414 Nicollet Mall
Minneapolis, MN 55401

April 10, 2020

—Via Electronic Filing—

Will Seuffert
Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
St. Paul, MN 55101

RE: REPLY COMMENTS
INTEGRATED DISTRIBUTION PLAN
DOCKET NO. E002/M-19-666

Dear Mr. Seuffert:

Northern States Power Company, doing business as Xcel Energy, submits to the Minnesota Public Utilities Commission the enclosed Reply Comments in response to the Comments filed by parties on March 17, 2020.

Pursuant to Minn. Stat. § 216.17, subd. 3, we have electronically filed this document with the Minnesota Public Utilities Commission, and copies have been served on the parties on the attached service list. Please contact Jody Londo at (612) 330-5601 or jody.l.londo@xcelenergy.com or me at (612) 330-6064 or bria.e.shea@xcelenergy.com if you have any questions regarding this filing.

Sincerely,

/s/

BRIA E. SHEA
DIRECTOR, REGULATORY & STRATEGIC ANALYSIS

Enclosures
c: Service List

STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

Katie J. Sieben	Chair
Valerie J. Means	Commissioner
Matthew Schuerger	Commissioner
Joseph Sullivan	Commissioner
John A. Tuma	Commissioner

IN THE MATTER OF THE DISTRIBUTION SYSTEM PLANNING FOR XCEL ENERGY

DOCKET NO. E002/M-19-666

REPLY COMMENTS

INTRODUCTION

Northern States Power Company, doing business as Xcel Energy, submits to the Minnesota Public Utilities Commission these Reply Comments in response to the Comments filed by parties on March 17, 2020.

Xcel Energy appreciates the opportunity to provide this Reply. The record contains sufficient information for the Commission to certify our proposed advanced grid investments. We remain willing to work with the Commission to provide additional time beyond the June 1 statutory deadline, but we oppose a contested case because it will result in significant delays to the important work necessary to provide additional benefits and rate options to our customers. Certification will allow us to begin having our crews and contractors start installing the new meters. Further, given the developments surrounding COVID-19, we believe the work of installing meters could provide positive employment benefits for this important infrastructure project. We address these and other issues raised in more detail below.

We received comments from ten parties on our 2020-2029 Integrated Distribution Plan (IDP). All parties that commented on whether the Commission should accept our IDP were appreciative of the robustness of our filing, and recommended it be accepted. Similarly, all parties that commented on our request to shift to a biennial IDP cadence, with our next report due November 1, 2021, were supportive of that cadence – although some suggested limited information continue to be updated annually. We appreciate parties' recognition of our stakeholder efforts and the completeness and robustness of our filing.[1]

[1] We provide additional information requested by parties and respond to the comments not addressed directly

The majority of comments focused on requests to certify a set of Advanced Grid Intelligence and Security (AGIS) investments and an advanced planning tool (APT) under Minn. Stat. § 216B.2425, subd. 2(e), as investments necessary to modernize the distribution system. Several parties stated support for the Company's overall AGIS proposal and APT, or for individual AGIS components, including advanced metering infrastructure (AMI) and the Field Area Network (FAN) necessary for the AMI meters and other advanced field equipment to operate. Several parties stated a preference that the Commission broadly define certification prior to certifying the Company's proposed investments. A couple of parties questioned the Company's ability to seek certification because it is no longer operating under a multi-year rate plan (MYRP). And, the Department of Commerce suggested a contested case be held prior to certification.

We believe the Commission's existing integrated distribution planning process provides a reasonable framework for reviewing the Company's certification requests. Indeed, the Commission has previously certified investments necessary to modernize the distribution system, and expressed its view that it is more prudent to develop the statutory certification criteria over time as the Commission gains experience with grid modernization.[2] However, the Commission articulated specific requirements for the Company to meet in making an advanced grid certification proposal.[3] The information we provided in the IDP related to our proposed AGIS and APT investments met those requirements, and we believe the investments should therefore be certified.

In asking for certification of these investments, we recognized that the June 1 statutory deadline for a Commission decision on certification may be challenging given the volume of information we submitted into the record. To that end, we offered to waive our right to this deadline and instead suggested it could be pushed back to September 1, 2020. However, referring the matter to the Office of Administrative Hearings (OAH) for a contested case would result in a delay of approximately 18-24 months, and is untenable from a project execution standpoint. Moreover, few parties engaged in discovery in this docket, which suggests that any extension – much less that needed for a contested case – would have limited value.

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in this Reply in Attachment A.

[2] *See* May 28, 2016 Order at page 9 (Docket No. E002/M-15-962).

[3] *See* August 7, 2018 Order Approving Pilot Program, Setting Reporting Requirements, and Denying Certification Request (Docket Nos. E002/M-17-775, E002/M-17-776).

Further, the Commission made it clear in its earlier certification decisions, as well as past Transmission Cost Recovery (TCR) rider dockets, that certification does not amount to a decision on cost recovery. Instead, certification is essentially a gate-keeping function for investments to become eligible (but not approved) for recovery through the TCR Rider. In other words, even if a project is certified, the Company retains the burden of proving the prudency of investments for cost recovery—whether through the TCR Rider or base rates. Here, our IDP filing squarely meets the requirements set out by the Commission in its prior certification decision, and our projects therefore merit passage through the gate of certification. We recognize that additional process and vetting of our proposed investments may be required, but this can occur at the cost-recovery stage, which is governed by a well-established set of standards and outcomes.

Right now, we are building the foundation of integrated distribution planning and grid modernization in Minnesota. A critical early step in this development is the Commission's decision on certifying the Company's AGIS investments – particularly the AMI proposal. Our current meter reading system is obsolete. The meters and replacement parts will no longer be produced after 2022, and the vendor will not support the system at all after 2025.[4] Our continued ability to accurately, timely, and cost-effectively bill our customers for their energy usage requires a new solution.

We believe the AMI and other complementary AGIS investments we proposed in the IDP are the right metering and grid modernization solutions for Minnesota. The AMI technology we proposed is not only equipped to capably read customer meters, but will unlock significant opportunities to reshape the rates and services we are able to offer – transforming energy usage in Minnesota – and also unlocking operational efficiencies and important engineering insights that will reshape our service to customers over time. We believe our planned AGIS investments are the best approach to providing our customers, the Commission, and other stakeholders the capabilities they want for the best price.

We recognize, however, that the world has changed since we submitted our IDP in November 2019, and we are sensitive to our customers' financial and other needs at this unprecedented time. In developing our AGIS plan and making our proposal, we had to strike a balance of evolving technology, maximizing the life of our current AMR system, and existing regulatory frameworks. Notwithstanding our relatively tight implementation schedule, we note that the majority of expenses for the AGIS investments are not scheduled to be incurred until 2022. We also have some flexibility in the implementation schedule we set out in our IDP, and we are open to

[4] The agreement with Cellnet has an option to extend through 2026 at a significantly increased cost.

adjusting that schedule, or developing other regulatory solutions to reduce the immediate financial impact of these investments. If the investments are certified, we believe there are a variety of solutions to addressing these financial concerns worth exploring in a future cost-recovery proceeding.

Delaying certification itself for an extended period of time to engage in a contested case, conduct a rulemaking, or simply wait to see how the present economic and societal situation plays out, could materially impact implementation and jeopardize the project. If a certification decision is not made by the latter half of this year, we would need to develop an alternative solution to ensure we can continue to meet our core utility responsibility of reading customer meters in order to provide timely and accurate bills to our customers. Fortunately, we believe the record we provided in support of our AGIS investments in the IDP is robust, and the Commission has all the information it needs to render a timely decision.

The balance of this Reply responds to parties and explains that certification is appropriate, sufficiently defined, and an available regulatory mechanism for the Company's advanced grid plan. We have met the Commission's requirements for certification, and our proposed AGIS and APT investments are therefore eligible for recovery in the TCR rider under Minn. Stat. § 216B.2425 and are consistent with public policy. Although we are supportive of parties' interests in fully understanding our proposed investments, we believe the additional process they have sought is best reserved for a cost-recovery proceeding.

We continue to respectfully request the Commission to:

- Accept the IDP;
- Certify the Company's proposed AGIS investments;
- Certify the Company's proposed APT investment; and
- Modify the IDP filing cadence to biennial.

REPLY COMMENTS

I. CERTIFICATION OF AGIS IS IN THE PUBLIC INTEREST

A substantial portion of our IDP filing detailed our AGIS initiative, including the information necessary to certify the requested investments. Nonetheless, although parties agreed that our filing was robust and complete and were generally aligned with our advanced grid vision and plan, several had concerns or questions about the process of certification and cost recovery. Some suggested that the Commission should delay certification pending a rulemaking on the standard for certification or to conduct a contested case. In the sections that follow, we address parties' primary contentions and discuss how:

- Certification is sufficiently defined and an available regulatory mechanism for the Company's advanced grid plan,
- The Company has met the Commission's requirements for certification,
- Additional process should wait until a cost-recovery proceeding, and
- Rider recovery of our proposed AGIS and APT investments is allowed by statute and consistent with public policy.

In this section, we discuss how the information we provided in the IDP shows the investments we have proposed are in the public interest and should be certified. The investments we have proposed are timely, the right technologies, and our plan is the right plan that maximizes our current systems and delivers immediate and future benefits to Minnesota and to our customers.

A. This is the Right Time for our AGIS Initiative

We have made incremental modernization efforts on the distribution system over many years and are on the forefront of many of the issues and changes underway in the industry. As a part of these overall modernization efforts, and as discussed in our IDP, now is the right time to begin a more significant advancement of the grid. Our current Automated Meter Reading (AMR) meters 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.

As discussed in the IDP, we currently contract with Landis+Gyr (Cellnet) to provide meter-reading services across our Upper Midwest system (Michigan, Minnesota, North Dakota, South Dakota, and Wisconsin). In addition to providing the meter readings, Cellnet owns and maintains the proprietary communication network and software used to transmit the readings. Cellnet also owns and maintains the meter communication modules, which are the radio interface installed as part of the electric meter.

We have maximized the value of the Cellnet AMR system for 25 years, but it is nearing end of life. Our current agreement with Cellnet expires at the end of 2025. Cellnet has informed the Company that we are the last customer using the technology, and it will stop manufacturing the AMR meter reading modules and components compatible with the current system in 2022. This means there will be no support for ongoing maintenance after that time, and we must plan a metering solution for the years 2022 and beyond.

The expiration of our Cellnet contract, however, has come as 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.

Although both the AMI and AMR systems provide billing data, as discussed in the IDP, AMI systems have two-way communications capabilities and provide additional features and information that can be used to support advanced time of use (TOU) rates, improve outage information, support demand response and distributed generation, and provide timely usage information that can help customers save money by managing their use of electricity. As the distribution system evolves with increasing amounts of DER, and customers expect timely energy usage data and the ability to connect their smart devices to their meter, we need updated facilities to meet these demands. Therefore, as we look to replace our meters, AMI is the appropriate 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.

Finally, the plan that we have proposed for Minnesota benefits from broader Xcel Energy AGIS efforts, as it incorporates efficiencies from AGIS work Xcel Energy is doing in other jurisdictions. For example, the plan contemplates engaging centralized subject matter experts in design decisions and implementation of common components, such as the AMI headend and its interfaces with Company systems. It also relies on using the same contractors for portions of the work. A schedule delay would mean that these parts of the work cannot be done in parallel, leading to a loss of resource and cost efficiencies and potentially knowledge base, in the case of contractors. It is also likely that the Minnesota portion of the overall AGIS project would take longer to complete in total, because our work in Minnesota would need to be reconfigured around the ongoing AGIS efforts in other jurisdictions that have committed timelines.

B. Our AGIS Proposal Brings the Right Technologies

We have proposed a suite of advanced grid initiatives that we believe are timely, measured, and foundational. They will begin to build on and create the value envisioned for the Advanced Distribution Management System (ADMS) we have underway. They will support the advanced rates we have proposed, those we have underway, and a further expansion of advanced rates contemplated in the cost-benefit analysis that accompanied our certification proposal in the IDP. They will immediately improve our reliability performance and our customers' reliability experience. They will immediately deliver better and more information that will help customers reduce energy use, help the Company increase the efficiency of its operations, and enable new customer programs and capabilities.

Our AGIS certification proposal includes a coordinated implementation of the following:

- *Advanced Metering Infrastructure (AMI).* 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.
- *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, new or planned intelligent field devices – up to and including meters at customers' homes and businesses and our information systems. AMI is dependent on the FAN to provide the communications capabilities between the meters and the Company's systems.
- *Fault Location, Isolation, and Service Restoration (FLISR).* A set of sensors and controls that rely on the ADMS and FAN to detect issues on our system, isolate them, and restore power – thereby decreasing the duration of and number of customers affected by an outage on the selected feeders.
- *Integrated Volt Var Optimization (IVVO).* An advanced application that uses specific field devices to optimize voltage as power travels from substations to customers and thereby decrease electrical losses across the system.

In the IDP and supporting information we provided with the IDP, we discussed the specific benefits of each of these technologies in depth. Below we highlight the key features of each, and why we selected them.

1. Our AMI Solution is Foundational

As explained in the Direct Testimony of Ms. Kelly A. Bloch included with the IDP, AMI is much more than a meter reading technology; it is a foundational component of the overall AGIS initiative because it provides a 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.

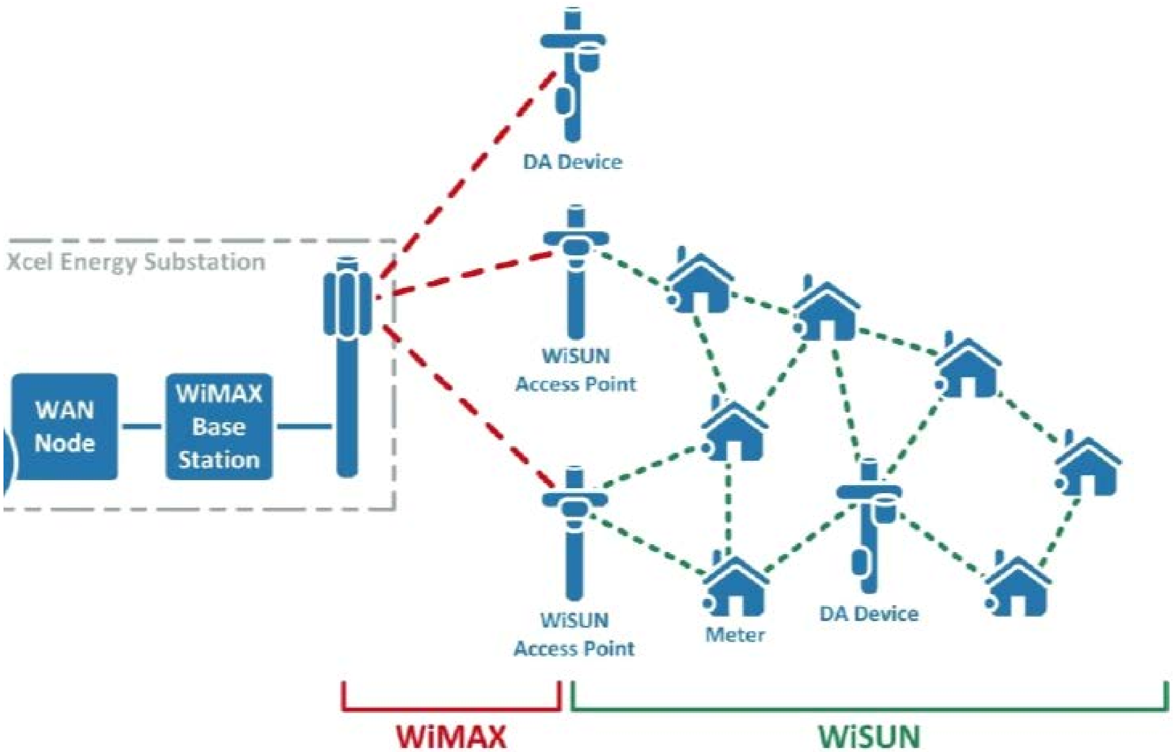
After determining, for the reasons described above, that AMI is the right technology for our customers and Minnesota, we issued a Request for Proposal (RFP) to select an AMI meter vendor that could provide an AMI meter, project management, and installation services. As described in detail in the IDP and supporting information, after reviewing RFP responses, we selected Itron as the AMI technology vendor for a number of reasons, including that it was the lowest cost/best overall value for an offering that included distributed intelligence or/edge technology, it met the Company's deployment schedule, and it was a single-vendor solution (Itron is already under contract for the FAN mesh network and the head-end software).

Our selection process also contemplated that 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, we put an emphasis on "future proofing" the capabilities to minimize the risk of obsolescence. To this end, in the IDP we discussed how we specifically sought and selected AMI technology that had a number of important characteristics that will make it a successful metering solution for years to come.

2. The FAN Uses Industry Standard Technologies and Protects Against Obsolescence

To provide communication between substations and field devices, including AMI meters, the FAN will use two industry standard wireless technologies: (1) Wireless Smart Utility Network (WiSUN) mesh network; and (2) a Worldwide Interoperability for Microwave Access (WiMAX) network, which would migrate to Long-Term Evolution (LTE) over time as technology advances. These two technologies are depicted below.

Figure 1 [IDP – Attachment M3 Figure 6] 1: WiSUN and WiMAX/LTE Networks



As discussed in the IDP, the FAN, in and of itself, does not provide direct benefits to customers or the Company. Rather, the benefits to customers are realized through FAN's support of, and interaction with, other programs and technologies – as well as its design and reliance on industry standard technologies. The mesh network design of FAN provides redundancy and will ensure the overall dependability of communications of the AGIS components. For example, if a device fails on the WiSUN network and can no longer communicate, the mesh configuration of the system will allow that node to be bypassed so other nodes will be unaffected and network communications will continue.

In addition to supporting the AGIS infrastructure, the FAN will support the ability to deploy computing capability closer to the field devices (for example, in substations) that will allow for quicker identification of potential issues and immediate resolution. This deployment will enable Xcel Energy to monitor and manage impacts of DER (for example, solar resources) and other events occurring on the grid in a more timely manner.

After exploring alternatives, including cellular carrier solutions and a dedicated AMI communications network (meaning a specific network for the singular purpose of supporting only meters and AMI), we determined the FAN is the right solution for Minnesota and for our customers because neither of these alternatives would match the features and capabilities of the FAN network that our analysis determined were essential to the future of our advanced grid needs. We summarized the results of our features and capabilities analysis in Attachment M3 of the IDP, page 114 of 143 (Table 36).

Finally, the FAN that we propose protects against obsolescence by constantly being validated, refreshed, updated, and enhanced by industry organizations (WiSUN alliance and IEEE standards bodies) to ensure it is staying abreast of technology changes and requirements. Our strategy is to deploy WiSUN capable networks with continued industry-standards-based technological extensions that meet our robust security and performance objectives. In other words, as vendors update technologies, we are working with them to increase interoperability.

Fresh Energy's Comments observed that our synergistic use of a single communications network for both AMI and intelligent grid devices is unique and as such, has their full support. We appreciate Fresh Energy's recommendation that the Commission approve our certification request for FAN, should the Commission choose to make a certification determination at this time. We also appreciate Fresh Energy's confirmation that we satisfied the Commission's content requirements, and demonstrated that the proposed FAN investment will advance multiple grid modernization goals by improving communications between the utility, customers, and grid infrastructure.

3. FLISR Provides Important Reliability and Resiliency Improvements

As discussed in the IDP, 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. 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. 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 identify 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.

As discussed in the IDP, our customer strategy is informed by customer expectations. Specific to reliability, we know that addressing service interruptions are important to all customer classes – and they expect that with an advanced grid, service interruptions will be less frequent in scope and duration. Referring to a storm-normalized industry index, Fresh Energy opined that the Company's reliability currently compares favorably and does not require improvement. As explained in the IDP, storm-normalized indices do not fully depict the customer experience. Further, the greatest improvement from FLISR is on major event days, which are removed from the normalized indices. So while we have consistently been in the 1st or 2nd quartile on a storm-normalized basis – on a *non*-normalized (all-day) basis, we have been in the 3rd or 4th quartile in relation to our peers four of the most recent nine years; the all-day experience is what customers care about.

The equipment underlying our FLISR proposal protects against obsolescence and will use components that are vendor-neutral, non-proprietary, standards-based, and interoperable. 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. And due to the open standards, we will have 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. Further, the remote and automated switching capabilities associated with FLISR supports a more *resilient* grid, in addition to the reliability benefits described in the IDP and this Reply. Whether storm-related or due to other unforeseen circumstances that limit employee movement (such as the COVID-19 pandemic), remote operations capabilities provide a means by which to perform critical operations when staff is otherwise limited in numbers or movement. This is a benefit to our customers that is difficult to quantify, but valuable nonetheless.

4. IVVO will Reduce Energy and Demand with No Customer Action Needed

Like FLISR, the equipment we have chosen for IVVO will provide value to our customers over a long time period. 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). We will deploy this equipment on our system, and the ADMS that we are in the process of implementing will run the IVVO application to achieve the benefits we described in the IDP. We outline the different operating modes available in ADMS 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.
- *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.

The IVVO plan we have proposed will result in energy savings for customers, will reduce electrical losses, avoid capacity costs, and thereby reduce carbon emissions. Our sourcing criteria for IVVO includes financial viability and long-term performance, and the equipment itself must be sufficiently robust to survive in a harsh outdoor environment and meet industry established testing standards to ensure longevity. As with other AGIS components, we also require interfaces for IVVO to follow open protocols that are not vendor specific to ensure interoperability between manufacturers, and we have selected equipment and controls that adhere to these principles and are highly configurable.

C. Our Implementation Plan for AGIS is Right for Minnesota and our Customers

The advanced equipment and capabilities we are investing in for our AGIS projects will not only improve our analysis, decision-making, and operations – they will immediately improve service to our customers. In this section, we summarize the benefits stemming from our AGIS proposal.

1. The AGIS Initiative Will Provide Immediate and Long-Term Value to Customers

Although each of the AGIS investments will take years to fully implement, they will immediately begin to provide value to our customers. We will begin to realize the value of AMI and FAN as they begin to measure customer usage and communicate it to the Company in 2021 – beginning the transition away from the aging AMR system. We outlined all the anticipated benefits of AMI, FAN, FLISR, and IVVO in the IDP and highlight key points below.

a. AMI Will Deliver Customer Benefits and Enable New Offerings

The system visibility and data that will be delivered by AMI will provide customer benefits in reliability and ability for remote connection, and enable 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.

Customers receiving AMI meters will immediately have access to much more granular energy usage data, which will be part of an enhanced customer portal that may include informational dashboards, energy usage alerts, and advisory tools. With AMI meters, customers will no longer have to call the Company to report an outage; the Company will experience efficiencies in responding to outages – reducing our costs and reducing outage times for customers; and, we will have better information to detect energy theft and unknown users more quickly. Finally, building on the advanced rates we already have underway,[5] we intend to implement advanced rates for all customers with AMI meters, which we captured in our cost-benefit analysis.[6]

Other benefits discussed in the IDP include improved customer choice and experience, enhanced DER integration, environmental benefits of enhanced energy efficiency, improved safety to both customers and Company employees, and improvements in power quality.

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[5] TOU pilot – Flex Pricing; An expanded electric vehicle charging service featuring advanced rate design and price signals to encourage off-peak energy usage; And our recently filed proposal to refresh our General Time of Use Service rates for the commercial and industrial class.

[6] Based on the Brattle Group Study discussed in the IDP that quantified the benefits of potential TOU and critical peak pricing (CPP) rates.

b. FLISR and IVVO are Scaled to Maximize Benefits

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 and included in the cost-benefit analysis provided in our IDP: (1) customer value due to a direct reduction in customer minutes out (CMO); and (2) patrol time savings due to the need to patrol a smaller portion of the system to find faults, which also contributes to an improvement in reliability. We have estimated that our FLISR deployment would reduce total CMO by over four million minutes in the first year after deployment begins – growing to over 26 million minutes annually once its fully deployed – directly benefiting approximately 300,000 customers.

We also expect to achieve certain non-quantifiable operational efficiencies due to the increased visibility and information provided by the FLISR field devices, including reduced 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 refining planning models and hosting capacity analysis, allowing planning engineers to more accurately distribute load along the feeders.

Similarly, IVVO has both quantifiable and non-quantifiable benefits. Quantifiable benefits include a reduction in energy consumption, reduced electric losses, and avoided capacity costs. As discussed in the IDP, we will install our selected IVVO equipment on 13 substations serving 224,000 customers. We believe it is reasonable to expect a 1.25 percent overall energy savings from our proposed IVVO implementation, which will also result in a carbon emissions reduction. We also expect savings in electrical losses, which we estimate to be 225 MWh in 2022, rising to approximately 900 MWh in 2025. Finally, we project that our IVVO proposal will reduce the NSP system peak demand by 0.7 percent, which is directly attributable to the energy reduction achievable at system peak.

We expect non-quantifiable benefits for IVVO to include fewer voltage-related complaints on IVVO-equipped feeders, and that customers will experience higher energy efficiencies from their personal electrical devices, resulting in lower bills. We also expect IVVO to increase the system's ability to host DER.

Finally, our goal with our FLISR and IVVO proposals was to optimize the value by maximizing the positive effects – reliability improvements for FLISR and energy savings for IVVO – while minimizing the associated investment. As such, we identified the points on our system where the technologies will achieve the greatest benefits, rather than a generalized deployment.

2. *The AGIS Initiative Will Result in Positive Economic Effects*

Our AGIS initiative is a multi-year plan that will result in significant capital investment and incremental jobs to Minnesota's economy. Specifically, nearly $600 million of capital investment and over $150 million of O&M spending. In addition to materials and software license contracts with vendors, the AMI meter installations will be completed by approximately 100 incremental contract union field technicians operating under IBEW bargaining agreements. Implementation of the FAN, FLISR, and IVVO technologies will also rely on qualified union linemen and field technicians, most of which will be Company resources, which will be supplemented with some incremental contracted union personnel under our current IBEW bargaining agreements. The project will also require a number of incremental positions for project management, data architects, engineers, analysts, and siting and land rights professionals, which we estimate will total approximately 40-50. This is in addition to the state and local revenues associated with permitting and taxes on the new infrastructure.

D. Advanced Planning Tool is in the Public Interest

We additionally proposed certification of an advanced system planning tool that will replace our currently obsolete system planning tool and deliver additional benefits in the form of more efficient planning and enhanced load forecasting. As discussed in Appendix D1 of the IDP, our current tool is obsolete; doing nothing to replace this critical aspect of our planning responsibilities is not an option. We selected LoadSEER from Integral Analytics which, as also recognized by Fresh Energy in Comments, is a state of the art tool that will enable us to deliver benefits to customers via more efficient planning, enhanced load forecasting capabilities, and better integration with the Company's other planning efforts. It will also enable our compliance with certain IDP requirements, including load and DER scenario analysis.

E. Summary

As discussed above and in depth in the IDP, these foundational and core investments will not only transform the customer experience – they will allow us to advance our technical capabilities to deliver reliable, safe, and resilient energy that customers value. The investments and the information we provided with the IDP satisfies the Commission's requirements for certification of grid modernization investments, discussed in greater depth below, and they should be certified. Without a timely and clear signal from the Commission certifying our AMI investments, we may need to shift directions and pursue an alternative path to ensure our ability to read customer meters as our current system phases out.

II. CERTIFICATION IS SUFFICIENTLY DEFINED AND AN AVAILABLE TOOL FOR THE COMPANY

Certification of grid-modernization investments is expressly permitted under Minnesota law. Specifically, Minn. Stat. § 216B.2425, subd. 2(e) requires that:

> a utility operating under a multiyear rate plan approved by the commission under section 216B.16, subdivision 19, shall identify in its report 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.

Minn. Stat. § 216B.2425, subd. 3 requires that, by June 1 of each even-numbered year, "the commission shall adopt a state transmission project list and <u>shall certify, certify as modified, or deny certification of the transmission and distribution projects proposed under subdivision 2</u>," including those projects identified as necessary to modernize the transmission and distribution system [emphasis added]. The result of a distribution project being certified is that it is then eligible for recovery via the TCR Rider, pursuant to Minn. Stat. § 216B.16, subd. 7b, subject to the utility proving that the costs were prudently incurred and achieve transmission system improvements at the lowest feasible and prudent cost to ratepayers.

Although this is a somewhat new statutory requirement that has been evolving over time, the Commission has developed parameters for certifying grid-modernization investments. In its initial ORDER CERTIFYING ADVANCED DISTRIBUTION-MANAGEMENT SYSTEM (ADMS) PROJECT UNDER MINN. STAT. § 216B.2425 AND REQUIRING DISTRIBUTION STUDY, June 28, 2016, Docket No. E002/M-15-962, the Commission declined to adopt "a comprehensive list of criteria" for addressing certification. Instead, the Commission decided it could certify projects and "interpret the statute on a case-by-case basis until such time as a comprehensive list of criteria is established."

Based on the review it conducted in that docket, the Commission certified the Company's ADMS project, finding that the project was consistent with the requirements of Minn. Stat. § 216B.2425, subd. 2(e), and was "an investment necessary to modernize the distribution system that will enhance reliability and increase energy conservation opportunities using control technologies and other innovative technologies." (Internal quotations omitted.) The Commission clarified, however, that its decision to certify ADMS did not imply any decision regarding recovery of the project's costs:

> The Commission's decision represents only a finding that the project is consistent with the requirements of section 216B.2425. Any rider recovery of costs associated with the project will be determined in response to a petition for rider recovery of those costs under Minn. Stat. § 216B.16, subd. 7b. At that time, Xcel will have the burden of establishing the prudence of the costs it requests to recover through the TCR Rider.

In its Order Approving Pilot Program, Setting Reporting Requirements, and Denying Certification Request, August 7, 2018, Docket Nos. E002/M-17-775, E002/M-17-776, the Commission expanded on its initial grid-modernization certification order. The Order established criteria for addressing future certification requests (including this one). Specifically, the Commission ordered that any future certification requests for grid-modernization investments include:

> (1) details on why the project is necessary for grid modernization; (2) how it is in the public interest; (3) how it is consistent with the Commission's Guiding Principles for Grid Modernization (Docket 15-556); (4) the intended objectives for the project; (5) a description of the available alternatives to meet the intended objectives; (6) a cost benefit analysis of the project; (7) and potential interrelation with other initiatives, projects, and Xcel's long-term grid modernization plans.

The Commission's Guiding Principles for Grid Modernization referenced in this Order are laid out in the Minnesota Public Utilities Commission Staff Report on Grid Modernization from March 2016, Docket No. E-999/CI-15-556. Specifically, the report identifies five guiding principles for grid modernization:

- 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;
- Ensure optimized utilization of electricity grid assets and resources to minimize total system costs;
- Facilitate comprehensive, coordinated, transparent, integrated distribution system planning.

