72,847	75,433	78,110	80,883	83,755	86,728	**996,591**	**433,842**
Device Replacements	0	0	0	0	12,059	38,654	62,172	85,943	87,722	89,538	91,391	93,283	95,214	97,185	99,197	101,250	103,346	105,485	107,669	109,897	**1,380,003**	**609,942**
Training	0	0	0	0	195	653	1,107	1,554	1,609	1,666	1,725	1,786	1,850	1,915	1,983	2,054	2,127	2,202	2,280	2,361	**27,066**	**11,765**
Contingency	0	0	0	0	2,471	7,885	12,612	17,431	17,792	18,160	18,536	18,920	19,312	19,711	20,119	20,536	20,961	21,395	21,838	22,290	**279,968**	**123,761**
TOTAL - On-going Asset/Device support Costs	***0***	***0***	***0***	***0***	***22,715***	***72,730***	***116,604***	***161,991***	***166,212***	***170,551***	***175,011***	***179,597***	***184,312***	***189,161***	***194,146***	***199,272***	***204,544***	***209,965***	***215,541***	***221,276***	***2,683,629***	**1,179,310**
Communications Network																						
FAN Network Infrastructure Distribution	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**	**0**
FAN Network Distribution Contingency	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**	**0**
TOTAL - Communications	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	**0**
TOTAL O&M	**0**	**0**	**17,731**	**37,764**	**56,373**	**107,475**	**116,604**	**161,991**	**166,212**	**170,551**	**175,011**	**179,597**	**184,312**	**189,161**	**194,146**	**199,272**	**204,544**	**209,965**	**215,541**	**221,276**	**2,807,527**	**1,271,993**
GRAND TOTAL CAPITAL & O&M	**20,159**	**234,675**	**4,046,762**	**6,340,573**	**6,527,407**	**5,905,710**	**116,604**	**161,991**	**166,212**	**170,551**	**175,011**	**179,597**	**184,312**	**189,161**	**194,146**	**199,272**	**204,544**	**209,965**	**215,541**	**221,276**	**25,663,468**	**18,478,587**