Finally, in the August 7, 2018 Order, the Commission certified the Company's proposed Residential TOU Rate Pilot. Again, the Commission clarified that "[t]his certification does not imply either of the following: (1) any finding of prudency with respect to the recovery of costs in a petition for rider recovery under Minn. Stat. § 216B.16, subd. 7b(b); or (2) certification or approval of any investments beyond those specifically associated with the Pilot."[7]

The bottom line of these decisions reveals an evolving set of certification evaluation criteria, but a consistent emphasis that, although certification signals a general level of support for a grid-modernization investment, it is essentially a gate-keeping function for investments to become <u>eligible</u> (but not approved) for recovery through the TCR Rider. Even after a project is certified, the Company still bears the burden of proving the prudency of investments for cost recovery—whether through the TCR Rider or base rates.

As discussed above in Section I and below in Section III, the Company provided voluminous information with its request for certification of the AGIS and APT investments that satisfies the Commission's specific standards for certification, and therefore, the projects should be certified.

III. THE COMPANY MET THE COMMISSION'S STANDARD FOR CERTIFICATION

No commenter contends that the Company's request for certification of AGIS and APT fails to satisfy the Commission's standards. Instead, they argue that other standards should be used to assess the proposed investments, or that the certification process should be paused pending additional process in the form of a rulemaking or contested case. As noted above, however, the Commission has set forth specific criteria for certification requests, and the Company's proposed investments satisfy not only these criteria, but the other standard suggested by commenters. Regardless of the standard applied, the Commission should not delay a decision on certification for the further development of procedures to address requests for certification. As the Commission noted in its first Order relating to certifying grid modernization investments, the Commission has taken a prudent and measured approach "to develop these criteria over time as the Commission gains experience with grid

[7] The Department recommends that, among other things, certification be limited to those investments for which the Company specifically has requested certification, in order to protect customers from "changing project descriptions." The Company agrees this is a reasonable limitation consistent with the Commission's prior orders.

modernization." That continues to be the prudent approach to interpreting Minn. Stat. § 216B.2425, and no commenter has presented a compelling reason to deviate from this course.

Below we briefly address how the Company's proposed AGIS and APT investments satisfy the Commission's existing certification criteria, as well as the alternative criteria suggested by several commenters. In the following section, we address why certification should not be postponed to engage in additional process related to these investments.

A. Certification Criteria from August 2018 Commission Order

Although the information submitted by the Company in the IDP related to the AGIS and APT investments is not limited to the criteria identified in the Commission's August 2018 Order, it satisfies the Commission's requirements for certification of grid modernization investments. Below we highlight specific portions of the filing that particularly address these criteria.

1. The AGIS and APT Investments are Necessary for Grid Modernization

The proposed AGIS investments are central to the Company's plans for grid modernization, and that is discussed extensively throughout the AGIS section of the IDP and the supporting testimony of Company witnesses Kelly A. Bloch, Chris C. Cardenas, Michael C. Gersack, and David C. Harkness. That said, the need for the investments is summarized in Sections IX.A and IX.B of the IDP.

Appendix D1 of the IDP includes a discussion of why the APT also is necessary for grid modernization. Section IV of Appendix D1 specifically highlights how the APT will "substantially facilitate our distribution planning process and enhance our hosting capacity analysis processes." First, the APT is a "foundational tool that will support distribution system modernization, thereby enhancing reliability." It will "significantly enhance our visibility into hourly forecasted load shapes, so that we may better identify and analyze potential issues and mitigation paths" and enable "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" by enabling "analysis at a more granular level than feeder and substation."

2. The AGIS and APT Investments are in the Public Interest

As discussed in Section I above, both the AGIS and APT investments are in the public interest.

3. The AGIS and APT Investments are Consistent with the Commission's Guiding Principles for Grid Modernization

As discussed in Section IX of the IDP, and in the testimony of Mr. Gersack, and for the reasons these investments are necessary for grid modernization highlighted above, the proposed AGIS investments are consistent with the Commission's Guiding Principles for Grid Modernization. Although each component of the AGIS investments supports different principles, taken as a whole, the AGIS investments align with all five of the guiding principles.

As discussed in Appendix D1 of the IDP, and for the reasons the investment is necessary for grid modernization highlighted above, APT also is consistent with the Commission's Guiding Principles for Grid Modernization. Specifically, the proposed investment aligns with the principles that investments (1) maintain and enhance reliability and resilience of the electricity grid, (2) ensure optimized utilization of electricity grid assets and resources, and (3) facilitate comprehensive, coordinated, transparent, integrated distribution system planning.

4. The Information Submitted with the IDP Lays Out the Intended Objectives for the AGIS and APT Investments

The intended objectives for the AGIS investments are discussed extensively in the testimony of Mr. Gersack. His testimony also includes an attached whitepaper on the Company's Advanced Grid Customer Strategy that discusses how the AGIS investments facilitate the Company's overall customer strategy.

The intended objectives for the APT investment are discussed throughout Attachment D1 of the IDP. In particular, Section II.A. lays out the capabilities the Company sought in a new load forecasting tool, and Section III.B. lays out the capabilities and benefits of the APT tool selected by the Company through the competitive bidding process.

5. The Information Submitted with the IDP Includes a Description of the Available Alternatives to the AGIS and APT Investments

We provided testimony from Ms. Bloch, Mr. Gersack, and Mr. Harkness with the IDP that extensively discusses the alternatives to AGIS considered by the Company. Alternatives to the AGIS investments as a whole are discussed in Section V(C) of Mr. Gersack's testimony. Alternatives to AMI are discussed in Section V(D)(6) of Ms. Bloch's testimony. Alternatives to the Company's plan to implement FLISR are discussed in Section V(F)(7) of Ms. Bloch's testimony. Alternatives to IVVO are discussed in Section V(G)(6) of Ms. Bloch's testimony. Alternatives to FAN are discussed in Section V(E)(4)(g) of Mr. Harkness's testimony. Appendices N2-N4 are the RFPs for AMI, the WiSUN mesh network portion of FAN, and IVVO.

The Company's analysis of alternatives to the APT tool is discussed at length in Appendix D1 of the IDP. The appendix includes a discussion of the Company's current load-forecasting tool, and its capabilities and limitations, in Section I.B. It also discusses the guiding factors used by the Company in selecting a new load forecasting tool, in Section II.A, and the Company's competitive bidding process used to select the APT tool, in Section II.B. Appendix N1 is the APT RFP issued by the Company.

6. The IDP Includes Cost Benefit Analyses for the AGIS and APT Investments

The Company conducted a detailed cost-benefit analysis for the AGIS investments and presented the results of this analysis in Section IX.F of the IDP, pages to 156 to 161. AGIS cost-benefit summaries were included as Attachments O1-O4, and an executable CBA model was included in workpapers. We also provided testimony underlying the analysis from the following witnesses: Ms. Bloch, Mr. Cardenas, Mr. Gersack, Mr. Harkness, and Dr. Ravikrishna Duggirala. Relevant aspects of this testimony were included with the IDP as Attachments M1-M5.

Similarly, the Company included a cost-benefit analysis for the APT investment and presented the results of this analysis in Attachment D1, Section III.D. An APT cost-benefit summary was included as Attachment D2, and an executable CBA model was included in workpapers.

7. The IDP Discusses Potential Interrelation of the AGIS and APT Investments with Other Initiatives, Projects, and Xcel's Long-Term Grid Modernization Plans

Section VI of Mr. Gersack's testimony discusses how the overall AGIS investments fit within the Company's overall grid-modernization and customer-experience plans. These topics also are discussed in greater detail in the Advanced Grid Customer Strategy whitepaper included with Mr. Gersack's testimony. At a technical level, Ms. Bloch specifically discusses interoperability of AMI, FLISR, and IVVO in Sections V.D.7., V.F.8., and V.G.7. of her testimony, and Mr. Harkness discusses interoperability of FAN through Section V.E.4. of his testimony.

The information included in the IDP related to the APT investment similarly discussed interrelation of the APT with other grid modernization initiatives and projects. Section II.A.3. of Attachment D1 discusses how integration with other resources and planning processes was a key consideration in selecting an advanced planning tool, and Section III.B.3 discusses how the APT selected by the Company through its competitive bidding process will integrate data source inputs and communicate with the Company's other planning processes.

In sum, both the AGIS and APT investments are necessary for grid modernization, in the public interest, and consistent with the Commission's Guiding Principles for Grid Modernization, and the Company included all information required by the Commission's August 2018 Order in Docket Nos. E002/M-17-775, E002/M-17-776 for both investments. The Commission, therefore, should certify them.

B. Alternative Criteria Proposed by Commenters

Several Commenters suggest that, rather than reviewing the AGIS and APT investments using the criteria from the Commission's August 2018 Order, the Commission should apply criteria from Proposed Motions of Commissioner Schuerger for May 25, 2016 Agenda Meeting in Docket No. E002/M-15-962. The Company does not take a position on whether these criteria are more appropriate than those ordered by the Commission on August 7, 2018. We note, however, that the Company's proposed AGIS and APT investments satisfy these alternate criteria, as well.

Under this proposed decision alternative, to obtain certification, a utility must demonstrate the following:

(1) the project is necessary to modernizing its distribution system with respect to (i) enhancing system reliability, (ii) improving system security, and/or (iii) increasing energy conservation by facilitating communication between the utility and its customers; and

(2) the project is a 'priority project,' that is, a project of such importance that it warrants current cost recovery through a rider while the project is being executed rather than delayed cost recovery in a rate case after the project has been completed.

These criteria are largely the same as those that are currently required. The first criteria – that a project be necessary to modernize a utility's distribution system – is a restatement of Minn. Stat. § 216B.2425, subd. 2(e). The second – that a project be a "priority project" – is satisfied for both the AGIS and APT investments.

Due to the importance and scope of the AGIS investments for which we are seeking certification, they are particularly appropriate for rider recovery. As discussed by Ms. Bloch, Mr. Cardenas, Mr. Gersack, and Mr. Harkness, the AGIS projects are fundamental elements of the Company's plans for modernizing the distribution grid. Along with the ADMS already approved by the Commission, AMI and the FAN are the core pieces of AGIS – the advanced meters and communication network needed to convey meter data to the Company's other systems. The other two projects proposed, FLISR and IVVO, are advanced applications for ADMS that we believe will provide substantial benefits to customers.

As discussed in the IDP, although portions of these investments will become operational earlier as equipment is installed, the projects as a whole will take several years to complete. The Company's schedule for meter installations runs from 2021 through 2024. Much equipment will be used and useful, however, before the projects are completed in 2024. As a result, rider recovery for these investments prior to project completion is appropriate, and they meet the standard for "priority projects" discussed above.

The APT similarly is a priority project. As explained in Attachment D1 of the IDP, the APT is a foundational tool that will support distribution system modernization, enhancing reliability and better facilitating our evaluation and identification of conservation opportunities. As seen in several sets of comments filed in this docket, we believe the APT will facilitate analysis the Commission and many stakeholders have asked for. Therefore, acquiring, implementing and certifying the APT now and using it in our 2020 planning process is important and aligned with the Commission's and stakeholder expectations for our future grid planning.

Additionally, the proposed decision alternative requires a utility to provide "the information that the Commission requires to make its certification determination," including the following:

- information establishing the necessity of the proposed project, including discussion of any alternatives to the project and the reasons the alternatives have been rejected, and discussion of how the proposed project comports with the Commission's grid modernization investigation in Docket No. E999/CI-15-556;

- identification of the expected improvements in distribution system reliability, security, and/or energy conservation that would result from the project, and how the project's performance will be measured to establish whether it has achieved the expected improvements;

- estimated cost of the project, including all mechanisms that will be employed to maximize cost reductions and minimize cost increases; and

- criteria that will be used by the utility to determine whether at any point it has become imprudent to bring the certified project to completion due to the project failing to meet its performance and/or cost expectations.

Again, this information is largely the same as what is currently required under the Commission's August 2018 Order. The two main differences are the proposed requirements that (1) the utility identify how a project's performance will be measured to establish whether it has achieved the expected improvements, and (2) the utility include criteria that will be used to determine whether it has become imprudent to bring a project to completion.

The IDP also contained information that satisfied the spirit of these items. To this end, starting at page 163 of the IDP, we discuss the holistic nature of our AGIS initiative, in that it 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 rollout of new products and services enabled by the AGIS initiative. We proposed metrics intended to keep stakeholders informed of the progress and value that the advanced grid is bringing to customers and also identify areas where we can focus additional resources to improve results. We outline our proposed metrics and reporting in Schedule 11 of Mr. Gersack's testimony (Attachment M1, page 301), and note a proposed May 2022 start date for the first report. We also note that we expect the report content and metrics to change over time as we move through the phases of AGIS implementation. Finally, we acknowledge that AGIS may also impact certain service quality metrics. We proposed that existing service quality reporting continue, and stated our intent to address any AGIS impacts to service quality metrics or thresholds in those separate proceedings. Finally, as also explained in the IDP and elsewhere in this Reply, we did not propose specific metrics related to future operational capabilities or products and services that will be enabled by AGIS at this time; rather, we proposed to develop metrics and reporting protocols associated with those capabilities, products, or services in future proceedings.

IV. ADDITIONAL PROCESS IS MORE APPROPRIATELY FOCUSED ON THE NEXT STAGE – COST RECOVERY

A. Additional Process Prior to Certification is Unnecessary

We appreciate that a number of commenters have asked for additional time and process so that they may fully vet the proposed AGIS and APT investments. That is why we initially offered to waive the statutory requirement, under Minn. Stat. § 216B.2425, subd. 3, that the Commission make a certification decision by June 1, 2020.

We continue to believe that we have the right to waive this deadline and are open to doing so, should the Commission find that helpful. No participant in the docket has objected to our offer, and, because the deadline exists as a utility protection—

facilitating the recovery of grid modernization investments through the TCR Rider—the Company may waive it. Under Minnesota law, statutory deadlines may be waived by a party for whom the deadlines are designed to protect. *See In re Commitment of Giem*, 742 N.W.2d 422, 431 (Minn. 2007). Consistent with this principle, the Commission has a longstanding practice of accepting utilities' offers to waive the ten-month review period under Minn. Stat. 216B.16, subd. 2, and its historical analogs. *See In the Matter of Northwestern Bell Telephone Company's Proposed Tariff to Discontinue Operator Services to Local Exchange Carriers, Order Accepting Waiver of Statutory Review Period and Granting Extension of Time for Parties' Reports*, Docket No. P-421/M-87-815 (March 18, 1988); *In the Matter of the Application by CenterPoint Energy Resources Corp., d/b/a CenterPoint Energy Minnesota Gas, for Authority to Increase Natural Gas Rates in Minnesota, Order Accepting Filing, Suspending Rates, and Extending Timeline*, Docket No. G-008/GR-19-524 (Dec. 18, 2019). We believe the Company's offer to waive the June 1 deadline under Minn. Stat. § 216B.2425, subd. 3, is lawful and consistent with Commission precedent.

That said, most commenters failed to propound any discovery in this docket. We received 50 information requests from Fresh Energy, 22 from the Environmental Law & Policy Center and Vote Solar, and 21 from the Citizens Utility Board of Minnesota. No other party or participant sent us more than one information request. As a result, at this time, it is unclear that waiving the statutory deadline is necessary.

Relatedly, even more expansive process at this stage – either in the form of a rulemaking or contested case – is unnecessary. As discussed above, the Commission's precedent shows that certification is, essentially, a gating function. The Commission has repeatedly said that certification does not constitute a determination of prudence and that the Company continues to bear the burden of proving prudence when seeking cost recovery for any certified projects. This is consistent with the language of Minn. Stat. § 216B.16, subd. 7b, the statute authorizing recovery of certified projects through the TCR Rider, which states that the Commission "shall approve the annual rate adjustments" incorporating grid modernization investments, only if "the costs included for recovery through the tariff were or are expected to be prudently incurred and achieve transmission system improvements at the lowest feasible and prudent costs to ratepayers." It also is consistent with the Commission's September 27, 2019 Order Authorizing Rider Recovery, Setting Return on Equity, and Setting Filing Requirements in Docket No. E002/M-17-797, which requires the Company to, among other things provide the Commission with "a business case and comprehensive assessment of qualitative and quantitative benefits to customers" related to AGIS, but only "[i]f and when Xcel requests cost recovery" for such investments.

A contested case simply is not needed in this proceeding, the result of which is an order authorizing the Company to prove the prudence of its investments in order to recover their costs through the TCR Rider. Were the result of certification a presumption of prudence, additional process could be beneficial.[8] Since it is not, however, and since few parties engaged in discovery in this docket to begin with, there is no reason to delay the Commission's certification decision. Nonetheless, because we submitted the IDP concurrently with our general rate case petition, we provided a robust record – including all information required in the Commission's Order in Docket E002/M-17-797. Should the Commission decide that a prudence determination is appropriate at the certification stage, we believe our Petition provides ample information on which to make that decision.

B. Implications of Substantially Delayed Certification

To be clear, we are not opposed to seeing the certification process evolve, and we would willingly participate in discussions in how to improve it. But, we do not believe it is appropriate to hold these certification requests and investments in limbo while that process moves forward. As discussed in the IDP and above, the Company's current meters have reached the end of their life, and the Company needs to begin transitioning its electric metering solution in the near future. Delaying certification pending a rulemaking proceeding or contested case would put unnecessary pressure and uncertainty on these investments, particularly when the Commission already has laid out a process for certification that has successfully vetted projects in past proceedings.

Specifically, were a decision on certification substantially delayed, the Company's planned implementation schedule would, at best, be compressed, potentially increasing costs for customers, and, at worst, portions of the projects would need to be abandoned altogether.

Our proposed AMI plan contemplates the Company making a modest final order for legacy equipment in 2022 – and largely relying our ability to reuse the legacy equipment we remove from the field as it is replaced with AMI equipment to meet near-term new business or meter replacement needs until AMI is fully deployed. A delay will likely require that our final order for equipment is much larger – we estimate approximately $8 million more than it otherwise would have been – as a later start with AMI will mean that we will have less legacy equipment to redeploy for ongoing metering needs until the Cellnet AMR system is fully replaced. Additionally, as we

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[8] Even were additional process warranted, it is not clear a contested case is the appropriate process. As a general matter, a contested case is warranted when "a proceeding involves contested material facts ***and*** there is a right to hearing under statute or rule[.]" Minn. R. 7829.1000 [emphasis added]. There are no contested material facts in this proceeding, given the Company is the only party to have introduced facts into the record, and the Company is unaware of any applicable statute or rule providing a right to a contested case.

replace each Cellnet AMR meter, our payments to Cellnet decrease. A schedule delay will push these savings out in time, eroding savings we have factored into our cost-benefit analysis of AMI. We have estimated the savings lost from a deployment that starts in 2022 instead of 2021 would be approximately $17 million.

Given support for our current meters will end in 2025 or 2026, a substantially delayed start to installation also means that more AMI and FAN infrastructure will need to be installed in a shorter amount of time. Whether and for what price our meter and installation vendors, Itron and Tribus, would be able to accommodate such a compressed schedule is unknown, and could require reopening our contracts with them, increasing the price of the project for our customers.

Relatedly, compressing the installation schedule would have impacts on our internal work teams and information systems, which would be required to handle a higher volume of work. For example, in addition to the physical act of removing each of our 1.3 million electric meters and replacing them with AMI meters, our information systems will have to process that information in a transparent and traceable manner – and within a narrow billing window. We are confident our systems can do this under the currently-planned schedule. However, we consider increased volumes associated with a compressed implementation schedule a risk that could also have cascading impacts, including inaccurate or delayed bills for customers.

The precise risks of delay are unknown, but likely would increase costs for customers. Aside from cost increases with our AMI vendors, were the installation schedule sufficiently compressed, we may need to adopt an AMR solution instead of AMI. Although the cost for such meters likely would be less than AMI, they would not provide our customers, the Commission, and other stakeholders the capabilities many are hoping to see. Moreover, such a solution likely would be a mere stopgap, and were the Commission to subsequently approve the Company's investment in AMI meters, the total cost for customers could be higher than currently projected.

C. Conditions on Cost Recovery Should Be Addressed in a Cost-Recovery Proceeding

It also is premature at this stage to address commenters' recommendations regarding specific cost caps, consumer protections, conditions on cost recovery, and specific performance metrics. We believe these are all important issues that deserve consideration, but they are more appropriately addressed in a cost-recovery proceeding, whether that be a proceeding related to the TCR Rider or a general rate case. For example, the Department recommends, among other things, that certification of the AGIS investments be conditioned on a finding that "any certification should be conditioned on a presumption that all revenues from the AGIS

Initiative belong to ratepayers unless otherwise approved by the Commission." Leaving aside whether this is an appropriate condition, were the AGIS investments certified but the Company not allowed to recover the investments in base rates or through a rider, the condition would be unreasonable. It therefore makes the most sense to address this and other proposed conditions in a cost-recovery proceeding.

That said, should the Commission agree that the more appropriate place to address these issues is a cost-recovery proceeding, we believe it is appropriate at this time to consider the process for such a proceeding. Although we do not believe referring these issues to the OAH for a contested case is necessary given that there are no contested material facts, we do believe providing expanded opportunities for stakeholders to vet our proposed investments is appropriate. Reference to the proceedings relating to the Metropolitan Emissions Reduction Plan (MERP), in which the Company sought to recover over a billion dollars of capital cost through the Emissions Reduction Rider, is informative. In the Commission's March 9, 2004 ORDER APPROVING XCEL'S PROPOSED PLAN, SUBJECT TO THE TERMS OF A SETTLEMENT AGREEMENT AND ADDITIONAL CONDITIONS AND CLARIFICATIONS (Docket No. E-002/M-02-633), the Commission summarized the unique procedural history of the docket:

> Due to the proposal's technical complexity, its significant financial implications for ratepayers, and the widespread public interest it had generated, the Commission scheduled a series of public hearings, convened a technical conference to explore the financial consequences of converting two of the plants to natural gas, and established a 90-day period for the parties to meet, develop the record, exchange information, and attempt to clarify and narrow the issues in dispute.

The Company would support similar process in a cost-recovery proceeding in order to provide interested parties with the opportunity to fully assess the Company's proposed investments and narrow the issues before the Commission.

V. RIDER RECOVERY IS AN ALLOWED AND APPROPRIATE MECHANISM FOR AGIS AND APT

Several commenters argue that, because the Company's multiyear rate plan, under Minn. Stat. § 216B.16, subd. 19, has ended, the Company is precluded from seeking certification, and ultimately rider recovery, of grid modernization investments. This argument fails for at least two reasons.

First, although the Company no longer is operating under a multiyear rate plan, on November 1, 2019, when it filed the IDP and sought certification of these investments, it was. Under Minn. Stat. § 216B.2425, subd. 2(e), the Company was required to identify the "investments that it considers necessary to modernize the transmission and distribution system." The Company's request for certification of grid modernization investments, therefore, was not only proper, it was required. Had we not identified the AGIS and APT projects in the IDP, we would have been in violation of this statute.

Second, this argument flips the requirements of Minn. Stat. § 216B.2425, subd. 2(e) on their head. As noted, this section is a requirement for utilities operating under multiyear rate plans; nothing within its text states that utilities not operating under multiyear rate plans are prohibited from identifying investments necessary to modernize the grid. Commenters' arguments to the contrary are entirely devoid of statutory or other legal support.

Put simply, because the Company was operating under a multiyear rate plan in November 2019, it was required (and had it not been required, it could have opted) to include these investments in its biennial distribution grid modernization report under Minn. Stat. § 216B.2425, subd. 2(e), which the Commission has said, in Docket No. E-002/M-17-776, may be combined with an IDP. And, under Minn. Stat. § 216B.2425, subd. 3, the Commission is required to make a certification decision regarding those investments. That the Company now is no longer operating under a multiyear rate plan is immaterial.

A number of commenters also suggest that certification, and potential rider recovery, for the proposed investments is inappropriate because of the size of the investments. That, however, reflects a fundamental misunderstanding of the purpose of riders. As noted by the Commission in a June 2010 Report to the Legislature, the creation of many riders was "prompted by the imposition of policy mandates, as well as a desire to recover very large capital expenditures for single projects (or a group of related projects) or to simply encourage certain types of expenditures."[9] Projects with capital expenditures similar to or even greater than the AGIS and APT investments routinely have been recovered through riders. For example, the Company has recovered the revenue requirements for (1) MERP through the Emissions Reduction rider; (2) CapX2020 transmission projects through the TCR rider; and (3) numerous wind projects through the Renewable Energy Standard rider. Certifying the AGIS and APT investments, therefore, is not only consistent with the legislature's direction that investments necessary to modernize the distribution system be eligible for recovery through the TCR rider, but also the Commission's precedent of rider recovery for similarly-scaled statutorily-authorized projects.

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[9] June 2010 Report to the Legislature: Utility Rates Study as Required by Laws of Minnesota, 2009, Chapter 110.

VI. THE COMPANY WILL BE SEEKING NEEDED AGIS-RELATED APPROVALS IN A FORTHCOMING PETITION

Finally, we note that we will be submitting a Petition seeking ancillary approvals that are necessary keep aspects of our proposed plan moving forward. We recognize that the Commission will not have made a certification decision. However, we believe it is important to take action to secure necessary Commission approvals in anticipation of certification to maintain our proposed timeline, as otherwise discussed in this Reply. The Petition we intend to submit will address the following topics discussed in the IDP:

- *Variance to Billing Content Rule Requirements*. With AMI, our customers will move to interval billing, which means that customer bills will report a total usage amount for the billing period, rather measuring from a "last meter reading." Reporting customers' meter readings is required under the Billing Content requirements of Minn. R. 7820.3500, so our Petition will seek a variance from these requirements.
- *Customer Opt-Out Option*. An opt-out option would allow certain customers the ability to choose whether to receive an AMI meter as part of the initial implementation, as well as to later have an AMI meter replaced with a non-AMI meter. Our Petition will propose a cost-causative framework, customer parameters, and explain how we will inform and educate customers on this option.
- *Remote Disconnect/Reconnect Framework*. A portion of the benefits included in the cost-benefit analysis for AMI are associated with our ability to disconnect and reconnect service without visiting a customer home or business. Our petition will propose a framework for this AMI capability and outline the anticipated benefits. We expect the framework to initially focus on reconnections for any reason, and be limited to non-credit-related disconnections.

CONCLUSION

We appreciate the opportunity to provide these Reply Comments. We respectfully request the Commission accept our Integrated Distribution Plan, certify our proposed advanced grid investments, and shift to a biennial cadence for filing future Integrated Distribution Plans.

Dated: April 10, 2020

Northern States Power Company

In this Attachment, the Company summarizes parties' comments responsive to the Commission's December 31, 2019 Notice and responds to certain comments not otherwise addressed in the body of our Reply.

I. COMMISSION NOTICE QUESTIONS – 2019 IDP

A. Should the Commission Accept or Reject Xcel Energy's Integrated Distribution Plan (IDP)?

All parties commenting on this agree the Commission should accept the Company's 2019 IDP. Of note, the Clean Energy Economy Minnesota (CEEM) stated its appreciation of our "sincere engagement and willingness to work with and learn with stakeholders." CEEM also noted our 2019 IDP was a strong effort that facilitated and represented stakeholder dialogue and that the Company provided an accessible narrative and extensive thought process to engage stakeholders and the Commission as we invest in grid modernization technologies.

Similarly, Fresh Energy noted the Company produced a strong second IDP that meaningfully builds on our inaugural plan, is responsive to stakeholder and the Commission's feedback – and recommends the Commission accept it. Fresh Energy portrays the combined IDP and AGIS information as a robust picture of the Company's focus for its distribution business and appreciates the work that we did to put plans in place for a suite of investments that will decisively move the Company toward achieving important energy policy goals, including significantly modernize our distribution system, reduce electricity consumption, facilitate greater use of DER and enhance reliability for all customers.

Also recommending the Commission accept the Company's 2019 IDP were the City of Minneapolis and the Department of Commerce – with the Department expressing its appreciation for the Company's considerable efforts in compiling this report and complying with the IDP Requirements and the Commission's Order.

B. Does the IDP Filed by Xcel Energy Achieve the Planning Objectives Outlined in the Filing Requirements as Amended by the Commission's July 16, 2019 Order?

Of the parties that assessed and commented on the IDP in relation to the Commission's planning objectives, parties generally agreed that the Company had met them. The Department's analysis was very thorough – examining each planning objective, concluding the Company had met them, and affirming its view that the Company had provided a detailed response to Order Point No. 5 of the

Commission's July 16, 2019 Order in Docket No. E002/M-18-251 requiring the Company to discuss how the information in our IDP relates to each objective and its location in the IDP, among other things.

C. What IDP Filing Requirements Provide the Most Value to the Process, and Why?

The Department suggested that the sections of our 2019 IDP related to cost-benefit analyses of distribution system investments, historical and projected budgeting processes, NWA analysis, and our approach to system planning seem to be valuable. A few other parties suggest changes to future IDPs, particularly in the area of Non-Wires Analysis (NWA).

We discuss the suggestions parties made for changes in Section I.D below. Of note, several parties expressed appreciation for the Company's stakeholder processes and inclusion of feedback from those sessions in our 2019 IDP.

D. Are there Filing Requirements That are Not Informative and/or Should be Deleted or Modified, and why?

In this section, we address parties' suggested changes to current requirements, other than shifting to a biennial cadence, which we address in Section I.E below.

1. Narrative Explaining Differences in the Current vs. Previous IDP Filing

The Department requested the Company to respond to whether it believes it would be reasonable for the Company to provide a narrative explanation of the differences between the new IDP filing and the previous IDP filing to help focus stakeholder review.

Although we appreciate the Department's goal of providing focus to the IDP and acknowledge that some of the content in the Company's 2019 IDP is the same as in the 2018 IDP, we do not believe it is reasonable to require a narrative that comprehensively explains all that might be different from the last IDP. The IDP requirements are extensive, and we take substantial time to meet all of them. Our 2019 IDP was nearly 1,600 pages long, which reflects both the robust initial and mid-2019 requirements the Commission established for the IDP and any advanced grid certification requests. Because we submitted the IDP concurrently with a general rate case petition, we provided an even more robust record – including all advanced grid investment cost recovery request information required in the Commission's September 27, 2019 Order in Docket E002/M-17-797. The length and content of our 2019 IDP also reflects the care the Company took in meeting the spirit and letter of those requirements.

The IDP already contains an executive summary of the highlights of the IDP and of the Company's advanced grid strategy. We also already do a compliance matrix – and we map the location of all content to the Commission's advanced grid principles. If parties believe the IDP is too lengthy and contains unnecessary information, we suggest they identify and communicate to the Commission a narrower set of information they believe is essential to their analysis that the Commission can weigh and consider in terms of setting future IDP requirements. However, we believe it is reasonable to expect parties read the IDP in the context of the Commission's requirements, which we understand are intended to give a comprehensive look at our distribution business.

2. Distribution System Performance Information

ELPC and Vote Solar requested more information about the Company's reliability performance and spending, and suggested adding several specific requirements to future IDPs toward locational reliability and equity.

Starting at page 124, we provide and discuss our system-wide reliability indices and our reliability management program. We also cite to our Quality of Service Tariff and our annual service quality report that all utilities file in compliance with Minnesota Rules. We believe the primary source for reporting our distribution performance should remain the Company's annual service quality filings, and/or as prescribed in the currently pending Performance-Based Ratemaking proceeding in Docket No. E002/CI-17-401. As such, we believe no change to IDP requirements with respect to reliability performance is necessary or appropriate at this time.

Specifically with respect to the ELPC/VS recommendations regarding adding locational reliability and equity reporting requirements to the IDP, we note these topics are being addressed in a different Commission proceeding. Reporting on locational reliability and equity in reliability was originally identified in parties' feedback in our Performance Based Ratemaking proceeding, referenced above. Ultimately, the Commission moved this issue from that proceeding to the Company's annual electric service quality report, which we believe is a more appropriate forum than the IDP to examine those issues.[1]

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[1] The Order in Docket No. E002/CI-17-401 has not been issued, this is based upon our understanding of the verbal decision.

Commission Staff has provided a proposal in our 2019 Electric Service Quality Annual Report,[2] which is awaiting Commission Notice for Comment. Staff's proposal includes a map with feeder level reliability detail and requests specific data points by feeder and for all sustained outages. Finally, we note that our current Electric Service Quality Annual Reports already provide some information on locational reliability:

- A list of the 25 worst performing feeders in each of our four Minnesota work centers, along with data points required by Minn. R. 7826.0700 subp. 2, section H – and additional info identified in consultation with Commission Staff.
- State-wide and metro area maps providing system average interruption duration index (SAIDI) and customers experiencing multiple interruptions (CEMI) data by feeder.

Given this already robust service quality reporting framework and the nascent nature of developing additional locational and equity reliability metrics and reporting, we believe it is appropriate at this time for the annual service quality filings to be the primary source for distribution system performance information.

3. Expand Discussion Regarding Smart Inverters

ELPC/VS asked the Company to explain when and why it expects the need for utility control over DERs to arise at projected future levels of DER penetration, and also recommended that the Commission modify filing requirement 3.C.3. for future IDPs as follows:

> Provide a discussion of whether external control through utility communication with smart inverters, above and beyond the autonomous functions associated with smart inverters, would be necessary to ensure the safe and reliable operation of the grid at the listed penetration levels.

We provide the requested discussion in Section III.D below and note that we are committed to implementing smart inverter settings as they become available and where it makes sense for our system. In future IDPs, we are happy to provide an overview of smart inverter developments and their role in efficiently integrating DER to maximize customer and grid benefits. We do not believe however, it is necessary

[2] Docket No. E002/M-19-261, January 28, 2020 Order, Order Point 11 and Attachment C to the Order.

to get more prescriptive with the requirements around smart inverters for future IDPs, as we discuss and explain in Section III.D below.

4. *Parameters for Future Stakeholder Meetings*

Several parties positively referenced the Company's stakeholder engagement efforts and stated appreciation that the Company had reflected stakeholder feedback in its IDP. We appreciate the level of engagement and input stakeholders provided to our 2019 IDP, and recognition of our efforts to both gather and incorporate stakeholder feedback. That said and pointing to some of our stakeholder efforts leading up to our 2019 IDP, the Interstate Renewable Energy Council (IREC) suggested the Commission order the Company to make all future IDP meetings open to any individual or party.

We believe there is no one-size-fits-all approach to stakeholder engagement, and do not believe it is necessary for the Commission to take action on this suggestion. We have made every effort to engage a broad set of stakeholders and perspectives in each of our 2018 and 2019 IDPs, as broadly recognized by a number of parties. Specific to IREC's comments, we worked with Great Plains Institute (GPI) to plan and facilitate our 2018 and 2019 IDP stakeholder workshops. In consultation with GPI, in the wake of our 2018 IDP and leading up to our 2019 IDP, we planned and held two broad workshops and two focused workshops on specific topics of interest by commenting parties – non-wires analysis and cost-benefit-analysis of grid modernization investments.[3] IREC registered to attend our December 12, 2018 general session, which provided an overview and highlights of the 2018 IDP, and made our business area experts available for questions and feedback on any and all content. GPI directly invited over 400 individuals (and included it in the GPI newsletter, which goes to thousands more) to our September 25, 2019 general session. This session provided an overview of key aspects of the 2019 IDP, including our 5-year budgets, DER forecasts, advanced grid plans, and our five-year action plan; we

[3] December 12, 2018, April 10, 2019; May 17, 2019; September 25, 2019.

again had several of our business area experts present and otherwise in attendance to answer questions and respond to feedback.[4]

Our goal for the two topical workshops was to foster a deeper understanding of stakeholder perspectives on the two primary common areas of interest, in order to incorporate the feedback into our next IDP. In consultation with GPI, one of the lessons learned from our 2018 IDP stakeholder engagement process was that hosting only large, open-to-the-public meetings did not allow ample time for the parties who would eventually submit comments on the IDP filing to fully flesh out their feedback in meetings – limiting the effectiveness of the stakeholder engagement process in terms of refining the filing in advance of filing and the formal comment and reply periods. With these factors in mind, GPI convened two meetings with only the parties who had submitted comments to the Commission in response to the Company's 2018 IDP filing, in order to allow a more focused conversation, followed later by a third meeting that was open to the public.

IDPs are filed as miscellaneous dockets and available for any party to participate; IREC chose to not participate in our 2018 IDP. IREC's Comments on our 2019 IDP were limited to commentary on our hosting capacity analysis, which is docketed in a separate proceeding (with the exception of the comment related to future stakeholder engagement). IREC was also invited and thus had the opportunity to participate and offer feedback in each of the two general IDP workshops leading up to the 2019 IDP. In summary, we believe IREC has had ample opportunity to participate in and offer feedback on both our 2018 and 2019 IDPs, and has not in any way been limited by our choice to go beyond the Commission's required level of stakeholder engagement and more deeply engage with stakeholders interested in certain aspects of the IDP.

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[4] This content is also compliant with IDP Requirement No. 2 as established in Docket No. E002/M-18-251, as follows:

> **2. Stakeholder Meeting(s):** Xcel should hold at least one stakeholder meeting prior to the November 1 filing of the Company's MN-IDP to obtain input from the public. The stakeholder meeting should occur in a manner timely enough to ensure input can be incorporated into the November 1 MN-IDP filing as deemed appropriate by the utility. At a minimum, Xcel should seek to solicit input from stakeholders on the following MN-IDP topics: (1) the load and distributed energy resources (DER) forecasts; (2) proposed 5-year distribution system investments, (3) anticipated capabilities of system investments and customer benefits derived from proposed actions in the next 5-years; including, consistency with the Commission's Planning Objectives (see above), and (4) any other relevant areas proposed in the MN-IDP. Following the November 1 filing, the Commission will issue a notice of comment period. If deemed appropriate by staff, an additional stakeholder meeting may be held in combination with the comment period to solicit input.

In summary, we agree with IREC that there is value in broad stakeholder input – and that is exactly what we have done with both our 2018 and 2019 IDPs. We also believe there are times when it is not only reasonable but appropriate and effective to engage a narrower set of stakeholders that have taken time to get involved on relevant issues and/or have specific expertise to offer. This is specifically the case with our 2019 IDP. There is no need for the Commission to take action on this suggestion. The Company has demonstrated its commitment to gathering and incorporating both broad and focused input from stakeholders and is committed to continue that practice.

E. Should the Commission Accept Xcel Energy's Request to File the Next IDP no Later than November 1, 2021? Should the Commission Move from an Annual to Biennial IDP filing for the Company Going Forward?

Of parties that commented on this issue, all recommended the Commission approve the Company's request to move its IDP cadence to biennial, with the Company's next report due November 1, 2021. Some parties also suggested certain limited aspects of the IDP would be valuable to remain on an annual filing basis. We appreciate parties' support for our request, and as also expressed in our 2019 IDP, we believe this would be the single most impactful change the Commission could make. We continue to believe the current annual filing requirement does not afford time for the Company to reflect on its processes, stakeholder feedback, the Commission's planning objectives, and any changes the Commission may make to future IDP requirements; it also does not allow the Company to make meaningful progress on its objectives. With the additional support of stakeholders in Comments, we respectfully request the Commission set the Company's next IDP filing date to November 1, 2021 and biennially afterward. If the Commission believes a limited annual update is necessary, the Company is open to certain annual updates as discussed below:

1. Hosting Capacity Analysis

CEEM suggested that we should continue to submit hosting capacity analysis (HCA) reports annually. We clarify that we are subject to Order requirements in the hosting capacity analysis proceedings to submit those reports annually, so a change in IDP cadence would have no effect on HCA.

2. Baseline Financial Data and Non-Wires Alternatives Analysis

The Department requested the Company to explain in our Reply whether providing the baseline financial data required by *IDP Requirements 3.A.26-30* and the NWA analysis required by *IDP Requirements E.1-2* is feasible on an annual basis. We note that these are two of the IDP components that require the most effort – particularly the NWA analysis. The Department did not suggest any procedure or process around providing this information annually, so we would ask the Department to provide more context to this request in Supplemental Comments. If the Commission determines a limited annual filing is necessary, we request the Commission to also authorize the Company to request certification of advanced grid investments on an annual basis. That said, we discuss each of the Department's requests.

We prepare our budgets on an annual basis, and could convert that into the IDP financial information categories and submit it in even-numbered years. However, the current IDP requirements for financial information include the provision of both forward and historic 5-year views, so no information would be lost by maintaining a biennial cadence for this information. Similarly with NWA analysis, it is part of our annual system planning process. We would not however, create a report or summary of that analysis like we currently do with the IDP. That said, doing so is feasible, but, it would be important to understand how the Department contemplates this information being used, so we can more fully assess what would be involved and thus whether we believe the Department's request is reasonable.

Finally, due to the rapid pace and changes underway with respect to grid advancement, we have previously requested the ability to submit advanced grid certification requests on an annual basis.[5] Pending further contextual information from the Department on the financial and NWA analysis information, if the Commission agrees to a biennial IDP cadence and that limited information is needed in non-IDP (even-numbered) years, we respectfully request the Commission to also authorize the Company to submit advanced grid certification requests in those years.

3. Grid Modernization Progress Reporting

Fresh Energy suggested parties may benefit from regular reporting on our progress implementing grid modernization projects that evolve from the IDP, such as AGIS. While not tied to whether the Commission should approve our request for a biennial IDP filing cadence, CUB also proposed reporting around our advanced grid investments. We anticipated the Commission and stakeholders would want and

[5] *See* Xcel Energy Biennial Grid Modernization Report, Docket No. E002/M-17-776 (November 1, 2017); Xcel Energy Reply Comments beginning at page 18 (February 26, 2018); and, the Commission's August 7, 2018 Order, Ordering Point No. 11, which was permissive for the Company to file a grid modernization report and certification request the following year in 2018 (an even-numbered year).

expect reporting on our progress and the value the advanced grid is bringing to customers. We discussed this starting at page 163 of the IDP and outlined proposed metrics and reporting associated with our AGIS certification request in Schedule 11 of Mr. Gersack's testimony (IDP Attachment M1, page 301).

We note that we have an established AGIS reporting framework in our Public Service Company of Colorado (PSCo) operating company that the Commission may want to also consider for Minnesota, should it certify our proposed advanced grid investments. That reporting however, is specific to the AGIS investments approved in the certificate of public convenience and necessity (CPCN) proceeding, which includes AMI, FAN (Wi-SUN component) and IVVO. We submit two reports each year of the project, as follows:

(1) In October, we submit a forecast report for the upcoming year, which includes a full-term business plan, including the scope of work; forecasted O&M and capital expenditures for the upcoming year; parent project numbers including details of additions and closings of parent project numbers; and planning and implementation of customer education surrounding the CPCN projects.

(2) In May, we submit an actuals report for the previous year, which includes a business plan overview of the previous year's progression; project milestones and overall project status; planning and implementation of customer education; the final cost per AMI meter, excluding installation and taxes, and the final cost per AMI meter including installation and taxes; the total AMI meters installed each year; O&M and actual capital spend for the previous calendar year; a comparison of the forecasted spend to the actual O&M and capital spend; a comparison of total spend to the overall budget; and a cost summary.

4. NWA Pilot

If the Company does not file its next IDP until 2021, the City of Minneapolis recommended the Company be required to propose a NWA pilot by November 1, 2020. Developing and proposing a NWA pilot by November 1, 2020 would be an aggressive timeline and we believe it may not be what the City is hoping for. We met with City representatives April 9, 2020 to discuss other Xcel Energy work and projects planned and ongoing within the City and to better understand the type of NWA project(s) they are interested in pursuing. We will be scheduling an additional meeting to further discuss NWA projects with the City within the next two weeks.

F. Are There Other Issues or Concerns Related to This Matter?

1. Community Climate Goals

The City of Minneapolis recommended the Company be required to consider the energy and climate goals of the Minnesota communities it serves along with customer preference trends when responding to the IDP Requirement 3.A.32 and the Commission's July 2019 IDP Order Point No. 7 in future IDPs – both of which relate to DER forecasting.[6] The City notes that it has local solar energy generation and equity goals and the utility is a critical partner in achieving its goals.

Xcel Energy works closely with the communities and customers it serves. We serve almost 450 communities[7] in Minnesota, each with differing goals and objectives. It is our responsibility to treat each community equitably while still working with them to help them reach their goals. We are proud of the initiatives we have undertaken as a Company to help our communities move forward with their climate goals. These include in-depth collaborative efforts such as the Minneapolis Clean Energy Partnership,[8] where we are currently working with the City on a number of projects. Some of these include:

- Developing a low income community solar garden on a city facility,
- Focused energy efficiency efforts on the lowest performing benchmarked commercial buildings,
- Focused energy efficiency efforts in city facilities to help them reach their energy reduction goals,
- Creating tools to support the City on their energy disclosure policies – including the building benchmarking tool, and
- Engaging the city in an electric vehicle fleet infrastructure installation pilot program.

While the Minneapolis Clean Energy Partnership is an extensive collaboration with dedicated staff from each Partner, we offer other options for our communities that help us to actively engage and often aid them in their climate goal development and

[6] IDP Requirement 3.A.32 requires the following: *Information on areas of existing or forecasted high DER penetration. Include definition and rational for what the Company considers "high" DER penetration;* July 2019 Order Point No. 7: *Xcel shall make the development of enhanced load and DER forecasting capabilities, as well as, tracking and updating of actual feeder daytime minimum loads, a priority in 2019 and include a detailed description of its progress in the Company's 2019 IDP.*
[7] Communities include cities, townships, villages, and counties.
[8] https://mplscleanenergypartnership.org/

implementation. Our Partners in Energy[9] program provides communities free services to develop an energy plan and assistance with implementing that plan over a two-year period. Each community has its own unique energy needs and priorities, and our Partners in Energy tailors its services to complement each community's vision. Since 2014 we have worked with 25 communities in Minnesota providing facilitated planning, project management and support services to participating communities.

With each of our 450 communities expressing different and sometimes unique priorities, our Community Relations and Account Managers actively engage with them to explore product offerings that will decrease energy consumption, decrease carbon emissions, and increase renewable energy. For example, our award-winning energy efficiency programs have consistently run for over 35 years. These programs offer energy saving and carbon reduction opportunities for all customers including: residential, low income, multi-family, and commercial. In 2019 we began offering our Certified Renewable Percentage (CRP), which allows customers to count the renewable energy portion of electricity delivered to them through our regular energy mix toward their energy goals. Our Solar*Rewards program offers incentivized payments to the customer for solar produced through rooftop solar in exchange for the renewable attributes or Renewable Energy Certificates (RECs). The Company also hosts one of the largest community solar garden programs in the country.

In summary, we have a long history of constructive relationships with the communities we serve, which includes helping them achieve climate and other energy goals. No change to the IDP requirements is necessary, as we are already factoring public policies and goals into our planning.

2. Working with our Communities During AGIS Implementation

In response to a request at the March 5, 2020 Presentation for information about how we plan to work with our communities as we implement AGIS, we provide the following information.

Working with the communities we serve – including local leaders, community groups and consumer advocacy groups – is an essential part of our advanced grid initiative. As 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, we will work closely

[9] https://www.xcelenergy.com/working_with_us/municipalities/partners_in_energy

with our communities throughout the planning and deployment process. We will also equip communities to answer questions and share information with their businesses and residents.

Communicating with community leaders and elected officials. We have a long track record of working closely with the 55 Minnesota Counties and 426 Minnesota Cities we serve. Our dedicated Community Relations Managers manage relationships with staff and elected officials in all communities working through various operational issues related to construction projects, permitting, rights-of-way, franchise agreements, vegetation management, facility relocations, and more. Close collaboration with community leaders, elected officials, and City/County staffs will be essential during each phase of our advanced grid plans. We will continue to convene in-person meetings with Mayors, Councilmembers, County Board Members and various local neighborhood organizations to share progress and receive feedback and closely coordinate with the various permitting authorities in City and County Public Works and Zoning departments. In addition, we will work closely with communities to understand concentrations of diverse communities and language consideration for particular communities and neighborhoods to ensure that communications are being translated as needed into Spanish, Hmong, and Somali.

Equipping local leaders and community groups with information. We recognize that communities can be powerful sources of information for residents and businesses, so we will equip local governments and community organizations with information and tools to share information and answer questions. We will collaborate with local stakeholders, including city staff, council members, neighbor organizations, home owners' associations, local nonprofits and others to share information at neighborhood events and through their own channels, including on websites and social media and in newsletters and emails. These relationships will be especially helpful in reaching non-English-speaking customers, and customers on fixed or low incomes.

3. Distribution Investments in the City of Minneapolis

The City of Minneapolis expressed a concern in Comments about the number of projects that exceed $2 million that the Company has in its 5-year budget for Minneapolis, given several of its priorities that might necessitate Xcel Energy work in the City. Our understanding of this comment is that it is based on an examination of only the projects included in the scope of our NWA analysis, which is a limited set of projects in relation to our overall 5-year budget and plans. We confirm that we currently have 27 projects planned or underway in the City of Minneapolis; seven of these are Mandates, five are Asset Health, and the remaining 15 are Capacity-related.

While none of the currently-funded Minneapolis projects meet the IDP criteria for NWA analysis, we are open to working with the city on pursuing a NWA pilot, as noted in Section I.E.5 above.

4. *Company Incremental System Investment Initiative*

Additionally, we note our appreciation for parties' interest in our Incremental System Investment (ISI) initiative. While we did not seek any Commission action in the IDP, we believe this is an important issue and as such included it in our budgets and included substantial discussion about it in the IDP. This initiative will have important resilience benefits for our system and significant economic impacts. We are prepared to more broadly initiate the ISI if the Commission agrees and wants to separately pursue or otherwise take up the matter.

II. COMMISSION NOTICE QUESTIONS – AGIS CERTIFICATION REQUEST

A. Should the Commission approve, modify, or deny certification of the following investments which are components of Xcel Energy's Advanced Grid Intelligence and Security (AGIS) Initiative at this time.

1. *Advanced Metering Infrastructure (AMI) and Field Area Network (FAN)*

IPS Solar observes that an approved roll-out of the Advanced Metering Infrastructure (AMI) would be particularly helpful for demand charge rate payers that need the sub-hourly load data to determine the extent of bill savings from peak shaving with on-site solar plus storage systems. This load profile information is also important for demand charge customers who are trying to decrease the amount of fossil fuels used during peak curtailment events and for Xcel to achieve a carbon free grid.

Fresh Energy stated its support for our proposed FAN investment, its belief that the Company satisfied the content requirements in the Commission's August 7, 2018 Order, and that we demonstrated our proposed FAN investment will advance multiple grid modernization goals by improving communications between the utility, customers, and grid infrastructure. Fresh Energy also expressed its full support for our approach of using a single communications network for both AMI and intelligent grid devices – saying, should the Commission choose to make a certification determination at this time, Fresh Energy recommends that the Commission approve the Company's certification request for FAN.

CUB suggests the Commission direct the Company to move forward with our proposed AGIS Initiative and specifically AMI and FAN. Despite clear statutory and therefore public policy support for recovery of certified advanced grid investments through a rider, CUB does not support certification due to its belief that AGIS investments should not be recovered through a Rider. Rider recovery of certified advanced grid investments is permitted under Minnesota Statute, which we more fully address separately in this Reply. CUB also asserts that if the Commission certifies the AGIS investments, rider recovery should be subject to certain consumer protections. As also discussed elsewhere in this Reply, any conditions on cost recovery are best addressed in a cost recovery proceeding – not a request for certification. As such, the Commission should reject CUB's suggested conditions until such a proceeding.

2. *Fault Location, Isolation, and Service Restoration (FLISR)*

Combined with ADMS and AMI, the addition of FLISR capabilities gained through more field devices and automation allows utilities to make more technically informed decisions about how to isolate, sectionalize and restore power during broader or extended outage situations. FLISR has both quantifiable benefits and non-quantifiable benefits. The most significant quantifiable benefit of FLISR is improved reliability for our customers, which we estimated in two parts: (1) customer savings due to a reduction in customer minutes out (CMO); and (2) patrol time savings due to the need to patrol a smaller portion of the system to find faults. From an operations perspective, the FLISR capabilities support a more resilient grid by helping us make more informed decisions during broader or extended outages when many decisions need to be made quickly. In these situations, which include extreme weather events or pandemic situations where crews are limited, better information and more remote control allows us to restore power and manage the system more efficiently. This is a benefit to customers that is difficult to quantify.

We agree with the Department's observation that the intent of FLISR is to facilitate a more timely and efficient restoration of service – which it further observes can fulfill the intent of the Commission's fourth Planning Objective. In making this observation, the Department also noted it is not in a position to evaluate the costs and benefits of our proposal at this time, however without specifying the reasons. We provided substantial information about FLISR's costs and benefits in our filing. We are happy to provide additional information if that would be helpful to the Department's evaluation, but need the Department to identify what it needs to evaluate our proposal.

Fresh Energy recommended that the Commission deny our certification request for FLISR, saying the Company has not sufficiently demonstrated the need for significant reliability improvement, but also requested we provide additional information. We respond to the specifics of Fresh Energy's Comments below, and additionally note that estimating the benefits of any new technology will not be perfect.

a. The Company Properly Applied the LBNL ICE Study

The Company maintains that the FLISR customer benefit we have estimated is fairly represented. We developed an internal tool that is based on the 2015 Lawrence Berkeley National Laboratory (LBNL) Study that was the foundation for the 2015 LBNL calculator. We point out that there are many variables required to calculate the benefit and that we used conservative estimates to avoid overstating the benefit:

1) *Escalation of value*: We chose to not escalate outage values, even at the rate of inflation (as suggested by LBNL). We did however escalate the cost of equipment at the inflation rate.
2) *Customer class allocation*: We chose to assign the category of "small" C&I to all C&I customers. This results in a more conservative estimation of benefits, since large C&I customers are estimated to have a larger financial impact from outages.
3) *Patrol time*: We chose to assign a conservative (10 minute) reduction in patrol time because we did not have hard data to validate a more probabilistic benefit.
4) *Frequency of successful operation*: We chose to attribute the benefit of only 75 percent of FLISR opportunities. We think this will prove conservative. This attribute is used to acknowledge that FLISR availability will be less than 100 percent due factors such as temporary reconfigurations for maintenance or previous system modifications during a storm.
5) *Revenue loss assumptions*: The Company applied an 18 percent reduction to the total cost values given by LBNL for all commercial customers. LBNL does not specify whether the impact reported by the companies participating in the survey included losses before or after taxes, thus we took the conservative view and assumed that the responses given by the participants included total revenue loss (including tax margins). The 18 percent reduction represents that conservative assumption.
6) *Population growth*. We kept growth flat for this analysis.

As we discuss further below, we are working on an analysis of sensitivities of these attributes and the estimated effects of momentary events and will provide more information in our Supplemental Reply Comments.

b. The Effects of Momentary Outages are Reasonably Represented in our Estimated Benefits

Fresh Energy points to the Company's explanation that FLISR will convert a portion of sustained interruptions to momentary interruptions for some customers and the fact that momentary outages can be disruptive, particularly to commercial customers.

First, it should be understood that FLISR capabilities allow for us to most frequently restore service to approximately two-thirds of customers affected by an outage within minutes of a fault – resulting in a momentary outage for these customers instead of a sustained outage. Further, FLISR will not increase the total number of interruption events (momentary plus sustained). Rather, many customers that would have experienced a sustained interruption will *instead* experience no outage or only a momentary interruption.

We recognize that, while a momentary outage can be disruptive to power-quality sensitive customers, for most customers, a momentary outage is much less disruptive than a sustained feeder-level outage, which has ranged on average from around 80 minutes during a mild weather year to over 300 minutes during a stormy year for customers in Minnesota. That said, we did not initially attempt to quantify the effects of replacing a sustained outage by a momentary, because customer abilities to ride through temporary events can vary greatly. Beyond that, FLISR is one of the most cost-effective solutions for improving reliability for customers because it comprehensively addresses outages for *all* reasons, compared to other reliability improvement projects that focus on a single type of outage, such as cable failures.

As we have explained, our feeders are designed to have segments – most frequently three in Minnesota – and our FLISR scheme works to avoid a sustained outage for all segments except the segment directly impacted by the fault. With FLISR, if a fault occurs at the end of a feeder, it is likely that no customers would experience a momentary outage, and FLISR would act to prevent a sustained outage for all but the final segment of the feeder that directly experienced the fault. This is because our preferred design utilizes *reclosers* rather than *switches*, which enable this improved capability. If the fault were to occur near the substation/at the beginning of the feeder, two of the three segments might experience a momentary but be spared a sustained outage – and only the first segment would experience a sustained outage.

An analysis that attempts to estimate the benefits of a new technology that is interlaced with customer perceptions of power disruptions is complex and requires many assumptions. As noted above, we are working on a sensitivity analysis to complement the analysis included in our IDP, but were unable to complete it in time to include with this Reply. We intend this analysis to illustrate the variations in benefits based on ICE calculator attributes noted above, along with momentary considerations – and are planning to include it in Supplemental Reply Comments. We caution however, that such an analysis may imply a false sense of precision. We believe it is reasonable to rely on the Company's current conservative benefits estimate, but plan to provide this information to be responsive to Fresh Energy's request in Comments for a further analysis of FLISR benefits.

We note that we also provide as Attachment B to this Reply, historical SAIDI and SAIFI information for the 206 circuits that are part of our FLISR proposal for each year 2015-2019 as requested by Fresh Energy.

c. Industry Benchmarking Indices may not Fully Portray the Customer Experience

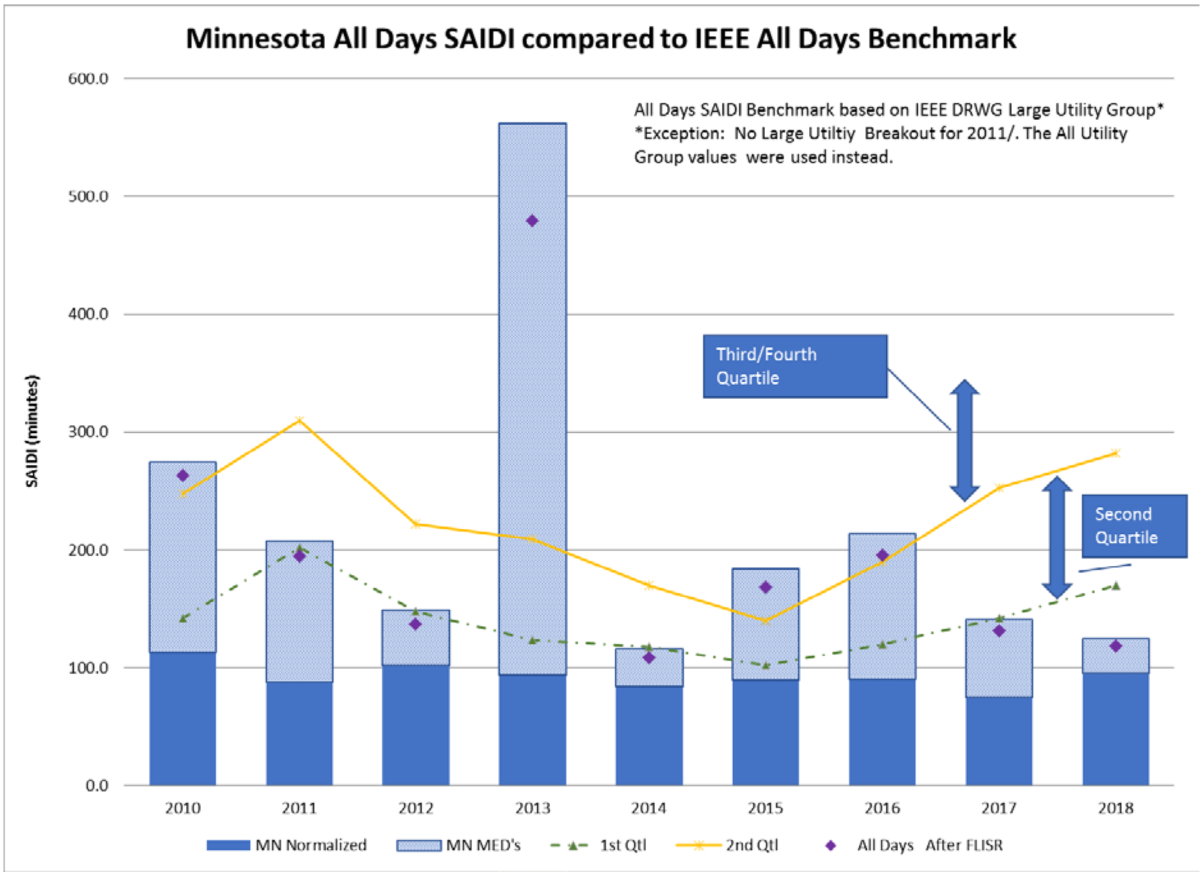
Fresh Energy supports its recommendation that the Commission deny our proposed FLISR initiative by saying that the Company's reliability already favorably compares to the industry, so no improvement from FLISR is necessary. We disagree for two primary reasons, which we discuss below:
(1) Industry indices that are based on storm-normalized information are not reflective of the actual customer experience; and
(2) Changing customer demands, including DER adoption and increased electrification will make the impact of outages less tolerable and require the Company and the industry as a whole to continuously find opportunities to improve reliability.

Normalized Industry Indices do not Depict the Customer Experience. A FLISR solution improves reliability regardless of the cause of the outage, making it an ideal solution to reduce outages *every day*. We benchmark our performance to other utilities using the IEEE-1366 methodology, which removes Major Event Days (e.g. impacts of heavy storms) from the resulting SAIDI and SAIFI results. So, the benchmarks that Fresh Energy references do not reflect the customer experience.