Northern States Power Company
AMI Benefit Calculations

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	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	TOTAL	NPV
Total Meters Replaced	*10,131*	*7,368*	*121,800*	*630,000*	*590,000*	*40,700*	*13,755*	*13,890*	*14,027*	*14,164*	*14,304*	*14,444*	*14,586*	*14,729*	*14,874*	*15,020*	*15,168*	***1,558,960***	
O&M ITEMS																			
Reduction in Field and Meter Services																			
Costs savings from remote disconnect capability	0	0	0	0	386,423	1,108,454	1,592,346	1,814,095	1,878,495	2,060,451	2,133,597	2,209,340	2,287,771	2,368,987	2,453,086	2,540,171	2,630,347	**25,463,562**	**12,291,603**
Reduction in trips due to Customer equipment damage	0	0	0	0	32,617	67,549	139,894	144,860	150,003	155,328	160,842	166,552	172,465	178,587	184,927	191,492	198,290	**1,943,406**	**940,688**
Reduction in "OK on Arrival" Outage Field Trips	0	0	0	0	135,529	280,680	581,288	601,924	623,292	645,419	668,331	692,057	716,625	742,065	768,408	795,687	823,934	**8,075,238**	**3,908,746**
Reduction in Field Trips for Voltage Investigations	0	0	0	0	74,833	154,978	320,960	332,354	344,152	356,370	369,021	382,121	395,686	409,733	424,279	439,341	454,937	**4,458,764**	**2,158,225**
TOTAL - Reduction in Field & Meter Services	***0***	***0***	***0***	***0***	***629,401***	***1,611,661***	***2,634,487***	***2,893,232***	***2,995,942***	***3,217,567***	***3,331,791***	***3,450,070***	***3,572,547***	***3,699,373***	***3,830,700***	***3,966,690***	***4,107,508***	***39,940,969***	***19,299,262***
Improved Distribution System Spend Efficiency																			
Efficiency gains reliability, asset health and capacity projects- O&M	0	0	0	0	1,159	2,401	4,972	5,148	5,331	5,520	5,716	5,919	6,129	6,347	6,572	6,805	7,047	**69,067**	**33,431**
TOTAL - Improved Distribution System Spend Efficiency	***0***	***0***	***0***	***0***	***1,159***	***2,401***	***4,972***	***5,148***	***5,331***	***5,520***	***5,716***	***5,919***	***6,129***	***6,347***	***6,572***	***6,805***	***7,047***	***69,067***	***33,431***
Outage Management Efficiency																			
Outage Management Efficiency (Storm spend O&M)	0	0	0	0	604	1,250	2,589	2,681	2,776	2,875	2,977	3,082	3,192	3,305	3,422	3,544	3,670	**35,965**	**17,409**
TOTAL - Outage Management Efficiency	***0***	***0***	***0***	***0***	***604***	***1,250***	***2,589***	***2,681***	***2,776***	***2,875***	***2,977***	***3,082***	***3,192***	***3,305***	***3,422***	***3,544***	***3,670***	35,965	17,409
TOTAL O&M BENEFITS	**0**	**0**	**0**	**0**	**631,163**	**1,615,312**	**2,642,048**	**2,901,061**	**3,004,049**	**3,225,962**	**3,340,484**	**3,459,071**	**3,581,868**	**3,709,024**	**3,840,695**	**3,977,039**	**4,118,224**	**40,046,001**	**19,350,101**
OTHER BENEFITS																			
Cost reductions																			
Reduced outage duration benefit	0	0	0	0	391,289	798,777	1,630,623	1,664,377	1,698,830	1,733,996	1,769,889	1,806,526	1,843,921	1,882,090	1,921,050	1,960,815	2,001,404	**21,103,587**	**10,323,309**
TOTAL - Cost Reductions	0	0	0	0	391,289	798,777	1,630,623	1,664,377	1,698,830	1,733,996	1,769,889	1,806,526	1,843,921	1,882,090	1,921,050	1,960,815	2,001,404	***21,103,587***	***10,323,309***
TOTAL OTHER BENEFITS	**0**	**0**	**0**	**0**	**391,289**	**798,777**	**1,630,623**	**1,664,377**	**1,698,830**	**1,733,996**	**1,769,889**	**1,806,526**	**1,843,921**	**1,882,090**	**1,921,050**	**1,960,815**	**2,001,404**	**21,103,587**	**10,323,309**
CAPITAL ITEMS																			
Capital gains and other avoided purchases																			
Efficiency gains reliability, asset health and capacity projects- CAP	0	0	0	0	189,547	386,940	789,900	806,251	822,940	839,975	857,363	875,110	893,225	911,715	930,587	949,850	969,512	**10,222,915**	**5,000,776**
Outage Management Efficiency (Storm spend CAP)	0	0	0	0	313,698	649,669	1,345,465	1,393,229	1,442,688	1,493,904	1,546,937	1,601,854	1,658,719	1,717,604	1,778,579	1,841,718	1,907,099	**18,691,164**	**9,047,289**
Avoided Meter Purchases	9,788	18,152	185,992	1,086,102	2,027,125	2,203,315	2,138,852	2,218,752	2,301,754	2,387,984	2,477,572	2,570,653	2,667,369	2,767,866	2,872,297	2,980,823	3,093,609	**34,008,006**	**17,455,428**
TOTAL - Efficiency gains and other avoided CAP purchases	9,788	18,152	185,992	1,086,102	2,530,369	3,239,924	4,274,216	4,418,231	4,567,383	4,721,863	4,881,872	5,047,617	5,219,313	5,397,185	5,581,464	5,772,392	5,970,221	***62,922,085***	***31,503,493***
Avoided Meter Reading CAP investment																			
Drive-by Meter Reading Cost - CAP	20,755	412,501	3,935,923	12,881,148	23,340,750	29,130,716	29,698,551	28,887,914	28,107,557	27,361,868	26,557,430	25,715,024	24,868,419	23,999,536	23,212,398	22,384,139	21,406,031	**351,920,659**	**189,681,697**
TOTAL - Avoided Meter Reading CAP Investment	***20,755***	***412,501***	***3,935,923***	***12,881,148***	***23,340,750***	***29,130,716***	***29,698,551***	***28,887,914***	***28,107,557***	***27,361,868***	***26,557,430***	***25,715,024***	***24,868,419***	***23,999,536***	***23,212,398***	***22,384,139***	***21,406,031***	***351,920,659***	***189,681,697***
TOTAL CAPITAL BENEFITS	**30,543**	**430,653**	**4,121,915**	**13,967,250**	**25,871,119**	**32,370,640**	**33,972,767**	**33,306,145**	**32,674,940**	**32,083,731**	**31,439,303**	**30,762,641**	**30,087,732**	**29,396,720**	**28,793,861**	**28,156,530**	**27,376,252**	**414,842,744**	**221,185,190**
GRAND TOTAL BENEFITS	**30,543**	**430,653**	**4,121,915**	**13,967,250**	**26,893,572**	**34,784,729**	**38,245,438**	**37,871,584**	**37,377,819**	**37,043,689**	**36,549,676**	**36,028,238**	**35,513,521**	**34,987,835**	**34,555,606**	**34,094,385**	**33,495,880**	**475,992,333**	**250,858,601**