The IEEE normalized benchmarks are intended to measure and compare utilities' performance over time and relative to each other, so are "normalized" to remove the effects of Major Event Days. This enhances the focus on reliability events and performance that is more within a utility's control; it does not reflect customers' experience. Customers only care that they experienced an outage; whether that outage occurred during a storm or some other major event is not relevant. We believe the total customer reliability experience is important, and therefore evaluated the benefits of our FLISR proposal from the perspective of outages on *all days*.

We summarize the storm-normalized and all-day SAIDI values for the State of Minnesota below to demonstrate the important difference in the customers' experience. We also note the all days IEEE benchmarking quartiles.

Figure 1: Minnesota All Days SAIDI compared to IEEE All Days Benchmark



Changing Customer Demands. One of the changing customer demands will be the impact of electrification. Customers will be increasingly dependent on an uninterrupted supply of power to recharge their electric vehicles or run an electric water heater during all types of weather – including during storms, or other major events that may be more likely to interrupt electric service than a typical day. What customers have felt is adequate service in the past will not be so in the future, and outages may have more disruptive impacts to customers' crucial needs. In addition, as more utilities modernize their grids to improve their operations, we do not expect the current reliability indices and quartile performance to remain stagnant.

d. The FLISR Project is Driven by Data, not Geography

Finally, in response to Fresh Energy's observation that a large percentage of FLISR deployment is focused in the metro area, we clarify that the FLISR initiative we proposed is driven by actual system outage data, not geography. FLISR improves reliability only from *mainline* outage events on feeders with existing strong ties to adjacent feeders; this is what allows for FLISR's automated switching. The metro area has a higher percentage of CMO attributable to mainline events – and due to its population density, is designed with comparatively stronger feeder ties – and therefore is the best candidate for a FLISR program. This compares to non-metro areas where *tap* level events comprise a higher percentage of CMO, and often have weaker feeder ties due to the lower population density.

Nonetheless, the Company's balanced approach does deploy FLISR in non-metro areas when possible. Additionally, as we progress through the 10-year deployment, we expect to make adjustments and increase investments in these areas as performance varies over time. Finally, regardless of geographic location, we believe all customers will indirectly benefit from FLISR through our ability to more quickly deploy crews to priority restoration work during major events, which will result in an overall improvement in restoration times for all customers.

e. FLISR Prepares us for the Future

FLISR can also automatically take into account distribution system variables that are becoming increasingly complex to handle manually. The increased amount of DER on the system makes the isolation and grid reconfiguration required for restoring power and planning switching more complex. In high PV penetration situations, solar production can offset a significant part of the load required for the feeder. Upon restoration, DER inverters do not re-start for five minutes, based on inverter settings. Therefore, at times the amount of power needed is more than when solar is being produced. The FLISR system considers solar production in a given switching scenario, so that the total feeder load of system when solar is not present is calculated—thereby avoiding local system overloads.

3. Integrated Volt-Var Optimization (IVVO)

Fresh Energy expressed enthusiasm and support for our proposed IVVO investment, but conditioned their support on a Company commitment to achieving a minimum 1.5 percent reduction in customer energy consumption. While we share the hope that IVVO will provide 1.5 percent energy savings, we do not have data to support that this level is achievable. Our test in Bloomington, Minnesota (described in IDP

Attachment M2, page 165) did not provide sufficient data that we can extrapolate and draw conclusively that we will be able to achieve an average of 1.5 percent savings across our proposed deployment area. We note additionally that we continue to believe the results in Minnesota are unlikely to achieve the same level of savings as our PSCo operating company affiliate has experienced due to the factors discussed in page 167 of the aforementioned document.

Fresh Energy additionally recommended the Commission require reporting of electrical loss savings and our proposed 0.7 percent system peak demand savings. As we discuss otherwise in this Reply, we have committed and proposed reporting associated with our AGIS proposal. With respect to IVVO specifically, we note that we expect to have the capabilities to report on the associated energy and demand savings. Pending Commission certification of an IVVO project for Minnesota, we will outline the technical assumptions associated with our calculations of system demand reductions, line losses, and energy reductions associated with the approved project.

B. Should the Commission Certify the Advanced Distribution Planning Tool at this time?

As explained in our filing, our current system planning tool is obsolete and must be replaced. The LoadSEER tool we selected will allow the Company to advance its forecasting and scenario analysis to improve its planning outcomes and to more fully comply with the Commission's IDP requirements. It is a foundational component of advancing our forecasting and planning capabilities to support a modern grid. As such, it is eligible for certification by the Commission under Minn. Stat. 216B.2425. We respectfully request the Commission certify the APT, allowing the Company to seek cost recovery in a subsequent cost-recovery filing.

Fresh Energy strongly supports our implementation of the proposed APT and noted its familiarity with LoadSEER from Integral Analytics and considers it to be a state-of the-art tool for load and DER forecasting. Fresh Energy further observes that this tool will be a major upgrade to the Company's distribution planning capabilities. Fresh Energy recommends that the Commission approve Xcel Energy's certification request for the APT, should the Commission choose to make a certification determination at this time.

The Department's Comments refer to the APT as "conceptual and not a discrete project or investment." This is not the case. As discussed in Appendix D1 of our filing, after a thorough solicitation and assessment process, we explained that we had selected a preferred advanced distribution planning tool and were in the advanced stages of procuring that tool as of November 1, 2019. We also explained that we had already begun to prepare our internal systems and processes to implement the APT – expecting 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. Noting it as an ambitious timeline, we explained that it would allow us to begin using the APT in our distribution planning processes stating in 2020-2021. Since filing our IDP, we selected LoadSEER (as stated in our January 23, 2020 response to Fresh Energy Information Request No. 21, sent to the Department as part of our response to DOC Information Request No. 1 on February 3, 2020), and clarify that we remain on track to implement it for use with our Fall 2020 system planning process.

Finally, without stating whether it supports the APT, the City of Minneapolis requested the Company to provide more clarity regarding the proposed functionality and use of the APT to support our NWA process. As discussed in the IDP, the APT tool will equip our system planners with enhanced capabilities to consider DER adoption scenarios and NWA in the analyses we perform to ascertain the best way to meet system capacity needs. 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 more valuable and harder to predict data points.

With more customers adopting DER and beneficial electrification, peak loading on a specific feeder may result in different levels of load, or may occur 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 and the types of customers served. However, as DER are often localized to a specific endpoint, 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.

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.

APT can further assist in the effort of assessing NWAs by simulating the addition of certain types of DER on a feeder as a forecast scenario. By generating an hourly load forecast, the forecast that is created with this NWA DER scenario can help predict the total number of hours per year during which the load on a feeder exceeds a particular threshold. This can help validate the efficacy of the NWA being studied.

C. What, if anything, should the Commission set as conditions or clarify if granting certification of these distribution projects?

Several parties suggested various levels of review of the costs associated with our AGIS and APT investments prior to certification. As the Commission has previously ordered, certification is not a determination of prudency, and a thorough review of costs for certified projects occurs as part of a subsequent cost recovery process. With respect to other conditions parties suggested the Commission apply to a certification determination, which are generally in the area of specific products and services or rate plans, we generally respond that it is too early for the Commission to broadly set conditions for what is presently, a thoroughly-scoped, but still preliminary plan.

While we are committed to the customer products and services outlined in our customer strategy, many are dependent on AMI and/or other AGIS components and may be otherwise interrelated with each other. Without a clear signal from the Commission from this proceeding, we may not proceed with our AGIS initiative as it is proposed in our 2019 IDP. Therefore, we would also reassess our customer strategy, potential products and services, and any associated timelines. That said, we respond to parties' comments suggesting a certification determination should be conditioned on specific product and service commitments.

1. Advanced Rate Design Roadmap

As a general matter, we believe that rate design is best and most comprehensively addressed in the context of either a general rate case, where regulators review a complete record and consider input from experts and stakeholders in a ratemaking proceeding, or alternatively, in a proceeding otherwise dedicated to rate-design topics. In our view, rate-design exploration is out of scope in an integrated distribution planning proceeding.

While we do not believe the IDP proceeding is the appropriate docket to explore rate design, we note that the Company is nonetheless enthusiastically pursuing advanced rate design in a number of other proceedings. The Company will soon launch its Residential Time of Use Rate Design Pilot program, Flex Pricing, and begin a two-year study of the influence of price signals and other information on customer energy use.[10] The pilot's rate design is based on an innovative approach, the Cost Duration Model, developed specifically to enable the rate-design study. The results of the pilot will help inform a future state, which may see the more sophisticated rate design in use more broadly among the Residential class.

In addition to studying the new rate design among residential customers in the Flex Pricing pilot, the Company has also proposed an expanded vehicle charging service for customers with electric vehicles (EVs) featuring advanced rate design and price signals to encourage off-peak energy usage.[11] Further, the Company has very recently filed a proposal to refresh its General Time of Use Service rates for the commercial and industrial class.[12] The Commission has invited other rate-design proposals into this dedicated proceeding and the Company looks forward to both receiving and providing feedback in this process.[13]

With respect to demand response (DR), we have already demonstrated our commitment to achieve an additional 400 MW by 2023 in our July 2019 IRP filing in Docket No. E002/RP-19-368. In addition to engaging stakeholders through the Demand Response Potential Study (provided by The Brattle Group) and development of our resultant plans, we engaged stakeholders on this as part of our IRP. Further development of our DR action plan will continue both through the ongoing IRP, our CIP proceedings, and further Commission filings, none of which would benefit from a pause to develop an Advanced Rate Design Roadmap. We note that we discuss how we incorporated the results of the Potential Study into our AGIS cost-benefit analysis in Section IV.A below.

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[10] See the March 18, 2020 Letter in Docket E002/M-17-775 informing the Commission that the launch of the pilot program is postponed due to the COVID-19 outbreak.
[11] Petition, August 30, 2019. Docket E002/M-19-559.
[12] Petition, January 17, 2020. Docket No. E002/M-20-86.
[13] Notice, January 24, 2020. Docket No. E002/M-20-86.

While we understand parties' interest in these topics and acknowledge and appreciate the link to the enabling technologies addressed in the Company's integrated distribution planning process, we do not believe these topics are properly in scope here. Instead, we believe parties have considerable opportunities to engage in the Commission's other active proceedings dedicated to rate design discussed above. Parties pointed to the Hawaii Public Utilities Commission Order requiring an Advanced Rate Design Roadmap in the cost recovery proceeding for AGIS investments as a model for Minnesota. We note the Company is in a much different spot than Hawaiian Electric in terms of Advanced Rate Design. In contrast to the Company, it is our understanding that at the time of the 2016 Order Hawaiian Electric did not have any pilots or outstanding proposals for default time based energy rates for any customer class. The below Figure was included in the Hawaiian Electric Advanced Rate Design timeline:

Figure 2: Hawaiian Electric 2016 Advanced Rate Design Timeline

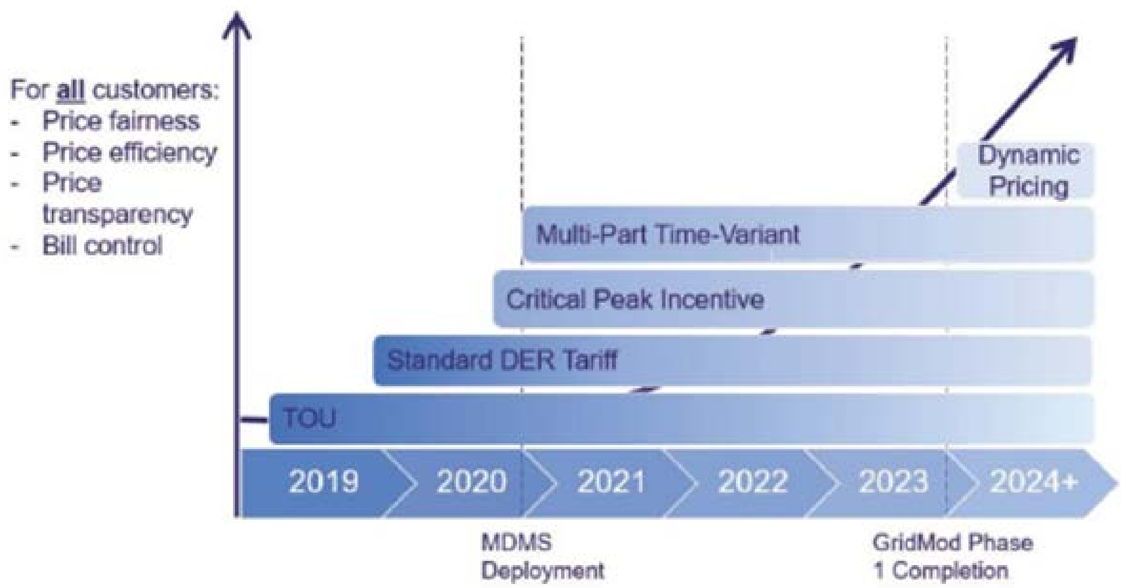

Figure 6: Proposed ARDS Timeline

Should the Commission wish to direct the Company to produce a draft Advanced Rate Design plan, we believe the Commission's recently established rate-design proceeding is the appropriate forum for such a plan in lieu of a general rate case proceeding.

With respect to the content of such a plan, several suggestions from parties would be unworkable in a "roadmap" phase until more information is known. For example, specific appropriate protections that may be needed for low income customers, or the appropriate enrollment mechanism, would be features of pilots or programs once design work is underway, stakeholders are consulted, and program features are weighed and balanced. We agree that these topics are critical design questions to be resolved for a program or pilot, but we disagree that the "roadmap" phase is where these questions are answered.

In short, while the Company does not oppose including a description of our advanced rate design efforts in future IDP filings, the Company is engaged in significant advanced rate-design initiatives today, and we see minimal value in establishing a new set of processes with the potential to slow down the progress currently being made. Should the Commission disagree, however, and direct the Company to produce a draft "roadmap" in docket E002/M-20-86, the Company would not oppose the following components:

- A summary of the Company's current advanced rate designs and demand management programs, advanced rate designs in development, and relevant industry best practices.
- A timeline for proposing advanced rates and/or demand management programs for all customer classes.
- A discussion on what should be discussed in petitions for rate design changes, including:
    - Whether program design strategies will be needed to support low-income customer participation in these offerings,
    - Application to distributed energy resources
    - Implementation plans, including education and outreach to customers.
    - Evaluation plans

2. Date-Certain Commitment to Customer Programs

The Customer Strategy provided in our 2019 IDP outlines a number of products and services that are enabled by the advanced grid and that are part of our roadmap to deliver on the customer benefits associated with and/or made possible by our AGIS initiative. Included in this Strategy are general timelines of our expected deployment of these products and services. While we understand the desire for the Company to provide more specific timing for certain products and services, it is not reasonable to expect that the Company can do so at this point in time. Setting aside the uncertainty of the Company's implementation plans that are contingent on a certification decision in this proceeding to move forward, the development of new products and services is not linear; it is also subject to a number of things outside of our control – including, but not limited to, the evolution of technology and customer acceptance.

Regarding Green Button Connect My Data (GBC) and the Home Area Network (HAN) outlined in our Customer Strategy, the Company commits to providing access to customers within one year after mass deployment of AMI meters begins. Based on the implementation timeline in our 2019 IDP, this would mean full implementation of GBC and HAN by mid-2022, which will align the delivery of these products with the beginning of substantial meter deployment.

CUB suggested that we allow customers to "bring their own device" to take advantage of HAN capabilities. We confirm that our HAN offering contemplates customers having that opportunity, provided it complies with associated technical and cybersecurity requirements that we are in the process of developing in conjunction with our meter vendor. With respect to GBC, it will complement and augment our current Green Button Download My Data (GBD), and be part of our customer portal. As we have explained, GBD allows customers to directly access and download their energy usage data (and share with any party they choose) and GBC will provide customers the opportunity to authorize the Company to transmit their energy data directly with third-parties on a one-time, ongoing, time-specific, or indefinite basis.

CUB further suggests the Commission should condition certification of its AGIS investments on the Company developing and implementing a generally accessible customer rates tool in a machine readable, electronic format that would allow anyone to model the impact of different rates on energy usage. A tool such as this is not related to or reliant on AGIS, or supported by the record, and as such, is out of scope for this proceeding. That said, we have undertaken a project to make rate information available in a machine-readable electronic format. Our expectation is that this project will be completed in parallel with our GBC and HAN projects.

3. *Third Party Access to Rate or Other Customer Data*

CUB also made several suggestions for various data be made available either on the Xcel Energy website or to third parties. Like rate design, it is not appropriate to make substantive decisions on issues around customer data and third party access in an IDP. These issues are complex, nuanced, and important. As such, they deserve a focused examination and development of a robust record, much like the Commission undertook in Docket No. E,G999/CI-12-1344. Further, while they are raised in the context of our AGIS initiative, they are not related or reliant on our request for certification in this proceeding.

That said, we provide a limited response to CUB's comments. With respect to the availability of historic billing information, we clarify that it is currently, and will continue to be available to customers. However, making this information available to third parties is, and we expect will continue to be, contingent on the customer of record authorizing a specific third party to have access. CUB also suggested changes to the Commission's current customer data access and third party authorization frameworks. As we have noted, third party access to customer data, including billing information, and any alterations to the current third party customer data access framework are outside the scope of this proceeding.

Finally, like a few other parties that conditionally support certification of the Company's proposed advanced grid investments, the City of Minneapolis outlines criteria it believes the Company should meet prior to the Commission granting cost recovery. We clarify that we are currently seeking certification, not cost recovery. For the reasons we have previously outlined, any conditions associated with cost recovery should be determined in a cost recovery proceeding. That said, many of the criteria suggested by the City are otherwise being addressed. Specifically, virtual energy audits, facility monitoring, commissioning, and saver's switch are part of our CIP plans Our IDP thoroughly explained how our AGIS and customer strategies support better integration of DER. Finally, we believe any changes to the Company's or the Commission's customer and third party data access frameworks are complex and deserve a focused examination and are thus more appropriately addressed in a separate proceeding. We note that the Commission currently has such an open proceeding in Docket No. E,G999/CI-19-505.

D. What should the Commission consider or address related to realizing benefits of each of the investments in the Company's AGIS Initiative for ratepayers?

Several parties recommended the Commission require the Company to track and report on the savings it claims in its CBA. While we thoughtfully prepared the CBAs that were part of our IDP and AGIS certification proposal and believe they are reasonable estimates, the specific benefit and cost amounts are from the point in time we began our analysis, and rooted in the specific deployment plan, scope, and timing that we proposed.

Any changes to that plan could significantly affect the identified benefits (and costs). For instance, the O&M reductions that stem from reduced payments to Cellnet as current meters are replaced with AMI meters; a delay, or a slowed or accelerated pace, will impact these projected savings. Another example is the Theft and Tamper Reductions, as discussed in the testimony of Chris Cardenas, are tied to the timing of the AMI meters deployed and implementation of analytical software needed. As this software can need up to 18 months of post deployment AMI data analysis to accurately predict false positives, the full benefits derived from Theft and

Tamper reduction would be significantly reduced if the current timing and scope of meter deployment is delayed, resulting in a recalculation of the benefit. Therefore, it would not be reasonable for the Company to commit to the costs or the savings we estimated in the CBA underlying our certification request.

Additionally, some of the benefits are more straightforward to measure than others. For example, fewer truck rolls compared to a reduction in CO_2 associated with time of use rates. As such, while we have taken care to reasonably approximate savings from our proposed investments, specific savings associated with implementation must be determined after we have guidance from the Commission as to the scope, scale, and timing of any investment deployments – and after the Commission understands and agrees on the ways that we propose to measure and track the savings.

That said, Fresh Energy additionally requested the Company to provide baselines, targets and a plan for measuring, verifying and reporting Figures it referenced, top benefit categories, and key CBA assumptions for the AGIS investments. We provided available documentation regarding the assumptions we used to develop the AGIS Cost Benefit Analysis for AMI, IVVO and FLISR in the IDP – specifically in the Direct Testimony of Company Witnesses Michael Gersack, Kelly Bloch, Christopher Cardenas, and Ravi Duggirala in Attachments M1, M2, M4, and M5, respectively. In each of the AGIS categories, witnesses devoted significant discussion of the assumptions underlying the baseline information used to develop the various benefit calculations.

For example, the underlying assumptions to calculate the benefit from a reduction in field trips due to damaged customer equipment is in Kelly Bloch's testimony. The Company on average experienced 1,796 trips per year due to damaged customer equipment (2014-2018) and estimated a 50 percent reduction in trips, as many of initial trips for investigation would be avoided as a result of the remote capabilities of the AMI technology. We included the calculated O&M savings of this benefit in Schedule 7 on page 199 of Attachment M2 (Kelly Bloch testimony).[14]

Finally, we note that we proposed metrics and reporting. See discussion beginning at page 163 of the IDP and the referenced Schedule 11 to Mr. Gersack's testimony at page 301 of Attachment M1.

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[14] Some portions of the calculations were provided as not public Trade Secret information, which we made available to the Department and OAG in accordance with the Minnesota Data Practices Act and other parties subject to a Non-Disclosure Agreement.

E. At the stage of certification, what consideration should the Commission give to subsequent cost recovery, via either the Transmission Cost Recovery rider or general rate case, for each of the AGIS investments?

The Company addresses this question in the body of our Reply Comments.

F. Are there any other issues or concerns related to this matter?

See Section III below.

III. OTHER ISSUES

A. The Company Appropriately Incorporated the Results of its Demand Response Potential Study

CUB suggested that the Company excluded the benefits of a majority of customer rate and service offerings identified in our Demand Response Potential Study – and suggested the Commission require the Company to implement an additional 400 MW of demand response by 2023. First, we clarify that we appropriately incorporated the programs that impact customer rates and that are in-line with our current time of use (TOU) pilot and proposal into our analysis of customer benefits of AMI.[15] We did not include *all* demand response programs outlined in the Demand Response Potential Study (by The Brattle Group), because not all demand reductions are dependent on AMI.

We note that we are also further exploring the other programs identified in the Study, which we outlined in our five-year action plan in our Integrated Resource Plan (IRP) filed July 1, 2019 in Docket No. E002/RP-19-378. Second, as also discussed in the IRP, we have already committed to add 400 MW of demand response in concert with the Commission's January 11, 2017 Order in our most recent integrated resource plan in Docket No. E002/RP-15-21.[16] Therefore, a requirement for a further addition of 400 MW of demand response in this case would go beyond the achievable potential identified in the Potential Study, is not supported by the record in this proceeding, and would not be reasonable or appropriate.

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[15] TOU Pilot, Docket No. E002/M-17-775; Pending TOU proposal, E002/M-20-86 – General TOU Service Tariff Petition).

[16] See Order Point No. 10.a. Xcel shall acquire no less than 400 MW of additional demand response by 2023.

B. Customer Costs

In Comments, XLI requested that we address the following: (a) total cost to ratepayers; (b) proposed revenue allocation and rate design outlining bill impacts for each customer class over the five-year period; (c) explanation of the relationship of distribution investments to transmission-level customers; and (d) explanation of the proposed rider methodology. In requesting this information, XLI referenced its belief that this information is well-within reason for a request and consistent with the spirit of Minn. R. 7843.0500, which governs resource plan approval. While resource plan rules do not apply to IDPs, we provide the requested information below.

1. Total Cost to Customers

We provided the total cost of our proposal on pages 21-23 of Attachment M1 to the IDP, and included the estimated revenue requirements underlying our estimated customer cost impacts on page 299 of the same attachment.

2. Revenue Allocation and Estimated Bill Impacts

We expanded our AGIS revenue requirement that illustrated residential customer impacts on page 299 Attachment M1 of the IDP to provide greater insight into the other classes, which we provide in the below table:

Table 1: Estimated AGIS Revenue Requirements by Class – State of Minnesota

Year	MN Total	Residential	Commercial Non-Demand	C&I Demand Billed	Lighting
2020	$10,415,136	$5,523,080	$468,243	$4,054,215	$369,598
2021	$30,613,493	$16,283,095	$1,415,004	$11,866,792	$1,048,602
2022	$41,933,397	$22,547,571	$2,337,632	$16,082,523	$965,670
2023	$56,842,434	$31,614,714	$3,659,659	$20,605,950	$962,111
2024	$63,589,359	$35,862,263	$4,306,718	$22,482,056	$938,322

In addition to expanding our estimated revenue requirement to all classes, we also expanded our estimated bill impacts, as illustrated in Tables 2, 3, and 4 below.[17] As also explained in the IDP, we clarify that "doing nothing" with respect to the Company's meter reading is not an option. As such, we portray a "Reference Case" that represents the estimated costs of an AMR drive-by meter reading solution. We believe the estimated Net Monthly Bill Impact, which portrays the total AGIS view *minus* the Reference Case is the relevant bill impact to consider.[18]

Table 2: Estimated Total Monthly Bill Impact of AGIS – State of Minnesota

Year	Residential	Commercial Non-Demand	C&I Demand Billed[19]
2020	$0.44	$0.55	$7.83
2021	$1.33	$1.68	$23.26
2022	$1.84	$2.80	$31.65
2023	$2.58	$4.47	$40.98
2024	$2.87	$5.34	$45.08

Additionally, the company expanded our estimated monthly bill impact for the reference AMR drive-by metering base case seen below. While this certainly costs less than our AGIS proposal, it is essentially a continuation of the meter reading status quo and provides none of the benefits such as advanced rate design or remote disconnect and reconnect.

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[17] Based on the proposed Class Cost of Service (CCOS) allocators from our MYRP submitted November 1, 2019 (Docket No. E002 GR-19-0564), consistent with the estimated residential rate impacts portrayed in the IDP. The CCOS is applied to the estimated revenue requirements of our proposed AGIS investments through 2024.
[18] We expect certain benefits to materialize as a reduction in revenue requirements from our greater AGIS rollout. However, we did not include those within our revenue requirement calculations as we wished to provide the most conservative view of the potential cost to customers. We will continue to engage with stakeholders to develop how AGIS benefits will be realized and delivered to the various customer classes over the life of the assets.
[19] Based on monthly average estimated usages – Residential 675kWh; Commercial Non-Demand 1,000kWh; C&I Demand 37,500 kWh.

Table 3: Estimated AMR Reference Case Monthly Bill Impact – State of Minnesota

Year	Residential	Commercial Non-Demand	C&I Demand Billed
2020	$0.01	$0.01	$0.06
2021	$0.19	$0.36	$1.79
2022	$0.62	$1.26	$5.80
2023	$1.18	$2.49	$10.95
2024	$1.51	$3.34	$14.14

Finally, the difference in the cost between the AGIS and AMR reference case seen below provides a better glimpse into the incremental cost of achieving the benefits provided by our AGIS proposal. This serves as a better proxy to understand the cost of AGIS on top of performing the basic meter reading necessary for the Company to do business.

Table 4: Estimated *Net* Monthly Bill Impact of AGIS – State of Minnesota

Year	Residential	Commercial Non-Demand	C&I Demand Billed
2020	$0.44	$0.54	$7.77
2021	$1.14	$1.32	$21.47
2022	$1.21	$1.54	$25.86
2023	$1.39	$1.98	$30.03
2024	$1.36	$1.99	$30.95

3. *Relationship of Distribution Investments to Transmission Customers & Potential Rider Recovery Methodology*

The Company agrees that distribution and transmission expenses are allocated to classes differently, including AGIS investments in future TCR recovery requests, which will require separate allocations of Transmission and AGIS expenses.

4. *Proportion of Total Costs*

CUB asserts that rider recovery of advanced grid investments will shift a large percentage of risk away from the Company and dampen the importance and transparency of rate cases. First, rider implementation allows for regulatory review and oversight of costs through regular filings. Further, and as otherwise discussed in this Reply, Rider recovery of advanced grid investments is consistent with public policy, authorized by statute, and falls within an established regulatory framework that works in concert with rate case proceedings. Finally, for context, T&D related costs are approximately 24 percent of total costs for all customers– largely recovered through base rates. The revenue requirement for the AGIS investments that we have proposed for certification is approximately eight percent of total T&D costs currently in base rates and riders.

C. NWA Analysis

Several parties suggested specific changes to future NWA analyses, or that the Commission refine expectations or establish a framework for NWA assessment across all utilities. Non-wires alternative analysis is being addressed by many in the industry. We have not yet seen a standard framework or approach emerge, but are continuing to monitor the industry, work on our process of identifying projects with the most potential for a potential NWA solution, and work on our NWA analysis. That said, and as also noted earlier, we look forward to the additional capabilities the APT will bring to our analysis.

1. *Candidate Projects*

As discussed in the IDP, we currently use several "filters" to identify traditional projects for NWA analysis. This includes type of project, project cost, and project timeline. We received several comments on these filters.

One suggestion was to include Asset Health and Reliability projects in our NWA analysis. These are necessary projects that involve replacing equipment that is reaching end of life or that has failed. This is a broad category that covers pole replacements, underground cables, storms, public damage repair, etc. It may be possible to include a portion of the sub-types within this category for potential NWA, but the overwhelming majority of projects – for example, pole replacement, storm response, and public damage repair – in this category require immediate attention and as such, do not lend themselves to NWAs. Further, due to the nascent state of NWA analysis in Minnesota and the industry, we believe we should remain focused for the foreseeable future on project categories that lend themselves to a more straightforward analysis and that will mostly likely lend themselves to a NWA solution.

Other comments suggested we should be including capacity projects in the first two years of our planning cycle rather than filtering those out and starting with projects needed in years three to five. It would be difficult to implement a NWA on a project that is in the first two years of our budget due to several factors. Much of the materials needed for either utility solutions or NWA solutions, including the equipment, the platform to operate the equipment, and software changes required to integrate with our systems among other things, have long lead times. Also, the annual planning process includes moving projects for year one into the design/construction phase in the 3rd quarter of the year, so when the IDP is submitted in November, the projects for year one and some year two projects are already in the design/construction phase.

Finally, we also received a specific question as to why an identified project for the Louise substation and feeder that exceeded the $2 million threshold and that met all other filters was not included in our analysis. We clarify that this project is in South Dakota and therefore did not include it in our Minnesota analysis.

2. *Project Cost Threshold*

While some parties opined that perhaps the current $2 million project cost threshold should be lowered to $1 million, ELPC/VS commented that based on their experience observing the NWA market, they agree it would be challenging at this time for NWA developers to provide cost-effective alternatives to traditional capacity projects that cost less than $2 million. We agree changing the threshold at this time is unlikely to result in a NWA project. We also continue to believe a $2 million threshold is appropriate and reasonable in the near-term while we and others gain experience with NWA analysis. Further, as we have explained, NWA is currently very labor intensive for our engineering team. Although this burden will lessen as we gain experience with the APT, we will likely need additional other tools to enable NWA analysis at any kind of significant numbers.

3. *Predictability of NWA Reliance*

We agree that knowing when load relief would be needed would help in NWA analysis and operation, but ultimately that will depend on the availability and accuracy of short-term (day ahead) load forecasts, which we are not currently equipped to perform on a feeder by feeder level. In long term forecasts, hourly-granularity forecasts looking years into the future as will be generated by APT would be based on linear regressions correlating historic loading with weather, economic, and customer behavioral trends to produce hourly forecasts based on a "typical" year. These however, will not be able to predict at which precise hours or on which precise days a NWA would be needed in the future. They can provide a reasonable assessment of the total number of hours per year the NWA might be needed. The demand for the NWA at any particular moment in time will depend on the prevailing weather, economic, and customer behavioral conditions. Additionally, due to the scenario analysis capabilities of APT, once a specific NWA solution is identified, APT would have the ability to analyze various loading and load relief scenarios to determine the efficacy of the NWA in a variety of situations.

4. Request for Proposals

A couple of parties suggested the Company issue requests for proposals (RFP) to supplement or replace the Company's internal analysis of potential NWA solutions for identified system risks.

In order to issue a RFP we would still need to work through the process of identifying and analyzing the project internally. Once that is complete we would need to do additional analysis and design to develop specifications for the RFP. Additionally, we would need to complete the RFP process by obtaining responses, screening the responses, completing technical and sourcing reviews, and contract negotiations. While there are some limited NWA pilot projects that involve RFPs in other states, the industry requires a fair amount of maturation, including standardization of communications between and among devices, standardized control platforms across various technology types, and development of cybersecurity protocols before third party solutions would be viable.

Given where the industry is currently at along with the resources needed to complete a RFP to appropriately consider and incorporate a NWA solution we feel it is best to wait until there are further industry developments and we have been able to investigate these requirements further.

5. Universal- or Dispersed-Scale Focus

IPS Solar observed that a portion of the solar solutions we examined to mitigate the identified risks were larger than current 10 MW and 20 MW (FERC) definitions of distributed generation facilities. We clarify that our NWA analysis is ultimately agnostic of a particular deployment strategy – universal-scale or dispersed – for a DER solution and rather is only concerned that the needed amount of DER to mitigate the capacity risk is installed at the right location(s) in the right timeframe. Despite this, each deployment strategy comes with its own set of advantages and challenges. A universal-scale solution offers the ability to control and manage the DER assets as directly as possible with utility-controlled access to the assets. However, this requires access to enough land to contain all of the DER assets, which can be especially challenging in some areas. A more distributed deployment can alleviate land constraints, but can also pose challenges with coordinating the interactions of DER with the grid across a larger geographic area; this can be further complicated in behind the meter (BTM) deployments.

6. *Treatment of Demand Side Management*

We would also like to take this opportunity to clarify the way we incorporated energy efficiency (EE) and demand response (DR) in our NWA analysis. The effect of EE achieved through utility DSM programs and occurring naturally outside of those programs is primarily addressed during our ordinary load forecast process. As we review historic peak loads for a feeder, we identify if some feeders are seeing a natural decline in peak load independent of weather and economic factors. This information. along with a comparison of historical and future EE achievements through DSM programs, and an expectation that naturally-occurring EE continues, helps inform the load forecasting process to determine whether to forecast a feeder as having growth in peak load, a flat trend in peak load, or tapering load growth in the forecast window.

In contrast, DR is an additional layer in the NWA analysis. DR differs from EE in that DR is dispatchable, allowing for demand reductions when needed, whereas demand reductions from EE are dependent on the usage pattern of the technology of the energy efficient equipment. To determine the potential benefit of DR, we analyze the feeders involved in each identified project and verify how often the feeder reaches its future peak. For feeders that have future peaks that are expected to exceed the capacity of current equipment, we estimate the peak load that can be reduced per hour by utilizing DR assets. We then apply this load reduction to the feeder peak day load curves, and then perform the solar PV and battery storage assessments using the reduced load levels.

7. *NWA Cost Estimates*

We received mixed feedback about the cost estimates that we used in our NWA analysis – some were in favor of the costs we used in our 2019 analysis (which were lower than the amounts we used in our 2018 IDP). Some thought our estimates were too high. We clarify that we validate our cost estimates using industry documentation and studies, and will continue to refine our cost estimates in the future.

In response to the ELPC/VS suggestion that we explore hybrid approaches to addressing NWA candidate projects with a "hybrid" approach – i.e., addressing N-0 risks with DER and N-1 risks with a traditional solution that might not be cost-effectively addressed by a NWA presently. As we explain below, a traditional project to resolve a N-1 risk will nearly always also solve an associated N-0 risk. So, if we were to employ a NWA for the N-0 risk and a traditional solution to solve the N-1, which also solves the N-0, the overall solution would not be cost effective for customers.

When we develop traditional projects to mitigate capacity risks on the system, in the interest of efficiency, we often group multiple risks together to be solved by one project. An example of this would be a project to install a new feeder circuit. Installing new feeder circuits can come with a higher cost as they often require thousands of feet of new circuit lines to extend from the substation to where the capacity is needed. A project such as this can be costly. Grouping risks together to be solved by such a project is important as it ensures that we are getting the most benefit possible from costly feeder additions – and this in turn improves the project's risk score, because it is solving multiple risks.

In almost all cases, removing certain risks from a project (such as N-0s) to be addressed by a NWA will not remove or defer the need for the traditional project itself, because the NWA is not able to solve all the risks. In the new feeder example, if you remove the N-0s from the project, the new feeder will still be needed to address the remaining significant N-1 risks tied to the project. However, when the new feeder is built, because it is still needed for the N-1 conditions, we would effectively address both risk conditions – as the new feeder would itself provide capacity to address the N-0 overloads, regardless of the presence of a separate NWA for those N-0s.

Finally, with respect to a comment regarding a need for a standard that accounts for costs relieved by lessened demand for peaking plant generation and transmission congestion-related costs in assessing benefits of an NWA, we agree in principle, however disagree in terms of practicality. It is certainly true that net costs of battery plus solar installations can be reduced when accounting for savings derived from stacked benefits. However, these additional stacked benefits are difficult to quantify for specific applications – and in some cases, lack the means of monetary compensation for assumed benefits. The intent of our NWA analysis and benefit assessment is to first quantify the risk on the system in a manner that is relevant for DER analysis, and then to provide a direct comparison of costs from strictly a capacity perspective.

D. Distributed Energy Resources

ELPC/VS requested that we provide a discussion of whether external control through utility communication with smart inverters, above and beyond the autonomous functions associated with smart inverters, would be necessary to ensure the safe and reliable operation of the grid at the listed penetration levels. They also recommended the Commission modify IDP Requirement 3.C.3 to include this discussion on a go-forward basis, as discussed in Section I.D.3 above. We provide expanded discussion here and as we previously noted, in future IDPs, we are happy to provide an overview of smart inverter developments and their role in efficiently integrating DER to maximize customer and grid benefits. We do not believe however, it is necessary to get more prescriptive with IDP requirements around smart inverters, as we explain.

We provided an overview of smart inverters and their role in the high PV penetration situations through the IDP requirements 3.A.7 and 3.A.33, which direct the Company to discuss how IEEE Standard 1547-2018 impacts distribution planning considerations, and how abnormal frequency and voltage issues can benefit from advanced inverter technology. The industry is starting to gain more experience with smart inverter technology and its role in mitigating impacts from higher levels of PV integration on the distribution system. The company participates in the Electric Power Research Institute (EPRI) Integration of Distributed Energy Resource Program (see Attachment C for an overview) and continues to keep abreast of the latest research and utility experience in this area. We are looking forward to the time when inverters that meet the new IEEE-1547-2018 standard will be available in the field, which is expected to occur in the year 2021.

Although not a "smart inverter" setting, the company often requires an inverter power factor setting of 0.98 on solar garden applications and this measure can eliminate more expensive upgrades such as increasing conductor size. We believe that the first "smart inverter" settings to be adopted should be the default autonomous settings as laid out in the standard that are "benign" or "do no harm" advanced inverter settings that would be specified by the utility. We also believe that some of the more advanced settings (i.e. Volt-Var) may require more lab testing and field demonstrations to ensure that it would not cause interferences with the distribution system.

EPRI research suggests that to fully understand the role smart inverters can play on a feeder, the individual feeder needs to be modeled. For the most part, our experience indicates that the solar gardens on our system are the systems most likely to cause impacts on our system, simply due to their size and number. Because of their size, the interconnection review process requires these projects to be studied individually and in more detail –these projects are likely to be the first projects where more sophisticated smart inverter settings are implemented. As smart inverters become available, we will evaluate how additional settings such as volt/var can help mitigate impacts and potentially eliminate grid upgrade requirements. We will continue to keep abreast of the latest research in this area. Initially volt/var settings could be a "set and forget" type setting or could be changed seasonally. Industry research suggests that significant gains can be made with the less dynamic settings. Changing the settings in a more dynamic fashion via sophisticated communications may not be necessary or cost-effective.

In future IDPs we will continue to provide an update of the latest smart inverter developments and the role that they can play in integrating higher levels of PV and other DER on our system. We do not believe however, it is necessary to get more prescriptive with the requirements around smart inverters, especially without significant operational experience on our system. If there is broad interest, there are various venues to discuss this topic, which would allow for a richer discussion and more dynamic feedback around industry questions. For example, we meet annually, at minimum, with the Technical Sub Group in support of the Technical Interconnection and Interoperability Requirements (TIIR) with a specific focus on smart inverter functions, as directed by the Commission.

Xcel Energy SAIDI and SAIFI Information - 2015-2019
Proposed FLISR Feeders

As requested by Fresh Energy in March 17, 2020 Comments

Proposed FLISR Feeders
System All Levels Impacts

Total All Levels Annual Contribution to MN Indices from FLISR candidate feeders

SAIDI 2015	2016	2017	2018	2019	SAIFI 2015	2016	2017	2018	2019
73.0	83.9	46.3	30.6	23.2	0.3	0.4	0.3	0.3	0.2

All Days - Individual Feeder Indices

Feeder	SAIDI 2015	2016	2017	2018	2019	SAIFI 2015	2016	2017	2018	2019
AHI021	578.5	127.4	487.1	155.6	128.2	1.13	1.99	1.15	1.08	1.46
AHI022	843.5	265.8	454.7	17.7	200.7	2.44	2.17	1.99	0.09	1.88
AHI025	0.8	102.1	11.9	148.5	65.0	0.00	1.98	0.10	1.04	1.06
AHI063	183.5	764.8	114.7	115.5	188.1	1.20	2.90	1.08	1.35	1.27
ALD072	53.2	728.2	12.8	5.7	1.5	0.23	4.19	0.12	0.09	0.01
ALD076	29.0	189.5	20.7	31.1	32.5	0.14	1.29	0.20	0.30	0.47
ALD084	216.1	671.9	27.0	12.9	167.5	0.57	1.35	0.13	0.14	2.13
ALD085	45.1	26.3	27.7	70.8	10.4	0.16	0.29	0.18	1.47	0.12
ALD088	508.6	61.2	130.5	113.8	43.8	0.81	0.47	1.32	1.58	0.41
ALD091	4.0	26.8	2.2	0.4	5.8	0.03	0.20	0.04	0.00	0.08
ALD093	1,234.8	82.3	33.5	235.7	46.7	2.26	1.01	0.37	2.21	0.13
ALD095	31.8	21.3	41.3	19.9	55.5	0.23	0.25	0.27	0.19	0.46
ALD098	55.0	110.3	39.7	7.5	25.5	0.69	2.40	0.53	0.14	0.59
ALK063	167.6	463.4	21.1	38.7	55.5	1.97	2.24	0.16	0.18	1.06
APA061	295.0	310.2	77.3	33.8	107.5	2.16	0.35	0.27	0.26	1.18
APA065	305.5	1,614.1	53.3	1.7	9.1	2.26	1.67	1.03	0.03	0.03
APA068	278.1	202.8	36.2	18.3	38.0	2.26	0.67	0.23	0.10	0.15
APA072	649.2	833.1	174.9	46.0	61.4	2.38	1.41	0.43	0.31	0.36
APA075	184.3	619.8	225.6	37.0	72.6	1.10	1.47	1.56	0.38	0.39
APA078	294.2	165.0	554.2	56.3	64.2	2.28	0.29	1.26	1.32	0.44
BCR061	341.6	179.8	44.8	45.2	98.6	2.30	1.47	1.21	0.80	1.32
BCR062	362.1	208.1	46.8	18.2	41.0	2.16	1.50	1.12	0.17	0.30
BCR082	412.0	276.6	715.6	112.0	166.8	0.75	1.35	1.23	0.82	2.37
BRP062	90.8	48.3	22.4	29.1	9.1	1.32	0.48	0.23	0.10	0.12
CEL062	1,782.3	54.5	83.0	58.8	6.5	1.18	0.51	1.38	0.52	0.11
CEL064	737.8	239.6	149.6	232.4	50.9	1.48	1.59	0.79	2.43	0.53
CEL066	309.8	110.1	305.2	42.0	54.9	0.28	1.28	1.40	0.40	0.55
CEL072	85.3	48.2	157.0	259.2	62.2	0.65	0.62	1.72	1.86	0.72
CEL075	895.5	216.1	31.2	0.4	25.3	1.10	0.13	0.08	0.00	0.19
CGR061	16.4	794.4	204.4	47.1	79.0	0.19	6.39	1.44	0.19	1.16
DBL067	92.5	13.8	363.8	47.4	23.4	1.19	0.19	5.23	0.55	0.25
DBL069	130.1	899.2	68.4	6.5	163.8	1.19	2.18	1.14	0.10	1.16
DBL073	126.9	132.7	10.2	296.2	16.0	2.12	0.29	0.12	3.35	0.13
DBL074	32.6	57.3	681.0	133.1	153.6	0.24	0.09	4.25	1.28	1.45
DBL081	260.4	151.4	28.1	16.6	140.1	2.25	1.46	0.30	0.26	0.17
DPN063	944.6	373.1	355.0	91.2	19.7	1.92	2.75	1.45	1.29	0.19
DPN073	561.3	435.0	256.1	75.4	62.0	0.65	0.68	1.72	1.20	0.30
EBL084	1,536.4	48.5	1,526.0	65.0	61.8	2.24	0.23	1.66	0.49	1.35
ECK063	98.6	57.8	11.7	13.6	5.6	0.25	0.29	0.14	0.12	0.07
EDA065	676.8	85.9	20.9	31.0	8.8	1.76	0.60	0.22	0.28	0.09
EDA068	32.0	3.0	1.3	0.4	4.9	0.04	0.04	0.01	0.01	0.09
EDA072	580.8	68.3	39.1	56.3	36.3	1.07	0.56	0.49	0.59	0.36
EDP072	0.0	19.7	356.0	76.7	0.0	0.00	0.03	3.00	1.18	0.00
EDP073	95.2	72.1	129.2	12.9	102.9	0.39	1.04	2.22	0.15	1.05
EDP091	22.6	271.1	36.6	19.2	138.8	0.20	2.30	0.27	0.20	2.52
EDP094	43.6	126.6	11.3	36.6	18.3	0.20	0.47	0.23	0.37	1.05
ELP063	58.7	44.6	173.4	83.5	219.4	1.00	0.09	2.22	1.05	0.34
ELP071	15.4	54.5	44.6	107.2	61.5	0.24	1.19	0.70	1.76	0.90
EXC062	707.2	329.6	299.2	208.9	112.4	2.57	4.76	1.57	0.70	0.56
GLK061	3,330.1	27.7	46.0	207.7	89.1	4.61	0.22	0.18	1.28	1.15
GLK063	1,023.8	106.6	144.1	192.0	199.7	2.44	0.31	1.64	1.47	1.83
GLK071	131.5	260.8	144.2	241.4	169.2	0.65	1.32	1.34	2.37	0.44
GLK074	673.0	92.5	210.7	193.0	383.5	4.46	0.70	2.60	1.47	3.01
GNL072	627.1	978.6	252.6	96.2	60.3	1.26	1.34	0.52	0.81	1.18
GSL064	1,098.6	639.9	253.8	315.9	20.5	3.79	1.69	0.79	2.45	0.17
GSL065	149.6	971.7	272.3	151.6	239.0	0.36	1.82	2.16	0.49	0.54
GSL074	1,123.9	1,980.6	689.2	140.4	126.9	4.24	3.75	3.53	0.45	1.30
GSL075	185.1	691.4	6.9	39.9	40.3	1.38	0.54	0.08	0.15	0.25
GSL076	724.3	235.4	79.3	90.6	138.4	3.29	2.44	1.15	1.29	1.24
GSL079	194.0	469.2	70.6	102.6	119.5	1.38	0.85	0.36	1.17	0.60
HOL061	878.2	487.6	93.5	245.4	237.5	3.63	3.72	1.16	4.52	2.14
HOL062	905.0	297.7	96.8	409.7	46.1	2.79	4.13	1.13	6.23	0.21
HWW072	258.8	10.8	9.9	4.8	7.6	0.42	0.08	0.10	0.05	0.11
IDA061	293.7	548.0	68.4	83.9	39.5	0.44	1.04	1.43	0.71	0.48
IDA062	636.2	101.4	86.1	30.5	57.4	0.63	1.19	0.39	0.32	0.74
IDA072	83.5	139.2	87.6	52.8	30.8	0.31	1.47	0.29	0.35	0.35
IDA073	247.1	586.6	85.9	74.4	70.0	1.68	1.46	0.44	0.56	1.00
IDA074	96.1	104.4	91.1	10.5	8.1	1.83	0.28	0.47	0.19	0.16
LIN031	163.6	122.0	178.3	77.7	102.5	0.60	1.14	0.52	0.43	0.70
LLK072	114.4	165.6	5.5	65.8	49.9	1.18	0.42	0.02	0.69	0.29
LOK083	53.0	114.1	85.4	82.0	223.0	0.26	1.22	2.26	0.30	2.65
LOK092	4.5	174.8	276.2	244.2	0.0	0.02	2.10	1.99	1.33	0.00
LOK093	259.2	113.2	92.8	151.0	32.0	2.33	1.26	1.36	1.51	0.40
LSP021	469.0	368.7	184.3	142.0	344.8	2.21	1.45	2.46	1.50	2.28
LSP022	685.2	902.8	109.0	517.7	777.8	3.22	5.23	2.12	3.27	4.79
MEL064	89.6	49.6	88.7	107.7	249.6	1.38	0.44	1.12	1.29	2.04
MEL067	152.5	808.9	83.2	117.8	17.5	3.32	1.64	1.45	1.41	0.12
MEL068	303.8	590.8	359.0	48.6	179.8	2.43	0.56	1.69	0.78	0.77
MEL069	571.6	10.8	352.0	422.1	68.1	2.23	0.14	4.50	4.72	0.33
MEL071	7.2	1,367.3	21.4	193.3	60.4	1.00	0.59	0.51	2.02	1.20

All Days - Individual Feeder Contributions to MN SAIDI

Feeder	SAIDI 2015	2016	2017	2018	2019	SAIFI 2015	2016	2017	2018	2019
AHI021	0.43	0.09	0.36	0.11	0.09	0.001	0.001	0.001	0.001	0.001
AHI022	1.05	0.33	0.56	0.02	0.24	0.003	0.003	0.002	0.000	0.002
AHI025	0.00	0.03	0.00	0.04	0.02	0.000	0.001	0.000	0.000	0.000
AHI063	0.26	1.08	0.16	0.16	0.26	0.002	0.004	0.002	0.002	0.002
ALD072	0.19	1.72	0.03	0.01	0.00	0.001	0.010	0.000	0.000	0.000
ALD076	0.07	0.45	0.05	0.07	0.08	0.000	0.003	0.000	0.001	0.001
ALD084	0.35	1.10	0.04	0.02	0.27	0.001	0.002	0.000	0.000	0.003
ALD085	0.13	0.08	0.08	0.20	0.03	0.000	0.001	0.001	0.004	0.000
ALD088	1.21	0.15	0.31	0.27	0.07	0.002	0.001	0.003	0.004	0.001
ALD091	0.00	0.02	0.00	0.00	0.00	0.000	0.000	0.000	0.000	0.000
ALD093	0.29	0.02	0.01	0.06	0.01	0.001	0.000	0.000	0.001	0.000
ALD095	0.13	0.09	0.17	0.08	0.24	0.001	0.001	0.001	0.001	0.002
ALD098	0.13	0.26	0.06	0.01	0.04	0.002	0.006	0.001	0.000	0.001
ALK063	0.28	0.77	0.03	0.06	0.07	0.003	0.004	0.000	0.000	0.001
APA061	0.44	0.46	0.11	0.05	0.16	0.003	0.001	0.000	0.000	0.002
APA065	0.11	0.56	0.02	0.00	0.00	0.001	0.001	0.000	0.000	0.000
APA068	0.37	0.26	0.04	0.02	0.05	0.003	0.001	0.000	0.000	0.000
APA072	0.81	1.04	0.22	0.06	0.07	0.003	0.002	0.001	0.000	0.000
APA075	0.60	2.00	0.72	0.12	0.23	0.004	0.005	0.005	0.001	0.001
APA078	0.37	0.20	0.68	0.07	0.08	0.003	0.000	0.002	0.002	0.001
BCR061	0.34	0.18	0.04	0.04	0.09	0.002	0.001	0.001	0.001	0.001
BCR062	0.77	0.44	0.10	0.04	0.08	0.005	0.003	0.002	0.000	0.001
BCR082	0.23	0.15	0.39	0.06	0.09	0.000	0.001	0.001	0.000	0.001
BRP062	0.08	0.04	0.02	0.02	0.01	0.001	0.000	0.000	0.000	0.000
CEL062	1.13	0.03	0.05	0.04	0.00	0.001	0.000	0.001	0.000	0.000
CEL064	1.21	0.39	0.24	0.37	0.08	0.002	0.003	0.001	0.004	0.001
CEL066	0.49	0.17	0.48	0.07	0.08	0.000	0.002	0.002	0.001	0.001
CEL072	0.08	0.05	0.15	0.24	0.06	0.001	0.001	0.002	0.002	0.001
CEL075	0.35	0.08	0.01	0.00	0.01	0.000	0.000	0.000	0.000	0.000
CGR061	0.03	1.46	0.37	0.09	0.14	0.000	0.012	0.003	0.000	0.002
DBL067	0.23	0.03	0.81	0.10	0.05	0.003	0.000	0.012	0.001	0.001
DBL069	0.05	0.36	0.03	0.00	0.06	0.000	0.001	0.000	0.000	0.000
DBL073	0.22	0.23	0.02	0.52	0.03	0.004	0.001	0.000	0.006	0.000
DBL074	0.04	0.08	0.92	0.18	0.20	0.000	0.000	0.006	0.002	0.002
DBL081	0.16	0.10	0.02	0.01	0.09	0.001	0.001	0.000	0.000	0.000
DPN063	1.26	0.49	0.46	0.12	0.03	0.003	0.004	0.002	0.002	0.000
DPN073	0.41	0.32	0.19	0.05	0.04	0.000	0.000	0.001	0.001	0.000
EBL084	1.62	0.05	1.59	0.07	0.06	0.002	0.000	0.002	0.001	0.001
ECK063	0.22	0.13	0.03	0.03	0.01	0.001	0.001	0.000	0.000	0.000
EDA065	0.53	0.07	0.02	0.02	0.01	0.001	0.000	0.000	0.000	0.000
EDA068	0.01	0.00	0.00	0.00	0.00	0.000	0.000	0.000	0.000	0.000
EDA072	0.35	0.04	0.02	0.03	0.02	0.001	0.000	0.000	0.000	0.000
EDP072	0.00	0.00	0.01	0.00	0.00	0.000	0.000	0.000	0.000	0.000
EDP073	0.13	0.10	0.18	0.02	0.14	0.001	0.001	0.003	0.000	0.001
EDP091	0.03	0.39	0.05	0.03	0.19	0.000	0.003	0.000	0.000	0.003
EDP094	0.01	0.03	0.00	0.01	0.00	0.000	0.000	0.000	0.000	0.000
ELP063	0.03	0.02	0.05	0.03	0.07	0.001	0.000	0.001	0.000	0.000
ELP071	0.03	0.12	0.10	0.23	0.02	0.001	0.003	0.001	0.004	0.000
EXC062	0.89	0.41	0.36	0.25	0.13	0.003	0.006	0.002	0.001	0.001
GLK061	4.12	0.03	0.06	0.25	0.11	0.006	0.000	0.000	0.002	0.001
GLK063	1.12	0.12	0.16	0.21	0.21	0.003	0.000	0.002	0.002	0.002
GLK071	0.28	0.54	0.30	0.50	0.34	0.001	0.003	0.003	0.005	0.001
GLK074	1.46	0.20	0.45	0.41	0.82	0.010	0.002	0.006	0.003	0.006
GNL072	0.82	1.28	0.33	0.12	0.08	0.002	0.002	0.001	0.001	0.001
GSL064	1.09	0.63	0.25	0.31	0.02	0.004	0.002	0.001	0.002	0.000
GSL065	0.10	0.64	0.18	0.10	0.15	0.000	0.001	0.001	0.000	0.000
GSL074	1.15	2.01	0.70	0.14	0.13	0.004	0.004	0.004	0.000	0.001
GSL075	0.14	0.54	0.01	0.03	0.03	0.001	0.000	0.000	0.000	0.000
GSL076	1.10	0.36	0.12	0.14	0.20	0.005	0.004	0.002	0.002	0.002
GSL079	0.23	0.56	0.08	0.12	0.14	0.002	0.001	0.000	0.001	0.001
HOL061	1.15	0.65	0.13	0.34	0.34	0.005	0.005	0.002	0.006	0.003
HOL062	1.34	0.44	0.14	0.60	0.07	0.004	0.006	0.002	0.009	0.000
HWW072	0.48	0.02	0.02	0.01	0.01	0.001	0.000	0.000	0.000	0.000
IDA061	0.19	0.36	0.04	0.05	0.03	0.000	0.001	0.001	0.000	0.000
IDA062	0.90	0.15	0.13	0.05	0.07	0.001	0.002	0.001	0.000	0.001
IDA072	0.19	0.31	0.20	0.12	0.07	0.001	0.003	0.001	0.001	0.001
IDA073	0.31	0.74	0.11	0.09	0.11	0.002	0.002	0.001	0.001	0.002
IDA074	0.16	0.17	0.15	0.02	0.01	0.003	0.000	0.001	0.000	0.000
LIN031	0.37	0.28	0.41	0.18	0.24	0.001	0.003	0.001	0.001	0.002
LLK072	0.19	0.27	0.01	0.11	0.08	0.002	0.001	0.000	0.001	0.000
LOK083	0.01	0.01	0.01	0.01	0.03	0.000	0.000	0.000	0.000	0.000
LOK092	0.00	0.02	0.03	0.02	0.00	0.000	0.000	0.000	0.000	0.000
LOK093	0.40	0.17	0.14	0.23	0.05	0.004	0.002	0.002	0.002	0.001
LSP021	0.45	0.36	0.18	0.14	0.33	0.002	0.001	0.002	0.002	0.002
LSP022	0.37	0.49	0.06	0.27	0.41	0.002	0.003	0.001	0.002	0.003
MEL064	0.02	0.01	0.02	0.02	0.05	0.000	0.000	0.000	0.000	0.000
MEL067	0.08	0.30	0.03	0.04	0.01	0.002	0.001	0.001	0.001	0.000
MEL068	0.16	0.34	0.20	0.03	0.10	0.001	0.000	0.001	0.000	0.000
MEL069	0.94	0.02	0.57	0.68	0.11	0.004	0.000	0.007	0.008	0.001
MEL071	0.00	0.16	0.00	0.02	0.01	0.000	0.000	0.000	0.000	0.000

Proposed FLISR Feeders
Mainline Feeder Level Only Impacts

Total Mainline Feeder Annual Contribution to MN Indices from FLISR candidate feeders