Northern States Power Company
FLISR Benefit Calculations

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	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	TOTAL	NPV
O&M BENEFITS																						
Operational Benefits	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**	**0**
TOTAL O&M BENEFITS	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
CUSTOMER BENEFITS																						
Customer Minutes Out- CMO Patrolling savings	0	0	0	40,757	175,083	271,514	355,725	453,382	539,313	649,433	725,847	789,440	789,440	789,440	789,440	789,440	789,440	789,440	789,440	789,440	**10,316,013**	**4,528,044**
Customer Minutes Out- CMO Customer Savings	0	0	0	2,754,556	4,809,980	6,277,181	8,295,139	10,426,430	12,214,741	14,325,875	15,433,977	16,164,602	16,164,602	16,164,602	16,164,602	16,164,602	16,164,602	16,164,602	16,164,602	16,164,602	**220,019,300**	**98,458,717**
TOTAL CUSTOMER IMPACTS	**0**	**0**	**0**	**2,795,313**	**4,985,063**	**6,548,696**	**8,650,864**	**10,879,813**	**12,754,055**	**14,975,308**	**16,159,824**	**16,954,042**	**16,954,042**	**16,954,042**	**16,954,042**	**16,954,042**	**16,954,042**	**16,954,042**	**16,954,042**	**16,954,042**	**230,335,313**	**102,986,762**
GRAND TOTAL BENEFITS	**0**	**0**	**0**	**2,795,313**	**4,985,063**	**6,548,696**	**8,650,864**	**10,879,813**	**12,754,055**	**14,975,308**	**16,159,824**	**16,954,042**	**16,954,042**	**16,954,042**	**16,954,042**	**16,954,042**	**16,954,042**	**16,954,042**	**16,954,042**	**16,954,042**	**230,335,313**	**102,986,762**