SAIDI 2015	2016	2017	2018	2019	SAIFI 2015	2016	2017	2018	2019
37.5	40.1	23.3	14.3	8.5	0.2	0.2	0.2	0.2	0.1

All Days - Individual Feeder Indices

Feeder	SAIDI 2015	2016	2017	2018	2019	SAIFI 2015	2016	2017	2018	2019
AHI021	559.0	79.0	451.0	149.7	54.7	1.00	1.00	1.00	1.00	0.99
AHI022	723.2	165.8	364.9	0.0	161.0	2.00	1.00	1.62	0.00	1.63
AHI025	0.0	30.5	0.0	84.9	61.0	0.00	0.90	0.00	0.94	1.01
AHI063	42.7	412.3	95.8	66.1	87.6	1.00	1.25	1.00	1.00	1.00
ALD072	39.0	74.0	0.0	0.0	0.0	0.08	0.77	0.00	0.00	0.00
ALD076	0.0	98.6	0.0	0.0	0.0	0.00	1.00	0.00	0.00	0.00
ALD084	5.0	83.1	0.0	0.0	94.6	0.14	0.16	0.00	0.00	1.47
ALD085	0.0	0.0	0.0	29.4	0.0	0.00	0.00	0.00	1.01	0.00
ALD088	428.9	0.0	58.0	58.0	0.0	0.46	0.00	1.00	1.00	0.00
ALD091	0.0	0.0	0.0	0.0	0.0	0.00	0.00	0.00	0.00	0.00
ALD093	704.2	78.6	0.0	220.3	0.0	1.73	0.99	0.00	1.99	0.00
ALD095	0.0	0.0	0.0	0.0	0.0	0.00	0.00	0.00	0.00	0.00
ALD098	52.1	83.3	0.0	0.0	0.0	0.64	2.01	0.00	0.00	0.00
ALK063	119.0	435.1	0.0	0.0	15.2	1.61	2.00	0.00	0.00	0.84
APA061	0.0	0.0	0.0	0.0	81.1	0.00	0.00	0.00	0.00	1.00
APA065	0.0	914.0	49.3	0.0	0.0	0.00	1.00	1.00	0.00	0.00
APA068	0.0	0.0	0.0	0.0	0.0	0.00	0.00	0.00	0.00	0.00
APA072	498.9	554.4	0.0	0.0	0.0	1.00	0.99	0.00	0.00	0.00
APA075	0.0	530.2	119.3	0.0	0.0	0.00	1.00	1.00	0.00	0.00
APA078	63.0	0.0	359.3	15.0	0.0	1.00	0.00	0.88	1.00	0.00
BCR061	115.3	130.9	0.0	17.0	67.0	1.94	1.00	0.00	0.71	1.00
BCR062	325.8	58.2	0.0	0.0	0.0	2.01	1.00	0.00	0.00	0.00
BCR082	0.0	33.1	660.1	0.0	112.5	0.00	1.00	1.00	0.00	1.99
BRP062	35.8	0.0	0.0	0.0	0.0	1.00	0.00	0.00	0.00	0.00
CEL062	197.8	0.0	50.3	0.0	0.0	0.28	0.00	1.01	0.00	0.00
CEL064	586.1	46.8	0.0	147.5	0.0	1.00	1.00	0.00	2.00	0.00
CEL066	0.0	78.8	69.1	0.0	0.0	0.00	1.00	1.00	0.00	0.00
CEL072	0.0	0.0	71.9	38.2	0.0	0.00	0.00	1.00	1.01	0.00
CEL075	856.4	0.0	0.0	0.0	0.0	1.01	0.00	0.00	0.00	0.00
CGR061	0.0	641.1	91.9	0.0	0.0	0.00	5.95	1.00	0.00	0.00
DBL067	34.9	0.0	273.2	0.0	0.0	1.00	0.00	3.98	0.00	0.00
DBL069	100.9	601.0	0.0	0.0	130.4	1.00	2.00	0.00	0.00	1.01
DBL073	105.2	0.0	0.0	175.1	0.0	2.00	0.00	0.00	1.99	0.00
DBL074	0.0	0.0	649.9	0.0	61.1	0.00	0.00	4.00	0.00	0.98
DBL081	116.5	50.6	0.0	0.0	0.0	2.01	0.99	0.00	0.00	0.00
DPN063	604.5	136.6	55.9	0.0	2.4	1.00	2.01	1.00	0.00	0.01
DPN073	0.0	0.0	95.3	0.0	0.0	0.00	0.00	1.09	0.00	0.00
EBL084	411.8	0.0	1,469.4	0.0	27.9	1.59	0.00	0.97	0.00	1.00
ECK063	0.0	0.0	0.0	0.0	0.0	0.00	0.00	0.00	0.00	0.00
EDA065	661.8	0.0	0.0	0.0	0.0	1.67	0.00	0.00	0.00	0.00
EDA068	0.0	0.0	0.0	0.0	0.0	0.00	0.00	0.00	0.00	0.00
EDA072	555.5	0.0	0.0	0.0	0.0	1.00	0.00	0.00	0.00	0.00
EDP072	0.0	0.0	356.0	40.0	0.0	0.00	0.00	3.00	1.00	0.00
EDP073	0.0	0.0	6.0	0.0	86.0	0.00	0.00	1.00	0.00	1.00
EDP091	0.0	142.8	0.0	0.0	82.5	0.00	2.00	0.00	0.00	2.00
EDP094	0.0	0.0	0.0	0.0	16.7	0.00	0.00	0.00	0.00	1.04
ELP063	0.0	0.0	151.1	83.1	7.5	0.00	0.00	2.09	1.05	0.05
ELP071	0.0	32.2	0.0	41.6	0.0	0.00	1.00	0.00	1.01	0.00
EXC062	0.0	212.5	93.6	0.0	0.0	0.00	4.23	1.00	0.00	0.00
GLK061	2,432.0	0.0	0.0	141.1	0.0	3.01	0.00	0.00	1.00	0.00
GLK063	926.1	0.0	79.0	79.2	0.0	2.01	0.00	1.13	1.01	0.00
GLK071	0.0	147.7	55.4	130.2	0.0	0.00	0.98	0.94	1.86	0.00
GLK074	377.8	0.0	67.9	66.2	181.7	4.00	0.00	2.00	1.00	1.99
GNL072	0.0	0.0	0.0	1.5	0.0	0.00	0.00	0.00	0.12	0.00
GSL064	809.2	171.8	0.0	163.5	0.0	3.04	0.98	0.00	2.01	0.00
GSL065	0.0	273.7	253.8	0.0	0.0	0.00	1.00	1.99	0.00	0.00
GSL074	660.8	842.2	439.6	0.8	93.3	2.00	2.00	2.02	0.07	0.98
GSL075	0.0	0.0	0.0	0.0	0.0	0.00	0.00	0.00	0.00	0.00
GSL076	634.9	146.1	50.9	52.8	66.7	2.00	2.00	1.00	1.00	1.00
GSL079	0.0	0.0	0.0	69.0	0.0	0.00	0.00	0.00	1.00	0.00
HOL061	817.5	243.5	70.6	142.5	0.0	2.97	2.97	0.98	2.98	0.00
HOL062	747.5	285.2	71.9	359.4	0.0	2.00	4.04	1.00	5.02	0.00
HWW072	242.9	0.0	0.0	0.0	0.0	0.30	0.00	0.00	0.00	0.00
IDA061	0.0	0.0	0.0	0.0	0.0	0.00	0.00	0.00	0.00	0.00
IDA062	0.0	53.2	0.0	0.0	9.1	0.00	0.95	0.00	0.00	0.32
IDA072	0.0	47.5	0.0	0.0	0.0	0.00	1.00	0.00	0.00	0.00
IDA073	62.1	417.3	0.0	0.0	9.1	1.00	1.00	0.00	0.00	0.35
IDA074	59.7	0.0	0.0	0.0	0.0	1.66	0.00	0.00	0.00	0.00
LIN031	0.0	80.7	0.0	0.0	0.0	0.00	1.00	0.00	0.00	0.00
LLK072	75.9	0.0	0.0	36.0	0.0	1.00	0.00	0.00	0.43	0.00
LOK083	0.0	0.0	55.0	0.0	83.3	0.00	0.00	2.00	0.00	1.70
LOK092	0.0	75.6	165.3	215.0	0.0	0.00	1.01	1.90	0.98	0.00
LOK093	135.8	0.0	49.1	62.8	0.0	1.44	0.00	1.00	1.00	0.00
LSP021	0.0	237.8	10.0	0.0	0.0	0.00	0.99	1.00	0.00	0.00
LSP022	353.0	643.9	76.9	434.0	433.1	1.00	2.82	2.00	2.01	2.45
MEL064	0.0	0.0	0.0	83.9	37.7	0.00	0.00	0.00	1.01	1.00
MEL067	97.0	702.2	66.4	52.8	0.0	2.01	0.94	1.30	1.00	0.00
MEL068	44.9	0.0	31.5	0.0	0.0	1.00	0.00	1.02	0.00	0.00
MEL069	477.1	0.0	247.4	341.9	0.0	1.00	0.00	3.72	4.01	0.00
MEL071	0.0	0.0	0.0	132.9	0.0	0.00	0.00	0.00	1.01	0.00

All Days - Individual Feeder Contributions to MN

Feeder	SAIDI 2015	2016	2017	2018	2019	SAIFI 2015	2016	2017	2018	2019
AHI021	0.41	0.06	0.33	0.11	0.04	0.001	0.001	0.001	0.001	0.001
AHI022	0.90	0.21	0.45	0.00	0.19	0.002	0.001	0.002	0.000	0.002
AHI025	0.00	0.01	0.00	0.02	0.02	0.000	0.000	0.000	0.000	0.000
AHI063	0.06	0.58	0.14	0.09	0.12	0.001	0.002	0.001	0.001	0.001
ALD072	0.14	0.17	0.00	0.00	0.00	0.000	0.002	0.000	0.000	0.000
ALD076	0.00	0.23	0.00	0.00	0.00	0.000	0.002	0.000	0.000	0.000
ALD084	0.01	0.14	0.00	0.00	0.15	0.000	0.000	0.000	0.000	0.002
ALD085	0.00	0.00	0.00	0.08	0.00	0.000	0.000	0.000	0.003	0.000
ALD088	1.02	0.00	0.14	0.14	0.00	0.001	0.000	0.002	0.002	0.000
ALD091	0.00	0.00	0.00	0.00	0.00	0.000	0.000	0.000	0.000	0.000
ALD093	0.17	0.02	0.00	0.05	0.00	0.000	0.000	0.000	0.000	0.000
ALD095	0.00	0.00	0.00	0.00	0.00	0.000	0.000	0.000	0.000	0.000
ALD098	0.12	0.20	0.00	0.00	0.00	0.002	0.005	0.000	0.000	0.000
ALK063	0.20	0.72	0.00	0.00	0.02	0.003	0.003	0.000	0.000	0.001
APA061	0.00	0.00	0.00	0.00	0.12	0.000	0.000	0.000	0.000	0.001
APA065	0.00	0.32	0.02	0.00	0.00	0.000	0.000	0.000	0.000	0.000
APA068	0.00	0.00	0.00	0.00	0.00	0.000	0.000	0.000	0.000	0.000
APA072	0.62	0.69	0.00	0.00	0.00	0.001	0.001	0.000	0.000	0.000
APA075	0.00	1.71	0.38	0.00	0.00	0.000	0.003	0.003	0.000	0.000
APA078	0.08	0.00	0.44	0.02	0.00	0.001	0.000	0.001	0.001	0.000
BCR061	0.11	0.13	0.00	0.02	0.06	0.002	0.001	0.000	0.001	0.001
BCR062	0.70	0.12	0.00	0.00	0.00	0.004	0.002	0.000	0.000	0.000
BCR082	0.00	0.02	0.36	0.00	0.06	0.000	0.001	0.001	0.000	0.001
BRP062	0.03	0.00	0.00	0.00	0.00	0.001	0.000	0.000	0.000	0.000
CEL062	0.13	0.00	0.03	0.00	0.00	0.000	0.000	0.001	0.000	0.000
CEL064	0.96	0.08	0.00	0.24	0.00	0.002	0.002	0.000	0.003	0.000
CEL066	0.00	0.12	0.11	0.00	0.00	0.000	0.002	0.002	0.000	0.000
CEL072	0.00	0.00	0.07	0.04	0.00	0.000	0.000	0.001	0.001	0.000
CEL075	0.34	0.00	0.00	0.00	0.00	0.000	0.000	0.000	0.000	0.000
CGR061	0.00	1.18	0.17	0.00	0.00	0.000	0.011	0.002	0.000	0.000
DBL067	0.09	0.00	0.61	0.00	0.00	0.002	0.000	0.009	0.000	0.000
DBL069	0.04	0.24	0.00	0.00	0.05	0.000	0.001	0.000	0.000	0.000
DBL073	0.19	0.00	0.00	0.31	0.00	0.004	0.000	0.000	0.003	0.000
DBL074	0.00	0.00	0.88	0.00	0.08	0.000	0.000	0.005	0.000	0.001
DBL081	0.07	0.03	0.00	0.00	0.00	0.001	0.001	0.000	0.000	0.000
DPN063	0.80	0.18	0.07	0.00	0.00	0.001	0.003	0.001	0.000	0.000
DPN073	0.00	0.00	0.07	0.00	0.00	0.000	0.000	0.001	0.000	0.000
EBL084	0.43	0.00	1.53	0.00	0.03	0.002	0.000	0.001	0.000	0.001
ECK063	0.00	0.00	0.00	0.00	0.00	0.000	0.000	0.000	0.000	0.000
EDA065	0.52	0.00	0.00	0.00	0.00	0.001	0.000	0.000	0.000	0.000
EDA068	0.00	0.00	0.00	0.00	0.00	0.000	0.000	0.000	0.000	0.000
EDA072	0.33	0.00	0.00	0.00	0.00	0.001	0.000	0.000	0.000	0.000
EDP072	0.00	0.00	0.01	0.00	0.00	0.000	0.000	0.000	0.000	0.000
EDP073	0.00	0.00	0.01	0.00	0.12	0.000	0.000	0.001	0.000	0.001
EDP091	0.00	0.20	0.00	0.00	0.11	0.000	0.003	0.000	0.000	0.003
EDP094	0.00	0.00	0.00	0.00	0.00	0.000	0.000	0.000	0.000	0.000
ELP063	0.00	0.00	0.05	0.03	0.00	0.000	0.000	0.001	0.000	0.000
ELP071	0.00	0.07	0.00	0.09	0.00	0.000	0.002	0.000	0.002	0.000
EXC062	0.00	0.26	0.11	0.00	0.00	0.000	0.005	0.001	0.000	0.000
GLK061	3.01	0.00	0.00	0.17	0.00	0.004	0.000	0.000	0.001	0.000
GLK063	1.01	0.00	0.09	0.09	0.00	0.002	0.000	0.001	0.001	0.000
GLK071	0.00	0.31	0.12	0.27	0.00	0.000	0.002	0.002	0.004	0.000
GLK074	0.82	0.00	0.15	0.14	0.39	0.009	0.000	0.004	0.002	0.004
GNL072	0.00	0.00	0.00	0.00	0.00	0.000	0.000	0.000	0.000	0.000
GSL064	0.80	0.17	0.00	0.16	0.00	0.003	0.001	0.000	0.002	0.000
GSL065	0.00	0.18	0.17	0.00	0.00	0.000	0.001	0.001	0.000	0.000
GSL074	0.68	0.86	0.44	0.00	0.09	0.002	0.002	0.002	0.000	0.001
GSL075	0.00	0.00	0.00	0.00	0.00	0.000	0.000	0.000	0.000	0.000
GSL076	0.97	0.22	0.08	0.08	0.10	0.003	0.003	0.002	0.001	0.001
GSL079	0.00	0.00	0.00	0.08	0.00	0.000	0.000	0.000	0.001	0.000
HOL061	1.07	0.33	0.10	0.20	0.00	0.004	0.004	0.001	0.004	0.000
HOL062	1.11	0.42	0.11	0.53	0.00	0.003	0.006	0.001	0.007	0.000
HWW072	0.45	0.00	0.00	0.00	0.00	0.001	0.000	0.000	0.000	0.000
IDA061	0.00	0.00	0.00	0.00	0.00	0.000	0.000	0.000	0.000	0.000
IDA062	0.00	0.08	0.00	0.00	0.01	0.000	0.001	0.000	0.000	0.000
IDA072	0.00	0.11	0.00	0.00	0.00	0.000	0.002	0.000	0.000	0.000
IDA073	0.08	0.53	0.00	0.00	0.01	0.001	0.001	0.000	0.000	0.001
IDA074	0.10	0.00	0.00	0.00	0.00	0.003	0.000	0.000	0.000	0.000
LIN031	0.00	0.19	0.00	0.00	0.00	0.000	0.002	0.000	0.000	0.000
LLK072	0.12	0.00	0.00	0.06	0.00	0.002	0.000	0.000	0.001	0.000
LOK083	0.00	0.00	0.01	0.00	0.01	0.000	0.000	0.000	0.000	0.000
LOK092	0.00	0.01	0.02	0.02	0.00	0.000	0.000	0.000	0.000	0.000
LOK093	0.21	0.00	0.08	0.10	0.00	0.002	0.000	0.002	0.002	0.000
LSP021	0.00	0.23	0.01	0.00	0.00	0.000	0.001	0.001	0.000	0.000
LSP022	0.19	0.35	0.04	0.23	0.23	0.001	0.002	0.001	0.001	0.001
MEL064	0.00	0.00	0.00	0.02	0.01	0.000	0.000	0.000	0.000	0.000
MEL067	0.05	0.26	0.02	0.02	0.00	0.001	0.000	0.000	0.000	0.000
MEL068	0.02	0.00	0.02	0.00	0.00	0.001	0.000	0.001	0.000	0.000
MEL069	0.79	0.00	0.40	0.55	0.00	0.002	0.000	0.006	0.006	0.000
MEL071	0.00	0.00	0.00	0.02	0.00	0.000	0.000	0.000	0.000	0.000

Proposed FLISR Feeders
System All Levels Impacts

	All Days - Individual Feeder Indices										All Days - Individual Feeder Contributions to MN SAIDI									
											Total All Levels Annual Contribution to MN Indices from FLISR candidate feeders									
											73.0	83.9	46.3	30.6	23.2	0.3	0.4	0.3	0.3	0.2
	SAIDI					SAIFI					SAIDI					SAIFI				
Feeder	2015	2016	2017	2018	2019	2015	2016	2017	2018	2019	2015	2016	2017	2018	2019	2015	2016	2017	2018	2019
MEL073	54.7	27.7	113.0	67.3	49.3	1.31	0.25	0.41	1.42	0.48	0.15	0.08	0.31	0.18	0.12	0.004	0.001	0.001	0.004	0.001
MEL075	10.7	264.0	110.8	81.6	22.7	1.06	0.42	2.27	1.20	0.12	0.02	0.35	0.15	0.11	0.03	0.002	0.001	0.003	0.002	0.000
MEL076	158.5	3.7	0.0	106.2	0.2	2.61	0.06	0.00	1.52	0.00	0.10	0.00	0.00	0.07	0.00	0.002	0.000	0.000	0.001	0.000
MEL077	451.0	8.7	19.4	68.6	170.1	3.04	0.14	0.32	0.36	0.88	0.11	0.00	0.00	0.02	0.04	0.001	0.000	0.000	0.000	0.000
MND061	700.7	698.0	539.6	320.4	101.9	1.38	3.23	1.21	3.32	1.21	0.67	0.67	0.51	0.30	0.10	0.001	0.003	0.001	0.003	0.001
MND062	234.5	503.9	377.9	230.4	44.9	0.63	3.32	2.37	2.60	0.43	0.48	1.03	0.78	0.48	0.09	0.001	0.007	0.005	0.005	0.001
MND063	457.4	282.0	149.3	106.2	77.4	1.49	2.45	1.33	0.42	0.28	0.65	0.40	0.21	0.15	0.11	0.002	0.003	0.002	0.001	0.000
MND071	227.9	317.3	247.1	187.4	243.2	0.60	4.97	1.05	2.19	2.37	0.43	0.59	0.46	0.34	0.44	0.001	0.009	0.002	0.004	0.004
MND072	893.0	408.5	147.8	610.3	156.7	3.42	2.30	0.37	4.17	1.25	1.40	0.64	0.23	0.94	0.24	0.005	0.004	0.001	0.006	0.002
MOL064	60.1	307.3	41.9	49.8	93.0	0.43	2.33	0.20	0.32	1.23	0.08	0.41	0.05	0.06	0.11	0.001	0.003	0.000	0.000	0.001
MOL066	226.2	766.6	660.3	114.0	179.1	2.78	2.09	1.05	0.79	1.28	0.52	1.76	1.52	0.26	0.41	0.006	0.005	0.002	0.002	0.003
MOL073	151.0	29.8	252.2	68.8	104.8	0.66	0.26	1.99	0.55	1.40	0.21	0.04	0.34	0.09	0.14	0.001	0.000	0.003	0.001	0.002
MPK063	410.5	85.8	26.9	64.8	77.3	2.36	0.37	0.24	0.46	1.20	1.17	0.24	0.08	0.18	0.21	0.007	0.001	0.001	0.001	0.003
MPK067	24.9	805.8	3.2	11.5	5.5	0.44	1.51	0.01	0.04	0.04	0.00	0.11	0.00	0.00	0.00	0.000	0.000	0.000	0.000	0.000
MPK068	113.5	139.3	23.3	184.2	27.6	0.67	0.99	0.21	2.44	0.28	0.28	0.34	0.06	0.45	0.07	0.002	0.002	0.001	0.006	0.001
MPK078	24.5	378.0	343.5	33.7	157.3	0.18	4.48	2.23	0.19	2.12	0.08	1.28	1.15	0.11	0.52	0.001	0.015	0.007	0.001	0.007
MPK085	78.6	110.3	55.3	26.7	109.5	0.63	0.53	0.58	0.26	1.16	0.21	0.24	0.12	0.05	0.22	0.002	0.001	0.001	0.001	0.002
MPK086	359.2	695.7	158.0	249.3	13.3	3.37	3.34	1.18	0.39	0.08	0.40	0.77	0.17	0.27	0.01	0.004	0.004	0.001	0.000	0.000
OAD063	178.3	65.3	79.3	39.6	88.8	1.20	0.16	0.26	0.27	1.26	0.34	0.12	0.15	0.07	0.17	0.002	0.000	0.000	0.001	0.002
OAD065	28.1	121.3	9.6	14.4	122.3	0.14	1.22	0.17	0.13	2.08	0.02	0.09	0.01	0.01	0.09	0.000	0.001	0.000	0.000	0.001
OAD072	322.3	43.1	93.1	168.6	32.5	2.39	0.24	0.56	2.30	0.21	0.60	0.08	0.17	0.31	0.06	0.004	0.000	0.001	0.004	0.000
OPK065	148.4	50.8	48.9	314.9	50.8	2.22	1.27	0.36	1.85	0.42	0.25	0.09	0.08	0.36	0.06	0.004	0.002	0.001	0.002	0.000
OPK071	103.8	107.6	225.0	406.1	91.5	1.20	2.11	2.28	3.48	1.04	0.05	0.05	0.11	0.19	0.04	0.001	0.001	0.001	0.002	0.000
OPK072	228.7	97.2	238.2	281.0	42.5	0.69	1.38	2.42	1.30	0.36	0.17	0.07	0.17	0.20	0.03	0.001	0.001	0.002	0.001	0.000
OPK073	259.4	695.7	903.1	244.8	100.8	2.04	3.65	4.74	0.93	0.50	0.56	1.50	1.94	0.39	0.16	0.004	0.008	0.010	0.001	0.001
OPK077	613.6	229.1	297.8	284.2	96.8	2.40	1.45	2.29	1.58	0.64	0.91	0.34	0.45	0.44	0.15	0.004	0.002	0.003	0.002	0.001
ORO061	175.6	60.4	71.8	152.0	11.3	0.33	0.20	0.21	2.22	0.18	0.20	0.07	0.08	0.17	0.01	0.000	0.000	0.000	0.002	0.000
ORO062	485.5	192.6	288.9	132.6	71.5	1.62	1.51	2.74	0.92	0.57	0.54	0.22	0.32	0.15	0.08	0.002	0.002	0.003	0.001	0.001
OSS077	289.5	191.5	130.9	82.3	104.1	2.58	0.80	1.44	0.37	0.41	0.37	0.24	0.16	0.10	0.13	0.003	0.001	0.002	0.000	0.001
PKL062	136.4	24.1	17.2	3.4	17.7	1.40	0.04	0.12	0.01	0.07	0.04	0.01	0.00	0.00	0.00	0.000	0.000	0.000	0.000	0.000
PKL063	632.4	52.7	396.7	110.2	2.0	1.05	0.38	0.76	0.42	0.02	0.10	0.01	0.06	0.02	0.00	0.000	0.000	0.000	0.000	0.000
PKL065	178.9	245.9	174.4	31.9	1.7	1.17	1.67	1.56	0.36	0.04	0.14	0.19	0.15	0.03	0.00	0.001	0.001	0.001	0.000	0.000
PKL071	28.3	4.6	0.6	138.5	4.9	0.14	0.05	0.02	0.75	0.07	0.00	0.00	0.00	0.02	0.00	0.000	0.000	0.000	0.000	0.000
PKL072	39.2	165.1	9.3	159.7	19.4	0.17	0.61	0.11	0.73	0.17	0.01	0.06	0.00	0.05	0.01	0.000	0.000	0.000	0.000	0.000
PKL073	242.9	51.7	9.2	71.7	86.3	0.35	0.21	0.08	0.33	0.80	0.09	0.02	0.00	0.03	0.03	0.000	0.000	0.000	0.000	0.000
PKL081	68.8	76.7	15.0	33.8	21.2	0.55	0.64	0.24	0.37	0.14	0.08	0.09	0.02	0.04	0.02	0.001	0.001	0.000	0.000	0.000
PKL082	76.7	1.2	8.7	14.6	46.2	0.06	0.02	0.08	1.05	0.20	0.04	0.00	0.00	0.01	0.02	0.000	0.000	0.000	0.001	0.000
PKL085	20.8	808.5	62.8	52.0	30.4	0.22	1.34	0.39	0.35	0.32	0.04	1.65	0.13	0.10	0.06	0.000	0.003	0.001	0.001	0.001
RAM063	18.2	154.0	17.5	133.3	44.1	0.05	0.33	0.21	1.42	1.10	0.03	0.26	0.03	0.22	0.07	0.000	0.001	0.000	0.002	0.002
RAM071	203.4	138.3	36.4	84.9	108.9	1.39	0.26	0.19	1.23	0.41	0.33	0.23	0.06	0.14	0.18	0.002	0.000	0.000	0.002	0.001
RAM073	159.2	694.0	58.7	149.8	62.2	0.67	2.61	0.42	1.63	0.45	0.28	1.22	0.10	0.27	0.11	0.001	0.005	0.001	0.003	0.001
RIV061	209.1	352.6	96.4	96.4	79.5	2.18	1.29	1.16	1.02	2.09	0.30	0.50	0.14	0.14	0.12	0.003	0.002	0.002	0.001	0.003
RIV063	167.4	134.1	37.8	151.6	93.6	1.37	1.14	0.48	2.22	0.87	0.13	0.10	0.03	0.11	0.07	0.001	0.001	0.000	0.002	0.001
RIV064	287.0	271.5	114.2	54.1	113.2	3.60	2.34	0.80	1.30	3.24	0.37	0.35	0.15	0.07	0.14	0.005	0.003	0.001	0.002	0.004
RIV073	42.0	777.2	32.4	11.2	34.8	0.49	1.20	0.18	0.07	0.09	0.05	0.95	0.04	0.01	0.04	0.001	0.001	0.000	0.000	0.000
RIV076	101.8	489.6	24.0	64.3	112.6	1.35	1.41	1.15	1.27	2.09	0.10	0.48	0.02	0.06	0.11	0.001	0.001	0.001	0.001	0.002
RLK065	474.9	139.9	87.2	49.9	142.6	1.14	1.18	1.21	0.28	1.36	0.13	0.04	0.02	0.01	0.05	0.000	0.000	0.000	0.000	0.000
RLK066	104.8	170.4	59.8	48.3	64.0	0.47	2.40	1.20	0.19	0.60	0.20	0.33	0.11	0.09	0.12	0.001	0.005	0.002	0.000	0.001
RLK069	448.3	128.9	511.1	110.8	61.0	1.15	1.28	3.18	1.26	0.71	0.61	0.17	0.69	0.16	0.09	0.002	0.002	0.004	0.002	0.001
RLK071	126.4	136.9	74.2	118.4	198.1	1.83	1.36	1.29	2.22	3.03	0.18	0.20	0.11	0.17	0.28	0.003	0.002	0.002	0.003	0.004
RLK073	140.8	89.2	119.9	32.4	49.6	1.23	0.35	0.97	0.27	0.24	0.20	0.13	0.17	0.05	0.07	0.002	0.000	0.001	0.000	0.000
RPL071	79.1	913.5	140.5	348.4	46.6	0.18	1.37	1.74	3.34	0.19	0.07	0.75	0.11	0.28	0.04	0.000	0.001	0.001	0.003	0.000
RPL074	82.1	267.9	80.1	65.3	430.4	0.14	1.32	0.33	0.27	1.23	0.04	0.14	0.04	0.03	0.22	0.000	0.001	0.000	0.000	0.001
RRK063	205.6	359.7	97.8	81.2	47.2	2.09	1.95	1.26	1.36	0.32	0.29	0.50	0.14	0.11	0.07	0.003	0.003	0.002	0.002	0.000
RRK064	32.0	784.8	14.9	320.9	34.4	0.32	1.35	0.08	3.14	0.19	0.09	2.12	0.04	0.92	0.10	0.001	0.004	0.000	0.009	0.001
RRK071	25.6	534.5	148.8	225.8	244.2	0.98	4.49	1.98	2.19	2.02	0.00	0.02	0.01	0.01	0.01	0.000	0.000	0.000	0.000	0.000
RWD063	312.2	695.5	273.1	341.7	90.5	1.96	1.64	3.19	3.90	0.55	0.27	0.61	0.24	0.30	0.08	0.002	0.001	0.003	0.003	0.000
RWD082	83.7	44.8	58.6	6.9	28.6	0.53	0.25	1.05	0.05	0.13	0.03	0.01	0.02	0.00	0.01	0.000	0.000	0.000	0.000	0.000
SAV063	98.3	18.6	39.4	11.1	92.9	0.97	0.11	0.15	0.12	1.15	0.16	0.03	0.07	0.02	0.18	0.002	0.000	0.000	0.000	0.002
SAV071	115.2	182.2	301.0	415.2	128.9	0.41	0.26	1.32	3.38	0.41	0.18	0.28	0.47	0.65	0.20	0.001	0.000	0.002	0.005	0.001
SAV073	53.1	32.0	149.3	102.0	353.8	0.06	0.32	1.19	0.44	1.57	0.04	0.03	0.12	0.08	0.27	0.000	0.000	0.001	0.000	0.001
SHP062	69.4	104.0	18.0	11.1	89.9	0.41	1.10	0.14	0.07	1.06	0.14	0.20	0.03	0.02	0.17	0.001	0.002	0.000	0.000	0.002
SHP072	49.3	45.2	45.5	29.8	18.2	0.19	0.22	0.36	0.10	0.21	0.08	0.07	0.07	0.05	0.03	0.000	0.000	0.001	0.000	0.000
SLP071	72.3	33.5	496.4	117.6	88.9	0.57	0.34	2.28	1.32	0.51	0.11	0.05	0.72	0.17	0.14	0.001	0.000	0.003	0.002	0.001
SLP075	56.7	93.2	289.8	71.7	26.0	1.56	0.42	4.26	1.34	0.11	0.07	0.12	0.36	0.09	0.03	0.002	0.001	0.005	0.002	0.000
SLP076	722.3	57.0	240.1	72.1	11.3	1.75	0.33	1.52	1.27	0.15	1.37	0.11	0.45	0.14	0.02	0.003	0.001	0.003	0.002	0.000
SLP077	844.0	337.0	26.3	137.9	327.0	2.21	0.44	0.19	1.14	2.48	0.97	0.38	0.03	0.16	0.37	0.003	0.000	0.000	0.001	0.003
SLP081	336.4	116.9	126.2	93.4	20.7	0.65	0.22	0.79	1.64	0.25	0.58	0.20	0.22	0.16	0.03	0.001	0.000	0.001	0.003	0.000
SLP083	126.0	73.0	56.6	28.7	65.0	0.27	0.42	0.26	0.25	0.29	0.27	0.15	0.12	0.06	0.13	0.001	0.001	0.001	0.001	0.001
SLP092	756.2	149.3	16.9	86.7	85.9	1.63	1.58	0.07	0.67	1.22	1.68	0.34	0.04	0.19	0.19	0.004	0.004	0.000	0.001	0.003
SLP093	198.6	29.5	243.1	47.6	198.6	1.08	0.16	1.71	0.45	2.24	0.44	0.07	0.54	0.10	0.43	0.002	0.000	0.004	0.001	0.005
SLP096	190.6	5.2	1,272.7	31.0	85.6	1.99	0.10	3.91	0.25	0.88	0.39	0.01	2.60	0.06	0.21	0.004	0.000	0.008	0.001	0.002
SLP097	654.1	39.5	229.3	37.9	63.9	1.14	0.22	2.45	0.27	0.76	0.67	0.04	0.23	0.04	0.07	0.001	0.000	0.002	0.000	0.001
SOU066	100.7	15.1	19.4	44.2	61.9	0.30	0.05	1.09	0.08	1.02	0.05	0.01	0.01	0.03	0.04	0.000	0.000	0.001	0.000	0.001
SOU073	16.8	117.4	21.0	9.1	6.7	0.16	1.28	0.08	0.14	0.18	0.02	0.14	0.02	0.01	0.01	0.000	0.002	0.000	0.000	0.000
SOU075	141.6	54.3	243.1	19.7	36.3	1.28	1.13	1.13	0.31	1.23	0.38	0.15	0.65	0.05	0.09	0.003	0.003	0.003	0.001	0.003
SOU077	8.0	56.2	31.1	19.9	7.4	0.13	0.48	0.19	0.24	0.10	0.02	0.17	0.09	0.04	0.02	0.000	0.001	0.001	0.001	0.000
SOU081	13.7	34.0	127.9	37.9	103.8	0.15	0.36	3.16	0.33	1.44	0.02	0.04	0.16	0.05	0.13	0.000	0.000	0.004	0.000	0.002
SOU083	33.8	144.6	182.8	49.2	39.3	0.38	0.42	0.93	0.76	0.39	0.07	0.30	0.39	0.10	0.08	0.001	0.001	0.002	0.002	0.001
SOU084	736.4	10.7	493.8	41.7	7.7	1.40	0.15	0.50	0.57	0.12	0.36	0.01	0.25	0.02	0.00	0.001	0.000	0.000	0.000	0.000

Proposed FLISR Feeders
Mainline Feeder Level Only Impacts

	All Days - Individual Feeder Indices										All Days - Individual Feeder Contributions to MN									
											Total Mainline Feeder Annual Contribution to MN Indices from FLISR candidate feeders									
											37.5	40.1	23.3	14.3	8.5	0.2	0.2	0.2	0.2	0.1
	SAIDI					SAIFI					SAIDI					SAIFI				
Feeder	2015	2016	2017	2018	2019	2015	2016	2017	2018	2019	2015	2016	2017	2018	2019	2015	2016	2017	2018	2019
MEL073	0.0	0.0	0.0	26.0	0.0	0.00	0.00	0.00	1.00	0.00	0.00	0.00	0.00	0.07	0.00	0.000	0.000	0.000	0.003	0.000
MEL075	0.0	0.0	73.0	60.8	0.0	0.00	0.00	2.00	1.00	0.00	0.00	0.00	0.10	0.08	0.00	0.000	0.000	0.003	0.001	0.000
MEL076	0.0	0.0	0.0	102.3	0.0	0.00	0.00	0.00	1.42	0.00	0.00	0.00	0.00	0.07	0.00	0.000	0.000	0.000	0.001	0.000
MEL077	196.8	0.0	0.0	0.0	0.0	1.15	0.00	0.00	0.00	0.00	0.05	0.00	0.00	0.00	0.00	0.000	0.000	0.000	0.000	0.000
MND061	612.9	630.0	483.6	262.4	53.0	0.99	2.99	1.00	3.00	0.91	0.59	0.61	0.46	0.25	0.05	0.001	0.003	0.001	0.003	0.001
MND062	0.0	313.1	216.4	126.2	24.4	0.00	2.61	2.00	2.20	0.19	0.00	0.64	0.45	0.26	0.05	0.000	0.005	0.004	0.005	0.000
MND063	249.1	123.2	66.3	0.0	0.0	1.01	1.93	1.00	0.00	0.00	0.35	0.17	0.09	0.00	0.00	0.001	0.003	0.001	0.000	0.000
MND071	0.0	239.1	0.0	92.1	182.3	0.00	4.11	0.00	1.00	1.98	0.00	0.45	0.00	0.17	0.33	0.000	0.008	0.000	0.002	0.004
MND072	678.3	287.0	0.6	415.5	129.3	3.00	2.00	0.08	2.22	1.00	1.06	0.45	0.00	0.64	0.20	0.005	0.003	0.000	0.003	0.002
MOL064	0.0	129.9	0.0	0.0	40.8	0.00	1.99	0.00	0.00	1.00	0.00	0.17	0.00	0.00	0.05	0.000	0.003	0.000	0.000	0.001
MOL066	75.3	70.3	0.0	0.0	0.0	2.01	1.00	0.00	0.00	0.00	0.17	0.16	0.00	0.00	0.00	0.005	0.002	0.000	0.000	0.000
MOL073	0.0	0.0	184.9	0.0	47.0	0.00	0.00	1.47	0.00	1.00	0.00	0.00	0.25	0.00	0.06	0.000	0.000	0.002	0.000	0.001
MPK063	371.0	0.0	0.0	0.0	57.8	2.11	0.00	0.00	0.00	1.00	1.06	0.00	0.00	0.00	0.16	0.006	0.000	0.000	0.000	0.003
MPK067	0.0	735.5	0.0	0.0	0.0	0.00	0.65	0.00	0.00	0.00	0.00	0.10	0.00	0.00	0.00	0.000	0.000	0.000	0.000	0.000
MPK068	12.5	33.1	0.0	149.7	0.0	0.34	0.55	0.00	2.02	0.00	0.03	0.08	0.00	0.36	0.00	0.001	0.001	0.000	0.005	0.000
MPK078	0.0	213.2	300.9	0.0	146.2	0.00	4.25	2.01	0.00	2.00	0.00	0.72	1.01	0.00	0.48	0.000	0.014	0.007	0.000	0.007
MPK085	0.0	0.0	24.5	0.0	94.1	0.00	0.00	0.30	0.00	0.99	0.00	0.00	0.05	0.00	0.19	0.000	0.000	0.001	0.000	0.002
MPK086	292.6	424.3	75.0	0.0	0.0	2.99	3.01	0.90	0.00	0.00	0.32	0.47	0.08	0.00	0.00	0.003	0.003	0.001	0.000	0.000
OAD063	160.1	0.0	0.0	0.0	0.0	1.00	0.00	0.00	0.00	0.00	0.30	0.00	0.00	0.00	0.00	0.002	0.000	0.000	0.000	0.000
OAD065	0.0	89.7	0.0	0.0	61.7	0.00	1.01	0.00	0.00	1.00	0.00	0.07	0.00	0.00	0.04	0.000	0.001	0.000	0.000	0.001
OAD072	236.4	0.0	0.0	99.1	0.0	1.99	0.00	0.00	1.99	0.00	0.44	0.00	0.00	0.18	0.00	0.004	0.000	0.000	0.004	0.000
OPK065	85.0	0.0	0.0	213.2	0.0	2.00	0.00	0.00	1.01	0.00	0.14	0.00	0.00	0.25	0.00	0.003	0.000	0.000	0.001	0.000
OPK071	68.2	83.6	0.0	292.1	89.0	1.00	0.96	0.00	3.01	1.00	0.03	0.04	0.00	0.14	0.04	0.000	0.000	0.000	0.001	0.000
OPK072	0.0	0.0	0.0	211.0	0.0	0.00	0.00	0.00	1.00	0.00	0.00	0.00	0.00	0.15	0.00	0.000	0.000	0.000	0.001	0.000
OPK073	39.3	592.6	513.7	0.0	0.0	0.46	2.13	1.97	0.00	0.00	0.08	1.27	1.11	0.00	0.00	0.001	0.005	0.004	0.000	0.000
OPK077	512.2	0.0	0.0	116.0	0.0	2.22	0.00	0.00	0.99	0.00	0.76	0.00	0.00	0.18	0.00	0.003	0.000	0.000	0.002	0.000
ORO061	0.0	0.0	0.0	120.4	0.9	0.00	0.00	0.00	2.00	0.05	0.00	0.00	0.00	0.13	0.00	0.000	0.000	0.000	0.002	0.000
ORO062	9.0	65.8	215.5	0.0	0.0	1.00	1.00	1.99	0.00	0.00	0.01	0.07	0.24	0.00	0.00	0.001	0.001	0.002	0.000	0.000
OSS077	51.8	0.0	73.6	0.0	0.0	1.00	0.00	0.99	0.00	0.00	0.07	0.00	0.09	0.00	0.00	0.001	0.000	0.001	0.000	0.000
PKL062	41.9	0.0	0.0	0.0	0.0	1.00	0.00	0.00	0.00	0.00	0.01	0.00	0.00	0.00	0.00	0.000	0.000	0.000	0.000	0.000
PKL063	0.0	0.0	0.0	0.0	0.0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.000	0.000	0.000	0.000	0.000
PKL065	27.0	49.9	116.6	0.0	0.0	0.96	1.00	1.00	0.00	0.00	0.02	0.04	0.10	0.00	0.00	0.001	0.001	0.001	0.000	0.000
PKL071	0.0	0.0	0.0	0.0	0.0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.000	0.000	0.000	0.000	0.000
PKL072	0.0	0.0	0.0	0.0	0.0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.000	0.000	0.000	0.000	0.000
PKL073	0.0	0.0	0.0	0.0	0.0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.000	0.000	0.000	0.000	0.000
PKL081	0.0	38.8	0.0	0.0	0.0	0.00	0.41	0.00	0.00	0.00	0.00	0.04	0.00	0.00	0.00	0.000	0.000	0.000	0.000	0.000
PKL082	0.7	0.0	0.0	10.0	0.0	0.01	0.00	0.00	1.00	0.00	0.00	0.00	0.00	0.00	0.00	0.000	0.000	0.000	0.000	0.000
PKL085	0.0	693.5	0.0	0.0	0.0	0.00	1.00	0.00	0.00	0.00	0.00	1.42	0.00	0.00	0.00	0.000	0.002	0.000	0.000	0.000
RAM063	0.0	0.0	0.0	68.9	9.0	0.00	0.00	0.00	1.00	1.00	0.00	0.00	0.00	0.12	0.01	0.000	0.000	0.000	0.002	0.002
RAM071	100.6	0.0	0.0	0.0	0.0	1.00	0.00	0.00	0.00	0.00	0.17	0.00	0.00	0.00	0.00	0.002	0.000	0.000	0.000	0.000
RAM073	0.0	167.6	0.0	0.0	0.0	0.00	2.00	0.00	0.00	0.00	0.00	0.29	0.00	0.00	0.00	0.000	0.004	0.000	0.000	0.000
RIV061	166.9	63.0	46.0	91.8	62.6	2.01	1.00	1.00	0.97	1.96	0.24	0.09	0.06	0.13	0.09	0.003	0.001	0.001	0.001	0.003
RIV063	63.2	87.6	0.0	84.6	0.0	0.99	1.00	0.00	1.00	0.00	0.05	0.07	0.00	0.06	0.00	0.001	0.001	0.000	0.001	0.000
RIV064	147.9	84.8	0.0	31.8	79.1	3.00	2.00	0.00	0.99	3.00	0.19	0.11	0.00	0.04	0.10	0.004	0.003	0.000	0.001	0.004
RIV073	0.0	697.9	0.0	0.0	0.9	0.00	1.00	0.00	0.00	0.00	0.00	0.85	0.00	0.00	0.00	0.000	0.001	0.000	0.000	0.000
RIV076	67.2	88.4	10.0	49.9	107.7	1.02	1.00	1.00	1.00	1.99	0.07	0.09	0.01	0.05	0.10	0.001	0.001	0.001	0.001	0.002
RLK065	423.0	0.0	0.0	0.0	85.4	1.00	0.00	0.00	0.00	1.00	0.12	0.00	0.00	0.00	0.03	0.000	0.000	0.000	0.000	0.000
RLK066	0.0	39.4	0.0	0.0	0.0	0.00	1.00	0.00	0.00	0.00	0.00	0.08	0.00	0.00	0.00	0.000	0.002	0.000	0.000	0.000
RLK069	402.2	0.0	442.1	51.9	5.7	1.00	0.00	2.01	1.00	0.33	0.55	0.00	0.59	0.08	0.01	0.001	0.000	0.003	0.001	0.000
RLK071	104.6	90.6	39.0	86.0	161.3	1.74	1.00	1.00	2.02	2.75	0.15	0.13	0.06	0.12	0.23	0.003	0.001	0.001	0.003	0.004
RLK073	78.1	0.0	41.3	0.0	0.0	0.82	0.00	0.63	0.00	0.00	0.11	0.00	0.06	0.00	0.00	0.001	0.000	0.001	0.000	0.000
RPL071	0.0	592.5	102.5	294.7	0.0	0.00	1.06	1.33	3.06	0.00	0.00	0.49	0.08	0.24	0.00	0.000	0.001	0.001	0.002	0.000
RPL074	0.0	165.7	0.0	0.0	397.9	0.00	1.01	0.00	0.00	0.99	0.00	0.08	0.00	0.00	0.20	0.000	0.001	0.000	0.000	0.000
RRK063	79.8	298.8	67.8	6.0	0.0	1.70	1.71	1.00	1.00	0.00	0.11	0.41	0.10	0.01	0.00	0.002	0.002	0.001	0.001	0.000
RRK064	0.0	713.9	0.0	293.9	0.0	0.00	1.00	0.00	2.98	0.00	0.00	1.93	0.00	0.85	0.00	0.000	0.003	0.000	0.009	0.000
RRK071	0.0	534.5	146.9	224.4	243.2	0.00	4.49	1.96	2.17	1.97	0.00	0.02	0.01	0.01	0.01	0.000	0.000	0.000	0.000	0.000
RWD063	83.0	0.0	152.4	215.9	0.0	1.00	0.00	2.01	3.00	0.00	0.07	0.00	0.13	0.19	0.00	0.001	0.000	0.002	0.003	0.000
RWD082	0.0	0.0	0.0	0.0	0.0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.000	0.000	0.000	0.000	0.000
SAV063	97.0	0.0	0.0	0.0	0.0	0.96	0.00	0.00	0.00	0.00	0.16	0.00	0.00	0.00	0.00	0.002	0.000	0.000	0.000	0.000
SAV071	0.0	0.0	101.3	308.5	0.0	0.00	0.00	0.99	2.99	0.00	0.00	0.00	0.16	0.48	0.00	0.000	0.000	0.002	0.005	0.000
SAV073	0.0	0.0	82.9	0.0	270.2	0.00	0.00	1.00	0.00	1.00	0.00	0.00	0.06	0.00	0.21	0.000	0.000	0.001	0.000	0.001
SHP062	0.0	60.8	0.0	0.0	76.1	0.00	1.00	0.00	0.00	0.98	0.00	0.12	0.00	0.00	0.15	0.000	0.002	0.000	0.000	0.002
SHP072	0.0	0.0	0.0	0.0	0.0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.000	0.000	0.000	0.000	0.000
SLP071	5.0	0.0	391.5	34.8	0.0	0.17	0.00	2.01	0.99	0.00	0.01	0.00	0.57	0.05	0.00	0.000	0.000	0.003	0.001	0.000
SLP075	16.9	0.0	159.4	35.0	0.0	1.00	0.00	3.77	1.00	0.00	0.02	0.00	0.20	0.04	0.00	0.001	0.000	0.005	0.001	0.000
SLP076	563.6	0.0	108.6	34.9	0.0	1.00	0.00	1.01	1.00	0.00	1.07	0.00	0.20	0.07	0.00	0.002	0.000	0.002	0.002	0.000
SLP077	707.0	0.0	0.0	121.8	185.7	1.86	0.00	0.00	1.00	1.99	0.81	0.00	0.00	0.14	0.21	0.002	0.000	0.000	0.001	0.002
SLP081	0.0	0.0	0.0	26.0	0.0	0.00	0.00	0.00	1.00	0.00	0.00	0.00	0.00	0.04	0.00	0.000	0.000	0.000	0.002	0.000
SLP083	0.0	0.0	0.0	0.0	0.0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.000	0.000	0.000	0.000	0.000
SLP092	486.3	74.4	0.0	0.0	0.0	1.00	0.87	0.00	0.00	0.00	1.08	0.17	0.00	0.00	0.00	0.002	0.002	0.000	0.000	0.000
SLP093	188.3	0.0	145.3	0.0	167.3	1.00	0.00	1.01	0.00	2.00	0.42	0.00	0.32	0.00	0.36	0.002	0.000	0.002	0.000	0.004
SLP096	187.3	0.0	702.6	0.0	70.3	1.96	0.00	2.78	0.00	0.72	0.39	0.00	1.44	0.00	0.17	0.004	0.000	0.006	0.000	0.002
SLP097	620.0	0.0	72.3	0.0	27.2	1.00	0.00	1.98	0.00	0.48	0.64	0.00	0.07	0.00	0.03	0.001	0.000	0.002	0.000	0.000
SOU066	0.0	0.0	11.0	0.0	60.7	0.00	0.00	1.00	0.00	1.00	0.00	0.00	0.01	0.00	0.04	0.000	0.000	0.000	0.000	0.001
SOU073	0.0	45.1	0.0	0.0	0.0	0.00	1.00	0.00	0.00	0.00	0.00	0.05	0.00	0.00	0.00	0.000	0.001	0.000	0.000	0.000
SOU075	60.0	38.0	183.6	0.0	20.9	1.00	1.00	1.01	0.00	1.00	0.16	0.10	0.49	0.00	0.05	0.003	0.003	0.003	0.000	0.003
SOU077	0.0	0.0	0.0	0.0	0.0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.000	0.000	0.000	0.000	0.000
SOU081	0.0	0.0	121.6	0.0	73.8	0.00	0.00	2.99	0.00	1.00	0.00	0.00	0.15	0.00	0.09	0.000	0.000	0.004	0.000	0.001
SOU083	0.0	0.0	0.0	0.0	0.0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.000	0.000	0.000	0.000	0.000
SOU084	686.0	0.0	0.0	0.0	0.0	1.00	0.00	0.00	0.00	0.00	0.34	0.00	0.00	0.00	0.00	0.000	0.000	0.000	0.000	0.000

Proposed FLISR Feeders
System All Levels Impacts

	All Days - Individual Feeder Indices										All Days - Individual Feeder Contributions to MN SAIDI									
Total All Levels Annual Contribution to MN Indices from FLISR candidate feeders											73.0	83.9	46.3	30.6	23.2	0.3	0.4	0.3	0.3	0.2
	SAIDI					SAIFI					SAIDI					SAIFI				
Feeder	2015	2016	2017	2018	2019	2015	2016	2017	2018	2019	2015	2016	2017	2018	2019	2015	2016	2017	2018	2019
SOU086	21.9	188.9	80.2	39.2	23.5	0.18	2.47	0.27	0.38	0.26	0.05	0.47	0.20	0.10	0.06	0.000	0.006	0.001	0.001	0.001
SOU087	131.6	126.8	134.2	120.1	123.9	0.38	0.69	1.07	0.75	2.00	0.26	0.25	0.26	0.23	0.23	0.001	0.001	0.002	0.001	0.004
STY061	264.8	91.8	100.8	139.3	79.2	0.82	0.32	1.35	1.34	1.33	0.69	0.24	0.26	0.36	0.21	0.002	0.001	0.003	0.003	0.003
STY062	23.6	30.6	63.8	29.9	77.2	0.19	0.20	0.33	0.31	0.53	0.04	0.05	0.11	0.05	0.13	0.000	0.000	0.001	0.001	0.001
STY065	116.6	50.3	30.6	45.7	36.8	1.11	0.28	0.18	0.24	0.20	0.25	0.11	0.06	0.09	0.08	0.002	0.001	0.000	0.001	0.000
STY071	47.0	20.0	70.7	32.5	217.8	0.39	0.33	1.09	0.14	1.31	0.08	0.03	0.12	0.06	0.37	0.001	0.001	0.002	0.000	0.002
STY072	62.8	1,188.3	150.1	373.1	5.9	0.45	1.29	2.21	2.05	0.05	0.09	1.71	0.22	0.53	0.01	0.001	0.002	0.003	0.003	0.000
STY075	75.1	137.2	27.6	352.9	90.0	0.62	1.45	0.19	2.64	0.64	0.11	0.21	0.04	0.53	0.13	0.001	0.002	0.000	0.004	0.001
TER061	48.4	275.8	145.4	127.1	95.1	0.14	0.71	2.12	1.17	1.00	0.04	0.21	0.11	0.09	0.07	0.000	0.001	0.002	0.001	0.001
TER066	32.3	51.5	88.5	5.2	13.6	0.53	0.25	1.20	0.04	0.13	0.00	0.01	0.01	0.00	0.00	0.000	0.000	0.000	0.000	0.000
TER073	50.3	31.1	50.5	31.8	87.9	0.24	0.12	1.03	0.38	1.13	0.00	0.00	0.00	0.00	0.01	0.000	0.000	0.000	0.000	0.000
TLK067	90.3	420.3	148.7	123.8	116.2	0.45	1.36	1.55	2.26	1.34	0.20	0.91	0.32	0.26	0.25	0.001	0.003	0.003	0.005	0.003
TWL062	112.5	576.1	37.8	26.8	113.8	1.08	1.36	0.49	0.25	1.35	0.25	0.99	0.06	0.05	0.19	0.002	0.002	0.001	0.000	0.002
TWL063	33.0	428.9	53.2	18.7	77.1	0.37	1.31	1.12	0.23	1.15	0.06	0.95	0.12	0.04	0.17	0.001	0.003	0.002	0.001	0.003
TWL064	108.4	341.1	93.1	10.2	22.5	0.59	2.37	0.35	0.18	0.31	0.24	0.50	0.14	0.01	0.03	0.001	0.003	0.001	0.000	0.000
TWL071	34.4	793.4	263.5	89.7	77.7	0.16	1.39	1.39	0.52	0.41	0.05	1.22	0.40	0.14	0.12	0.000	0.002	0.002	0.001	0.001
TWL072	85.9	721.2	854.2	40.8	119.4	0.54	1.48	1.33	0.36	1.37	0.17	1.44	1.71	0.08	0.23	0.001	0.003	0.003	0.001	0.003
TWL078	86.5	145.2	34.2	67.1	88.0	0.76	2.38	1.28	1.44	1.05	0.09	0.15	0.04	0.07	0.09	0.001	0.002	0.001	0.001	0.001
TWL079	156.4	1,182.3	104.4	67.8	101.2	0.34	3.08	1.59	0.94	0.67	0.38	2.86	0.25	0.16	0.24	0.001	0.007	0.004	0.002	0.002
TWL083	85.5	258.5	101.0	6.1	56.9	1.16	2.48	1.09	0.06	1.05	0.04	0.12	0.05	0.00	0.03	0.001	0.001	0.001	0.000	0.001
UPP081	386.4	261.1	288.5	102.8	325.0	1.26	0.44	2.75	1.71	3.04	0.18	0.13	0.14	0.05	0.15	0.001	0.000	0.001	0.001	0.001
UPP084	103.9	61.2	406.9	324.4	18.0	0.35	0.42	3.47	3.13	0.22	0.29	0.17	1.14	0.90	0.05	0.001	0.001	0.010	0.009	0.001
VKG072	46.7	425.8	39.4	54.4	31.1	0.33	1.22	0.45	0.48	0.28	0.06	0.58	0.05	0.07	0.04	0.000	0.002	0.001	0.001	0.000
WCS064	263.7	19.0	578.8	406.4	44.1	0.73	0.11	4.67	2.27	0.28	0.26	0.02	0.57	0.41	0.04	0.001	0.000	0.005	0.002	0.000
WES061	61.4	1,185.3	50.0	14.5	53.7	1.16	1.36	0.12	0.08	0.33	0.11	2.13	0.09	0.03	0.09	0.002	0.002	0.000	0.000	0.001
WES062	328.8	297.2	32.5	75.5	26.6	3.72	1.17	0.15	1.04	0.25	0.63	0.56	0.06	0.14	0.05	0.007	0.002	0.000	0.002	0.000
WES063	38.6	1,406.7	34.7	9.3	20.3	1.01	2.71	1.18	0.10	0.02	0.03	1.12	0.03	0.01	0.02	0.001	0.002	0.001	0.000	0.000
WES064	72.1	965.2	386.1	6.3	227.3	1.44	2.89	1.36	0.11	0.59	0.07	0.90	0.36	0.01	0.21	0.001	0.003	0.001	0.000	0.001
WES072	181.9	492.7	100.5	271.7	64.5	1.19	1.37	0.54	1.89	0.35	0.34	0.92	0.19	0.51	0.12	0.002	0.003	0.001	0.004	0.001
WES073	192.3	1,947.5	265.2	279.1	287.7	2.06	5.31	1.34	3.22	1.37	0.50	5.00	0.68	0.71	0.72	0.005	0.014	0.003	0.008	0.003
WES075	117.8	625.8	127.0	22.5	16.0	0.40	1.41	1.07	0.10	0.14	0.27	1.43	0.29	0.05	0.04	0.001	0.003	0.002	0.000	0.000
WES076	17.0	331.0	12.6	330.4	13.6	0.19	0.24	0.04	3.51	0.15	0.02	0.47	0.02	0.46	0.02	0.000	0.000	0.000	0.005	0.000
WIL072	704.3	65.9	1.7	194.0	45.1	1.36	0.65	0.03	1.35	0.40	0.39	0.04	0.00	0.11	0.02	0.001	0.000	0.000	0.001	0.000
WIL073	943.6	72.7	69.0	189.7	83.4	1.23	0.54	0.29	2.21	1.14	2.43	0.19	0.18	0.48	0.21	0.003	0.001	0.001	0.006	0.003
WIL074	66.9	108.1	181.0	147.9	26.2	0.65	0.39	1.35	1.26	0.39	0.09	0.15	0.25	0.20	0.04	0.001	0.001	0.002	0.002	0.001
WIL075	689.8	16.9	73.4	114.2	32.0	2.67	0.26	1.43	1.43	0.54	0.79	0.02	0.08	0.13	0.04	0.003	0.000	0.002	0.002	0.001
WIL083	838.8	40.3	39.8	11.8	91.4	3.32	0.28	0.37	0.58	1.46	0.43	0.02	0.02	0.01	0.04	0.002	0.000	0.000	0.000	0.001
WIL092	29.3	103.3	422.3	21.2	40.9	0.31	0.34	3.42	0.15	0.56	0.02	0.06	0.24	0.01	0.02	0.000	0.000	0.002	0.000	0.000
WIL098	15.1	25.7	128.5	18.5	36.5	0.14	0.23	1.78	0.25	1.14	0.03	0.04	0.21	0.03	0.06	0.000	0.000	0.003	0.000	0.002
WRR064	209.3	384.9	44.6	68.7	28.2	1.37	3.09	0.43	1.35	0.40	0.33	0.61	0.07	0.11	0.05	0.002	0.005	0.001	0.002	0.001
WRR075	101.5	635.8	28.2	44.3	29.9	0.12	2.85	0.18	0.57	0.31	0.17	1.07	0.05	0.07	0.05	0.000	0.005	0.000	0.001	0.001
WRR085	109.4	704.1	16.3	131.7	2.1	0.48	2.45	0.30	0.47	0.04	0.01	0.09	0.00	0.02	0.00	0.000	0.000	0.000	0.000	0.000
WTN061	837.9	515.3	145.3	595.1	442.3	2.20	4.14	2.03	3.05	2.08	0.91	0.56	0.16	0.66	0.49	0.002	0.004	0.002	0.003	0.002
WYO021	137.9	182.6	307.2	306.4	469.9	1.12	1.22	1.31	2.32	1.68	0.25	0.33	0.56	0.56	0.89	0.002	0.002	0.002	0.004	0.003
WYO032	23.2	12.3	476.2	63.1	58.7	0.23	0.16	2.03	1.12	0.65	0.03	0.01	0.54	0.07	0.07	0.000	0.000	0.002	0.001	0.001
YAM021	581.2	126.6	215.4	255.6	30.9	2.43	0.58	1.23	1.67	0.18	0.54	0.12	0.20	0.24	0.03	0.002	0.001	0.001	0.002	0.000