Northern States Power Company
IVVO Benefit Calculations

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	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	TOTAL	NPV
OTHER BENEFITS																						
Energy Savings																						
Energy Reduction	0	0	165,891	423,491	910,125	1,577,997	1,904,520	1,963,148	2,014,173	2,063,569	2,041,390	1,994,758	2,019,200	2,085,180	2,025,146	2,026,282	2,185,792	2,206,891	2,172,820	2,129,363	**31,909,736**	$14,934,748
Loss Savings	0	0	3,155	8,234	18,167	32,238	39,806	41,776	43,440	44,870	45,454	45,229	46,713	49,088	48,089	48,350	52,370	53,018	52,442	52,442	**724,883**	$333,272
Total Fuel Savings	0	0	169,046	431,724	928,293	1,610,235	1,944,326	2,004,924	2,057,613	2,108,438	2,086,844	2,039,988	2,065,913	2,134,268	2,073,236	2,074,632	2,238,162	2,259,909	2,225,262	2,181,806	**32,634,620**	$15,268,020
Carbon Emissions Benefits																						
Carbon Reduction	0	0	94,698	230,703	479,367	643,180	656,339	645,988	537,529	340,791	312,713	309,097	303,111	284,879	316,482	328,421	341,160	345,262	349,364	353,466	**6,872,548**	$3,599,824
Total Carbon Emissions Savings	0	0	94,698	230,703	479,367	643,180	656,339	645,988	537,529	340,791	312,713	309,097	303,111	284,879	316,482	328,421	341,160	345,262	349,364	353,466	**6,872,548**	$3,599,824
TOTAL OTHER BENEFITS	**0**	**0**	**263,744**	**662,427**	**1,407,660**	**2,253,415**	**2,600,664**	**2,650,912**	**2,595,141**	**2,449,229**	**2,399,557**	**2,349,085**	**2,369,024**	**2,419,147**	**2,389,718**	**2,403,054**	**2,579,322**	**2,605,171**	**2,574,626**	**2,535,271**	**39,507,168**	**$18,867,844**
DEMAND BENEFITS																						
Deferral of Capital Investments As Demand Reduction	0	0	45,106	113,532	227,415	386,537	456,612	457,807	459,632	460,716	460,890	465,302	468,166	470,601	475,990	480,620	485,452	488,836	495,037	489,665	**7,387,915**	$3,481,566
TOTAL DEMAND	**0**	**0**	**45,106**	**113,532**	**227,415**	**386,537**	**456,612**	**457,807**	**459,632**	**460,716**	**460,890**	**465,302**	**468,166**	**470,601**	**475,990**	**480,620**	**485,452**	**488,836**	**495,037**	**489,665**	**7,387,915**	**$3,481,566**
GRAND TOTAL DEMAND & OTHER BENEFITS	**0**	**0**	**308,850**	**775,959**	**1,635,075**	**2,639,951**	**3,057,277**	**3,108,719**	**3,054,774**	**2,909,945**	**2,860,447**	**2,814,387**	**2,837,189**	**2,889,748**	**2,865,708**	**2,883,673**	**3,064,774**	**3,094,007**	**3,069,663**	**3,024,937**	**46,895,083**	**$22,349,410**

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NOT PUBLIC DATA HAS BEEN EXCISED

Schedule 10 – Summary of Xcel Energy's Analysis Supporting AMI Meter Vendor Selection

Trade Secret Justification

Schedule 10 is an internal assessment summary that the Company has designated as Trade Secret information in its entirety as defined by Minn. Stat. § 13.37, subd. 1(b). The analysis and information contained therein has not been publicly released. This summary was prepared by Major Products & Programs Sourcing employees and their representatives in 2019. This Schedule contains information regarding bidder responses to requests for proposal (RFPs) issued by the Company, including sensitive pricing and other bid data; the Company's proprietary analysis of selected bids; market intelligence; and potential comparative bidder cost and negotiation planning information. Because this overall analysis derives independent economic value from not being generally known to, and not being readily ascertainable by proper means by, other persons who can obtain economic value from its disclosure or use, Xcel Energy maintains this information as a trade secret.

This presentation is marked as "Non-Public" in its entirety. Pursuant to Minnesota Rule 7829.0500, subp. 3, we provide the following description of the excised material:

1. **Nature of the Material**: Internal assessment of responses to RFPs.
2. **Authors**: Major Products & Programs Sourcing employees and their representatives.
3. **Importance**: The Company's proprietary analysis of RFP responses.
4. **Date the Information was Prepared**: This assessment was prepared in second quarter of 2019.