Proposed FLISR Feeders
Mainline Feeder Level Only Impacts

	All Days - Individual Feeder Indices										All Days - Individual Feeder Contributions to MN									
Total Mainline Feeder Annual Contribution to MN Indices from FLISR candidate feeders											37.5	40.1	23.3	14.3	8.5	0.2	0.2	0.2	0.2	0.1
	SAIDI					SAIFI					SAIDI					SAIFI				
Feeder	2015	2016	2017	2018	2019	2015	2016	2017	2018	2019	2015	2016	2017	2018	2019	2015	2016	2017	2018	2019
SOU086	0.0	169.8	0.0	0.0	0.0	0.00	2.08	0.00	0.00	0.00	0.00	0.43	0.00	0.00	0.00	0.000	0.005	0.000	0.000	0.000
SOU087	0.0	0.0	0.0	0.0	39.1	0.00	0.00	0.00	0.00	1.00	0.00	0.00	0.00	0.00	0.07	0.000	0.000	0.000	0.000	0.002
STY061	0.0	0.0	47.8	55.2	35.5	0.00	0.00	1.00	0.99	0.99	0.00	0.00	0.12	0.14	0.09	0.000	0.000	0.003	0.003	0.003
STY062	0.0	0.0	0.0	0.0	0.0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.000	0.000	0.000	0.000	0.000
STY065	74.1	0.0	0.0	0.0	0.0	1.00	0.00	0.00	0.00	0.00	0.16	0.00	0.00	0.00	0.00	0.002	0.000	0.000	0.000	0.000
STY071	0.0	11.1	44.0	0.0	185.3	0.00	0.18	0.82	0.00	1.00	0.00	0.02	0.08	0.00	0.31	0.000	0.000	0.001	0.000	0.002
STY072	0.0	1,090.4	113.5	189.1	0.0	0.00	1.00	2.00	1.43	0.00	0.00	1.57	0.16	0.27	0.00	0.000	0.001	0.003	0.002	0.000
STY075	0.0	60.0	0.0	117.8	0.0	0.00	1.00	0.00	1.05	0.00	0.00	0.09	0.00	0.18	0.00	0.000	0.002	0.000	0.002	0.000
TER061	0.0	94.7	75.9	88.5	95.1	0.00	0.39	1.00	1.02	1.00	0.00	0.07	0.06	0.07	0.07	0.000	0.000	0.001	0.001	0.001
TER066	26.9	0.0	0.0	0.0	0.0	0.48	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.000	0.000	0.000	0.000	0.000
TER073	0.0	0.0	0.0	0.0	75.1	0.00	0.00	0.00	0.00	0.96	0.00	0.00	0.00	0.00	0.01	0.000	0.000	0.000	0.000	0.000
TLK067	0.0	303.1	82.9	88.8	53.9	0.00	1.00	1.00	2.00	1.00	0.00	0.66	0.18	0.19	0.11	0.000	0.002	0.002	0.004	0.002
TWL062	0.0	419.6	0.0	0.0	75.0	0.00	0.99	0.00	0.00	1.00	0.00	0.72	0.00	0.00	0.13	0.000	0.002	0.000	0.000	0.002
TWL063	0.0	364.4	42.8	0.0	65.6	0.00	1.00	1.00	0.00	0.99	0.00	0.81	0.09	0.00	0.14	0.000	0.002	0.002	0.000	0.002
TWL064	0.0	191.8	0.0	0.0	0.0	0.00	2.00	0.00	0.00	0.00	0.00	0.28	0.00	0.00	0.00	0.000	0.003	0.000	0.000	0.000
TWL071	0.0	515.3	143.4	0.0	1.1	0.00	0.99	1.00	0.00	0.09	0.00	0.79	0.22	0.00	0.00	0.000	0.002	0.002	0.000	0.000
TWL072	28.1	475.2	739.8	0.0	69.5	0.32	1.00	1.00	0.00	0.98	0.06	0.95	1.48	0.00	0.14	0.001	0.002	0.002	0.000	0.002
TWL078	11.1	100.0	9.0	33.4	58.8	0.17	2.00	1.00	1.00	0.83	0.01	0.10	0.01	0.03	0.06	0.000	0.002	0.001	0.001	0.001
TWL079	0.0	718.6	50.0	0.0	0.0	0.00	2.00	1.00	0.00	0.00	0.00	1.74	0.12	0.00	0.00	0.000	0.005	0.002	0.000	0.000
TWL083	66.4	233.9	90.1	0.0	53.6	0.99	2.27	0.99	0.00	0.99	0.03	0.11	0.04	0.00	0.03	0.000	0.001	0.000	0.000	0.000
UPP081	0.0	0.0	213.1	53.9	159.6	0.00	0.00	2.00	1.02	1.95	0.00	0.00	0.10	0.03	0.08	0.000	0.000	0.001	0.000	0.001
UPP084	0.0	0.0	331.3	240.1	0.0	0.00	0.00	3.02	2.30	0.00	0.00	0.00	0.93	0.67	0.00	0.000	0.000	0.008	0.006	0.000
VKG072	0.0	397.6	0.0	0.0	0.0	0.00	1.00	0.00	0.00	0.00	0.00	0.54	0.00	0.00	0.00	0.000	0.001	0.000	0.000	0.000
WCS064	0.0	0.0	419.0	349.7	27.4	0.00	0.00	4.19	1.79	0.19	0.00	0.00	0.41	0.35	0.03	0.000	0.000	0.004	0.002	0.000
WES061	46.2	549.6	0.0	0.0	0.0	1.01	1.00	0.00	0.00	0.00	0.08	0.99	0.00	0.00	0.00	0.002	0.002	0.000	0.000	0.000
WES062	261.9	211.1	0.0	35.8	0.0	3.00	1.00	0.00	0.82	0.00	0.50	0.40	0.00	0.07	0.00	0.006	0.002	0.000	0.002	0.000
WES063	37.1	438.5	26.0	0.0	0.0	1.00	2.00	1.00	0.00	0.00	0.03	0.35	0.02	0.00	0.00	0.001	0.002	0.001	0.000	0.000
WES064	37.2	531.2	301.2	0.0	0.0	1.00	2.00	0.99	0.00	0.00	0.03	0.50	0.28	0.00	0.00	0.001	0.002	0.001	0.000	0.000
WES072	79.3	401.3	0.0	90.3	0.0	1.00	1.00	0.00	1.26	0.00	0.15	0.75	0.00	0.17	0.00	0.002	0.002	0.000	0.002	0.000
WES073	123.9	667.3	212.3	235.5	201.3	1.84	3.94	1.00	3.00	1.00	0.32	1.71	0.54	0.60	0.51	0.005	0.010	0.003	0.008	0.003
WES075	0.0	378.7	105.9	0.0	0.0	0.00	1.00	1.00	0.00	0.00	0.00	0.87	0.24	0.00	0.00	0.000	0.002	0.002	0.000	0.000
WES076	0.0	0.0	0.0	233.6	0.0	0.00	0.00	0.00	3.00	0.00	0.00	0.00	0.00	0.32	0.00	0.000	0.000	0.000	0.004	0.000
WIL072	661.1	0.0	0.0	0.0	0.0	1.00	0.00	0.00	0.00	0.00	0.37	0.00	0.00	0.00	0.00	0.001	0.000	0.000	0.000	0.000
WIL073	800.5	0.0	0.0	107.8	69.5	1.00	0.00	0.00	1.00	0.98	2.07	0.00	0.00	0.27	0.18	0.003	0.000	0.000	0.003	0.003
WIL074	0.0	0.0	18.0	120.6	0.0	0.00	0.00	1.00	1.00	0.00	0.00	0.00	0.02	0.16	0.00	0.000	0.000	0.001	0.001	0.000
WIL075	573.4	0.0	43.9	0.0	0.0	2.01	0.00	1.00	0.00	0.00	0.66	0.00	0.05	0.00	0.00	0.002	0.000	0.001	0.000	0.000
WIL083	777.8	0.0	0.0	4.1	9.9	2.03	0.00	0.00	0.46	0.99	0.40	0.00	0.00	0.00	0.00	0.001	0.000	0.000	0.000	0.000
WIL092	0.0	0.0	365.1	0.0	0.0	0.00	0.00	3.00	0.00	0.00	0.00	0.00	0.20	0.00	0.00	0.000	0.000	0.002	0.000	0.000
WIL098	0.0	0.0	90.4	0.0	30.0	0.00	0.00	1.49	0.00	1.00	0.00	0.00	0.15	0.00	0.05	0.000	0.000	0.002	0.000	0.002
WRR064	89.0	343.6	0.0	21.3	0.0	1.00	3.02	0.00	1.00	0.00	0.14	0.54	0.00	0.03	0.00	0.002	0.005	0.000	0.002	0.000
WRR075	0.0	375.5	0.0	0.0	0.0	0.00	2.01	0.00	0.00	0.00	0.00	0.63	0.00	0.00	0.00	0.000	0.003	0.000	0.000	0.000
WRR085	0.0	327.5	0.0	0.0	0.0	0.00	1.99	0.00	0.00	0.00	0.00	0.04	0.00	0.00	0.00	0.000	0.000	0.000	0.000	0.000
WTN061	0.0	233.2	116.7	520.6	0.0	0.00	2.01	1.00	1.98	0.00	0.00	0.25	0.13	0.58	0.00	0.000	0.002	0.001	0.002	0.000
WYO021	71.2	129.1	183.8	177.3	387.7	1.00	1.00	0.99	2.04	1.29	0.13	0.23	0.33	0.33	0.74	0.002	0.002	0.002	0.004	0.002
WYO032	0.0	0.0	463.7	54.0	0.0	0.00	0.00	1.99	1.00	0.00	0.00	0.00	0.53	0.06	0.00	0.000	0.000	0.002	0.001	0.000
YAM021	0.0	0.0	157.8	143.6	0.0	0.00	0.00	0.99	1.00	0.00	0.00	0.00	0.15	0.13	0.00	0.000	0.000	0.001	0.001	0.000

Xcel Energy SAIDI and SAIFI Information - 2015-2019
Proposed FLISR Feeders - Notes

As requested by Fresh Energy in March 17, 2020 Comments

Xcel Energy provides this information in response to a request from Fresh Energy in its March 17, 2020 Comments.

"Fresh Energy requests that the Company, in its reply comments, provide the historical SAIDI and SAIFI each year 2015-2019 for the 206 circuits it proposes for FLISR. "

NOTES:
The "all day" provided is for events occurring on all days in the time period.

Columns B-K provide the individual SAIDI and SAIFI for each feeder.
This is calculated based on all the outage events that impact that feeder divided by the # of customers on the feeder.
SAIDI= (the individual feeders customer Minutes Out/# of customers on the feeder)
SAIFI =(sustained customer interruption/# of customers on the feeder)

Columns L-U provide the individual feeder SAIDI and SAIFI contribution to the overall Minnesota SAIDI
Overall Minnesota SAIDI Contribution is all outage events that impact the listed feeder, divided by all Minnesota customers

Columns V-AO are similar to columns B-U, with the exception that the indices are calculated based on only mainline feeder events.

SAIDI is calculated based only on benefits to improving the indices' contribution from feeder-level events. There is the possibility that FLISR could improve reliability during a substation transformer, substation or transmission event, but this was not included in the calculation. FLISR is not intended and cannot improve reliability from tap, secondary, services, or service transformer events.
Preliminary feeder selection for FLISR was based primarily on improvement opportunities found through identification of feeders with a high impact to the mainline all days SAIDI average for 2013-2017, and feeders that are designed and equipped to be able to take advantage of FLISR's sectionalizing capabilities.

ELECTRIC POWER RESEARCH INSTITUTE

Integration of Distributed Energy Resources

PROGRAM 174 OVERVIEW

INDUSTRY CONTEXT

The grid integration of distributed energy resources (DERs) is a defining challenge to today's electric power system. It is requiring wholesale reevaluation of established utility functions related to planning, operations, protection, metering, communications, cyber security, and customer programs. Driven by both technology advancements and public policy supports, rising adoptions of DERs are increasingly spurring utilities to update and evolve their processes, teach staff new skills, implement innovative software applications such as DERMS, and deploy improved infrastructure. Tremendous investments are being made, including advanced modeling and simulation, laboratory testing, and field demonstrations. Utilities are working to keep pace with changing customer attitudes and to support DER policy and regulatory goals while maintaining safety, reliability, and power quality. Effectively achieving this outcome will require coordinated research and development efforts that embrace learning and collaboration.

PROGRAM OVERVIEW

PROGRAM DESCRIPTION

This program addresses utility industry technical and economic challenges to integrate distributed solar, battery storage, and other distributed energy resources (DER). Managing and screening interconnection requests, modeling and analyzing grid impacts, specifying grid-support functions and settings, and applying monitoring and control systems are relatively new activities and require new learning for most utilities. Effective integration of DER needs to be considered in all aspects of distribution planning, operation, protection coordination, voltage regulation, power quality and safety. Hosting DER also brings new economic challenges and tradeoffs for providing reliable service with increasing deployment levels. Business risks and opportunities need to be evaluated.

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APPROACH

The research is aimed to provide practical tools, resources, and guides that can be applied in day-to-day processes. The nature of projects includes modeling and simulation, lab testing, field evaluation, software development, data analytics, industry surveys, standards support and working group facilitation. All projects aim to provide industry leadership and build on previous work related to DER integration. Deliverables include tools, software, algorithms, technical reports, whitepapers, webcasts and training courses.

DER business practices, strategy and cost-benefit analysis are key elements, including assessment of non-wires alternatives and optimizing PV operation with storage and controllable loads. Tools such as PVAT (PV Adoption Tool), DER Settings Tool, DERMS Testbed and smart inverter simulators are developed through this program.

RESEARCH VALUE

The knowledge acquired through this research program will support members to:

- Analyze DER integration issues and make decisions about levels, settings and types of DER
- Manage interconnection queues and identify effective screening methods
- Model, predict, and address grid issues caused by rising DER levels
- Determine requirements and take advantage of evolving standards for DER interconnection
- Train staff on integration technology (smart inverters, grid edge devices, control systems etc.)
- Develop architectures and select technologies for managing and integrating DER
- Assess both technical and economic aspects of DER integration with existing distribution assets
- Apply data analytics for assessment and insight into DER settings, performance, cost and benefit
- Prepare existing and future distribution grids for more effective integration

PROGRAM STRUCTURE

174A
Grid Impact Analysis of DER

174B
Smart Inverters, Grid Supportive Technologies

174C
DERMS and Microgrid Integration

174D
Practices, Programs and Economics

174E
Technology Transfer

UTILITY-DRIVEN PROJECT SET ORGANIZATION

The organization of research in the DER Integration area is driven by the needs and interests of member utilities. Program participation is selectable to the project-set level, so it is important that the structure reflect present utility needs as DER levels rise.

The structure was last updated in 2018 with the consolidation of EPRI's DERMS research from a variety of areas into a single coordinated project set.

The present organization includes five areas, summarized here and described in detail in the following pages.

This organization will continue to be updated as technologies evolve and new DER integration challenges emerge.

174A | GRID IMPACT ANALYSIS OF DER

Performing modeling to understand integration challenges, and developing techniques, tools, and guidelines for DER applications.

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GOALS

- Understanding the power system impacts of managed and unmanaged DER
- Enabling higher levels without compromising safety, reliability, efficiency, or power quality

RESEARCH NEEDS

- Develop simplified approaches for finding best DER settings and functions
- Analyzing the impacts of DER functions on grid operations and planning
- Improving support in commercial tools and sharing leading practices
- Quantifying the impact of DERMS and flexible interconnection solutions (FICS)

VALUE

- Increased utilization of power delivery assets
- Methods for evaluating DER impacts
- Improved understanding of impacts to maximize technical, policy, and business goals

PROJECTS	DELIVERABLE TYPE
Simplified Methods for Determining Smart Inverter Functions and Settings	Technical Update and Tools
Maximizing DER Hosting and Grid Utilization through Flexible Interconnection	Technical Update
Quantifying the Technical Benefits of DERMS	Technical Update
Impact of Autonomous DER Functions on Centralized Voltage Optimization	White Paper
DER Modeling and Simulation Workshop - Sharing Leading Practices	Workshop
DER Modeling Recommendations and Guidelines	Technical Update
Closed Loop Control Interactions on High Penetration DER Systems	Technical Update
Inverter-based Supplemental Grounding Tool	Software

"EPRI's technical advice, sharing industry best practices, and test simulation results were instrumental to Hydro One's DER technical interconnection requirements update. We revisited our transfer trip requirements, aligned with the latest IEEE and CSA standards, incorporated DERMS and flexible hosting capacity capability, and updated our technical requirements for the current and upcoming DER landscape"

Adnan Akhtar
Hydro One

"EPRI's insights during the Voltage Optimization with Smart Inverters study design phase and their independent verification of the results provided valuable feedback on our internal tools and processes as well as a high degree of confidence in the conclusions"

Cody Davis and Midhat Mafazy
Ameren Illinois

174B | SMART INVERTERS, GRID SUPPORTIVE TECHNOLOGIES

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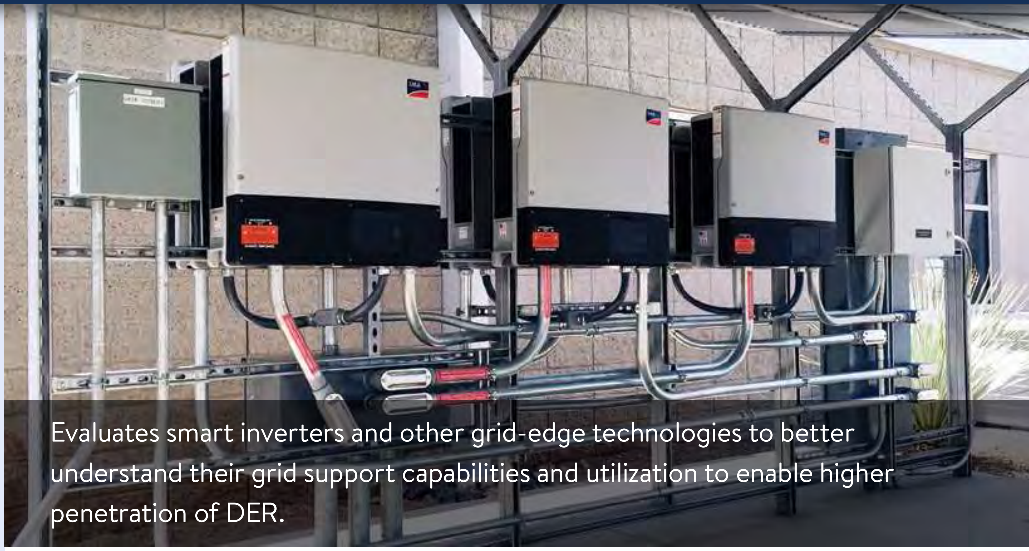

"In collaborating with EPRI via their Smart Inverters and Grid Supportive Technologies program, Southern Company has gained a better understanding about real-world capabilities of today's commercial inverters. Demonstrating inverters from different manufacturers has informed how Southern Company continues to approach interconnecting distributed energy resources."

Andrew Ingram
Southern Company

"EPRI's insights on Smart Inverters, and the ability of P174B leads to address Ameren's specific questions/concerns related to grid supportive functions (via emails, calls or tailored workshops), provided valuable feedback to Ameren Illinois engineers."

Midhat Mafazy
Ameren Illinois

GOALS

- Increase understanding of DER technologies including PV, ES and controllable loads to address integration challenges of higher penetration of DER
- Advance the state of grid supportive technologies and their utilization

RESEARCH NEEDS

- Steady state and dynamic characterization of smart inverters
- Assessment of advanced grid support functions in real world deployment scenarios
- Development of validated inverter models for accurate assessment of DER response to grid fault conditions

VALUE

- Efficient utilization of smart inverters and other advanced grid edge technologies to maximize customer and grid benefits

PROJECTS	DELIVERABLE TYPE
Smart Inverter Functions Impact on Islanding Detection by Group of Inverters: Laboratory Evaluation of IEEE 1547 2018 Compliant Units	Technical Update
Fourth EPRI Smart Inverter Workshop: Utility Experience of Deploying Smart Inverters	Workshop
Inverter Fundamentals and Grid Support Functions	Tutorials
DER Plant Commissioning Guideline as per IEEE 1547-2018 Requirements	Technical Update
Review of Service Transformer Topologies Typically Used for DER Interconnection	Tech Brief
DER Data Analytics Repository: New Analysis Tools for Field Performance Assessment	Web-based Resource
Grid-Forming Inverter - Model Development and Performance Assessment	Technical Update
Grid Support Functions Impact on Smart Inverter Performance and Secondary Circuit	Analysis Tool
Assessment of Smart Inverter Modeling in Distribution Planning Tools	Tech Brief
Communication Architecture Requirements for Smart Inverter Use Cases - Phase Two	Technical Update
Evaluating the State of Functional and Communications Interoperability in Inverter-based DER: Interoperability Evaluation and Market Survey	Tech Brief

174C | DERMS AND MICROGRID INTEGRATION

Defining and aligning DERMS functionality, accelerating product availability, assessing emerging systems, and understanding value streams.

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GOALS

- Identify DERMS requirements and assess the current market landscape to enable utilities understand, specify and deploy DERMS
- Conduct laboratory testing and field demonstrations to identify incremental value streams and benefits of DERMS

RESEARCH NEEDS

- Technical specifications to support DERMS RFPs
- Cohesive integration and sustainable architecture for DER Management
- Technology maturity and readiness level of commercial systems
- Value streams and benefits of DERMS to the power system

VALUE

- Reduced time and effort for DERMS selection with improved quality
- Reducing architectural debt avoiding vendor lock in, achieving scalable systems, avoiding premature system obsolescence

PROJECTS	DELIVERABLE TYPE
Defining DERMS Service Performance Metrics	Technical Update
DERMS RFP Repository	Web Database
Reference Design and Implementation of a Local DER Gateway	Technical Update and Software
TSO/DSO Coordination for DER Management	Technical Update
DERMS for DER Flexible Interconnection: Evaluation of Commercial DERMS	Technical Update
DER Estimation and Forecasting Methods and Applications for Grid Operations	Technical Update
DERMS Vendor Landscape	Technical Update
Utility DERMS Demonstration & Pilots: Lessons Learned and Gap Assessment	Technical Update
Low Cost Telemetry Requirements for DER Management	Technical Update
Sizing, Design & Implementation Considerations for Microgrids	Technical Update
Quantifying the value of DERMS for flexible DER interconnection	Technical Update
Utility Experience of deploying DERMS	Interest Groups

"EPRI's DERMS interest group has been very productive in exemplifying the challenges and considerations when selecting and attempting to implement a DERMS. The EPRI DERMS tutorial was very informative and helped APS internally align with the concept that a DERMS solution need not be exclusively a centrally-controlled system but may also be effectively employed as a federated system."

Michael McMaster
Program Lead – DERMS,
Arizona Public Service

"EPRI's DERMS team worked with PG&E to help scope requirements for future DERMS R&D projects. The project allowed PG&E to chart future investments in an Integrated Grid Platform that can interact with DERs to provide grid services where cost effective. It also helped PG&E to chart a future R&D and product strategy that combined with the Integrated Grid Platform will position PG&E to meet the future needs of the changing energy grid."

Alex Portilla
Manager, Grid Innovation,
Grid Integration & Innovation (GII)
PG&E

174D | PRACTICES, PROGRAMS AND ECONOMICS

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The presence of widespread DERs impacts a range of fundamental utility operational and business processes that have high visibility to customers, governments, and regulatory bodies. DERs also have economic implications that are not fully understood due to changing standards and market rules, as well as technology advancements.

"EPRI's application of its cost benefit analysis method informed Entergy's understanding of the economic value provided by distributed energy storage on a specific distribution circuit, evaluating capacity deferral value along with potential revenues from wholesale market participation."

Sharma Kolluri
Entergy Service Inc.

"EPRI conducted an assessment that drew from national data and benchmarking with other utilities, and helped inform the technical review practices Duke Energy currently uses to review DER interconnection applications."

Wesley Davis
Duke Energy

GOALS

- Evolve utility operational and business processes intended to optimally manage greater DERs on distribution
- Inform utility strategic planning rationales via sound economic and qualitative DER-related analyses

RESEARCH NEEDS

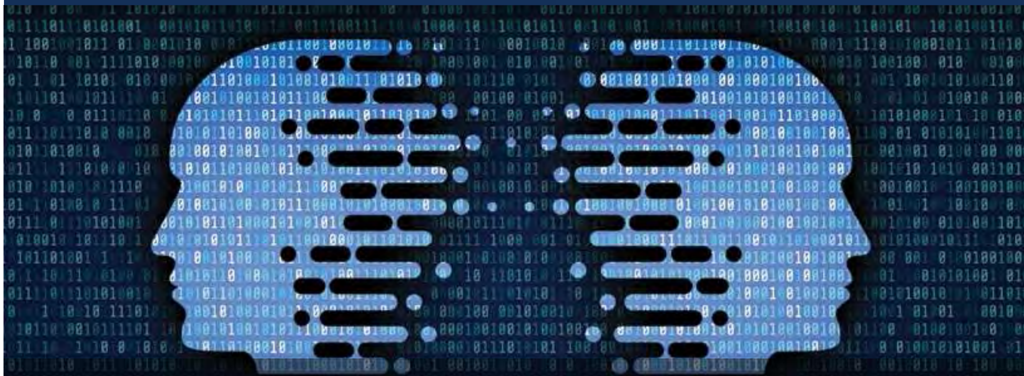
- DER interconnection and management best practices
- Value assessments of DERs, including as non-wires alternatives
- Greater consideration of DERs in distribution planning

VALUE

- Execute leading practices and strategies for economically managing DERs on distribution that provide utility and system benefits.
- Enable time savings, process efficiencies, avoided costs and savings, customer equity, and business model reforms

PROJECTS	DELIVERABLE TYPE
Integrating Hosting Capacity Analysis into the Utility Interconnection Technical Review Process	Technical Update
White Paper Series: Flexible Interconnection	White Papers
Compensating DER Owners for Utility Control of Behind-the-Meter Systems:	White Paper
Energy Storage Interconnection Practices	White Paper
Interconnection Documents Repository	Database
Time & Locational Value of DER on Distribution, Part II	Technical Update
Cost-Benefit Analysis Module for the DER Valuation Estimation Tool (DER-VET)	Software
Solar PV-based Non-Wires Alternatives	Technical Update
The Value of Advanced Inverter Functions: Voltage Management	Technical Update

174E | TECHNOLOGY TRANSFER



The value of your research investment depends on transfer of results to your staff and day to day operation. DER integration results are now delivered in a wide range of formats to promote transfer, keep members informed and enable the sharing of field experience and practices.

GOALS

- Provide regular technical updates and resources designed to keep members up to date on integration issues, standards activities, and changes in technology, challenges and practices

RESEARCH NEEDS

- Staying up to date on evolving standards and interconnection practices
- Learning from demonstrations, case studies and field experiences
- Accessing resources to support integration of DER
- Sharing problems and solutions related to DER interconnection decision process

VALUE

- Stay informed on key integration technical developments;
- Engage with experts in standards activities;
- Share and gain knowledge between members; and
- Solving problems via research and collaboration

PROJECTS	DELIVERABLE TYPE
Program Updates, Overviews of Current Topics, Review of Standards Efforts, Trainings and Conference Participations	Webcasts, Mail and White Papers
DER Field Experience Interest Group	Webcasts and Tech Brief Series
Storage and Distributed Generation Engineering Guide (moving to on line resource via member's center):	Reference Document
DER Integration Results Finder, Interconnection Documents, DERMS Language, Solar Data, Analytics and Screening Processes	On-line Resources
Solar and Distributed Energy Resources Hotline (on-line Forum)	One-line Resource

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"The EPRI DER Field Experience Interest Group, both WebEx discussions and technical briefs, have enabled sharing of useful field experiences, lessons-learned and mitigation ideas. These have provided Xcel valuable insights on a number of contemporary technical challenges in integrating distributed energy resources into our electric distribution grid."

Craig Groeling,
Sr. Principal Engineer,
Xcel Energy

"EPRI's assessment of inverter on-board islanding detection performance provided timely results in light of new distributed generation ride-thru requirements. Of value to AEP, the collaborative effort created models for generic detection methods and was able to verify results with different feeders, DG types, penetration levels and load variations."

Tom Weaver
Distribution Manager,
American Electric Power

UTILITY PROJECTS AND DEMONSTRATIONS

WHY EPRI FOR YOUR DEMONSTRATION?

Demonstrations and pilots can be complex and expensive. Experience and attention to detail are needed to turn experimental data into actionable insights. Leverage EPRI's objective, scientifically-based methods to realize the full value of your project. Here we bring EPRI's trusted technology, tools, and collaborative approach to address your unique research needs.

EXPERIMENTAL DESIGN

Success or failure in a demonstration is often decided before ever breaking ground on a new project. Put EPRI's collective wisdom and industry expertise to work for you as you collaborate with vendors ensure high quality outcomes. Members value EPRI guidance throughout the demonstration process from the initial requirements definition and RFP design all the way to acceptance testing and field commissioning. All of EPRI's extensive laboratory and software tools are available for demonstration planning, site selection, pre-demonstration characterization, and performance validation.

ANALYTICS

Poorly analyzed experimental results are an all-to-common impediment to a successful demonstration project. EPRI utilizes the latest in analytical tools, statistical modeling, and artificial intelligence to derive valuable insights for your engineers, executives, and stakeholders. Members benefit from an EPRI team dedicated to finding the most clear and effective means to visualize and communicate results. Your findings will be available in a variety of forms including concise reporting, webcasts, in-person meetings, and facilitated stakeholder workshops.

MONITORING AND DATA COLLECTION

Confidence in research results often hinges upon having high-quality, reliable, and methodical approaches to data collection and management. For more than 10 years, EPRI has focused on developing a robust monitoring platform capable of scaling from a single PV system application, up to an entire substation or more. Members expect EPRI's proprietary DIAMOND system to securely catalog this measured data alongside data imported from existing systems (such as SCADA or AMI). This systematic approach to managing data ensures faster demonstrations with more accurate results.

RECENT PROJECTS

Tucson Electric Power: Project RAIN – First of kind DERMS demonstration bringing together PV, storage, and flexible loads through open standards-based communication. Product Id: 3002017454

Pacificorp: Advancing Smart Inverter Integration in Utah – In-depth look at utility strategy for smart inverters, including evaluating hosting capacity benefits, settings, and interconnection requirements. Product Id: 3002015319

Salt River Project: Advanced Inverter Project – Investigation of advanced inverter applications for voltage management in collaboration with central control systems and existing utility infrastructure. Product Id: 3002016626

INTEREST GROUPS AND MEMBER RESOURCES

SIMPLIFYING ACCESS TO INFORMATION

With so much going on in the DER area, it can be challenging to find the information you need and to stay up to date regarding the projects and learnings of other utilities worldwide. To help address this challenge, the DER Integration program facilitates a set of interest groups and maintains a number of online information resources for program members.

FIELD EXPERIENCES INTEREST GROUP

A utility interest group that meets monthly to share experiences and learnings gained through all stages of DER planning, interconnection, installation, monitoring and operation.

DERMS INTEREST GROUP

A utility interest group focused on
(1) dialogue regarding active DERMS projects, status and learnings
(2) identification of gaps and industry needs for DER management and
(3) updates from relevant conferences and standards activities (e.g. IEEE, IEC).

TSO/DSO COORDINATION FOR DER MANAGEMENT WORKING GROUP

A working group of utilities and DERMS technology providers to (1) develop standard methods, functions and messages for DER to serve bulk-system needs, and (2) develop coordination methods between ISO/TSO/DSO/aggregators to manage distribution and transmission constraints when DER are providing market services.

DER SETTINGS INTEREST GROUP

An interest group for utilities sharing and discussing issues and field experience associated with advanced autonomous functions and settings.

DER BUSINESS STRATEGY ADVISORY COUNCIL

An advisory group for guiding research, sharing insights, and exchanging ideas for improving utility DER strategy. Topics include: DER valuation, DER program design and business models, and adoption forecasting and planning.

DER RESEARCH RESULTS FINDER

An online tool at der.epri.com that allows users to perform advanced searches for available EPRI reports and resources related to DER integration.

INTERCONNECTION DOCUMENTS REPOSITORY

A searchable repository of publicly-available utility interconnection documents, including technical interconnection requirements, screening practices, and other related documents.

DERMS RFP LANGUAGE REPOSITORY

An online repository with (a) example utility RFPs for DERMS and (b) reference EPRI language for specifying select DERMS features.

DER FORUM

An online discussion forum dedicated to DER. The DER Forum, available at derforum.epri.com, provides an effective means for conducting and archiving peer-to-peer dialogue on all things DER.

DER DATA ANALYTICS REPOSITORY

A growing online repository of data analytic algorithms related to DER performance monitoring, detection, function verification and control.

DER DASHBOARDS

An available service for utilities, establishing public or private dashboards for viewing and evaluating the performance of DER plants.
See examples at dashboards.epri.com.

The Electric Power Research Institute, Inc. (EPRI, www.epri.com) conducts research and development relating to the generation, delivery and use of electricity for the benefit of the public. An independent, nonprofit organization, EPRI brings together its scientists and engineers as well as experts from academia and industry to help address challenges in electricity, including reliability, efficiency, affordability, health, safety and the environment. EPRI also provides technology, policy and economic analyses to drive long-range research and development planning, and supports research in emerging technologies. EPRI members represent 90% of the electricity generated and delivered in the United States with international participation extending to 40 countries. EPRI's principal offices and laboratories are located in Palo Alto, Calif.; Charlotte, N.C.; Knoxville, Tenn.; Dallas, Texas; Lenox, Mass.; and Washington, D.C.

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CERTIFICATE OF SERVICE

I, Paget Pengelly, hereby certify that I have this day served copies of the foregoing document on the attached list of persons.

xx by depositing a true and correct copy thereof, properly enveloped with postage paid in the United States mail at Minneapolis, Minnesota

xx electronic filing

Docket Nos. E002/M-19-166

Dated this 10th day of April 2020

/s/

____

Paget Pengelly
Regulatory Administrator

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Generic Notice	Commerce Attorneys	commerce.attorneys@ag.state.mn.us	Office of the Attorney General-DOC	445 Minnesota Street Suite 1400 St. Paul, MN 55101	Electronic Service	Yes	OFF_SL_19-666_Official
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